2022 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC ECONOMICS

Independent Market Monitor
for the Midcontinent ISO

June 9, 2023

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

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
CRA	Competitive Retail Area
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
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
RAN	Resource Availability and Need
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 *2022 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

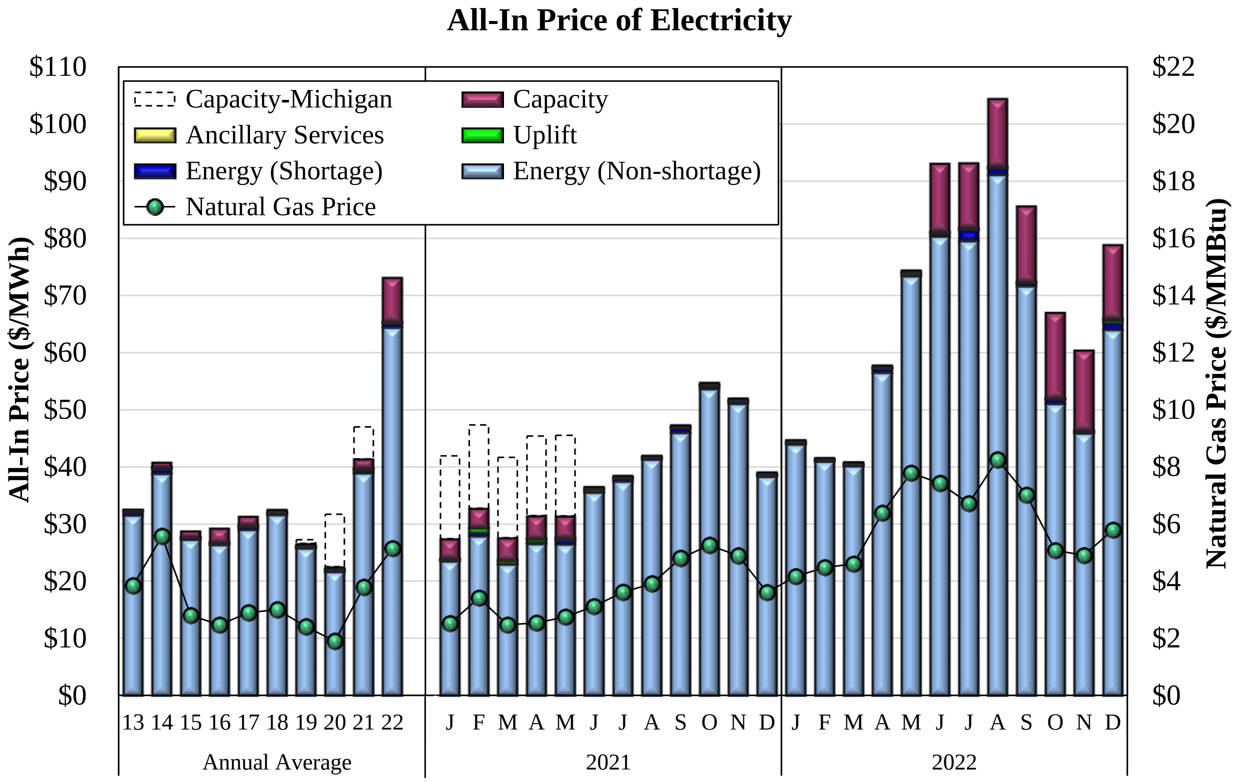
MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west, to Michigan in the east, and to Louisiana in the south. The MISO South subregion shown to the right in blue was integrated in late 2013.

MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, 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

The MISO energy and ancillary services markets generally performed competitively in 2022. Multiple factors affected market outcomes, including higher average load caused by economic growth as the effects of COVID-19 diminished, the continuing change in the resource mix, and rising natural gas prices. The figure below shows a 65 percent increase in real-time energy prices throughout MISO, which averaged $65 per MWh. Multiple factors contributed to this increase, including a 36 percent increase in natural gas prices, a reduction in coal conservation measures by the fall, the effects of Winter Storm Elliott in late December, and a 2 percent increase in average load.



Frequent transmission congestion often caused prices to diverge throughout MISO. The value of real-time congestion increased by nearly thirty percent to a record $3.6 billion in 2022, largely because of rising natural gas prices and higher wind output throughout the year. Wind output now contributes to just under half of MISO's real-time congestion. Congestion also resulted in wind curtailments averaging approximately 726 MW per hour and as high as 5.9 GW in some hours. Ten percent of this congestion occurred during Winter Storm Elliott in just two days.

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

- Conservative static ratings by most transmission owners;
- Not utilizing network reconfigurations to redirect flows around overloaded constraints;
- Issues in defining and coordinating market-to-market constraints;
- More active and larger transmission derates by MISO operators; 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.

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. As in prior years, the price-cost mark-up was effectively zero, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.2 percent of load, which is effectively *de minimus*. Consequently, market power mitigation measures were applied infrequently.

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 should be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides several recommendations, five of which are new this year. MISO has continued to respond to past recommendations and implemented several key changes in 2022.

Key changes included:

- Transitioning to a seasonal market with availability-based accreditation for conventional resources. The first auction under this new framework ran in the spring of 2023;
- Implementing changes in the reliability commitment process in late 2022 and early 2023 to reduce unnecessary resource commitments and associated RSG;
- Continuing to lower the Generator Shift Factor (GSF) cutoff for constraints, which allows a broader set of generators to be utilized to manage transmission constraints; and
- Improving the demand curves for the Short-Term Reserve (STR) product and the Ramp-Up Capability product.

These improvements have improved the performance of the markets and the operation of the system. These improvements and other recommendations are discussed throughout this report.

Winter Storm Elliott Event

MISO experienced a significant event late in the year—Winter Storm Elliott—that stressed its ability to maintain reliability and assist its neighbors. We evaluate this event because it illuminates market and operational issues that do not arise under normal conditions. During the event, widespread extremely cold temperatures simultaneously increased demand and reduced supply. MISO and most neighboring control areas experienced large load forecasting errors, causing capacity shortfalls in a number of these areas. Tight gas supply conditions contributed to the capacity shortages. These events are evaluated in Section II.E of the report.

The most serious reliability issues were experienced by TVA, which implemented rolling blackouts throughout the day on December 23. MISO provided extensive support to TVA and other neighboring LBAs, including Southern Company, AECI, SPP, and PJM. Unusually large exports and wheels contributed to more than $350 million in real-time congestion on December 23 and 24. MISO took unprecedented actions to maintain exports to its neighbors, including:

- Committing many resources to sustain the exports, even as congestion caused a large number of resources to be "stranded" behind constraints. These commitments generated more than $11 million in RSG;
- Calling a capacity emergency with no forecasted capacity deficiency in order to curtail Load Modifying Resources (LMRs) that would otherwise be unavailable;
- Deciding not to curtail non-firm exports to a number of areas that MISO's operating procedures called for it to cut; and
- Manually redispatching (MRD) generation to manage severe congestion associated with the unusually large net exports to neighboring areas.

The last action, which involves directing a unit's output to a fixed level, can be necessary when the cost of moving the resources needed is higher than the perceived value of managing the flows on the constraint. MRD is not ideal because it prevents the market from properly pricing the congestion, is often inefficient, and can generate large uplift costs. These actions generated an additional $19 million in uplift costs during the event.

Our evaluation of this event highlights opportunities for operational improvements and we provide the following recommendations for MISO to consider:

1. To avoid MRDs in the future, we recommend that MISO:
    a. Add higher-priced steps to the Transmission Constraint Demand Curves (TCDC).
    b. Improve its procedures to increase TCDCs as needed to ensure that the dispatch model will reasonably manage network flows and violations under all conditions.
2. Strengthen controls and logging to reduce deviations from its operating procedures.
3. To the extent that operating actions will be taken in the future primarily to support neighboring areas, MISO should:
    a. Modify its operating procedures to specify these actions and the requisite criteria for taking each action; and
    b. Establish operating agreements with neighboring areas to better coordinate during emergencies and to establish equitable provisions to allocate the associated costs.

Future Market Needs

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market. Although the nature and pace of the change is uncertain, MISO will have to adapt to new operational and planning needs. MISO has been grappling with these issues in several initiatives. Fortunately, MISO's markets are robust and well-suited to facilitate this transition without fundamental market changes. However, we discuss below some key improvements that will be needed as this transition occurs.

Over the past decade, the penetration of wind 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 join new wind resources in the interconnection queue. The most significant supply-side challenges 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 example, conventional resources will increasingly have to ramp up quickly in the evenings as the sun sets, particularly in the winter season since load peaks in the evening.
- *Distributed Energy Resources*: MISO is grappling with visibility and uncertainty around these resources. They are generally going to be connected to the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets.[1]
- *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 increasing economic in the future.

MISO has managed the growth in intermittent resources reliably so far, but we discuss three critical improvements in the following subsections that will be needed:

- Improving shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise;
- Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides; and
- Accrediting capacity resources based on their marginal contribution to reliability.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves rather than not serve the energy demand). When an RTO is short of reserves, the value of the foregone reserves should set the clearing price for reserves and be embedded in

1 See: 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).

all higher-value products, including energy. Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. We expect the frequency of shortages to rise in the future as intermittent output volatility increases.

The shortage value is established by the reserve demand curve for each reserve product, so efficient shortage pricing requires a properly-valued operating reserve demand curve (ORDC). An efficient ORDC should reflect the marginal reliability value of reserves at each shortage level, which is equal to: *the value of lost load (VOLL) * the probability of losing load*. Unfortunately, neither of these two components is efficiently reflected in MISO's ORDC.

Improving the VOLL. We conducted a literature review and ultimately utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. Based on this analysis, we recommend MISO update its current assumed VOLL of $3500 to an efficient VOLL of $25,000 per MWh. Although we support this value as the basis for an efficient ORDC, we believe it would be reasonable to cap the maximum ORDC at a lower value (e.g., $10,000) because: (i) very few shortages would be priced in this range; (ii) pricing shortages at higher prices could result in inefficient interchange with MISO's neighbors who price shortages at lower levels; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

Improving the Slope of the ORDC. The slope of the ORDC should be determined by how the probability of losing load changes as the level of operating reserves falls. We estimated the probability of losing load using a Monte Carlo model that simulated: generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty. Considering all these factors produces a flatter slope for the ORDC than MISO's current approach. Adopting this approach to determine the ORDC slope along with a reasonable VOLL will result in more efficient economic signals to govern both short-term and long-term decisions by MISO participants.

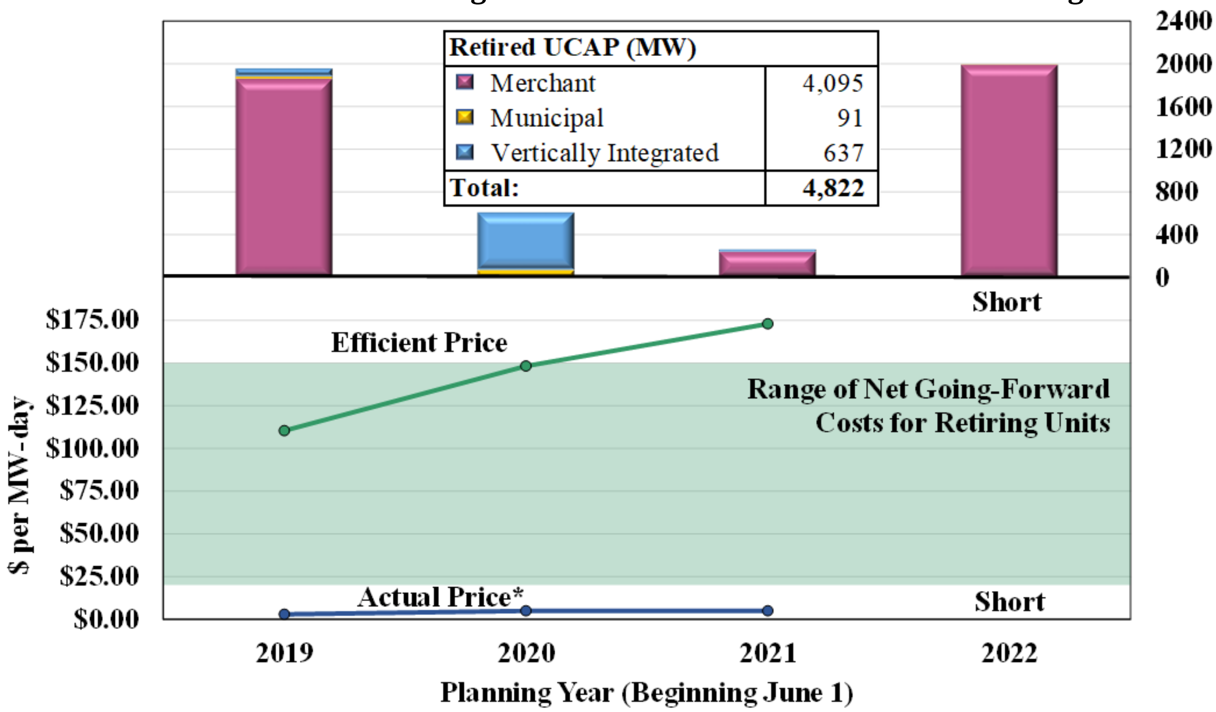
Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets is to reform the capacity market so it provides efficient economic incentives. These reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy. The problem is that the demand for capacity does not reflect its true reliability value. The fixed quantity of required demand subject to a deficiency price represents a "vertical demand curve." The implication of a vertical demand curve is that the first MW of surplus capacity beyond the minimum requirement has no reliability value. Clearing prices under a vertical demand curve (where it intersects supply) will be close to zero when the market has even a small surplus.

In reality, each unit of surplus capacity above the minimum requirement will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. Hence, the true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve, which will set capacity prices that reflect this marginal reliability value.

The effect of setting inefficiently low prices has manifested in a shortage in the Midwest region in the 2022/2023 PRA by facilitating a sustained trend of retirements of resources that would have been economic to remain in operation. This outcome is demonstrated in the following figure, which shows: a) the economic capacity in the Midwest (by type of participant) that retired each year; b) the actual capacity prices compared to our estimate of an efficient capacity price in each year; and c) the range of net going-forward costs that resources would have needed to recover in the capacity auction to avoid suspension or retirement.

Inefficient Auction Clearing Prices and Retirements in the Midwest Region



* Actual prices are the unconstrained auction clearing prices of the Midwest. Zone 7 separated in 2019 and 2020.

Most of the inefficient retirements over the past four years were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from MISO's inefficient capacity prices. MISO's poor capacity market design led to a shortage of resources in the 2022/2023 PRA in the Midwest. MISO was not short in the 2023/2024 PRA as its load forecast and requirements fell and some new capacity resources entered. However, we expect this design flaw to cause the region to struggle to maintain adequate resources.

In conclusion, implementing a reliability-based demand curve should be one of MISO's highest priorities under its Reliability Imperative because it will:

- Establish stable and efficient capacity prices to govern investment and retirement decisions, which is particularly important for unregulated competitive suppliers;
- Ensure that participants supplying more than their share of the required capacity in MISO receive capacity revenues that reflect their contribution to the system's reliability needs (this is most vertically integrated utilities whose regulated retail customers currently support the bulk of the costs of MISO's generating resources); and
- Provide incentives for load-serving entities (LSEs) that do not have sufficient capacity to plan better by contracting for existing capacity or building new capacity.

Improving MISO's Capacity Accreditation

A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. This value depends on (a) the timing of the system's hours of greatest need and (b) the factors that affect the availability of a resource in those hours. Importantly, the hours of greatest need are affected by the portfolio of generation and the output profile of the portfolio – this value can be characterized as a "marginal value". For resources to be accredited accurately, RTOs must utilize methods that determine their marginal value.

MISO's recently implemented availability-based accreditation is generally consistent with this principle because it measures resources' availability during the tightest hours, which are determined by the operating characteristics of the existing generation portfolio. Intermittent resources are generally accredited using methods that predict the expected output of the resources under different conditions. One such method is the Expected Load Carrying Capability (ELCC) used by MISO, although its current approach is not marginal.

If MISO fails to accredit resources based on their marginal value, the inflated accreditation to low-value (over-saturated) resources will substantially increase costs to consumers and undermine incentives to the resources with high-value attributes that the system needs. Additionally, accurate accreditation will inform the states' integrated resource planning processes and ensure that these processes produce resource plans that will satisfy the reliability needs of the MISO region. For all of these reasons we find that accrediting all resources based on their marginal reliability value is essential for satisfying MISO's reliability imperative.

Other Important Market Design Improvements

As MISO's generating fleet transforms, its markets will play an essential role in integrating new resources and maintaining reliability. Improving shortage pricing, the capacity demand curve, and capacity accreditation are the highest priority changes. However, Section II.B of the report recommends other important improvements to account for the rising system uncertainty and to improve the utilization of the network as transmission flows become more volatile. These are changes that will be key for successfully navigating the transition of MISO's portfolio:

- Introduction of an uncertainty product to reflect MISO's current and future need to commit resources to have sufficient supply available in real time to manage uncertainty;
- Implementation of a look-ahead dispatch and commitment model in the real-time market;
- Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
- Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives.

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 day-ahead prices converge with real-time prices, because this will result in resource commitments that efficiently satisfy the system's real-time operational needs. In 2022:

- The difference between day-ahead and real-time prices, including day-ahead and real-time uplift charges, was roughly 3 percent. This is good convergence overall.
- 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. Average cleared virtual transactions in the Midwest and South increased by 36 and 15 percent in 2022, respectively. Our evaluation of virtual transactions revealed:

- The vast majority of the virtual trading was by financial participants whose transactions were the most price sensitive and the most beneficial to the market;
- Most of the virtual transactions improved price convergence and economic efficiency in the day-ahead market based on our detailed assessment of the transactions; and
- 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.

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 reliance on revenue from the capacity market to maintain resource adequacy. Hence, improving MISO's ORDC is 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. Initially, ELMP's effectiveness was limited, but MISO has implemented a number of our recommendations in recent years. Section IV.C of this report shows that the average effects of ELMP on MISO's real-time energy prices rose 24 percent to $1.45 per MWh in 2022. While some of this increase is due to the effects of Winter Storm Elliott in December and higher natural gas prices, much of it is due to the recent ELMP changes.

In addition to FSRs, emergency actions and emergency resources can set prices in ELMP during emergencies. In 2021, MISO implemented our recommendations to expand the set of resources that can set prices during an emergency event[2] and increased the default minimum offer floors for emergency resources. These changes significantly improved MISO's emergency pricing.

However, pricing when large quantities of LMRs are deployed is still problematic because the ELMP model cannot ramp other units up quickly enough to replace them. Hence, they can set inefficiently high prices when they are no longer needed. This causes excessive non-firm imports, increased settlement costs, and inflated DAMAP uplift payments to resources that must be held down at overstated prices to make room for the imports and load curtailments. To address this concern, we recommend MISO reintroduce LMR curtailments as an STR demand in the ELMP model instead of energy demand. This will allow the ELMP model to more accurately determine whether they are needed without manipulating the energy dispatch.

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

Evaluating uplift costs is important because they are difficult for customers to forecast and hedge, and generally reveal areas where the market prices do not fully capture the needs of the system. Most uplift costs are the result two primary forms of guarantee payments made to ensure resources cover their as-offered costs and provide incentives to be 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. Day-ahead RSG payments fell 25 percent to total $65 million. However, excluding the effects of Winter Storm Uri in 2021, day-ahead RSG fell 9 percent from last year. As usual, almost all day-ahead VLR costs were accumulated in two load pockets in MISO South.

2 Resources offering up to a four hour start and minimum run time may now set the price during emergencies.

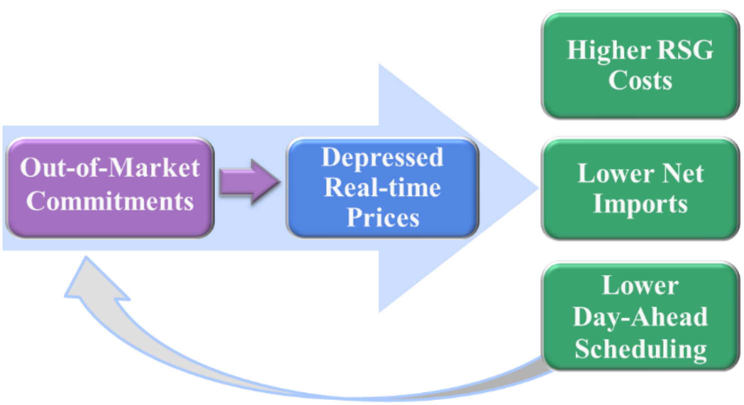
Real-time RSG. Real-time RSG payments fell 40 percent in 2022, largely because RSG payments generated in Winter Storm Uri in 2021 were around $125 million, dwarfing the real-time RSG payments of $24 million paid in Winter Storm Elliott in 2022.

Real-Time Commitment Patterns

Out-of-market commitments by MISO account for most of the RSG incurred in real time, which we assess in Section IV.E of this report. This assessment reveals a pattern of increasing capacity-related commitments beginning in the summer months. During the summer quarter, MISO's day-ahead and real-time RSG payments more than doubled over the prior year. Our evaluation showed that of the RSG costs incurred to maintain sufficient capacity (rather than to manage congestion or satisfy local reliability needs):

- Only 7.5 percent was associated with real-time commitments that were actually needed;
- Another 37 percent appeared to be needed when the commitment decision was made; and
- More than 50 percent was associated with excess commitments that were not forecasted to be needed. More than a third of the excess is associated with resources being started earlier than needed or not being decommitted when they are no longer needed.

These results indicate opportunities for substantial improvements in MISO's commitment processes. This is important because excess out-of-market commitments undermine the markets by creating a self-enforcing cycle of excess commitments. They tend to depress real-time prices, which increases RSG costs and reduces supply – increasing the need for more out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 97.5 percent of peak real-time load in 2022), and b) reduce net imports in the real-time market.



We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have recommended a number of improvements designed to reduce the frequency of unnecessary commitments, including:

- Eliminating the use of manual inputs to the LAC model to address uncertainty since they cause it to recommend unnecessary commitments, increasing STR requirements instead.
- Deferring commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Use reserve demand curves and TCDCs in the LAC and other commitment models that are more closely aligned with the market demand curves.

MISO has created a team to evaluate existing tools and operating practices and has begun working with the IMM to make recommended changes. Improving operator logging is also important because it will facilitate better understanding of the causes of excess commitments.

Real-Time Generator Performance

We monitor and evaluate the poor performance of some generators in following MISO's dispatch instructions on an ongoing basis. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) averaged nearly 1,000 MW and almost 1300 MW in the worst 10 percent of hours. This continues to raise economic and reliability concerns because these deviations are often not detected by MISO's operators. The largest source of dispatch deviations are wind resources, which is due to: (a) forecast errors and (b) the fact that wind resources causing congestion are often indifferent to following dispatch. Section IV.I. provides an example of the latter. Such deviations can result in severe transmission violations and compel MISO to use out-of-market actions.

To address this issue, we propose a deviation penalty based on the marginal congestion component (MCC) of the resource's LMP that is described in Section IV.G. For deviations that load a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is appropriate because it reflects the congestion value of the deviation volumes and scales with the severity of congestion. Our analysis of this proposal shows that it would produce very small penalties for most types of resources, but the largest penalties for the wind resources that are deviating and causing constraint violations. In summary, the proposed penalties will improve dispatch incentives for all resources, but particularly for those whose deviations cause the most serious reliability concerns.

Coal Resource Operations

As natural gas and energy prices rose during the summer months of 2021, the economic operating margins of MISO's coal-fired resources rose substantially and caused them to operate economically at higher capacity factors than in 2020. This also resulted in more frequent starts and higher output in 2021 until fuel limitations and other supply chain issues compelled many coal resources to begin running less to conserve coal. Many coal resources began engaging in coal conservation strategies in late 2021 that persisted through most of 2022. The coal supply chain issues began to dissipate in the fall of 2022. Apart from this issue, coal units generally operated economically, although regulated utilities designated their units "must-run" roughly half of their operating hours. This compels the market to dispatch them and has resulted in them running uneconomically in seven percent of their operating hours.

Wind Generation and Forecasting

Installed wind capacity now accounts for over 30 GW of MISO's installed capacity and produced 13 percent of all energy in MISO in 2022. Wind output also increased by 23 percent compared to 2021 and almost 75 percent over the past three years to average 11.3 GW per hour. MISO set a new all-time wind record on November 30 at 24 GW. These trends in wind output are likely to continue for the next few years as investment remains strong. The report identifies a number of operational and market issues associated with the growth of wind resources.

Day-Ahead Scheduling. Wind suppliers generally under-schedule wind in the day-ahead market, averaging roughly 1,200 MW less than their real-time output. This can be attributed to the suppliers' contracts and the financial risk related to being allocated RSG costs when day-ahead wind output is over scheduled. Under-scheduling can create price convergence and resource commitment issues. These issues are partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers.

Real-Time Wind Forecasting. One of MISO's operational challenges is the large dispatch deviations that can be caused by wind forecast errors. The unit's forecast is used by MISO to set the unit's dispatch maximum and, because wind offer prices are low, the forecast also tends to determine the dispatch level. Dispatch deviations caused by wind forecast errors contribute to higher congestion and under-utilization of the transmission network, supply and demand imbalances, and cause non-wind resources to be dispatched at inefficient levels.

Most wind resources rely on the MISO forecast in real-time, which we evaluate in this report. We find that MISO's simple persistence forecast (i.e., the most recently observed wind output will continue) tends to often produce large errors. We developed a forecast methodology that is also persistence-based, but also incorporates the recent direction in output changes. Our analysis of this approach shows that this modest change would substantially improve the MISO forecast – reducing the frequency of the highest portfolio-level errors by more than 90 percent, while reducing the highest average unit-level errors by 45 percent. Improving the forecast of wind resources' output will be increasingly important as the penetration of intermittent resources increases. We recommend that MISO implement such a change in forecast methodology.

Transmission Congestion

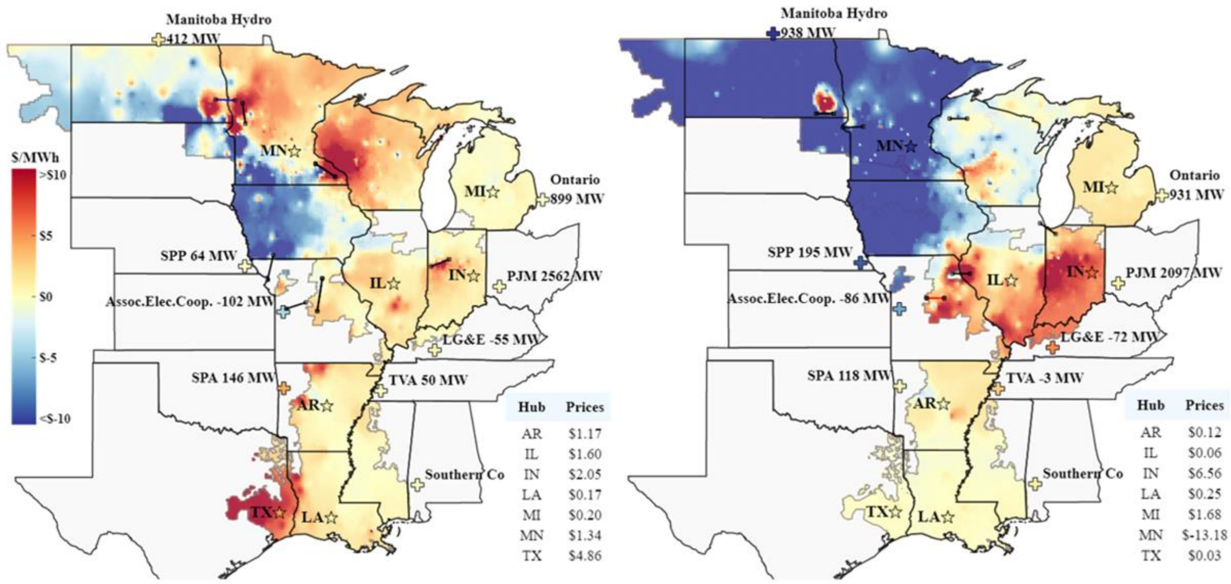
Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location given the marginal energy costs, network congestion, and losses. Because most transactions are settled through the day-ahead market, most congestion costs are collected in this market. The maps below show the changes in congestion patterns between 2021 and 2022.

Congestion Costs in 2022

The value of real-time congestion rose 30 percent in 2022 to $3.7 billion. The maps below show where the congestion became more severe in 2022.

Average Real-Time Congestion Components in MISO's LMPs

2021 **2022**



The substantial increase in real-time congestion was caused be the following factors:

- A substantial increase gas prices, beginning in the spring quarter, contributed to much of this increase because it raised the cost of re-dispatching natural gas-fired generation.
- Roughly $360 million of this increase was related to severe congestion that occurred during Winter Storm Elliott over just two days in December.
- Transmission constraints loaded by wind resources accounted for an increasing level of real-time congestion— exceeding $1.5 billion in 2022—because of the continued entry of new wind resources in MISO, SPP, and PJM that increase loadings on key constraints.
- Available relief on wind-related constraints has fallen in recent years because of the retirement of some key coal and gas-fired resources.
- Higher imports from Manitoba occurred in 2022, where in 2021 hydro output has been limited by drought conditions.

Not all of the $3.7 billion in real-time congestion cost is collected by MISO through its markets, primarily because there are loop flows caused by external areas and flow entitlements granted to PJM, SPP, and TVA under JOAs, resulting in uncompensated use of MISO's network. Hence, day-ahead congestion costs increased by 35 percent to $2.2 billion in 2022.

Day-ahead congestion revenues are used to fund MISO's FTRs. FTRs represent the economic property rights associated with the transmission system and serve as a hedge against day-ahead congestion costs. If the FTRs issued by MISO are physically feasible (do not imply more flows over the network than the limits in the day-ahead market), then MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs—to pay them 100 percent of the FTR entitlement. FTRs were fully funded in 2022.

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 more than $1 billion in real-time congestion costs in 2022 – 30 percent of real-time congestion costs. We continue to recommend 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 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). As a result, MISO often uses lower fixed ratings, which reduces MISO's utilization of its transmission network. We estimate MISO could have saved over $540 million in congestion costs in 2022 by using temperature-adjusted and emergency ratings. In late 2020, FERC issued a proposed rule that would make this a requirement. We urge MISO to work with the TOs to provide such improved ratings in a more timely manner than required by the Rule.

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. This is done currently to mitigate reliability concerns under procedures established with the transmission owners impacted by the reconfiguration. Such procedures should be expanded to economically manage congestion. The report illustrates examples of constraints that generated tremendous amounts of congestion and compelled sizable and sustained wind curtailments.

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. Congestion on MISO's M2M constraints nearly doubled to total $2 billion in 2022, which was more than 30 percent of all congestion in MISO. Because there are so many MISO constraints that are affected by generators in SPP and PJM, it is increasingly important that M2M coordination operate as effectively as possible.

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), which is responsible for managing the constraint. Our analysis of M2M coordination provided the following findings:

- M2M coordination has generally contributed to shadow price convergence over time and lowered costs of managing congestion. However, we also find that coordination could be improved with three key changes and deliver substantial additional savings.
- *Relief request software*. Improving the software used to determine the amount of relief requested by the MRTO from the NMRTO will provide significant savings. The current process often produces suboptimal relief quantities that prevent the NMRTO from providing all available economic relief or can cause a constraint to oscillate from binding to unbinding. Based on our analysis of this issue with SPP, we believe improving the relief requests would generate well over $100 million in annual savings.
- *Five-percent test*: Constraints are identified as M2M constraints if the NMRTO has substantial market flows on the constraint or has a single generator with a GSF greater than five percent on the constraint. The five percent test has frequently resulted in constraints designated as M2M constraints for which the benefits of coordinating are extremely small. Hence, we recommend that MISO replace the current five-percent test with a test based on the NMRTO's relief capability on the constraint.
- *Automation of the M2M Processes*. MISO has made progress in improving the M2M processes over the years, particularly in the area of testing new constraints in a timely manner. Given that much of this process continues to be implemented manually, there are still significant opportunities to improve the timeliness with which constraints are tested and activated by expanding the automation of the M2M processes.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

The capacity surplus MISO had enjoyed prior to the 2022/2023 Planning Year dwindled in recent years as the retirements of baseload resources have mostly been replaced with intermittent renewable resources. In 2022:

- 4 GW of resources retired or suspended operations in MISO, comprised mostly of coal, gas steam, and nuclear resources. The continuing trend of suspensions and retirements into the 2022/2023 Planning Year resulted in a capacity shortage in the Midwest region.

- 2 GW of new unforced capacity entered MISO, including a 1.1 GW natural gas-fired combined-cycle in the Central region. 2.8 GW (nameplate) of wind resources were added in 2022, providing 380 MW of unforced capacity. 600 MW of solar unforced capacity entered, primarily in the North and Central regions.

MISO was not short of capacity in the 2023/2024 PRA as its load forecast and requirements fell and some new capacity resources entered. Nonetheless, we expect the retirement trends above to continue and for MISO to continue to struggle to maintain adequate resources if it does not improve the price formation in its capacity market. These price formation issues discussed above substantially affect the net revenues available to new and existing resources in MISO, which is discussed in the next subsection.

Long-Term Signals: Net Revenues

Market prices should provide 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 2022.

We find net revenues rose in almost all regions in 2022 as rising natural gas prices contributed to higher energy and ancillary services prices throughout MISO. High capacity prices and congestion caused net revenues for new combustion turbines and combined-cycle resources to generally exceed their cost of new entry in most of the Midwest region. This is not likely to be sustained given the falling capacity prices and natural gas prices in early 2023. In other areas, including all of the South, net revenues were well short of those needed to support investment in new resources. This is largely a result of the market design issues described above.

PRA Market Design

MISO has implemented two significant changes in its capacity market to more effectively and efficiently satisfy its resource adequacy requirements – (i) a seasonal capacity market; and (2) an availability-based accreditation for thermal resources. We provided extensive feedback and analyses to MISO in the implementation of these changes. The first PRA with these changes occurred in early May and while it could have gone more smoothly, the results were consistent with the design of the market. We have identified elements of these new designs that could be improved in the future and will continue to discuss them with MISO and its participants.

We have also recommended several other improvements to the PRA. A number of these changes involve improving the accuracy of the supply and demand in the PRA, including:

- Disqualifying energy efficiency from selling capacity in the PRA or improving Tariff provisions to help ensure that they provide some value to MISO;
- Improving the accreditation rules for emergency-only resources in the PRA; 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.

We will continue to discuss these improvements with MISO along with the high-priority changes to the capacity demand curve and accreditation methodologies that will allow the MISO region to remain reliable as its generation fleet transitions.

Long Range Transmission Planning

In July of 2022 the MISO Board approved $10.3 billion of Long Range Transmission Plan (LRTP) projects. The LRTP Tranche 1 evaluation focused on the most clearly beneficial projects as well as projects that could use existing rights-of-way. As MISO moves towards evaluating Tranche 2 of the LRTP, it will be increasingly important to accurately evaluate the costs and benefits of the transmission investments to avoid costly, inefficient investments. This is also becoming important for the MTEP process as costs have risen sharply in recent years.

This is critical because inefficient investment in transmission can undermine incentives that govern other long-term decisions that address congestion at a fraction of the costs of the transmission upgrades. These long-term decisions include generation investment and retirement decisions, investment in energy storage and grid-enhancing technologies, and improved siting decisions by new clean energy resources. We provide several recommendations in this report to improve the evaluation and selection of projects in future LRTP tranches.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2022, importing an average of 4.2 GW per hour in real time, down from 4.6 GW in 2021. MISO's imports from PJM in 2022 averaged 2.2 GW per hour, down 20 percent from 2021. 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 efficient external transaction scheduling. We also assess the coordination of interchange with PJM. Efficient interchange is essential because poor interchange can reduce dispatch efficiency, increase uplift costs, and sometimes create operating reserve shortages.

Interface pricing. To calculate an accurate congestion price at the interface, an RTO must assume the sources or sinks in the neighboring area (referred to as the "interface definition"). Ideally, RTOs would assume sources and sinks throughout each RTO's footprint since this is what happens in reality. Unfortunately, MISO agreed to adopt a "common interface" definition for the PJM interface in June 2017 consisting of 10 generator locations near the PJM seam. This has increased interface price volatility, resulted in less efficient imports and exports, and raised costs for customers in both regions. Hence, we encourage MISO to consider revising its interface pricing with PJM to match our recommended pricing for the SPP interface.

At the SPP interface, we have verified that redundant congestion pricing is occurring based on their overlapping interface definitions. In other words, when an M2M constraint binds in both markets, both RTOs will settle with an importer/exporter at the full congestion value of the constraint in each respective market. This results in duplicative payments/charges and inefficient incentives to schedule imports or exports. We encourage MISO to adopt an efficient interface pricing method at the SPP interface and its other interfaces by removing all external constraints from its interface prices (i.e., pricing only MISO constraints). If SPP does the same, the redundant congestion issue will be eliminated, and the interface prices will be efficient.

Interchange Coordination. Coordinated Transaction Scheduling (CTS) is the most promising means to improve interchange coordination. CTS allows participants to submit offers to transact within the hour if the forecasted spread in the RTOs' real-time interface prices is greater than the offer price. MISO worked with PJM to implement CTS on October 3, 2017. The participation in CTS has been minimal because of high transmission charges and persistent forecast errors have likely deterred traders from using CTS. Hence, it has produced very little of the sizable savings it could generate. To improve the CTS process, we recommend that MISO:

- Eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same;
- Modify the CTS to clear transactions every five minutes through the real-time dispatch model based on the most recent five-minute prices in the neighboring RTO area; and
- Implement a CTS process with SPP based on this type of five-minute clearing process.

Our analysis of the benefits of this change in Section VII.B of this report shows that it would have raised the production cost savings in 2022 of the CTS process with PJM from actual savings of $3 million under the current approach to more than $100 million under the 5-minute adjustment approach. We estimate savings of $63 million for a similar approach with SPP. This would also improve incentives for participants to utilize CTS because profits would have exceeded $60 million versus only $76,000 under the current approach at the PJM interface.

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy. MISO had 12 GW of DR resources in 2022, which included 4.2 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. MISO has recently made several changes to improve the accessibility and information on the availability of LMRs. These changes are discussed in Section IX.A. Although they are clear improvements, we still have concerns that LMRs are not as accessible or as valuable as generating resources from a reliability perspective. Hence, we recommend MISO make further accreditation improvements for LMRs.

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;[3] 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 schedules and the associated payments fell 34 percent 2022 as resources we previously identified as engaging in problematic conduct ceased participation in MISO. Almost all of the payments to these resources produced no meaningful demand curtailments and were largely the result of opportunistic conduct. To address this issue, we recommended two potential improvements to provide more efficient incentives and ensure all payments are justified:

- DRRs should be obligated to submit their anticipated consumption absent any curtailments, which could be the basis of legitimate settlements. This could be monitored to identify when a participant has submitted inaccurate data to inflate their settlements.
- MISO should establish a price floor that is significantly higher than typical LMPs, which would effectively preclude the strategies we detected. This is reasonable because a load could just not consume at the current price rather than offer curtailments as a price-taker.

Emergency Demand Response Resources (EDRs). These are called in emergencies, but not obliged to offer and do not satisfy capacity requirements unless cross-registered as LMRs.

Energy Efficiency (EE). MISO also allows energy efficiency to qualify to provide capacity. It is important that payments to EE be justified, and that the accreditation of EE is accurate. We have concerns in both regards, finding that:

- Making capacity payments for assumed load reductions provides compensation that is redundant to customers' retail electricity bill savings and is, therefore, not efficient;
- MISO must be able to accurately calculate how much the load has been reduced by EE in peak hours, which is inevitably based on an array of speculative and highly uncertain assumptions; and
- The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE.

To evaluate the accuracy of the claimed savings, the IMM performed an audit of EE capacity that had been sold in the PRA in prior years. Based on this audit, we found that (a) The EE resources audited did not actually reduce MISO's peak demand, (b) virtually all of the claimed savings were associated with product purchases by others that would have occurred without the EE resource, and (c) the claimed savings were not reasonably verified as the Tariff requires.

[3] 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.

These findings are unfortunate because MISO's customers paid more than $17 million to these resources in a prior PRA and received virtually nothing in return. Since MISO's EE program is not addressing a known inefficiency and the quantities are difficult to accurately estimate or verify, we have recommended that MISO disqualify EE from selling capacity. Alternatively, MISO should make Tariff changes to ensure that any payments to EE resources are justified.

Table of Recommendations

Although the markets performed competitively in 2022, we make 31 recommendations in this report intended to further improve their performance. Five are new this year, while 23 were recommended previously. MISO addressed three of our recommendations since our last report.

The table below shows the recommendations organized by market area. They are numbered to indicate the year in which they were introduced and the recommendation number in that year. We also indicate whether each would provide high benefits and can be achieved in the near term.

SOM Number	Recommendations	High Benefit	Near Term
Energy and Operating Reserves and Guarantee Payments			
2021-2	Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS.		
2021-5	Modify the Tariff to improve rules related to demand participation in energy markets.		✓
2020-1	Develop a real-time capacity product for uncertainty.		
2016-1	Improve shortage pricing by adopting an Operating Reserve Demand Curve reflecting the expected value of lost load.	✓	✓
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		
Transmission Congestion			
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 testing criteria defining market-to-market constraints.		
2019-3	Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities.	✓	
2016-3	Enhance authority to coordinate transmission and generation planned outages.		

SOM Number	Recommendations	High Benefit	Near Term
2014-3	Seek joint operating agreements with the control areas around MISO to improve congestion management and coordination during emergencies.		
Market and System Operations			
2022-2	Improve the real-time wind forecast by adopting enhancement to its current persistence forecasting methodology.	✓	✓
2022-3	Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions		
2021-3	Evaluate and reform the unit commitment processes.	✓	✓
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	Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices.	✓	
2018-4	Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions.		✓
2017-2	Remove transmission charges from CTS transactions.	✓	✓
2017-4	Improve operator logging tools and processes related to operator decisions and actions.		
2016-6	Improve the accuracy of the LAC recommendations and record operator response to LAC recommendations.		✓
Resource Adequacy and Planning			
2022-4	Improve the LRTP processes and benefit evaluations.	✓	✓
2022-5	Implement jointly optimized annual offer parameters and improve outage penalty provisions in the seasonal capacity market.		
2020-4	Develop marginal ELCC methodologies to accredit DERs, LMRs, battery storage, and intermittent resources.	✓	
2019-5	Improve the Tariff rules governing Energy Efficiency and their enforcement.		✓
2017-7	Establish PRA capacity credits for emergency resources that better reflect their expected availability and deployment performance.		
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.		
2010-14	Improve the modeling of demand in the PRA by implementing reliability-based demand curves.	✓✓	✓

I. Introduction

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. This annual report summarizes this evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets that are 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 Markets – that utilize the lowest-cost resources to satisfy the system's demands and manage flows over the transmission network, while providing economic signals to govern short- and long-run decisions by participants.

Financial Transmission Rights (FTRs) – that are funded by the congestion revenues collected through the MISO markets and allow participants to hedge congestion costs by entitling holders to the day-ahead congestion costs paid between locations.

Ancillary Services Markets (ASM) – that include contingency reserves and regulation that are jointly optimized with the energy market to schedule resources and price shortages efficiently.

Capacity Market – that is implemented through the Planning Resource Auction (PRA) to compensate resources for meeting resource adequacy. The capacity market requires reform to facilitate efficient investment and retirement decisions.

The energy and ancillary services markets provide a robust foundation for the long-term challenges that lie ahead. Our evaluation of the markets' performance in 2022 reveals that the markets performed competitively with no substantial evidence of market manipulation or market power abuses. Nonetheless, we identify a number of potential improvements in the design and operation of the markets that would allow them to operate more efficiently and provide better economic signals to market participants.

MISO continued to respond to our past recommendations, allowing the markets to evolve to meet the changing needs of the system. Key changes or improvements during 2022 included:

- Critical changes to MISO's Resource Adequacy construct include moving toward a seasonal market and availability-based accreditation. The first auction under this new framework ran in the Spring of 2023.

- Changes to the demand curves for the Short-Term Reserve (STR) product and the Ramp-Up Capability product.

- The implementation of some changes in the reliability commitment process in late 2022 and early 2023 to reduce unnecessary commitments of resources and associated RSG.

These changes should improve the performance of the markets and the operation of the system. We discuss these improvements in more detail throughout the remaining sections of this report. While these improvements are valuable, we also identify and continue to recommend essential changes to MISO's shortage pricing, capacity market design, and congestion management. MISO is currently working on each of these changes, as they promise to provide substantial short-term benefits. More importantly, they will position MISO to successfully navigate the transition of its fleet to much higher reliance on intermittent and energy storage resources.

These and our other recommendations are listed and discussed in Section X of the report, which describes the status of each existing recommendation and identifies recommendations that have been addressed by MISO over the past year.

