**2022 STATE OF THE MARKET REPORT
FOR THE MISO ELECTRICITY MARKET**

ANALYTIC APPENDIX

Prepared By:

POTOMAC
ECONOMICS

**Independent Market Monitor
for the Midcontinent ISO**

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I. INTRODUCTION

This Analytic Appendix provides an extended analysis of the topics raised in the main body of the State of the Market Report. We present the assumptions, methods, and motivation for each of the analyses. Therefore, it is intended to serve as a useful reference document to accompany the report since our conclusions from these analyses and how they relate to the performance of the markets are discussed in the report. In addition, the body of the report includes a discussion of our recommendations to improve the design and competitiveness of the market.

The sections and analyses are intended to track the order of topics in the main body of the State of the Market Report. However, this appendix contains many figures and tables that are not included in the report. These figures and tables provide additional insight and detail or show the analytic results in a more disaggregated form.

We want to express our appreciation to MISO staff for their cooperation and support in providing data, other information, and feedback on numerous topics and issues addressed in this report.

II.   PRICES AND LOAD TRENDS

In this section, we provide our analyses of the prices and outcomes in MISO's day-ahead and real-time energy markets.

A.   Market Prices

In a well-functioning, competitive market, suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should correspond closely with resources' marginal production costs, which are primarily comprised of fuel costs for most resources.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly "all-in" price of electricity from 2021 to 2022 along with the price of natural gas at the Chicago Citygate trading hub. The leftmost section shows the annual average prices for 2013 through 2022. The all-in price represents the cost of serving load in MISO's electricity market. It includes the load-weighted real-time energy cost, as well as real-time ancillary services costs, uplift costs, and capacity costs (PRA clearing price multiplied by the capacity requirement) per MWh of real-time load. We separately show the portion of the all-in energy price that is associated with shortage pricing for one or more products.

Figure A1: All-In Price of Electricity
2021–2022
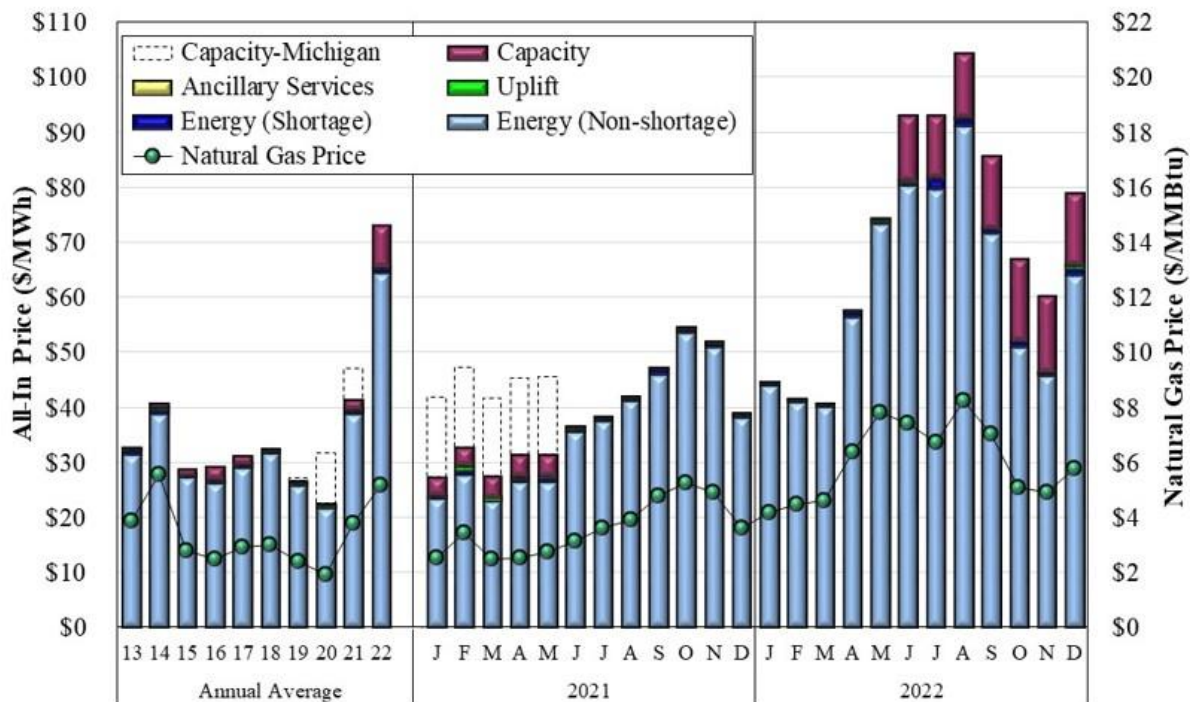
Figure A2: Cross Market All-In Price Comparison

To provide perspective on how the MISO markets compare to the other eastern RTOs, Figure A2 shows the all-in price for each market from 2020 through 2022. 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 A2: Cross Market All-In Price Comparison
2020–2022
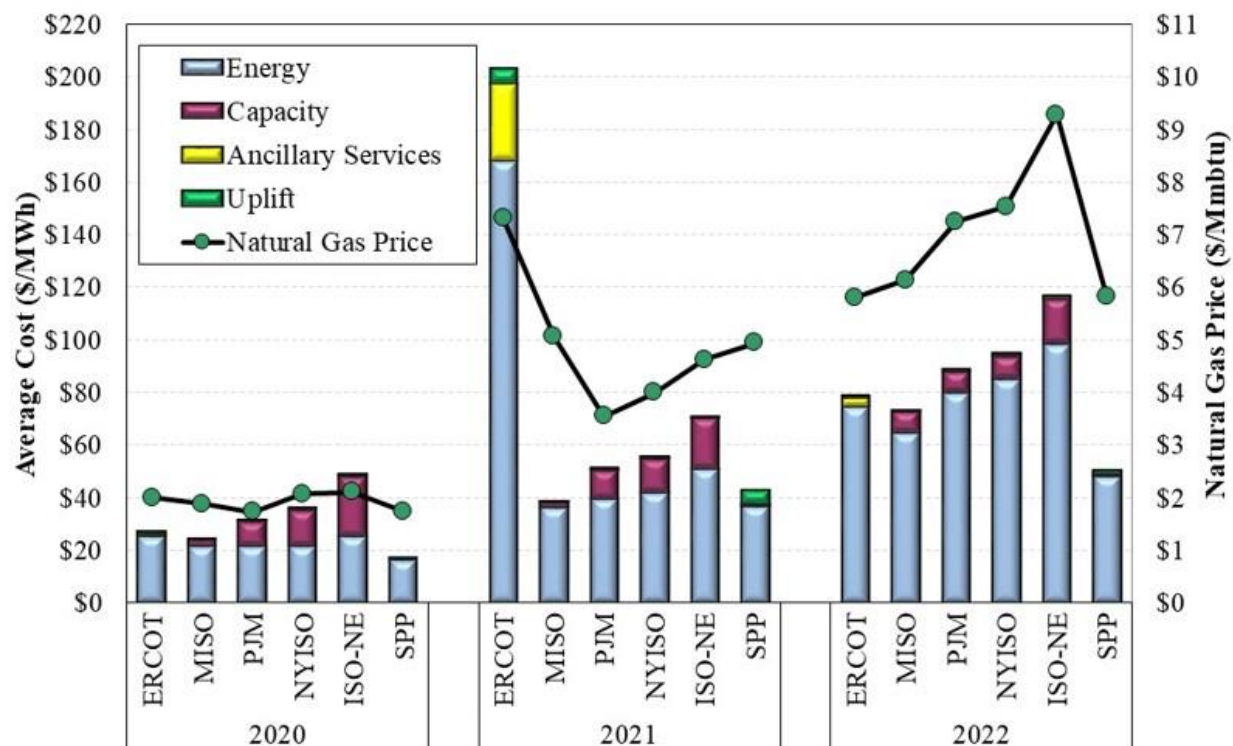
Figure A3: Real-Time Energy Price-Duration Curves

Figure A3 shows the real-time hourly prices at seven representative locations in MISO in the form of a price-duration curve. A price-duration curve shows the number of hours (on the horizontal axis) when the LMP is greater than or equal to a particular price level (on the vertical axis). The differences between the curves in this figure are due to congestion and losses, which cause energy prices to vary by location.

The table inset in the figure provides the percentage of hours with prices greater than $200, greater than $100, and less than $0 per MWh in the three most recent years. The highest prices often occur during peak load periods when shortage conditions are most common. Prices in these hours are an important component of the economic signals that govern investment and retirement decisions. Broad changes in prices are generally driven by changes in underlying fuel prices that affect many hours. In contrast, changes in prices at the high end of the duration curve are usually attributable to differences in weather-related peak loads that impact the frequency of shortage conditions.

Figure A3: Real-Time Energy Price-Duration Curve
2020–2022

Share of All Hours with LMP	2020			2021			2022		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Indiana Hub	0.1%	0.5%	0.2%	0.5%	2.7%	0.0%	1.9%	13.3%	0.0%
Michigan Hub	0.3%	0.8%	0.2%	0.5%	2.2%	0.0%	1.5%	10.6%	0.0%
Minnesota Hub	0.1%	0.2%	1.6%	0.8%	2.8%	0.8%	0.7%	4.3%	2.5%
Arkansas Hub	0.1%	0.2%	0.4%	0.7%	1.7%	0.0%	0.9%	6.7%	0.0%
Louisiana Hub	0.2%	0.5%	0.2%	0.6%	1.4%	0.0%	1.0%	7.8%	0.0%
Texas Hub	0.5%	0.8%	0.3%	1.5%	2.3%	0.0%	0.9%	7.1%	0.0%
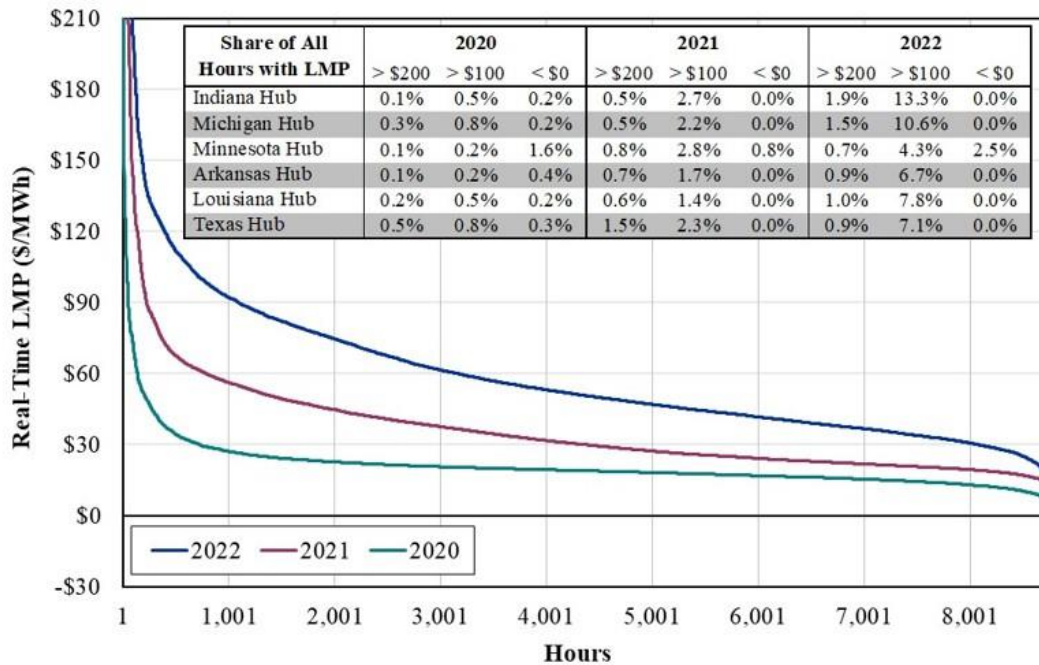
Figure A4: MISO Fuel Prices

As we have noted, fuel prices are a primary determinant of overall electricity prices because they constitute most of the generators' marginal costs. Hence, because natural gas-fired resources set energy prices in a large share of hours, electricity prices tend to be highly correlated with natural gas prices. Coal-fired units frequently set prices in off-peak hours.

Figure A4: MISO Fuel Prices
2021–2022

Annual Average	2020	2021	2022
Chicago NG	$1.88	$3.57	$6.14
Henry NG	$1.99	$3.69	$6.39

Annual Average	2020	2021	2022
IB Coal	$1.25	$2.07	$5.98
PRB Coal	$0.68	$0.96	$1.01
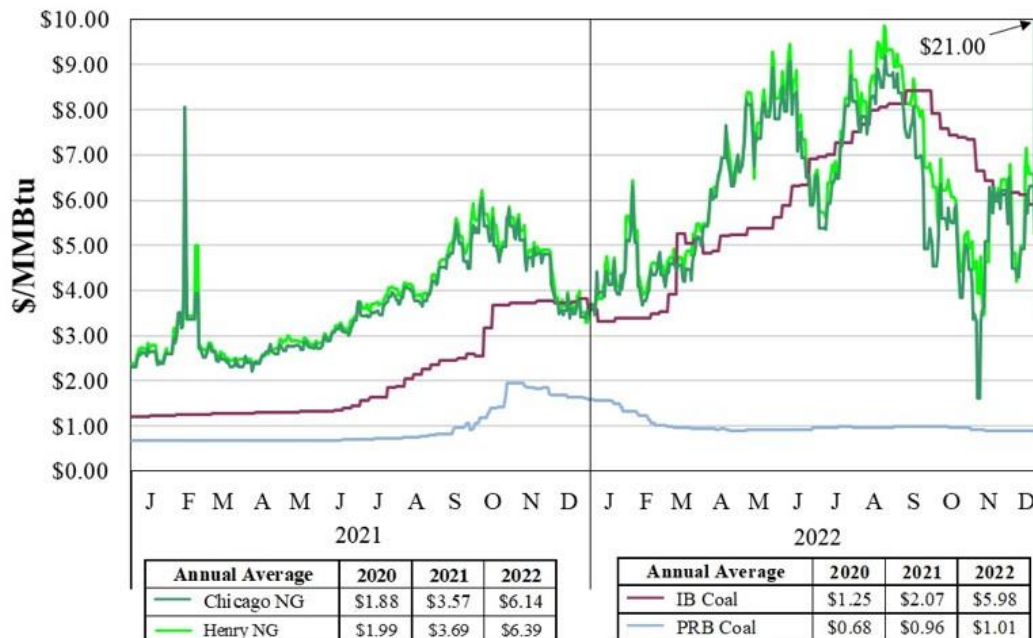
Figure A4 shows the prices for natural gas at Henry Hub and Chicago Citygate and two types of coal in the MISO region since the beginning of 2021. The figure shows nominal prices in dollars per million British thermal units (MMBtu). The table below the figure shows the annual average nominal prices between 2020 and 2022 for each type of fuel.

   Figure A5: Implied Marginal Heatrate

Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. To estimate the effects on prices of factors other than the change in fuel prices, we calculate an "implied marginal heat rate." This is calculated by dividing the real-time energy price by the natural gas price. Figure A5 shows the monthly and annual average implied marginal heat rates in the blue bars, plotted against the left axis, and the average nominal system marginal price (SMP) in the red diamonds plotted against the right axis. To calculate this metric, we first calculate a daily implied heatrate based on the daily average SMP divided by the daily maximum gas price between Chicago Citygate and the Henry Hub. We then average the daily values for each month to calculate the monthly averages.

Figure A5: Implied Marginal Heatrate
2021–2022
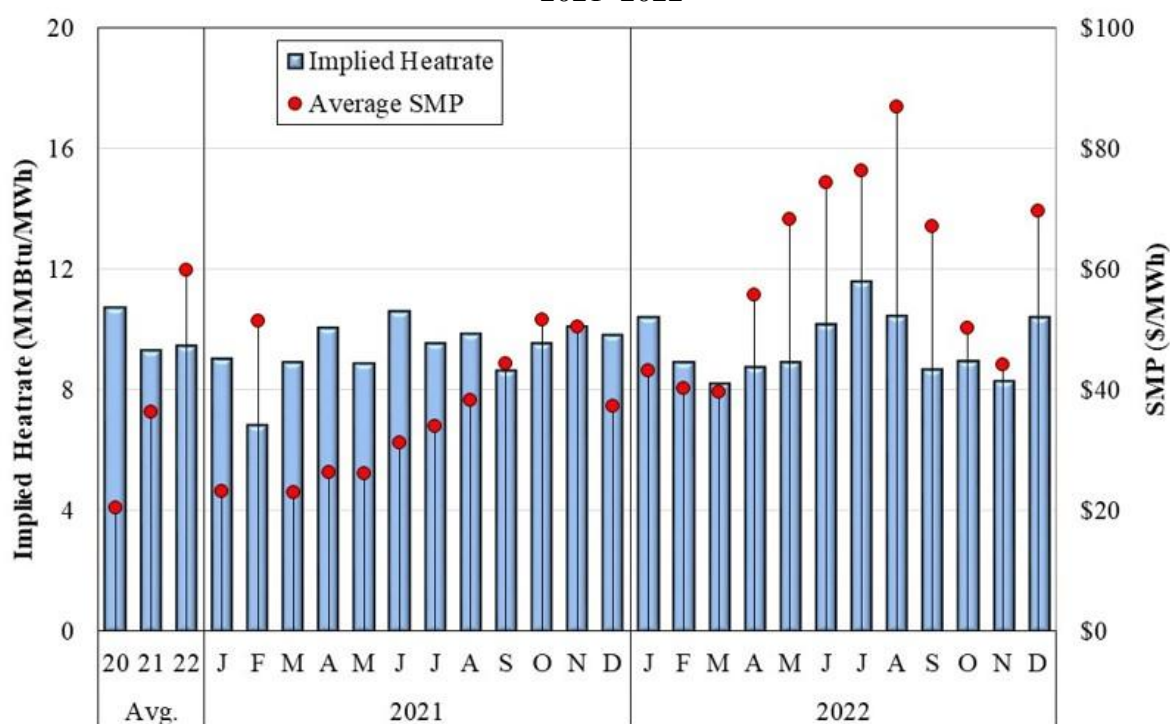
B.   Fuel Prices and Energy Production

   Figure A6: Price Setting by Unit Type

Figure A6 examines the frequency with which different types of generating resources set the real-time SMP in MISO. The top panel in the figure shows the average prices when each type of unit was on the margin, and the bottom panel shows the share of market intervals that each type of unit set the real-time price.

While baseload coal-fired units historically set prices in the majority of hours, that share has been declining over time. 2018 was the first year that coal resources set the marginal energy price less frequently than gas-fired resources. Nearly all wind resources can be economically curtailed when contributing to transmission congestion. Because their incremental costs are mostly a function of lost production tax credits, wind units often set negative prices in export-constrained areas when they must be ramped down to manage congestion.

Figure A6: Price-Setting by Unit Type
2021–2022
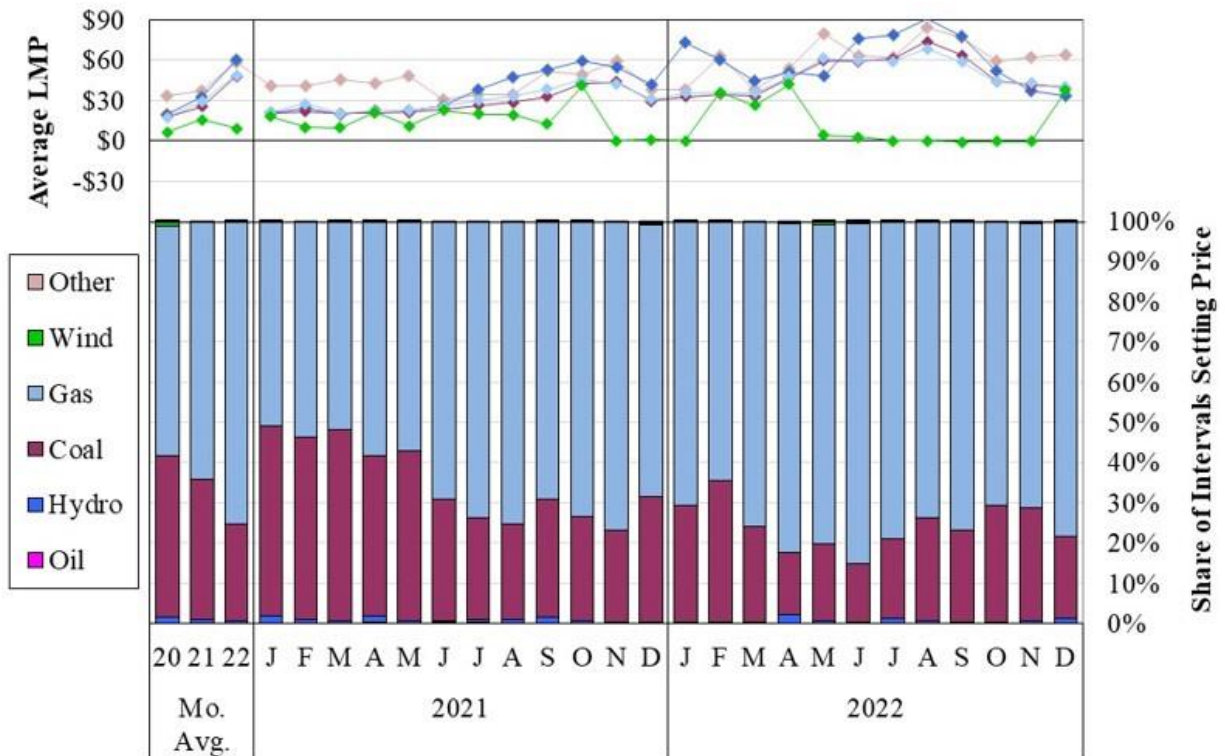
Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type

Table A1 summarizes how changes in fuel prices have affected the share of energy produced by fuel-type, as well as the generators that set the real-time energy prices in 2022 compared to 2021. The lowest marginal cost resources (coal and nuclear) produce half of the total energy. Because natural gas-fired units are higher marginal-cost resources, they tend to produce a lower share of MISO's energy than their share of MISO's installed capacity. While wind resources comprise a small share of MISO's unforced capacity because of their intermittent nature, their contribution to energy output is much higher.

Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type
2021–2022

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

C.   Load and Weather Patterns

Figure A7: Load Duration Curves and 2022 Peak Load

Although market conditions can still be tight in the winter and shoulder seasons because of generation, transmission outages, and fuel supply issues, MISO continues to be a summer-peaking market. To show the hourly variation in load, Figure A7 shows load levels for 2022 and the prior two years in the form of hourly load duration curves. These curves show the number of hours on the horizontal axis in which load is greater than or equal to the level indicated on the vertical axis. We show curves for 2020 through 2022 separately.

Figure A7: Load Duration Curves and 2022 Peak Load
2020–2022
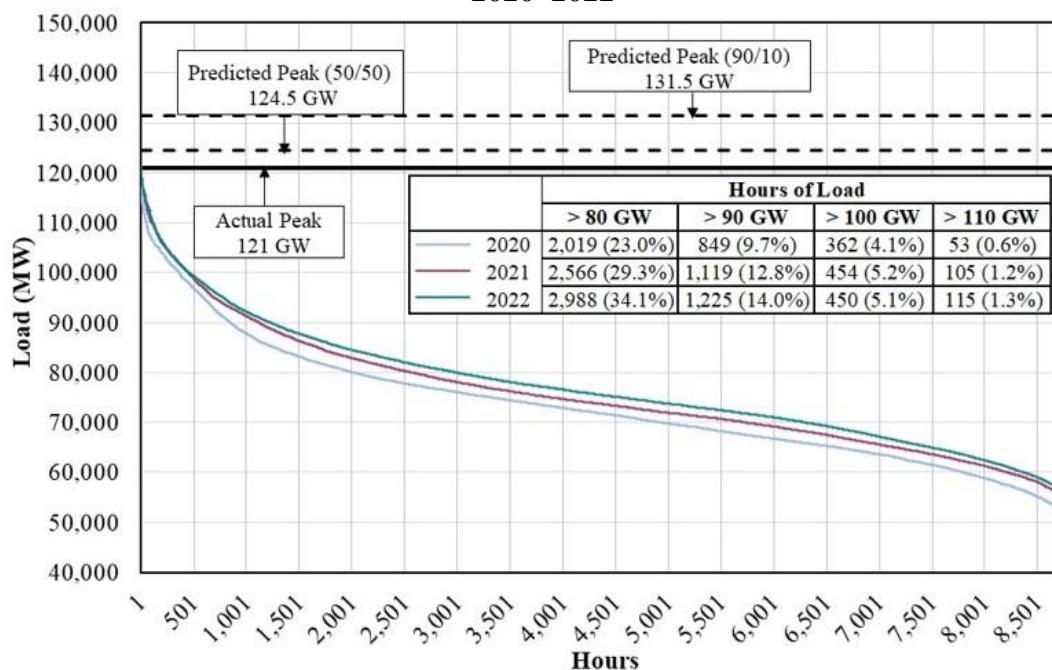
Load duration curves reveal the changes in load that are due to economic activity and weather conditions, among other things. The inset table indicates the number and percentage of hours when load exceeded 80, 90, 100, and 110 GW. The figure shows the actual and predicated peak load for 2022. The "Predicted Peak (50/50)" is the predicted peak load where MISO expected the load could be higher or lower than this level with equal probability. The "Predicted Peak (90/10)" is the predicted peak load where actual peak will be at or below this level with 90 percent probability (i.e., there is only a 10 percent probability of load peaking above this level).

Figure A8: Heating and Cooling Degree-Days

MISO's load is temperature sensitive. Figure A8 illustrates the influence of weather on load by showing heating and cooling degree-days that are a proxy for weather-driven demand for energy. These are shown along with the monthly average load levels for the prior three years.

The top panel shows the monthly average loads 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) averaged over the 10 years prior to 2020 across four representative cities in MISO Midwest and two cities in MISO South.[1] The table at the bottom shows the year-over-year changes in average load and degree-days.

Figure A8: Heating and Cooling Degree-Days
2020–2022

% Chg 21-22	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	2%	7%	-2%	4%	4%	7%	1%	3%	-4%	2%	-5%	1%	6%
Degree Days	2%	21%	-12%	6%	26%	26%	-6%	7%	-13%	12%	-29%	6%	17%

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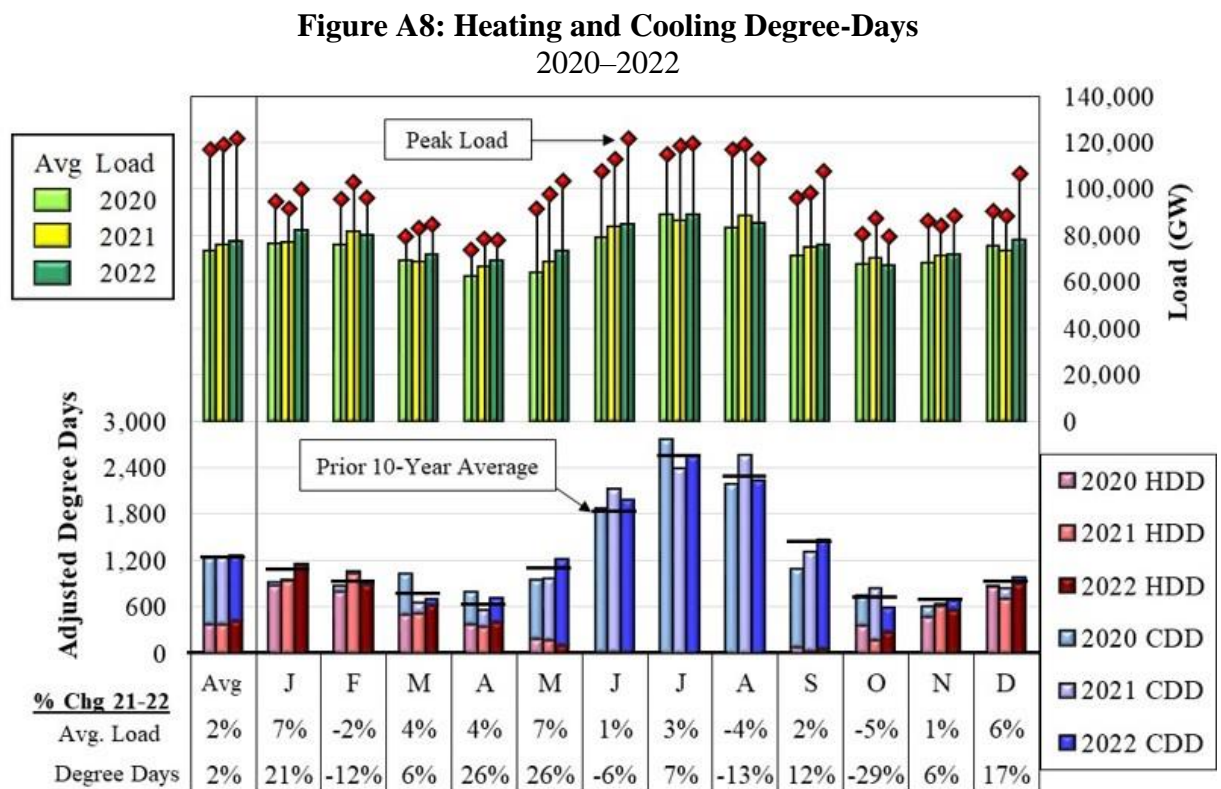
[1] HDDs and CDDs are defined using daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). For example, a mean temperature of 25 degrees Fahrenheit in a particular week in Minneapolis results in (65-25) * 7 days = 280 HDDs. To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (i.e., so that one adjusted-HDD has the same impact on load as one CDD). This factor was estimated using a regression analysis.

D. Ancillary Services Markets

Scheduling of energy and operating reserves, which include regulating reserves and contingency reserves, is jointly optimized in MISO's real-time market software. As a result, opportunity cost trade-offs result in higher energy prices and reserve prices. Energy and ancillary services markets (ASM) prices are additionally affected by reserve shortages. When the market is short of one or more ancillary services products, the demand curve for that product will set the market-wide price for that product and be included in the price of higher valued reserves and energy. Ancillary services products include regulation, short-term reserves, and contingency reserves, which is comprised of spinning reserves and supplemental reserves.[2] Total operating reserves are the sum of these products.

The demand curves for the various ancillary services products in 2022 were:

- Regulation: varies monthly according to the prior month's gas prices and averaged $289.41 per MWh.

- Spinning Reserves: $65 per MWh (for shortages between zero and 10 percent of the market-wide requirement) and $98 per MWh (for shortages greater than 10 percent).[3]

- Total Operating Reserves:[4]

  - For cleared reserves less than four percent of the market-wide requirement, the Value of Lost Load ($3,500 per MWh) minus the monthly demand curve price for regulation.

  - For cleared reserves between four and twelve percent, the estimated probability of lost load based on a single large resource contingency.

  - For cleared reserves between twelve percent and the Most Severe Single Contingency (MSSC), the curve is flat at $2,100 per MWh and then steps down to $1,100 per MWh.

- Short Term Reserves: In November 2022, MISO implemented a multi-step curve that reached a high step of $500 per MWh, replacing its previously curve set at $100 per MWh.

The most important reserve constraint is the market-wide operating reserve requirement (contingency reserves plus regulation). This is because a shortage of total operating reserves has the greatest potential impact on reliability. Accordingly, the total operating reserve constraint has the highest-priced reserve demand curve. To the extent that increasing load and unit retirements reduce the capacity surplus in MISO, more frequent operating reserve shortages will play a key role in providing long-term economic signals to invest in new resources.

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[2] Contingency Reserves provide a 10-minute response rate, whereas short-term reserves provide a 30-minute response rate.

[3] There is an additional $50 per MWh penalty called the "MinGenToRegSpinPenalty."

[4] There is no separate demand curve for Supplemental Reserves. Prices for Supplemental Reserves during shortages are established by the Total Reserve demand curve (known as the operating reserve demand curve or ORDC).

Figure A9: Real-Time Ancillary Services Clearing Prices and Shortages

Figure A9 shows monthly average real-time clearing prices for the four ancillary service products: regulation, spinning reserves, supplemental reserves, and short-term reserves.

Supplemental reserves are the lowest quality contingency reserve because the technical requirements are less stringent than for regulation and spinning reserves. But because supplemental reserves will be short in conjunction with total reserves, a shortage of supplemental reserves is an operating reserve shortage. This will result in the largest shortage-pricing component in each of the other reserve prices and in the energy price. Figure A9 shows the frequency with which the system was short of each class of reserves, as well as the impact of each product's shortage pricing.

Figure A9: Real-Time ASM Prices and Shortage Frequency
2022
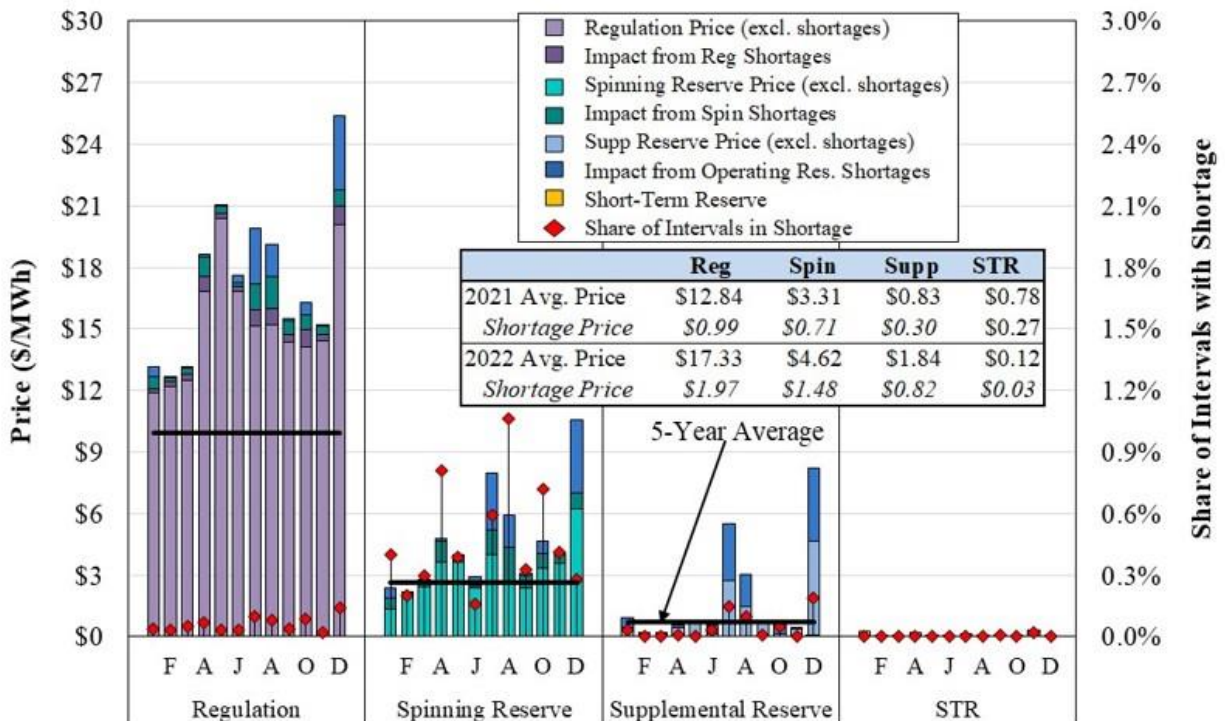
Note: Supplemental Reserve shortages in the figure reflect Operating Reserve shortages.

Additionally, higher-quality reserves can always be substituted for lower-quality reserves. Therefore, the price for spinning reserves will always be equal to or higher than supplemental reserves. Likewise, when a shortage occurs in a lower-quality reserve product, it appears in the price of all higher-quality reserves.

Figure A10: Regulation Offers and Scheduling

ASM offer prices and quantities are the primary determinants of ASM outcomes. Figure A10 examines average regulation capability on MISO resources. Regulation capability is less than

spinning reserve capability because (a) it can only be provided by regulation-capable resources, and (b) it is limited to five minutes of bi-directional ramp capability.

Clearing prices for regulating reserves can be considerably higher than the highest-cleared regulation offer prices because they reflect opportunity costs incurred when resources must be dispatched up or down from their economic level to provide bi-directional regulation capability. In addition, as the highest-quality ancillary service, regulation can substitute for either spinning or supplemental reserves. Hence, any shortage in those products will be reflected in the regulating reserve price as well.

Figure A10: Regulation Offers and Scheduling
2022
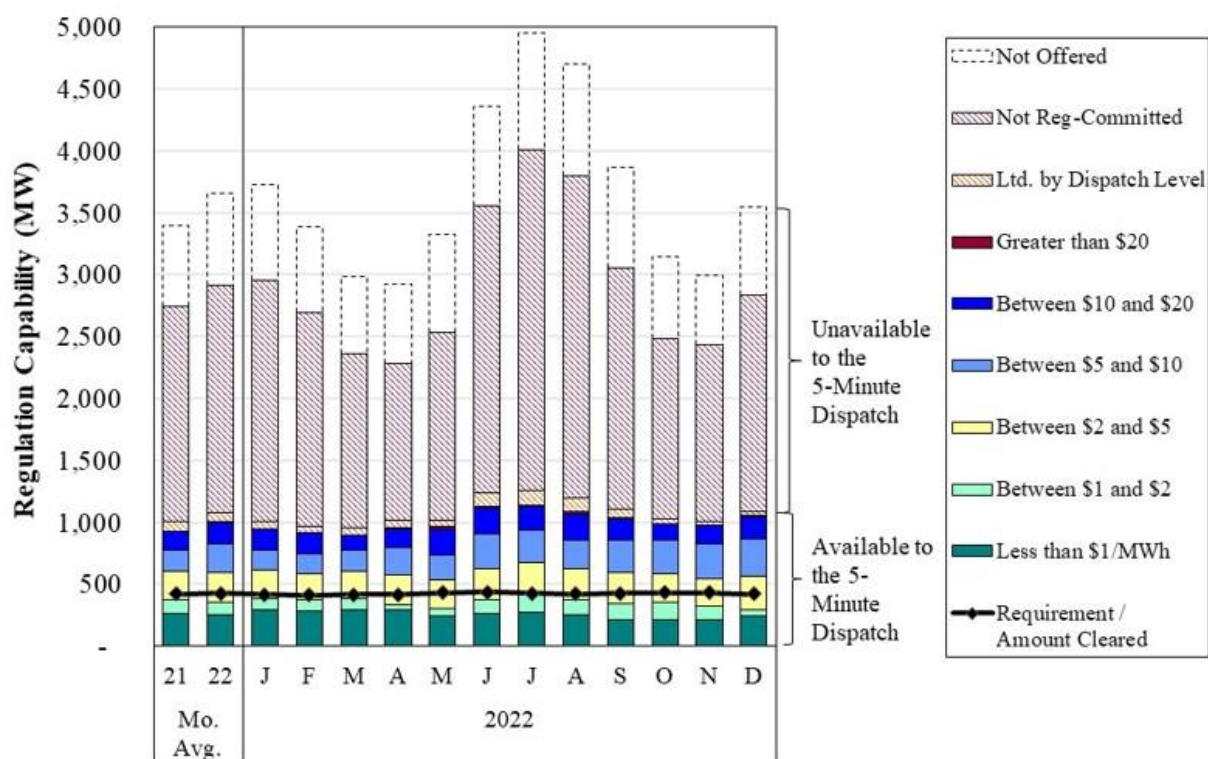
The figure above distinguishes between the regulation that is available to the five-minute dispatch in the solid bars and quantities that are unavailable in the hashed bars. The figure separately shows the quantities unavailable because they are not offered by participants, not committed by MISO, or limited by dispatch level (i.e., constrained by a unit's operating limits).

Figure A11: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can be provided by online resources for up to 10 minutes of ramp capability (limited by available headroom above their output level). Supplemental reserves are provided by offline units that can respond within 10 minutes, including their startup and notification times. The contingency reserve requirement is satisfied by the sum of the spinning reserves and supplemental reserves.

As noted above, higher-valued reserves can be used to fulfill the requirements of lower-quality reserves. Therefore, prices for regulation always equal or exceed those for spinning reserves, which in turn always equal or exceed prices for supplemental reserves. As with regulation, spinning and supplemental reserve prices can exceed the highest cleared offer as a result of opportunity costs or shortage pricing.

Figure A11 shows the quantity of spinning and supplemental reserve offers by offer price. Of the capability not available for dispatch, the figure distinguishes between quantities not offered, derated, and limited by dispatch level.

Figure A11: Contingency Reserve Offers and Scheduling
2022
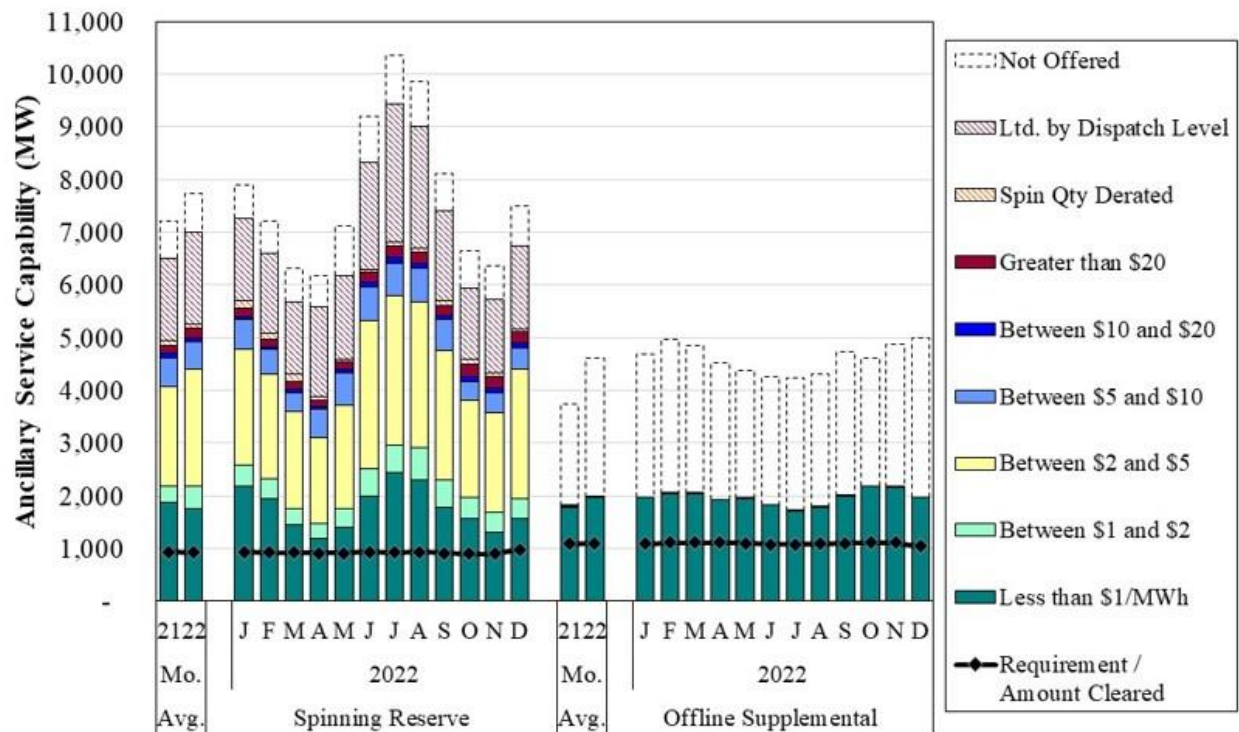
III.   FUTURE MARKET NEEDS

In this section, we illustrate the dramatic changes in MISO's generation portfolio and the implications of these changes. We then identify the key market issues, non-market issues, and improvements that will allow MISO to successfully navigate this transition.

A.   Future Market Needs

Figure A12: Anticipated Resource Mix

MISO's supply portfolio is expected to change substantially over the next 20 years. MISO's interconnection queue is comprised of mostly renewable resources. MISO currently has more than 1400 active projects in the interconnection queue, totaling over 240 GW. More than half of these are solar projects or hybrid solar projects, and another 10 percent are wind projects or hybrid wind projects.[5] Over the past few years, MISO has been producing three potential Future Scenarios to bound its expectations regarding the future needs of the system.[6] Future 2 is an intermediate case that is the primary basis for MISO's long-range transmission planning. Figure A12 shows the mix of resources in the prior Future 2 case published two years ago, as well as the most recent Future 2A published this year. The stacked bars indicate the amount of capacity by fuel type in each year and case, beginning with the 2022 resource mix.

Figure A12: Anticipated Resource Mix

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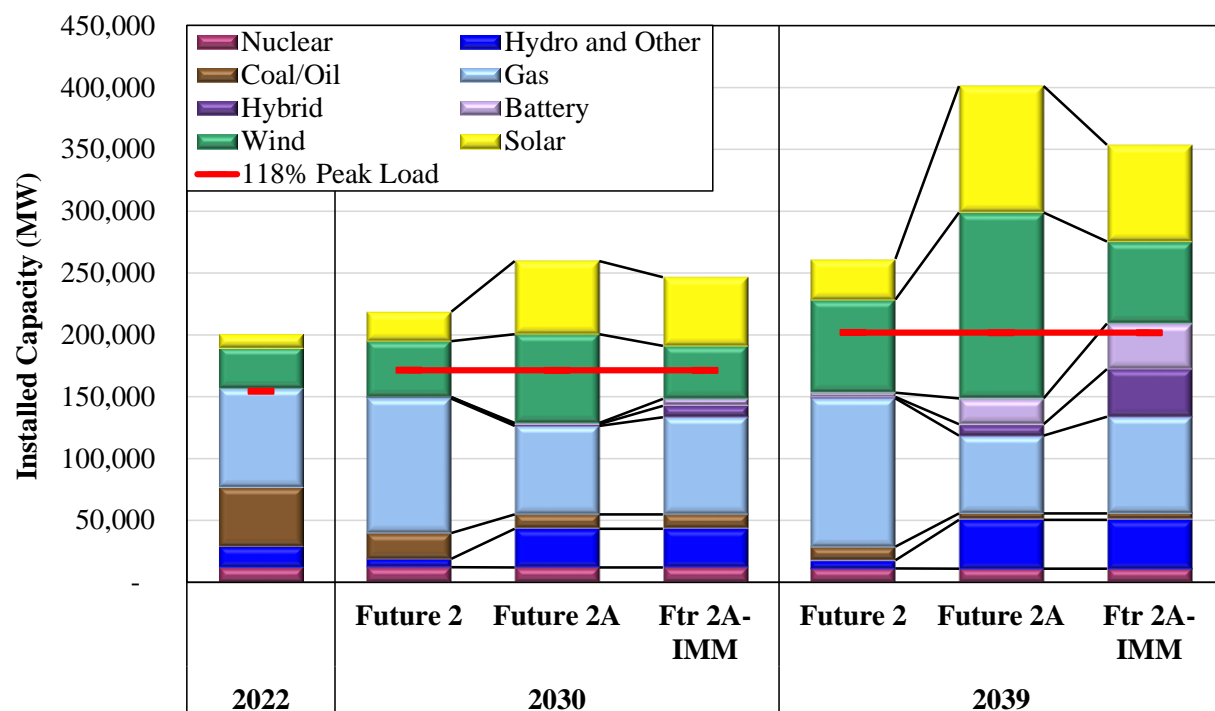
5   See: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf
6   Id.

As described in the report, we do not find Future 2A to be a very probable case. It uses unreasonably high accreditation assumptions for wind and solar resources, which causes its capacity expansion model, EGEAS, to forecast that enormous quantities of these resources will be built to satisfy reliability objectives. The figure includes a modified Future 2A-IMM case that assumes intermittent resources would not be built to satisfy reliability objectives due to the fact that their reliability value falls as more enter. To calculate the differences in the IMM case, we determine the amount of capacity credit assumed to be provided by wind and solar resources built by EGEAS, then calculated an amount of batteries, hybrid resources, and gas resources that would provide the same capacity value. The purpose of this case is to illustrate the sizable effects of the assumptions MISO used in the EGEAS model and the value in reconsidering this case before using it to determine future transmission needs.

Figure A13 and Figure A14: Share of Load Served by Wind Generation

We conducted an analysis to illustrate the cumulative share of MISO's load served by wind and how this share has changed over the past five years. In our analysis, we determined for each hour the total real-time wind generation and MISO's total real-time load, as well as regional calculations of the same metrics. The wind generation share of load for each hour was calculated by dividing the total wind generation in the hour by the total load for the same hour. For the regional calculation, the numerator was the wind generated in MISO's Midwest, and the denominator used was the sum of MISO's real-time load in the Central and North regions for the same hour. At the displayed datapoints we counted the total number of hours where wind generation exceeded that threshold and divided it by the number of hours in the dataset (8,760 hours for non-leap years).

In Figure A13 and Figure A14 below, the x-axis represents the percentage of load served by wind, and the y-axis shows the percentage of hours during the year when at least that wind share of load prevailed. The light blue background represents the values associated with wind output in 2022, while the green line illustrates the same values for 2016, and the maroon line for 2019. The figure illustrates the degree to which wind met or exceeded percentages of load served beginning at zero percent (by definition, all intervals would be zero percent or greater). For example, in Figure A13, at the 15 percent wind penetration threshold, the percent of hours that were at or above that level in 2022 was 52 percent, calculated by exceeding the 15 percent threshold for 4,582 hours, or around six months of the year. We indicate in the table the average, median, and maximum share of MISO's load that was served by wind output in 2016, 2019, and 2022.

As none of the wind generation is currently sited in MISO's South, Figure A14 below provides the calculated percentage of load served by wind generation over the same time period in the Midwest. In addition to the elements in the market-wide figure, the Midwest figure brings a dropline at 30 percent, which is the level noted in the RIIA studies as the point at which renewable penetration could require additional investment and market design changes.

Figure A13: Share of MISO Load Served by Wind Generation
2017–2022

	Year	Wind Share Percentage		
		Average	Median	Max Share
	2017	8.0%	7.3%	22.5%
	2020	11.5%	10.6%	31.8%
	2022	15.1%	14.7%	34.8%
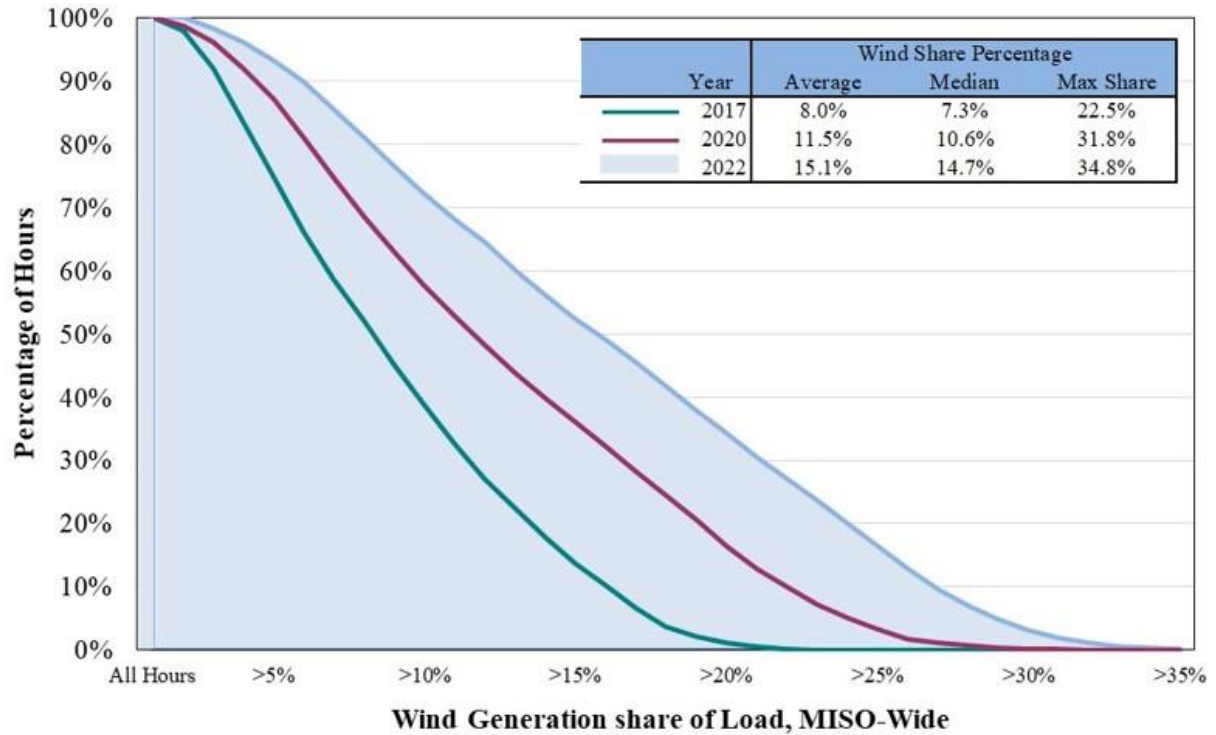
Figure A14: Midwestern Load Share Served by Wind Generation
2017–2022

	Year	Midwest Wind Share Percentage		
		Average	Median	Max Share
	2017	12.4%	11.3%	34.9%
	2020	18.1%	16.6%	49.3%
	2022	23.8%	23.2%	55.2%
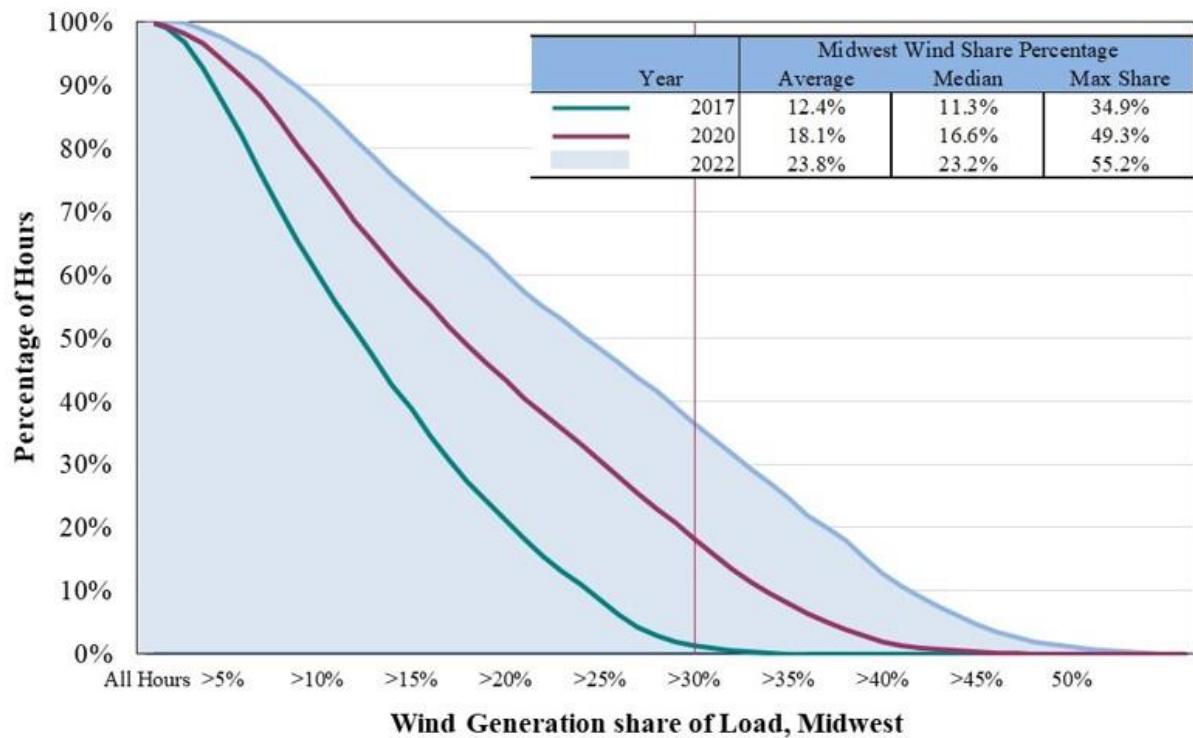
Figure A15 and Figure A16: Daily Range of Wind Generation Output

Operational challenges arise because of the substantial fluctuations of the wind output. As these fluctuations grow, so do the wind forecast errors. To illuminate these challenges, we examined the daily range in wind output along with the average wind output each day from January through August in Figure A15, and September through December, a period during which wind output was relatively high, in Figure A16.

Figure A15: Daily Range of Wind Generation Output
January – August 2022
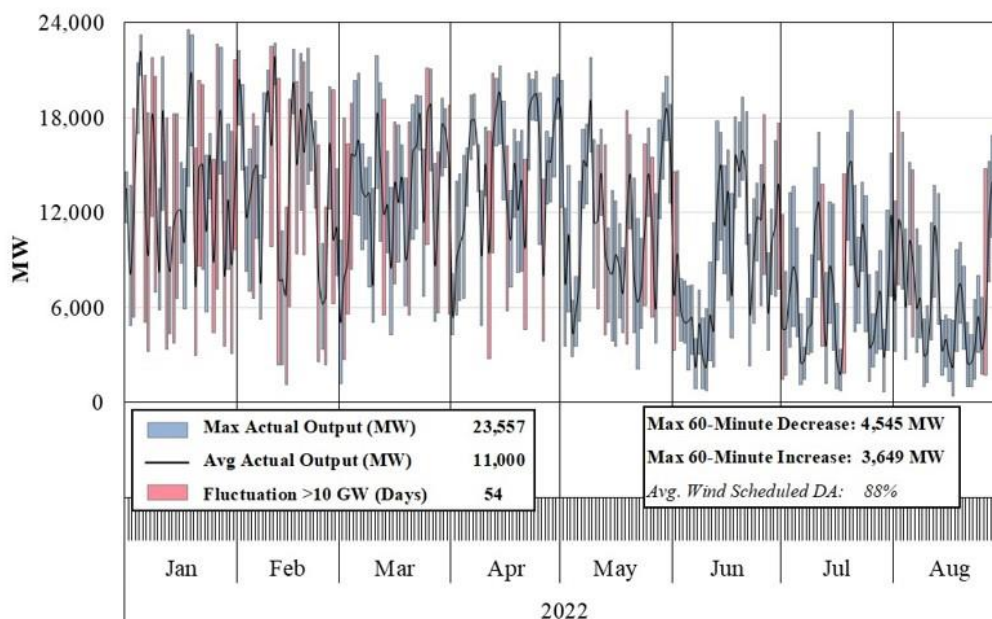
Figure A16: Daily Range of Wind Generation Output
September – December 2022
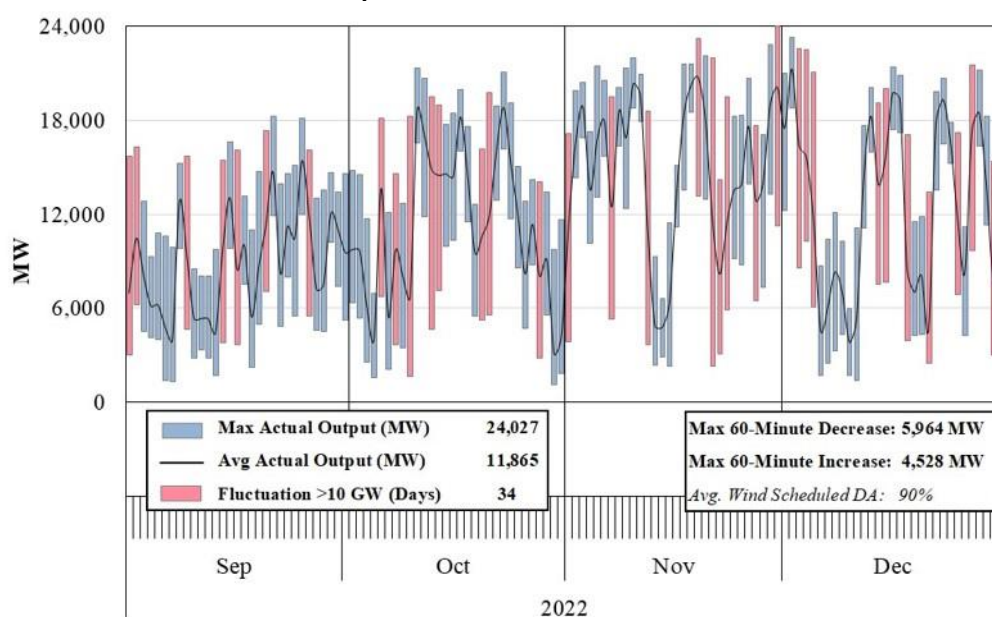
In the figures, we plot the range of hourly wind output (minimum to maximum) for each day in the blue and pink bars. The black line represents the average wind production each day. The pink bars represent days when wind output fluctuated by more than 10 GW.

Figure A17: Net Load in MISO on a Representative Winter Day

MISO's interconnection queue is comprised of mostly renewable resources. Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years.[7] Given the timing of the expected increases and decreases in the output from solar resources in MISO, a large quantity of these resources would likely lead to significant changes in the system's ramping needs. Once solar resource output increases in the late morning, the conventional resources will need to ramp down to balance the solar output. A second demand to ramp up conventional resources will occur as solar output falls off sharply in the evening hours. These patterns are sharpest in the winter because MISO's load peaks in the early morning and in the evening.

Figure A17 illustrates these changes in ramp demands. It shows the net load on February 14, 2021 in the black line. The maroon line shows the actual solar production. The dotted and solid orange lines represent forecasted hourly solar production in 2030 consistent with the 5th and 95th percentile output levels, respectively. The green dotted and solid lines at the top of the figure represent the 5th and 95th percentile net load in 2030, respectively. These forecasts are based on MISO's Future Scenario 2 projected solar capacity of 27.5 GW. We used hourly solar production observed between February 10 and February 20, 2021 to calculate the 5th and 95th percentile of anticipated hourly solar production. We assumed that load growth and growth in wind would scale up proportionally.

Figure A17: Net Load in MISO on a Representative Winter Day

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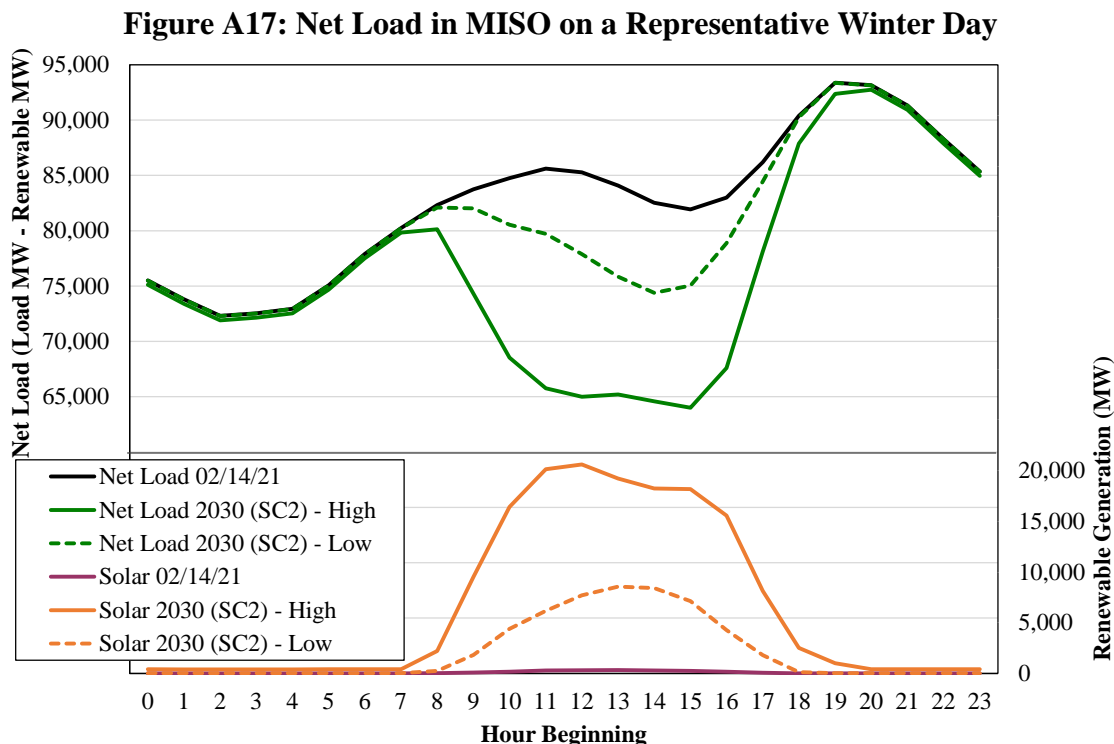
7   See: *Final Draft MTEP20 Full Report,* https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf

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

Figure A18: Uncertainty and MISO's Operating Requirements

The current market structure may limit MISO's ability to realize the potential benefits of high renewable growth over the next five to ten years. Renewable technologies offer clean and low marginal-cost electricity at the expense of greater uncertainty and lower reliability than conventional resources. While increases in supply uncertainty will affect MISO's planning processes and operations, market systems and products may need to be modified in turn to compensate and send signals for flexible resource investment.

Figure A18 shows the market-wide net uncertainty from the perspectives of one and four-hour forecast leads. This is calculated using historical data on the combined impact of generation resource forced outages and forecast errors from load and renewables. We calculate the uncertainty typically faced on the system (the 50th percentile) and in the hours when uncertainty is higher (higher percentiles). The figure shows the uncertainty one hour ahead and four hours ahead (blue bars). The red, green, and purple lines indicate the underlying contributing factors of load forecast error, renewable forecast error, and generating resource trips and derates.

Figure A18: Uncertainty and MISO's Operating Requirements
January 2021 to December 2022
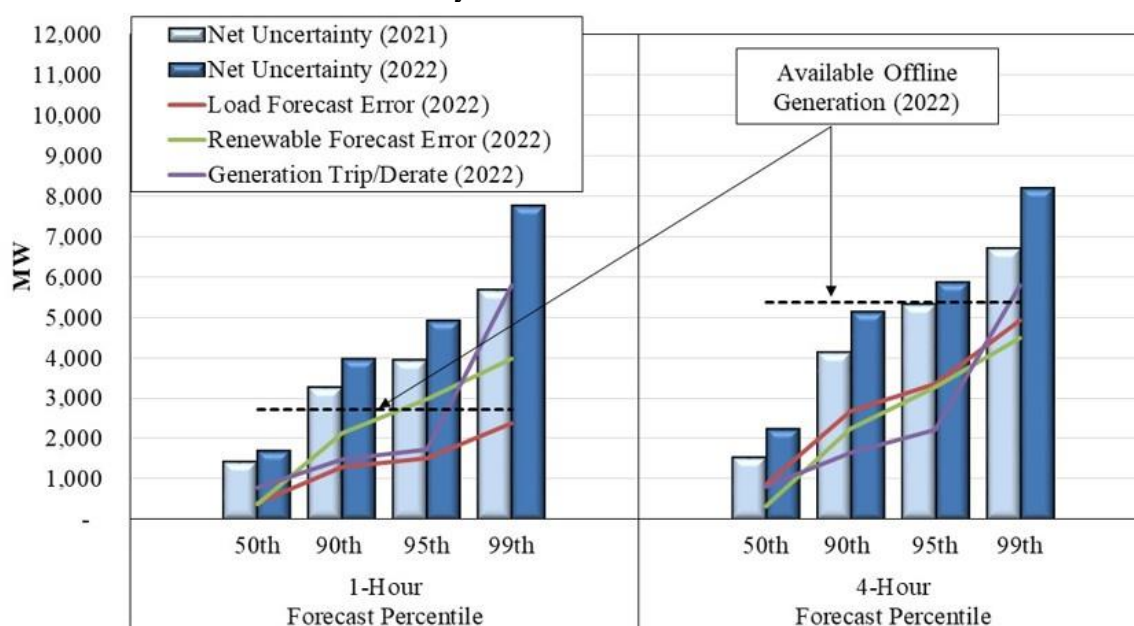
Figure A19: Comparison of IMM Economic ORDC to the Current ORDC

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-term, 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.

While MISO has experienced few energy shortages, reserve shortages in (co-optimized) energy and ancillary markets are much more common (i.e., RTOs will hold less reserves than required rather than not serving the energy demand). 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.

MISO's shortage pricing is based on its total Operating Reserve Demand Curve (ORDC). 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 slope of the ORDC is not based on the probability of losing load;

- 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 $1,100 per MWh and $2,100 per MWh; and

- MISO's current VOLL of $3,500 per MWh is significantly understated.

Figure A19: Comparison of IMM Economic ORDC to the Current ORDC
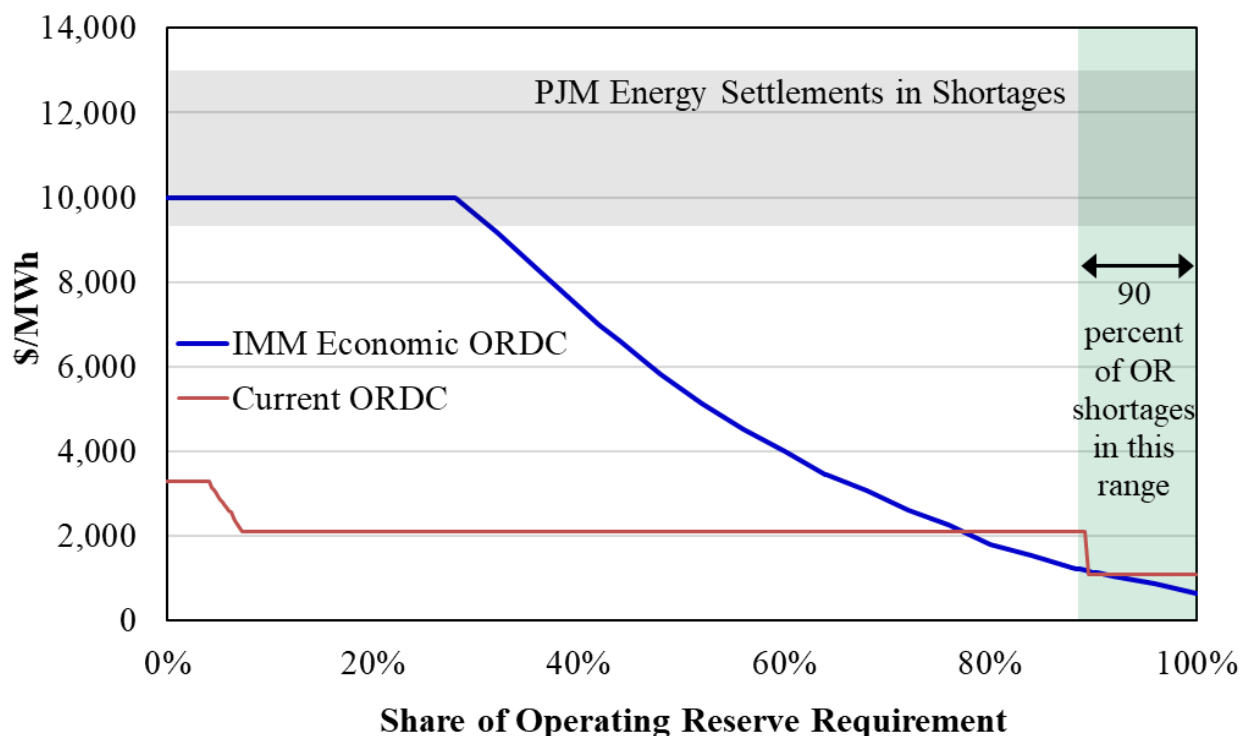
Figure A19 shows the current ORDC and a curve that illustrates the IMM's economic ORDC. The shape of the current curve is initially flat for an extended range at $2,100 per MWh, then $1,100 per MWh. As shortage levels increase on the $1,100 per MWh step of the current ORDC, the prices remain fixed and do not accurately reflect the fact that the probability of losing load is increasing as the complement of reserves held is decreasing.

The IMM's economic ORDC reflects the marginal value of lost load based on an assumed VOLL of $25,000 per MWh and a probability of losing load that the IMM estimated using a Monte Carlo simulation. The inputs to this simulation are described below.

