2019 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC ECONOMICS

**Independent Market Monitor
for the Midcontinent ISO**

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Guide to Acronyms

AAR	Ambient Adjusted Rating
AMP	Automated Mitigation Procedure
ARC	Aggregator of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Market
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CDD	Cooling Degree Day
CONE	Cost of New Entry
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 the market design and operating procedures. This Executive Summary to the *2019 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 December 2013.

MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, its ancillary services market in 2009, and its most recent capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably and 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 in 2019

The MISO energy and ancillary services markets generally performed competitively in 2019. Multiple factors affected market outcomes in 2019, including a changing resource mix and significantly lower natural gas prices. The 20 percent reduction in natural gas prices combined with a 2 percent decrease in average load contributed to a 19 percent decrease in real-time energy prices throughout MISO, which averaged $26 per MWh in 2019.

Frequent transmission congestion often caused prices to vary throughout MISO in 2019. The value of real-time congestion fell by 35 percent in 2019 to $0.9 billion, which was due to:

- Key transmission upgrades in MISO and in neighboring regions;

- The addition of a 1,000 MW combined-cycle unit in a South load pocket; and
- The reduction in natural gas prices, which has reduced the spread in costs between the generators that are redispatched to manage the flows over binding constraints.

Although it fell in 2019, real-time congestion was higher than optimal because several key issues continue to encumber congestion management in MISO, including:

- Usage of very conservative static ratings by most transmission operators;
- Limitations of MISO's authority to coordinate outages; and
- Issues in defining and coordinating market-to-market constraints.

To address these concerns, we continue to recommend a number of improvements to lower the cost of managing congestion on MISO's system.

Competitive Performance

Outcomes in the MISO markets continue to show a consistent overall relationship between energy and natural gas prices, which is expected in a well-functioning, competitive market. Natural 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 that reflect a resource's marginal costs.

In addition, we evaluate the competitive performance of the MISO markets by assessing the resource specific conduct of its suppliers, which was broadly consistent with expectations for a workably competitive market. We use 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. Our analysis revealed the price-cost mark-up was effectively zero in 2019. This indicates that the MISO markets were highly competitive in 2019.

- The "**output gap**" is a measure of potential economic withholding. It remained unchanged from 2018, averaging less than 0.1 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

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

Market Design Improvements in 2019

Although MISO's markets continue to perform competitively, we have identified a number of key areas that could be improved or that will need to be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides a number of recommendations, five of which are new this year.

MISO has continued to respond to our past recommendations and implemented several key market design changes in 2019 to that will improve the performance of its markets.

- In February, FERC approved tariff changes to increase MISO's market access to LMRs by allowing MISO to schedule LMRs in advance of an anticipated emergency and requiring LMRs to register availability consistent with their seasonal capability.
- In May, MISO implemented a number of key changes that have significantly improved generators' incentives to follow MISO's dispatch instructions and the operational performance of the system overall. These change included:
  - Changes in the Uninstructed Deviation thresholds and rules;
  - Improvements in the Price Volatility Make-Whole Payment settlement formulas affecting units that are not performing well in following dispatch instructions;
  - Modifications to MISO's regulation commitment process to reduce the volume of regulation-based deratings, while expanding the units available to schedule to provide regulation.
- In October, MISO filed tariff changes that would prevent resources from qualifying to provide capacity if they are on outage during the peak summer months.
- In November, MISO modified the ELMP framework to allow the costs of fast-start resources scheduled in the day-ahead market to participate in setting real-time prices.
- In December, MISO lifted the energy offer cap from $1,000 per MWh to $2,000 per MWh as mandated by FERC.
- MISO also proposed a number of recommended improvements to the market power mitigation provisions in Module D in December that were approved by FERC and implemented in early 2020.

A number of these improvements have measurably improved the performance of the markets or the operation of the system, which is discussed throughout this report.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

Since its inception, MISO has enjoyed a surplus of capacity beyond the minimum reliability requirement. MISO's capacity surplus has dwindled in recent years as older baseload units have entered long-term suspension or retired. The accelerating retirements of baseload resources are being replaced with intermittent renewable resources. In 2019, 3.3 GW of resources retired in MISO, nearly 90 percent of which were coal-fired resources. We expect this to continue because of sustained low natural gas prices and the weak economic signals provided by MISO's current capacity market.

In 2019, more than 4.5 GW of new capacity entered MISO. Two large natural gas-fired combined-cycle resources totaling 1.8 GW entered MISO South, one in a key constrained area.

More than 2 GW (nameplate) of wind resources were added in 2019, but wind resources provide much less reliability value than conventional resources. Additional investment in wind resources is likely to occur in the coming years, particularly since most Multi-Value Projects (MVP) that expand transmission from favorable wind areas are underway or completed, the cost of which total more than an estimated $6.5 billion.

Based on the capacity market design concerns we discuss in this report, we expect the installed capacity in MISO to continue to fall. In the near-term, our assessment indicates that the system's resources should be adequate for the summer of 2019 if the peak conditions are not substantially hotter than normal. In the long term, however, we are very concerned about the adequacy of MISO's resources. As we explain in this report, the fundamental problem is the relatively low net revenues generated in MISO's markets.

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 2019. We find:

- Compared to 2018, net revenues fell at all locations.
- Net revenues continued to be substantially less than necessary for new investment to be profitable in any MISO area (i.e., is less than the annual Cost of New Entry, or "CONE");
- Net revenues for a number of the existing resources are less than necessary to cover their Going-Forward Costs (GFCs), providing economic incentives to retire these units; and
- Low natural gas prices have led to low energy prices, which have disproportionately affected the net revenues of non-gas-fired resources, most notably coal and nuclear units.

The low level of net revenues generated by the MISO markets is problematic for both existing resources and potential new resources. Improving price signals and associated net revenues will require improvements in MISO shortage pricing and its capacity market design. Capacity market design issues have contributed to understated price signals, which will become an increasing concern as the capacity surplus falls.

Evaluation of PRA Results

MISO administers a Planning Resource Auction (PRA) to allow its participants to buy and sell capacity in various zones in MISO and satisfy the capacity requirements established in Module E of the MISO Tariff. The auction includes MISO-wide requirements, local clearing requirements in ten zones, and models a transfer constraint between MISO South and MISO Midwest regions. Beginning in the 2019/2020 PRA, MISO established external resource zones to prevent external resources from satisfying the local requirements of internal zones.

The capacity auction design issues described below, along with modest changes in supply and demand, have resulted in extremely low prices in most areas over the past two years:

- In the 2019/2020 PRA, lower capacity requirements and the establishment of external zones contributed to a MISO-wide clearing price of $2.99 per MW-day in unconstrained zones and $24.30 per MW-day in Zone 7.
- In the 2020/2021 PRA, Zone 7 cleared at CONE as a result of being short of resources, while all other zones cleared from $4.75 to $6.88 per MW-day.

Zone 7 was an outlier in the most recent auction partly because MISO implemented tariff changes that prevent units on outage during the peak months from qualifying to sell capacity.

Outside of Zone 7, these prices produced by the PRA have been close to zero and generally represented less than *two* percent of the revenue needed to support investment in new peaking resources. These prices are inefficiently low, which is important because capacity revenues should provide existing resources that are needed with sufficient revenues to cover the cost of remaining in operation and performing maintenance. In this report, we include an analysis of MISO's capacity at risk, and find that typical coal and nuclear resources exhibit revenue shortfalls under the current capacity construct. But for supplemental revenues provided outside of the market, these resources would be uneconomic to continue operating at prevailing prices.

PRA Market Design

The low clearing prices throughout most of the footprint in the recent auctions are a result of several capacity market design issues that undermine the efficiency of the PRA. The most significant design flaw relates to how the demand for capacity is represented. Demand in the PRA is modeled as a single requirement (and single zonal requirements), and a deficiency price prevails if the market is short (as occurred in Zone 7 in the most recent auction). This establishes a "vertical demand curve" for capacity, which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value and results in inefficient capacity market outcomes.

To address this issue, we continue to recommend that MISO adopt a sloped demand curve to reflect the reliability value of resources that are in excess of MISO's minimum clearing requirement. This report shows that such a change would benefit MISO's regulated participants by lowering their net costs of satisfying the planning requirements. Because most of their planning needs are self-supplied, however, the effects on the regulated participants of improving the demand curve is much smaller than the effects on competitive loads and competitive suppliers. These competitive participants rely on economic market signals to guide their long-term investment and retirement decisions. Hence, it would be extremely valuable to improve the PRA design to establish efficient prices, even if they are only used to settle with competitive participants.

In addition to addressing the fundamental design issue related to the modeling of the demand in the PRA, we have recommended a variety of other improvements to the PRA. A number of these changes involve improving the accuracy of the supply and demand in the PRA, including:

- Limiting emergency-only resources to participate in the capacity market only if they are able to be available within a reasonable amount of time during an emergency.
  - In May 2020, MISO filed changes that would only allow LMRs with lead times of 6 hours or less to participate as capacity resources, which is an improvement.
- Disqualify energy efficiency from selling capacity in the PRA.
- Reforming resource accreditation to better reflect the reliability value of resources by recognizing all outages and derates during tight conditions, including those that are not reported.
- Procuring capacity to serve all firm load, including behind-the-meter firm process load.

Other improvements we recommend that do not specifically involve the supply or demand for capacity in the PRA include:

- Transitioning to a seasonal capacity market.
- Improving the modeling of transmission constraints in the PRA.

A number of these recommendations are likely to be addressed through MISO's RAN initiative, which is discussed in Section X.D of the report.

Day-Ahead Market Performance and Virtual Trading

The day-ahead market is critically important 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 the resource commitments needed to efficiently satisfy the system's real-time operational needs. In 2019:

- The difference between day-ahead and real-time prices was 0.7 percent, after accounting for day-ahead and real-time uplift charges, which is good convergence overall.
- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence in various locations.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Average cleared virtual transactions rose 11 percent in 2019 to average nearly 17 GW per hour. Our evaluation of virtual transactions revealed:

- Approximately 90 percent 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.

- 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 Uplift

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. Additionally, efficient price signals during shortages and tight operating conditions can reduce the reliance on revenue from the capacity market to maintain resource adequacy.

Real-Time Price Formation

Among the most important aspects of MISO's real-time price formation are the:

- Pricing of real-time operating reserve shortages and transmission shortages; and
- Ability to allow peaking resources and emergency actions to set real-time prices through the Extended Locational Marginal Pricing (ELMP) model.

In many regards, MISO's markets are at the forefront of market design. MISO jointly optimizes operating reserves and energy in the real-time markets, which allows the demand curves for reserves to contribute to setting prices when the market cannot satisfy reserve requirements. This is the most efficient means to price shortages. Shortage pricing plays a pivotal role in compensating flexible resources that are needed to resolve the shortages. This will be increasingly important as intermittent renewable resources continue to enter the MISO market. Although MISO's shortage pricing methodology is reasonable, we have two concerns that undermine the efficiency of MISO's shortage pricing:

- MISO's operating reserve demand curve (ORDC) is not efficient because it does not reflect the expected Value of Lost Load (VOLL) – we recommend MISO introduce an efficient ORDC as described in Section IV.D.; and
- The shortage pricing is undermined by allowing offline resources to set prices in the ELMP model. Hence, we recommend that MISO disable its offline resource pricing.

Improving MISO's shortage pricing is essential because it will align shortage pricing with the marginal reliability value of the foregone reserves.[1] Adopting an ORDC that is similar to the curve we estimate and discuss in this report will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

1 Based on recent studies and a model developed by Lawrence Berkeley National Laboratory, we recommend MISO establish its ORDC based on a VOLL of more than $20,000 per MWh. The slope of the ORDC should be determined by how the LOLE changes as the level of operating reserves falls. The LOLE depends on the countless combinations of random contingencies and conditions that could occur when MISO is short of reserves. Using a Monte Carlo Model, we estimate a reasonable slope for the ORDC.

In addition to MISO's shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation. ELMP's greatest value is its capability to allow online peaking resources and emergency supply to set prices when they are economic for satisfying the system demands. Our evaluation of the performance of the online pricing in the current ELMP model, however, shows that it has only been partially effective.[2]

- ELMP raised real-time prices by an average of $0.35 per MWh in 2019.
- The price effects should increase because MISO began allowing fast-start resources committed in the day-ahead market to set prices in November 2019.
- We also propose changes to the ramp assumptions used by ELMP, which we estimate would have increased real-time prices by more than $0.95 per MWh.

In high-load hours when reliance on peaking units is relatively high, these price effects are far greater, which provides much better incentives to schedule imports and exports efficiently and facilitates efficient generator commitments in the day-ahead market. Hence, improving the performance of ELMP should remain a high priority.

Unfortunately, the ELMP model also allows offline fast-start resource to set prices during reserve or transmission shortages (i.e., offline pricing). Offline pricing continues to distort outcomes by preventing the markets from pricing shortages that result from unexpected changes in conditions. When wind output drops unexpectedly, a large unit goes out of service, an export is curtailed, or many other unforeseen things occur, transitory shortages can occur. Allowing offline units to set prices as if they were committed and dispatched is essentially setting prices as if the MISO operators have perfect foresight. This is not true in the real world and pricing these transitory shortages is critical because it compensates the flexible resources that can respond to these shortages and allow MISO to maintain system reliability. Hence, we continue to strongly recommend that MISO terminate offline ELMP pricing, except when units are starting.

Managing the Flows on the RDT and Regional Reserves

Since the integration of the South, MISO's intra-regional transfers have been constrained to adhere to contractual limits. MISO has taken two actions to prevent exceeding these limits: implementing a post-contingent constraint to hold headroom on the RDT and actively managing the RDT limit to avoid unmodeled exceedances. Additionally, MISO frequently commits resources out-of-market to maintain sufficient reserves in each subregion. These actions result in RSG and congestion management costs. To allow the market to satisfy these needs, we recommended that MISO introduce a 30-minute reserve product for each region. MISO filed this "Short-Term Reserve" product in October 2019 and FERC approved the filing in January 2020. It is scheduled to be implemented in December 2021.

2 This evaluation is described in Section IV.B.

Finally, 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 allow the Joint Parties to sell operating reserves with the transmission capacity on the RDT (above the RDT limit). MISO could then compensate the Joint Parties by paying them the clearing price for subregional reserves, as well as paying for the deployment of the reserved transmission (equal to the $500 per MW RDT demand curve level times the deployment quantity). Under this approach, SPP and the Joint Parties would have been compensated $3.25 million during the emergency events that occurred on January 17–18, 2018. This payment is reasonable compensation for the excess transfers that may occur under emergency conditions.

Emergency Events in 2019

Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. Emergency actions were taken on four of the following five days in 2019:

- *January 30, 2019*: MISO issued a Maximum Generation Event in the North and Central regions because extremely cold weather resulted in a sharp decline in wind output, issues with transmission elements (circuit breakers), and uncertainty regarding forced outages that may result from the cold temperatures.

- *January 31, 2019*: MISO downgraded the January 30 emergency (to an EEA 1), but started or extended 198 units totaling 13.3 GW through noon on January 31. These actions were taken, in part, over concerns that some resources might fail to restart if they shut down. As a result, the supply margins the following day were large, averaging more than 6.5 GW in the morning hours, and generating more than $8 million in RSG.

- *May 16–17, 2019*: MISO scheduled LMRs the night before in anticipation of an emergency during the peak hours, and then cancelled the emergency just before noon. The sudden loss of a large unit in the South, combined with very conservative reserve and load forecast determinations, led MISO to declare an emergency and reschedule short-lead LMRs that were not necessary. MISO also called for LMRs to curtail on May 17 that were subsequently cancelled.

- *November 13, 2019*: Extremely cold temperatures throughout much of the Southern U.S. led to increased exports and and a tight supply margin. Despite MISO's shortage of reserves in the South during the morning ramp hours and a significant requested derate of the RDT, MISO did not declare the emergency that was warranted.

All of these events were regional events where the primary concern would be violating the RDT flow limit if system contingencies were to occur. These types of emergencies are relatively new, having not occurred prior to 2016. Based on our review of these events, which is provided in

Section IV.G, we find that MISO's emergency declarations and actions were inconsistent from event to event. Hence, we recommend MISO strengthen its operating procedures to clarify the criteria and improve the operator logging of regional emergency declarations and actions.

Real-Time Generator Performance

A substantial concern we evaluate is the poor performance of some generators in following MISO's dispatch instructions. 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 more than 165 MW in hours when generators are generally ramping up and more than 365 MW in the worst 10 percent of these periods. This continues to raise substantial economic and reliability concerns because these deviations were often not detected by MISO's operators.

We previously recommended that MISO develop better uninstructed deviation thresholds and improved price volatility make-whole payment formulas to improve incentives for generators to follow dispatch signals. MISO implemented both of these recommended changes in May 2019, which have improved the performance of MISO's generators substantially. Generator dragging fell roughly 10 percent in 2019 from the prior year. Additionally, MISO implemented a procedure in early 2018 to receive real-time alerts from the IMM that identify resources that are not following dispatch. Consistently responding to these alerts will improve MISO's awareness of its generators' availability and strengthen incentives for participants to update their real-time offers to reflect their true capabilities.

Wind Generation and Forecasting

Installed wind capacity now exceeds 22 GW as 2 GW entered in 2019. Wind output also increased by 10 percent to average 6.4 GW, accounting for 9 percent of all generation in 2019. MISO set several all-time wind records in 2019, peaking for the year on December 30 at 16.9 GW. Output has continued to grow in 2020 and MISO most recently set a new wind output record at 18.1 GW on April 9, 2020. These increasing trends in wind output are likely to continue for the next few years as investment remains strong.

Although wind generation promises substantial environmental benefits, its output is intermittent and presents operational challenges. These challenges will be amplified as wind's share of total output increases. One of the operational challenges is the large dispatch deviations that can be caused by wind forecast errors. The forecast is used by MISO to set wind units' dispatch maximum and, because their offer prices are low, the forecast also tends to set their dispatch level. Average dispatch deviations by wind units were larger than any other class of resource. The wind deviations caused by 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. Hence, we recommended a number of changes to the uninstructed deviation thresholds and settlement rules and price volatility make whole payment formulas in order to provide incentives for wind resources to forecast their output accurately. MISO implemented these recommendations in May 2019, which has significantly improved its wind forecasting.

In particular, these changes caused most wind suppliers to accept MISO's wind forecast for their resources, which greatly reduced the forecast errors because many of the suppliers' forecasts were highly biased. We identified a methodological concern that caused the MISO forecast to also be biased (although less than the suppliers'), which MISO remedied in early 2020.

Uplift Costs

RSG payments are made in both the day-ahead and real-time markets to ensure a supplier's offered costs (including commitment costs) are recovered when a unit is dispatched.

- Nominal real-time RSG payments fell 6 percent to roughly $75 million in 2019.
- Day-ahead RSG fell by 10 percent to $36 million. Half of this RSG was associated with Voltage and Local Reliability (VLR) commitments in MISO South.

MISO also made 34 percent more RSG payments in 2019 associated with commitments made to maintain enough online capacity in the South to prevent exceeding the RDT limit after a major contingency. These commitments are effectively satisfying a 30-minute reserve requirement.

To allow the MISO markets to satisfy this requirement, we recommended that MISO develop a 30-minute sub-regional reserve product consistent with the operating requirements described above. FERC has approved MISO's proposal to implement such a product (its Short-Term Reserve product) and is targeting introduction in December 2021. In the meantime, MISO applied its Reserve Procurement Enhancement (RPE) to the RDT in August 2018. This holds 10-minute reserves in the South as a proxy for these 30-minute operating requirements.

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 market transactions are settled through the day-ahead market, most congestion costs are collected in this market.

Congestion Costs in 2019

The value of real-time congestion fell 35 percent in 2019 to roughly $900 million. Nearly half of the reduction was attributable to new transmission facilities and line upgrades in MISO and neighboring regions, while almost 10 percent was related the entry of a 1,000 MW combined-cycle facility in Amite South in May. The 20 percent reduction in natural gas prices also contributed to the lower congestion levels. Congestion tends to track natural gas prices because natural gas-fired units are generally dispatched to manage the flows over binding constraints.

Not all of the $900 million in real-time congestion is collected by MISO through its markets, primarily because there are loop flows caused by others and flow entitlements granted to PJM, SPP, and TVA which do not pay MISO for use of the network. Hence, day-ahead congestion costs fell to $528 million in 2019, down 30 percent from last year.

These 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. In 2019, FTR obligations exceeded congestion revenues by $63.6 million – a shortfall of 4.4 percent before auction residual collections. This is not good because underfunding FTRs degrades the value of the FTRs. Ultimately, this harms transmission customers when they receive reduced revenues from the sale of the FTRs.

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, including the following three issues.

Outage Coordination. Transmission and generation outages often occur simultaneously that affect the same constraint. In 2019, multiple simultaneous generation outages contributed to more than $150 million in real-time congestion costs – nearly 25 percent of real-time congestion costs. We recommend MISO explore alternatives to improve 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.

Improved Transmission Ratings. Most transmission owners do not actively adjust their facility ratings to reflect ambient temperatures. As a result, MISO uses more conservative seasonal ratings, which reduces MISO's utilization of the true network capability. Additionally, many TOs do not provide emergency ratings that are generally safe to use for contingent constraints (where the flow would move to this rating only after a contingency has occurred). We estimate

MISO could have saved $114 million in congestion costs in 2019 by using temperature-adjusted and short-term emergency ratings. This supports continued efforts with transmission owners to receive and use these ratings. We have also recommended that MISO improve its systems and processes to allow TOs to provide such ratings in a more timely manner.

Reduce the GSF Cutoff for Constraints with Limited Relief. MISO employs a GSF cutoff of 1.5 percent so that electrically-distant generators will not be re-dispatched to manage congestion. This reduces the complexity and solution time of its market software. While this is generally reasonable, it excludes valuable congestion relief on some constraints – generally low-voltage and M2M constraints. This can reduce reliability, increase M2M settlement costs, and lead to FTR shortfalls. Our analysis shows $67 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent on a limited number of constraints. Hence, we recommend that MISO reduce the GSF cutoff where feasible and beneficial.

Given the vast costs incurred annually to manage congestion, initiatives to improve the efficiency of congestion management are likely to be among the most beneficial initiatives to pursue. Hence, we encourage MISO to assign a high priority to addressing these issues.

Market-to-Market Coordination

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and there are 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 fell 24 percent in 2019 to $388 million, which is more than a third of all congestion in MISO. Because there are so many MISO constraints that are substantially 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 shows that for the most frequently binding M2M constraints, the M2M coordination has generally contributed to shadow price convergence over time and lowered costs of managing the congestion. However, we also find that the coordination could be improved through four key changes and could deliver substantial additional cost savings.

Improve the relief request software: The relief requested by the MRTO from the NMRTO is essential because suboptimal relief quantities can prevent the NMRTO from providing available economic relief or cause a constraint to oscillate from binding to unbinding in alternating intervals. During a recent one year period, we estimated that the real-time congestion on MISO and SPP M2M constraints would have fallen by $41 million if the two RTOs requested optimal quantities of relief from each other. Hence, we have recommended that MISO work with SPP to improve the relief request software.

Replace the 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 five percent or greater shift factor on the constraint (i.e., 20 MW of output changes the flows by 1 MW). We have found that the five percent test has frequently resulted in constraints being designated as M2M constraints for which the benefits of coordinating are extremely small. Hence, we recommend that MISO replace the current five-percent test by tests based on the NMRTO's relief capability on the constraint. We also recommend that raise-help wind resources not be included in this test (or in the five-percent test). Wind resources cannot generally increase output to provide relief because they are usually producing as much output as they are able.

Lower the GSF cutoff. Our study shows MISO's GSF cutoff discussed above is impairing MISO's ability to provide relief on externals constraints, which is resulting in much more costly settlements with PJM and SPP. We recommend that MISO lower the cutoff for M2M constraints to allow more of its generators to be used to manage the congestion on these constraints.

Improve the Automation of the M2M Processes. MISO has made great progress in improving the M2M processes over the years, particularly in the area of testing new constraints in a timely manner to determine whether they should be defined as M2M constraints. Our analysis shows, that there is still significant opportunity for improving the timeliness with which constraints are tested and how quickly coordination is activated after M2M constraints bind.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2019, importing an average of 6.2 GW per hour in real time. MISO remained a net importer of energy from PJM in 2019, with imports averaging more than 2.7 GW per hour, up 30 percent from 2018. Price differences at the interfaces between MISO and neighboring areas create incentives to schedule imports and exports between areas. Because of the key role interface prices play in facilitating efficient external transaction scheduling, we evaluate interface pricing in this report. We also assess and discuss MISO's coordination of interchange with PJM. Efficient interchange is essential because poor interchange can increase price volatility, 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 the power sources and sinks throughout each RTO's footprint since this is what happens in reality. However, in response to a concern we first raised in 2012 regarding redundant pricing of congestion at the PJM-MISO interface, MISO agreed to adopt a new "common interface" definition for the PJM interface in June 2017. This new interface definition consists of 10 generator locations near the PJM seam, with five points in MISO's market and five in PJM. Our evaluation of the performance of this common interface reveals that it has increased interface price volatility, resulted in less efficient imports and exports, and raised costs for customers in both regions.

At the SPP interface, we have verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. 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 the congestion at the interface accurately.

Ultimately, we continue to recommend that MISO implement an efficient interface pricing framework at all of its interfaces by implementing two changes:

1. Removing all external constraints from its interface prices (i.e., pricing only MISO constraints). If SPP and PJM do the same, the redundant congestion issue will be eliminated and the interface prices will be efficient.
2. Adopting accurate assumptions regarding where imports source and exports sink when calculating interface congestion. MISO's assumptions for most interfaces, including SPP, are good. The common interface adopted with PJM is the notable outlier.

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.

Up until early 2019, there had been almost no participation in CTS. We have previously shown that high transmission charges and persistent forecast errors have likely deterred traders from using CTS. In 2019, the average quantity of CTS transactions offered and cleared rose to 220 MW and 65 MW, respectively. Most of these transactions were in the import direction, submitted by a participant with long-term firm transmission rights that can avoid the charges that deter other traders. The CTS process implemented between the New York ISO and ISO New England is more widely used because they apply no charges to these transactions.

However, forecasts are an issue for all of the current CTS processes and it is unlikely that PJM and MISO can substantially improve their forecasts given the timing of the information used. To improve the CTS process and maximize its savings, we recommend that MISO:

- Eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same; and
- Modify the CTS to clear transactions every 5 minutes through the real-time dispatch model based on the most recent 5-minute prices in the neighboring RTO area; and
- Implement a CTS process with SPP based on this type of 5-minute clearing process.

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. With the resolution of issues related to FERC Order 745 by the U.S. Supreme Court in early 2016, MISO continues to seek to expand its DR capability. This includes efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 13.5 GW of DR resources, which includes almost 4.5 GW of behind-the-meter generation. However, most of MISO's DR capability is in the form of interruptible load developed under regulated utility programs. Nearly 90 percent of MISO's DR resources are capacity resources or LMRs that can only be accessed after MISO has declared an emergency.

MISO has recently made several changes to improve accessibility and real-time information on the availability of LMRs. In early 2019, FERC approved tariff changes to: a) allow MISO to schedule LMRs in anticipation of an emergency event to access longer-lead resources, b) require additional testing for LMRs, and c) require LMRs to register availability consistent with their seasonal capability. As part of the RAN initiatives, MISO has also proposed tariff changes that reduce the allowable lead time for qualifying LMRs to 6 hours and accredits resources based on the availability throughout the planning year. Although we still have concerns that LMRs are not as accessible and do not provide comparable reliability to generating resources, these changes are clear improvements.

In addition to active demand response, MISO also allows energy efficiency (EE) to qualify to provide capacity. The quantity of EE participating in the PRA has been growing rapidly and is playing a more pivotal role in satisfying MISO's resource adequacy needs. Given the rapid increase in EE capacity, it is important that providing credits to EE is justified and that the accreditation of EE is accurate. We have concerns in both regards, finding that:

- Making payments equal to the capacity price for assumed load reductions provides redundant compensatation to cutomers' electricity bill savings and is, therefore, not economically efficient or necessary;
- Even were such payments justified, 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.

Since MISO's EE program is not addressing a known economic inefficiency and the qualification quantities cannot be estimated with reasonable accuracy, we recommend MISO disqualify EE measures from participating in MISO's capacity auction.

Table of Recommendations

Although the markets performed competitively in 2019, we make 29 recommendations in this report intended to further improve their performance. Five are new this year, while 23 were recommended previously. It is not unexpected that recommendations carry over from prior years since many of them require software changes that can take years to implement. MISO addressed four of our recommendations in 2018 and early 2019, as discussed in Section X.

The table 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 indicate whether each would provide high benefits and whether it can be achieved in the near term.

SOM Number	Recommendations	High Benefit	Near Term
Energy Pricing and Transmission Congestion			
2019-1	Improve the relief request software for market-to-market coordination.	✓	
2019-2	Improve the testing criteria for defining market-to-market constraints.		
2019-3	Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities.	✓	✓
2018-1	Improve emergency pricing by establishing an efficient default floor and accurately accounting for emergency imports.	✓	
2018-2	Lower GSF cutoff for constraints with limited relief.		
2016-1	Improve shortage pricing by adopting an improved Operating Reserve Demand Curve reflecting the expected value of lost load.	✓	✓
2016-3	Enhance authority to coordinate transmission and generation planned outages.		
2015-1	Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources.	✓	✓
2015-2	Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities.	✓	
2012-5	Introduce a virtual spread product.		
2014-3	Improve external congestion related to TLRs by developing a JOA with TVA.		
2012-3	Remove external congestion from interface prices.		✓

SOM Number	Recommendations	High Benefit	Near Term
Operating Reserves and Guarantee Payments			
2010-11	Incorporate expected deployment costs into the selection criteria when clearing reserve products.		
2018-3	Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when the reserves are deployed.		
Dispatch Efficiency and Real-Time Market Operations			
2019-4	Clear CTS transactions every five minutes based on the most recent five-minute prices in the neighboring RTO area.	✓	
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.		
2017-5	Evaluate the feasibility of implementing a 15-minute day-ahead market under the Market System Enhancement.	✓	
2016-6	Improve the accuracy of the LAC recommendations.		✓
Resource Adequacy			
2019-5	Remove eligibility for energy efficiency to sell capacity.		✓
2018-5	Improve capacity accreditation by accounting for unforced and unreported outages and derates during tight supply periods.	✓	
2018-6	Modify the supply and demand inputs for capacity by: a) accounting for behind-the-meter process load, b) improving planning assumptions, and c) validating suppliers' data.		✓
2017-6	Require the ICAP of Planning Resources be deliverable.		✓
2017-7	Establish PRA capacity credits for emergency resources that better reflect their expected availability and performance.		
2015-6	Improve the modeling of transmission constraints in the PRA.		
2014-5	Transition to seasonal capacity market procurements.		
2014-6	Define local resource zones based on transmission constraints and local reliability requirements.		
2010-14	Improve the modeling of demand in the PRA.	✓✓	

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 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) and which 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 lay ahead. Our evaluation of the markets' performance in 2019 reveals that the market performed competitively with no substantial evidence of market manipulation or market power abuses. However, we do identify a number of potential improvements in the design or operation of the markets that would allow them to operate more efficiently and provide better economic signals to market participants.

MISO has continued to respond to our past recommendations, allowing the markets continue to evolve to meet the changing needs of the system. Key changes or improvements during 2019 include:

- In February, FERC approved tariff changes that increase MISO's access to Load Modifying Resources (LMRs) by allowing MISO to schedule LMRs in advance of an anticipated emergency and requiring availability consistent with their seasonal capability.

- In April, MISO implemented capacity accreditation changes that treat generator planned outages during emergencies that were not scheduled far in advance as forced outages, although these changes have had very small effects.
- On May 1, MISO implemented a number of key changes that have improved the operational performance of the system, including:
  - Uninstructed Deviation rule changes and improved the Price Volatility Make-Whole Payment settlement formulas that have improved generators' incentives to follow MISO's dispatch instructions.
  - Improvements to MISO's regulation commitment process to reduce the volume of regulation-based capacity deratings, while expanding the regulation resource pool available for least-cost scheduling.
- In October, MISO filed proposed tariff changes that would prevent resources from qualifying to be planning resources and participate in the Planning Resource Auction if they are on outage for three of the months from June through September.
- In November, MISO modified ELMP to allow the costs of Fast-Start Resources scheduled in the day-ahead market to participate in setting real-time prices.
- In December, MISO lifted the energy offer cap from $1,000 per MWh to $2,000 per MWh as mandated by FERC, and proposed a number of improvements we recommended to the market power mitigation provisions in Module D, most of which have subsequently been approved.

A number of these improvements have measurably improved the performance of the markets or the operation of the system. We analyze and discuss these improvements throughout the remaining sections of this report.

Our analysis in this report supports a number of recommendations that are discussed in the various sections of the report. Some of these recommendations address specific current issues that affect the performance of the market, while others propose longer-term changes to prepare the MISO markets to continue to perform well as its generating portfolio evolves. These recommendations are listed and discussed in Section X of the report, which provides a description of the status of each existing recommendation and a discussion of the recommendations that have been addressed by MISO over the past year.

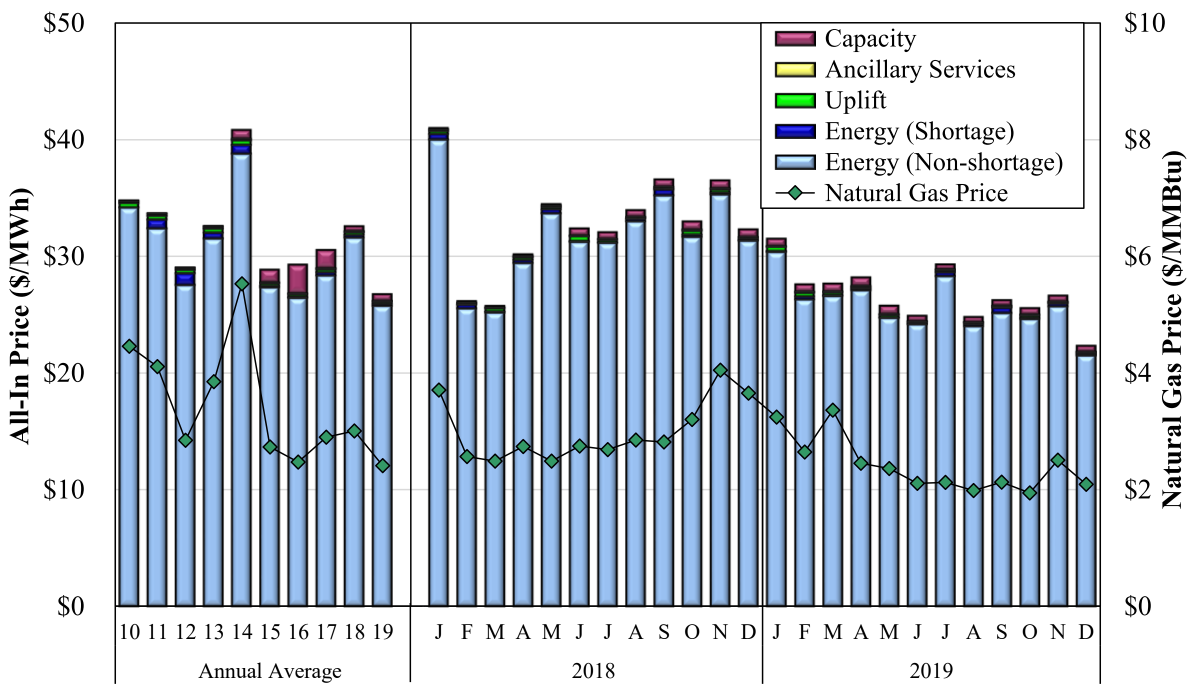
II. PRICE AND LOAD TRENDS

MISO's wholesale electricity markets in the day-ahead and real-time markets 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 2019

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 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. We separately show the portion of the all-in price that is associated with shortage pricing. Figure 1 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
2018–2019



*Energy prices are separated into Shortage and Non-shortage after 2010.

The all-in price fell 18 percent in 2019 to an average of $26.76 per MWh because:

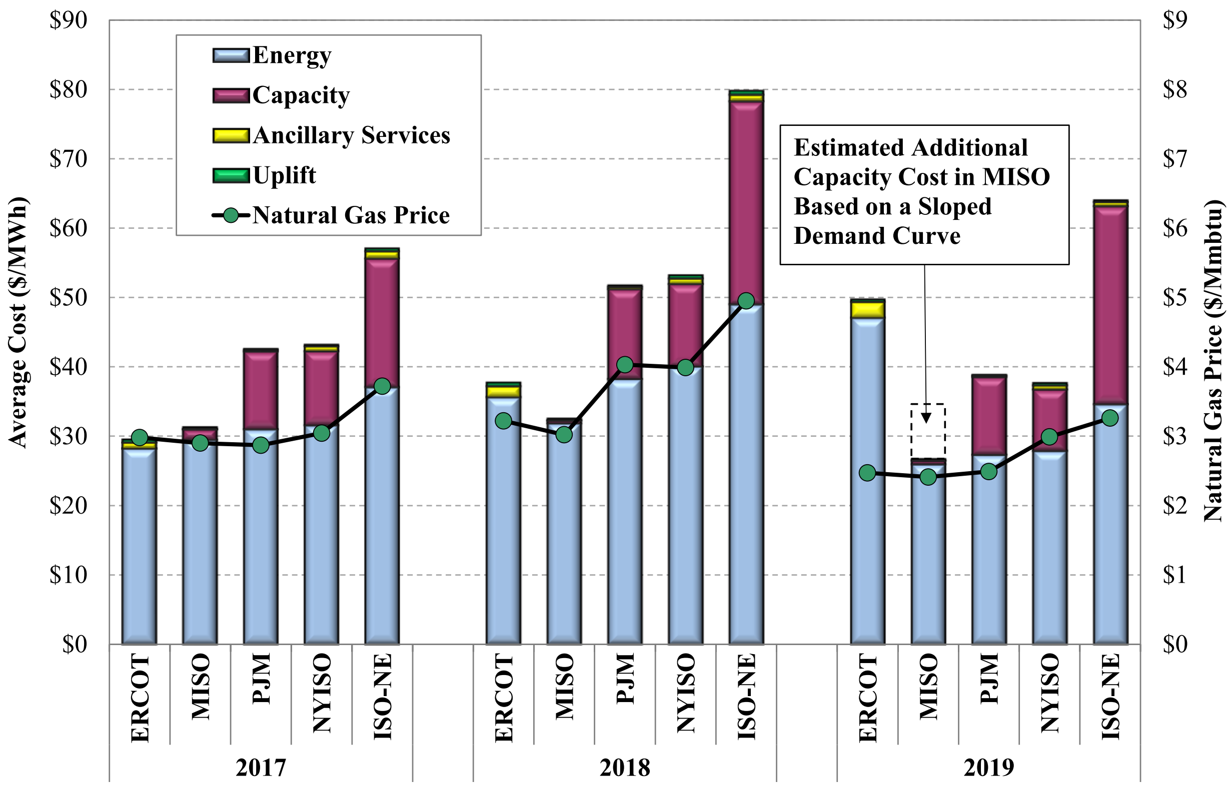
- Energy prices fell by 19 percent, largely because of lower natural gas prices and average load. Natural gas prices fell 20 percent to average $2.40 per MMBTU and average load fell 2 percent. The shortage pricing contributions remained low at less than one percent.
- The ancillary services component remained very small at $0.07 per MWh.

- The 2019/2020 capacity auction cleared at $2.99 per MW-day in all zones, except Zone 7 that cleared at $24.30 per MW-day. These prices are effectively zero – capacity remains undervalued because of shortcomings in the PRA design, which we discuss below.
- The uplift component of the all-in price fell by 12 percent to $0.18 per MWh.[3]

The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected in well-functioning, competitive markets because fuel costs are the majority of most suppliers' marginal production costs. Suppliers have strong incentives in competitive markets to offer at their marginal cost, so fuel price changes result in comparable offer price changes.

To provide perspective on how the MISO markets compare to the other eastern RTOs, Figure 2 shows the all-in price for each market from 2017 through 2019. These markets have migrated to similar market designs, including locational 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.

Figure 2: Cross Market All-In Price Comparison
2017-2019

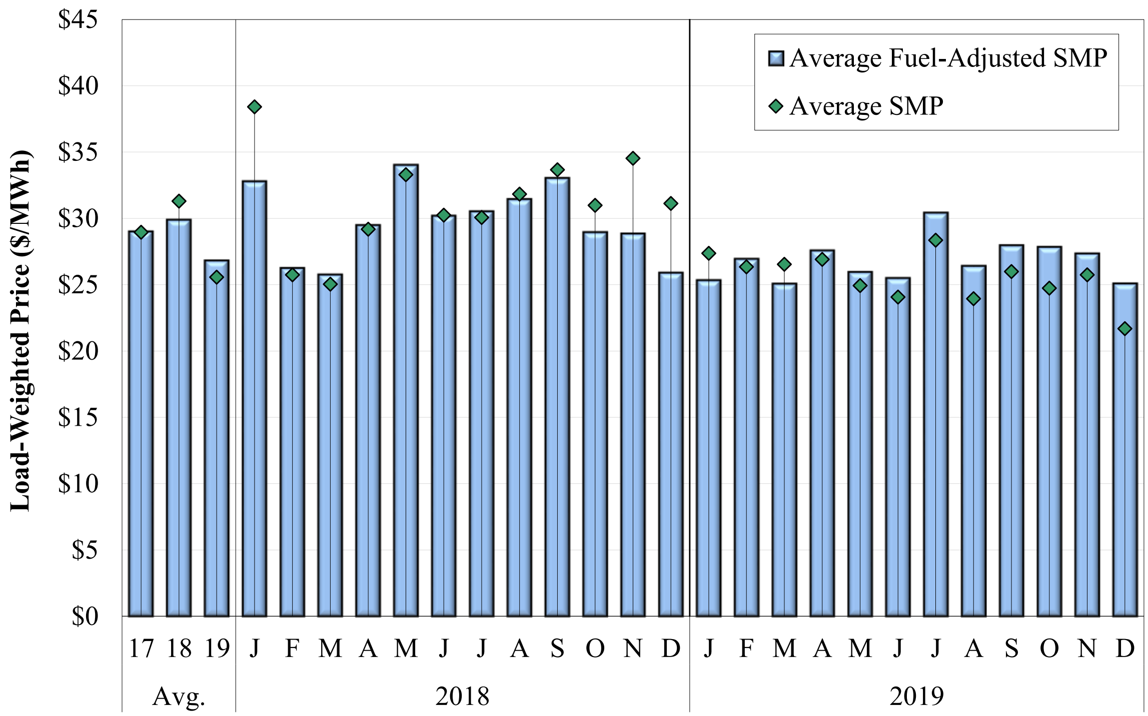


3 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make Whole Payments (PVMWPs). PVMWPs are made to ensure resources are not harmed when following MISO's dispatch instructions.