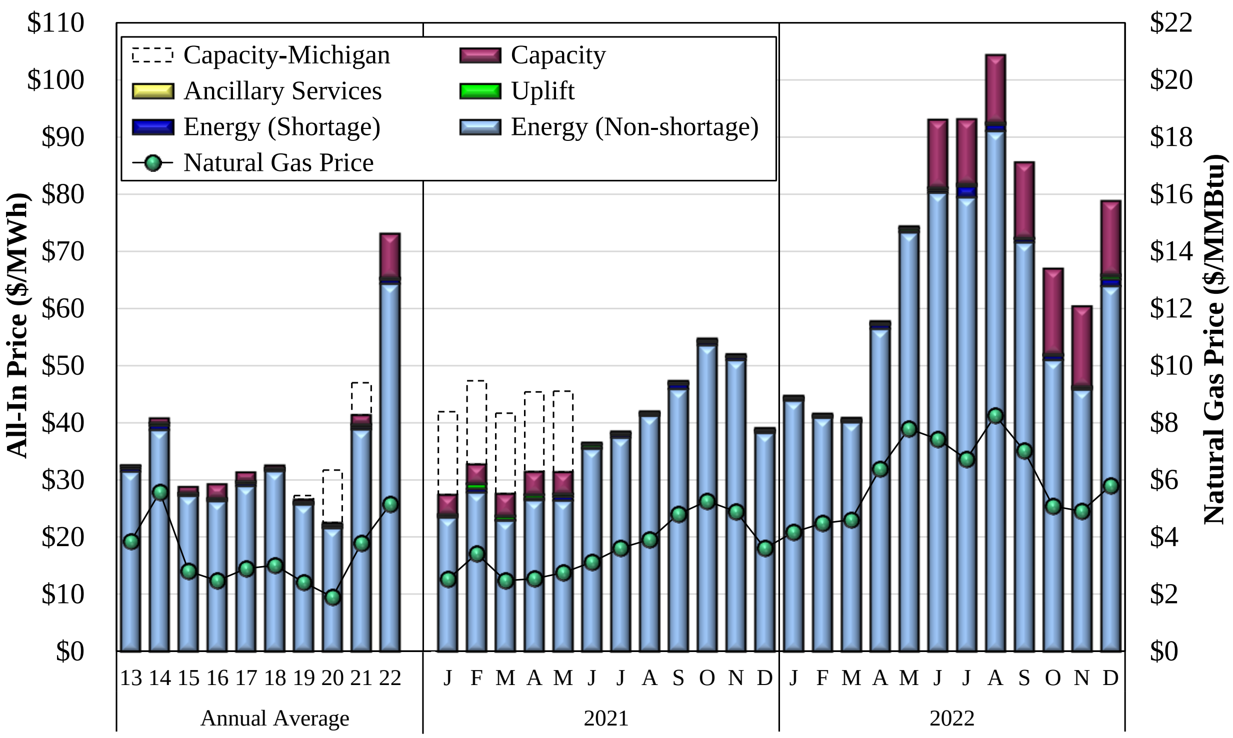
II. Price and Load Trends

MISO's wholesale electricity markets in the day-ahead and real-time timeframes facilitate the efficient commitment and dispatch of resources to satisfy the needs of the MISO system. The resulting prices also play a key role in providing short- and long-term incentives for MISO's participants. This section reviews overall prices, generation, and load in these markets.

A. Market Prices in 2022

Figure 1 summarizes changes in energy prices and other market costs by showing the "all-in price" of electricity, which is a measure of the total cost of serving load from MISO's markets. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[4] We separately show the portion of the all-in price that is associated with shortage pricing, as well as the higher all-in price components associated with the much higher capacity price in Michigan in the 2020/2021 planning year in the transparent bars. Figure 1 also shows average natural gas prices to highlight the trend in the relationship between natural gas and energy prices.

Figure 1: All-In Price of Electricity
2021–2022



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

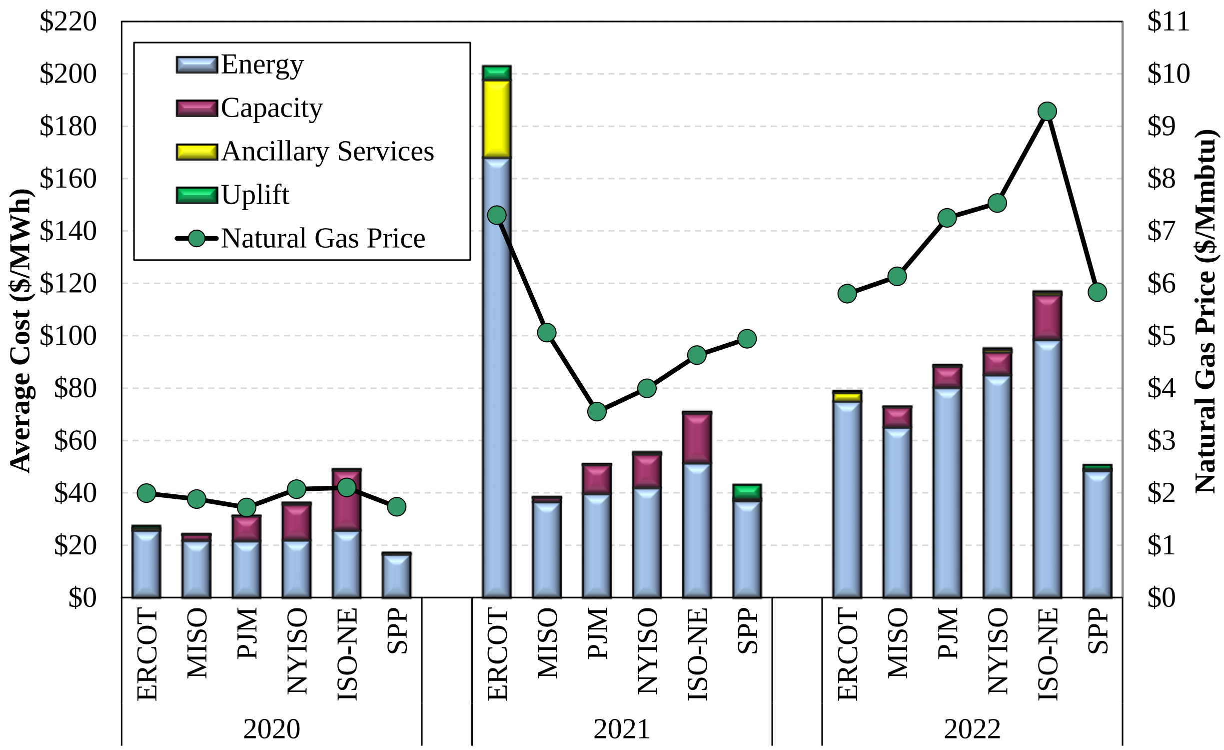
The all-in price rose 77 percent in 2022 to an average of $73 per MWh. This increase was largely caused by rising fuel prices and the effects of the Winter Storm Elliott.

- Energy prices rose 65 percent to the highest level in the last ten years as natural gas prices increased 36 percent. Coal supply chain limitations contributed to higher prices because coal conservation measures raised the costs of a large share of the coal fleet.
- Shortage pricing rose 57 percent over last year partly because MISO eliminated the $200 per MWh step on the Operating Reserve Demand Curve (ORDC) in late 2021.
- The ancillary services component contributed only $0.16 per MWh.
- The capacity component of the all-in price rose nearly five times over 2021 because the Midwest region cleared at CONE in the 2022/2023 capacity auction.
- The uplift component of the all-in price fell 34 percent to $0.21 per MWh.[5]

The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected because fuel costs are the majority of most suppliers' marginal production costs. In competitive markets, suppliers have strong incentives to offer at their marginal costs, so fuel price changes result in comparable offer price changes. To compare these results to other RTOs, Figure 2 shows the all-in prices in the Eastern RTOs and ERCOT.

Figure 2: Cross Market All-In Price Comparison

2020–2022



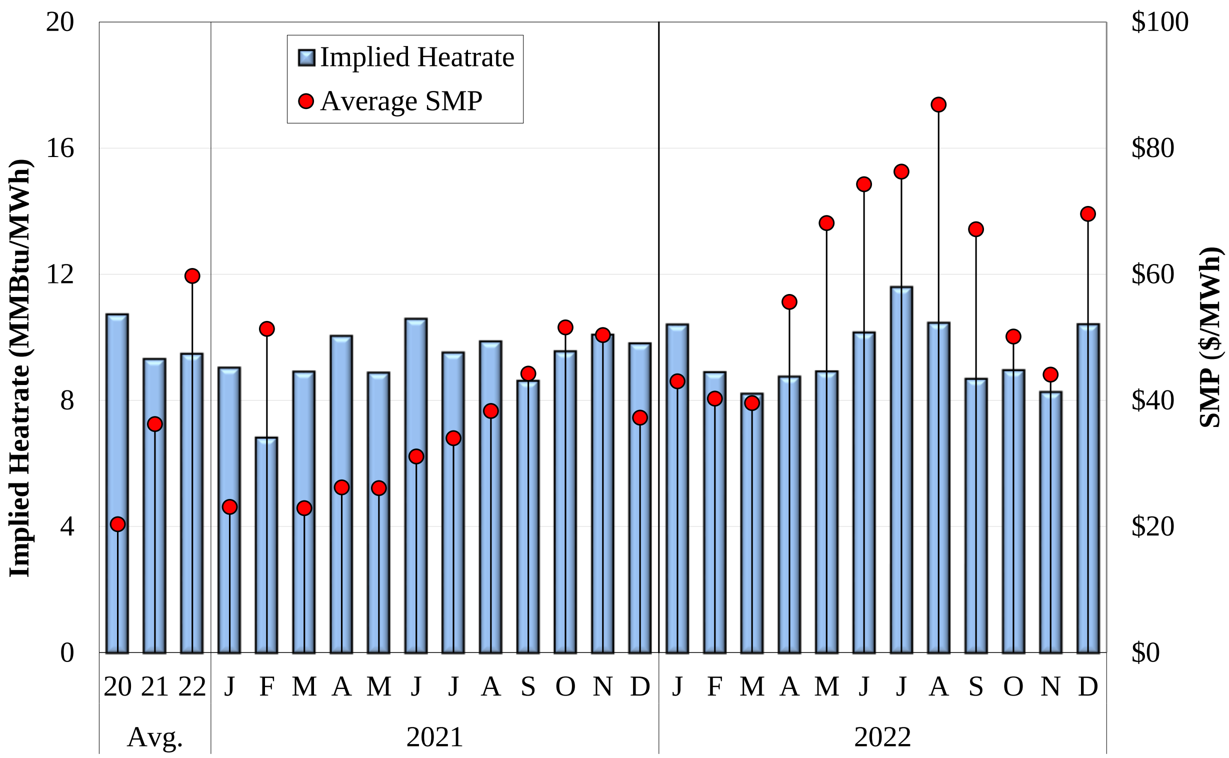
5 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs).

Each of these RTO markets have converged to similar market designs, including nodal energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT). However, the details of the market rules can vary substantially. The market prices and costs in different RTOs can be affected by the types and vintages of the generation, the input fuel prices and availability, and differences in the transmission capability of the network.

In Figure 2, MISO exhibits among the lowest all-in prices because of its low natural gas prices and weak shortage pricing, even though the capacity market cleared in shortage in June 2022. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. ISO New England's high capacity prices were largely due to load being over-forecasted in its 3-year ahead forward capacity market. Its relatively high energy prices are caused by higher gas prices that reflect pipeline constraints.

To estimate the effects on prices of factors other than the change in fuel prices, we calculate an "implied marginal heat rate". This is calculated by dividing the real-time energy price by the natural gas price. Figure 3 shows the monthly and annual average implied marginal heat rates in recent years.[6]

Figure 3: Implied Marginal Heat Rate
2021–2022



While the nominal SMP in 2022 increased by 65 percent relative to 2021, the implied marginal heat rates were virtually unchanged from 2021 to 2022. The slight increase in 2022 is largely

6 See Section II.A of the Appendix for a detailed explanation of this metric.

due to the higher level in December that is attributable to the Winter Storm Elliott event. Most of the other differences in system marginal prices were caused by changes in fuel prices. In the future, implied heat rates are likely to become less predictable as the generating fleet transitions.

B. Fuel Prices and Energy Production

As natural gas prices rose to the highest levels in years, this improved the operating margins for non-gas-fired resources. One would have expected this to lead to higher coal-fired output and lower gas-fired output, which did not occur for reasons discussed in this subsection. Additionally, the resource mix continued to evolve in 2022. MISO lost 4 GW of Unforced Capacity (UCAP) from retirements and suspensions and added 2 GW of new resources. These included a new 1.1 GW natural gas-fired combined-cycle resource in the Central region and over 600 MW of new solar. While approximately 2.8 GW of new installed wind capacity entered MISO in 2022, this only constitutes a few hundred MW of new Unforced Capacity.

Table 1 below summarizes the share of capacity (in UCAP), energy output, and how frequently different types of resources were marginal in setting system-wide energy prices and locational energy prices in 2021 and 2022.

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

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Nuclear	11,701	10,870	9%	9%	16%	15%	0%	0%	0%	0%
Coal	43,123	39,544	34%	31%	40%	34%	35%	24%	77%	63%
Natural Gas	59,901	61,032	47%	48%	29%	33%	64%	75%	96%	90%
Oil	1,474	1,523	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	3,695	4,228	3%	3%	1%	1%	1%	1%	1%	2%
Wind	4,454	4,709	3%	4%	13%	16%	0%	0%	62%	68%
Solar	1,037	1,808	1%	1%	0%	0%	0%	0%	1%	3%
Other	2,734	2,599	2%	2%	1%	2%	0%	0%	8%	5%
Total	**128,120**	**126,312**								

Energy Output Shares. The lowest marginal cost resources (coal and nuclear) became more profitable as energy prices rose. Fuel supply issues and other supply chain problems led many coal resources to restrict their operations to conserve coal,[7] leading to a reduction in their share of energy output. This caused the share of energy produced by natural gas resources to rise even though they were less economic. As wind capacity continued to grow, their share of output rose to 16 percent in 2022. Nuclear output fell slightly as an 800 MW nuclear unit retired in May.

7 These issues and others related to the operation of MISO's coal resources are discussed in Section IV.H.

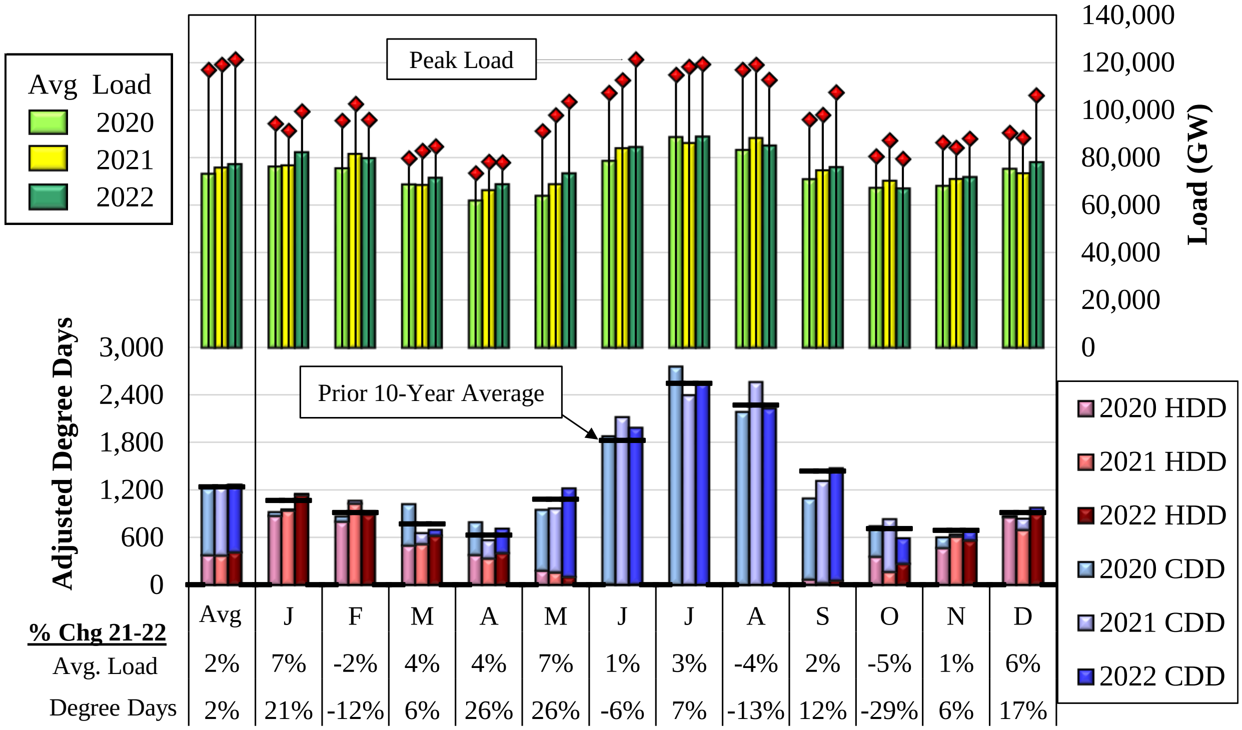
Price-Setting. Coal resources set system-wide prices in just 24 percent of hours, generally in off-peak periods. This is down from 35 percent in 2021 as they produced less energy and were more deeply inframarginal. Although natural gas-fired units produced only 33 percent of the energy in MISO, they set the system-wide energy price in 75 percent of all intervals, up from 64 percent and including almost all peak hours. In addition, congestion often causes gas-fired units to set prices in local areas (90 percent of intervals) when lower-cost units are setting the system-wide price. Likewise, wind units set prices in more than two-thirds of all intervals as growing wind output has resulted in increasingly frequent congestion.

C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are generally determined by weather. Figure 4 indicates the influence of weather by showing the heating and cooling needs together with the monthly average load over the past two years. The top panel shows the monthly average load in the bars and the 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.[8]

Figure 4: Heating and Cooling Degree Days

2020–2022



8 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).

In 2022, both the average load and the number of degree days rose 2 percent over 2021. Some notable cold and hot weather episodes occurred throughout 2022, including:

- Warmer than normal temperatures in May and June led to higher cooling demand.
- Above-normal temperatures in September increased cooling demand and the seasonal peak load of 108 GW occurred on the first day of the Fall quarter.
- Between December 23 and 25, arctic temperatures in the central U.S. caused emergencies that are discussed below in subsection E. Average and low temperatures were 15 to 35 degrees below normal and led to unusually high peak loads above 100 GW.

MISO's annual peak load of 122 GW occurred on June 21, as higher than normal footprint-wide temperatures led to high peak cooling demand. Peak load was 1.6 percent lower than the 50/50 forecasted peak of 124 GW from MISO's *2022 Summer Seasonal Assessment.*

D. Ancillary Services Markets

Since their inception in 2009, co-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs 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.

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 the spinning reserve requirements, so the spinning reserve price will always be equal to or higher than the Contingency Reserve price. Similarly, regulation prices will include components associated with spinning reserve and Contingency Reserve shortages.[9] Likewise, energy prices include all ASM shortage values plus the marginal cost of producing energy. MISO's demand curves specify the value of each of its reserve products. When the market is short of a reserve product, the demand curve for the product will set its market clearing price and affect the prices of higher-valued reserves and energy through the co-optimized market clearing.

Ancillary Services Prices in 2022

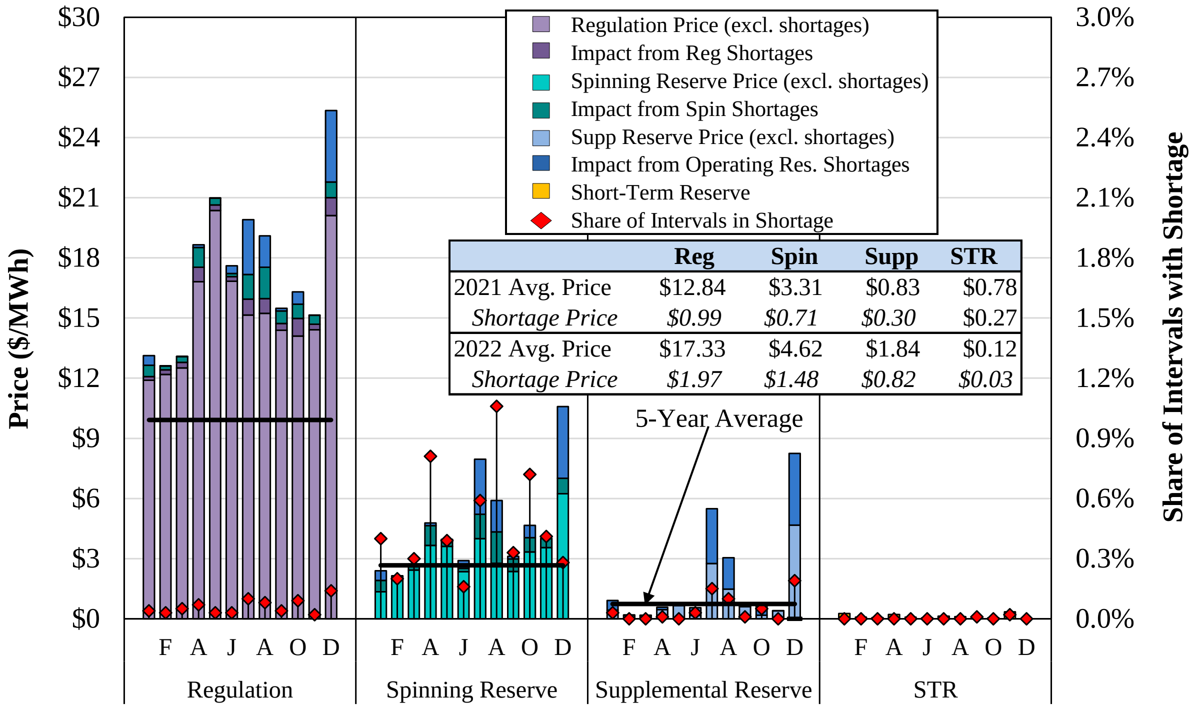
For each product, Figure 5 shows monthly average real-time prices, the contribution of shortage pricing to each product's price and the share of intervals in shortage. The figure also shows the 5-year average price of the reserve products, except for Short-Term Reserves (STR) that were implemented in December 2021. The average clearing prices rose significantly for all reserve products in 2022, primarily because of changes in natural gas prices and the effects of Winter

9 The demand curve for regulation, which is indexed to natural gas prices, averaged $289.41 per MWh in 2022, up from $280.24 per MWh in 2021. 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%).

Storm Elliott in December discussed later in this section. Higher opportunity costs caused by higher natural gas prices contributed to the 40 percent increase in spinning reserve prices.

Figure 5: Real-Time ASM Prices and Shortage Frequency

2022



Short-Term Reserves. Based on our recommendation, MISO implemented a 30-minute reserve product (short-term reserves or "STR") in December 2021. We had recommended the requirements be applied locally to zones with VLR requirements, but they are currently only applied to MISO and its two subregions. STR prices have averaged close to zero in the day-ahead and real-time markets (under $1 per MWh), excluding the effects of Winter Storm Elliott.

MISO enforces STR requirements in its two subregions by enforcing reserve procurement enhancement (RPE) constraints over the Regional Directional Transfer (RDT) constraint. The RPE binds when headroom on the RDT plus the available STR in the importing subregion is limited. Although the STR product is producing benefits for MISO, we recommended two key changes to improve its performance, one of which MISO implemented late in 2022:

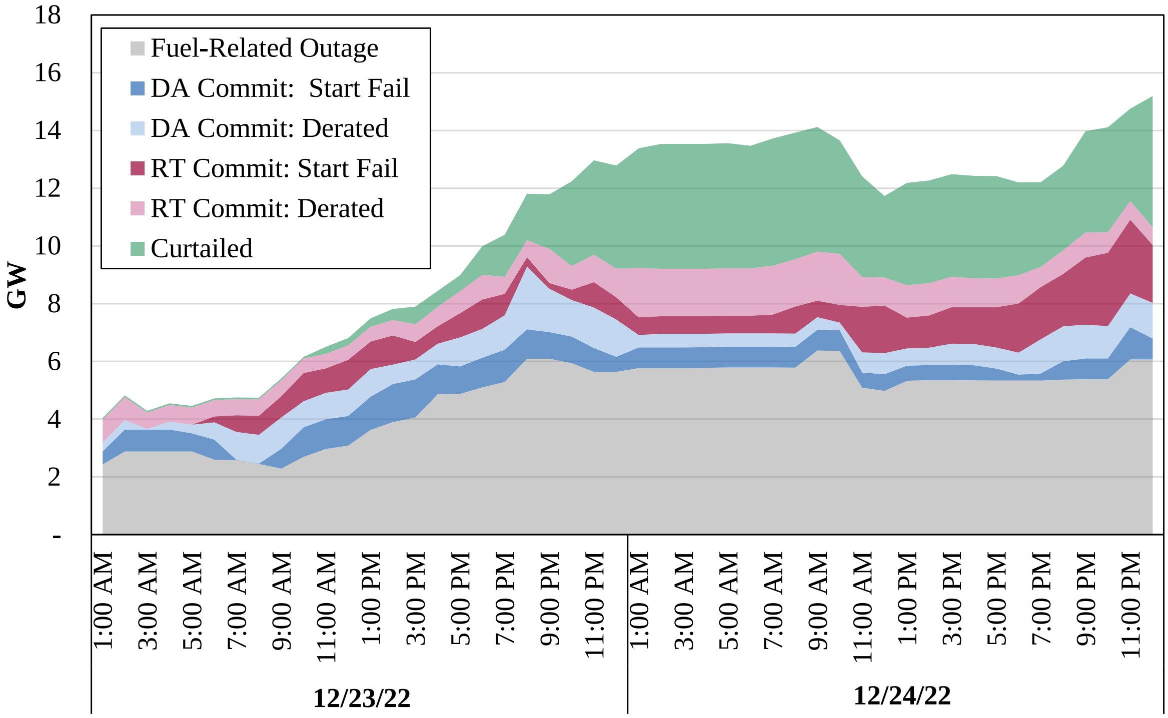
- Application of appropriate demand curves to price STR shortages efficiently. In November 2022, MISO implemented a multi-step curve that reached a high step of $500 per MWh, replacing its previously set curve set at $100 per MWh.
- Expansion of the RPE constraints to enforce STR requirements in local reserve zones that have VLR requirements that cause large amounts of uplift costs. Enforcing local STR requirements will provide efficient incentives for suppliers to invest in fast-start units that can satisfy the VLR requirements.

E. Winter Storm Elliott and Market Outcomes

In 2022, MISO experienced a significant event at the end of the year—Winter Storm Elliott—that stressed its ability to maintain reliability and assist its neighbors. In this subsection, we provide a description of the event, the impacts on the markets, and recommendations we identified to improve operation of the system under emergency conditions.

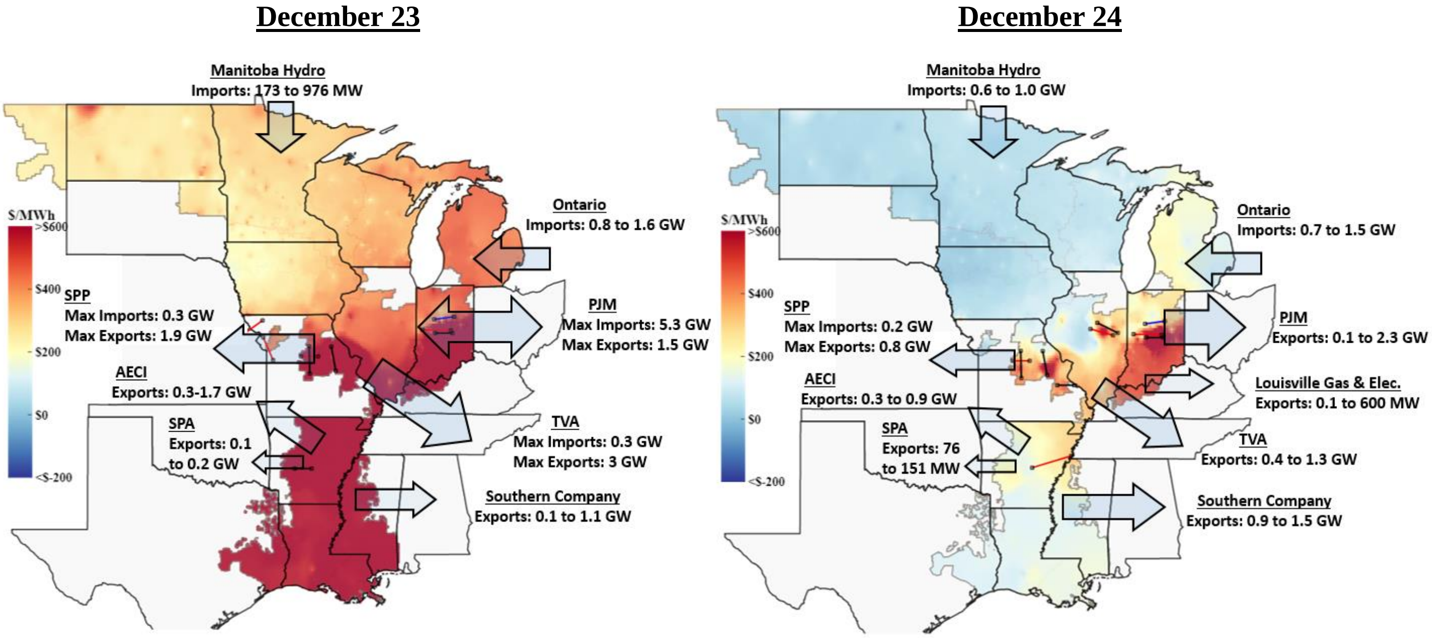
On December 23, temperatures throughout MISO ranged from 20 to 35 degrees below normal as a bomb cyclone hit much of the central United States. MISO and most neighboring control areas experienced large load forecasting errors, causing capacity shortfalls in a number of these areas. Tight gas supply conditions contributed to the capacity shortages. Many gas-fired resources committed after the day-ahead market were unable to procure gas and several others ran out of fuel. This contributed to 15 GW of fuel-related outages and derates by the end of the day on December 24 as shown in Figure 6. The fuel supply issues were partly due to frozen wells in the Marcellus shale area and issues with compressors that caused pipeline pressure issues.

Figure 6: Gas-Fired Generation Outages
December 23–24, 2022



The most serious reliability issues were experienced by TVA, which implemented rolling blackouts throughout the day on December 23. MISO provided extensive support to TVA and other neighboring LBAs, including Southern Company, AECI, SPP, and PJM. Figure 7 illustrates the unusually large exports and wheels that were scheduled and contributed to more than $350 million in real-time congestion between December 23 and 24, as shown by the average LMPs on those days.

Figure 7: Winter Storm Elliott Power Flows and Locational Prices



On December 23, MISO imported from Manitoba, Ontario, and PJM, and exported to TVA, Southern Company, AECI and SPP. On December 24, fuel supply issues in PJM caused typical import flows to reverse overnight and become large export flows throughout the day. The large and unusual exports caused severe congestion in MISO.

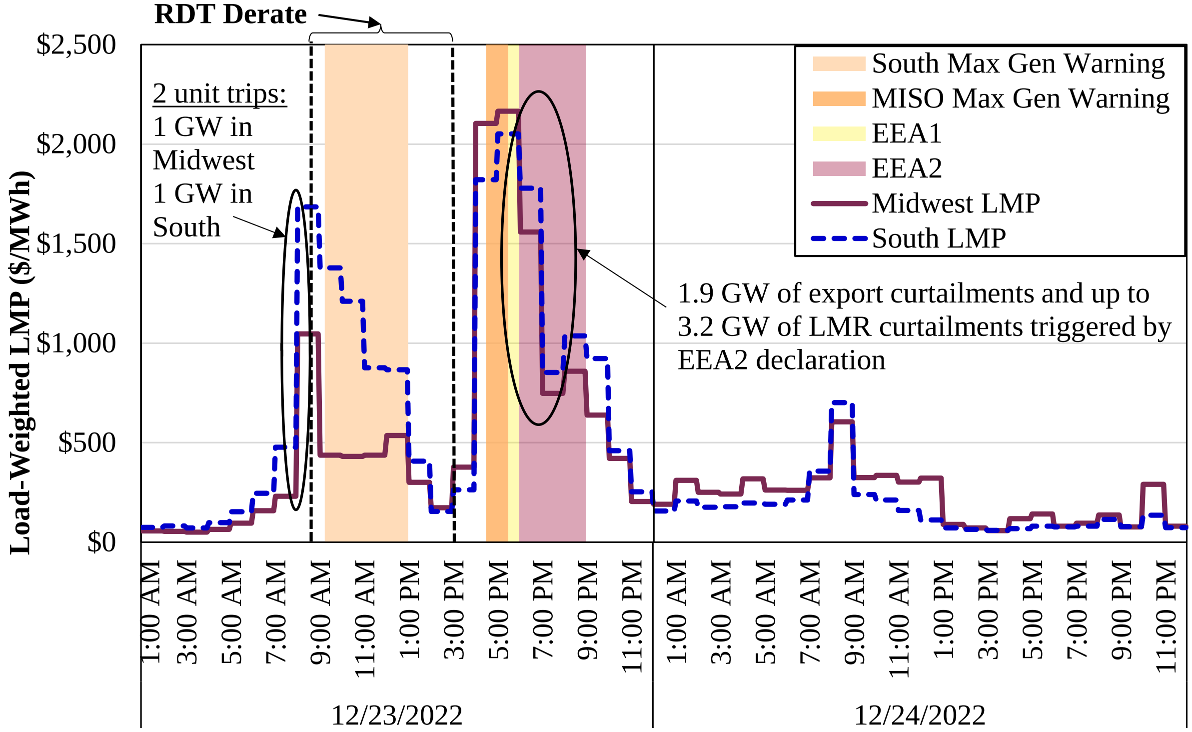
Real-Time Pricing and Emergency Declarations During Elliott

Figure 8 shows prices and the emergency declarations by MISO during the event. On the morning of December 23, SPP and TVA requested that MISO derate the RDT from 3000 to 1500 MW, which triggered a violation of the RDT and prompted MISO to declare a Maximum Generation Warning in the South. Additionally, two large units tripped off shortly before the derate. Together, these events caused prices to spike up, particularly in the South.

MISO's emergency procedures would call for it to curtail non-firm exports under MISO-wide or subregional emergency declarations. At the time of the Maximum Generation Warning in the South, MISO had almost 3 GW of non-firm exports to Southern Company, TVA, SPP and AECI that could have been curtailed to relieve the RDT violation and the subregional emergency, but MISO choose not to curtail the vast majority of these exports.

Later that afternoon, as imports from PJM were falling and exports to TVA were growing, MISO moved through its emergency procedures to an EEA2. MISO was not forecasting a capacity shortage and still had large quantities of non-firm exports available to cut prior to these emergency declarations. However, MISO took these actions in order to sustain the exports to its neighbors, particularly to TVA that was shedding load.

Figure 8: Winter Storm Elliott Emergency Declarations and Prices
December 23–24, 2022



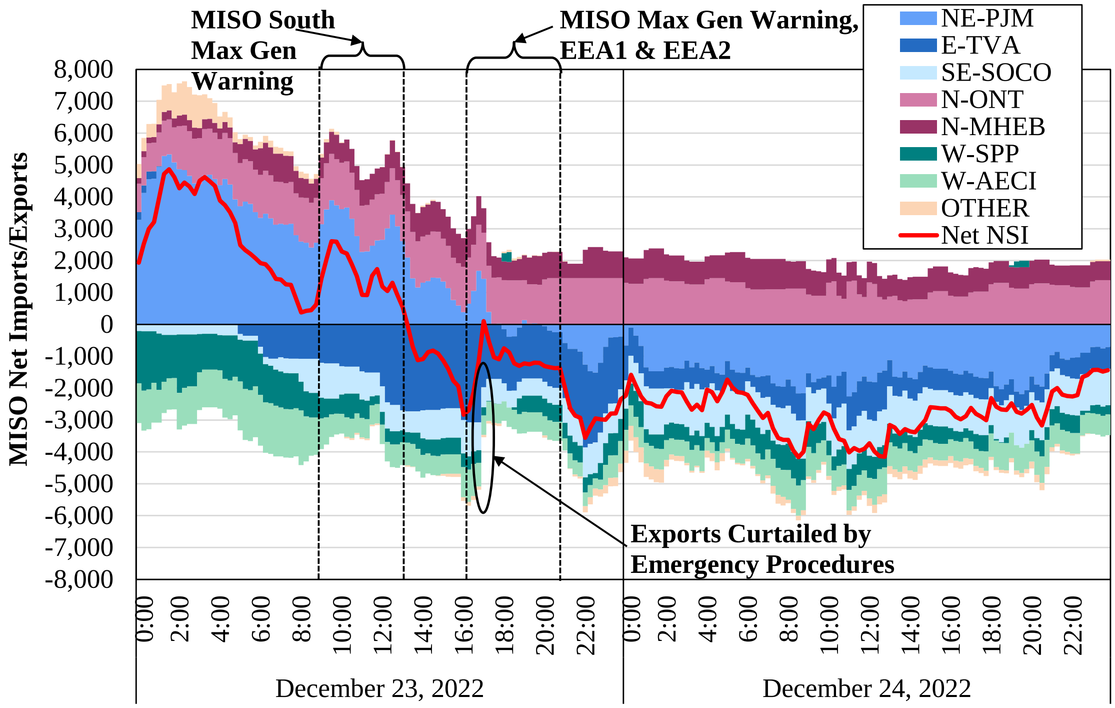
MISO ultimately declared the EEA2 to access LMRs in order to provide additional exports to TVA. Unfortunately, the EEA2 procedures also require cuts to non-firm exports. As a result, instead of providing the additional 1.5 GW TVA requested, the EEA2 led MISO operators to curtail 1.4 GW of exports to TVA and additional amounts to other areas.

Import and Export Trends During Elliott

Figure 9 shows the net imports (positive values) and exports (negative values) on December 23 and 24, with the red line indicating the net scheduled interchange across those days. Maroon shaded areas are imports/exports over northern interfaces, while the blue shaded areas show the eastern interfaces and green shaded areas show the western interfaces.

On December 24, MISO's total net exports grew as net imports from PJM on December 23 fell and became substantial net exports. Although no MISO capacity emergencies or shortages occurred on December 24, MISO took unprecedented actions to maintain exports to its neighbors. MISO committed many resources to sustain the exports, even as the congestion caused an increasing number of resources to be "stranded" behind constraints. These commitments generated more than $11 million in RSG.

Figure 9: Net Scheduled Interchange During Winter Storm Elliott



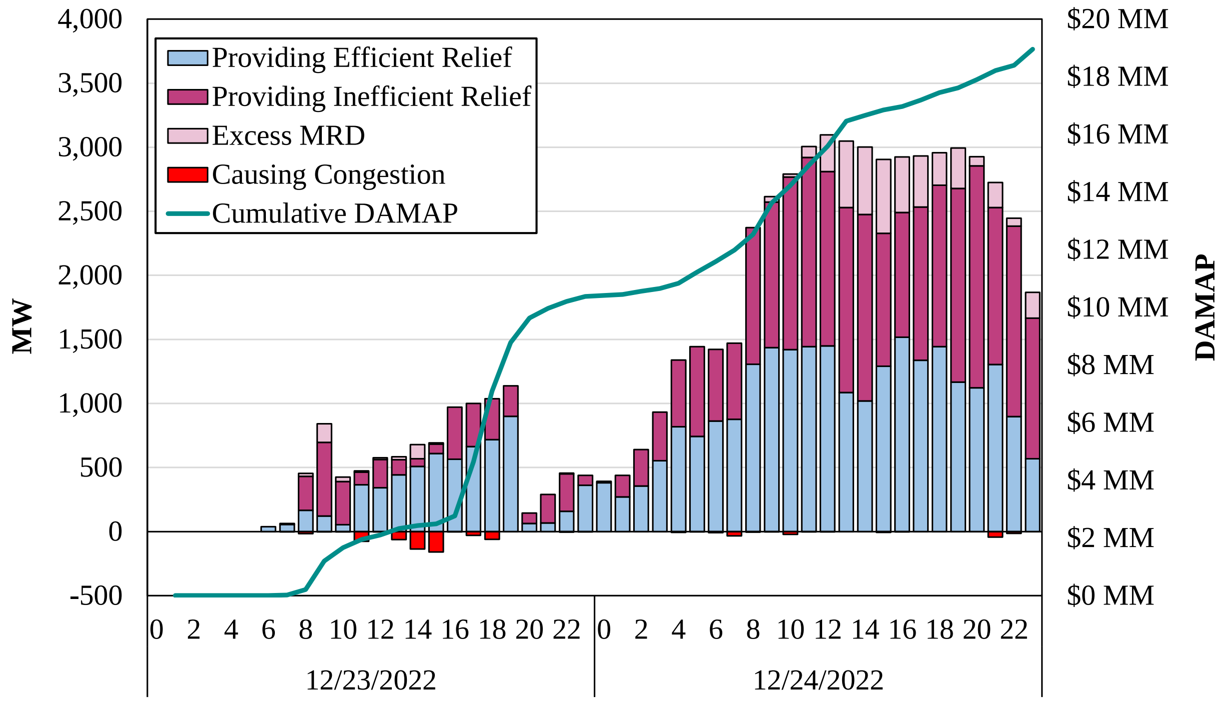
Manual Redispatch During Elliott

MISO responded to a number of transmission violations by using manual redispatch (MRD). MRD directs a unit's output to a fixed amount and is necessary when the value of managing the flows on a transmission constraint is not high enough for the real-time dispatch to move the resources needed to manage the flows. MRD is not ideal because it prevents the market from properly pricing the congestion, is often not efficient, and can generate large uplift costs.

Figure 10 shows the increasing levels of MRDs implemented on December 23 and 24 along with the Day-Ahead Margin Assurance Payments (DAMAP) paid to MRD units. To determine how efficient these manual dispatch actions were, we conducted a simulated dispatch analysis for December 23 and 24. We removed all the resource MRDs and adjusted the TCDCs on the relevant constraints to a maximum of $10,000 per MWh of flow. Increasing the TCDC allowed the dispatch model to recognize the value of moving the resources and keeping the flows below the limits of the constraints. The simulation allowed us to divide the MRD actions taken by MISO into the following categories:

- Efficient: the simulation dispatched the units to the MRD level;
- Inefficient: other, less costly resources would have been dispatched for the constraint;
- Excessive: the MRD provided more relief than necessary to manage the constraint; and
- Harmful: the MRD caused congestion by increasing the flows on a constraint.

Figure 10: Manual Re-Dispatch and Associated DAMAP
December 24, 2022



Our analysis shows that less than half the MRDs during Winter Storm Elliott were efficient. On December 24, a substantial amount of MRDs were excessive, particularly in the peak hours. This indicates why manually dispatching resources is not preferred and should be avoided if possible. Even when the same dispatch would result, MRDs: (a) prevent prices from reflecting the marginal costs of the resources being moved, and (b) require MISO to make the resource whole to the inaccurate price by paying unjustified DAMAP.

Our evaluation of this event highlights the following opportunities for operational improvements:

4. To avoid MRDs in the future, we recommend that MISO:
    a. Add higher-priced steps to the Transmission Constraint Demand Curves (TCDC).
    b. Improve its procedures to increase TCDCs as needed to ensure that the dispatch model will reasonably manage network flows and violations under all conditions.
5. Strengthen the operating controls and logging to minimize deviations from its operating procedures.
6. To the extent that operating actions will be taken in the future primarily to support neighboring areas, MISO should:
    a. Modify its operating procedures to specify these actions and the requisite criteria for taking each action; and
    b. Establish operating agreements with neighboring areas to better coordinate during emergencies and to establish equitable provisions to allocate the associated costs.

III. Future Market Needs

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market, which will require MISO to adapt to new operational and planning needs. MISO has been grappling with these issues through several initiatives, including the Renewable Integration Impact Assessment (RIIA), the Regional Resource Assessment (RRA), and the publication of the *MISO Futures Report*.

With the exception of its capacity market, MISO's markets are well-suited to facilitate this transition and fundamental market changes will not be needed. However, a number of key improvements will be critical as MISO proceeds through this transition. We discuss the key issues in this section that MISO will be facing in the coming decades and recommend both principles and specific market improvements MISO should consider as it moves forward.

We begin the chapter with a discussion of the remarkable changes anticipated in MISO's generation portfolio and the implications of these changes. We then identify the key market and non-market issues and improvements that will allow MISO to successfully navigate this transition.

A. MISO's Future Supply Portfolio

Over the past decade, the penetration of wind resources in the MISO system has consistently increased as baseload coal resources have gradually retired. To date, MISO has effectively managed the operational challenges of integrating wind and solar resources while losing conventional resources. However, the trend of increased intermittent resource penetration and retirement of conventional resources is expected to accelerate as large quantities of solar and battery storage resources join new wind resources in the interconnection queue. Currently, MISO's interconnection queue is comprised almost entirely of renewable resources, sometimes combined with batteries to form "hybrid" facilities. MISO has more than 1400 active projects in the interconnection queue, totaling over 240 GW. More than half of these are solar projects or hybrid solar projects and another 10 percent are wind projects or hybrid wind projects.[10] Distributed energy resources may also grow and play a more substantial role in MISO in the future.

Changes are also anticipated on the demand side. MISO's Transmission Expansion Planning (MTEP) study includes a scenario that examines a significant electrification of the transportation sector with the widespread adoption of electric vehicles (EVs). Such a transition may substantially change typical load profiles and congestion patterns. Nonetheless, the most

10 MISO Futures Report, April 2021 (updated December 2021), https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

significant changes are likely the supply-side changes discussed above. Figure 11 shows the anticipated mix of resources based on MISO's Futures Scenarios that are used for MTEP studies, RIIA, and resource adequacy studies. We show Future scenarios 1 and 3, which are intended to bracket the possible growth in renewables that MISO anticipates through 2039. Future 3 scenario includes significant assumed electrification of both the transportation sector, (primarily EVs) and residential heating/cooling (advanced heat pumps). While intended to bound the possible scenarios, recent state-level policy initiatives and potential federal initiatives may result in even more significant changes.