Table A2: Summary of Direct Survey Outage Costs Studies

VOLL is a widely understood concept that represents the lost value to consumers when electricity service is interrupted. It can be thought of as the value of reliable service and it is usually measured by estimating interruption or outage costs. Outage costs are typically estimated through survey methods, although many studies have been conducted using only macroeconomic analysis. Although macroeconomic analysis has the advantage of relying on widely available data, it also tends to be much less accurate. The survey studies have the distinct advantage of creating data using actual customer experiences regarding outages. Survey methods underpin the major benchmark studies of outage costs in US jurisdictions including key meta studies that have established versatile outage cost estimators.

The most widely referenced meta studies have been conducted by Sullivan, et al. of the Berkeley National Laboratory. An initial study was conducted in 2009 (2009 Berkeley Study) and later updated in 2015 (2015 Berkeley Study). A precursor to the Berkeley studies (Lawton and Sullivan 2001) was used as the basis for the 2005 MISO VOLL study. The estimated coefficients of the econometric model from Lawton and Sullivan were used to establish a range of outage cost values in MISO using 2005 MISO-specific data. Some significant survey-based outage cost studies have also been conducted in other countries.

Table A2 summarizes the results of these survey-based studies. The results in the table are organized in two sections based on the different service classes within the studies. The first set of studies listed in the table divide the classes between Residential, Large Commercial/Industrial, and Small Commercial/Industrial. The second set of studies divide the classes between Residential, Commercial, and Industrial.

The table shows that the average outage costs range from $6,900 per MWh for residential customers, up to $105,000 per MWh for small commercial and industrial customers. Given MISO's current VOLL assumption of $3,500 per MWh, these results indicate the need to revisit and update the VOLL assumption to a more reasonable level.

We believe the most reasonable means to do this is to use the Berkeley model with updated data for MISO. The Berkeley model relies on previous survey-based outage studies that form a meta data set used as a basis for an econometric model.

Table A2: Summary of Direct Survey Outage Costs Studies

	System Wide		Residential		Large C/I		Small C/I		Source
US Southwest					$	11,099	$	44,803	Berkely - LEI ERCOT
US (2009)			$	135	$	10,422	$	21,522	Berkely - LEI ERCOT
US (2015)			$	4,175	$	27,577	$	373,177	Berkely (2015)
US-MISO			$	2,195	$	37,063	$	53,454	SAIC - LEI ERCOT
NZ 2018 (lower)			$	4,477	$	8,735	$	46,676	NZ Power/PWC
NZ 2018 (upper)			$	9,231	$	44,368	$	90,602	NZ Power/PWC
					Commercial		Industrial		
New Zealand (2012)	$	52,206	$	14,346	$	98,274	$	39,056	NZEA - LEI ERCOT
Australia Victoria	$	56,214	$	5,240	$	36,207	$	13,228	LEI ERCOT
Autralia	$	57,821							LEI ERCOT
Ireland (2010)	$	12,066	$	22,740	$	12,994	$	4,177	LEI ERCOT
Ireland (2007)	$	20,575							LEI ERCOT
Average	$	39,776	$	6,949					
Average (Large C/I and Small C/I)					$	23,211	**$**	**105,039**	
Average (Commercial Industrial)					**$**	**49,159**	$	18,820	
Average Non-Residential					$	54,080			
Average Commercial/Small C/I, excl.Berkely 2015, NZ 2012)					$	44,542			

Note: All values in 2023 $/MWh

The econometric model in the Berkeley studies estimates the effects on outage costs from key parameters specific to individual customer classes. In particular, the estimated coefficients of the econometric model can be applied to estimate outage costs for specific regions, time periods, and customer classes. We used 2021 MISO data, assumed a one-hour outage, and found:

- *Residential customers:* The outage costs range from $4,200 per MWh to $4,600 per MWh, depending on customer income.

- *Large non-residential customers:* The outage costs ranged from $36,000 per MWh for a non-manufacturing customer to $84,000 per MWh for a manufacturing customer.

- *Small commercial/industrial customers:* Outage costs range from $96,000 per MWh for non-manufacturing customers to $211,000 per MWh for manufacturing customers.

The small commercial/industrial estimates are outside the range of values found by all other studies. Accordingly, to identify a reasonable VOLL for MISO, we use the average of the residential and large commercial/industrial valued from the Berkley Model. We weighted the outage cost estimate for the two groups in accordance with annual MWh of consumption in MISO in 2021. This weighted average yielded a MISO-wide outage cost of $25,000 per MWh. We propose that MISO use this as the VOLL in the ORDC.

Figure A20: Participation of Resources in Loss of Load Probability

The current ORDC includes all resources greater than 100 MW in the loss of load estimation. This equal treatment ignores the reality that some resources and technology types operate more often and have a greater contribution to system reliability. Our proposed alternative Participation Factor (PF) for each generation technology type is similar to the NERC-defined Weighted Service Factor. It equals the sum of the online capacity for that type, divided by the sum of the

type's installed capacity across all hours of the historical period. This metric is different from a traditional capacity factor, which measures energy output as a share of generation capability. The PF assumes resources are contributing their full capacity to satisfying energy, ancillary services, headroom, and ramp capability needs.

As shown in Figure A20, these two methodologies result in modest differences in participation factors. Because all nuclear resources are larger than 100 MW, the current methodology has a 100 percent participation factor. Our alternative IMM approach has a lower participation factor that reflects outages during the study period. The most significant differences impact combustion turbines, gas steam units, and combined-cycle resources. These intermediate load technologies have higher shares of large resources than the share of capacity committed. Since an uncommitted, offline resource is not at risk of taking a forced outage, this is the appropriate means to measure participation.

Figure A20: Participation of Resources in Loss of Load Probability
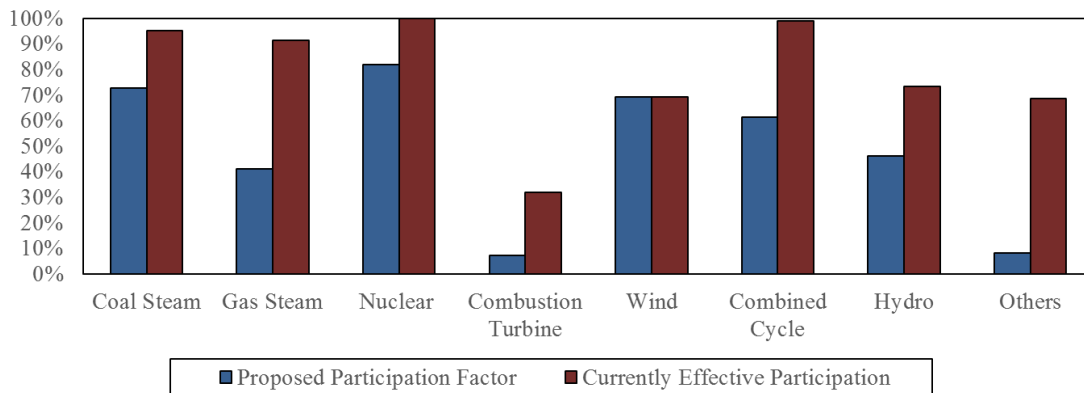
Figure A21: ORDC-Estimated Unit Failure Risk

NERC GADS failure rates, measured by the Mean Service Time to Unplanned Outage (MSTUO), vary significantly among technology types. This is a key input to the ORDC because it determines how likely it is that contingencies will occur that cause a loss of load. The technology-specific values, shown in blue, range from 30 hours per unplanned outage for combustion turbines to over 4,000 hours for nuclear units. Under MISO's current ORDC, all generators are assumed to have an equivalent rate of forced outage. Shown in the figure below as the maroon bar, this assumption is inconsistent with resources' actual failure rates.

Figure A21: ORDC – Estimated Unit Failure Risk
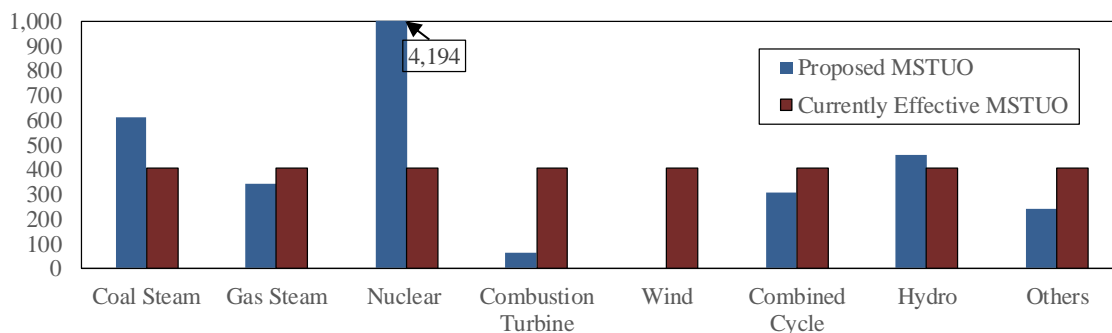
Based on these proposed parameters, we estimated the generator forced outages as follows. For each simulation iteration, each non-wind generator was assigned a random number between zero and one. If the assigned random number was less than 1-$e^{(-PF * ORP / MSTUO)}$, the generator was simulated to be forced out of service. We assumed a two-hour outage recovery period (ORP), which is the number of hours MISO needs to fully respond to supply-side contingencies in the RAC process.

Intermittent resources and net imports were simulated as supply-side forecast risks using similar methodologies. First, a distribution of actual aggregate forecast errors was calculated from the historical period. The errors equaled the difference between actual capability in hour t and the forecasted capability schedule two hours prior to t. Next, a distinct random number between zero and one was assigned to each supply group for each iteration. This number served as the distribution probability. The simulated forced outage equivalent was the maximum of zero and the inverse of the normal cumulative distribution with mean and standard deviations calculated from the group forecast error distribution.

Figure A22: Distribution of Outage Risks by Technology Type

After calculating aggregate forced outage, intermittent resource forecast, and NSI scheduling risks, these values were summed by iteration of a Monte Carlo simulation. Conditional probabilities at a given reserve level were calculated as the number of iterations with forced outages greater than or equal to that reserve level divided by the total number of iterations. These probabilities accurately reflected the risk to real-time operations of losing load at any reserve shortage level.

Figure A22 shows the average risk associated with each resource type according to the current and proposed methodologies. The relative size of the pie charts indicates the average level of risk estimated by each methodology, while the slices of the pie indicate each resource type's contribution within the methodology.

Figure A22: Distribution of Outage Risks by Technology Type
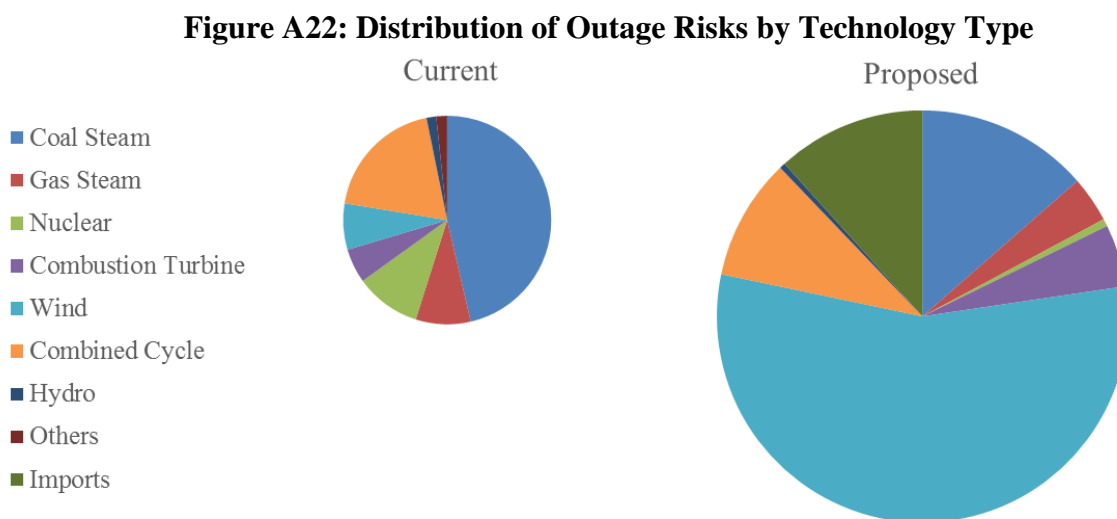
These results show a four-fold increase in outage risk under the IMM-proposed methodology, in part because our methodology accounts for the risk of multiple simultaneous outages. While the risk increased for most technologies, there are other notable differences. Wind units accounted for more than 50 percent of the total outage risk in the proposed model. The volatility of wind, coupled with significant forecasting errors, has created unique challenges. As wind and solar penetration increases, this formulation will better capture the loss of load risks. The greatest decline shown in the figure is the contribution of nuclear resources. These resources rarely fail, so their risk to real-time reliability is greatly reduced under the proposed methodology.

C.   Capacity Market Design

The PRA consisted of a single-price auction to determine the clearing prices and quantities of capacity procured in MISO and in each of the ten zones. The demand in this market is implicitly defined by the minimum resource requirement and a deficiency price, based on the CONE that MISO updates annually. These requirements result in a vertical demand curve, which implies that demand is insensitive to the price and any additional available capacity beyond the minimum resource requirement is effectively worthless to MISO. In this section, we describe the implications of the vertical demand curve on the market's performance and the benefits of improving the representation of demand by using a reliability-based demand curve. In particular, we discuss the benefits of this change for the integrated utilities in the MISO area. We begin below by discussing the attributes of supply and demand in a capacity market.

Attributes of Demand in a Capacity Market

The demand for any good is determined by the value that the buyer derives from the good. For capacity, the value is derived from the reliability provided by the capacity to electricity consumers. The implication of a vertical demand curve like MISO's 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 reliability-based demand curve. The fact that a vertical demand curve does not reflect the underlying value of capacity to consumers is the source of a number of the concerns described in this section.

Attributes of Supply in a Capacity Market

In workably competitive capacity markets, the competitive offer for existing capacity (i.e., the marginal cost of selling capacity) is generally close to zero, ignoring export opportunities. A supplier's offer represents the lowest price it would be willing to accept to sell capacity. This is determined by two factors: (1) the costs the supplier will incur to satisfy the capacity obligations for the resource, known as the "going-forward costs" (GFC), and (2) the amount of expected net revenues from energy and ancillary services markets to cover the GFCs).

Two primary principles govern capacity supply offers:
- *Capacity Obligations*: Suppliers that sell capacity in MISO are not required to accept costly obligations that could substantially increase the suppliers' costs of selling capacity.

- *Effects of GFCs*: For most units, the net revenues from RTOs' energy and ancillary services markets are sufficient to keep the units in operation. Therefore, no capacity revenue is needed, which would cause the supplier to submit a capacity offer of zero.

Figure A23: Surplus and Shortage Capacity Cases with Vertical Demand Curve

Because GFCs are generally covered by energy revenues and capacity obligations are not costly to satisfy, most suppliers are willing to be price-takers in the capacity market, accepting any non-zero price for capacity. When the low-priced supply offers clear against a vertical demand curve, only two outcomes are possible, as shown in Figure A23 below.

Figure A23: Surplus and Shortage Capacity Cases with Vertical Demand Curve
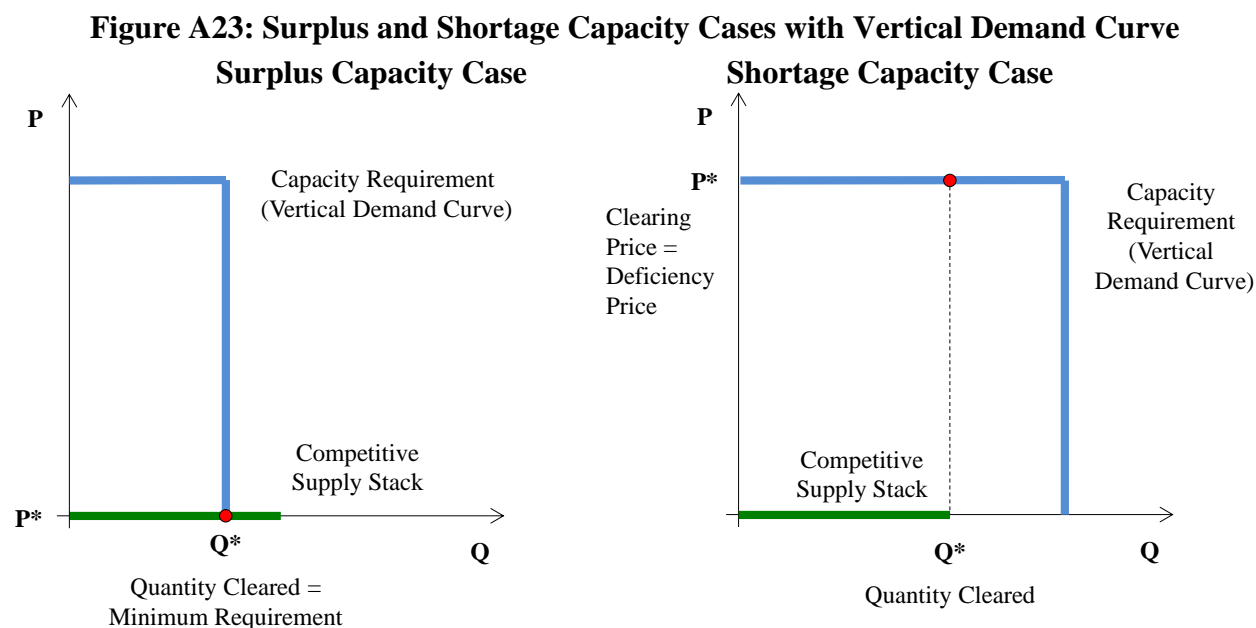
This figure shows that:

- If the market is not in a shortage, the price will clear at a price close to zero.
- If the market is in shortage, the supply and demand curves do not cross and the price will clear at the deficiency price.

This pricing dynamic and the associated market outcomes raise at least three significant issues regarding the long-term performance of the current capacity market:

- Because prices produced by such a construct do not accurately reflect the true marginal value of capacity, the market will not provide efficient long-term economic signals to govern investment and retirement decisions.
- This market will result in substantial volatility and uncertainty, which can hinder long-term contracting and investment by making it extremely difficult for potential investors to forecast the capacity market revenues. This difficulty would undermine the effectiveness of the capacity market in maintaining adequate resources, even when short-term prices rise.
- A market that is highly sensitive to small changes in supply creates a strong incentive for suppliers to withhold capacity to raise prices. Withholding in such a market is nearly

costless because the foregone capacity sales would otherwise be priced at close to zero. Hence, market power is a greater potential concern, even if the market is not concentrated.

Figure A24: Reliability-Based Demand Curve

A reliability-based demand curve addresses each of the shortcomings described above. Importantly, it recognizes that the initial increments of capacity in excess of the minimum requirement are valuable from both a reliability and economic perspective. The figure below illustrates the sloped demand curve and the difference in how prices would be determined.

Figure A24: Sloped Demand Curve
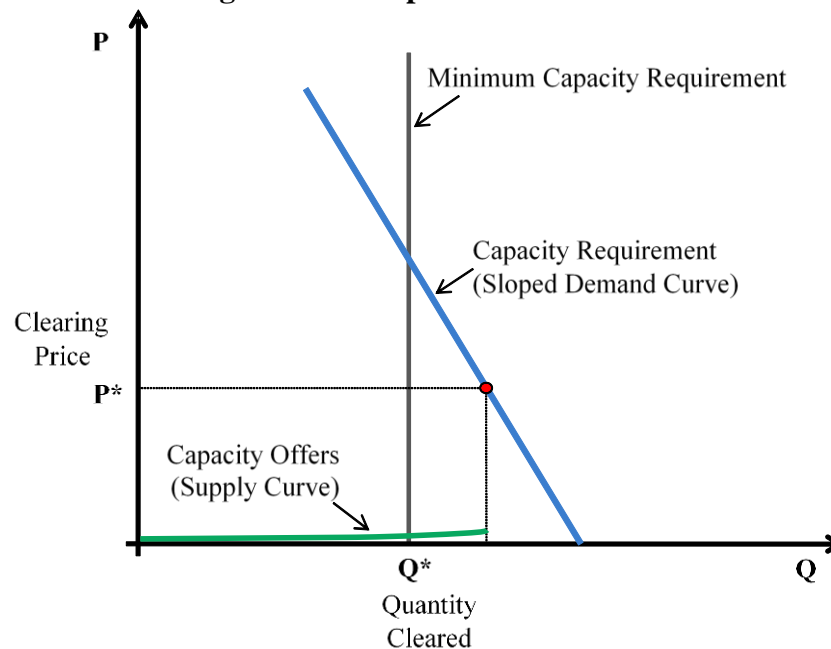
When a surplus exists, the price would be determined by the marginal value of additional capacity as represented by the reliability-based demand curve, rather than by a supply offer. This provides a more efficient price signal from the capacity market. In addition, the figure illustrates how a reliability-based demand curve would serve to stabilize market outcomes and reduce the risks facing suppliers in wholesale electricity markets. Because the volatility and its associated risk is inefficient, stabilizing capacity prices in a manner that reflects the prevailing marginal value of capacity would improve the incentives of suppliers that rely upon these market signals to make investment and retirement decisions.

A reliability-based demand curve reflects the marginal value of capacity because the sloped portion is based on the reliability benefit of exceeding planning reserves. A reliability-based demand curve will also significantly reduce suppliers' incentives to withhold capacity from the market by increasing the opportunity costs of withholding (foregone capacity revenues) and decreasing the price effects of withholding. This incentive to withhold falls as the market approaches the minimum capacity requirement level. While it probably would not completely mitigate potential market power, a reliability-based demand curve would significantly improve suppliers' incentives.

If a reliability-based curve is introduced, MISO will need to work with its stakeholders to develop the various parameters that define the demand curve. We recognize that this process is likely to be difficult. However, in simply approving a minimum requirement and a deficiency price (i.e., a vertical demand curve), some of the most important parameters have been established implicitly with no analysis or discussion. In particular, such an approach establishes a demand curve with an infinite slope, but with no support for why it is efficient or reasonable.

Short-Term Effects of PRA Reform

Figure A25: Supply and Demand in 2021/2022 PRA

To demonstrate the significance of the flawed vertical demand curve, we estimated the clearing price in MISO that would have prevailed in the 2021/2022 PRA if MISO had employed reliability-based demand curves, as shown in Figure A25. The blue dashed line in Figure A25 represents the vertical demand curve actually used in the 2021/2022 PRA, and the solid green line indicates the maximum amount of capacity in MISO that was not stranded behind auction constraints. We constructed the supply curve using all capacity that was offered into the MISO auction either with an associated price or through self-supplied resources from Fixed Resource Adequacy Plans.

Figure A25: Supply and Demand in 2021/2022 PRA
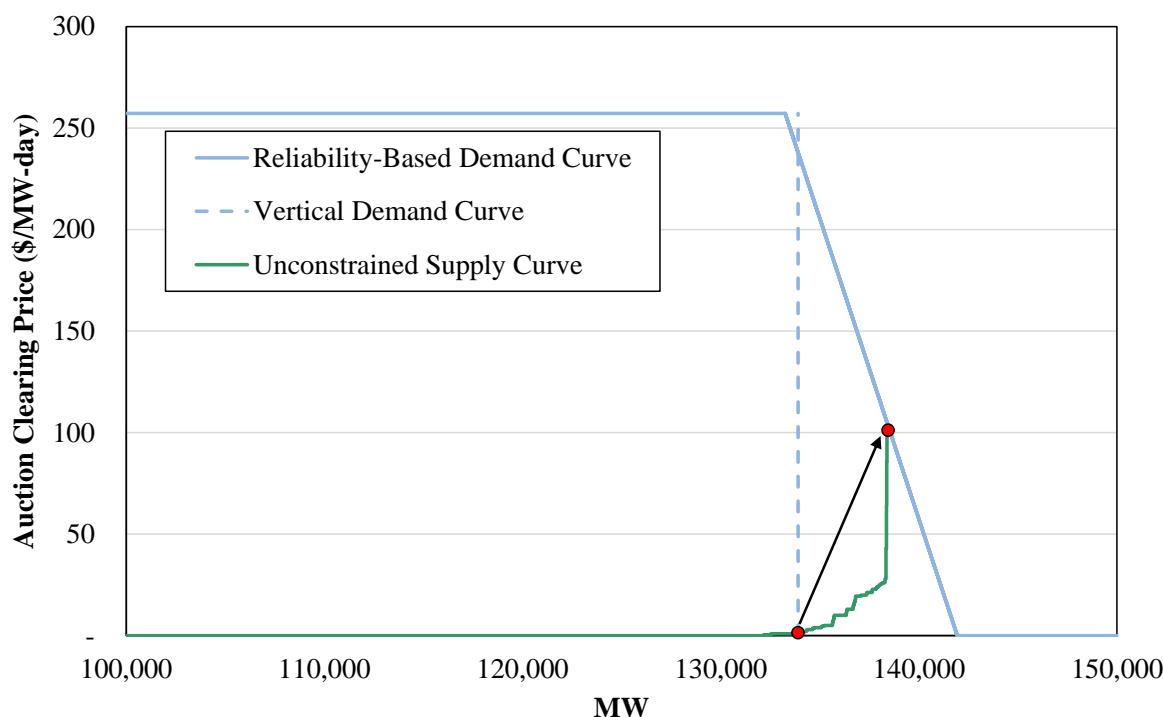
The top of the sloped demand curve used in this simulation is at 1.05 x CONE and 98.8 percent of the planning reserve margin requirement (PRMR). The sloped demand curve and the vertical demand curve intersect at CONE. In other words, the sloped demand curve price is equal to CONE at the PRMR quantity. For our simulation, we assumed a linear demand curve where the zero-crossing point (the point where additional capacity is assumed to have no value) determines the slope of the demand curve. Any sloped capacity demand curve must be parameterized

through analysis and discussion with market participants. The capacity demand curve for the New York Control Area (i.e., all of New York) crosses zero at 112 percent of the minimum capacity requirement. The capacity demand curve for the PJM crosses zero at 107.5 percent of the minimum capacity requirement. For our simulation, we used a slightly steeper slope than PJM and assumed a zero-crossing point of 106 percent of the MISO-wide PRMR. Changing this slope will change the precise clearing price we estimate, but not the overall conclusion that assuming a vertical demand curve produces prices that do not reflect the marginal reliability value of capacity resources in MISO.

Figure A26: Inefficient Auction Clearing Prices and Associated Retirements

As predicted in prior years, inefficient capacity auction design and correspondingly low-capacity auction clearing prices led to a large number of retirements in recent years. In Figure A26 below, we illustrate the amount of capacity lost between 2019 and 2022 because of inefficient market design. In the top panel we plot the amount of unforced capacity (UCAP) that retired that may have remained in service had MISO employed a reliability-based demand curve. The colors of the bars represent the types of market participants, such as merchant, municipal, and vertically-integrated utilities. In the bottom panel, we show the range of net going-forward costs in the green shaded area, calculated as the TSAC-based going-forward costs adjusted for net revenues, that resources would need to recover through the capacity auction in order to avoid suspension or retirement. The actual price represents the auction clearing price in each year's auction, and the efficient price represents the alternative auction clearing prices that would have resulted from a reliability-based demand curve. Since the Midwest was short in 2022, the 2022/2023 auction clearing price was the Cost of New Entry (CONE) in the Midwest.

Figure A26: Inefficient Auction Clearing Prices and Associated Retirements
Midwest, 2019–2022
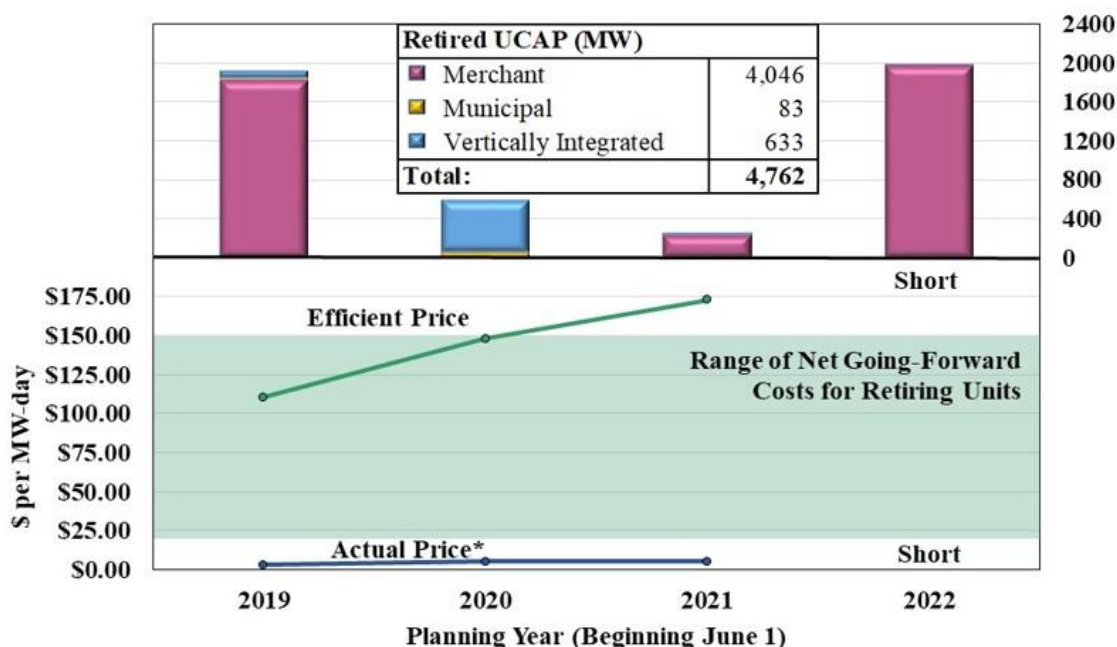
* Actual prices are the unconstrained auction clearing prices of the Midwest. Zone 7 separated in 2019 and 2020.

Table A3: Effects of Sloped Demand Curve by Type of Participant

Based on the simulation described in the prior section, we estimated how improving the design of the PRA would have affected various types of market participants in the 2021/2022 PRA. We calculated the simulated settlements for each participant based on their net sales. The change in settlement is calculated by changing the price and quantity for each participant. For the buyer-side settlement, costs increase resulting from higher capacity prices and an increase in their capacity requirement of approximately five percent. This is because of the market clearing at a surplus level of approximately five percent above the current requirement. For the seller-side settlement, revenues increase because of higher sales prices and, for those with economic excess, higher sales volumes. Economic excess is the uncleared volumes under the vertical demand curve that are economic relative to other uncleared offers to meet the additional demand under the sloped demand curve. We then aggregated the participant-level results into four categories: competitive suppliers (merchant generators), competitive retail LSEs, municipal and cooperative entities, and vertically integrated utilities.

These effects are important because the economic price signals from the wholesale market guide key decisions by unregulated participants in MISO, including competitive suppliers and competitive retail LSEs. These effects are shown in Table A3 below. The values are aggregated for participants whose net revenues would increase and for those whose net revenues would decrease (or costs that would increase).

Table A3: Effects of Sloped Demand Curve by Type of Participant
2021–2022 PRA

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

IV. ENERGY MARKET PERFORMANCE AND OPERATIONS

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

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

Figure A27 and Figure A28: Day-Ahead Energy Hub Prices and SMP

Figure A27 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on non-holiday weekdays) at six hub locations in MISO and the day-ahead System Marginal Price (SMP).

Figure A27: Day-Ahead Hub Prices and SMP
Peak Hours, 2021–2022
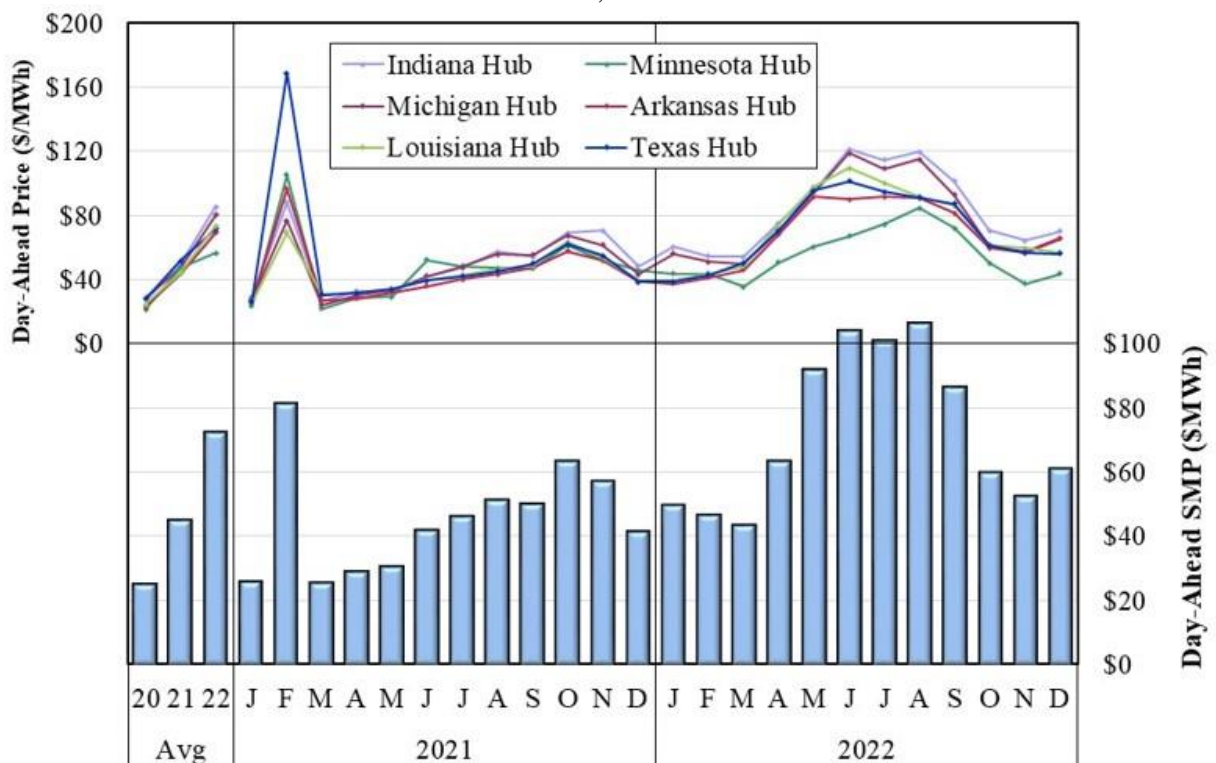
Figure A28 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Higher prices in one location relative to another indicate congestion and loss factor differences between those areas.

Figure A28: Day-Ahead Hub Prices and SMP
Off-Peak Hours, 2021–2022
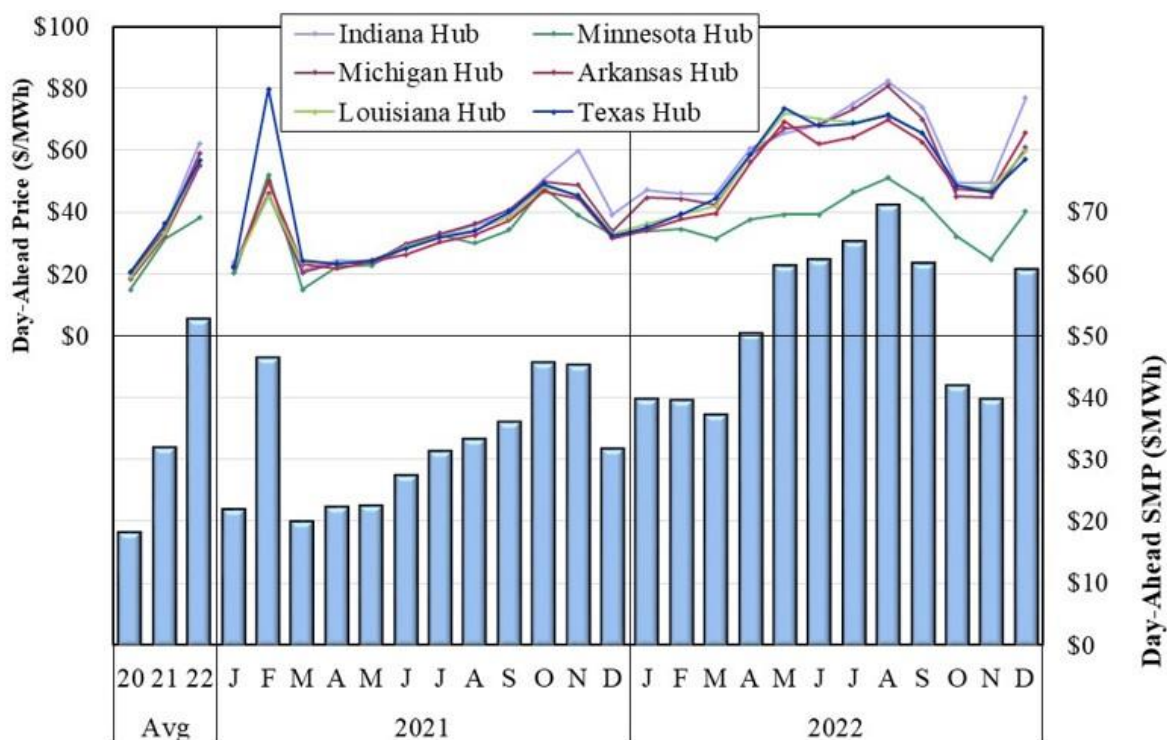
Convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market, which is vital for overall market efficiency. If the day-ahead prices fail to converge with the real-time prices, then the real-time physical dispatch is not being anticipated in the day-ahead market. This can result in:

- Generating resources not being efficiently committed because most are committed through the day-ahead market;

- Consumers and generators being substantially affected because most settlements occur through the day-ahead market; and

- Payments to FTR holders not reflecting the true transmission congestion on the network, which will ultimately distort future FTR prices and revenues.

Participants' day-ahead market bids and offers should reflect their expectations of the real-time market the following day. However, a variety of factors can cause real-time prices to be significantly higher or lower than those anticipated in the day-ahead market. While a well-performing market may not result in prices converging on an hourly basis, they should converge on a longer-term basis.

A modest day-ahead price premium reflects rational behavior because purchases in the day-ahead market are subject to less price volatility, which is valuable to risk-averse buyers. Additionally, purchases in the real-time market are subject to the allocation of real-time Revenue Sufficiency Guarantee (RSG) costs that are typically much larger than day-ahead RSG costs. Most day-ahead purchases can avoid these RSG costs.

Figure A29 to Figure A34: Day-Ahead and Real-Time Prices

The next seven figures summarize price convergence in the MISO markets by showing monthly average prices in the day-ahead and real-time markets at representative locations in MISO, along with the average RSG costs allocated per MWh.[8] The table below the figures shows the average day-ahead and real-time price difference, including and excluding RSG charges. Real-time RSG is assessed to deviations from the day-ahead schedules that are settled through the real-time market, including net virtual supply. Real-time RSG charges are generally much higher than day-ahead charges and, therefore, should lead to modest day-ahead price premiums.

Figure A29: Day-Ahead and Real-Time Prices
2021–2022: Indiana Hub

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

Excluding RSG	3	4	-2	0	45	2	-6	3	2	3	4	-2	-1	-3	3	-2	6	0	-2	2	5	1	-3	7	-3	5	-24
Including RSG	2	1	-3	0	23	1	-8	1	-2	-1	1	-4	-3	-3	3	-3	5	-1	-2	-1	3	0	-4	6	-3	4	-26

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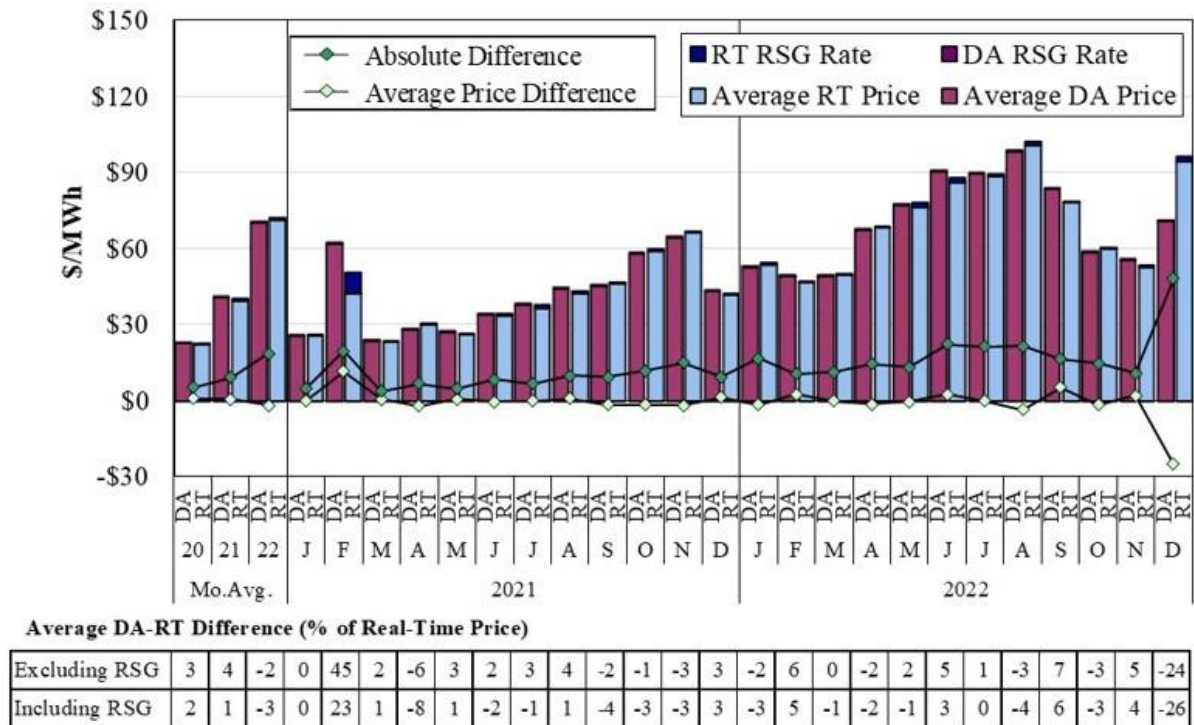
8   The rate is the Day-Ahead Deviation Charge (DDC) Rate, which excludes the location-specific Congestion Management Charge (CMC) Rate and Pass 2 RSG.

Figure A30: Day-Ahead and Real-Time Prices
2021–2022: Michigan Hub

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

Excluding RSG	2	4	1	1	35	0	-2	3	1	4	4	-1	1	0	2	-2	7	3	-2	7	8	1	-2	7	1	6	-19
Including RSG	1	1	-1	0	14	-1	-4	1	-3	0	1	-3	-1	-1	1	-3	6	3	-3	5	6	-1	-3	7	1	4	-21
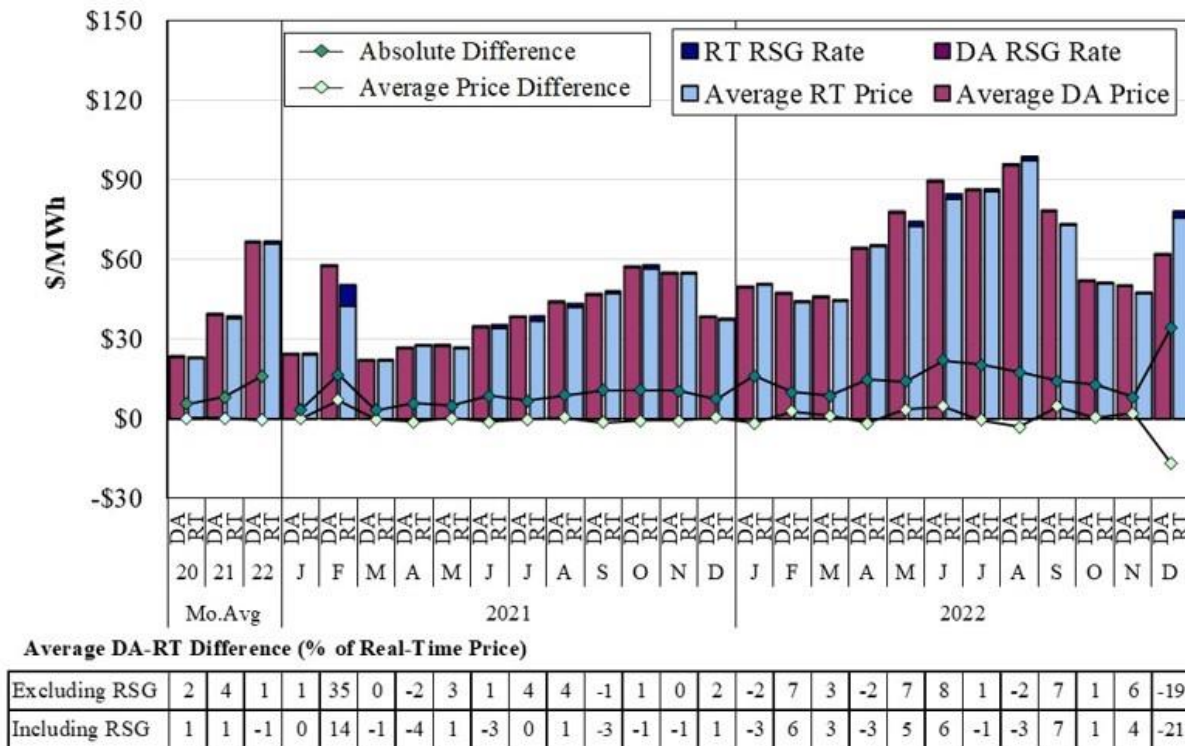
Figure A31: Day-Ahead and Real-Time Prices
2021–2022: Minnesota Hub

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

Excluding RSG	-1	2	3	0	20	4	-13	-8	-2	5	4	-5	1	3	1	5	9	8	4	2	15	-1	-3	8	1	6	-13
Including RSG	-2	-1	0	-1	6	3	-15	-9	-5	1	1	-7	-2	2	0	3	8	8	2	-1	10	-2	-5	7	0	4	-17
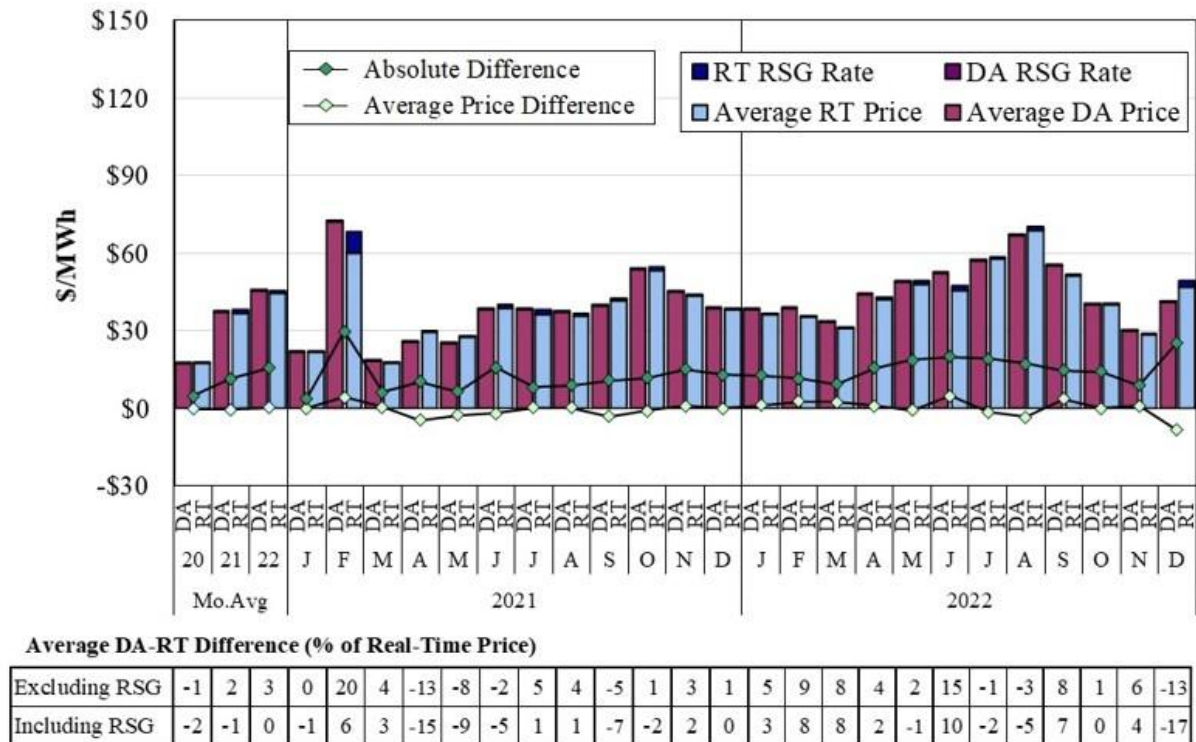
Figure A32: Day-Ahead and Real-Time Prices
2021–2022: Arkansas Hub

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

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Excluding RSG	2	0	0	3	-5	-2	-3	1	5	0	6	-3	0	6	-1	0	4	4	4	8	6	-3	-5	4	-2	-2	-16
Including RSG	1	-3	-2	3	-14	-3	-6	-1	1	-5	3	-5	-2	5	-2	-2	3	3	3	6	3	-5	-7	4	-3	-3	-18
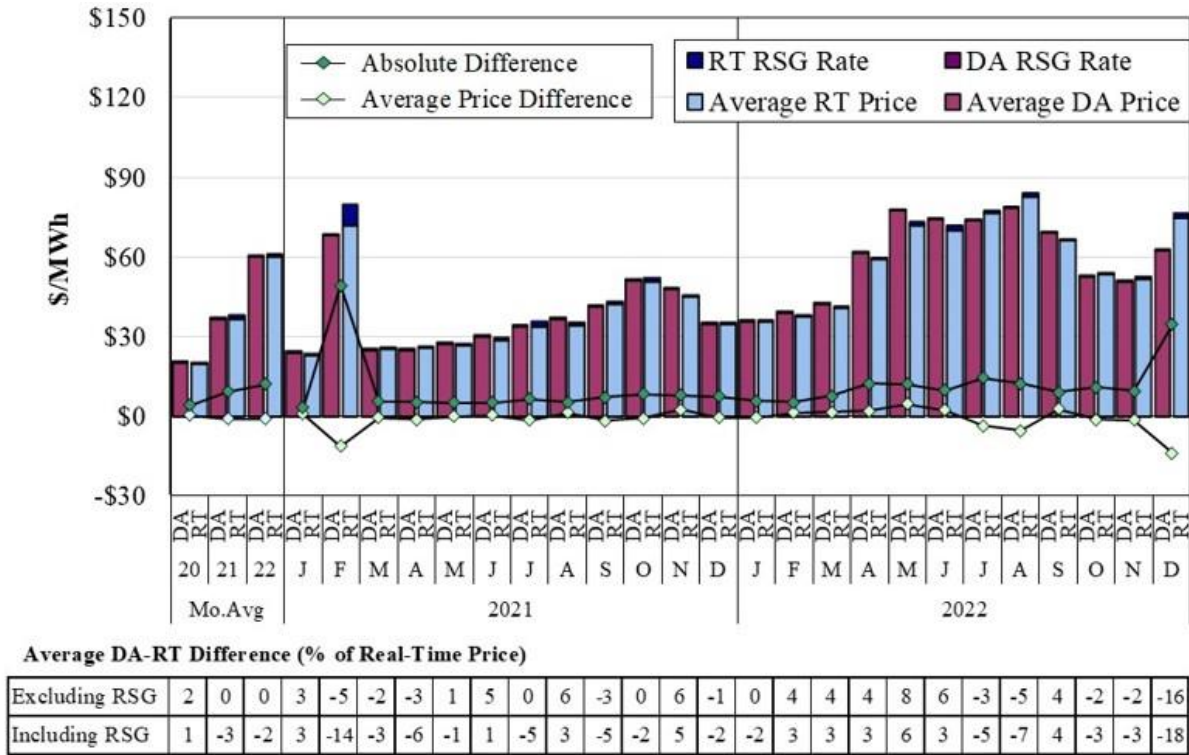
Figure A33: Day-Ahead and Real-Time Prices
2021–2022: Louisiana Hub

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

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Excluding RSG	3	2	0	2	-1	-10	2	2	6	4	12	-3	5	4	0	-2	6	4	4	10	7	1	-6	3	-1	0	-20
Including RSG	2	-1	-1	1	-14	-10	0	1	2	0	8	-5	3	3	-1	-3	5	4	4	8	5	0	-7	3	-1	-1	-23
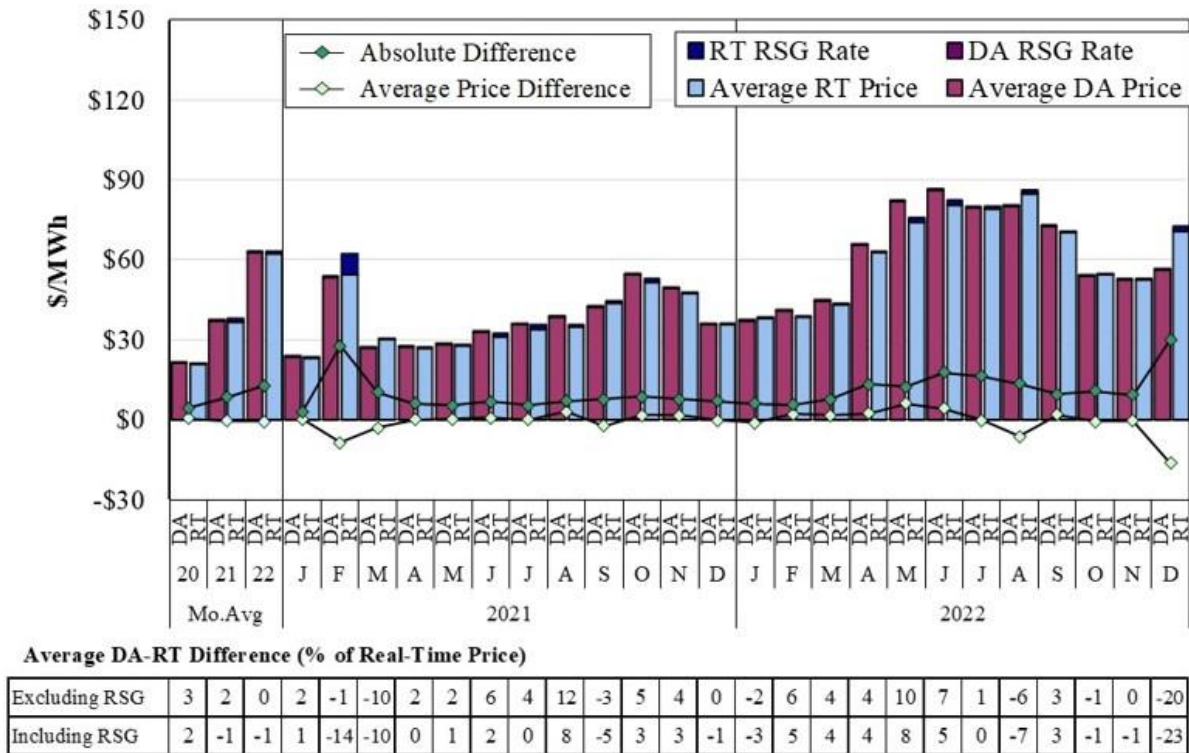
Figure A34: Day-Ahead and Real-Time Prices
2021–2022: Texas Hub
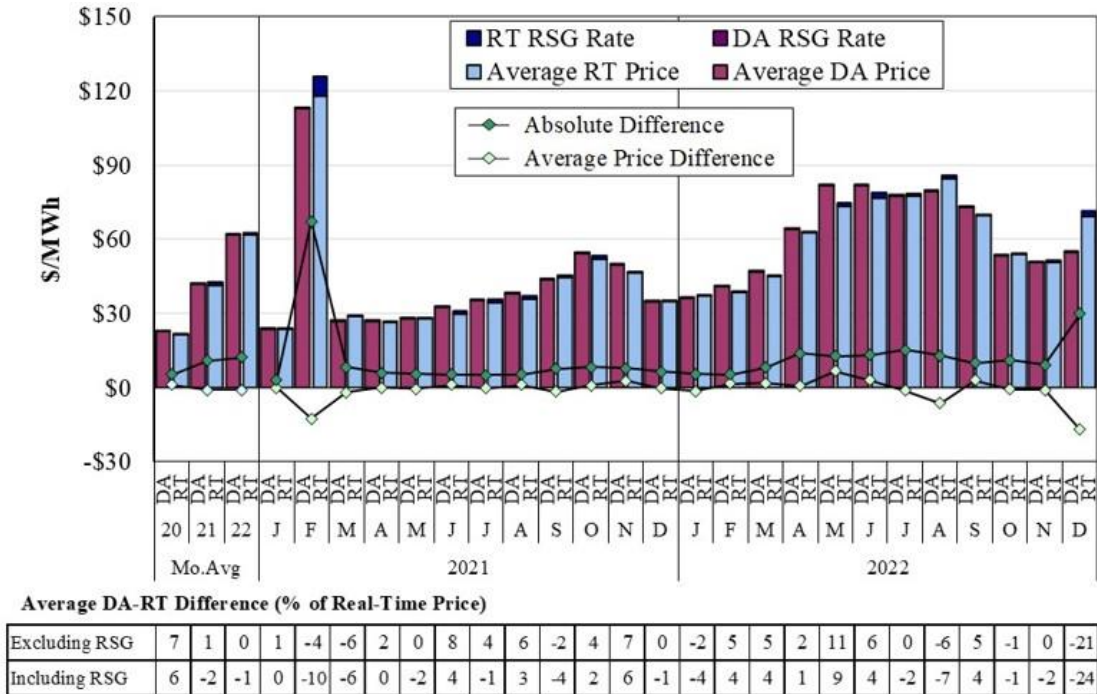
Figure A35: Day-Ahead Ancillary Services Prices and Price Convergence

Price convergence is also important in the ancillary services markets, which are jointly optimized with the energy markets. Figure A35 shows monthly average day-ahead clearing prices for each ancillary services product, along with day-ahead and real-time price differences.

Figure A35: Day-Ahead Ancillary Services Prices and Price Convergence
2022
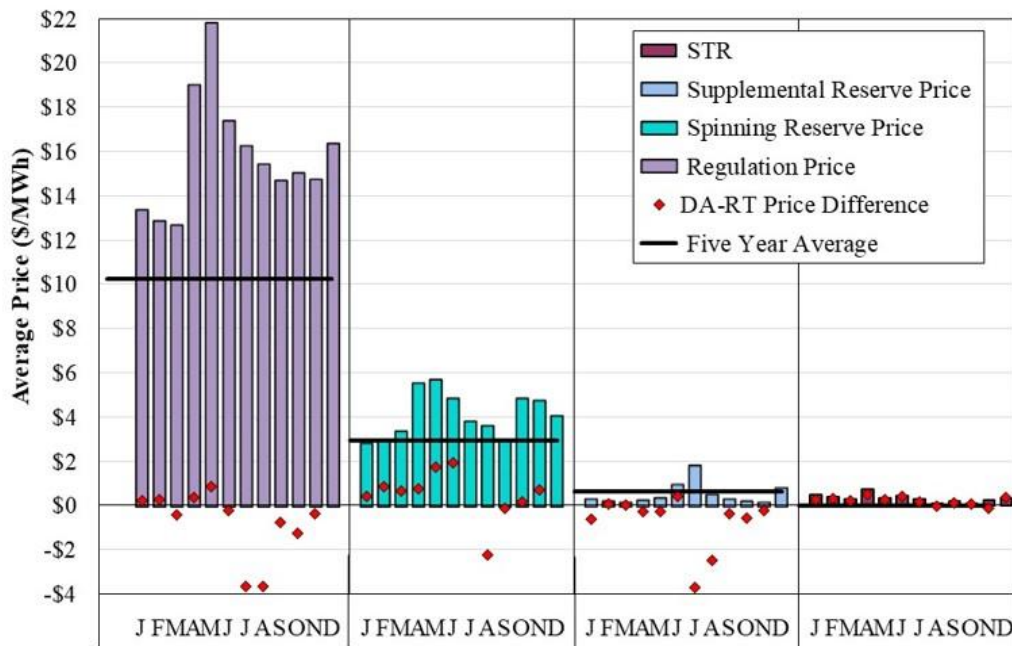
B.   Day-Ahead Load Scheduling

Load scheduling, Net Scheduled Interchange (NSI), and virtual trading in the day-ahead market play an important role in overall market efficiency by promoting optimal commitments and improved price convergence between day-ahead and real-time markets. Day-ahead load is the sum of physical load and virtual load. Physical load includes cleared price-sensitive load and fixed load. Price-sensitive load is scheduled (i.e., cleared) if the day-ahead price is equal to or less than the load bid. A fixed-load schedule does not include a bid price, indicating a desire to be scheduled regardless of the day-ahead price.

Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or resources. Similar to price-sensitive load, virtual load is cleared if the day-ahead price is equal to or less than the virtual load bid. Net day-ahead load is defined as day-ahead cleared physical load, plus cleared virtual load minus cleared virtual supply, plus NSI. The differences between net day-ahead load and real-time load are important because they can undermine the efficiency of the generator commitment patterns and raise RSG costs.

When net day-ahead load is significantly less than real-time load, particularly in the peak-load hour of the day, MISO will frequently need to commit peaking resources after the day-ahead market to satisfy the system's real-time demand. This can contribute to suboptimal real-time pricing and can result in inefficient outcomes when lower-cost generation scheduled in the day-ahead market is displaced by peaking units committed in real time. Because these peaking units frequently do not set real-time prices (even though they are more expensive than other resources), the economic feedback and incentive to schedule more fully in the day-ahead market will be diluted.

Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

- Supplemental commitments made by MISO for reliability after the day-ahead market;

- Self-commitments made by market participants after the day-ahead market;

- Under-scheduled wind output in the day-ahead market; and

- Real-time net imports above day-ahead schedules.

Figure A36 to Figure A38: Day-Ahead Scheduled Versus Actual Loads

To show net day-ahead load-scheduling patterns, Figure A36 compares the monthly average day-ahead scheduled load to average real-time load. The figure shows only the daily peak hours when under-scheduling are most likely to require MISO to commit additional units. The table below the figure shows the average scheduling levels in all hours and for the peak hour. We show peak hour scheduling separately by region in Figure A37 and Figure A38.

Figure A36: Day-Ahead Scheduled Versus Actual Loads
2021–2022, Daily Peak Hour

Share of Actual Load (%)																												
	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.4	98.6	98.7	98.5	98.5	98.3	97.2	97.7	98.9	99.7	99.8	98.3	99.2	97.8	98.9	98.9	97.8	97.3	97.5	97.6	99.2	99.8	98.9	100.8	99.7	97.6	98.7
Peak Hours	99.0	98.1	98.7	98.4	98.2	98.9	96.9	97.4	98.7	99.0	98.3	97.5	99.2	97.7	98.6	99.2	98.1	97.1	97.0	97.1	99.0	99.9	98.3	100.7	101.4	98.3	98.1
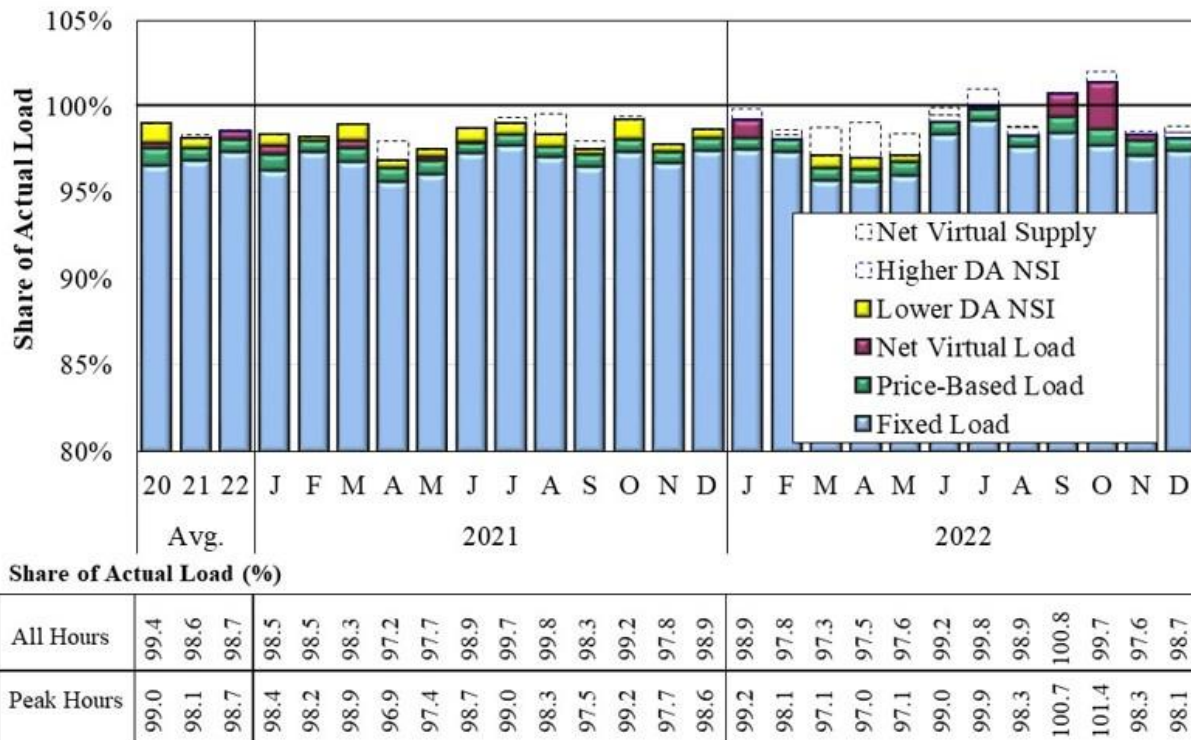
Figure A37: MISO Midwest Day-Ahead Scheduled Versus Actual Loads
2021–2022, Daily Peak Hour

Share of Actual Load (%)																												
	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.1	97.6	98.3	97.5	97.3	96.4	96.0	97.0	97.9	99.4	99.0	97.9	98.5	96.5	98.2	99.3	97.7	96.4	96.4	96.4	98.8	99.9	98.8	100.4	99.6	96.9	98.3
Peak Hours	98.8	97.2	98.6	98.5	97.4	97.3	96.0	96.5	97.6	98.3	96.9	97.0	98.7	97.6	99.0	99.8	98.1	96.5	96.0	96.2	98.2	99.7	98.4	101.0	101.5	99.0	98.5
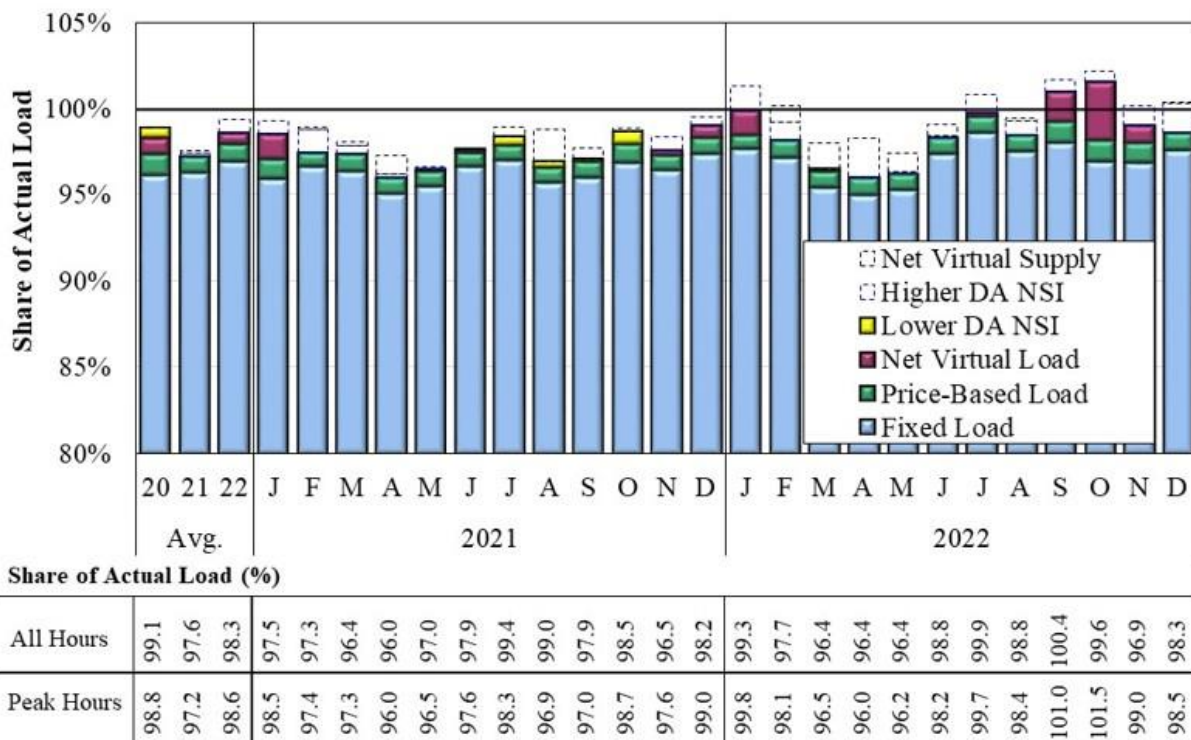
Figure A38: MISO South Day-Ahead Scheduled Versus Actual Loads
2021–2022, Daily Peak Hour

Share of Actual Load (%)

	20	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	100.5	101.5	100.3	101.7	104.0	103.9	100.7	99.8	101.5	100.6	101.7	99.3	101.0	102.2	101.0	98.0	100.3	99.8	100.7	100.4	100.6	99.8	99.9	102.5	100.1	99.6	101.6
Peak Hours	99.9	100.9	99.5	101.3	103.6	102.3	100.3	99.2	101.6	100.9	101.8	99.3	100.2	101.4	101.3	98.8	100.0	98.8	99.1	99.0	99.7	99.7	98.7	101.8	100.1	98.1	100.8

(Avg. columns: 20, 21, 22 | 2021: J–D | 2022: J–D)
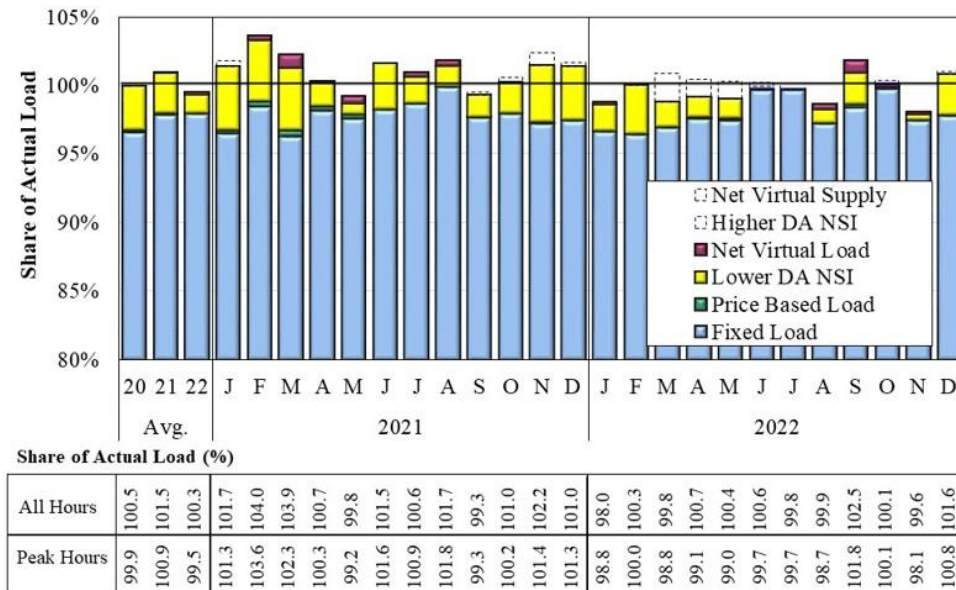
C. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is important because it is used by the Forward Reliability Assessment Commitment (FRAC) process.

