2018 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKET

ANALYTIC APPENDIX

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Independent Market Monitor for the Midcontinent ISO

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I. Introduction

This Analytical Appendix provides an extended analysis of the topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, our conclusions from these analyses and how they relate to performance of the markets are discussed in the main body of the Report. In addition, the body of the Report includes a discussion of our recommendations to improve the design and competitiveness of the market.

MISO has operated competitive wholesale electricity markets for energy and financial transmission rights (FTRs) since April 2005. MISO added regulating and contingency reserve products (jointly known as ancillary services) in January 2009 and added a capacity market in June 2009. The capacity market was replaced in June 2013 by the annual Planning Resource Auction (PRA).

Key changes or improvements implemented in 2018 included:

- On January 4, FERC granted MISO the authority to define Dynamic Narrow Constrained Areas (DNCAs) consistent with our SOM Recommendation 2012-9.
- On July 1, MISO implemented five-minute real-time settlements.
- On August 23, FERC granted MISO RSG mitigation authority for resources committed in MISO South for the RDT constraint and granted MISO the authority to apply the Reserve Procurement Enhancement (RPE) to the RDT.
- In October, MISO filed to reform Uninstructed Deviation and related make-whole payments, which FERC approved in January 2019 and were implemented in May 2019.
- In December 2018, MISO filed Tariff changes as part of the Resource Availability and Need (RAN) efforts to improve testing and access to LMRs, which FERC approved in February and March of 2019.

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. discussed

A. 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. Although coal-fired resources historically have been marginal in a large share of hours, low natural gas prices in recent years have caused gas-fired units to be marginal in most peak hours. Additionally, congestion frequently causes gas-fired units to set prices in local areas.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly "all-in" price of electricity from 2017 to 2018 along with the price of natural gas at the Chicago Citygate trading hub. The leftmost section shows the annual average prices for 2016 through 2018. The all-in price represents the cost of serving load in MISO's real-time market. It includes the load-weighted real-time energy price, 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
2017–2018

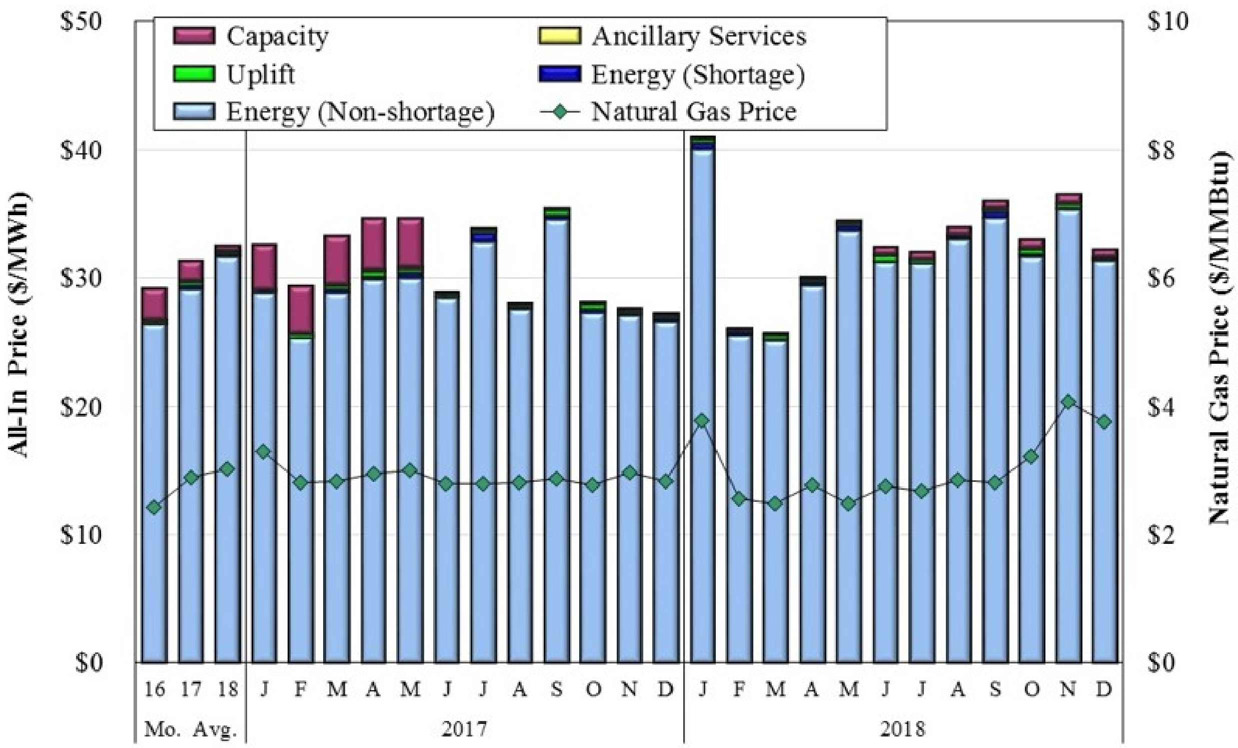


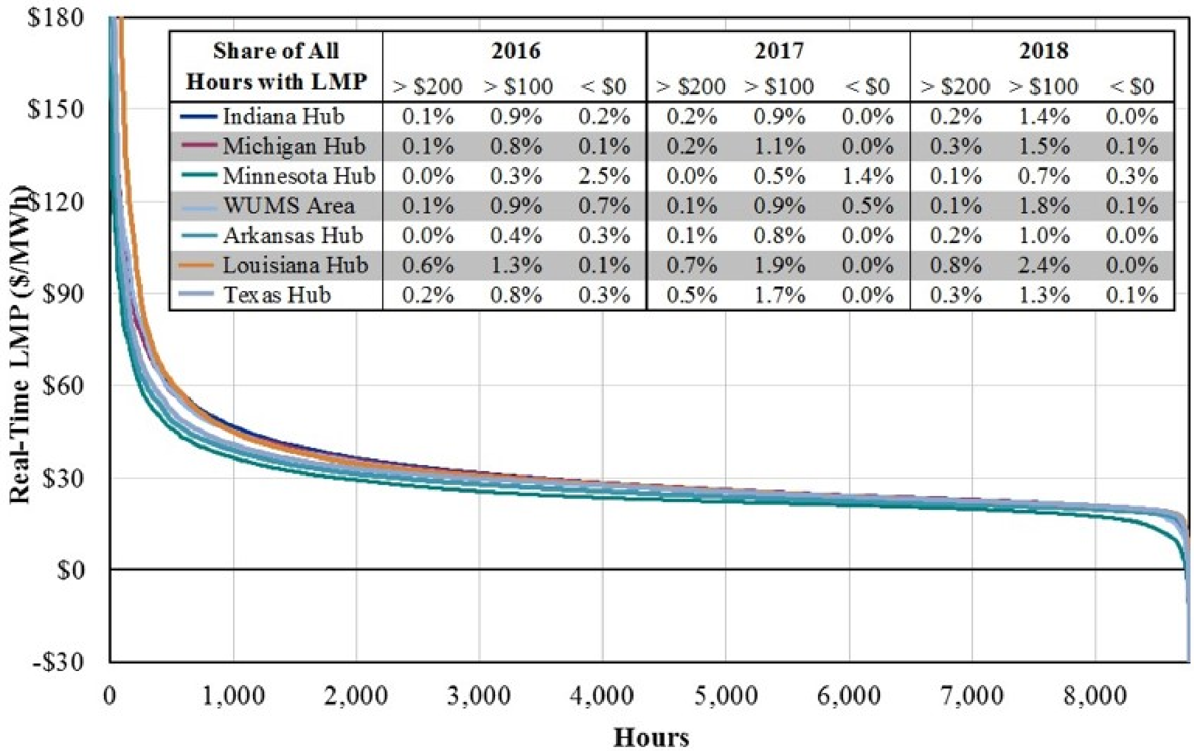
Figure A2: Real-Time Energy Price-Duration Curves

Figure A2 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 A2: Real-Time Energy Price-Duration Curve
2018



Share of All Hours with LMP	2016			2017			2018		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Indiana Hub	0.1%	0.9%	0.2%	0.2%	0.9%	0.0%	0.2%	1.4%	0.0%
Michigan Hub	0.1%	0.8%	0.1%	0.2%	1.1%	0.0%	0.3%	1.5%	0.1%
Minnesota Hub	0.0%	0.3%	2.5%	0.0%	0.5%	1.4%	0.1%	0.7%	0.3%
WUMS Area	0.1%	0.9%	0.7%	0.1%	0.9%	0.5%	0.1%	1.8%	0.1%
Arkansas Hub	0.0%	0.4%	0.3%	0.1%	0.8%	0.0%	0.2%	1.0%	0.0%
Louisiana Hub	0.6%	1.3%	0.1%	0.7%	1.9%	0.0%	0.8%	2.4%	0.0%
Texas Hub	0.2%	0.8%	0.3%	0.5%	1.7%	0.0%	0.3%	1.3%	0.1%