Figure 11: Anticipated Resource Mix

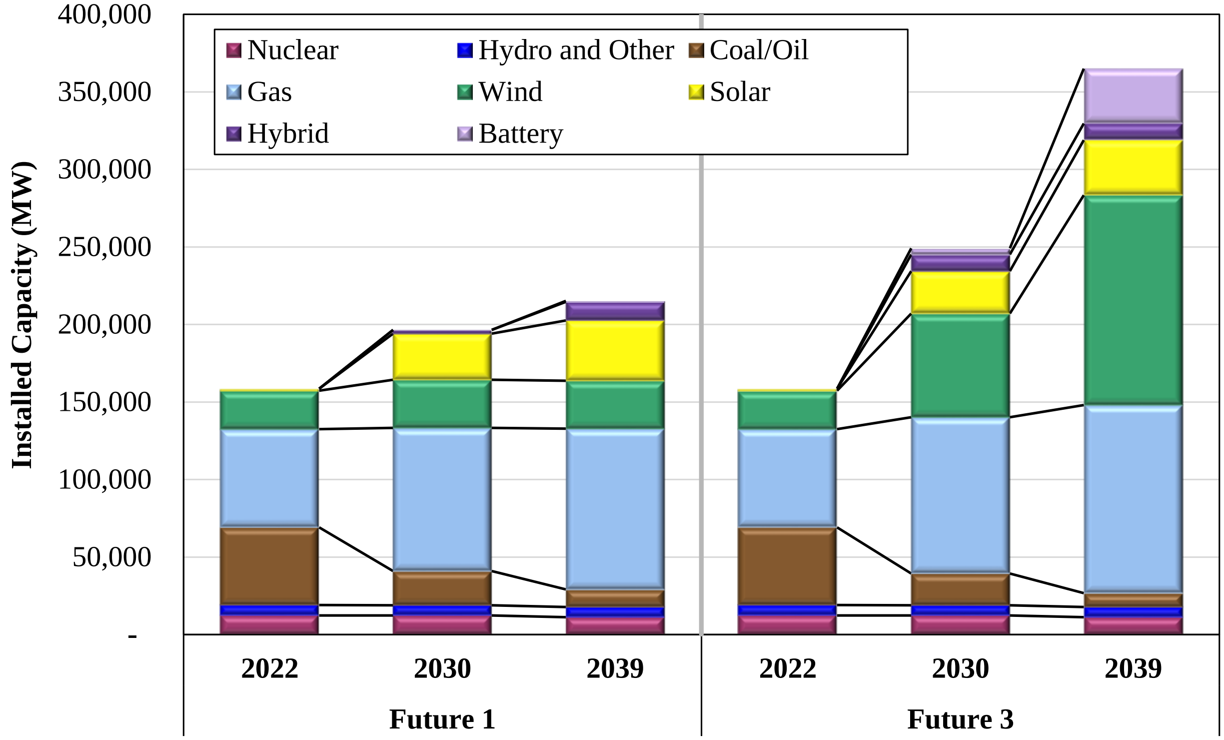
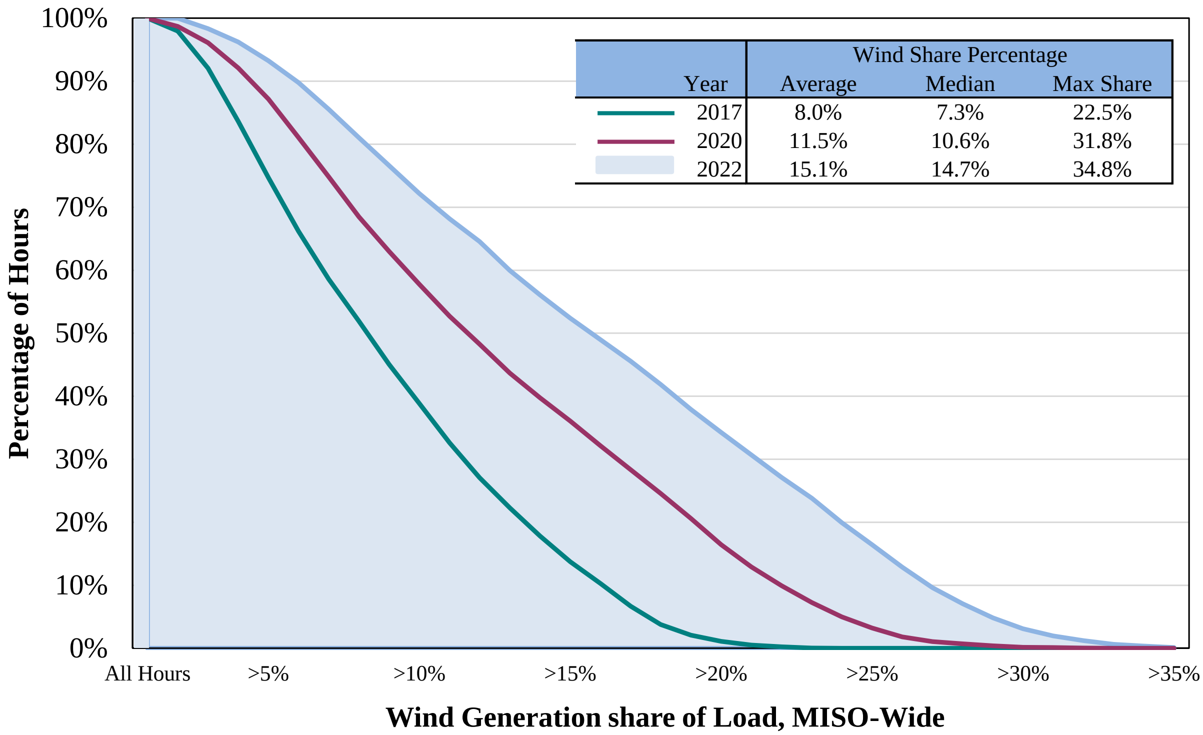


Figure 11 shows that both scenarios forecast substantial penetration of solar resources in the coming years, which is likely based on the fact that solar resources dominate the interconnection queue. Both scenarios also show that coal-fired resources are likely to retire rapidly over the next 10 years, much of which will be replaced by natural gas-fired resources. This expectation is reasonable because MISO will continue to have a need for dispatchable generation that can be used to satisfy load and manage congestion in the face of the increase in uncertain intermittent output. The Future 3 scenario forecasts that gas-fired resources will provide the dispatchable energy needed to maintain reliability, but advances in batteries may enable some of these resources to be displaced by storage resources. In such a scenario, it will become even more critical that MISO improve its market software to allow the markets to optimize both long- and short-duration storage resources. This will require MISO to develop a look-ahead dispatch and commitment model that optimizes multiple hours, which we recommend MISO begin evaluating.

Expansion of Wind Resources

Average hourly wind output continued to grow in 2022, rising 23 percent over 2021 to 11 GW. Hence, wind resources continue to produce increasing shares of the total generation in MISO, increasing from 13 percent of all energy in 2021 to 16 percent in 2022. However, wind generation varies substantially from day to day and often from hour to hour. In some hours, wind generation served over one third of the load in MISO in 2022, which presents increasing operational challenges that MISO must confront. Figure 12 below shows the cumulative share of MISO's load served by wind, and how this share has changed over the past five years. The x-axis represents the percentage of load served by wind. The y-axis shows the percentage of hours during the year when wind output exceeded that share of load. So, for example, in 2022, in 52 percent of the hours, over 15 percent of the load was served by wind.

Figure 12: Share of MISO Load Served by Wind Generation
2017–2022

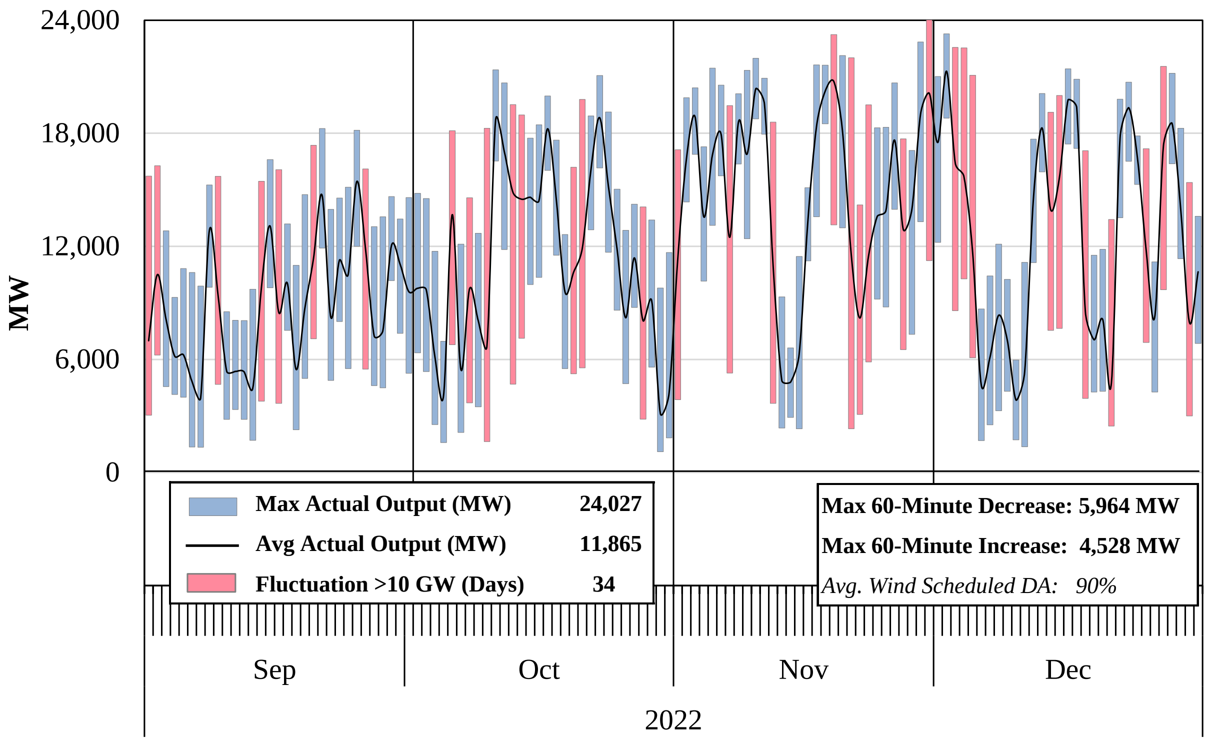


This figure shows that wind output as a share of load in MISO has been growing rapidly. To see the changes over time, notice in the figure that for half of the hours of the year, wind was serving more than 7 percent of the load in 2017, 11 percent in 2020, and roughly 15 percent of the load in 2022. We expect this trend to continue and, as wind generation increases, the operational challenges of managing this generation will increase.

Wind Fluctuation. The operational challenges associated with managing wind generation arise because of the substantial uncertainty of the wind output. As uncertainty grows, so do the errors in forecasting the wind output. To illustrate these challenges, Figure 13 shows the daily range in wind output along with the average wind output each day from September through December 2022, a period during which wind output was relatively high. This period included a new all-time peak wind output of more than 24 GW on November 30, a day when wind served more than 30 percent of the demand in MISO.

On the days colored pink in the figure, wind output fluctuated by more than 10 GW. MISO has generally been able to manage these increasingly large fluctations in wind output. They will continue to be more challenging and can lead to operational issues when the fluctuations are not forecasted accurately. Sharp changes in output can be more difficult to manage because MISO is limited in how quickly it can move other resources. As the figure reports, wind dropped by as much as 6,000 MW in one hour during this period. As wind penetration increases, the need to have other flexible resources available to manage the intermittent output will rise.

Figure 13: Daily Range of Wind Generation Output
September – December 2022



Often the highest output from wind resources occurs in overnight hours. As wind capacity continues to grow, this may place increasing pressure on older, uneconomic baseload resources to cycle off overnight. It also will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods. Finally, Figure 13 also shows that MISO continues to experience periods when wind output is close to zero. This underscores the importance of having sufficient dispatchable resources available to satisfy the system demands when intermittent generation is not available.

Transmission Congestion Caused by Wind. In addition to the issues caused by the uncertainty of wind output, the concentration of wind resources in the western areas of MISO's system has created growing network congestion in some periods that can be difficult to manage. MISO's Dispatchable Intermittent Resource (DIR) type has been essential in allowing MISO to manage congestion caused by wind output. DIR participation by wind resources increases MISO's control over wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). In the longer term, innovative management of the transmission system, including integration with other controllable network facilities (e.g., HVDC, PARs, switches, and battery facilities) will be pivotal in integrating much larger quanitities of wind resources. We discuss possible approaches in the next subsection.

Penetration of Solar Resources

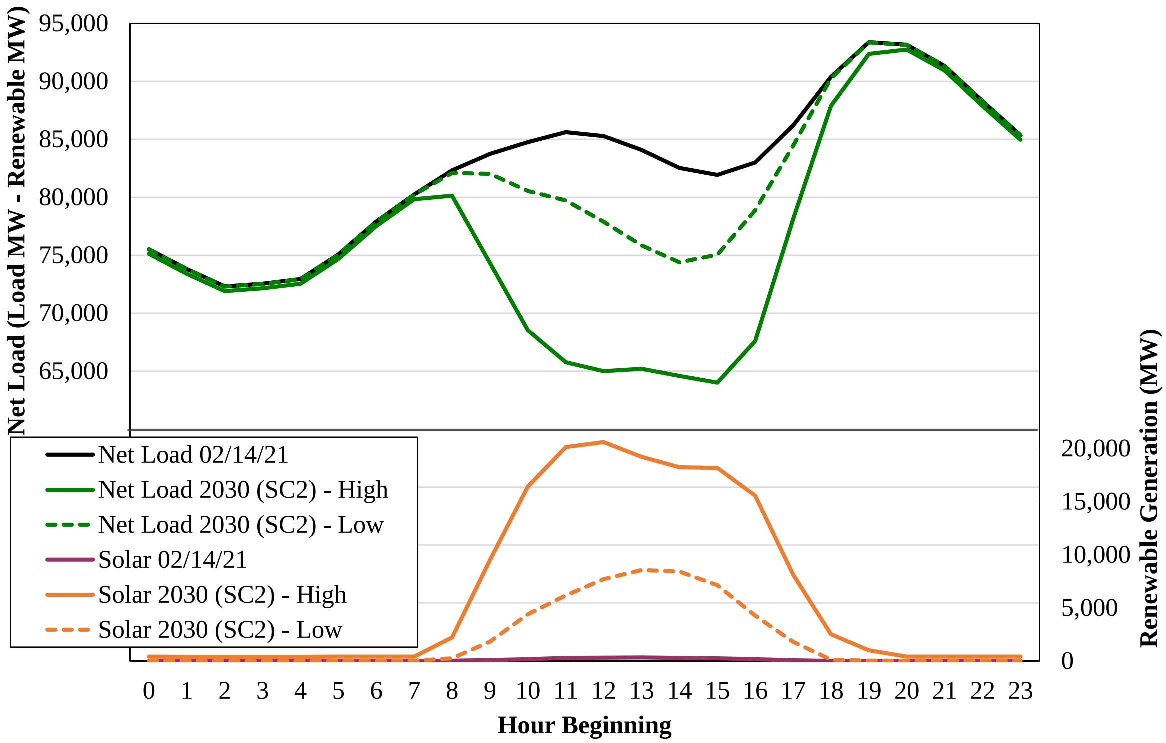
Scenario 1 of Figure 11 shows that solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This expectation is likely driven by the fact that solar resources dominate the interconnection queue, a large share of which may not ultimately enter the MISO market. Nonetheless, the penetration of solar resources will likely be substantial and present new challenges for MISO's operators and its markets. Currently, solar resources with a peak output of 2,500 MW are online in MISO, the vast majority of which entered in 2022.

Given the expected operating profile of solar resources, a large influx of these resources will lead to significant changes in the system's ramping needs. The morning ramp demand occurs between 6 a.m. and 8 a.m. will continue to primarily be served by conventional resources. Once solar resource output spikes in the late morning and through the afternoon, the conventional resources will likely need to ramp down to balance the solar output. As solar output falls off sharply in the evening hours, a second ramping demand of conventional resources will occur. These patterns are particularly challenging in the winter season because MISO's load peaks in the early morning and in the evening when solar output is lowest. These ramp management challenges have already been observed in solar-rich western markets.

Figure 14 shows the "net load" that must be served by conventional resources in MISO under different solar penetration scenarios. In this figure, net load is the system load minus the output of intermittent resources. This curve has been referred to as the "duck curve" because of its shape. This figure is based on the load on a relatively cold winter day—February 14, 2021. Data for modeling solar resources is from the Futures Scenario 2 from MISO's MTEP and RIIA processes, which is an intermediate case. Because solar output from a fixed set of resources can vary substantially, the figure shows a high solar and low solar case under this Futures Scenario.

This figure shows the typical dual peak in load that often occurs in the winter, one in the morning and one in the evening. Because the solar output rises, peaks, and then falls between these two daily peaks, it increases the need for the conventional generation fleet to ramp. In the high solar case, the net load falls sharply after the morning peak as solar output increases.

Figure 14: Net Load in MISO on a Representative Winter Day



Likewise, the net load increases sharply from 4 p.m. to 10 p.m. as evening sets in. The net load that would be served by conventional resources in this case would rise by more than 25 GW. This ramp could be even larger if wind happens to be falling in these hours. This underscores the importance of having generation available and flexible enough to satisfy these needs.

Distributed Energy Resources

Another developing area that MISO is addressing is Distributed Energy Resources (DERs) and Energy Storage Resources (ESRs). MISO has begun discussing the challenges that are anticipated to arise from these resources, especially with visibility and uncertainty around operation of these resources. They are generally going to be located and operated on the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets, which creates RTO challenges.[11]

According to the 2022 OMS DER Survey, 11.5 GW of DER currently exists in MISO, and only around 60 percent is registered. Almost a third of this is solar PV, approximately half is demand response, and the rest is other DER types that include battery storage and small-scale generation. We do not anticipate large-scale entry of DER resources, but MISO should be prepared because

11 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).

technologies and business models can change rapidly. DERs will 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 has important implications for how DERs are integrated operationally through the MISO markets.
- *Economic Incentives*: To the extent that DERs participate in or are affected by retail programs or utility rates, wholesale market rules and settlements may result in inefficient incentives to develop and operate the DERs.

In the next subsection, we recommend guiding principles and objectives for MISO's effort to accommodate DERs to address these challenges.

Energy Storage Resources

Order No. 841 required MISO to enable ESRs to participate in the market, recognizing the operational characteristics of ESRs. Figure 11 above shows that MISO forecasts only moderate growth in ESRs over the next decade. Based on the trends we are observing in other markets, we believe this forecast is likely conservative. Installation costs of ESRs are likely to fall as they proliferate. This trend, along with the increases in intermittent resource price volatility discussed above, are likely to increase the economic value of ESRs. This is particularly true if MISO adopts the shortage pricing improvements described below, which would efficiently compensate ESRs for the value they provide in mitigating or eliminating transitory shortages.

Although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not fully substitutable for conventional generation. This is particularly true as the quantities of ESRs rise, which causes the marginal value of ESRs to fall. Therefore, it will be critical to adopt an accurate accreditation methodology for ESRs along with other new technologies as we discuss in the following subsection.

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

MISO has managed the growth in intermittent resources reliably. Some have suggested that fundamental changes in MISO's markets are needed in response to the dramatic change in its future generation portfolio. Fortunately, this is not true. MISO's markets are robust and are fundamentally well-suited to accommodate the transition in MISO's generating fleet, although incremental improvements will be needed. MISO has already begun the process of making 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 its ability to control its wind resources; and
- Improving its wind forecasting and incentivizing suppliers to use MISO's forecasts.

As the resource fleet transitions, some needs may arise that are not currently satisfied by the markets, such as increased needs for voltage support in some locations or system-wide needs for inertial support.[12] We support MISO's continuing evaluation of these issues and will work with MISO to determine, to the extent they arise, whether they would be best addressed through the markets, through non-market settlements, or through interconnection requirements. However, the vast majority of issues that will arise over the next decade can be addressed with the following improvements to the MISO markets in three key areas:

1. Improvements in the Energy and Ancillary Services Markets
    - Introduction of an uncertainty product to reflect MISO's need to commit resources to have sufficient supply available in real time to manage uncertainty;
    - Introduction of a look-ahead dispatch and commitment model in the real-time market;
    - Shortage pricing reforms to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise; and
    - Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives.
2. Improvements in the Operation and Planning of the Transmission System
    - Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
    - Improvements to the transmission planning processes and benefit-cost analyses.
3. Improvements in the Capacity Market
    - Reforming capacity accreditation so that resource capacity credits under Module E accurately reflect reliability values; and
    - Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides.

1. Improvements in the Energy and Ancillary Services Markets

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

Uncertainty Product and Look-Ahead Dispatch

As MISO transitions to a fleet that is far more dependent on intermittent resources, supply uncertainty will increase markedly, affecting MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be

12 Recent studies have determined that inverter-based resources (IBR) such as intermittent solar and wind, can provide many of the grid-forming benefits provided by conventional resources with the necessary configuration and investment in power electronics. See: https://www.nrel.gov/news/program/2021/landmark-demonstration-shows-wind-turbine-can-provide-fundamental-grid-stability.html.

paramount to ensuring it can maintain reliability. Figure 15 shows the "net uncertainty" that MISO currently faces in the operating horizon. This is calculated using historical data on the combined impact of generation resource forced outages and forecast errors from load and renewables. We calculate the uncertainty typically faced on the system (the 50th percentile) and in the hours when uncertainty is higher (higher percentiles). The figure shows the uncertainty one hour ahead and four hours ahead (blue bars). The red, green, and purple lines indicate the underlying contributing factors of load forecast error, renewable forecast error, and generating resource trips and derates in 2022.

Figure 15: Uncertainty and MISO's Operating Requirements
January 2021 to December 2022

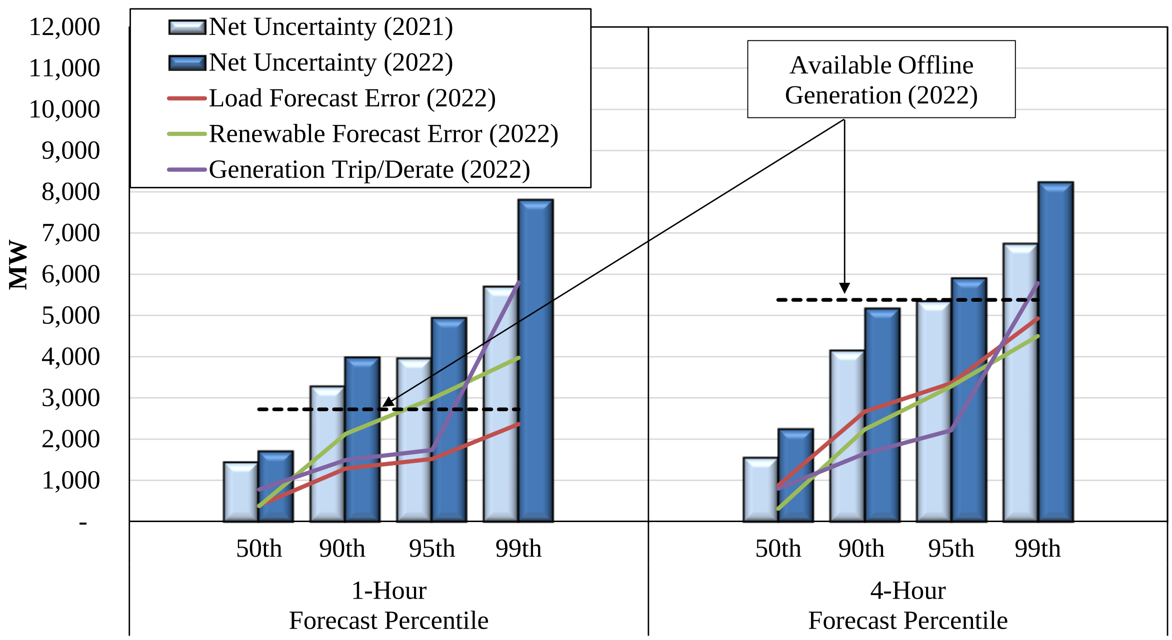


Figure 15 shows that the factors contributing to uncertainty increased in 2022. MISO continues to routinely commit resources outside of the market to ensure it will have sufficient generation available to satisfy the system's needs and respond to uncertainty. These requirements cause RSG costs to be incurred almost every day. If these requirements were reflected in a market product, prices would more efficiently reflect these requirements, less out-of-market intervention by MISO's operators would be needed, and the associated RSG costs would largely disappear.

As intermittent generation increases, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that MISO develop a spot capacity product for the day-ahead and real-time markets to account for increasing uncertainty associated with load, intermittent generation, NSI, and other factors. The product should be co-optimized with energy and other ancillary services products. Clearing such a product on a market basis would allow MISO's prices to reflect the need for this capacity to address uncertainty, reduce RSG, and reward the flexible resources that can meet this need.

In the longer term, we recommend MISO consider implementing this product along with other existing products through a look-ahead dispatch and commitment model that would optimize the dispatch of resources in future periods of up to four hours. Adding tools such as a look-ahead dispatch and commitment model will enable more efficient management of increased storage and DERs, which will be important as the penetration of these resource types in MISO grows. Currently, MISO may not be able to optimize these types of resources over its current 5-minute dispatch interval.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., less reserves will be held than required). When an RTO is short of reserves, the value of the foregone reserves should set the clearing price for reserves and be embedded in all higher-value products, including energy. The shortage value is established in the reserve demand curve for each reserve product, so efficient shortage pricing requires properly valued reserve demand curves.

Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.

The most highly valued reserve demand curve in MISO is the total Operating Reserve Demand Curve (ORDC). Shortages of total operating reserves are the most severe reserve shortages and the most likely to impact pricing during capacity emergencies. An efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies, including multiple simultaneous contingencies; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. The marginal reliability value of reserves at any shortage level is equal to the expected value of lost load. This is equal to the following product at each reserve level:

Net value of lost load (VOLL) * the probability of losing load

MISO's current ORDC does not efficiently reflect the value of reserves and is based on an understated VOLL. Hence, we recommend that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC as described below.

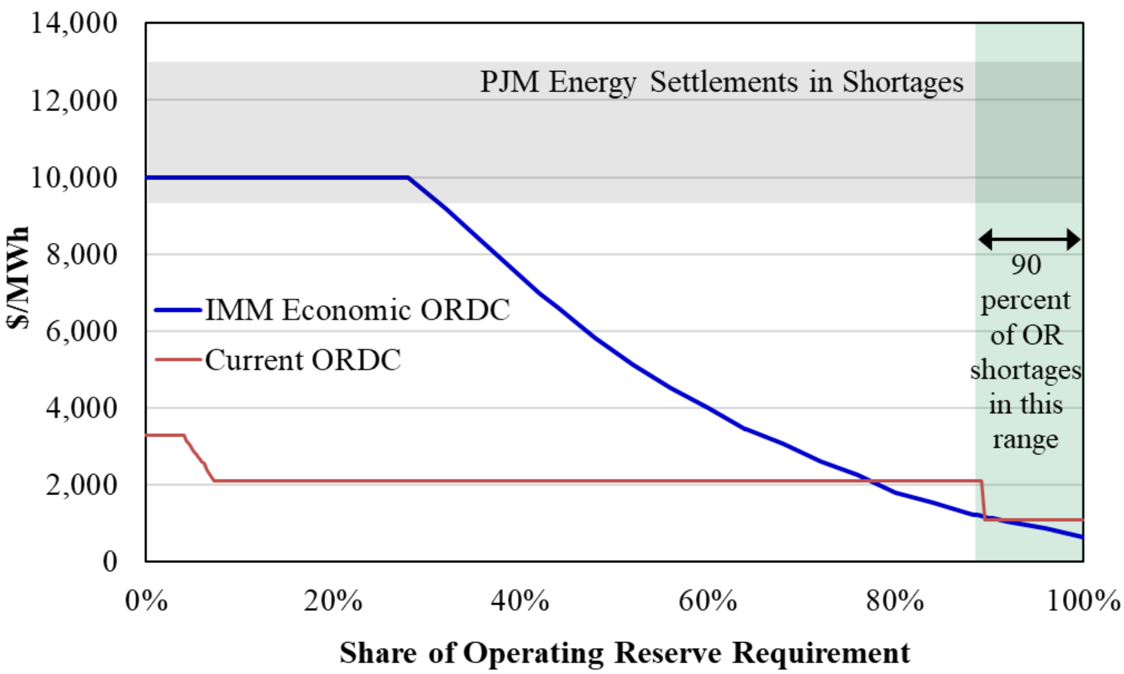
Improving the VOLL. We conducted a literature review and utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study, as well as a number of others, estimated a much different VOLL for residential customers and for commercial/industrial customers with the latter being much higher. Using the Berkeley Model and 2018 data for MISO, we estimated VOLL for residential customers ranging from $4,200 to

$4,600 per MWh, and for commercial customers ranging from $36,000 and $84,000 per MWh.[13] Weighting these values based on the 2021 load data in MISO yields an average VOLL of $25,000 per MWh. We recommend MISO adopt this VOLL or a comparable value.

Improving the Slope of the ORDC. The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on accurately estimating the vast combinations of random contingencies and conditions that could occur when MISO is short of reserves. To model these random factors, we estimated the probability of losing load using a Monte Carlo simulation.[14] This simulation includes generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty.

Combining our recommended VOLL with our estimate of the ORDC slope gives the IMM Economic ORDC shown in Figure 16 (royal blue line). The figure also shows MISO's current ORDC, which is significantly understated for almost all shortage quantities.

Figure 16: Comparison of IMM Economic ORDC to the Current ORDC



Our proposed ORDC plateaus at $10,000 per MWh for three primary reasons: (i) very few shortages would be priced in this range as the figure shows; (ii) pricing shortages at prices exceeding $10,000 per MWh could result in inefficient interchange because most of MISO's neighbors price shortages at lower prices; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

13 The calculation of these values is described in more detail in Section III.B of the Analytic Appendix.

14 The simulation estimated the conditional probabilities across 10,000 iterations, which is described in Section III.B of the Analytic Appendix.

In conclusion, an economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. Adopting this will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

Objectives for Accommodating Distributed Energy Resources

In response to FERC Order 2222, MISO is engaging stakeholders to identify technical, market, and reliability issues associated with alternative DERs. There are a wide range of possible DER models with varying roles between MISO, the LSEs, DER aggregators, and individual DERs. As MISO develops new market rules and processes, it should seek to ensure that DERs will support reliability and provide efficient incentives for DERs and non-DERs. To achieve these two goals, we recommend that MISO address the following primary 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 DERs locationally*. The locational effects of DERs must be reflected in MISO's operations and settlements in order to provide efficient investment incentives and to utilize them effectively. Hence, accurate locational metering will be essential.
- *Avoid Duplicative Payments*. In many cases DERs will already be participating in non-wholesale markets or distribution programs. Duplicative payments will provide inefficient investment and operating incentives and should be avoided if possible.
- *Account for DERs in the Planning Process*. This includes the use of accurate operational and locational information about DERs that will need to be provided by DER owners.
- *Develop accurate accreditation methods for DERs*. Most DERs will be less accessible and controllable than conventional resources. Accurate accreditation is essential to provide efficient incentives to invest in DERs and other resources needed for reliability.

DERs may present new challenges. The evolving rules should provide efficient incentives to be controllable and require visibility and verification. This will be key to integrating DERs reliably.

2. Improvements in the Operation and Planning of the Transmission System

As intermittent output grows and the variability of the flows over the transmission network increases, critical bottlenecks are likely to emerge that will continue to increase congestion and lead to growing levels of output curtailments. Therefore, maximizing the utilization of the transmission network 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 utilization of the network and other key improvements are discussed below.

Transmission Optimization

One of MISO's core functions is ensuring the transmission system can reliably support the MISO markets. New challenges will emerge with the accelerating growth of renewables and likely increased distances will occur between load centers and generating resources. These challenges will arise partially because large fluctuations in intermittent output can cause substantial changes in transmission flows, potentially resulting in more erratic and severe congestion patterns that are more difficult to forecast. Additionally, much heavier reliance on intermittent and inverter-based resources may raise issues related to other system attributes that are currently provided by conventional resources, such as inertial support, voltage and current stability, and reactive power.

MISO is actively engaging stakeholders in studying potential future scenarios and challenges to the bulk electric system and grid operations through both the MTEP and RIIA studies. These studies allow MISO to identify the investments and processes that may be necessary to address the needs of the system. This may include technologies and processes that will allow MISO to optimize the operation of network by redirecting flows to minimize congestion, or by using dynamic line ratings for transmission facilities to recognize factors other than temperatures.

These technologies may enable large cost savings with little or no impact on reliability. These technologies have been referred to as "grid-enhancing technologies" and the processes are referred to as "grid optimization". In addition to reducing network congestion, these processes and technologies may improve MISO's ability to plan for and manage transmission and generation outages, as well as fluctuations in flows caused by loads and intermittent generation.

In 2020, FERC convened a technical conference to discuss the opportunities and barriers to the utilization of such technologies.[15] Realizing the benefits of such technologies and process improvements will require that MISO devote resources in the coming years to integrating such technologies into its operations and market systems. These efforts are likely to be synergistic with integration and utilization of new resource types, including energy storage and DERs. We recommend that MISO anticipate these needs in the near term because the benefits of such improvements are likely to grow substantially as MISO's generating fleet transitions.

Long-Range Transmission Planning

An important component of the transition of MISO's generation portfolio is the evolution of its transmission network to facilitate the delivery of its clean resources to the loads in MISO. The evolution of the transmission network is guided by MISO's planning studies to identify constraints that will bind as MISO's renewable resource portfolio expands and the transmission investments that would mitigate these constraints.

15 See Docket No. AD19-19. In February 2022, FERC issued an NOI (see AD22-5) on Dynamic Line Ratings that may lead to a rulemaking that may include requirements for enabling and integrating these technologies.

Most of these investments are identified through the Long-Range Transmission Planning (LRTP) process, which identifies transmission investments in four tranches. Tranche one was approved in July of 2022 to address key constraints throughout MISO and is now under review in state regulatory proceedings. Tranche 1 included more than $10 Billion in network investments. Tranche 2 is intended to identify additional transmission upgrades in the Midwest region assuming greater load growth (Future 2A), while Tranche 3 is intended to identify transmission upgrades in the South region. Tranche 4 will identify projects to enable interregional transfers.

As MISO moves towards developing and evaluating Tranche 2, it will be increasingly important to evaluate the costs and benefits of the alternative transmission investments in a manner that ensures that the investments are economically efficient. This is important not only because inefficient investments can generate substantial costs for MISO's customers, but also because inefficient transmission investments can undermine the performance of MISO's markets. It can fundamentally alter incentives of developers and existing suppliers to make long-term generation investment and retirement decisions that would allow MISO to manage congestion at costs that are a fraction of the costs of investing in transmission upgrades.

In order to ensure that future cost-benefit analyses are as accurate as possible, we recommend that MISO develop analyses that reflect the following factors:

1. Congestion and reliability constraints are substantially affected by suppliers' resource siting and retirement decisions. Hence, forecasted siting and retirement assumptions should be based on the economic incentives provided by the market. This can be accomplished by employing a capacity expansion model that optimizes these decisions.
2. Storage resources can often resolve transmission and reliability constraints caused by fluctuations in intermittent output at a fraction of the cost of building new transmission. The same may be true in the future of grid-enhancing technologies. Hence, future studies should include such alternatives when evaluating the benefits of new transmission.
3. Valid cost-benefit analyses must ensure logical consistency between all base cases and all LRTP cases. All estimated benefits should include all costs incurred to realize the benefits. Likewise, all foregone costs deemed to be benefits must include the foregone benefits of such actions as an offsetting cost in the analysis. This will ensure that benefit-cost ratios are valid and are a sound basis for the sizable investments proposed.
4. All "but for" base cases must reflect an accurate forecast or assumption regarding market participant actions and investments that would take place absent the LRTP investments.

Although it is highly likely that the Tranche 1 investments evaluated by MISO and approved by the Board of Directors will produce benefits that are substantially higher than their costs, the Tranche 1 analysis was not consistent with some of the factors listed above. Therefore, we are recommending that MISO upgrade its analysis to address these factors in its future analyses of LRTP Tranches 2, 3, and 4 and other future MVP initiatives. This will help ensure that the resulting transmission upgrades are economic and do not undermine the performance of the MISO markets and decisions of its participants.

3. Improvements in the Capacity Market

As in other RTO markets, the capacity market plays a key role in facilitating efficient investment and retirement decisions. Although most of the participants in the MISO markets are vertically-integrated regulated utilities, efficient capacity market outcomes will nonetheless provide key incentives that influence these long-term decisions and resource planning processes. Additionally, MISO has a number of merchant generators and other types of unregulated market participants. Therefore, we believe the improvements discussed below are essential changes to facilitate MISO's transition of its generating portfolio.

Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets that will be needed to satisfy the reliability imperative is reforming the capacity market to provide efficient economic incentives. These reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy.

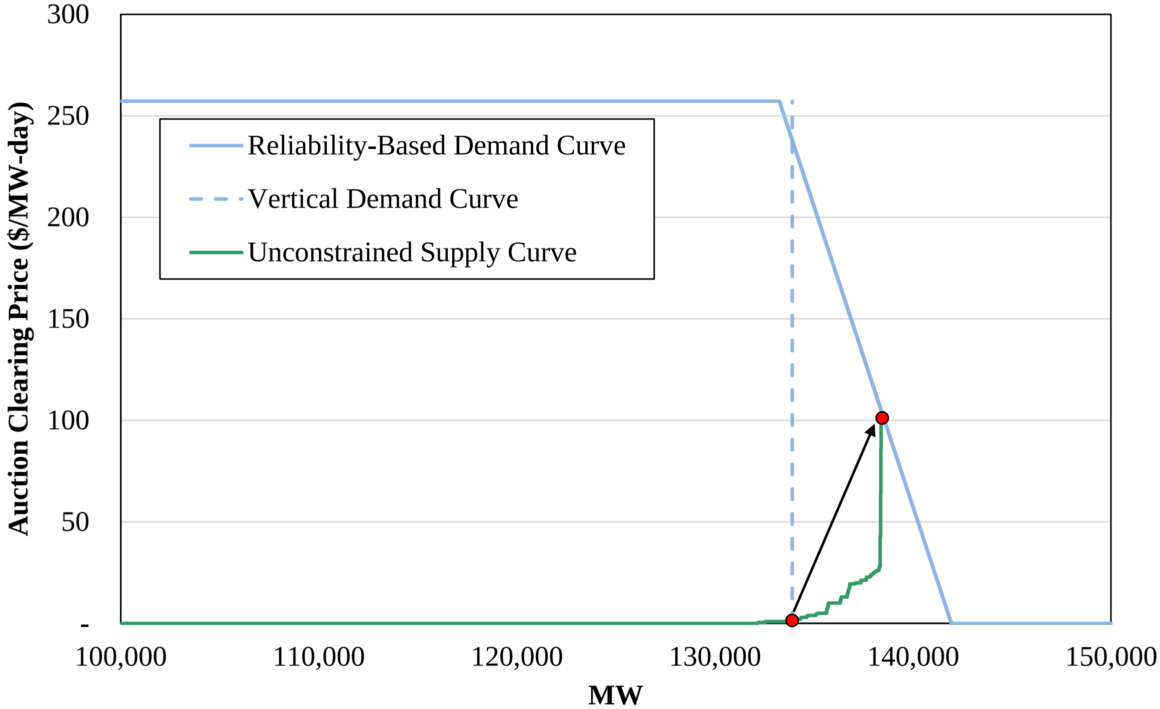
The problem with MISO's current capacity market is that the demand for capacity does not reflect the true reliability value of capacity. The fixed quantity of required demand subject to a deficiency price represents a vertical demand curve for the market. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement increases system reliability and lowers energy and ancillary services costs, although these effects diminish as the surplus increases.

The true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve. Implementing a reliability-based demand curve will:

- Establish stable and efficient capacity prices to facilitate efficient market incentives that govern not only new investment decisions, but also resource retirement decisions;
- Ensure that participants supplying more than their share of the required capacity receive capacity revenues that reflect their contribution to the system's reliability needs; and
- Provide incentives for load-serving entities that do not own sufficient capacity to plan efficiently by contracting for existing capacity or building new capacity.

To demonstrate the significance of this improvement, we simulated the clearing price in MISO that would have prevailed in the 2021/2022 PRA had MISO employed sloped demand curves in the PRA (Appendix Section III.C describes the assumptions underlying this curve). Figure 17 provides a representation of the sloped demand curve for all of MISO. The blue dashed line in the figure represents the vertical demand curve actually used in the auction. The solid green line is the capacity supply curve, reflecting resource offer prices and quantities. Resources that are self-supplied in accordance with Fixed Resource Adequacy Plans are represented with $0 offers.

Figure 17: Supply and Demand in 2021/2022 PRA



This illustrative example shows that the reliability-based demand curve would have increased prices from close to $0 to $100 per MW-day. In the actual 2021/2022 MISO PRA, prices were close to zero in both subregions. However, because the transfer constraint was binding, prices under a reliability-based demand curve would vary between the subregions, clearing at $150 per MW-day in the Midwest and $13 per MW-day in the South. Although this remains well below the cost of new entry of roughly $250 per MW-day, this price would support revenues for existing resources that are needed to maintain reliability and ensure they remain in operation.

Unfortunately, because the PRA sets prices far below efficient levels (close to zero) by design, our resource adequacy concerns that we have raised for almost 15 years materialized. MISO's inefficiently low capacity prices led to a sustained trend of retirements in recent years. A substantial share of these retiring resources would have been economic to remain in operation had MISO priced capacity efficiently in the PRA. Most of the inefficient retirements over the past four years—almost 5 GW—were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Captive retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from the inefficient capacity market signals. MISO's poor capacity auction design has driven economic resources into retirement and ultimately led MISO to be short of resources in the Midwest region. These issues are likely to persist unless and until MISO addresses the problems caused by its poor representation of capacity demand.

Short-Term Effects of PRA Reform on Different Types of Participants

The next analysis estimates how improving the design of the PRA would have affected various types of market participants in the 2021/2022 PRA. We calculated the simulated settlements for each participant based on its net sales. We then aggregated the participant-level results into four categories: competitive suppliers (merchant generators), competitive retail LSEs, municipal and cooperative entities, and vertically-integrated utilities. The results are shown in Table 2.

Table 2: Effects of Sloped Demand Curve by Type of Participant
2021–2022 PRA

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated LSEs	$148.4M	-$27.3M	$121.1M
Municipal/Cooperative	$67.2M	-$81.2M	-$14.0M
Merchant	$59.3M		$59.3M
Retail Choice/Competitive LSEs		-$166.4M	-$166.4M

This table shows that the vertically-integrated utilities would have benefited in aggregate by more than $120 million from the use of the sloped demand curve, and 70 percent of participants in that category would have realized almost $150 million in increased revenues. The effects on the vertically-integrated utilities were significant because they tend to have surplus capacity. Hence, vertically-integrated utilities would realize significant benefits from a sloped demand curve because it would allow them to sell their excess capacity at prices that reflect its value.

While some municipal and cooperative entities also would have benefitted from the adoption of a sloped demand curve in the 2021–2022 auction, on net the costs to municipal and cooperative entities would have increased by $14 million because many of them do not own sufficient resources to meet their own requirements. Improving pricing in the PRA would provide stronger and more efficient incentives for them to plan and contract for resources to satisfy their needs.

The effects on the competitive participants are more important because the economic price signals from the wholesale market guide key decisions by the unregulated participants in MISO, including competitive suppliers and competitive retail LSEs.

- Merchant generators would have received almost $60 million more in capacity revenue, providing more efficient signals to maintain existing resources and build new resources. This revenue would have been key in maintaining economic resources that have retired over the past few years that caused MISO to now be short of resources in the Midwest.
- Costs borne by competitive retail load providers would have risen by $166.4 million per year. This is desirable because it provides incentives for these LSEs to arrange for their capacity needs and contribute to satisfying resource adequacy in MISO.

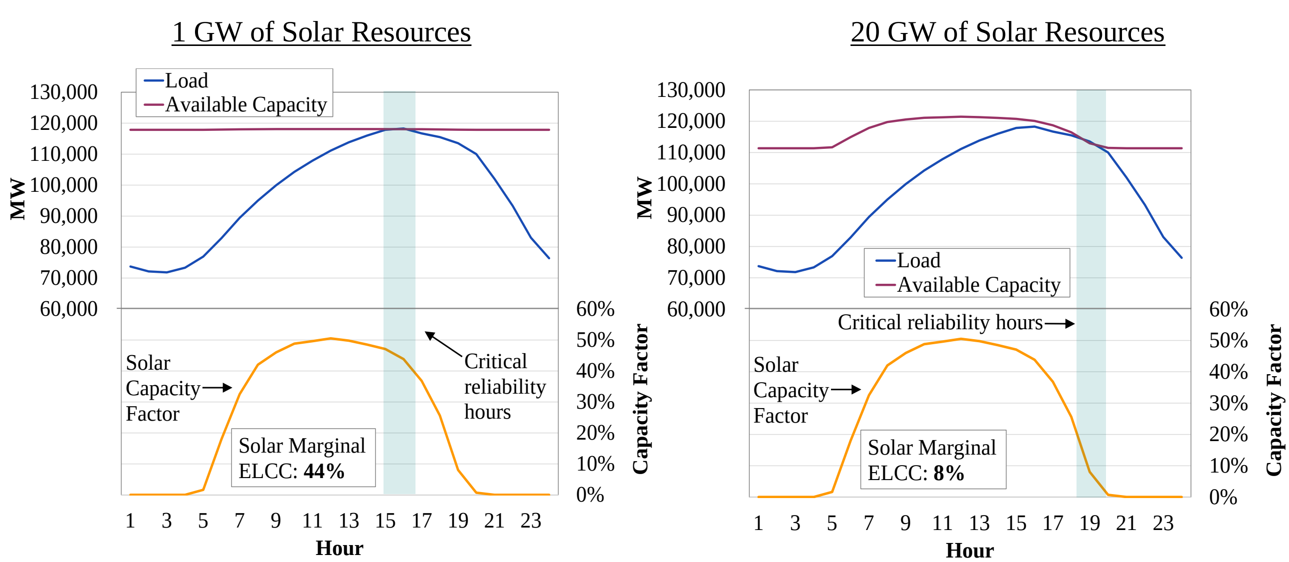
Non-Thermal Capacity Accreditation

A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. This value depends on (a) the timing of the system's hours of greatest need and (b) the factors that affect the availability of a resource in those hours. Importantly, the hours of greatest need are affected by the portfolio of generation and the output profile of the portfolio. Because the value of each additional MW is determined in part by the portfolio of existing generation, this value can be characterized as a "marginal value". For resources to be accredited accurately, RTOs must utilize methods that determine the marginal value of different types of resources.