Figure A39: Daily MTLF Error in Peak Hour

Figure A39 shows the MTLF error as a percent of actual load in the peak hour of each day.

Figure A39: Daily MTLF Error in Peak Hour

	2021	2022
Absolute Average Peak Load Forecast Error	1.7%	1.8%
Average Forecast Minus Avg RT Load	1.2%	1.3%
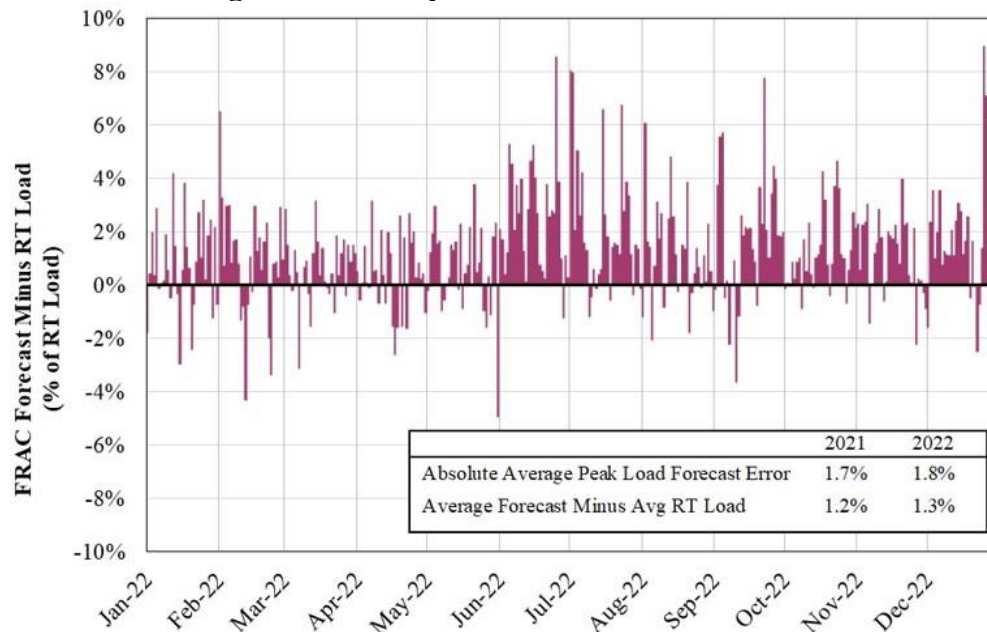
D. Hourly Day-Ahead Scheduling

The day-ahead energy and ancillary services markets clear on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of each hour.

MISO has several options to manage the impact of top-of-the-hour changes in real time, including staggering unit commitments (which can result in increased RSG payments) or proactively using load offsets in order to reduce ramp impacts. Nonetheless, the real-time ramp demands created by the current hourly resolution of the day-ahead market can be substantial and can produce significant real-time price volatility. MISO should consider implementing a shorter scheduling interval in the day-ahead market.

Figure A40: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A40 below shows the implied generation ramp demand attributable to day-ahead commitments and physical schedules compared to real-time load changes. When the sum of these changes is negative, online generators are forced to ramp up in real time to balance the market. When the sum of these factors is positive, generators are forced to ramp down in real time. The greatest ramp demand periods occur at the top of the hour because of day-ahead commitment changes and changes in NSI.

Figure A40: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2022
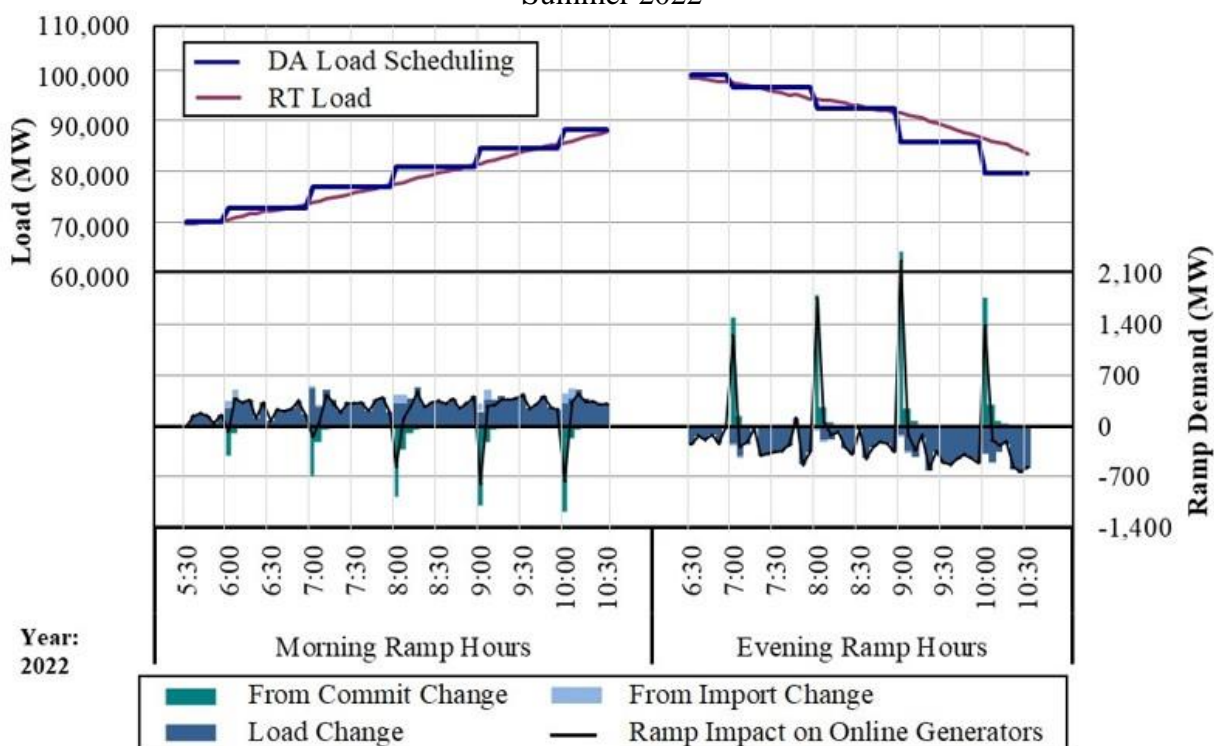
E.   Virtual Transactions in the Day-Ahead Market

Virtual trading provides essential liquidity to the day-ahead market because it constitutes a large share of the price sensitivity at the margin that is needed to establish efficient day-ahead prices. Virtual transactions scheduled in the day-ahead market are settled against real-time prices. Virtual trading is profitable when a trader buys low and sells high. For virtual demand bids, this is when the real-time energy price is higher than the day-ahead price. For virtual supply offers, this is when the day-ahead energy price is higher than the real-time price.

Accordingly, if virtual traders expect day-ahead prices to be higher than real-time prices, they sell virtual supply forward and buy it back financially in the real-time market. If they forecast higher real-time prices, they buy virtual load. This trading is one of the primary means to arbitrage prices between the two markets. Numerous empirical studies have shown that this arbitrage converges day-ahead and real-time prices and, in doing so, improves market efficiency and mitigates market power.[9]

Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies, while large losses may indicate an attempt to manipulate day-ahead prices. Attempts to create artificial congestion or other price movements in the day-ahead market using a virtual position would cause prices to diverge from real-time prices. This divergence would cause the virtual position to be unprofitable. We monitor for such behavior and utilize mitigation authority to restrict virtual activity when appropriate.

Figure A41 and Figure A42: Day-Ahead Virtual Transaction Volumes

Figure A41 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market from 2021 to 2022. Figure A42 separates the 2022 volumes by region. The virtual bids and offers that did not clear are shown as dashed areas at the end points (top and bottom) of the solid bars. These are virtual bids and offers that were not economic based on the prevailing day-ahead market prices (supply offered above the clearing price and demand bid below the clearing price).

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9   Chaves, Jose Pablo and Yannick Perez. 2010. Virtual Bidding: A Mechanism to Mitigate Market Power in Electricity Markets: Some Evidence from New York Market, Working Paper.

Hadsell, Lester, and Hany A. Shawky. 2007. One-Day Forward Premiums and the Impact of Virtual Bidding on the New York Wholesale Electricity Market Using Hourly Data, Journal of Futures Markets 27(11).

Mercadal, Ignacia. 2015. Dynamic Competition and Arbitrage in Electricity Markets: The Role of Financial Players. Working Paper, University of Chicago, October 2015.

Figure A41: Day-Ahead Virtual Transaction Volumes
2021–2022
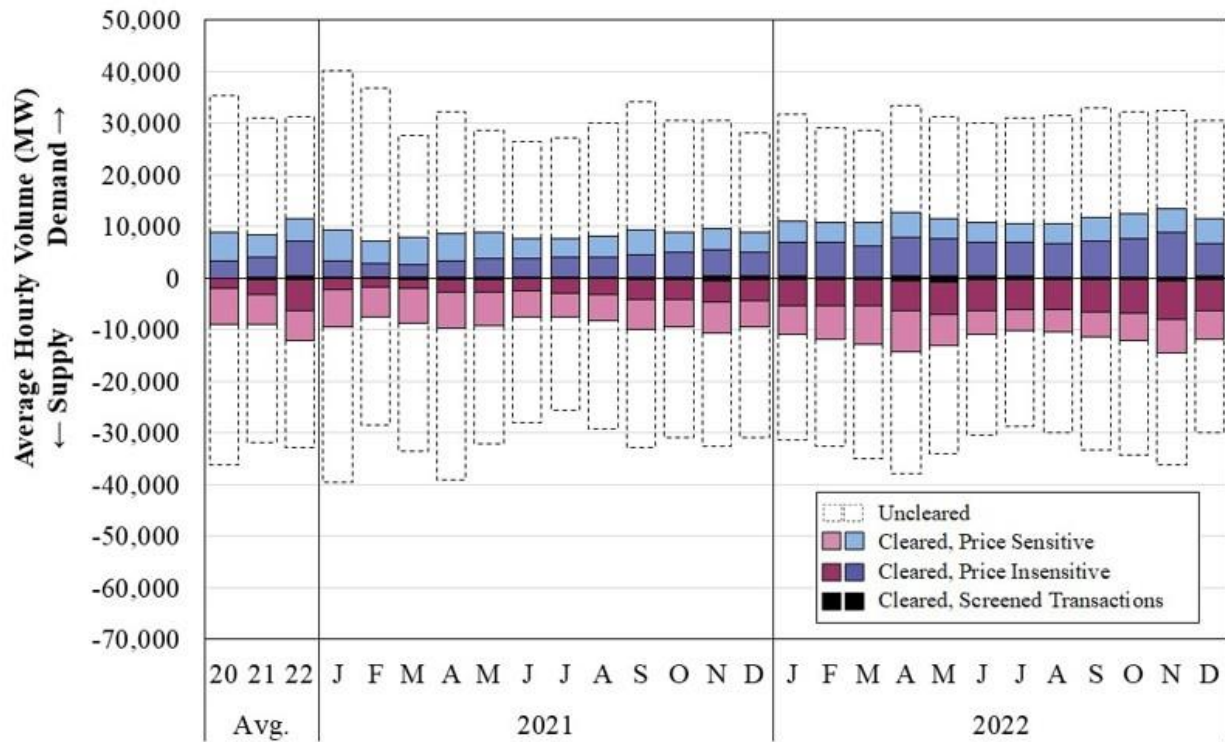
Figure A42: Day-Ahead Virtual Transaction Volumes by Region
2022
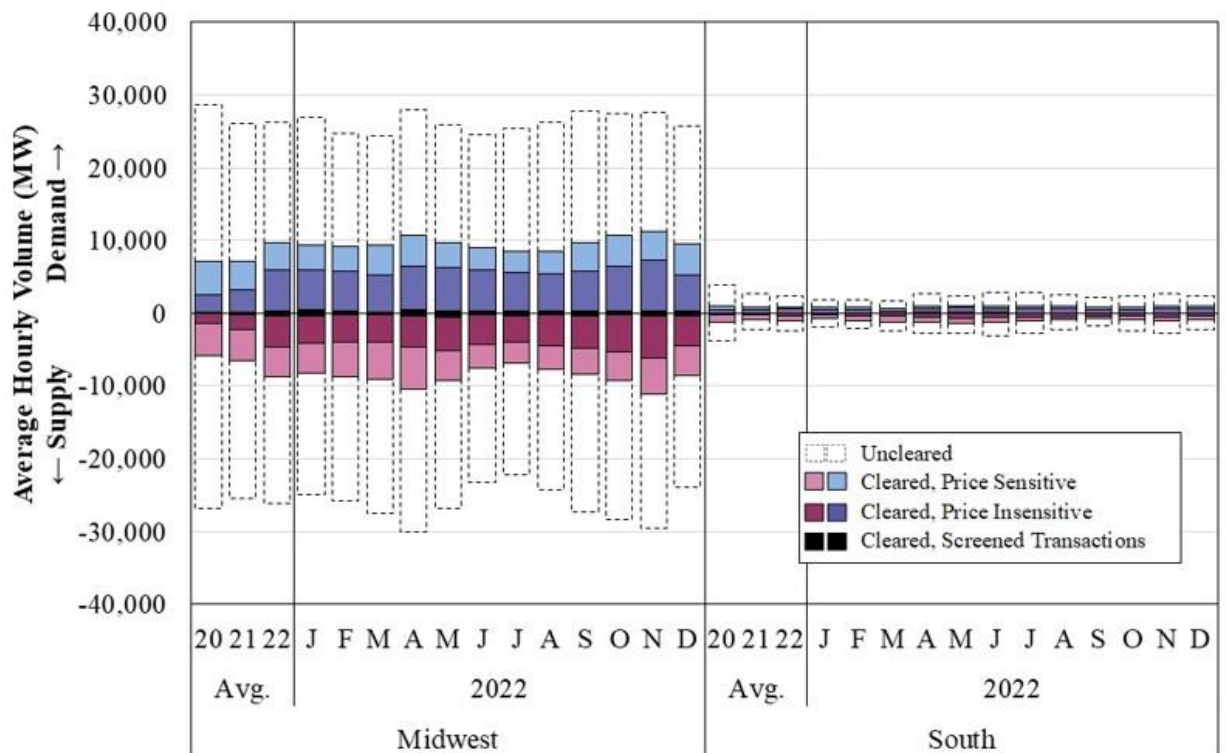
The figures above separately distinguish between price-sensitive and price-insensitive bids. Price-insensitive bids are those that are very likely to clear (supply offers priced well below the expected real-time price and demand bids priced well above the expected real-time price). For the purpose of these figures, bids and offers submitted at more than $20 above or below an expected real-time price are considered price insensitive. A subset of these transactions contributed materially to an unexpected difference in congestion between the day-ahead and real-time markets and warranted further investigation. These volumes are labeled 'Screened Transactions' in the figures.

Figure A43 to Figure A46: Virtual Transaction Volumes by Participant Type

The next figures show day-ahead virtual transactions by participant type. This is important because participants engage in virtual trading for different purposes. Physical participants are more likely to engage in virtual trading to hedge or manage the risks associated with their physical positions. Financial participants are more likely to engage in speculative trading intended to arbitrage differences between day-ahead and real-time markets. The latter class of trading is the conduct that improves the performance of the markets. Figure A43 shows the same results but additionally distinguishes between physical participants that own generation or serve load (including their subsidiaries and affiliates) and financial-only participants. Figure A44 and Figure A45 show the same values by region, and Figure A46 shows these values by type of location.

Figure A43: Virtual Transaction Volumes by Participant Type
2022
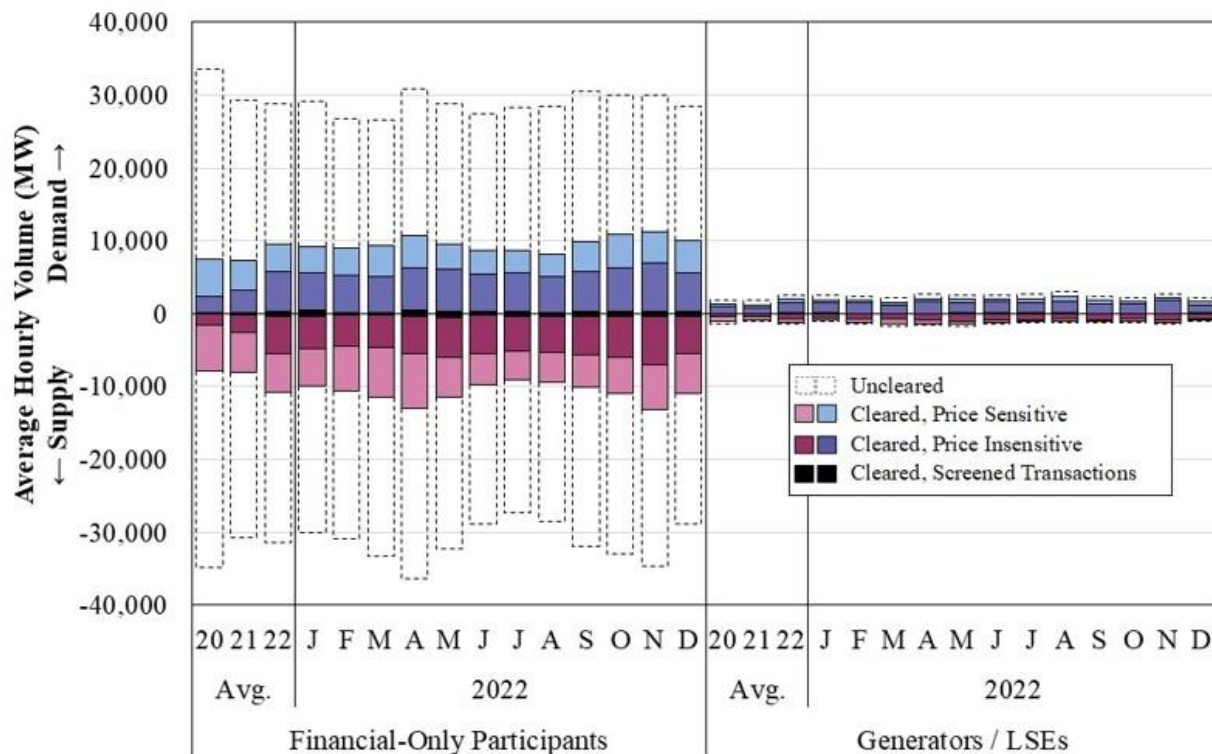
Figure A44: Virtual Transaction Volumes by Participant Type
MISO Midwest, 2022
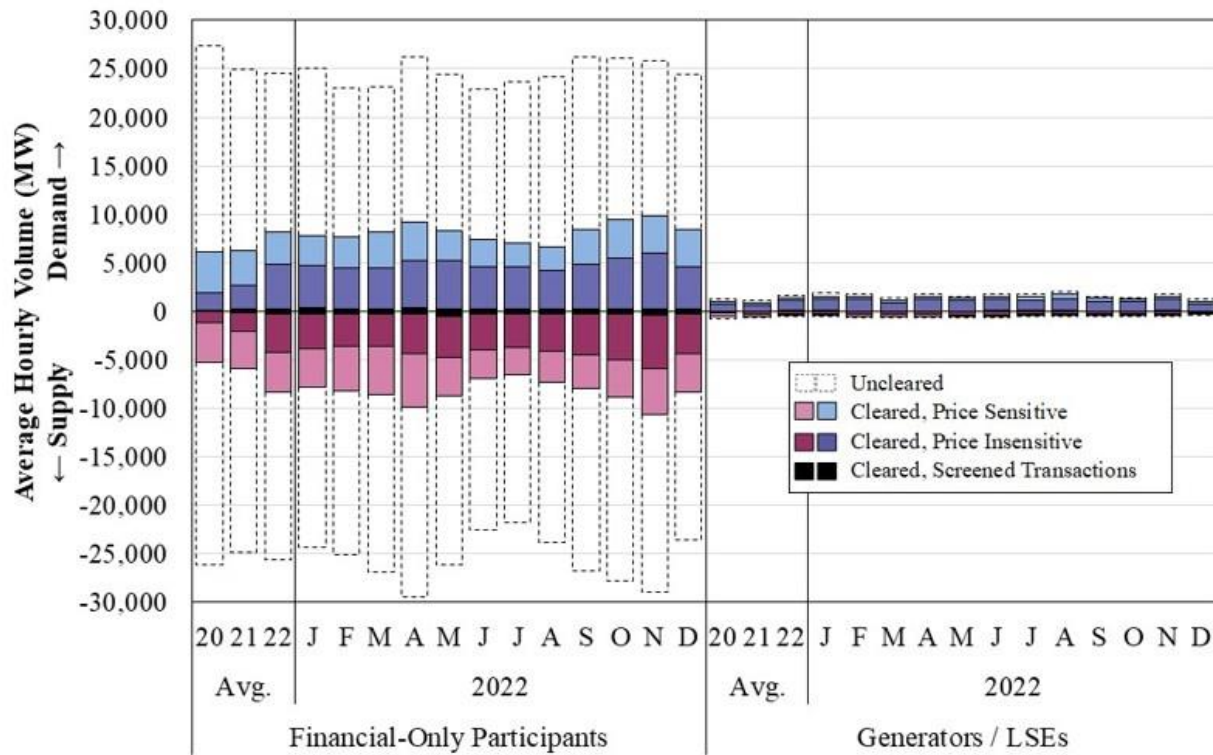
Figure A45: Virtual Transaction Volumes by Participant Type
MISO South, 2022
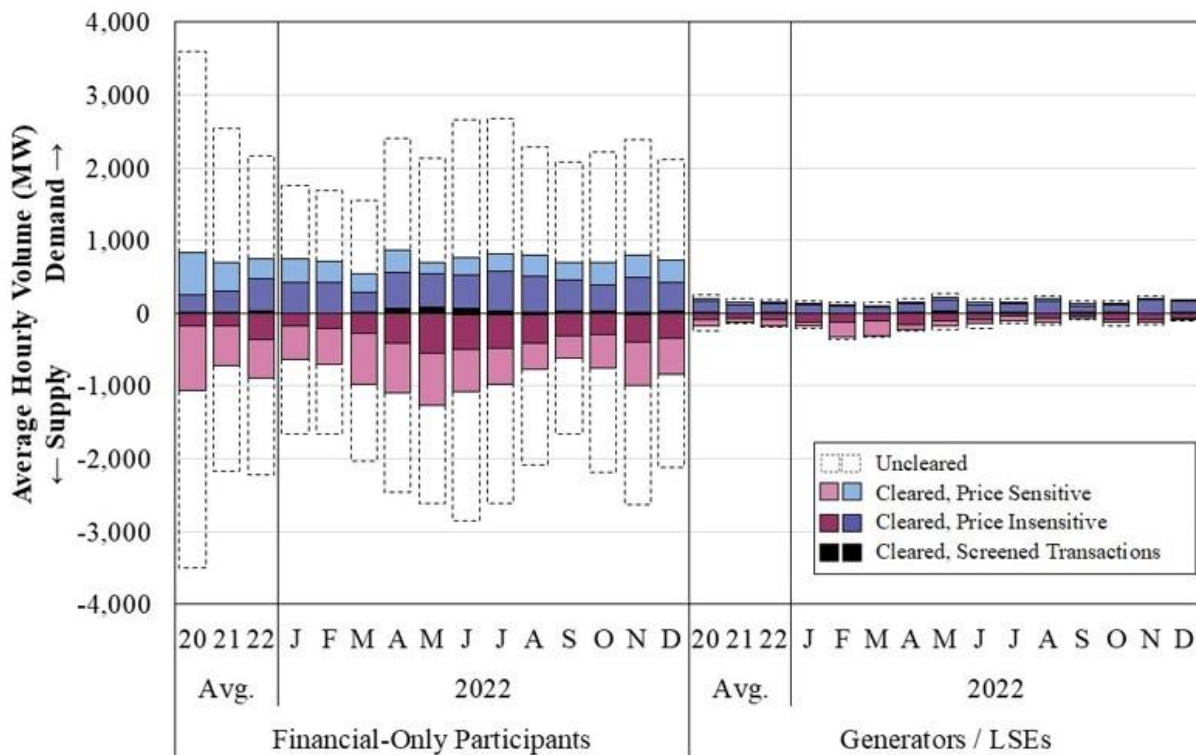
Figure A46: Virtual Transaction Volumes by Participant Type and Location
2020–2022
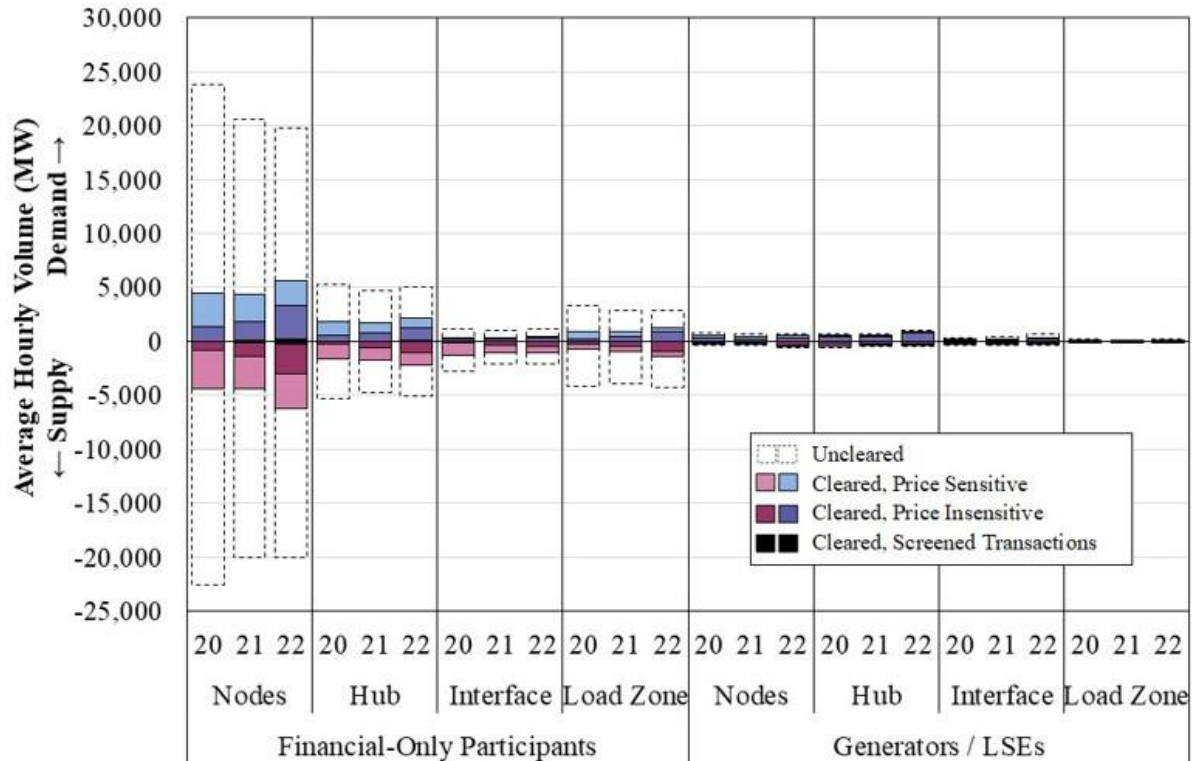
Figure A46 above disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many electrical nodes and, therefore, are less prone to congestion-related price spikes than generator locations.

Figure A47: Matched Price-Insensitive Virtual Transactions

Figure A47 shows monthly average cleared virtual transactions that are considered price insensitive. As discussed above, price-insensitive bids and offers are priced to make them very likely to clear. The figure also shows the subset of transactions that are "matched," which occur when the participant clears both insensitive supply and insensitive demand in a particular hour.

Price-insensitive transactions are most often placed for two reasons:

- A participant seeks an energy-neutral position relative to a particular constraint. This allows the participant to arbitrage differences in congestion and losses between locations.

- A participant seeks to balance their portfolio. RSG or Day-Ahead Headroom and Deviation Charges (DDC) to virtual participants are assessed to net virtual supply, so participants can avoid such charges by clearing equal amounts of supply and demand.

Figure A47: Matched Price-Insensitive Virtual Transactions
2021–2022
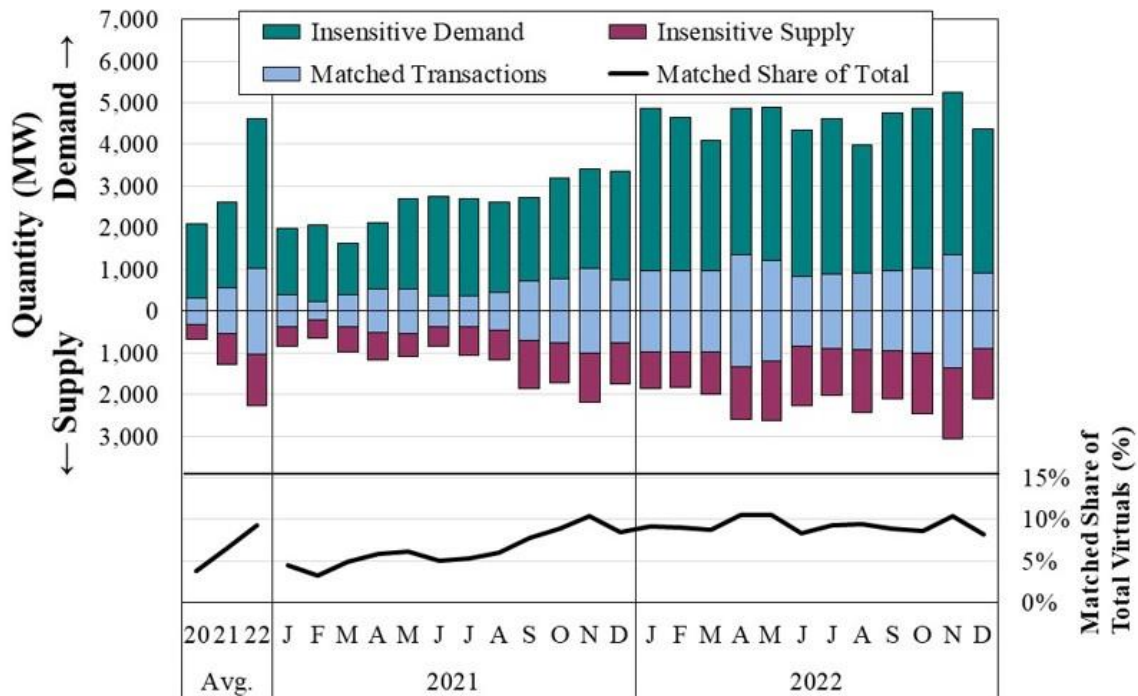
Figure A48: Comparison of Virtual Transaction Levels

To compare trends in MISO to other RTOs, Figure A48 shows cleared virtual supply and demand in MISO, ISO-NE, and NYISO as a share of actual load.

Figure A48: Comparison of Virtual Transaction Levels
2021–2022
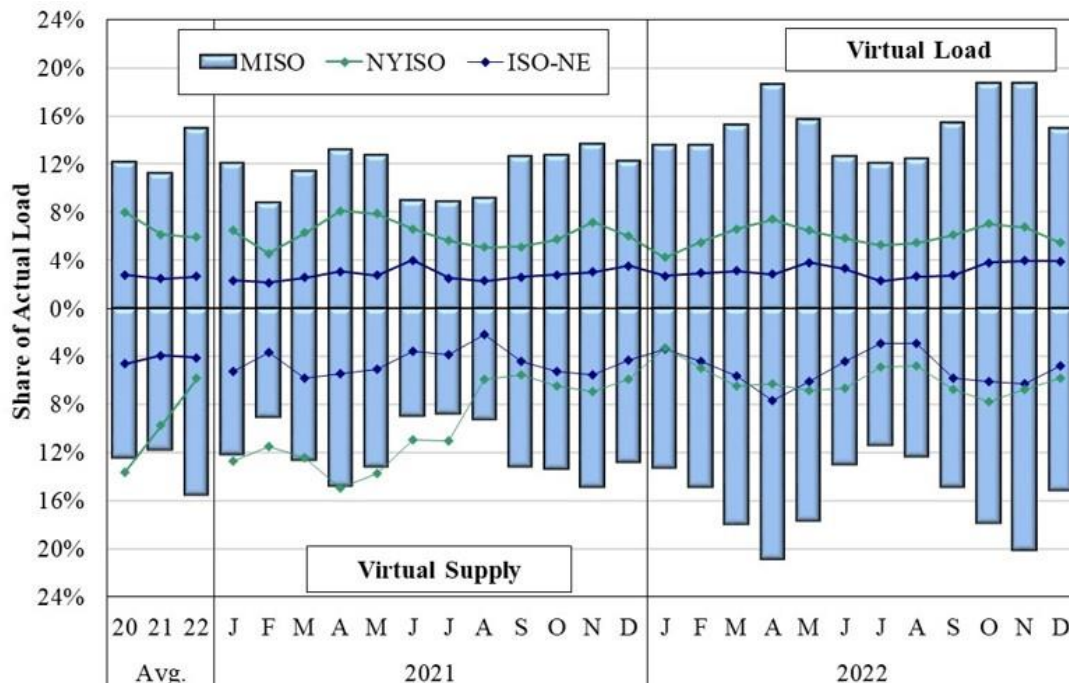
F.   Virtual Profitability

The next set of charts examines the profitability of virtual transactions in MISO. In a well-arbitraged market, profitability is expected to be low. However, in a market with a prevailing day-ahead premium, virtual supply should generally be more profitable than virtual demand.

Table A4: Comparison of Virtual Trading Volumes and Profitability

To provide perspective on the virtual trading in MISO, Table A4 compares virtual trading in MISO to trading in NYISO, ISO New England, SPP, and PJM.

Table A4: Comparison of Virtual Trading Volumes and Profitability

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

Figure A49 to Figure A50: Virtual Profitability

Figure A49 shows monthly total profits and average gross profitability of cleared virtuals—the difference between the day-ahead price at which the virtuals were bought/sold and the real-time price at which these positions were covered. Gross profitability excludes RSG cost allocations.

Figure A49: Virtual Profitability
2021–2022
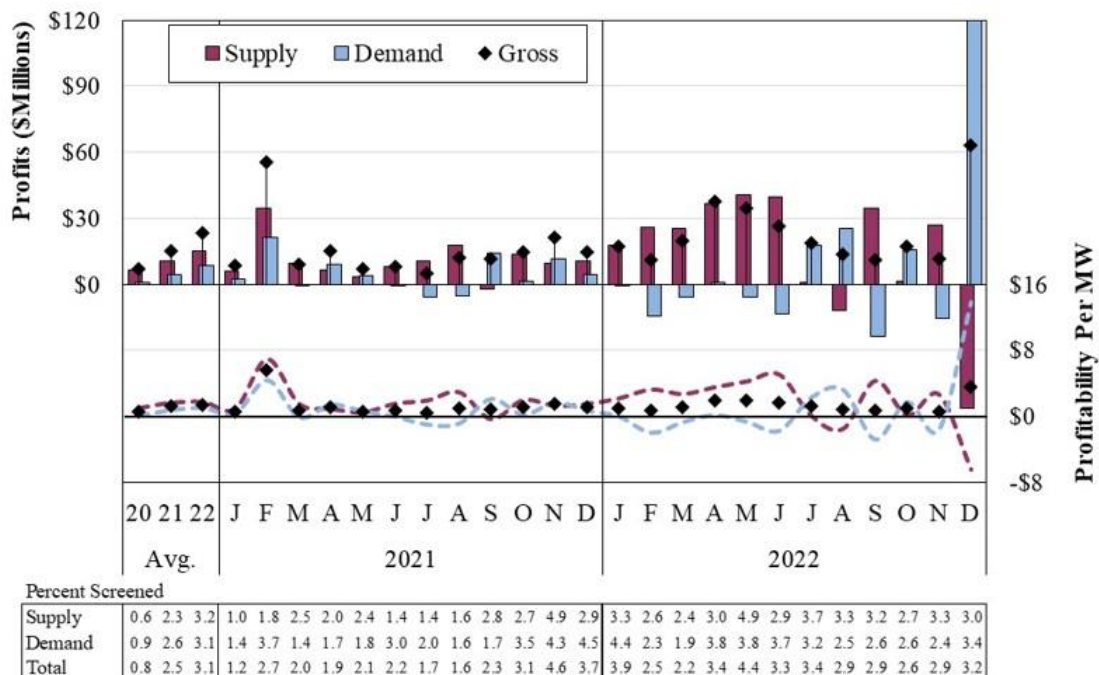
Figure A50 shows the same results disaggregated by type of market participant.

Figure A50: Virtual Profitability by Participant Type in 2022
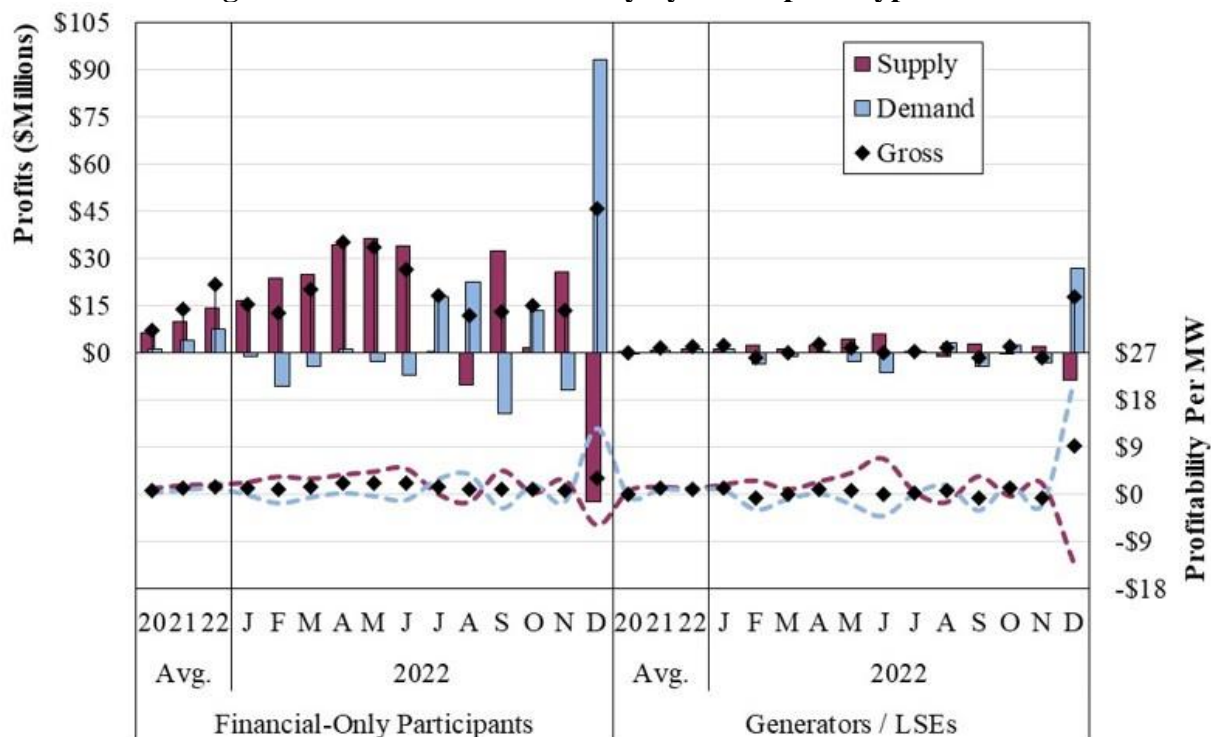
G.   Benefits of Virtual Trading

We conducted an empirical analysis of virtual trading in 2022 that evaluated virtual transactions' contribution to the efficiency of market outcomes. Our analysis categorized virtual transactions into those that led to greater market efficiency as evidenced by their profitability on consistently modeled constraints, those that did not improve efficiency as evidenced by their unprofitability, and those transactions that, while profitable, did not produce efficiency benefits. We examined our results both in terms of quantities (MWh) and net profits.

The virtual transactions in each category provide an indication of what percentage of virtual activity contributed to market efficiency. Net profits, calculated as the difference between the profits and the losses on consistently modeled constraints, indicate whether virtual transactions contributed to better market efficiency in MISO by providing incrementally better commitments in the day-ahead market and leading to better convergence.

To conduct our analysis, we first identified constraints that were modeled consistently in the day-ahead and real-time markets and those that were not. We categorized efficiency-enhancing virtual transactions as those that were profitable based on congestion modeled in the day-ahead and real-time markets, as well as the marginal energy component (system-wide energy price). We did not include transactions that were profitable because of unmodeled constraints or day-ahead and real-time marginal loss factor divergence. Profits from these factors do not lead to more efficient day-ahead market outcomes. We also identified virtual transactions that were

unprofitable but efficiency-enhancing because they led to improved price convergence. This happens when virtual transactions respond to a real-time price trend but overshoot, so they are ultimately unprofitable at the margin.

We designed tests based on an observed transaction at time *t* and an associated lagged value (*t-24* for observations in hours 0–11 and *t-48* for observations in hours 12–24). These lagged values correspond to the real-time prices a participant would have observed by the time the participant submitted bids or offers for the next day in the day-ahead market. We used three tests to identify unprofitable efficiency-enhancing virtual transactions:

- Convergence Test: Whether the absolute value of the difference between the day-ahead and real-time LMPs at time *t* was less than the absolute value of the differences between the day-ahead and real-time LMPs in the lagged time period.

- Day-Ahead Price Movement Test: Whether the movement in the day-ahead price improved convergence as defined by the absolute value of the difference between the day-ahead and real-time LMP at time *t* being smaller than the absolute value of the difference between the lagged day-ahead price and the current real-time price.

- Virtual Directional Test: Whether the virtual trade helped move the day-ahead price in the right direction—the virtual bid or offer would have been profitable based on the lagged difference between the day-ahead and real-time price.

Virtual transactions that did not improve efficiency were those that were unprofitable based on the energy and congestion on modeled constraints and did not contribute to price convergence.

Table A5 to Table A7: Efficient and Inefficient Virtual Transactions in 2022

The following three tables summarize the virtual transaction quantities, profits, and losses in the efficiency-enhancing and non-efficiency-enhancing categories in 2022. Table A5 shows all participants combined, Table A6 shows financial participants, and Table A7 shows physical participants.

Table A5: Efficient and Inefficient Virtual Transactions in 2022

	All Participants		
	MWh	**Convergent Profits**	**Rent-Seeking Loss**	**Rent-Seeking Congestion**
Efficiency Enhancing (Profitable)	104,157,385	$1,991.5M	$5.5M	-$72.0M
Efficiency Enhancing (Unprofitable)	16,585,283	-$162.4M	$10.6M	$20.9M
Total Efficiency	*120,742,668*	*$1,829.1M*	*$16.1M*	*-$51.1M*
Not Efficiency Enhancing (Profitable)	6,253,172	-$46.7M	$15.8M	$86.9M
Not Efficiency Enhancing (Unprofitable)	78,967,627	-$1,580.9M	$14.0M	-$1.4M
Total Inefficiency	*85,220,798*	*-$1,627.7M*	*$29.8M*	*$85.5M*
Total	**205,963,467**	**$201.4M**	**$45.9M**	**$34.4M**

Table A6: Efficient and Inefficient Virtual Transactions in 2022 – Financial Participants

	Financial Participants			
	MWh	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	92,126,308	$1,771.9M	$2.0M	-$74.5M
Efficiency Enhancing (Unprofitable)	14,349,361	-$141.4M	$9.6M	$18.5M
Total Efficiency	*106,475,669*	*$1,630.5M*	*$11.6M*	*-$55.9M*
Not Efficiency Enhancing (Profitable)	5,422,658	-$42.7M	$14.0M	$79.9M
Not Efficiency Enhancing (Unprofitable)	66,910,978	-$1,389.8M	$14.4M	-$2.7M
Total Inefficiency	*72,333,636*	*-$1,432.4M*	*$28.4M*	*$77.2M*
Total	**178,809,305**	**$198.1M**	**$40.0M**	**$21.2M**

Table A7: Efficient and Inefficient Virtual Transactions in 2022 – Physical Participants

	Physical Participants			
	MWh	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	12,031,077	$219.6M	$3.5M	$2.4M
Efficiency Enhancing (Unprofitable)	2,235,921	-$21.0M	$1.1M	$2.4M
Total Efficiency	*14,266,999*	*$198.6M*	*$4.5M*	*$4.8M*
Not Efficiency Enhancing (Profitable)	830,514	-$4.1M	$1.8M	$7.1M
Not Efficiency Enhancing (Unprofitable)	12,056,649	-$191.2M	-$.4M	$1.3M
Total Inefficiency	*12,887,163*	*-$195.3M*	*$1.4M*	*$8.3M*
Total	**27,154,161**	**$3.4M**	**$5.9M**	**$13.2M**

The profits and losses shown in the tables above are useful because they account for the fact that some transactions are relatively more efficient or relatively more inefficient than others. Each table also shows rents earned by virtual transactions, which are profits that do not produce efficiency benefits. The rents reflect profits associated with un-modeled day-ahead constraints and differences in the loss components between the two markets. These rents do not generally indicate a concern with virtual trading but rather opportunities for MISO to improve the consistency of its modeling between the day-ahead and real-time markets.

Importantly, the total benefits are much larger than the marginal net benefits shown above because: a) profits of efficient virtual transactions become smaller as prices converge; and b) losses of inefficient virtual transactions get larger as prices diverge. To accurately calculate this total benefit would require one to re-run all of the day-ahead and real-time market cases for the entire year. Nonetheless, our analysis allows us to establish with a high degree of confidence that virtual trading was beneficial to market efficiency in 2022.

H.   Evaluation of ELMP Effects

MISO introduced pricing reforms for its day-ahead and real-time energy markets through the implementation of the Extended Locational Marginal Pricing algorithm (ELMP) on March 1,

2015. ELMP is a price-setting engine that affects prices but does not affect the dispatch. ELMP reforms pricing by allowing online inflexible resources to set the LMP if the inflexible unit is economic. These resources include online "Fast-Start Resources" (currently including units that can start within 60 minutes) and demand response resources. MISO implemented changes in 2017 and 2019 to expand the set of eligible FSRs to set prices, which has improved the performance of ELMP to better reflect energy costs. MISO implemented another of our recommendations in September 2021 to relax the down ramp rate limit on FSRs dispatched at their economic minimums. Relaxing the ramp rate allowed them to be considered marginal and set prices unless dispatched to zero. Previously, ELMP did not allow resources to set prices when the ELMP dispatch model sought to ramp them down at their maximum ramp rate, which prevented FSRs that were needed to satisfy the system demands from setting prices. Together, these changes have significantly improved real-time price formation in MISO.

ELMP reforms addressed a long-standing recommendation to remedy issues that we first identified shortly after the start of the MISO energy markets in 2005. The pricing algorithm in UDS did not always reflect the true marginal cost of the system because inflexible high-cost resources were frequently not recognized as marginal, even though they were needed to satisfy the system's energy demand. The most prevalent class of such units is online natural gas-fired turbines that often have a narrow dispatch range. Because it is frequently not economic to turn them off (they are the lowest cost means to satisfy the energy needs of the system), it is appropriate for the energy prices to reflect the running cost of these units.

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 2021, MISO implemented recommended changes to its emergency pricing by: (i) expanding the set of resources that can set prices during an emergency event[10] and setting minimums on the Tier 1 and 2 Emergency Offer Floor Prices at $500 and $1,000 per MWh, respectively.[11] MISO also updated the value of Reserve Procurement Enhancement (RPE) constraints to $200 per MWh during emergencies. These changes will help ensure that MISO's emergency pricing will set more efficient pricing during emergencies.

> *Figure A51 to Figure A53: ELMP Price Effects*

Figure A51 to Figure A53 summarize the effects of ELMP by showing the average upward effects via the online pricing, average downward effects via the offline pricing,[12] and the frequency that the ELMP model altered the prices upward and downward. These metrics are shown for the system marginal price (i.e., the market-wide energy price) in the real-time market and day-ahead market, as well as for the LMP at the most affected locations (i.e., congestion-related effects). Additionally, to show the size of the ELMP price adjustments, the tables below each of the first two figures show the size of the adjustments in those intervals that the ELMP model affected the price.

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

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

[12]   MISO turned off the offline ELMP pricing in October 2021 until changes can be made in MISO's software that will only allow offline resources to set prices in ELMP if the LAC tool has committed resources within 10-15 minutes or the resources can start in 10-15 minutes.

Figure A51: The Effects of Fast Start Pricing in ELMP
Real-Time Market, 2021–2022

% of Intervals Affected by > +/- $0.10

	21	22	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	56	57	36	57	44	61	54	68	61	60	54	66	61	52	56	49	42	54	58	60	59	51	75	58	63	55
SMP Decrease	2	1	3	6	2	3	5	1	1	1	1	1	1	0	0	0	0	1	1	4	1	1	2	0	4	1
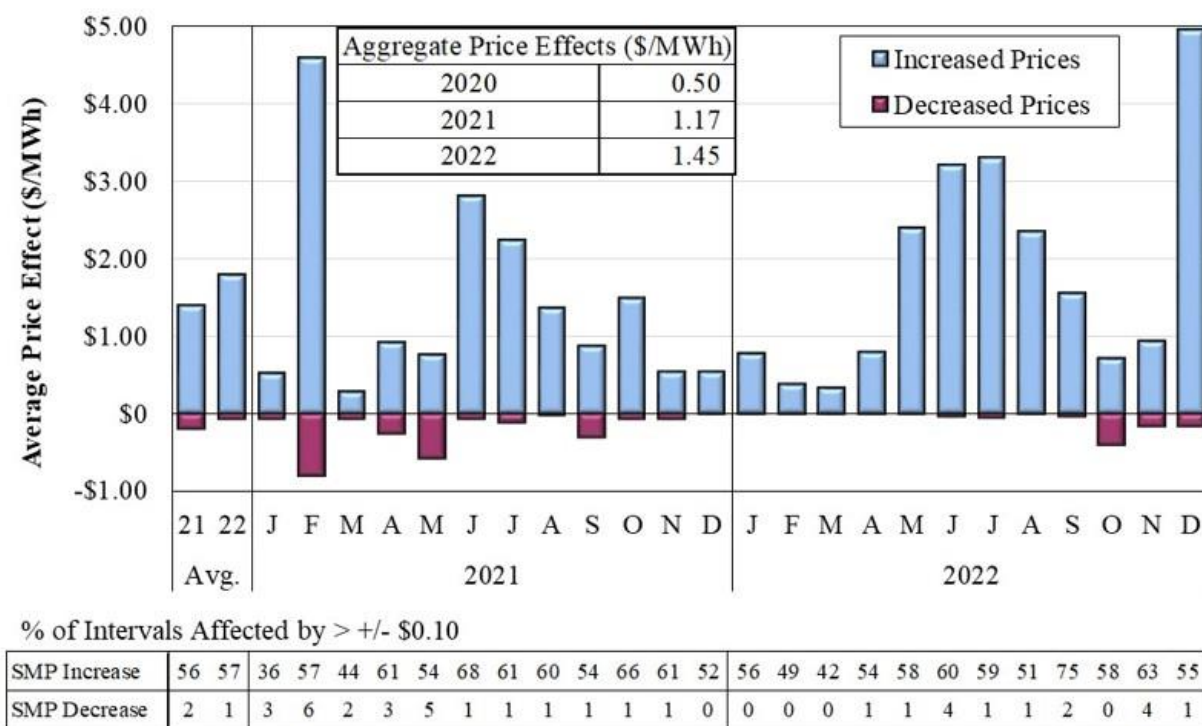
Figure A52: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, 2022

Change in Affected Intervals ($/MWh)   2022

	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	0.15	0.08	0.07	0.08	0.36	0.59	0.61	0.59	0.25	0.18	0.09	0.26
SMP Decrease	-0.05	-0.02	-0.02	-0.03	-0.08	-0.05	-0.07	-0.04	-0.04	-0.03	-0.19	-0.06
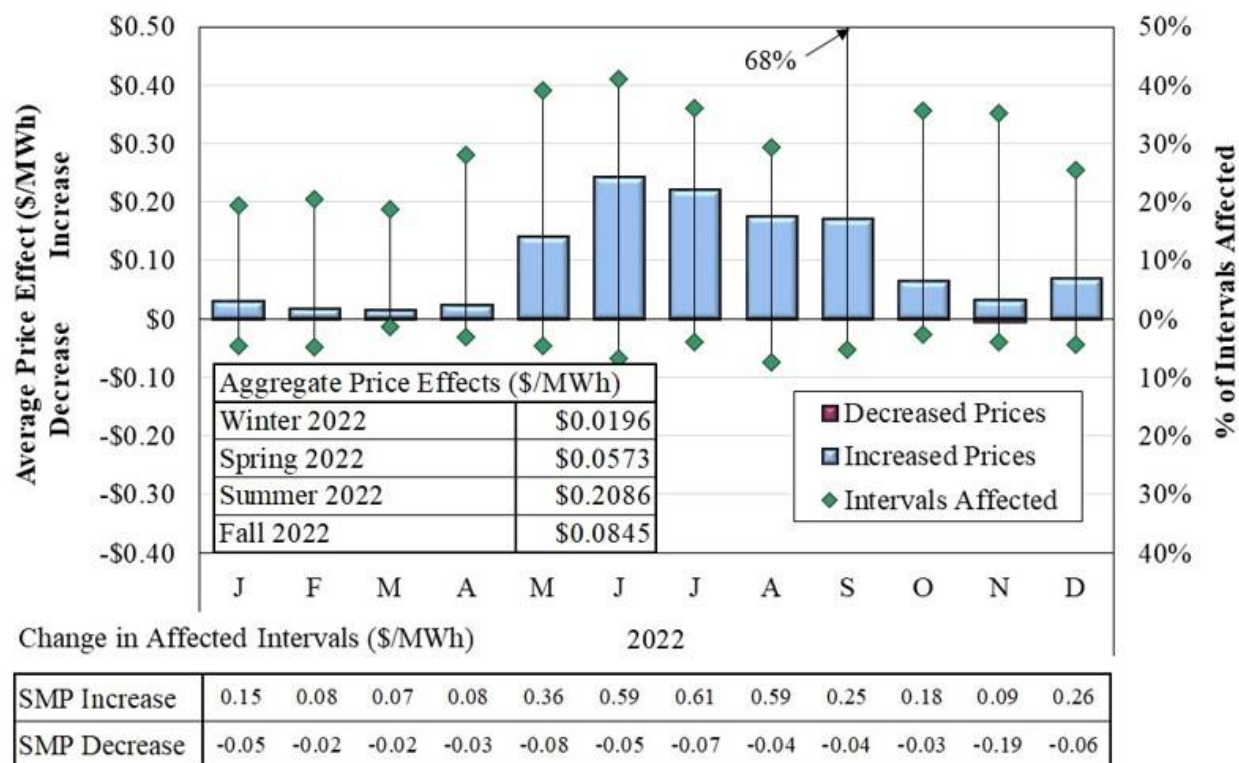
Figure A53: Price Effects of ELMP at Most Affected Locations
Real-Time Market, 2021–2022
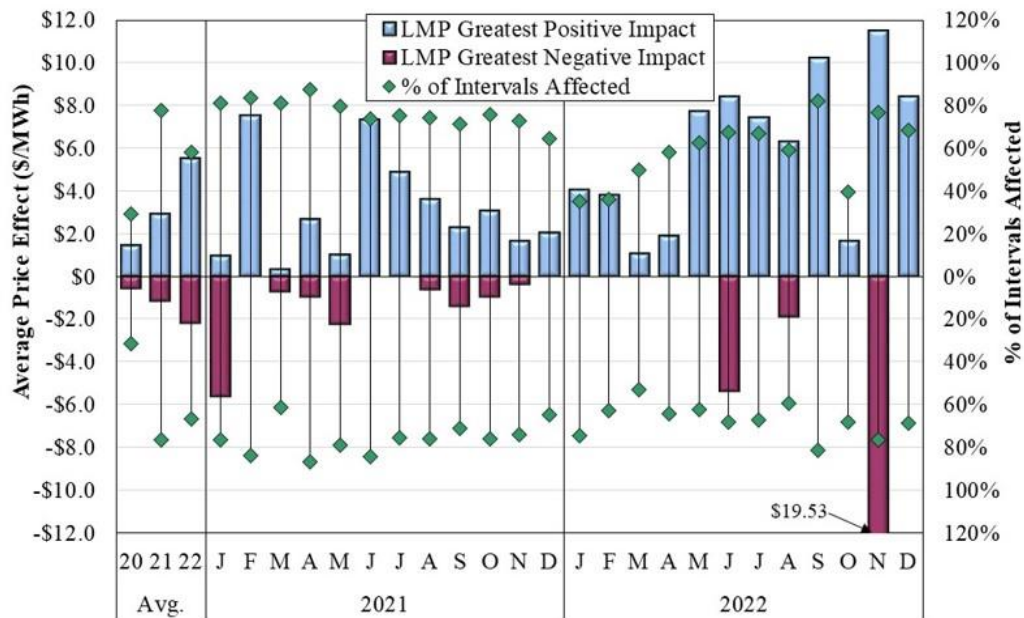
Figure A54 and Figure A55: EEA2 Pricing and RDT Flows

Figure A54 shows the ex-ante and ex-post pricing outcomes on June 10, 2021 when MISO declared an EEA2 event in the Midwest region and committed 3.2 GW of Midwest LMRs. The RDT flows are shown in the bottom panel with ex-post LMPs for the Midwest (red line) and South (blue) alongside the ex-ante SMP (black dashed) in the top panel.

Figure A54: Actual EEA2 Pricing and RDT Flows
June 10, 2021
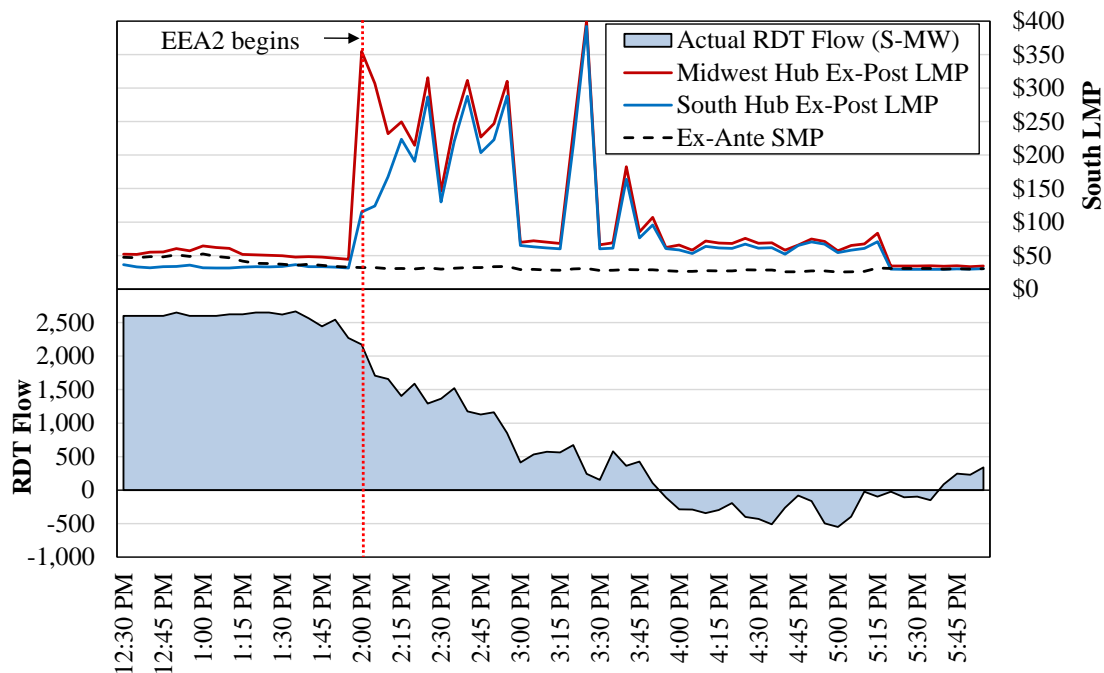
Figure A55 below shows the same event after modeling our recommendation to model LMRs as STR demand in the ELMP model. The lines from the first figure are shown as semi-transparent to compare the alternative market solution.

Figure A55: Simulated, Proposed EEA2 Pricing and RDT Flows
June 10, 2021
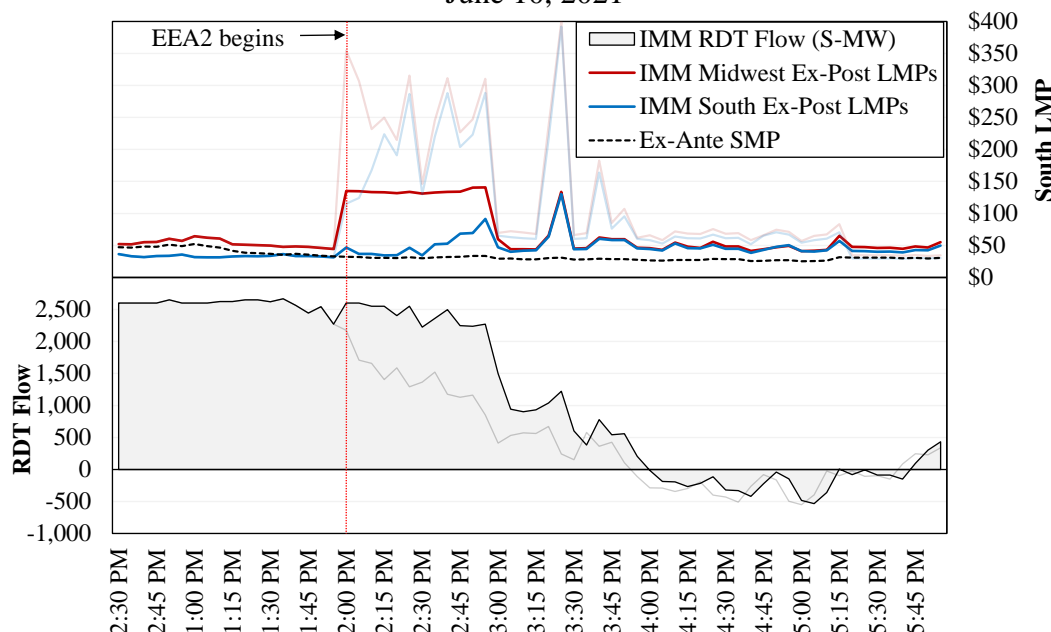
I.   Spinning Reserve Shortages

Figure A56: Market Spin Shortage Intervals Versus Rampable Spin Shortage Intervals

MISO operates with a minimum required amount of spinning reserves that can be deployed immediately for a contingency response. Market shortages generally occur because the costs that would be incurred to maintain the spinning reserves exceed the spinning reserve penalty factor (i.e., the implicit value of spinning reserves in the real-time market).

Units scheduled for spinning reserves may temporarily be unable to provide the full quantity in 10 minutes if MISO is ramping them up to provide energy. To account for concerns that ramp-sharing between ASM products could lead to real ramp shortages, MISO maintains a market scheduling requirement that exceeds its real "rampable" spinning requirement by more than 200 MW. As a result, market shortages can occur when MISO does not schedule enough resources in the real-time market to satisfy the market requirement but is not physically short of spinning reserves.[13] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as much as possible.

Figure A56 shows all intervals in 2022 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements.

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[13]   It is also possible for the system to be physically short temporarily, when units are ramping to provide energy, but not indicate a market shortage because ramp capability is shared between the markets.

Figure A56: Market Spin Shortage Intervals Versus Rampable Spin Shortage Intervals
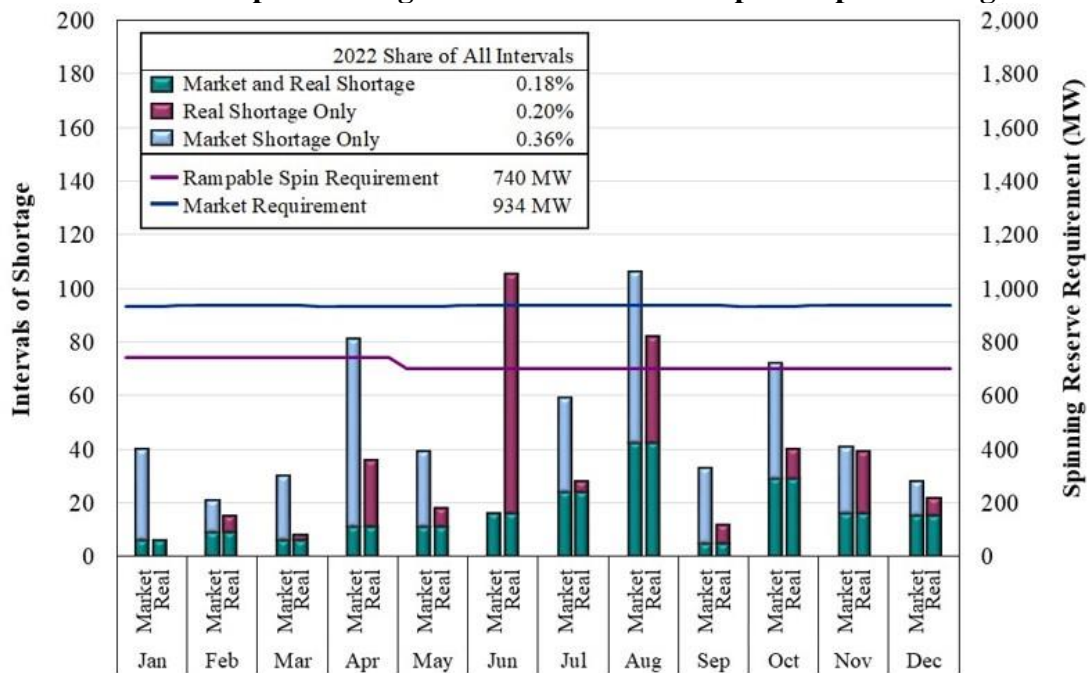
J. Supplemental Reserve Deployments

Figure A57: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A57 shows offline supplemental reserves deployed in 2021 and 2022, separately showing those that were successful within 10 and 30 minutes.

Figure A57: Supplemental Reserve Deployments
2021–2022
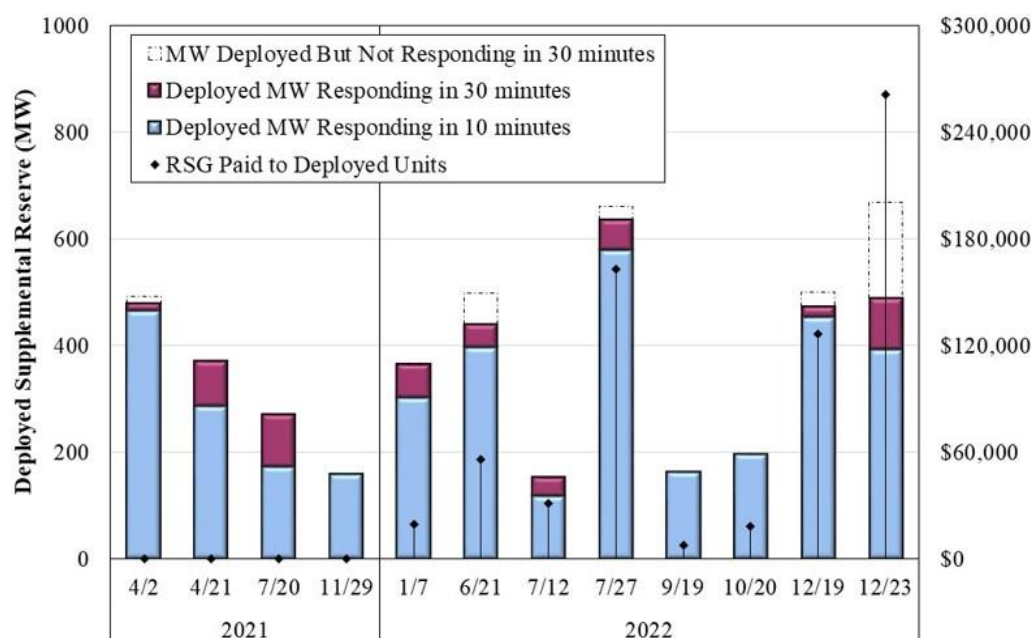
The figure includes the RSG payments to deployed offline reserves. Because their commitment costs are not considered when scheduling supplemental reserves, high uplift payments could indicate a need to consider expected deployment costs when scheduling reserves.

K.   Uplift Costs: RSG Payments

RSG payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[14] Generally, MISO makes most of these out-of-merit commitments in real time to satisfy the reliability needs of the system and to account for changes occurring after the day-ahead market. Because these commitments receive market revenues from the real-time market, their production costs in excess of these revenues are recovered under real-time RSG payments. MISO commits resources in real time for many reasons, including to (a) meet capacity needs that can arise during peak load or sharp ramping periods, (b) meet real-time load that was under-scheduled in the day-ahead market, or (c) secure a transmission constraint, a local reliability need, or to maintain voltage in a location.

MISO makes many voltage and local reliability (VLR) commitments, predominantly in the day-ahead market. Most VLR commitments occur in the South region to manage load pocket requirements. In order to satisfy these requirements and accommodate the startup times of the required resources, MISO makes reliability commitments in advance of or in the day-ahead markets. A significant portion of the day-ahead RSG is associated with these VLR resources.

Peaking resources are the most likely to receive RSG payments because they are the highest-cost class of resources and, even when setting the price, they receive minimal LMP margins to cover their startup and no-load costs. Additionally, peaking resources frequently do not set the energy price because they are operating at their economic minimum, so the price is set by a lower-cost unit. This increases the likelihood that an RSG payment may be required.

Figure A58 and Figure A59: RSG Payments

Figure A58 shows the total day-ahead RSG payments and distinguishes between payments made for VLR and capacity needs. In addition, capacity payments made to units in MISO South NCAs are separately identified because these units are typically committed for VLR and are frequently subject to the tighter VLR mitigation criteria. In August 2022, MISO implemented a new op guide to fully incorporate the impacts of the addition of a large, 1 GW combined-cycle facility in early 2021 in WOTAB. The categorized columns represent monthly nominal RSG, and the green circles are total monthly RSG adjusted for changes in fuel prices. Figure A59 shows total real-time RSG payments and distinguishes among payments made to resources committed for overall capacity needs, to manage congestion, or for voltage support.

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14   Specifically, this is the lower of a unit's as-committed or as-dispatched offered costs.