The market prices and costs in different RTOs can be significantly affected by the types and vintages of the generation, the input fuel prices and availability, and differences in the capability of the transmission network. Figure 2 shows that MISO exhibits the lowest all-in prices of the markets shown because of its relatively low natural gas prices, relatively weak shortage pricing, and lack of a functional capacity market. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. Two hours of severe shortages in ERCOT in 2019 caused its all-in price to exceed all other markets except New England. ISO New England's high capacity prices was 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 a fuel price-adjusted System Marginal Price (SMP) based on the marginal fuel in each five-minute interval with each interval's SMP indexed to the three-year average of the marginal fuel price.[4]

Figure 3: Fuel-Adjusted System Marginal Price
2018–2019



While the nominal SMP in 2019 fell by 18 percent over 2018, the fuel-price adjusted SMP fell by 10 percent. After controlling for fuel prices, the adjusted SMP decline can be attributed to two main factors: generation demand and generation mix. These factors shifted and augmented the market supply and demand curves, leading to lower prices in 2019.

- Generation Demand: The combination of a two percent decrease in load and a 1.2 GW increase in net imports reduced total generation demand by 4 percent in 2019.

4 See Figure A4 in the Appendix for a detailed explanation of this metric.

- Generation Mix: Greater availability of nuclear resources and continued wind penetration combined to increase the output of non-fossil fuel generation sources by 8 percent, while the output of higher-cost fossil fuel resources decreased.

B. Fuel Prices and Energy Production

The substantial changes in fuel prices during 2019 altered the generation output in MISO. Low natural gas prices increased MISO's natural gas-fired output and decreased the output from coal-fired resources. Additionally, the resource mix changed slightly in 2019, as nearly 3 GW of coal retirements in the Midwest were replaced by additions of 1.8 GW of gas resources in the South, 0.5 GW of gas resources in the Midwest, and 2.1 GW of wind in the Midwest. Table 1 below summarizes the share of capacity, energy output, and how frequently different types of resources were marginal in setting system-wide energy prices and local energy prices in 2018 and 2019.

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

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
Nuclear	12,225	12,107	10%	9%	16%	17%	0%	0%	0%	0%
Coal	48,775	46,864	38%	37%	47%	39%	45%	47%	78%	81%
Natural Gas	55,240	56,673	43%	44%	27%	31%	54%	51%	87%	89%
Oil	1,691	1,568	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,966	4,034	3%	3%	1%	2%	1%	1%	1%	2%
Wind	3,005	3,660	2%	3%	8%	9%	0%	1%	31%	38%
Other	2,678	2,703	2%	2%	2%	1%	0%	0%	2%	2%
Total	**127,580**	**127,608**								

Energy Output Shares. The lowest marginal cost resources (coal and nuclear) operated at the highest capacity factors. However, falling natural gas prices resulted in lower output from coal resources and higher output from natural gas resources. Natural gas resources' share of output grew to 31 percent, but it remained well below its share of capacity (44 percent). Much of this increase was from combined-cycle resources that have displaced higher-cost coal output.

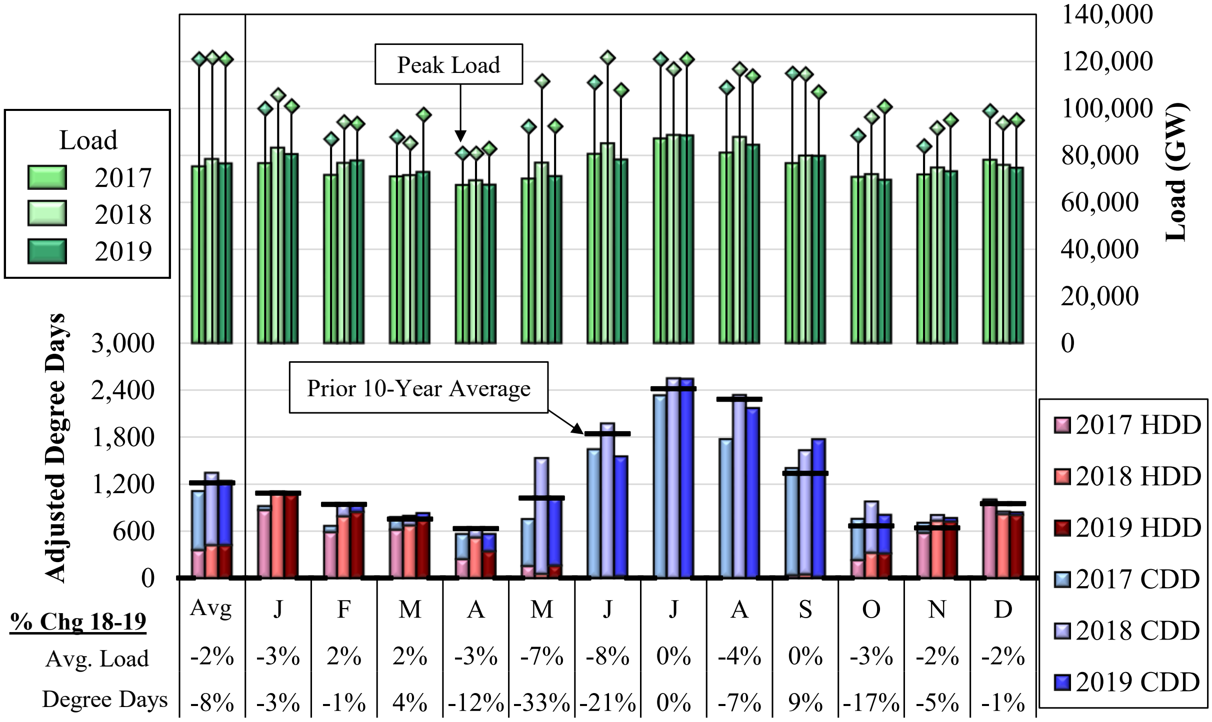
Price-Setting Shares. Coal resources set system-wide prices in 47 percent of hours, generally in off-peak hours. Although natural gas-fired units produce less than one-third of the energy in MISO, they play a pivotal role in setting energy prices. Gas-fired units set the system-wide price in more than half of all intervals for the year, including almost all peak hours when prices are highest. In addition, congestion often causes gas-fired units to set prices in local areas when lower-cost units are setting the system-wide price. This is why they set local LMPs in 89 percent of intervals and why they are a key driver of energy prices. Multiple types of resources may be marginal at different locations in the same interval because of binding transmission constraints.

Wind Resources. The capacity values in Table 1 are unforced capacity, so they are derated from installed capacity levels to account for outages and intermittency. This has the largest effect on wind units, which are derated by more than 80 percent. Hence, they account for only 3 percent of the unforced capacity but 9 percent of energy output. Wind units also often cause congestion on lines exiting their locations, causing them to set prices in more than one third of all intervals.

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.[5]

Figure 4: Heating and Cooling Degree Days
2017–2019



The average number of degree days fell by 8 percent overall in 2019, which was generally due to milder weather during the summer months. However, hotter than usual temperatures in September led to significantly higher cooling degree days in that month.

5 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).

MISO's annual peak load of 121 GW occurred on July 19, consistent with the typical occurrence of annual system peak around the third week of July. After accounting for voluntary LMR curtailments, actual peak load was two percent below the 50/50 forecasted peak of 125 GW from MISO's *2019 Summer Resource Assessment.*

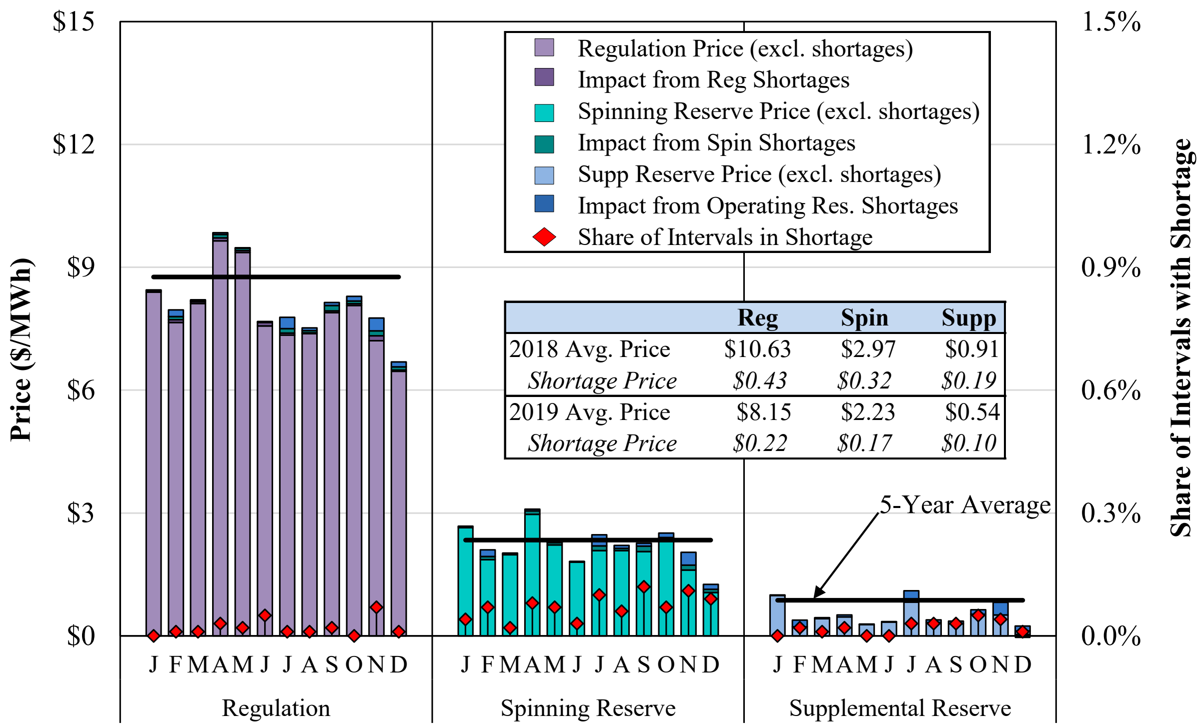
D. Ancillary Services Markets

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.

Ancillary Services Prices in 2019

For each product, Figure 5 shows monthly average real-time prices, the contribution of shortage pricing to each product's price in 2019, and the share of intervals in shortage. The figure also shows the 5-year nominal average price of the reserve products.

Figure 5: Real-Time ASM Prices and Shortage Frequency
2019



MISO's demand curves specify the value 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.

The supplemental reserves only contribute to meeting the market-wide operating reserve (i.e., contingency reserves) requirement. Spinning reserves can satisfy the operating reserve requirement, so the spinning reserve price will include a component for the operating reserve shortages. Hence, energy prices include the sum of the shortage values of all ASM products plus the marginal cost of satisfying the energy demands. Likewise, regulation prices will include components associated with spinning reserve and operating reserve shortages.[6]

Figure 5 shows that average clearing prices declined for all three ancillary services. The primary factors causing the decreases were:

- A reduction in opportunity costs resulting from lower natural gas prices;
- The reduction in transmission congestion; and
- Improvements to MISO's regulation commitment processes in May 2019 that increased the capacity available for co-optimization between energy, regulation, and spinning reserves by minimizing real-time regulation deratings.

Deployment Costs of Reserve Providers

When selecting and clearing resources to provide reserves, MISO does not consider the costs to produce energy during reserve deployment events. Resources are deployed for spinning reserves on a pro rata basis, and they are made whole to their energy offers. This results in scheduling inefficiencies because suppliers that receive make-whole payments have no incentive to incorporate expected deployment costs in their offers. This is a problem because resources with very high deployment costs are generally not economic reserve providers. Hence, scheduling them to provide reserves is inefficient and raises costs to MISO's consumers. Recently, a larger number of resources with extremely high deployment costs have been providing spinning reserves. To illustrate this increased exposure, Figure 6 provides the spinning reserve offers from December 17, 2019. We assume a one-hour spinning reserve deployment beginning at 6:20 a.m., and calculate the uplift that would be owed to individual spinning reserve units per MWh.

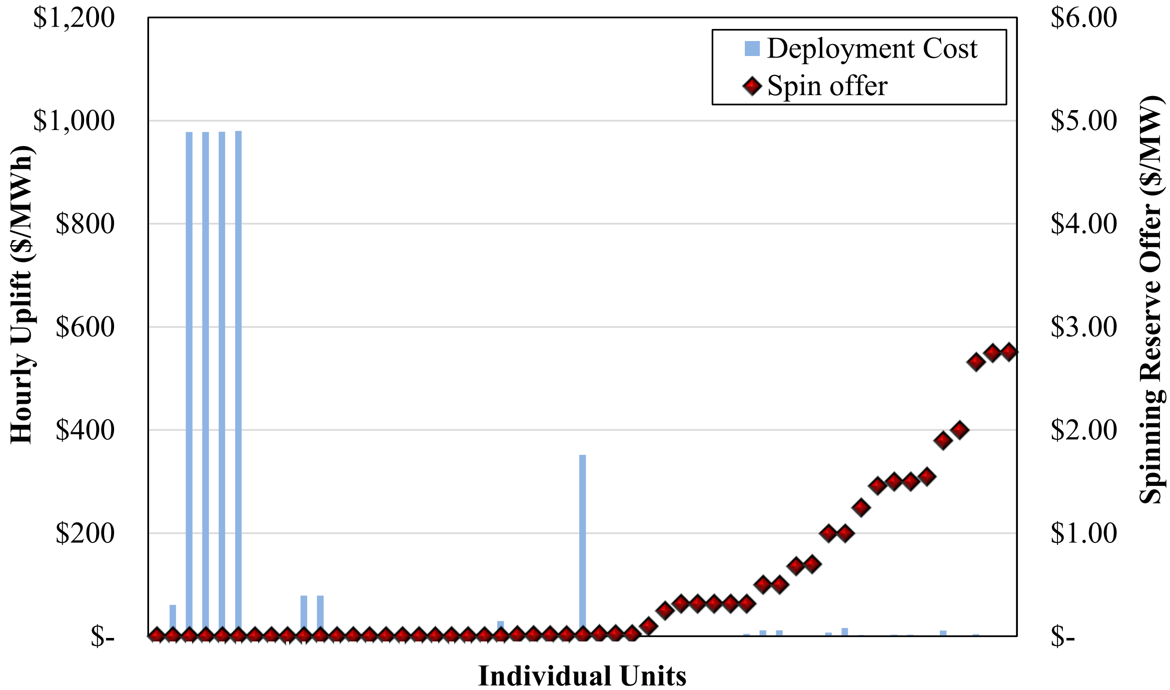
The supply curve for spinning reserves based on units' offers is shown by the red diamonds. In this example, units that would have been eligible for high make-whole payments were self-scheduled by market participants to provide ancillary services.

Figure 6 shows that resources with extremely high deployment costs appear to be low-cost suppliers in the spinning reserve market based on their offers (and in this case are self-scheduled). If you assume one 30-minute deployment per week, resources whose costs are $1000 or higher would be anticipated to have deployment risk availibility offers at or above $3

6 The demand curve for regulation, which is indexed to natural gas prices, averaged $132.49 per MWh in 2019, down from $140.58 in 2018. 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%).

per MWh. In 80 percent of the cases since 2017 when spinning reserves were deployed, resources pricing an availability offer above $3 per MWh would not have been selected.

Figure 6: Deployment Cost Example
December 17, 2019 at 6:20 a.m.



The exposure of MISO's loads to these uplift costs will grow as more of these types of resources participate in the operating reserve markets. We estimate that based solely on the participation of the units shown in the figure above, that MISO will incur roughly $1.4 million of inefficient uplift per year. This structure also raises gaming concerns as reserve providers could engage in conduct to inflate such make-whole payments.

Therefore, we reintroduce a recommendation that MISO reduce the risk of high-cost deployments by selecting reserves based on the expected value of the cost of deployment. There are two ways that MISO can address this concern:

1) Eliminate the make-whole payment made to spinning reserve providers when they are deployed; or

2) Calculate the expected value of the out-of-market deployment cost for each unit and schedule reserves based on that metric.

Incorporating deployment risk into the reserve selection criteria will reduce the frequency that demand side and other high energy cost resources provide reserves and reduce the associated out-of-merit uplift costs of deploying them.

III. Day-Ahead Market Performance

MISO's electricity spot markets operate together in a two-settlement system, clearing once in the day-ahead market and resettling imbalances in the real-time market. The day-ahead market operates in advance of the real-time market and is largely financial, establishing financially-binding, one-day forward contracts for energy and ancillary services.[7] The real-time market clears based on actual physical supply and demand. Supply or demand scheduled day-ahead receive financially-binding schedules and settle any deviations at real-time prices.[8] Based on our evaluation herein, we have concluded the day-ahead market performed competitively in 2019.

The performance of the day-ahead market is important for the following reasons:

- 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;[9]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

A. Summary of Day-Ahead Outcomes

Most of the settlements in MISO occur through the day-ahead market, as roughly 99 percent of MISO's load clears in the day-ahead market (net of virtual transactions and changes in net interchange). This small average difference in net load scheduling indicates that modeling in the day-ahead and real-time markets are consistent. The day-ahead energy prices averaged $27 per MWh in 2019, down 18 percent from 2018. Congestion caused prices at the day-ahead hubs to range from $23 per MWh at the Minnesota Hub to $28 per MWh at the Indiana Hub. These results converged well with the real-time market results as discussed in the next subsection.

The primary difference between the day-ahead and real-time markets is that the day-ahead market is scheduled hourly while the real-time market operates on a 5-minute basis. This creates some issues in managing MISO ramp demands, i.e., the need to schedule generation to 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 the top of the hour. To improve the operation of the system, we have recommended that MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market.

7 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.

8 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.

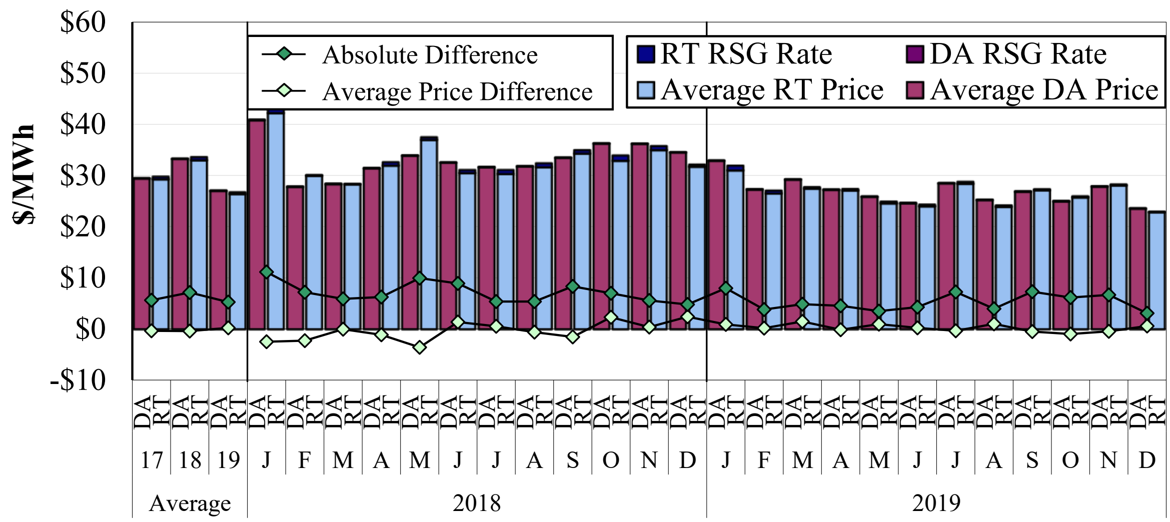
9 After the day-ahead market, MISO runs its Forward Reliability Assessment Commitment (FRAC) and Look-Ahead Commitment (LAC) process, both of which may cause MISO to make additional commitments.

B. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which it converges with real-time market outcomes. 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, a number of 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 7 shows monthly and annual price convergence statistics. The upper panel shows the results for the Indiana Hub, while the table below shows seven hub locations in MISO. 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 table shows the average price difference adjusted to account for the difference in RSG charges.

Figure 7: Day-Ahead and Real-Time Prices
2018–2019



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

Indiana Hub	-1	-1	1	-6	-8	0	-4	-10	4	2	-2	-4	7	1	7	3	1	5	-1	4	1	-1	4	-2	-4	-2	3
Michigan Hub	-2	-1	-1	-2	1	-1	-2	-9	4	1	-4	-5	4	-2	5	-6	0	4	-2	3	1	-5	4	1	-4	-1	3
Minnesota Hub	-1	-1	1	3	-6	1	0	-4	-2	3	-4	-6	2	1	4	-4	-1	4	0	4	2	-3	6	1	0	2	5
WUMS Area	-1	-1	0	2	-3	0	-6	-1	-2	-8	1	-4	3	0	7	1	1	7	-12	6	-6	-11	6	4	-3	5	5
Arkansas Hub	0	-1	1	-7	-1	0	-4	4	4	3	-4	-11	3	-1	4	0	-3	5	1	6	8	-1	2	-2	-4	-3	4
Louisiana Hub	-1	-2	5	3	3	0	-3	10	-13	9	-12	-18	4	-5	4	3	0	15	9	11	10	0	6	2	1	-3	2
Texas Hub	1	-1	-1	-5	-1	0	-5	8	2	4	-5	-12	2	-1	3	1	1	7	0	9	1	5	-18	1	-16	-1	4

Convergence was good overall. Day-ahead premiums were less than one percent on average after adjusting for the real-time RSG, which averaged $0.37 per MWh. However, divergence occurred in some months for some locations because of transient conditions in 2019:

- In early March, significant under-scheduling of wind in the day-ahead market contributed to a system-wide day-ahead SMP premium.
- Unusual cold weather in March in the South contributed to a 15 percent day-ahead premium at the Louisiana Hub as virtual traders anticipated real-time price spikes that did not materialize. MISO rescheduled several outages in anticipation of the cold weather.
- In April and May, multiple real-time commitments in the South for local transmission and the RDT led to roughly a 10 percent day-ahead premium at the Louisiana Hub.
- Episodes of real-time congestion attributable to transmission outages and generator derates contributed to divergence in WUMS in April and June.
- In mid-August, hot weather, unit outages, and transmission outages in the Western load pocket contributed to high real-time prices at the Texas Hub.
- In early October, forced transmission outages, fuel-associated generation derates, and transmission derates caused by hot weather conditions contributed to high real-time prices for three days at the Texas Hub.

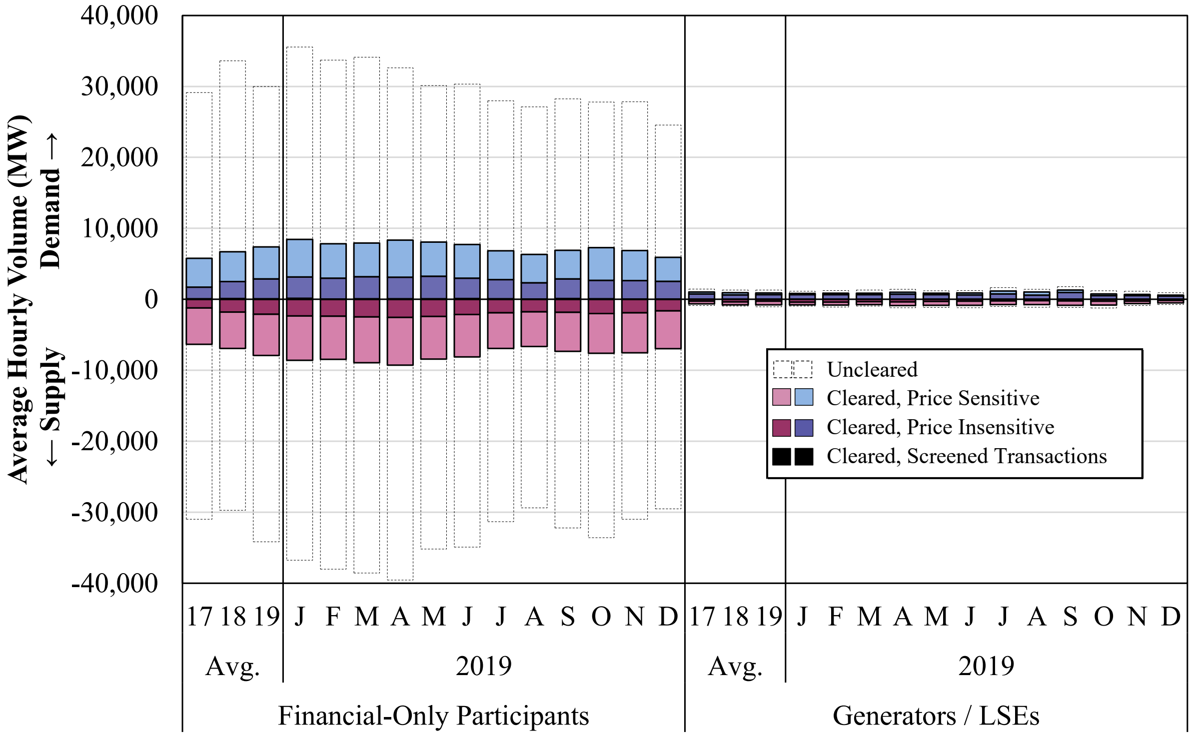
The market can be slow to react to these periods of substantial real-time congestion, in part because participants must engage in high-risk day-ahead market trades (i.e., virtual load at some locations and virtual supply at others) to arbitrage these differences. We have recommended a virtual spread product that we discuss in the next subsection, which would allow a participant to more effectively arbitrage the congestion-related differences between the two markets.

C. 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. As such, virtual day-ahead purchases or sales cannot perform in real time and, therefore, settle against the real-time price. 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 8 shows the average offered and cleared virtual supply and virtual demand in the day-ahead market.

Figure 8 shows that offered virtual volumes increased by one percent over last year, although a 15 percent increase in virtual supply offers offset a 10 percent decrease in virtual demand offers. Average cleared transactions rose 11 percent, largely driven by financial-only participant activity. Average virtual demand offered in the South fell by 34 percent. Although this trend began in December 2018, a persistent day-ahead premium at the South hubs throughout the Spring months sustained this trend through the end of the year.

Figure 8: Virtual Demand and Supply in the Day-Ahead Market
2019



Financial participants account for the vast majority of the virtual activity in MISO, as few generators and LSEs hedge their generation or load positions using virtual transactions. Financial participants, who tend to offer more price-sensitively, provided key liquidity to the day-ahead market.

Several participants submit "backstop" bids, which are bids and offers priced well below (in the case of 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 clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

Figure 8 distinguishes between bids and offers that are price-sensitive and those that are price-insensitive (i.e., those that are very likely to clear). Price-sensitive transactions provide more liquidity in the day-ahead market and facilitate price convergence. Price-insensitive transactions effectively indicate a preference for the transaction to clear regardless of the price.[10] These transactions constitute a large share of all virtual transactions, and occur for two primary reasons:

- To establish an energy-neutral position between two locations to arbitrage congestion-related price differences between the day-ahead and real-time markets. We refer to these transactions as "matched" transactions; and

10 Bids/offers are considered price-insensitive when demand bids are more than $20 above or supply offers are $20 below an expected real-time price (an average of recent real-time prices in comparable hours).

- To balance the participant's portfolio to avoid RSG deviation charges assessed to net virtual supply, which is deemed to cause RSG under MISO's cost allocation.

The average hourly volume of matched transactions in 2019 increased by 19 percent from 2018 to 666 MW. Matched transactions are used to arbitrage congestion-related price differences while avoiding energy price risk. We continue to recommend MISO implement a virtual spread product that would allow participants to engage in such transactions price-sensitively. This product would allow participants to specify the maximum congestion between two points they are willing to pay for a transaction. Comparable products exist in both PJM and ERCOT.

Finally, price-insensitive bids and offers that contribute to a significant congestion divergence between the day-ahead and real-time markets are labeled "Screened Transactions" in the figure. We investigate these trades because they may be attempts to manipulate day-ahead prices. The screened transactions share was less than one percent and did not raise concerns in 2019.

D. Virtual Activity and Profitability

To provide perspective on the the virtual trading in MISO, Table 2 compares virtual trading in MISO to trading in NYISO and ISO New England.

Table 2: Comparison of Virtual Trading Volumes and Profitability
2019

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	10.8%	-$0.07	11.3%	$0.94
NYISO	6.7%	$0.17	14.5%	$0.43
ISO-NE	2.3%	-$1.20	4.9%	$1.26

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 efficient cost allocation of RSG that MISO uses. The table also shows that the liquidity that virtual trading provides in MISO translates to relatively low virtual profits. Virtual supply profits are higher than virtual load because they are allocated the RSG they are deemed to have caused.

Gross virtual profitability fell by 46 percent in 2019, averaging $0.45 per MWh. As the volume of cleared virtual transactions increases, the virtual profits tend to decrease as price convergence improves. Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $0.46 per MWh compared to $0.34 per MWh. The fact that virtual transactions are profitable on average is desirable because profitable transactions generally promote convergence between day-ahead and real-time prices.

Virtual supply profitability fell 30 percent, averaging $0.94 per MWh, while virtual demand was less profitable than in 2018 at -$0.07 per MWh. Day-ahead premiums in March and May 2019 at Louisiana Hub contributed to high virtual supply profitability, averaging $2.42 and $3.46 per MWh in those months. Gross profits are higher for virtual supply because more than half of these profits were offset by real-time RSG costs allocated to net virtual supply. Virtual demand does not bear capacity-related RSG costs because they are a "helping deviation."

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.

E. Benefits of Virtual Trading

We conducted an empirical analysis of virtual trading in MISO in 2019 that evaluated the contribution of virtual trading to the efficiency of the market outcomes. We determined that 58 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 were unprofitable, which occurs when virtual transactions respond to a real-time price trend but overshoot, so they are ultimately unprofitable. 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 III.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 3 shows the total amount of efficient and inefficient virtual transactions by market participant type.

Table 3: Efficient and Inefficient Virtual Transactions by Type of Participant in 2019

	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	66,782,554	$481.1M	-$7.9M	6,999,168	$41.6M	-$.4M
Efficiency Enhancing (Unprofitable)	10,149,592	-$39.0M	$6.9M	1,161,082	-$3.2M	$.6M
Not Efficiency Enhancing (Profitable)	4,247,529	-$18.9M	$35.7M	578,694	-$.9M	$1.9M
Not Efficiency Enhancing (Unprofitable)	52,491,005	-$393.4M	-$3.2M	5,844,266	-$34.8M	-$.0M
Total	**133,670,680**	**$29.9M**	**$31.5M**	**14,583,209**	**$2.8M**	**$2.1M**

The table shows that 58 percent of all virtual transactions were efficiency-enhancing, and convergent profits were positive on net for all virtual transactions by $32.7 million. While substantial, this is down by 57 percent from 2018, likely because of the decrease in transmission congestion in 2019. 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.

To accurately calculate this total benefit would require one to rerun all of the day-ahead and real-time market cases for the entire year. However, this analysis allows us to estimate with a high degree of confidence that virtual trading was beneficial in 2019.

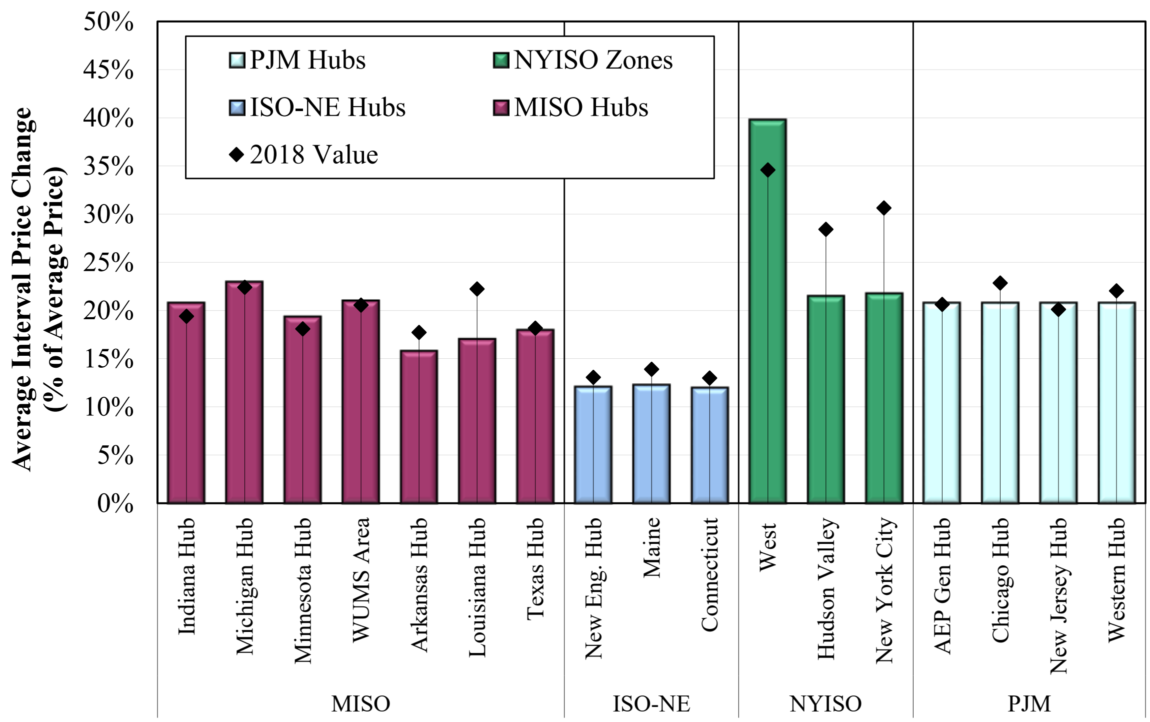
IV. Real-Time Market Performance

The performance of the real-time market is crucial because it governs the dispatch of MISO's resources and sends economic signals that facilitate scheduling in the day-ahead market and longer-term investment decisions. This section evaluates two broad aspects of the real-time market: real-time pricing and real-time market operations. In the pricing area, we summarize price volatility, and the effectiveness of the Extended Locational Marginal Pricing (ELMP) model to allow peaking resources and emergency resources to set prices, and assess MISO's shortage pricing. Our review of operational issues includes: (a) uplift costs that are generally caused by operator actions, (b) the management of flows over the RDT interface between the Midwest and the South, (c) the management of emergency events in 2019, (d) the dispatch of MISO's intermittent wind resources, and (e) outage scheduling.

A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the system demands can change rapidly and supply flexibility is restricted by physical generator limitations and network constraints. The day-ahead market operates on a longer time horizon with more commitment options and additional liquidity provided by virtual transactions. Because real-time flexibility is limited, the system is frequently "ramp-constrained" (i.e., units unable to move quickly enough to achieve their optimal output). This results in transitory price spikes. Figure 9 compares 15-minute price volatility at various locations in MISO and in three neighboring RTOs.

Figure 9: Fifteen-Minute Real-Time Price Volatility in 2019



The results in Figure 9 show:

- Volatility in 2019 was similar at most locations to 2018.
- Volatility at the Louisiana Hub and Arkansas Hub fell by 5 and 2 percentage points, respectively, as congestion fell in these areas.
- MISO generally experienced price volatility comparable to PJM and NYISO (apart from NYISO West) in 2019.
- Only the price volatility in ISO New England was lower than in MISO, generally because it experiences much less congestion than each of the other RTOs.

Volatility in MISO primarily occurs when ramp constraints bind and cause sharp price movements, which tends to happen when:

- Actual load is changing rapidly, including non-conforming load associated with industrial facilities that can change sharply and without advance notice;
- Net Scheduled Interchange (NSI) changes significantly;
- Wind output changes sharply; or
- The load-offset parameter (used to manage control-area performance) is not set optimally to manage anticipated ramp changes.

MISO has made significant efforts to improve the commitment, dispatch, and pricing of units in recent years. MISO implemented a "Ramp Capability" product in the spring of 2016 to hold additional ramp capability when the projected benefits exceed its cost. This product has improved MISO's management of the system's ramp demands and mitigated its price volatility.

B. Fast-Start Pricing in ELMP

MISO implemented the Extended Locational Marginal Pricing algorithm in March 2015 and expanded the set of resources eligible to set prices in May 2017.[11] In November 2019, MISO further expanded ELMP to allow Fast-Start Resources[12] (FSR) committed in the day-ahead market to participate in real-time price setting. 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 FSRs and emergency resources to set prices when they are:

- *Online* and deemed economic and needed to satisfy the system's needs; or
- *Offline* and deemed economic during transmission or energy shortage conditions.

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11 Prior to May 2017, the only online units eligible to set prices in ELMP were those that: a) could start in 10 minutes or less, b) had a minimum runtime of one hour or less, and c) were not scheduled in the day-ahead market. Phase 2 extended participation to include resources with up to a one-hour start up time.

12 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff as a "Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 60 minutes of being notified and that has a minimum run time of one hour or less…."

The online resource component of these reforms was intended to remedy issues that we initially identified shortly after the start of the MISO energy markets in 2005 that caused real-time prices in some periods to be substantially understated. This led to increased RSG costs and poor pricing incentives to schedule generation and interchange. Although they may not appear to be marginal in the 5-minute dispatch, the ELMP model recognizes that inflexible peaking resources are marginal and should set prices to the extent that are needed to satisfy the system's needs.

The second reform allows offline fast-start resources to participate in setting prices under transmission and reserve shortage conditions. In theory, it is efficient for offline resources to affect prices only when: a) they are feasible (can be started quickly to address the shortage) and b) they are economic for addressing the shortage. However, when units that are neither feasible nor economic to start are allowed to affect energy prices, the resulting prices will be inefficiently low.

ELMP had a modest effect on MISO energy prices in 2019, increasing the market-wide real-time prices by only $0.14 per MWh on average overall, down from $0.36 per MWh in 2018. Mild conditions muted the overall price effects of ELMP because FSRs were not needed as frequently in 2019, while lower natural gas prices also contributed to the reduction. ELMP had larger effects at certain congestion locations – the average effects ranged from -$0.73 to $4.48 per MWh at the most affected locations each month. As expected, ELMP had almost no effect in the day-ahead market because the overall supply is much more flexible and includes virtual transactions. To evaluate the effectiveness of ELMP, we separately assess the online and offline aspects of ELMP in the subsections below.

Evaluation of Online Pricing of Fast-Start Resources

Our prior evaluations concluded that the relatively small effects of the online pricing occurred because a very small share of MISO's resources were initially eligible to set prices. This was expanded somewhat when MISO implemented ELMP Phase II in May 2017 and ELMP Phase III in November 2019. Even with these changes, we estimate that the online pricing in ELMP would only have increased real-time prices by $0.35 per MWh. This is shown in Table 4 along with a recommended improvement in a key assumption in ELMP that determines *how* resources participate in ELMP.

ELMP does not allow resources to set prices when the dispatch model seeks to ramp them down at their maximum ramp rate. This ramp test substantially reduces the resources that qualify as marginal price-setting resources. In both the ISO-NE and NYISO variants of ELMP, a resource may be considered marginal and set prices unless it is dispatched to zero, regardless of whether it is being ramped down at its maximum rate. This is a significant advantage over MISO's ELMP approach, as shown in Table 4.

Table 4: Evaluation of ELMP Online Pricing

Alternative ELMP Methods	Avg. Price Increase ($/MWh)	% of Fast-Start Peaker Eligible	% of Intervals Affected
Current Including Day-Ahead Units	$0.35	32.8%	11.1%
No Ramp Limitation	$0.96	56.9%	21.2%

Expanding eligibility to day-ahead units has been a substantial improvement, allowing almost one-third of all peaking resources to be eligible to set prices. However, we continue to recommend that MISO relax the ramp limitations for units in the ELMP model to better determine whether the fast-start units are needed to satisfy the system's needs. The table above shows that relaxing the downward ramp limitation on the peaking resources would have increased ELMP's effectiveness in allowing LMPs to reflect the costs of peaking resources needed to satisfy the system's demands, raising average prices by $0.96 per MWh. These more efficient prices will have large beneficial effects on high-load days, improving the commitment of resources and the scheduling of imports and exports. Hence, we continue to recommend this reform as a high priority improvement for MISO.

Evaluation of Offline ELMP Pricing

We have evaluated the offline pricing during transmission violations and operating reserve shortages. This is when ELMP sets prices based on the hypothetical commitment of an offline unit that MISO could have utilized to address the shortage. This is only efficient when the offline resource is: a) feasible to address the shortage, and b) economic to commit. When units set prices that do not meet these criteria, the resulting prices will be inefficiently low.

When an offline unit is both feasible and economic, one would expect the unit will usually be started by MISO. When resources are not started, we infer that a) the operators did not believe the unit could be online in time to help resolve the shortage, and/or b) that the operators did not expect that the unit would be economic to operate for the remainder of its minimum runtime. Therefore, our evaluation quantifies how frequently the offline resources that set prices are actually started by MISO operators, and how frequently they are actually economic in retrospect based on MISO's ex ante real-time prices. Table 5 below summarizes our results.

Table 5: Evaluation of Offline ELMP Price Setting in 2019

	Economic*	Started	Economic & Started
Operating Reserve Shortages	6%	4%	**2%**
Transmission Shortages	25%	8%	**5%**

**Does not include units that were never started, which would increase the values to: 27% for OR shortages and 34% for Tx shortages.*

This table shows that the offline units that set prices during both operating reserve and transmission shortages are rarely economic and feasible (2 and 5 percent of intervals, respectively). Based on these results, we conclude that ELMP's offline pricing component is not satisfying the economic principles outlined above and is undermining price formation during shortage conditions. As the Commission has recognized, efficient shortage pricing is essential, so we continue to recommend that MISO disable the offline pricing logic.

C. Emergency Pricing in ELMP

Like the online pricing of FSRs, ELMP allows emergency resources to set prices when they are needed by assuming a default offer cost for the emergency MWs and allowing the ELMP model to dispatch them down. This is a key capability that only the MISO market currently enjoys, which is intended to prevent emergency actions from distorting real-time prices. A more detailed discussion reviewing the emergency events in 2019 is contained in Subsection G below, but our evaluation of MISO's emergency pricing reveals the following issues.

Asymmetric Ramp Rate Assumptions

When large quantities of emergency MWs are called, it can cause ELMP to determine emergency resources are marginal and eligible to set price too frequently. This issue stems from the ramp rate limitations applied in ELMP. ELMP assumes LMRs and emergency imports can ramp down to zero within five minutes. However, the ramp rates of the other generating units that must replace them are not relaxed, which can cause the ELMP model to determine that the emergency MWs are needed when they are not. In other words, if the emergency schedules exceed the five-minute ramp-up capability of MISO's generation resources, the emergency resources will set the price. This results in artificially high prices that cannot be avoided with the current ELMP.

These high emergency prices incentivize participants to schedule imports from external areas that are ultimately overcompensated. This is what occurred on January 30, 2019. Four GW of LMR curtailments set a very high price that persisted, despite 6 GW of additional real-time imports. To address this issue, we recommend that MISO modify the ramp assumptions in ELMP to remove the asymmetry of the ramp rate assumptions described above. Alternatively, MISO could also consider adding the volume of LMR and emergency schedules to the Short-Term Reserve requirement. Shifting this demand curve outward would allow market resources to replace the emergency resource capacity with 30 minutes of ramp. The market would continue to use the emergency floor price when emergency capacity is needed, but it would reduce the likelihood that it will set price when it is not needed.