MISO's recently implemented availability-based accreditation is generally consistent with this principle because it measures resources' availability during the tightest hours, which are determined by the operating characteristics of the existing generation portfolio. Intermittent resources are generally accredited using methods that predict the expected output of the resources under different conditions. One such method is the Expected Load Carrying Capability (ELCC) used by MISO, although its current approach is not marginal.

The following figure shows how the increasing penetration of one type of resource with similar output profile can affect the critical reliability hours and alter the marginal ELCC of the resources. This figure shows an illustrative example of the marginal ELCC value of solar resources in MISO based on a hypothetical peak summer day based on two different levels of solar resource penetration (1 GW and 20 GW).

Figure 18: Marginal Reliability Value of Solar Resources
Under 1 GW and 20 GW Penetration Scenarios



This figure shows that in a system with relatively low solar penetration (left panel), critical reliability hours occur in late afternoon when load is peaking and solar output is relatively high. Under these conditions, we estimate a marginal ELCC of 44 percent.

With high solar penetration (right panel), there is abundant available generation in the afternoon, which shifts the timing of critical hours towards the evening. The marginal value of solar falls under these conditions to a marginal ELCC of 8 percent because additional solar generation provides less reliability benefit when critical hours mostly occur in the evening.

The same principles apply to other types of generation, such as natural gas-only resources in the winter. Increasingly, critical reliability hours in the winter are likely to occur when natural gas availability is limited, causing natural gas-only resources that rely on non-firm fuel purchases to provide diminishing levels of reliability to the system. These changes must be reflected in the capacity accreditation framework to ensure that the market will perform well and maintain resources with attributes that are needed to maintain reliability.

If MISO fails to accredit resources based on their marginal value, the inflated accreditation to low-value (over-saturated) resources will substantially increase costs to consumers and undermine incentives to the high-value resources the system needs. Additionally, accurate accreditation will inform the states' integrated resource planning processes and ensure that these processes produce resource plans that will satisfy the reliability needs of the MISO region.

Marginal capacity accreditation is consistent with the principles that underlie MISO's market design. All of MISO's market products are priced based on marginal value and marginal cost. In MISO's capacity market, all sellers are paid a marginal clearing price. Hence, it is appropriate and necessary to determine capacity credit values such that an additional unit of capacity from any source provides the same amount of incremental reliability. This is accomplished by a marginal accreditation approach, and we continue to believe that the adoption of such an approach for all non-thermal resources is essential for satisfying MISO's reliability imperative.

IV. Energy Market Performance and Operations

MISO's electricity markets operate together in a two-settlement system, clearing in the day-ahead and real-time timeframes. The day-ahead market is financially binding, establishing one-day forward contracts for energy and ancillary services.[16] The real-time market clears based on actual physical supply and demand, settling any deviations from day-ahead contracts at real-time prices.[17] The performance of both markets is essential.

Day-ahead market performance is important because:

- Most resources in MISO are committed through the day-ahead market, so good market performance is essential to ensure efficient commitment of MISO's resources;[18]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market -- 98.5 percent in 2022 (net of virtual transactions); and
- The value of entitlements of firm transmission rights are determined by day-ahead market outcomes (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, while also establishing prices that indicate the real-time value of energy and ancillary services. These prices send economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. This section evaluates the performance of the day-ahead and real-time markets in key areas, as well as how they were operated by MISO.

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

The day-ahead energy prices tracked the real-time price trends described in Section II.A, rising substantially in 2022 as natural gas and coal prices increased. Average day-ahead energy prices across MISO increased 74 percent from 2021 to $65 per MWh. Congestion caused day-ahead prices at MISO's hubs to range from $47 per MWh at the Minnesota Hub to roughly $74 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 on a five-minute basis. This creates some issues in managing MISO ramp demands—i.e., the need to schedule generation to

---

16 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.

17 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.

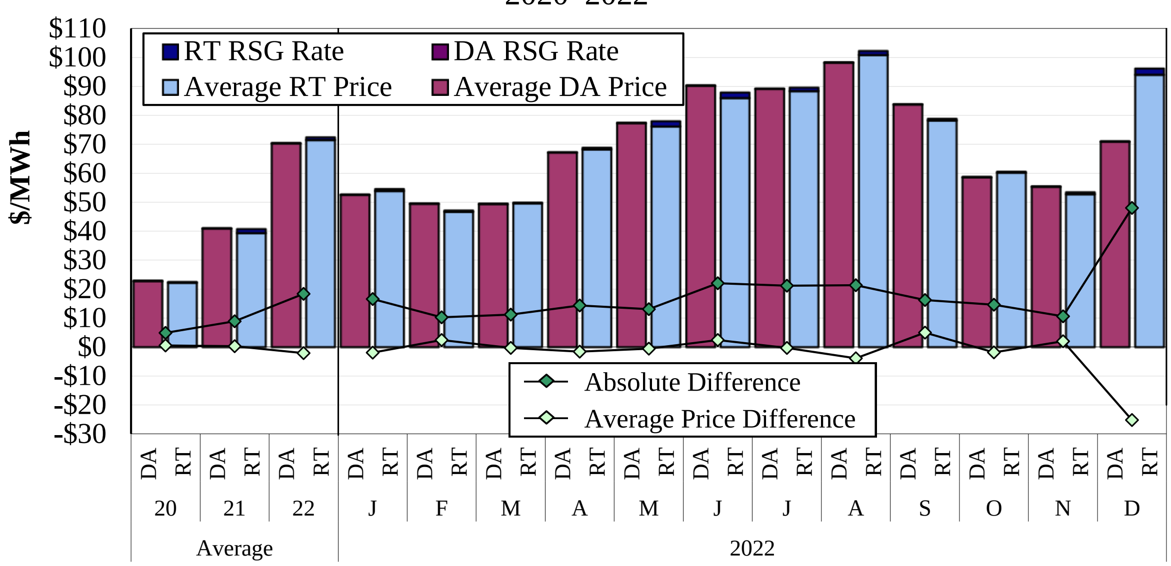
18 After the day-ahead market, MISO runs its Forward Reliability Assessment Commitment (FRAC) and Look-Ahead Commitment (LAC) process that may cause MISO to make additional commitments.

rise or fall gradually as load and other conditions change over the day. Since large changes in supply tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at these times. We have recommended MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market to improve the operation of the system.

The primary measure of performance of the day-ahead market is how well its prices converge to the real-time market prices. The real-time market clears actual physical supply and demand for electricity, and participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, several factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead market, such as wind or load forecast error, real-time output volatility, and forced generation or transmission outages. While 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 the monthly average prices plus the allocated RSG costs for the Indiana Hub. The real-time RSG charges (allocated partly to real-time deviations from day-ahead schedules) tend to be much larger than day-ahead RSG charges (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 difference (as a percentage) between day-ahead and real-time prices for six hub locations in MISO, accounting for the allocated RSG costs.

Figure 19: Day-Ahead and Real-Time Prices at Indiana Hub
2020–2022



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

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D
Indiana Hub	2	1	-3	-3	5	-1	-2	-1	3	0	-4	6	-3	4	-26
Michigan Hub	1	1	-1	-3	6	3	-3	5	6	-1	-3	7	1	4	-21
Minnesota Hub	-2	-1	0	3	8	8	2	-1	10	-2	-5	7	0	4	-17
Arkansas Hub	1	-3	-2	-2	3	3	3	6	3	-5	-7	4	-3	-3	-18
Louisiana Hub	2	-1	-1	-3	5	4	4	8	5	0	-7	3	-1	-1	-23
Texas Hub	6	-2	-1	-4	4	4	1	9	4	-2	-7	4	-1	-2	-24

These results indicate that price convergence was good overall. Day-ahead prices were about three percent lower than real-time prices after adjusting for the real-time RSG costs, which averaged $0.99 per MWh. Divergence between day-ahead and real-time prices occurred primarily because of transient conditions in 2022. The most significant source of divergence occurred during Winter Storm Elliott in December. During this event, MISO experienced extended periods of shortage pricing that was particularly significant in the South.

B. Virtual Transactions in the Day-Ahead Market

A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. The buyer (or seller) enters the real-time long (or short). Since they do not produce or consume physical energy, virtual transactions positions settle against real-time prices. Virtual transactions are essential facilitators of price convergence because they are used to arbitrage price differences between the day-ahead and real-time markets. Figure 20 shows the average offered and cleared virtual supply and demand. The figure separately shows financial-only participants and physical participants.

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

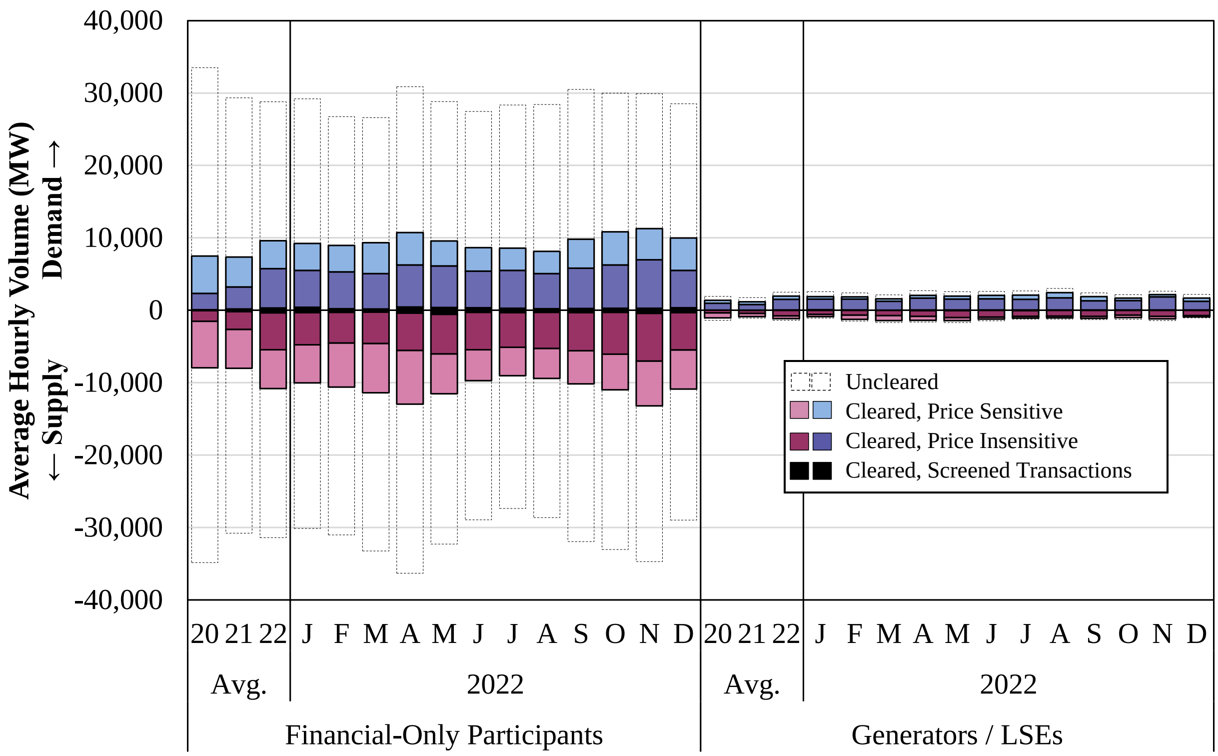


Figure 20 shows that financial participants continue to account for the vast majority of virtual transactions, although the limited quantities scheduled by physical participants grew roughly 50 percent. In total, cleared transactions increased by 35 percent, driven by increases in cleared virtual activity of 36 percent in the Midwest and of 15 percent in the South.

Figure 20 indicates the following additional key findings:

- Financial participants offer more price-sensitively and provide day-ahead market liquidity.
- 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) constitute a significant share of all virtual transactions. They provide less liquidity to the market and can raise manipulation concerns.
  - Most price insensitive transactions are used to arbitrage congestion-related price differences by allowing participants to establish an energy-neutral position between two locations (offsetting virtual supply and demand positions at two locations). We refer to these transactions as "matched" transactions.
  - Matched transactions avoid RSG deviation charges and carry no energy price risk. Their average hourly volume increased by 90 percent from 2021 to 2,063 MW.
  - We continue to recommend MISO implement a "virtual spread product" that would allow participants to engage in such transactions price-sensitively. Comparable products exist in both 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 3.1 percent of all transactions and raised no concerns in 2022.

Virtual Activity and Profitability

Gross virtual profitability rose 14 percent in 2022 to average $1.37 per MWh, up from $1.20 per MWh in 2021. Both virtual demand and virtual supply profitability increased substantially. Some of this increase was due to high profits during Winter Storm Elliott in December, when real-time price spikes raised virtual demand profitability to average almost $14 per MWh.

In general, gross profits are higher for virtual supply because more than half of these profits are offset by real-time RSG costs allocated to participants with net virtual supply positions. This allocation eliminates the incentive for virtual suppliers to pursue low-margin arbitrage opportunities. Virtual demand does not bear capacity-related RSG costs because they reduce the need for real-time capacity commitments. Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $1.45 per MWh compared to $0.83 per MWh.

To provide perspective on the virtual trading in MISO, Table 3 compares virtual trading in MISO to trading in NYISO, ISO New England, SPP, and PJM. This table shows that virtual trading is generally more active in MISO than in other RTOs, even after adjusting for the much larger size of MISO. This is partly due to the more efficient allocation of RSG costs that MISO uses. The table also shows that liquidity provided by virtual trading in MISO translates to relatively low virtual profits. Virtual supply profits are higher than virtual load because of the RSG cost allocation discussed above.

Table 3: Comparison of Virtual Trading Volumes and Profitability
2022

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	14.9%	$1.00	15.5%	$1.73
NYISO	5.9%	$5.15	5.9%	$0.10
ISO-NE	3.1%	-$0.60	4.9%	$2.84
SPP	9.4%	$0.05	16.2%	$7.83
PJM	5.7%	$4.72	4.0%	-$0.19

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

Benefits of Virtual Trading

We studied the contribution of virtual trading to market efficiency in 2022. We determined that 60 percent of all cleared virtual transactions in MISO were efficiency-enhancing and led to convergence between the day-ahead and real-time markets. The majority of efficiency-enhancing virtual transactions were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price).

A small share of the efficiency-enhancing virtual transactions was unprofitable, which occurs when virtual transactions respond to a real-time price trend but overshoot. We did not include profits from un-modeled constraints or from loss factors in our efficiency-enhancing category because these profits do not increase day-ahead efficiency. A detailed description of our methodology can be found in the Appendix Section IV.G.

Virtual transactions that did *not* improve efficiency led to divergence and were generally those that were unprofitable based on the energy and congestion on modeled constraints. They can be profitable when they profit from un-modeled constraints or loss factor differences. Table 4 shows the total amount of efficient and inefficient virtual transactions by market participant type.

The table shows that 60 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $201.4 million, up from $133.2 million in 2021. However, this value significantly understates the net benefits of the virtual transactions because it measures the profits at the margin.

In other words, the total benefit is much greater than the marginal benefit, because:

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

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant in 2022

Transaction Category	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	92,126,308	$1,771.9M	-$72.4M	12,031,077	$219.6M	$5.9M
Efficiency Enhancing (Unprofitable)	14,349,361	-$141.4M	$28.1M	2,235,921	-$21.0M	$3.5M
Not Efficiency Enhancing (Profitable)	5,422,658	-$42.7M	$93.8M	830,514	-$4.1M	$8.9M
Not Efficiency Enhancing (Unprofitable)	66,910,978	-$1,389.8M	$11.7M	12,056,649	-$191.2M	$.9M
Total	**178,809,305**	**$198.1M**	**$61.2M**	**27,154,161**	**$3.4M**	**$19.1M**

Although we are not able to rerun the day-ahead and real-time market cases for the entire year, this analysis provides a high degree of confidence that virtual trading was beneficial in 2022.

C. Real-Time Market Pricing

Efficient real-time market outcomes are essential because they provide incentives for suppliers to be available and to 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 in this subsection because it is addressed in Section III.B, which discusses the future needs of the MISO markets. Efficient shortage pricing is essential for the market to perform well, especially as the reliance on intermittent resources rises.

Fast-Start Pricing by the ELMP Model

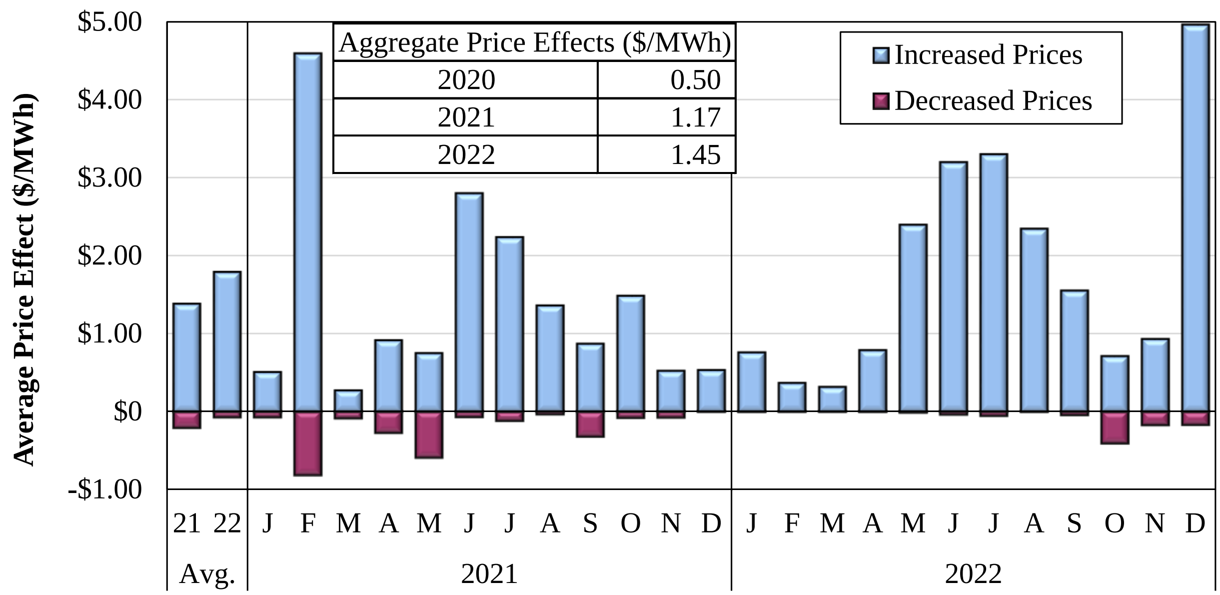
Beyond shortage pricing, a key element of MISO's real-time pricing is its Extended Locational Marginal Pricing (ELMP) algorithm that was implemented in March 2015. While MISO's dispatch model calculates "ex ante" real-time prices every five minutes, these real-time prices are re-calculated by the ELMP model and used for real-time settlements. ELMP is intended to improve price formation by establishing prices that better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP reforms pricing by allowing Fast-Start Resources (FSRs) and emergency resources to set prices when needed and economic to satisfy the system's needs.[19]

19 MISO had previously allowed offline fast-start resources to set prices under transmission and reserve shortage conditions, which was inefficient and was suspended in ELMP in October 2021.

When FSRs are not reflected efficiently in prices, the resulting understatement of prices leads to higher RSG costs and poor pricing incentives for scheduling generation and interchange. Although FSRs may not appear to be marginal in the five-minute dispatch, the ELMP model recognizes that peaking resources are marginal and should set prices to the extent they are needed to satisfy the system's needs.

Although the initial impacts from ELMP were small, MISO implemented a number of recommendations to improve its effectiveness from 2017 through 2019 that have improved price formation. MISO implemented a final key recommendation in September 2021 to address an issue that had prevented FSRs that were needed to satisfy the system demands from setting prices. Together, these changes have significantly improved real-time price formation in MISO. The following figure summarizes the effects of the ELMP pricing model in 2022.

Figure 21: The Effects of Fast Start Pricing in ELMP
2021–2022



% of Intervals Affected by > +/- $0.10

SMP Increase	56	57	36	57	44	61	54	68	61	60	54	66	61	52	56	49	42	54	58	60	59	51	75	58	63	55
SMP Decrease	2	1	3	6	2	3	5	1	1	1	1	1	1	0	0	0	0	1	1	4	1	1	2	0	4	1

As shown in Figure 21, the effects of ELMP on MISO's real-time energy prices rose 24 percent in 2022. This increase was due to a combination of the ELMP improvements described above, the high price effects in December, higher natural gas prices, and the elimination of offline ELMP pricing in the fall of 2021. We expect ELMP will continue to perform well because of the improvements MISO has made in recent years. As expected, ELMP had almost no effect in the day-ahead market because the supply is far more flexible and includes virtual transactions.

Emergency Pricing by the ELMP Model

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 2021, MISO implemented recommended improvements to its ELMP emergency pricing. MISO expanded the set of resources that can set prices during an emergency[20] and established minimums on the Tier 1 and Tier 2 Emergency Offer Floor Prices applied to emergency resources at $500 per MWh and $1,000 per MWh, respectively.[21] In previous years, MISO's emergency offer floor prices were set inefficiently low. MISO updated the value of RPE constraints to $200 per MWh during emergencies. These changes have helped ensure that MISO's emergency pricing sets more efficient prices during emergencies.

Modifying the Market Pricing during LMR Deployments

While EEA2 events that prompt MISO to deploy LMRs have been rare, pricing during these events has not been efficient in many cases. The ELMP model that produces prices during emergency conditions determines whether emergency resources should set prices by attempting to dispatch them down and allow other resources to replace them. The theory is that if the ELMP model cannot ramp the resources to zero, then they are needed and should set real-time prices. While 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 the ramp capability on other resources to replace the LMRs in a single dispatch interval. Therefore, they often set prices long after they are no longer needed. This has resulted in:

- Elevated prices and excessive non-firm imports as participants respond to these prices;
- High prices extending beyond the emergency area to all of MISO once supply is adequate and the constraint into the area unbinds; and
- Large uplift payments in the form of price-volatility make-whole payments that must be made to resources that are held down to make room for the LMRs and non-firm imports.

We recommend MISO consider revising its emergency pricing model to reintroduce LMR curtailments as Short-Term Reserves, instead of energy demand, to produce more efficient emergency pricing and better align ex-ante and ex-post results. We previously validated the value of this approach by simulating the emergency that occurred on June 10, 2021. This simulation was described in the *2021 State of the Market Report* and showed that the actual prices set between $200 and $400 per MWh for almost two hours would have been less than $150 per MWh. This demonstrates the significantly improved pricing outcomes resulting from treating LMRs as Short Term Reserves demand in the ELMP pricing model.

---

20 Resources offering up to four hours to start and a minimum run time up to four hours may now set the price during emergency conditions (Tier 0 Emergency Offer Floor Price) when MISO declares a Max Gen Alert.

21 Tier 1 Emergency Offer Floor Prices apply when MISO declares a Max Gen Warning, while Tier 2 applies when MISO declares a Max Gen Event Step 2.

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

Evaluating uplift costs is important because these costs are difficult for customers to forecast and hedge, and they generally reveal areas where the market prices do not fully capture the cost of system requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments to ensure resources cover their as-offered costs and provide incentives to be available and flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure the total market revenue for a unit committed economically or for reliability 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.

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

Day-Ahead and Real-Time RSG Costs

Figure 22 shows monthly day-ahead RSG costs categorized by the underlying cause. Most RSG payments for Voltage and Local Reliability (VLR) are made in the day-ahead market because most VLR commitments are made before or during the day-ahead market process. Because fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[22] The maroon bars show all the RSG paid to units started for VLR before the day-ahead market cleared, except that the VLR costs incurred for the Western Op Guide (replaced by the Southeast Texas (SETEX) Op Guide in August 2022) is shown in the maroon striped bars. The blue part of the bars shows RSG incurred for commitments made to maintain system-wide capacity.

Nominal day-ahead RSG payments fell 25 percent in 2022 to total $65 million, although it fell only 9 percent if the effects of Winter Storm Uri in February 2021 are excluded. Almost all day-ahead VLR costs accrue in two load pockets in MISO South, but three new gas-fired combined-cycle units exceeding 3 GW in total came online in MISO South in the past 3 years that reduced the need for these VLR commitments. In August 2022, MISO implemented a new op guide to fully incorporate the impacts of the addition of a large, 1 GW combined-cycle facility in early 2021 in WOTAB. We encourage such updates to be implemented in a timelier manner to avoid unnecessary commitments.

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

Figure 22: Day-Ahead RSG Payments
2021–2022

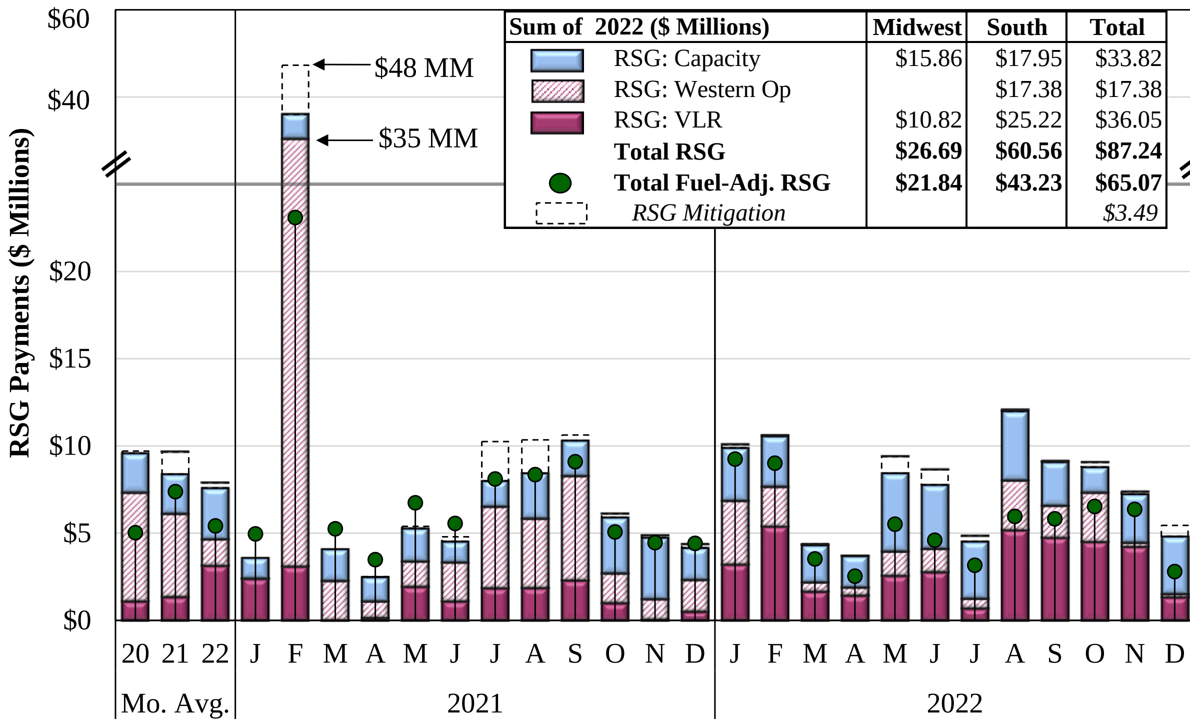
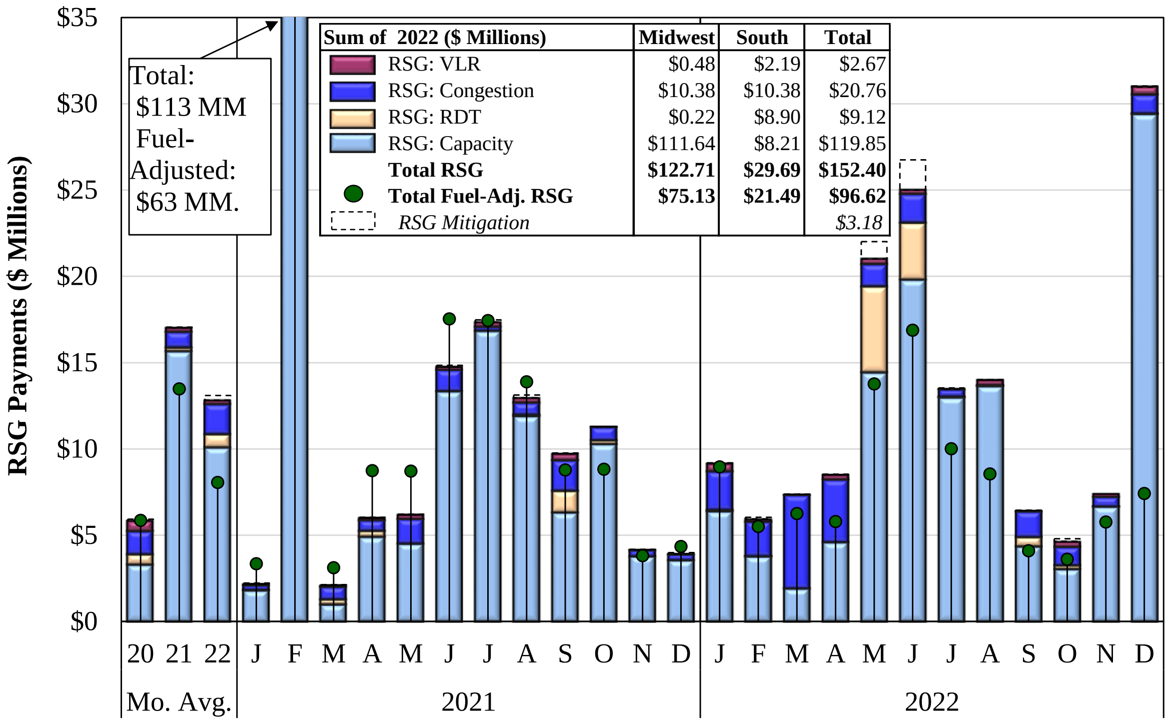


Figure 23 shows the same categories of real-time RSG payments, and includes RSG costs for units committed to: a) manage congestion, and b) manage RDT flows or create regional reserves.

Figure 23: Real-Time RSG Payments
2021–2022



The figure shows that real-time nominal RSG payments fell 40 percent in 2022, largely because real-time RSG was very high in 2021 during and after Winter Storm Uri. MISO incurred roughly $100 million during that event, compared to $24 million that MISO incurred during Winter Storm Elliott. Although RSG was lower on average, MISO incurred higher RSG between May and August in 2022 and commitment patterns played a key role. We evaluate and discuss the resource commitments in the next subsection.

Price Volatility Make-Whole Payments

PVMWPs address concerns that resources can be harmed by responding to volatile five-minute price signals. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and come in two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP). DAMAP payments are made when resources produce output at a level less than both the day-ahead schedule and the economic output level given its offer price. RTORSGP payments are made when a unit is operated higher than its economic output level. Table 5 shows the annual totals for DAMAP and RTORSGP, along with the price volatility at the system level (SMP volatility) and at the unit locations receiving the payments (LMP volatility). We separately indicate the amount of PVMWP MISO incurred excluding Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022.

Table 5: Price Volatility Make-Whole Payments ($ Millions)
2020–2022

	DAMAP		RTORSGP		Total	Avg. Market-Wide Volatility	Avg. Locational Volatility
	Midwest	South	Midwest	South			
2022	$69.9	$11.1	$5.2	$1.5	$87.7	15.2%	21.0%
WS Elliott	*$23.0*	*$0.7*	*$0.0*	*$0.1*	*$23.8*		
2021	$33.0	$14.2	$4.0	$2.1	$53.3	13.4%	14.3%
WS Uri	*$6.5*	*$6.9*	*$0.0*	*$1.3*	*$14.7*		
2020	$23.2	$4.5	$1.8	$0.5	$30.0	14.3%	19.2%

PVMWPs rose 65 percent over 2021. A large portion of the DAMAP in 2021 occurred in February 2021 when prices reached $3,500 per MWh for several hours during load shed conditions, while a large portion of the DAMAP in 2022 occurred in December when MISO experienced prolonged shortage pricing and emergency pricing. Some of the year-over-year increase was due to higher energy prices that resulted from higher fuel prices.

E. Real-Time Commitment Patterns

Excluding the very high RSG payments incurred during winter storm events (Uri in 2021 and Elliott in 2022), real-time fuel-adjusted RSG payments increased by 69 percent from 2020 to 2021 and 47 percent from 2021 to 2022. In 2021, we identified a pattern of increasing capacity-related commitments beginning in the summer months. Figure 24 shows monthly RSG costs in 2022 for resources committed in real time for capacity. We have evaluated these costs and categorize the RSG according to that which was:

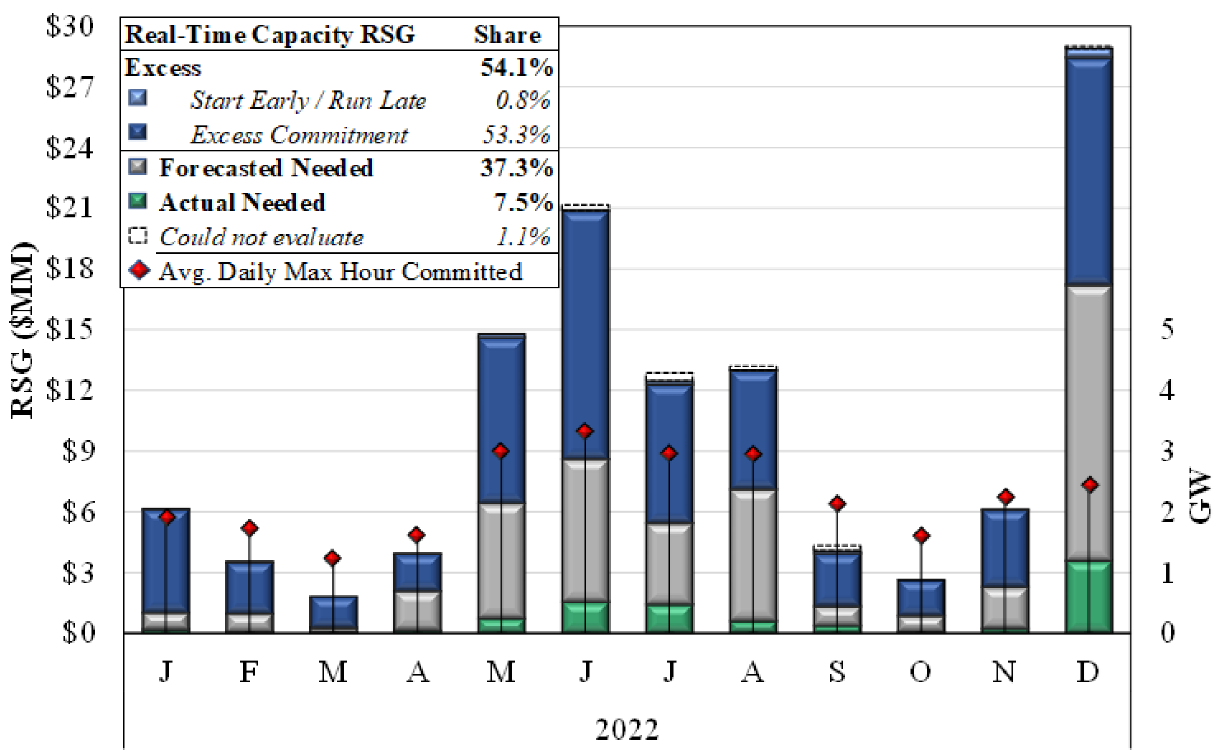
- Actually needed to cover load and reserves;
- Not needed based on actual load but that MISO forecasted as needed; and
- Not needed based on actual load or forecasted load (excess commitments).

The figure also shows the monthly GW average of the daily maximum commitment. For purposes of this evaluation, we accept the commitment criteria and capacity requirements that MISO employs. Accepting these requirements and targets, our evaluation finds that:

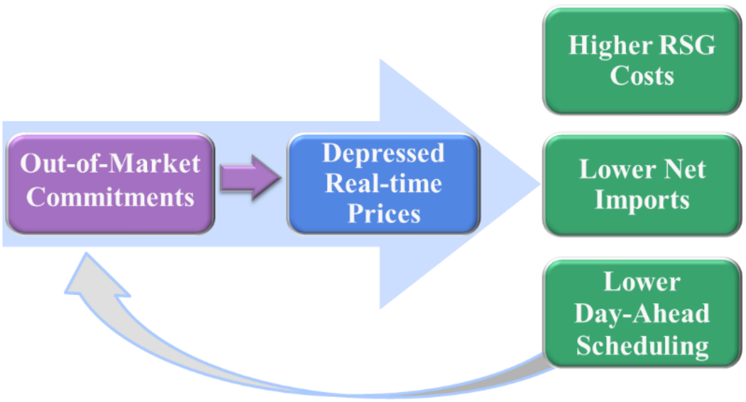
- Roughly 7.5 percent of the capacity-related RSG costs were actually needed, while another 37 percent appears to have been needed when commitment decisions were made.
- 54 percent of the capacity-related RSG costs were associated with commitments that were not needed or forecasted to be needed when they were made (i.e., excess).
- A small portion of the excess commitments was associated with resources being started earlier than needed or not being decommitted when no longer needed.

These results raise substantial concerns not only because of the costs they generate, but more importantly for the secondary adverse effects they have on MISO's market outcomes.

Figure 24: Monthly Real-Time Capacity Commitments and RSG Costs in 2022



Excess out-of-market commitments undermine the performance of the markets by creating a self-enforcing cycle of excess commitments. As the illustration below shows, they depress real-time prices, which increases RSG costs and reduces supply – increasing the need for out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 98 percent of peak real-time load in 2022), and b) reduce net imports in the real-time market.



We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have recommended a number of improvements designed to reduce the frequency of unnecessary commitments, including:

- Eliminating the use of manual inputs to the LAC model to address uncertainty since they cause it to recommend unnecessary commitments, increasing STR requirements instead.
- Deferring commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Use reserve demand curves and TCDCs in the LAC and other commitment models that are more closely aligned with the market demand curves.

MISO has created a team to evaluate existing tools and operating practices and has begun working with the IMM to make recommended changes. Improving operator logging is also important because it will facilitate better understanding of the causes of excess commitments.

F. Regional Directional Transfer Flows and Regional Reliability

The scheduled transfers between the South and Midwest are limited to contractual limits. MISO has taken two actions to prevent exceeding these limits: (a) implementing a post-contingent constraint to hold headroom on the RDT, and (b) actively managing the RDT limit to avoid unmodeled exceedances. The latter involved MISO binding the RDT in real time at an average of 318 MW below its contractual limit.

Flows on the RDT averaged 807 MW in the South to North direction in 2022 but flows across the RDT in the North to South direction were generally correlated with wind output. Importantly, limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties' systems is inefficient. To reduce these inefficiencies, we recommend that MISO explore better coordination and settlements on the constraints in adjacent areas that are affected by the transfers. This would increase MISO's ability to transfer power while reducing the congestion effects on its neighbors.

Currently, all wind resources in MISO are in the Midwest Region, so when MISO experiences high wind, the RDT flows tend to be in the North to South direction. Conversely, when wind falls sharply, flows tend to reverse to the South to North direction. The ability of the MISO market to shift the quantity and direction of flows by more than 5,000 MW provides tremendous value to the customers in both regions.

G. Real-Time Dispatch Performance

MISO issues dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Good performance of MISO's generators is essential to efficiently managing congestion and maintaining reliability in MISO. Therefore, it is critical that MISO's markets provide adequate incentives for its generators to perform well in following MISO's dispatch instructions. Failing to meet the dispatch instruction is known as "dragging", and it can be measured in each 5-minute interval or summed over a longer period (e.g., 60-minutes). Table 6 shows the average 5-minute and 60-minute average hourly dragging in recent years in all hours and in hours when generation must ramp up or down rapidly in the morning and evening.

Table 6: Average Five-Minute and Sixty-Minute Net Dragging
2018–2022

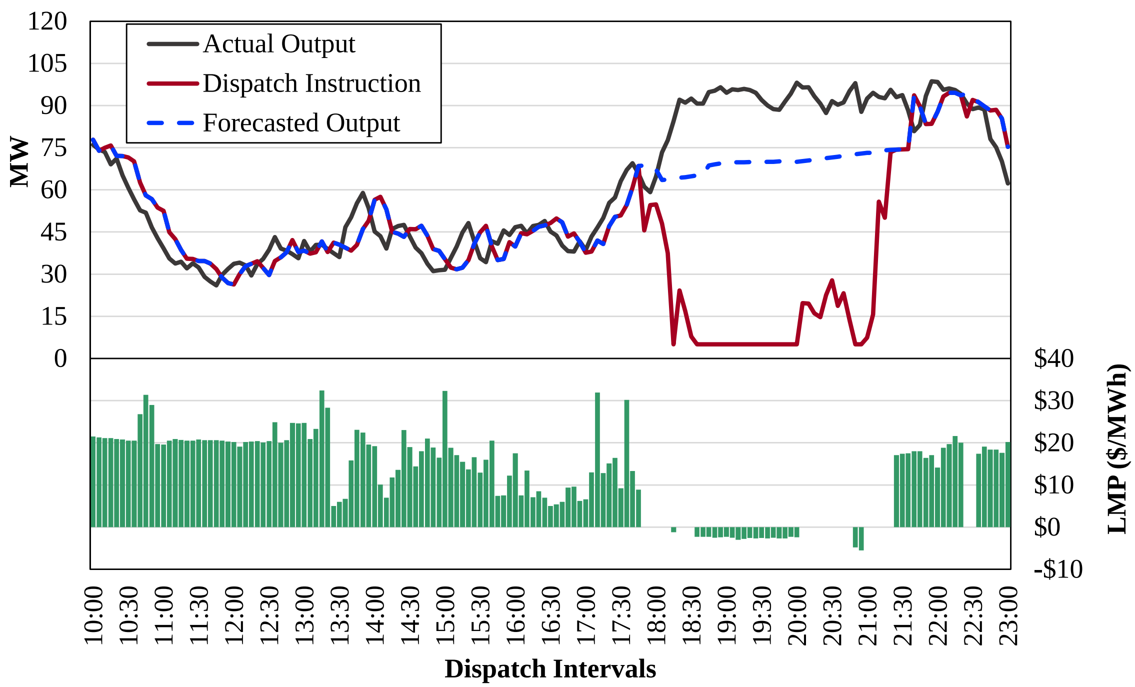
	5-min Dragging		60-min Dragging		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2022	637	660	1,049	1,009	1,341	1,275
2021	611	629	956	908	1,338	1,290
2020	573	563	957	862	1,289	1,193
2019	525	526	851	787	1,163	1,078
2018	595	563	991	851	1,305	1,216

Table 6 shows that the 60-minute dragging in all hours increased 11 percent from 2021 to 2022. Dragging raises a substantial concern because capacity on resources that are not following dispatch instructions is effectively unavailable to MISO. Almost 20 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because MISO operators do not perceive this effective loss of capacity and, therefore, may not make economic or needed commitments. Some of these 60-minute deviations may indicate units that are derated and physically incapable of increasing their output. Because participants are obligated to report derates under the Tariff, we have referred the most significant "inferred derates" to FERC enforcement. Additionally, such conduct can qualify as physical withholding when no physical cause for the derate exists.

The failure to follow dispatch instructions generally creates the greatest adverse effects when the resource affects a binding transmission constraint. In this case, the real-time market dispatch will produce dispatch instructions and prices that assume the resource will follow the dispatch instructions. Figure 25 shows the actual output of a wind resource from 10 a.m. to 11 p.m. on a given day, along with the forecasted output, dispatch instruction, and the LMP at the resources' location. The forecast matches the dispatch instruction whenever the unit is not curtailed because: (a) the forecast is assumed to be the unit's economic maximum level and (b) the unit is offered at a negative price. Since MISO uses a persistence forecast, the forecast always equals the observed output of the unit roughly 10 minutes earlier, except when the unit is curtailed.

From approximately 6 p.m. to 9:15 p.m., the real-time dispatch model attempted to curtail this unit and generally set prices at zero or at a slightly negative price. These prices reflect the substantial congestion that the dispatch model recognized assuming this unit will follow the dispatch instruction. In reality, the congestion was more severe because the excess output from this unit increased the flow on the constraint by as much as 38 MW, violating the modeled limit for the constraint by as much as 9 percent.

Figure 25: Example of Wind Resource Failing to Follow Dispatch Instructions



These findings indicate the importance of improving generators' incentives to follow dispatch instructions and update to resources' real-time offers in a timely manner. We discuss below our recommendation for improving these incentives for units that overload transmission constraints.