Figure A58: Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2021–2022

Sum of 2022 ($ Millions)		Midwest	South	Total
RSG: Capacity		$15.86	$17.95	$33.82
RSG: Western Op			$17.38	$17.38
RSG: VLR		$10.82	$25.22	$36.05
Total RSG		**$26.69**	**$60.56**	**$87.24**
● **Total Fuel-Adj. RSG**		**$21.84**	**$43.23**	**$65.07**
RSG Mitigation				*$3.49*
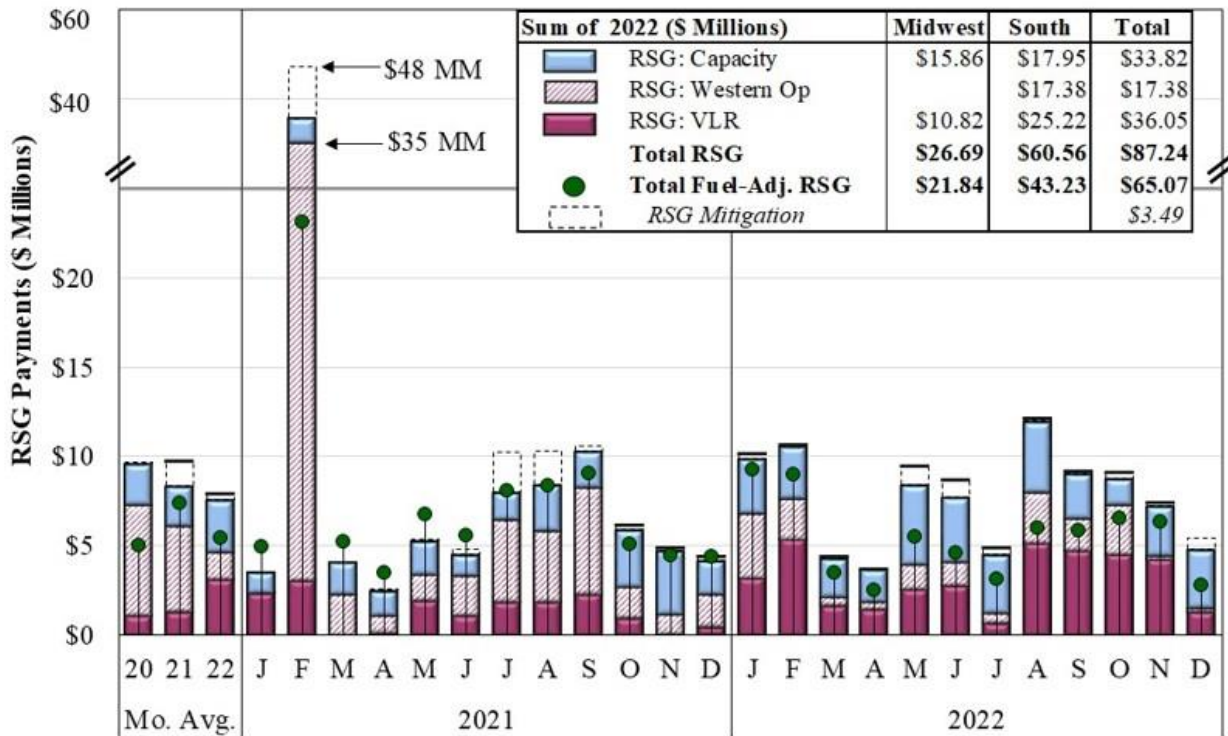
Figure A59: Real-Time RSG Payments
Fuel-Cost Adjusted, 2021–2022

Sum of 2022 ($ Millions)		Midwest	South	Total
RSG: VLR		$0.48	$2.19	$2.67
RSG: Congestion		$10.38	$10.38	$20.76
RSG: RDT		$0.22	$8.90	$9.12
RSG: Capacity		$111.64	$8.21	$119.85
Total RSG		**$122.71**	**$29.69**	**$152.40**
● **Total Fuel-Adj. RSG**		**$75.13**	**$21.49**	**$96.62**
RSG Mitigation				*$3.18*

Total:
$113 MM
Fuel-
Adjusted:
$63 MM.
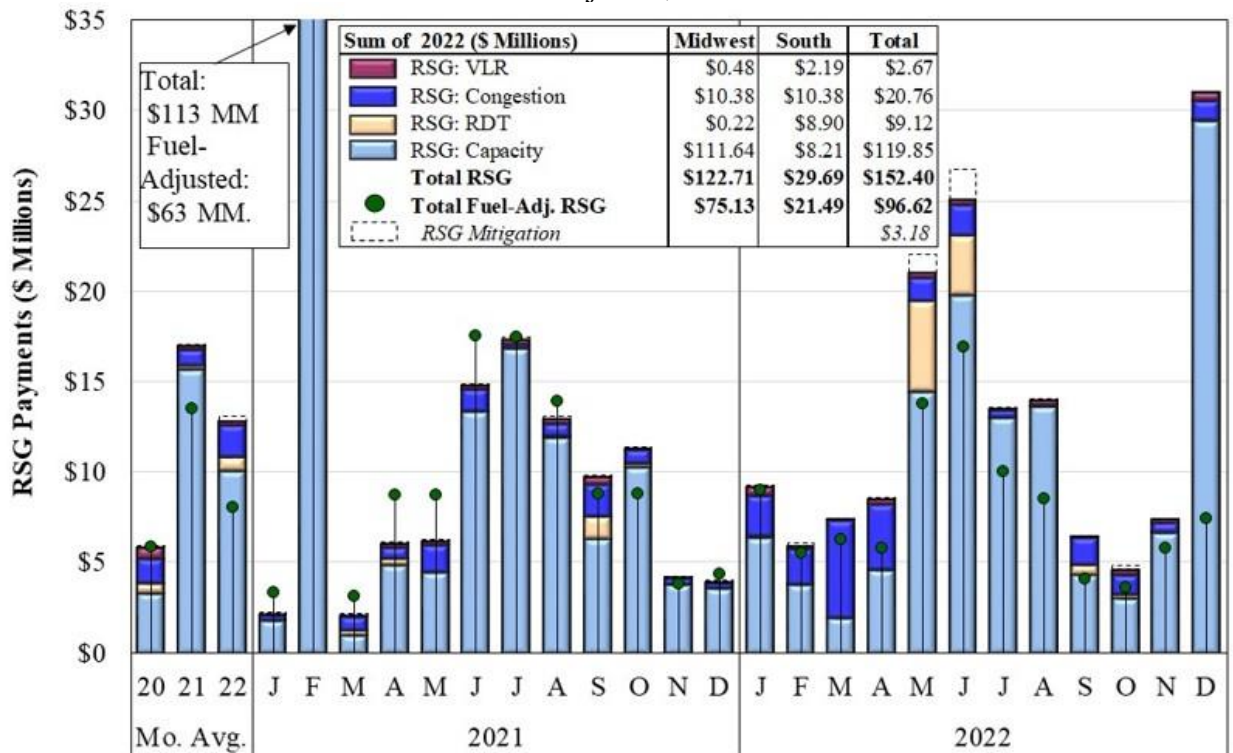
Figure A60: RSG for Units Committed for RDT

MISO has made a substantial number of resource commitments in the Midwest or South to satisfy regional capacity needs when the Regional Directional Transfer constraint is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region.

These commitments are made outside of the market because MISO's markets do not include regional capacity requirements. In more recent months, particularly during periods of high generator outages in MISO South, MISO has incurred significant RSG for these types of commitments, and the costs of the commitments are allocated across the entire MISO footprint under the DDC rate. We evaluated the magnitude of these costs to determine the benefit of a regional reserve product, which FERC approved in January 2020. MISO implemented the "Short-Term Reserve" product in December 2021.

Figure A60 below shows the total RSG that MISO has incurred for these commitments since January 2021 and in which region (Midwest or South) the commitments were located. The maroon segment of the bars shows RSG payments to resources in the Midwest, and the blue bar segments indicate the resources that were committed in the South region.

Figure A60: RSG for Units Committed for RDT
2021–2022
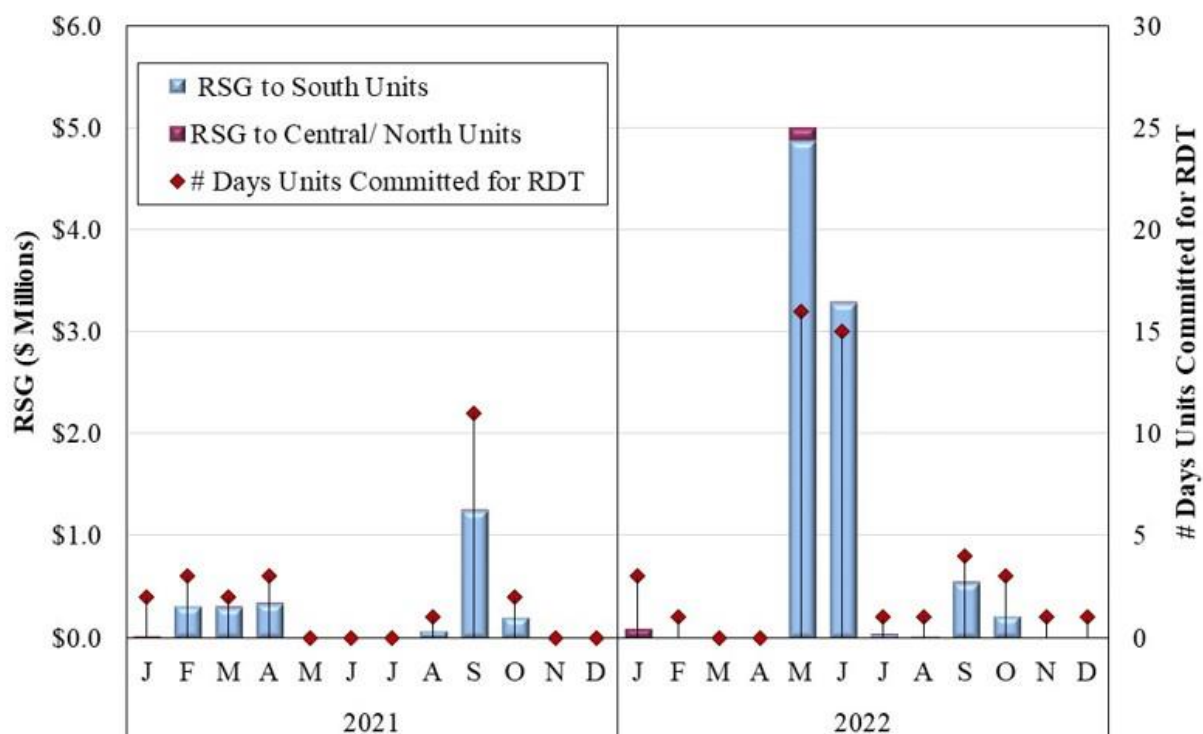
Figure A61: Allocation of RSG Charges

The RSG process was substantively revised in April 2011 to better reflect cost causation. Under the revised allocation methodology, RSG-eligible commitments are classified as satisfying either a congestion management (or other local need) or a capacity need. When committing a resource for congestion management, MISO operators identify the particular constraint that is being relieved. Supply and demand deviations from the day-ahead market that contribute to the need for the commitment, or deviations that increase flow on the identified constraint, are allocated a share of the RSG costs under the Constraint Management Charge (CMC) rate. Any residual RSG cost is then allocated market-wide on a load-ratio share basis ("Pass 2").[15]

Figure A61 summarizes how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month from 2020 to 2022. Until March 2014, the CMC allocations were inappropriately limited based on the GSF of the committed unit, which caused a significant portion of constraint-related RSG costs to be allocated under the DDC charge. Additionally, we show the RSG costs incurred to satisfy VLR requirements in both the DA and the RT markets, which are allocated locally. We also show the RSG costs incurred to satisfy DA capacity, which are allocated market-wide.

Figure A61: Allocation of RSG Charges
By Month, 2020–2022

Allocations ($ Millions)		
Sum	**2021**	**2022**
RT VLR	$3.38	$2.29
Pass 1: CMC	$5.32	$10.71
Pass 1: DDC	$161.08	$95.32
Pass 2	$29.54	$13.29
DA Capacity	$25.30	$28.49
DA VLR	$73.24	$55.41

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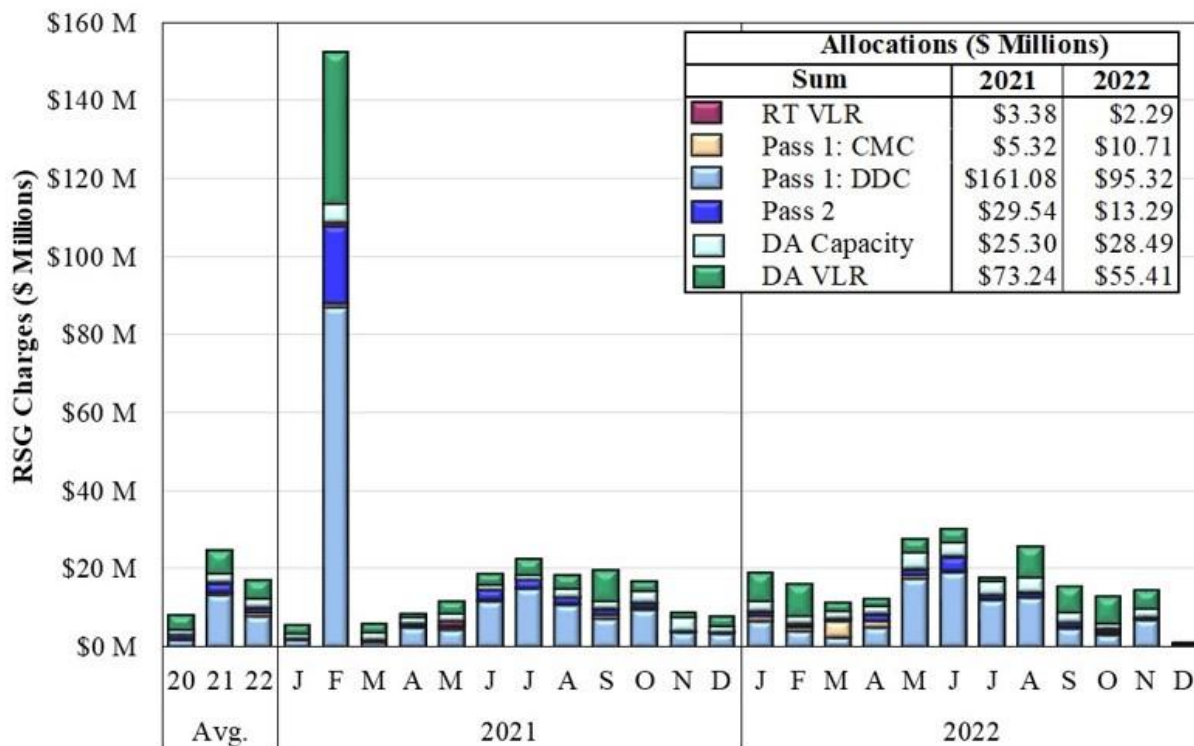
[15]   A portion of constraint-related RSG costs may be allocated to "Pass 2" if they are associated with real-time transmission derates or loop flow.

L.   Uplift Costs: Price Volatility Make-Whole Payments

MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers following MISO's dispatch signals are not financially harmed, removing a potential disincentive to providing more operational flexibility.

The PVMWP consists of two separate payments: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Operating Revenue Sufficiency Guarantee Payment (RTORSGP). DAMAP is paid when a resource's day-ahead margin is reduced as a result of being dispatched in real time to a level below its day-ahead schedule and it has to buy its day-ahead scheduled output back at real-time prices. Often, this payment is the result of short-term price spikes in the real-time market that are due to binding transmission constraints or ramp constraints. Conversely, the RTORSGP is made to a qualified resource that is unable to recover incremental energy costs when dispatched above its economic level in real time. Opportunity costs for potential revenues are not included in either payment.

> *Table A8: Price Volatility Make-Whole Payments*

Table A8 shows the annual totals for DAMAP and RTORSGP, along with the price volatility at the system level (SMP volatility) and at the unit locations receiving the payments (LMP volatility). We separately indicate the amount of PVMWP MISO incurred during the February 2021 arctic event (Winter Storm Uri) and the December 2022 arctic event (Winter Storm Elliott).

Table A8: Price Volatility Make-Whole Payments
2021–2022 ($ Millions)

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

> *Table A9: Causes of DAMAP*

In addition to the reliability consequences of resources failing to follow MISO's dispatch signals, prolonged dragging can result in substantial DAMAP. DAMAP costs arise when generators are dispatched below their day-ahead schedule when economic, which erodes their margins earned in the day-ahead market.

This payment was intended to provide incentives for generators to be flexible and to be held harmless if MISO directs them to dispatch down in response to real-time prices. DAMAP was not intended to hold generators harmless when they produce less output than would be economic because they are performing poorly. Previously, generators would not lose eligibility for DAMAP when they perform poorly, and we addressed this in our recommendations. In May

2019, MISO implemented changes to the Uninstructed Deviation thresholds and PVMWP formulations that have resulted in lower unjustified DAMAP payments.

Table A9 shows the causes of DAMAP in 2022 compared to 2021. The table shows the total DAMAP, the shares of DAMAP that are paid to units following MISO's dispatch signals, and the shares paid to units that are not performing well in following dispatch signals.

Table A9: Causes of DAMAP

Item Description	2021		2022	
	DAMAP ($ Millions)	% Share	DAMAP ($ Millions)	% Share
Following Instruction	$33.5	78%	$56.9	81%
SE Issue	$0.2	0%	$0.5	1%
Inferred Derate	$1.3	3%	$2.2	3%
Dragging - Failing New Threshold	$1.5	4%	$2.6	4%
Wind Unjustified	$0.1	0%	$0.3	0%
Dragging - Not Failing New Threshold	$6.1	14%	$7.7	11%
Total	**$42.8**	**100%**	**$70.3**	**100%**

M.   Real-Time Commitment Patterns

Figure A62: Monthly Real-Time Capacity Commitments and RSG Costs

In 2021, we identified a pattern of increasing capacity-related commitments beginning in the summer months. To identify real-time capacity commitments and the associated RSG that were excess (not needed to meet MISO's requirements), we calculated the difference between planned generation capacity and load[16] on an hourly basis in two ways: (1) using the target load value from the forecast for the run hour that showed the highest need[17]; and (2) using the actual load value that occurred in the run hour assuming perfect foresight. Under these two scenarios, we flagged unit hours when the planned generation capacity exceeded the target load at the time of the commitment. We ran these calculations for both the Midwest and South subregions and for the MISO footprint[18] – a unit must be flagged as unneeded based on its own subregional needs and the MISO-wide needs to be considered excess.

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[16]   Planned generation capacity is Scheduled Generation MW + Reserves + Headroom, and Load is adjusted for NSI and the RDT (when assessed on a Subregional basis) and includes applicable reserve requirements.

[17]   We use hourly forecast data from the operating day leading up to the run hour. For each lead hour, we compare forecasted load (adjusted for scheduled NSI) to the sum of generation in the plan prior to real-time commit decisions (e.g., day-ahead scheduled, must-run, reserves, and forecasted wind/solar) and all the available generation that can be started by the run hour. We use the target load from the lead hour with the tightest forecasted margin.

[18]   When evaluating the MISO Footprint as a whole, we include offline units eligible for short-term reserves (STR) in planned generation and the prevailing STR requirement in the load (up to 4.5 GW). We additionally run an iteration where we omit offline STR units and only add the Contingency Reserve requirement to load (approximately 2.1 GW) to determine whether MISO was meeting online needs with commits.

In Figure A62, we express RSG in millions of dollars for each month of the year as follows:

- "Actual Needed" RSG, denoted by green bars, from commitments that were not were not flagged as excess in either of the two scenarios;

- "Forecasted Needed" RSG, denoted by gray bars, from commitments that were flagged as excess under scenario (2) but not (1); and

- "Excess" RSG, denoted by light to dark blue bars, from excess commitments that were flagged as excess under both scenarios, further delineated by what portion of the commitment was excess.

The figure also shows the monthly GW average of the daily maximum commitment plotted against the right axis.

Figure A62: Monthly Real-Time Capacity Commitments and RSG Costs
2022

Real-Time Capacity RSG	Share
Excess	**54.1%**
Start Early / Run Late	*0.8%*
Excess Commitment	*53.3%*
Forecasted Needed	**37.3%**
Actual Needed	**7.5%**
Could not evaluate	*1.1%*
Avg. Daily Max Hour Committed	
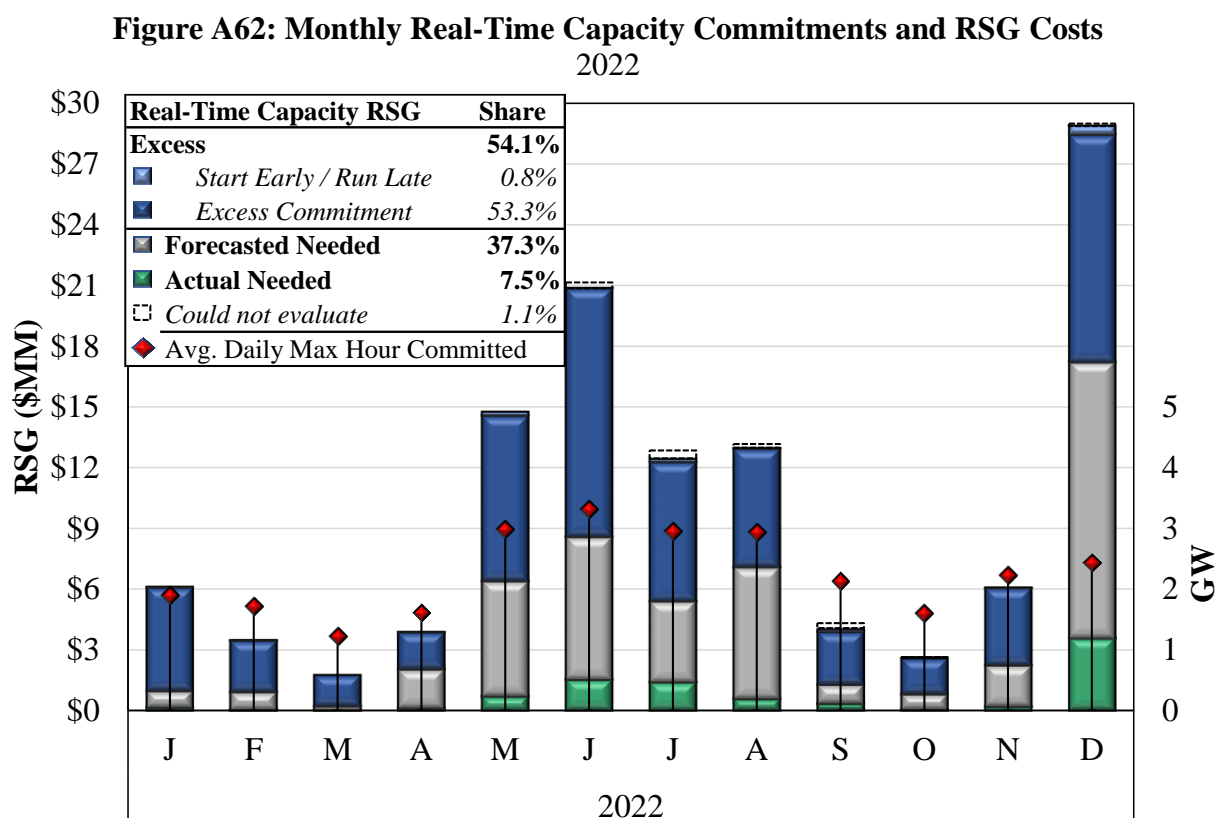
N. Generation Availability and Flexibility in Real Time

The flexibility of generation available to the real-time market provides MISO the ability to manage transmission congestion and satisfy energy and operating reserve obligations. In general, the day-ahead market coordinates the commitment of most of the generation that is online and available for real-time dispatch. The dispatch flexibility of online resources in real time allows the market to adjust supply on a five-minute basis to accommodate NSI and load changes and manage transmission constraints.

Figure A63: Changes in Supply from Day Ahead to Real Time

Figure A63 summarizes changes in supply availability from the day-ahead to real-time markets. Differences between day-ahead and real-time availability are generally attributable to real-time forced outages or derates and real-time commitments and de-commitments by MISO or by its generation owners. The figure shows six types of changes: (1&2) generating capacity self-committed or de-committed in real time; (3) capacity scheduled in the day-ahead market that is not online in real time; (4) capacity derated in real time (separated by resources cleared and not scheduled in the day-ahead market); and (5) increased available capacity (increases from day-ahead capacity); and (6) units committed for congestion management.

The figure separately indicates the net change in capacity between the day-ahead and real-time markets. Net losses of supply along with other factors often cause MISO to commit additional resources for capacity, which are not included in the figure.

Figure A63: Changes in Supply from Day Ahead to Real Time
2021–2022
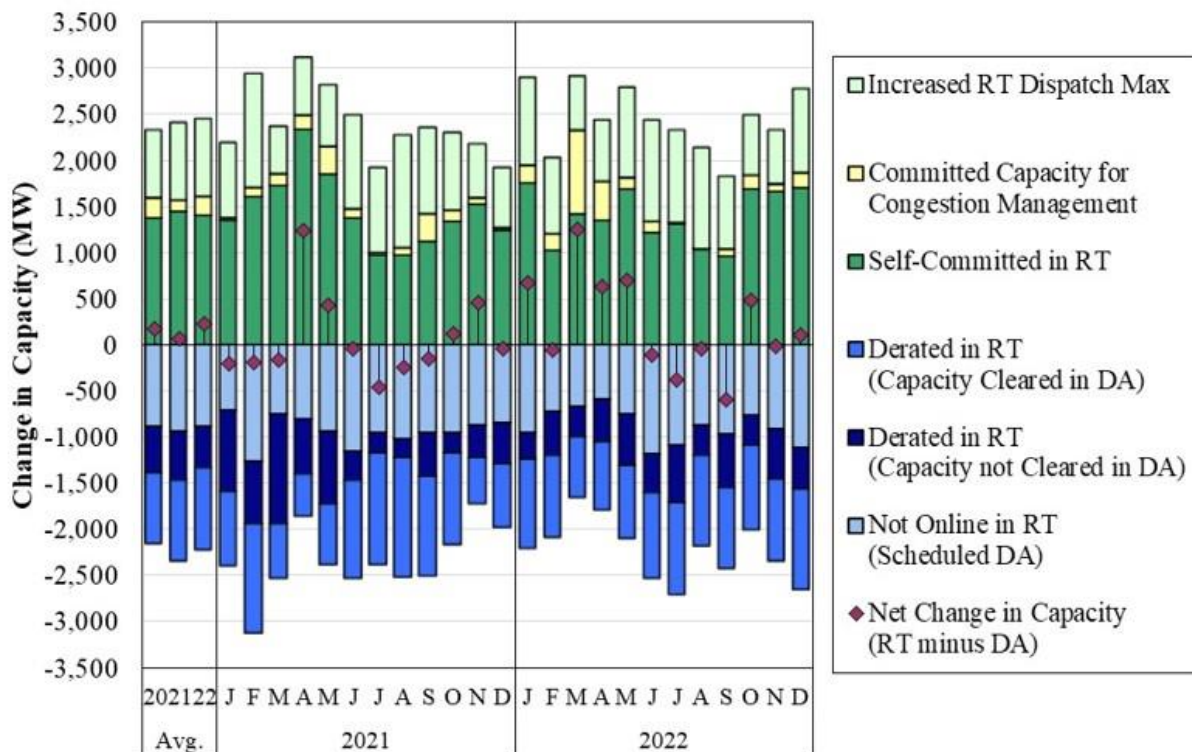
O. Look Ahead Commitment Performance Evaluation

MISO's Look Ahead Commitment (LAC) model minimizes the total production cost of committing sufficient resources to meet the short-term load forecast. This is the primary tool that MISO uses to make economic commitments of peaking resources in real time. To evaluate the performance of the LAC (whether the commitments that LAC recommended were in fact economic), we compared the LAC recommendations to the Unit Dispatch System (UDS) results. We also assess the extent to which MISO operators follow the LAC recommendations.

Figure A64: Economic Evaluation of LAC Commitments

For our analysis, we labeled resources that were online in a LAC solution that were not previously committed as "recommendations." We only consider recommendations that would have to be acted on before a new LAC case runs (based on the unit's startup time) because we expect operators to wait to commit resources when possible. We ignore repeated recommendations within the unit's minimum runtime to avoid excessively weighting repeated LAC recommendations that operators oppose. We determined whether the recommendations would have been economic by comparing the estimated real-time revenues, using ELMP prices, over the minimum runtime of the unit to the total production cost of the unit (including start cost, no load costs, and incremental energy costs). A unit was "started in real time" if it came online between the time of the LAC recommendation and the end of the unit's minimum runtime.

Figure A64: Economic Evaluation of LAC Commitments
2021–2022
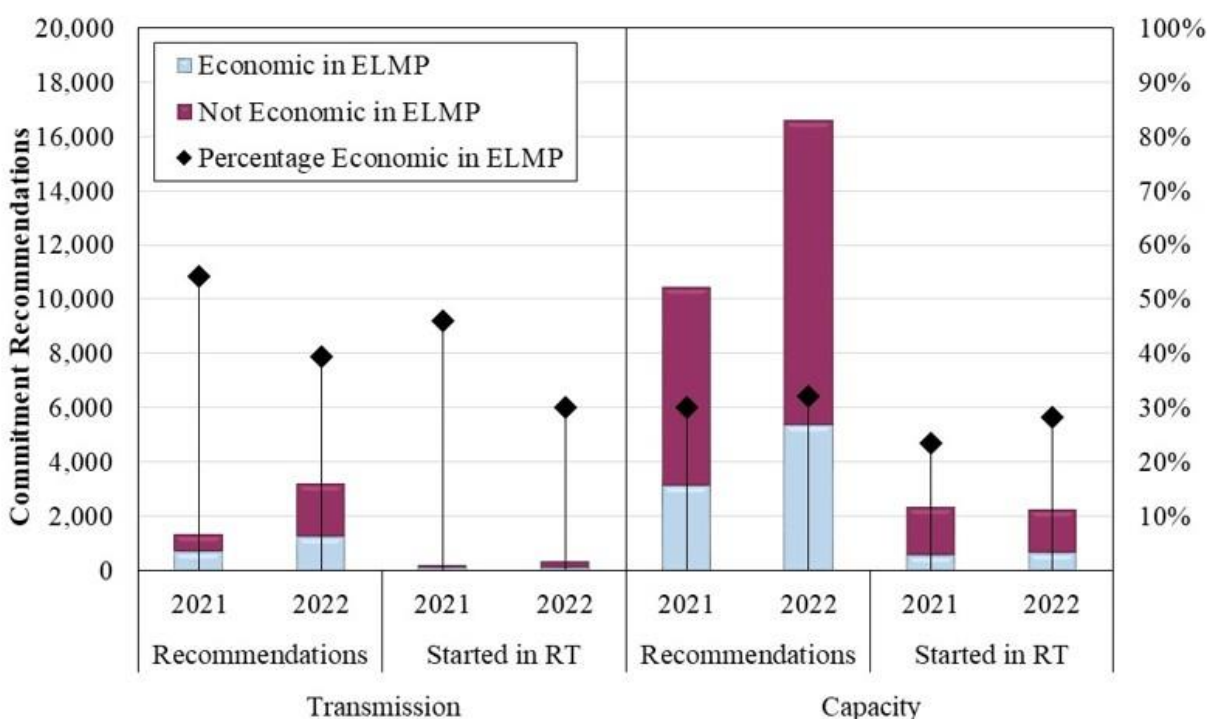
Figure A64 above shows the results of our analysis. The left panel represents LAC commitment recommendations for transmission constraints, and the right panel represents all other LAC commitment recommendations. In each panel, the stacked bars on the left show all the distinct recommendations that LAC made throughout 2021 and 2022, indicating the recommendations that were economic and not economic based on the real-time ex-post energy prices. The right stacked bars show the portion of the recommended resources that were actually started, distinguishing between those that were and were not economic. The diamond in each bar indicates the share of those recommendations that were economic.

P. Real-Time Dispatch Performance

MISO sends dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Historically, MISO would assess penalties to generators if deviations from these instructions remain outside an eight-percent tolerance band for four or more consecutive intervals within an hour. However, in May 2019 MISO altered the Uninstructed Deviation (UD) threshold from being based on output to being a function of the offered ramp rate. MISO's criteria for identifying deviations, both the percentage bands and the consecutive interval test, had been significantly more relaxed than most other RTOs'.

Having a relatively relaxed tolerance band allowed resources to produce far less than their economic output level by responding poorly to MISO's dispatch signals over many intervals (i.e., by "dragging" over an hour or more). Additionally, suppliers could effectively derate a unit by simply not moving over many consecutive intervals (i.e., "inferred derates").

As long as the dispatch instruction is not outside of the allowable tolerance, a resource can simply ignore its dispatch instruction. Because it is still considered to be on dispatch, it can receive Day-Ahead Margin Assurance Payments (DAMAP) and avoid RSG charges it would otherwise incur if it were to be derated. These criteria exempt the majority of deviation quantities from significant settlement penalties. In this section, we calculate two types of deviations to evaluate generator performance:

- Five-minute deviation is the difference between MISO's dispatch instructions and the generators' responses in each interval.

- 60-minute deviation is the effect over 60 minutes of generators not following MISO's dispatch instructions.

We calculate the net 60-minute deviation by calculating the difference between the energy the generators would have been producing had they followed MISO's dispatch instructions over the prior 60 minutes versus the energy they were actually producing.

Figure A65 and Figure A66: Frequency of Net Five-Minute Deviations

Figure A65 shows a histogram of MISO-wide net five-minute deviations from 6 a.m. to 10 p.m., which includes MISO's high-ramp and peak hours in the summer and winter seasons. Figure A66 shows the same results for the ramp-up hours. These hours are particularly important because MISO's need for generators to follow their dispatch signals is largest in these hours. When the demands on the system increase rapidly and resources do not respond, MISO will not be able to satisfy its energy and reserve requirements. In each figure, the curve indicates the share of deviations (on the right vertical axis) that are less than the deviation amount (on the horizontal axis). The markers on this curve indicate three points: the percentage of intervals with net positive deviations less than -500 MW, less than zero MW, and the median deviation.

Figure A65: Frequency of Net Deviations
Ramp and Peak Hours, 2022
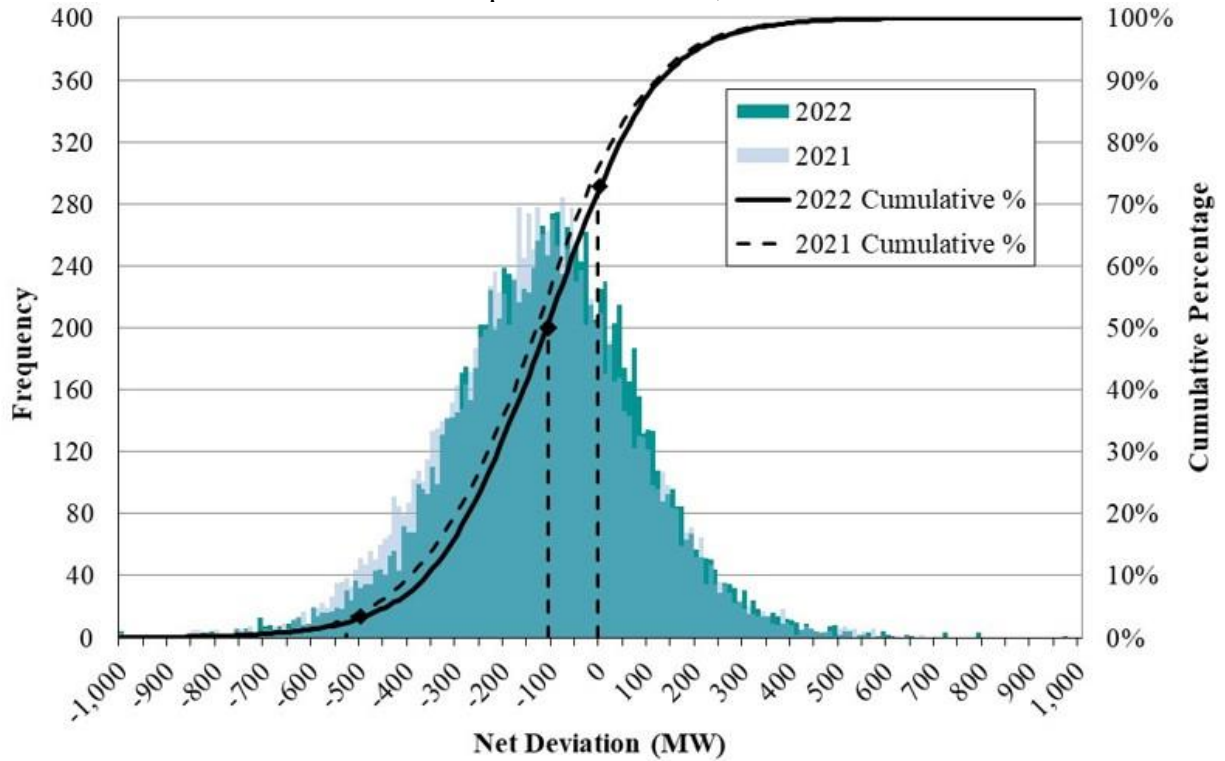
Figure A66: Frequency of Net Deviations
Ramp-Up Hours, 2022
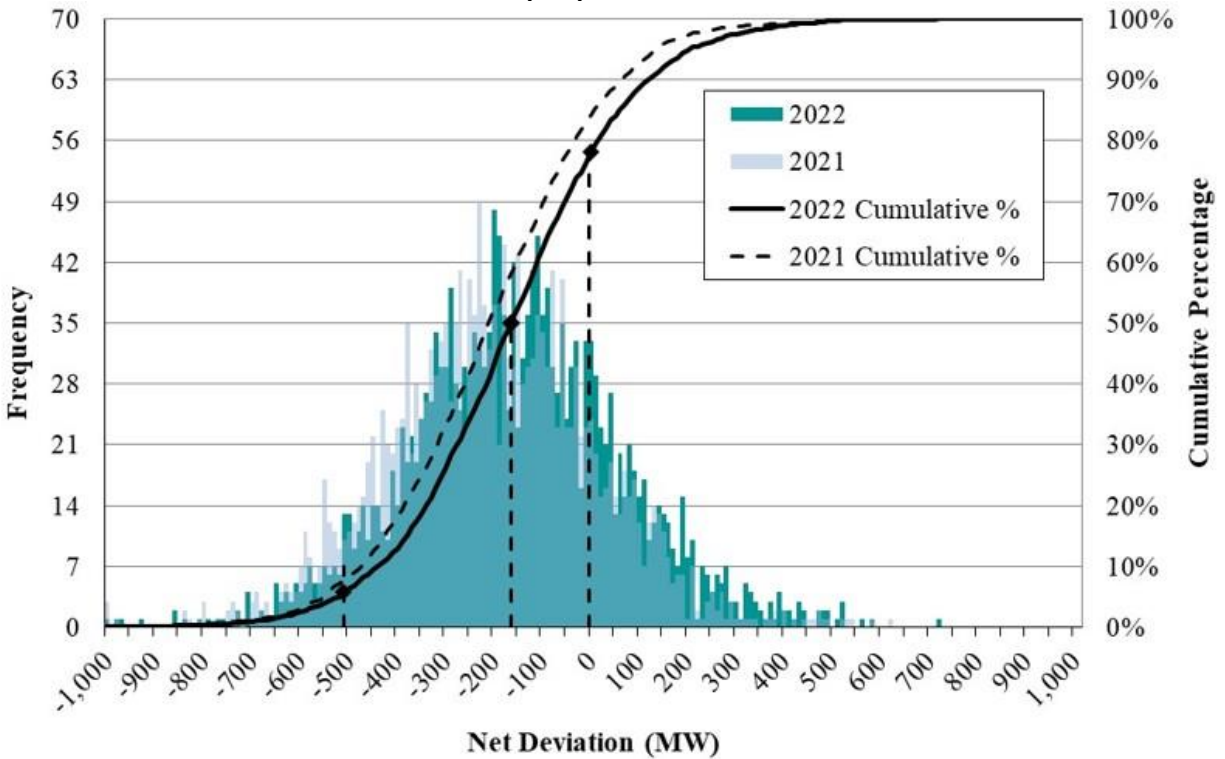
Table A10: Average Five-Minute and Sixty-Minute Net Dragging

Table A shows the size of the five-minute and 60-minute net deviations during the ramp hours and in all hours. The table shows these results from 2018 through 2022. In the columns to the right, we highlight the worst 10 percent performing resources and the average deviations associated with those resources.

Table A10: Average Five-Minute and Sixty-Minute Net Dragging
2018–2022

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

Figure A67 to Figure A69: 60-Minute Deviation by Fuel and Hour

In the next three figures, we estimated the sources of 60-minute net deviations by fuel type and their impact. The horizontal axis is hour beginning (HB) of the day. The vertical stacked bars are the average 60-minute deviations for each HB, where red, blue, and green are the deviations from coal, gas, and wind units, respectively. The three charts represent all year, winter only, and the summer season only.

Figure A67: 60-Minute Deviation by Fuel and Hour
2022
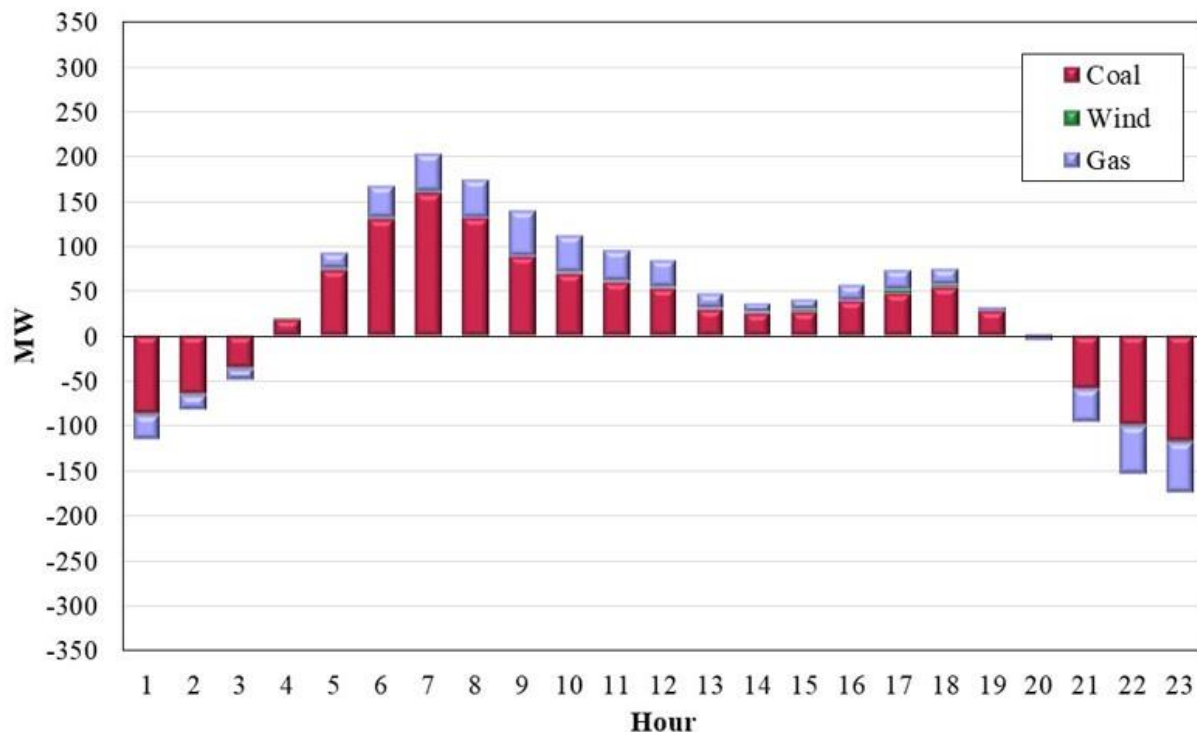
Figure A68: 60-Minute Deviation by Fuel and Hour
Summer 2022
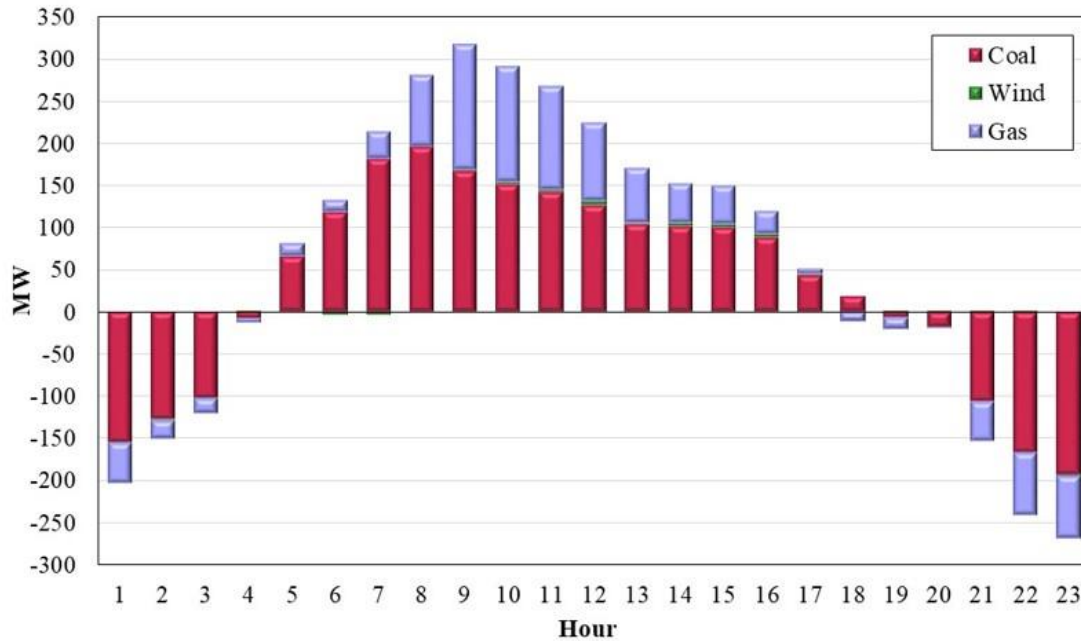
Figure A69: 60-Minute Deviation by Fuel and Hour
Winter 2022
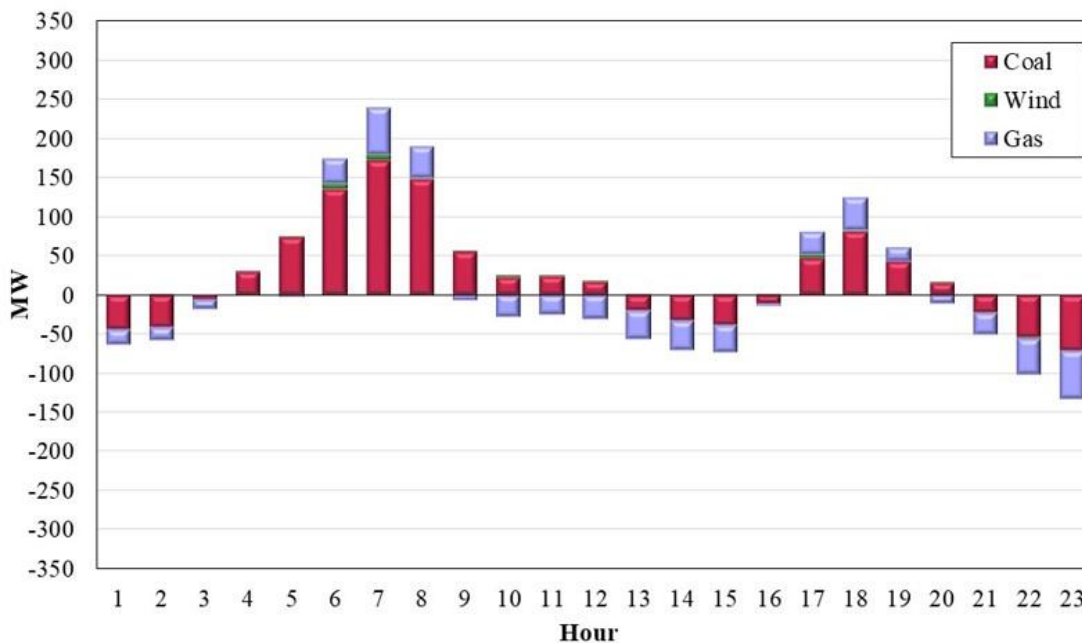
Figure A70: 60-Minute Deviations by Type of Conduct

To better show the effects of the deviations, we measured dragging by hour of the day in Figure A70, as well as the dragging that prevailed in the worst 10 percent of hours. The annual averages over all hours are shown for both dragging and overproduction in the inset table.

Figure A70: Hourly 60-Minute Deviations by Type of Conduct in 2022

Categories	Avg.	90th Pct.
5-Minute Deviation – Dragging (MW)	(256)	(441)
5-Minute Deviation – Over-Production (WM)	227	343
60-Minute Deviation – Dragging (MW)	(204)	(469)
60-Minute Deviation – Over-Production (WM)	90	223
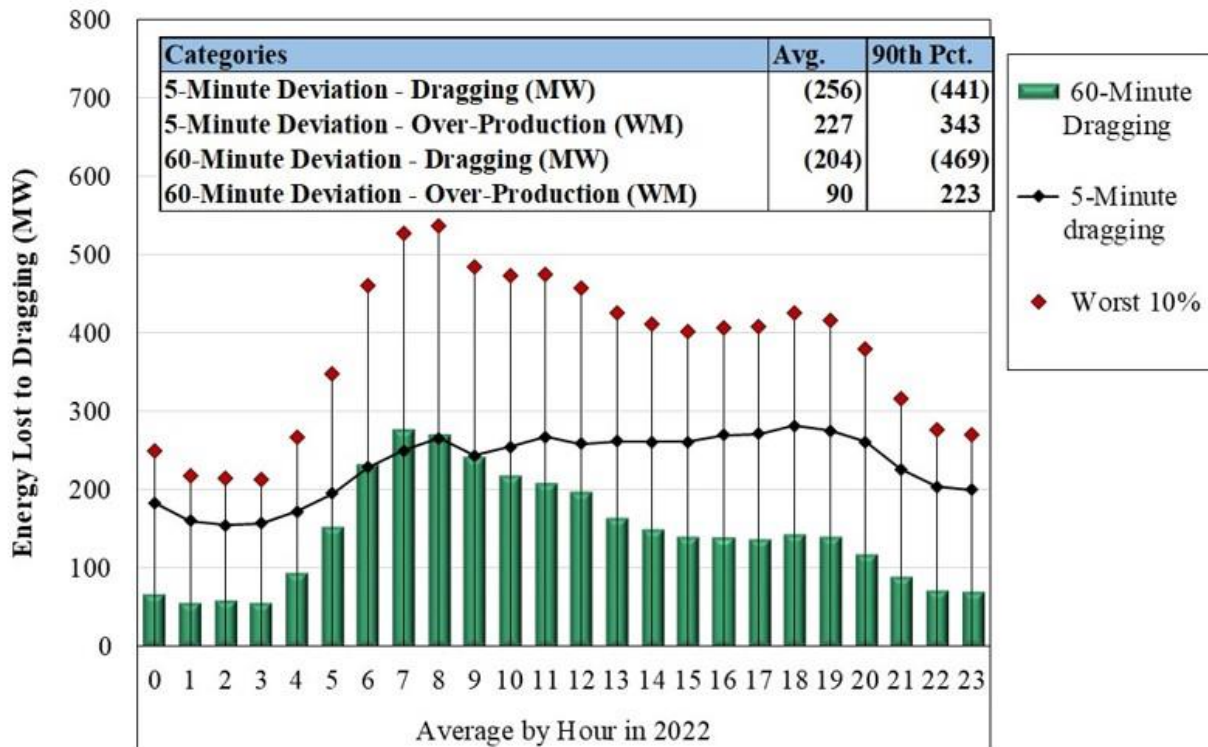
Figure A71: DAMAP to Dragging Units by Fuel Type

The next figure shows the DAMAP caused by 60-minute deviations. The horizontal axis shows the hours beginning (HB) throughout the day. The vertical stacked bars are DAMAP in dollars to units with 60-minute deviations from their dispatch instructions. Different colors represent fuel types, where maroon shows coal units, blue is for gas units, and the green are wind units.

Figure A71: DAMAP to Dragging Units by Fuel Type

DAMAP while dragging	2021	2022
Others	$95,261	$53,306
Gas	$3,135,657	$2,492,370
Wind	$40,644	$33,101
Coal	$4,221,308	$7,728,776
Total	$7,492,869	$10,307,553
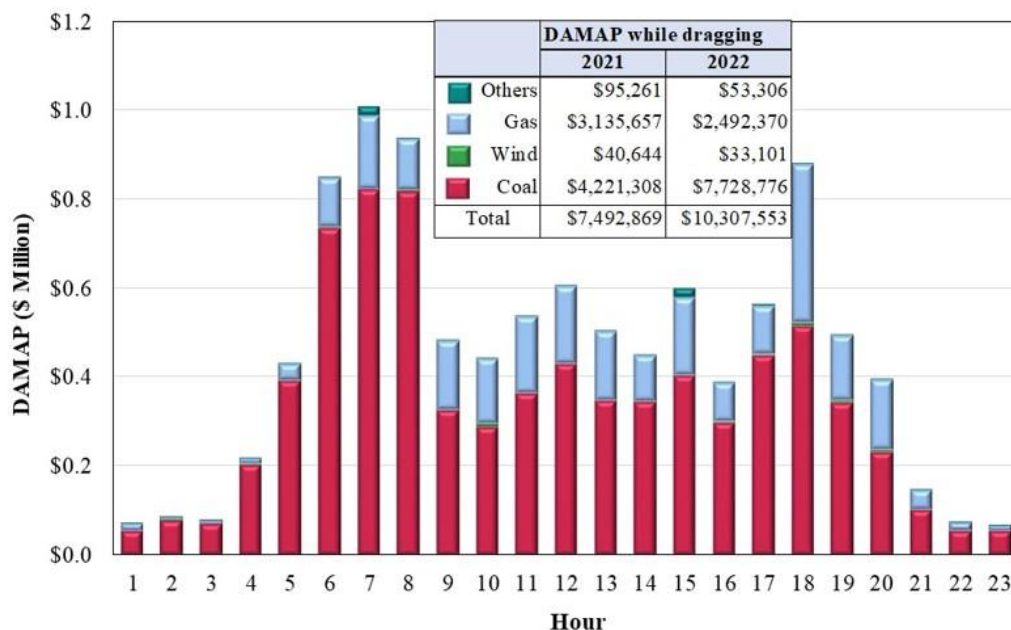
Table A11: Proposed Uninstructed Deviation Penalties and Effective Rate in 2022

The report shows that current settlement rules are insufficient for generation deviations outside the uninstructed deviation (UD) tolerance bands. Deviations that persist for less than 20 minutes are exempted from any financial penalty. The most significant penalty is the excessive energy price, paid at the lower of LMP and as-offered cost on excessive energy volumes. This provides a very weak incentive, particularly to renewable resources, which often set price at their cost when curtailed. In these cases, the renewable resource is financially indifferent between following dispatch and producing excessive energy. This indifference is especially harmful when the excess energy causes transmission overloads that are difficult to manage.

To address this concern, which is bound to grow as more intermittent resources enter the system, we are recommending an improvement to the penalty structure that would be based on the marginal congestion component (MCC) of the resource's LMP. For excessive or deficient energy that loads a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is appropriate because it reflects the incremental congestion value of the deviation volumes and scales with the severity of congestion. Table A11 shows the effects of this proposed penalty by unit type. Penalty rates are provided in terms of per unit of deviation MWh (columns 3 and 4) and per unit of total output (columns 5 and 6). Total penalties incurred during 2022 are shown in the second column.

Table A11: Proposed Uninstructed Deviation Penalties and Effective Rate in 2022

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

Q.   Coal Resource Operations

Table A12: Coal-Fired Resource Operation and Profitability

We screened every coal unit commitment between 2017 and 2022 and identified commitments as being economic when the committed resources had been:

- Offered economically and scheduled in the day-ahead market; or

- Offered with a must-run status and were profitable – when market revenues cover their commitment and variable operating costs by the first full day after the commitment.[19]

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[19]   The resources' start-up costs are determined based on how long the resource has been offline – cold vs. hot start-up costs. The start-up costs are amortized over five days – a minimum typical cycle for coal resources.

In this analysis, we calculated the operating net revenue for every hour based on the units' reference prices. For coal units that were conserving coal, we used reference prices based on the variable costs and excluding opportunity costs. We assumed start costs based on reference prices for units that were must-run. We summed up the start costs across all starts and subtracted that from the total operating revenues net of all operating costs.

Table A12 summarizes the results of this evaluation in three timeframes—2017 through 2020, 2021, and 2022—to delineate between the prevailing natural gas prices of those periods. The third column in each timeframe summarizes the net operating revenues earned by coal suppliers associated with their decisions to start and operate those resources. Ultimately, these values reflect the aggregate economic impact of the resource owners' decisions.

Table A12: Coal-Fired Resource Operation and Profitability
2017–2022

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

R. Dispatch of Peaking Resources

Peak demand is often satisfied by generator commitments in the real-time market. Typically, peaking resources account for a large share of real-time commitments because they are available on short notice and have attractive commitment-cost profiles (i.e., low startup costs and short startup and minimum-run times). These qualities make peaking resources optimal candidates for satisfying the incremental capacity needs of the system. However, they generally have high incremental energy costs and frequently do not set the energy price because they are often dispatched at their economic minimum level (causing them to run "out-of-merit" order with an offer price higher than their LMP). When a peaking unit does not set the energy price or runs out of merit, it will be revenue-inadequate for covering its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

MISO's aggregate load peaks in the summer, so the dispatch of peaking resources has the greatest impact during the summer months when system demand can, at times, require substantial commitments of such resources. In addition, several other factors can contribute to commitments of peaking resources, including day-ahead net scheduled load that is less than actual load, transmission congestion, wind forecasting errors, or changes in real-time NSI.

Figure A72: Dispatch of Peaking Resources

Figure A72 shows average hourly dispatch levels of peaking units in 2021 and 2022 and evaluates the consistency of peaking unit dispatch and market outcomes. The figure is disaggregated by the unit's commitment reason and separately indicates the share of the peaking resource output that is in merit order (i.e., the LMP exceeds its offer price).

Figure A72: Dispatch of Peaking Resources
By Commitment Reason, 2021–2022
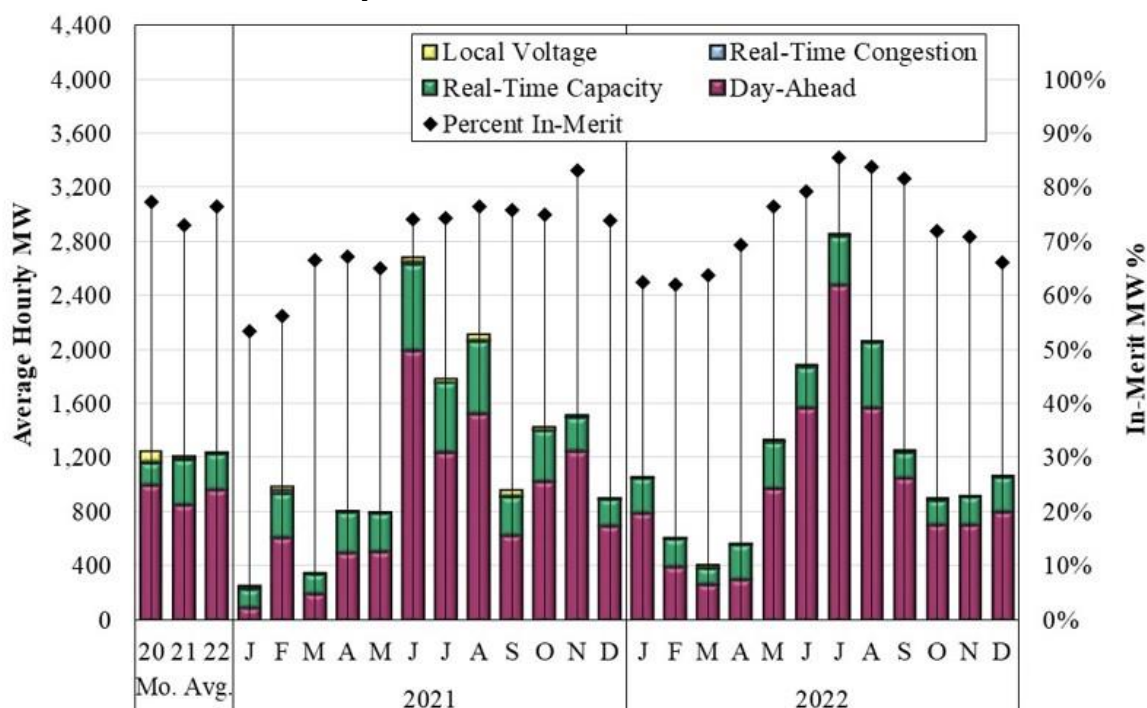
S.   Wind Generation

Wind generation in MISO has grown steadily since the start of the markets in 2005. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent and, as such, presents unique operational and scheduling challenges.

Over 90 percent of MISO's wind units are Dispatchable Intermittent Resources (DIR). DIRs are physically capable of responding to dispatch instructions and can, therefore, set the real-time energy price. DIRs can submit offers in the day-ahead market, are eligible for all uplift payments, and are subject to all typical operating requirements. For both DIR and non-DIR wind units, MISO utilizes short and long-term forecasts to make assumptions about wind output. The prevalence of DIRs allows MISO to rarely utilize manual curtailments to ensure reliability. Wind resources are also qualified to sell capacity under Module E of the Tariff based on their contribution to satisfying MISO's planning requirements.[20]

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[20]   Capacity credits for wind resources are determined by evaluating a unit's performance during the peak hour of each of the prior 17 years' 8 highest-load days (136 hours). For the 2022–2023 Planning Year, the system-wide capacity credit for wind is 15.5 percent, while individual credits range from 0.4 to 32.3 percent.

Table A13: Day-Ahead and Real-Time Wind Generation

Table A13 shows the hourly average real-time wind output and the wind scheduled in the day-ahead market. In the second to last set of columns, we indicate the top five percent of average hourly output by season, and in the far-right columns we indicate the average and absolute value of the real-time forecast error.

Table A13: Day-Ahead and Real-Time Wind Generation
2019–2022

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

Note 1: 2019 Forecast Error calculated for 7/10-12/31.
Note 2: %* Change between 2021 and 2022.

Wind 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. Under-scheduling of output in the day-ahead market can create price convergence issues and lead to uncertainty regarding the need to commit resources.

Convergence issues are partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers. Since the most significant effect of day-ahead under-scheduling of wind is its effects on the transmission flows and associated congestion in the day-ahead and real-time markets, we evaluate the extent to which virtual transactions offset the flow effects of the wind under-scheduling. We calculated the percentage of flows from wind units on every constraint in the day-ahead and real-time markets. We estimated profits on those constraints by virtual positions, which we aggregated by year and by monitored element. We identified constraints where either the day-ahead or real-time constraint flows associated with wind exceeded 20 percent and sorted by virtual profitability on the constraints.

Figure A73 and Table A14: Virtual Transaction Effects on Day-Ahead Constraints Affected by Wind Scheduling

In Figure A73, we show the top 10 constraints identified in our analysis. In the figure, we illustrate the average day-ahead flow from wind generators in the blue bars, the real-time equivalent in the red diamonds, and day-ahead virtual flow as a green transparent bar on top of the blue bar. These values are expressed as a percentage of the rating on the impacted constraints. We have masked the identity of the constraints in the figure.

Figure A73: Virtual Impacts on Top 10 Constraints Affected by Wind

Cons. (Top 10)	RT Congestion ($ MM)	Virtual Profits ($ MM)
A	$117	$22
B	$65	$19
C	$46	$13
D	$234	$11
E	$58	$11
F	$135	$11
G	$60	$8
H	$47	$7
I	$10	$6
J	$13	$5
Total	$783	$111
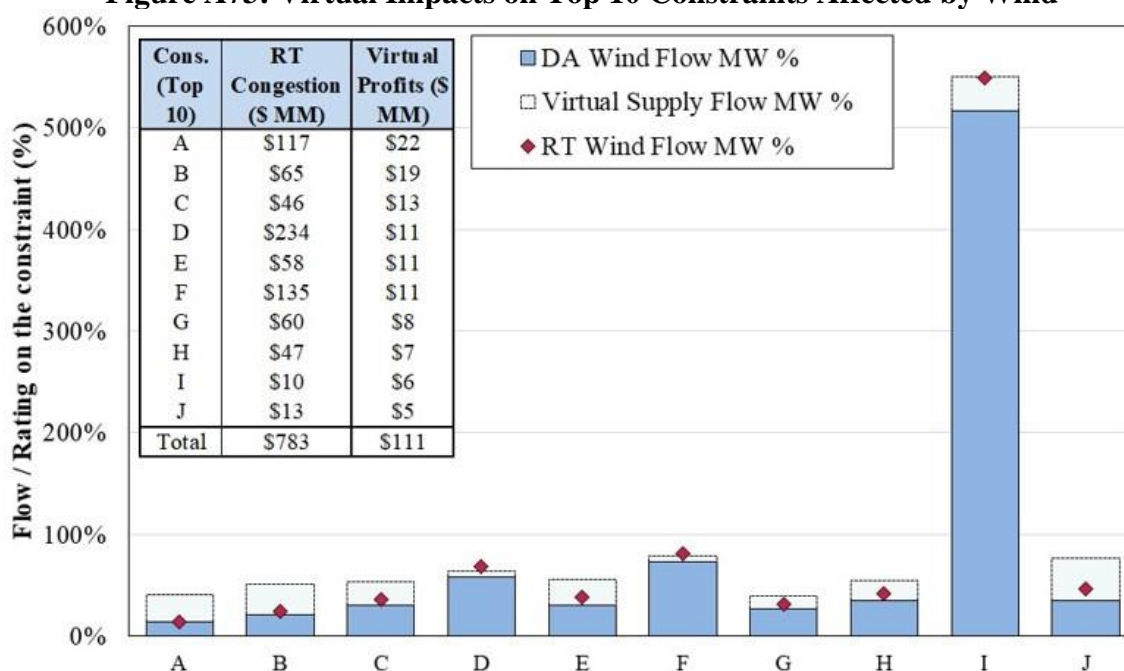
In Table A14 below, we show the total number of wind-impacted constraints that we identified in one of six categories, the aggregate amount of congestion associated with the constraints in each category, and the virtual profitability in each category.

Table A14: Aggregate Virtual Impacts on Constraints Affected by Wind
2022

Item Description (2022)	Number of Constraints	RT Congestion ($ MM)	Virtual Profitability ($ MM)
Constraints where wind has significant impact	402	$2630	$193
Constraints where wind has significant impact and RT Wind Flow > DA Wind Flow	358	$2572	$189
Constraints where wind has significant impact and DA Wind Flow > RT Wind Flow	44	$58	$4
Constraints where wind has significant impact and RT Wind Flow > DA Wind Flow and Virtual Supply > 0	255	$1978	$198
Constraints where wind has significant impact and RT Wind Flow > DA Wind Flow and Virtual Supply < 0	103	$595	-$9
Constraints where wind has significant impact and DA Wind Flow > RT Wind Flow and Virtual Supply > 0	0	$0	$0

Figure A74: Generation Wind Over-Forecasting Levels

In 2016, we identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output. The wind forecasts are important because MISO uses them to establish wind resources' economic maximums in the real-time energy market. Because wind resources typically offer at lower prices than any other resources, their forecasted output also typically matches their MISO dispatch instructions, absent congestion. Dispatch deviations arise because an over-forecasted resource will produce less than the dispatch instruction. Figure A74 shows the monthly absolute average forecast errors from the wind resources in the bars, as well as the average forecast error plotted as a line against the right axis in 2021 and 2022. MISO changed its forecasting methodology in early 2020, and this led to a significant reduction in both absolute average and average forecast errors.

Figure A74: Generation Wind Over-Forecasting Levels
2021–2022
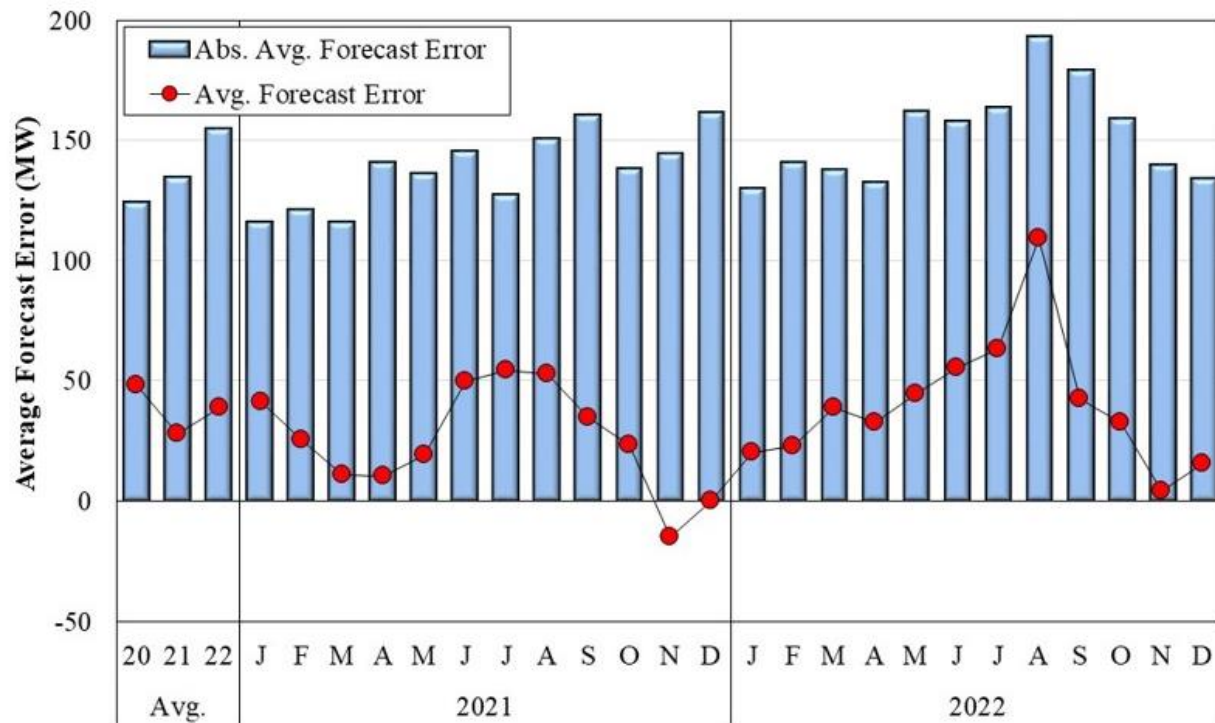
Figure A75: Wind Forecast Methodology Improvement

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

MISO's near-term forecast is primarily a "persistence" forecast that assumes future wind resource output will match the most recent output observation. We developed a forecast methodology that is also persistence-based, but also incorporates the recent direction in output changes. The IMM Forecast employs a trended-persistence approach calculated using data on the prior 10 minutes of actual output to project 10 minutes into the future.

The forecast is sensitive to the observed rate of change two intervals and one interval prior. If the rate of change in both intervals is in the same direction, the rate of change in the most recent interval is assumed to continue. If the direction of change is different in the prior to intervals, we assume the average change if the prior interval showed the bigger change and no change if the prior interval showed the smaller change. We also include a dampening factor that restricts the rate of change as a resource approaches its physical minimum and maximum operating limits. The forecasted is limited to half of the headroom (capacity minus current output) upward and

half of the current output downward. Figure A75 shows the result of the IMM's approach compared to the incumbent vendor forecast.