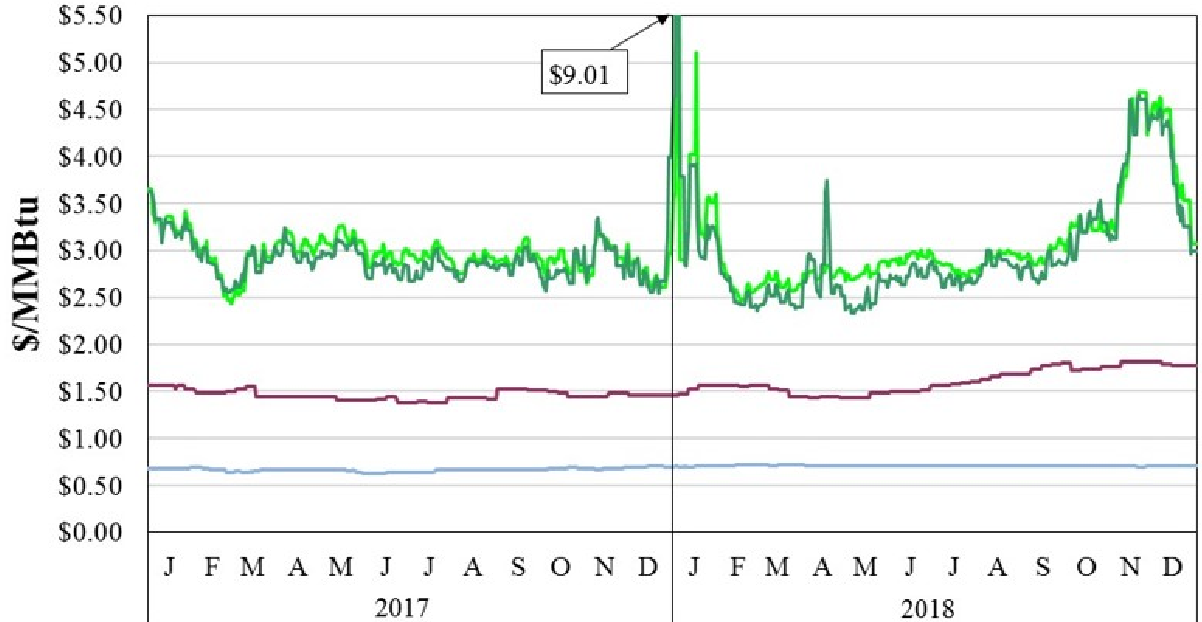
Figure A3: MISO Fuel Prices

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 A3 shows the prices for natural gas, oil, and two types of coal in the MISO region since the beginning of 2017.[1] The figure shows nominal prices in dollars per million British thermal units (MMBtu). The table below the figure shows the annual average nominal prices since 2016 for each type of fuel.

Figure A3: MISO Fuel Prices

2017–2018



Annual Average	2016	2017	2018
Chicago NG	$2.47	$2.90	$3.02
Henry NG	$2.48	$2.96	$3.12

Annual Average	2016	2017	2018
IB Coal	$1.31	$1.46	$1.61
PRB Coal	$0.58	$0.67	$0.71

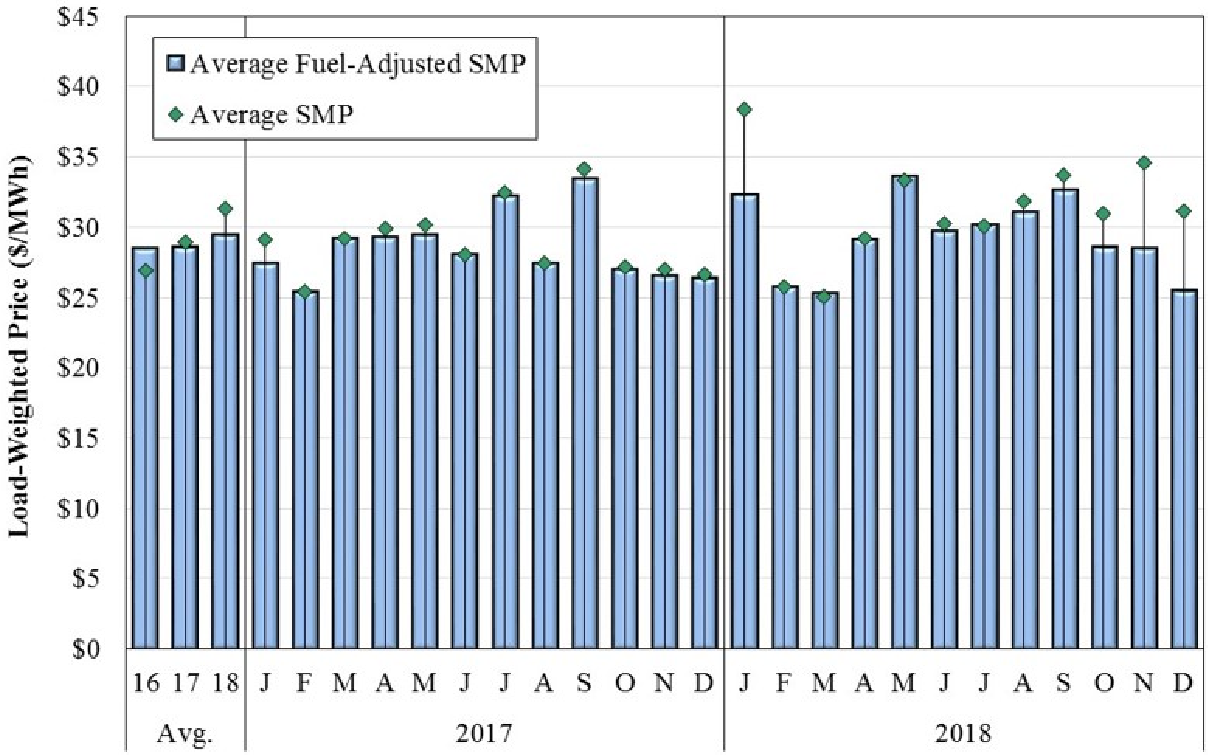
Figure A4: Fuel-Price-Adjusted System Marginal Price

Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. In Figure A4, we calculate a fuel-price-adjusted system marginal price (SMP). The SMP indicates the system-wide marginal cost of energy (excluding congestion and losses); the fuel adjustment isolates variations in prices that are due to factors other than fluctuations in fuel prices, such as changes in load, net imports, or available generation. The available generation can change from period to period as a result of unit additions or retirements and from interval to interval because of unit outages or deratings, congestion management needs, or output by intermittent resources.

1 Although output from oil-fired generation is typically minimal, it can become significant if natural gas supplies are interrupted during peak winter load conditions. The majority of MISO coal-fired generators have historically received supplies from the Powder River Basin or other Western supply areas.

To calculate this metric, the SMP of each real-time interval was indexed to the average fuel price of the marginal fuel from 2016 through 2018. Downward adjustments were the greatest when fuel prices were the highest and vice versa. Multiple fuels may be marginal, so we calculate each interval's SMP adjustment on a quantity-weighted basis. This methodology does not account for some impacts of fuel price variability, such as changes in generator commitment and dispatch patterns or relative inter-regional price differences—the result of differences in regional generation mix—that would impact the economics of interchange with neighboring areas.

Figure A4: Fuel Price-Adjusted System Marginal Price
2017–2018



B. Price Setting by Fuel Type

Figure A5: Price Setting by Unit Type

Figure A5 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 have historically set price in the majority of hours, that share has been declining over time. The year 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 A5: Price-Setting by Unit Type
2017–2018