Default Emergency Price Floors

During emergency events, MISO can access supply outside of the market that is unavailable during non-emergency conditions, some of which is not dispatchable. To prevent the emergency supply from depressing prices inefficiently, MISO's emergency pricing construct applies Emergency Offer Floor Prices to these emergency MWs in the ELMP pricing engine to allow them to set prices. An efficient Emergency Offer Floor Price should satisfy the following criteria:

- The value should reflect the cost of reliability requirements or constraints that would not be satisfied without the emergency MWs;
- The value should be stable and knowable in advance; and
- The value should not be subject to manipulation by any single entity.

The offer floors are set based on the highest resource offers (economic or emergency, depending on the emergency tier) in the affected area. Because these offer floors are set by suppliers' offers, the floors can vary widely. In 2018, MISO declared five emergencies in local areas throughout the footprint. In 2019, MISO also declared local emergencies in the Central and North Regions on two days in January and on one day in the South in May. In most of these cases, we believe the emergency offer floors applied in these events substantially understated the true value of emergency power. However, the risk remains that a single entity could raise a single resource's offer and sharply inflate the emergency offer floor price.

We conducted an analysis to determine the volatility of calculated emergency offer floor prices in 2019 based on resources' offers in all hours. This analysis shows the emergency offer floor prices that would have prevailed were MISO to have declared an emergency in the South or Midwest regions. In Table 6, we show the minimum and maximum values that were calculated by region, as well as the largest inter-hour change.

Table 6: Extreme Values of Emergency Offer Floor Prices

2019

Region	Extreme Values		Largest Inter-hour Change
	Minimum	Maximum	
MIDWEST	$122	$1,288	$783
SOUTH	$79	$338	$234

Our results indicate that the current emergency floor price calculations result in a high degree of variability because they depend on suppliers' offers. For instance, for at least one interval the emergency offer floor price in MISO South would have been as low as $79 per MWh, which is close to the emergency offer floor during some of the emergencies in MISO South in prior years. This vastly understates the reliability risks of the emergency and, therefore, does not satisfy the principles above. As a consequence, the energy prices would not induce imports from other regions or provide adequate compensation for resources needed to resolve the emergency.

Alternatively, the emergency offer floor price in the Midwest would have exceeded $1,200 per MWh during emergency conditions on some occasions, and it could be more than $2,000 if a supplier submits a high-priced offer. This is inefficiently high for regional emergencies where violating the RDT is the primary reliability risk. The value of the RDT is indicated by its transmission constraint demand curve level of $500 per MWh. To address the concerns with the emergency pricing, we recommend MISO establish new rules for determining the emergency offer floors to ensure that they are set at levels that reflect the reliability risks of the emergency.

Regional Emergency Pricing Flaw

One final emergency pricing issue came to light during the regional emergency event that occurred in MISO South on September 15, 2018 when MISO scheduled emergency imports over the Southern Company interface. As these transactions were ramped down in the ELMP model to determine whether they should set prices, the flows over the RDT should have risen. Due to a flaw in the ELMP model, however, the RDT flows were not affected by the ramping down the emergency imports over the Southern Company interface. This caused the emergency imports to appear to be less necessary and undermined the emergency pricing during that event. We recommend that MISO correct this flaw as soon as practicable.

D. Shortage Pricing in MISO

Virtually all shortages in (co-optimized) energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves than required rather than not serving the energy demand). MISO also experiences capacity shortages, which we discuss in Subsection G below. When an RTO is short of reserves, the value of the foregone reserves should set the reserve market clearing price and be embedded in all higher-value products, including energy. This 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 reflect the value of reserves because:

- The probability of losing load is not calculated in a rigorous manner;
- Only a small portion of the curve is based on the probability of losing load – over 90 percent of the current ORDC is set by administrative overrides of $200, $1,100, and $2,100; and
- MISO's current VOLL of $3,500 is significantly understated.

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 ultimately utilized a model developed by Lawrence Berkeley National Laboratory to estimate a new 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. We used 2018 data for MISO to estimate VOLLs for residential customers that ranged from $3,600 to $3,900, while manufacturing and non-manufacturing commercial load registered outage costs of $32,000 and $73,000 per MWh, respectively.[13] Weighting these values based on the load data in MISO from 2018 yields an average VOLL of $23,000 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 countless combinations of random contingencies and conditions that could occur when MISO is short of reserves. To model these random occurrences, we estimated the probability of losing load using a Monte Carlo simulation[14]. This simulation includes all generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty. Considering all of these factors produces a flatter slope for the ORDC.

13 We did not include small commercial and industrial loads from the Berkeley model as they were much higher and we did not find them to a reasonable reflection of the VOLL in MISO for reasons detailed in Section IV of the Analytic Appendix.

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

The results of our recommended VOLL and improved ORDC slope is reflected in the IMM's Economic ORDC that is shown in Figure 10 as the royal blue line. Our proposed ORDC plateaus at $10,000 per MWh for three primary reasons:

- First, very few shortages would be priced in this range as the figure shows that more than 90 percent of all shortages would be priced less than $2,000.
- Second, pricing shortages at prices exceeding $10,000 could result in inefficient external transactions because most of MISO's neighbors price shortages at much lower prices.
- Pricing shortages at much higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints, the most valuable of which are currently priced at $3,000 per MWh.

Figure 10: Comparison of IMM Economic ORDC to Current ORDC

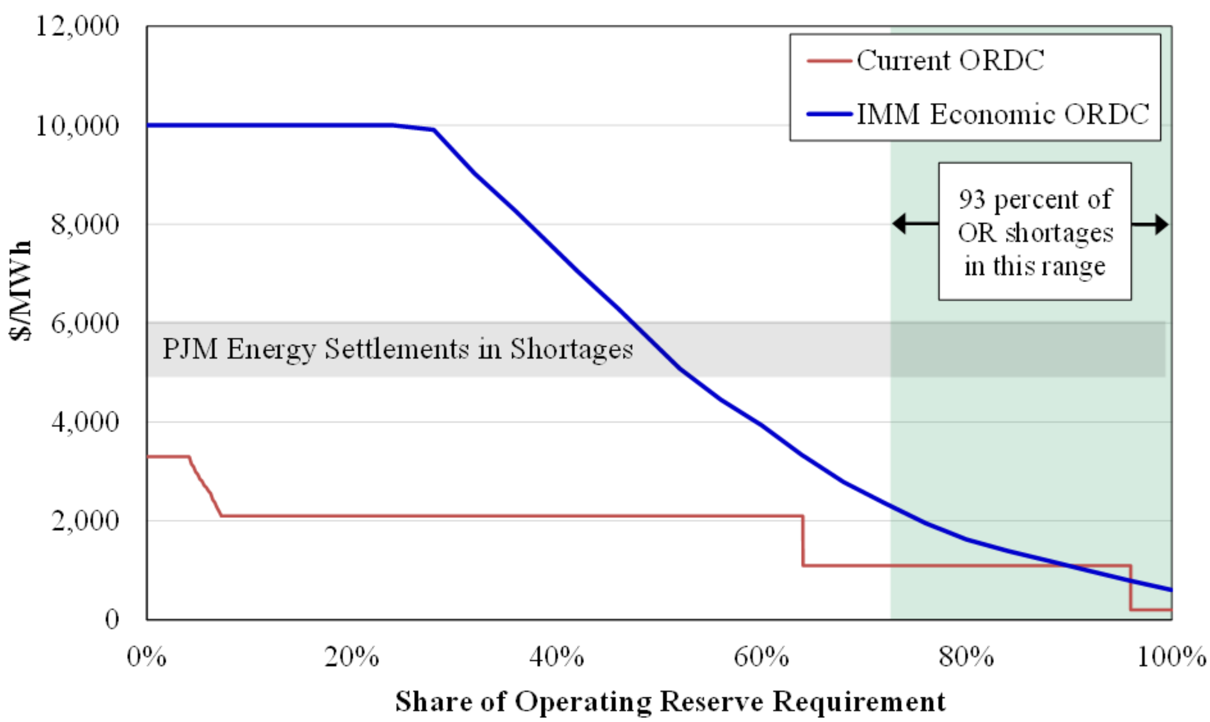


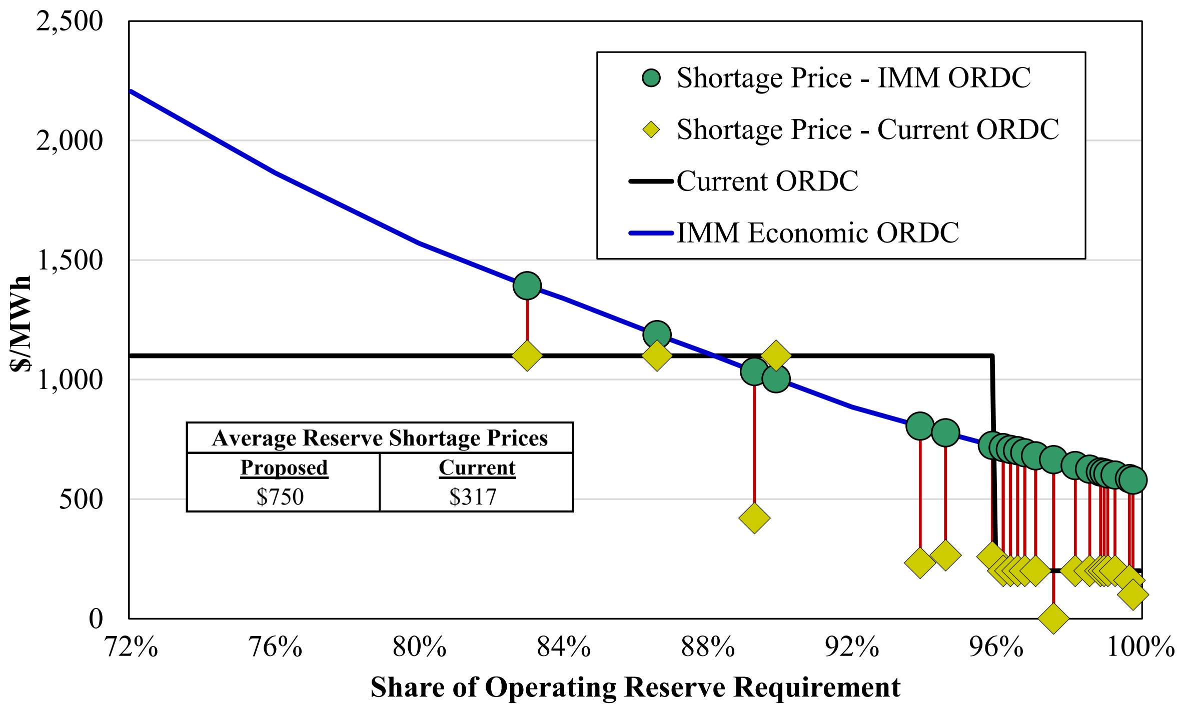
Figure 10 also shows the current ORDC after implementation of FERC Order 831 in December 2019, represented by the red line. The current ORDC prices small shortages of less than four percent at the lowest step of $200. As reserve levels fall (and shortages increase), the current ORDC abruptly steps up to price the shortage at $1,100 and then $2,100. The single step to $2,100 in the MISO-proposed ORDC is intended to be consistent with FERC's Offer Cap rule, but it does not reflect the expected value of lost load that underlies the IMM curve.

The current curve used in MISO will set inefficiently low prices at most shortage levels and inefficiently high prices when shortages are in the 100 to 300 MW range. The sharp increase in the current ORDC at 96 percent of MISO's reserve requirement can lead to excessive price volatility at low shortage levels. An economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. This will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants. Therefore, we strongly recommend that MISO upgrade its ORDC to improve the efficiency of its shortage pricing.

Evaluation of Actual Pricing of Operating Reserve Shortages

In addition to evaluating the design of the ORDC, we assessed the shortage pricing results during operating reserve shortages in MISO in 2019. Figure 11 provides our results comparing MISO's actual prices during shortages with the prices that would occur under the IMM Economic ORDC. We truncated the curve to highlight the part of the ORDC where shortages occurred in 2019.

Figure 11: Comparison of Actual Shortage Pricing to IMM ORDC Shortage Pricing
2019



In 2019, MISO experienced a total of 24 operating reserve shortages across 16 days. The figure shows that most of these shortages would have been priced much higher if the IMM ORDC were used, increasing the average shortage price by more than double. This indicates the value of transitioning to an ORDC that is more reflective of the true reliability costs of the shortages.

In addition, in nearly one quarter of these intervals, offline resource participation in ELMP artificially depressed the shortage prices by not allowing the ORDC to set the energy and operating reserve prices (when the yellow diamonds are below the black line. We continue to find that the offline ELMP methodology is artificially suppressing shortage pricing and, by doing so, adversely affecting the short and long-term decisions guided by these prices. Therefore, we continue to recommend that the offline ELMP pricing be disabled.

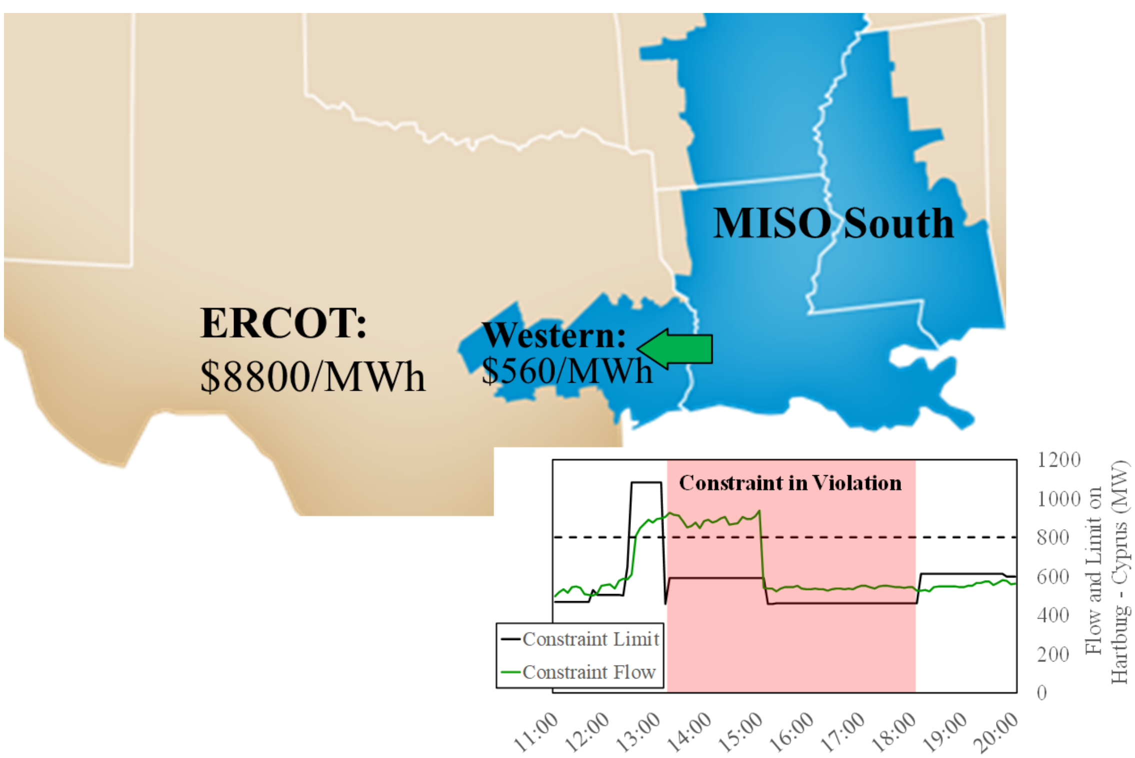
Case Study: Hot Weather and High Prices on August 12–16

Between August 12 and 16, ERCOT experienced a record peak load, multiple shortages, and extremely high prices. On two of those days, ERCOT declared an emergency (EEA1). On August 13, conditions were extremely tight in the MISO Western Load Pocket because of a transmission derate and a generator outage in the load pocket, which brought MISO to the edge of having to shed load in the area. Figure 12 depicts the conditions on this day.

Prices in ERCOT were $9,000 per MWh, and ERCOT requested a key unit in MISO's load pocket to switch out of MISO and into ERCOT. The VOLL in ERCOT is assumed to be $9,000 per MWh, although it was not close to shedding load at the levels of operating reserves that existed during these hours in ERCOT. In contrast, although MISO narrowly avoided shedding load in the pocket, the prices at the Texas Hub in the load pocket ranged from $500 to $800 per MWh. The prices in MISO were well below any reasonable estimate of VOLL and were, therefore, inefficient.

The relative prices in the two markets undermined reliability by creating strong incentives for resources to switch into ERCOT in the short run. In the long-run, failing to efficiently price the shortage that prevailed in MISO weakens incentives for participants to invest in new resources and maintain existing resources in this area. This underscores the importance of improving shortage pricing in MISO both market-wide and in local areas.

Figure 12: Conditions in ERCOT and MISO South (Western Load Pocket)
August 13, 2019



Achieving efficient shortage pricing in local areas, such as the Western Load Pocket, is the focus of a number of our recommendations in this report:

- Implement Short Term Reserves (STR) in the load pockets, which will allow the market to price local shortages like this one on August 13;
- Improving the assumed VOLL that would apply to all types of reserve shortages in MISO; and
- Defining local capacity zones based on constraints and local reliability requirements. This is not currently the case – all of the load pockets in Texas and Louisiana are grouped together in the same capacity zone, obscuring the value of resources in these areas.

E. Uplift Costs

Uplift costs are very important because they are costs that are difficult for customers to forecast and hedge, and they generally reveal areas where the market prices do not fully capture the system's requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments in real time to ensure resources cover their as-offered costs and, therefore, have incentives to be available and flexible:

- 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.
- Price Volatility Make Whole Payments ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

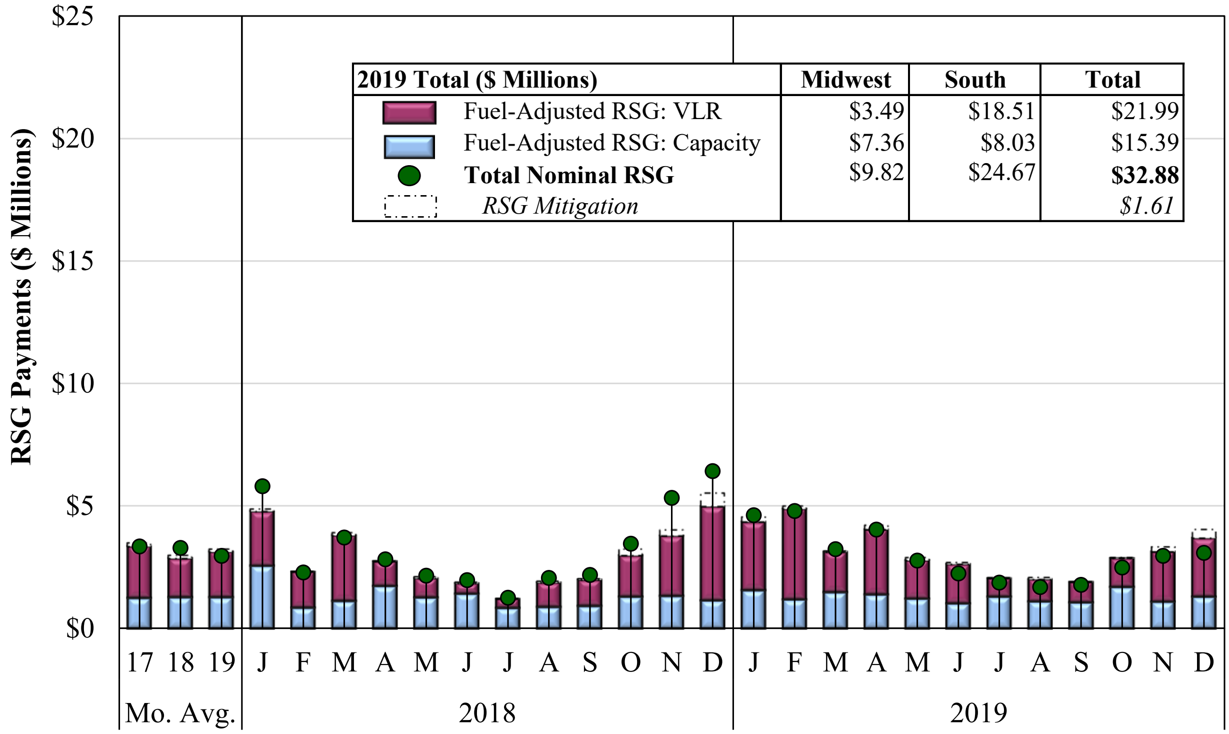
Resources committed before or in the day-ahead market receive a day-ahead RSG payment as needed to recover their costs. Resources committed by MISO after the day-ahead market receive a real-time RSG payment as needed to ensure they recover their as-offered costs. The day-ahead RSG costs for economic commitments are recovered on a pro-rata basis from all scheduled load. The real-time RSG costs are recovered via charges to participant actions 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 13 shows monthly day-ahead RSG payments by the underlying cause of the RSG. 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. Because fuel prices have considerable influence over suppliers' production costs, the figures show RSG payments in both nominal and fuel-adjusted terms.[15] The maroon bars show the RSG paid to units started for VLR before the day-ahead market. Nominal day-ahead RSG costs fell by 10 percent, however, on a fuel price adjusted basis RSG rose by 9 percent because natural gas prices were 20 percent lower in 2019 relative to 2018.

15 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are, therefore, greatest for periods when fuel prices were highest and vice versa.

Figure 13: Day-Ahead RSG Payments
2018–2019



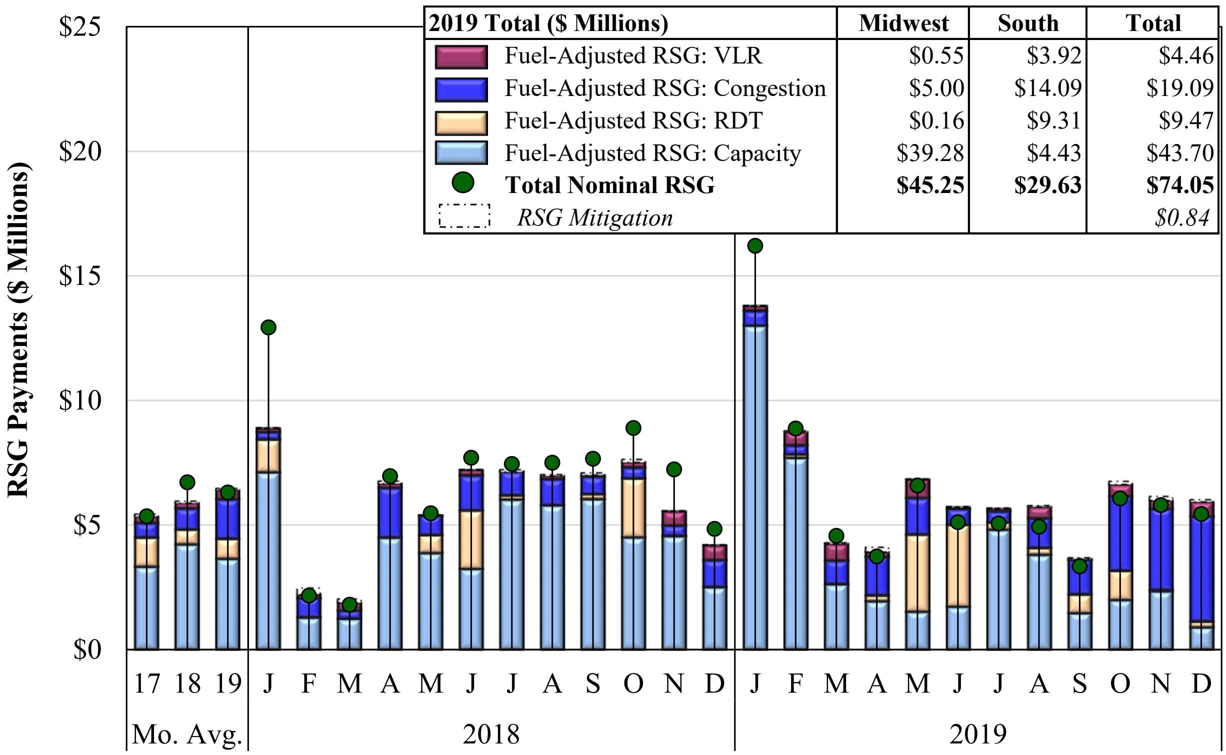
Almost all of the VLR costs are accumulated in two load pockets in MISO South. A Local Transmission Emergency in MISO South in June 2018 led MISO to create a new Operating Guide to manage a key constraint. This contributed to a significant increase in VLR-associated RSG in the winter months. In May 2019, a new gas-fired combined-cycle unit came online in MISO South that reduced the need for VLR commitments in that region. Nonetheless, 50 percent of all day-ahead RSG payments were caused by VLR needs in the South in 2019.

Figure 14 shows the comparable monthly RSG payments from the real-time market. This figure shows the same categories of RSG, although it also includes two categories of RSG that do not appear in the day-ahead RSG figure:

- Transmission congestion-related RSG: associated with units committed after the day-ahead market to manage flows on a constraint; and
- RDT related RSG: associated with units committed after the day-ahead market to manage flows on the RDT or to create regional reserves/headroom to be able to respond reliably to the largest contingency in the region without overloading the RDT.

This figure shows that nominal real-time RSG payments fell 6 percent in 2019, largely driven by lower fuel prices. Adjusting for changes in fuel prices, real-time RSG increased by 9 percent in 2019.

Figure 14: Real-Time RSG Payments
2018–2019



The increase in fuel-adjusted RSG costs were the result of several discrete events in 2019:

- Emergency events in the North and Central Regions in late January and early February contributed to a 66 percent increase in real-time RSG payments over this period in 2018.
- In May and June, MISO committed several resources for the RDT that resulted in more than $6 million in associated RSG.
- After a mid-May emergency in the South, MISO committed resources in the South for the RDT on a nearly daily basis through the end of the month.

Effects of Outage Studies on RSG. When transmission providers submit proposed outages, MISO conducts planning studies to determine whether the resulting outage impacts on system topology will require out-of-merit generation resources to be committed. These commitments can contribute to significant uplift payments and sustained divergence between the day-ahead and real-time prices. Between October and December 2019, we identified two cases where units were being committed for an extended period pursuant to the findings of an outage study. The conditions driving the results of the outage study subsequently changed, making it likely the commitments were no longer necessary. In total, the commitments that resulted from these studies generated almost $8 million in RSG payments. These cases raise two concerns:

1. These commitments were not made through the day-ahead market, which would have allowed the market to adjust other commitments and reduce the costs of satisfying the reliability concerns. Unfortunately, MISO does not currently have a process to allocate

transmission-related commitment costs through the day-ahead market. Hence, these commitments are generally made after the day-ahead market so they can be allocated as constraint-related commitments. We encourage MISO to develop a process to include transmission-related commitments in the day-ahead market.

2. MISO could revisit the results of outage studies more frequently, particularly when conditions change, to avoid incurring inefficient RSG costs. We encourage MISO to develop a process to do so, including monitoring the available resources that may address outage-related transmission constraints at lower costs than the resources identified in the outage studies.

Market Improvements that will Reduce RSG. We previously recommended that MISO implement a regional 30-minute reserve product (short-term reserves) to allow the markets to procure the resources needed to satisfy these regional requirements and the VLR requirements that result in substantial day-ahead RSG costs. In January 2020 FERC approved MISO's proposed short-term reserve product, and implementation is scheduled for December 2021.

In the meantime, MISO applied the Reserve Procurement Enhancement (RPE) to the RDT in August 2018 to satisfy the regional requirements with the 10-minute reserve capability.[16] This allows MISO's market commitments to better satisfy these needs. In the longer-term, pricing these local reserve requirements with the STR product will provide efficient incentives for participants to invest in fast-starting generation that is well-suited to satisfy the requirements.

Finally, we are recommending changes to the ramp assumptions used in ELMP to make it more effective, which will lower real-time RSG (see above for more detail).

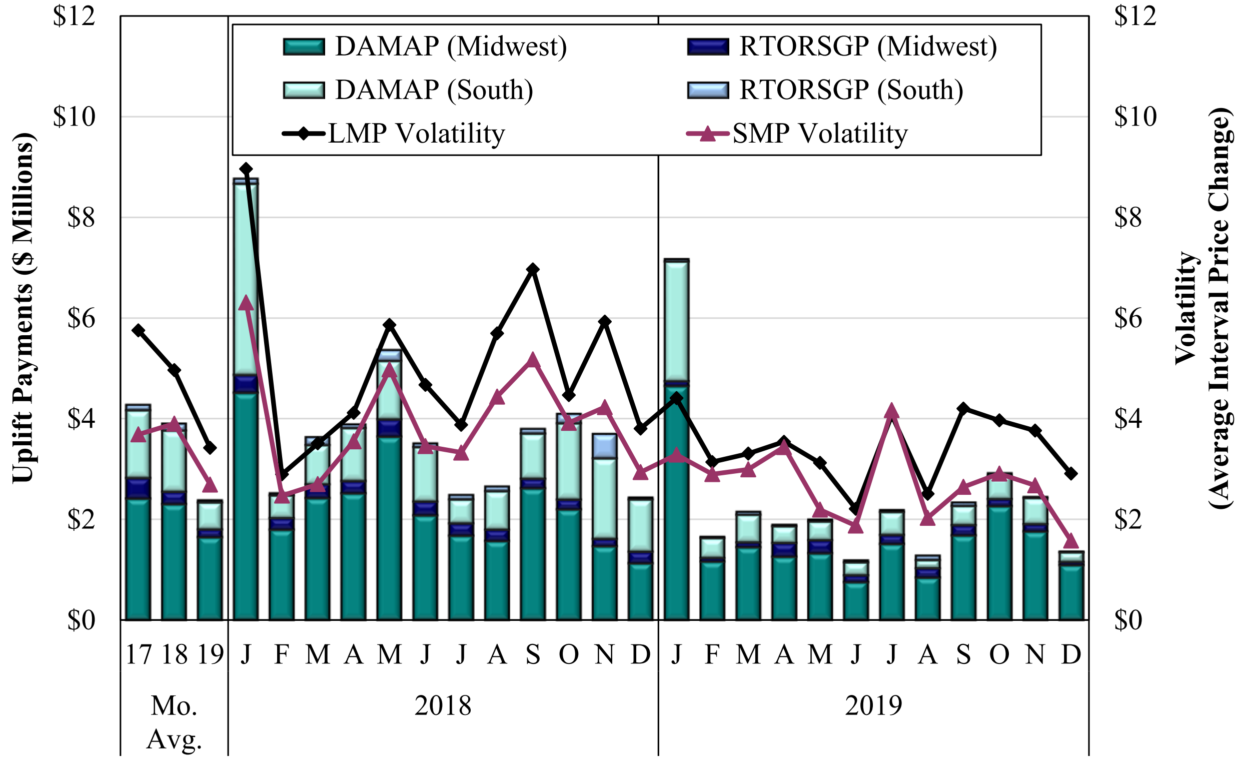
Price Volatility Make-Whole Payments

PVMWPs address the concerns that resources can be harmed when responding flexibly to volatile five-minute price signals. Hence, these payments provide suppliers the incentive to offer flexible physical parameters. These payments 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.

Figure 15 shows the monthly 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).

16 Short term reserves will satisfy this requirement after the December 2021 implementation of that product.

Figure 15: Price Volatility Make-Whole Payments
2018–2019



The highest DAMAP in 2019 occurred in January when emergency events and associated pricing resulted in DAMAP in the Midwest that exceeded $4.5 million. However, the figure shows that the overall PVMWP levels decreased by nearly 40 percent in 2019. Multiple factors contributed to this decrease, including the following changes in market conditions:

- LMP volatility dropped 31 percent in 2019 compared to 2018; and
- Fuel prices fell by 20 percent.

In addition, key improvements in the market rules we recommended also contributed to the reductions, resulting in year-over-year PVMWP declines in the summer and fall quarters by 50 and 30 percent, respectively. These improvements included:

- In May 2019, multiple settlement changes were implemented that contributed to the year-over-year reduction in PVMWP, including:
  - A new settlement rule that calculates PVMWP on a sliding scale to account for the generators' actual performance in following MISO's dispatch instruction;
  - Revised Uninstructed Deviation (UD) thresholds and settlement rules for Excessive (EXE) and Deficient Energy (DFE) that provide stronger incentives to follow setpoints; and
  - A recommended enhancement to MISO's regulation commitment process.

- In July 2018, MISO fixed a flaw that had resulted in unjustified DAMAP for wind units.

In prior *State of the Market Reports*, we expressed concerns that a large share of the DAMAP had been paid to units running at uneconomic output levels because they were not following dispatch instructions or because State Estimator model errors caused MISO to issue dispatch instructions that were less than optimal at some locations. MISO's May 2019 changes to the UD threshold and PVMWP settlements were responsive to our prior IMM recommendations and has resulted in a significant decrease in unjustified DAMAP payments. In particular, DAMAP payments to resources that were not following their dispatch instructions fell by 89 percent.

F. Regional Directional Transfer Flows and Regional Reliability

Since the integration of the South into MISO, the transfers between the South and Midwest have been constrained to adhere 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 at an average of 300 MW below its contractual limit. During the winter months in 2019, the RDT bound frequently in the South to North direction because of the cold weather in the Midwest Region. In other months, the flow frequently flowed from North to South, particularly during periods when a large quantity of resources were on outage in the South. 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.

MISO frequently commits resources out-of-market to maintain sufficient reserves in each subregion. These actions result in RSG and congestion management costs. To allow the market to satisfy these needs, we recommended that MISO introduce a 30-minute reserve product for each region. MISO filed the Short-Term Reserve product in October 2019, and FERC approved the filing in January 2020. Implementation is scheduled for December 2021.

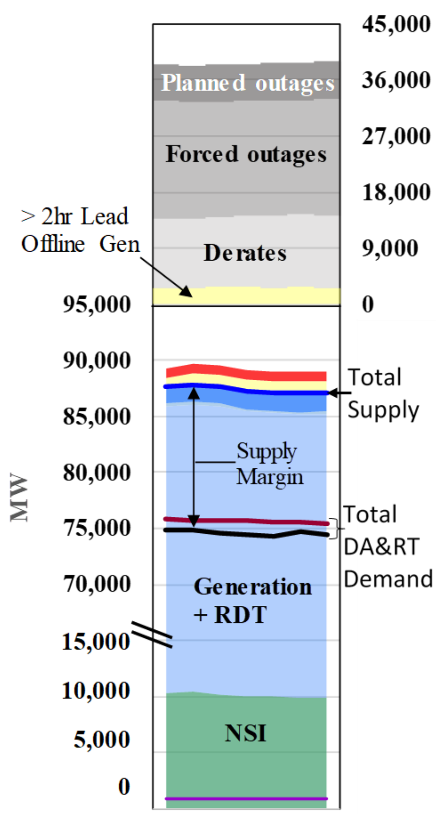
Importantly, limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties' systems is inefficient. To reduce these inefficient costs in managing the transfers with the RDT, we recommend that MISO allow SPP and the Joint Parties to sell operating reserves using the transmission capacity on the RDT above the RDT limit. MISO could then compensate SPP and the Joint Parties by paying them the clearing price for subregional reserves, as well as paying for the deployment of the reserved transmission (equal to the $500 per MWh RDT demand curve level times the deployment quantity).

Under this approach, SPP and the Joint Parties would have been compensated $3.25 million during the emergency events that occurred on January 17-18, 2018 when MISO substantially exceeded the RDT limit. This payment would provide reasonable compensation to SPP and the Joint Parties for the excess transfers that may occur under emergency conditions.

G. Detailed Review of Emergency Events

Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. Much of this increase is attributable to a narrowing reserve margin and impacts of the market's evolving generation mix. Investments in gas-fired resources, renewable resources, and Load Modifying Resources (LMRs) have replaced much of the energy lost because of retirements of coal and nuclear baseload resources. Increased intermittent output and its associated fluctuations, along with increased reliance on LMRs that can only be deployed during emergencies, has resulted in more frequent emergency events. These events are important to evaluate because they reveal how well the market performs under stress, and this helps inform improvements in both market design and operations.

MISO declared two regional emergencies in 2019 and chose not to declare an emergency on another occasion despite it meeting the criteria for one. MISO scheduled LMRs four times between January and May,[17] and two of the LMR deployments were scheduled in advance of declaring an emergency to access resources limited by long notification times.[18] MISO did not take more extensive emergency actions, such as scheduling emergency imports.



Although each emergency had unique characteristics, the events reveal some continuing issues and opportunities for improvements. We utilize figures that show each component of the supply and demand so they can be analyzed. The illustration to the left shows each element included in the figures.

The total available supply is shown in the figure with a royal blue line and it is comprised of NSI (green area), online generation plus RDT capability into the area plus offline resources that can start in less than 30 minutes (light blue area), online emergency generator ranges utilized (dark blue area), and emergency transactions (if any, they are shown in orange). The purple line at the bottom represents deployed LMR capacity, when relevant.

This total available supply can be compared to the total demand. Total demand is equal to the actual real-time load plus a regional reserve requirement based on the largest generator contingency. The figure includes this total

17 Three of the four LMR schedules were related to the same event.

18 Tariff changes that were accepted by FERC early in the year allow MISO to schedule LMRs in advance of anticipated emergencies in order to access the LMRs with long notification times.

demand (black line), the day-ahead forecast of total demand (maroon line), and the two-hour demand forecast when relevant (not shown). The supply margin can be determined at any point in time as the difference between total demand (the black line) and the total available supply (the royal blue line). MISO experiences a capacity deficiency when the black line crosses above the royal blue line, which will result in MISO exceeding the RDT scheduling limit when the largest contingency occurs in the North or South.[19]

The figure also shows supply components that are *not* available to the real-time market (above the royal blue line). This supply includes offline generators with modest start times (< 2 hours and > 30 minutes), shown by the yellow area, and offline emergency generation (Available Maximum Emergency – AME) shown by the red area. The top panel of the figure shows other unavailable generation, including offline generation with long lead times (> 2 hours) shown in yellow, as well as planned outages, forced outages, and derates (shown in shades of gray).

January 30–31, 2019: Emergency Conditions in the Midwest

In late January 2019, MISO declared Cold Weather Alerts for January 29 through February 1 because of extremely low temperatures throughout the Midwest region. On January 30, MISO issued a Maximum Generation Event in the North and Central Regions because the unusually cold weather resulted in a) a sharp decline in wind output relative to the day-ahead forecast, b) issues with transmission elements (circuit breakers) impacted by arctic conditions, and c) uncertainty regarding forced outages that may result from the cold temperatures. Figure 16 below illustrates conditions in the Midwest on January 30, 2019.

Emergency Actions on January 30. In the early morning hours of January 30, MISO declared an Energy Emergency Alert (EEA) Level 1 beginning at 5:00 a.m., allowing MISO to access emergency generation. By 6:19 a.m. the forecasted load indicated that MISO would be facing a tight supply margin during the morning ramp hours, so MISO elevated the Emergency to an EEA 2 beginning at 8:00 a.m.

The EEA 2 provided MISO access to approximately 2.5 GW of LMRs in the North and Central Regions. An additional 1,500 MW of LMRs voluntarily curtailed, with the net result that the actual load was significantly under the forecasted value. This was the first time that MISO deployed LMRs in the Central and North Regions. On average, the 184 deployed LMRs provided 75 percent of the scheduled MW reductions.

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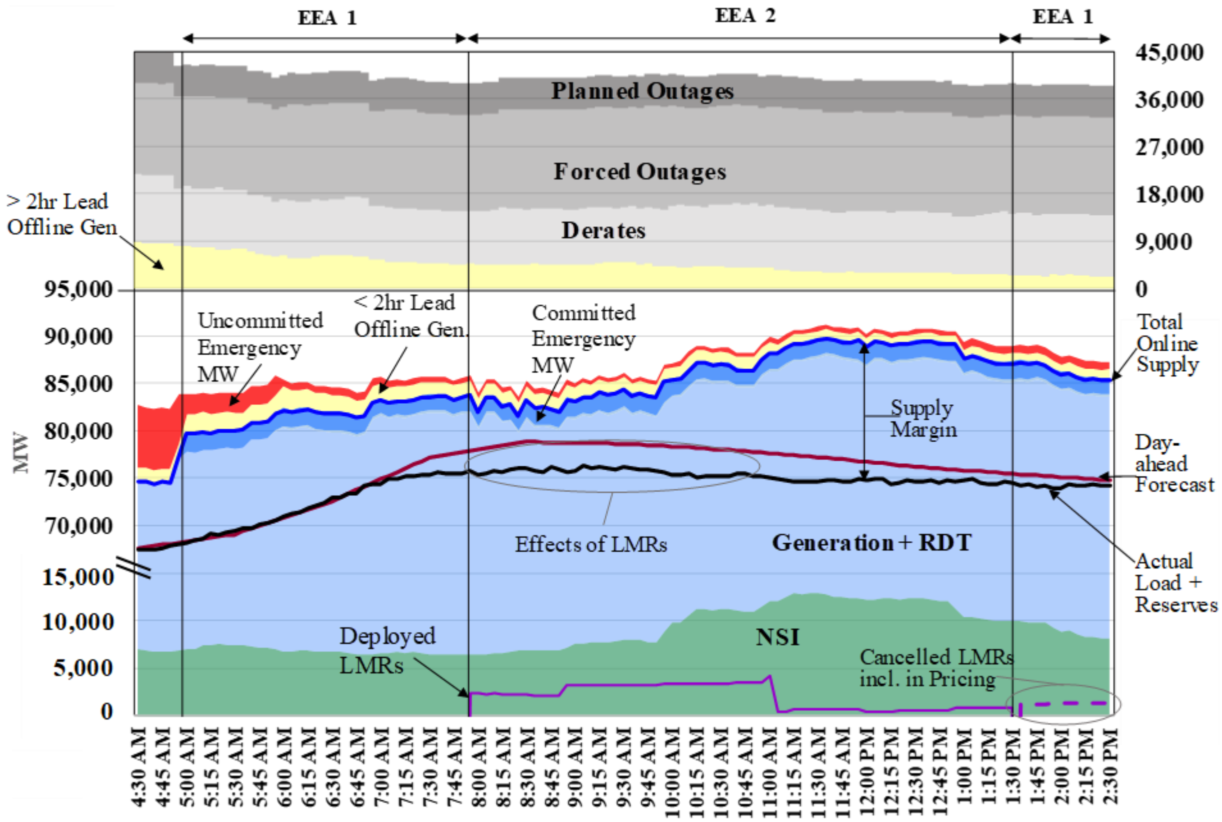
19 Under the RDT agreement, MISO is required to schedule transfers within limits (nominally 3000 MW from North to South and 2500 MW from the South to the North) within 30 minutes following a contingency.