Aligning Uninstructed Deviation Penalties with Congestion Impact

Current settlement rules are insufficient for generation deviations outside the uninstructed deviation (UD) tolerance bands and deviations that persist for less than 20 minutes are exempted from any financial penalty. The most significant penalty is the excessive energy price, paid at the lower of LMP and as-offered cost on excessive energy volumes. This provides a very weak incentive, particularly to renewable resources, which often set price 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 the excess energy causes transmission overloads that are difficult to manage.

To address this concern, which is bound to grow as more intermittent resources enter the system, we are recommending an improvement to the penalty structure that would be based on the marginal congestion component (MCC) of the resource's LMP. For excessive or deficient energy that loads a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is appropriate because it reflects the incremental congestion value of the deviation volumes and scales with the severity of congestion. The table below shows how this penalty would have affected different types of units in 2022.

Table 7: Proposed Uninstructed Deviation Penalties and Effective Rate in 2022

		Avg. Deviation Penalty ($/MWh)		Avg. Penalty ($/MWh of Output)	
Unit Type	**Total Penalty**	**Excessive**	**Deficient**	**Excessive**	**Deficient**
Gas Turbine	$405,553	$6.12	$5.43	$0.003	$0.003
Coal	$1,033,785	$11.58	$6.50	$0.003	$0.002
Combined Cycle	$489,974	$4.82	$4.02	$0.002	$0.002
Other	$645,519	$5.65	$4.77	$0.002	$0.003
Solar	$71,627	$10.01	$3.60	$0.009	$0.008
Wind	$3,298,440	$40.83	$1.81	$0.032	$0.001

There are several key takeaways from this table:

- The average penalty rate per MWh of output is extremely low at less than $0.01 for most conventional generation. Resources that follow dispatch instructions reasonably well should be minimally impacted by this proposal.
- The deviation penalty rate is material, averaging $17.02 and $4.23 for excessive energy and deficient energy, respectively. These rates vary based on the duration and congestion caused by different units' deviation. These penalties should promote better performance.
- The penalties and penalty rates are largest on excessive energy from wind resources. Nearly all wind resources – those that use the MISO forecast – are exempt from UD penalties Except when curtailed. Nonetheless, they would account for a disproportionate share of the penalties. Because they have such fast ramp rates, failure to follow dispatch can result in large deviations that cause serious constraint violations with little warning.

The proposed penalties will improve dispatch incentives for all resources, and particularly for those whose deviations cause the most serious reliability concerns.

Dispatch Operations: Offset Parameter

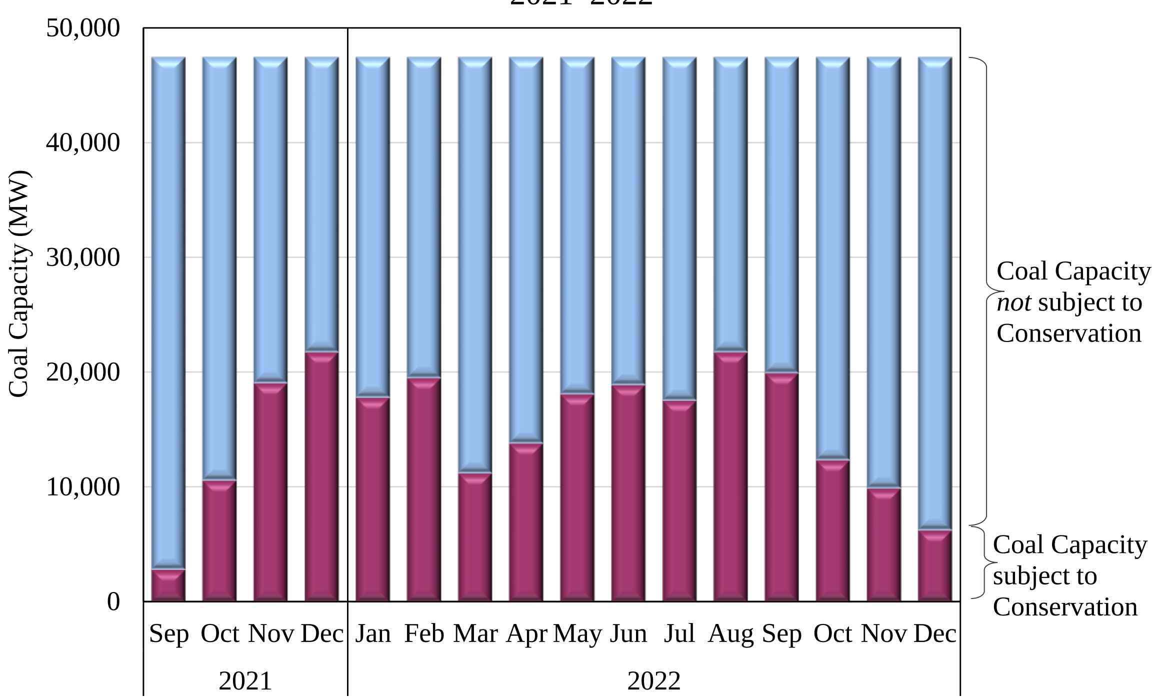
The offset parameter is a quantity chosen by the MISO real-time operators to adjust the modeled load to be served by the UDS. A positive offset value is added to the short-term load forecast to cause an increase in the generation output, while a negative offset decreases the load and the corresponding dispatch instructions. Offset values may be needed for many reasons, including: a) generator outages that are not yet recognized by UDS; 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 believe 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, so large changes in the offset can lead to sharp changes in prices. Our analysis shows large offset increases sometimes lead to operating reserve shortages and associated price spikes. Conversely, offset reductions sometimes mute legitimate shortage pricing. MISO utilizes a tool that recommends offset values. We are concerned about some of the logic and calculations underlying these recommendations, which have sometimes led to poor offset selections. In response to these concerns, MISO has made some changes and agreed to work with us to resolve other concerns.

H. Coal Resource Operations

In the summer of 2021, as natural gas and energy prices rose during the summer months, the economic operating margins of MISO's coal-fired resources rose substantially and caused them to operate at higher capacity factors. However, multiple coal-fired resources began to experience COVID-related supply chain issues, transportation limitations, and shortages of reagents by the fall. These limitations led to coal conservation strategies that substantially reduced their output beginning in the fall of 2021. Figure 26 shows the quantities of resources conserving coal by month from the fall of 2021 through December 2022.

Figure 26: Coal Capacity Impacted by Coal Conservation Measures
2021–2022



This figure shows that by February 2022, lower-than-expected December gas prices and mild conditions allowed many resources to build up their coal inventories. At the end of the winter quarter, the number of resources conserving coal fell by 40 percent. Coal resources were utilized at higher rates through the summer of 2022, and coal conservation increased up through September. After September, coal supply constraints eased as railroads were able to provide more coal deliveries in MISO.

In Table 8, we summarize our analysis of coal resource operations, including how they are started and how profitably they operated. Because many of the regulated utilities operate differently than unregulated merchant generators, the table shows our results for them separately.

Table 8: Coal-Fired Resource Operation and Profitability
2017–2022

	2017-2020			2021			2022		
	Annual Starts	**% of Starts**	**Net Rev. ($/MWh)**	**Starts**	**% of Starts**	**Net Rev. ($/MWh)**	**Starts**	**% of Starts**	**Net Rev. ($/MWh)**
Regulated Utilities	1839		**$3.54**	1718		**$14.04**	1765		**$22.41**
Profitable Starts	1570	87%		1564	91%		1635	93%	
Offered Economically	*727*	*39%*		*885*	*52%*		*754*	*43%*	
Must-Run and profitable	*843*	*48%*		*679*	*40%*		*881*	*50%*	
Unprofitable (Must Run)	269	13%		154	9%		130	7%	
Merchants	187		**$5.05**	124		**$14.96**	84		**$30.42**
Profitable Starts	184	97%		124	100%		84	100%	
Offered Economically	*143*	*70%*		*124*	*100%*		*84*	*100%*	
Must-Run and profitable	*41*	*27%*		*0*	*0%*		*0*	*0%*	
Unprofitable (Must Run)	4	3%		0	0%		0	0%	

Table 8 shows that in 2022, coal resources were much more profitable than in recent years—their net revenues rose to almost $23 per MWh on average. These values are roughly six times higher than the average net revenues coal resources earned between 2017 and 2020. Although coal-fired resources were more economic in 2022, the fuel limitations and other supply chain issues limited the increase in their output.

Table 8 also shows that the share of resources running profitably increased significantly in 2022. This was likely due to the increasing energy prices. However, MISO's regulated utilities often continue to operate their resources as "must-run," running them regardless of the price. In contrast, MISO's unregulated merchant generators always offered economically in 2022 and ran profitably in 100 percent of their run hours.

I. Wind Generation

As discussed in Section III.A, wind capacity is continuing to grow in MISO. Accounting for over 29 GW of MISO's installed capacity, wind resources produced 16 percent of all energy in MISO in 2022. Section III.A also discusses the long-term challenges this will present and the market enhancements that we recommend. This subsection describes key trends related to wind output, wind scheduling, and wind forecasting. These results are summarized in Table 9.

Table 9: Day-Ahead and Real-Time Wind Generation

	Name Plate Capacity	Avg. Output (GW)			RT Seasonal Avg. Output (GW)			RT Top 5% Hourly Avg. Output (GW)			2 Hour Forecast Error (%)	
		RT	DA	%	Jan.-Apr.	May-Aug.	Sep.-Dec.	Jan.-Apr.	May-Aug.	Sep.-Dec.	Avg. Error	Abs. Avg.
2022	29,109	11.3	10.1	-10.8	13.7	8.4	11.9	21.6	18.0	21.6	2.3%	6.6%
% *	*8%*	*23%*	*26%*		*37%*	*20%*	*11%*	*16%*	*18%*	*8%*		
2021	26,862	9.2	8.0	-13.0	10.0	7.0	10.7	18.6	15.3	19.9	-3.3%	6.7%
2020	24,450	8.1	6.6	-19.3	8.4	6.4	9.5	16.1	13.9	17.4	-2.0%	7.6%
2019	19,127	6.5	5.5	-15.9	7.2	4.7	7.5	14.4	11.4	14.6	-3.9%	7.8%

Note 1: 2019 Forecast Error calculated for 7/10-12/31.

Note 2: % Change between 2021 and 2022.*

Wind Output Trends

Average wind output has been growing rapidly, increasing 23 percent from last year and 74 percent over 2019, just three years ago. The table also reveals the seasonal wind output patterns, with output decreasing in summer months and at its highest levels in the spring and fall seasons. Both the average seasonal output and the output in the highest wind hours have been consistently rising over the past three years. We expect this trend to continue given the new wind projects in MISO's interconnection queue and the state and federal incentives available to wind resources.

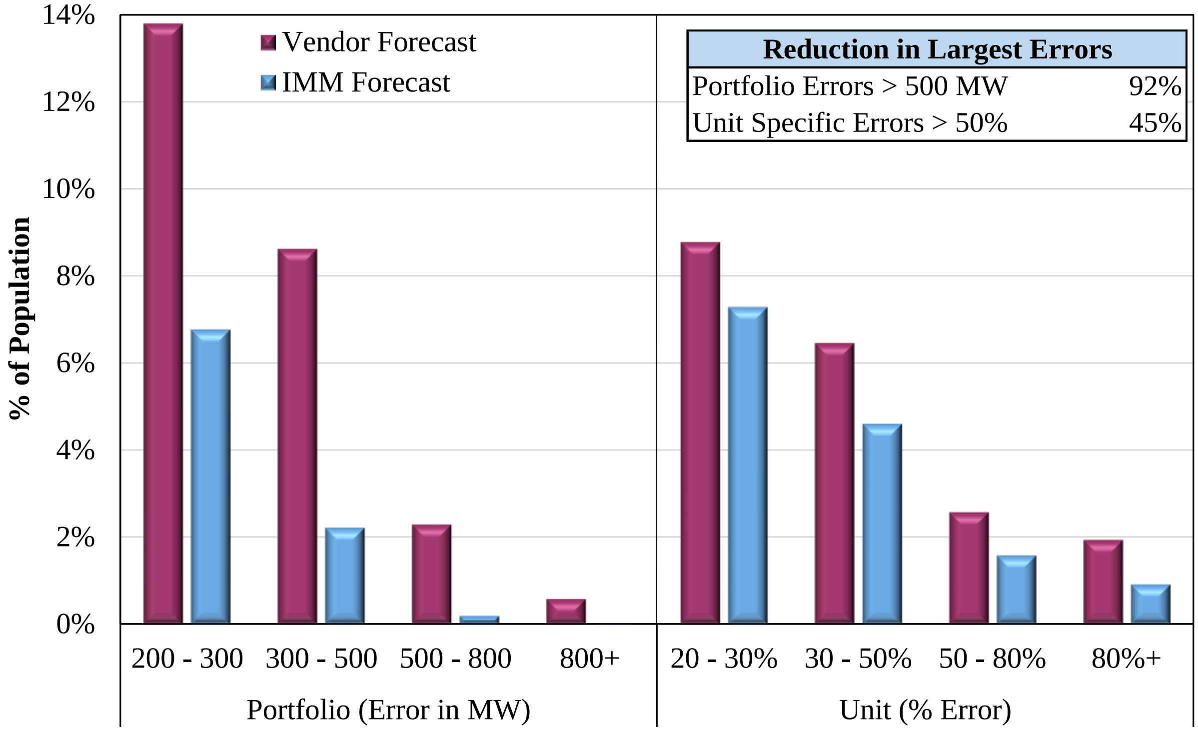
Wind Forecasting

The sharp rise in wind output has increased the operational challenges associated with managing the ramp demands resulting from the wind output fluctuations that are described in Section III.A. The accuracy of the wind forecasts plays a key role in managing these challenges. The wind forecasts are important because MISO uses them to establish wind resources' economic maximums in the real-time market. Because wind units offer at prices lower than other units, the forecasted output also typically matches the dispatch instruction, absent congestion. Wind suppliers can submit their own forecasts or rely on MISO's forecasts. MISO's settlement rules provide strong incentives for participants to use MISO's forecast and most wind resources do so.

MISO's Wind Forecasts. MISO implemented a change in early 2020 that reduced a relatively large bias in MISO's near-term forecast used in the real-time market dispatch. However, the forecast errors are still frequently large. MISO's near-term forecast is primarily a "persistence" forecast that assumes future wind resource output will match the most recent output observation. We developed a forecast methodology that is also persistence-based, but also incorporates the recent direction in output changes.

Figure 27 compares the IMM methodology to the current methodology employed by MISO's wind vendor. This figure shows that substantial improvement can be achieved by modestly changing the current persistence forecast – this change would reduce the frequency of the highest portfolio-level errors by more than 90 percent, while reducing the highest average unit-level errors by 45 percent.

Figure 27: Wind Forecast Methodology Improvement



Improving the forecast of wind units' output will be increasingly key for managing congestion and maintaining system reliability as the penetration of intermittent resources rises. We recommend that MISO develop and implement such a change in forecast methodology.

Market Participant Forecasts. Some of the bias and the remaining errors are due to a small number of wind suppliers that continue to submit less accurate forecasts than MISO's forecast. MISO modified its Tariff to clarify that submitting intentionally inaccurate forecasts is a violation of the MISO Tariff. We monitor this conduct on an ongoing basis and these Tariff changes should improve our ability to enlist FERC enforcement to deter it.

Wind Scheduling in the Day-Ahead Market

Table 9 shows that wind suppliers generally schedule less output in the day-ahead market than they actually produce in real time. Under-scheduling of wind averaged roughly 1,200 MW. This can be attributed to suppliers' contracts and financial risks related to RSG cost allocations when day-ahead wind output is over scheduled. Under-scheduling can create price convergence issues and uncertainty regarding the need to commit other resources, which is partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers.

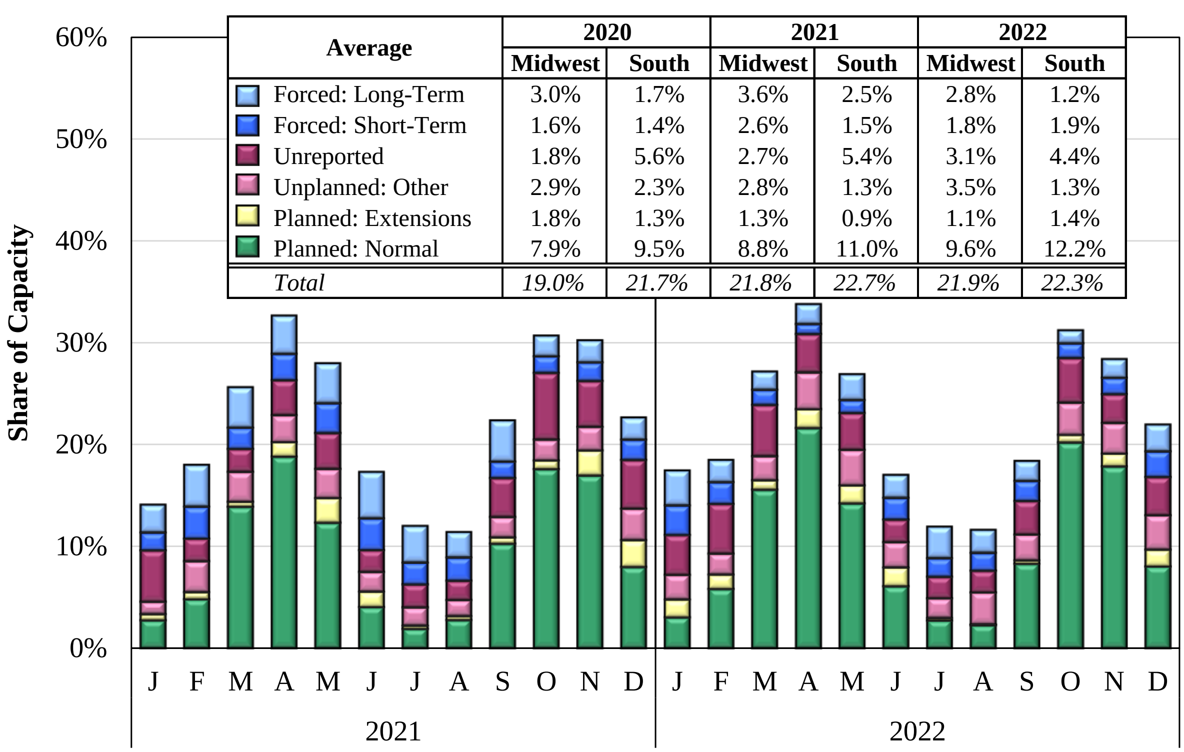
Since the most significant effect of under-scheduling wind in the day-ahead market is its effects on the transmission flows and associated congestion, we evaluated the extent to which virtual transactions offset the flow effects of wind under-scheduling. In evaluating these patterns, we found that virtual suppliers made approximately $193 million on a total of 402 wind-impacted constraints, with nearly 60 percent of the profits occurring on the ten constraints. The virtual activity serves a valuable role in facilitating more efficient day-ahead scheduling.

J. Outage Scheduling

Coordination of planned outages is essential to ensure that enough capacity is available if contingencies or higher than expected load occurs. MISO approves planned outages that do not violate reliability criteria but otherwise does not coordinate outages, which raises significant economic concerns and reliability risks. To evaluate the outages that occurred in 2022, Figure 28 shows MISO's outage rates in MISO Midwest and MISO South in 2021 and 2022.

Figure 28 shows that outage rates in 2022 were slightly lower than in 2021. As in prior years, true planned outages were relatively low for most of the summer. While the overall level of outages does not raise concerns, poorly coordinated outages do frequently raise concerns in local areas. In the *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 it is important for MISO to acquire the authority to deny or postpone outage requests that will create severe congestion or regional shortages. This is particularly important as many planned outages are scheduled or extended with very little advance notice. MISO has developed reports to assist participants in coordinating planned outages based on forecasted capacity margins, but our concerns regarding outage scheduling remain.

Figure 28: Generation Outages in 2021 - 2022



Average	2020		2021		2022	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	3.0%	1.7%	3.6%	2.5%	2.8%	1.2%
Forced: Short-Term	1.6%	1.4%	2.6%	1.5%	1.8%	1.9%
Unreported	1.8%	5.6%	2.7%	5.4%	3.1%	4.4%
Unplanned: Other	2.9%	2.3%	2.8%	1.3%	3.5%	1.3%
Planned: Extensions	1.8%	1.3%	1.3%	0.9%	1.1%	1.4%
Planned: Normal	7.9%	9.5%	8.8%	11.0%	9.6%	12.2%
Total	*19.0%*	*21.7%*	*21.8%*	*22.7%*	*21.9%*	*22.3%*

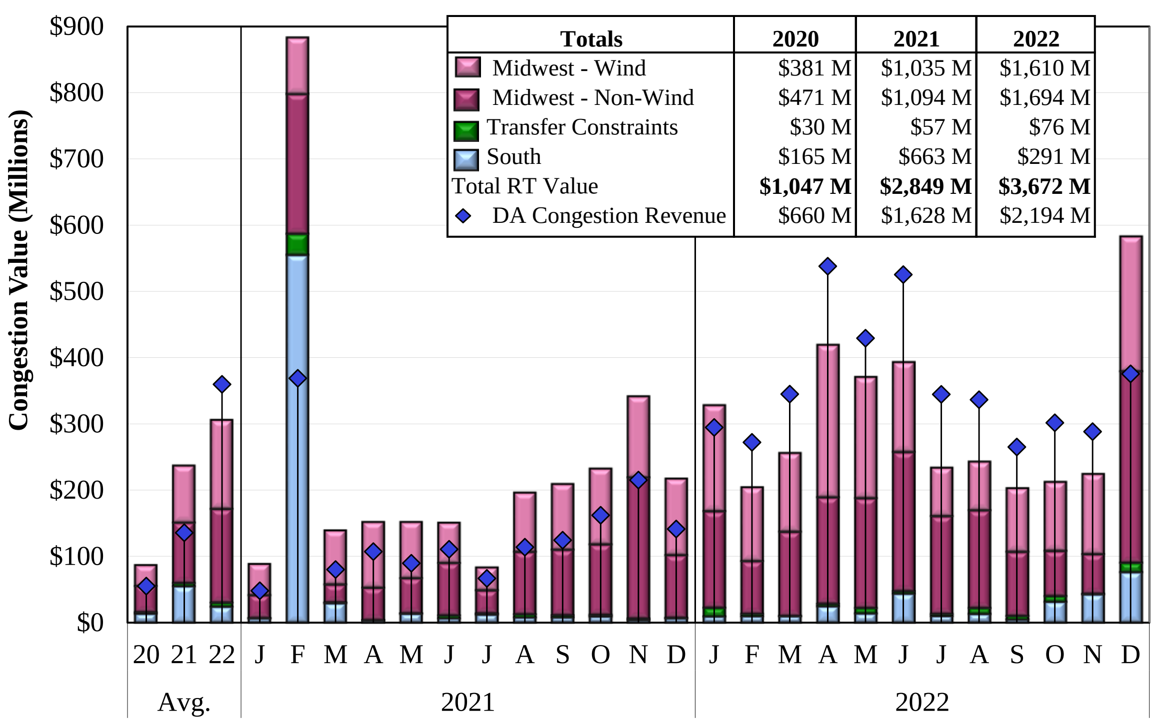
V. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, the MISO markets establish resource dispatch levels and calculate associated transmission congestion costs that keep power flows within transmission operating limits. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost units to meet demand. The resulting "out-of-merit" costs incurred to avoid violating transmission constraints are reflected in the marginal congestion component (MCC) of the LMPs (one of three LMP components). The MCCs can vary widely across the system, they are higher (and raise LMPs) in "congested" areas where generation relieves the constraints and are lower (and lower LMPs) where generation loads the constraints. These create valuable locational price signals that reflect the efficient dispatch of generation to manage network congestion, and that provide economic signals that facilitate efficient investment and maintenance of resources.

A. Real-Time Value of Congestion in 2022

We begin by summarizing the value of real-time congestion, calculated as the product of physical flow over each constraint and the economic value of the constraint (i.e., the "shadow price"—the production cost savings from relieving the constraint by one MW). This is the value of congestion that occurs as MISO dispatches its system. Figure 29 shows the monthly real-time congestion value over the past two years along with day-ahead congestion revenue.

Figure 29: Value of Real-Time Congestion
2021–2022

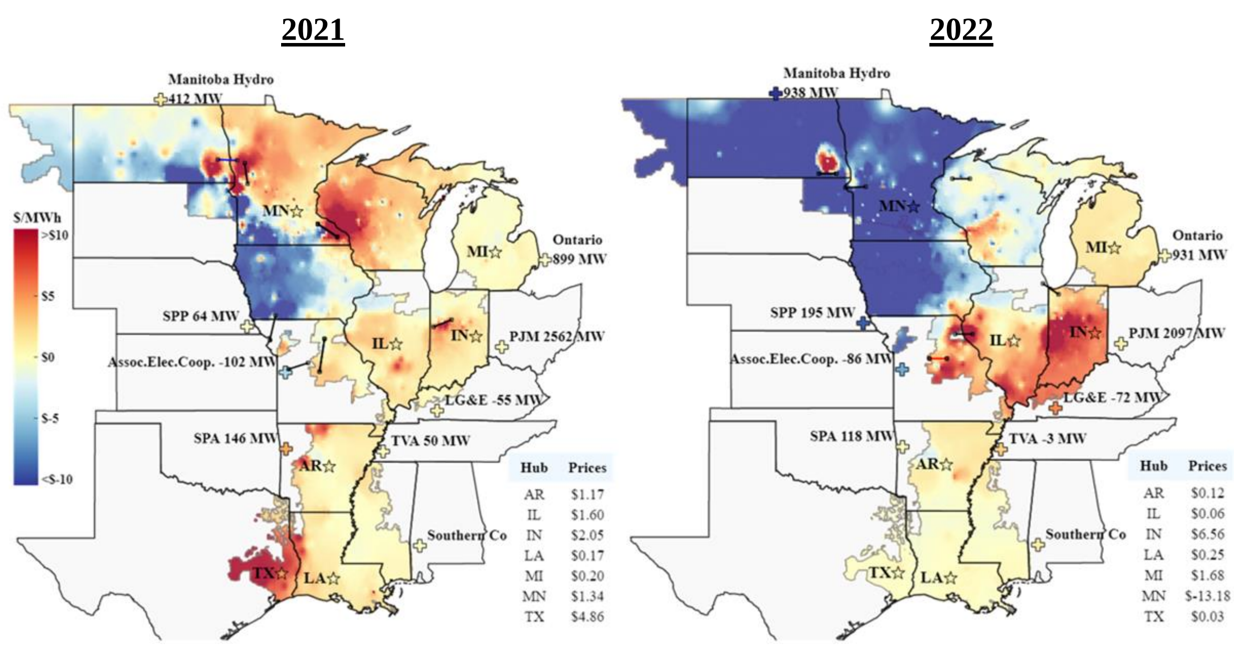


The value of real-time congestion continued to rise significantly in 2022 to total $3.7 billion. Increasing wind output and rising natural gas prices beginning in 2021 and continuing into 2022 together caused real-time congestion to triple from 2020 to 2021 and increase an additional 29 percent from 2021 to 2022. Extreme weather events also contributed to higher congestion. For example, Winter Storm Elliott contributed to more than $350 million in congestion in just two days in December 2022.

Wind-driven congestion continued to grow along with wind capacity in the Midwest subregion, accounting for about 44 percent of all real-time congestion compared to 36 percent in 2021. Continued expansion of nearby wind resources in SPP and PJM have contributed to the congestion on these constraints. Additionally, the retirement of some key coal and gas-fired resources in recent years that had provided relief on these constraints in the past also contributed to the increase in wind-related congestion.

Figure 30 illustrates the locational difference in average marginal congestion components of MISO LMPs between 2021 and 2022. The warmer colors indicate areas of MISO's footprint where prices were generally higher than the system marginal price, whereas cooler colors indicate areas of MISO's footprint where prices were generally lower than the system marginal price. The neutral shading indicates areas where there tended to be less congestion throughout the year.

Figure 30: Average Real-Time Congestion Components in MISO's LMPs



This figure shows that average imports from Manitoba increased in 2022 as drought conditions resolved in early 2022. This increase in imports contributed to the increased congestion in the North region along with the increased wind output.

The substantial increase in congestion over the past two years underscores the importance of improving the utilization of MISO's transmission network through improved transmission ratings, network reconfiguration, and strategic transmission investment. We have also identified operational improvements in how MISO manages congestion and administers the market-to-market coordination with SPP and PJM. Improvements in both areas will increase MISO's utilization of the transmission system and we are working with MISO to implement them.

B. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational prices that reflect energy costs, congestion, and losses on the network. MISO collects congestion revenue in the day-ahead market from load based on the differences in the congestion component of the LMPs at locations where energy is produced and consumed. The resulting congestion revenue is paid 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. The rights to the remaining transmission capability are sold in the FTR market, with this revenue contributing to the recovery of the costs of the network. FTRs provide a means for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that network flows sold as FTRs do not exceed flows scheduled in the day-ahead market, MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs (i.e., to pay them 100 percent of the FTR entitlements).

In addition to summarizing the day-ahead congestion, this subsection evaluates two key market outcomes that reveal how well the network is modeled in the day-ahead and FTR markets:

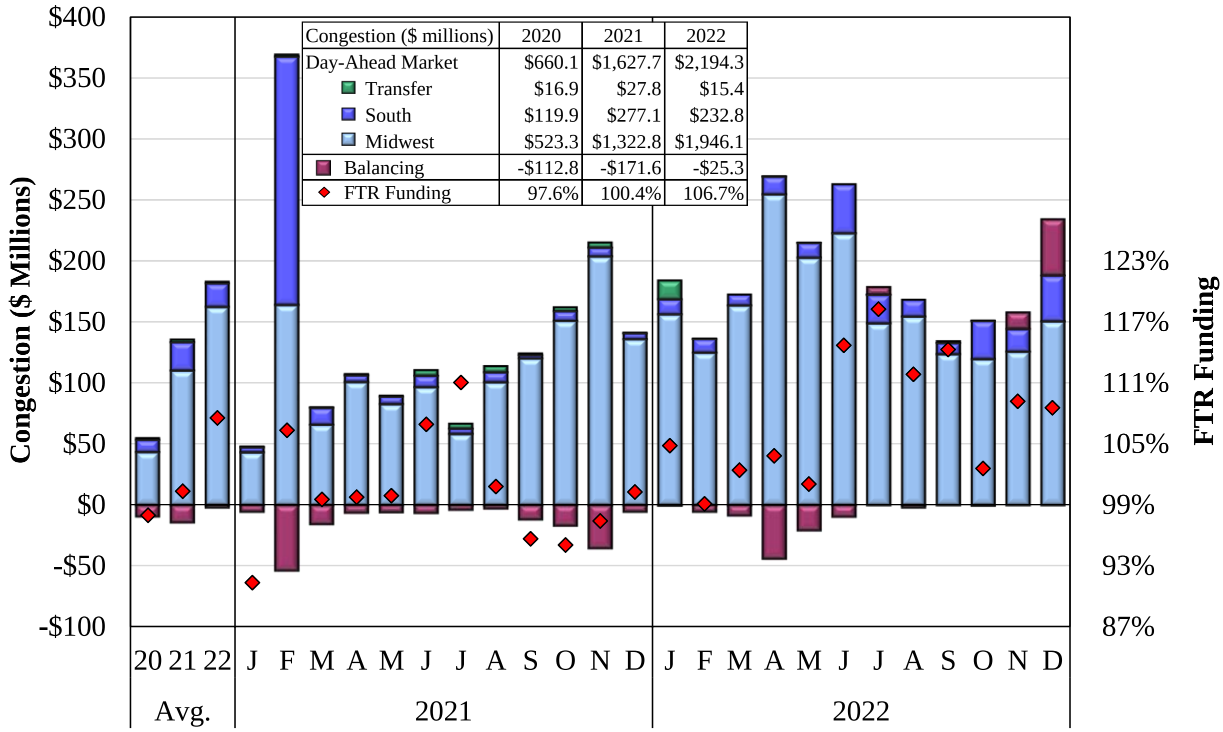
- *FTR Funding*: If MISO does not collect enough congestion in the day-ahead market to satisfy the FTR entitlements, FTR funding will be less than 100 percent, indicating that MISO issued more FTRs than the day-ahead network model could accommodate; and
- *Balancing Congestion*: If day-ahead schedules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

Figure 31 below summarizes the day-ahead congestion by region (and between regions), balancing congestion incurred in real time, and the FTR funding levels from 2021 to 2022.

Day-Ahead Congestion Costs

Day-ahead congestion costs increased by 35 percent to $2.2 billion in 2022. The day-ahead congestion costs collected through the MISO markets were about 60 percent of the value of real-time congestion on the system. The additional congestion in real time typically reflects loop flows across the MISO system caused by others who do not pay MISO and by entitlements on the MISO system granted to SPP and PJM.

Figure 31: Day-Ahead and Balancing Congestion and FTR Funding
2020–2022



Note: Funding surplus may be greater than the difference between day-ahead congestion and obligations to FTR holders because it includes residual revenue collections from the FTR auctions.

Day-ahead congestion costs increased in the Midwest because of the trends discussed earlier in wind production and natural gas prices, as well as the impacts of Winter Storm Elliott in December. Congestion fell in the South in 2022, largely because of the extraordinary congestion experienced in the South in February 2021 during Winter Storm Uri.

FTR Surpluses and Shortfalls

Overfunding and underfunding of FTRs is caused by discrepancies between the modeling of transmission constraints and outages in the FTR auctions and the day-ahead market. For example, if the flow on a binding day-ahead market constraint is below the flow scheduled in the FTR market, a congestion shortfall will occur. Conversely, a surplus will result when flow on a binding day-ahead constraint is higher than the flow sold in the FTR market.

In 2022, day-ahead congestion revenues exceeded FTR obligations by 7 percent. These FTR surplus revenues are distributed back to transmission customers. Some changes were made in the FTR modeling process in the 2021–2022 annual FTR auction and carried forward into the current FTR year. These changes include updating the constraints based on changes in the generation fleet and adopting conservative assumptions regarding outages and available transmission capability. These are intended to help ensure full funding of the FTR auction. During 2022, there was some variability in FTR funding month-to-month:

- FTR surpluses were unusually large, exceeding $160 million, during the summer months owing in part to changes in commercial flow assumptions. This surplus reflected an underselling of some paths in both the annual and monthly auctions.
- In October, the surplus was lower than adjacent months in part because a single TO failed to report known planned transmission outages before the annual auction, a Tariff requirement for TOs. In this instance, surplus collections were used to subsidize the shortfalls caused by the over-allocated FTRs. This is a serious concern, and we are working with MISO to improve its enforcement of the Tariff in this area.

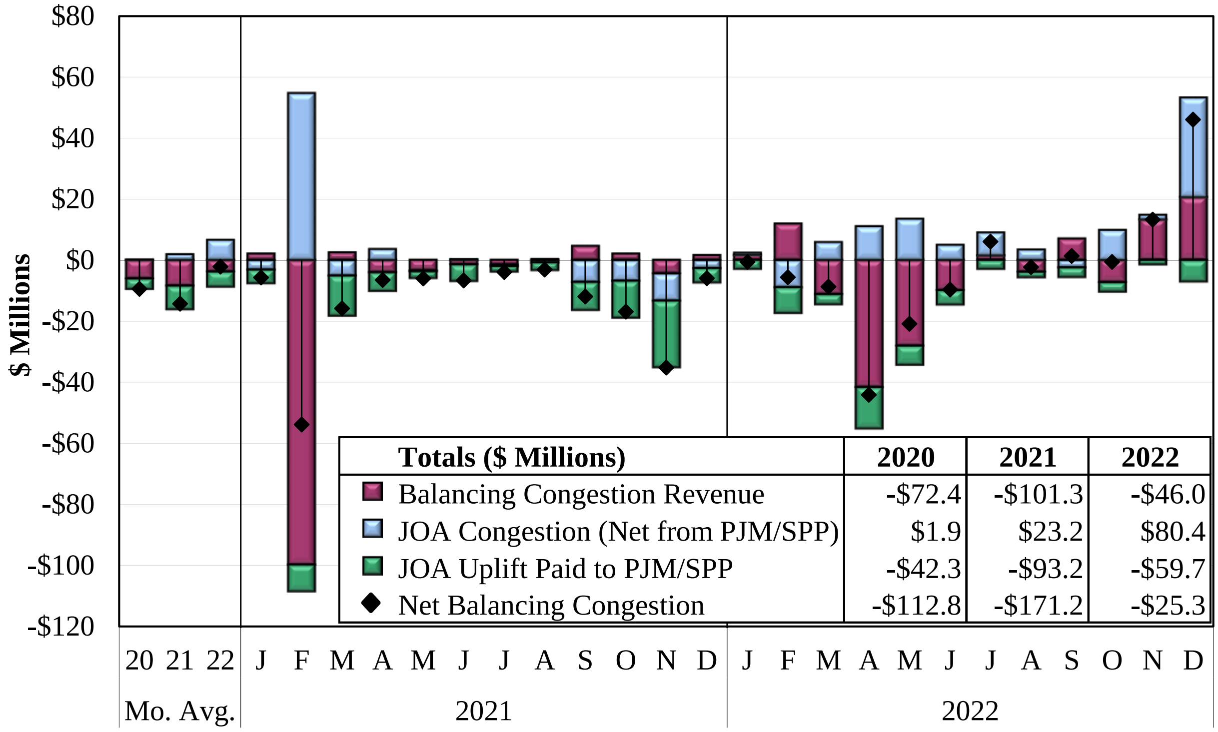
In the past, external constraints and low-voltage constraints tended to be underfunded because a higher proportion of their FTR flows were below the GSF cutoff applied in the day-ahead and real-time markets. This cutoff caused MISO to under collect day-ahead congestion revenues. FTRs impacted by SPP constraints coordinated under M2M, for example, were funded at 94 percent of the total obligation in 2021. In 2022, MISO responded to our recommendation by making several stepped reductions in the GSF cutoff. Those reductions contributed to full FTR funding on jointly-coordinated SPP constraints. In contrast, FTRs over the transfer constraints between the South and Midwest regions tend to be overfunded because they can bind in both directions. This causes them to not be fully subscribed and to generate substantial surpluses when the constraint binds.

Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) occur when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, negative balancing congestion is the cost of re-dispatching generation to reduce real-time flows on a constraint from day-ahead scheduled flow levels. Conversely, positive balancing congestion occurs when real-time constraints bind at flow levels higher than those scheduled in the day-ahead market.

Large amounts of negative balancing congestion costs typically indicate real-time transmission outages, derates, or loop flows that were not fully anticipated in the day-ahead market. Net negative balancing congestion must be uplifted to MISO’s customers. These costs are collected from all real-time loads and exports on a pro-rata basis. While real-time forced outages and derates cannot be eliminated, persistent high levels of negative balancing congestion may indicate day-ahead modeling issues. Accordingly, RTOs should seek to minimize the shortfalls by achieving maximum consistency between the day-ahead and real-time market models. Figure 32 shows the 2021 through 2022 monthly balancing congestion costs incurred by MISO.

Figure 32: Balancing Congestion Revenues and Costs
2020-2021



Net balancing congestion decreased by $146 million from 2021 to 2022, primarily because of the unusually large net balancing congestion caused by Winter Storm Uri in February 2021. Regardless, the components of the total balancing congestion changed significantly in 2022, including balancing congestion revenue surpluses of $56 million and JOA congestion nearly quadrupling to $80 million. JOA congestion payments are transfer payments for market flows that exceed entitlements on coordinated M2M constraints. The most significant balancing congestion event in 2022 that resulted in sizable JOA congestion and balancing congestion surpluses occurred in December during Winter Storm Elliott. During that event, MISO experienced a number of substantial transmission violations as it supported extensive exports to its neighbors. These additional flows above transmission limits resulted in net balancing congestion surpluses exceeding $50 million in December.

FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion. These are instrumental in allocating and pricing transmission rights. Because transmission customers pay for the embedded costs of the transmission system, they are entitled to its economic property rights. This is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers based on their network load and resources. ARRs give customers the right to receive the FTR auction revenues from the sale of the FTRs or to convert their ARRs into FTRs directly to receive day-ahead congestion revenues.

FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion, resulting in low FTR profits for the buyers (day-ahead congestion payments minus the FTR price). Even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may still cause actual congestion to be much higher or lower than FTR auction values. These variations can be minimized if MISO uses the most up-to-date outage information in its FTR modeling processes. To facilitate the FTR process, market participants are required to report all known planned outages 12 months in advance even when specific dates have not been finalized. Longer notice is even better since the AAR allocation process begins 16 months before the FTR year.

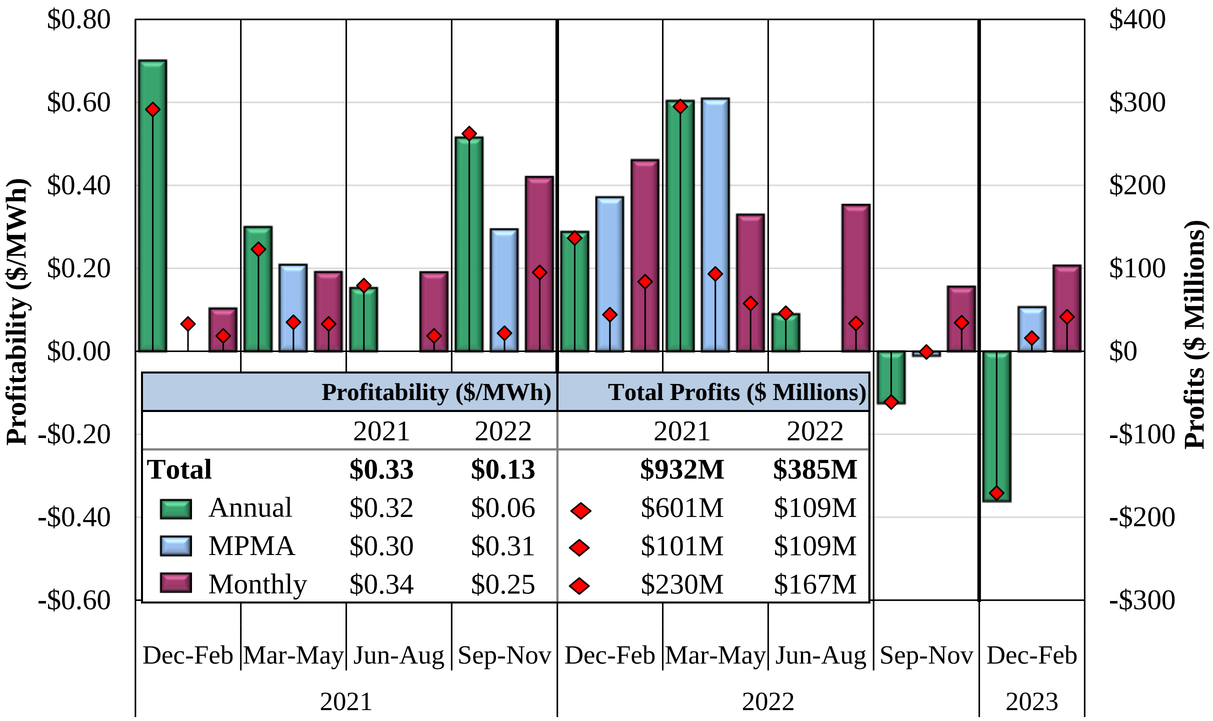
MISO currently runs two types of FTR auctions:

- 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 for future periods in the current planning year.

FTR Market Profitability

Figure 33 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market in the bars. The profit margin for each class of FTRs is shown in the red diamonds. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Figure 33: FTR Profits and Profitability
2021–2022



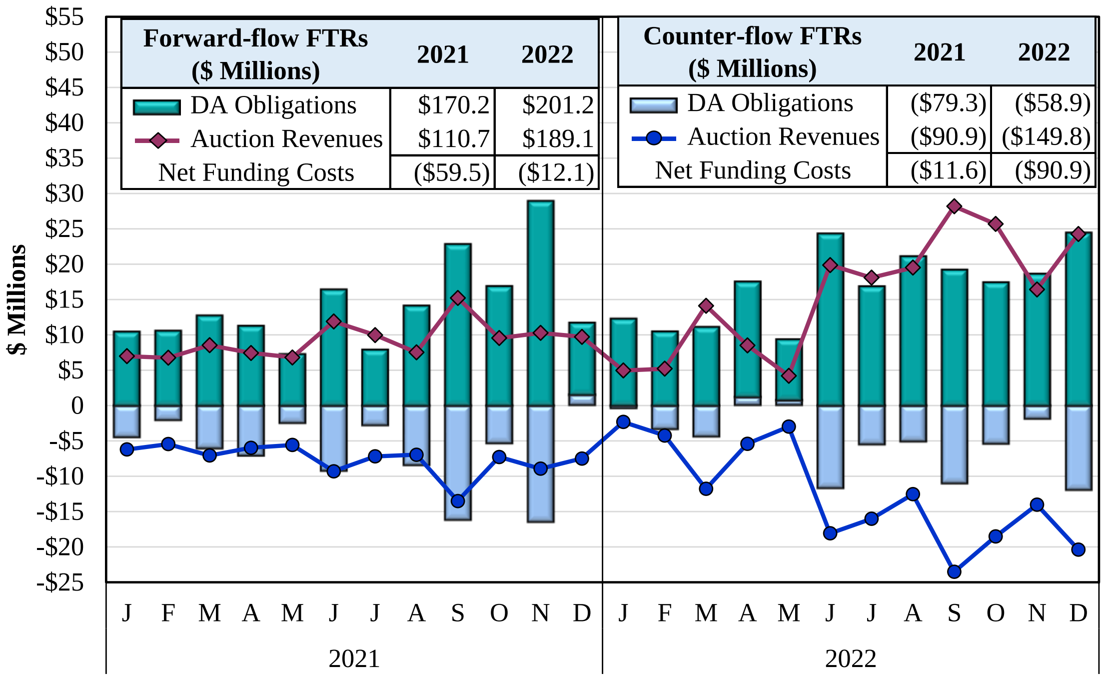
	Profitability ($/MWh)		Total Profits ($ Millions)	
	2021	2022	2021	2022
Total	**$0.33**	**$0.13**	**$932M**	**$385M**
Annual	$0.32	$0.06	$601M	$109M
MPMA	$0.30	$0.31	$101M	$109M
Monthly	$0.34	$0.25	$230M	$167M

Annual FTR Profitability. Figure 33 shows that FTRs issued through the annual FTR auction were profitable overall, but fell sharply to roughly $100 million as FTRs acquired in the fourth quarter were substantially unprofitable. Some of this decrease was due to unusually high congestion and associated FTR profits in 2021 as natural gas prices rose unexpectedly throughout the year and Winter Storm Uri generated unanticipated congestion. In 2022, the higher natural gas prices were largely anticipated prior to the FTR auction and conditions moderated late in the year because of warmer weather, the easing supply concerns in Europe, and a significant LNG export facility outage. The unexpected drop in natural gas prices late in 2022 likely led participants to expect higher congestion in the fourth quarter than actually occurred.