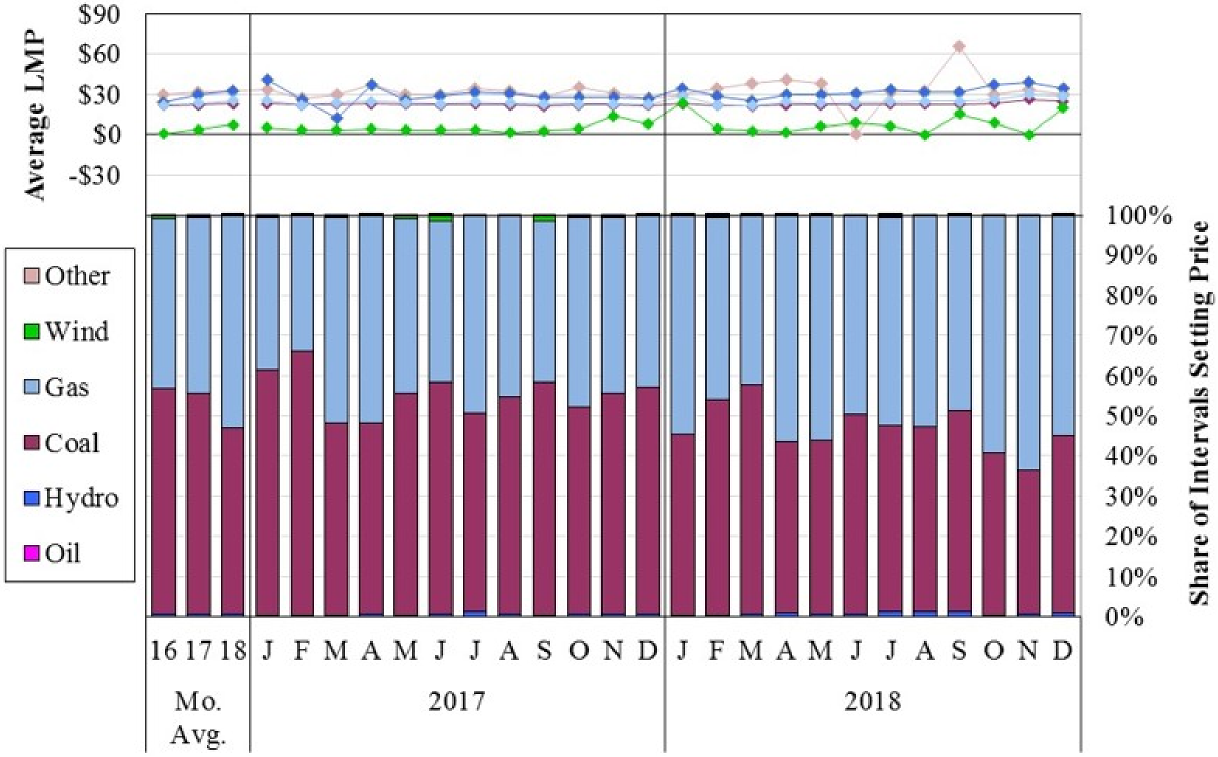


Table A1: Capacity, Energy Output and Price-Setting by Fuel Type

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 2018 compared to 2017. The lowest marginal cost resources (coal and nuclear) produce most of the energy. Because they are higher marginal-cost resources, natural gas-fired units 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
2017–2018

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2017	2018	2017	2018	2017	2018	2017	2018	2017	2018
Nuclear	12,420	12,225	10%	10%	16%	16%	0%	0%	0%	0%
Coal	50,843	48,775	39%	38%	47%	46%	55%	46%	84%	78%
Natural Gas	55,794	55,240	43%	43%	23%	27%	44%	53%	85%	87%
Oil	1,904	1,691	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,929	3,966	3%	3%	1%	1%	0%	1%	1%	1%
Wind	2,610	3,005	2%	2%	8%	8%	0%	0%	30%	31%
Other	2,273	2,678	2%	2%	4%	2%	0%	0%	4%	2%
Total	**129,773**	**127,580**								

C. Load Patterns

Figure A6: Load Duration Curves and Peak Load

Although market conditions can still be tight in the winter and shoulder seasons because of generation and transmission outages and fuel supply issues, MISO continues to be a summer-peaking market. To show the hourly variation in load, Figure A6 shows load levels for 2018 and prior years in the form of hourly load duration curves. The load duration 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 2016 through 2018 separately.

These 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 of load. The figure shows the actual and predicated peak load for 2018. The "Predicted Peak (50/50)" is the predicted peak load in 2018 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 A6: Load Duration Curves and 2018 Peak Load
2016–2018

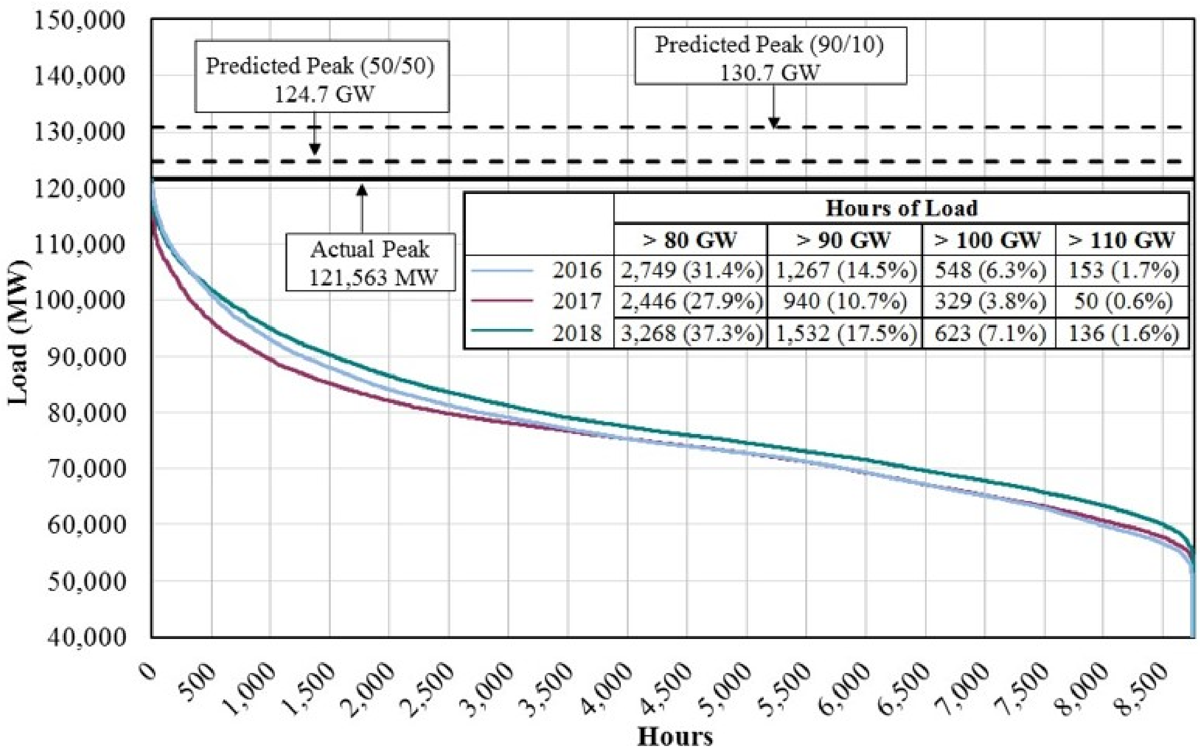
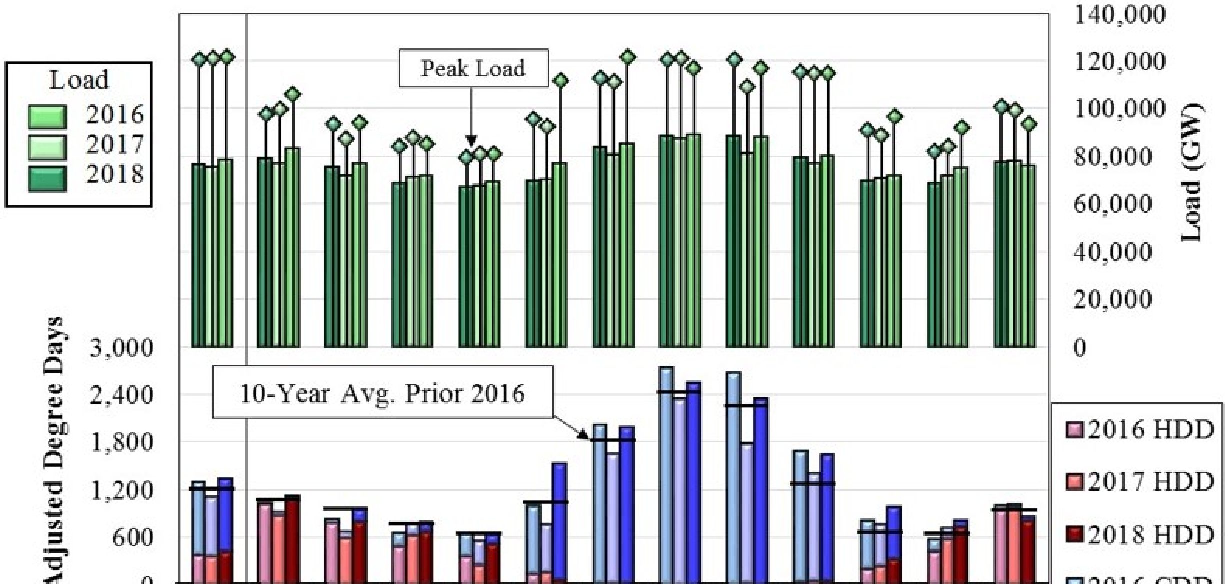


Figure A7: Heating and Cooling Degree-Days

MISO's load is temperature sensitive. Figure A7 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 2016 across four representative cities in MISO Midwest and two cities in MISO South.[2] The table at the bottom shows the year-over-year changes in average load and degree-days.

Figure A7: Heating and Cooling Degree-Days
2016–2018



% Chg 17-18	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	4%	8%	7%	1%	3%	10%	5%	2%	8%	4%	1%	4%	-3%
Degree Days	21%	20%	42%	2%	13%	103%	20%	9%	31%	16%	29%	13%	-16%

D. Net Revenue Analysis

In this subsection, we summarize the long-run 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 net revenues to finance new investment when additional capacity is needed. However, even if the system is in long-run equilibrium, random factors in each year (e.g., weather conditions, generator availability, transmission topology

2 HDDs and CDDs are defined using aggregate 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.

changes, outages, or changes in fuel prices) will 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 9,800 Btu per kWh.[3] The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

Figure A8 and Figure A9: Net Revenue and Operating Hours

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. The CONE for a CT is estimated to be $89.61 per kW-year.[4] For a CC, the CONE is about $110.76 per kW-year. Cost changes for the CC resulted in a significant decline since last year.

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 for 2017 and 2018 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 drop lines 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.