Figure A75: Wind Forecast Methodology Improvement
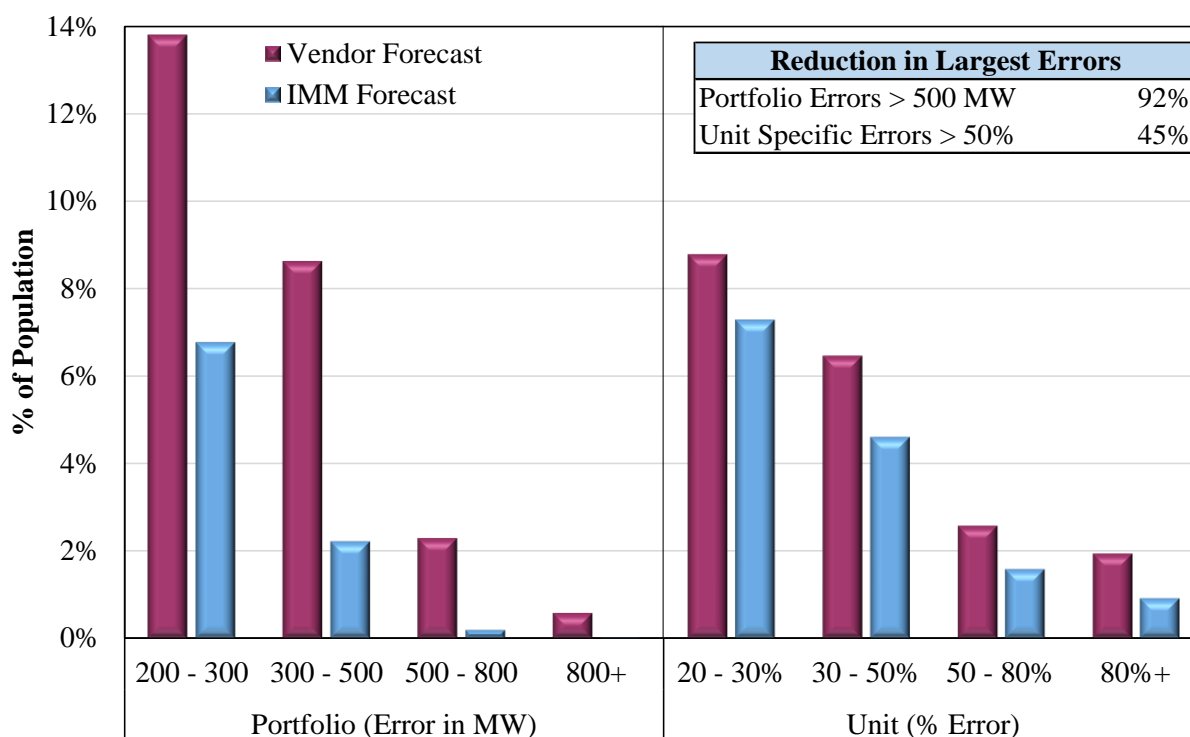
Figure A76: Wind Generation Volatility

Wind output can be highly variable and must be managed through curtailment, the re-dispatch of other resources, or commitment of peaking resources. Figure A76 summarizes the volatility of wind output on a monthly basis over the past two years by showing:

- The average absolute value of the 60-minute change in wind generation in the blue line;

- The largest five percent of hourly decreases in wind output in the blue bars;

- The maximum hourly decrease in each month in the drop lines; and

- Changes in wind output from economic curtailments are excluded from this analysis.

Figure A76: Wind Generation Volatility
2021–2022
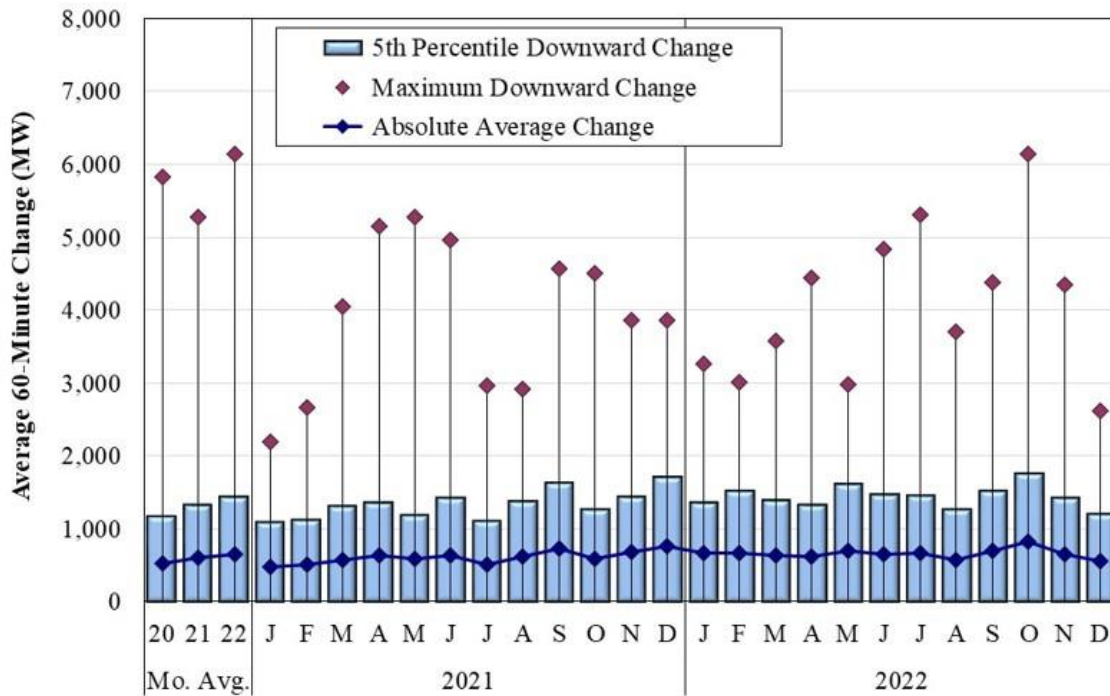
Figure A77: Wind Generation Capacity Factors

Wind capacity factors are measured as actual output as a percentage of nameplate capacity and can vary by season and location. Figure A77 shows average hourly wind capacity factors by month, shown separately for two MISO Coordination regions (North and Central).

Figure A77: Wind Generation Capacity Factors
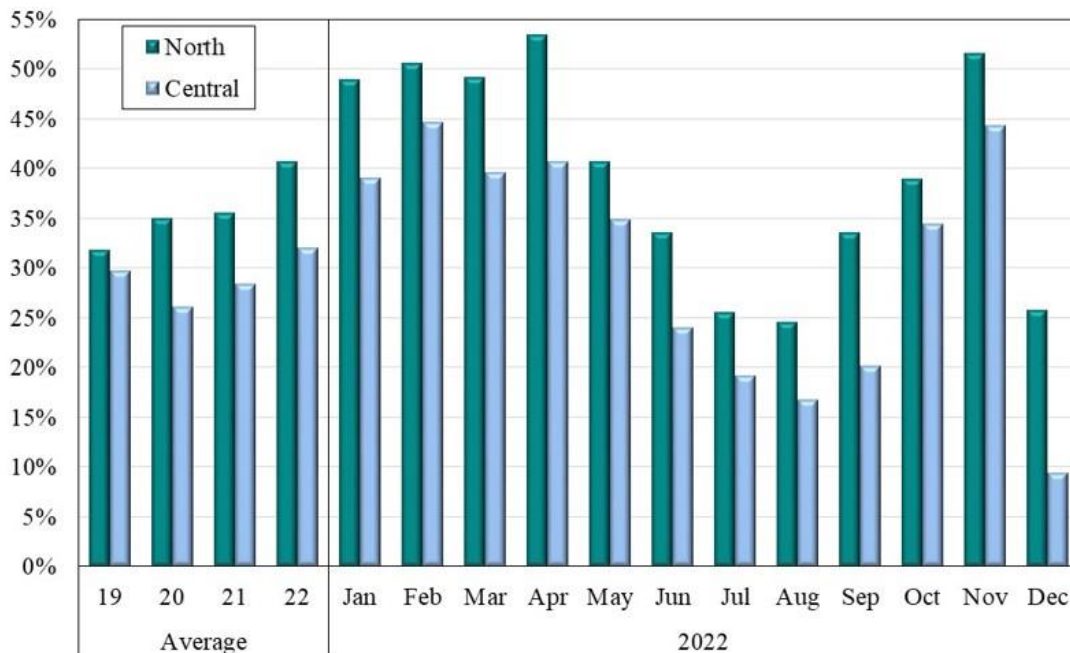
T.   Outage Scheduling

Figure A78: MISO Outages

Figure A78 shows the monthly average planned and unplanned generator outage rates for the two most recent years (and annual averages for the last three years). Only full outages are included, so partial outages or deratings are not shown. The figure also distinguishes between short-term unplanned outages (lasting fewer than seven days) and long-term unplanned outages (seven days or longer). Additionally, the figure distinguishes between normal planned outages and short-notice planned outages that are scheduled within seven days of the actual start of the outage. Planned outages are often scheduled in low-load periods when economics are favorable for participants to perform maintenance, although short-notice planned outages and short-term unplanned outages are frequently the result of emergent operating problems.

Short-notice and short-term outages are important to review because they are more likely to reflect attempts by participants to physically withhold supply from the market. It is less costly to withhold resources for short periods when conditions are tight than to take a long-term outage. We evaluate market power concerns related to potential physical withholding in Section VIII.G.

Figure A78: MISO Outages
2021–2022

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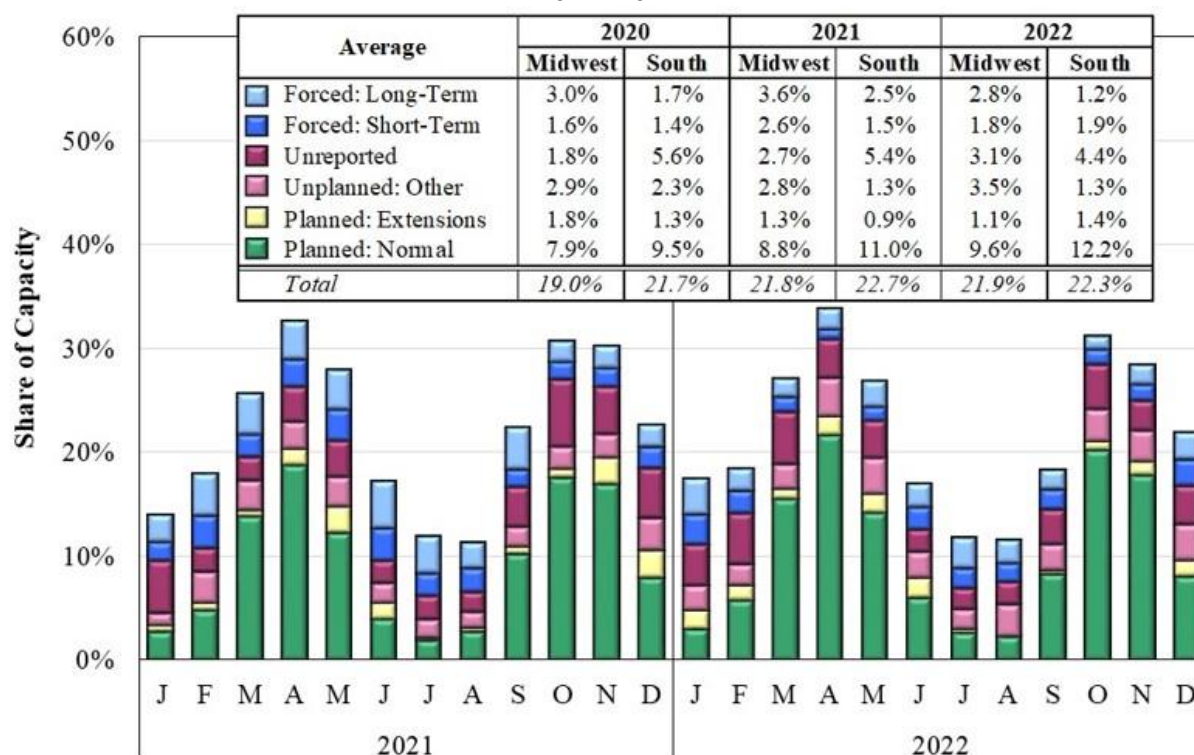
V. TRANSMISSION CONGESTION AND FTR MARKETS

Managing transmission congestion is among MISO's most important roles. MISO monitors thousands of potential network constraints throughout its system. MISO manages flows over its network by altering the dispatch of its resources to avoid overloading these transmission constraints. This establishes efficient, location-specific prices that represent the marginal costs of serving load at each location.

Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because of limited transmission capability. The result is that higher-cost units must be dispatched in place of lower-cost units to avoid overloading transmission facilities. In LMP markets, this generation re-dispatch, or "out-of-merit," cost is reflected in the congestion component of the locational prices. The congestion component of the LMPs can vary substantially across the system, causing higher LMPs in "congested" areas.

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 economic signals that facilitate efficient investment and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion

This section reviews the value of real-time congestion, which is different from congestion revenues collected by MISO. The value of congestion is defined as the marginal value, or shadow price, of the constraint times the power flow over the constraint. If a constraint is not binding, the shadow price and congestion value will be zero. This indicates that the constraint is not affecting the economic dispatch or increasing production costs. For at least two reasons, MISO does not collect the full value of the congestion on its system.

First, the congestion value is based on the total flow over the constraint, and MISO settles with only part of the flows on its constraints. Generators serving loads outside of MISO contribute to flows over MISO's system (known as "loop flows") and do not pay MISO for their congestion value. Additionally, neighboring PJM and SPP have entitlements to flow power over MISO's system and their real-time flows up to their entitlement levels do not settle with MISO.

Second, most flows are settled through the day-ahead market. Once a participant has paid for flows over a constraint in the day-ahead market, the participant does not have to pay again in the real-time market that only settles on deviations from the day-ahead market. Therefore, when congestion is not foreseen and not fully anticipated in day-ahead prices, MISO will collect less congestion revenue in the day-ahead market than the real-time value of congestion on its system.

Figure A79: Value of Real-Time Congestion by Coordination Region

Figure A79 shows the total monthly value of real-time congestion by MISO's Reliability Coordination regions in 2021 and 2022. The bars on the left panel of the chart show the average monthly value of the past three years.

Figure A79: Value of Real-Time Congestion by Coordination Region
2021–2022

Totals	2020	2021	2022
Midwest - Wind	$381 M	$1,035 M	$1,610 M
Midwest - Non-Wind	$471 M	$1,094 M	$1,694 M
Transfer Constraints	$30 M	$57 M	$76 M
South	$165 M	$663 M	$291 M
Total RT Value	**$1,047 M**	**$2,849 M**	**$3,672 M**
◆ DA Congestion Revenue	$660 M	$1,628 M	$2,194 M
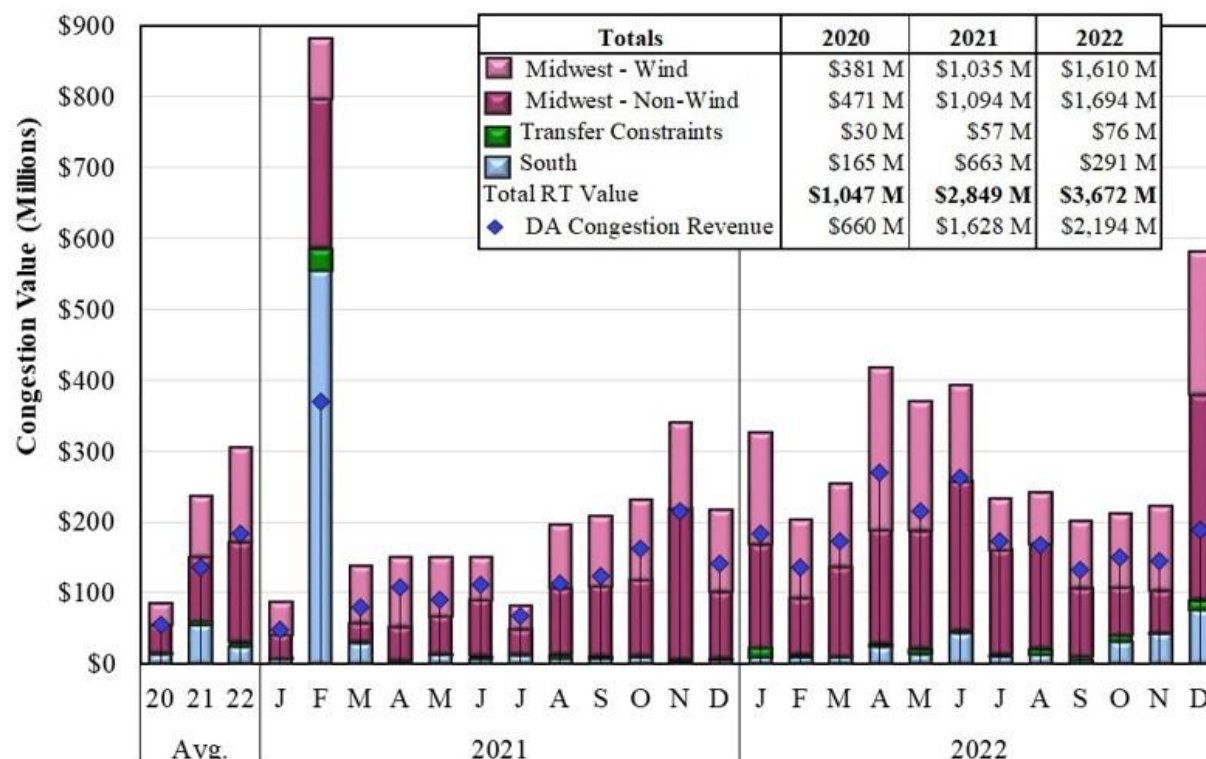
Figure A80: Value of Real-Time Congestion by Type of Constraint

To better identify the drivers of the real-time congestion value, Figure A80 disaggregates the results by the MISO subregion and by the two types of constraints:

- Internal Constraints: Constraints internal to MISO where MISO is the Reliability Coordinator that are not coordinated with PJM or SPP.

- MISO market-to-market (M2M) Constraints: MISO constraints coordinated with SPP and PJM through the M2M process.

The flow on PJM and SPP M2M constraints is limited to the MISO market flow, and this flow is used in our measure of congestion value. Market flow is defined as MISO's flow on the constraints in MISO's dispatch model and does not represent the total flow on these constraints. The internal constraints represented in the MISO dispatch model include the total flow.

Figure A80: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2020–2022
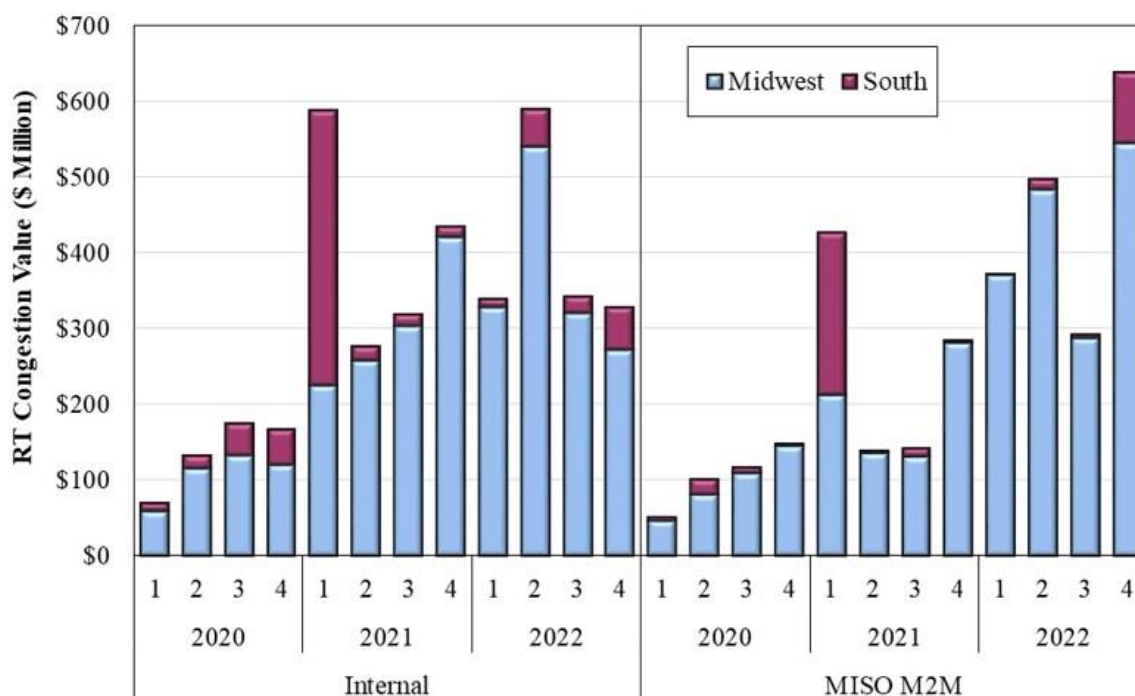
B.   Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the LMPs at locations where energy is scheduled to be produced and consumed.

The resulting congestion revenue is paid to the holders of Financial Transmission Rights (FTR). FTRs represent the economic property rights of the transmission system, entitling the holder to the day-ahead congestion revenues between two points on the network. A large share of the value of these rights is allocated to MISO market participants. The residual FTR capability that has not been allocated is sold in the FTR markets, with the resulting market revenues 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 they 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 FTR holders 100 percent of the FTR entitlement.

Figure A81: Day-Ahead and Balancing Congestion and FTR Funding

Figure A81 shows the total day-ahead congestion revenues for constraints in MISO Midwest, MISO South, and the transfer constraints between MISO Midwest and MISO South for the last two years. It also shows balancing congestion revenue (net congestion collections in real time), as well as the funding level of the FTRs.

Figure A81: Day-Ahead and Balancing Congestion and FTR Funding
2020–2022

Congestion ($ millions)	2020	2021	2022
Day-Ahead Market	$660.1	$1,627.7	$2,194.3
◼ Transfer	$16.9	$27.8	$15.4
◼ South	$119.9	$277.1	$232.8
◻ Midwest	$523.3	$1,322.8	$1,946.1
◼ Balancing	-$112.8	-$171.6	-$25.3
◆ FTR Funding	97.6%	100.4%	106.7%
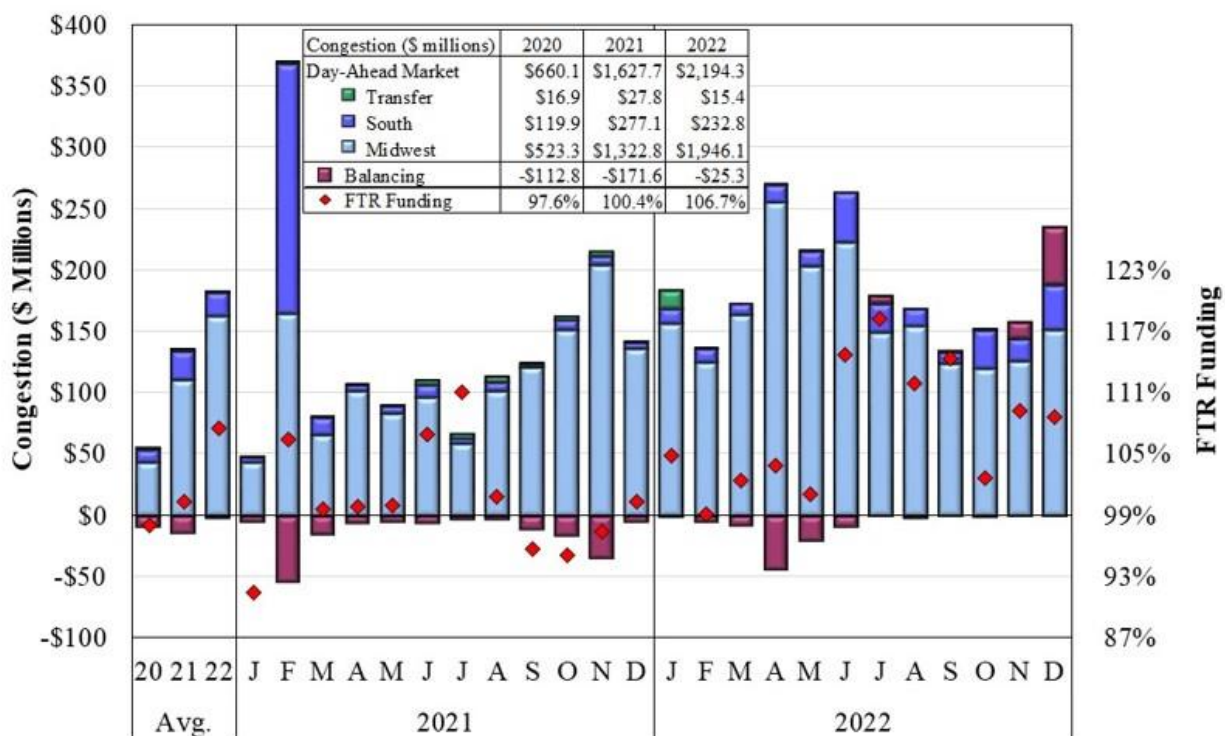
An FTR is a forward purchase of day-ahead congestion costs that allows participants to manage day-ahead congestion risk. Transmission customers pay for the embedded costs of the system and, therefore, are entitled to the system's economic property rights. This allocation of property rights is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers associated with their historical usage of the network given their network load and generating resources. ARRs are a MW value defined between two locations on the network, and they give customers the right to receive the FTR revenues that MISO collects when it sells FTRs that correspond to the ARRs. Customers can also convert their ARRs into FTRs directly.

MISO is obligated to pay FTR holders the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[21] Congestion revenues collected in MISO's day-ahead market fund the FTR obligations. Surpluses and shortfalls are limited when participants hold FTR portfolios consistent with the capability of the network. When MISO sells FTRs that reflect different network capability than is available in the day-ahead market, shortfalls or surpluses can occur. Reasons for differences between FTR capability and day-ahead capability include:

- Loop flows caused by generators and loads outside the MISO region;[22] and

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[21]   An FTR obligation can be in the counter-flow direction and can require a payment from the FTR holder.

[22]   "Loop Flows" cannot be directly calculated and, in this context, would be measured as real-time flows less the calculated real-time market flows from PJM, SPP, and the MISO commercial flows (which include MISO market flows and the impacts of physical transactions). For example, when Southern Company generation serves its own load, some of this would flow over the MISO transmission system and this would be "loop flow." The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

- Transmission outages or other factors that cause system capability modeled in the day-ahead market to differ from capability assumed when FTRs were allocated or sold.

Transactions that cause unanticipated loop flows are a problem because MISO collects no congestion revenue from them. If MISO allocates FTRs for the full capability of its system, loop flows can create an FTR revenue shortfall. This is because only part of the network is being used by MISO participants who pay congestion charges.

During each month, MISO will fund FTRs by applying surplus revenues from overfunded hours *pro rata* to shortfalls in other hours. Monthly congestion revenue surpluses accumulate until the end of the year, when they are prorated to reduce any remaining FTR shortfalls. MISO has continued to work to improve the FTR and ARR allocation processes.

Figure A82: FTR Funding by Type of Constraint and Control Area

At an aggregate level, MISO's FTRs were fully funded in 2022. However, it is important to examine funding at a more detailed level to understand where inconsistencies may exist between the FTR market and the day-ahead market. Examining funding by Local Balancing Authority (LBA) can illuminate any potential cost-shifting that may be occurring among participants.

Figure A82 shows the monthly FTR surpluses and shortfalls (in both dollars and percentage terms) by LBA for 2022. The LBAs are masked with sequential letters. The constraints in each LBA include all internal and MISO-coordinated M2M constraints. External M2M constraints are summarized by the coordinating RTO. Other external TLR constraints are categorized as Non-MISO.

Figure A82: FTR Funding by Type of Constraint and Control Area
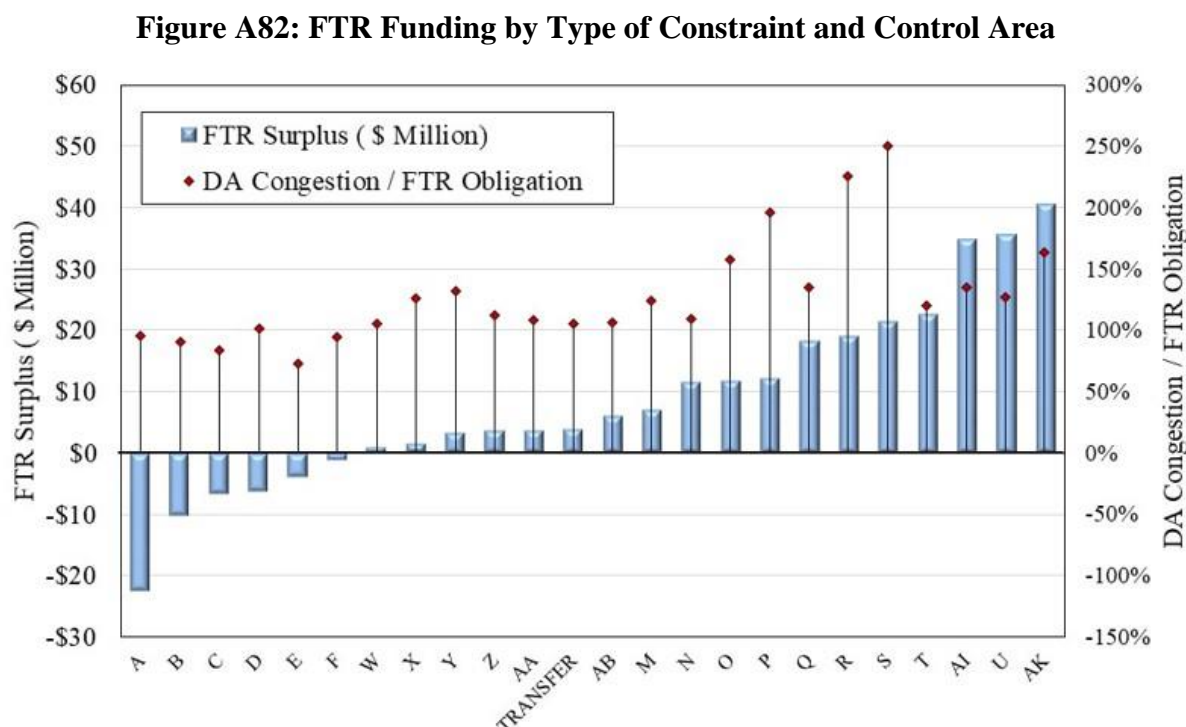
Notes: Only includes control areas that are over- or under-funded by $1.1MM.   Year: 2022

Figure A83: Balancing Congestion Revenues and Costs

Balancing congestion revenues are congestion collections in the real-time market based on deviations from day-ahead congestion outcomes. The magnitude of balancing revenues should be small if the day-ahead market accurately forecasts the real-time network capabilities. However, balancing congestion revenue shortfalls occur when the day-ahead model is not fully consistent with the real-time network topology. For example, if MISO does not model a constraint in the day-ahead market and it binds in real time, MISO can accumulate a substantial amount of negative balancing congestion costs. Failure to model the constraint can allow day-ahead scheduled flows over the constraint to exceed the real-time limit. The costs to "buy back" the day-ahead flows, or balancing congestion costs, must be collected through an uplift charge to MISO's customers.

To understand balancing congestion revenues, Figure A83 shows these amounts disaggregated into (1) the real-time congestion revenues (costs) collected by having to increase (or reducing) the MISO flows over binding transmission constraints and (2) the M2M payments made by (or to) PJM and SPP under the Joint Operating Agreements (JOAs). For example, when PJM exceeds its flow entitlement on a MISO-managed constraint, MISO will re-dispatch to reduce its flow and generate a cost (shown as negative in the figure). PJM's payment to MISO for this excess flow is shown as a positive revenue to MISO. We have also included JOA uplift in the real-time balancing congestion costs. JOA uplift results from MISO exceeding its Firm Flow Entitlement (FFE) on PJM M2M constraints and having to buy that excess back from PJM at PJM's shadow price. Like other net balancing congestion costs, JOA uplift costs are part of revenue neutrality uplift costs collected from load and exports.

Figure A83: Balancing Congestion Revenues and Costs
2020–2022

Totals ($ Millions)	2020	2021	2022
Balancing Congestion Revenue	-$72.4	-$101.3	-$46.0
JOA Congestion (Net from PJM/SPP)	$1.9	$23.2	$80.4
JOA Uplift Paid to PJM/SPP	-$42.3	-$93.2	-$59.7
Net Balancing Congestion	-$112.8	-$171.2	-$25.3
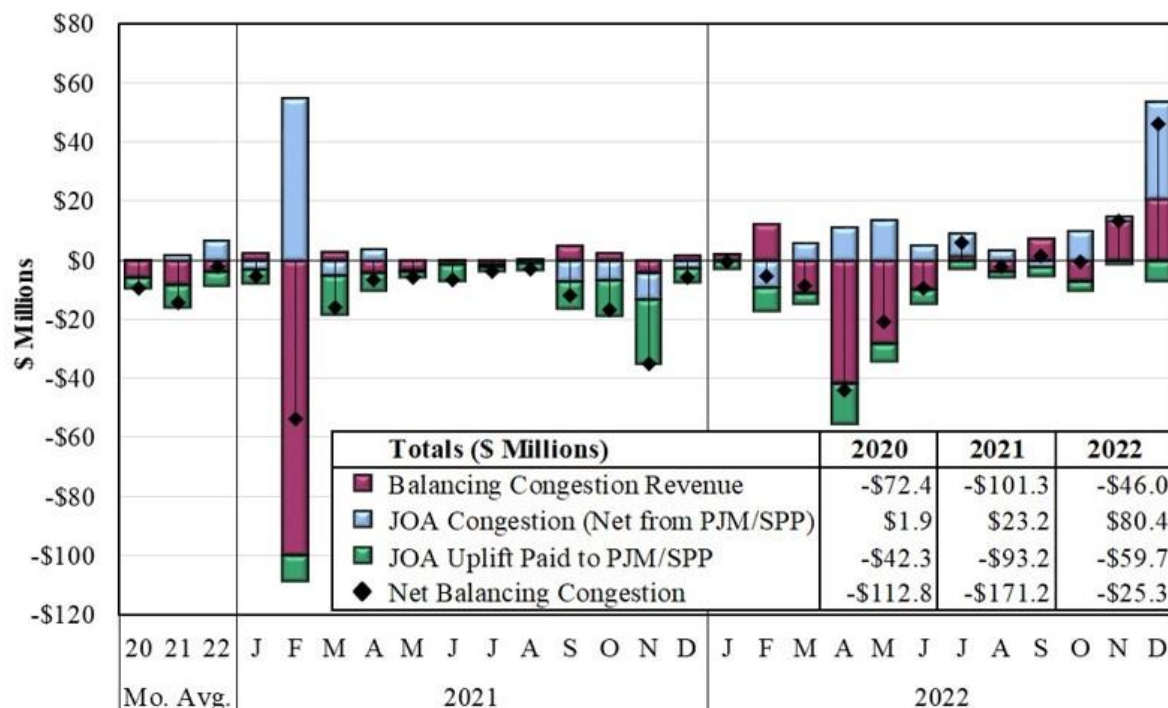
C.   Key Congestion Management Issues

This subsection identifies two key opportunities to improve the congestion management broadly.

Coordinating Outages that Cause Congestion

Generators take planned outages to conduct periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various systems. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces the transmission capability of the system. MISO evaluates only the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages. Different participants may independently schedule generation and/or transmission outages in a constrained area. Absent a reliability concern, MISO does not have the tariff authority to deny or postpone a planned outage, even when it will likely have substantial economic effects.

Figure A84: Congestion Affected by Multiple Planned Generation Outages

Figure A84 provides a high-level evaluation of how uncoordinated planned outages may affect congestion. It shows the real-time congestion value that was incurred from January 2021 through December 2022. We identify the portion of the congestion on constraints substantially impacted by two or more planned generation outages that affected at least 10 percent of the constraints' flows. The maroon bars represent the congestion attributable to multiple planned generation outages, and the blue bars indicate the total congestion not attributable to concurrent planned generation outages. The diamonds indicate the percentage share of congestion that was due to concurrent planned generation outages.

Figure A84: Congestion Affected by Multiple Planned Generation Outages
2021–2022
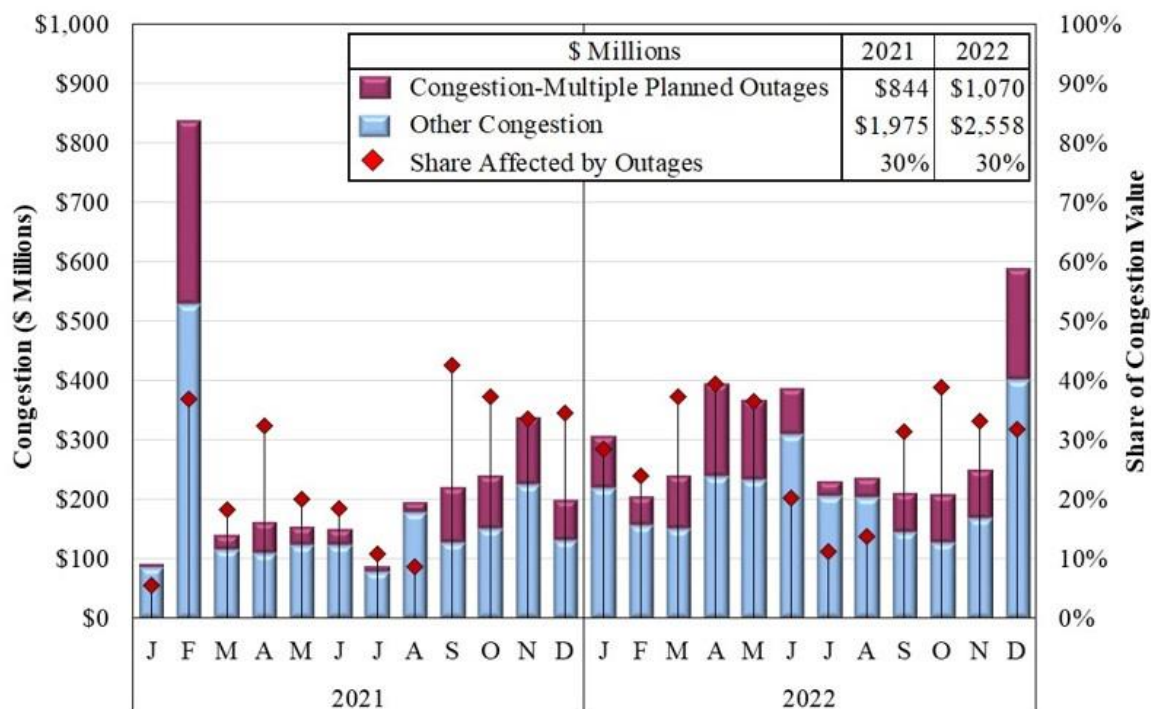
Identification and Implementation of Reliable and Efficient Reconfigurations

Today, transmission flows and congestion are primarily controlled by altering the output of resources in different locations. They can also sometimes be altered by reconfiguring the network (e.g., opening a breaker). This is done on a regular basis by Reliability Coordinators to manage congestion for reliability reasons, normally under the procedures established in Operating Guides in consultation with impacted Transmission Owners (TO).

Figure A85: Impacts of Reconfiguration on Rochester-Wabaco 161 kV Line

A costly constraint exists in MISO that primarily limits the output of wind resources in the North, and it can be reliably managed with a reconfiguration that, when used, reduces the congestion by roughly two-thirds and reduces wind curtailments. Figure A85 shows congestion in real time on the Rochester-Wabaco 161 KV line during selected days in June and July 2021. The maroon-shaded area represents congestion on the Rochester-Wabaco 161 kV line, and the blue-shaded area represents other congestion in the region. The green line, plotted against the right axis, represents flows on Rochester-Wabaco 161 kV after the reconfiguration was made, and the black line indicates the limit of the Rochester-Wabaco 161 kV.

Figure A85: Impacts of Reconfiguration on Rochester-Wabaco 161 kV Line
June - July 2021
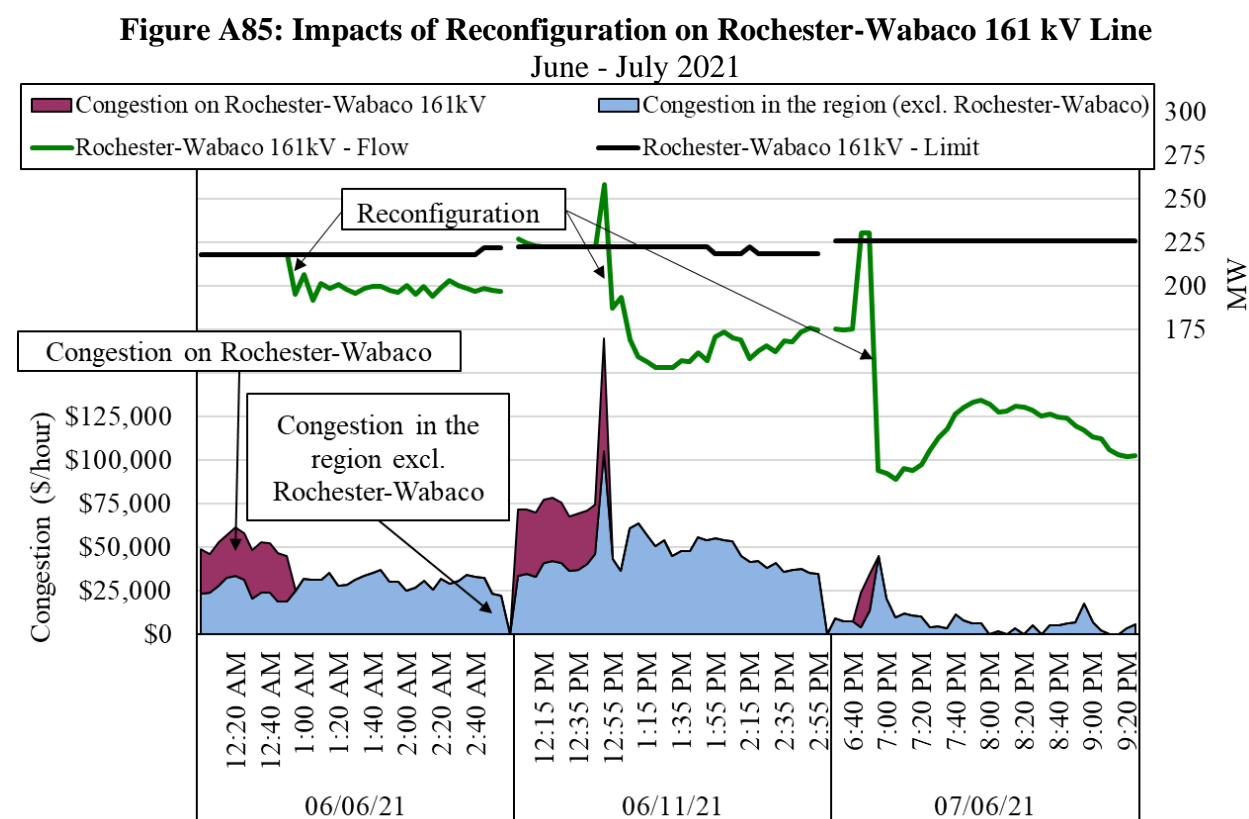
D. Transmission Ratings and Constraint Limits

For most transmission constraints, the ability to flow power through the facility is related to the heat caused by the power flow. When ambient temperatures are cooler than the typical

assumptions used for rating the facilities, additional power flows can be accommodated.[23] Therefore, if transmission owners develop and submit Ambient Adjusted Ratings (AARs) for temperature, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most transmission owners do not currently provide AARs.

For contingency constraints, ratings should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in the short term if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits as called for under the Transmission Owner's Agreement.[24] However, we have identified some transmission owners that provide only normal ratings for most facilities.

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.

Estimated Benefits of Using AARs and Emergency Ratings

The analysis in this section examines the potential value of more fully utilizing the existing transmission network. This value could be realized by operating to higher transmission limits that would result from consistent use of temperature-adjusted, emergency ratings for MISO's transmission facilities.

Figure A86: Potential Value of Additional Transmission Capability

To estimate the congestion savings of using temperature-adjusted ratings, we performed a study using NERC/IEEE estimates of ambient temperature effects on transmission ratings. Using the formulae and data from IEEE Standards (IEEE Std C37.30.1™-2011), we derived ratios of allowable continuous facility current (flow) at prevailing ambient temperatures to the Rated Continuous Current for different classes of transmission elements (e.g., Forced Air-Cooled Transformers and Transmission Lines). We used the most conservative class of permissible ratings increases under the Standard for the type of element (Line or Transformer). We then used the ambient temperatures prevailing in the transmission area to estimate the temperature-adjusted rating. We calculated the value of increasing the transmission limits by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint.

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[23]   In some areas where wind speed is a more important ambient factor than temperature, permissible ratings could be significantly impacted by the measured wind speed. We have not estimated benefits of improved ratings due to wind speed measurements or other factors that if measured could allow for a dynamic increase in ratings.

[24]   The Transmission Owners Agreement calls for transmission owners to submit normal transmission ratings on base (non-contingency) constraints and emergency ratings on contingency constraints ("temporary" flow levels 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 flows that will occur if the contingency happens), it is generally safe to use the emergency ratings.

To estimate the benefits of providing emergency ratings, we identified transmission elements with identical normal and emergency ratings. For these elements, we assumed that the short-term emergency rating would increase by 10 percent. This is a reasonable assumption given that the average emergency ratings, when provided by a transmission owner, are 9 to 17 percent higher for each facility type and voltage class combination.

Figure A86 shows the estimated benefits of increasing the incremental transmission capability that could be made available by consistently utilizing temperature-adjusted emergency ratings. The results are shown by month and region for the last two years.

Figure A86: Potential Value of Additional Transmission Capability
2021–2022

Year	AAR Benefit	Emerg. Benefit	Share of Congestion
2021	$180.7 M	$133.2 M	11.0%
2022	$334. M	$207.8 M	14.9%
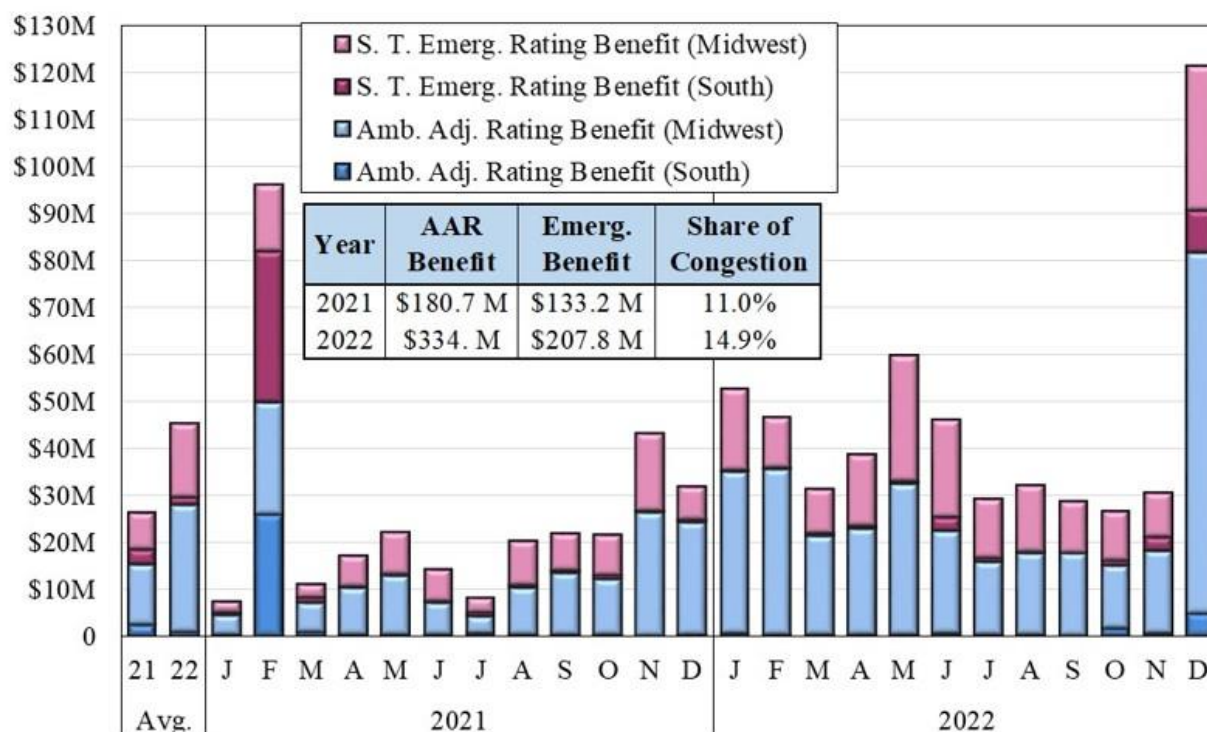
Figure A87: Estimated Actual Savings of AARs

Only two transmission owners currently utilize dynamic or temperature-adjusted ratings on a significant number of transmission facilities. We have estimated the savings that are currently being achieved by these transmission owners because they temperature-adjust a substantial number of their transmission facilities. Neither transmission owner adjusts their ratings on an hourly basis to maximize the benefits, but the benefits are still substantial. Figure A87 summarizes our estimates of the congestion savings by region that have actually been realized from these two transmission owners' use of temperature-adjusted ratings. The congestion savings are calculated as the product of the prevailing shadow price and the difference between the constraint limit (including the temperature adjustment) and the seasonal emergency rating. This methodology is a conservative estimate of savings, given that the shadow price would increase if the market were controlling to a lower, non-adjusted rating.

Figure A87: Estimated Actual Savings of AARs
2021–2022

Total	2021	2022	2021-22
Midwest	$45.2 M	$94.5 M	**$139.7 M**
South	$20.0 M	$13.8 M	**$33.7 M**
Total	$65.1 M	$108.3 M	**$173.4 M**
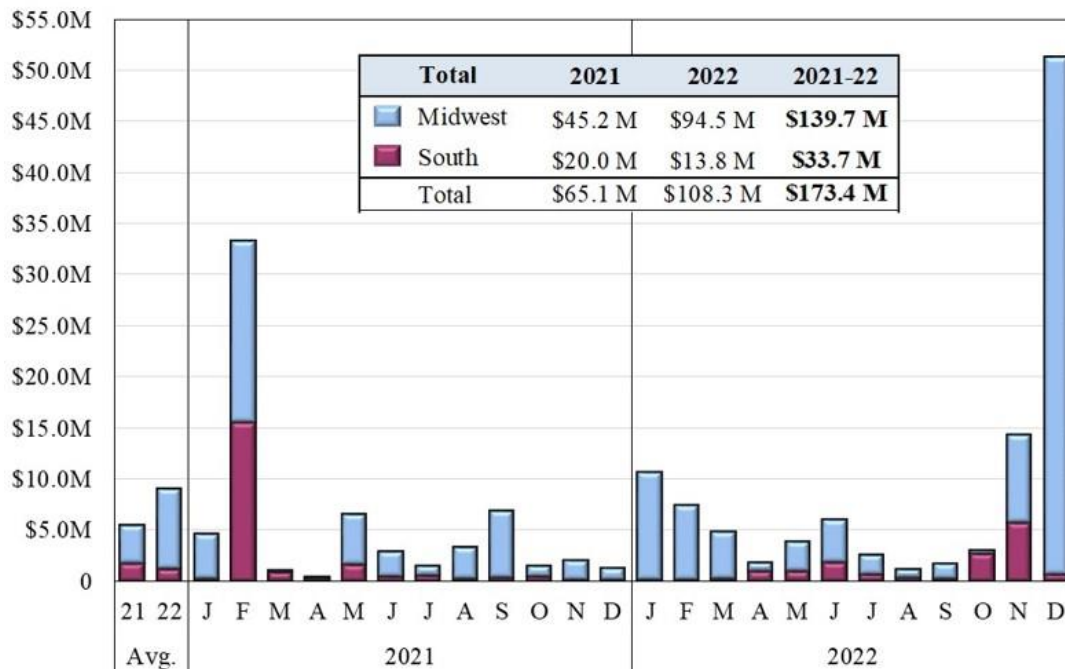
Figure A88: Area-Specific Savings Potential of Ratings Enhancement

Figure A88 organizes the potential savings in the 24 most congested areas in MISO. The bars indicate the relative ambient temperature-adjusted and short-term emergency savings potential in each area. The drop lines show the number of transmission elements that would need to be temperature-adjusted in order to realize two-thirds of the potential benefits in each area.

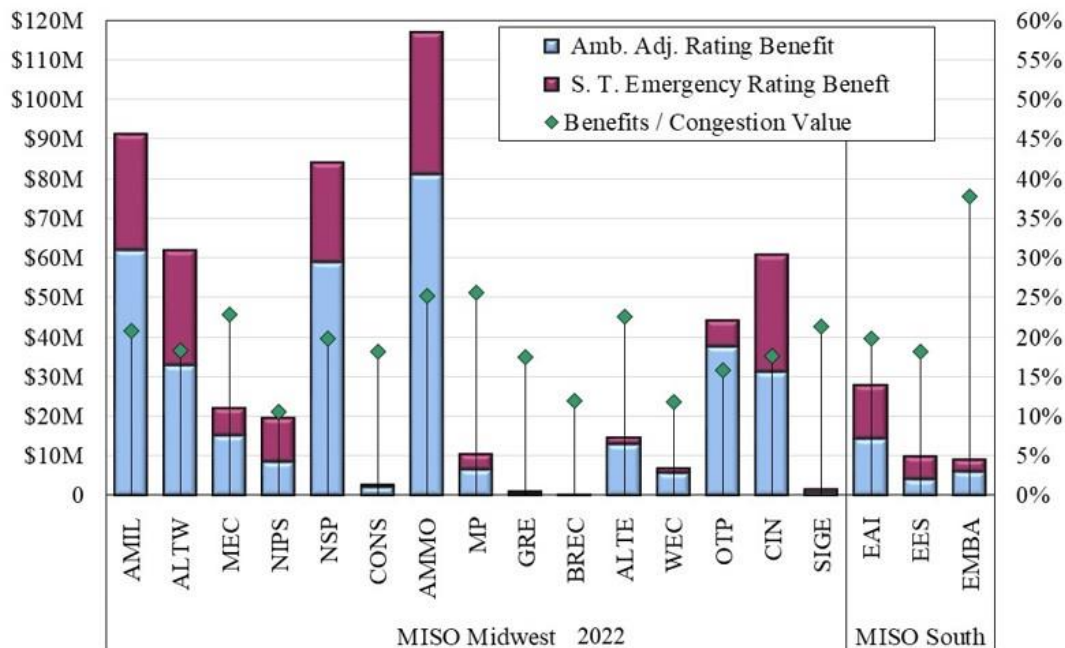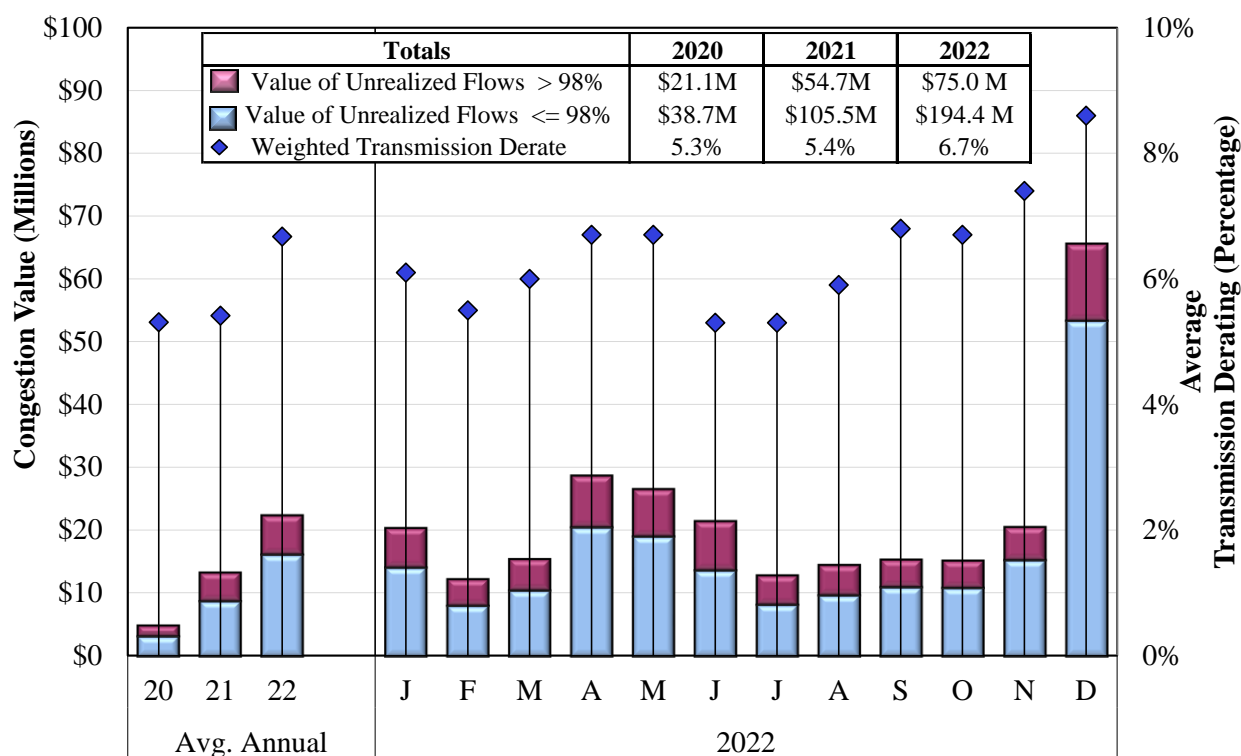**Figure A88: Area-Specific Savings Potential of Ratings Enhancement**

Figure A89: Value of Unrealized Transmission Flows from Limit Control Derates

MISO reduces transmission line limits in real time to manage congestion when certain factors cause uncertainty in transmission flows, including non-conforming load, external loop flows, or wind volatility. MISO's line limit adjustment is referred to as the "limit control." The implication of using lower ratings includes higher production costs.

We conducted an analysis to determine whether MISO has employed more conservative limit control derates on the transmission system compared to prior years. Figure A88 also shows the congestion value of flows on constraints that were associated with those line deratings. The blue and red bars represent the sum of potentially unnecessary congestion costs for those constraints which were derated below the constraints' true capacity. The blue bar value is representative of a subset of constraints that were limited to at or below 98 percent of the true line limit.

The blue bar is calculated by multiplying the difference in the quantity that can flow between 98 percent of the actual line limit and the flow at the limit control value (less than or equal to 98 percent) times the constraint's shadow price. Then each constraint's congestion value is summed over each month to produce the blue bars shown. Similarly, the red bars show the congestion effects of the deratings between 98 and 100 percent of the line rating. The congestion cost was calculated by multiplying the difference in flows between 100 percent and 98 percent of the line limit times the constraint's shadow price, and then subtotaled by month.

Figure A89: Value of Unrealized Transmission Flows from Limit Control Derates

Totals	2020	2021	2022
Value of Unrealized Flows > 98%	$21.1M	$54.7M	$75.0 M
Value of Unrealized Flows <= 98%	$38.7M	$105.5M	$194.4 M
Weighted Transmission Derate	5.3%	5.4%	6.7%

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

The separate JOAs between MISO and PJM and SPP establish M2M processes for coordinating congestion management of designated transmission constraints on each of the RTOs' systems. The objectives of these processes are to pursue reliable congestion management, efficient generation re-dispatch on these constraints, and consistent prices between the markets.

The monitoring RTO (MRTO) is the RTO responsible for the security and monitoring of the physical flow on the flowgate. When a M2M constraint is activated, the MRTO provides its shadow price to the counterparty market along with the requested relief (i.e., the desired reduction in flow). The shadow price measures the MRTO's marginal cost for relieving the constraint. The relief requested varies considerably by constraint and over the coordinated hours for each constraint. The relief request is based on market conditions and is generally automated (although it can be manually selected by Reliability Coordinators). When the non-monitoring RTO (NMRTO) receives the shadow price and requested relief quantity, it uses both values in its real-time market to provide as much of the requested relief as it can at a marginal cost up to the MRTO's shadow price. From a settlement perspective, each market is allocated Firm Flow Entitlement (FFE) on each of the M2M constraints. Settlements between the RTOs are based on their flows over the constraint relative to their FFEs.

Figure A90 and Figure A91: PJM and SPP Market-to-Market Events

Figure A90 and Figure A91 show the total number of M2M constraint-hours coordinated with PJM and SPP, respectively. The top panel shows flowgates coordinated by PJM/SPP, while the bottom panel shows MISO flowgates. The darker-shaded bars show the number of peak hours when M2M flowgates were active. The lighter shade shows the total for off-peak hours.

Figure A90: Market-to-Market Events: MISO and PJM
2021–2022
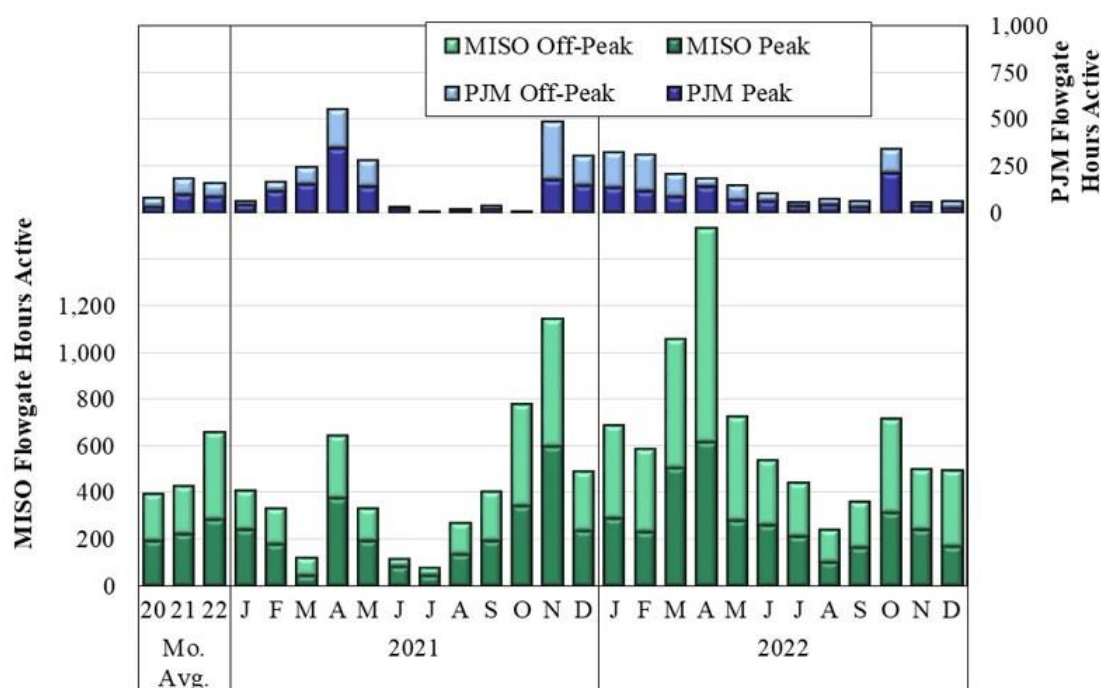
Figure A91: Market-to-Market Events: MISO and SPP
2021–2022
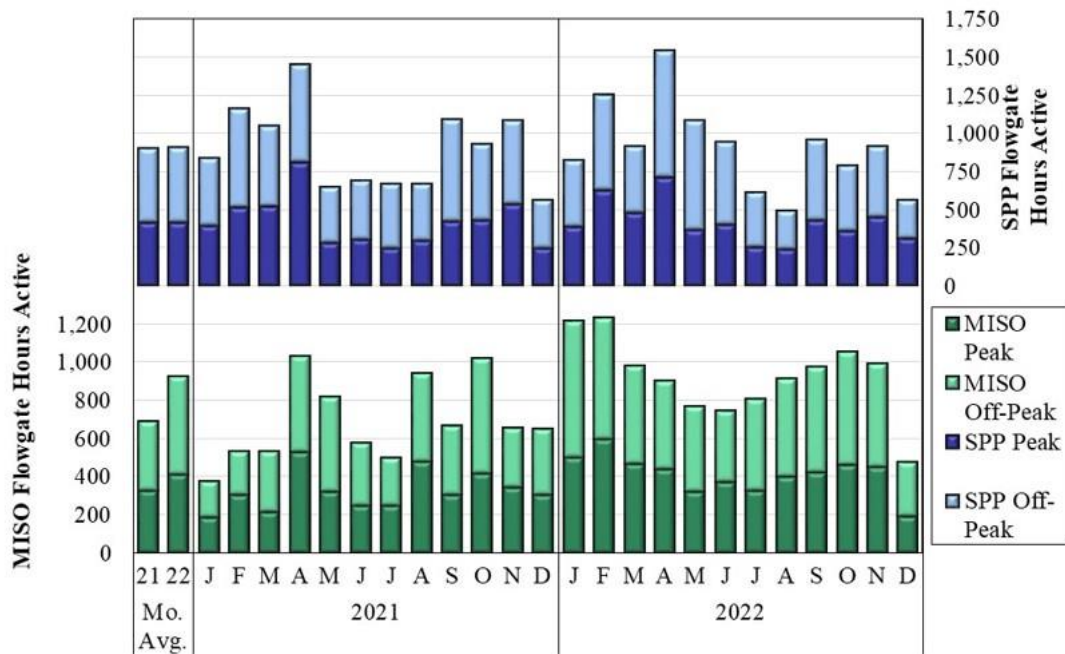
Figure A92: Market-to-Market Settlements

Figure A92 shows MISO's M2M settlements with SPP and PJM. These settlements are based on the NMRTO's market flow relative to its FFE. If the NMRTO's market flow is less than its FFE, then it is paid for its unused entitlement at its cost of providing relief. If the NMRTO's flow exceeds its FFE, then it owes the cost of the MRTO's congestion for each MW of excess flow.

Figure A92: Market-to-Market Settlements
2021–2022
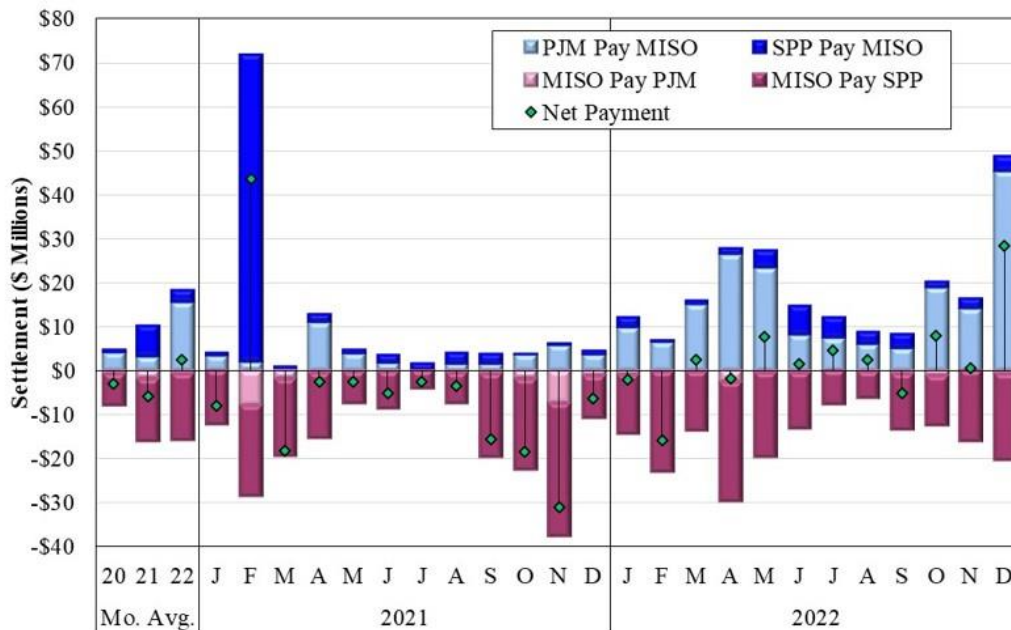
In the figure, positive values represent payments made to MISO on coordinated flowgates and negative values represent payments from MISO to PJM and SPP on coordinated flowgates. The diamond marker shows net payments to or from MISO in each month.

Table A15: Real-Time Congestion on Constraints Affected by Market-to-Market Issues

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 after the M2M process is initiated.

Convergence is much less reliable in the day-ahead market, but MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016. The RTOs have not actively utilized this process, so it has not had substantial effects. However, we will continue to evaluate the effectiveness of this process in improving day-ahead market outcomes. SPP has not agreed to implement a similar day-ahead coordination procedure.

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

- Failure to test constraints that would likely qualify to be M2M constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as M2M; and
- Delays in activating M2M constraints when they are binding.

These issues can result in a failure to coordinate M2M congestion, causing inefficient dispatch and inappropriately high congestion costs. Serious equity concerns can also arise if the external area exceeds its flow entitlement on the constraint without compensating the MRTO. Hence, we identify constraints that were not coordinated because of these issues. These screens identified 58 non-M2M constraints that should have been coordinated as M2M with either PJM or SPP in 2022, down from 75 in 2021. We then quantified the congestion on these constraints, which is shown in Table A15.

Our screening accounts for the time required to identify, test, and activate a M2M:

- *Never Classified as M2M.* Most of these constraints were not classified because testing was not requested by MISO. To account for transitory constraints that would not warrant testing, we exclude constraints that only bound on one day during the year.
- *Delay in Testing.* We removed the first two days a constraint bound in real time to account for the expected time it takes to perform the tests.
- *Delay in Activation.* We did not remove any days if the constraint had been previously identified as M2M.

Table A15: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2020–2022

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

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

Figure A93: Congestion Costs on PJM and SPP Flowgates

Because MISO market flows comprise a small share of their physical capability, external M2M constraints account for a small share of congestion value in MISO's market. However, these external constraints do have significant impacts on locational pricing and market revenues for MISO generators. Figure A93 details the contribution to congestion pricing in MISO markets associated with SPP and PJM transmission constraints. The figure shows the total share of the locational congestion prices in MISO's LMPs that are attributable to PJM and SPP constraints coordinated through the M2M process.

The pricing effects in the figure are sub-divided into conventional and non-conventional M2M procedures (i.e., using overrides, safe operating modes, TLRs, or other processes to manage the congestion). Although often justified, these non-conventional means are generally less efficient and lead to higher congestion costs, so it is valuable to understand the extent to which they are being utilized.

Figure A93: Congestion Costs on PJM and SPP Flowgates
2022
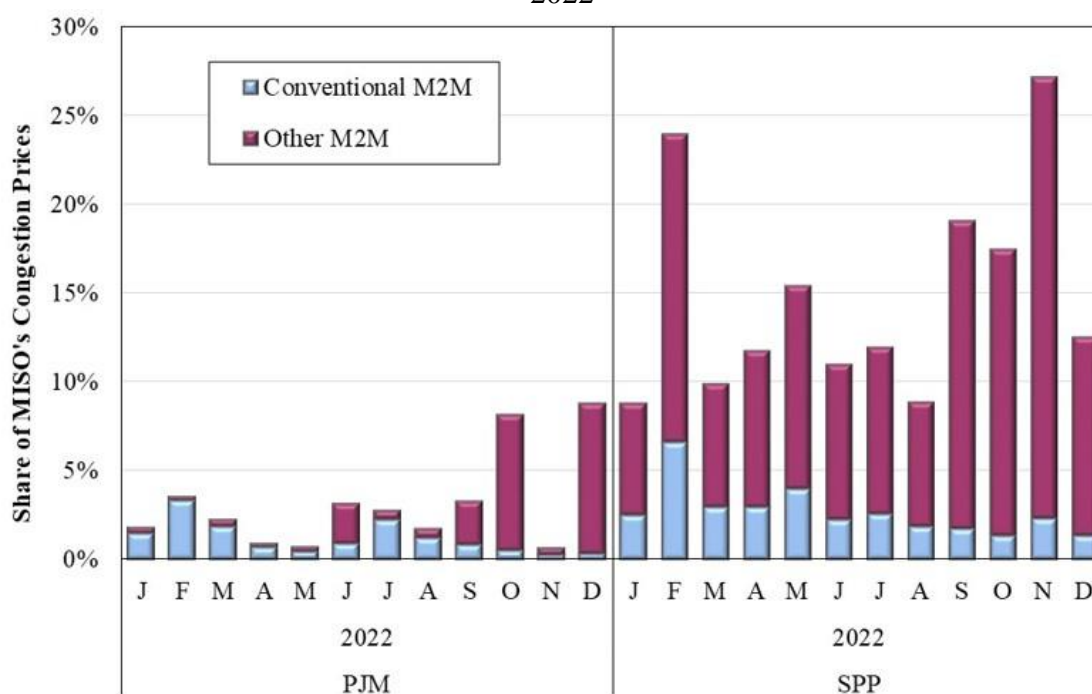
Market-to-Market Test Criteria Software

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 five 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.

Figure A94: Share of the Relief from the MRTO

Figure A94 evaluates the effectiveness of the coordination process by showing 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.[25] The size of the bubbles indicates the amount of congestion associated with each constraint, and the colors separately identify MISO and SPP constraints. Perfect convergence would cause the data points to lie on the dashed 45-degree line. Even if the observations fall on this line, convergence may still be poor during some events or periods. When both percentages are high, the value of coordinating the constraint is limited because the NMRTO has a small share of the relief capability.