Figure 16: Emergency Conditions in MISO Midwest
January 30, 2019



The figure shows that supply was more than adequate, although the margin would have been relatively tight in the morning hours without the emergency generation that MISO committed. Although MISO would not have been short of supply, the extreme weather led to heightened forced outage concerns that justify MISO's emergency declaration. By noon time, net imports had increased by roughly 8 GW from the day-ahead schedules, largely because of higher prices produced by MISO's emergency pricing discussed below, leading MISO to cancel all but 1 GW of the LMRs at 11 a.m. Given the 15 GW supply margin at that point, MISO could have downgraded the emergency at that point and canceled all of the LMRs.

Emergency Actions on January 31. Later in the day on January 30, MISO started or extended 198 units totaling 13.3 GW through noon the following day and extended the EEA1 emergency status. These actions were taken, in part, over concerns that some resources might fail to restart if they shut down. As a result, the supply margins the following day were large, averaging more than 6.5 GW in the morning hours, and generating more than $8 million in RSG.

Emergency Pricing during the Event. Although MISO never approached a capacity deficiency during this event, the emergency pricing produced relatively high prices as shown in Figure 17. On January 30, the default emergency offer floor was set above $600 per MWh. The emergency MWs frequently set ELMP prices between 8 a.m. and 11 a.m. for the reasons discussed below.

When emergency resources are deployed, generators must ramp down to accommodate the influx of emergency power and maintain the energy balance. For pricing purposes, MISO's ELMP models emergency output as dispatchable with an offer price set in accordance with the emergency offer floor prices (Tier I or II). The ELMP model determines whether the emergency output is economic by ramping up lower-cost non-emergency resources. Because the total emergency output (including LMRs) was so large on that day, the ELMP model generally lacked the ramp capability to displace the emergency resources within a five-minute market interval. Hence, the default emergency offer set prices consistently above $600 per MWh from 8 a.m. to 11 a.m. on January 30 even though the system would not have been deficient without the LMRs.

Figure 17: Emergency Pricing in MISO Midwest

January 30, 2019

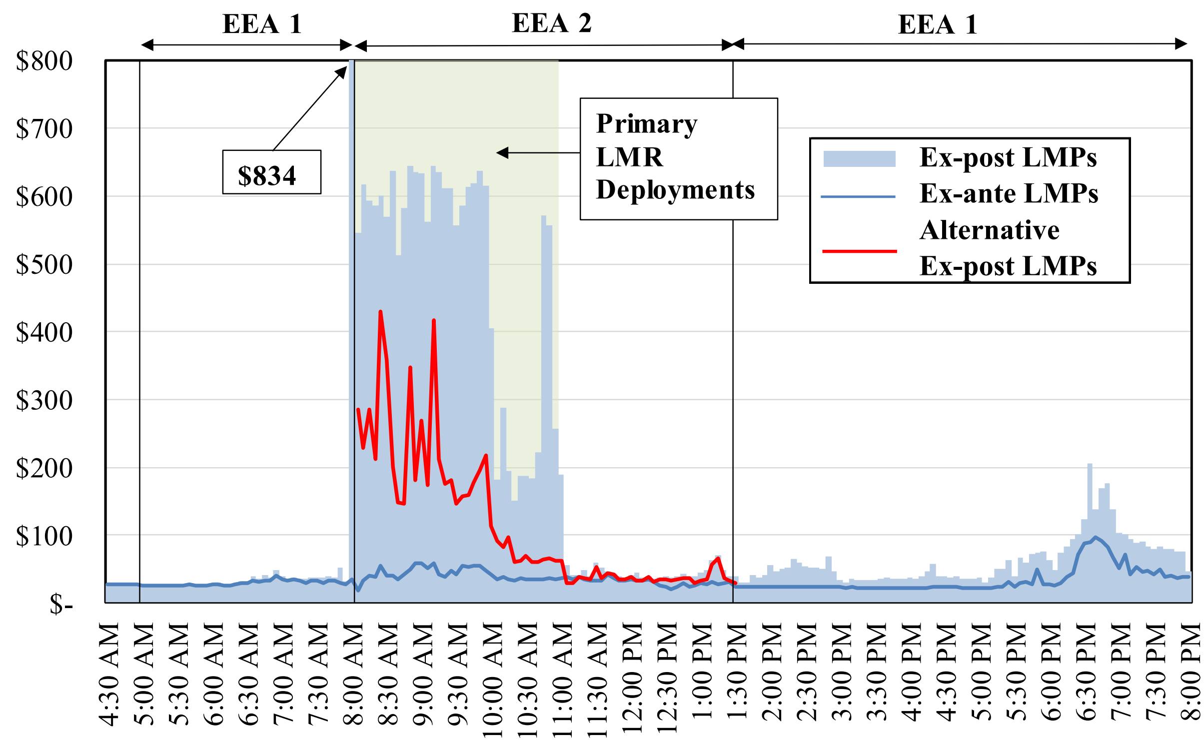


Figure 17 shows the prices that would have resulted if non-emergency resources were allowed more than five minutes of ramp capability to replace the emergency MWs in the ELMP model. This alternative series (shown by the red line) only allows emergency resources to set prices if they are truly needed to satisfy the system's demand. Our analysis shows that these more efficient prices during the event would have been 61 percent lower in the Midwest Region and 68 percent lower in the South Region across the EEA 2 event. The higher emergency pricing significantly lowered RSG and raised PVMWPs, resulting in a net make-whole payment increase of $3 million. We have recommended that MISO evaluate the ramp assumptions in ELMP, which could rationalize pricing in these types of events.

May 16, 2019: Emergency Event and LMR Deployments in MISO South

In February 2019, FERC accepted changes to MISO's Tariff allowing MISO to schedule long-notification LMRs in advance of an anticipated emergency. MISO exercised this option in mid-May because it believed the conditions for the following day's peak indicated a potential shortage. Late in the evening of May 15, MISO declared a Maximum Generation Alert for MISO South for the peak hours of the following day and scheduled more than 400 MW of long-lead LMRs. The risk in this type of regional emergency is that MISO will not be able to respond within 30 minutes if the largest unit is lost, causing MISO to violate the RDT contract limit. Conditions on that day are shown in Figure 18 below.

Figure 18: Maximum Generation Emergency in MISO South

May 16, 2019

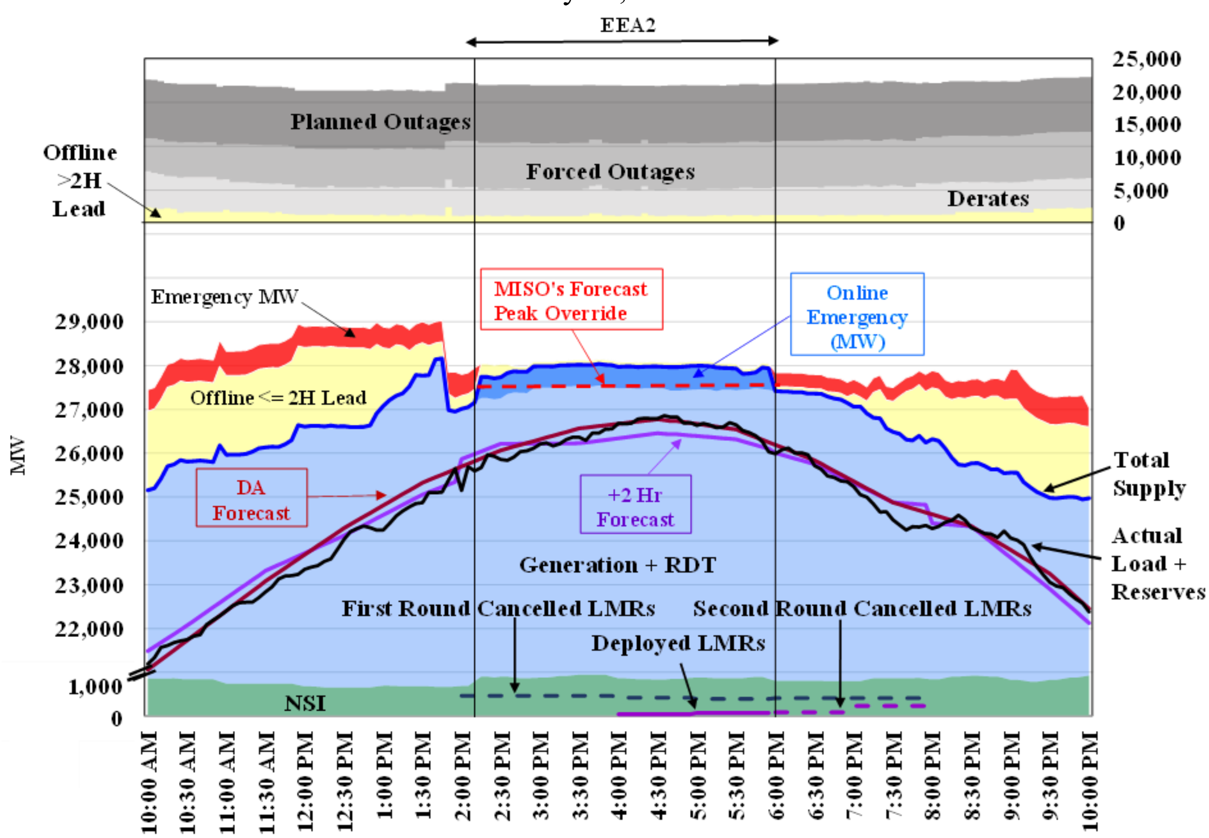


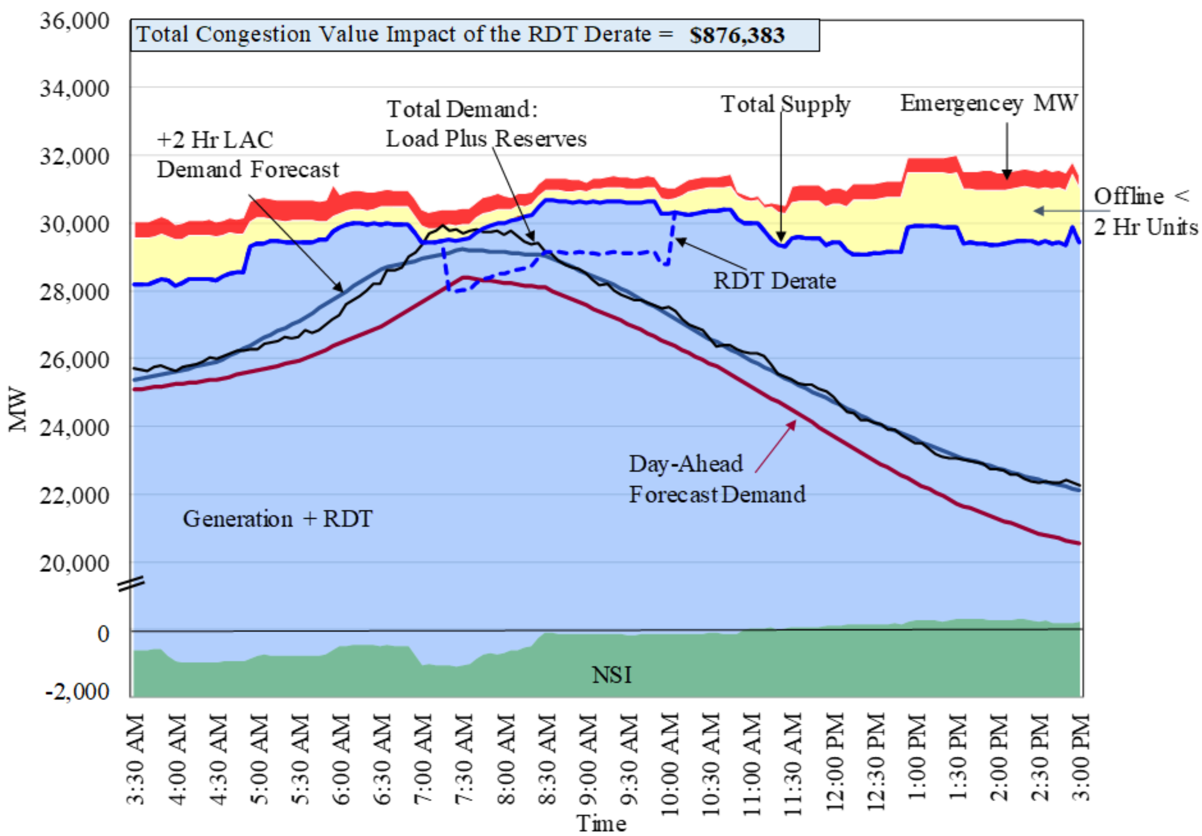
Figure 18 shows that up until 1:30 p.m., MISO had more than enough supply to satisfy the system's demand, exhibiting a surplus of roughly 3 GW. Hence, MISO cancelled the LMRs. However, at 1:44 p.m. the largest online unit in the South tripped offline and MISO declared an Emergency Event Step 2a (EEA2), scheduling a much smaller amount of LMRs because of the LMRs' notification times. In retrospect, this decision was curious because it was still forecasting a surplus of more than 600 MW in the peak hour without the emergency resources it called upon or the LMRs that were curtailed. MISO's perception of an emergency occurred because the operator entered an override to the load forecast, increasing the forecast by more than 1,000 MW (indicated by the red dotted line in Figure 18). The override resulted in an apparent capacity deficiency that prompted the emergency. Additionally, MISO miscalculated its reserve needs by assuming it must prepare for a contingency that was 40 percent larger than the largest online unit. Finally, MISO's capacity assumptions over-counted the loss of a unit that was in testing at the time, counting the full unit capacity as lost, as opposed to a smaller component that had been online. In total, these factors indicate that the emergency called in this case was not warranted.

Additionally, just after midnight, MISO called for LMRs to curtail on May 17 from 2 p.m. to 7 p.m., which it subsequently cancelled. Like May 16, it did not appear that LMRs would be needed on May 17. In all, MISO called LMRs 3 times on these two days, using 60 percent of the 5 calls they can make for the entire planning year, while no curtailments were needed.

Cold Temperatures and Tight Conditions on November 13

On November 13, record cold temperatures impacted much of the Southeast, creating challenging operating conditions in MISO South and neighboring areas. Temperatures in Little Rock, AR fell to 18 degrees Fahrenheit, almost 30 degrees below the historical average low temperature on that day, and MISO set a record high load for November. Figure 19 below shows conditions in MISO South on that day.

Figure 19: Conditions in MISO South
November 13, 2019



As 7:00 a.m. approached, forecasts were indicating that the margin in the South was small enough that an emergency declaration was warranted. The supply margin declined further as exports were scheduled from MISO South to support neighboring areas, including exports as high as 1,000 MW into Southern Company. This caused MISO to go into a shortage at roughly 7:00 a.m., such that it would not be able to withstand the largest contingency without violating the RDT (shown in the figure where the black demand line crosses the royal blue total supply line).

At 7:10 a.m., conditions deteriorated when SPP requested that MISO derate the RDT from 3,000 MW to 1,500 MW until 10 a.m. in order to reduce flows on multiple violated SPP constraints. The derate resulted in the RDT actually being violated and binding at $500 per MWh for 30 minutes, which increased MISO congestion costs by more than $800,000. This was a very poor outcome because:

- Derating the RDT was costly and not an efficient or effective means to provide congestion relief to SPP;
- Similar to prior events, the constraints in SPP that caused the call for the RDT derate were not visible to MISO nor were they communicated to MISO in a timely manner;
- MISO failed to declare an emergency as it is called for in its procedures, which would have provided effective relief.

We have discussed these findings with MISO and continue to provide input on potential improvements to its emergency procedures. We also continue to discuss improvements in RDT operations with MISO, including increasing MISO's visibility on SPP constraints and utilizing other coordination methods to provide more economic relief on SPP's constraints rather than modifying the limits on the RDT.

Accessibility of Emergency Resources

Emergency-only resources are mainly LMRs but are also EDRs and internal generators that are only available during a declared emergency (Available Maximum Emergency or "AME"). While not required to submit economic offers, LMRs are required to submit their availability to the Market Communication System (MCS), which may be substantially less than the quantity of capacity they cleared in the PRA. This becomes the basis for deployment during emergencies.

AME resources are only available after an EEA 1 has been declared, and they may have long notification times that prevent MISO from utilizing them. LMRs are only obligated to curtail load up to five times per year. Prior to February 2019, LMRs only needed to be available during the summer months, and MISO could only call on them during a declared emergency – a Maximum Generation Event Level 2b or higher. This made LMRs accessible only after all other conventional resources had been utilized in emergencies.

In February 2019, FERC approved MISO's Tariff revisions that expanded MISO's access to LMRs.[20] LMRs are now required to provide MISO with their best availability in all seasons, with the requirement that they are still fully available throughout the summer. MISO may also schedule LMRs in anticipation of an emergency event to access longer-lead resources, but curtailment is still only required if the emergency event is actually declared two hours prior to their scheduled deployment. In May 2020, MISO filed Tariff changes that would fully accredit LMRs with registered lead times under 6 hours and that provide curtailments at least ten times per year. LMRs registering longer notification times and fewer curtailments receive progressively lower accreditation values.[21]

Until MISO is able to implement the changes proposed in May 2020, we are concerned that emergency-only resources are not comparable to other resources in satisfying MISO's reliability needs. Table 7 below quantifies the amount of LMR and emergency-only generation that would have been available based on:

- the 2020/2021 LMR cleared capacity and current registered notification times; and
- the amount of time between MISO's emergency declaration and when the resources were needed.

For AME resources, we determined the actual amount of AME that was available for the events based on notification times because generators may choose to offer as AME at any time. AME quantities tend to be small during peak hours and are much larger during off-peak hours.

Table 7 shows that the lead times vary significantly and that MISO frequently declares emergencies less than 15 minutes prior to the beginning of the emergencies when conditions are generally the tightest. During these events, only 11 percent of LMRs and 20 percent of AME resources were available to help resolve the emergency. These short lead times are not surprising because emergencies tend to occur when there are multiple concurrent contingencies and/or higher than expected load that is not foreseen far in advance. For this reason, emergency resources with longer notification times provide much less value in most emergency events. Additionally, DR resources with long notification times generally must continue to be served along with other firm load.

20 See "Order Accepting Tariff Revisions, Subject to Condition, and Granting Waiver," issued February 19, 2019, under Docket No. ER19-650-000.

21 Docket No. ER20-1852-000. For the 2022/23 Planning Year, resources with notification times from 6 to 12 hours are eligible for a 50% credit for a year provided they permit 10 calls; starting in PY2023/24 resources with notification times > 6 hours are ineligible for capacity credits. For resources with < 6 hour notification times, BTMG resources remain eligible for full credit, but LMR resources offering between 5 and 10 calls per year receive 80 percent credit starting in PY2022/23.

Table 7: Availability of Emergency Resources during Events
2020/2021 Planning Resource Auction Results

Event	Lead Time to Event	Available Capacity (MW) LMR-DR**	LMR-BTMG**	AME***
April 4, 2017	Less than 15 Minutes	356.8	980.3	695.0
January 17, 2018	1.5 - 2 Hours	4,403.6	3,047.0	1,648.8
September 15, 2018	Less than 15 Minutes	356.8	980.3	143.0
January 30, 2019	1 - 1.5 Hours	1,624.6	1,547.9	521.0
May 16, 2019				
Advance Schedule *	12 + Hours	7,557.4	4,444.9	N/A
Second Emergency	Less than 15 Minutes	356.8	980.3	80.0
May 17, 2019 *	12 + Hours	7,557.4	4,444.9	N/A
Total Cleared Capacity		**7,557.4**	**4,444.9**	**N/A**

* Pre-Scheduled LMRs were cancelled in advance of event, no response required. Pre-scheduling of LMRs in advance of emergency declarations began after February 19, 2019 (Docket No. ER19-650-000).
** LMR Capacity determined from PRA 2020/21 results and registered lead times.
*** AME is actual energy available as Emergency Resources within lead time on date of event.

The other events were called between 90 minutes and 2 hours prior to the emergency, which allowed MISO much greater access to the emergency resources. Based upon current registration data, 62 percent of all emergency resources that cleared MISO's 2020/2021 PRA are expected to be available within 2 hours, up from 39 percent two years ago. This increase is attributable to MISO's 2019 Tariff changes that now require LMRs to provide documentation to support longer notification times. Even with this improvement, however, access to emergency-only resources remains a concern given MISO's reliance on them to meet its resource adequacy needs.

Finally, procuring capacity from long-notification emergency resources tends to degrade reliability because the resources receive capacity credit for the curtailment quantity plus transmission losses and, for some LSEs, credit toward their PRMR. Providing a capacity credit that exceeds the curtailment quantity is only reasonable if the RTO is confident that it will not have to serve this load during emergencies. The long notification times offered by many of these resources invalidate this assumption. Therefore, we continue to encourage MISO to improve its capacity accreditation rules under Module E to reflect the diminished reliability provided by emergency-only resources.

H. Generator Dispatch Performance

MISO issues energy dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. The performance of MISO's generators is essential to efficiently managing congestion and maintaining reliability in MISO. Therefore, it is very important that MISO's markets provide adequate incentives for its generators to perform well in following MISO's dispatch instructions. We evaluate and discuss generator performance in this subsection.

MISO had previously assessed penalties for deviations from this instruction when deviations remained outside of an eight percent tolerance band for four or more consecutive five-minute intervals within an hour. In May 2019, MISO altered the uninstructed deviation (UD) threshold calculations from an output-based tolerance to a tolerance calculated as a function of the offered ramp rate.[22] The purpose of the tolerance threshold is to permit deviations to balance the physical limitations of generators with MISO's need for units to follow dispatch instructions. This was in response to recommendations that we made in previous *State of the Market Reports* for MISO to:

- Improve the tolerance bands for UD (i.e., deficient energy and excessive energy) to better identify units that are not following dispatch; and
- Modify the PVMWP rules to adjust the payment based on the generators' performance.

Additionally, MISO implemented a procedure in early 2018 to receive real-time alerts from the IMM that identify resources that are not following dispatch. This allows MISO to contact the generator and place it off-control when warranted. We are continuing to work with MISO to develop improved internal procedures to detect unreported derates or operational issues not reflected in resource offers, and to facilitate timely offer updates by market participants. MISO's real-time operators are also responsible for identifying resources that are performing poorly.

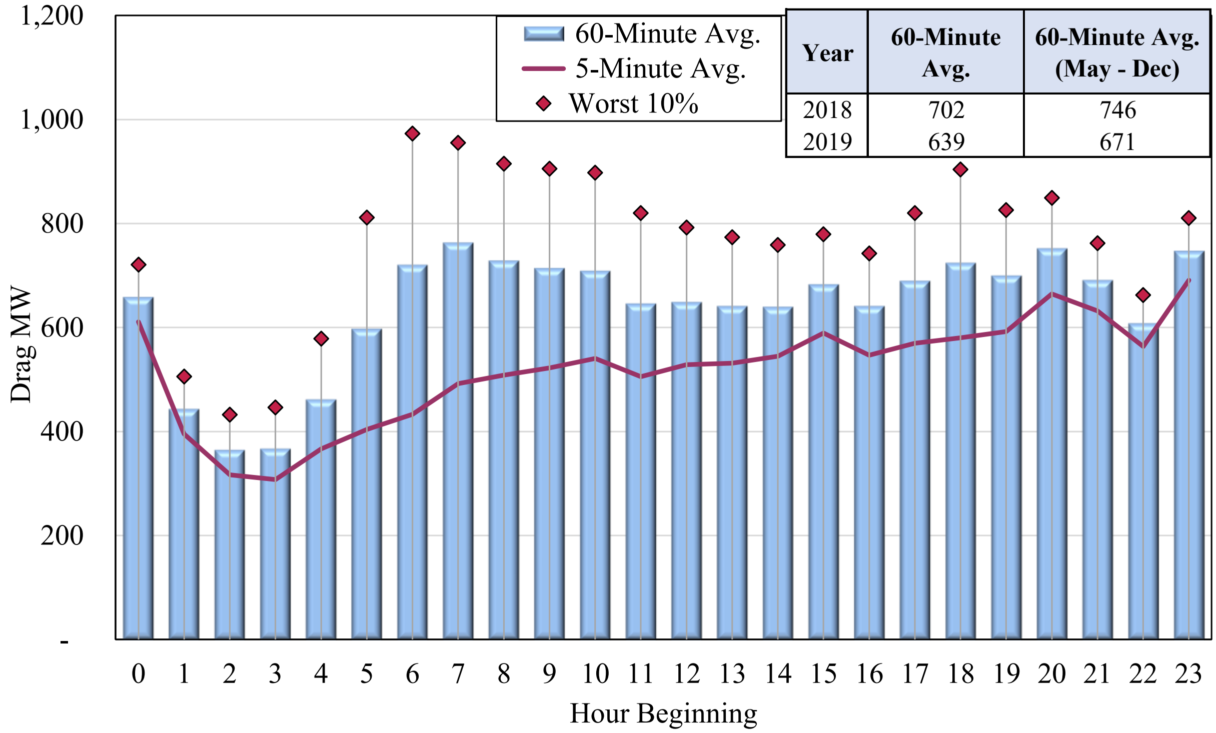
Together, these changes have significantly improved the performance of MISO's generators. We summarize this performance in the Figure 20. This figure shows the average sixty-minute and five-minute average hourly dragging in 2019. The blue bars represent the average 60-minute dragging, and the red line represents the five-minute average dragging. The diamonds represent the worst 10 percent of dragging for each hour. The inset table indicates the average hourly dragging values in 2018 and 2019, as well as the period from May through December that indicates the improvement attributable to the updated UD thresholds and PVMWP formulations.

Figure 20 shows the average 60-minute dragging amount is highest in the morning ramp-up hours and during the evening ramp-down period. Dragging is high in the morning ramp hours because generators are asked to ramp up consistently as load rises. Dragging is high in the evening hours because online generators are asked to ramp up as other generators are going offline or as load is rising during the evening peak in the winter season.

The figure shows that the 60-minute dragging fell roughly 10 percent in 2019, but it continues to raise substantial concerns because much of this capacity is effectively unavailable to MISO since the resources are not following the dispatch instructions. Almost 20 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because it indicates that MISO is not perceiving this effective loss of capacity and, therefore, may not be making commitments that are economic or needed for reliability.

22 Docket No. ER19-199-000.

Figure 20: Average Five-Minute and Sixty-Minute Net Dragging
2018–2019



Year	60-Minute Avg.	60-Minute Avg. (May - Dec)
2018	702	746
2019	639	671

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 there is not physical cause for the derating. We have identified such cases, and MISO has imposed physical withholding sanctions.

These findings indicate the importance of continuing to seek means to improve:

- Generator performance in following dispatch instructions; and
- The timeliness of suppliers' updates to their real-time offers, which should indicate their resources' true capabilities.

Dispatch Operations: Offset Parameter

The offset parameter is a quantity chosen by the MISO real-time operators to adjust the load to be served by the UDS. A positive offset value is added to the short-term load forecast to increase the generation dispatched, while a negative offset decreases the load and the corresponding dispatched generation. 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 are associated with increased 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 that in the five percent of hours with the largest changes in offset values:

- Decreases in offset values by 600 MW or more correspond to decreases in SMP of more than $39; and
- Increases in offset values of greater than 600 MW correspond to SMP increases of $90.

We monitor offset values because large changes, although infrequent, can sometimes contribute to price spikes or mute legitimate shortage pricing. MISO has a project scheduled for deployment in 2020 to improve the offset determinations. We encourage MISO to continue its efforts to further automate offset decision-making and to substantially improve the logging of the offset choices.

I. Wind Generation

Installed wind capacity now exceeds 22 GW and accounted for 9 percent of generation in 2019. In 2019, 2 GW of wind capacity entered MISO and we expect development to continue. Although wind generation promises substantial environmental benefits, its output is intermittent and presents operational challenges. These challenges are amplified as wind's share of total output increases.

Day-Ahead and Real-Time Wind Generation

Figure 21 shows the average monthly wind output scheduled in the day-ahead market compared to the actual real-time wind output. It also shows the amount of virtual supply scheduled on average at wind locations and at the Minnesota hub, which is close to many of MISO's wind resources. In prior years, the virtual supply tended to compensate for under-scheduling by wind suppliers in the day-ahead market, but this response has not been as large recently.

Average real-time wind generation in MISO increased more than 10 percent in 2019 to 6.4 GW. MISO set several all-time wind records in 2019, peaking for the year on December 30 at 16.9 GW. MISO's electricity produced from wind resources continued to increase in early 2020 and set multiple records into 2020, most recently at 18.1 GW on April 9, 2020. Output increases in 2019 were most significant in Spring (22 percent higher) and Fall (25 percent higher). We expect this trend to continue as more wind resources are added to the system. The figure shows that wind output is substantially lower during summer months than during shoulder months, which makes it relativeley less valuable to the system in term of reliability.

Figure 21: Day-Ahead and Real-Time Wind Generation
2018–2019

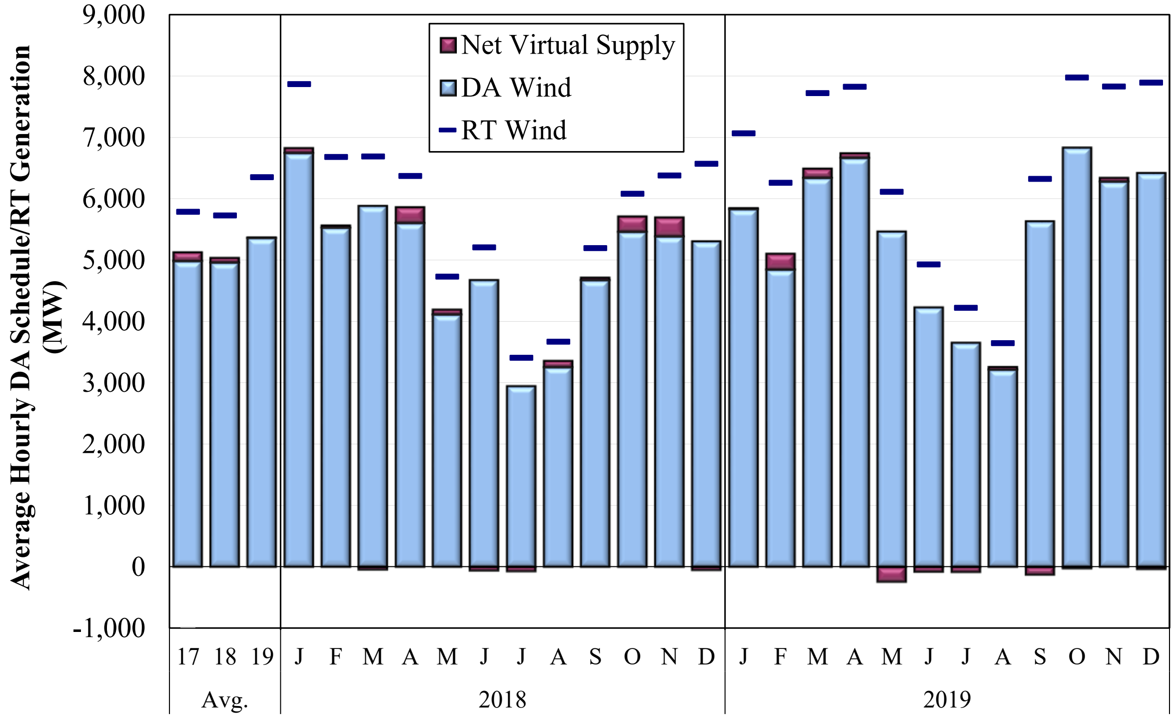


Figure 21 also shows that wind suppliers often schedule less output in the day-ahead market than they actually produce in real time. This can be attributed to some of the suppliers' contracts and the financial risk related to being allocated RSG costs when day-ahead wind output is over-forecasted. Underscheduling can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. This convergence issue is partially addressed by virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers. Under-scheduling of wind averaged roughly 1,000 MW per month.

As total wind capacity continues to grow, the operational challenges will grow related to output volatility and congestion that must be managed by MISO. Sharp reductions in output can lead to substantial price volatility and require MISO to make real-time commitments to replace lost output. MISO has been adapting its markets and processes to address these challenges, including the introduction of the ramp product in 2016. Improving shortage pricing will be an essential component of this evolution. In 2018, MISO began studying the potential implications of differing wind/solar penetration levels under the Renewable Integration Impact Assessment (RIIA).[23] Phase 1 and 2 of the RIIA wrapped up in November 2019. MISO concluded that if it exceeds 30 percent intermittent renewable generation, the additional renewable resources would present challenges to reliability if they are not addressed. Further studies continue into 2020, which focus on sensitivity analysis and revisiting key assumptions.

23 See documents at: https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment.

The concentration of the wind resources in the western areas of MISO's system has also 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 this volatility. DIR participation by wind resources provides MISO much more timely control over its wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions).

Wind Forecasting

As intermittent wind generation grows, the importance of the near-term forecasts of wind output grows. The wind forecasts are important because MISO uses them to establish wind resources' economic maximum in the real-time energy market. Because wind resources offer at prices lower than any other resources, the forecasted output also typically matches the MISO dispatch instruction, absent congestion.

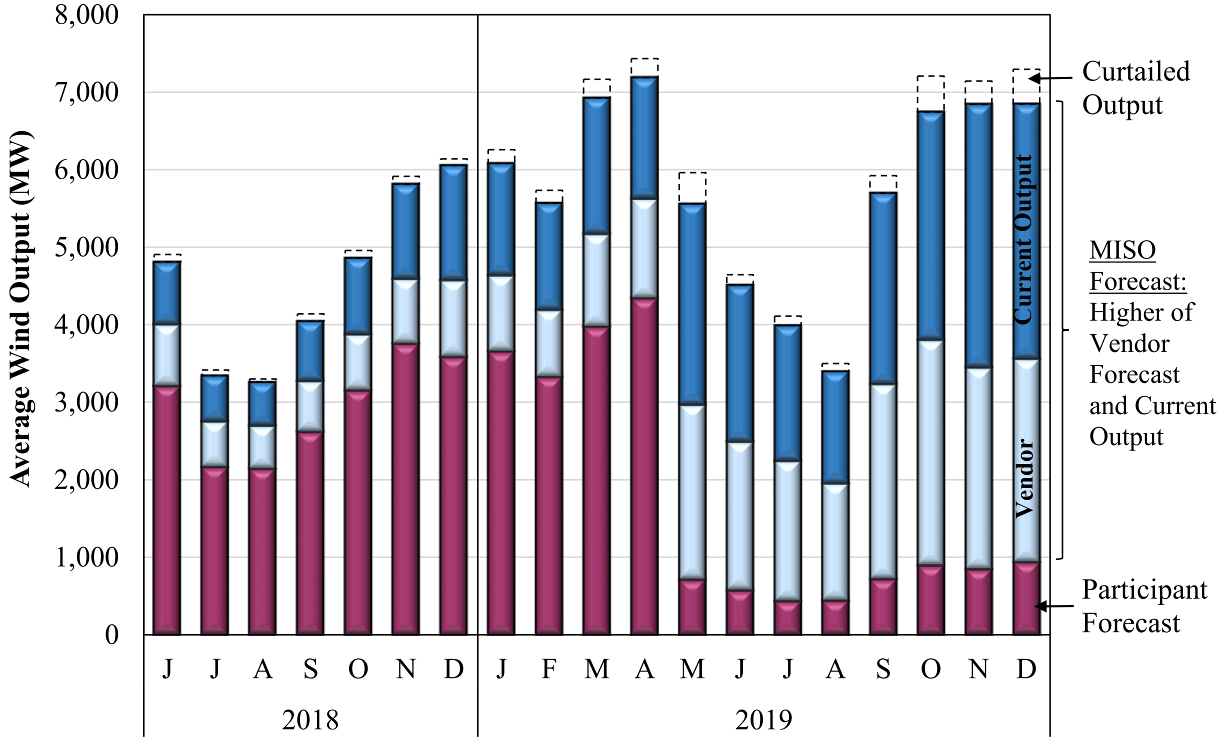
In 2017, we identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output in real time. Because an over-forecasted resource will produce less than the dispatch instruction, this will result in dispatch deviations. Our analysis of wind forecast errors in 2019 showed that:

- Wind resources in aggregate consistently over-forecast their output capability.
- In 2018, forecast errors averaged almost 200 MW in the real-time market.
- The implementation of recommended changes made in mid-2019 that are discussed below contributed to forecast errors dropping to less than 150 MW on average.

MISO implemented critical changes in May 2019 to its uninstructed deviation thresholds and PVMWP formulas that significantly improved its wind forecasting. The prior rules regarding uninstructed deviations created inefficient incentives for wind resources to over-forecast their output to avoid uninstructed deviations and associated penalties. These penalties potentially arise when a wind resource under-forecasts its output, MISO provides a dispatch instruction matching its forecast, then it produces more than the dispatch instruction because the wind is stronger than forecasted. One of the key changes MISO implemented was to relieve wind resources of the uninstructed deviation penalties for resources that use the MISO wind forecast.

The significance of this change is apparent in Figure 22 below that shows the average wind output, and the portion of the output that is forecasted by the participant versus MISO. This figure shows that when MISO's changes were implemented at the beginning of May, most resources stopped using their own forecasts and transitioned to using the MISO forecast, which is a composite forecast that is the higher of: its vendor forecast and the current output of the wind resource. This transition to the MISO forecast accounted for the significant improvement in the average wind forecasts reported above.

Figure 22: Generation Resource Switching to MISO Forecasts
2018–2019



As usage of the MISO forecast increased, MISO and its wind forecast vendor have made several improvements to improve the accuracy of their real-time projections. However, even though MISO's composite forecast was a significant improvement over the participant forecasts, we have raised concerns that its "higher of" methodology results in a biased forecast that distorts the MISO dispatch and its management of congestion. The average error produced by this methodology from August 1 to the end of 2019 was 106 MW. If MISO simply used either the vendor forecast or the current output as the forecast for its wind resources, this average error would have been between -1 and -2 percent. Hence, we recommended that MISO eliminate the higher of logic that was systematically over-forecasting the wind output.

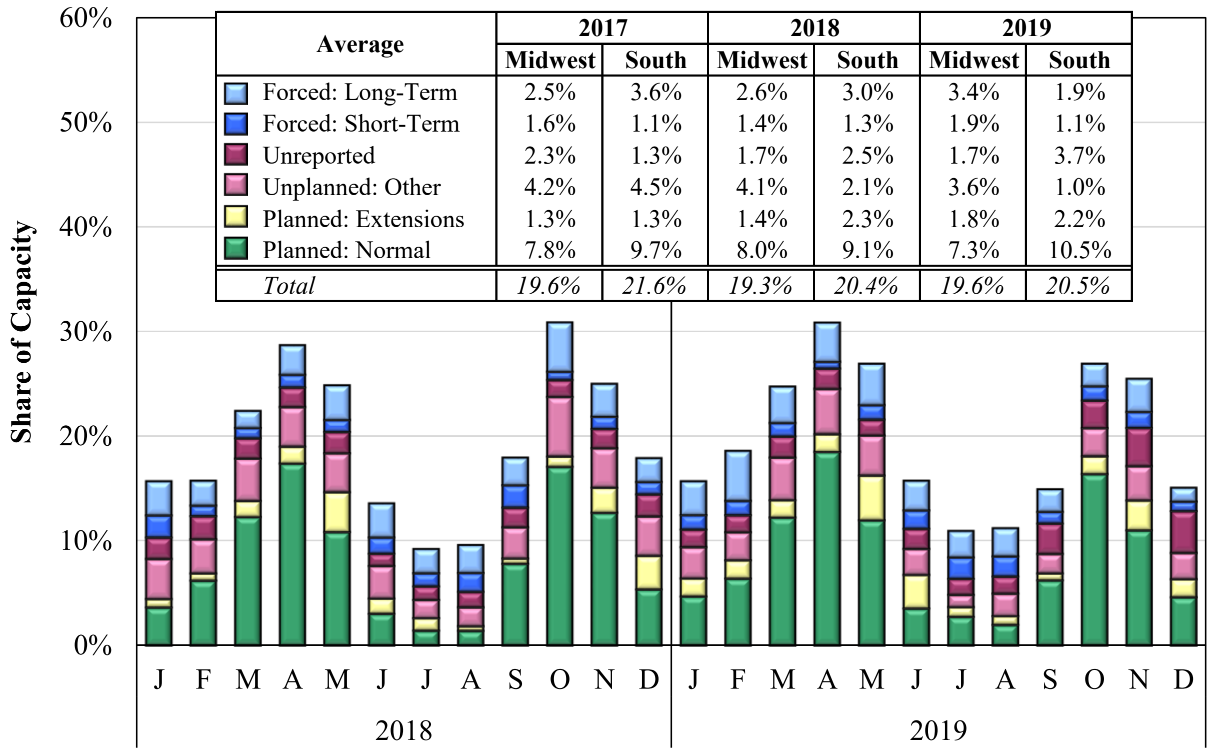
On February 3, 2020 MISO adopted this recommendation and eliminated the "higher-of" logic, which has significantly improved the wind forecasts. This was an excellent first step and we encourage MISO to evaluate a persistence-based forecast for the real-time dispatch period that could further improve its forecast accuracy.

Lastly, we are concerned that MISO allows wind resources to provide its ramp product. We recommend that MISO disqualify wind resources from providing the ramp product. Wind resources clear ramp capability only in the up direction when curtailed for congestion management. Deploying this capacity as energy in subsequent periods would contribute to reliability problems by overloading constraints and negate any benefit in meeting the market-wide generation demand.

J. Outage Scheduling

Proper coordination of planned outages is essential to ensure that enough capacity is available to meet load if contingencies or higher than expected load occurs. MISO approves all planned outages that do not violate reliability criteria but otherwise does not coordinate outages. This lack of coordination raises significant economic concerns and reliability risks. To evaluate the outages that occurred in 2019, Figure 23 shows MISO's available capacity, outages, peak load, and emergency conditions in MISO Midwest and MISO South.

Figure 23: MISO Outages
2018–2019



Average	2017		2018		2019	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	2.5%	3.6%	2.6%	3.0%	3.4%	1.9%
Forced: Short-Term	1.6%	1.1%	1.4%	1.3%	1.9%	1.1%
Unreported	2.3%	1.3%	1.7%	2.5%	1.7%	3.7%
Unplanned: Other	4.2%	4.5%	4.1%	2.1%	3.6%	1.0%
Planned: Extensions	1.3%	1.3%	1.4%	2.3%	1.8%	2.2%
Planned: Normal	7.8%	9.7%	8.0%	9.1%	7.3%	10.5%
Total	*19.6%*	*21.6%*	*19.3%*	*20.4%*	*19.6%*	*20.5%*

Outage rates in 2019 were comparable to 2018. In May and early June, planned outage extensions and forced outages, particularly in the South, contributed to multiple declarations of Conservative Operations, Maximum Generation Alerts, and Maximum Generation Events. As in prior years, true planned outages were low for most of the summer. Outages during the spring shoulder period were higher than last year, while fall outage rates were generally lower than last year.