3 These assumptions are used in the 2019 EIA Annual Energy Outlook. See: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

4 The CONE value for the CT is published each year by the IMM along with the assumptions for the purposes of establishing offer caps in Narrow Constrained Areas.

Figure A8: Net Revenue and Operating Hours
MISO Midwest Region, 2016–2018

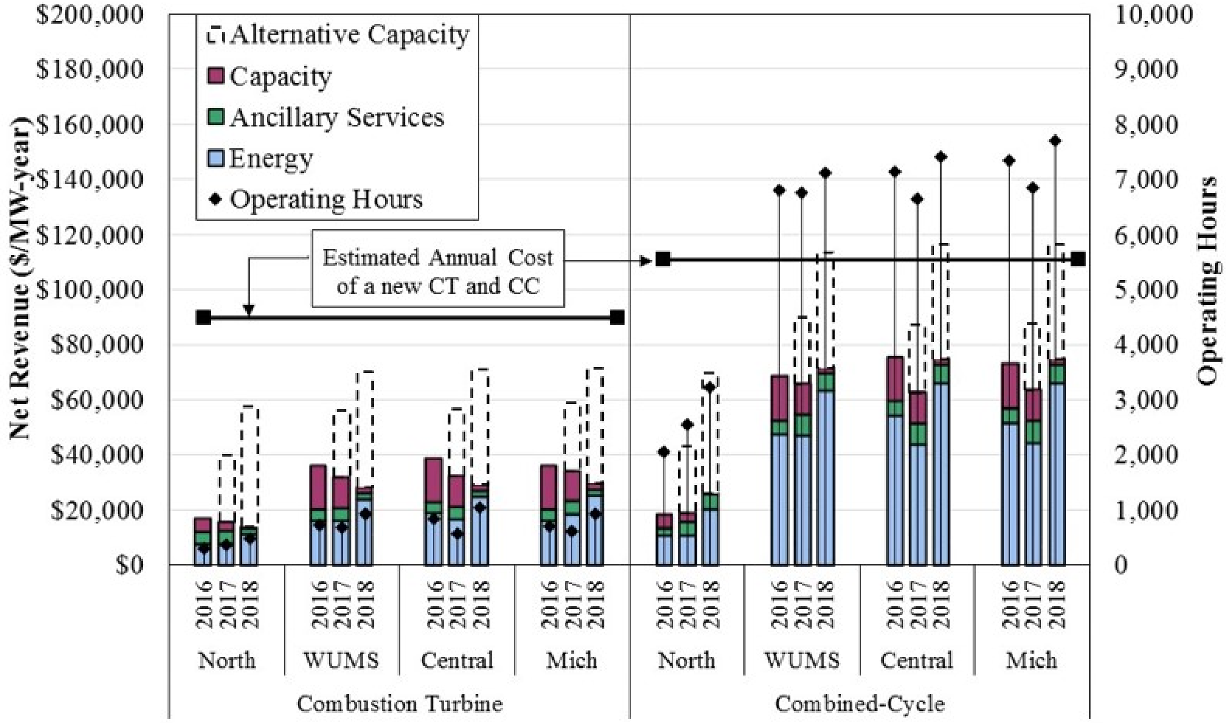
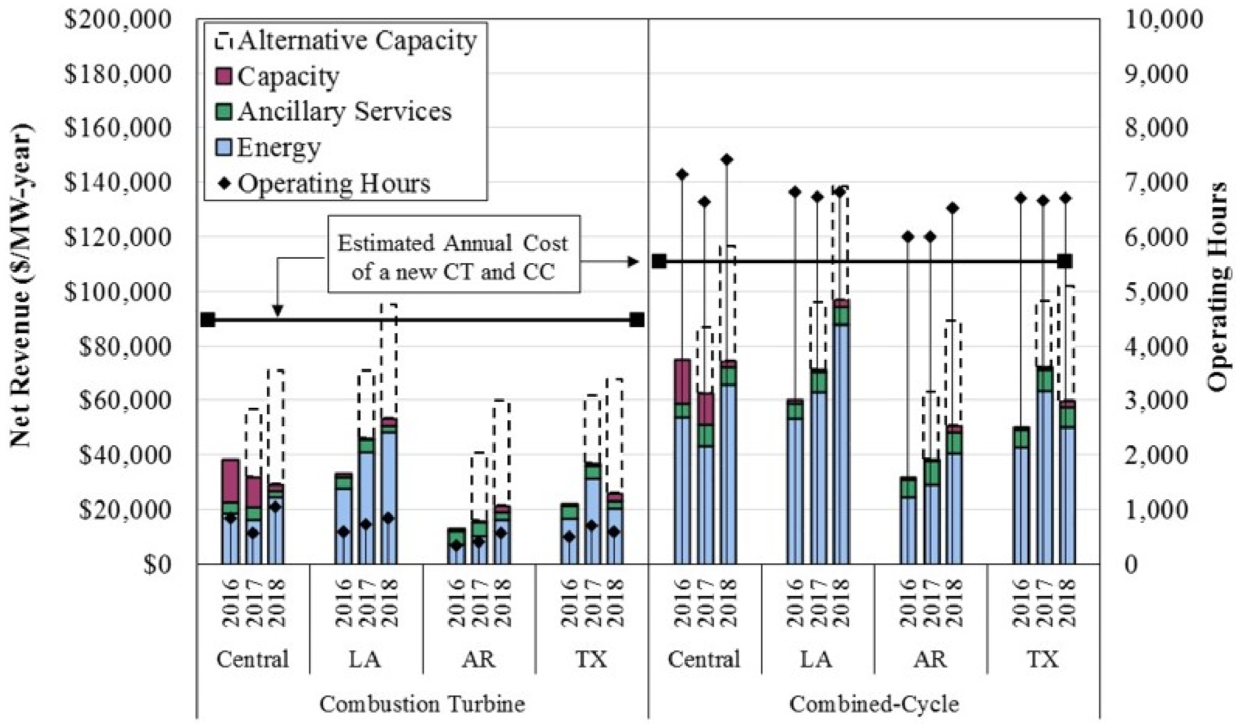


Figure A9: Net Revenue and Operating Hours
MISO South Region, 2016–2018



III. Resource Adequacy

This section examines the supply and demand conditions in the MISO markets. We summarize load and generation within MISO and evaluate the resource balance in light of available transmission capability on the MISO network.

In 2018, there were 130 market participants that either owned generation resources (totaling 175 GW of nameplate capacity) or served load in the MISO market.[5] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

MISO serves as the reliability coordinator for an additional 16 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.[6]

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. Generating Capacity and Availability

Figure A10: Distribution of Existing Generating Capacity

Figure A10 shows the December 2018 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.

5 As of January 2019, MISO membership totaled 464 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

6 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 A10: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2018

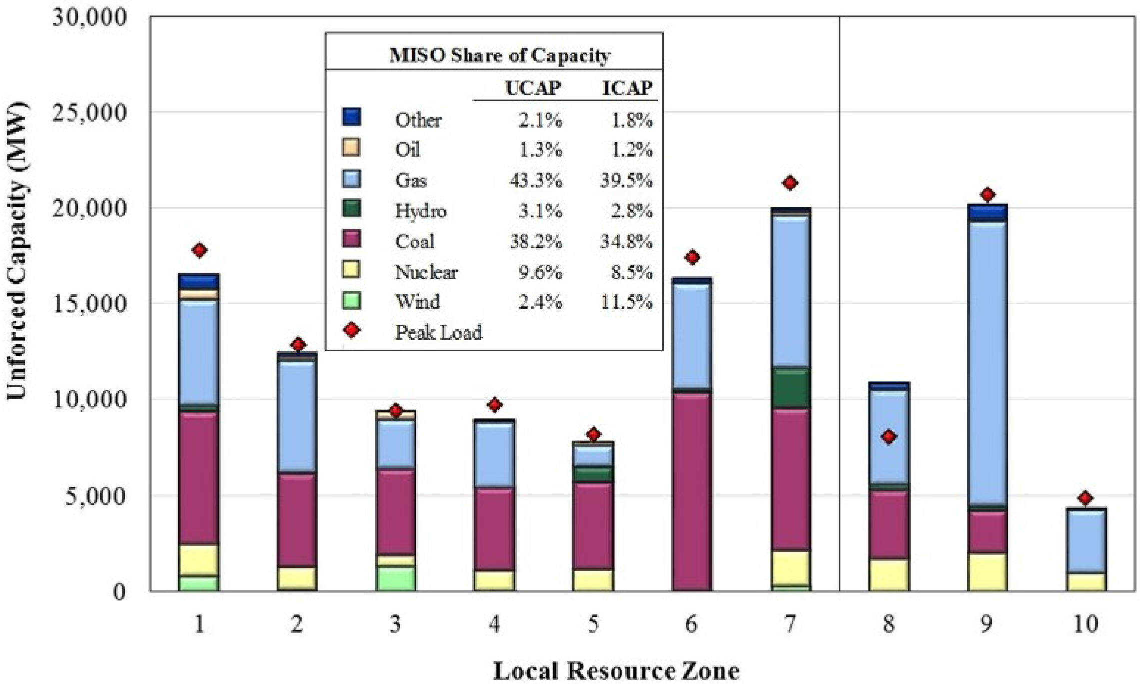


Figure A11: Resource Additions and Retirements

Figure A11 shows the change in the UCAP values during 2018 in each zone caused by resource retirements, additions, and interconnection changes.