FTR Profitability in the MPMA and Monthly Auction. Figure 33 shows that the FTRs purchased in the MPMA and prompt month auction were similar to last year, remaining close to $100 million and $200 million, respectively. In general, the MPMA and monthly markets should produce prices that are more in line with anticipated congestion because they are cleared much closer to the operating timeframe when better information is available to forecast congestion.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 34 compares the auction revenues from the MPMA prompt month (the first full month after the auction) to the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-flow and counter-flow FTRs. The net funding costs shown in the inset tables represent the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold forward-flow FTRs at a price less than their ultimate value or bought counter-flow FTRs at a price greater than their ultimate value.

Figure 34: Prompt-Month MPMA FTR Profitability
2021–2022



The analysis shows that the discount in the sale for forward-flow FTRs decreased from 35 percent in 2021 to just 6 percent in 2022, which translated into net funding costs (i.e., profits from these FTRs) of $12 million. These results indicate that the markets expected congestion costs to be relatively high.

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 is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint.[23] Net funding deficits for counter-flow FTRs increased significantly in 2022, indicating that MISO substantially over-paid for these FTRs compared to the day-ahead congestion value.

Overall, these results indicate that the MPMA lacks the liquidity needed to erase the differences between FTR prices and congestion values. Barriers to participation should be identified and eliminated, which should improve convergence between the auction revenues and the associated day-ahead FTR obligations. If such improvements cannot be identified, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale of forward-flow FTRs at very low prices and/or the sale of counter-flow FTRs at unreasonably high prices.

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

MISO's market-to-market (M2M) process under Joint Operating Agreements (JOAs) with neighboring RTOs enables the RTOs to efficiently manage constraints affected by both RTOs. The process allows each RTO to utilize re-dispatch from the other RTOs' units to manage its congestion if it is less costly than its own re-dispatch.

Under the M2M process, each RTO is allocated Firm Flow Entitlements (or FFEs) on the coordinated constraint. The process requires the RTOs to calculate the shadow price on the constraint based on their own cost of relieving it and the RTO with the lower cost of relief reduces the 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) will compensate it for this relief by paying it the marginal value of the relief. Conversely, if the NMRTO's market flow exceeds its FFE, the NMRTO will pay the MRTO for the excess flow times the marginal costs incurred by the MRTO.

Summary of Market-to-Market Settlements

Congestion on M2M constraints within and outside of MISO increased overall in 2022:

- Congestion on MISO M2M constraints almost double over 2021 to total $2 billion.

23 For example, assume MISO issued 250 MW of FTRs over an interface that now can support only 200 MW of flow. MISO could sell 50 MW of counter-flow FTRs to reduce the FTR obligation to 200 MW.

- Congestion on external M2M constraints (those monitored by PJM and SPP) fell 12 percent year over year to $121 million.

Table 10 shows MISO's annual M2M settlements with SPP and PJM over the past two years.

Table 10: M2M Settlements with PJM and SPP ($ Millions)
2021–2022

	PJM	SPP	Total
2022	$180	-$149	$31
2021	$18	-$88	-$70

This shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. Twenty-five percent of PJM's payments to MISO occurred in December during Winter Storm Eliot. Another 28 percent occurred in March and April when wind generation was high, making it more difficult to manage M2M constraints significantly impacted by wind resources, which have fast ramp rates that create volatility and oscillation in relief request quantities from the non-monitoring RTO.

MISO generally makes M2M payments to SPP, partly because SPP enjoys relatively high FFEs on key constraints in both SPP and MISO. Some of the differences in the RTOs' FFE levels can be attributed to differences in the completeness of the historic transmission reservations included in the FFE calculations by SPP versus MISO. A substantial portion of MISO's historic transmission reservations are not included in the FFE calculations. We also question the wisdom of basing FFEs on *reservations* rather than *schedules*. Schedules are generally a fraction of the reservation quantities and schedules more accurately represent the historic use of the system. As wind output along the SPP seam grows and generator retirements reduce MISO's ability to relieve the wind-related constraints, we expect the payments to SPP to continue to grow.

Market-to-Market Effectiveness

One metric we use to evaluate the effectiveness of the M2M process is tracking the convergence of the shadow prices of M2M constraints in each market. When the process is working well, the NMRTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to 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 is initiated.

However, we found that on some constraints, shadow prices fail to converge because the MRTO does not request sufficient relief to achieve convergence. This can occur because the current relief request software does not consider the shadow price differences between the RTOs. When the NMRTO's shadow price is sustained at a much lower level, the relief requested should increase to lower congestion costs and accelerate convergence. At other times, the software can request too much relief and cause constraints to bind and unbind in subsequent intervals, which is 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 provided by the NMRTO 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 a M2M constraint raises two types of concerns:

- *Efficiency concerns*. The savings of coordinating with the NMRTO to relieve the constraint are not achieved and congestion costs are higher than necessary.
- *Equity concerns*. The NMRTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the MRTO.

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

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

We developed a series of screens to identify constraints that should have been coordinated but were not because of these three issues. Table 11 shows the total congestion on these constraints. For the first two reasons (never classified and testing delay), we account for time needed to test a constraint by removing the first day a constraint was binding.

Table 11: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2020–2022

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2020	2021*	2022*	2020	2021*	2022*	2020	2021*	2022*
Never classified as M2M	$4	$17	$6	$34	$50	$55	$38	$68	$61
M2M Testing Delay	$2	$20	$7	$18	$55	$44	$20	$75	$51
M2M Activation Delay	$3	$2	$1	$2	$34	$6	$5	$36	$7
Total	$9	$39	$14	$54	$139	$105	$62	$179	$119

*We have excluded the Winter Storm Uri days (02/13-02/19/2021) and Winter Storm Elliott days (12/22-12/27/2022).

Historically, the highest congestion impacts occurred on constraints that MISO failed to test, prompting an IMM recommendation in 2016 for MISO to improve M2M identification and testing procedures. In December 2017, MISO implemented a tool to improve these procedures, which resulted in significant improvements in the process in 2018 and 2019. More recently, congestion associated with failure to test constraints or delays in testing constraints increased sharply in 2021 and 2022, partly because of the increase in natural gas prices and the volatility of wind-related congestion. However, based on these results, we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process, particularly with SPP.

Market-to-Market Test Criteria Software

Identifying the constraints to coordinate under the M2M processes is important to ensure both efficient and reliable coordination, to establish equitable settlements, and to improve the price signals in the NMRTO market. Currently, a constraint will be identified as a M2M constraint when the NMRTO has:

- A generator with a shift factor greater than 5 percent; or
- Market flows over the MRTO's constraint of greater than 25 percent of the total flows (for the SPP JOA) or 35 percent of the total flows (for the PJM JOA).

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available.[24] The single generator test is particularly questionable because it ignores the size and economics of the unit—this test does not ensure that the NMRTO has any economic relief.

Our analysis of this area of the M2M process, presented in detail in Section V.E of the Analytic Appendix, shows that there are a number of M2M constraints for which the NMRTO has a very small portion of the economic relief and very little ability to assist in managing the congestion. If the NMRTO's market flows are also low on these constraints, then they should not be M2M constraints because the savings of coordinating are likely less 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 coordinating are very small—particularly high-voltage constraints where GSFs tend to be higher. Hence, we recommend the five percent test be replaced by two potential 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. In other words, the five percent test is identifying more constraints that are not beneficial to coordinate (i.e., false positives) than the number of new constraints that would warrant coordination under the relief-based tests. This is important because the number of coordinated market-to-market constraints has been rising rapidly in recent years.

---

24 Economic relief is categorized as any redispatch relief that could be provided within five minutes time with a shadow price less than or equal to $200.

Other Key Market-to-Market Improvements

Our evaluation indicates two additional improvements that MISO should pursue that would improve the efficiency and effectiveness of the M2M coordination with SPP and PJM:

- Some of the costliest M2M constraints are more efficient for the NMRTO to monitor because it has most of the effective relief capability. MISO and SPP began using software in 2017 that enables the transfer of responsibility to the NMRTO, but it has rarely been used. PJM has postponed implementation of this software and currently only allows such transfers in limited circumstances. We recommend MISO continue working with SPP and PJM to improve the procedures to transfer the monitoring responsibility to the NMRTO when appropriate.
- In response to concerns about volatility caused by M2M coordination, MISO has developed software that is intended to allow the MRTO to control oscillations on constraints where both the MRTO and the NMRTO have fast-ramping resources responding to M2M price signals. SPP has agreed to use this software. Thus far the software has been very limited in use but in concept it should enable control of oscillations, at the risk of the NMRTO producing a higher shadow price than the MRTO for limited periods.
- Convergence of M2M constraints is much worse in the day-ahead market. MISO and PJM implemented a process coordinate and exchange FFEs in the day-ahead market, but do not actively use this process. Further, SPP was not modelling MISO's constraints in its day-ahead market until October 2022, which led to inefficient resource commitment in MISO. For instance, roughly 20 percent of the total congestion in winter 2022 accrued on two constraints impacted by a jointly owned resource that participates in MISO and SPP. Because SPP did not model MISO's constraints in its day-ahead market, the unit appeared economic in SPP's day-ahead market but not in MISO's. Since SPP began modeling some of the constraints in the fall of 2022, convergence has improved on some constraints. However, we recommend MISO continue to work with SPP and PJM to improve the day-ahead modeling and convergence of M2M constraints.

D. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur when MISO models the impact of its own dispatch on external constraints. MISO is obligated to activate these constraints and reduce its market flows when other system operators invoke Transmission Loading Relief (TLR) procedures. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers. MISO receives relief requests that are often inefficient and inequitable for these constraints 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 are relieving the constraint; and

- Virtually all of MISO's flows over external constraints are deemed to be non-firm (and thus subject to curtailment before firm transactions) even though most of MISO's flows are associated with dispatching network resources to serve MISO's load.

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

In recent years, TLRs called by IESO have resulted in thousands of MWs of transaction curtailments from PJM to MISO and costly price spikes throughout MISO. There are many other actions that are less costly than curtailing vast quantities of PJM-to-MISO transactions. Unfortunately, the TLR process is indiscriminate and does not facilitate the most efficient relief. Therefore, we continue to recommend that MISO work with both TVA and IESO to develop JOAs that would reduce the costs of this external congestion.

E. Transmission Ratings and Constraint Limits

For the past several years we have estimated significant potential benefits from improved utilization of the transmission system, especially broader application of Ambient Adjusted Ratings (AARs) and emergency ratings. For most transmission constraints, the ability to flow power through the facility is related to the heat caused by the power flow. When temperatures are cooler than the typical assumption used for rating the facilities, additional power flows can be accommodated.[25] Therefore, if TOs develop and submit ratings adjusted for temperature or other relevant ambient conditions, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most TOs do not provide ambient-adjusted ratings. We believe that at least one of the reasons for this is that there is little economic incentive to do so. In December 2021, FERC issued Order 881 that requires TOs to provide AARs and emergency ratings based on facility specific evaluations within three years.[26]

Estimated Benefits of Using AARs and Emergency Ratings

As in past years, we have estimated the value of operating to higher transmission limits that would result from consistent use of temperature-adjusted, emergency ratings for MISO's

25 Temperature is one common dynamic factor. In some regions, ratings are more dependent on other factors, such as ambient wind speed and humidity. Ratings used during night-time hours can be adjusted for the absence of solar heating. Our analysis evaluates only ambient temperature impacts.

26 MISO made a compliance filing on July 12, 2022 in ER22-2363 but FERC has yet to approve it.

transmission facilities.[27] This analysis is described in detail in Section V.D of the Analytic Appendix and summarized in Table 12.

Table 12: Benefits of Ambient-Adjusted and Emergency Ratings
2021–2022

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2021	**Midwest**	$153.4	$94.89	$248.3	29	11.3%
	South	$27.3	$38.32	$65.6	1	10.0%
	Total	**$180.7**	**$133.2**	**$313.9**	**30**	**11.0%**
2022	**Midwest**	$326.4	$188.67	$515.1	22	15.3%
	South	$7.6	$19.11	$26.7	2	9.3%
	Total	**$334.0**	**$207.8**	**$541.8**	**24**	**14.9%**

Across the past two years, the results show average benefits of 13 percent of the real-time congestion value. The total potential savings in 2022 were over half a billion dollars. The benefits of temperature adjustments tend to accrue primarily in the non-summer months when static ratings are most understated. The benefits of using emergency ratings are more evenly distributed throughout the year. The Analytic Appendix details how these estimated benefits in 2022 are distributed in the areas served by transmission owners.

Recommended Improvements to Achieve the AAR Benefits

As MISO plans for compliance with Order 881, we encourage it to accelerate efforts to implement AARs and Emergency Ratings in real time, and MISO should enable forecasted ratings in the day-ahead market as soon as practicable. This should include beginning to collect the data and information necessary to validate transmission ratings consistent with the requirements of Order 881 and the TO Agreement.

This is particularly important because progress on implementing AARs has been extremely slow. We estimated the benefits that have been achieved by the TOs since they began working with MISO to implement new AARs prior to Order 881. This evaluation shows:

- The voluntary efforts by TOs to implement new AARs prior to 881 have largely stalled as MISO and TOs have discontinued organized efforts to expand use off AARs and Emergency ratings prior to Order 881 compliance.
- The MISO/TO voluntary program had been identifying facilities with the potential for significant congestion savings through use of AARs and Emergency ratings but very little had actually been implemented yet through the program.

27 We used temperature and engineering data to estimate the temperature adjustments. To estimate the effects of using emergency ratings, we assume that the emergency ratings are 10 percent higher than the normal ratings. This is consistent other facilities for which TOs submit emergency ratings. We then estimated the value of both of these increases based on the shadow prices of the constraints.

- The MISO/TO programs selection of candidate facilities for evaluation based on historical congestion failed to identify a large share of the binding facilities (i.e., a large amount of congestion occurs on facilities that were not significantly binding in prior quarters).
- A third of unrealized benefits from use of AARs and Emergency ratings occurs on transformers where TOs frequently provide only a single base rating for all transformers (without facility specific evaluations) for use in all conditions and for all contingencies.

F. Other Key Congestion Management Issues

MISO generally experiences significant real-time congestion each year—rising in 2022 to a record $3.7 billion. Hence, improvements aimed at the efficiency of its congestion management can deliver sizable savings. Many of these improvements we discussed above. We discuss four remaining improvements in this subsection.

Transmission Derates by MISO Operations

MISO generally derates transmission constraints by a few percent to account for the fact the actual flows often deviate from the flows modeled in the real-time dispatch. Such derates have been growing over the past two years. Prior to 2020, these transmission derates averaged about 5 percent but have grown to nearly 7 percent in in 2022 and early 2023. We are investigating these increases because the real-time value of the lost transmission capability is large. This lost value totaled $269 million in 2022 and the increase in derates from pre-2020 levels accounts for over $80 million of the lost transmission value.

To the extent that this increase reflects increased uncertainty regarding wind output and the poor performance of some wind resources in following dispatch signals, we are recommending improvements to address these issues. This includes implementing improved excessive and deficient energy penalties to improve suppliers' incentives to follow dispatch signals and improving real-time wind forecasting methodologies.

Generation Shift Factor Cutoff

MISO employs a GSF cutoff to limit the number of resources and loads that are deemed to affect the flows over a constraint in its market models. This is intended to allow the models to solve more quickly, but it also reduces the efficiency of the solutions. Previously, we recommended that MISO lower the GSF cutoff in both the day-ahead and real-time markets to manage flows on market-to-market constraints. Beginning in October 2021, MISO began the process of gradually reducing the GSF cutoff in both markets and continues to closely monitor market performance and market outcomes. Barring significant market or operational issues, the cutoff ultimately will be reduced to 0.5 percent or lower. This will produce substantial savings at little or no cost.

Coordinating Outages that Cause Congestion

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

Participants tend to schedule planned outages in shoulder months, assuming the opportunity costs of taking outages 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 does not have the authority to deny or postpone a planned outage, even when it could have sizable economic benefits. Figure 35 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value for 2021 and 2022 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 35: Congestion Affected by Multiple Planned Generation Outages
2021–2022

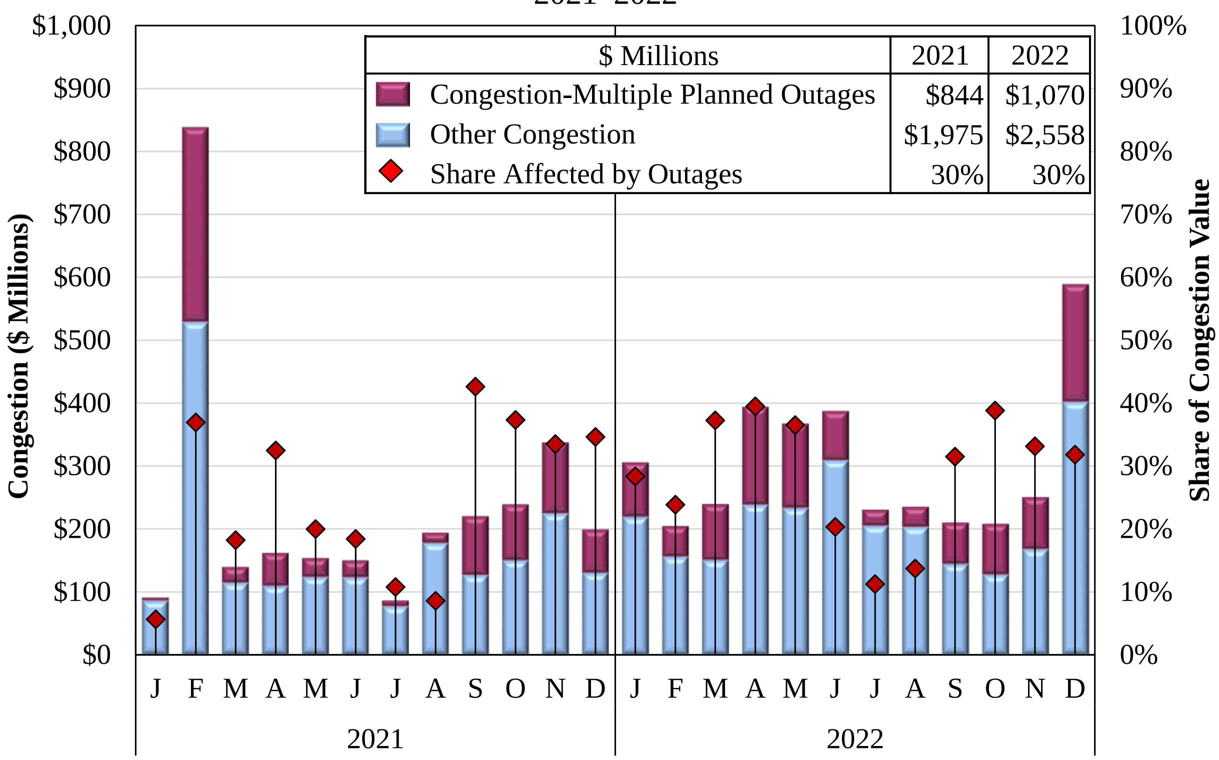


Figure 35 shows that 30 percent of the total real-time congestion on MISO's internal constraints in 2022 ($1.1 billion) was attributable to multiple planned generation outages. In several months, planned outages caused significant congestion, including almost a third of all congestion in a number of months. The large increase in outage-related congestion costs in 2022 was associated with the severe congestion costs during Winter Storm Elliott in December, higher natural gas prices throughout the year, and wind-related congestion. Figure 35 may understate the effects of planned generation outages on MISO's congestion because we do not include the effects of transmission outages that are scheduled at the same time as planned generation outages. We continue to recommend that MISO seek broader authority to coordinate planned generation and transmission outages in order to reduce unnecessary economic costs and enhance reliability.

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 such options are reliable and economic. This is done on a regular basis by Reliability Coordinators to address congestion-related reliability concerns, normally under the procedures established in Operating Guides in consultation with the TOs. However, tremendous benefits can be achieved by utilizing reconfiguration options economically to manage congestion.

To illustrate these benefits, we evaluated the costliest constraint during the summer of 2021, the Rochester-Wabaco 161 KV line, which generated over $57 million in congestion. Our study demonstrated that the reconfiguration immediately reduced the overall congestion that had occurred on Rochester-Wabaco by two thirds. After the immediate shift in congestion caused by the reconfigurations, the congestion on other nearby facilities tended to dissipate as generation moved to manage the congestion more efficiently on the other facilities. Hence, the benefits of the reconfiguration in mitigating the severe congestion on this facility are larger over time.

We have identified similar events in 2022 and we believe this case study is representative of the opportunities to develop economic reconfiguration options on other frequently binding constraints and deploying them as regular congestion management actions. Therefore, we continue to recommend that MISO work with TOs to develop tools, processes, and procedures to identify and analyze reconfiguration options and then 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. As of March 2023, two of seven reconfiguration requests were successfully implemented. However, MISO has no near-term plans to develop tools internally to suggest economic reconfiguration options, nor has it developed a process to ensure that evaluations of alternatives are timely. We recommend MISO pursue these enhancements.

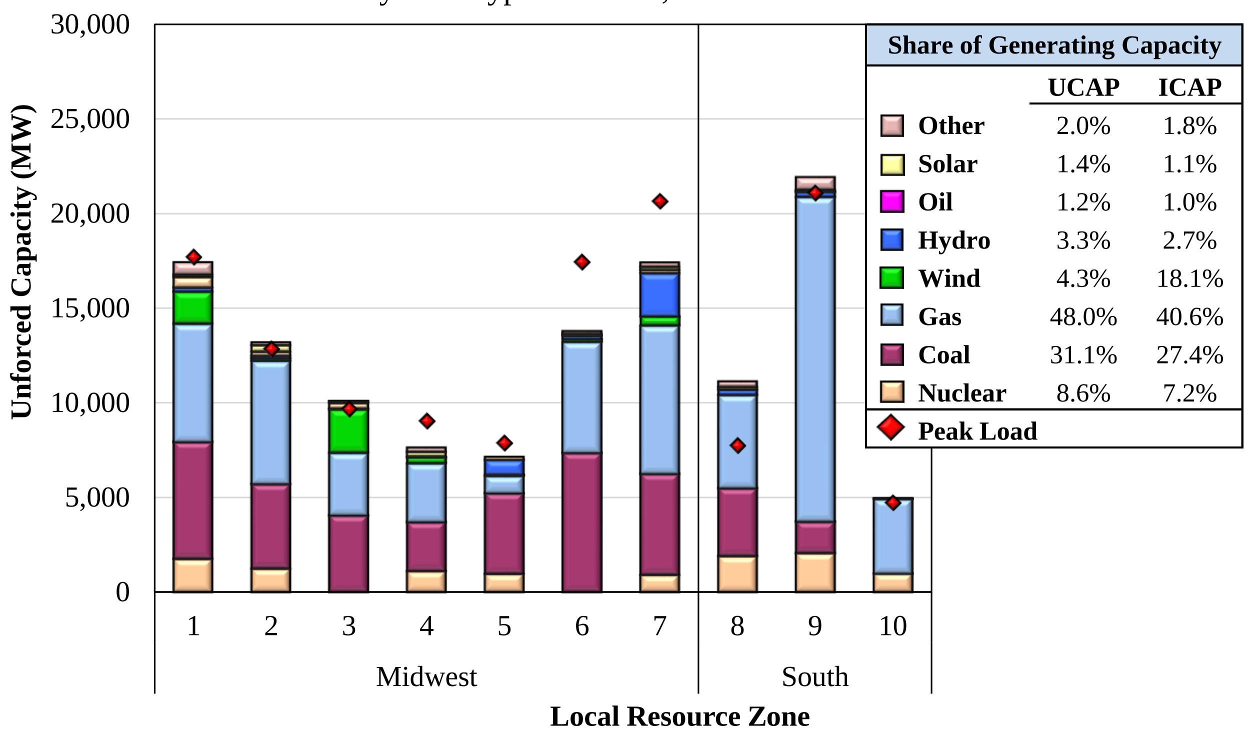
VI. Resource Adequacy

This section evaluates the performance of the markets in facilitating the investment and retirement decisions necessary to maintain resources to meet system reliability. We assess the adequacy of the supply in MISO for the upcoming summer and discuss recommended changes that would improve the performance of the markets.

A. Regional Generating Capacity

This first subsection shows the distribution of existing generating capacity in MISO. Figure 36 shows the distribution of Unforced Capacity (UCAP) at the end of 2022 by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[28] UCAP values account for forced outages and intermittency. Therefore, UCAP values for wind units are much lower than Installed Capacity (ICAP) values, as shown in the inset table. Hence, although wind is over 18 percent of MISO's ICAP, it is 4.3 percent of the UCAP.

Figure 36: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2022



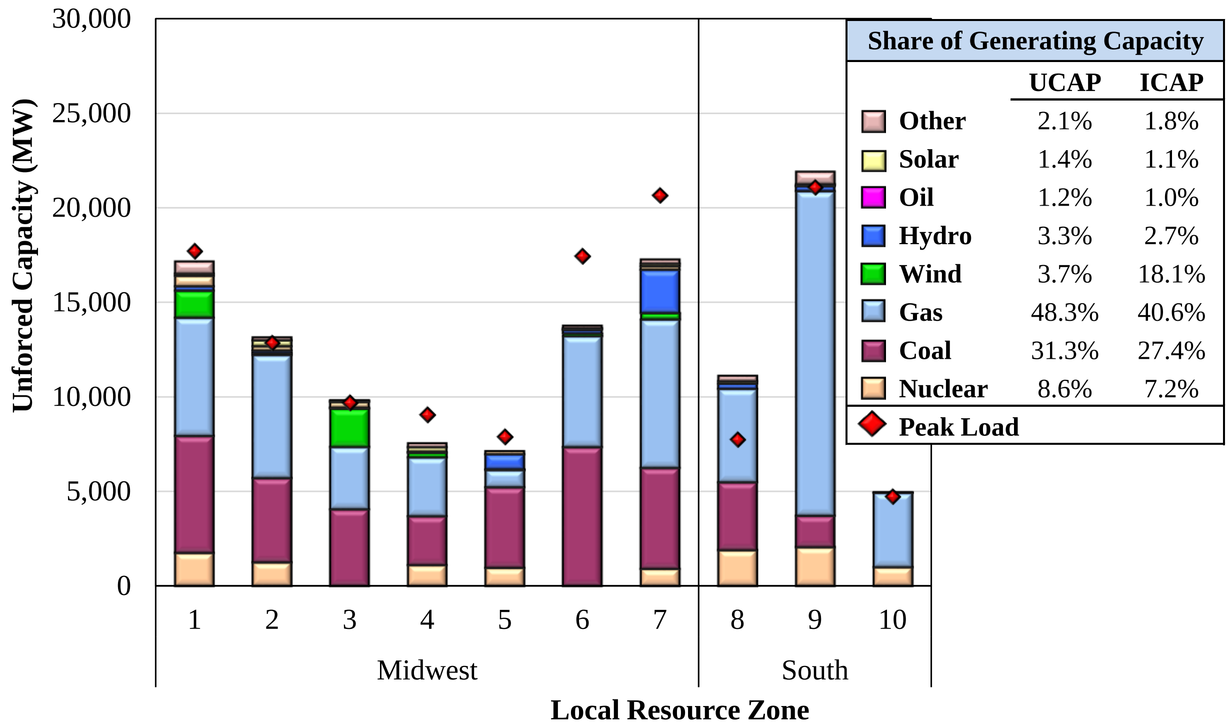
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from MISO South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

28 UCAP was based on data from the MISO PRA for the 2021-2022 Planning Year and excludes LMR capacity.

B. Changes in Capacity Levels

Capacity levels have been falling in recent years because of accelerating retirements of baseload resources, which are being partially replaced with intermittent renewable resources. Figure 37 shows the capacity additions (positive values) and losses during 2022. The hatched bar indicates newly suspended resources, which rarely return to service. 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 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 being used. Figure 37 does not show retirements for resources in 2022 that were suspended in 2021.

Figure 37: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in 2022



Capacity Losses

In 2022, 4 GW of resources retired or suspended operations in MISO, consisting of primarily coal, gas steam, and nuclear resources. Some of the suspended unforced capacity is under consideration for partial replacement and could return as new generation (primarily solar and battery) in the next three years.[29] We expect baseload retirements to continue in the near term because of the weak economic signals provided by MISO's current capacity market.

29 See MISO Generator Replacement Requests: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

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 a reliability solution (e.g., transmission upgrades) can be implemented or the reliability condition no longer exists. SSRs have been granted infrequently, and currently two resources in MISO are designated SSR.

New Additions

In 2022, 2 GW of unforced new capacity entered MISO. A 1.1 GW natural gas-fired combined-cycle resource entered MISO in the Central region. Approximately 2.8 GW (nameplate) of wind entered, although their total UCAP value is only 380 MW because they provide less reliability than conventional resources. Approximately 600 MW (UCAP) of solar resources also entered in 2022, primarily in the North and Central regions. Additional investment in wind resources is likely to occur given continued Federal subsidies and MISO state policies.

C. Planning Reserve Margins and Summer 2023 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2023. Assumptions regarding the supply that will be available during the summer peak and the peak load can substantially change the planning reserve margins. Therefore, Table 13 presents a base case scenario and four additional scenarios that more realistically represent the range in MISO's summer peak reliability margin.

Base Scenario. We have worked closely with MISO to align our base scenario with MISO's assumptions in its *2023 Summer Resource Assessment*, including the 1,900 MW transfer limit assumption between MISO South and Midwest.[30] This scenario also assumes that: a) MISO will be able to access all demand response resources in any emergency, and b) the summer planned outages will be limited to those scheduled and approved by April 1, 2023. The planning reserve margin shown is 19.2 percent – which exceeds the installed capacity Planning Reserve Margin Requirement (PRMR) of 15.9 percent.

To report all values in the Summer Assessment on an ICAP basis, we: (a) replaced the UCAP-based PRM added to 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 up based on the ratio of the ICAP and UCAP PRM values. As conventional resources retire, we expect MISO's summer margins to fall below the planning requirement.

30 We do not think this is a reasonable assumption based on real-time operations, but we include this assumption to align our Base Case with MISO's Base Case.

Realistic Scenario. Unfortunately, the assumptions in the base scenario are not very realistic, so we include a realistic scenario that assumes that:

- The transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations;
- 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 be able to access 75 percent of demand response resources in an emergency situation, consistent with historical observations.

Table 13: Summer 2023 Planning Reserve Margins

		Alternative IMM Scenarios*			
				High Temperature Cases	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	123,735	123,735	123,735	123,735	123,735
High Load Increase	-	-	-	7,040	7,040
Total Load (MW)	123,729	123,729	123,729	130,775	130,775
Generation					
Internal Generation Excluding Exports	132,837	132,837	132,837	132,837	132,837
BTM Generation	4,333	4,333	3,104	4,333	3,104
Unforced Outages and Derates**	-	(13,270)	(13,270)	(20,870)	(20,870)
Adjustment due to Transfer Limit	(2,067)	-	-	-	-
Total Generation (MW)	135,103	123,900	122,671	116,300	115,071
Imports and Demand Response* **					
Demand Response (ICAP)	8,304	6,228	3,108	6,228	3,108
Firm Capacity Imports	4,136	4,136	4,136	4,136	4,136
Margin (MW)	23,813	10,535	6,186	(4,110)	(8,459)
Margin (%)	**19.2%**	**8.5%**	**5.0%**	**-3.1%**	**-6.5%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,858)	(6,798)	(6,798)	(6,798)	(6,798)
Non-Firm Net Imports in Emergencies	4,708	4,708	4,708	4,708	4,708
Expected Margin (MW)	21,662	8,445	4,096	(6,201)	(10,549)
Expected Margin (%)	**17.5%**	**6.8%**	**3.3%**	**-4.7%**	**-8.1%**

* Assumes 75% response from DR.
** Base scenario shows approved planned outages for summer 2023. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2023 Summer Assessment.
*** Cleared amounts for the Summer Season of the 2023/2024 planning year.
**** Base scenario assumes 5% forced outage rate for internal and BTM generation. Alternative cases use historical average forced outages/derates during peak summer hours.

In this realistic scenario, the planning reserve margin falls to 8.5 percent. This planning reserve margin would raise concerns for many RTOs, but MISO has the unique advantage of having substantial import capability from virtually every direction. Only a small amount of this import capability is reserved on a firm basis and used to import capacity. The remaining capacity is available on a non-firm basis to be used to resolve shortages when they occur. Hence, the table includes additional imports that reflect the average amount of additional imports during emergency conditions.[31] This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO. The table also shows the capacity that would be lost based on a historical average forced outage rate of around 5 percent. When offset by the non-firm imports, the realistic margin falls to 6.8 percent.

Unfortunately, even the realistic scenario is optimistic because it assumes all resources not in a forced outage will be available during an emergency. However, since emergencies are the result of unforeseen events, MISO has historically declared emergencies between 10 minutes and four hours in advance. Because a large quantity of emergency resources offer longer notification times (often up to 12 hours), the second realistic scenario assumes only emergency resources that can start in two hours or less will be accessible, which reduces emergency demand response and behind-the-meter generation. This lowers the planning reserve margin to 5.0 and further to 3.3 percent after accounting for expected forced outages and non-firm summer imports.

High Temperature Scenarios. We include two other variants of the realistic scenarios to include the effects of hotter than normal summer peak conditions. The high-temperature scenarios are important because hot weather significantly affects *both* load and supply. High temperatures can reduce the maximum output limits of many of MISO's generators when outlet water temperature or other environmental restrictions cause certain resources to be derated.[32] On the load side, we assume MISO's "90/10" forecast case (which should occur one year in ten).

The high-temperature cases using the realistic scenario and realistic plus limited emergency-only capacity both show that MISO's margin will be substantially negative (ranging from -3.1 to -6.5 percent). MISO will likely be well into emergency conditions in these cases because it must have a positive margin of 2,400 MW to satisfy its operating reserve requirements. We note, however, that the roughly 9 GW of firm and non-firm imports shown in the table is far less than the total import capability. Therefore, MISO would not likely need to shed load in most of these cases provided that its markets are effective in motivating high levels of imports.

Overall, these results indicate that the system's resources are adequate for summer 2023 but may run short if the peak demand conditions are much hotter than normal. Going forward, planning reserve margins will likely continue to decrease as fossil-fuel and nuclear resources retire and are replaced by renewable resources. Therefore, it remains important for the capacity market and shortage pricing to provide efficient economic signals to maintain adequate resources.

---

31 The additional imports are consistent with the non-firm external support assumptions in MISO's 2023-2024 LOLE study.

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

D. Capacity Market Results

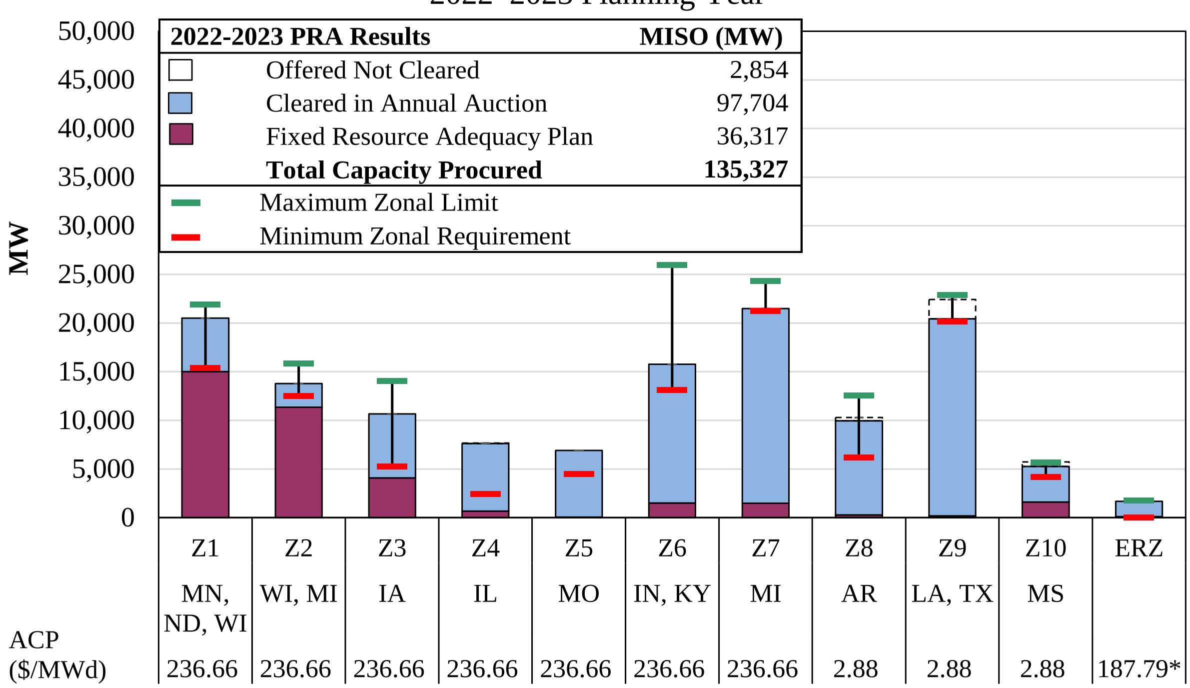
The purpose of capacity markets is to facilitate long-term resource decisions to satisfy RTOs' planning requirements in conjunction with their energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions to build new resources, make capital investments in or retire existing resources, and import or export capacity.

MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the PRA. Resources clearing in MISO's PRA receive capacity revenues that, in addition to energy and ancillary services market revenues, should signal when new resources are needed.

PRA Results for the 2022–2023 Planning Year

Figure 38 shows the outcome of the PRA held in late March 2022 for the 2022–2023 Planning Year. The figure shows the minimum and maximum amount of capacity that can be purchased in the red and green lines. The stacked bars show the total amount of capacity offered. The stacked bars include capacity offered but not cleared (ghost bars), capacity cleared (blue bars), or self-supplied (maroon) in each zone. Zonal obligations are set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement, equal to the local reliability requirement minus the maximum level of capacity imports. The maximum is equal to the obligation plus the limit on capacity exports.

Figure 38: Planning Resource Auctions
2022–2023 Planning Year



*Weighted Average Clearing Price

Prices. Zones 1 through 7 cleared at $236.66 per MW-day, the Cost of New Entry (CONE) for Zone 3, partially because of an increased load forecast and the retirements of multiple conventional resources that were replaced by the addition of renewable resources that are less reliable because of their intermittent nature. Zones 8 through 10 (MISO South) cleared at $2.88 per MW-day. MISO South Prices were extremely low and provided less than three percent of the revenues needed to cover the cost of new entry for a new peaking resource. External resource zones cleared at a weighted average price of $187.79 per MW-day.

We conducted an analysis that illustrates how capacity auction results in previous years contributed to the 2022–2023 Midwest capacity shortage. Since 2019, MISO has lost almost 5 GW of resources that would have been economic if MISO had employed a reliability-based (sloped) demand curve. Our estimated auction clearing prices in prior capacity auction years would have covered the net going forward costs of most of these resources, which would likely have allowed MISO to avoid the current capacity shortage. This is the predictable result of the flawed market design. If reliability is truly imperative, this flaw should be addressed by adopting a reliability-based demand curve. We discuss this further in Section III.B.

PRA Results for the 2023–2024 Planning Year

MISO substantially reformed its capacity market in 2022, adopting a seasonal market construct and an availability-based Seasonal Accredited Capacity (SAC) methodology for resources participating in the PRA.[33] These changes addressed two recommendations that we have made in recent *State of the Market* reports.[34] This new construct was introduced in the 2023–24 PRA held in April 2023. The results are summarized in Table 14.

Table 14: 2023–24 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)	
				Rest of Market	Zone 9 (LA,TX)
Summer 23	132,891	6,483	0.10	$10.00	
Fall 23	125,795	10,587	0.01	$15.00	$59.21
Winter 23/24	128,104	11,378	0.01	$2.00	$18.88
Spring 24	124,389	10,049	0.01	$10.00	
PRA Year	127,795	9,624	0.13	$9.25	$24.52

Across the four seasons, market clearing prices average $9.25 per MW-day, with a low of $2 in the winter, a high of $15 in the fall, and $10 in the summer and spring. Prices separated in Zone 9 in the fall and winter with prices clearing at $59.21 and $18.88 per MW-day, respectively,

33 Docket No. ER22-495-000.

34 See Recommendations 2014-5 and 2018-5 from prior *State of the Market Reports*.

because of tight supply in this zone. Nonetheless, these prices are much lower than the prices that were set at CONE of $237 per MW-day in the Midwest (Zones 1 to 7) in the 2022–23 PRA.

This collapse in the prices was the result of a 6 GW increase in net capacity in the summer season of the 2023–2024 planning year and the vertical demand curves utilized in the market. The following factors contributed to this increase in net capacity in the Midwest:

- 2.1 GW decrease in PRMR from lower coincident peak forecasts and a lower PRM;
- 1.1 GW addition of new thermal capacity that more than offset 0.9 GW of retirements;
- 250 MW increase in accreditation of Midwest resources in the transition to SAC;
- 640 MW of new solar resources;
- 1.2 GW of additional wind: 450 MW of new wind resources and a 740 MW increase in existing wind capacity from procuring firm transmission to be deliverable; and
- 1.1 GW increase in LMRs, mostly from External Resources and demand response.

Most of the increase in net capacity is associated with reduced requirements and an increase in voluntary participation (e.g., LMRs and more converted wind deliverability). The change in requirements year-to-year is difficult to predict, but the change in participation is likely a reaction to the high prices the previous year. While there was a net gain in thermal capacity in this upcoming planning year, we expect continued retirements of aging coal and gas resources in future years. Rapid increases in solar and wind resources will also continue, but these resources are limited in the ability to satisfy MISO's reliability needs.

Unfortunately, MISO's capacity market is not designed to send efficient price signals to spur the development of new dispatchable resources. Addressing this inefficiency requires MISO to correct the representation of demand by adopting a reliability-based demand curve (RBDC). Under the sloped demand curve proposed by MISO, the summer capacity prices would have risen more than five-fold to more than $50 per MW-day. This price effect would have been much larger absent the sizable decrease in capacity requirements in this planning year.

Discussion of Other Issues Affecting the Performance of the PRA

Transfer Constraint. As part of the Settlement Agreement with SPP, MISO may dispatch up to 2,500 MW of energy transfers from MISO South to MISO Midwest. However, MISO limits the transfer capability in the South to North direction to 1,900 MW in the PRA. This reduction is made to account for firm interregional transmission reservations held by participants. Unfortunately, this reduction is not warranted because these reservations do not encumber MISO's utilization of the RDT. This constraint bound in the 2022–2023 PRA and caused the significant price separation between MISO South and MISO Midwest, contributing to the capacity shortage in the Midwest. Increasing the limit to an expected transfer capability closer to 2,500 MW would allow MISO to utilize its capacity more fully in MISO South. Hence, we recommend that MISO revise its transfer limit in future PRAs.

E. Long-Term Economic Signals

Price signals in MISO's markets play an essential role in coordinating commitment and dispatch of units in the short term, while providing long-term economic signals that govern investment and retirement decisions for generators and transmission facilities. This subsection evaluates the long-term economic signals produced by MISO's markets by measuring the net revenue a new generating unit would have earned in MISO's markets in 2022.

Net revenue is the revenue a unit earns above its variable production costs if it runs when it is economic to run. Well-designed markets should produce net revenue sufficient to support new investment at times when existing resources are not adequate to meet the system's needs. Figure 39 and Figure 40 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the last three years in the Midwest and South regions. For comparison, the figures also show the annual net revenue that would be needed for these investments to be profitable (i.e., the Cost of New Entry or "CONE"). We include in our analysis ghost bars that indicate the alternative net revenues that these resources would have received were MISO to have employed a sloped demand curve in its capacity market (as we discuss in Section III.B).