In our 2016 SOM 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 designed to assist participants in coordinating planned outages based on forecasted capacity margins.

- Twice weekly, MISO posts the Maintenance Margin that contains historical actual outages and projected outages by date and region.
- In December 2019, MISO began posting a daily Multiday Operating Margin Forecast Report that indicates the system-wide anticipated capacity margin available during the projected peak hour for the following six days.

We have also recommended that MISO improve its capacity accreditation rules to improve suppliers' incentives to schedule outages efficiently and be available when needed. In 2017, MISO introduced the Resource Availability and Need (RAN) project to address these issues. In March 2019, FERC accepted MISO's Phase 1 proposed Tariff changes[24] that: (a) increase MISO's ability to call LMRs, and (b) modify capacity accreditation rules to deter generators from scheduling short-notice outages during tight conditions. They became effective April 1, 2019. The accreditation change will have very limited effects and we continue recommend more substantial accreditation changes that would provide much stronger incentives for generators to better plan and coordinate outages and to make resources available during tight conditions (see Section VI.G for more detail).

K. Conclusions

The operation of MISO's real-time market and associated real-time pricing is essential for achieving both the reliability and economic benefits that MISO provides to the region. This section of the report evaluates a wide array of real-time pricing and operational issues. Overall, we conclude that the MISO markets operated well in 2019, but this section also identifies a number of key improvements listed below.

- *Improve Shortage Pricing*: This report describes recommended changes to MISO's shortage pricing that would substantially improve generators' incentives to be available when needed and reward generators for flexibility. This is particularly important in MISO given the poor design of its capacity market because it will also improve longer-term incentives to invest in new resources when needed and maintain existing resources.
- *Eliminate Offline ELMP Pricing:* In order for MISO's pricing of operating reserve shortages and transmission shortages to be accurate, it must disable its offline ELMP pricing. Allowing resources that are not utilized to set prices when uncertain market conditions result in shortages prevents the MISO markets from providing efficient incentives to the flexible resources that MISO needs to manage the shortages.
- *Improve Emergency Floor Prices:* The emergency pricing rules that set the offer price floors based on a single supplier's offer can result in prices that are much higher or much lower than efficient levels. We recommend that MISO establish rules in the Tariff governing the calculation of the emergency offer floors that will ensure they are set at

24 Docket No. ER19-915-000.

efficient levels. MISO has indicated that addressing this recommendation is a high priority in the Integrated Roadmap process for 2020.

- *Fix Emergency Pricing Flaw*: We recommend that MISO correct the ELMP model to recognize the effects of emergency imports on the RDT flows. This is a less significant issue because it only affects prices during regional emergencies in which MISO has scheduled emergency imports.
- *Modify Ramp Constraints in ELMP*: We continue to recommend that MISO evaluate options for improving the ramp constraints in ELMP to ensure that it appropriately determines when emergency MWs and fast-start units are needed and should set prices. To date, MISO has not taken any action on this recommendation.
- *Engage Joint Parties in Managing Regional Emergencies*: The primary risk of regional capacity deficiencies is that MISO may exceed the RDT after a contingency occurs. When this would not cause significant reliability issues, the joint parties could sell operating reserves above the RDT limit and be compensated based on the regional short-term reserve prices. We recommend MISO pursue this with the Joint Parties.
- *Improve Regional Emergency Procedures and Declarations*: Emergency events have become more frequent beginning in 2017. The timing of MISO's emergency declarations has been inconsistent relative to the regional capacity margins (the difference between the regional supply and demand). MISO has been working with the IMM to clarify its operating procedures, tools, and criteria for declaring emergencies, and improve its logging of these determinations.
- *Actively Coordinate Outages*: We have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. In 2019, multiple simultaneous generation outages contributed to more than $150 million in real-time congestion costs – nearly 25 percent of real-time congestion costs. We recommend that MISO explore alternatives to improve 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.

V. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, MISO manages power flows over the network by setting resource dispatch levels that establish efficient, location-specific prices representing the marginal costs of serving load at each location. Transmission congestion arises when network constraints prevent MISO from fully dispatching the lowest-cost units, so higher-cost units must be dispatched in their place. This "out-of-merit" cost is reflected in the congestion component of MISO's locational prices.[25] The congestion component can vary widely across the system, raising LMPs in "congested" areas where generation relieves the constraints and lowering LMPs in areas where generation loads the constraints.

These congestion-related price signals are valuable not only because they induce generation resources to produce at levels that efficiently manage network congestion but also because they provide longer-term location-specific economic signals that facilitate efficient investment and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion in 2019

We calculate the value of real-time congestion by multiplying the physical flow over each constraint by the economic value of the constraint (i.e., the "shadow price", which is the production cost savings from relieving the constraint by one MW). This metric indicates the congestion that occurs as MISO dispatches its system. Figure 24 shows the monthly real-time congestion values in 2018 and 2019.

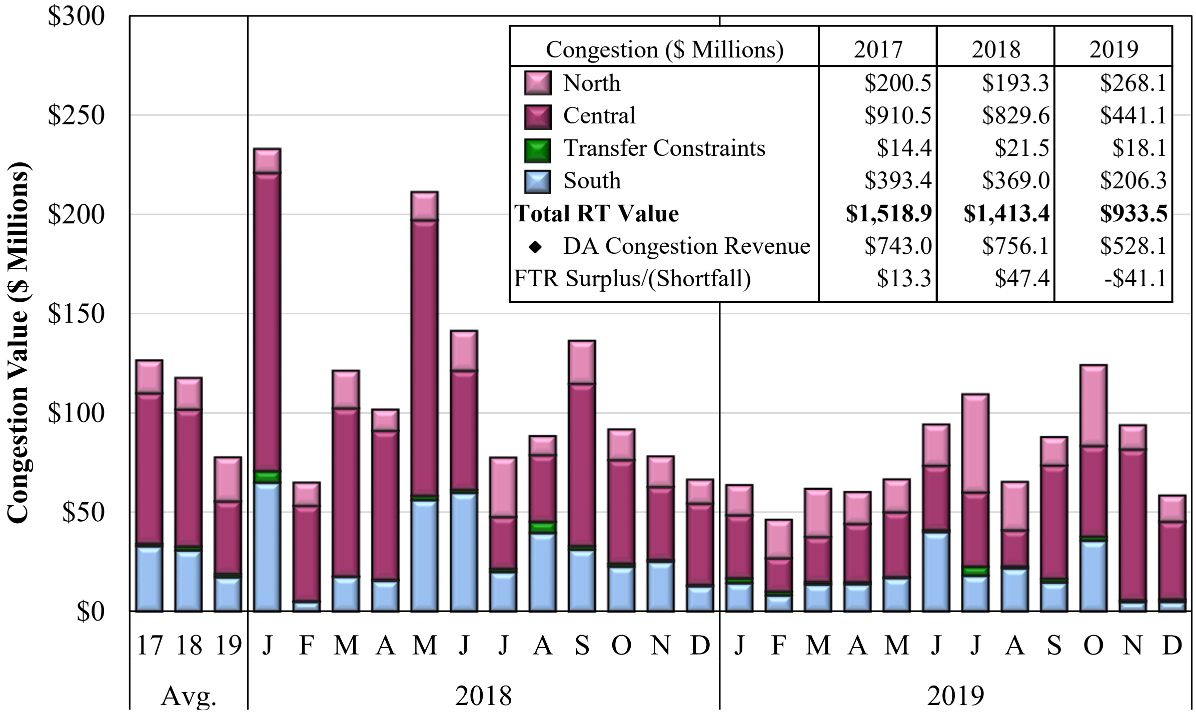
The value of real-time congestion fell 35 percent relative to 2018, totaling $0.9 billion. Congestion in the South and in the Central Regions fell by almost half, whereas congestion in the North rose by 38 percent. In the winter months, real-time congestion fell by 54 percent compared to 2018 because the 2019 cold conditions were shorter and impacted just the Midwest Region. Milder weather conditions and fewer critical transmission outages in the Spring contributed to a 54 percent drop in real-time congestion that quarter. In the Fall, total congestion in the Midwest was similar to the prior year. On November 13, planned and unplanned generator outages and high load contributed to the highest daily congestion value in 2019.

Multiple factors contributed to the overall decrease in congestion. Nearly half of the reduction was attributable to new transmission facilities and line upgrades in MISO and in neighboring regions, and almost 10 percent was related to a May addition of a 1,000 MW combined-cycle

25 The marginal congestion component, or "MCC," is one of three LMP components, which also includes a marginal energy component and a marginal loss component.

facility in Amite South.[26] Additionally, congestion tends to track natural gas prices because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Natural gas prices fell 20 percent year over year.

Figure 24: Value of Real-Time Congestion and Payments to FTRs
2018–2019



Congestion ($ Millions)	2017	2018	2019
North	$200.5	$193.3	$268.1
Central	$910.5	$829.6	$441.1
Transfer Constraints	$14.4	$21.5	$18.1
South	$393.4	$369.0	$206.3
Total RT Value	**$1,518.9**	**$1,413.4**	**$933.5**
◆ DA Congestion Revenue	$743.0	$756.1	$528.1
FTR Surplus/(Shortfall)	$13.3	$47.4	-$41.1

Improved manageability also reduced congestion in 2019. When flows on transmission facilities cannot be maintained below the facility limits, the transmission constraint demand curve will set the shadow price on these unmanageable constraints. During 2017 and 2018, two-thirds of the congestion (about $1 billion per year) accrued on these constraints. Only 53 percent of congestion in 2019 was unmanageable, a $470 million decrease over the 2017 to 2018 period. Congestion on manageable constraints, those maintained at their transmission limit, was relatively unchanged in 2019. Coupled with increased binding constraint hours in 2019, this finding indicates a marked improvement in both reliability (less transmission exceedances) and costs to customers (lower shadow prices). The figure also shows day-ahead congestion revenue and FTR accounting, which we discuss below.

Although real-time congestion management improved in 2019 over prior years, several key issues continue to hinder congestion management in MISO. These issues are each discussed in this section and include:

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26 Most of these projects are constructed under The MISO Transmission Expansion Plan (MTEP). Since 2003, MISO has constructed $23 billion in transmission projects, which has contributed significantly to reduced congestion costs and reduced curtailments of intermittent resources.

- Usage of very conservative ratings by most transmission operators;
- Limitations of MISO's authority in outage coordination;
- Procedural issues in defining, activating, and coordinating market-to-market constraints; and
- Congestion caused by TLR response on external constraints.

B. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect energy costs, congestion, and losses on the network. MISO collects congestion revenue in the day-ahead market 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, which are economic property rights to flow power over 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. Residual transmission capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an instrument for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that flows over the network sold as FTRs do not exceed flow limits 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).

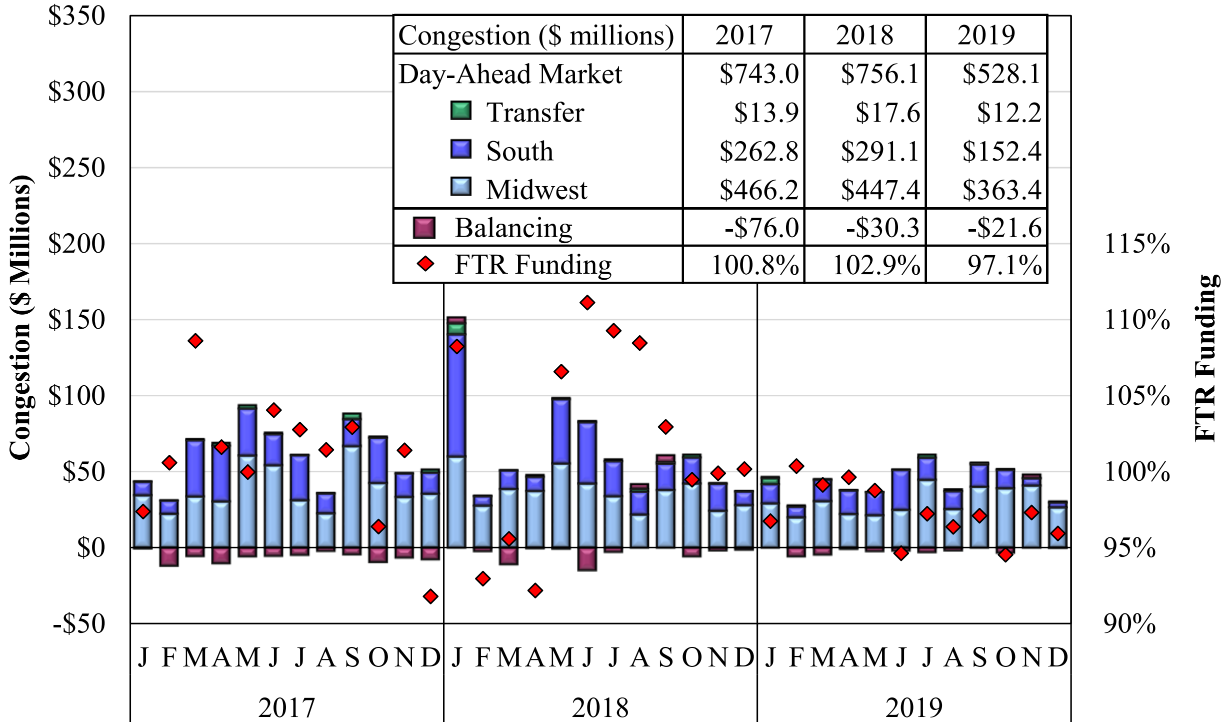
In addition to summarizing the trends in day-ahead congestion, this section evaluates to aspects of how the day-ahead network is modeled:

- *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 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 costs of doing so is uplifted to MISO customers as "balancing congestion".

Figure 25 summarizes the day-ahead congestion by region (and between regions), as well as the balancing congestion incurred in real time and the FTR funding levels from 2017 to 2019.

Figure 25: Day-Ahead and Balancing Congestion and FTR Funding
2017–2019



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

Day-ahead congestion costs fell 30 percent to $528 million in 2019. The day-ahead congestion costs collected through the MISO markets were slightly more than half of the value of real-time congestion on the system. This substantial difference is caused by loop flows that do not pay MISO for use of its network and entitlements on the MISO system granted to SPP and PJM and other JOA parties that are not included in the day-ahead congestion settlement.

In the Spring, day-ahead congestion decreased 39 percent compared to the same quarter in 2018. More than half of this was attributable to fewer critical transmission outages and generally milder weather conditions. Transmission upgrades and improvements in MISO's modeling alignment between the day-ahead and real-time markets contributed to the reduction. FTRs were not fully funded in 2019 partly because of modelling differences between the FTR markets and the day-ahead markets, and we describe this in more detail below.

FTR Shortfalls

Overfunding and underfunding of FTRs is caused by discrepancies in the modeling of transmission constraints and outages in the FTR auctions versus the day-ahead market. For example, if a day-ahead market constraint's limit decreases below what cleared the FTR market, a congestion shortfall will occur. In 2019, FTR obligations exceeded congestion revenues by $63.6 million – a shortfall of 4.4 percent before auction residual collections.

External constraints and low-voltage constraints near the edge of the MISO footprint have tended to be underfunded because a higher proportion of their FTR flows are below the GSF cutoff applied in the day-ahead and real-time markets. This cutoff results in the failure to collect all the congestion revenue necessary to satisfy the obligations on some constraints. FTRs impacted by SPP constraints, for example, were underfunded by 35 percent in 2019.[27] In contrast, FTRs impacted by the transfer constraints between the South and Midwest regions tend to be overfunded because they can bind in both directions. This causes them not to be fully subscribed and to generate surpluses when binding in either direction.

The most significant causes for episodic underfunding continue to be planned and unplanned transmission outages – particularly forced and short-duration scheduled outages that are not reflected in the FTR auctions. This can cause funding levels to vary substantially by local balancing area (LBA).[28] The FTR obligations for transmission constraints in six LBAs were underfunded by 20 percent or more. This potentially raises concerns regarding the incentive to fully report outages because FTR underfunding costs are socialized to all MISO areas. In contrast, reporting outages earlier or more completely could result in fewer FTRs being awarded to LSEs affiliated with the transmission owner.

Balancing Congestion

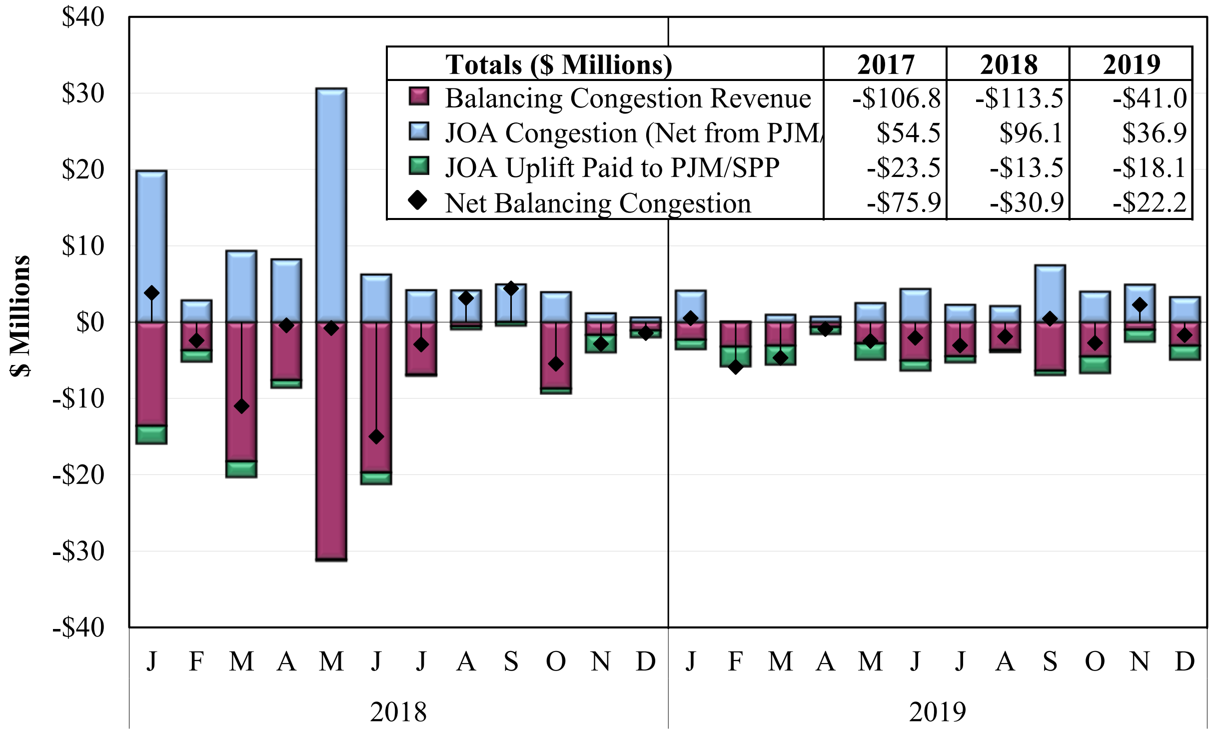
Balancing congestion shortfalls (negative balancing congestion revenue) occur when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, the costs of re-dispatching generation to manage constraints in real time to reduce day-ahead scheduled flows are negative balancing congestion. Conversely, positive balancing congestion occurs when real-time constraints bind at flows higher than 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 26 shows the monthly balancing congestion costs incurred by MISO over the past two years.

27 Improvements to the GSF cutoff are discussed and recommended later in this subsection.

28 See Figure A86 in the Analytic Appendix.

Figure 26: Balancing Congestion Costs
2017–2019



Net balancing congestion costs fell 28 percent in 2019 to just over $22 million, including JOA uplift of $18 million. JOA uplift payments are made to pay for market flows that exceed entitlements on coordinated M2M constraints. MISO had balancing congestion shortfalls in most months, but overall the levels were considerably lower than in prior years.

C. Key Congestion Management Issues

Given that MISO generally experiences between $1 and $1.5 billion in real-time congestion each year, improvements that can improve the efficiency of its congestion management can deliver sizable savings. Some of these opportunities are discussed below in the subsection evaluating market-to-market coordination. This subsection identifies two key opportunities to improve the management of congestion more broadly.

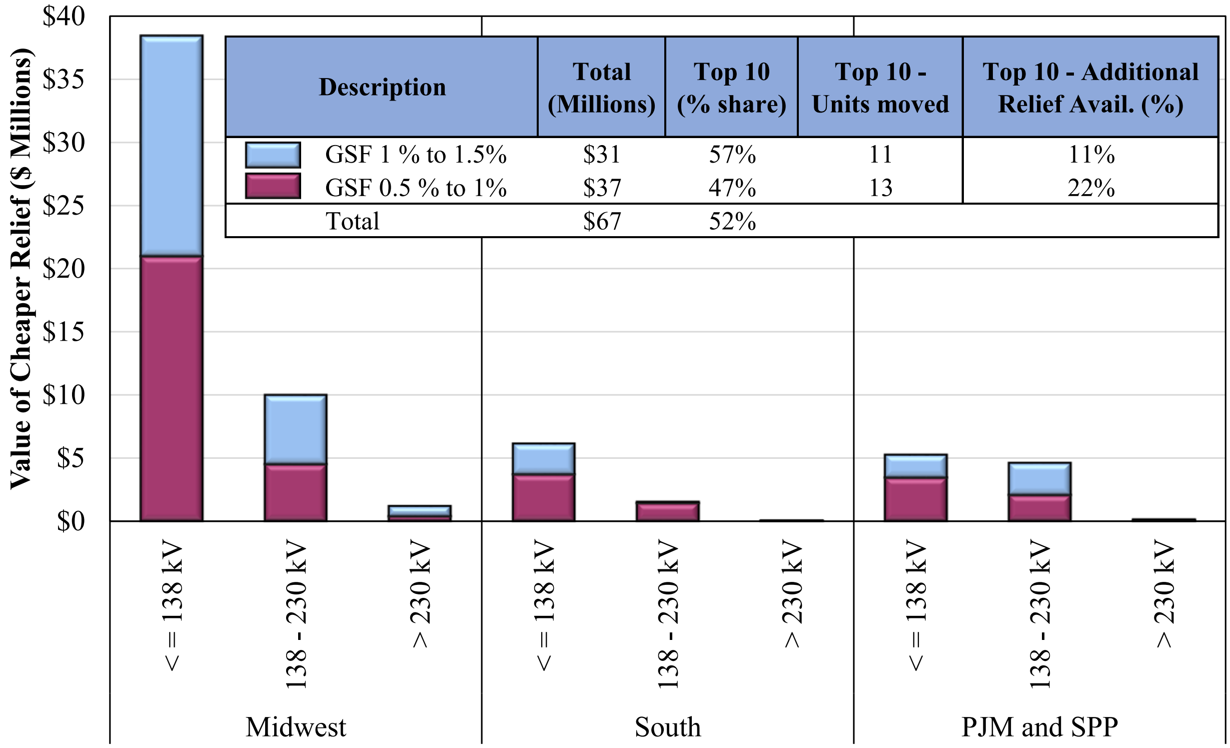
Modifying GSF Cutoffs for Congestion Management

A generation shift factor (GSF) indicates how changes in net injections at a given node will impact flows on the constraint. We evaluate the economic benefits of modifying the GSF cutoff MISO uses in its market software. MISO employs a GSF cutoff of 1.5 percent so that electrically-distant generators will not be re-dispatched to manage congestion. This reduces the complexity and solution time of MISO's market software.

Factoring performance implications into system design is a reasonable practice. However, the loss of congestion relief can adversely affect reliability, increase M2M settlements, and lead to FTR shortfalls. SPP and PJM both recognize these concerns and no longer apply a cutoff in their markets. While eliminating the cutoff may be untenable, we evaluated the benefits of reducing the GSF cutoff down to 0.5 percent and believe this level would address our concerns.

In Figure 27, we show the economic value of the additional congestion relief that can be achieved by lowering the GSF cutoff, along with the portion of the benefits that can be achieved by lowering the cutoff on just ten constraints with the highest benefits.

Figure 27: Value of Additional Available Relief
2019



Description	Total (Millions)	Top 10 (% share)	Top 10 - Units moved	Top 10 - Additional Relief Avail. (%)
GSF 1 % to 1.5%	$31	57%	11	11%
GSF 0.5 % to 1%	$37	47%	13	22%
Total	$67	52%		

This analysis shows $67 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent. Most of the benefits were concentrated on a small number of low-voltage constraints and Market-to-Market (M2M) constraints. MISO could capture more than half of the benefits if they implemented a 0.5 percent GSF cutoff for just ten constraints. This is key because it would likely not be feasible to reduce the cutoff on all constraints. Hence, we recommend MISO develop the capability to reduce the GSF cutoff on individual constraints.

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 reduces the transmission capability of the system during the outages. When submitted, MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages.

Participants tend to schedule planned outages in shoulder months, assuming that 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 28 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value incurred in 2018 and 2019 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 28: Congestion Affected by Multiple Planned Generation Outages
2018–2019

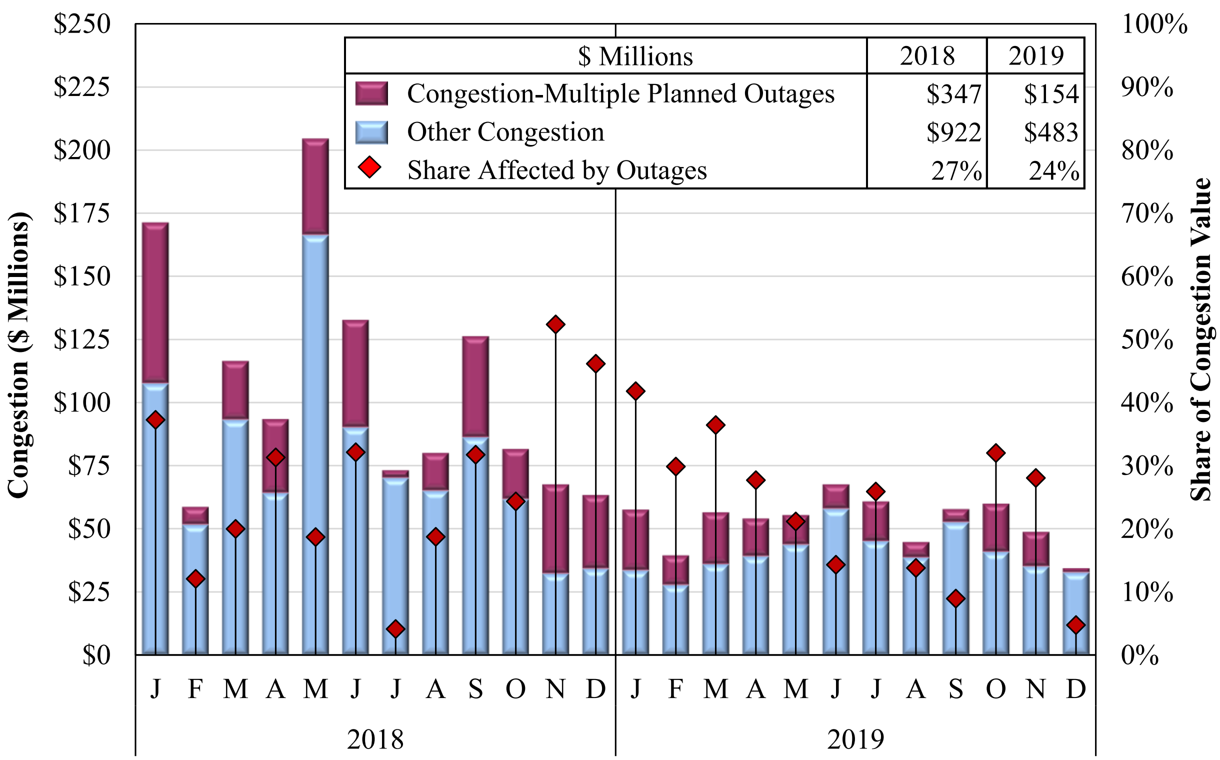


Figure 28 shows that 24 percent of the total real-time congestion on MISO's internal constraints in 2019 – $154 million – was attributable to multiple planned generation outages. In most months, planned outages caused significant congestion, including about half of all congestion in November and December combined. Figure 28 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.

Given how costly outages can be, we continue to recommend that MISO seek expanded authority to coordinate planned generation and transmission outages in order to reduce unnecessary economic costs.

D. Transmission Ratings and Constraint Limits

For the past several years we have estimated significant potential benefits from improved utilization of the transmission system, in particular more robust use of Ambient Adjusted Ratings (AARs) for temperature and other factors. 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.[29] Therefore, if transmission owners 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 transmission owners do not provide ambient-adjusted ratings.

Additionally, ratings for contingency constraints should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in 2-4 hours if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits as called for under the Transmission Owner's Agreement.[30] However, we have identified some transmission owners that provide only normal ratings for most facilities.

Estimated Benefits of Using AARs and STEs

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 transmission facilities. We used temperature and engineering data to estimate the increase in transmission ratings that would result from temperature-adjustments. To estimate the effects of using emergency ratings for facilities for which only normal ratings have been provided, we assume that the emergency ratings are 10 percent higher than the normal ratings. This is consistent with the data for other facilities for which TOs submit emergency ratings.

We then estimate the value of these increases (both the temperature-based increases and the emergency rating increases) based on the shadow prices of the constraints. This analysis is described in detail in Section V.E of the Analytic Appendix and summarized in Table 8.

29 Temperature is one common dynamic factor. In some regions, ratings are more dependent on other factors, such as ambient wind speed and humidity. Our analysis evaluates only ambient temperature impacts.

30 The TO Agreement calls for TOs to submit normal ratings on base (non-contingency) constraints and emergency ratings on contingency constraints ("temporary" flow that can be reliably accommodated for two to four hours). Because most constraints are contingency constraints (i.e., the limit is less than the rating to prepare for additional post-contingency flows), it is generally safe to use the emergency ratings.

Table 8: Benefits of Ambient-Adjusted and Emergency Ratings
2018–2019

		Savings ($ Millions)			# of Facilites	
		Ambient Adj. Ratings	Emergency Ratings	Total	for 2/3 of Savings	Share of Congestion
Total Estimated Benefits						
2018	Midwest	$77	$48	$125	19	12.7%
	South	$7	$18	$25	2	7.1%
	Total	**$85**	**$66**	**$150**	**21**	**11.2%**
2019	Midwest	$62	$36	$98	18	14.5%
	South	$4	$12	$16	3	8.0%
	Total	**$66**	**$48**	**$114**	**21**	**13.0%**

Across the past two years, the results show average benefits equal to 12 percent of the real-time congestion value, including an average of $75 million per year for ambient temperature-adjusting the ratings and $57 million per year for using emergency ratings. The benefits of temperature adjustments tend to accrue primarily in the non-summer months when static ratings are most understated. For example, in the summer months, the average increase in transmission ratings was only 7 percent, while the average increase was almost 10 percent in other seasons. The benefits of using emergency ratings are more evenly distributed, as one would expect. The analytical appendix details show how these estimated benefits in 2019 are distributed in the areas served by transmission owners.

Actual Saving Achieved by Two of MISO's TOs

In 2015, MISO began a pilot program to employ temperature-adjusted, short-term emergency ratings on several key facilities operated by Entergy. Over time, the program has expanded to include additional Entergy facilities and has yielded clear benefits without causing reliability issues. Further expansion of the program to other transmission operators would generate considerable congestion management savings throughout MISO. Only one other transmission owner currently utilizes temperature-adjusted ratings on a significant number of its transmission facilities.

We have estimated the savings that are currently being achieved by these two transmission owners. At least one transmission owner adjusts its ratings on an hourly basis to maximize the benefits, and the benefits are substantial, as shown in Table 9. These benefits are estimated by multiplying the rating increases (from the static rating level) by the marginal value of the transmission capacity as measured by the prevailing shadow prices.

From 2018 to 2019, the actual savings totaled $44 million – almost 7 percent of the congestion cost on these transmission facilities. Over $31 million of the savings were on Entergy's transmission facilities in the South – 8 percent of the congestion cost on those facilities. This methodology is a conservative estimate of savings, given that the shadow price would be higher if the market was controlling to a lower, non-adjusted rating.

Table 9: Estimated Achieved Savings by Two Transmission Owners
2018–2019

	Savings ($ Millions)	Share of Congestion	Facilities in Program
Achieved Ambient-Adjusted Benefits by 2 Transmission Owners			
Midwest	$12.7	4.8%	48
South	$31.2	7.7%	122
Total	**$43.9**	**6.6%**	**170**

We believe that at least one of the reasons why most transmission owners do not provide temperature-adjusted ratings is that there is little economic incentive to do so. One means to address this issue is to provide an economic incentive to the TOs that is related to the benefits of the additional transmission capability. This is reasonable because using higher transmission limits would reduce congestion costs and benefit system load. Since the FTR market limits flows to the static seasonal ratings, use of temperature-adjusted day-ahead ratings will result in day-ahead congestion surpluses. These surpluses are equal to the increase in the limit times the shadow price of the constraint. A portion of this surplus could be used to compensate the TOs. There could also be opportunities for TOs to determine a TCDC price above the static rating that would align their expectation of incremental risk with surplus compensation.

In conclusion, we continue to recommend that MISO work with TOs to gather and use temperature-adjusted, short-term emergency ratings, which could include creating economic incentives for them to provide such ratings. Additional savings could be achieved by using predictive ratings in the day-ahead market based on forecasted temperatures and wind speeds.

Recommended Improvements to Achieve the AAR Benefits

The benefits shown above assume that each of the constraints that were deemed to be adjustable with temperature were adjusted and that STEs were used for each constraint. In reality, it takes some time to prepare MISO's systems to receive the dynamic adjustments in the ratings and for the TO to gather the information to calculate the adjustments. Currently, MISO can accept new constraints to be adjusted when it updates its transmission model once per quarter. Unfortunately, a sizable portion of the benefits are lost by not being able to more quickly activate a constraint when it begins to bind or when an outage causes a new constraint to bind. In addition, MISO does not currently have a process to calculate AARs for its day-ahead market.

Therefore, we recommend that MISO work to improve the flexibility of its systems and process to enable more dynamic and accurate ratings. We recommend improvements in three areas:

- *System flexibility*: Allow more rapid addition of facilities for which TOs can provide AARs or dynamic line ratings (reflecting factors other than temperature), including those identified in the outage coordination process.
- *Forecasted ratings*: New systems are needed to accept or calculate forecasted ratings for use in the day-ahead market, reliability assessments, and FTR markets.
- *Improving Validation and Transparency*: MISO should more actively validate transmission ratings, which will require new processes and the collection of key data (e.g., limiting elements, post-contingent actions, and times associated with the STEs).

Together, these changes will substantially improve the utilization of MISO's transmission network and ultimately lower the costs to MISO's customers. These recommended changes have been introduced in the MISO Integrated Roadmap and initially have been prioritized as a high priority. As MISO increases its system flexibility, it will be able to capture a larger share of the total potential benefits from the use of ambient temperature-adjusted ratings.

Table 10 shows the total estimated benefits from AARs over the past two years and the share of the benefits that could be achieved under different scenarios including:

- MISO's current practice of updating its network model quarterly and assuming TOs take at least one week to gather the information to begin submitting AARs after the constraint begins binding significantly;
- Shortening the model updates to once every two weeks, still assuming TOs require one week to begin submitting AARs; and
- Implementing AARs for new constraints instantaneously with no lag on the part of MISO or the TO.

We recognize that it may not be possible or cost-effective to adjust all constraints, so we assume that MISO and its TOs will only activate constraints to be adjusted when they have been binding significantly or are projected to bind. We use a variety of thresholds ranging from constraints that have produced $65,000 in real-time congestion over the past two weeks to one million over the past four months, which are listed in detail in the Analytic Appendix in Section V.E. If a constraint passes any of these thresholds, it is included in our analysis presented in Table 10.

Table 10: Available AAR Benefits from Enhanced System Flexibility

Additional Benefits from System Flexibility	AAR Benefits ($ Millions)	Incremental AAR Benefits ($ Millions)	% of Total Benefits
Total AAR Benefits (2018- 2019)	**$151**		
Current System - Quarterly Updates	$66		44%
Bi-Weekly Model Update - 1 Week Lag	$104	$37	69%
Continuous Updates with No Lag	$142	$39	95%

This table shows that under the current processes at MISO, only 44 percent of the potential benefits would have been captured over the past two years. However, by increasing the flexibility of the system to incorporate new adjustable constraints every two weeks, the portion of the benefits captured rises to almost 70 percent or $104 million. Finally, if MISO and the TOs collaborate to eliminate substantially all delays in beginning to adjust new constraints, it can capture 95 percent of the estimated benefits. Capturing these benefits likely requires MISO or the TOs to identify constraints prospectively through its forward processes, including the outage coordination process.

MISO has begun taking steps in this direction. Beginning in the June 2020 EMS Model updates, MISO provides temperature “nodes” in the model for each TO that can be used to perform real-time temperature adjustments to specific transmission facilities. This will enable TOs to begin providing AARs for a new constraint much more rapidly than the current quarterly updates. MISO plans to regularly update the model to map new facilities to use these nodes.

However, these benefits are only achievable if MISO’s TOs decide to participate in providing AARs and STEs. To that end, it remains critical for MISO to work the TOs to secure their agreement to provide improved ratings and maximize the efficiency and effectiveness of the process to receive these ratings.

Finally, FERC began three separate proceedings related to transmission utilization:

- Notice of Inquiry (NOI) FERC’s Transmission Incentives Policy (PL19-3);
- Technical Conference on Managing Transmission Line Ratings (AD19-15); and
- Workshop on Grid Enhancing Technologies (AD19-19).

We participated in these proceedings along with MISO and many MISO stakeholders. One of the most immediate questions FERC sought comments on is whether TOs should be required to provide AARs and short-term emergency ratings. While there was not a consensus among participants, we support such a requirement. We also support FERCs general objective of facilitating the entry and utilization of grid-enhancing technologies that can be used to more actively manage the network and lower congestion costs. Such technologies would likely require MISO to implement system changes.

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

MISO’s market-to-market (M2M) process under the Joint Operating Agreement (JOA) 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. The RTO with the lower-cost 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 and Convergence

Congestion on MISO M2M constraints fell 24 percent to total $388 million in 2019. Congestion on external M2M constraints (those monitored by PJM and SPP) fell 33 percent to $34 million in 2019. Net payments totaling $36 million flowed from PJM to MISO in 2019, a 62 percent decrease from 2018. Net payments generally flowed from PJM because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. The decrease in net payments was largely due to significant payments from PJM to MISO in January and May 2018, when a pseudo-tied unit and wind units in PJM had large impacts on MISO constraints. MISO's M2M settlements with SPP in 2019 resulted in net payments of $17 million from MISO to SPP, comparable to 2018.

We evaluate the effectiveness of the M2M process by 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 over time and substantially lowers the MRTO's shadow price when the M2M process is initiated.

However, we evaluate three aspects of the M2M process that affect the efficiency and effectiveness of the process: how well and timely the processes are administered, the flow relief requested by the MRTO, and the testing criteria for identifying M2M constraints. These three areas are summarized below.

Evaluation of the Administration of Market-to-Market Coordination

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.

Each of these issues is significant because when a M2M constraint is not identified or activated, it raises the following concerns:

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

We developed a series of screens to identify constraints that should have been coordinated but were not because of the issues listed above. Table 11 shows the total congestion on constraints that were not coordinated but should have been because of the three reasons described above. 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
2017–2019

	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
Item Description	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Never classified as M2M	$85	$5	$1	$109	$15	$14	$194	$21	$15
M2M Testing Delay	$19	$22	$8	$11	$8	$10	$31	$29	$17
M2M Activation Delay	$6	$11	$1	$12	$7	$1	$18	$18	$2
Total	$110	$38	$10	$133	$30	$25	$243	$68	$34

This table shows that the largest congestion over the past three years occurred on constraints that were never classified as M2M constraints even though they would likely pass the M2M tests. This prompted a recommendation in the 2016 SOM (2016-2) 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. The congestion in this area is now less than 10 percent of the level in 2017.

The congestion values in the other two areas have also improved, falling by more than half from 2018 to 2019. This indicates that MISO has been successful continuing to improve its M2M processes.

Market-to-Market Relief Software

When a M2M constraint binds, coordination is initiated by the MRTO that is responsible for the constraint. The MRTO coordinates management of the constraint with the NMRTO by sending its marginal cost of providing relief on the constraint (i.e., the "shadow price") and the quantity of relief it would like the NMRTO to provide (at a cost not to exceed the shadow price).

Hence, a key component of successful M2M coordination is optimizing the amount of relief that the MRTO requests from the 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 have evaluated the extent to which the relief request software produces sub-optimal relief requests and the results of this evaluation are shown in Table 12.

Table 12: Frequency of Substantial Relief Request Issues

	MISO Flowgates		SPP Flowgates		All Flowgates	
	Intervals	Share	Intervals	Share	Intervals	Share
Total Coordinated Intervals	**13,857**	**100%**	**32,201**	**100%**	**46,058**	**100%**
Undersized Relief Request	149	1.1%	1,315	4.1%	1,464	3.2%
Oscillation	75	0.5%	1,590	4.9%	1,665	3.6%
Volatile Relief Request	2,529	18.3%	7,523	23.4%	10,052	21.8%
Intervals Exceeding Limit	**317**	**2.3%**	**6,133**	**19.0%**	**6,450**	**14.0%**

The current methodology results in one or more of these three flawed or inefficient relief request outcomes in 26 percent of intervals.

- *Volatile relief requests.* Volatile requests impact about 22 percent of coordinated intervals. Some volatile requests occur when the NMRTO cannot satisfy the requested relief. There is little efficiency loss in these cases because the NMRTO is providing all its available economic relief.
- *Undersized relief requests*. SPP constraints accounted for 90 percent of these intervals. We attribute this to the much greater frequency that flows exceeded the limits of SPP's constraints – 19 percent versus 2 percent of MISO's constraints. Violations often result in understated relief requests because of the "Discretionary Relief Amount" flaw. Poor price convergence and higher costs is the result of requesting too little relief.
- *Oscillation*. SPP-monitored constraints were more subject to oscillation than MISO constraints, accounting for 95 percent of all oscillation intervals. The worst oscillation occurred on facilities where the MRTO has almost no redispatch capability, or when the NMRTO has a relatively high proportion of the fast-ramping, inexpensive relief capability.

Oscillation has occurred on SPP constraints heavily impacted by MISO wind generation. The RTOs activate "Power Swing" software as needed to reduce or dampen the oscillation power swings. This software holds the shadow price used by the NMRTO constant based on the average shadow price of the MRTO for prior intervals. Although an improvement, it is not a long-term solution.

We have also estimated the cost of congestion that would be eliminated if MISO and SPP were able to request the optimal amount of relief from each other. During the period we previously studied, from June 2018 through May 2019, the real-time congestion on M2M constraints would have fallen by $41 million as a result of requesting an optimal amount of relief. These savings provide substantial support for improving the relief request software.