Figure A11: Resource Additions and Retirements
2018, By Fuel Type and Zone

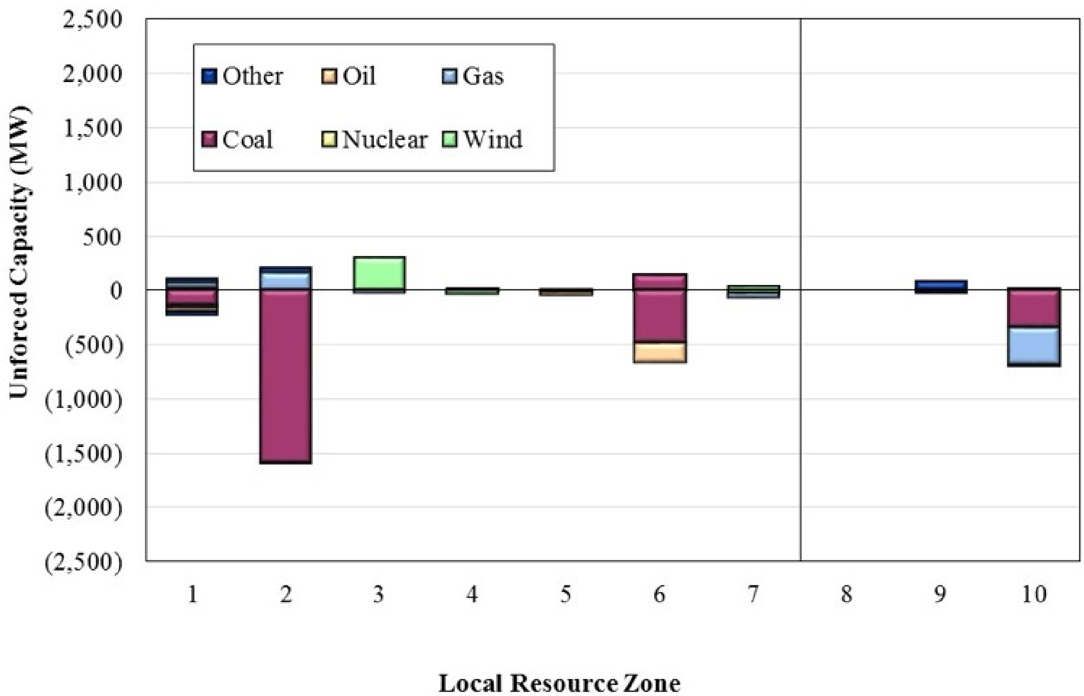
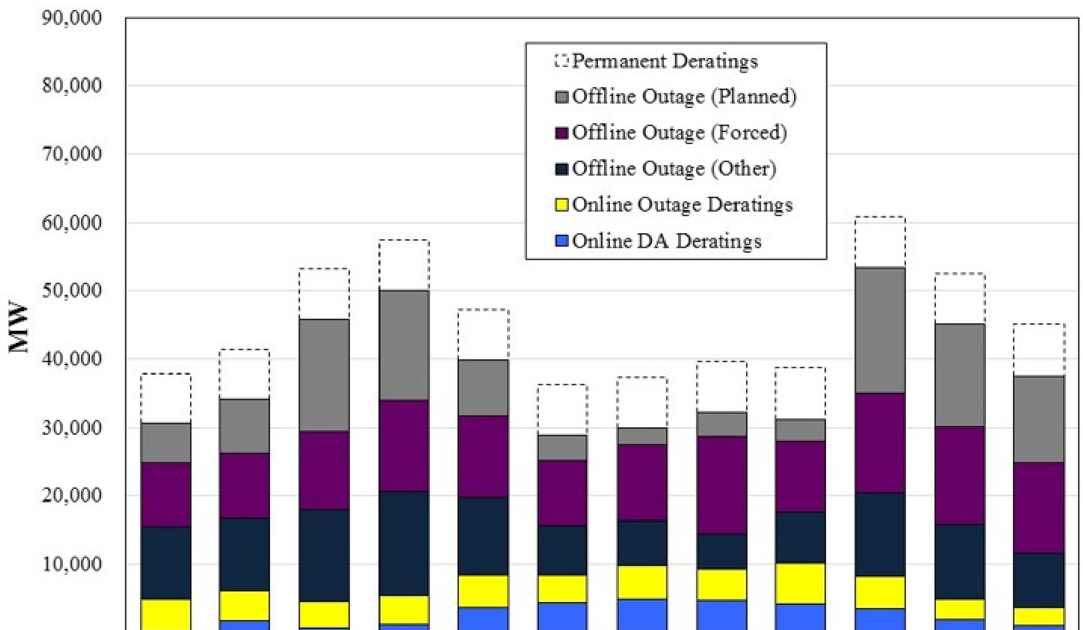


Figure A12: Capacity Unavailable During Peak Load Hours

Figure A12 shows only offline or otherwise unavailable capacity during the peak hour of each month. Maintenance planning should maximize resource availability in summer peak periods when system demands (and prices) are highest. As a consequence of greater resource utilization and environmental restrictions, non-outage deratings are expected to be the greatest during these periods.

Figure A12: Capacity Unavailable During Peak Load Hours
2018



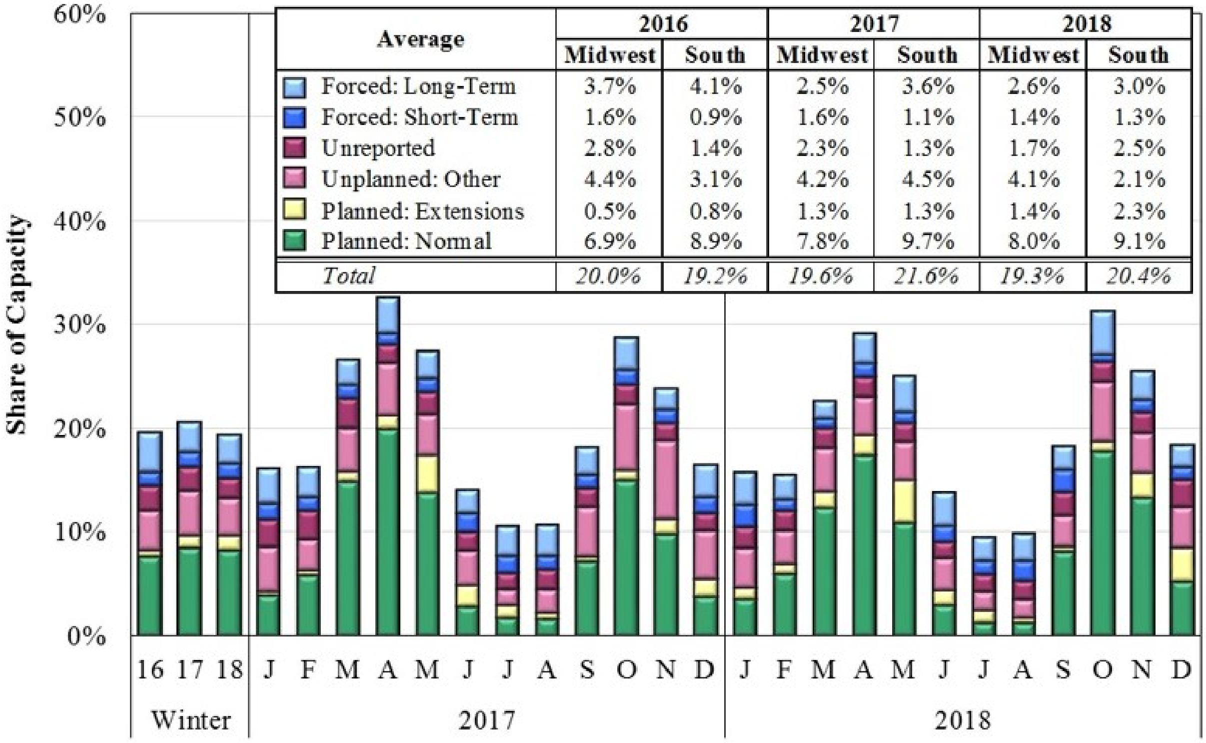
8 AM	8 AM	7 AM	7 AM	3 PM	3 PM	4 PM	4 PM	4 PM	3 PM	6 PM	8 AM	Peak Hour
Jan 17	Feb 8	Mar 14	Apr 5	May 29	Jun 29	Jul 13	Aug 27	Sep 4	Oct 3	Nov 13	Dec 11	Peak Date
106,064	94,555	85,311	80,969	111,557	121,563	116,599	116,986	114,739	96,401	92,058	94,212	Peak Load

Figure A13: Generator Outage Rates

Figure A13 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; 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 A13: Generator Outage Rates
2016–2018



Average	2016 Midwest	2016 South	2017 Midwest	2017 South	2018 Midwest	2018 South
Forced: Long-Term	3.7%	4.1%	2.5%	3.6%	2.6%	3.0%
Forced: Short-Term	1.6%	0.9%	1.6%	1.1%	1.4%	1.3%
Unreported	2.8%	1.4%	2.3%	1.3%	1.7%	2.5%
Unplanned: Other	4.4%	3.1%	4.2%	4.5%	4.1%	2.1%
Planned: Extensions	0.5%	0.8%	1.3%	1.3%	1.4%	2.3%
Planned: Normal	6.9%	8.9%	7.8%	9.7%	8.0%	9.1%
Total	*20.0%*	*19.2%*	*19.6%*	*21.6%*	*19.3%*	*20.4%*

B. Planning Reserve Margins and Resource Adequacy

Table A2: Capacity, Load, and Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2019. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2019 Summer Resource Assessment,* including the 1,500 MW transfer limit assumption[7] between MISO South and 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 capacity auction 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.