Figure A94: Share of the Relief from the MRTO

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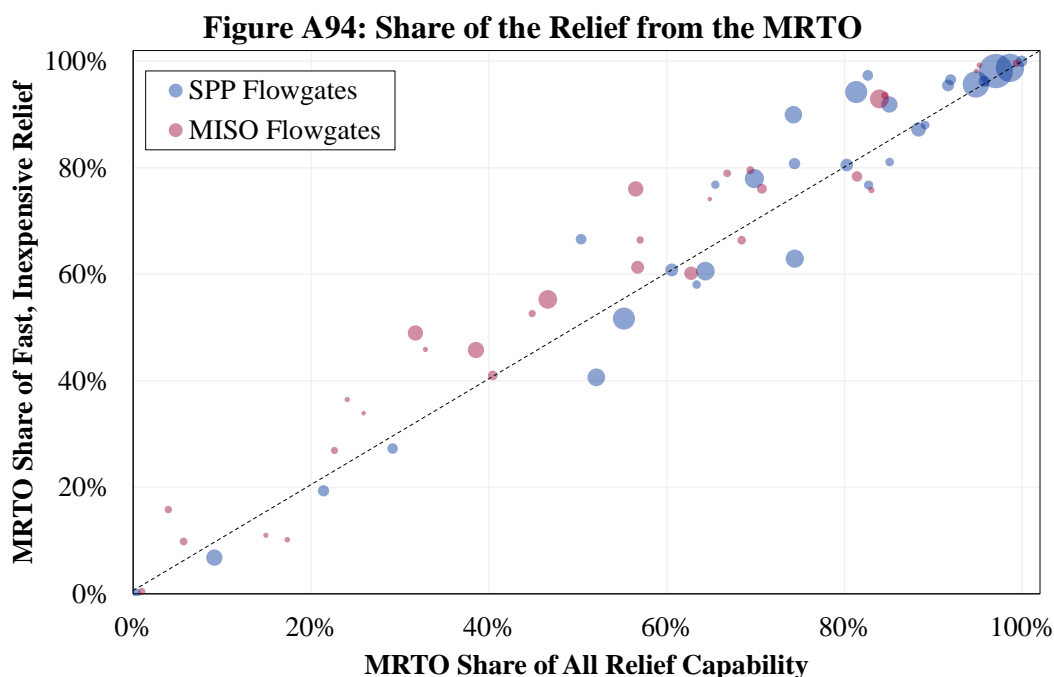
[25]   Economic relief is any relief that could be provided within five-minutes with a cost of less than to $200/MW.

Figure A95: Production Cost Savings and Relief Distribution

To evaluate the value of these constraints being coordinated, Figure A95 shows the relationship between the MRTO's relief capability (as it rises to 100 percent, the NMRTO relief falls to 0 percent) and the production cost savings of coordinating the constraint. As before, the size of the bubbles indicates the amount of congestion associated with each constraint, and the colors separately identify MISO and SPP constraints.

Figure A95: Production Cost Savings and Relief Distribution
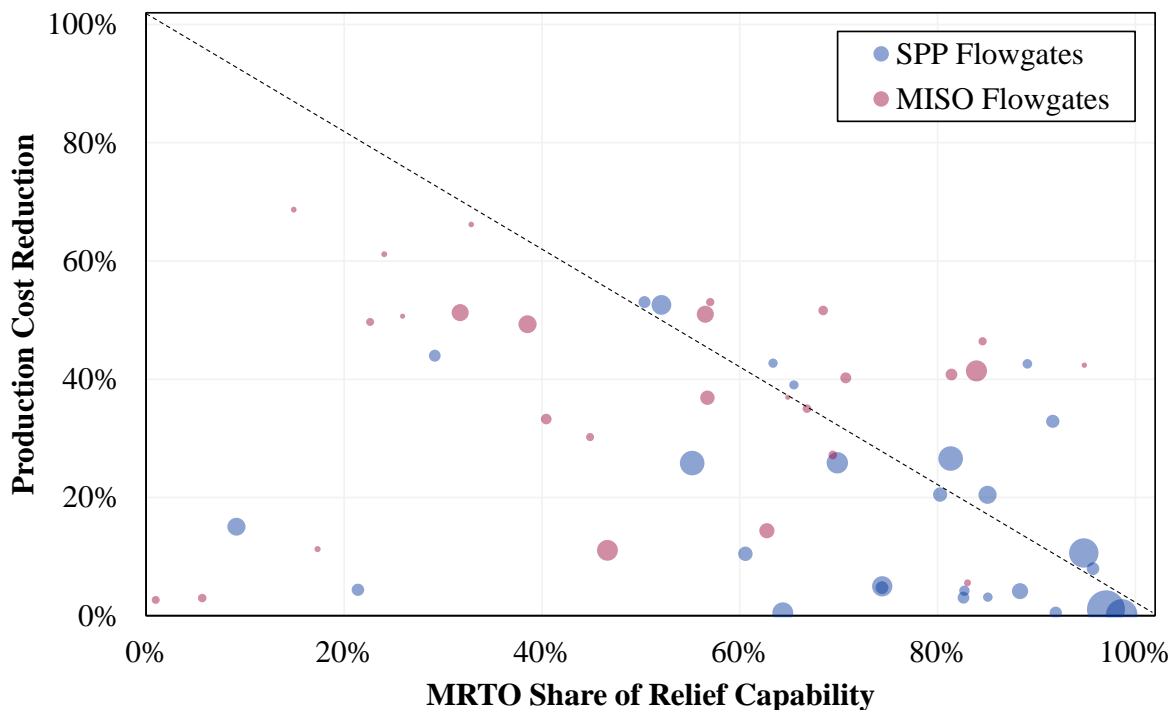
F. Congestion on Other External Constraints

This subsection provides an analysis of congestion that occurs on external constraints located in adjacent systems that are not coordinated through the M2M processes. MISO incurs congestion on external constraints when a neighboring system calls a TLR for a constraint. When this occurs, MISO activates the constraint as it would an internal constraint, seeking to reduce its flow over the constraint by the amount of the required relief. To provide the requested relief, MISO calculates its market flows before the TLR is called and sets a limit equal to the market flows less the requested relief. This process will be efficient only if the cost of providing the relief is less costly than the other system's cost to manage the flow on the constraint. Unfortunately, this has historically not been true. One concern is that the relief obligations are based on its forward flows, not MISO's net flows that may be lower than the forward flows because of counterflow on the constraint. Because the relief obligation may be outsized, it is often very costly to provide the relief, and MISO's marginal cost of providing the relief is included in its LMPs.

Figure A96: Real-Time Valuation Effect of TLR Constraints

Because external constraints can cause substantial changes in LMPs in MISO, we estimate these effects by calculating the increase in real-time payments by loads and the reduction in payments to generators caused by the external constraints.[26] Figure A96 shows increases and decreases in hourly revenues that result from binding TLR constraints. The reported congestion value for these constraints is low because MISO's market flow on external flowgates is generally low or negative. Therefore, the reported congestion value masks the larger impact that these constraints have on MISO's dispatch and pricing.

Figure A96: Real-Time Valuation Effect of TLR Constraints
2021–2022
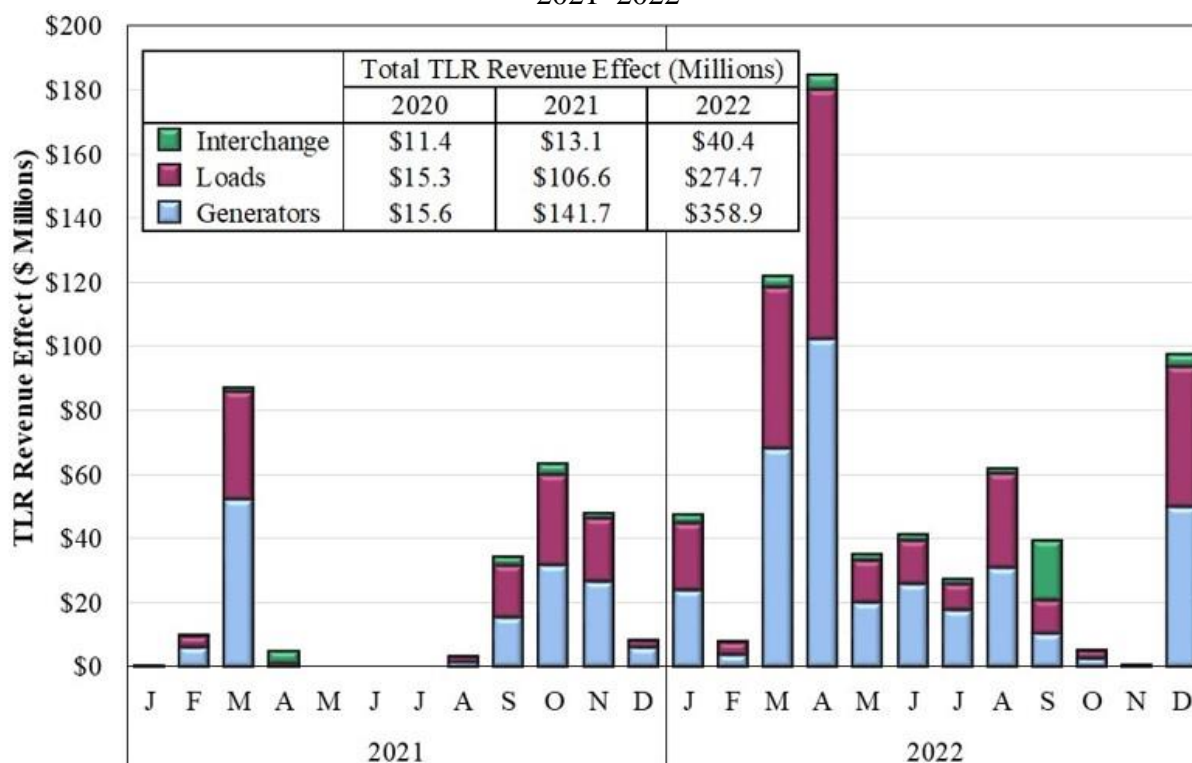
With the exception of M2M coordination between MISO and PJM, MISO and SPP, and NYISO and PJM, Reliability Coordinators in the Eastern Interconnect continue to rely on TLR procedures and the North American Electric Reliability (NERC) Interchange Distribution Calculator (IDC)[27] to manage congestion caused in part by schedules and the dispatch activity of external entities.

Before energy markets were introduced in 2005, nearly all congestion management for MISO transmission facilities was accomplished through the TLR process. TLR is an Eastern

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26   External constraints also affect interface prices settlements, an issue that is further evaluated in Section VII.C.

27   To implement TLR procedures on defined flowgates, Reliability Coordinators depend upon the IDC. The IDC provides Reliability Coordinators with the amount of relief available from curtailment of physical transactions. In addition, MISO, PJM, and SPP provide their market flow impacts to the IDC for Reliability Coordinators to use in the TLR process.

Interconnection-wide process that allows Reliability Coordinators to obtain relief from external entities that have scheduled transactions that load the constraint. When an external, non-M2M constraint is binding and a TLR is called, MISO receives a relief obligation from the IDC. MISO responds by activating the external constraint so that the real-time dispatch model will re-dispatch its resources to reduce MISO's market flows over the constrained transmission facility by the amount requested.

External entities not dispatched by MISO also contribute to total flows on MISO flowgates. If external transactions contribute more than five percent of the total flow on a MISO binding facility, MISO can invoke a TLR to ensure that these transactions are curtailed to reduce the flow over the constrained facility.

When compared to economic generation dispatch through LMP markets, the TLR process is an inefficient and rudimentary means to manage congestion. TLR provides less timely and less certain control of power flows over the system. We have found in prior studies that the TLR process resulted in approximately three times more curtailments on average than would be required by economic re-dispatch.

Table A16: Economic Relief from TVA and AECI Generators on MISO Constraints

Table A16 illustrates the potential savings that could be achieved by utilizing TVA and AECI generation to provide lower cost relief on constraints binding in MISO. Our analysis focuses on economic relief on MISO's internal constraints.

The purpose of this analysis is to quantify the potential value of a joint operating agreement to coordinate economic congestion management with TVA. The left column indicates the value of real-time congestion in cases where economic relief is available from TVA and AECI, while the right column shows the potential savings available through economic coordination.

Table A16: Economic Relief from TVA and AECI Generators on MISO Constraints
2022

	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
TVA Generators	$713.4 M	$25.6 M
AECI Generators	$697.7 M	$72.2 M
Total*	**$964.8 M**	**$86.6 M**

* Total represents the total impact of TVA generators that includes AECI generators, avoiding any double counting.

G.   Congestion Manageability

MISO uses its real-time market model to maintain flow on each activated constraint at or below the operating limit while minimizing total production cost. As flow over a constraint approaches

its limit, the constraint is activated in the market model. This causes MISO's energy market to alter the dispatch of generation that affects the transmission constraint as determined by their Generation Shift Factors (GSFs).[28]

While this is intended to reduce the flow on the constraint, some constraints can be difficult to manage if the available relief from generating resources is limited. The available relief is reduced when the most effective generators: (a) are not online; or (b) have inflexible operating parameters (lower than actual physical capabilities).

When available relief capability is insufficient to control the flow over the transmission line in the next five-minute interval, we refer to the constraint as "unmanageable". The presence of an unmanageable constraint does not mean the system is unreliable because MISO's performance criteria allow for 20 minutes to restore control on most constraints. If control is not restored within 30 minutes, a reporting criterion is triggered. Constraints most critical to system reliability (e.g., those that could lead to cascading outages) are operated more conservatively.

Figure A97: Constraint Manageability

The next set of figures depicts the manageability of internal and MISO-managed M2M constraints. Figure A97 shows how frequently-binding constraints were manageable and unmanageable in each month from 2021 to 2022.

Figure A97: Constraint Manageability
2021–2022

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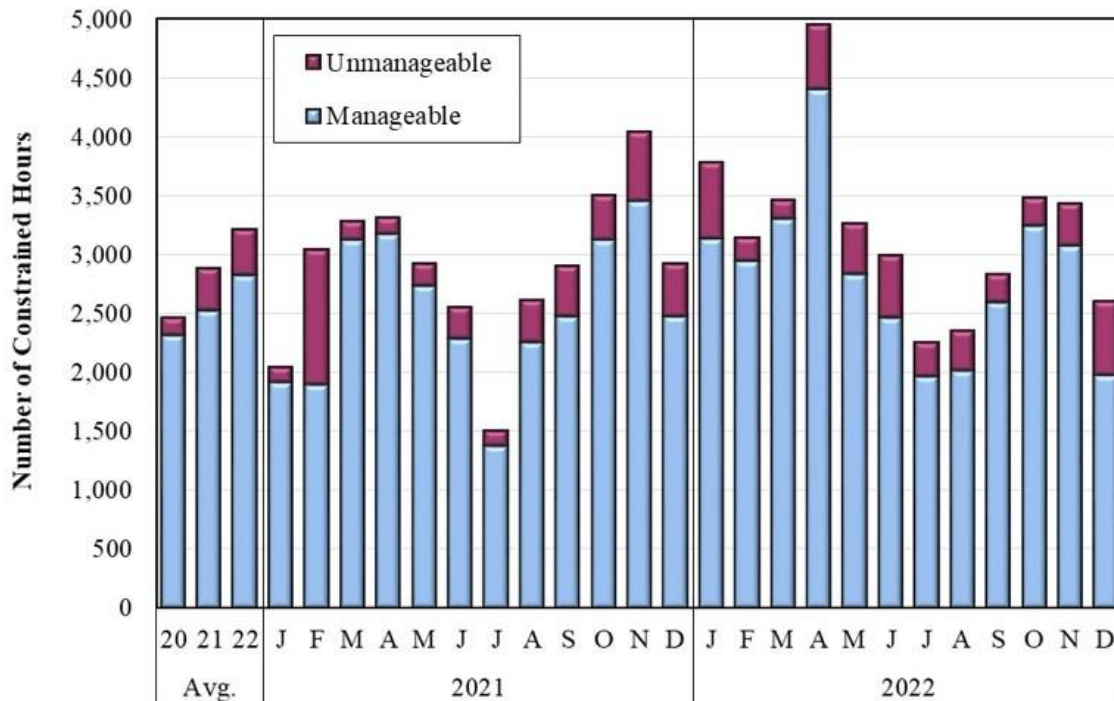
[28] GSFs are the share of flow from a generator that will flow over a particular constraint. A negative shift factor means the flow is providing relief (or "counter-flow") in the direction the constraint is defined, and a positive shift factor means flow is in the direction of the constraint.

Figure A98: Real-Time Congestion Value by Voltage Level

Given the frequency that constraints are unmanageable, it is critical that unmanageable congestion be priced efficiently and reflected in MISO's LMPs. The real-time market model utilizes Transmission Constraint Demand Curves (TCDCs) that cap the marginal cost (shadow price) that the energy market will incur to reduce constraint flows to their limits. These TCDCs set the shadow price and, thus, the congestion component of the LMPs at all locations affected by the violated constraints. Hence, efficient market performance requires the TCDC to reflect the reliability cost of violating the constraint.

Figure A98 examines manageability of constraints by voltage level. Given the physical properties of electricity, more power flows over higher-voltage facilities. This characteristic causes resources and loads over a wide geographic area to affect higher-voltage constraints. Conversely, low-voltage constraints typically must be managed with a smaller set of more localized resources. As a result, these facilities are often more difficult to manage.

Figure A98 separately shows the value of real-time congestion on constraints that are not in violation (i.e., "manageable"), the congestion that is priced when constraints are in violation (i.e., "unmanageable"), and the congestion that is not priced when constraints are in violation. The unpriced congestion is based on the difference between the full reliability value of the constraint (i.e., the TCDC) and the relaxed shadow price used to calculate prices.[29]

Figure A98: Real-Time Congestion Value by Voltage Level
2020–2022

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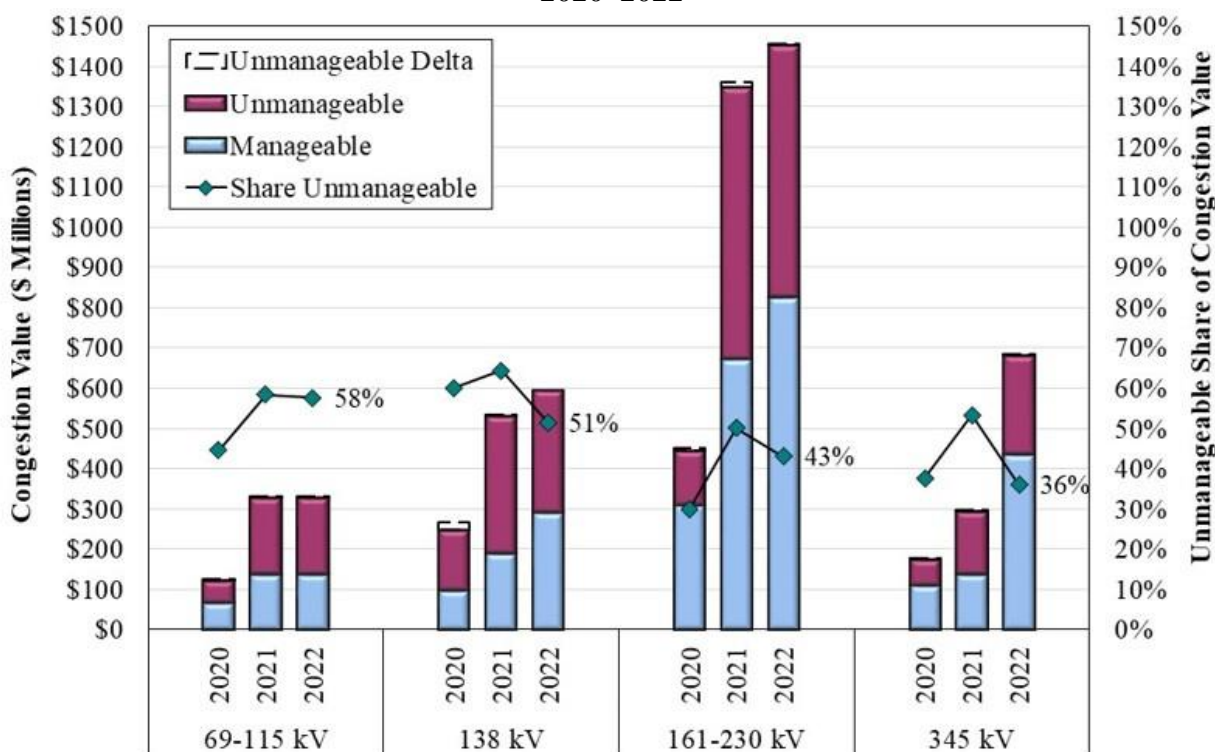
[29]   This figure excludes some less common voltages, such as 120 and 500 kV, and about six percent of total congestion value due to constraints that could not be classified according to voltage class.

H.   FTR Market Performance

Because an FTR represents a forward purchase of day-ahead congestion costs, FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion. When this occurs, FTR profits are low because the profits equal the FTR price minus the day-ahead congestion payments. 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 much lower than the values established in the FTR markets. MISO currently runs the FTR market in two timeframes: an annual auction for the June to May planning year and the MPMA for the current and future months. The MPMA facilitates FTR trading for future months or seasons remaining in the planning year. Residual transmission capacity not sold in the seasonal auction is sold in the monthly auctions. Additionally, MISO facilitates bilateral FTR trades in the monthly FTR auctions.

Figure A99: FTR Profits and Profitability

Figure A99 shows our evaluation of the profitability of these auctions by presenting the seasonal profits for FTRs sold in each market. The values are calculated seasonally even though the FTRs are sold for durations of one year, one season, or one month. The "Monthly" values shown in this figure are the prompt month in the MPMA, while the "MPMA" values are for future months and seasons remaining in the planning year.

Figure A99: FTR Profits and Profitability
2021–2022
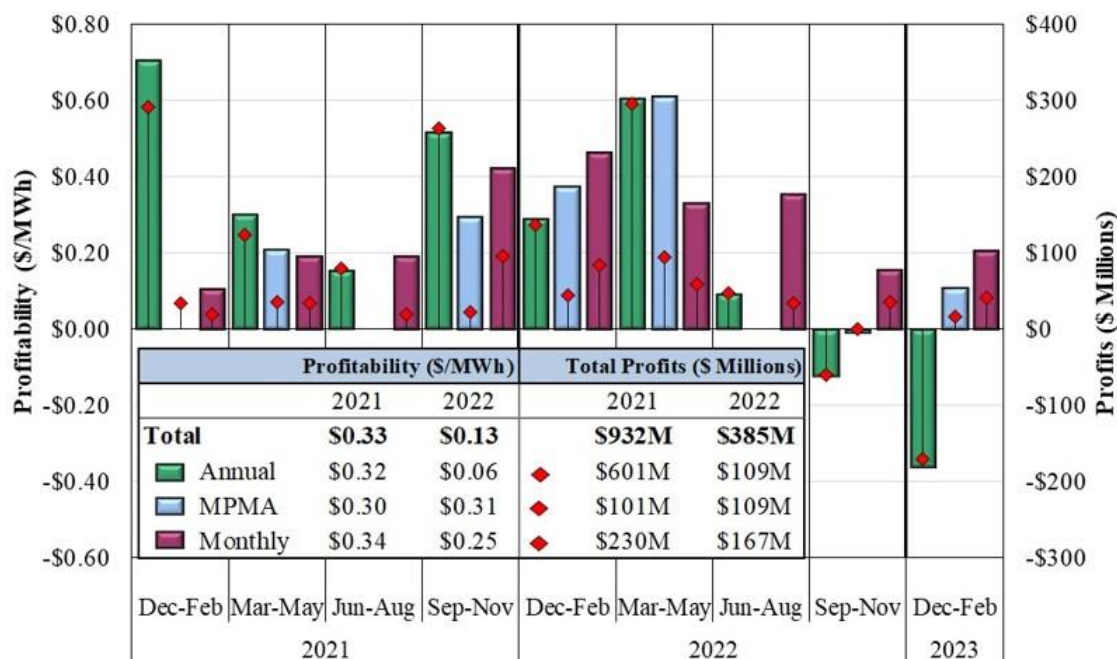
Figure A100 to Figure A102: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly auctions for 2020 to 2022. The bottom panels show the total profits and losses, while

the top panel shows the profits and losses per MWh. The results include FTRs sold and purchased. FTRs sold are netted against FTRs purchased. For example, if an FTR purchased in round one of the annual auction is sold in round two, the purchase and sale would net to zero.

Figure A100: FTR Profitability
2020–2022: Annual Auction
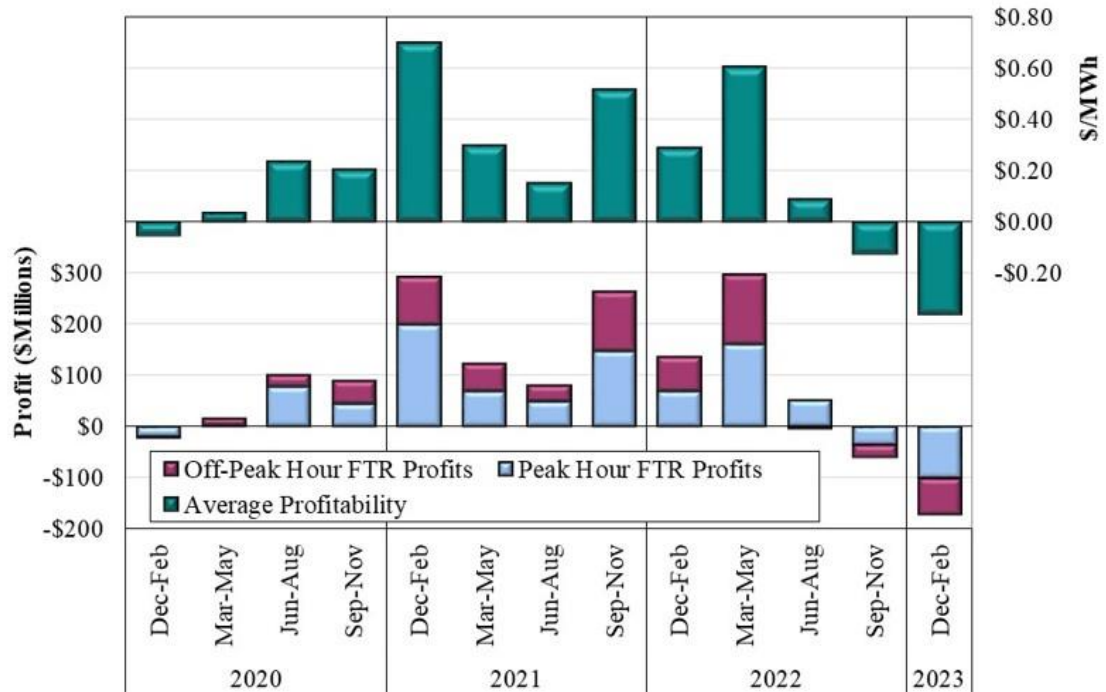
Figure A101: FTR Profitability
2021–2022: Monthly Auction
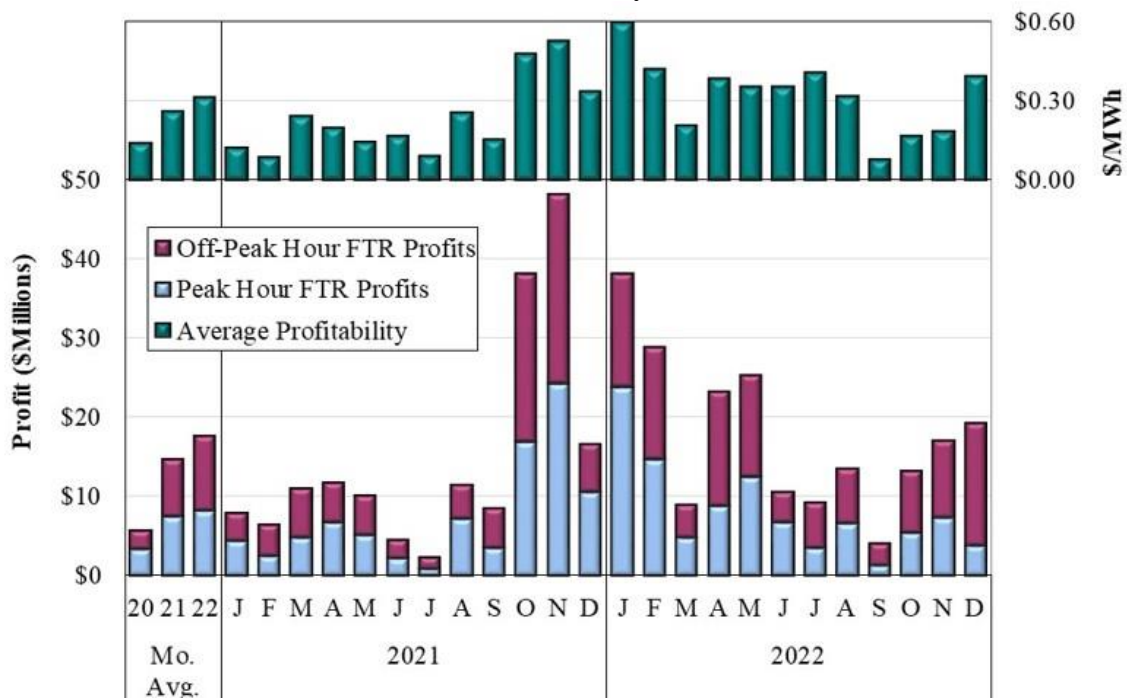
Figure A102: FTR Profitability
2020–2022 Seasonal Auction MPMA
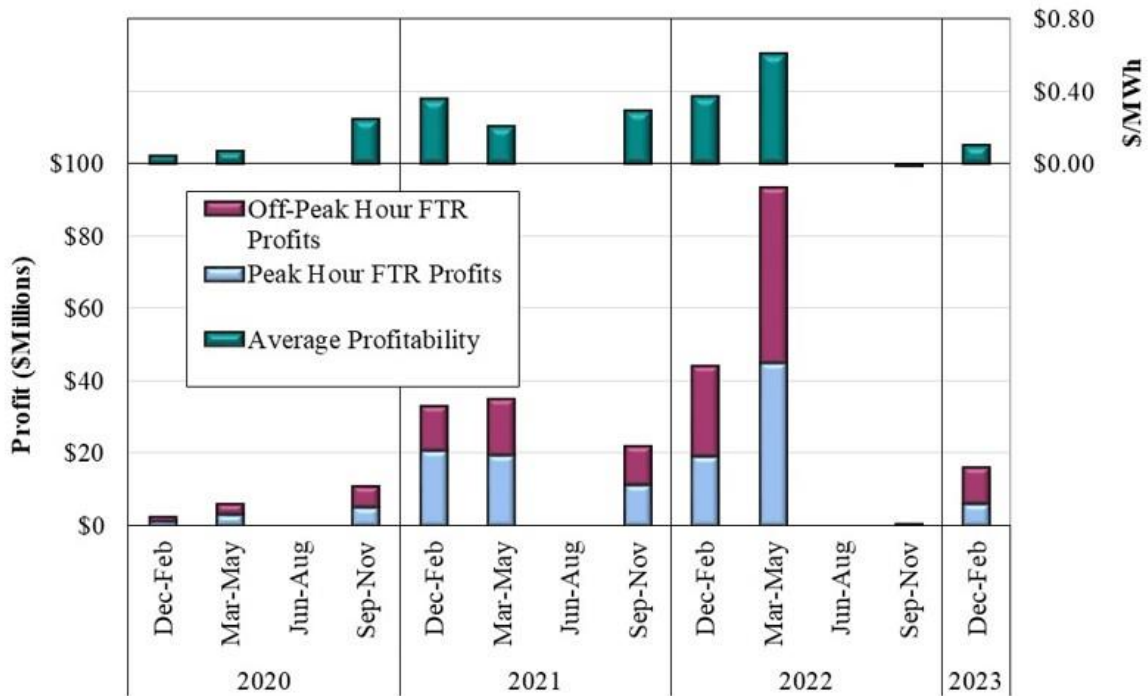
Figure A103 to Figure A114: Comparison of FTR Auction Prices and Congestion Values

The next 12 figures compare monthly FTR auction revenues to the day-ahead FTR obligations at four locations in the Midwest and three locations in the South in peak and off-peak hours.

Figure A103: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2021–2022: Off-Peak Hours
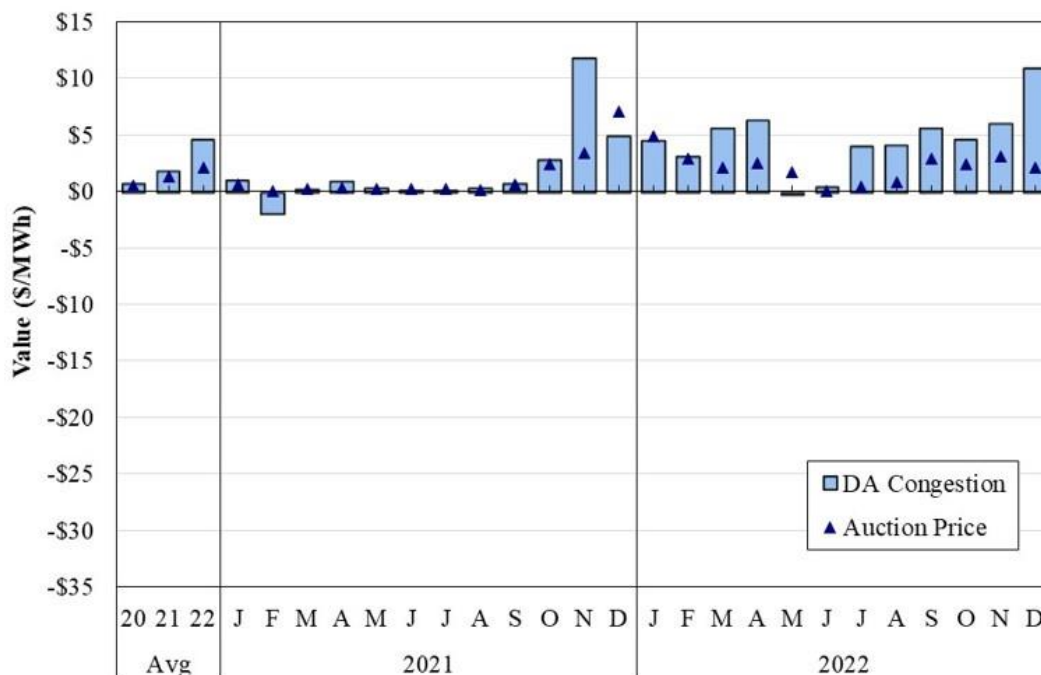
Figure A104: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2021–2022: Peak Hours
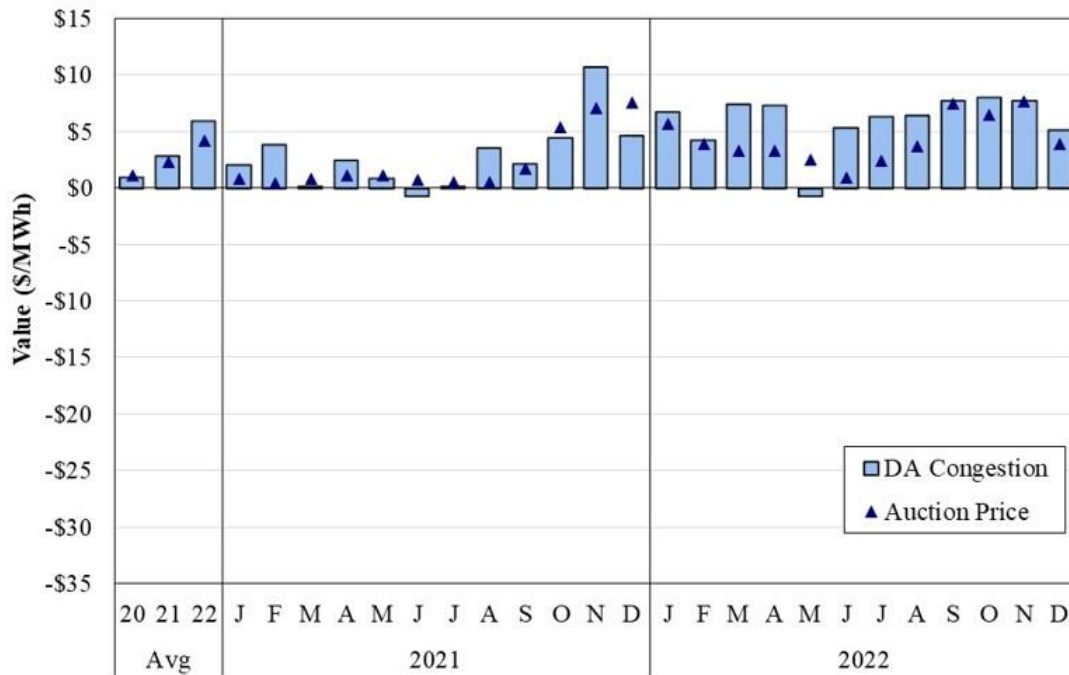
Figure A105: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2021–2022: Off-Peak Hours
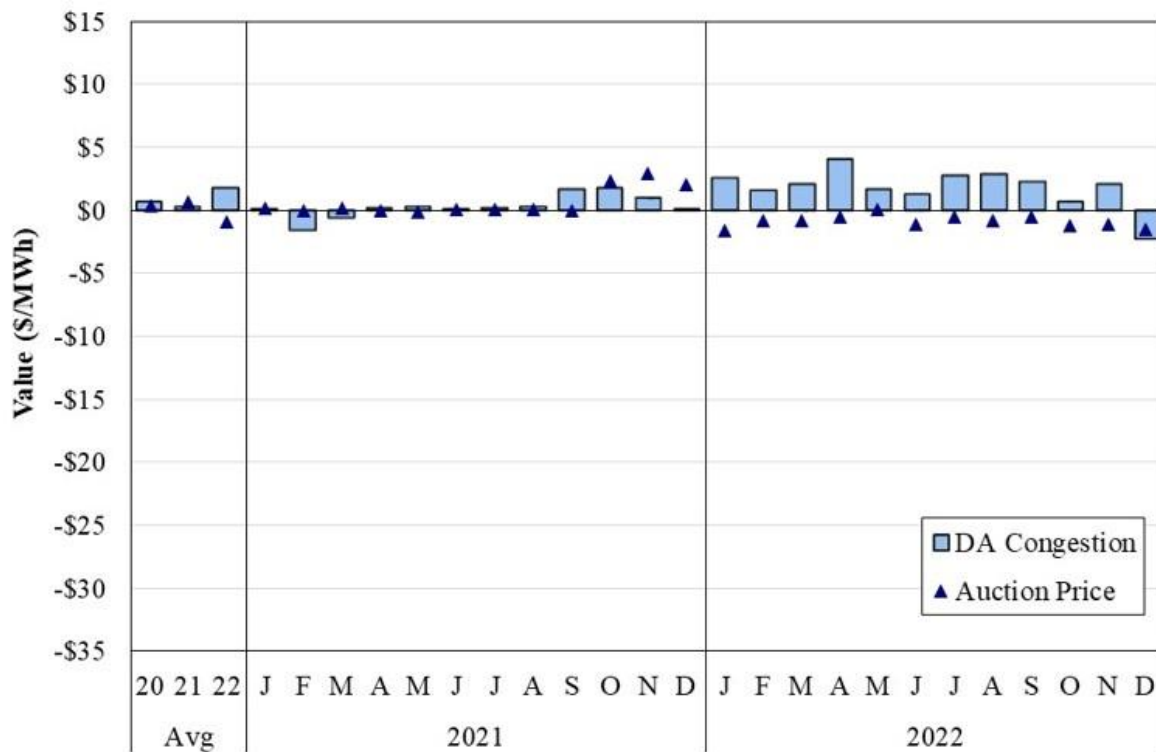
Figure A106: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2021–2022: Peak Hours
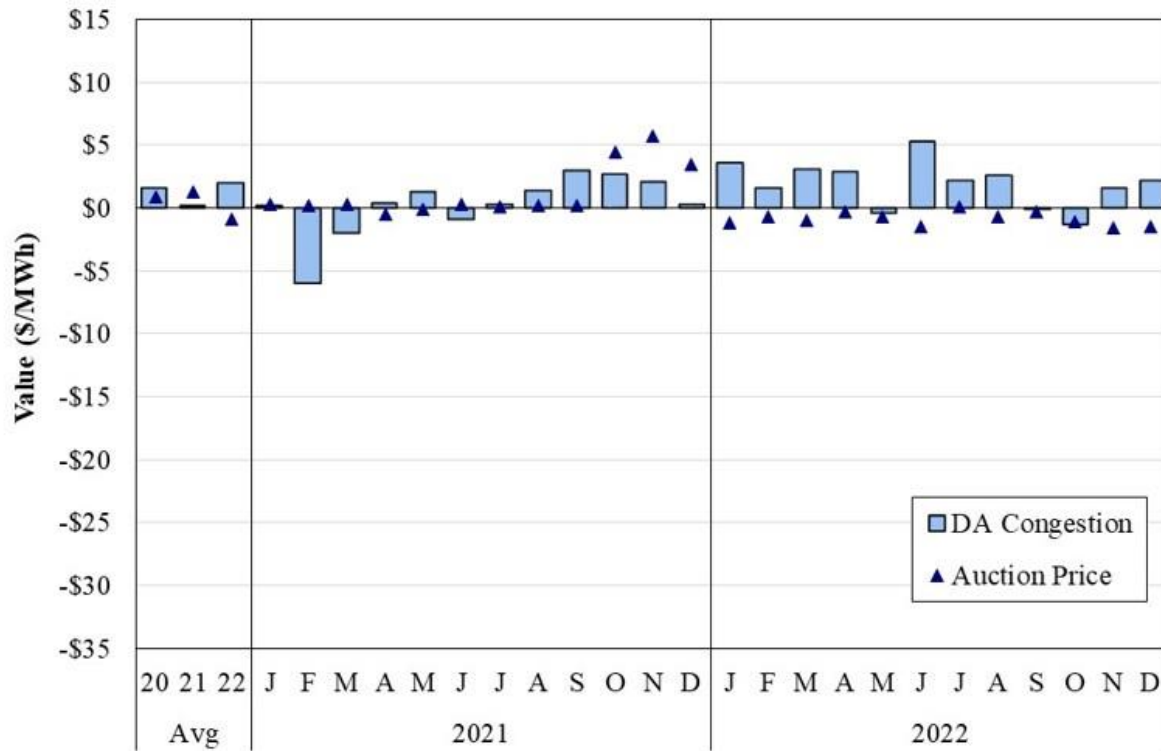
Figure A107: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2021–2022: Off-Peak Hours
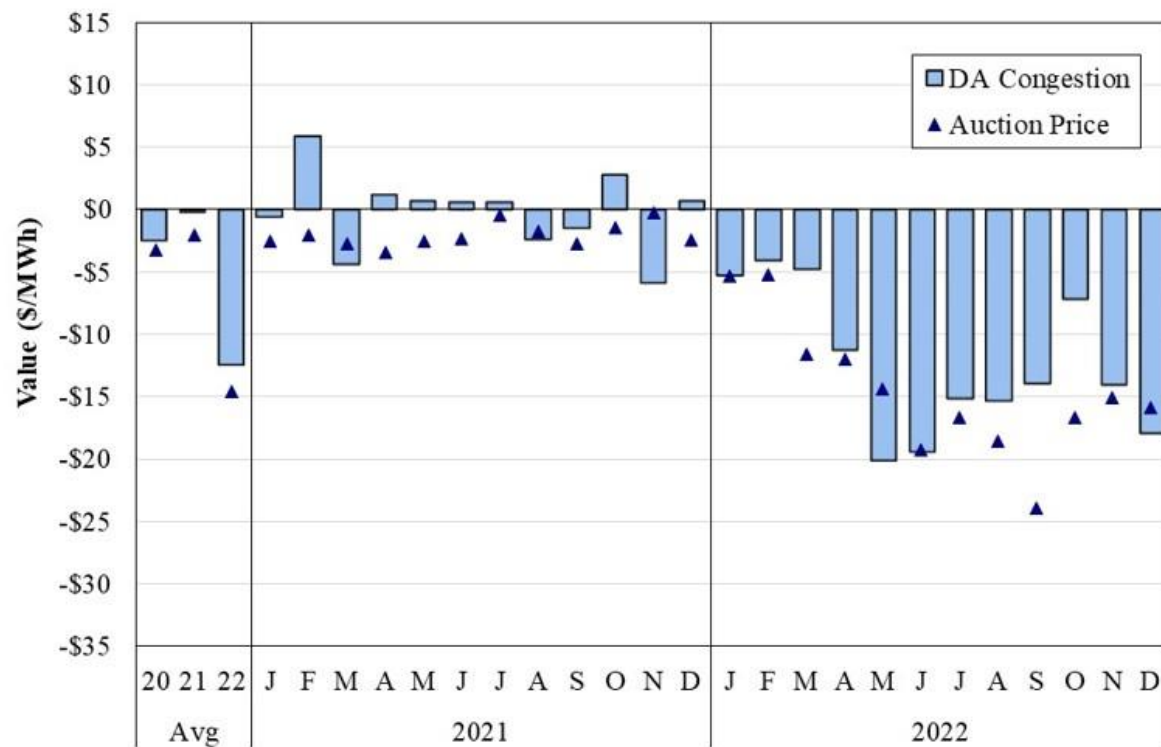
Figure A108: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2021–2022: Peak Hours
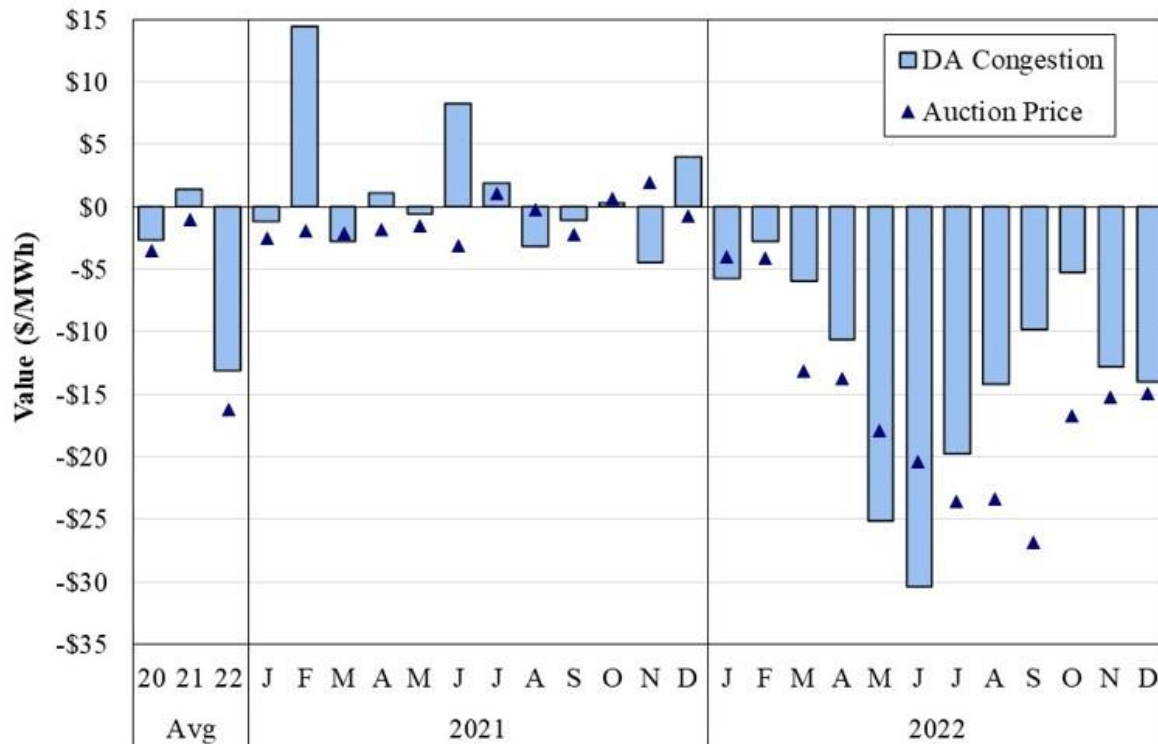
Figure A109: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2021–2022: Off-Peak Hours
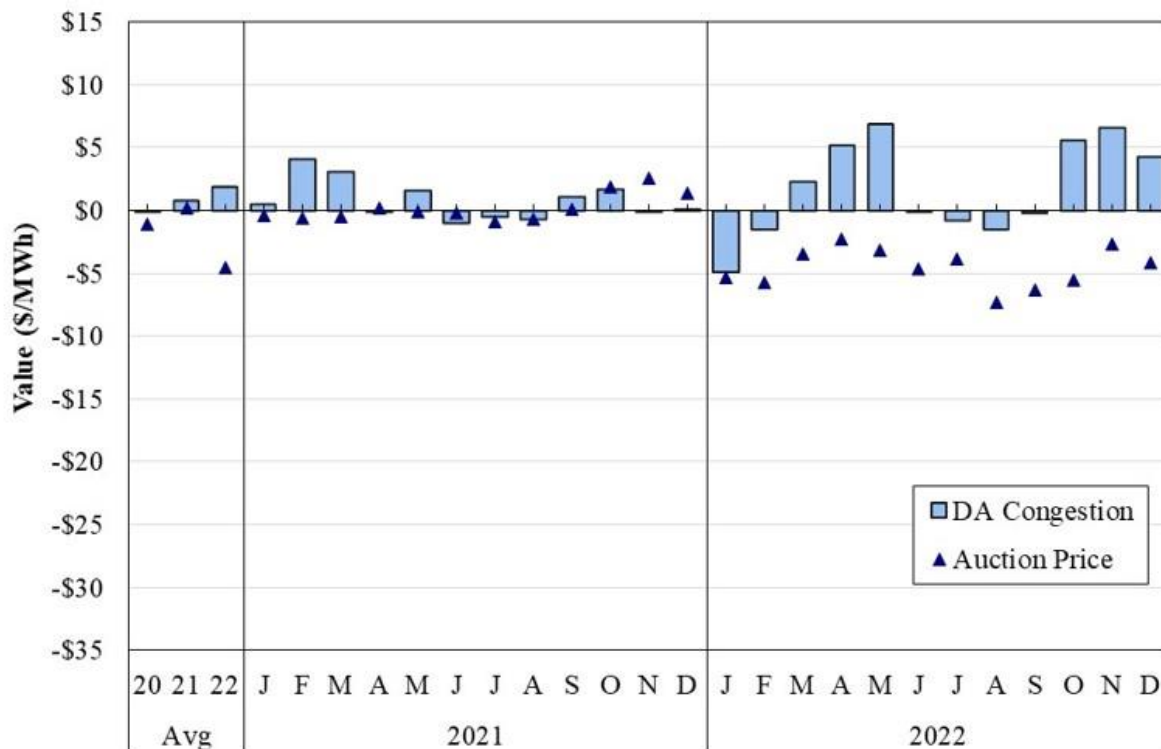
Figure A110: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2021–2022: Peak Hours
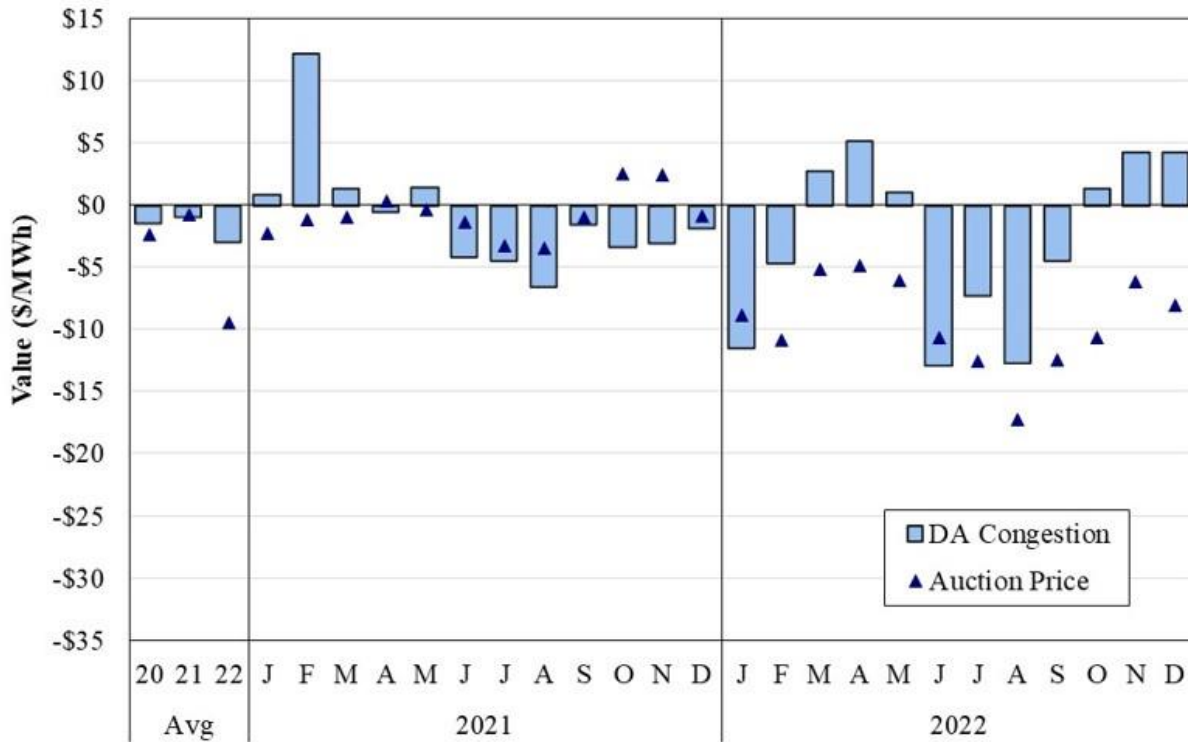
Figure A111: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2021–2022: Off-Peak Hours
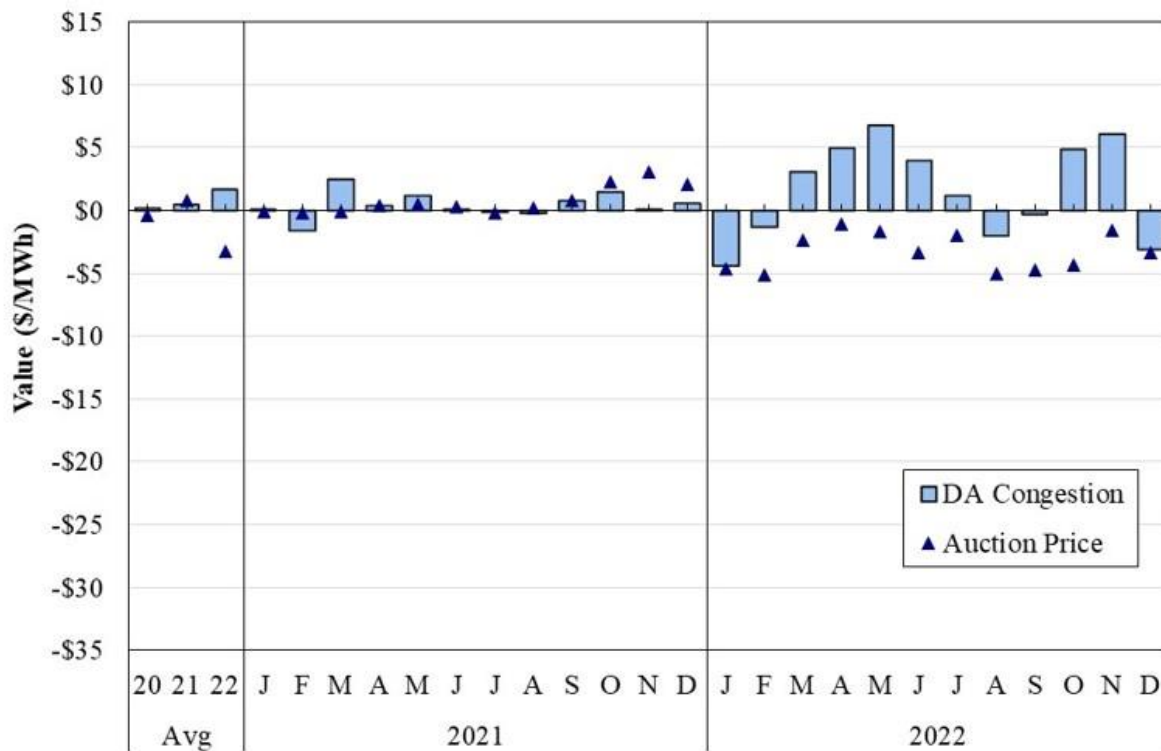
Figure A112: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2021–2022: Peak Hours
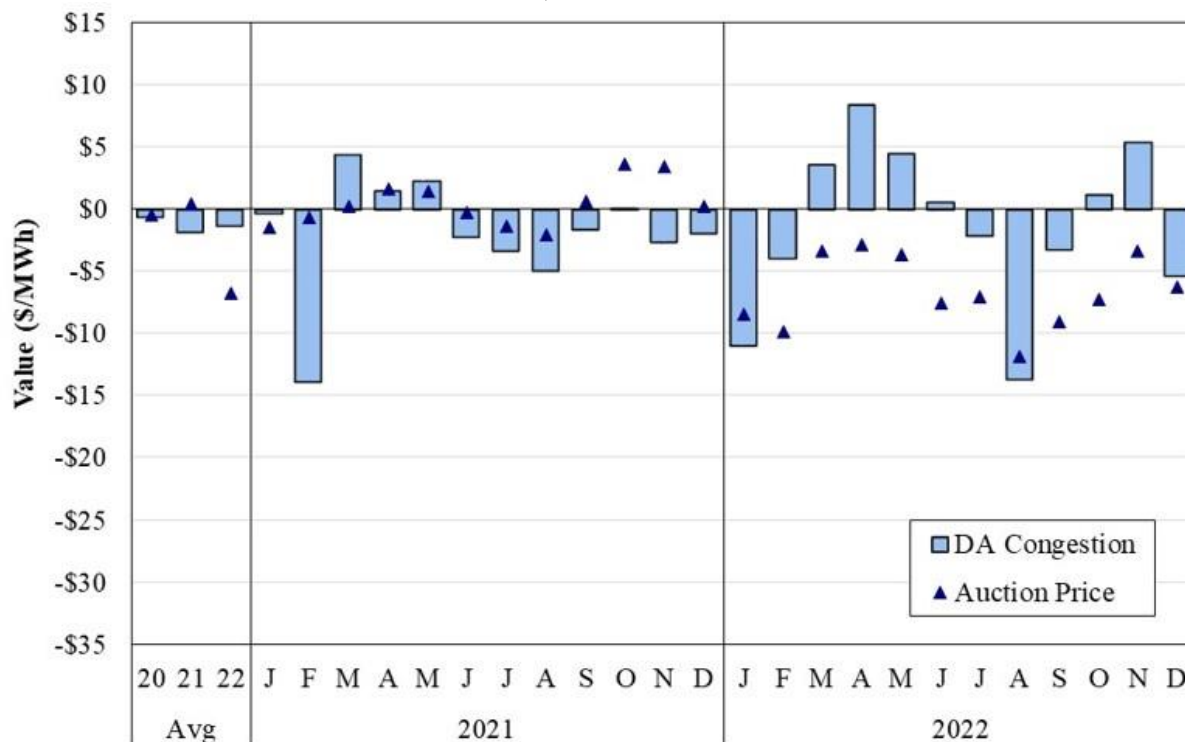
Figure A113: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2021–2022: Off-Peak Hours
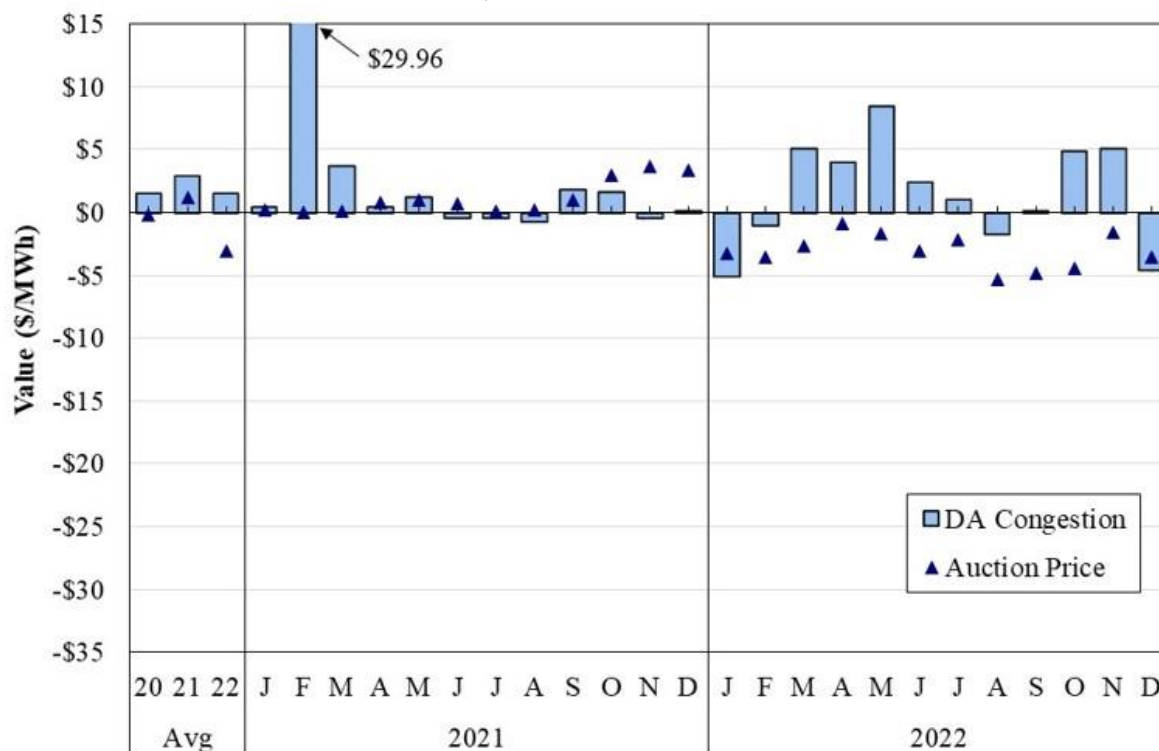
Figure A114: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2021–2022: Peak Hours
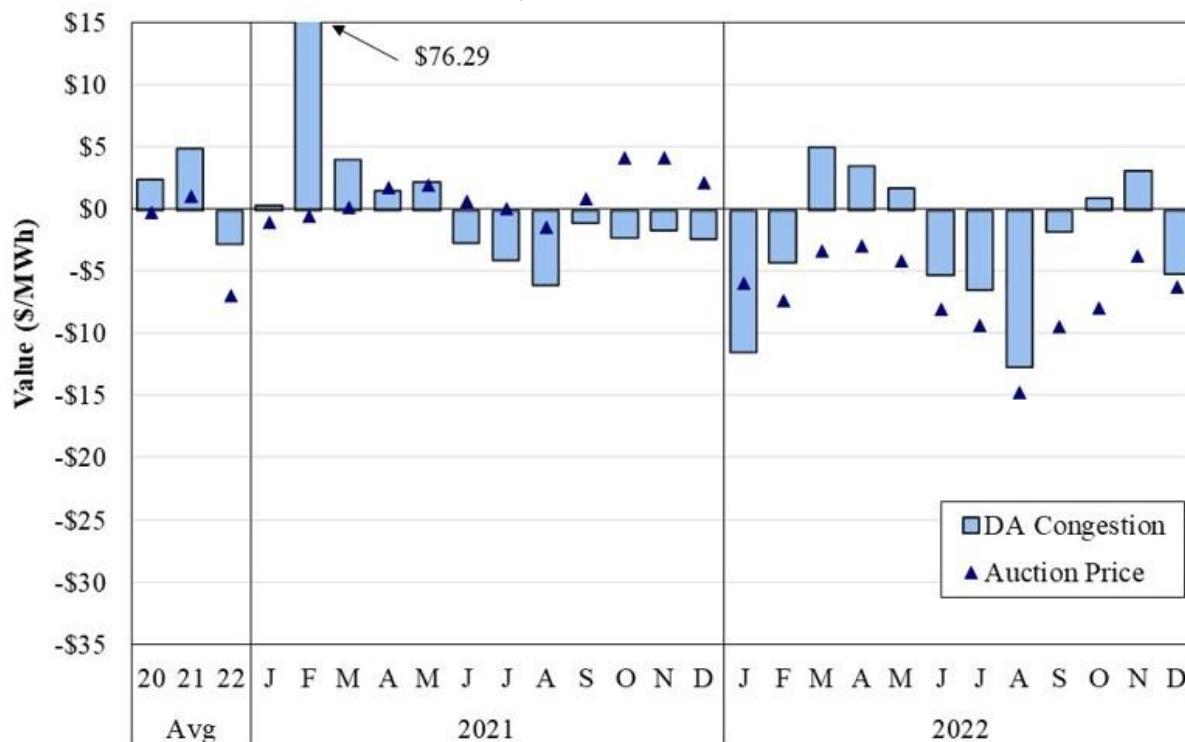
I.   Multi-Period Monthly FTR Auction Revenues and Obligations

In the MPMA FTR auctions, 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 that transmission path. For example, if MISO issues 250 MW of FTRs over a path that now can only accommodate 200 MW of flow, MISO can sell 50 MW of counter-flow FTRs so that MISO's net FTR obligation in the day-ahead market is only 200 MW.

MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative financial residual. Hence, it can sell counter-flow FTRs to the extent that it has sold forward-flow FTRs in the same auction. This limits MISO's ability to resolve feasibility issues through the MPMA FTR auctions. In other words, when MISO knows a path is oversold, as in the example above, it often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always bad because it may be costlier to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

Figure A115: Prompt-Month MPMA FTR Profitability

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A115 compares the auction revenues from the monthly FTR auction to the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-direction FTRs and counter-flow

FTRs. The net funding costs are the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold FTRs at a price less than their value.

Figure A115: Prompt-Month MPMA FTR Profitability
2021–2022
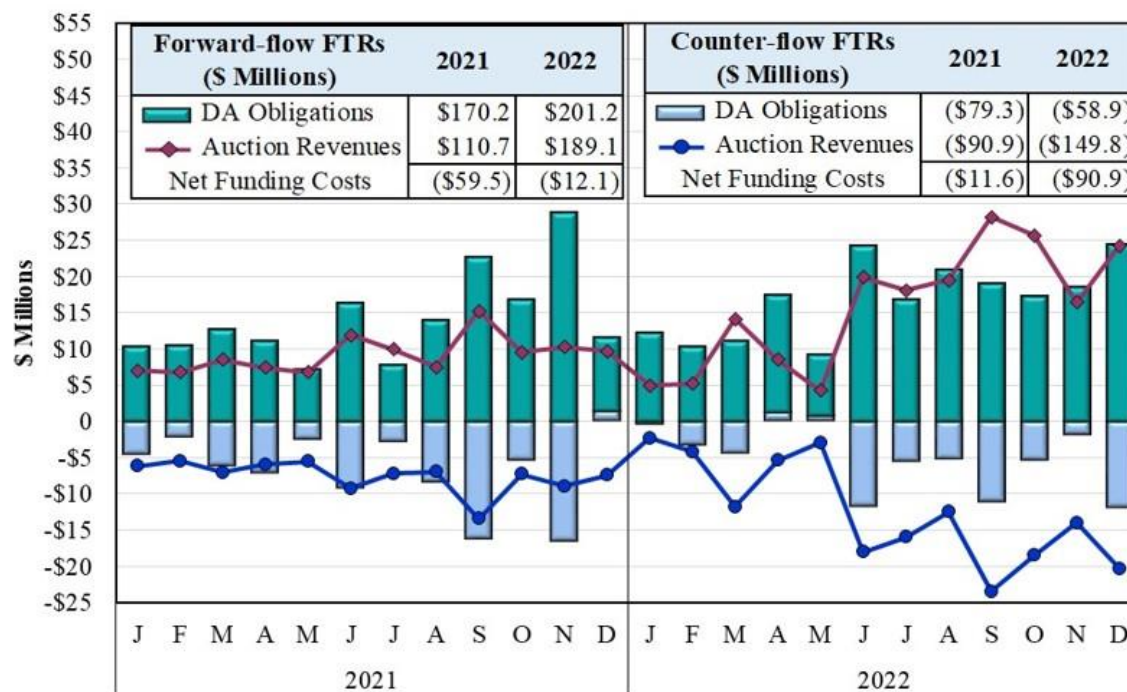
VI.   RESOURCE ADEQUACY

This section examines the supply and demand conditions in the MISO markets. We summarize load and generation within MISO. In 2022, there were 135 market participants that either owned generation resources (totaling 190 GW of nameplate capacity) or served load in the MISO market.[30] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

MISO serves as the reliability coordinator for an additional 15 GW of resources, which we exclude from our analysis unless noted. The largest non-market coordinating member is Manitoba Hydro. It does not submit bids or offers but may schedule imports and exports.[31]

MISO reorganized its reliability coordination function in 2014 into three regions: North, Central (together known as Midwest), and South. These regions are defined as follows:

- North (formerly West)—Includes MISO control areas that had been located in the North American Electric Reliability Corporation's (NERC) MAPP region (all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota);

- Central (formerly East and Central)—Includes MISO control areas that had been located in NERC's ECAR and MAIN regions (all or parts of Illinois, Indiana, Iowa, Kentucky and Michigan, Missouri, and Wisconsin); and

- South—Includes MISO control areas that joined in December 2013 (all or parts of Arkansas, Louisiana, Mississippi, and Texas).

In many of our analyses, we evaluate separately the existing NCAs: currently WUMS, North WUMS, Minnesota (including portions of IOWA), WOTAB, and Amite South because the binding transmission constraints that define these areas require a closer examination. (A detailed analysis of market power is provided in Section VIII of this Appendix.)

A.   Regional Generating Capacity

Figure A116: Distribution of Existing Generating Capacity

Figure A116 shows the December 2022 distribution of existing generating resources by Local Resource Zone. The figure shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the annual peak load in each zone. UCAP values for wind are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. The inset table in the figure breaks down the total UCAP and ICAP by fuel type. The mix of fuel types is important because it determines how changes in fuel prices, environmental regulations, and other external factors may affect the market.

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[30]   As of February 2023, MISO membership totaled over 500 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

[31]   Manitoba does submit a limited amount of offers under the External Asynchronous Resources (EAR) procedure, which permits dynamic interchange with such resources through the five-minute dispatch.