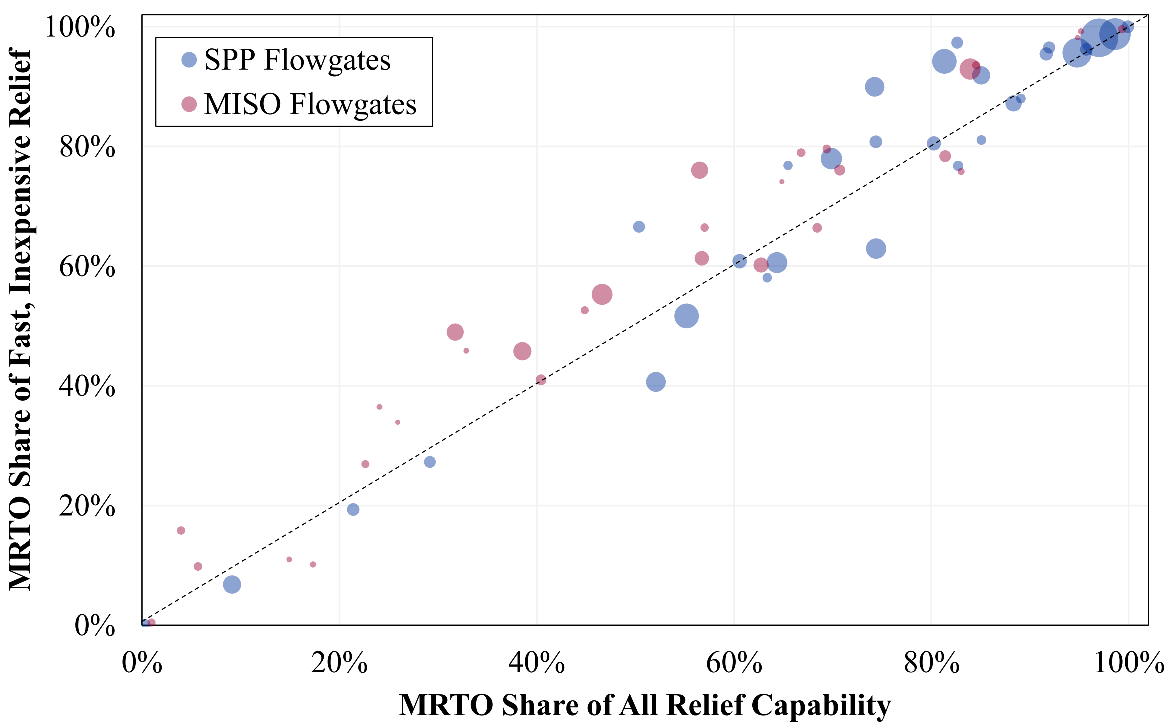
Market-to-Market Test Criteria Software

Identifying the constraints to coordinate 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 (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. 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. To illustrate this issue, Figure 29 shows the share of economic relief from SPP and MISO for their respective M2M constraints binding from June 2018 through May 2019. This figure shows the portion of the total relief on the x-axis and the available economic relief on the y-axis that is held by the MRTO.[31]

Figure 29: Share of the Relief from the MRTO



31 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.

When both percentages are very high, the expected value of coordinating the congestion management of the constraint is limited because the NMRTO has a very small share of the relief capability. The figure shows that there are several M2M constraints for which the NMRTO has a very small portion of the economic relief – those in the extreme upper-right portion of the figure. These are constraints for which the NMRTO has very little ability to assist in managing the congestion. If the NMRTO's market flows are also low on these constraints, then they are likely constraints that should not be designated as M2M constraints because the production cost savings of coordination may not exceed the administrative burden.

Based on this analysis we find that the current tests, particularly the five percent GSF test, could be significantly improved. We find that the five percent test is not reliable and has identified several constraints for which the benefits of coordinating are very small. Since GSFs are higher on high-voltage facilities, they tend to pass this test more often than they would be based on available relief. The five percent test only exists as a proxy that indicates the NMRTO may be able to provide relief from at least one generator.

A better test would be based on the *actual* available relief. 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 relief capability from the NMRTO; and/or
- The NMRTO relief as a percentage of the transmission limit.

Using threshold values for these tests of 10 percent would be reasonable because it correlates well with coordination benefits. Our analysis shows that implementing this recommendation would likely reduce the total number of M2M constraints. In other words, we find that the five percent test is identifying more constraints that are not highly beneficial to coordinate (i.e., false positives) and should be undefined than the number of new constraints that would warrant coordination under our improved relief-based tests.

Finally, in addition to changing the fundamental basis for one of the two M2M tests, our evaluation revealed one other aspect of the tests that could be improved. "Raise help" wind resources should only be considered in the market flow test. Raise-help wind resources cannot generally increase output to provide relief because they are usually producing as much output as they are able. Most wind resources have zero or negative marginal costs, so they operate to their maximum capability under almost all conditions. Therefore, they generally cannot increase output to provide relief.

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 most costly M2M constraints are more efficient for the NMRTO to monitor because it has the vast majority of the effective relief capability. To facilitate transferring monitoring responsibility, MISO and SPP began using new software in 2017 that enables this transfer, but it has rarely been used. PJM has agreed to use this software and currently only allows such transfers in limited circumstances. Hence, we recommend that MISO continue working with SPP and PJM to improve the procedures to transfer the monitoring responsibility to the NMRTO when appropriate.
- Convergence of M2M constraints is much worse in the day-ahead market. MISO and PJM implemented our recommendation to coordinate/exchange FFE in the day-ahead market in late January 2016, but they do not actively utilize this process. Further, we have found that SPP does not appear to be modelling MISO's constraints in its day-ahead market. We recommend MISO work with SPP and PJM to improve the day-ahead modeling and convergence of the M2M constraints.

F. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur on external constraints when other system operators call for a TLR, which causes MISO to activate the external constraint in MISO's real-time market. 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, 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, these external constraints often bind severely and produce substantial costs in MISO. 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 TVA that would allow TVA and MISO to coordinate the relief on each other's transmission system more efficiently. To quantify the potential value of such a JOA, Table 13 shows the total congestion and potential savings in periods when TVA had lower-cost relief available than MISO on MISO's constraints (first row) and TVA's constraints (second row).

Table 13: Economic Relief from TVA Generators in 2019

Status	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$131.0	$6.6
TVA (TLR) Constraints binding in MISO	$3.8	$1.3
Total	**$134.8**	**$7.9**

This analysis shows that coordination would lower costs on both systems, make MISO's relief obligations more equitable, and reduce price distortions caused by TVA's TLRs. It also shows that a JOA with TVA could substantially lower the costs of managing key MISO constraints.

In early 2020, TLRs called by IESO have become frequent. We are investigating the justification for these TLRs and evaluating their effects. In general, such TLRs result in thousands of MWs of transaction curtailments from PJM to MISO, which has resulted in costly price spikes throughout MISO. Like the TVA constraints, 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 recommend that MISO work with both TVA and IESO to develop JOAs that would reduce the costs of this external congestion.

G. FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion. 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 in order 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). It is important to recognize, however, that even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may cause actual congestion to be much higher or lower than FTR auction values. MISO currently runs:

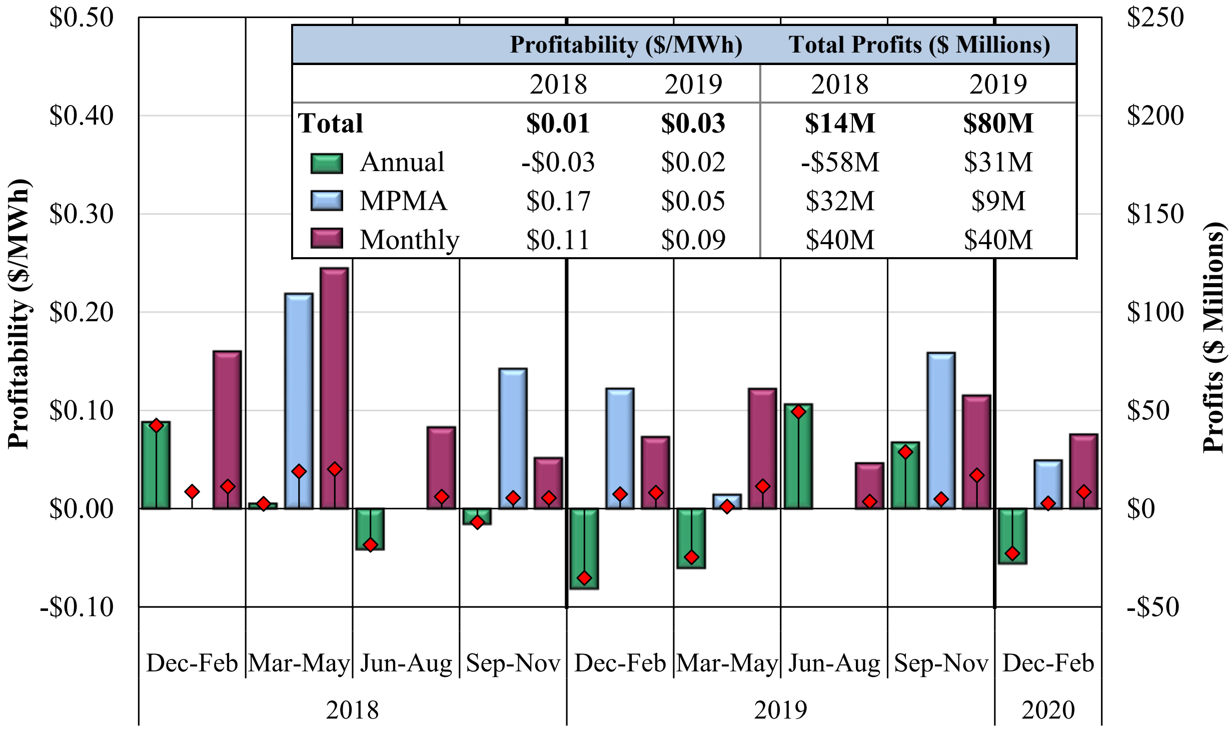
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards. The MPMA facilitates FTR trading for future periods in the current planning year.

FTR Market Profitability

Figure 30 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Annual FTR Profitability. Figure 30 shows that FTRs issued through the annual FTR auction were profitable overall as losses in the first and second quarters of 2019 were offset by profits in the rest of the year. In prior years, FTR losses were partly attributable to market participants nominating and self-scheduling ARRs along historically unprofitable paths. This practice has steadily declined over the past four years.

Figure 30: FTR Profits and Profitability
2018–2019



FTR Profitability in the MPMA. Figure 30 shows that the FTRs purchased in the MPMA and prompt month have been profitable, although the profitability of FTRs purchased in the MPMA and monthly auctions fell 71 and 18 percent, respectively, over last year. In general, these markets tend to produce prices that are more in line with anticipated congestion than the annual auction, which produced profits of $31 million, in part because they occur much closer to the operating timeframe when better information is available to forecast congestion.

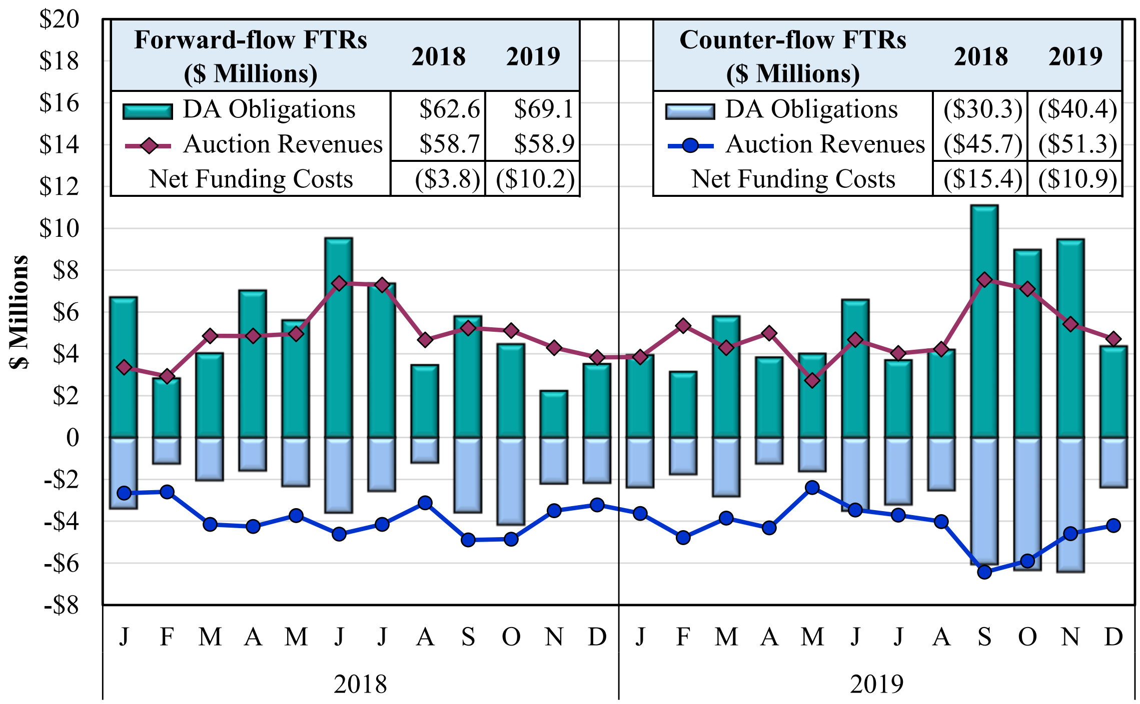
Multi-Period Monthly FTR Auction

In the MPMA FTR auction, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint.[32]

MISO is restricted in its ability to sell counter-flow FTRs because it is prohibited from clearing the MPMA with a negative financial residual. That means that MISO can only fund the purchase of counter-flow FTRs with net revenues from same auction. This artificial restriction limits MISO's ability to resolve feasibility issues through the MPMA. In other words, when MISO knows a path is oversold, MISO often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always inefficient because it may be more costly to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 31 compares the auction revenues from the MPMA prompt month (the first full month after the date of the auction) to the day-ahead FTR obligations associated with the FTRs sold.

Figure 31: Prompt-Month MPMA FTR Profitability
2018–2019



32 As an illustration, 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 so the FTR obligation in the day-ahead market would be 200 MW.

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.

This figure shows that MISO sold forward-flow FTRs at roughly 15 percent less than their ultimate value in 2019. However, MISO paid participants 27 percent more to accept counter-flow FTRs than the value of these obligations in 2019, down from 51 percent in 2018. While the negative auction residual restriction artificially limits MISO's ability to sell counter-flow FTRs, this limitation benefited MISO's customers in 2019 based on the pattern of inflated prices for counter-flow FTRs shown in the figure.

Overall, these results indicate that the MPMA is less liquid than is necessary to erase the systematic differences between FTR prices and values. The best option for addressing this issue is to examine the rules and requirements that may be limiting participation in the FTR markets. If barriers to participation can be identified and eliminated, we would expect better convergence between the auction revenues and the associated day-ahead FTR obligations.

Additionally, if liquidity and performance can be improved, we recommend that MISO eliminate the arbitrary negative auction residual restriction since there is no need to require each auction strip to have a positive residual. MISO could consider applying positive residuals from prior MPMA cycles to resolve infeasibilities for the prompt month. This will allow MISO to enter the day-ahead market with a feasible set of FTR obligations. Alternatively, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale of forward-flow FTRs at unreasonably low prices and/or the sale of counter-flow FTRs at unreasonably high prices.

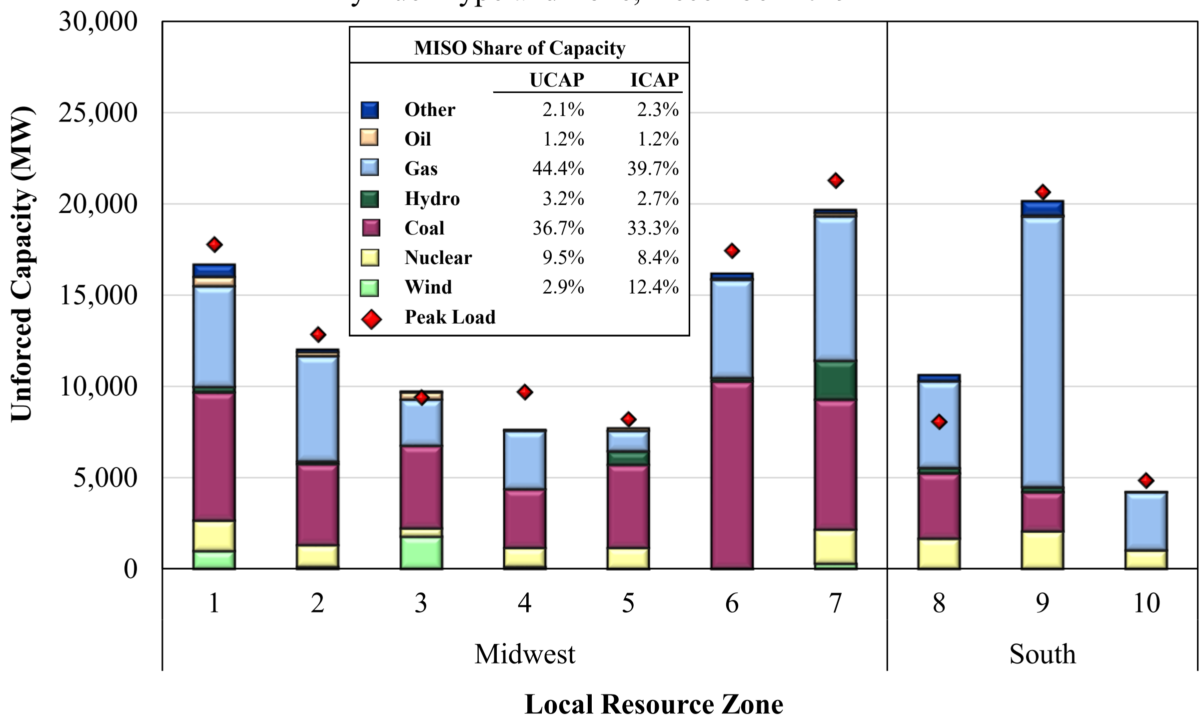
VI. RESOURCE ADEQUACY

This section evaluates the adequacy of the supply in MISO for the upcoming summer and discusses improvements to MISO markets that would promote efficient investment and retirement decisions to satisfy MISO's long-term resource adequacy needs.

A. Regional Generating Capacity

The first two figures in this section show the distribution of existing generating capacity by Local Resource Zone (LRZ) and fuel type. Figure 32 shows the distribution of Unforced Capacity (UCAP) at the end of 2019 by zone and fuel type, along with the 2019 coincident peak load in each LRZ.[33] UCAP values account for forced outages and intermittency. Therefore, UCAP values for wind units are significantly lower than Installed Capacity (ICAP) values, as shown in the inset table. Hence, although wind is over twelve percent of MISO's ICAP, it is three percent of the UCAP.

Figure 32: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2019



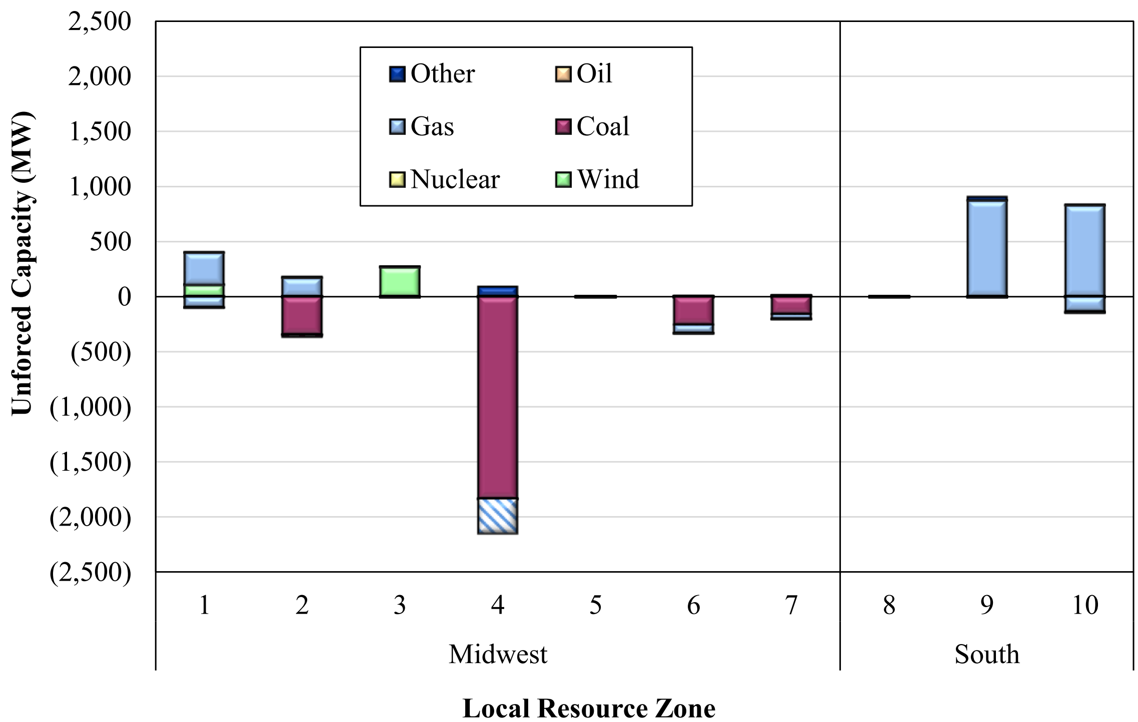
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the MISO South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

33 UCAP was based on data from the MISO PRA for the 2019/2020 Planning Year and excludes LMR capacity.

B. Changes in Capacity Levels

Capacity levels have been falling in MISO because of accelerating retirements of baseload resources, which are being replaced with intermittent renewable resources. Figure 33 shows the capacity additions (positive values) and losses during 2019. The hatched bar in the figure indicates resources that have suspended, which rarely return to service.

Figure 33: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in 2019



Capacity Losses

In 2019, 3.3 GW of resources retired in MISO, nearly 90 percent of which was coal-fired generation. Environmental regulations and sustained low gas and associated energy prices led to continuing coal-fired unit retirements, which totaled more than 2.8 GW in 2019. These retirements produced a net unforced capacity loss of 2.9 GW. We expect this to continue because of sustained low natural gas prices and the weak economic signals provided by MISO's current capacity market.

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO at least 26 weeks in advance. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR) and provide compensation. An SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. SSR status has been granted very infrequently, and currently no resources in MISO are designated SSR.

New Additions

More than 4.5 GW of new capacity entered MISO in 2019. Two large natural gas-fired combined-cycle resources totaling 1.8 GW entered in MISO South, one in a key constrained area. More than 2 GW (nameplate) of wind capacity entered, but their UCAP values shown in Figure 33 are much smaller because they provide less reliability than most other resources. Additional investment in wind resources is likely to occur in the coming years, particularly since Multi-Value Projects (MVP) that expand transmission from favorable wind areas are underway or completed, the cost of which total more than an estimated $6.5 billion.

C. Planning Reserve Margins and Summer 2020 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2020. Assumptions regarding the supply that will be available during the summer peak and the peak load can substantially change the planning reserve margins. Therefore, we present a base case and four additional scenarios that more realistically represent MISO's summer peak reliability margin. Table 14 summarizes these results.

Table 14: Summer 2020 Planning Reserve Margins

		Alternative IMM Scenarios*			
				High Temperature	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	124,866	124,866	124,866	124,866	124,866
Energy Efficiency Programs	(650)	(650)	(650)	(650)	(650)
High Load Increase	-	-	-	7,032	7,032
Total Load (MW)	124,216	124,216	124,216	131,898	131,898
Generation					
Internal Generation Excluding Exports	134,773	134,773	134,668	134,773	134,668
BTM Generation	4,445	4,445	3,047	4,445	3,047
Unforced Outages and Derates**	(167)	(10,899)	(10,899)	(18,499)	(18,499)
Adjustment due to Transfer Limit	(1,749)	-	-	-	-
Total Generation (MW)	137,302	128,320	126,816	120,720	119,216
Imports and Demand Response* **					
Demand Response	7,557	5,668	3,303	5,668	3,303
Capacity Imports	3,833	3,833	3,833	3,833	3,833
Margin (MW)	24,476	13,604	9,735	(1,678)	(5,546)
Margin (%)	**19.7%**	**11.0%**	**7.8%**	**-1.3%**	**-4.2%**
Effects of Non-Firm Imports					
Summer Peak Net Imports	1,609	1,609	1,609	1,609	1,609
Expected Margin (MW)	26,085	15,214	11,345	(68)	(3,937)
Expected Margin (%)	**21.0%**	**12.2%**	**9.1%**	**-0.1%**	**-3.0%**

* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2020. Alternative realistic cases use historical average unforced unit unavailability during July and August peak hours. High temperature incremental outages based upon MISO's 2020 Summer Assessment.

*** Cleared amounts for the 2020/2021 planning year.

Base Case. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2020 Summer Resource Assessment,* including the 1,900 MW transfer limit assumption between MISO South and Midwest.[34] This case also assumes that: a) MISO will be able to access all demand response resources in a given emergency situation, and b) the summer planned outages will be limited to those scheduled and approved by April 1, 2020. The planning reserve margin in this case is 19.7 percent, which substantially exceeds the Planning Reserve Margin Requirement (PRMR) of 18.0 percent.

Realistic Case. Unfortunately, the assumptions in the base case 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 two years' summer peak months during on-peak hours; and
- MISO will only be able to access 75 percent of demand response resources in a given emergency situation, consistent with historical observations.

In this Realistic Scenario, the planning reserve margin falls to 11.0 percent, well below the 18.0 percent capacity requirement. 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 the shortages when they occur. Hence, the table includes additional imports that reflect the average amount of additional imports during summer peak conditions. This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO. The table shows that including these non-firm imports raises the margin to roughly 12 percent, which remains significantly less than the reliability requirement.

Realistic Scenario < 2 Hour Emergency Resources. Unfortunately, even the realistic scenario is likely to be excessively optimistic because it assumes all resources will be available when an emergency occurs. In general, not all resources are available in emergencies because emergencies are often precipitated by unforeseen outages and other contingencies. MISO has historically detected and declared emergencies between 10 minutes and 4 hours in advance. Because a large quantity of emergency resources have much longer notification times (often up to 12 hours), this alternative scenario assumes only emergency resources that can start in two hours or less will be accessible. This case substantially reduces the emergency demand response capacity and behind-the-meter generation. In this scenario, the planning reserve margin is only 7.8 percent, which is extremely low. Like the prior scenario, this relatively low margin does not

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

reflect MISO's ability to access additional imports on a non-firm basis. Including typical peak levels of non-firm imports raises the planning reserve margin to 9.1 percent.

High Temperature Cases. We include two additional cases that modify the Realistic Scenario and Realistic Scenario < 2 Hour Emergency Resources cases to include the effects of hotter than normal summer peak conditions. The high-temperature cases are important because hot weather can significantly affect *both* load and supply. High ambient 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.[35] On the load side, we assume MISO's "90/10" forecast case (which should only occur one year in ten).

The high-temperature cases using the realistic scenario and realistic plus limited emergency-only capacity both show that MISO will likely be short of capacity and enter emergency conditions. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no assumed forced outages – generally ranging from five to eight percent. Non-firm imports may help to fill the margin deficit but would not likely be sufficient to account for typical levels of forced outages.

Overall, these results indicate that the system's resources are likely adequate for summer 2020 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 and nuclear resources retire and are replaced by renewable resources. Additionally, we are concerned that an increasing amount of the capacity reserve margin is being provided by LMRs whose availability is limited. Therefore, it remains important for the capacity market to provide the efficient economic signals to maintain an adequate resource base. These issues are discussed later in this section.

D. Capacity Market Results

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

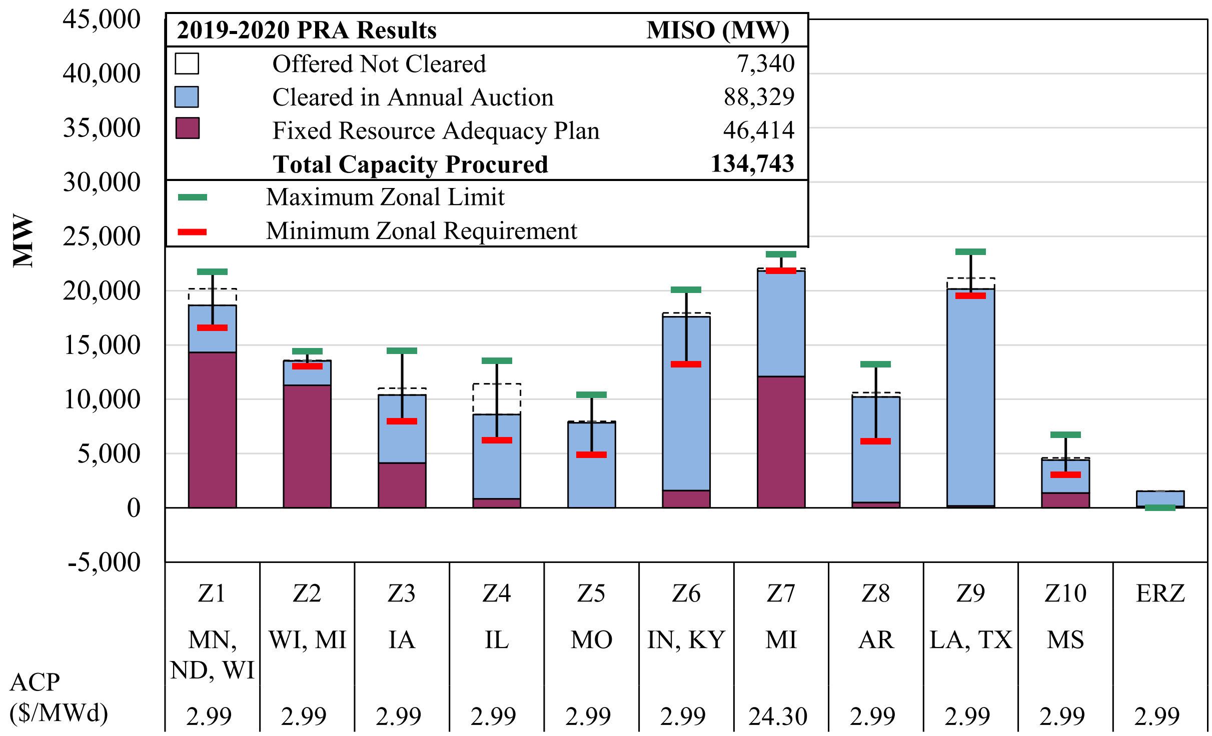
MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the PRA. Resources clearing in MISO's PRA receive capacity revenues that, in addition to energy and ancillary services market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

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

PRA Results for the 2019/2020 Planning Year

Figure 34 shows the outcome of the PRA held in late March 2019 for the 2019/2020 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, which is equal to the local reliability requirement minus the maximum level of capacity imports. The maximum amount is equal to the obligation plus the maximum level of capacity exports.

Figure 34: Planning Resource Auctions
2019/2020 Planning Year



Prices. Zone 7 was constrained on the local clearing requirement and cleared at $24.30 per MW-day, while the clearing price in all other zones was $2.99 per MW-day. A $2.99 per MW-day auction clearing price is extremely low and provides suppliers with less than two percent of the revenues needed to cover the cost of new entry for a new peaking resource. We discuss the underlying causes of these low prices in the Subsection G, discussing capacity market design.

Qualifications of Supply in the PRA

We have become increasingly concerned that MISO's PRA rules allow resources that cannot satisfy MISO's reliability needs to provide capacity, including: a) Load Modifying Resources

(LMRs) with long notification times, and b) resources that are not fully deliverable. Additionally, MISO does not procure capacity for all of MISO's firm load. Resolving these concerns would result in price signals that better reflect the value of capacity in MISO. In this subsection, we evaluate the impact that addressing these issues would have had on prices in the 2020/2021 PRA, which was conducted in March of 2020.

Our PRA analysis starts with a base case scenario that reflects the actual PRA clearing prices in the 2020/2021 auction. We then produce scenarios that show the PRA clearing prices that would have resulted if the supply and demand were adjusted to:

a) disqualify LMRs that require more than six hours of notification time to deploy[36],
b) limit the capacity that can be sold to the deliverable ICAP amount[37], and
c) reflect the requirement to serve firm behind-the-meter load.

The individual scenarios were then combined to show the impact of implementing all of the recommendations together. In addition to evaluating the base case scenarios against the current capacity auction construct that relies on a vertical demand curve, we also conducted a series of similar sensitivities assuming a sloped demand curve. This has been a long-standing recommendation intended to allow the PRA to facilitate efficient investment and retirement decisions. The results of our analysis are shown in Table 15 below.[38]

Table 15: Alternative Capacity Auction Clearing Prices
2020/2021 Planning Resource Auction

Alternative Capacity Auction Scenarios	Affected UCAP	Vertical Demand Curve Prices*			Sloped Demand Curve Prices**		
		Unconstrained South	Zone 9 (LA, TX)	Unconstrained North	Unconstrained South	Zone 9 (LA, TX)	Unconstrained North
Base Scenario		$4.75	$6.88	$5.00	$148.23	$155.10	$148.23
- LMR > 6 hr Notification Time	1,226.6	$12.12	$12.12	$12.12	$168.51	$168.51	$168.51
- Undeliverable ICAP	2,933.2	$14.99	$20.02	$25.38	$200.86	$200.86	$200.86
+ Procurement for BTM Firm Load	270.2	$4.75	$23.64	$5.00	$152.89	$171.94	$152.89
Combination of Alternative Scenarios	4,384.3	$27.20	$27.20	$108.00	$213.61	$213.61	$234.23

* Zone 7 (MI) fell short of its Local Clearing Requirement and cleared at CONE ($257.73). This result applies to all other vertical demand scenarios.
** Zone 7 clears at $270.41 (5% above CONE) in all sloped demand scenarios.

36 MISO filed tariff changes regarding LMR accreditation on May 18, 2020, Docket No. ER20-1846-0000.

37 In 2020, MISO addressed our deliverability concerns by filing changes to the deliverability requirements for conventional resources in Docket No. ER20-1942-000 on May 29 and for intermittent resources in Docket No. ER20-2005-000 filed on June 5.

38 The Unconstrained North is Zones 1 through 6. The Unconstrained South is Zones 8 and 10. The external zones have clearing prices that fall between the Unconstrained North and South.

These scenarios show that improving the qualification of LMRs, enforcing deliverability, and procuring for all of MISO's firm load together would have significantly increased prices and tightened the capacity margin by almost 4,400 MW. Prices in the Midwest region would have exceeded $108 per MW-day assuming that none of the undeliverable resources would take steps to increase their deliverability.

Improving the representation of demand in the capacity market has even greater effects. The sloped demand cases show that the prices outside of Zone 7 would have been between $214 and $234 per MW-day after implementing our recommended improvements. These prices efficiently reflect the underlying supply and demand for capacity as discussed below in subsection G.

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 limited the transfer capability in the South to North direction to 1,500 MW in the PRA. The constraint was not binding in the 2019/2020 PRA and, therefore, had no impact on clearing prices. This limit was later increased to 1,900 MW for the 2020/2021 PRA. However, increasing the limit to an expected limit closer to 2,500 MW would allow MISO to more fully utilize its planning reserves in MISO South. 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 coordinated 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. 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 2019.

Net revenue is the revenue a new unit would earn 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 35 and Figure 36 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.

Figure 35: Net Revenue Analysis
Midwest Region, 2017–2019

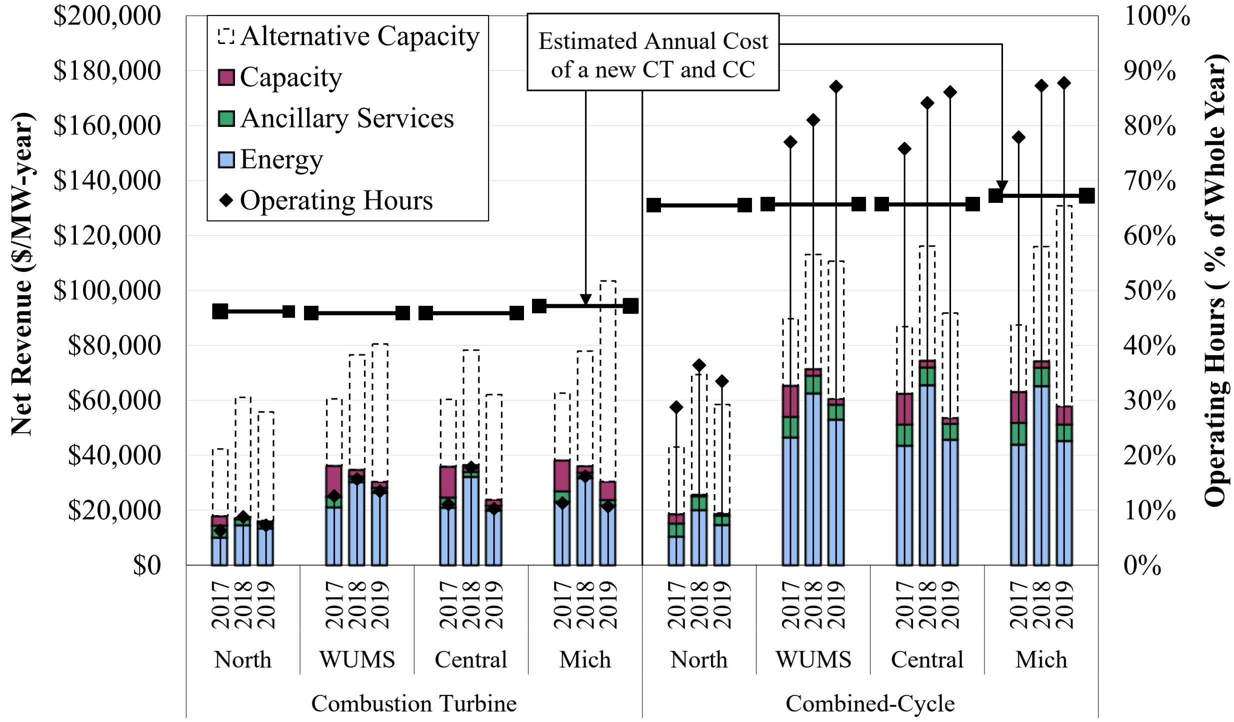
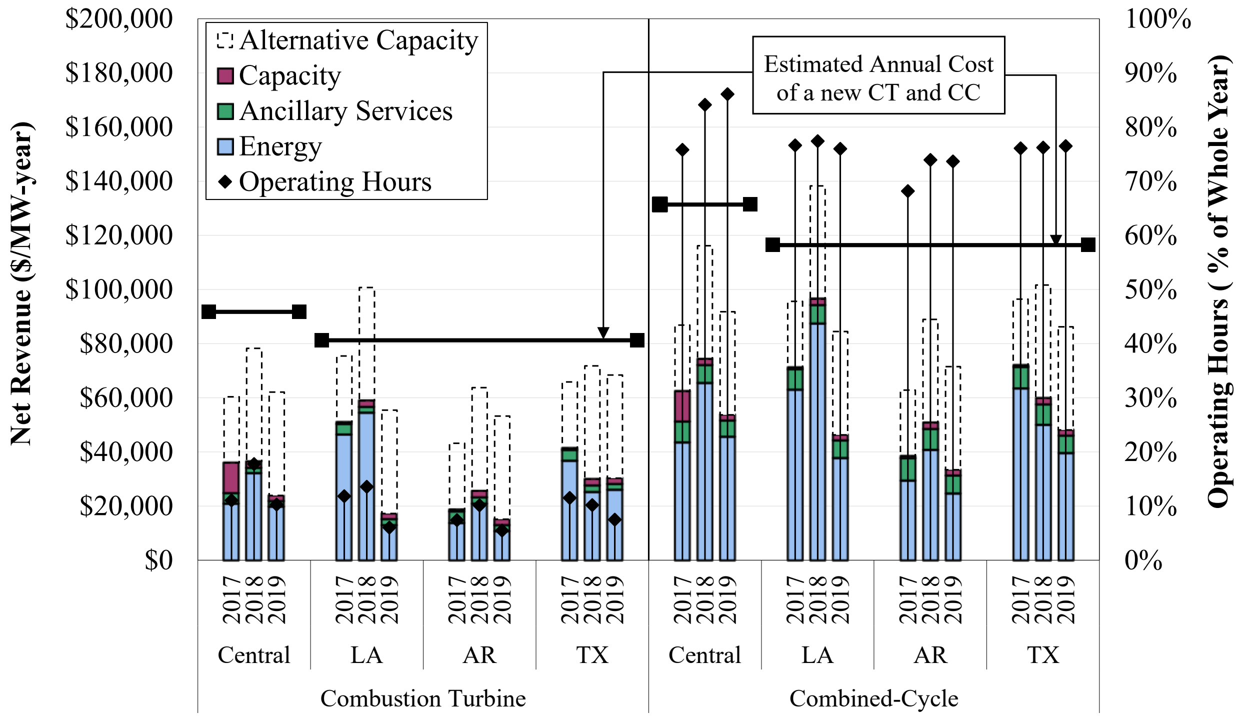


Figure 36: Net Revenue Analysis
South Region, 2017–2019



Note: "Central" refers to the Central region of MISO Midwest and is included for reference purposes.

Net revenues fell in all regions in 2019, as lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO. Net revenues were not sufficient to motivate investment in a CT or a CC in any location. The relatively low net revenues are consistent with expectations because of low natural gas prices, infrequent shortages, the prevailing capacity surplus, and capacity market design issues. Lower capacity auction clearing prices in almost all zones in the 2019/2020 PRA was a contributing factor to the lower net revenues. In 2019, a new 1,000 MW combined-cycle resource came online in Louisiana, which contributed to fewer price spikes in that region in 2019.

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 sloped demand curve in the Planning Resource Auctions, the annual net revenues would have increased year over year for both resource types in all regions. This would have made CTs profitable to build in Michigan.

The lack of the sloped demand curve raises particularly timely concerns. MISO's capacity surplus is dissipating as resources face substantial economic pressure. Competitive suppliers are facing increasing incentives to export capacity to PJM or retire. To improve these price signals, we recommend a number of changes to both the energy and capacity markets in this Report. The capacity market design recommendations are discussed later in this section.

F. Existing Capacity at Risk Analysis

Since its inception, MISO has enjoyed a surplus of capacity beyond the minimum reliability 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 falling 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 to suspend or retire prematurely. Moreover, some resources may reduce maintenance expenditures, leading them to have more frequent forced outages and deratings.