Historically a significant amount of capacity has been on planned outage during the summer peak months, and these outages were generally not scheduled well in advance. Additionally, a

7 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.

significant amount of capacity is generally unavailable to MISO's real-time market due to unreported outages and derates that are only evident through resource offers into MISO's DART system. Emergency-only resources may participate as capacity resources with registered lead times less than or equal to 12 hours, yet most emergencies have been declared within two hours. Emergency-only resources with longer lead times are less useful when MISO enters emergency conditions, particularly when those resources are demand-side management and represent load that must continue to be served until it is able to curtail.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[8] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation; and (e) full response from imports and Demand Response (DR) resources that cleared the PRA (behind the meter generation, interruptible load, and direct controllable load management).

Table A2 below shows our base case and four alternative scenarios that examine the impact of short-notice planned outages, variations in emergency-only resources' lead times, and unusually hot temperatures on MISO's planning reserve margins. 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 A2 include a number of cases:

- Column 1: Base case that assumes a 1,500 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, 2019.
- 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 two years' summer peak months during on-peak hours.
- Column 3: Modifies column 2 by removing emergency-only resources that cannot respond within two hours because these resources can only be accessed if MISO calls a Maximum Generation Emergency. Because these events are often precipitated by unforeseen outages and other contingencies, MISO often is not able to declare this type of event more than two hours in advance of the most critical conditions.
- 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).

The high-temperature cases are important because hot weather can significantly affect *both* load and supply. High ambient temperatures can reduce the maximum output limits of many MISO

8 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).

generators, while outlet water temperature or other environmental restrictions cause certain resources to be derated.[9] In its *2019 Summer Assessment*, MISO shows a high-load scenario that includes an estimate of high temperature derates. While we believe this scenario is a realistic forecast of potential high-load conditions, we continue to believe that it likely understates the derates that may occur under high-temperature conditions.

Table A2: Capacity, Load, and Reserve Margins
Summer 2019

		Alternative IMM Scenarios			
				High Temperature Cases	
	Base Scenario	Realistic Scenario	Realistic <=2HR*	Realistic Scenario	Realistic <=2HR*
Load					
Base Case	124,744	124,744	124,744	124,744	124,744
High Load Increase	-	-	-	6,554	6,554
Total Load (MW)	124,744	124,744	124,744	131,298	131,298
Generation					
Internal Generation Excluding Exports	134,856	134,856	134,422	134,856	134,422
BTM Generation	4,588	4,588	2,845	4,588	2,845
Unforced Outages**	(338)	(10,486)	(10,486)	(11,833)	(11,833)
Adjustment due to Transfer Limit	(1,220)	-	-	-	-
Total Generation (MW)	137,885	128,958	126,781	127,610	125,434
Imports and Demand Response*					
Demand Response	7,684	7,684	5,093	7,684	5,093
Capacity Imports	3,272	3,272	3,272	3,272	3,272
Margin (MW)	24,097	15,170	10,402	7,269	2,501
Margin (%)	**19.3%**	**12.2%**	**8.3%**	**5.8%**	**2.0%**
Effects of Non-Firm Imports					
Summer Peak Net Imports	2,161	2,161	2,161	2,161	2,161
Expected Margin (MW)	26,258	17,330	12,563	9,429	4,662
Expected Margin (%)	**21.0%**	**13.9%**	**10.1%**	**7.6%**	**3.7%**

* Assumes 100% response from resources available within 2 hours.
** Base scenario shows approved planned outages for 19/20 summer.
Alternatives use historical average unforced unit unavailability during July and August peak hours.
*** Cleared amounts for the 2019/2020 planning year.

C. 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.

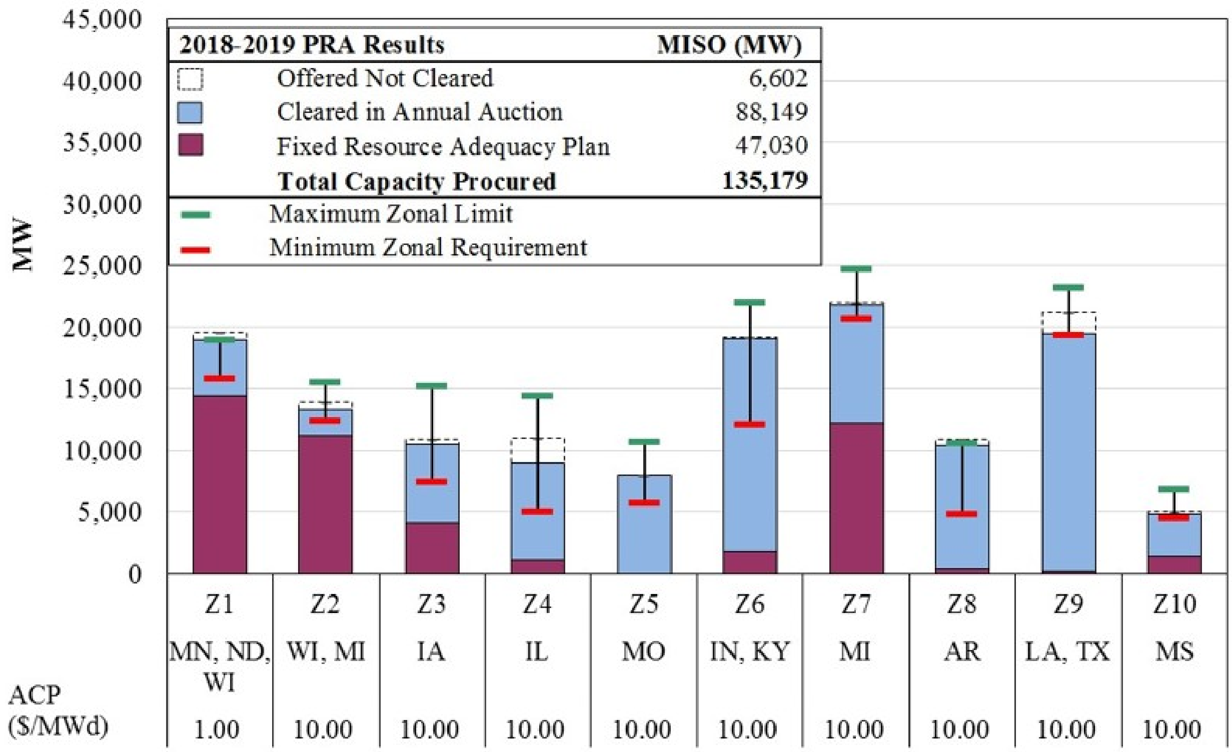
9 There is significant uncertainty regarding the size of these derates, so our number in the table is an average of what was observed on extreme peak days in 2006 and 2012.

Figure A14: Planning Resource Auction

Figure A14 shows the zonal results of the 2018/2019 annual PRA, held in the spring of 2018 and covering June 2018 to May 2019. The green diamond marks the capacity obligation, which is the total amount required to be procured by LSEs in each zone. Differences between this amount and the cleared amount are constrained by each zone's local clearing requirement (LCR) and export limit. As a result of poor market design, the 2018/2019 auction cleared all zones at $10.00 per MW-day (less than one percent of the cost of new entry), except for Zone 1 that was export-constrained and cleared at $1.00 per MW-day,.

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.

Figure A14: Planning Resource Auction
2018–2019



D. Capacity Market Design: Modeling the Demand Curve Efficiently

The PRA consists 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 Cost of New Entry (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 for market performance and the benefits of improving the representation of demand in the capacity market using a sloped 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 sloped 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 expected net revenues from energy and ancillary services markets cover the GFCs).