Figure 39: Net Revenue Analysis
Midwest Region, 2020–2022

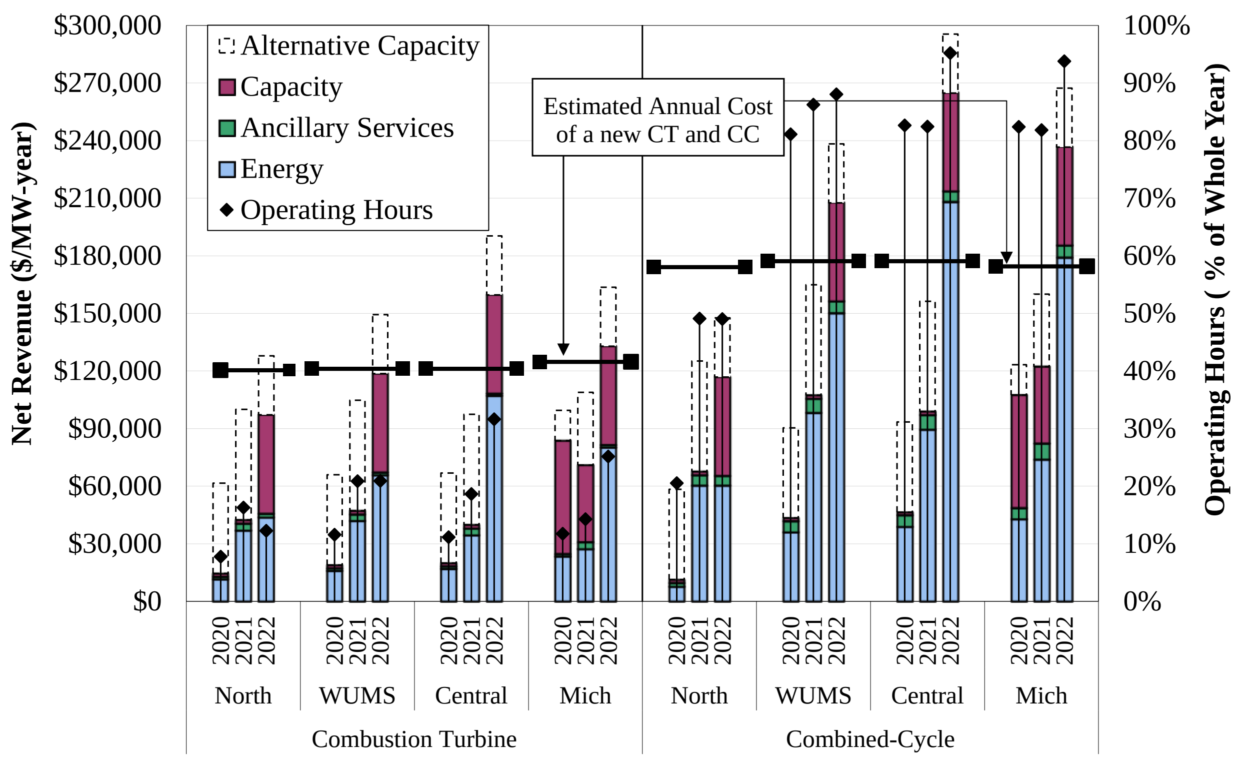
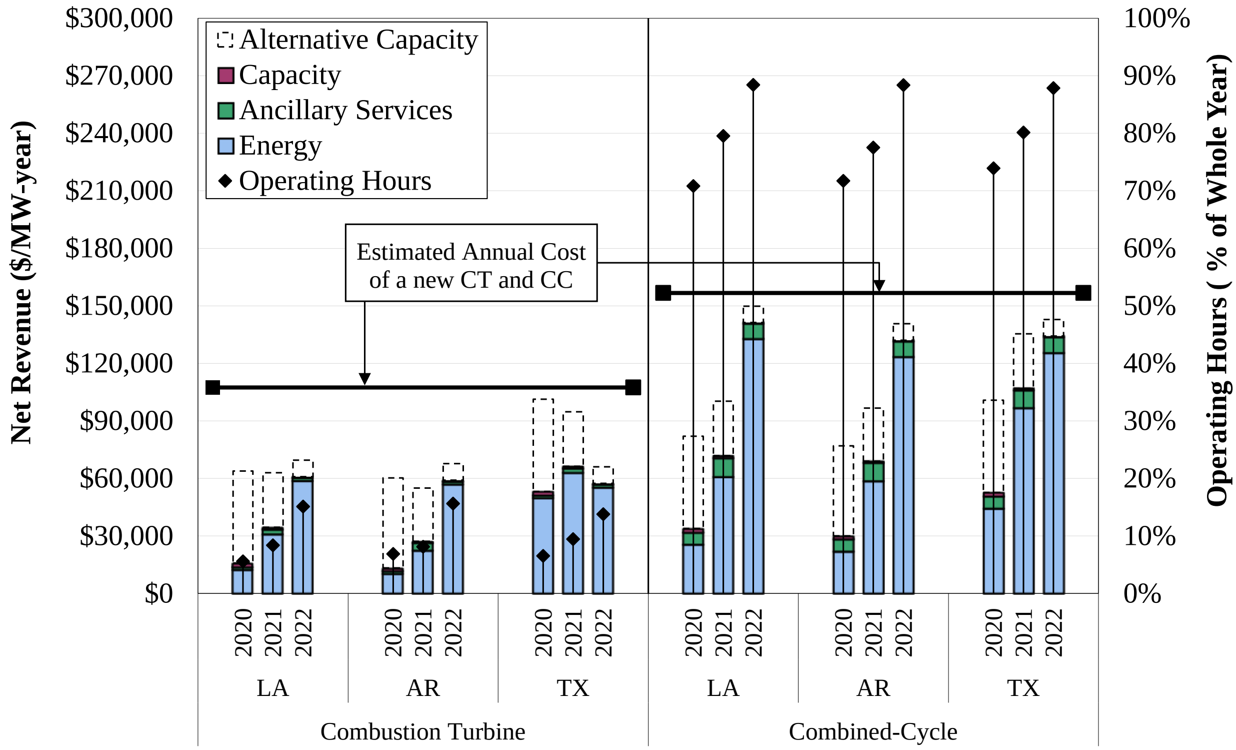


Figure 40: Net Revenue Analysis
South Region, 2020–2022



These figures show that net revenues rose substantially in all regions in 2022, partly because higher natural gas prices contributed to higher energy and ancillary services prices throughout MISO, and partly because MISO experienced a period of sustained high prices during Winter Storm Elliott in December. The capacity shortage and sharp increase in congestion caused net revenues to exceed the cost of new entry for combined-cycle and combustion turbine resources in eastern areas in the Midwest region. We do not expect this to continue given the reductions in natural gas and capacity prices that have occurred in early 2023.

Overall, MISO's economic signals continue to be undermined by capacity market design issues, including a poor representation of demand as a single quantity value (i.e., a vertical demand curve). Had MISO employed a reliability-based demand curve in the Planning Resource Auctions, the annual net revenues would have been significantly higher in recent years and sustained economic merchant resources that have been retiring prematurely. This raises particularly timely concerns as MISO's capacity surplus is dissipating and resources face substantial economic pressure. As noted above, this design flaw contributed to the capacity shortage in the Midwest Region in the 2022–2023 PRA and reduced MISO's overall reliability. This issue is discussed in more detail along with our recommendation to address it in Section III.

F. Existing Capacity at Risk Analysis

Since its inception, MISO has enjoyed a capacity surplus beyond the minimum requirement. MISO's capacity surplus has dwindled in recent years as older baseload units have entered long-term suspension or retired. This trend has largely been due to sustained low natural gas prices and the poor design of MISO's capacity market that results in understated capacity prices.

Well-designed markets should provide sufficient net revenues to cover the costs of remaining in operation (i.e., Going-Forward Costs or "GFCs") for resources that provide material reliability. When resources cannot recover their GFCs, they are at risk of suspending or retiring prematurely. Moreover, some resources may reduce maintenance expenditures, leading them to have more frequent forced outages and deratings.

We conducted an analysis to evaluate MISO's capacity at risk for long-term suspension or retirement for three types of technologies in MISO: coal, nuclear, and wind. Our analysis shown in Figure 41 compares the annual resource net revenues to the GFCs. The net revenues and GFCs are based on technology-specific heat rates, variable costs, capacity factors and Technology-Specific Avoidable Costs (TSACs). A detailed description of our analysis can be found in the Appendix Section VI.F.

Figure 41: Capacity at Risk by Technology Type
2022

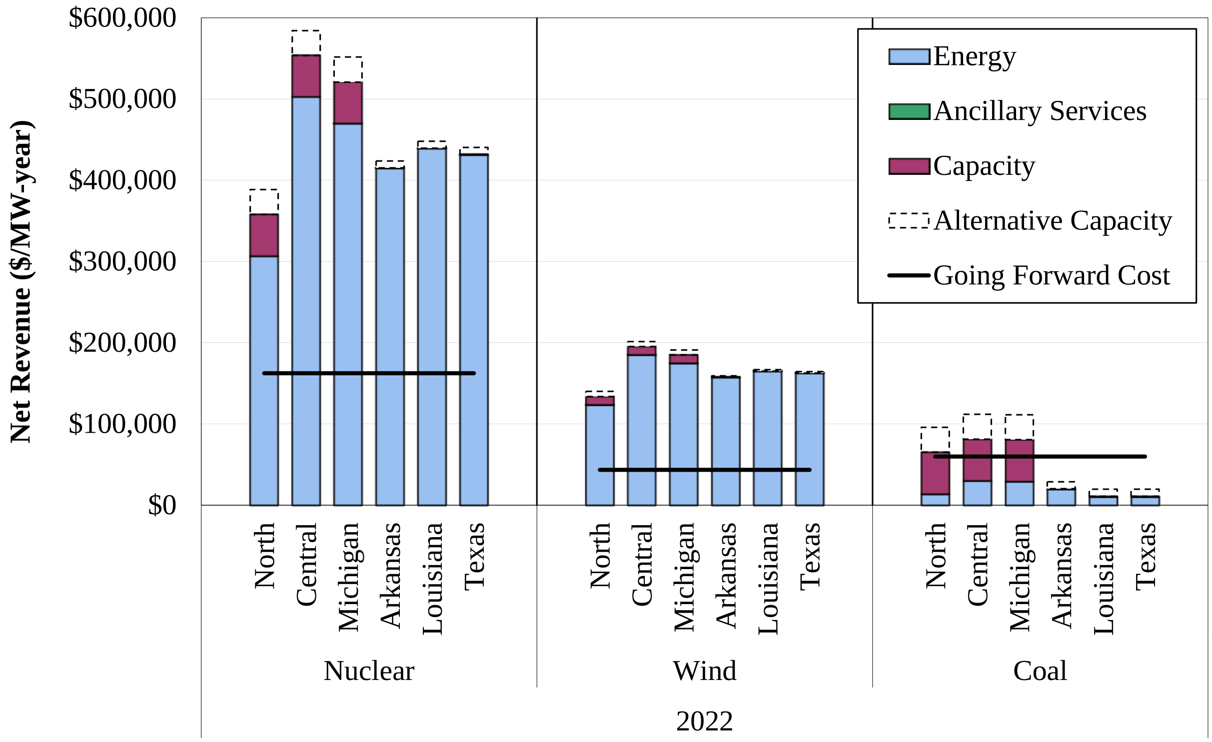


Figure 41 shows that while nuclear and wind resources are more than revenue adequate, even without including tax credits, typical coal resources exhibit revenue shortfalls under the current capacity construct. Even with the higher gas prices in 2022, many coal resources must rely on capacity auction revenue to cover their going-forward costs. Many coal-fired resources in MISO are owned by vertically-integrated utilities that have guaranteed returns on investment through cost-of-service rates. Barring out-of-market cost recovery and the capacity shortage pricing that occurred in the 2022–2023 PRA, most of these resources would be uneconomic to continue operating at the prices that prevailed in 2022. However, if MISO prices capacity efficiently (by adopting a reliability-based demand curve), typical coal resources would be able to recover their GFCs in the Midwest and avoid premature retirements. A more detailed analysis of the range of net revenues for existing individual coal resources by zone over the past two years is shown in Section VI.F of the Analytic Appendix.

G. Capacity Market Reforms

Although a reliability-based demand curve that we describe in Section III.B is the most important design improvement, followed by improving the accreditation of capacity resources, we have also recommended that MISO consider the following additional improvements to provide better long-term incentives to MISO's suppliers and ensure that MISO's resource adequacy needs are satisfied.

Improvements to the Seasonal Market

During MISO's SAC filing in 2022, we raised some issues concerning elements that we believed reduced the benefits of the two broad changes implemented by MISO (seasonal market and accreditation based on availability during tight hours):[35]

- The seasonal design has four seasons that clear simultaneously at the beginning of the planning year. We had recommended that MISO run prompt seasonal auctions so that participants could make auction decisions with less uncertainty and optimize their offers in the upcoming season given the results of the prior seasons; and

- The implemented design still generally overvalues inflexible resources, such as accrediting offline resources with 24-hour lead times comparably to online resources or fast-starting gas turbines.

We have also identified some additional issues with the design since the implementation of the new construct. Under the current design, if an MP does not replace ZRCs for a resource on planned outage for more than 31 days in a season, the Capacity Replacement Non-Compliance Charge (CRNCC) is assessed.

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

The 31-day penalty threshold creates some inefficient incentives:

(1) It allows a resource on outage the entire season (over 90 days) to be profitably sold; and

(2) It creates incentives to schedule long-term planned outages that straddle seasons to avoid the CRNCC, which could degrade reliability.

We recommend that MISO reform this penalty structure to address these incentives concerns.

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 instructed by MISO. If they are not available to mitigate capacity shortages during emergencies, then they are not providing the reliability value MISO assumes and for which they are compensated. Some emergency-only resources have long notification times (up to 12 hours) or long start-up or shutdown times that render them essentially unavailable in most emergencies, which tend to occur with less than two hours warning. Therefore, we recommend that MISO develop a reasonable methodology for accrediting emergency-only resources in the PRA.

MISO filed Tariff changes in March 2023 that restrict the use of emergency commitment status in energy offers, which will be effective June 2023.[36] MISO intends to make a follow-up filing effective June 2024 to account for restricted availability of AME in accreditation and allow operators to call on AME resources with more than 2-hour lead times in advance of emergency declarations.

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. It runs a power-flow model after the initial PRA solution to determine whether any constraints are binding. Although transmission constraints have not been prevalent in the past, this is a poor approach that will fail to efficiently price any constraints that arise. Instead, MISO should model these 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. This would allow the zonal prices to accurately reflect these constraints.

36 Docket No. ER23-1523-000.

VII. External Transactions

A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because of its 12 interfaces with neighboring systems that have a total interface capability of 14 GW. Hence, the magnitude of the changes in imports and exports in response to prices can be large and significantly affect market outcomes. Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. MISO remained a substantial net importer in 2022:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 4.1 and 4.2 GW, respectively (positive NSI values reflect net imports).
- MISO's largest and most actively scheduled interface is the PJM interface. MISO was a net importer from PJM in 2022.
  - Hourly real-time imports from PJM averaged 2.2 GW, down 20 percent from 2021.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.

Scheduling that is responsive to interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area. Participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. The lack of RTO coordination of external transactions causes aggregate changes in transactions to be far from optimal. To evaluate the efficiency of external scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions.

In 2022, nearly 60 percent of the transactions with PJM and over 60 percent of the transactions with SPP were scheduled in the profitable direction. Even though transactions are scheduled in the efficient direction more than half of the time, large untapped savings are available because it is often economic to schedule significantly more or less interchange. Many hours still exhibit large price differences that offer substantial production cost savings.

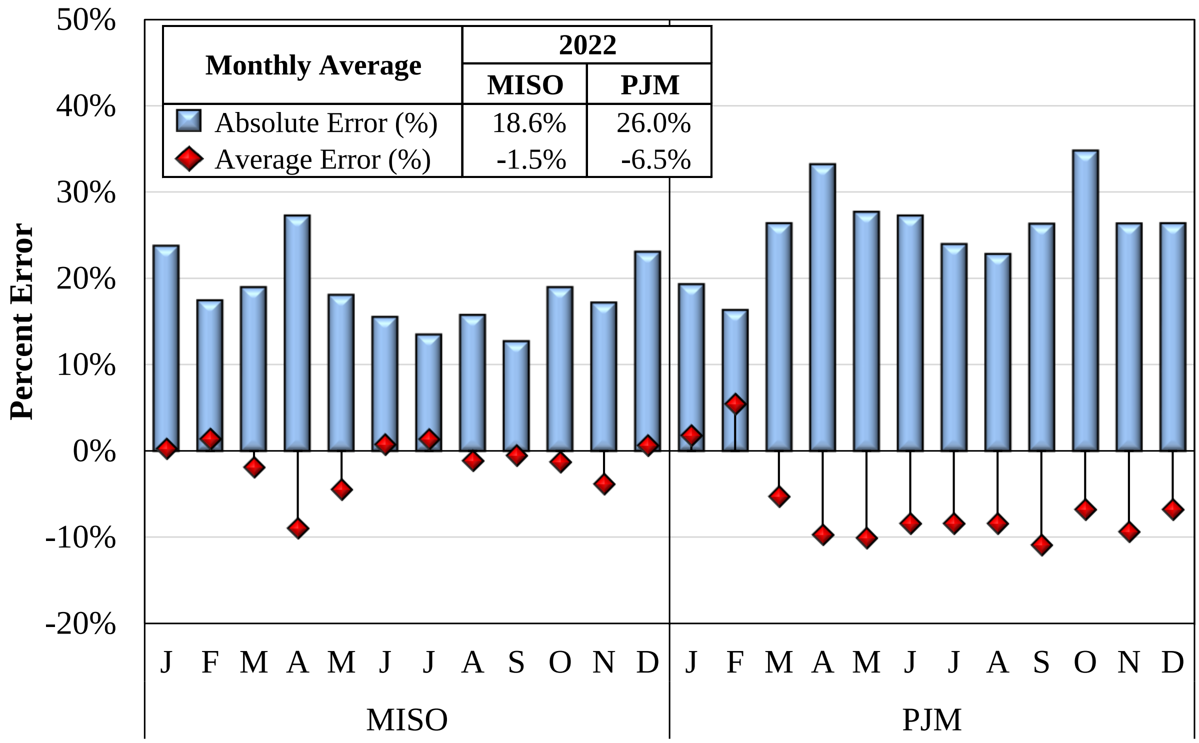
B. Coordinated Transaction Scheduling

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 prior to the interval is greater than the offer price. CTS transactions are settled based on real-time interface prices. In this subsection, we discuss the performance of the current CTS system and a fundamental reform to the CTS design that would allow it to perform much better.

Summary of CTS Performance

Up until early 2019, there had been almost no participation in CTS. In 2022, the hourly average quantity of CTS transactions offered and cleared remained extremely low at 50 MW and 23 MW, respectively. Over 99 percent of the transactions over the past two years have been in the import direction. CTS transactions remain a *de minimus* fraction of transactions at the PJM interface. We have previously shown that high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling. We have also concluded that persistent forecasting errors by MISO and PJM have likely hindered the use of CTS. We evaluated the forecasting errors for each RTO, measuring the percentage difference between the actual LMP and the forecasted price used for CTS. In Figure 42, we show the forecasting errors by month in both average and absolute average terms for both MISO (left-hand chart) and PJM (right-hand chart).

Figure 42: MISO and PJM CTS Forecast Errors
2022



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM where the forecasts are both large and biased. In 2022, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -6.5 percent, and the average of the absolute difference was 26 percent.[37] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was -1.5 percent, and the average

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

of the absolute difference was 18.6 percent. When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface because they create substantial risk for participants scheduling transactions through the CTS process. The poor forecasts suggest that CTS would likely clear many transactions that are uneconomic based on real-time spreads if participants submitted relatively low-cost CTS offers. These forecasts would also cause CTS to not clear many transactions that would otherwise be economic.

A comparable mechanism to CTS is in place between the New York ISO and ISO New England and is widely used, in part because the forecast prices are more accurate, and no charges are applied to these transactions. Hence, we continue to recommend that MISO eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same. Additionally, we have concluded that it is unlikely for the RTOs to substantially improve their forecasts given the timing of the information used. Hence, we recommend the RTOs mitigate the adverse effects of the forecasts by modifying the CTS to clear transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The following is an evaluation of this recommendation.

CTS with Five-Minute Clearing

We ran a simulation for 2022 of a CTS process that clears based on recent five-minute prices to evaluate the benefits of our recommendation. Instead of the markets clearing CTS offers on a 15-minute basis using forecasted prices from 30 minutes prior, the markets in our simulation clear CTS transactions every five minutes using interface price spreads from the previous interval. For each interval, we estimate an optimal clearing amount based on:

- The previous five-minute spread less cleared transaction fees;
- Assumed relationships of the price in PJM and MISO to changes in the transactions scheduled between them, which was based on a regression analysis we performed; and
- An assumed aggregate offer curve beginning at the level of the incremental charges and rising at a rate of $1 per MWh every 167 MW ($6 per 1000 MW).

We identify the optimal clearing amount, accounting for any changes in the actual scheduled NSI, by applying the following constraints: (1) maximum change between five-minute intervals of 500 MW (in either direction), and (2) maximum total CTS import and export limits of 5,000 MW. Based on the adjustments calculated for each five-minute interval, we are able to estimate the price changes, production cost savings, and profits of the CTS participants.

We also used this model to evaluate the benefits of a five-minute CTS with SPP, with tighter constraints since MISO has a smaller interface with SPP than PJM: (1) maximum 5-minute change of 250 MW (in either direction), and (2) maximum total CTS import and export limits of 2,000 MW. Table 15 summarizes the results for both markets.

This analysis shows that redesigning the CTS process to adjust NSI on a five-minute basis offers substantial savings that are not being captured under the current process. The recommended five-minute CTS with PJM would have achieved more than $40 million in production cost savings versus only $3 million under the current process. Although adjustments would have occurred in 88 percent of intervals, these savings do not require large adjustments—which average roughly 100 MW. A five-minute CTS with SPP would have achieved more than $56 million in production cost savings with a similar level of adjustments.

Table 15: CTS with Five-Minute Clearing Versus Current CTS
2022

	Percent of Intervals Adjusted	Production Cost Savings	Profits	Percent Unprofitable
PJM				
Current CTS	2.9%	$2,905,265	$76,892	12.2%
5-Minute CTS*	88.5%	$41,095,475	$20,663,002	23.0%
SPP				
5-Minute CTS*	95.2%	$56,130,144	$28,293,175	25.9%

* Results omit Dec 23-24 when MISO and PJM had very high prices from Winter Storm Elliott.

The improvement in the incentives for participants to utilize the CTS process is also notable. The CTS participants would have earned over $20 million from the cleared CTS transactions with PJM compared to profits in 2022 of just $77,000 under the current process. The poor price forecasts and high charges applied to any CTS offers leave little to no opportunity to profit by participating in the CTS. Five-minute CTS in SPP would have also been very profitable for participants, producing profits of over $28 million. Hence, using the most recent five-minute prices is a substantial improvement and leads to more efficient CTS adjustments. We recommend MISO pursue this form of CTS process with both PJM and SPP.

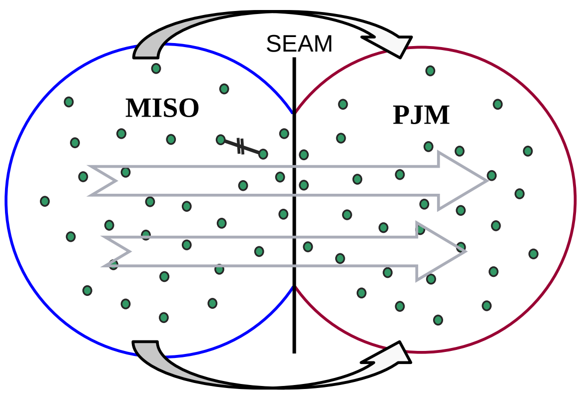
C. Interface Pricing and External Transactions

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

- It is the sole means to facilitate efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is an essential basis for CTS to maximize the utilization of the interface.

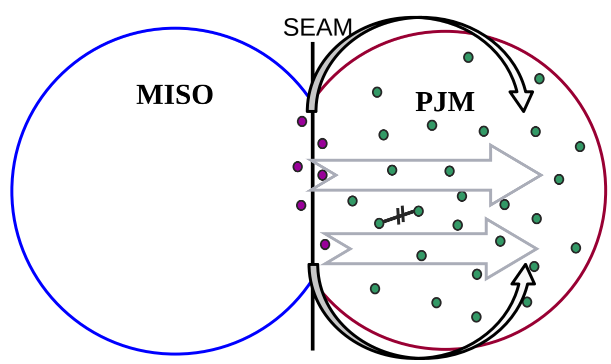
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling power from the lower-cost system to the higher-cost system until the SMPs equalize. However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from 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 accurately calculated. In contrast, *the source of an import (or sink for an export) is not known*, so it must be assumed in order 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 provide an efficient transaction scheduling incentive and lower the costs for both systems.



In reality, 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 the power sinking throughout PJM. This is accurate because PJM will ramp down all its marginal generators when it imports power.

Because both RTOs price congestion on M2M constraints, some congestion had been redundantly priced by MISO and PJM and by MISO and SPP. To address this concern, PJM and MISO agreed to implement a "common interface" that assumes the power sources and sinks from 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 with 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 of the RTOs.

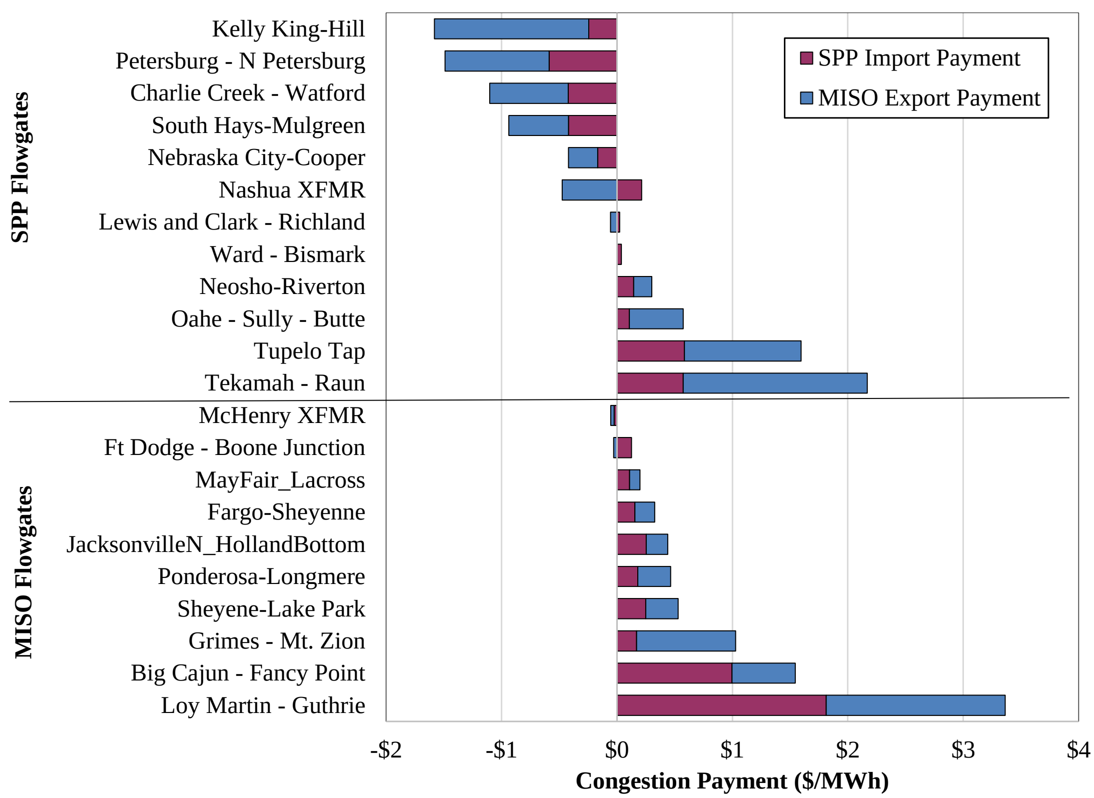


We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger average errors and volatility at the interface. These results indicate that this approach was a mistake. Fortunately, MISO only uses this type of interface definition at the PJM interface, whereas PJM uses this approach on all its interfaces.

We have recently studied interface pricing at the MISO-SPP interface and verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. In other words, when a M2M constraint binds, both RTOs price and settle with external transactions based on their respective estimates of the entire congestion effects of the transaction. Since both RTOs have relatively good models, their estimates are typically very similar, resulting in a rough doubling of the congestion settlement.

To show how this occurs, we have calculated the average interface pricing component associated with selected individual M2M constraints. These coordinated constraints had congestion value exceeding one million dollars between June 2018 and May 2019. Figure 43 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints. The congestion payments are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount; whereas a positive value indicates that the participant would be paid for congestion relief.

Figure 43: Constraint-Specific Interface Congestion Prices



Even though their interface definitions differ somewhat, this figure shows that both RTOs estimate very similar effects on each of the jointly managed constraints. Unfortunately, this results in congestion payments and charges that are roughly double the efficient level—the payment made by the MRTO. Although these payments may appear small, it is because they are averages of many intervals. In some intervals, the distortions exceed $30 per MWh.

This is important because it results in poor incentives for participants to schedule imports and exports when M2M constraints are binding significantly. It also results in additional costs for the RTOs. When SPP makes a payment for an external transaction because it would relieve a MISO constraint, this payment is not recouped through the M2M process. In other words, if both RTOs pay $20 per MWh for congestion relief to the same participant ($40 per MWh), MISO would receive some relief for having made the payment, while SPP as the NMRTO would receive no credit and would generally recover the costs of its payment through an uplift charge to load. Of course, these effects would be reversed if MISO pays a participant to schedule a transaction that relieves an SPP M2M constraint. Hence, this is an issue that hurts both RTOs while leading to inefficient transaction schedules and higher costs.

Given our findings regarding the common interface approach adopted with PJM, this approach should not be considered at the SPP interface. We encourage MISO and SPP to adopt an alternative approach to settle interchange congestion accurately. Hence, we recommend that the RTOs employ their current interface definitions, but that M2M constraints modeled by both RTOs only be included in the MRTO's interface price.

Interface Pricing for Other External Constraints

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

In addition to the inequity, these congestion payments motivate 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's pricing of the external TLR constraints is generally vastly overstated and provides inefficient scheduling incentives.

Fortunately, this issue is not difficult to address. We have recommended since 2012 that MISO simply remove the congestion related to external constraints from each of its interface prices. This change would resolve the interface pricing issue associated with external constraints on all of MISO's other interfaces (excluding the PJM and SPP interfaces).

VIII. Competitive Assessment and Market Power Mitigation

This section contains our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2022. Market power in electricity markets exists when a participant has the ability and incentive to raise prices. Market power in electricity markets can be indicated by a variety of empirical measures, which we discuss in this section.

A. Structural Market Power Indicators

Economists and antitrust agencies often utilize market concentration metrics to evaluate the competitiveness of a market. The most common metric is the Herfindahl-Hirschman Index (HHI), which is calculated as the sum of the squared market shares of each supplier. An HHI of less than 1000 is generally considered low, while an HHI higher than 1800 is considered high. Market concentration is low for the overall MISO area (624) but very high in some local areas, such as WUMS (3944) and the South Region (3997), where a single supplier operates more than 60 percent of the generation. However, the HHI metric does not include the impacts of load obligations, which affect suppliers' incentives to raise prices. HHI also does not account for the difference between total supply and demand, which is important because excess supply results in more competitive markets. Hence, the HHI is limited as an indicator of overall competitiveness.

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

We also evaluate local market power by identifying pivotal suppliers for relieving 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 severe potential local market power concerns where tighter market power mitigation measures are employed. A BCA is defined when non-NCA transmission constraints bind. The BCA includes all generating units with significant impact on power flows over the constraint. Our results showed that a supplier was frequently pivotal in both types of constrained areas:

- On average, 57 percent of the active BCA constraints had at least one pivotal supplier.
- Over 90 percent of the binding constraints into both the MISO South NCAs and the Midwest NCAs had at least one pivotal supplier.

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

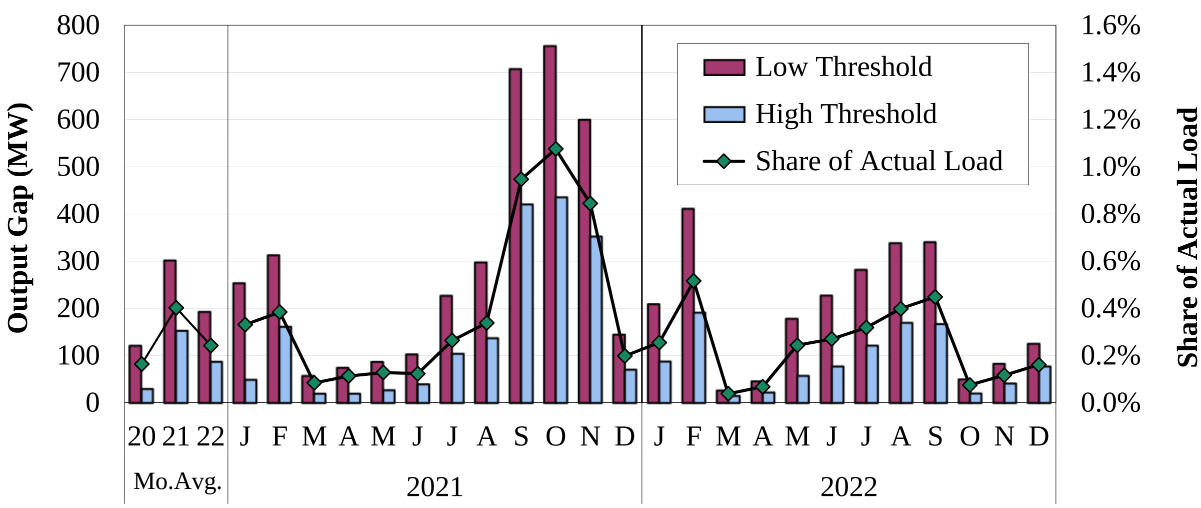
B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate measures of overall market competitiveness, including a "price-cost mark-up". This measure compares the system marginal price based on actual offers to 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 -0.5 percent in 2022. The mark-up was negative because the monthly mark-up was negative in a number of months. Coal conservation measures, which were in place throughout the year and impacted coal resource references, may have contributed to the decrease in mark-up.

Figure 44 shows the "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. 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 both units that are online and submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 44: Economic Withholding – Output Gap Analysis

2021–2022



Low Threshold Results by Unit Status (MW)

Offline	8	38	95	0	90	3	0	9	8	27	46	129	103	35	9	22	24	17	20	103	118	184	238	256	27	47	82
Online	114	264	99	254	223	55	75	79	96	201	252	577	652	565	136	188	387	11	27	75	110	98	100	84	23	36	43

High Threshold Results by Unit Status (MW)

Offline	7	28	59	0	70	2	0	8	7	22	38	98	62	19	7	21	20	12	17	51	67	110	156	151	12	36	59
Online	23	125	28	49	91	18	20	20	33	82	100	322	373	333	64	67	171	4	6	7	10	12	14	16	8	6	19

The figure shows that the average monthly output gap level was 0.2 percent of load in 2022, which is effectively *de minimus*, and slightly lower than in 2021. Beginning in the fall of 2021, multiple coal-fired resources employed fuel conservation measures to ensure that they would have sufficient fuel inventory going into the winter months. Several of these resources had not requested reference level consultations to reflect their conservation plans. In contrast, by winter 2022, most coal-fired resources experiencing fuel and reagent supply issues reflected the conservation measures in their reference levels. Although these results raise no competitive concerns, we monitor these levels on an hourly basis and routinely investigate potential withholding.

C. Summary of Market Power Mitigation

Market power mitigation in 2022 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent. Market power mitigation in MISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria. The mitigation measure for economic withholding caps a unit's offer price when the offer exceeds the conduct threshold and raises energy market clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently. The mitigation thresholds differ depending on the three types of constrained areas that may be subject to mitigation:

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

The market power concerns associated with NCAs and Dynamic NCAs are greatest because they address chronic or severe congestion. As a result, conduct and impact thresholds for NCAs and Dynamic NCAs are much lower than they are for BCAs. The thresholds for NCAs depend on how frequently the NCA constraints bind, while a fixed threshold of $25 per MWh is used for Dynamic NCAs. No Dynamic NCAs were declared in 2022. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

The incidence of mitigation was relatively unchanged in 2022, affecting less than one percent of real-time market hours across 38 days, although energy mitigation for offer-capping during Winter Storm Elliott contributed to another 147 hours. Assuming the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to the exercise of market power as long as it is liquid, with fulsome participation by physical and virtual trading participants. Hence, mitigation was applied on eight day-ahead market days in 2022, excluding the additional eight days around Winter Storm Elliott when offer-capping was applied. Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive.

RSG payments occur when a resource is committed out-of-market to meet the system's capacity needs, local reliability requirements, or to manage congestion. If the resource offers include inflated economic or physical parameters, it may result in inflated RSG payments and the resource may be mitigated. Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition is generally robust to satisfy those needs.

Average day-ahead RSG mitigation was 77 percent lower in 2022 compared to 2021, largely because of nearly $10 million of day-ahead RSG mitigation that occurred during Winter Storm Uri in February 2021. Excluding February 2021, day-ahead RSG mitigation fell by roughly one third. Average monthly real-time RSG mitigation rose sharply in 2022, partly because of the increase in gas prices. A large unit in the Midwest experienced more than $1.7 million in real-time RSG mitigation in June.

IX. DEMAND RESPONSE AND ENERGY EFFICIENCY

Demand Response (DR) involves actions taken by electricity consumers to reduce their consumption when their value of consuming electricity is less than the prevailing marginal cost to supply it. Facilitating DR is valuable because it contributes to:

- Improved operational reliability in the short term;
- Least-cost resource adequacy in the long term;
- Reductions in price volatility and other market costs; and
- Mitigation of market power.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. 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. Hence, it is important to provide efficient incentives for DR resources and to integrate them into the MISO markets in a manner that promotes efficient pricing and other market outcomes. In this section, we discuss the current level of participation of DR and energy efficiency resources (EE) and identify some significant concerns that have arisen related to MISO's approach to incorporating these demand resources in the market as supply resources.

A. Demand Response Participation in MISO

Table 16 shows DR participation in MISO and compares it to NYISO and ISO-NE in the last three years. The table shows DR resources in MISO can be divided into one or more of the following three categories:[38]

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

As shown in Table 16, MISO had more than 12 GW of DR capability available in 2022, slightly more than in 2021. Between 2020 and 2021, DR capability fell 10 percent because no Energy Efficiency (EE) Resources cleared the PRA after the 2020/2021 auction, as discussed below, and fewer Emergency Demand Response resources have been participating in MISO year over year.

38 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
2020–2022

		2020	2021	2022
MISO[1]		**13,528**	**12,197**	**12,389**
	LMR-BTMG	3,892	4,068	4,169
	LMR-DR	7,557	7,152	7,543
	LMR-EE	650	0	0
	DRR Type I	739	711	582
	DRR Type II	101	115	127
	Total Cross-Registered as LMR	*381*	*476*	*150*
	Emergency DR	1,439	785	456
	Total Cross-Registered as LMR	*470*	*158*	*337*
NYISO[2]		**1,199**	**1,170**	**1,234**
	Special Case Resources - Capacity	1,195	1,168	1,231
	Emergency DR	4	2	3
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**3,448**	**3,934**	**4,076**
	Active Demand Capacity Resources	455	511	466
	Passive Demand Resources	2,993	3,423	3,610

[1] Registered as of December 2022. All units are MW.
[2] Registered as of July 2022. Source: Annual Report on Demand Side Management of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Capacity supply obligations as of December 2022. Source: ISO-NE Monthly Market Reports.

MISO's demand response capability constitutes around ten percent of peak load, which is a larger portion than in NYISO but slightly less than in ISO-NE. It exhibits varying degrees of responsiveness to prevailing system conditions. The first and largest category of DR (accounting for almost 95 percent of MISO's total DR) is LMRs. These capacity resources are interruptible load developed under regulated utility programs and behind-the-meter-generation. A second category is Demand Response Resources (DRRs) that can participate in MISO's capacity, energy, and ancillary services markets and are of two types, as we explain below. A third category is Emergency Demand Response (EDR). Resources may cross-register as LMRs and DRRs or EDRs, and in the table we indicate the amount of capacity that was cross-registered.

LMRs

LMRs are planning resources and thus have an obligation to curtail as instructed during emergencies. MISO can only deploy these resources during a declared emergency. Many of these legacy demand-side programs are administered by regulated utilities, such as interruptible load and direct load control programs that target residential, small commercial, and industrial customers. They also include behind-the-meter generation (BTMG). These resources do not submit an economic offer price, but LMR deployment triggers MISO's emergency offer floor price mechanism. In the PRA, MISO classifies interruptible load resources as LMR-DR and BTMG resources as LMR-BTMG. As shown in Table 16, almost all the DR in MISO participate as emergency resources, mainly in the LMR category.

Demand Response Resources

DRRs are a category of DR that are assumed to be able to respond to MISO's real-time curtailment instructions. As Table 16 shows, this category comprises only a small portion of MISO's total DR capability. These resources can participate in the energy, ancillary services, and capacity markets. Most DRRs opt to participate in the capacity markets as LMRs, which lessens 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 can supply a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. These resources can qualify as Fast-Start Resources and set price in ELMP.[39]
- 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.

Aggregators of Retail Customers (ARCs) and Load-Serving Entities (LSEs) are eligible to offer DRR capability into the energy and ancillary services markets. DRR Type II resources can currently offer all ancillary services products, whereas DRR Type I units can provide all products except regulating reserves on account of their fixed-quantity demand reduction offers.

DRR Type I resources accounted for almost all of DRR scheduling in 2022. The scheduling of these resources 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.

Emergency DRs

The third category of DR is Emergency DRs (EDR), which totaled 456 MW in 2022. These DRs do not have a must-offer requirement unless cross-registered and cleared as an LMR in the PRA. DR resources that clear MISO's PRA can offer as EDRs rather than LMRs during emergencies. These resources specify their availability and costs in the day ahead. If an emergency ensues 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 with their offers during emergencies.

Finally, DR resources may count toward fulfillment of an LSE's PRMR if the resource can curtail load within 12 hours and is available during the summer months. As part of the RAN

---

39 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.

initiatives, FERC has approved Tariff changes that reduce the allowable lead time for qualifying LMRs to six hours and accredits resources based on the availability throughout the planning year. These changes began in the 2022/2023 planning year and phase in across multiple planning years to allow participants to modify existing contracts and replace affected capacity.[40]

MISO did not call upon LMRs between 2007 and 2016. However, beginning in 2017, LMRs have become increasingly important in both planning and operations during emergency events. From April 2017 through December 2022, LMRs were deployed nine times in MISO South and four times in MISO Midwest. The most recent deployment occurred in December 2022 during Winter Storm Elliott, when MISO called on LMRs to provide support to a neighboring system that was shedding load. We discuss the 2022 emergency events in detail in Section II.E.

B. DRR Participation in Energy and Ancillary Services Markets

DRR settlements increased substantially in 2021 to almost $38 million, up from roughly $16 million in 2020. In contrast, payments to DRRs fell 34 percent in 2022 as resources that we had investigated ceased participation. Our investigation began in 2021 after DRR settlements increased significantly. The results raised significant concerns regarding the market design and rules, the inefficient incentives they provide, and the resulting participant conduct. In particular, we identified two types of problems with the settlement rules and participants' conduct.

Payments for artificial "curtailments". These are payments for energy that the participant never intended to consume. For example, consider an industrial facility registered as DRR with a peak load of 100 MW that will be offline for maintenance. Such a DRR could offer 100 MW of "curtailments" as a price-taker (at a very low price) even though its planned consumption was zero. Hence, the resource will be scheduled and paid the prevailing LMP for providing nothing.

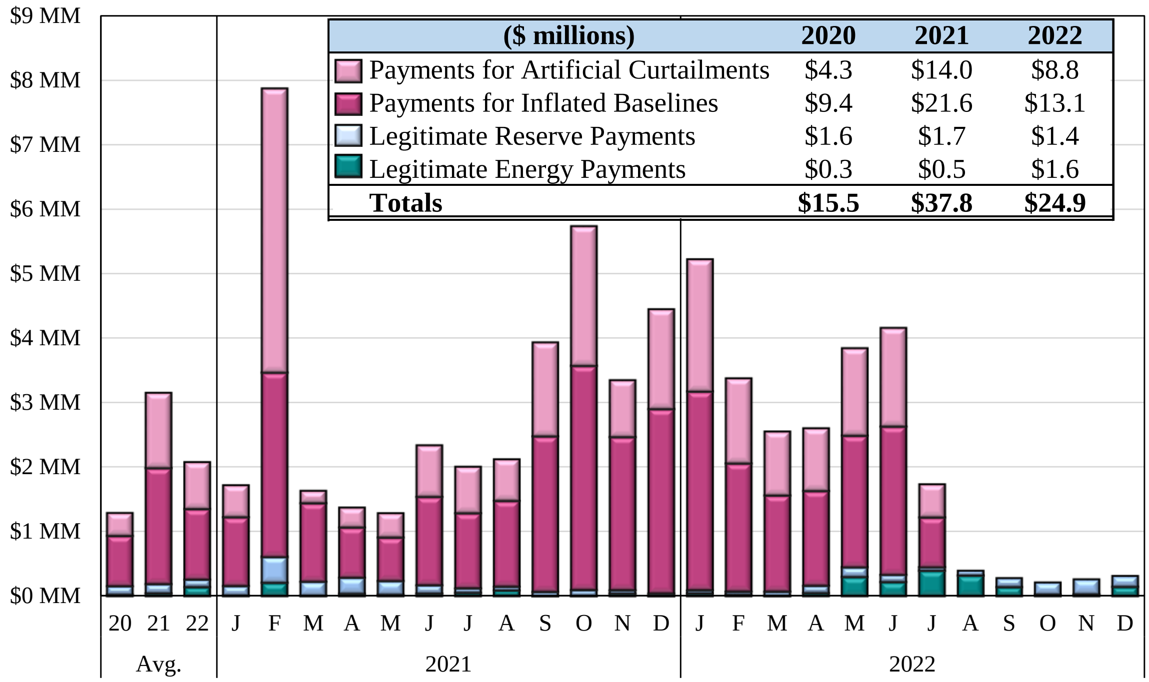
Inflating the baseline level. Hours when curtailments are scheduled are not included in the baseline calculation because, presumably, the consumption in these hours is less than normal. Some participants have inflated their baseline by offering as a price-taker in almost all hours, which will cause their curtailment offer to be scheduled and the hour to be excluded from the baseline. The participant can then simply not offer the curtailment when its load is highest, causing the baseline to substantially exceed the participant's typical consumption for the DRR resource. Having established the inflated baseline, the participant can then return to offering curtailments as a price-taker when consuming at typical levels and be paid for the difference between the peak load level and the typical load level.