Figure A116: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2022
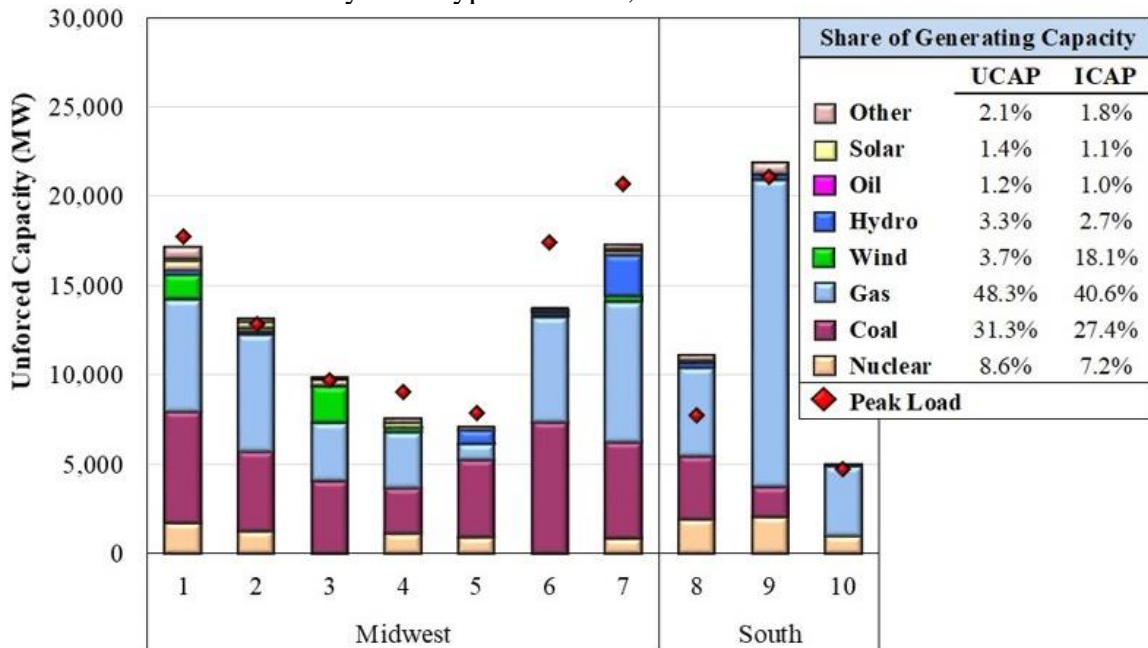
B. Changes in Capacity Levels

Figure A117: Additions and Retirements of Generating Capacity

Figure A117 shows the change in the UCAP values during 2022 in each zone caused by resource retirements, additions, and interconnection changes. The hatched area represents capacity that entered long-term suspension in 2022 and is not expected to return to the market.

Figure A117: Additions and Retirements of Generating Capacity
2022, By Fuel Type and Zone
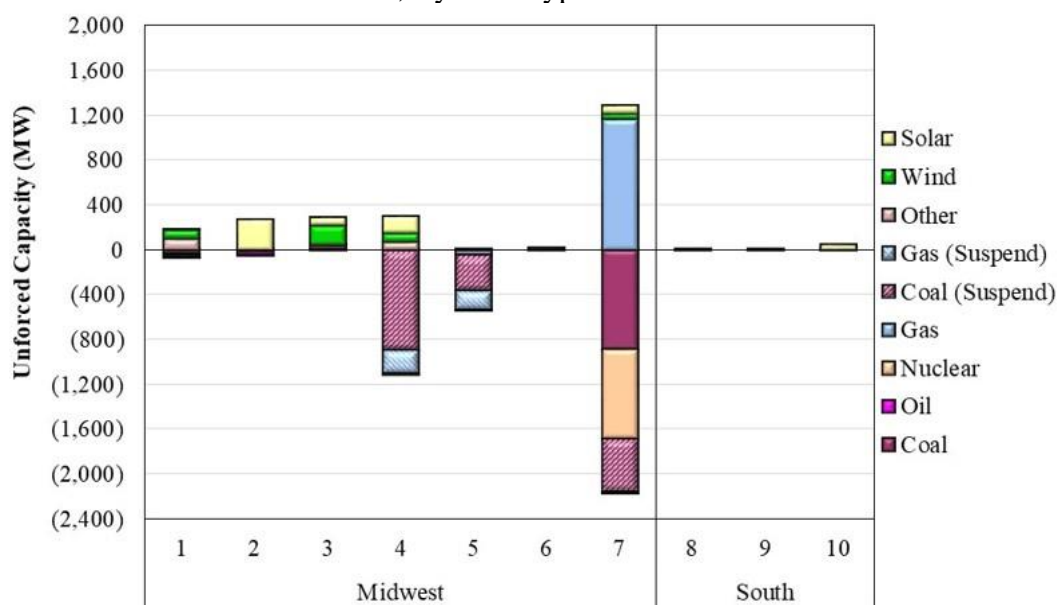
C.   Planning Reserve Margins and Summer Readiness

Table A17: Summer 2023 Planning Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2023. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2023 Summer Resource Assessment,* including a 1,900 MW transfer limit assumption[32] between MISO South and MISO Midwest. We provide four additional scenarios that we describe in detail below and that we believe more realistically represent MISO's summer peak reliability margin.

MISO's reliability assessment is designed to ensure that an adequate supply margin exists across the forecasted summer peak to maintain the NERC reliability standard that the risk of loss of load does not exceed one day in ten years. The Planning Reserve Margin Requirement (PRMR) is determined through the Loss of Load Expectation (LOLE) study that currently assumes that no planned outages are scheduled across the summer peak, and that all LMRs and emergency-only resources can be fully utilized in the event of a declared emergency.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[33] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation based on wind accreditation; and (e) full response from both imports and Demand Response (DR) resources that cleared the PRA (behind the meter generation, interruptible load, and direct controllable load management).

Table A17 below shows our base case and four alternative scenarios that examine the impact on MISO's planning reserve margins from short-notice planned outages, variations in emergency-only resources' lead times, and unusually hot temperatures. In this summer assessment, we include a conservative measure of historical non-capacity imports during the summer peak in order to calculate an expected margin around the summer peak.

The columns in Table A17 include a number of cases:

- Column 1: Base case that assumes a 1,900 MW transfer limit between the South and Midwest, that MISO will be able to access all demand response resources in a given emergency situation, and that the summer planned outages will be limited to those scheduled and approved by April 1, 2023. We replace the UCAP-based PRM added to demand response resources with an ICAP-based PRM to be consistent with reporting the Summer Assessment on an ICAP basis, and for wind we used the wind ELCC value and applied an ICAP-based PRM to assume a wind ICAP value.

- Column 2: Assumes that the transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations, and that planned and unreported outages and derates will be consistent with the average of the previous three years' summer peak

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[32]   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.

[33]   Expected peak load in reserve margin forecasts are generally median "50/50" forecasts (i.e., there exists a 50 percent chance load will exceed this forecast and a 50 percent chance it will fall short).

months during on-peak hours. This scenario also assumes that MISO will only be able to access 75 percent of demand response resources in a given emergency situation, consistent with historical observations.

- Column 3: Modifies column 2 by removing emergency-only resources that cannot respond within two hours because Maximum Generation Emergency events are often precipitated by unforeseen outages and other contingencies. MISO is often not able to declare this type of event more than two hours in advance of the most critical conditions and has historically detected and declared emergencies between 10 minutes and four hours in advance of the emergency situation.

- Columns 4 and 5: The same as columns 2 and 3 with an additional assumption that hotter than normal summer peak conditions prevail that correspond to a "90/10" case (i.e., 90 percent chance load is lower and ten percent chance load is higher, which means it should only occur one year in ten).

Table A17: Summer 2023 Planning Reserve Margins

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

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

D.   Capacity Market Results

In June 2009, MISO began operating the monthly Voluntary Capacity Auction (VCA) to allow load-serving entities (LSEs) to procure capacity to meet their Tariff Module E capacity requirements. The VCA was intended to provide a balancing market for LSEs, with most capacity needs being satisfied through owned capacity or bilateral purchases. The PRA replaced the VCA in June 2013 and incorporates zonal transfer limits to better identify regional capacity needs throughout MISO. Zonal capacity import and export limits, if they bind, cause price divergence among the zonal clearing prices.

> *Figure A118: Planning Resource Auction*

Figure A118 shows the zonal results of the 2022/2023 annual PRA. 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)[34] 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 capacity imports. The maximum amount is equal to the obligation plus the maximum capacity exports. The figure shows the auction clearing prices (ACP) in $/MW-day below each of the zones. The ACPs for external resource zones (ERZ) are weighted based on the cleared capacity in each ERZ.

Figure A118: Planning Resource Auction
2022–2023 Planning Year

2022-2023 PRA Results	MISO (MW)
Offered Not Cleared	2,854
Cleared in Annual Auction	97,704
Fixed Resource Adequacy Plan	36,317
Total Capacity Procured	**135,327**
Maximum Zonal Limit	
Minimum Zonal Requirement	

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ
	MN, ND, WI	WI, MI	IA	IL	MO	IN, KY	MI	AR	LA, TX	MS	
ACP ($/MWd)	236.66	236.66	236.66	236.66	236.66	236.66	236.66	2.88	2.88	2.88	187.79*

*Weighted Average Clearing Price

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34   Participants can elect to cover all or part of their obligation via a Fixed Resource Adequacy Plan (FRAP), which exempts resources from participating in the auction. FRAPs are counted against local clearing requirements, but they cannot set the clearing prices.

E.   Long-Term Economic Signals

In this subsection, we summarize the long-term economic signals produced by MISO's energy, ancillary services, and capacity markets. Our evaluation uses the "net revenue" metric, which measures the revenue that a generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. Well-designed markets should provide sufficient *expected* net revenues to finance new investment when additional capacity is needed. However, random factors in each year (e.g., weather conditions, generator availability, transmission topology changes, outages, or changes in fuel prices) can cause the net revenues to be higher or lower than the equilibrium value.

Our analysis examines the economics of two types of new units: a natural gas combined-cycle (CC) unit with an assumed heat rate of 6,600 Btu per kWh and a natural gas combustion turbine (CT) unit with an assumed heat rate of 9,905 Btu per kWh.[35] The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

> *Figure A119 and Figure A120: Net Revenue Analysis*

The next two figures compare the net revenue plus the capacity market revenue that would have been received by new CC and CT units in different MISO regions compared to the revenue that would be required to support new investment in these units. To determine whether net revenue levels would support investment in new resources, we first estimate the annualized cost of a new unit. The figures show the estimated annualized cost, which is the annual net revenue a new unit would need to earn in MISO wholesale markets to make the investment economic. The estimated Cost of New Entry (CONE) for each type of unit is shown in the figure as horizontal black segments and is based on data from the U.S. Energy Information Administration (EIA) and various financing, tax, inflation, and capital cost assumptions.

Combined-cycle generators run more frequently and earn more energy rents than simple-cycle CTs because CC units have substantially lower production costs per MWh. Therefore, the estimated energy net revenues for CC generators tend to be substantially higher than they are for CT generators. Conversely, capacity and ancillary services revenues typically account for a comparatively larger share of a CT's net revenues. Capacity requirements and import and export limits enforced in the Planning Resource Auction (PRA) vary by zone, so capacity revenues vary depending on the clearing price in each zone. The estimated net revenues earned by these two types of resources in different MISO regions are shown as stacked bars in the figure.

We added a transparent bar to illustrate the net revenues that CTs and CCs would have realized if MISO improved its modeling of demand efficiently in its capacity auction. The diamonds show the estimated run hours of each unit type during the year. We reproduce the Central Region results on the MISO South figure for comparison purposes.

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[35]   These assumptions are used in the 2020 EIA Annual Energy Outlook. See:
https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

Figure A119: Net Revenue Analysis
Midwest Region, 2020–2022
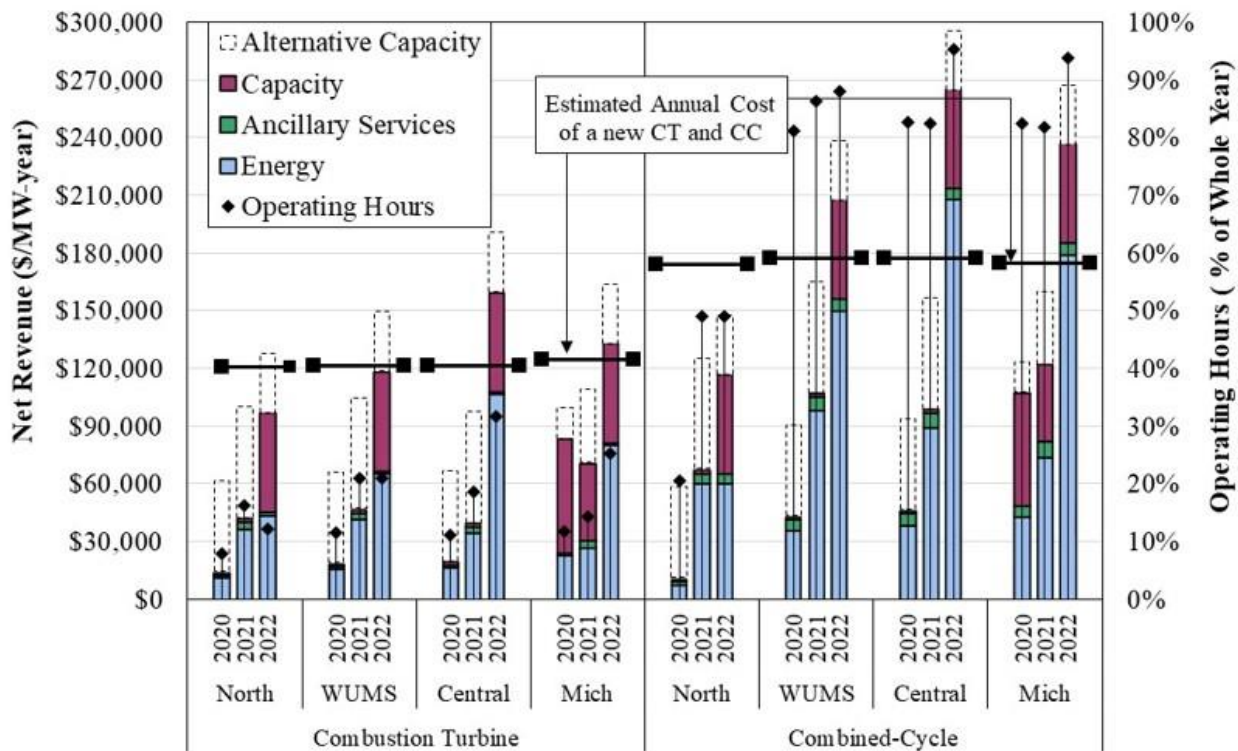
Figure A120: Net Revenue Analysis
South Region, 2020–2022
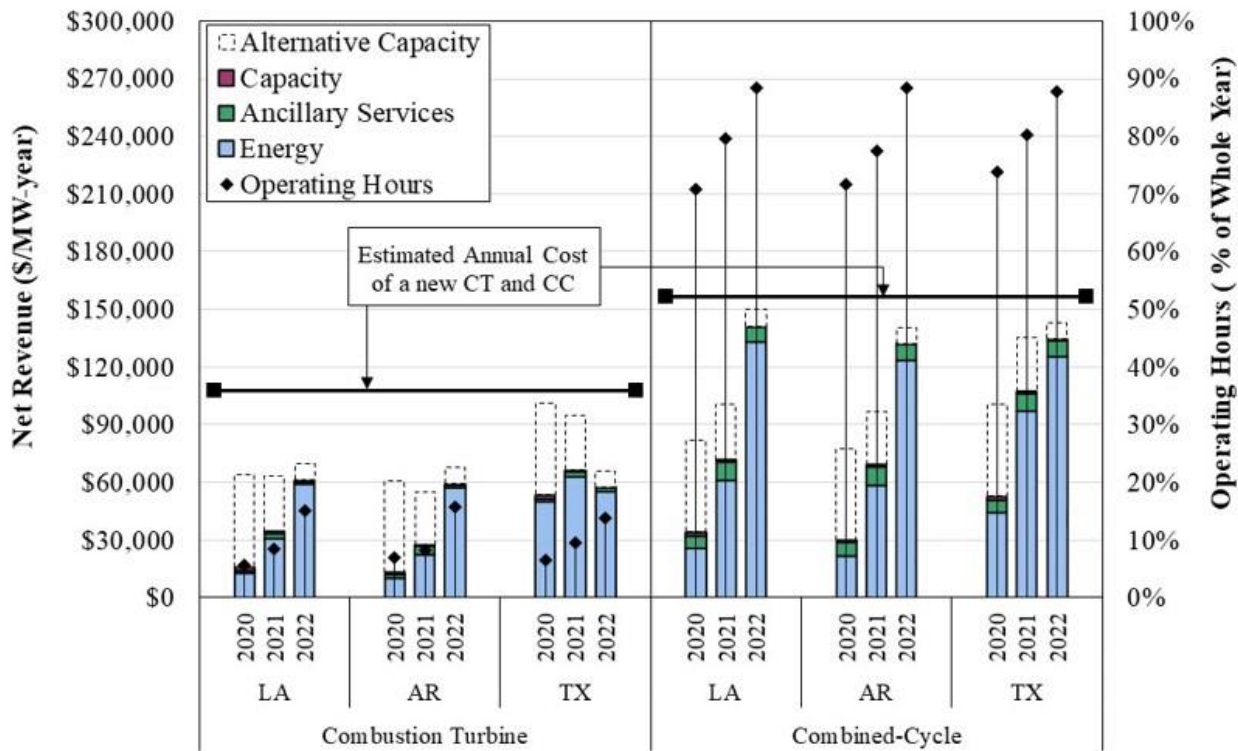
F. Existing Capacity at Risk Analysis

Prior to 2022, MISO enjoyed a surplus of capacity. When resources are unable to recover their fixed costs in the long run, they may be suspended or retired. MISO's capacity surplus dwindled in recent years as older, baseload units with higher fixed costs have entered long-term suspension or retired, and in the 2022/2023 capacity auction the Midwest Region was in shortage. This trend had largely been due to falling natural gas prices and the poor design of MISO's capacity market that results in understated capacity prices. Most of the new capacity entering MISO is either gas-fired generators or renewable resources.

Figure A121: Capacity at Risk by Technology Type

We conduct an analysis to evaluate capacity at risk for long-term suspension or retirement for three types of technology in MISO: nuclear, wind, and coal. Our analysis compares the annual resource net revenues to the technology-specific Going Forward Costs (GFCs) defined in Module E of MISO's Tariff. For coal unit net revenue, we included the median unit's two-year historical net revenues within the relevant resource adequacy zone. For nuclear, we assume a 2,156 MW unit with VOM costs of $10 per MWh and that the resource runs year-round. Finally, for wind we assume a 200 MW unit with $0 marginal costs and a 30 percent capacity factor. This analysis is illustrated on Figure A121 below. The blue bars indicate the revenues that the resources received through the energy markets, and the maroon bars represent capacity market revenues on a dollar per MW-year basis. The ghost bars represent capacity revenues that the resources would have received were the PRA to employ a sloped demand curve. Alternative wind capacity values are much smaller than coal and nuclear because of the much smaller UCAP value that wind receives for its ICAP compared to conventional resources.

Figure A121: Capacity at Risk by Technology Type
2022
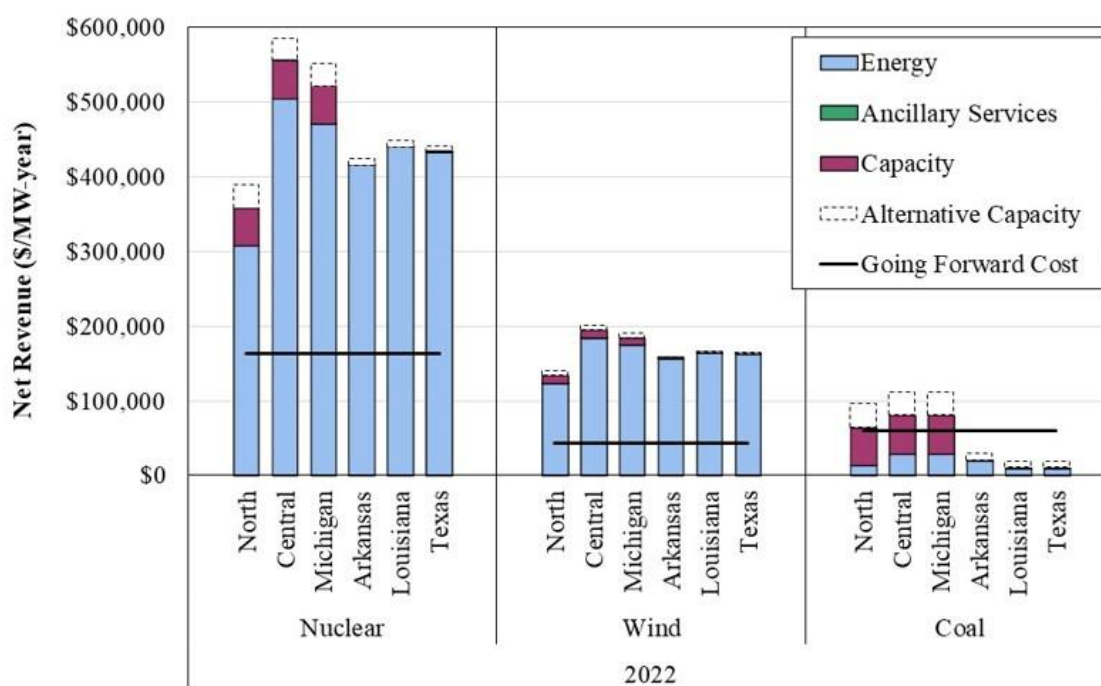
VII. EXTERNAL TRANSACTIONS

MISO is a net importer of power during nearly all hours and seasons. Given this reliance on imports, the processes to schedule and price interchange transactions can have a substantial effect on the performance and reliability of MISO's markets.

Imports and exports can be scheduled on a 15-minute basis, although the schedules are submitted 20 minutes before the transaction period starts. The scheduling notification period was reduced from 30 minutes to 20 minutes on October 15, 2013, to satisfy the requirements of FERC's Order 764. Participants must reserve ramp capability in order to schedule a transaction, and MISO will refuse transactions that place too large a ramp demand on the system. On October 3, 2017, MISO implemented Coordinated Transaction Scheduling (CTS) with PJM that allows market participants to schedule transactions based on the forecasted price spread between markets. This section reviews the magnitude of the interchange and the efficiency of the scheduling process.

A. Overall Import and Export Patterns

Figure A122 to Figure A125: Average Hourly Imports

The following four figures show the daily average of hourly net imports (i.e., imports net of exports) scheduled in the day-ahead and real-time markets in total and by interface. The first figure shows the total net imports in the day-ahead market, distinguishing between weekdays (when demands are greater) and weekends.

Figure A122: Average Hourly Day-Ahead Net Imports
2022
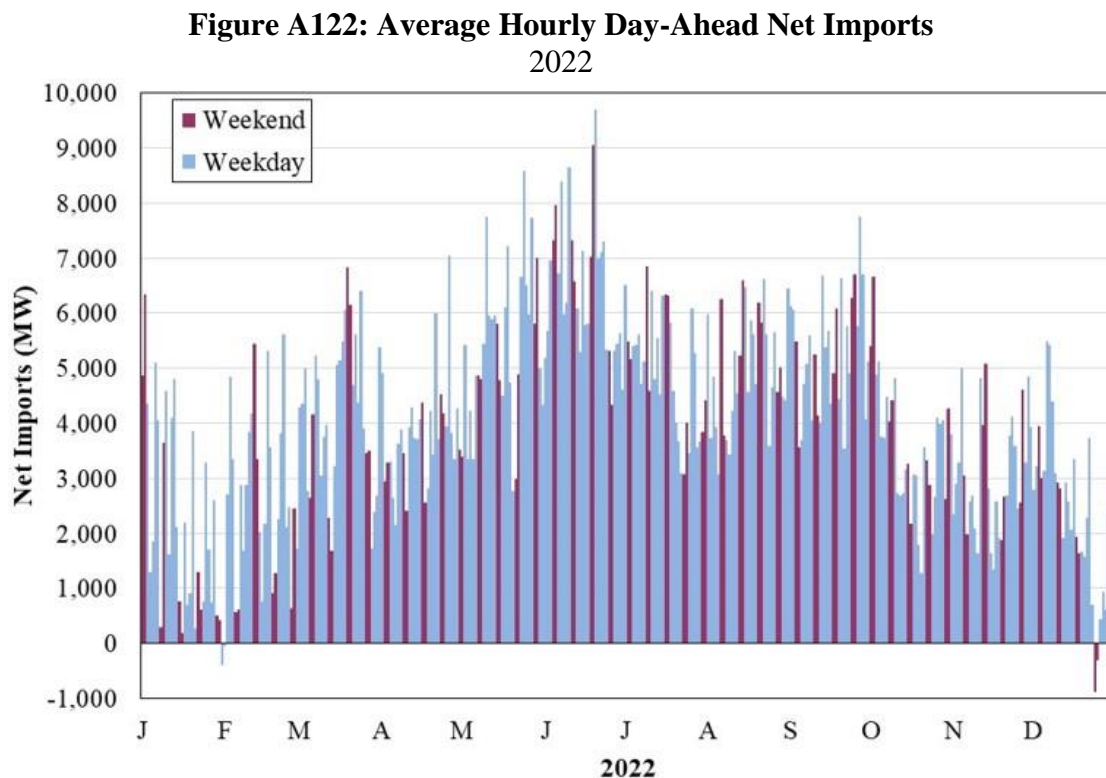
The second figure shows real-time net imports and changes from day-ahead net import levels. When net imports decline in real time, MISO may be compelled to commit peaking resources. The third and fourth figures show the data by interface.

Figure A123: Average Hourly Real-Time Net Imports
2022
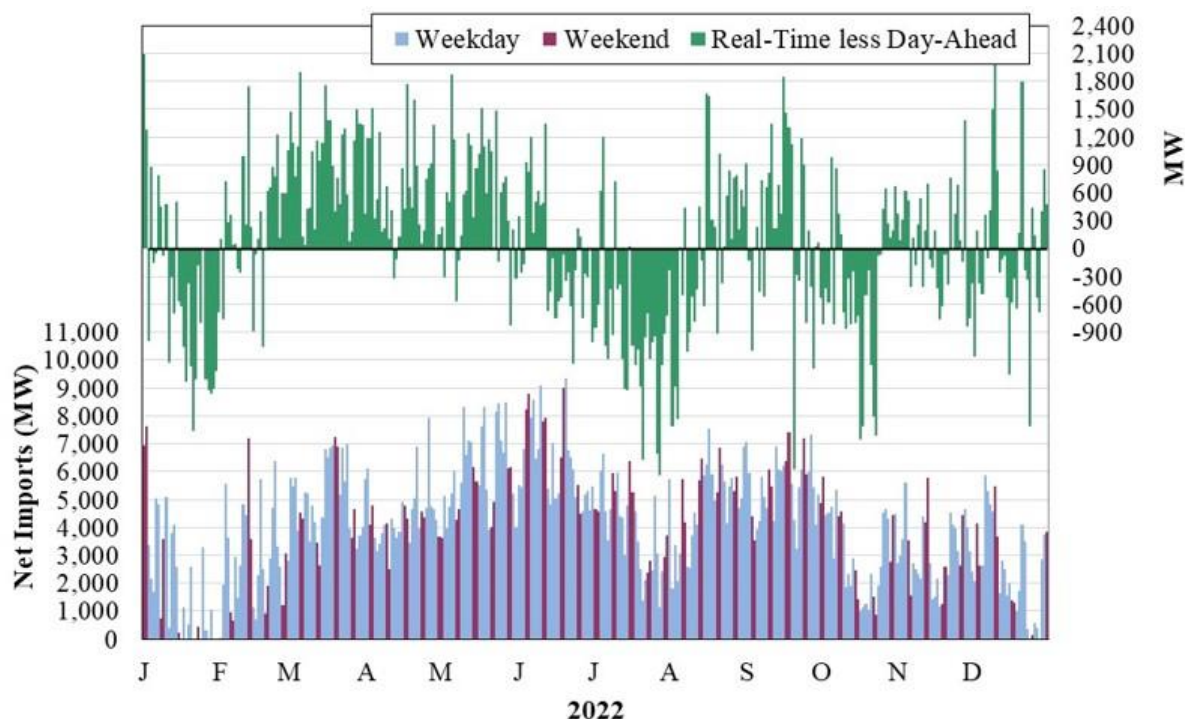
Figure A124: Average Hourly Day-Ahead Net Imports
2022, by Interface
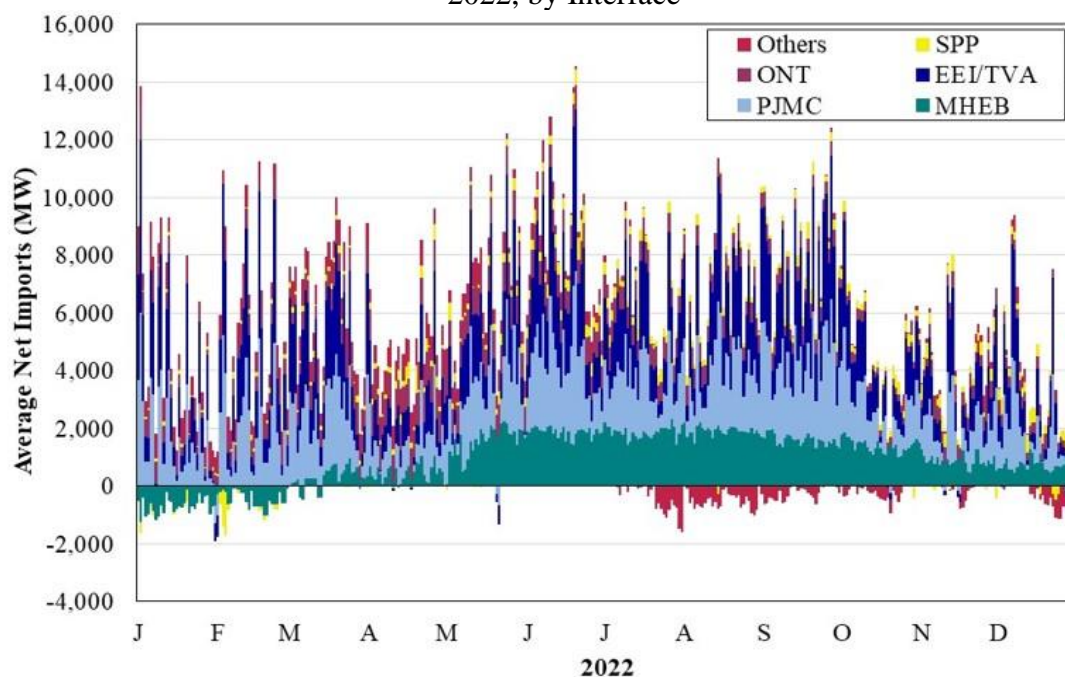
Figure A125: Average Hourly Real-Time Net Imports
2022, by Interface
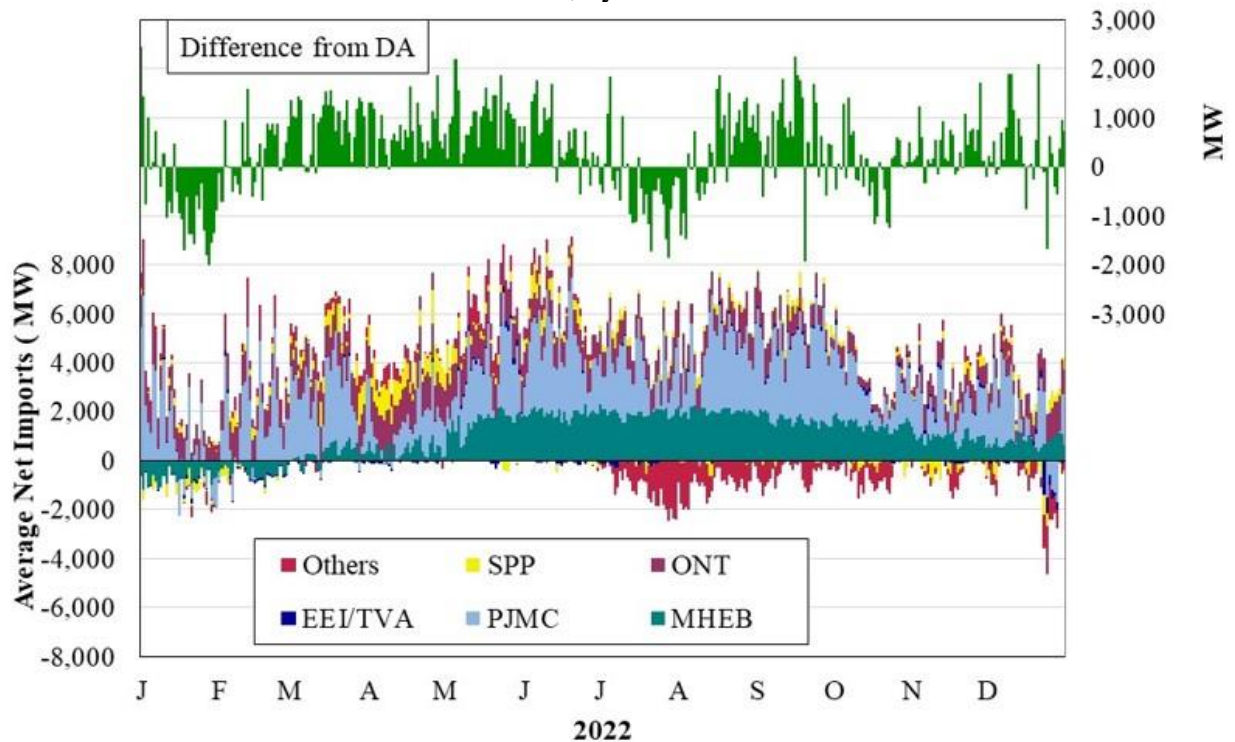
Figure A126 and Figure A127: Average Hourly Real-Time Net Imports by Interface

The next two figures examine net real-time imports for the PJM and Manitoba/Ontario interfaces. The interface between MISO and PJM, both of which operate LMP markets over wide geographic areas, is one of the most significant interfaces for MISO because the interface can support interchange in excess of 5 GW per hour. Relative prices in adjoining areas govern net interchange. Therefore, price movements cause participants' incentives to import or export to change over time.

Accordingly, Figure A126 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2021 and 2022, along with the standard deviation of such imports.[36] Figure A127 shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

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[36] Wheeled transactions, predominantly from Ontario to PJM, are included in the figures.

Figure A126: Average Hourly Real-Time Net Imports from PJM
2021–2022
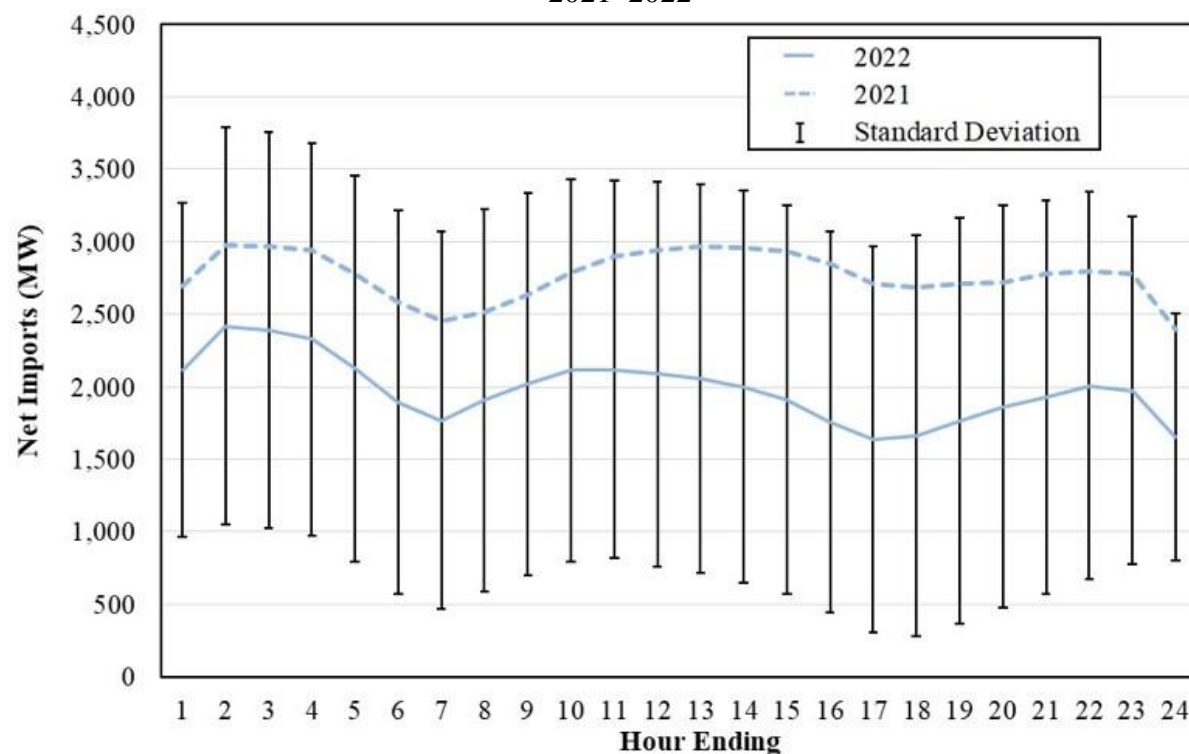
Figure A127: Average Hourly Real-Time Net Imports from Canada
2021–2022
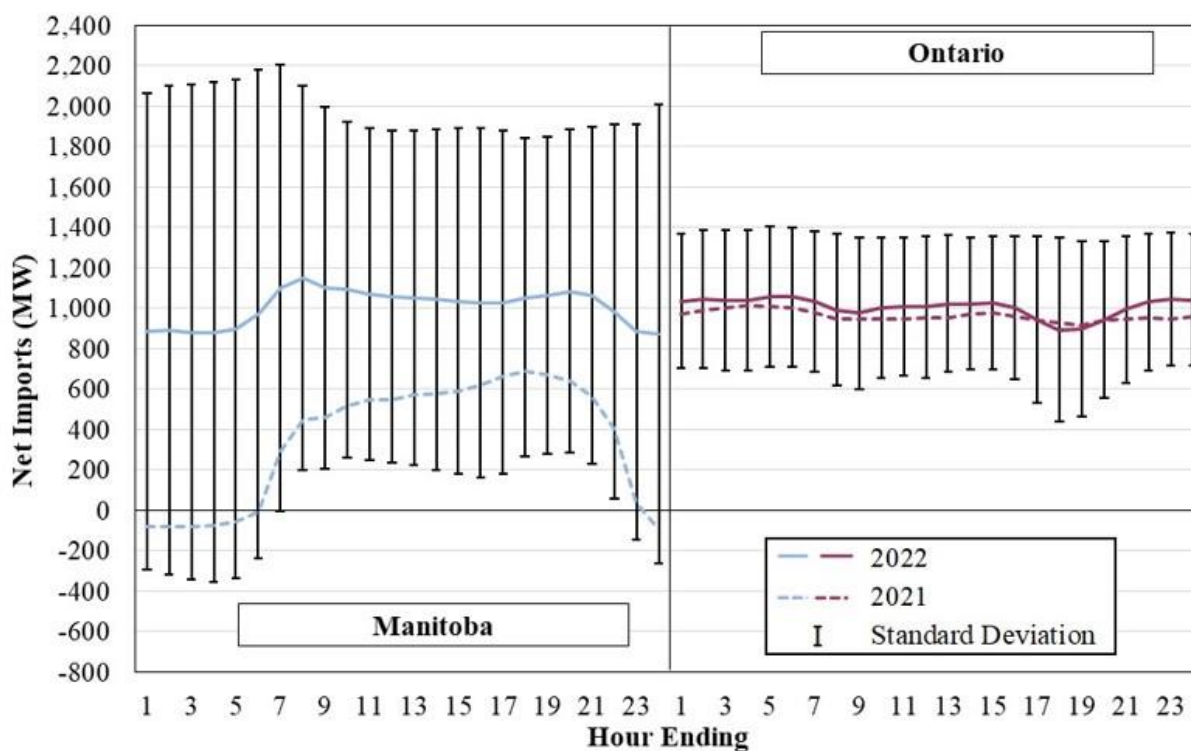
B. Coordinated Transaction Scheduling

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 if the forecasted spread between the MISO and PJM real-time interface prices is greater than the offer price. Participants' offers, which can be multi-part offers with separate prices for increasing quantities, must be submitted 75 minutes before the specific interval. Offers then clear if they are greater than the spread in forecasted interface prices 30 minutes prior to the interval. CTS transactions are settled based on real-time interface prices.

Figure A128: CTS Versus Traditional NSI Scheduling

Since its inception in October 2017, there has been very little participation in CTS. We have previously shown that high transmission and energy charges have deterred traders from using CTS in lieu of traditional transaction scheduling. To determine the impact that the transaction fees have on CTS, we conducted an analysis comparing:

- a scheduling strategy using CTS offers, to:
- a strategy using short-lead time transactions scheduled 30 minutes ahead (i.e., the traditional means of scheduling transactions).

Excluding the charges applied to CTS transactions, the CTS transactions should be more profitable if the mechanism operates effectively because participants are able to submit an offer price. In contrast, the traditional scheduling mechanism requires participants to submit transactions that are not price-sensitive and are based on their expectations of the price spreads that will exist when the transactions are flowing. The results of our analysis for 2022 are shown in Figure A128 below.

In this analysis, we compare 1 MW CTS transactions offered at various target spreads, from $0 to $20 in increments of $5, to 1 MW short-lead scheduled transactions initiated when the actual real-time interface price spread 30-minutes prior to the transaction exceeded the applicable target spread. Our analysis applies to both imports and exports. All offered CTS exports incur reservation charges of $0.80 per MWh and an additional $1.75 per MWh if they clear. Offered CTS imports incur reservation charges of $0.28 per MWh and an additional $0.55 per MWh if they clear. Cleared short-lead transactions incur the total costs listed above, based on direction. The CTS transactions tend to incur much higher costs because they incur a reservation charge for every MW bid/offered even though a very small share clear.

In Figure A128, the solid bars represent gross profits ($ per MWh) from each strategy, and the diamonds represent net $ per MWh revenues (including reservation and other market charges).

Figure A128: CTS Versus Traditional NSI Scheduling in 2022

Figure A129: MISO and PJM CTS Forecast Errors

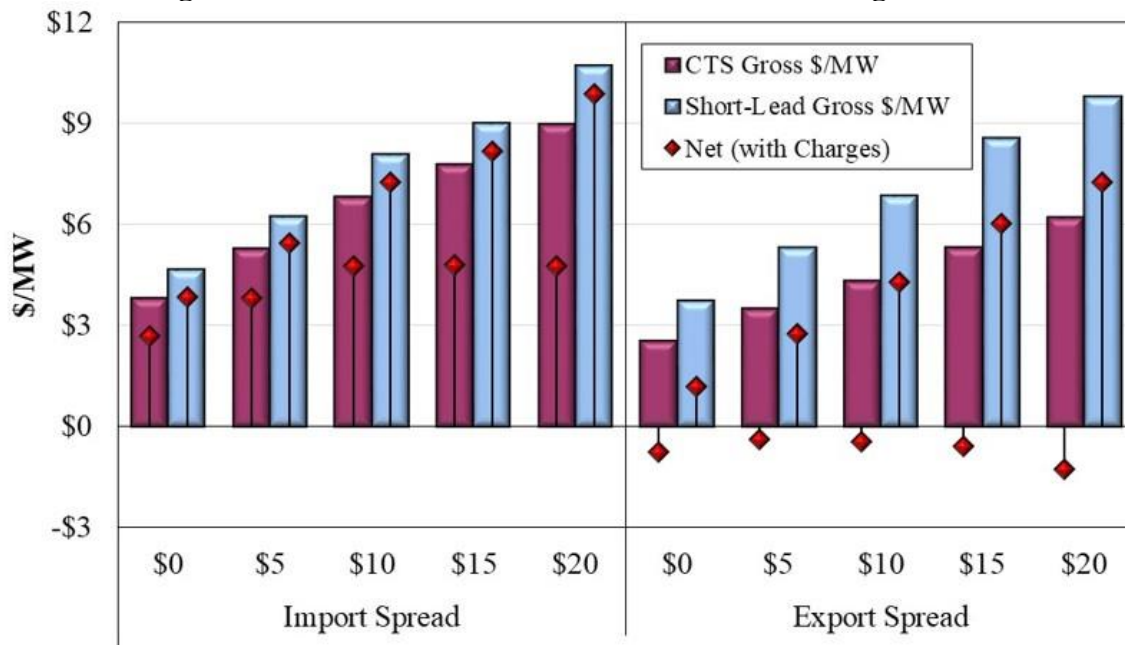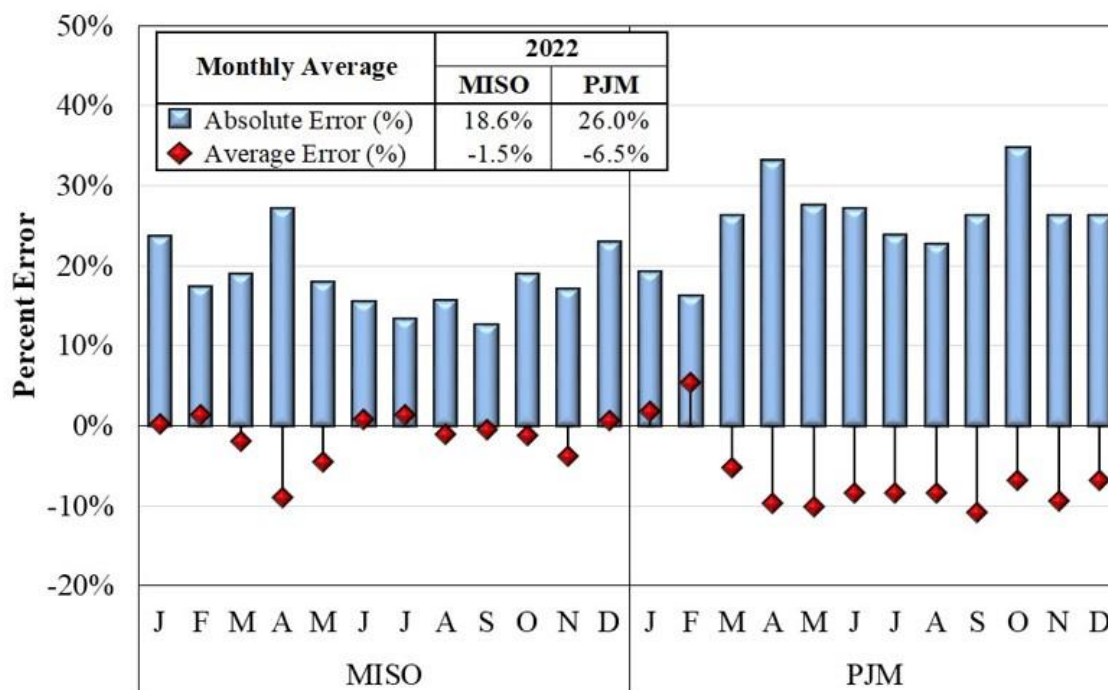The adoption of CTS has been limited because of persistent forecasting errors in both MISO and PJM. We measured the difference between the actual LMP and the forecasted price used for CTS. In Figure A129, we show the differences by month as a share of average LMPs, in both average and absolute average terms.

Figure A129: MISO and PJM CTS Forecast Errors

The red diamonds represent the monthly average of the differences between the real-time LMPs at the respective RTOs' interface (five-minute prices averaged to 15-minute intervals) and the 15-minute forecasted interface prices used for CTS, expressed as the percentage difference relative to average real-time LMPs. Positive error means that the forecasted prices, on average, were lower than real-time LMPs, while negative error means the forecasted prices were higher. The blue bars show this error calculation in absolute terms. The table in the chart provides these respective error calculations on an annual basis.

Table A18: CTS with Five-Minute Clearing Versus Current CTS

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

- the previous five-minute spread less cleared transaction fees;

- assumed relationships of the price in PJM and MISO to changes in the transactions scheduled between them ("convergence slopes"), which was based on a regression analysis we performed; and

- an assumed aggregate offer curve beginning at the level of the incremental charges and rising at a rate of $1 per MWh every 167 MW ($6 per 1000 MW).

We adjust the optimal adjustment, accounting for any changes in the actual scheduled NSI, and apply the following constraints: (1) maximum change between five-minute intervals of 500 MW (in either direction), and (2) maximum total CTS import and export limits of 5,000 MW. We then use the simulated clearing and the convergence slopes to adjust the ex-ante LMPs of the two markets in each five-minute interval. We evaluate the production cost savings by multiplying the simulated clearing times the average of the simulated LMP and actual LMP for each side of the transaction, which assumes an initial savings based on the actual savings and incremental savings that shrink linearly to the simulated LMP.

We further used this model to evaluate the benefits of a five-minute CTS with SPP, with tighter constraints since it has a smaller interface than PJM: (1) maximum change between five-minute intervals of 250 MW (in either direction), and (2) maximum total CTS import and export limits of 2,000 MW.

Profits are net CTS imports into MISO times the spread between the MISO and the external simulated LMPs. We evaluate the percentage of total intervals in the year where these profits are less than or equal to $0. We also measure the percentage of total intervals where the cleared CTS volumes increased or decreased from the previous interval. We also run the simulation with actual cleared CTS MW with PJM from 2022 for comparison purposes. We use the actual clearing and the convergence slopes to adjust the ex-ante LMPs of the two markets and then repeat the calculations from above. Table A18 summarizes these results.

Table A18: CTS with Five-Minute Clearing Versus Current CTS
2022

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

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

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.

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 scheduling incentive and lower the costs for both systems.
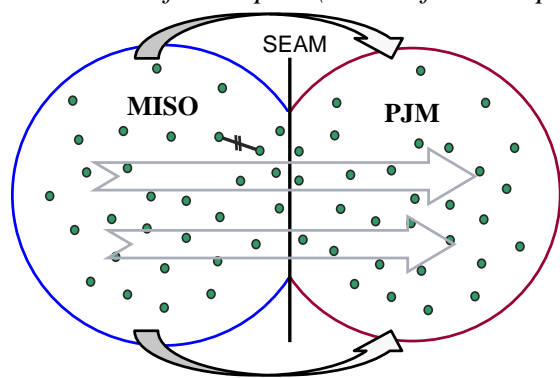
In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure on the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to 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.
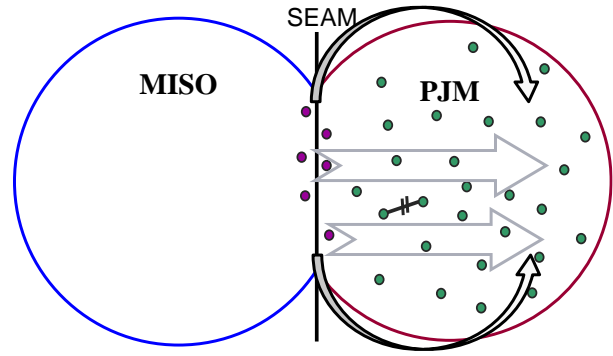
We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger 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. Selected analyses of the MISO-SPP interface are described below.

Figure A130: Constraint-Specific Interface Congestion Prices

Both MISO and SPP both employ reasonable interface definitions to estimate how imports from and exports to the other area will affect their transmission constraints. An unintended consequence of this is how congestion is priced on M2M constraints because they are activated and modeled in both RTOs' real-time markets. This causes SPP and MISO to "double pay" transactions for the congestion effects on M2M constraints.

To show how this occurs, we calculated the average interface pricing component associated with selected individual M2M constraints. These coordinated constraints had congestion values exceeding $1 million between June 2018 and May 2019. Figure A130 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints. The congestion payments are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount; whereas a positive value indicates that the participant would be paid for congestion relief.

Figure A130: Constraint-Specific Interface Congestion Prices
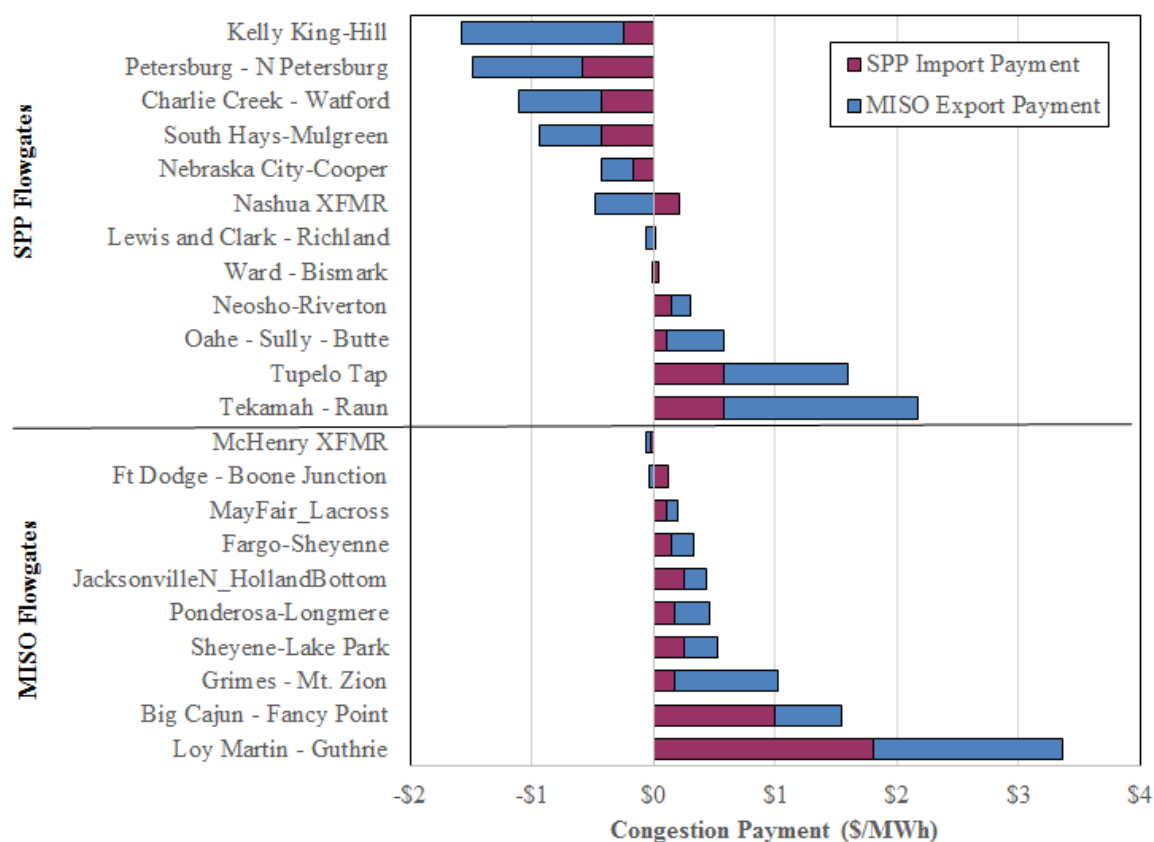
Even though their interface definitions differ, this figure shows that both RTOs estimate very similar effects for each of the jointly managed constraints. This results in congestion payments and charges that are roughly double the efficient level. The payments made by the MRTO alone are efficient because they reflect the marginal cost of managing the constraint.

Interface Pricing and External TLR Constraints

M2M constraints activated by PJM or SPP are one type of external constraint that MISO activates in its real-time market. MISO also activates constraints located in external areas when the external system operator calls a TLR. It is appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs. This enables MISO to respond to TLR relief requests as efficiently as possible. While re-dispatching internal generation is required to respond to TLRs, MISO is not obligated to pay participants to schedule transactions that 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 these external transactions provide.[37] Because MISO receives no credit for this relief and no reimbursements for the costs it incurs, it is inequitable for MISO's customers to bear these costs. Most of these costs are paid in the form of balancing congestion that is uplifted to MISO load.

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[37]   Likewise, transactions scheduled in MISO's day-ahead market and curtailed via TLR on an external flowgate are compensated by MISO as if they are relieving the constraint even though this effect is excluded from MISO's market flow calculation.

In addition to this inequity, these congestion payments motivate participants to schedule transactions inefficiently for at least three reasons. First, these beneficial transactions are already being fully compensated by the area where the constraint is located in most cases. For example, when IESO calls a TLR, it will establish an interface price (or congestion settlement) for a transaction over its interface with MISO that includes the effect of the transaction on its own constraint. MISO's additional payment is redundant and inefficient.

Second, the TLR process assigns market flow obligations and curtails physical schedules to enable the owner to manage a given flowgate. Any reduction in flow above these amounts results in a decrease in the monitoring area's need to reduce its own flows and can lead to unbinding of the transmission constraint in the monitoring area. MISO's current interface pricing compensates schedulers for inefficient added relief at the expense of MISO customers.

Finally, MISO's shadow cost for external TLR constraints is frequently and significantly overstated compared to the monitoring system operator's true marginal cost of managing the congestion on the constraint. As shown above in Section V.F, this causes the congestion component of the interface prices associated with TLR constraints to be highly distortionary and provides inefficient scheduling incentives.

D. Price Convergence Between MISO and Adjacent Markets

Like other markets, MISO relies on participants to increase or decrease net imports to cause prices to converge with adjacent markets. Given future price uncertainty when transactions are scheduled, perfect convergence is not expected. Transactions can start and stop at 15-minute intervals during an hour and must be scheduled 20 minutes in advance of the operating period.

Figure A131 and Figure A132: Real-Time Prices and Interface Schedules

Our analysis of these schedules is presented in two figures, each with two panels. The left panel displays a scatter plot of real-time price differences and net imports during all unconstrained hours. Good market performance would be characterized by net imports into MISO when its prices are higher than those in neighboring markets. The right side of each figure shows monthly averages for hourly real-time price differences between adjacent regions and the monthly average magnitude of the hourly price differences as average absolute differences. In an efficient market, prices should converge when the interfaces between regions are not congested. Figure A131 shows these results for the MISO-PJM interface, and Figure A132 shows the results for the MISO-IESO interface.

Figure A131: Real-Time Prices and Interface Schedules
PJM and MISO, 2022
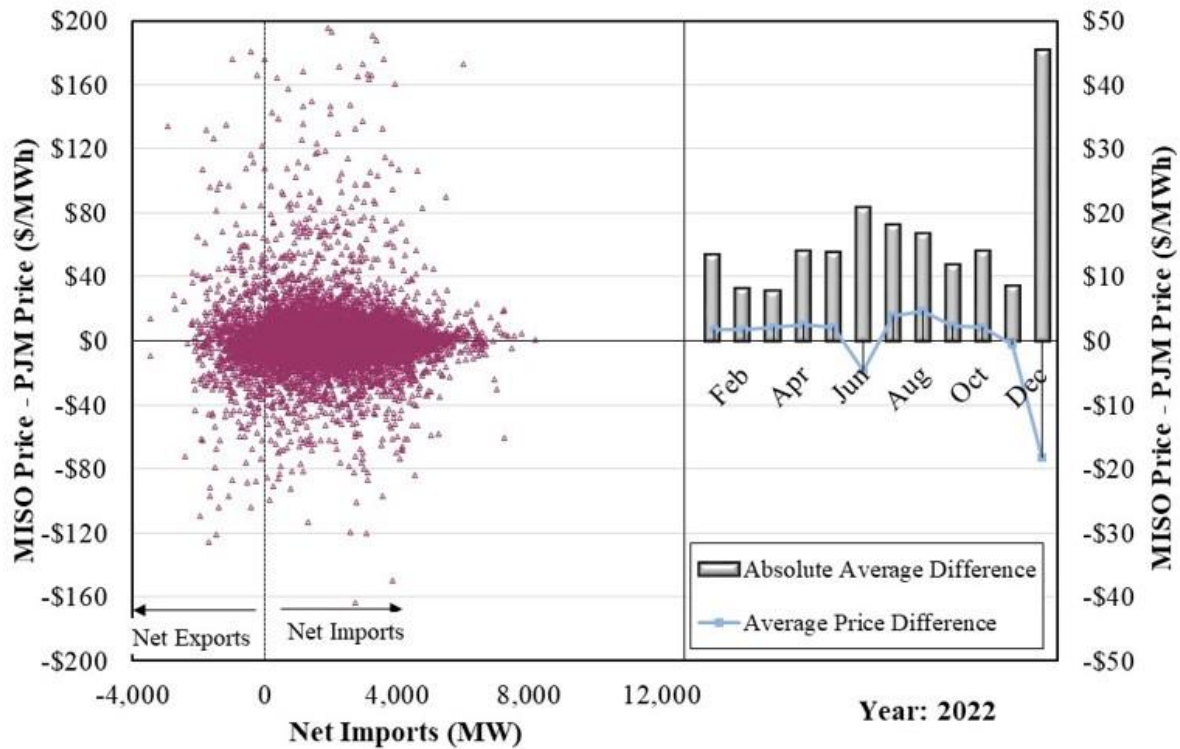
Figure A132: Real-Time Prices and Interface Schedules
IESO and MISO, 2022
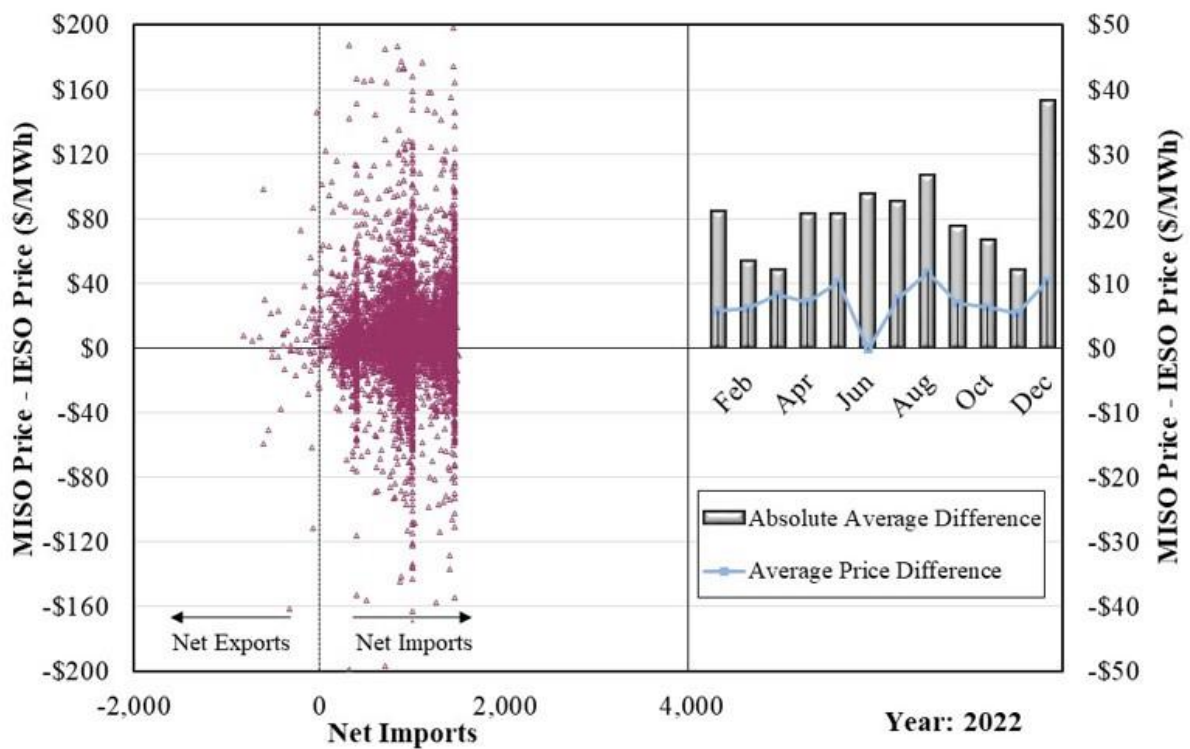
VIII.   COMPETITIVE ASSESSMENT AND MARKET POWER MITIGATION

This section evaluates the competitive structure and performance of MISO's markets using various measures to identify the presence of market power and, more importantly, to assess whether market power has been exercised. Such assessments are particularly important for LMP markets, because while the market as a whole may normally be highly competitive, local market power associated with chronic or transitory transmission constraints can make these markets susceptible to the exercise of market power.

A.   Structural Market Power Indicators

This first subsection provides three structural analyses of the markets. The first is based on the concentration of supply ownership in MISO as a whole and in each of the regions within MISO. The second and third analyses address the frequency with which suppliers in MISO are "pivotal" and are needed to serve load reliably or to resolve transmission congestion. In general, the two pivotal supplier analyses provide more accurate indications of market power in electricity markets than the market concentration analysis.

Figure A133: Market Shares and Market Concentration by Region

The first analysis shows the market concentration using the Herfindahl-Hirschman Index (HHI). The HHI is calculated by summing the square of each participant's market share in percentage terms. Antitrust agencies characterize markets with an HHI less than 1000 as unconcentrated and those with an HHI in excess of 1800 as highly concentrated. Figure A133 shows generating capacity-based market shares and HHIs for MISO and its subregions.

Figure A133: Market Shares and Market Concentration by Region
2021–2022
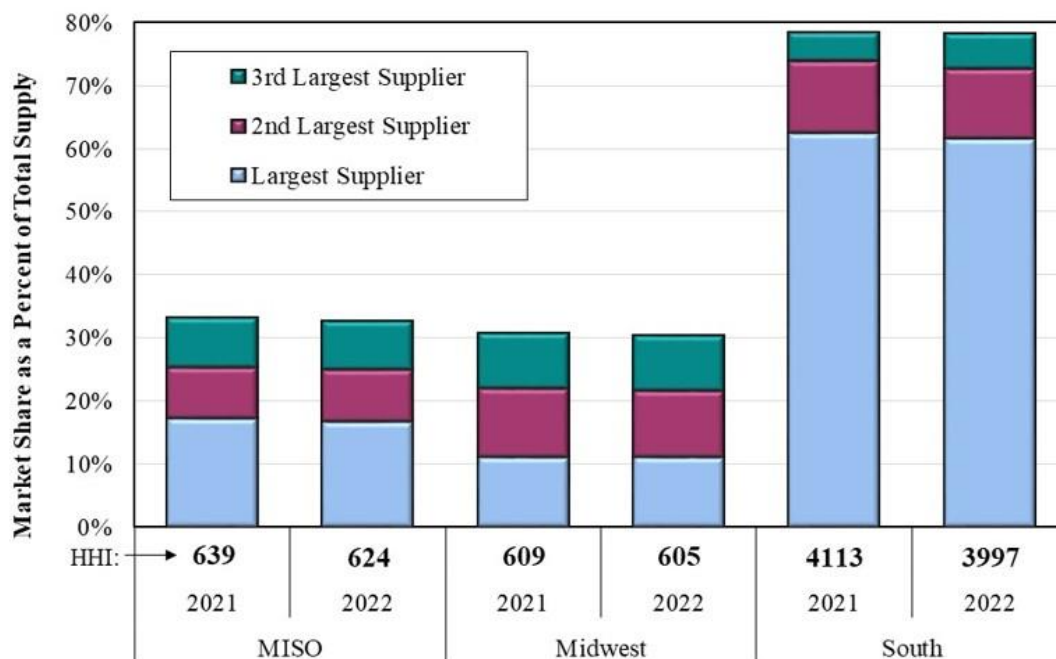
Market shares and the HHI are only general indicators of market concentration and not a definitive measure of market power. The most significant shortcoming of market shares and HHIs for identification of market power in electricity markets is that they generally do not account for demand or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness. Because market shares and HHI do not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, these measure alone do not allow for conclusive inferences regarding the overall competitiveness of electricity markets. The next two analyses more accurately reveal potential competitive concerns in the MISO markets.

Figure A134: Pivotal Supplier Frequency by Region and Load Level

A better measure of potential market power is the pivotal supplier metric. This metric considers both the supply, demand, and import capability into the market. A supplier is pivotal when some of its resources are needed to satisfy the demand (i.e., it is a monopolist over some portion of the load).

Figure A134 summarizes the results of this analysis, showing the percentage of total hours with a pivotal supplier by region and load level. Prices are most sensitive to withholding under high-load conditions, which makes it more likely that a supplier could profitably exercise market power in those hours. The percentages shown below the horizontal axis indicate the share of hours that comprise each load-level share.

Figure A134: Pivotal Supplier Frequency by Region and Load Level
2021–2022
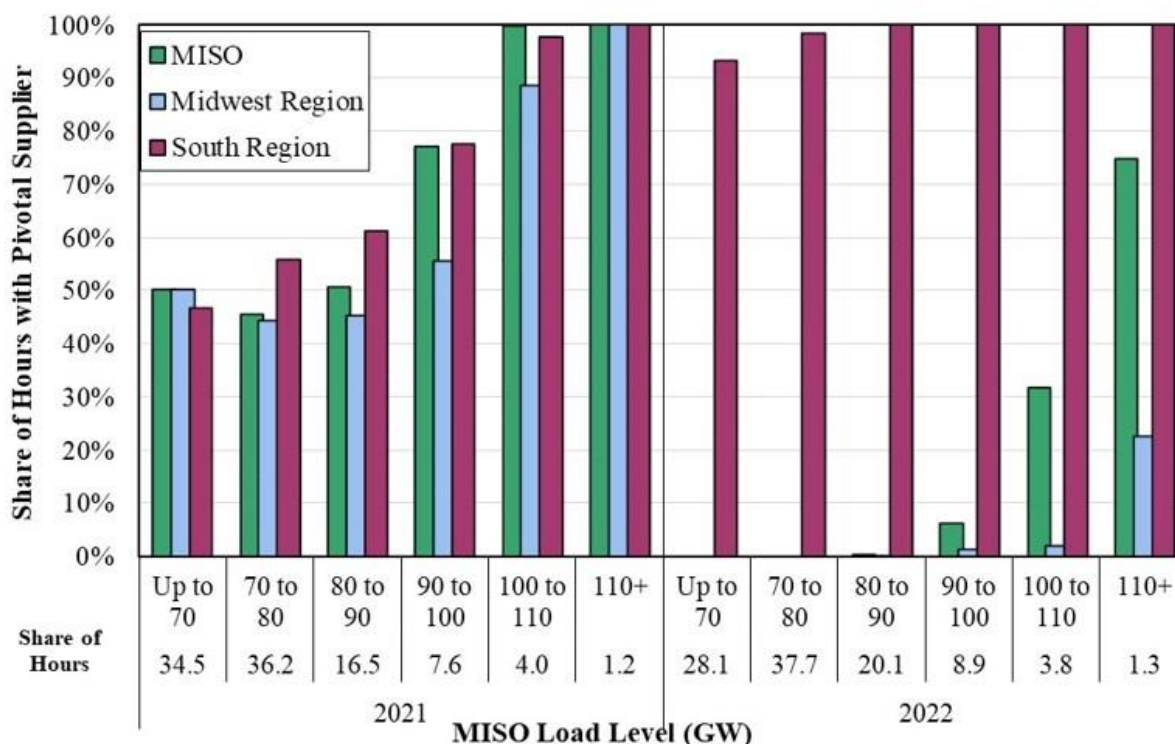
While the regional pivotal supplier analysis is useful for evaluating a market's competitiveness, the best approach for identifying local market power requires a still more detailed analysis focused on specific transmission constraints that can isolate locations on the transmission grid. Such analyses, by specifying when a supplier is pivotal relative to a particular transmission constraint, indicates local market power more precisely than either the HHI or RDI can.

A supplier is pivotal on a constraint when it has the resources to load the constraint to such an extent that all other suppliers combined are unable to relieve the constraint. This is frequently the case for lower-voltage constraints because the resources that most affect the flow over the constraint are those nearest to the constraint. If the same supplier owns all or a substantial share of these resources, that supplier is likely pivotal for managing the congestion on the constraint. As a result, such a supplier can potentially manipulate congestion and control prices.

Two types of constrained areas are defined for purposes of market power mitigation: Broad Constrained Areas (BCAs) and Narrow Constrained Areas (NCAs), including *Dynamic* Narrow Constrained Areas. The definitions of BCAs and NCAs are based on the electrical properties of the transmission network that can lead to local market power. NCAs are chronically constrained areas where one or more suppliers are frequently pivotal. As such, they can be defined in advance and are subject to tighter market power mitigation thresholds than BCAs. There are three NCAs in MISO Midwest (the Minnesota NCA, the WUMS NCA, and the North WUMS NCA) and two in MISO South (WOTAB and Amite South NCAs).[38]

Market power associated with BCA constraints can also be significant. When a non-NCA transmission constraint binds, a BCA is defined that includes all resources that significantly affects the power flows on the constraint. BCA constraints are not chronic like NCA constraints. However, they can raise competitive concerns. Because of the vast number of potential constraints and the fact that the topology of the transmission network can change significantly when outages occur, it is neither feasible nor desirable to define all possible BCAs in advance.