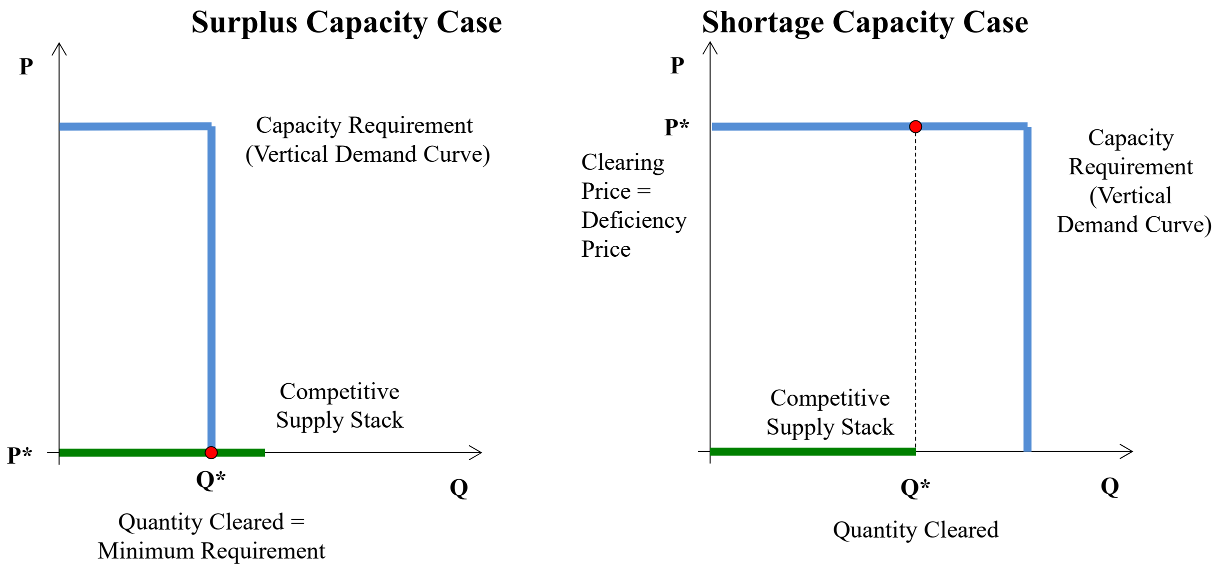
Two primary principles govern capacity supply offers:

- *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 resources, the net revenues available from RTOs' energy and ancillary services markets are sufficient to keep the resources in operation. Therefore, no additional revenue is needed from the capacity market, which would cause the supplier to submit a capacity offer of zero.

Figure A15: 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 A15 below.

Figure A15: 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, which characterizes the 2018/2019 auction results in MISO. Almost all zones in MISO cleared at \$10 per MW-day, except for Zone 1 that cleared essentially at zero, implying that additional existing capacity has no value to MISO.
- If the market is in shortage, as indicated in the figure on the right, then the supply and demand curves do not cross, and the price will clear at the deficiency price.

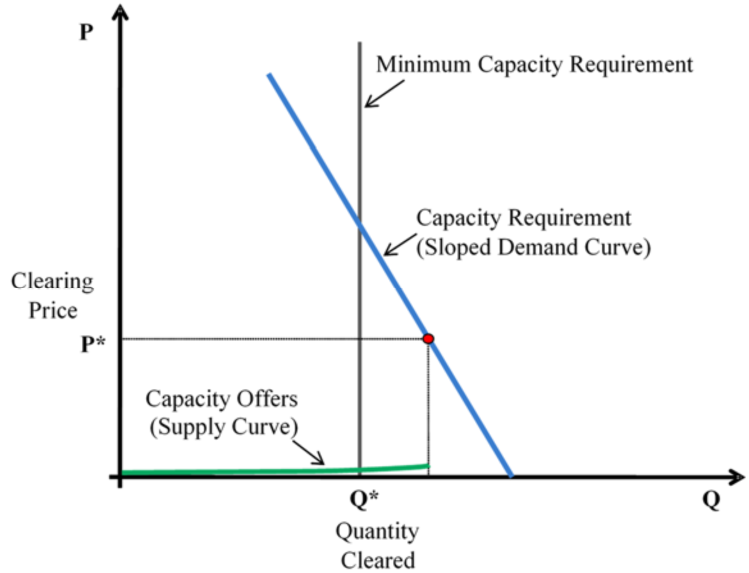
This pricing dynamic and the associated market outcomes raise at least three significant issues regarding the long-term performance of the current capacity market:

- 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 A16: Sloped Demand Curve

A sloped 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 A16: Sloped Demand Curve



When a surplus exists, the price would be determined by the marginal value of additional capacity as represented by the sloped 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 sloped 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 sloped demand curve reflects the marginal value of capacity because the sloped portion is based on the reliability benefit of exceeding planning reserves. A sloped 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 would not likely completely mitigate potential market power, a sloped demand curve would significantly improve suppliers' incentives.

If a sloped demand 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 and contentious. 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 analysis or support for why an infinite slope is efficient or reasonable.

Short-Term Effects of PRA Reform

Figure A17: Supply and Demand in 2019-2020 PRA

To demonstrate the significance of the flawed vertical demand curve, we estimated the clearing price in MISO that would have prevailed in the 2019/2020 PRA if MISO employed sloped demand curves in the PRA, as shown in Figure A17. The blue dashed line in Figure A17 represents the vertical demand curve actually used in the 2019/2020 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.

The sloped demand curve we use in this simulation is similar to the curve used by MISO witnesses in the analysis of MISO's "competitive retail solution" in FERC Docket Number ER17-284. The top of the curve is at 1.05 x Net CONE and 98.8% of the planning reserve margin requirement (PRMR). The sloped demand curve and the vertical demand curve intersect at net CONE. In other words, the sloped demand curve price is equal to net 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% of the minimum capacity requirement. The capacity demand curve for the PJM crosses zero at 107.5% of the minimum capacity requirement. For our simulation, we used the average of these two values and assumed a zero-crossing point of 109.75% 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 A17: Supply and Demand in 2019-2020 PRA

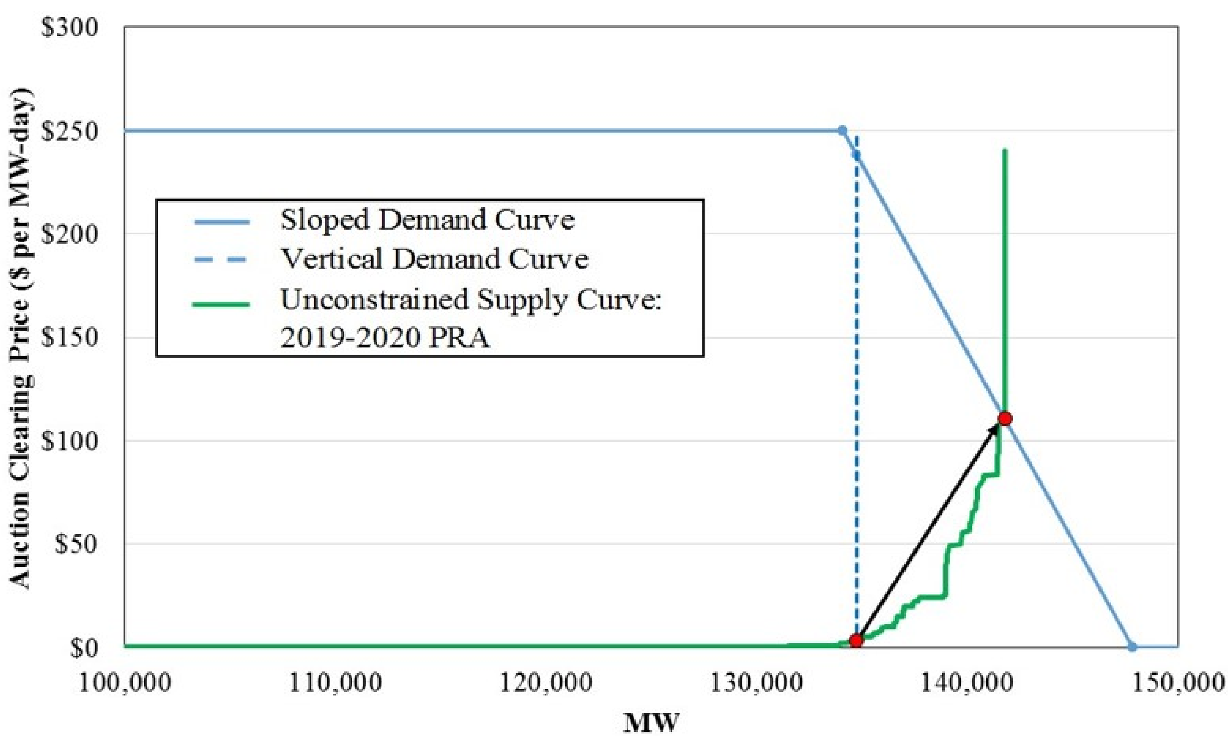


Table A3: Effects of Sloped Demand Curve by Type of Participant

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 2019/2020 PRA. We calculated the simulated settlements for each participant based on their net sales. The change in settlement is calculated by changing price and quantity for each participant. For the buyer-side settlement, costs increase because of a higher capacity price and an increase in their capacity requirement of approximately five percent because of the market clearing at a surplus level of approximately five percent. For the seller-side settlement, revenues increase because of higher sales prices and, for those with economic excess, higher sales volume. 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 three categories: competitive suppliers, competitive retail LSEs, 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. For each type of participant, 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
2019-2020 PRA ($Millions)

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically-Integrated LSEs	$ 348	-$ 316	$ 32
Merchant Generators	$ 390		$ 390
Retail Choice Load		-$ 422	-$ 422

Although the vertically-integrated utilities are the largest group of participants, the aggregate changes in net revenues and costs are smaller than for other types of participants. The vertically-integrated LSEs would have benefited in aggregate by $32 million from the use of the sloped demand curve. The effects on the vertically-integrated LSEs are smaller on average than the competitive participants because the LSEs tend to self-supply most of their requirements through owned generation or bilateral purchases. Hence, the vertically-integrated LSEs’ exposure to the PRA price is limited. Overall, 42 percent of these participants would benefit by implementing a sloped demand curve because they can sell their excess resources at an efficient price.