These two strategies were involved in the vast majority of payments to DRR Type 1 resources. Figure 45 below shows all payments to such resources over the past three years. It separates the

40 Beginning in the 2022/2023 PRA, LMRs that register with six hours or less notification time and can provide curtailments at least ten times per year are able to fully qualify as capacity resources, and LMRs with longer registered lead times and fewer curtailments have proportionally less capacity.

payments to those that are associated with the artificial curtailments, inflated baselines, and legitimate payments for energy curtailments and ancillary services.

Figure 45: Energy Market Payments to DRR Type I Resources
2021–2022



($ millions)	2020	2021	2022
Payments for Artificial Curtailments	$4.3	$14.0	$8.8
Payments for Inflated Baselines	$9.4	$21.6	$13.1
Legitimate Reserve Payments	$1.6	$1.7	$1.4
Legitimate Energy Payments	$0.3	$0.5	$1.6
Totals	**$15.5**	**$37.8**	**$24.9**

Figure 45 shows that the payments to DRRs had been almost entirely attributable to the two strategies described above. We found that less than 6 percent of the payments in 2021 were legitimate, and 12 percent in 2022. This increased percentage was due to the fact that the DRRs that engaged in these strategies are no longer participating in MISO as of August 2022, which also reduced the reserve payments to DRR to $25 million.

Based on these results, it is essential that MISO revise its DRR rules and Tariff provisions to provide efficient incentives and to ensure that all payments made to DRRs result in real curtailments. We recommend two potential improvements to help achieve these objectives:

- DRRs should be obligated to submit their anticipated consumption absent any curtailments. The settlements could then be based on the lower of this value and the current baseline. This anticipated consumption data could be monitored and evaluated to identify when a participant submitted false or misleading data to inflate its settlements.
- MISO could establish a price floor that is significantly higher than typical LMPs. If a participant does not wish to consume at expected real-time prices, it should simply not consume, rather than offering curtailments as a price-taker. There is no reasonable basis to pay for curtailments offered at prices below expected real-time prices. Eliminating the ability to submit price-taking curtailment offers would virtually eliminate both strategies described above.

C. Energy Efficiency in MISO's Capacity Market

MISO allows energy efficiency (EE) to provide capacity. The quantity of EE participating in the PRA grew rapidly until the 2021/2022 PRA, when the sole participating provider of EE was disqualified. Table 17 summarizes the EE quantities over the past five PRAs. After the disqualification described below, the quantity has remained equal to or close to zero.

Table 17: Growth of Energy Efficiency in MISO

Planning Year	Enrolled Qty	Net Sales	Offer MW	Cleared/FRAP
2017/18	98	0	98	98
2018/19	173	0	173	173
2019/20	312	0	312	312
2020/21	650	0	650	650
2021/22	0	0	0	0
2022/23	0	0	0	0
2023/24*	4.5	0	4.5	4.5

*Average of four seasons.

In contrast to other LMRs, EE measures do not provide a dispatchable product and do not provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. The IMM performed an audit of EE capacity in 2021. Based on this audit, we found the EE resources did not actually reduce MISO's peak demand, and their capacity accreditation grossly overstated their reliability value. MISO validated these findings and ultimately disqualified the audited EE participant from participating in the 2021/2022 PRA.

We still recommend MISO revise its Tariff to strengthen the requirements and validation processes to ensure that only legitimate EE resources are qualified in the future. Although making these Tariff improvements should be MISO's focus in the near-term, we still believe that EE resources should not be qualified to participate in the capacity market for three reasons:

- *EE Payments are Inefficient*. Making payments to customers directly or to intermediaries is not efficient because customers already have efficient incentives to make energy efficiency investments. The savings they receive via lower electricity bills include the energy and capacity costs of serving them.
- *EE Capacity Values are Highly Uncertain*. It is not possible to accurately calculate how much the load has been reduced by EE in peak hours because it is based on an array of speculative assumptions. This uncertainty regarding their capacity value is why EE is not comparable to any other capacity resources since they can be tested and verified.
- *Cost Shifting Concerns*. The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE. To avoid cost shifting, an LSE must control for the effects of the EE by explicitly grossing up their forecasts to counter the effect of EE, but they are not required to do so.

For these reasons, it would be best to simply eliminate MISO's EE program. In the alternative, MISO should develop and file the Tariff improvements described above.

X. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2022 overall, we recommend a number of improvements in MISO's market design and operating procedures. These thirty-one recommendations are organized by the aspects of the market that they affect:

- Energy and Operating Reserve Markets and Pricing: 6 total
- Transmission Congestion: 7 total, 1 new
- Market and System Operations: 10 total, 2 new
- Resource Adequacy and Planning: 8 total, 2 new

Twenty-six of the recommendations were recommended in prior *State of the Market* Reports. This is not surprising because some recommendations require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes.

MISO addressed four of our past recommendations since our last report. We discuss recommendations that have been addressed at the end of this section. For any recurring recommendations, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendations.

A. Energy and Operating Reserve Markets and Pricing

Many of MISO's reliability needs are addressed through its operating reserve requirements that ensure resources are available to produce energy when system contingencies occur. However, to the extent that MISO has system needs that are not reflected in the operating reserve requirements, MISO may commit resources out-of-market that require a guarantee payment to recover their as-offered costs. As a general matter, MISO's market requirements should reflect its operating needs to the maximum extent feasible to allow the markets to satisfy and price these needs efficiently. The recommendations in this subsection are intended to improve this consistency between market requirements and operating requirements.

2021-2: Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS

In studying emergency events that have occurred in MISO when it has deployed large quantities of LMRs, we have found that MISO emergency pricing often does not establish efficient prices. Currently, LMRs are modeled in the ELMP pricing engine 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 is often not possible to replace a large volume of LMRs within a single dispatch interval with nonemergency ramping generation. This causes the LMRs to appear to be needed and set prices long after MISO's resources are sufficient to replace them by ramping up. This concern could be addressed by treating the LMRs as an operating reserve demand in the ELMP model, which would eliminate the need for other resources to be able 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.

Importantly, once the LMRs are no longer needed, they would stop setting real-time prices simply because other resources are ramp constrained. Therefore, we recommend that MISO reintroduce LMR curtailments as STR demand in its ELMP price model to determine when they should set prices during emergency conditions.

Status: In 2022, MISO has agreed on the problem identified, but MISO has indicated that further study and prototyping of potential software solutions will be needed. This issue is included in MISO's 5-year plan. We believe it is likely that it could be resolved more quickly.

Next Steps: MISO should complete its study and prototyping of software solutions.

2021-5: Modify the Tariff to improve rules related to demand participation in energy markets

In the past few years, we have identified a number of cases where demand response resources or energy efficiency resources were paid substantial amounts for load reductions that were not realized. Some of this was due to conduct of the resources, while some is due to suboptimal Tariff and settlement rules. Changes and clarifications in these rules will address both of these issues and ensure that MISO customers receive the benefits of the load reductions for which they have paid. This includes changes to baseline and settlement calculations to ensure that the estimated load reductions truly represent the additional load that would have existed but for the demand response resource. We recommend that MISO work with us to identify and implement these changes.

Status: MISO agrees with these issues and is actively evaluating this recommendation as part of its comprehensive investigation of demand response participation in all MISO markets. MISO believes it is appropriate to revisit the measurement and verification protocols codified in Attachment TT of the Tariff.

Next Steps: MISO plans to review best practices in measuring and validating demand response and to investigate and frame the issue and evaluate any next steps, including an evaluation of requirements of FERC Order 2222 on DERs. MISO indicates it will also consider filing limited modifications and clarifications to Tariff rules identified by the IMM to address gaming and manipulation vulnerabilities.

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

We recommend MISO evaluate the development of a real-time capacity product in the day-ahead and real-time markets to account for increasing uncertainty associated with intermittent generation output, NSI, load, and other factors. Such a product should be co-optimized with the current energy and ancillary services products. These capacity needs are currently procured out-of-market through manual commitment by MISO's operators. Clearing this product on a market basis would allow MISO's prices to reflect the need for commitments and reduce RSG. The resources that would provide this product would include online resources and offline resources that are 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's reliance on intermittent resources increases. The transition in the generating fleet will increase supply uncertainty, which will in turn increase the real-time capacity needs of the system and the costs of satisfying them. Hence, we recommend MISO establish a real-time capacity product or uncertainty product that would be implemented under MISO's current market software.

Status: MISO agrees with the IMM's description of the issue. However, MISO believes enhancements to its Ramp Product and new Short-Term Reserve product that are underway will help. MISO plans to further evaluate the need for a new uncertainty product and will continue working on improving the LAC process to address uncertainty. This recommendation is ranked as a medium priority.

Next Steps: While we agree that enhancements to the Ramp and STR products will help, MISO should complete its evaluations of an uncertainty product and prioritize the design and implementation of it.

2016-1: Improve shortage pricing by adopting an improved Operating Reserve Demand Curve reflecting the expected value of lost load

Efficient shortage pricing is the primary incentive for both dispatch availability and flexibility. As the primary determinant of shortage pricing, the ORDC must accurately reflect the value of reliability. An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to the product of: (a) probability of losing load and (b) the value of lost load (VOLL). Such an ORDC will track the escalating risk of losing load as shortfalls increase.

The shortage prices will send more efficient signals for participants to take actions in response to the shortage and help maintain the reliability of the system. Additionally, as MISO integrates larger quantities of renewables, the ORDC will be pivotal in compensating flexible resources that can start quickly and ramp rapidly to manage the uncertain output of intermittent resources.

MISO's current ORDC does not reflect the reliability value of reserves, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's pay-for-performance rules price modest shortages as high as $6,000 per MWh (sum of the shortage pricing and capacity performance settlement), which will lead to inefficient imports and exports when both markets are tight.

Hence, we recommend MISO reform its ORDC by updating its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load. We have estimated that a reasonable VOLL for MISO would exceed $20,000 per MWh. Although the ORDC should be based on this VOLL, it would be reasonable to cap the ORDC at a lower price level for deep shortages, such as $10,000 per MWh. Almost all of MISO's shortages are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.

Status: MISO agrees with the recommendation and is working to develop and implement a solution. This item is currently classified as Active and a high priority by MISO. MISO is working on reforms to the ORDC and VOLL in 2023.

Next Steps: This recommendation should be one of MISO's highest priorities since it is critical for achieving the goals of the Reliability Imperative and requires no substantial additional resources. Hence, MISO should complete its discussions with stakeholders and file proposed enhancements with FERC.

2012-3: Remove external congestion from interface prices

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of each of MISO's interface prices associated with the external constraints.

Status: This recommendation was originally made in our *2012 State of the Market Report* and there was no progress or change in Status in 2022. MISO agrees that interface pricing would be improved by eliminating external congestion on all interfaces. Nonetheless, MISO has no plans to address this recommendation until after implementation of the 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 its interchange transactions. MISO has said that it would evaluate the non-market interfaces as part of the Market Systems Enhancement.

Next Steps: MISO should develop the work plan necessary to modify its interface prices as part of its Market Systems Enhancement.

2012-5: Introduce a virtual spread product

Virtual traders arbitrage congestion-related price differences between the day-ahead and real-time markets, which improves the performance of the markets. They do this by clearing offsetting virtual supply and demand transactions that results in taking a position on the flows over a constraint without taking any net energy position. Because both transactions must clear to create an energy-balanced position, they are generally offered price-insensitively. A virtual spread product enabling participants to arbitrage congestion in a price-sensitive manner would be much more efficient. Participants offering such a product would specify the maximum congestion between two points they are willing to pay. This would reduce the risk participants currently face when they submit a price-insensitive transaction.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO originally agreed with this recommendation, but in 2018 MISO indicated that technical feasibility was a concern under the current systems. The status of this project is inactive, and it is deferred beyond the 5-year action plan. The IMM continues to encourage MISO to reconsider this recommendation.

B. Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, real-time spot market prices affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest market priorities is to produce real-time prices that accurately reflect supply, demand, and network conditions. This is the objective of the recommendations in this subsection.

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

During a number of recent storm events in 2021 and 2022, MISO has experienced operational challenges requiring extraordinary operator actions to manage network flows. During both transmission and capacity emergencies, the current TCDCs limit the ability of MISO's market dispatch to manage 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 of managing 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 the flows over other constraints. This has often compelled MISO operators to manually dispatch generation to reduce flows on overloaded constraints, which is costly and distorts market outcomes.

Therefore, we recommend MISO add higher segments to the TCDCs to allow the dispatch model to limit excessive violations. MISO should also improve its procedures to increase the TCDCs for a constraint when the violations raise reliability concerns or are sustained. Additionally, uncertainty regarding network flows has often caused operators to derate transmission constraints. Adding lower-priced segments to the TCDCs that would account for the value of holding back transmission capability to manage uncertainty could be valuable and we recommend MISO consider this as an alternative to its current approach to lowering transmission limits.

Status: This is a new recommendation. MISO's initial response indicated agreement with the problem and MISO has been discussing the recommendation with the IMM.

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

We recommend MISO develop resources and processes to analyze and identify economic reconfiguration options for managing congestion in coordination with the TOs. Today, transmission congestion is primarily managed by altering the output of resources in different locations. However, it can also sometimes be highly economic to alter the configuration of the network (e.g., opening a breaker). Today, this is widely employed by Reliability Coordinators to manage congestion for reliability reasons under the procedures established in consultation with the transmission owners impacted by the reconfiguration. Such procedures could be expanded to relieve costly binding constraints that are generating substantial congestion costs.

In our *2021 Annual State of the Market Report*, we presented an analysis of one constraint that generated over $57 million in congestion during the summer quarter. The constraint primarily limits the output of wind resources in the North region. The constraint has a reconfiguration option that reduces the congestion in that path by more than two-thirds and substantially reduces wind curtailments when used. Unfortunately, it is rarely used because the congestion on the constraint rarely raises reliability concerns. This constraint serves as an instructive case study showing the potential for substantially reducing congestion costs and wind resource curtailments by deploying reconfiguration options economically as a regular congestion management action.

Hence, we recommended MISO work with the transmission owners to develop tools and processes to identify economic reconfiguration options along with the criteria to be used to deploy them. The criteria would ensure that reconfiguration options are not implemented when they would generate adverse reliability effects elsewhere on the system. Studying and identifying such options and criteria in advance for MISO's most congested paths will provide a powerful tool for managing congestion and lowering the associated costs for MISO's customers.

Status: MISO agrees with this recommendation and has been working with the TOs through the Reconfiguration for Congestion Cost Task Team (RCCTT) to develop a process for accepting and evaluating requests. The proposed process is currently being reviewed and commented on in the Reliability Subcommittee (RSC). However, MISO is not currently developing a process for MISO itself to identify and analyze reconfiguration options. It is also not planning on developing processes to validate TOs' responses to recommended reconfiguration options. To date, some valuable options have been denied by TOs in the absence of verified concerns.

Next Steps: Once the new process document is finalized, MISO will develop internal operating procedures to carry out the tasks identified in the new process. In the longer-term, we recommend that MISO develop processes and/or tools to identify potential reconfiguration options that can be evaluated and managed by MISO.

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 that the monitoring RTO (MRTO) requests from the non-monitoring RTO (NMRTO). If the request is too low, then the NMRTO will not provide all its economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTO. If the request is too high, it can result in congestion oscillation that can raise costs.

We find that the current relief request software does not always request enough relief from the NMRTO. This can occur because the current software does not consider the shadow price differences between the RTOs. Therefore, when the NMRTO's shadow price is much lower and does not converge with the MRTO's shadow price, the relief requested from the NMRTO should increase. This would lower congestion costs and accelerate convergence. At other times, the software can request too much relief and cause constraints to bind and unbind in subsequent intervals, which is called "oscillation". Oscillations have become a substantial issue as rapid-ramping wind resources in both MISO and neighboring RTOs load the same constraints.

To address these issues in the short term, we continue to recommend 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 provided by the NMRTO in the dispatch of the MRTO.

Status: MISO agrees with the issue and has indicated that it will evaluate potential solutions. In 2021, MISO and SPP implemented a near-term tool using "predicted" UDS flow to address oscillations, but it has not yet been configured properly to be effective. MISO believes the IMM solution, though likely better, will require more significant changes and is not currently pursuing it. Unfortunately, it is not clear whether the current tool will be effective if MISO implements it properly, and it is not likely to increase relief requests when they are too low.

Next Steps: MISO should use the tool properly and assess its effects. After making this assessment, MISO should determine whether a more efficient solution is warranted to address oscillations and work with the IMM to identify the other improvements in the relief request software that will be needed to address this recommendation.

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

The original intent of this recommendation was to identify constraints that will benefit from M2M coordination or for which the NMRTO's market flows are a substantial contributor to the congestion. Currently, a M2M constraint will be identified when the NMRTO has:

- a generator with a shift factor greater than 5 percent; or
- Market Flows over the MRTO's constraint of greater than 25 percent of the total flows (SPP JOA) or 35 percent of the total flows (PJM JOA).

These two tests are not optimal in identifying 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 be much better at identifying the most valuable constraints to define as M2M constraints. Accordingly, we recommend that MISO work with PJM and SPP to introduce a test based on the available flow relief that can be provided by the NMRTO to replace the current five-percent-shift-factor test.

Status: MISO agrees and has indicated that it will evaluate the IMM's recommended solutions and their effects on the administration of JOAs. However, MISO has put this recommendation as a low priority and will resume discussions after completion of the update to the Freeze Date Firm Flow Entitlement (FFE) methodology. We continue to believe this recommendation is unrelated to the FFE methodology and encourage MISO to address it in a more timely manner.

Next Steps: MISO has noted the testing criteria may be considered and implemented with mutual agreement with no Tariff changes. Hence, we recommend that MISO propose these changes to its JOA partners and pursue improvements in the near term.

2019-3: Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities

For years we have reported unrealized annual savings well in excess of $100 million that would have resulted from increased use of AARs and Emergency Ratings. The first step to realize these savings is for the MISO TOs to commit to providing AARs and Emergency Ratings. However, MISO's current systems and processes would not allow it to capture all these savings. Our report identifies key recommended enhancements, including:

1. System Flexibility: MISO should enable more rapid additions of new AAR elements.
2. Forward Identification: MISO should support identifying additions to AAR programs based on forward processes including outage coordination.

3. Forecasted Ratings: MISO should enable use of forecasted AARs in the day-ahead market and Forward Reliability Commitment Assessment (FRAC). Currently, MISO does not have a process to receive or use forecasted ratings.

In addition, we recommend MISO make changes to support current and future needs related to verification of transmission ratings and situational awareness. MISO currently does not receive or maintain important data on transmission elements including: 1) Rating Methodologies, 2) limiting elements for transmission constraints and 3) response times for post-contingent actions. We recommend MISO make necessary changes to enable receipt of this information, which will improve its operational awareness and transmission planning. Although the benefits of the last three improvements would be difficult to quantify, we believe the reliability and market benefits are likely large and will grow in the future.

Status: MISO agrees with this recommendation, and it has been designated as a high priority. FERC Order 881 requires the use of AARs and Emergency Ratings in real time and forecasted ratings in the day-ahead. It also requires transmission owners to provide rating methodologies to RTO/ISOs and their market monitors. In 2022, MISO filed compliance plans for Order 881, which will address a large share of this recommendation. However, Order 881 does not require MISO to collect the information needed to validate ratings although we believe this is essential. Accordingly, we have provided a detailed list of data we recommend MISO collect to establish its capability to adequately validate transmission ratings provided by transmission owners.

Next Steps: MISO should complete implementation of Order 881 and begin collecting the data necessary for it to effectively validate transmission ratings. These plans should include completing its scoping of improvements that can be implemented through the MSE project or through other means to facilitate the receipt and use of AARs and Emergency Ratings.

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

MISO is responsible for approving the schedules of planned transmission and generation outages. This approval process considers only reliability concerns associated with requested outages and not the potential economic costs. As a result, we have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. In 2022, multiple simultaneous generation outages contributed to more than $1 billion in real-time congestion costs, or 30 percent of real-time congestion costs, indicating large potential savings.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to MISO's, with the exception of ISO-New England. ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, which has been found to have been very effective at avoiding unnecessary congestion costs. We recommend

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 little progress has been made to date. MISO has not sought additional outage coordination authority but began working on an evaluation approach for measuring costs and benefits of rescheduling outages in 2022. Economic considerations for outage coordination continue to be in the RAN work plan.

Next Steps: MISO should consider accelerating the process to address this recommendation and file for increased authority to coordinate outages.

2014-3: Seek joint operating agreements with the control areas around MISO to improve congestion management and coordination during emergencies

As noted in prior years, the dispatch of the integrated MISO system has increased the frequency of TLRs called for constraints in TVA, AECI and IESO. TLRs result in substantial congestion costs, which could be mitigated and produce sizable benefits for MISO if it were to develop redispatch agreements with TVA and IESO. Under such agreements, the TLR process could be replaced with a coordination process that would allow MISO and its neighbors to procure economic relief from each other, which will lower costs and improve reliability. Additionally, coordination between MISO and its neighbors has been inconsistent during emergency conditions, as highlighted by events during Winter Storms Uri and Elliott. 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 agrees with this recommendation and has reached out to both IESO and TVA regarding agreements. IESO has indicated they are working on major system changes and are postponing further discussions. MISO is working on a balancing authority agreement with TVA and plans to start discussions on a JOA once the BA agreement is complete. MISO also agrees that JOAs with other adjacent control areas to coordinate during emergencies would be valuable.

Next Steps: MISO should continue to attempt to negotiate redispatch agreements with TVA and IESO that will allow economic coordination and redispatch to efficiently manage congestion on their respective systems. Additionally, coordinated emergency procedures and settlements should be proposed with each of MISO's neighbors.

C. Market and System Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which includes 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 and 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 seek to improve MISO's operating actions and real-time market processes.

2022-2: Improve the real-time wind forecast by adopting enhancements to its current persistence forecasting methodology

MISO's near-term wind forecast for each resource is used in its real-time dispatch as its Economic Maximum level. Hence, efficient dispatch of the system requires that this near-term forecast be as accurate as possible. Currently, MISO utilizes a "persistence" forecast that assumes wind resources will produce the same amount of output as it most recently observed. The downside of this approach is that the forecasted output will be predictably lower when output has been increasing and will be predictably higher when wind output is dropping.

We recommend that MISO improve the performance of its real-time market by modifying its persistence forecast to recognize the recent movement in wind output. We demonstrated this approach in this report and showed that large portfolio errors (above 500 MW) could be reduced by 92 percent and large unit-level errors (above 50 percent) could be reduced by 45 percent by adopting such an approach.

Status: This is a new recommendation.

2022-3: Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions

Currently, generators do not accrue excess or deficient energy penalties until they exhibit such deviations for four consecutive intervals. Even after this time, the current penalties do not ensure that generators will benefit by following MISO's dispatch instructions. This is particularly concerning when resources load binding transmission constraints. In this case, UDS assumes all dispatch instructions will be followed and the flows will be consistent with the dispatch. If generators do not follow the instructions, the constraint flows can substantially exceed the transmission limits. This raises substantial economic and reliability concerns.

To address this, we recommend that MISO implement EXE/DFE penalties based on generators' LMP congestion component. The application of the penalty could begin in the first interval that a generator deviates and increase in size the longer the deviations persist.

Status: This is a new recommendation.

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 ultimately needed to satisfy MISO's energy, operating reserves, or other reliability needs. We also identified the assumptions, procedures, and forecasting issues that have 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 distort long-term price signals. Therefore, it is important to minimize excess out-of-market commitments and the accompanying RSG costs. We recommend that MISO:

1. Implement the identified improvements in its tools, procedures, and the criteria used to make out-of-market commitments.
2. Ensure that operators can observe the relevant offer costs that MISO will guarantee associated with each out-of-market commitment.
3. Update VLR operating guides in a timely manner when resources enter or exit the VLR area or transmission upgrades are made that affect the VLR area.

Status: MISO agrees with this recommendation and worked with the IMM in 2022 to begin implementing improvements to its procedures and the LAC process. MISO has committed to continuing this work in 2023.

Next Steps: The IMM provided nineteen specific recommendations to improve the out-of-market generator commitments. MISO and the IMM plan to work through these recommendations in 2023.

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, the need to manage fluctuations in net load (load less intermittent output) will grow. Because these demand changes occur in multi-hour timeframes, managing them efficiently requires the market to optimize both the commitment and dispatch of resources over multiple hours. This multi-hour optimization will also allow the markets to optimize the scheduling of energy storage resources. This is important because these resources are likely to play a key role in operating an intermittent-intensive system.

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

Status: MISO has indicated general agreement to add the development of a look-ahead commitment and dispatch solution engine to its R&D prioritization, and MISO recognizes the need for this capability will increase in the future to manage storage resources.

Next Steps: MISO should prioritize further evaluation of this recommendation and begin the R&D necessary for design and implementation of 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 very different operational and market results than transmission emergencies. These differences are sometimes justified because of different system needs. Often, however, insufficient supply in a local area (i.e., a local capacity deficiency) will lead to transmission overloads as the real-time dispatch seeks to serve the load by importing power into the area. In these cases, the reliability actions and market outcomes should be comparable regardless of whether operators decide to 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 – which resulted in very different market outcomes and price signals. The divergence of the outcomes was a concern, and we continue to recommend MISO bring alignment between the two types of emergencies by:

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

<u>Status</u>: MISO agrees emergency procedures can be better aligned and should include all appropriate reliability actions and tools for managing the system under different types of emergencies. MISO indicates this effort is Active. In 2021, MISO updated some of its procedures to improve its emergency actions and its Reserve Zone definitions to reflect emergency conditions. This will allow more timely responses to emergency conditions.

<u>Next Steps</u>: The IMM and MISO continue to discuss the emergency procedures and supporting tools. MISO will need to develop specific procedures regarding how it will increase its TCDCs and Post Reserve Deployment Constraint Demand Curves to ensure efficient locational pricing during transmission emergencies. This includes establishing prices approaching VOLL in the constrained areas when load-shedding is deployed in a transmission emergency.

2019-4: Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices

We have concluded that persistent sizable forecasting errors by MISO and PJM have hindered the use of CTS. These errors severely hinder the effectiveness of CTS, clearing transactions that are uneconomic based on real-time prices or not clearing transactions that would have been economic. Given the timing of the forecasts and the resources necessary to improve them, we have little optimism that substantially improving the forecasts is possible.

Hence, we recommend the RTOs modify the CTS to clear CTS transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The most recent five-minute prices are a much more accurate forecast of the prices in the next five minutes. Additionally, making adjustments every five minutes rather than every 15 minutes would result in more measured and dynamic adjustments that would achieve larger savings. We have estimated annual production costs savings exceeding $40 million, which are much larger than can be achieved by improving the current process.

Status: MISO agrees with the IMM that forecasts used in the 15-minute clearing have been inaccurate and that the IMM solution would improve accuracy and result in more efficient transactions. However, MISO has no current plans for further effort as MISO believes the IMM solution would require significant time and effort by MISO and PJM. Given other priorities and the dependency on MSE, MISO designated this issue inactive and will consider evaluating it once resources are available. This recommendation maps to issue IR066.

Next Steps: Given the substantial benefits available from a well-functioning CTS process, we continue to recommend that MISO evaluate the software requirements for implementing this recommendation and begin discussing this proposal with both PJM and SPP.

2018-4: Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions

Over the past few years, MISO has experienced a significant increase in the frequency of generation emergencies, primarily at the regional level. Based on our review of these events, we find that MISO's emergency declarations and actions have been inconsistent from event to event. This includes both the timing of the declarations and the forecasted regional capacity margins (the difference between the regional supply and demand). Hence, we recommend that MISO evaluate its operating procedures, tools, and criteria for declaring emergencies. This should include clarifying the criteria for making each emergency declaration and logging the factors that are the basis for operator actions.

Status: MISO agrees and is actively evaluating its operating procedures, tools, and criteria for declaring emergencies to improve consistency. MISO continues to work with the IMM to identify and review changes to MISO's Emergency Operating Procedures related both to declaring emergencies and documenting the emergency actions taken. 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 prior to and during an emergency. In 2022, MISO made some clarifications to the MISO's Emergency Procedures and plans to work with the IMM to improve its processes and procedures.

Next Steps: We recommend MISO continue the collaborative work described above to improve the clarity of the procedures and the tools used to trigger the declarations of different levels and types of emergencies. Improving the logging of the emergency determinations and actions should be a high priority.

2017-2: Remove transmission charges from CTS transactions

CTS with PJM was implemented in October 2017. It promised substantial economic benefits by adjusting the scheduled interchange based on forecasted energy prices in the two RTO areas. CTS transactions give the RTOs the ability to dynamically schedule the interface and lower the costs of serving load in both regions. We had advised the RTOs not to apply transmission charges or allocate costs to these transactions because they do not cause any of these costs. Nonetheless, MISO and PJM apply transmission reservation charges to these transactions when they are offered (not just when they are scheduled) and additional charges when they are scheduled. The reservation portion of charges are a substantial barrier to submitting CTS offers.

Our analyses have shown that CTS transactions are unprofitable only because of the transmission charges. CTS transactions would not only be profitable, but more profitable than conventional scheduling, but for the transmission charges. This suggests that participants would utilize the CTS process if these charges were eliminated, particularly the reservation charges.

We continue to recommend MISO not wait for PJM and to eliminate its own charges. MISO should also eliminate the requirement that participants reserve transmission for CTS transactions since the RTOs can make interface adjustments by utilizing any available transmission capability.

Status: MISO agrees that CTS has not performed well and that the transmission reservation charges are a significant factor. Although forecast errors are also an important factor limiting the performance of CTS as MISO has cited, the removal of the reservation charge is the easiest and most effective near-term improvement. This item was inactive in 2022 and MISO does not anticipate any activity in 2023. We believe this is not the right decision because the CTS process will not be effective unless the current charges are eliminated.

Next Steps: MISO should reconsider its decision to suspend action on this recommendation. Most of the benefits from this recommendation could be achieved by eliminating the reservation charges, so we encourage MISO to remove these charges at a minimum.

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

Operator decisions in all the MISO functions, including the day-ahead and real-time markets, can significantly impact both market outcomes and reliability. While automated tools and models support most of the market operations, it is still necessary for operators to take actions outside of the markets. Although these operator actions are necessary, it is also critical both from a management oversight and a market monitoring perspective for the actions to be logged in a manner that enables oversight and evaluation. Operator actions can indicate market performance or design issues, and they can point to potential market improvements or procedural improvements that would lower overall system costs.

Examples of operator adjustments include:

- Real-time adjustments to market load with the "load-offset" parameter, made to account for supply and demand factors that cause the dispatch model inputs to be inaccurate.
- Real-time adjustments to model inputs to LAC for wind and load to compensate for forecast errors.
- Adjustments to TCDCs to manage transmission constraints under changing conditions.
- Limit Control changes that alter the real-time limits for transmission constraints.
- Requests for M2M constraint tests and activations.
- Manual redispatch of resources that are made to satisfy system needs.
- Changes in operating status of generating units, including placing a unit "off-control," which causes the unit to receive a dispatch instruction equal to its current output.

Actions that impact settlements tend to be more completely logged. For example, manual generator commitments are well-logged because the reason and timing of the commitment are used by the settlement system to allocate RSG charges. However, other actions listed above are logged in a narrative field that is inconsistently populated and difficult to use for evaluation. Because these actions can have significant cost and market performance implications, we recommend MISO upgrade its systems and procedures to allow these and other operator actions to be logged in a more complete and detailed manner.

Status: MISO agrees with the importance of this issue and with the IMM recommendations. MISO has made some improvements in logging features within the current MCS and has put more emphasis on training for operators to facilitate clear and concise log entries. MISO indicates that requirements are being identified for further enhancements to the operator logging functionality in MCS.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. MISO should complete appropriate designs for future logging processes, including what operator logging should occur through the MCS or through separate systems.

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

MISO has 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. Our evaluation of the LAC results in 2019 and 2020 indicates that the commitment recommendations are not accurate. In 2020, 65 percent of the LAC-recommended resource commitments were ultimately uneconomic to commit at real-time prices and in 2019 it was 69 percent. We also found that operators only adhered to 17 percent of the LAC recommendations in 2020, which may be attributable to the inaccuracy of the recommendations. We continue to recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop logging and other procedures to record how operators respond to LAC recommendations.

Status: MISO generally agrees with this recommendation. In the last several years MISO has implemented tools that support the review of recommendations from LAC and operator commitments. This includes tools to measure the LAC's accuracy and metrics to assess commitment decisions. In late 2021 into 2022, MISO devoted additional resources to identify the causes of inaccurate LAC recommendations. This recommendation maps to issue IR008.

Next Steps: MISO added a LAC Phase II plan intended to implement enhancements in 2023. We expect to work with MISO to evaluate and discuss high-value enhancements.

D. Resource Adequacy and Planning

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to facilitate efficient investment and retirement decisions. The efficiency of MISO's market signals has become increasingly important as planning reserve margins in MISO have fallen, particularly as evidenced in the capacity market shortage in the Midwest in MISO's 2022-23 planning resource auction. We have identified a number of critical issues that are undermining the economic signals provided by the MISO planning resource auctions. The impacts of these issues are mitigated to some extent by the fact that regulated utilities serve load in a large portion of MISO. Hence, these regulated utilities may invest in new resources and maintain needed existing units 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, it is critically important to respond to the recommendations in this subsection that are intended to establish the efficient price signals necessary to ensure that the market will facilitate investment in resources over the long term.

2022-4: Improve the LRTP processes and benefit evaluations

As MISO moves towards evaluating Tranche 2 of the LRTP, it will be increasingly important to evaluate the costs and benefits of the alternative transmission investments in a process that avoids costly inefficient investments. This is also becoming important for MISO's MTEP process as costs have risen sharply in recent years. This is important because inefficient investment in transmission can undermine incentives that govern other long-term decisions that address congestion at a fraction of the costs of the transmission upgrades. These long-term decisions include generation investment and retirement decisions, investment in energy storage and grid-enhancing technologies, and improved siting decisions by new clean energy resources.

Therefore, we recommend MISO develop improved methodologies and assumptions for future LRTP Tranches, including:

1. Using forecasted siting and retirement assumptions that are based on the economic incentives provided by the market. This can be accomplished by employing a capacity expansion model that optimizes these decisions.
2. Including an evaluation of energy storage alternatives when evaluating the benefits of transmission investment.
3. Maintaining logical consistency between all base cases and all LRTP cases, including:
    - Ensuring that any estimated benefits include all of the costs incurred to realize the benefits; and
    - Incorporating the "foregone benefits" as a cost associated with any "foregone costs" that are deemed to benefits, such as the forgone transmission investments.
4. All "but for" base cases should reflect an accurate forecast or assumption regarding market participant actions and investments that would take place absent the LRTP investments.

We also recommend that MISO consider whether its allocation of the LRTP costs and requirement to show that all zones benefit may become a barrier to efficient investments.

Status: This is a new recommendation. IMM and MISO are discussing the issues identified.

2022-5: Implement jointly optimized annual offer parameters and improve outage penalty provisions in the seasonal capacity market

MISO ran the first seasonal PRA in April 2023. The initial implementation included only seasonal offer parameters, which raises substantial challenges for participants that have annual going forward costs they must cover. For example, suppliers with a resource that requires a capital investment to remain in operation would find it difficult to offer such costs since it will not know how many seasons in which the resource will clear. MISO is considering giving participants the option of an annual offer in addition to the seasonal offers.

Additionally, MISO implemented penalties that applied to any resource with non-exempt outages exceeding 31 days as part of this new framework. This framework has created some distorted incentives for the market participants:

- We observed a number of suppliers shifting their longer outages to straddle seasons. This can be problematic for outages that are shifted from shoulder seasons into higher-demand winter and summer seasons.

- The penalty framework can make it profitable for resources that will be out of service the entire season to sell capacity and pay the penalty.
- The penalty is difficult to accommodate under the market power mitigation rules because expected penalties cannot be included in resources' reference levels under the Tariff.

To address these issues, we recommend that MISO:

1. Implement annual offer parameters that are jointly optimized with the seasonal parameters in the PRA.
2. Reform the penalty provisions and mitigation measures to improve participants' outage scheduling and offer incentives.

2020-4: Develop marginal ELCC methodologies to accredit DERs, LMRs, battery storage, and intermittent resources

The ELCC represents the amount of planning resource requirements that a resource is capable of satisfying. Such a methodology is needed for intermittent resources because the amount that it will be producing in peak hours is highly variable and uncertain. The unique characteristics of storage resources, LMRs, and DERs also require an ELCC approach to accurately accredit them.

The current ELCC methodology applied to wind resources accredits them roughly 15 percent of their nameplate level on average. Unfortunately, this reflects the average reliability contribution of all wind resources, not the marginal reliability value of these resources. This results in excessive accreditation for these resources that provides poor investment, retirement, and planning incentives. Therefore, we recommend MISO implement marginal accreditation for all of these types of resources.

Status: MISO initiated work on this issue in 2022. MISO evaluated ELCC along with other potential solutions to more accurately accredit non-thermal resources. MISO's initial proposal reflects a marginal accreditation approach, and it should have a final proposal in early 2023.

Next Steps: Continue discussion with stakeholders and finalize its proposal for filing.

2019-5: Improve the Tariff rules governing Energy Efficiency and their enforcement

The increasing levels of Energy Efficiency ("EE") capacity credits raise concerns because the claimed savings are based on a wide array of speculative assumptions, and we have found them to be vastly overstated. Hence, EE resources to date have yielded very little real benefits. We recommend the following changes to ensure that the savings offered are more likely to be real:

- Clarify the Tariff to require a contractual relationship with the end-use customer that: (a) prompts an action that would not likely have occurred otherwise, and (b) transfers the energy efficiency credits from the customer to the supplier;
- Specify that baseline assumptions must reflect prevailing consumer preferences and purchase patterns, rather than minimum efficiency standards.

- Enforce the measurement and verification rules by requiring some form of credible measurement of the savings, even if simply by sampling or surveying after installation.

Status: MISO agrees that Tariff clarifications could be made on EE resources for ownership rights, baseline assumptions, and measurement & verification (M&V) protocols but has no activity underway.

Next Steps: MISO should work with its stakeholders and the IMM to complete its evaluation and prioritize changes to address this recommendation.

2017-7: Establish PRA capacity credits for emergency resources that better reflect their expected availability and deployment performance

Emergency-only resources, including LMRs and other emergency resources, can sell capacity and are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate shortages during emergency events, they provide little value. Some emergency resources have long notification or start-up times that render them unavailable in an emergency. Operators typically do not declare emergency events more than a few hours in advance because they are often caused by contingencies or unexpected changes in wind output or load. Hence, emergency resources with long notification times provide little value in most emergencies. This is not a problem for conventional resources with long start times because an emergency need not be declared to commit these resources. Therefore, we recommend that MISO account for the availability impacts of the emergency designation in its accreditation.

Status: MISO agrees with the recommendation and filed in March to allow the rules restricting use of the emergency commit status to be effective for June 1, 2023 (Planning Year 2023/24). Other changes to Module C and Schedule 53 will be requested to be effective in time for Planning Year 2024/25. In 2022, MISO implemented rules pertaining to LMRs by imposing tighter standards for notification times and call limits. This recommendation has been aligned with IR025 (sub issue RASC009) and is deemed to be a high priority by MISO.

Next Steps: MISO should continue working with stakeholders and develop possible alternatives for addressing this recommendation.

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

MISO employs a relatively simple representation of transmission limits in the PRA, modeling only aggregate import and export limits to and from each capacity zone. Additionally, MISO accommodates the transfer limitations between the MISO South and Midwest regions. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified zonal import or export limits. Ultimately, these issues lead to sub-optimal capacity procurements and sub-optimal locational prices. Hence, we recommend that

MISO add transmission constraints to its auction model to address potential simultaneous feasibility issues and to reflect the differing impact 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. Ultimately, this is a very simple version of a constrained optimal dispatch (much simpler than MISO's energy market). It would allow MISO to represent all regional constraints that may be affected by multiple local zones (e.g., the way the three zones in MISO South affect the south-to-north transfer constraint) and activate any constraints that may arise in its simultaneous feasibility assessment.

Status: MISO agrees with the issues identified and has done some preliminary analysis of this recommendation. MISO believes it is a large effort impacting a number of models and that further evaluation is required.

Next Steps: MISO should evaluate the software and other implications of implementing an efficient locational framework in the PRA. Building on the concepts implemented for the RDT constraint, modeling could be expanded 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. In some cases, however, capacity is needed in certain load pockets within an LBA. For example, NCAs in MISO South have substantial capacity needs to satisfy local reliability requirements. In neither case, however, can the capacity prices in the PRA reflect the need for capacity because of the limited transmission capability into the areas. Therefore, we recommend that MISO adopt procedures for defining capacity zones that would allow the zones to be determined by transmission constraints and other local reliability needs rather than the historical LBA boundaries that are unrelated to the transmission network.

Status: Although MISO indicates that it agrees with the recommendation, it is currently in an inactive status. MISO indicates it will evaluate this recommendation further after completing higher priorities such as the RAN.

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

2010-14: Improve the modeling of demand in the PRA by implementing reliability-based demand curves

The use of only a minimum requirement coupled with deficiency charges to represent demand in MISO's capacity market results in an implicit vertical demand curve for capacity. This does not efficiently reflect the reliability value of capacity and understates capacity prices as capacity levels continue to fall. This is particularly harmful as large quantities of resources are facing the decision to retire in response to prevailing market conditions. In this report, we identify more than 5 GW of economic resources that have retired prematurely primarily because of the severely understated capacity prices produced by MISO's PRA. These uneconomic retirements have caused MISO's capacity levels in the Midwest region to fall below the minimum requirement in the 2022-2023 PRA, resulting in prices throughout the Midwest clearing at CONE.

This is evidence that implementing a reliability-based demand curve is required to satisfy MISO's Reliability Imperative. A reliability-based demand curve that is sloped (rather than vertical) would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also would produce more efficient and stable capacity prices, particularly as the supply of available regional capacity moves toward the minimum planning reserve requirement. This report shows that this recommendation would lower the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

Understated capacity prices are particularly harmful to MISO's integrated utilities, most of which own surplus capacity and are compelled to sell it at inefficiently depressed prices. They are also problematic for unregulated participants that rely on the market to retain adequate resources to ensure reliability.

Status: MISO agrees with the IMM's concern and has been engaging the IMM and stakeholders including MISO states on this issue. This recommendation maps to RASC-2019-8 (Sloped Demand Curve in the Capacity Market (misoenergy.org)) in the MISO Dashboard.

Next Steps: MISO needs to continue to develop the details of its proposal. It plans to file proposed changes to implement a Reliability-Based Demand Curve in 2023 if it gains adequate support from its market participants and states.

E. Recommendations Addressed by MISO or Retired

In this subsection, we discuss past recommendations that MISO has addressed since last year.

2020-3: Remove eligibility for wind resources to provide ramp product

Wind resources are currently qualified to supply MISO's ramp product, although they generally can only ramp up when they are dispatched down for congestion. This makes wind units a poor option to provide the ramp product because they will generally be loading transmission constraints if MISO attempts to ramp them up. Therefore, we recommended that MISO remove eligibility for wind resources to provide the ramp product. MISO filed at FERC in February 2023 to adopt this recommendation. If approved, this will improve the performance of the ramp product by causing MISO to procure ramp capability from other types of resources that are better suppliers of ramp.

2018-3: Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when the reserves are deployed

This recommendation would improve the performance of MISO's markets, lower the costs of satisfying regional capacity requirements, and equitably compensate the joint parties. Nonetheless, we are retiring the recommendation because the joint parties had minimal interest in modifying the agreement to implement this recommendation.

2018-5: Improve capacity accreditation by basing it on resource availability during tight supply periods

Accreditation is one of the largest opportunities for improvement to MISO's capacity market. We recommended MISO improve its accreditation methodology based on resource availability in the tightest margin hours. This would account for *all* outages and derates, as well as long start times and other inflexibilities. MISO filed these proposed changes, which FERC approved in 2022 and MISO is implementing in early 2023.

2014-5: Transition to seasonal capacity market procurements

Both the needs of the system and the available system supply change substantially from one season to the next. To improve the performance of the capacity market in meeting these seasonal needs, we recommended that MISO clearing the PRA on a seasonal basis rather than on an annual basis. MISO filed this proposed change, which FERC approved in 2022 and MISO is implementing the first seasonal PRA in Spring of 2023.