Figure A135 to Figure A136: Pivotal Suppliers on Transmission Constraints

The next two figures evaluate potential local market power by showing the frequency with which suppliers are pivotal on individual NCA and BCA constraints. Figure A135 shows the percentage of all market intervals, by season, during which at least one supplier was pivotal for each type of constraint. Figure A136 shows the percentage of the intervals with active constraints in each season with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs in the Midwest region are combined.

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[38]   Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, the conduct-impact thresholds that applied to the NCAs for the second half of 2022 ranged from $24.35 per MWh in Minnesota to $100.00 per MWh in Amite South. The North WUMS, WUMS, and WOTAB thresholds were $417.08, $30.98, and $100 per MWh, respectively. The NCA thresholds are updated annually on June 1.

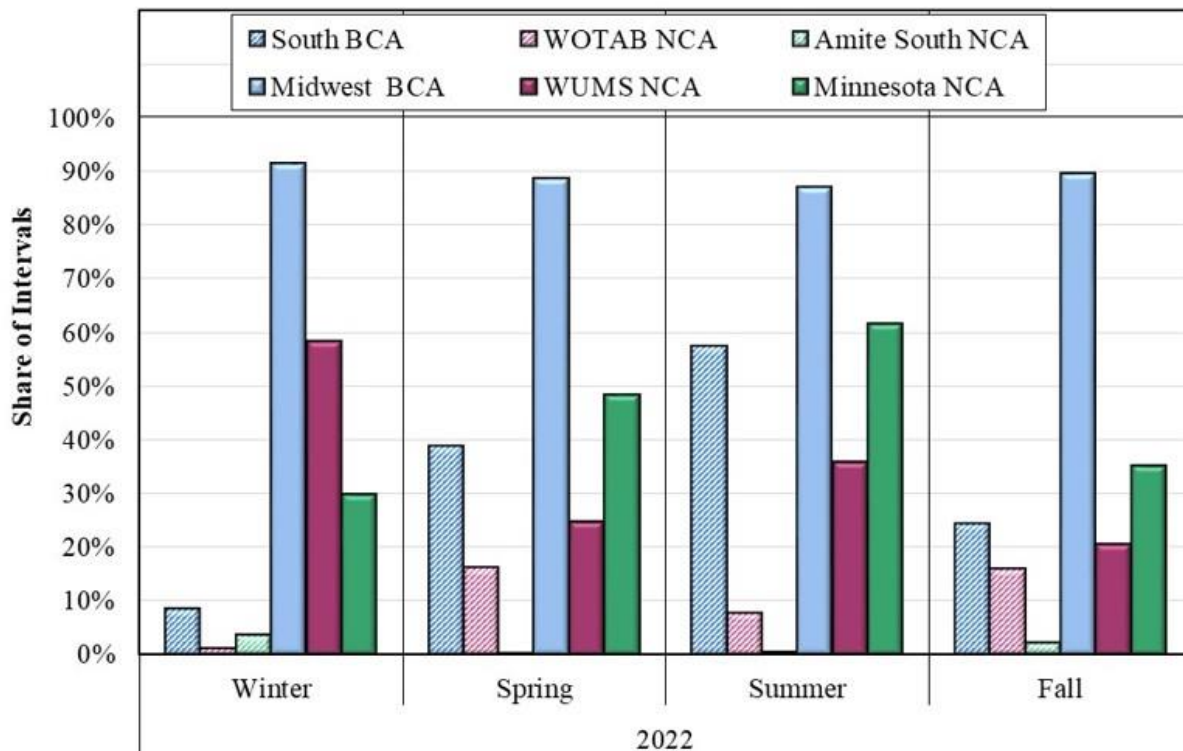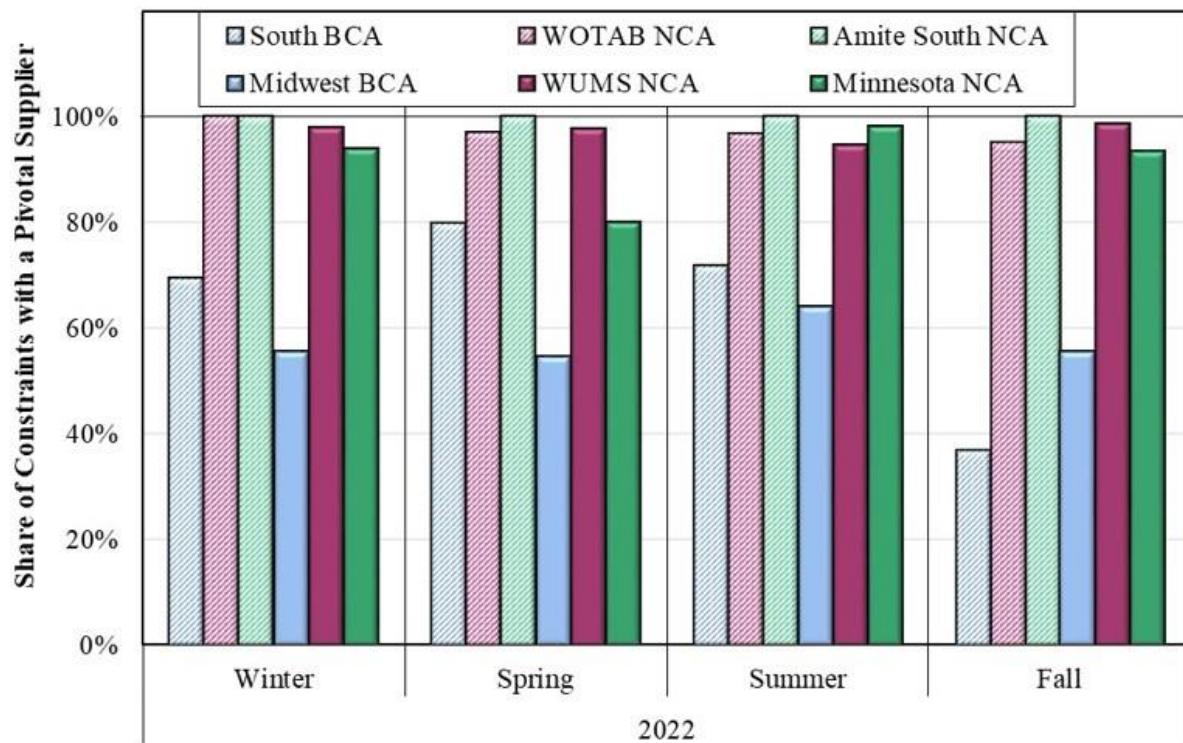**Figure A135: Percentage of Intervals with at Least One Pivotal Supplier**
2022

Figure A136: Percentage of Active Constraints with a Pivotal Supplier
2022

B.   Participant Conduct – Price-Cost Mark-Up

The structural analyses in the prior subsection indicate the likely presence of local market power associated with transmission constraints in the MISO market area. In the next three subsections, we analyze participant conduct to determine whether it was consistent with competitive behavior or whether there were indications of attempts to exercise market power. We test for two types of conduct consistent with the exercise of market power: economic withholding and physical withholding. Economic withholding occurs when a participant offers its resource at a price substantially above a competitive offer (i.e., above its marginal cost) in an effort to raise market clearing prices or increase RSG payments. Physical withholding occurs when an economic unit is unavailable to produce some or all of its output. Such withholding is generally achieved by claiming an outage or derating a resource, although other physical parameters can be manipulated to achieve a similar outcome.

One metric to evaluate the competitive performance of the market is the price-cost mark-up, which estimates the "mark-up" of real-time market prices over suppliers' competitive costs. It compares a simulated SMP under two separate sets of assumptions: (1) suppliers offer at prices equal to their reference levels, and (2) suppliers' actual offers. We then calculate a yearly load-weighted average of the estimated SMP under each scenario. The percentage difference in estimated SMPs is the mark-up. This analysis does not account for physical restrictions on units and transmission constraints or potential changes in the commitment of resources, both of which would require re-running market software.

The price-cost mark-up metric is useful in evaluating the competitive performance of the market. A competitive market should produce a small mark-up because suppliers should have incentives to offer at their marginal costs. Offering above marginal costs under competitive conditions could lead to resources not clearing the market, which would result in lost revenue contributions to cover fixed costs. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs. Nonetheless, we found an average system marginal price-cost mark-up of -5 percent in 2022, varying monthly from a high of 6.2 percent to a low of -17 percent. Multiple coal-fired resources' references were impacted by coal conservation measures to ensure sufficient coal inventory could be maintained at the plants in spite of multiple supply chain constraints.

C.   Participant Conduct – Potential Economic Withholding

An analysis of economic withholding requires a comparison of actual offers to competitive offers. Suppliers lacking market power maximize profits by offering resources at their marginal costs. A generator's marginal cost is its incremental cost of producing additional output. Marginal cost may include inter-temporal opportunity costs, risk associated with unit outages, fuel, variable operations and maintenance (O&M), and other costs attributable to the incremental output. For most fossil fuel-fired resources, marginal costs are closely approximated by variable production costs that primarily consist of fuel and variable O&M costs.

However, marginal costs can exceed variable production costs. For instance, operating at high output levels or for long periods without routine maintenance can cause a unit to face an increased risk of outage and O&M costs. Additionally, generating resources with energy

limitations, such as hydroelectric units or fossil fuel-fired units with output restrictions because of environmental considerations, may forego revenues in future periods to produce in the current period. These units can incur inter-temporal opportunity costs of production that can ultimately cause their marginal cost to exceed variable production cost.

Establishing a competitive benchmark for each offer parameter, or "reference level," for each unit is a key component of identifying economic withholding. MISO's market power mitigation measures include a variety of methods to calculate a resource's reference levels.[39] We use these reference levels for the analyses below and in the application of mitigation. The comparison of offers to competitive benchmarks – reference prices plus the applicable threshold specified in the Tariff – is the "conduct test," which is the first prerequisite for imposing market power mitigation. The second prerequisite is the "impact test," which requires that the identified conduct significantly affect market prices or guarantee payments.

To identify potential economic withholding, we calculate an "output gap" metric based on a resource's startup, no-load, and incremental energy offer parameters. The output gap is the difference between the economic output level of a unit at the prevailing clearing price, based on the unit's reference levels, and the amount actually produced by the unit. In essence, the output gap quantifies the generation that a supplier may be withholding from the market by submitting offers above competitive levels. Therefore, the output gap for any unit would generally equal:

$Q_i^{econ} - Q_i^{prod}$ when greater than zero, where:

$$Q_i^{econ} = \text{Economic level of output for unit i; and}$$
$$Q_i^{prod} = \text{Actual production of unit i.}$$

To estimate Q_i^{econ}, the economic level of output for a particular unit, it is necessary to look at all parts of a unit's three-part reference level: start-up cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time.

We employ a three-stage process to determine the economic output level for a unit in a particular hour. First, we examine whether the unit would have been economic for commitment on that day if it had offered our estimate of its marginal costs. In other words, we examine whether the unit would have recovered its actual startup, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP, constrained by the unit's economic minimum and maximum, for its minimum run time. Second, if a unit was economic for commitment, we then identify the set of contiguous hours when it was economic to dispatch.

Finally, we determine the economic level of incremental output in hours when the unit was economic to run. When the unit was not economic to commit or dispatch, the economic level of output was considered to be zero. To reflect the timeframe when such commitment decisions are

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[39]   See Module D, Section 62.a, which states: "These market power Mitigation Measures are intended to provide the means for the Transmission Provider to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the Markets and Services administered by the Transmission Provider, while avoiding unnecessary interference with competitive price signals."

typically made in practice, this assessment was based on day-ahead market outcomes for non-quick-start units and on real-time market outcomes for quick-start units.

Our benchmarks for units' marginal costs are imperfect, particularly during periods with volatile fuel prices. Hence, we add a threshold to the resources' reference level to determine Q_i^{econ}. This ensures that we will identify only significant departures from competitive conduct. The thresholds are based on those defined in the Tariff for BCAs and NCAs and are described in more detail below.

Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers. This would indicate transmission constraints, reserve considerations, or other changes in market conditions between the unit commitment and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. Hence, the output gap formula used for this report is:

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:

Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, we exclude infeasible energy that is due to ramp limitations from the output gap.

Figure A137: Economic Withholding – Output Gap Analysis

Figure A137 shows monthly average output gap levels for the real-time market in 2021 and 2022. The output gap shown in the figure and in the table includes two types of units:

   (1) online and quick-start units available in real time, and

   (2) offline units that would have been economic to commit.

The data are arranged to show the output gap using the mitigation threshold in each area ("high threshold") and one-half of the mitigation threshold ("low threshold"). Resources located in NCAs are tested at the comparatively tighter NCA conduct thresholds, and resources outside NCAs are tested at BCA conduct thresholds.

The high threshold for resources in BCAs is the lower of $100 per MWh above the reference or 300 percent of the reference. Within NCAs the high thresholds that were effective beginning on June 1, 2022 were $30.98 per MWh for resources located in the WUMS NCA, $17.08 for those in the North WUMS NCA, $24.35 for those in the Minnesota NCA, and $100.00 for both the WOTAB and Amite South NCAs. The low threshold is set to 50 percent of the applicable high threshold for a given resource. For example, for a resource in Amite South, the low threshold would be $50.00 per MWh, or 50 percent of $100.00. For a resource's unscheduled output to be included in the output gap, its offered commitment cost per MWh or incremental energy offer must exceed the given resource's reference, plus the applicable threshold. The lower threshold would indicate potential economic withholding of output that is offered at a price significantly above its reference yet within the mitigation threshold.

Figure A137: Economic Withholding – Output Gap Analysis
2021–2022

Low Threshold Results by Unit Status (MW)

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

High Threshold Results by Unit Status (MW)

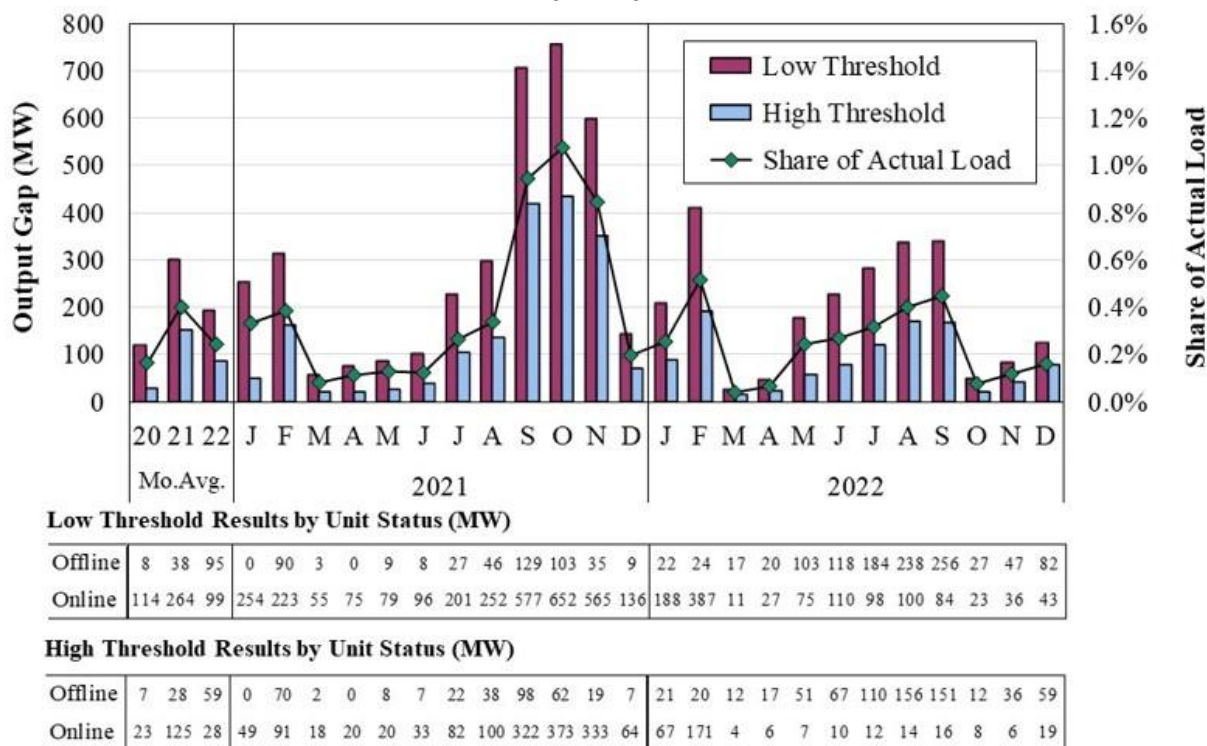|				J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	7	28	59	0	70	2	0	8	7	22	38	98	62	19	7	21	20	12	17	51	67	110	156	151	12	36	59
Online	23	125	28	49	91	18	20	20	33	82	100	322	373	333	64	67	171	4	6	7	10	12	14	16	8	6	19

Figure A138 to Figure A141: Real-Time Average Output Gap and Load

Any measure of potential withholding inevitably includes some quantities that can be justified. Therefore, we generally evaluate not only the absolute level of the output gap but also how it varies with factors that can cause a supplier to have market power. This process lets us test if a participant's conduct is consistent with attempts to exercise market power.

The most important factors in this type of analysis are participant size and load level. Larger suppliers generally are more likely to be pivotal and tend to have greater incentive to increase prices than relatively smaller suppliers. Load level is important because the sensitivity of the price to withholding usually increases with load, particularly at the highest levels. This pattern is due in part to the fact that rivals' least expensive resources will be more fully utilized serving load under these conditions, leaving only the highest-cost resources to respond to withholding.

The effect of load on potential market power was evident earlier in this section in the pivotal supplier analyses. The next four figures show output gap in each region by load level and by unit type (online and offline), and they show the two largest suppliers in the region versus all other suppliers separately. The figures also show the average output gap at the high and low mitigation thresholds defined above.

Figure A138: Real-Time Average Output Gap and Load
Central Region, 2022

MISO Load Level (GW) 2022
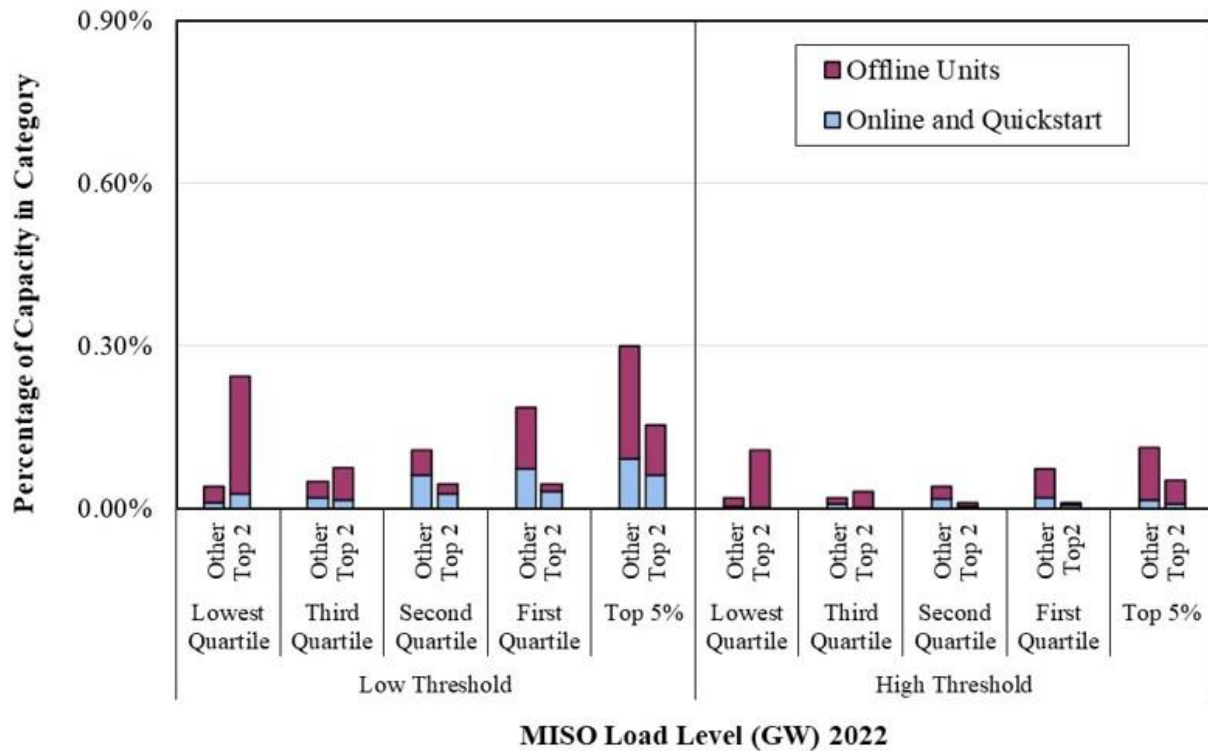
Figure A139: Real-Time Average Output Gap and Load
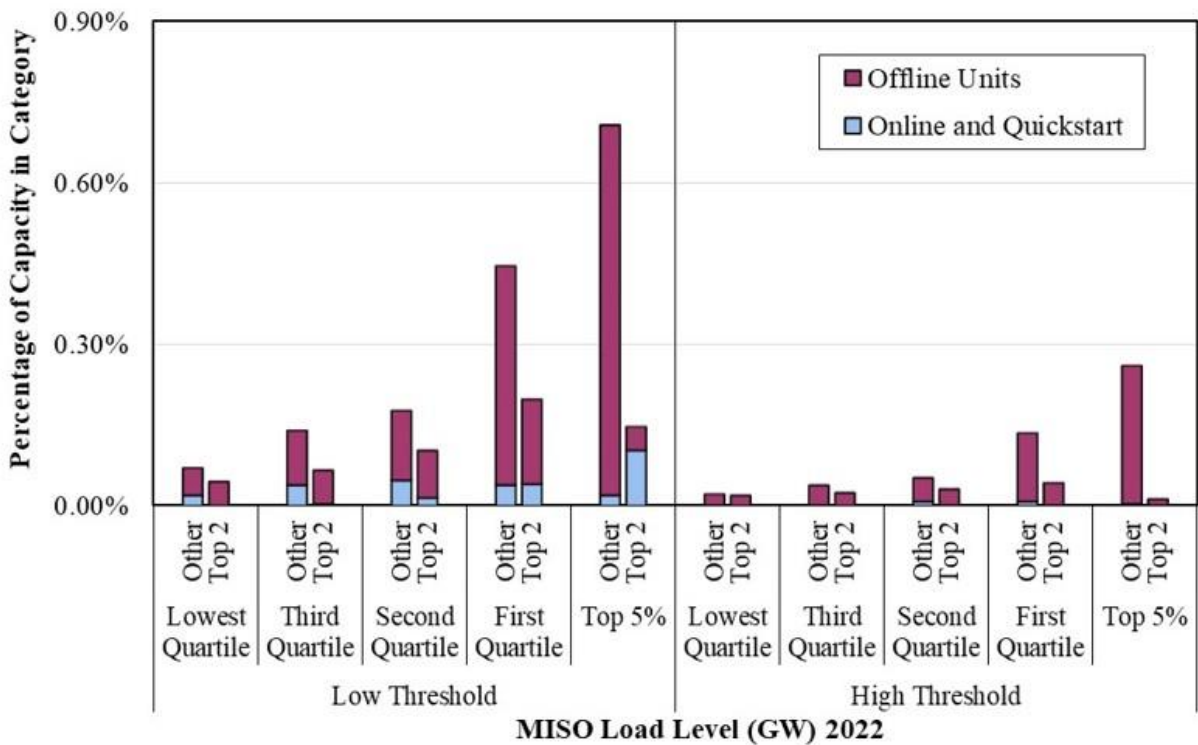MISO South, 2022

MISO Load Level (GW) 2022

Figure A140: Real-Time Average Output Gap and Load
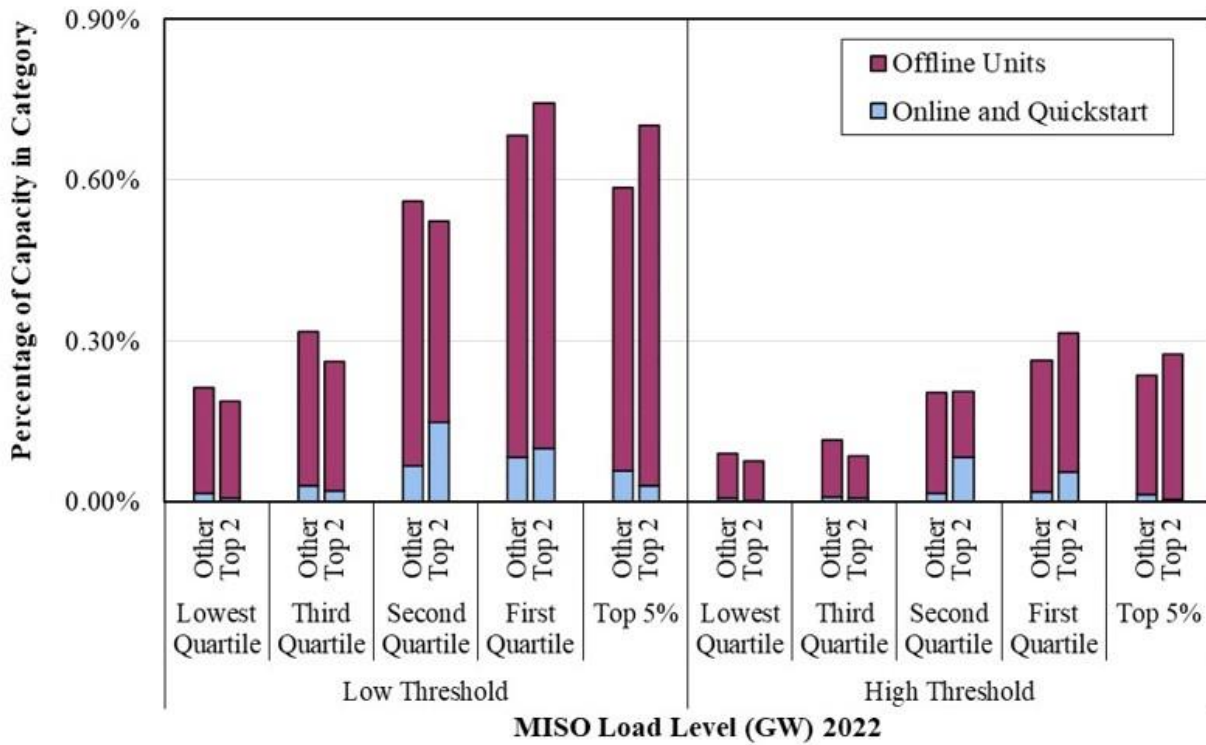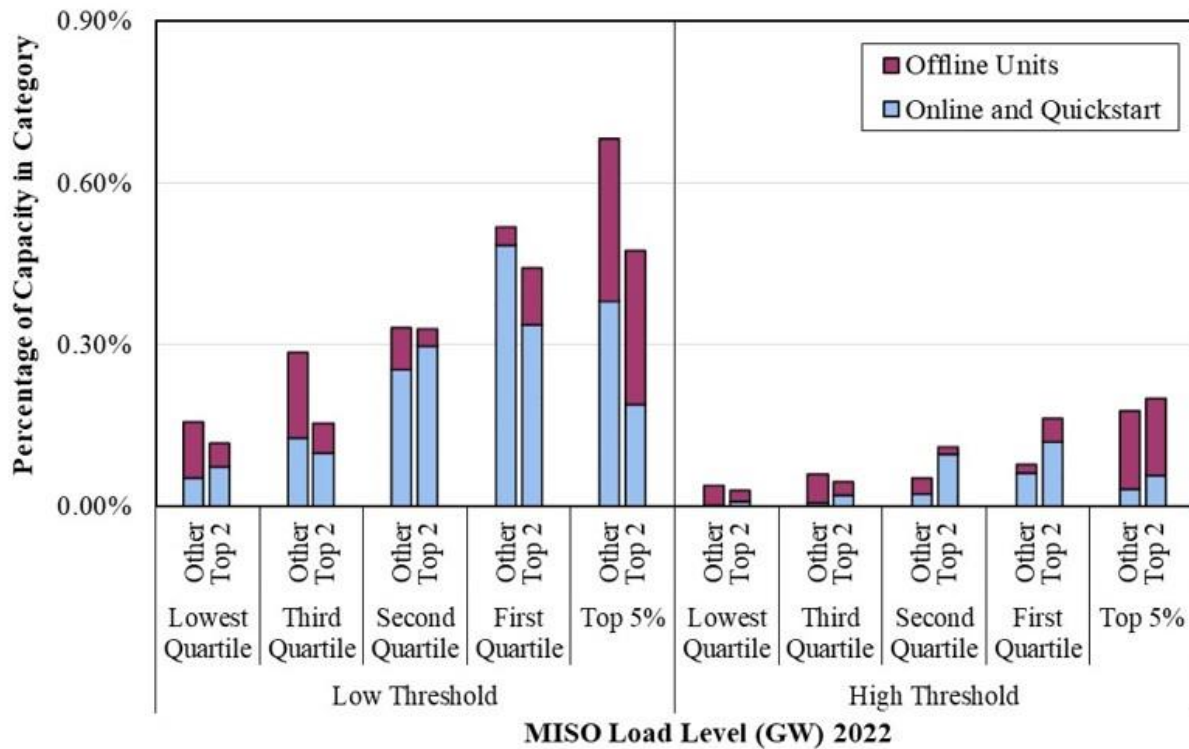North Region, 2022

Figure A141: Real-Time Average Output Gap and Load
WUMS Area, 2022

D.   Market Power Mitigation

In this next subsection, we examine the market power mitigation measures imposed in 2022. When the set of Tariff-specified criteria are met, a mitigated unit's offer price is capped at its reference level, which is a benchmark designed to reflect a competitive offer. MISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds and when the effects of that conduct on market outcomes exceed well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently while effectively mitigating abuses of market power.

Participants are subject to potential mitigation when transmission constraints bind that result in local market power. The mitigation thresholds differ for two types of constrained areas: BCAs and NCAs. Market power concerns are greater in chronically constrained NCAs where a supplier is typically pivotal. As a result, the conduct and impact thresholds for NCAs, which are a function of the frequency of the congestion, are generally lower than for BCAs.

Figure A142: Day-Ahead and Real-Time Energy Offer Mitigation by Month

Figure A142 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month.[40] Mitigation generally occurs more frequently in the real-time market because the day-ahead market has virtual participants and many more commitment and dispatch options available, both of which provide liquidity. This makes the day-ahead market much less vulnerable to withholding and market power.

**Figure A142: Day-Ahead and Real-Time Energy Offer Mitigation by Month**
2022
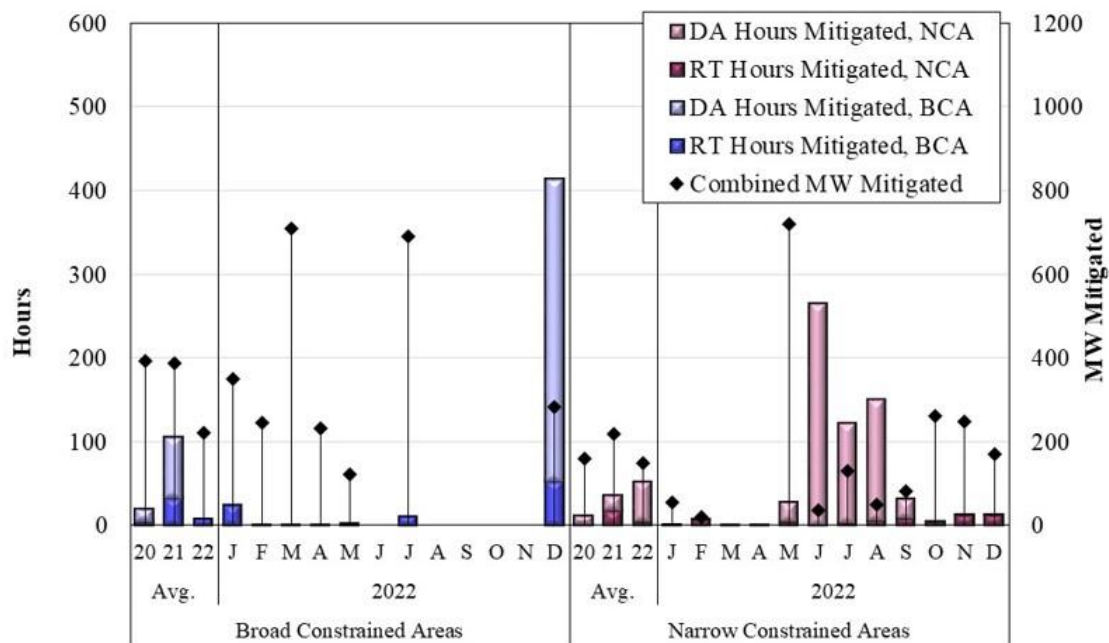
Note: Removed offer capping mitigations.

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[40]   Throughout the Winter Storm Uri and Winter Storm Elliott arctic events, real-time market mitigation measures were used to enforce the $1,000 per MWh soft offer cap and $2,000 per MWh hard offer caps.

Figure A143: Day-Ahead and Real-Time RSG Mitigation by Month

Participants can exercise market power by raising their offers when their units must be committed to resolve a constraint or to satisfy a local reliability requirement. This can compel MISO to make substantially higher RSG payments. MISO's mitigation measures address this conduct and are triggered when: (1) the unit is committed for a constraint or a local reliability issue; (2) the unit's offer exceeds the conduct threshold of: the greater of $25 or a 25 percent increase in production costs. Figure A143 shows the frequency and amount by which RSG payments were mitigated in 2021 and 2022 and average amounts for the last three years.[41]

Figure A143: Day-Ahead and Real-Time RSG Mitigation by Month
2021–2022

Note: Removed RT RSG offer capping mitigation.
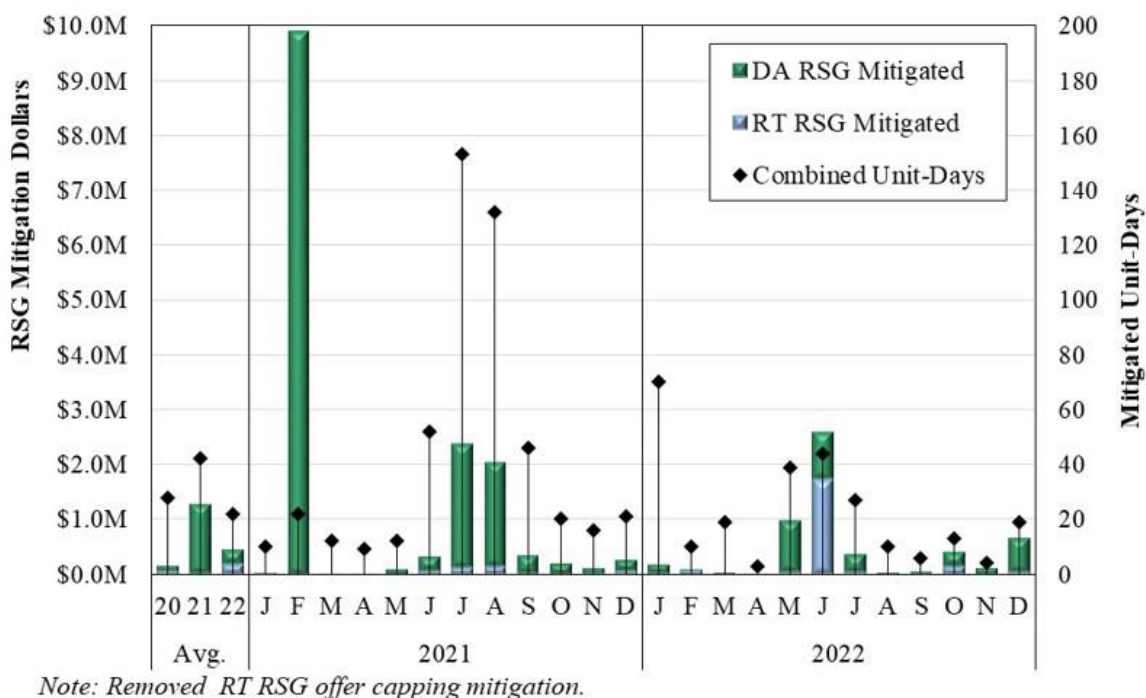
E.   Evaluation of RSG Conduct and Mitigation Rules

We routinely evaluate the effectiveness of the mitigation measures in addressing whether potential market power has been exercised to affect energy prices, ancillary services prices, or RSG payments. In this subsection we evaluate RSG-associated conduct.

Figure A144 to Figure A146: Real-Time RSG Payments by Conduct

We evaluate conduct associated with RSG payments in the following figures, separating the payments associated with resources' reference levels and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceeded their reference levels. The results are shown separately for units committed for capacity, regional capacity needs (i.e., the RDT), for VLR requirements, and for congestion management.

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[41]   Nearly $10 million of day-ahead RSG mitigation occurred during the February 2021 Winter Storm Uri event.

The "Mitigated" category includes day-ahead and real-time amounts. Figure A144 shows all of MISO, while Figures A145 and A146 distinguish between the Midwest and South, respectively.

Figure A144: Real-Time RSG Payments by Conduct
By Commitment Reason, 2022

2022 ($ Millions)	Capacity		Constraint		VLR		RDT		Total	
	$M	Share	$M	Share	$M	Share	$M	Share	$M	Share
Mitigated	0.0	0%	4.4	25%	0.0	0.0%	0.0	0.0%	4.4	2%
Other Conduct	6.6	5%	0.2	1%	1.4	2.8%	0.3	3.5%	8.5	4%
High Energy Offer	5.0	4%	0.7	4%	3.1	6%	0.3	4%	9.1	4%
High Commitment Costs	35.4	27%	3.9	22%	4.1	8%	4.0	51%	47.3	23%
RSG at Reference	82.8	64%	8.5	48%	41.6	83%	3.2	42%	136.1	66%
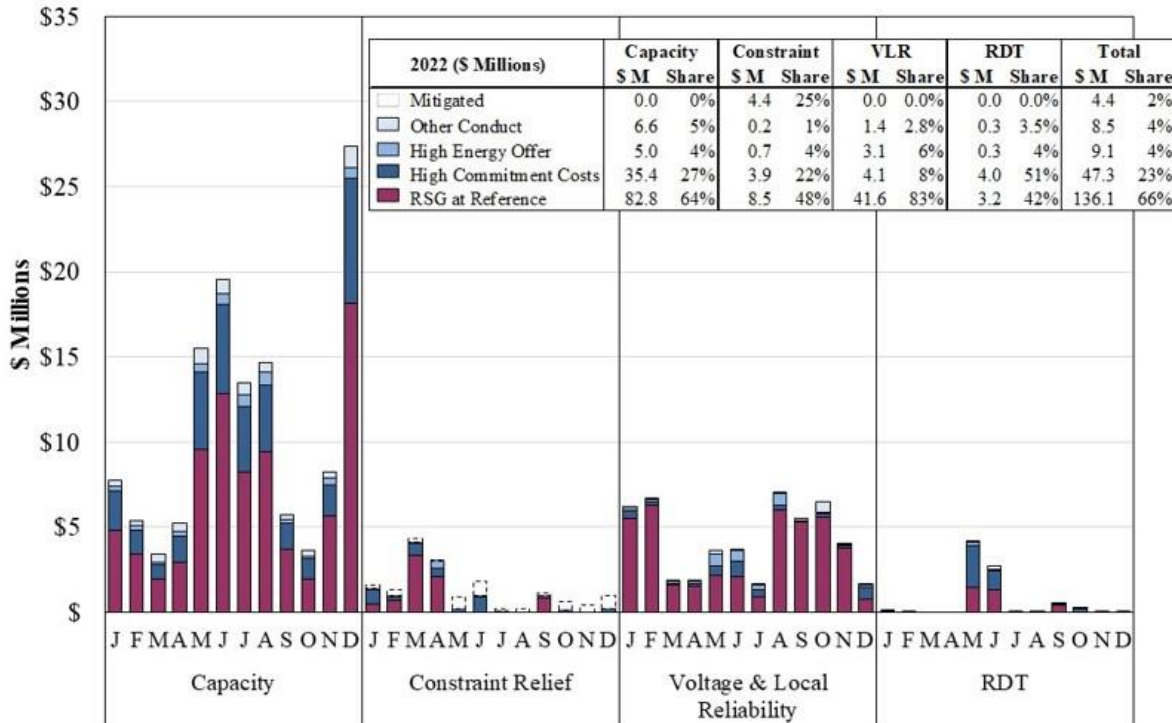
Figure A145: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2022

2022 ($ Millions)	Capacity		Constraint		VLR		RDT		Total	
	$M	Share	$M	Share	$M	Share	$M	Share	$M	Share
Other Conduct	4.8	5%	0.2	2%	0.1	1%	0.0	3%	5.0	5%
High Energy Offer	3.2	4%	0.2	2%	0.3	3%	0.0	3%	3.6	3%
High Commitment Costs	25.6	28%	2.1	28%	1.5	18%	0.1	61%	29.3	28%
RSG at Reference	57.0	63%	5.1	68%	6.4	77%	0.1	33%	68.6	64%
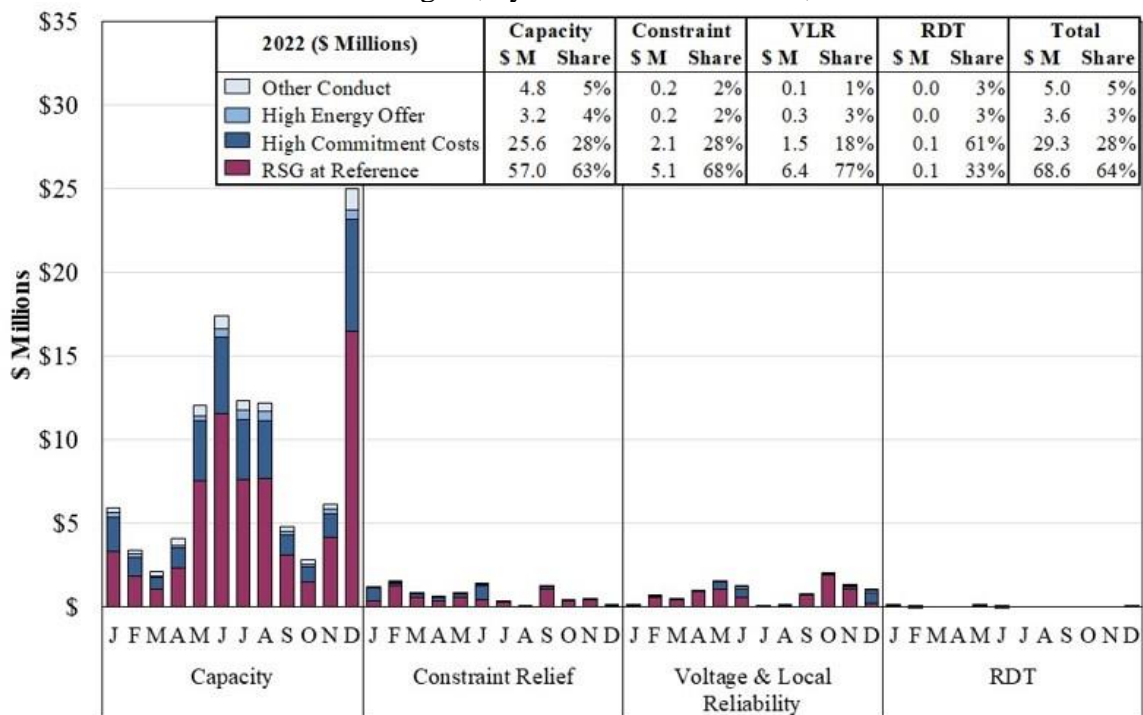
Figure A146: Real-Time RSG Payments by Conduct
MISO South, by Commitment Reason, 2022

2022 ($ Millions)	Capacity		Constraint		VLR		RDT		Total	
	$ M	Share	$ M	Share	$ M	Share	$ M	Share	$ M	Share
Other Conduct	0.8	4%	0.0	0%	1.1	3%	0.2	3%	2.1	3%
High Energy Offer	1.0	5%	0.5	6%	2.3	7%	0.2	4%	4.0	6%
High Commitment Costs	4.0	22%	1.1	15%	1.9	6%	3.2	51%	10.3	16%
RSG at Reference	12.2	68%	5.8	78%	28.4	84%	2.7	42%	49.0	75%
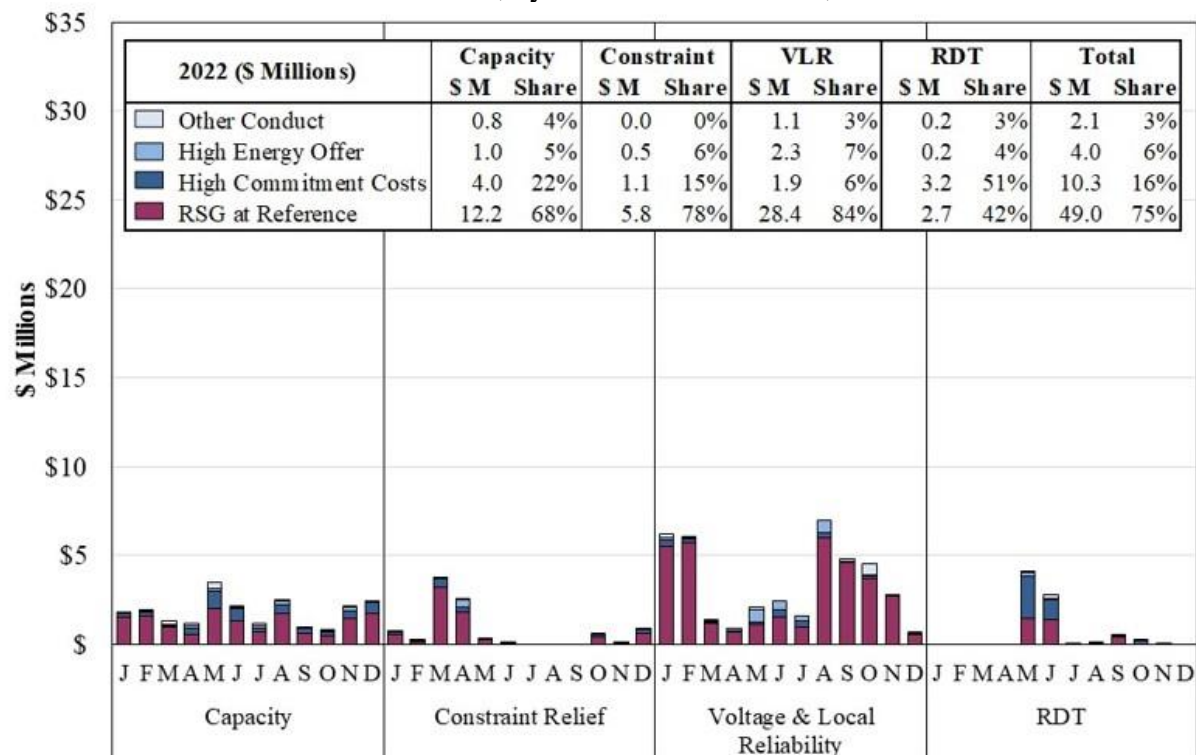
Prior to June 2015, the RSG mitigation measures included conduct tests that were performed on each bid parameter individually and employed a $50 per MW impact threshold. In contrast, the voltage and local reliability (VLR) mitigation utilizes a conduct test based on the aggregate as-offered production cost of a resource. This method recognizes the joint impact of all the resources' offer parameters. When units committed for VLR require an RSG payment, every dollar of increased production cost will translate to an additional dollar of RSG, so the conduct test also serves as an impact test.

In late June 2015, FERC approved a $25 or 25 percent conduct test for constraint commitments patterned after the VLR mitigation framework and eliminated the impact test. In August 2018, FERC approved MISO's mitigation authority for resources committed for the RDT in MISO South that employs the same mitigation measures as for resources committed for transmission congestion.[42] These changes have improved the effectiveness of the RSG mitigation measures.

F.   Participant Conduct – Ancillary Services Offers

In this section, we review the conduct of market participants in the ancillary services markets by summarizing the offer prices and quantities for spinning reserves and regulation.

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42   Docket No. ER18-1464-003.

Figure A147 to Figure A149: Ancillary Services Market Offers

Figure A147 to Figure A149 evaluate the competitiveness of ancillary services offers. These figures show monthly average quantities of regulation and spinning reserve offered at prices ranging from $10 to $50 per MWh above reference levels, as well as the share of total capability that those quantities represent.

Figure A147 shows the offers for all of MISO, while the two figures that follow separately show the offers in the MISO South and MISO Midwest regions. As in the energy market, ancillary services reference levels are resource-specific estimates of the competitive offer level for the service, which are the marginal costs of supplying the services. We exclude supplemental (contingency reserves) from this figure because this product is almost never offered at more than $10 per MWh above reference levels.

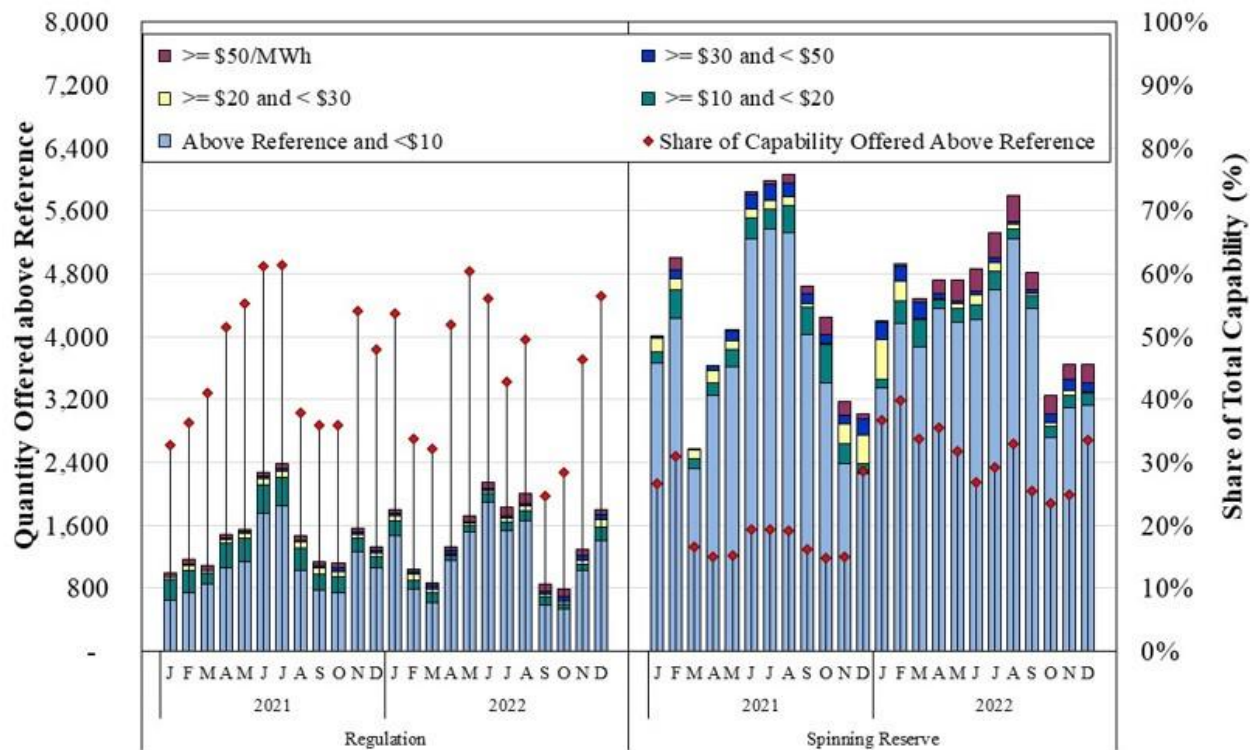**Figure A147: Ancillary Services Market Offers**
2021–2022

Figure A148: Ancillary Services Market Offers
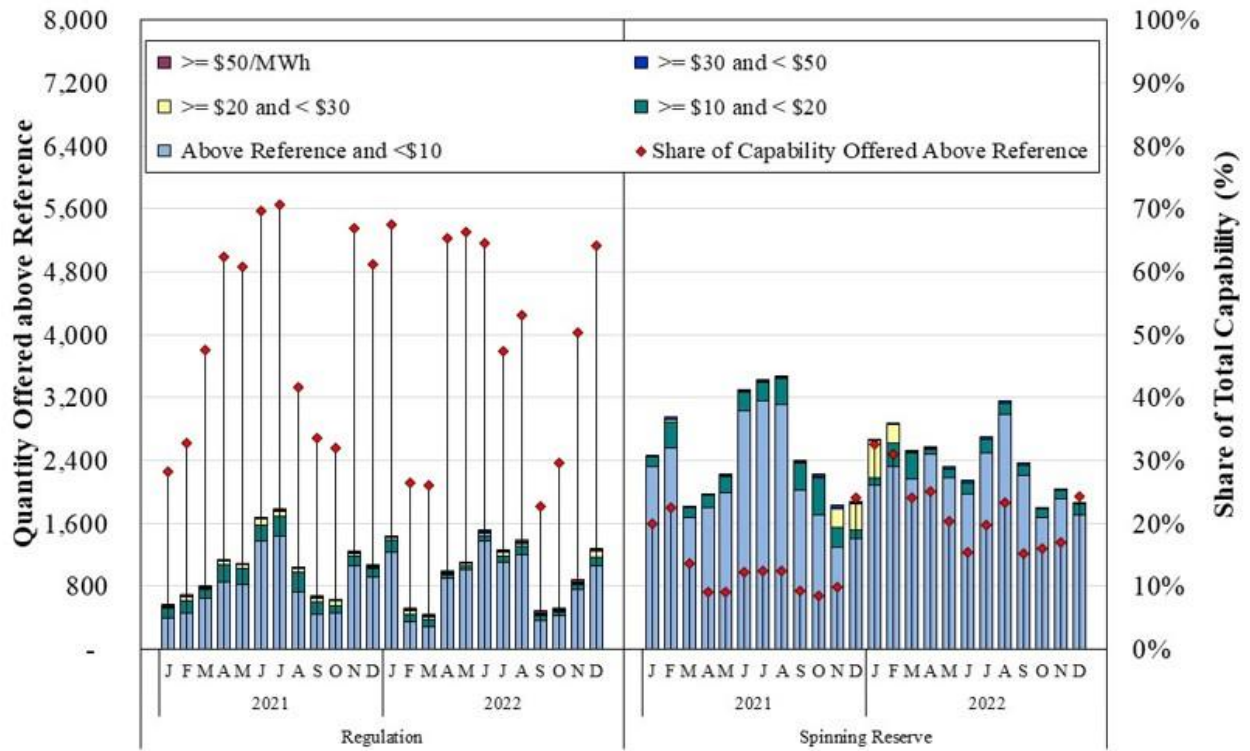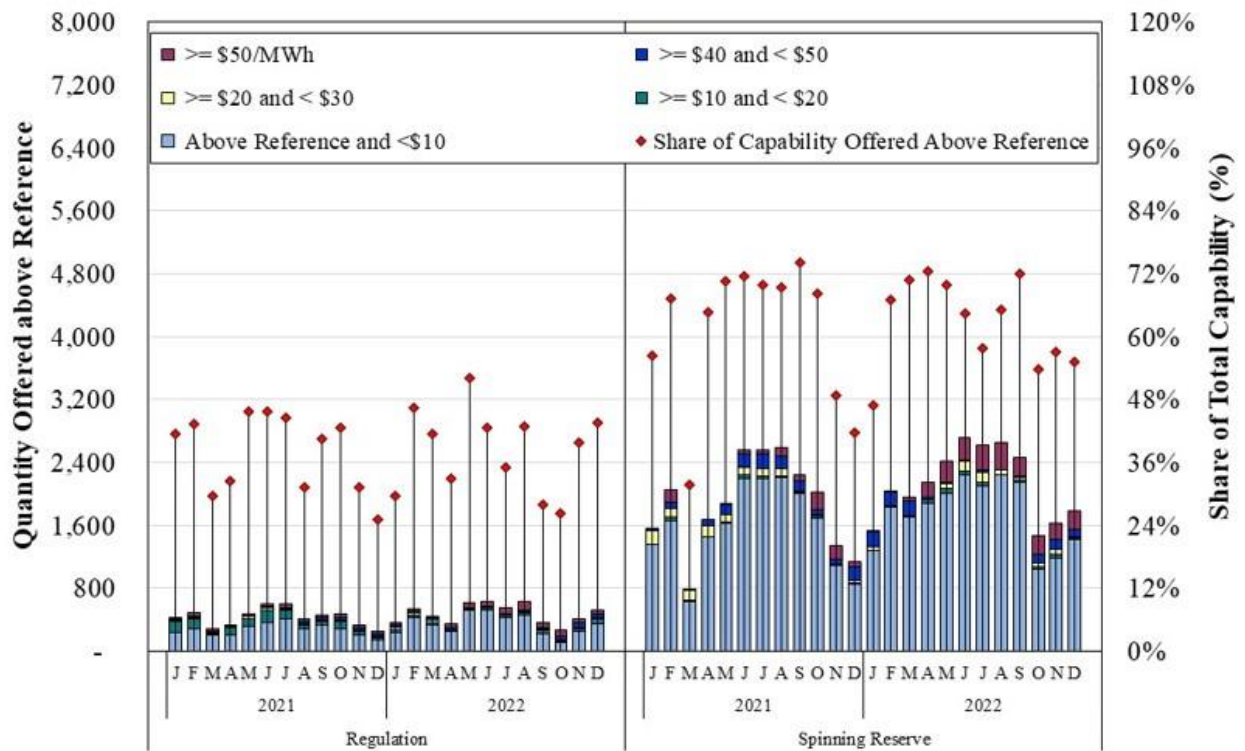Midwest Region, 2021–2022

Figure A149: Ancillary Services Market Offers
MISO South, 2021–2022

G.   Participant Conduct – Physical Withholding

The previous subsections analyzed offer patterns to identify potential economic withholding. By contrast, physical withholding occurs when a unit that would be economic at the prevailing market price is unavailable to produce some or all its output as a result of offering restricted physical parameters or declaring other conditions. For instance, this form of withholding may be accomplished by a supplier unjustifiably claiming an outage or derating its resource (lowering the economic maximum parameter). Although we analyze broad patterns of outages and deratings for this report, we also monitor for potential physical withholding on a day-to-day basis and audit outages and deratings that have substantial effects on market outcomes.

Figure A150 to Figure A152: Real-Time Deratings and Forced Outages

The following three figures show, by region, the average share of capacity unavailable to the market in 2022 because of forced outages and deratings. As with the output gap analysis, this conduct may be justifiable or may represent the exercise of market power. Therefore, we evaluate the conduct relative to load levels and participant size to detect patterns consistent with withholding. Attempts to withhold would likely occur more often at high-load levels when prices are most sensitive to withholding. We also focus particularly on short-term outages and short-term deratings that last fewer than seven days because long-term forced outages are less likely to be profitable withholding strategies. Taking a long-term, forced outage of a unit that would be economic during the outage would likely cause the supplier to forego greater potential profits on the unit during hours when the supplier does not have market power than it could earn in the hours in which it is exercising market power.

Figure A150: Real-Time Deratings and Forced Outages
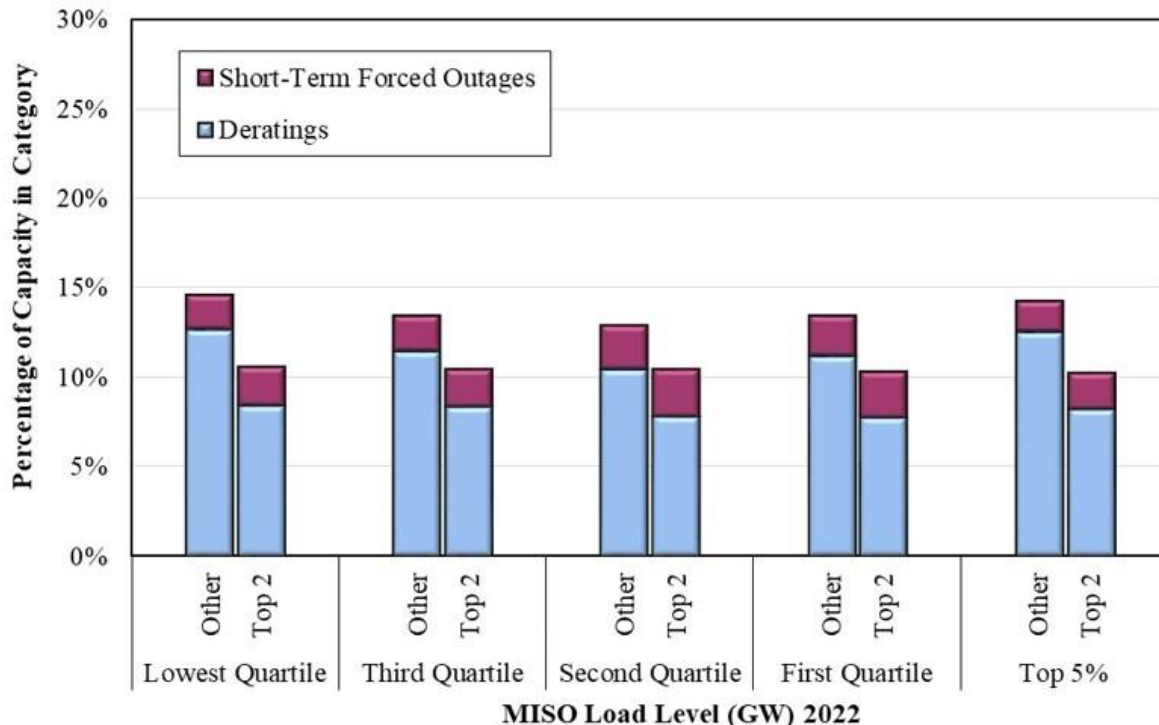Central Region, 2022

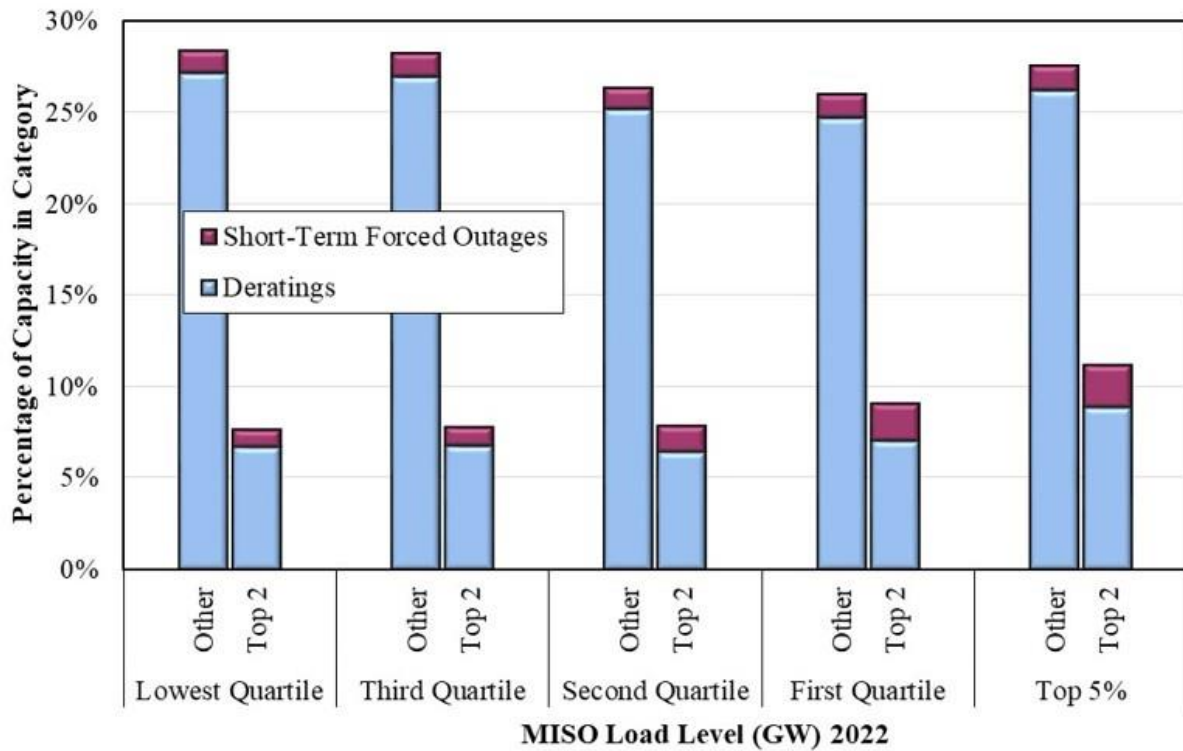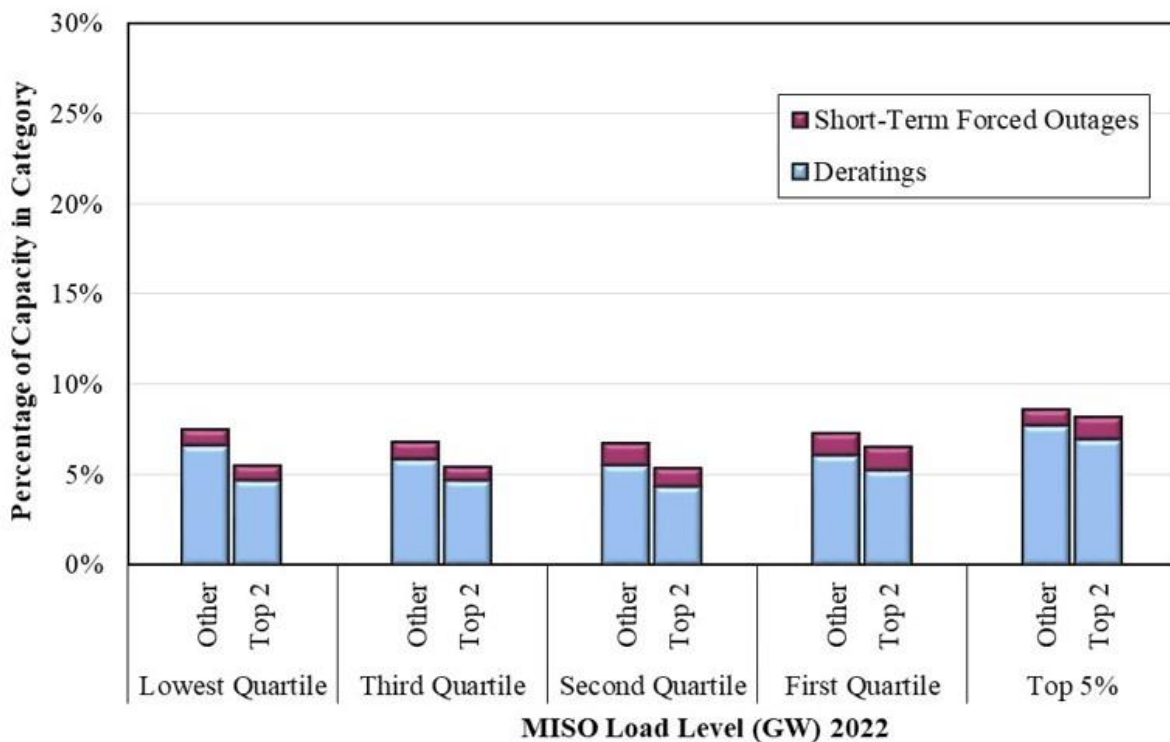**Figure A151: Real-Time Deratings and Forced Outages**
MISO South, 2022

Figure A152: Real-Time Deratings and Forced Outages
North Region, 2022

IX.   DEMAND RESPONSE PROGRAMS

Response (DR) involves actions taken to reduce consumption when the value of consumption is less than the marginal cost to supply the electricity. DR allows for participation in the energy markets by end users and contributes to reliability in the short term, least-cost resource adequacy, and (c) reductions in price volatility and other market costs. 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 DR through the wholesale markets.

A.   Demand Response Participation in MISO

DR resources are categorized as either: a) Emergency DR, which responds to capacity shortages; or b) Economic DR, which responds to market schedules.

Emergency DR. MISO calls emergency demand response resources in anticipation of a system emergency, thereby supporting reliability. However, emergency DR is not price-responsive and does not yet participate directly in the MISO markets. Emergency DR includes:

1. Load-Modifying Resources (LMRs) that are obliged to curtail in emergencies and satisfy planning reserve margin requirements (PRMR).

   - LMR-BTMG: These behind-the-meter generation assets do not have a direct interconnection to MISO.

   - LMR-DR: This primarily includes legacy interruptible demand administered under regulated utility programs.

2. Emergency Demand Response Resources (EDRs) that are called in emergencies but are not obliged to offer and do not satisfy MISO's PRMR.

LMRs can also register as Emergency Demand Response resources (EDRs), which participate differently than LMRs. EDRs submit offers on a day-ahead basis. During emergency conditions, MISO selects offers in economic merit-order based on the offered curtailment prices up to a $3,500-per-MWh LMP cap. EDR participants who curtail their demand are compensated at the greater of the prevailing real-time LMP or the offer costs (including shut down costs) for the amount of verifiable demand reduction provided. EDR resources are eligible to set the price.

Economic DR. These resources respond to energy market prices not only during emergencies, but at any time when energy prices exceed the marginal value of the consumer's electricity consumption. The real-time market is significantly more volatile than the day-ahead market because of physical limitations that affect its ability to respond to changes in load, interchange, and system contingencies, such as generator or transmission outages. DR resources tend to be more valuable in real time during abrupt periods of shortage when prices rise sharply.

In the day-ahead market, prices are less volatile and supply alternatives are much more available. Consequently, DR resources are generally less valuable in the day-ahead market. On a longer-term basis, however, consumers can shift consumption patterns in response to day-ahead prices, such as from peak to off-peak periods, thereby flattening the load curve. MISO's economic DR

is limited to two types of Demand Response Resources (DRRs) that economically respond to prices in the energy and ancillary services markets:

- DRR Type 1: These resources can supply a fixed quantity of energy or contingency reserves through physical load interruption. These resources provide a "Target Demand Reduction Amount". In ELMP, MISO includes DRR Type I resources as Fast-Start Resources that may set prices if they meet the eligibility requirements.

- DRR Type 2: These resources supply varying levels of energy or operating reserves on a five-minute basis and can set ex-ante prices. They are "dynamic pricing" resources – the most efficient form of DR because they set efficient prices throughout the day.

DRRs are eligible to participate in all of the MISO markets, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff. However, DRR Type I units cannot provide regulating reserves given their operating limitations.

Table A19: DR Capability in MISO and Neighboring RTOs

Table A19 shows total DR capabilities of MISO and neighboring RTOs. Because of differences in their requirements and responsiveness, individual classes of DR capability are not comparable.

Table A19: DR Capability in MISO and Neighboring RTOs
2020–2022

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

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

For resources outside of MISO, the following types of demand response are shown in the table:

- *Special Case Resources*: A demand response program that helps to maintain reliability by calling on electricity users to reduce consumption during times of shortage conditions.

- *On-Peak Resources*: Resources that will reduce consumption on summer non-holiday weekdays from 1–5 p.m. and on December-January non-holiday weekdays from 5–7 p.m.

- *Seasonal-Peak Resources*: Resources that reduce consumption during the months of January, June, July, August, and December in the times of highest load consumption.

B.   DRR Participation in Energy and Ancillary Services Markets

Figure A153: Energy Market Payments to DRR Type I Resources

Figure A153 shows all payments to DRR Type 1 resources over the past two years. It separates the payments into three categories:

- Legitimate payments for energy curtailments (blue) and ancillary services (green).

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

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

For both strategies, we calculated alternative baselines based on the average historic load of each DRR Type 1 resource. For *inflated baselines*, we multiplied the hourly real-time LMP at a resource's location times the difference between the actual baseline and the highest of the alternative baseline and the actual load. For *artificial curtailments*, we multiply the real-time LMP times the difference between the lower of the actual and alternative baselines and the load meter.

Figure A153: Energy Market Payments to DRR Type I Resources
2021–2022

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