In this year's report, we conduct an analysis to evaluate MISO's capacity at risk for long-term suspension or retirement for three types of technology in MISO: coal, nuclear, and wind. Our analysis compares the annual resource net revenues to the GFCs and is shown in Figure 37. 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 37: Capacity at Risk by Technology Type
2019

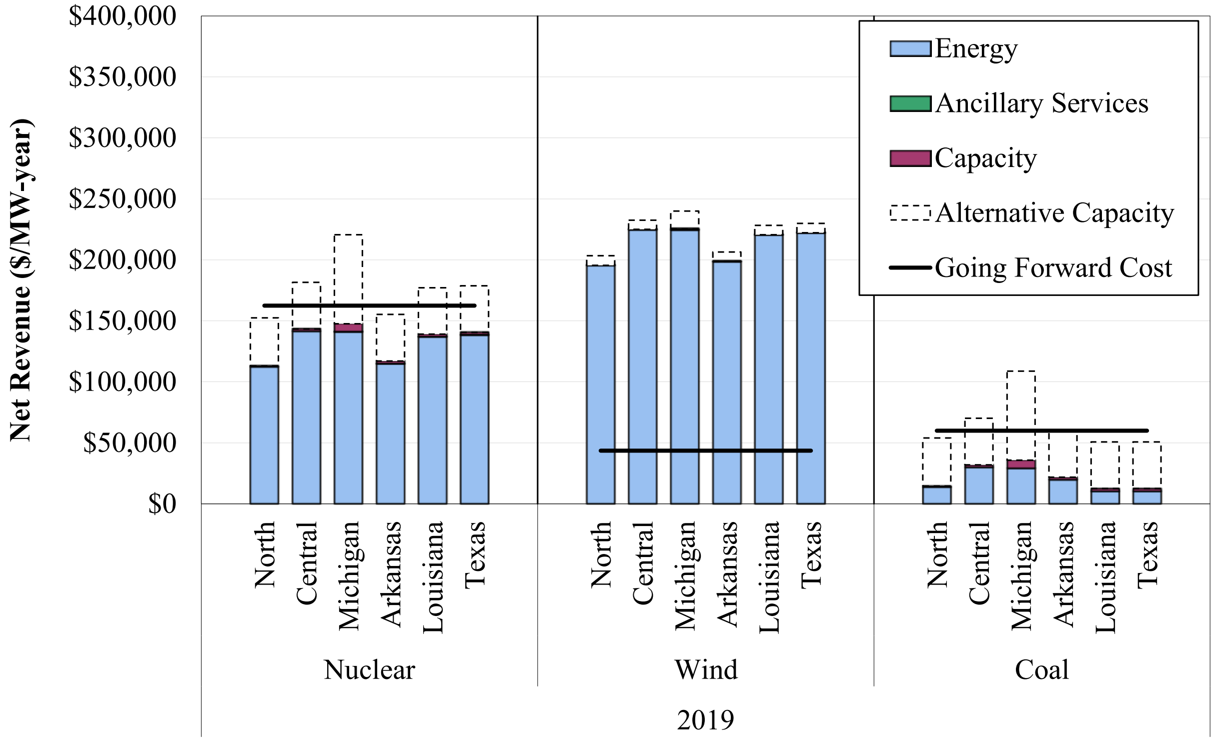
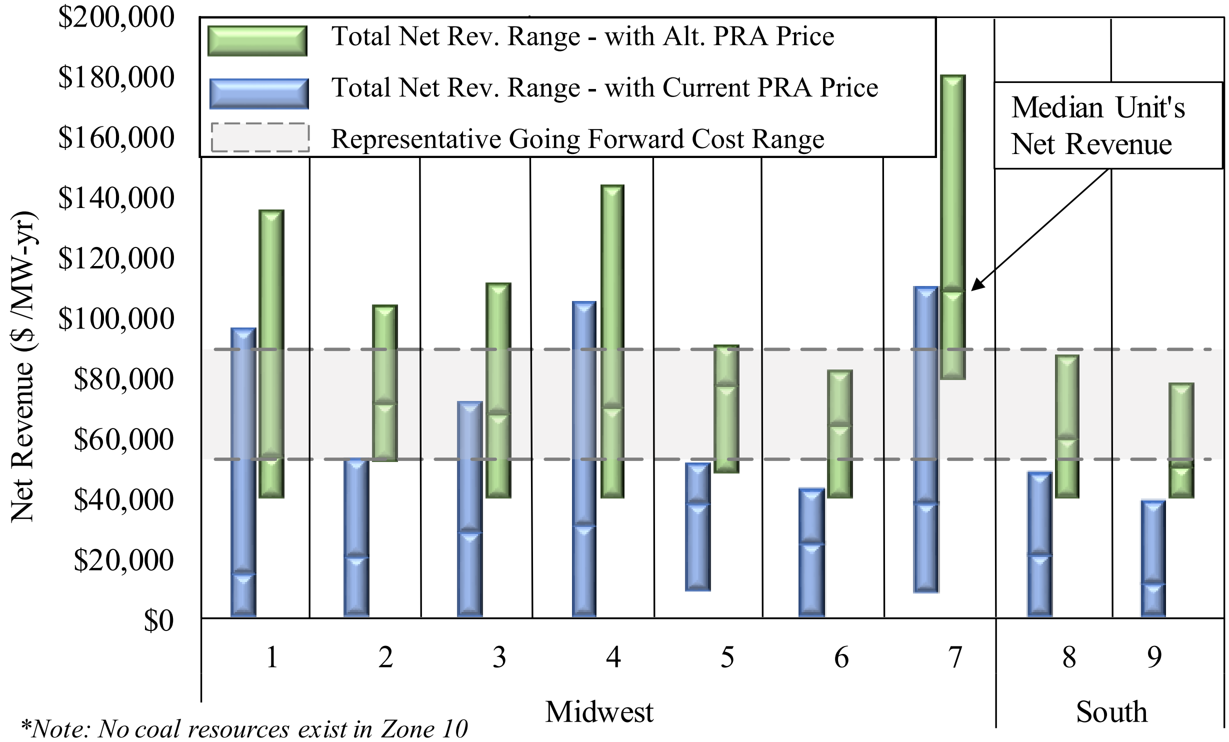


Figure 37 shows that while wind resources are more than revenue adequate, typical coal and nuclear resources exhibit revenue shortfalls under the current capacity construct. Persistent low natural gas prices have suppressed energy prices in the past few years, and revenues from the capacity auction do not offset lower energy prices. Many coal-fired resources in MISO are owned by vertically-integrated utilities that have guaranteed returns on investment that are approved through rate cases. Barring out-of-market cost recovery, these resources would be uneconomic to continue operating at prevailing prices.

Figure 37 also shows that were MISO to price capacity efficiently (by adopting a sloped demand curve), typical coal and nuclear resources would be able to recover their GFCs in most regions.

While a generic capacity at risk analysis is useful, an examination of MISO's actual coal resources by zone is warranted. In Figure 38, we plot the range of net revenues for existing coal resources by local reliability zone in MISO over the past two years. This analysis includes capacity auction revenues from MISO's 2019/2020 PRA in the blue bars, as well as alternative net revenue ranges were MISO to employ a sloped demand curve in the capacity auction in the green bars. The median unit net revenues are represented by the horizontal line in the middle of the green and blue bars. In the grey shaded region, we indicate a range of reasonable GFCs for the existing coal resources.

Figure 38: Coal-Fired Resource Net Revenues Under Alternative Demand Curves
2019



**Note: No coal resources exist in Zone 10*

Our analysis shows that under MISO's current vertical demand curve capacity auction construct, coal resources generally do not recover sufficient net revenues to cover a reasonable range of GFCs. However, were MISO to employ a sloped demand curve in the capacity auction, many of the coal resources would recover their GFCs through the MISO markets in each of the zones. This is particularly important for merchant generators who are unable to recover their GFCs through rate cases. This raises substantial concerns because a large share of these resources remain necessary in the near-term to satisfy MISO's resource adequacy requirements.

Were MISO's coal resources to base retirement decisions on investment signals from MISO's current capacity construct, around 18 GW of coal would retire under the prevailing auction clearing prices. This is unrealistic in the near-term because resource retirements would result in higher capacity prices once shortages begin to occur. A final analysis detailed in Section VI.F of the Analytic Appendix shows that if all coal resources were to offer at their GFC levels, PRA clearing prices would increase to at least $149 per MW-day in all zones and coal retirements would total roughly 5 GW. This underscores how MISO's poorly designed capacity market can distort market signals and lead to inefficient investment and retirement decisions.

G. Capacity Market Design

We have consistently expressed concern in the past about the low clearing prices in the PRA and have explained that it is attributable to a fundamental design flaw. The PRA is adversely affected by at least two factors discussed in this subsection:

(1) The design of the PRA demand curve; and

(2) The local resource zones that do not adequately reflect transmission limitations.

PRA Demand Curve

The demand for capacity in the PRA continues to poorly reflect the true reliability value of capacity and undermines the market's ability to provide efficient economic signals. The demand in MISO's planning resource auction is set at the single level necessary to satisfy MISO's minimum planning reserve requirements with the price capped at a deficiency price based on the cost of building a new resource. This single-quantity demand represents a vertical demand curve for the market.

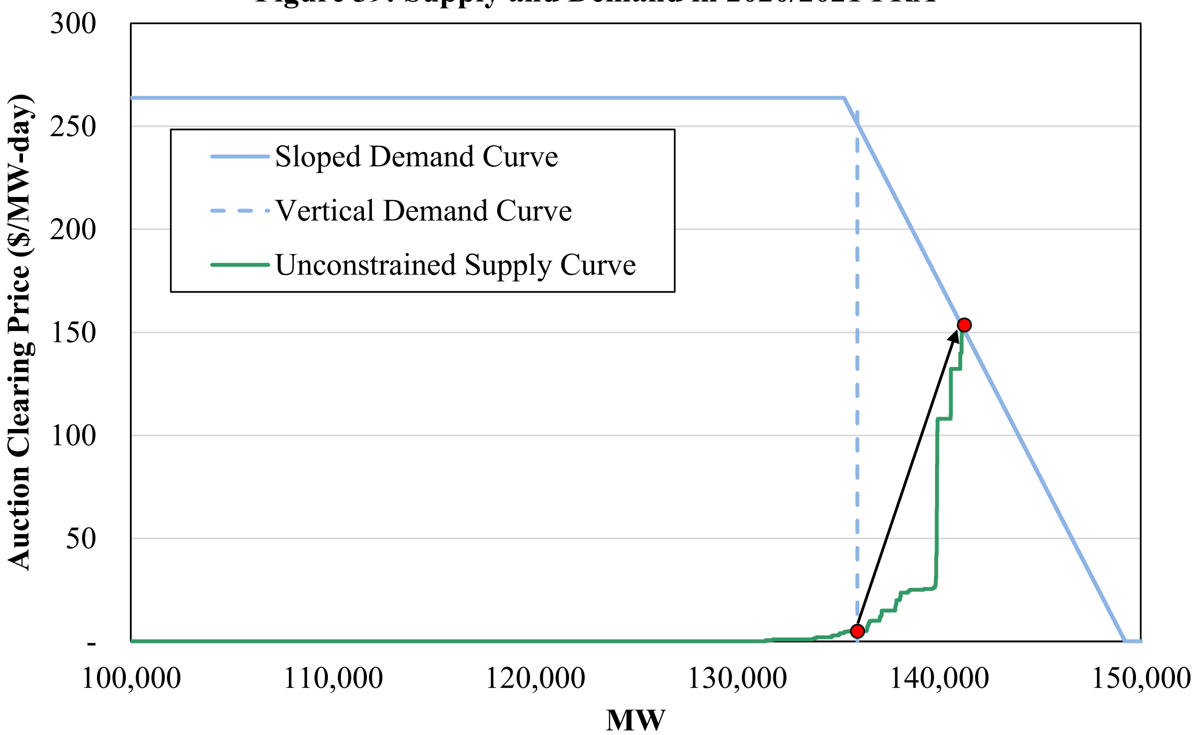
The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. The contribution of surplus capacity to reliability can only be captured by a sloped demand curve. The fact that a vertical demand curve does not reflect the underlying value of capacity to consumers is the source of our major concerns associated with the PRA market design.

We have sought to address this flaw by recommending that MISO implement a sloped demand curve. A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power because a market with a vertical demand curve is highly sensitive to withholding. Clearing at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless because the foregone capacity sales would otherwise be priced at close to zero. The benefits of a sloped demand curve will increase as planning reserve margins fall as competitive resources continue to retire.

To demonstrate the significance of the design flaw, we simulated the clearing price in MISO that would have prevailed in the 2020/2021 PRA if MISO employed sloped demand curves in the PRA (Appendix Section VI.G describes the assumptions underlying this curve). Figure 39 depicts this simulation. 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 each resource's offered capacity that was not stranded behind transmission constraints. Resources that are self-supplied in accordance with Fixed Resource Adequacy Plans are represented with $0 offers.

In the 2020/2021 MISO PRA, Zones 1 through 6 and 8 through 10 cleared at clearing prices between $4.75 per MW-day and $6.88 per MW-day. These prices are close to zero, reflecting less than 3 percent of the CONE for investing in a combustion turbine in the Midwest. Zone 7 was short of the local clearing requirement and cleared at the $257.53 per MW-day price cap set at the CONE in that region. Almost 136 GW of capacity cleared in the 2020/2021 auction.[39]

Figure 39: Supply and Demand in 2020/2021 PRA



In our sloped-demand-curve simulation, we found that more than 141 GW of capacity cleared, while 431 MW of offered capacity would not have cleared. Auction clearing prices by zone would have been:

- $148 per MW-day in Zones 1 through 6, 8, and 10, and for all external zones;
- $155 per MW-day in Zone 9; and
- $270 per MW-day in Zone 7, which is 5 percent higher than CONE.

[39] In January 2020, FERC accepted MISO's Tariff revisions (Docket No. ER20-129-000) that disqualify resources that will be on outages that exceed 90 days during the first 120 days of the planning year, and this revision resulted in a significant amount of capacity to be disqualified because of extended outages across the 2020 summer months.

There was also no stranded capacity because: a) the Sub-Regional Power Balance Constraint did not bind, and b) export-limited zones did not bind. The prices in all zones except for Zone 7 are roughly 30 times higher than the actual clearing prices. While the sloped demand curve prices are a more accurate reflection of the marginal reliability value of capacity in MISO, they are still roughly half of the CONE for new resources. Importantly, however, this price would motivate competitive suppliers to keep economic resources from retiring or exporting to other RTOs because it would cover the GFCs for most of the existing resources.

This enormous difference in price highlights the serious impact of the flaw in the current market design and the benefits of remedying the flaw by implementing a sloped demand curve.

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

Based on the simulation described in the prior subsection, we estimated how improving the design of the PRA would have affected various types of market participants in the 2020/2021 PRA. We calculated the simulated settlements for each participant based on their net sales. We then aggregated the participant-level results into three categories: competitive suppliers, competitive retail LSEs, and vertically-integrated utilities, which is shown in Table 16.

Table 16: Effects of Sloped Demand Curve by Type of Participant
2020/2021 PRA

Type of Participant	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated	$677.0M	-$653.0M	$24.0M
Merchant Generators	$622.5M		$622.5M
Retail Choice Load		-$646.5M	-$646.5M

This table shows that the vertically-integrated utilities would have benefited in aggregate by $24 million from the use of the sloped demand curve. The effects on the vertically-integrated utilities are very small because they tend to self-supply most of their requirements through owned generation or bilateral purchases. Hence, their exposure to the PRA price is relatively small. Overall, more than half of the large, vertically-integrated utilities would benefit from the sloped demand curve because they can sell their excess resources at an efficient price.

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 significantly more revenue (close to $625 million) through the PRA, providing more efficient signals to maintain existing resources and build new resources. This effect will grow as capacity margins fall in MISO.
- Likewise, costs borne by competitive retail loads would have risen by almost $650 million. This is desirable because it provides incentives for these LSEs to arrange for their capacity needs and contribute to satisfying MISO's resource adequacy needs.

Reforming the Accreditation of Capacity in MISO

MISO's historic accreditation methodology tended to provide excessive capacity credit to its resources because it did not account for unreported outages and derates or any type of outage other than a forced outage. The current accreditation also tends to under-weight forced outages for units that are not called on to run frequently. For example, a unit that is only committed 4 percent of the hours and fails to start half of the time will appear to have a very good forced outage rate of 2 percent.

MISO filed a Tariff change approved by FERC in March 2019 that reduces the accredited capacity of resources taking short-notice planned outages that occur during emergency conditions.[40] However, this change had an extremely small effect because emergency events are very infrequent and because it does not include unreported outages and derates. Hence, it does little to address the accreditation concerns discussed above.

Therefore, we continue to recommend additional changes to resource accreditation based on the availability of resources during the tightest margin hours of the year. This methodology would include all types of outages and derates including those that are not reported to MISO. The changes to the methodology would measure resource availability at times when the system needs them the most – when the day-ahead supply margin (total available supply minus total demand, including reserves) is smallest (we use the tightest 5 percent of hours).

The estimated impact of the proposed changes is shown in Table 17. The table shows the amount of capacity in each major resource category along with the median value of the current UCAP derate (the XEFORd rate) and the UCAP derate under the IMM proposed methodology. This analysis is discussed in further detail in Section VI.G of the Analytic Appendix.

Table 17: Alternative Capacity Accreditation Derates by Resource Class

Resource Class	Capacity (MW)*	Current UCAP Derate (XEFORd)	IMM Proposal: Outages & Derates in Tightest Hours
Combined Cycle**	17,989	2.6	17.5
Coal	50,474	7.6	20.2
Combustion Turbine (Gas)	27,127	4.9	12.4
Nuclear	12,393	2.4	13.7
Steam Turbine (Gas)	12,787	6.4	19.7

* Includes units with an obligation to offer UCAP in the 2020/21 PRA. Excludes a small number of units that have an XEFORd of 0 and newer units that were not in operation prior to 9/1/2019.

** A few additional units are excluded from this resource class due to anomalous outage patterns.

40 Docket No. ER19-915-000.

Table 17 shows that the changes proposed by the IMM would have a significant impact on the accreditation of resources. The IMM proposal is more effective in estimating resources' expected contribution to maintaining reliability in the most critical hours than the existing accreditation methodology. This is particularly true for older peaking resources that are rarely needed but frequently fail when committed, as well as older gas steam and coal-fired resources that have long notification and start-up times. These resources provide much lower reliability value to the system because they cannot be utilized if fluctuations in intermittent resources, unexpected changes in loads, or generation outages lead to tight conditions when they happen to be offline. Our proposed accreditation changes address all of these issues.

The fact that the accreditation of resources would fall would not necessarily increase capacity prices significantly for two reasons:

1. MISO would be procuring more reliable UCAP under this methodology so its capacity requirements would fall significantly; and
2. Suppliers would likely make changes in their maintenance and outage scheduling patterns to avoid being unavailable in tight hours, which we believe would significantly change accreditation levels for some of the resource types shown in Table 17:
    - Combined-cycle generators show an increase in the median UCAP derate to 17.5 percent, which can be substantially mitigated by altering the timing of planned outages.
    - Nuclear generators schedule planned outages more than 3 years in advance and have very little flexibility in maintenance schedules. These generators show an increase in the median UCAP derate of 13.7 percent. A large portion of this increase is from the scheduling of these planned outages during tight periods.

On the basis of these results, we recommend that MISO modify the current capacity accreditation construct to adopt changes that would be consistent with the IMM proposal.[41] An additional benefit of this approach is that it would resolve all concerns with the accuracy and completeness of the reported outages and derates because the accreditation would include all outages and derates, whether they are reported or not.

Other Recommended Improvements to the PRA

Although a sloped demand curve 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.

41 In 2019, MISO began exploring a similar accreditation methodology based on availability during the tightest hours but is still in the early stages and there has not been any FERC filings. See Resource Availability and Need (RAN) - Resource Accreditation (RASC010).

Accreditation of Emergency Resources. Emergency-only resources, including LMRs and emergency-only 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 2 hours warning. Therefore, we recommend that MISO develop a reasonable methodology for quantifying the capacity credit for emergency-only resources in the PRA.

Seasonal Capacity Market. A seasonal market would better align the revenues and requirements of capacity with the value of the capacity. In its initial work on a possible seasonal capacity market, MISO proposed two seasons: summer and winter. We have recommended that MISO define four seasons, which would facilitate savings for participants by:

- Allowing high-cost units to suspend during the shoulder months or not keep the unit staffed in the months when they are unlikely to be economic to dispatch; and
- Allowing suppliers to retire or suspend units at four points in time during the year (between seasons) without having to purchase replacement capacity.

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.

Disqualifying Energy Efficiency (EE) from Selling Capacity. As discussed in more detail in Section IX.D, EE measures do not provide a dispatchable product or provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. Additionally, the quantification of the EE is based on speculative assumptions and the resulting capacity payments to EE represents an inefficient subsidy. Therefore, we recommend MISO disqualify EE measures from satisfying capacity requirements or participating in the PRA.

VII. External Transactions

A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because it has 12 interfaces with neighboring systems with 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 2019:

- Day-ahead and real-time net scheduled interchange (NSI) averaged 5.2 and 6.2 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 2019.
  - Hourly average real-time imports from PJM were 2.7 GW, up 30 percent from 2018.
  - 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 the interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area. Significant events in 2019 underscore this:

- On January 30, MISO declared a Maximum Generation Event in the North because of extremely cold temperatures. Prices in MISO were consistently above $600 per MWh between 8 a.m. and 11 a.m. Net imports increased by almost 10 GW above the day-ahead scheduled interchange by noon in response to the price signals.
- On November 13, record cold temperatures that affected much of the Southeast and SPP resulted in an RDT limit reduction and very high prices in the South. Exports from the South were as high as 1,000 MW when prices spiked to $1,000 per MWh. In response, exporters cut the majority of their exports and caused prices to fall in the South.

Participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. Additionally, the lack of RTO coordination of participants' schedules causes aggregate changes in transaction schedules to be far from optimal. To evaluate the efficiency of interregional 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 2019, slightly less than 70 percent of the transactions with both PJM and 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 interchange or less interchange. Many hours still exhibit large price differences that offer substantial production cost savings.

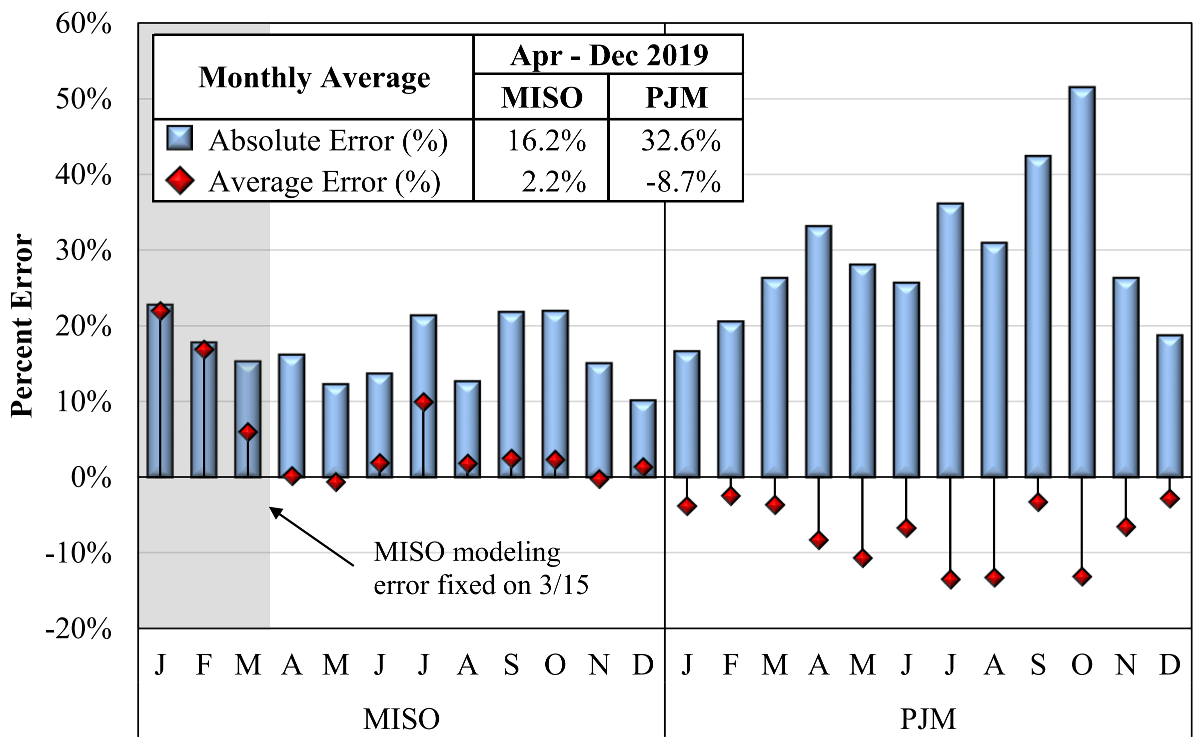
B. Coordinated Transaction Scheduling

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.

Up until early 2019, there had been almost no participation in CTS. In the summer of 2018, MISO identified a forecasting error that was addressed in March 2019. In 2019, the average quantity of CTS transactions offered and cleared rose to 220 MW and 65 MW, respectively. Over 90 percent of these transactions were in the import direction. While use of CTS increased slightly in 2019, the transactions remain a small 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 difference between the actual LMP and the forecasted price used for CTS.

In Figure 40, we show the differences by month as a percent of average LMPs, in both average and absolute average terms.

Figure 40: MISO and PJM CTS Forecast Errors
2019



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM. From April through December, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -8.7 percent, and the average of the absolute difference was 32.6 percent.[42] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was 2.2 percent, and the average of the absolute difference was 16.2 percent. When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface. In fact, the poor forecasts suggest that CTS is likely clearing many transactions that are uneconomic based on real-time spreads, as well as not clearing 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 consider modifying the CTS to clear transactions every 5 minutes through UDS based on the most recent 5-minute prices in the neighboring RTO area. Finally, we encourage MISO to implement a CTS process with SPP based on this type of 5-minute clearing process.

C. Interface Pricing and External Transactions

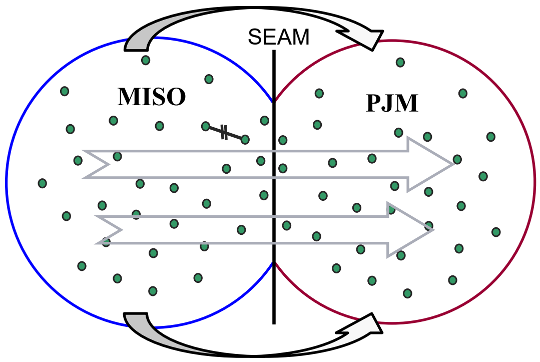
Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule flows between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- 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 their system (the system marginal price, or "SMP"). Participants would respond by scheduling 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.

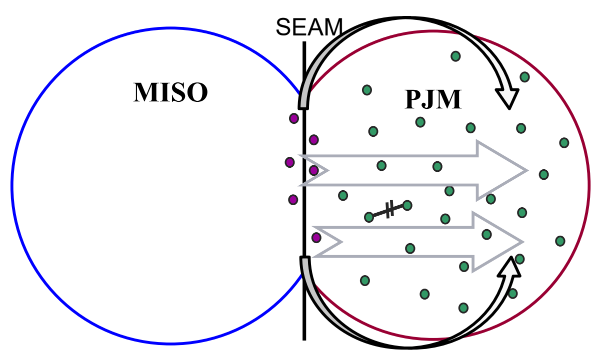
42 PJM's forecast prices come from its intermediate term security constrained economic dispatch tool (IT SCED). We excluded January through March from annual averages because of the aforementioned modeling error.

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 below on 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 of 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. 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 on the right below. 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 of its interfaces.

We have recently studied interface pricing at the MISO-SPP interface in collaboration with the SPP MMU. We have verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. 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. Because MISO receives no credit for this relief and no reimbursements for the millions of dollars in costs it incurs each year, 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 all of 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 2019. 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 (625) but very high in some local areas, such as WUMS (2392) and the South Region (4028), 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, 73 percent of the active BCA constraints had at least one pivotal supplier.
- Nearly all of the binding constraints into the two MISO South NCAs and the three Midwest NCAs had at least one pivotal supplier.

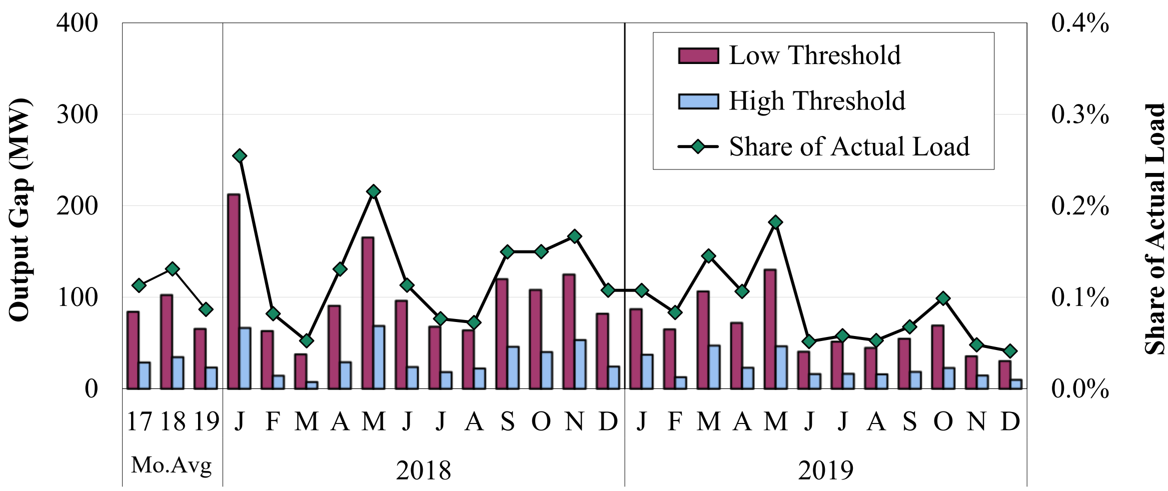
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 –0.1 percent in 2019, varying monthly from a high of 5.4 percent to a low of -3.7 percent. The negligible average mark-up indicates that MISO's energy markets produced very competitive results.

Figure 41 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 mitigation threshold (the "high threshold") and a "low threshold" equal to one-half of the conduct mitigation 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 41: Economic Withholding – Output Gap Analysis
2018–2019



Low Threshold Results by Unit Status (MW)

Offline	6	12	13	30	0	0	3	41	12	4	9	17	17	6	3	30	2	31	12	15	8	9	9	10	15	10	5
Online	78	90	52	182	63	37	88	124	84	64	54	102	90	118	78	56	63	75	60	114	33	42	36	45	54	25	25

High Threshold Results by Unit Status (MW)

Offline	6	10	11	20	0	0	2	35	9	3	9	16	16	5	3	24	2	28	8	10	7	9	8	8	11	10	5
Online	23	24	12	46	14	7	26	33	15	15	13	30	24	48	21	13	11	19	15	36	9	8	7	10	12	4	4

The figure shows that the average monthly output gap level was less than 0.1 percent of load in 2019, which is effectively *de minimus*. 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 2019 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent, while RSG mitigation rose modestly. 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 it exceeds the conduct threshold and the offer raises 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 conduct threshold of $25 per MWh is used for Dynamic NCAs. No Dynamic NCAs were defined in 2019. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

The incidence of mitigation increased by 17 percent in the real-time market in 2019, but still it was only imposed in less than one percent of hours in the real-time market. 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 not imposed in any hours in the day-ahead market. 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 these needs.

In 2019, RSG mitigation increased by 8 percent. Real-time RSG mitigation increased by 18 percent, largely because of enhanced mitigation authority for resources committed to manage RDT flows into MISO South. VLR requirements are one frequent cause of commitments and RSG. Most VLR commitments are in MISO South and are subject to tighter mitigation thresholds because competition to satisfy these requirements is limited.

IX. Demand Response and Energy Efficiency

Demand Response (DR) involves actions taken to reduce consumption when the value of consumption is less than the marginal cost to supply the electricity. DR 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 it into the MISO markets in a manner that promotes efficient pricing and other market outcomes.

A. Demand Response Participation in MISO

DR resources can be divided into one or more of the following three categories:[43]

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

Table 18 compares the total DR participation in MISO, NYISO, and ISO-NE in the prior three years. The table shows that MISO had more than 13.5 GW of DR capability available in 2019, up five percent from 2018. This total will likely drop over the next few years as a result of MISO's proposed accreditation changes to LMRs discussed below. MISO's demand response capability constitutes more than ten percent of peak load, which is a larger portion than in NYISO but slightly less than in ISO-NE. MISO's capability exhibits varying degrees of responsiveness. Approximately 90 percent of the MISO DR is in the form of LMRs that are interruptible load developed under regulated utility programs and behind-the-meter-generation (BTMG). The MISO DR capability also includes two types of Demand Response Resources (DRRs) that are able to participate in MISO's markets.

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

Table 18: Demand Response Capability in MISO and Neighboring RTOs
2017–2019

		2017	2018	2019
MISO[1]		**11,495**	**12,931**	**13,611**
	LMR-BTMG	3,822	4,496	4,480
	LMR-DR	6,112	7,137	7,684
	DRR Type I	620	621	811
	DRR Type II	0	3	13
	Emergency DR	941	674	624
NYISO[2]		**1,237**	**1,314**	**1,288**
	Special Case Resources - Capacity	1,221	1,309	1,282
	Emergency DR	16	5	6
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**2,655**	**2,988**	**3,309**
	RT DR Resources/DR Assets	683	262	321
	On-Peak Demand Resources	1,418	2,214	2,440
	Seasonal Peak Demand Resources	554	512	548

[1] Registered as of December 2019. All units are MW.
[2] Registered as of July 2019. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Seasonal audited capabilty as of December 1, 2019. Source: ISO-NE Demand Response Working Group Presentation.

B. Demand Response Resources

Only a small portion of MISO's total DR resources are capable of responding to MISO real-time dispatch signals and can qualify as DRRs. These resources can participate fully in the energy, ancillary services, and capacity markets. DDRs 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.[44]
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and, like generating resources, can set prices.

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 are prohibited from

44 Provided that 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.

providing regulating reserves because of the physical requirements; namely, the ability to respond to small changes within four seconds.

Although 41 DRRs were active in the MISO markets in 2019, roughly one-third of these became active in the second half of the year and only cleared a small amount of energy and reserves in the MISO markets. Almost 90 percent of these were DRR Type I resources that provided an average of 17 MW per hour of contingency reserves. As MISO's capacity surplus dissipates because of the retirement of large baseload resources that are largely being replaced by intermittent resources, DR resources are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. It is important, therefore, to ensure that real-time markets produce efficient prices when DR resources are deployed.

C. LMRs and EDRs

While DRRs are valuable for their ability to respond to prices, they are a very small portion of the DR in MISO. The majority of DR in MISO participate as emergency resources, including the LMR and EDR categories. MISO can deploy these resources only during a declared emergency. These resources generally are legacy demand side programs administered by LSEs, 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).

LMRs are planning resources and thus have an obligation to curtail during emergencies. There is no economic offer price, but deployment of LMRs trigger 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 we show below, LMRs make up a large majority of DR in MISO.

In contrast to LMRs, EDRs do not have a must-offer requirement and only reflect a small portion of DR in MISO. These resources specify their availability and costs in the day ahead timeframe. If an emergency ensues in real time, MISO selects EDR offers in economic merit order based on the offered curtailment prices up to $3,500 per MWh. EDR participants who curtail their demand 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, Module E of MISO's Tariff allows DR resources to count toward fulfillment of an LSE's PRMR if the resource is able to curtail load within 12 hours and is available during the summer months. As part of the RAN initiatives, MISO has proposed Tariff changes that reduce the allowable lead time for qualifying LMRs to 6 hours and accredits resources based on the availability throughout the planning year. MISO's proposal would phase in across multiple planning years, starting in 2022/2023, in order to allow participants to modify existing contracts and replace affected capacity.

Prior to 2017, LMRs had not been called in MISO since 2007. They have, however, become increasingly important in both planning and operations during emergency events. Beginning in April 2017 through 2019, LMRs have been deployed five times in MISO South and twice in MISO Midwest. Four of these calls have occurred in January 2018 or 2019 because of unusually cold temperatures. We discuss the 2019 emergency events in detail in Section IV of this Report.

D. Energy Efficiency in MISO's Capacity Market

When demand response assets were introduced in MISO's capacity markets, MISO also allowed energy efficiency (EE) to qualify to provide capacity. The quantity of EE participating in the PRA has been growing rapidly and is playing a more pivotal role in satisfying MISO's resource adequacy needs. Table 19 summarizes the EE quantities over the past four PRAs. In the most recent auction the EE measures cleared 650 MW, equivalent to about one-fifth of accredited wind resource capacity.

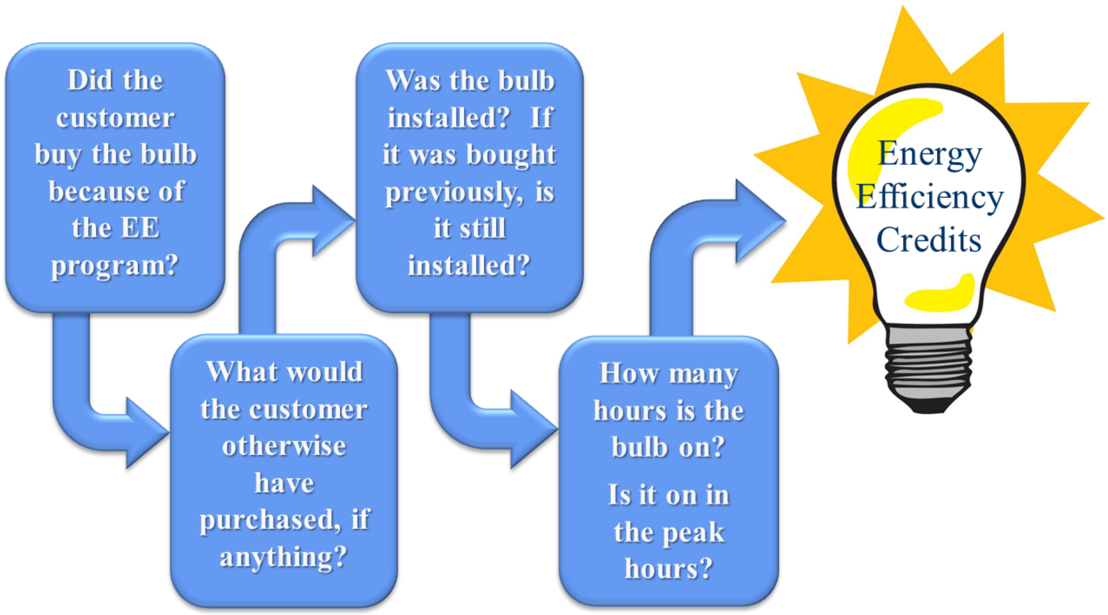
Table 19: Growth of Energy Efficiency in MISO

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

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. Given the rapid increase in EE capacity, it is important that providing credits to EE is justified and that the accreditation of EE is accurate. Our evaluation raises concerns in both regards.

Economic Justification for EE. Making payments to customers directly or to intermediaries that facilitate EE investments is justified to the extent that such payments are efficient and lead to more economically efficient EE investments. Absent MISO's EE program, customers that reduce energy consumption be purchasing energy efficient technologies will receive savings via lower electricity bills. Some states provide a further incentive for such savings via tax credits and rebates. Since electricity rates should include both the energy and capacity costs of serving retail customers, the savings customers receive when investing in EE should reflect the full value of the capacity savings. Therefore, making capacity payments for assumed load reductions essentially double-compensates such customers and is, therefore, not efficient or necessary.

Accuracy of EE Accreditation. Even were such payments justified, MISO must be able to accurately calculate how much the load has been reduced by EE in peak hours. Unfortunately, this is not possible because MISO must make an array of speculative assumptions as illustrated below for a lighting program.



Although MISO has been diligent to make the most reasonable assumptions they can, the resulting capacity credits are unlikely to be accurate.

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 investments by explicitly grossing up their forecasts to counter the effect of EE measures. If the capacity requirements of the LSE in question fall as peak load falls, it will receive a windfall at the expense of other MISO customers. MISO acknowledges this concern by limiting the period in which an EE measure is awarded capacity to the initial deployment year and three subsequent periods.

Since MISO's EE program is not addressing a known economic inefficiency, we recommend MISO disqualify EE measures from participating in MISO's capacity auction.

E. Conclusions

Demand response is a valuable capability and improves the performance of the market. MISO has a substantial amount of DR capability and it has been growing in recent years. We expect that MISO will rely on DR more frequently in the coming years as its capacity margin falls. This report identifies concerns in Section IV regarding the accessibility of LMRs during emergencies and in this section regarding the justification of enabling EE to satisfy capacity requirements. We recommend improvements in both areas to address these concerns.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently in 2019 overall, we recommend a number of improvements in MISO's market design and operating procedures. These twenty-nine recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion: 12 total, 3 new.
- Operating Reserves and Guarantee Payments: 2 total, 0 new.
- Dispatch Efficiency and Real-Time Market Operations: 6 total, 1 new.
- Resource Adequacy: 9 total, 1 new.

Twenty-four of the recommendations discussed below were recommended in prior State of the Market Reports. This is not surprising because some of the recommendations can require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes. Since these processes can be time consuming and software changes must be prioritized with other software projects, recommendations can take multiple years to complete.

MISO addressed six of our past recommendations in 2019 or early 2020. In November 2019, MISO provided the MISO Board of Directors a detailed summary of MISO's review and response to the outstanding IMM recommendations.[45] 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 Pricing and 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, longer-term forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest priorities from an economic efficiency standpoint must be to produce real-time prices that accurately reflect supply, demand, and network conditions. A number of the following recommendations address this area.

45 See Memorandum MISO Response to the IMM 2018 State of the Market Report, from Clair Moeller President, to MISO Market Committee of the Board of Directors, November 4, 2019.

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 of 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 is evident when the NMRTO's cost of providing relief (shadow price) is much lower than the MRTO's cost of managing the constraint. 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 not converging with the MRTO's shadow price, the software should be modified to increase the relief requested from the NMRTO. This would lower congestion costs and accelerate convergence.

At other times, the software can request too much relief and cause constraint oscillation. Oscillation is a term used by M2M operators indicating that the constraint is binding and unbinding in subsequent intervals. In these instances, the NMRTO over-relieves the constraint in the first interval such that it unbinds, which causes the MRTO to ask for no relief in the second interval and for the constraint to bind severely in the third interval.

To improve the M2M coordination, we recommend that MISO consider the following short and long-term improvements to the relief requests. In the short-term, MISO should base relief requests on the RTOs' respective shadow prices and implement an automated means to control for constraint oscillations. In the long-term, MISO should use dynamic transmission constraint demand curves to more accurately reflect the actual relief provided by the NMRTO in the dispatch of the MRTO.

Status: This is new recommendation.

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

Similar to relief request software, the rules for determining constraints that qualify as flowgates have not been significantly revised since 2004. The original intent 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. Coordinating on such constraints will also improve price signals in the NMRTO's area. Currently, a constraint will be identified as a M2M constraint when the NMRTO has:

- a generator with a shift 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 may do a better job of identifying the most valuable constraints to define as M2M constraints. Our analysis shows that a number of constraints are coordinated where the NMRTO has very little effective relief or market flow, while other constraints are not coordinated where in aggregate the NMRTO does have significant effective relief. 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 as a replacement for the current five percent shift factor test.

Status: This is new recommendation.

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

As reported in our SOM for several years, there are unrealized annual savings well in excess of $100 Million from increased use of Ambient Adjusted Ratings (AARs) and Short-Term Emergency Ratings (STEs). (See SOM Recommendation 2015-2). Although the most important step will be MISO's Transmission Owners (TOs) committing to providing AARs and STEs, MISO's current systems and processes would not allow it to capture all of these savings. This report identifies key areas where we recommend MISO make enhancements, including improving:

1. System Flexibility: MISO should enable rapid additions of new elements to AAR programs. Today, new elements can be added manually via phone calls or via automated ICCP, which can require model updates that are only implemented once per quarter.

2. Forward Identification: MISO should also support identification of 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 general process to receive or use forecasted ratings. In combination with other elements of this recommendation, enabling forecasted ratings would enhance both reliability and efficiency.

In addition, MISO should 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 and Emergency Ratings. We recommend that MISO make necessary changes to enable receipt and maintenance of this information, which will improve its situational awareness in real-time operations and improve the accuracy of its transmission planning results.

Although the benefits of the last three improvements would be difficult or impossible to quantify, we believe the reliability and market benefits are likely large and will grow in the future.

Status: This is new recommendation.

2018-1: Improve emergency pricing by establishing an efficient default floor and accurately accounting for emergency imports

Emergency pricing is a key element of the MISO market because it is intended to ensure that prices are set that efficiently reflect emergency conditions during the events. These prices, in turn, facilitate efficient responses that allow MISO to resolve the emergency. Additionally, efficient shortage and emergency pricing are the primary incentives for both availability and flexibility. The performance of emergency pricing can be assessed because MISO has experienced several emergencies over the past few years. Our evaluation of MISO emergency pricing has revealed some important observations:

- The Emergency Tier I and Tier II Offer Floors have not been established at reasonable levels. These default floors are set by a supplier's offer, which has resulted in them often being inefficiently low and can result in them being inefficiently high.
- The emergency pricing model incorrectly calculates ex-post RDT flows when emergency interchange transactions are dispatched down during regional emergencies.

Therefore, we recommend that MISO implement specified emergency default floors that result in price levels that reflect the severity of the emergency and correct the flaw in the RDT flow calculation.

Status: MISO agrees with the importance of emergency pricing and the two recommended improvements, although it has indicted the IMM's recommended solution is significantly impacted by the ongoing Market System Enhancement (MSE) program. In the 2020 MISO work plan priority it was designated as low. However, MISO intends to work with the IMM and participants to develop improved emergency offer floors and anticipates a FERC filing late in 2020. MISO believes the software changes to address the emergency offer floors are minimal.

Next Steps: Develop a proposal with the IMM and Stakeholders to improve the emergency offer floors. MISO will coordinate with the Market System Enhancement (MSE) effort on software changes for import accounting to fix the flaw in the ex-post RDT flow calculations.

2018-2: Lower GSF cutoff for constraints with limited relief

MISO currently employs a 1.5 percent generator shift factor (GSF) cutoff to identify which generators to optimize in its dispatch when managing the flows on a transmission constraint. This limits the number of generators that are assumed to substantially affect the flows on a constraint and is done primarily to ensure that the dispatch model will solve in a reasonable amount of time. In most cases, this is a reasonable cutoff. However, there are some constraints, generally lower voltage facilities, where employing a 1.5 percent cutoff eliminates most of the economic relief available to manage the constraint. This can greatly increase the costs of managing the constraints and can, in some cases, raise reliability concerns. Substantial costs and reliability effects are incurred currently because the cutoff prevents the market from managing and pricing congestion on some constraints. In 2019, $67 million in congestion occurred on such constraints.

To improve the management of congestion on these constraints, we recommend that MISO implement the capability to employ a lower GSF cutoff for the dispatch model for a limited number of constraints. In addition to improving economic efficiency, this will also address some M2M settlement and FTR funding issues that arise because the market flows calculated for M2M settlements and the FTR market do not employ a GSF cutoff. It is important to note that MISO's M2M coordination partners, PJM and SPP, have both eliminated their GSF cutoffs when dispatching and pricing coordinated flowgates.

Status: MISO has thus far prioritized this as low and it has not been evaluated by MISO, although we continue to assign this a high priority in the Integrated Roadmap. MISO has indicated that it is evaluating this recommendation in 2020.

Next Steps: MISO should complete its evaluation of this recommendation to allow it to prioritize this recommendation. MISO has indicated that the IMM's recommended solution is significantly impacted by the ongoing Market System Enhancement (MSE) program.

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

We recommend that MISO reform its ORDC. As the primary determinant of shortage pricing in MISO's energy markets, the ORDC must accurately reflect the value of reliability. Efficient shortage pricing is the primary incentive for both availability and flexibility. This will also reduce reliance on the capacity market for providing long-term price signals for investment and retirement. MISO's current ORDC does not reflect reliability value, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's recent changes will 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.

An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to:

*probability of losing load * net value of lost load (VOLL)*

The economic ORDC has substantial advantages. The shortage pricing under the economic ORDC will track the escalating risk of losing load as shortfalls increase. In the range where most shortages occur, the economic ORDC is sometimes higher and sometimes lower than MISO's current curve, so it should not substantially increase consumer costs for these shortages. The resulting prices will send more efficient signals for participants to take actions in response to the shortage, which helps 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 counteract the uncertain output of the intermittent resources.

For MISO to implement this recommendation, it would need to update its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load. We have reviewed the studies of VOLL and 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 allow the ORDC to plateau at a lower price level for deep shortages, such as $10,000 per MWh. Although this price levels may seem very high, almost all of MISO's shortages have been and are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.

<u>Status:</u> MISO has indicated general agreement with the recommendation. MISO implemented changes related to FERC Order 831 on December 1, 2019. Those changes included raising the Energy Offer Hard Cap to $2,000 and adding another step to MISO's ORDC at $2,100 per MWh. This item is currently classified as a High by MISO going into the Integrated Roadmap Stakeholder voting process.

<u>Next Steps</u>: MISO will be reviewing several aspects of shortage and emergency pricing (see IR071). In 2020, MISO plans to: (1) evaluate the IMM's methodology to create the loss-of-load probability curve for different reserve levels or develop an alternative methodology; (2) work with the IMM to establish a reasonable cost of shedding firm load (i.e., VOLL); and (3) begin to engage Market Participants to discuss proposed changes.

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. In other words, MISO can only deny or reschedule a planned outage if it threatens reliability. 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 2019, multiple simultaneous generation outages contributed to more than $150 million in real-time congestion costs – nearly 25 percent of real-time congestion costs.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to MISO's, with the exception of ISO New England. The ISO New England does have the authority to examine economic costs in evaluating and approving transmission outages. It can deny or move outages if doing so will result in "significantly reduced congestion costs."[46] The ISO New England program has been found to have been very effective at avoiding unnecessary congestion costs.[47]

We recommend that MISO explore alternatives to improve 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.

Status: MISO indicated agreement with the issue, but has not supported seeking additional outage coordination authority and it is currently listed as Inactive. MISO is considering other improvements under the Resource Availability and Need (RAN) initiative. Economic considerations for outage coordination continues to be on the work plan, but the current target within MISO is to start scoping is 2024.

Next Steps: Consider accelerating the process to address this recommendation and filing for increased authority to coordinate outages.

2015-1: Improve ability for online resources to set prices in ELMP and suspend pricing by offline resources

MISO has partially implemented this recommendation by allowing resources that can be started within 60 minutes (previously limited to 10 minutes) in 2017, and allowing resources committed in the day-ahead market to set prices in November 2019. These changes have resulted in significant improvements.

Even with these changes, our analysis continues to indicate that ELMP could be improved by removing the ramp restriction that limits the ability of FSRs to set prices when they are the marginal source of supply in MISO. This can be attributed to modeling assumptions governing the ability of peaking resources to ramp down and other resources to ramp up in the ELMP model. To address this issue and allow peaking resources to set prices efficiently, we recommend that MISO relax the ramp-down limitation for FSRs in the ELMP model.

46 ISO-NE Market Rules: Section III, Market Rule 1 – Appendix G; June 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency, Presentation by ISO NE.

47 Ibid.

In addition, we continue to find that ELMP's offline pricing has generally resulted in inefficiently low ELMP prices during shortage conditions. The offline peaking resources that set prices are rarely utilized and economic in the periods in which they set prices. Hence, we continue to find that it is adversely affecting MISO's real-time prices and recommend that MISO suspend the offline pricing.

Status: MISO is also evaluating the relaxation of the ramp constraints on FSRs and the recommendation to discontinue allowing offline FSRs to set prices for congestion management. MISO discussed the ramp constraint evaluation in an ELMP III whitepaper and plans to continue this evaluation. MISO also plans to work with the IMM to investigate the use of offline FSRs to set prices.

Next Steps: We note that MISO closed the related Roadmap Item (MR018) and this is not being discussed in the current Roadmap prioritization. However, we recommend that MISO assign a high priority to completing its evaluation and considering implementing the remaining recommended changes to the ELMP model to allow it to set efficient real-time prices.

2015-2: Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities

Our analysis of transmission ratings submitted to MISO by transmission owners for use in MISO's real-time and day-ahead markets continues to show that few transmission owners are utilizing MISO's capability to accommodate temperature-adjusted or "ambient-adjusted ratings" (AARs). We have found that most transmission owners provide seasonal ratings only, and that seasonal ratings can be up to 30 percent lower than the ratings that may be reliably used based on actual ambient temperatures. Our analysis showed potential savings from reduced congestion costs of $85 and $66 million in 2018 and 2019, respectively, if transmission owners had provided temperature-adjusted ratings.

Additionally, the transmission owner's agreement calls for transmission owners to provide short-term emergency ratings (STEs), which can be 10 to 15 percent higher than the normal ratings. Our analysis also shows potential savings in congestion costs of $66 and $48 million in 2018 and 2019, respectively, could have been achieved by ensuring that all transmission owners provide short-term emergency ratings that can be used by MISO as appropriate.

In 2019, FERC began considering whether to make submission of AARs a broad requirement.[48] While this may become a specific requirement we continue to recommend that MISO work with transmission owners to voluntarily ensure more complete and timely use of both temperature-adjusted ratings and short-term emergency ratings.

48 See Docket No. AD19-15 Managing Transmission Line Ratings.

Status: In 2019, MISO and the IMM worked with several TOs to evaluate the suitability and benefits of providing AARs and STEs, however, progress continues to be limited.

Next Steps: MISO should increase the priority of working with TOs to identify and implement AARs and STEs. The IMM will continue to work with MISO to solicit agreements from transmission owners to provide AARs and STEs.

2012-5: Introduce a virtual spread product

When attempting to profit from congestion-related price differences, many virtual traders clear similar virtual supply and demand volumes to buy or sell the flows on a constraint without taking any energy price risk. Currently, the most effective strategy for clearing an energy-balanced portfolio is to submit price insensitive virtual bids and offers. A virtual product enabling participants to arbitrage congestion spreads in a price-sensitive manner would be more effective and efficient. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., by scheduling a transaction). This would reduce the risk participants currently face when they submit a price-insensitive transaction because price-insensitive transactions can be highly unprofitable for the participant. They can also produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO originally agreed with this recommendation and the proposed resolution, but in 2018 MISO indicated that technical feasibility was a concern under the current systems. Hence, this recommendation is included in MISO's Roadmap as a Parking Lot item pending performance enhancements expected from the Market Systems Enhancement.

Next Steps: The IMM agrees with MISO's decisions to consider this recommendation further upon completion of the Market System Enhancement.

2014-3: Improve external congestion related to TLRs by developing a JOA with TVA and IESO

As noted in prior years, the integration of MISO South has increased the frequency of TLRs called by TVA. Substantial benefits for MISO could be achieved by developing a joint operating agreement that would allow MISO's day-ahead scheduled flows to be considered firm in the relief calculations. In addition, the TLR process could be replaced with a coordination process that would allow MISO and TVA to procure economic relief from each other. Additionally, IESO has begun calling costly TLRs frequently in 2020, so expanding this recommendation to include the development of a JOA with IESO is warranted.

Status: MISO agrees with this recommendation. In the last few years, MISO has met with TVA a number of times to resolve specific transmission coordination and TLR issues. MISO has also proposed a JOA that would allow MISO and TVA to provide economic redispatch under certain circumstances, but no agreement was reached. In late 2019, MISO indicated that these discussions would likely continue into 2020.

MISO has indicated that it is addressing these inefficiencies from TLR on TVA flowgates through additional broader solutions. MISO points to efforts with the Congestion Management Process (CMP) Working Group on improvements in TLR relief requests and on implementing the Parallel Flow Visualization (PFV) targeted for end-of-year 2020. While we believe both of these efforts are important, they do not address the more direct need to rationalize the TLR processes and to pursue more equitable and efficient congestion management processes with TVA.

<u>Next Steps</u>: We continue to monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs, including when TLRs are called on flowgates as proxies for lower-voltage constraints where MISO has little ability to provide cost-effective relief and where local actions (redispatch and reconfiguration) are likely far more effective. MISO should continue to attempt to negotiate JOAs with both TVA and IESO that will allow economic coordination and redispatch to efficiently manage congestion on their respective systems.

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 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.

<u>Status</u>: This recommendation was originally made in our *2012 State of the Market Report.* MISO originally focused only on the PJM interface in discussing this issue with its stakeholders. For the PJM interface, MISO ultimately decided to implement PJM's common interface, but our evaluation of the common interface has demonstrated that this was a mistake. We encourage MISO to begin a process of transitioning to a more efficient solution.

MISO has indicated agreement with this recommendation but has not begun work to address the pricing issues at all of MISO's other interfaces, and it is currently inactive in the MISO Roadmap. Therefore, we continue to recommend that MISO take any necessary steps to remove external congestion from its interface prices at all other interfaces. 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: Develop the workplan necessary to modify its interface prices as part of its Market Systems Enhancement.

B. Operating Reserves and Guarantee Payments

Many of MISO's reliability needs are addressed through its operating reserve requirements that ensure resources are available to produce when system contingencies occur. However, to the extent that MISO has system needs that are not addressed by the operating reserve requirements, MISO may take out-of-market actions to commit resources that are not economic at prevailing prices and, therefore, 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 these needs efficiently and allow the market prices to reflect the costs. The recommendations in this section are generally intended to improve this consistency between market requirements and operating requirements. This section also recommends changes in guarantee payments designed to improve participants' incentives.

2010-11: Incorporate expected deployment costs into the selection criteria when clearing reserve products.

The MISO ancillary services market does not consider the expected costs of deployment when clearing reserve products; rather, the availability offer is the only economic consideration. When deployed, reserve providers may be eligible for Price Volatility Make Whole Payments or Revenue Sufficiency Guarantee payments that cover start-up, hourly and incremental energy costs. Ignoring these risks results in an inefficient selection of reserve providers. By factoring the expected costs of deployment into the scheduling process, MISO will reduce uplift costs without limiting the ability of high-commitment cost resources to participate in the market.

In our 2016 report, we removed this recommendation because the exposure declined when the most costly resource stopped participating in the market. In this report, we are reinstating and broadening the scope of the 2010 recommendation as increased participation from DRR Type I Resources and ESRs and the introduction of the STR product have renewed its significance. Including the expected value of the deployment costs in the procurement process would result in more efficient reserve scheduling. Hence, we recommend that MISO address this issue in one of two ways, either by:

- Calculating the expected value of the out-of-market deployment cost for each unit, and adding that expected cost to each unit's reserve offer; or
- Eliminating guarantee payments made to reserve providers when they are deployed.

Although the first option is more difficult, it is a superior approach because it reduces the risks faced by these participants and facilitate their participation in the market when they are economic.

Status: As noted this recommendation was originally made in the *2010 State of the Market Report* and then was removed in our 2016 report. We are reinstating this recommendation and are providing new analysis in this report. We have presented this in the MISO Integrated Roadmap process.

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

Regional emergency events have sometimes caused MISO to exceed the RDT. To avoid this in the future, MISO will hold regional reserves that will better allow it to respond to regional system contingencies. While we recommended these changes in MISO reserve markets, MISO should also consider procuring these regional reserves on the RDT from the joint parties. For example, if the RDT limit is 3,000 MW, the parties could agree to sell 500 MW of reserves (allowing MISO to flow 3,500 MW after a contingency). In return, MISO would pay the joint parties the clearing price for regional reserves and pay for the deployment of the reserves.

The deployment cost would be equal to the quantity of the reserves deployed times the shadow price of the RDT (which would generally be $500 per MWh when the reserves are deployed and the RDT substantially exceed its limit). Hence, if the flows rise to 3,500 MW after a contingency, the joint parties would receive 500 MW times $500 per MWh. These costs would naturally be collected through the real-time market as the flows over the RDT rise.

Importantly, MISO has developed a tool to identify the quantity of reserves that may be feasibly deployed given the flows that the deployment would cause on the joint parties' transmission systems.

Status: The RDT Agreement expires in 2021, so this recommendation is timely. MISO agrees there could be potential benefits of this recommendation in the form of reduced reserve and production costs. However, this will require discussions with Southwest Power Pool and the Joint Parties to fully understand the feasibility and costs of this recommendation.

Next Steps: MISO should develop a proposal and quantity the savings of this approach in preparation for the upcoming discussions regarding renewing or replacing the RDT Agreement.

C. Dispatch Efficiency and Real-Time Market 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.

2019-4: Modify CTS to clear CTS transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area

Until early 2019, there had been almost no participation in Coordinated Transaction Scheduling (CTS). 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, therefore, previously recommended that MISO eliminate the fees it charges to CTS transactions and encourage PJM to do the same (see recommendation 2017-2).

However, we have also concluded that persistent forecasting errors by MISO and PJM have likely hindered the use of CTS. Our analysis shows substantial forecast errors in the prices used for CTS, particularly in PJM. From April through December, the average absolute value of the forecast error (between PJM's real-time LMPs and its forecast prices) was 32.6 percent, while the comparable average error for MISO was 16.8 percent.[49] When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface, as well as clearing many transactions that are uneconomic based on real-time spreads or not clearing transactions that would otherwise be 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 5 minutes through UDS based on the most recent 5-minute prices in the neighboring RTO area. The most recent 5-minute prices are a much more accurate forecast of the prices in the next 5 minutes. Additionally, making adjustments every 5 minutes rather than every 15 minutes would result in more measured and dynamic adjustments that would achieve larger savings.

<u>Status</u>: This is a new recommendation.

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 generation emergencies, primarily at the regional level. Based on our review of these events in Section IV.G, we find that MISO's emergency declarations and actions were 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). In some cases, emergency events were not declared after a capacity deficiency had been forecasted or actually

49 PJM's forecast prices come from its intermediate term security constrained economic dispatch tool (IT SCED). We excluded January through March from annual averages because of the aforementioned modeling error.

occurred. In other cases, emergencies have been declared when it is unclear in retrospect that an emergency declaration was needed to prevent a capacity deficiency.

Hence, we recommend that MISO evaluate its operating procedures, tools and criteria for declaring emergencies. This should include clarifying the criteria for declaring differing levels of emergencies, both regionally and for the entire footprint. Additionally, factors that contributed to the operator decisions should be well-logged.

Status: In 2019, MISO worked with the IMM to review changes to MISO's Emergency Operating Procedures and determine if additional documentation is needed for the logging/documentation of events.

Next Steps: Continue to work together to improve the clarity of the procedures and the tools used to trigger the declarations of varying levels and types of emergencies.

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 that the RTOs not 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, which are substantial. Given that a small portion of the offered transactions are scheduled, the reservation charges alone translate to $0.80 per MWh on scheduled imports and more than $3 per MWh on scheduled exports since the start of CTS through December 2019 and largely diminish the incentive to submit CTS bids and offers in lieu of traditional scheduling. This is consistent with reality – CTS offers were small initially in November 2017 but had fallen consistently and were effectively zero for the majority of months in 2018. CTS transactions did increase slightly in 2019 after MISO corrected a forecasting error in the CTS logic, but it remains a small fraction of transactions at the PJM interface.

Additionally, 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.

The decision by the RTOs to apply charges to CTS transactions is regrettable because CTS promises substantial savings and required considerable resources to implement. Therefore, we recommend that MISO unilaterally eliminate all charges from CTS transactions. Although

MISO should encourage PJM to do the same, there is no reason to wait for PJM to agree to eliminate its charges. MISO should also eliminate the requirement that participants reserve transmission for CTS transactions since the RTOs can make interface adjustments by directly utilizing any and all available transmission capability in real time. Hence, there is no reason to require participants to reserve transmission for these transactions.

Status: MISO agrees that CTS has not performed well and that the charges are a factor. However, MISO favors addressing other factors, including reducing the forecasting errors. Although we fully support this intention, it is separable from the negative effects of the charges so both sources of dysfunction in the CTS should be addressed. This item (IR066) was placed in the Integrated Roadmap Parking Lot in 2018 and will be Inactive in 2019 in the Integrated Roadmap. We believe this is is a poor decision because the CTS process will not be effective unless the current charges are eliminated.

Next Steps: We believe MISO should reconsider its decision not to remove the charges that are applied to CTS transactions.

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 have very significant impacts on both market outcomes and reliability. While automated tools and models support most of the market operation, it is still necessary for operators to make decisions and adjustments to model inputs and results.

Although it is necessary and beneficial for operators to have the authority to perform all these actions, 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 evaluation and understanding. 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 forecasted load with the “load-offset” parameter, which are made to account for a myriad of real-time supply and demand factors that cause the dispatch model inputs to be inaccurate.
- Adjustments to TCDCs that are warranted 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 lead to settlement changes tend to be completely and accurately 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, many other actions listed above are logged in a narrative field that is inconsistently populated and difficult to use for evaluation purposes.

Because these actions can have significant cost and market performance implications, we recommend that MISO upgrade its systems and procedures to allow these and other operator actions to be logged in a more complete and detailed manner. In particular, the transition to the Market Systems Enhancement could include enhancements to the logging tools to enable the improved logging.

Status: MISO has indicated agreement with this recommendation. In 2019, MISO reviewed planned improvements with the IMM.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. In 2020, MISO intends to work on a broader, more detailed and integrated solution as part of MISO Communication System (MCS) enhancements.

2017-5: Evaluate the feasibility of implementing a 15-minute day-ahead market under the Market System Enhancement

Currently the MISO day-ahead market is hourly and the real-time dispatch is conducted on a 5-minute basis. When the MISO market was initiated, the overall day-ahead market software performance and timeline did not permit more resolution. However, the hourly granularity creates significant operational drawbacks. By producing hourly schedules based on 60 minutes of ramp capability and hourly load forecasts, the day-ahead schedules cannot track the expected changes in real-time system needs, particularly during ramping periods. It also regularly results in generator schedule changes from hour to hour that are not feasible, which results in substantial make-whole payments.

More granular day-ahead market schedules would lower these uplift costs and better prepare the system to respond to the real-time needs. Therefore, as MISO proceeds with the Market Systems Enhancement effort, we recommend that it evaluate the feasibility of solving the day-ahead market with 15-minute scheduling intervals. With advances in computing power, this is likely feasible and cost-effective.

Status: MISO indicated agreement with this recommendation. However, MISO has removed evaluation of an intra-hour day-ahead market in its MSE Primary Business Requirements and plans to defer this evaluation until after MSE delivery.

Next Steps: We continue to encourage MISO to do this evaluation as part of the MSE project to allow these changes to be delivered under the MSE if feasible.

2016-6: Improve the accuracy of the 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 2018 and 2019 indicates that the commitment recommendations are not accurate – 82 and 69 percent, respectively, of the LAC-recommended resource commitments are ultimately uneconomic to commit at real-time prices. We also found that operators only adhered to 29 percent of the LAC recommendations in 2019, which may be attributable to the inaccuracy of the recommendations. In 2016, one significant source of potential error was identified related to wind output assumptions and MISO resolved this issue. However, other potential issues will also need to be addressed to facilitate accurate LAC results. Hence, we recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop procedures and logging processes to record operator decisions to respond to the LAC recommendations.

Status: MISO generally agrees with this recommendation. In 2017, MISO addressed the IMM concerns regarding inaccurate wind assumptions in the LAC, but have made only limited improvements to LAC since then. In 2018, MISO implemented tools that support the review of LAC recommendations by the operators.

Next Steps: We recommend that MISO allocate resources to work with the IMM to evaluate the sources of LAC's forecast errors and to identify potential improvements to the LAC inputs or model to improve its accuracy. Once it is performing sufficiently well, we recommend improvements to MISO's procedures to increase adherence to the LAC recommendations.

D. Resource Adequacy

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to provide economic signals, together with MISO's energy and ancillary services markets, to facilitate efficient investment and retirement decisions. These economic signals will be increasingly important as planning reserve margins in MISO fall because of low prevailing energy prices, which will increase retirements of uneconomic units.

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 the resources over the long term that are necessary to maintain reliability.

2019-5: Remove eligibility of Energy Efficiency to sell capacity

As we detail in this report, Energy Efficiency (EE) capacity credits have been rising and have become substantial. This is a concern because the quantities are based on a wide array of speculative assumptions and are impossible to verify over time. Additionally, the EE capacity is not transparent in the operating horizon or in the planning horizon.

More importantly, providing capacity credits and associated market payments to Energy Efficiency in MISO is inefficient. In most cases, it will serve as an inefficient subsidy to take actions that customers already have the incentive to undertake. Retail customers pay electric rates that include all of the costs of serving them, including energy, ancillary services, capacity costs, transmission and distribution costs. Therefore, when they purchase energy efficient equipment, the electric bill savings include all of these elements. Additional incentives that are funded through MISO's capacity market, therefore, are extraneous and inefficient. OMS recognized that there was no need for a MISO EE program in its prior comments, stating that "[EE] activities should not be seen as new program areas for the Midwest ISO, but rather be as incidental assistance".[50]

Further, MISO's treatment of EE shifts costs between customers. When EE lowers the peak demand of an LSE, the LSE will receive a windfall benefit in the form of a lower capacity requirement even though it was not involved in achieving the savings. The funding of the capacity payments essentially comes from other participants in MISO's capacity market, so costs are shifted from the LSE serving the customer to other LSEs. This could be addressed if the LSE's load reduced by the energy efficiency were "reconstituted" by adding the estimated energy efficiency peak load reduction back to the forecasted load for purposes of establishing the LSE's capacity requirements. However, given that this program is not efficient, we do not recommend that MISO pursue rules to negate this cost shifting. Instead, we recommend that MISO terminate its EE capacity market rules and program.

<u>Status</u>: This is a new recommendation.

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50 See *OMS Response to Hot Topic – Energy Efficiency,* December 6, 2007.

2018-5: Improve capacity accreditation by accounting for unforced and unreported outages and derates during tight supply periods

Accreditation is one of the largest opportunities for both short- and long-term improvements under Module E. Generating resources are currently qualified to sell capacity based on their forced outage performance, which is considered in the calculation of their UCAP levels. Under MISO's existing capacity accreditation construct, resource UCAP values are determined by discounting resource total installed capacity using forced outages that participants self-report to GADS.[51] This is problematic because:

- Other types of outages and derates also reduce MISO's access to capacity resources and result in the same reliability impacts as forced outages;
- Contrary to what is assumed in the LOLE studies, unforced outages and derates are regularly observed during MISO Capacity Emergencies.
- Suppliers do not completely report their outages and derates;
- Less reliable resources that are rarely needed are credited as fully available when they are not asked to run, inflating their UCAP levels.

Therefore, we recommend MISO improve its accreditation methodology accounting for *all* outages and derates, whether planned/unplanned or reported/unreported. These outages and derates have comparable effects on MISO's reliability as forced outages because they reduce the available supply in an unplanned manner.[52] We recommend a more complete solution that would:

a) Expand this improvement to include all unforced and unreported outages and derates; and

b) Calculate the accreditation based on outages and derates that occur during the tightest supply conditions.

These changes would result in sizable accreditation improvements and eliminate the current incentive for suppliers to not report their outages and derates. Adopting this accreditation reform would better represent the reliability value that resources provide to MISO in periods when the resources are needed and can be easily adapted to a seasonal capacity accreditation construct.

<u>Status</u>: MISO is currently evaluating this issue as part of the Resource Availability and Need (RAN) process. Multiple options are currently being evaluated with stakeholders through the Resource Adequacy Subcommittee.

51 An exception to this exists for Load Modifying Resources that receive additional capacity credit associated with the PRMR value and transmission losses. A second exception to this is for wind resources whose accreditation is based on their history of delivered energy rather than forced outages or derates.

52 FERC approved MISO's January 2019 Tariff filing that reduces the accreditation of resources taking short-notice outages during emergency conditions. This will not significantly affect the resources' accreditation, but it is a slight improvement. See the Order issued March 29, 2019 in Docket No. ER19-915-000.

Next Steps: We will continue to work with MISO to develop and evaluate accreditation improvements to discuss with market participants, and make a FERC filing later in 2020.

2018-6: Modify the supply and demand inputs for capacity by: a) accounting for behind-the-meter process load, b) improving planning assumptions, and c) validating suppliers' data

Calculating capacity requirements and supply accurately is key for the market to perform well. We recommend improvements in three areas:

1. Planning Resources that are qualified through Generator Verification Tested Capacity (GVTC) tests currently deduct both station service loads (associated with the power generation equipment) and process loads (typically industrial loads consisting of combinations of heat and power) from their installed capacity (ICAP). Unlike station service loads, the process loads continue when the power generation equipment is out of service. Therefore, this load must be served along with MISO's other firm load, which should be recognized in the capacity requirements.

2. As a general principle, the planning assumptions should match real operations to the maximum extent possible. In calculating the demand for capacity, MISO implicitly assumes in its planning models that generation is fully available except when it experiences forced outages. However, this is not consistent with reality because substantial quantities of unforced outages and derates do occur during peak load conditions. This results in understated planning reserve requirements. We recommend that MISO review these assumptions.

3. We have identified a number of areas where erroneous data has been submitted by suppliers, resulting in sizable capacity accreditation inaccuracies. These errors have included: temperature and humidity corrections to GVTC test data, GVTC adjustments for process loads, especially from Combined Heat and Power (CHP) facilities, and simultaneous capabilities of interdependent power generation equipment during MISO system peak conditions. We recommend that MISO validate and verify such data when submitted by suppliers to qualify and accredit planning resources.

Status: MISO staff continues to coordinate with the IMM on potential solutions to all 3 issues. The second item has been prioritized as High in the Integrated Roadmap, and will be addressed through RAN initiative, however item 1 was not included for prioritization. For item 3, some process improvements have been made and MISO has validated a larger share of the data submitted by suppliers for the 2020 PRA.

Next Steps: Work to address items 1 and 2 through the RAN. Item 3 could be completed through the accreditation refinements for cogeneration facilities. MISO expects to file changes to accreditation in 2020, addressing both 2018-5 and 2018-6 recommendations.

2017-6: Require the ICAP of Planning Resources be deliverable

The Tariff requires that all types of resources be deliverable to load in order to be eligible to be capacity resources. Deliverability is determined by, among other things, demonstrating Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS) coupled with firm transmission reservations. However, MISO has implemented its deliverability requirements in a manner that is not comparable for the NRIS and ERIS resources:

- The entire ICAP level of the NRIS resources must be deliverable, but
- ERIS resources need only secure firm transmission for the UCAP level of their resources, which can be 5 to 10 percent less than the ICAP level.

The requirements imposed by MISO on ERIS resources is not consistent with the intent of the Tariff. We recommend that MISO determine deliverability for all resources based on the entire ICAP of conventional planning resources (whether they are NRIS or ERIS resources). This will ensure consistency with the planning studies, which assume that resources will perform up to their ICAP level when they are available. This will also ensure consistency with the performance requirement of the Tariff Section 69A.5 with the ICAP must-offer requirement. By making this change, ERIS resources would be required to procure firm transmission service in the amount of their ICAP level that they choose to convert to ZRCs.

This may not be appropriate for intermittent resources because these resources cannot qualify to provide capacity at levels approaching their ICAP level. Therefore, it is likely the firm transmission service requirement would be set more appropriately at the upper end of the distribution of expected hourly output for wind resources, rather than their ICAP levels.

Status: MISO filed Tariff changes to address this recommendation.[53]

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-only resources, can sell capacity and are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate capacity shortages during emergency events, then they are not providing the reliability value assumed in the planning studies 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 an emergency. Operators typically do not see and declare emergency events more than a few hours in advance of the shortage because they are often caused by unexpected contingencies or unexpected changes in wind output or

53 Docket ER20-1942-000 and Docket ER20-2005-000.

load. Hence, LMRs and other emergency resources with long notification times would provide little value in most emergencies. This is not a problem for conventional resources with long notification or start times because an emergency need not be declared to commit these resources.

Therefore, we recommend that MISO develop a reasonable methodology for quantifying the capacity credit for emergency-only resources in the PRA. Such a methodology should consider factors that reduce the expected availability of resources, including the resources' seasonal availability, the time to deployment (notification plus start-up time/shut-down time), the variation in available curtailment quantity, and historical performance. The objective of these changes should be to qualify emergency-only resources at levels that would accurately reflect their expected availability during emergency conditions. This is comparable in principle to MISO's UCAP methodology for all other resources.

Status: MISO submitted a Tariff filing in May to address part of this recommendation.[54]

Next Steps: Continue to evaluate resource accreditation for emergency-only resources. MISO is working toward a potential FERC filing to address capacity accreditation for all resource types, including emergency resources.

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

MISO employs a relatively simple representation of transmission limits in the PRA, generally 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 as an additional constraint. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified import or export limits for one or more zones. 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 as needed 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.

54 Docket ER20-1846-000.

Status: This recommendation was partially addressed through the Tariff changes that establish External Resource Zones as neighboring balancing areas with their loadings on the RDT consistent with how it is modeled in the day-ahead and real-time markets. A similar approach could be taken to represent how all internal and external zones affect flows on key transmission constraints. This recommendation is not aligned with the MISO Roadmap and MISO indicates it is inactive. MISO intends to prioritize this work after the conclusion of discussions around a seasonal Planning Resource Auction, which are currently ongoing.

Next Steps: MISO will need to 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.

2014-5: 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. This can be recognized by clearing the PRA on a seasonal basis rather than on an annual basis as is currently the case. This would produce the following benefits:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- Resources retiring mid-year would have more flexibility to retire mid-year without having to procure significant replacement capacity to satisfy post-retirement capacity obligations;
- The qualification of resources with extended outages can better match their availability; and
- The duration of SSR contracts can be matched with planning seasons, which removes a barrier for SSR Units to serve as Planning Resources.

Status: MISO had originally proposed a two-season proposal. Use of two seasons does not capture the opportunity for savings that could be achieved by scheduling efficient economic outages during the shoulder months and only reduces the benefits of a seasonal structure. This recommendation is aligned with the MISO's RAN Initiative and is being considered as part of RAN Phase 3.

Next Steps: To capture the benefits described above, we recommend that MISO evaluate the costs and benefits of implementing four seasonal requirements. MISO has begun these discussions in the Resource Adequacy Subcommittee.

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 boundaries that are unrelated to the transmission network.

Status: MISO has engaged its stakeholders in a discussion of the criteria for establishing zones based primarily on transmission constraints, but a proposal has not been finalized. MISO indicates work to address this recommendation is currently deferred. This topic is not aligned with the MISO Roadmap Project and is currently in an inactive status.

Next Steps: Evaluate the benefits of improving the zonal definitions.

2010-14: Improve the modeling of demand in the PRA

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 reasonably reflect the reliability value of capacity and understates capacity prices as capacity levels fall toward the minimum requirement. This is particularly harmful as large quantities of resources are presently facing the decision to retire in response to the market conditions driven by historically low natural gas prices.

A sloped demand curve 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 capacity market moves toward the minimum planning reserve requirement. If this recommendation is not addressed, the MISO markets will not facilitate efficient investment and retirement decisions by participants that sustain an adequate resource base. Instead, MISO will have to rely primarily on the states requiring regulated utilities to build new resources.

Understated capacity prices are a particular problem in Competitive Retail Areas (CRAs) where competitive suppliers rely on the market to retain adequate resources to ensure reliability. In 2016, MISO developed a proposal to improve the capacity pricing in CRAs that FERC ultimately rejected. We offered an alternative proposal that would have utilized a sloped demand curve to establish prices for competitive suppliers and loads. If a sloped demand curve cannot be implemented for all participants in the PRA, we recommend MISO implement one for the competitive loads and suppliers.

Status: MISO is not in agreement on this issue, particularly for non-retail choice areas, because it lacks support among the states.

Next Steps: MISO should continue to work with its stakeholders and the Organization of MISO States (OMS) to move toward a consensus regarding the objective of facilitating efficient investment through the resource adequacy construct. The IMM will support this process by continuing to highlight the benefits of MISO establishing efficient capacity price signals, which include lowering the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

Recommendations Addressed by MISO

In addition to the progress made on a some of recommendations discussed above, MISO addressed several past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions in 2019 and early 2020. These recommendations are discussed below, along with unresolved recommendations that are not included in this year's report.

2017-1: Improve the market power mitigation rules

Over the past few years, the IMM identified a number of potential improvements to Module D Mitigation authority that are modest in scope and impact, but together will ensure that the market power mitigation provisions are fully effective.

The changes in the market power mitigation rules include:

- Modify the impact test and sanction provisions to include the impact of negative prices in order to effectively mitigate conduct whose effect is to lower prices at locations and aggravate transmission constraints.
- Modify the price impact threshold for ancillary services products to better reflect the prevailing clearing prices.
- Improve the generation shift factor cutoff for the application of BCA mitigation.
- Improve certain aspects of the market power mitigation sanction calculations.

Status: MISO agrees with this recommendation and MISO has filed these Tariff changes with FERC on December 20, 2019.[55] FERC has approved all of the proposed changes, with the exception of the changes to the physical withholding provision for non-capacity resources.

55 2019-12-20 Docket No. ER20-665-000; 2019-12-20 Docket No. ER20-668-000; Docket No. ER20-669-000

2014-2 and 2016-4: Introduce a 30-minute reserve product to reflect both VLR and regional reserve requirements

MISO has been incurring substantial RSG costs to satisfy VLR requirements and to manage flows on the RDT. MISO incurs these costs to prepare the area to withstand the largest contingencies. To address these needs, we recommended that MISO create a 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets (rather than through out-of-market commitments that result in uplift costs). This would be beneficial because it would provide market signals to build fast-start units or other resources that can satisfy the VLR or RDT needs at a lower cost (because they can satisfy the requirements while offline).

Status: This recommendation was originally proposed in our *2014 State of the Market Report*. MISO initially classified this recommendation as a high priority in the Roadmap process and assigned a forecasted implementation time in the second quarter of 2019. Subsequently, MISO merged this recommendation with another existing Roadmap project, *Short Term Capacity Pricing and Reliability Requirements,* which is intended to create a 30-minute reserve product to address both of these recommendations. MISO has completed the conceptual design of the Short-Term Reserve product. MISO made a tariff filing on October 4, 2019, which has been approved by FERC.[56] This project is currently planned for implementation in the fourth quarter of 2021.

2016-8: Validate wind resources' forecasts and use results to correct dispatch instructions

MISO's Tariff requires that a market participant's offers reflect the known physical capabilities and characteristics of its resources, including forecast maximum limits for wind resources that are DIRs. Other than ensuring that forecasts are timely, MISO does not validate the accuracy of wind suppliers' forecasts used to develop dispatch instructions for the DIRs. In 2016 and 2017, certain suppliers' wind forecasts were consistently biased, and many were consistently over-forecasted by more than 10 percent. Because the MISO dispatch uses these forecasts as the dispatch maximum, the lack of validation subjects the MISO energy dispatch to chronic shortfalls related to the over-forecasting. Additionally, over-forecasting can lead to inaccurate assumed system flows that result in inefficient congestion management.

We recommend that MISO develop appropriate operating procedures, including any necessary Tariff provisions to implement performance standards, in order to validate market participant forecasts. Real-time utilization of the most accurate forecasts will produce more appropriate dispatch instructions for dispatchable wind resources even when a participant's forecast is chronically inaccurate.

56 2019-10-04 Docket No. ER20-42-000

Status: MISO worked with the IMM to make settlement rule changes in the Spring of 2019 that have incentivized use of MISO's forecast. In addition, MISO has implemented processes to better detect and remedy chronic participant forecast inaccuracy.

2012-16: Re-order MISO's emergency procedures to utilize demand response efficiently

Until recently, demand response resources could not be curtailed by MISO before MISO has invoked nearly all other emergency actions, some of which are very costly and adversely impact the market. MISO recently filed and implemented changes that allow it to schedule LMRs in advance of calling an emergency, but the LMRs are not obligated to curtail unless MISO ultimately declares the highest level of emergency. This is a significant improvement and additional improvements would be subsumed in recommendation 2018-4, which is focused on improvement of emergency declarations and processes.

2016-9: Improve the qualification of planning resources and treatment of unavailable resources

Resources with no reasonable expectation of being available during system peak conditions should not qualify as planning resources, but market rules and Tariff provisions had imposed no requirement that market participants with inoperable units downgrade their operating status. For example, resources on extended forced or planned outages that occurred after performing their GVTC test often qualified as planning resources even though they cannot be restored to service prior to the end of the system peak season. Therefore, we recommended that MISO require unavailable resources to be suspended and not qualified to sell capacity if they will not be operable during the peak season of the upcoming planning year.

Status: Tariff changes were filed to preclude resources with outages expected to last for any ninety (90) or more of the first 120 calendar days of the Planning Year from participation in the PRA or inclusion in a FRAP. These changes were approved by FERC on January 30, 2020 and MISO implemented this requirement for the 2020/2021 PRA.

Recommendations Removed but not addressed by MISO

2015-5: Implement firm capacity delivery procedures with PJM

In June 2016, approximately 2 GW of capacity in MISO began pseudo-tying to PJM because it was sold in the PJM capacity market. Under its Capacity Performance construct, PJM completed its five-year transition period and now requires external resources to pseudo-tie to PJM. Pseudo-tying has imposed substantial costs on the joint region by reducing dispatch efficiency and reliability.

We developed proposed "Capacity Delivery Procedures" that would facilitate the delivery of MISO capacity to PJM without incurring the adverse effects of pseudo-tying the resources. PJM has refused to consider these provisions as an alternative to pseudo-tying external resources. Therefore, we filed[57] a 206 complaint against PJM to eliminate the pseudo-tying requirement and replace it with a reasonable alternative, which could be the Capacity Delivery Procedures. FERC has taken no action on the 206 Complaint, but both RTOs have made tariff changes to limit the harm from pseudo-tied generation. However, the changes implemented by the RTOs are unreasonably restrict capacity trading. We are removing this recommendation because future changes will likely depend on FERC's Order on our Section 206 complaint.

[57] FERC Docket No. EL17-62-000