The more significant effects are experienced by the competitive participants. Merchant generators would have received significantly more revenue ($390 million) through the PRA, providing more efficient signals to maintain existing resources and build new resources. This effect will grow as capacity margins fall in MISO. Costs borne by competitive retail loads would rise by $422 million under a sloped demand curve.

Long-term Effects of a Sloped Demand Curve on Vertically-Integrated LSEs

LSEs and their ratepayers should benefit in the long term from a sloped demand curve. LSEs in MISO have generally planned and built resources to achieve a small surplus on average over the minimum requirement because:

- Investment in new resources is "lumpy," occurring in increments larger than necessary to match the gradual growth in an LSE's requirement; and
- The costs of being deficient are large.

Under a vertical demand curve, the cost of the surplus must entirely be borne by the LSEs' retail customers because LSEs will generally receive very little capacity revenue to offset the costs that they incurred to build the resources. Because this additional capacity provides reliability value to MISO, the fact that LSEs receive no capacity revenues is inefficient. Adopting a sloped demand curve would benefit most regulated LSEs as we explain below.

Table A4: Costs for a Regulated LSEs under Alternative Capacity Demand Curves

Table A4 shows how hypothetical LSEs are affected by a sloped demand curve when they hold varying levels of surplus capacity beyond the minimum capacity requirement. The scenarios assume: (1) an LSE with 5,000 MW of minimum required capacity; (2) net CONE of $65,000 per MW-year and demand curve slope of -0.01 (matching the slope of the NYISO curve); and (3) a market-wide surplus of 1.5 percent, which translates to an auction clearing price of $4.74 per kW-month ($54.85 per kW-year).

For each of the scenarios, we show the amount that the LSE would pay to or receive from the capacity market along with the carrying cost of the resources the LSE built to produce the surplus. Finally, in a vertical demand curve regime where the LSE will not expect to receive material capacity revenues for its surplus capacity, all of the carrying cost of the surplus must be paid by the LSE's retail customers. The final column shows the portion of the carrying cost borne by the LSE's retail customers under a sloped demand curve.

Table A4: Costs for a Regulated LSE under Alternative Capacity Demand Curves

LSE Surplus	Market Surplus	Capacity Market Revenues ($Million)	Carrying Cost of Surplus ($Million)	Carrying Cost Borne by Retail Load	Surplus Cost: Sloped Demand Curve	Surplus Cost: Vertical Demand Curve
1.0%	1.5%	$-1.43	$3.25	100%	$4.68	$3.25
2.0%	1.5%	$1.41	$6.50	78%	$5.09	$6.50
3.0%	1.5%	$4.25	$9.75	56%	$5.50	$9.75
4.0%	1.5%	$7.10	$13.00	45%	$5.90	$13.00

These results illustrate three important dynamics, namely that the sloped demand curve:

- *Does not raise the expected costs for most regulated LSEs*. In this example, if an LSE fluctuates between one and two percent surplus (around the 1.5 percent market surplus), its costs will be virtually the same under the sloped and vertical demand curves.
- *Reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE at surplus levels between one and four percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.
- *Reduces the share of costs borne by retail customers*. Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds the market's surplus. Under the three percent case, for example, the current market would produce almost no capacity revenue even though the LSE's surplus is improving reliability for the region. Under the sloped demand curve in this case, almost half of the costs of the new unit would be covered by the capacity market revenues.

Hence, although a sloped demand curve could increase costs to non-vertically integrated LSE's that must purchase large quantities of capacity through an RTO's market, the example above shows that this is not the case for the vertically-integrated LSEs that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's LSEs in satisfying their planning reserve requirements. In addition, this will provide efficient market signals to other types of market participants, such as unregulated suppliers, competitive retail providers, and capacity importers and exporters.

As discussed in more detail in the Report, understated capacity prices are a particular problem in Competitive Retail Areas (CRAs) where unregulated suppliers rely on the market to retain resources MISO needs to ensure reliability.

Qualifications and Accreditation of Supply in the PRA

We have become increasingly concerned that MISO's rules: a) allow unavailable resources to satisfy its capacity requirements, and b) does not procure capacity for all of its firm load. Hence, we have recommended several improvements to MISO's Planning Resource Auction that would result in better price signals for the value of capacity in MISO.

Table A5: Alternative Capacity Auction Clearing Prices in 2019-2020 PRA

We evaluated the impact that these changes would have had on the clearing prices in the 2019-2020 capacity auction by re-solving the Planning Resource Auction.

Starting with the base clearing scenario that represents the actual PRA results, we analyzed scenarios to show the effects of improving the qualification of capacity resources and demand for capacity. In the first scenario, we identified resources that had a planned or forced outage covering most of the summer period and removed the UCAP associated with these resources from the offer stack.

In our second scenario, we determined the amount of ICAP on ERIS resources that may not be deliverable because some resources do not hold firm transmission up to their full ICAP levels. We converted this ICAP into UCAP and removed this difference from the capacity auction supply stack to re-clear the auction. Although this change removes a significant amount of capacity, we expect that were MISO to adopt our recommendation, resources would procure more firm transmission in order to qualify a larger amount of capacity in the auction.

In our third scenario, we applied the planning reserve margin requirement (PRMR) to the firm process and electric load behind the meter and netted the load plus PRMR from the UCAP of the associated cogeneration facility. MISO's current practice is to net the load from the ICAP value, which effectively does not procure the capacity needed to reliably serve the firm process loads.

The results of these scenarios are shown in Table A5 below. The first column labels the scenario, and the second column indicates the quantity of UCAP affected (on the supply side or demand side) by the sensitivity. The middle two columns show the resulting clearing prices of the sensitivities market-wide and in the constrained Michigan zone. We show the resulting prices in these areas using the current vertical demand curve, while the two columns to the right indicate our results using a sloped demand curve.

Table A5: Alternative Capacity Auction Clearing Prices in 2019-2020 Planning Resource Auction

Alternative Capacity Auction Scenarios	Affected UCAP	Vertical Demand Curve		Sloped Demand Curve	
		Unconstrained Price	Constrained Price (MI)	Unconstrained Price	Constrained Price (MI)
Base Scenario		$2.99	$24.30	$110.38	
- Known Outages	635.4	$4.95	$243.37	$121.52	$243.37
- Undeliverable ICAP (Conventional Gen.)	1,515.3	$9.82	$24.31	$137.57	
+ Procurement for BTM Firm Load	306.5	$4.95	$24.30	$115.90	
Combination of Alternative Scenarios					
- Known Outages, BTM Firm Load	941.9	$5.00	$243.37	$127.07	$243.37
- All Changes	2,455.8	$15.00	$243.37	$149.07	$243.37

Reforming the Accreditation of Capacity in MISO

Generating resources are currently qualified and accredited to sell capacity based on their forced outages, which is considered in the EFORd calculation that is the basis of their UCAP levels. Under MISO's existing capacity accreditation construct, resources' UCAP values are determined by discounting their total installed capacity based on forced outages that participants self-report to GADS between September 1st and August 31st for the previous 3 years.[10] We have identified a number of issues with MISO's current accreditation methodology, which include incomplete GADS reporting by market participants, inaccurate Generation Verification Testing (GVTC) data submitted into GADS, and improper weighting of forced outage hours in the accreditation

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

penalty by resource classification. The net result is that the assumed reliability value of resources that participate in MISO's capacity auction is inconsistent their true value.

In March 2019, FERC approved a MISO tariff change[11] that penalizes short-notice non-forced outages that occur during a declared Maximum Generation Emergency as forced outages (and derates) for the purpose of calculating a resource's forced outage rate for the next applicable Planning Year. Specifically, resources would be penalized based on a number of planned outage hours equal to the greater of: (1) the period during which the resource's outage overlaps with the Maximum Generation Emergency or (2) 24 hours. Planned outages scheduled 120 days in advance receive a Safe Harbor.

We evaluated the impact of this tariff change on resources with UCAP in the 2019 Planning Year by using GADs and CROW data from September 1, 2015 through August 31, 2018. We also evaluated an alternative accreditation methodology we are recommending that would calculate a resource's UCAP derate amount based on its average outages and derates occurring during the five percent of hours with the smallest day-ahead supply margins (total supply – total demand).

To determine the subset of tight hours, we divided the September 1, 2015 through August 31, 2018 accreditation period into three years (September – August) and selected the five percent of hours with the smallest margin in the day-ahead market.[12] We also added in all hours of declared emergencies during the accreditation period (if not already included in the tightest margin hours). This subset of hours goes into the denominator of our alternative forced outage rate calculation. In the numerator of the UCAP derate ratio, we determined the total availability of generator resources during the same subset of hours. Availability is based on the resources' offered economic maximum or emergency maximum (in the real-time market) when resources were on control or offline, or the actual output of the resource while running off control. We subtract the resource's availability from its installed capacity (ICAP) to determine the derate quantity. We then use outage data reported in CROW to establish safe harbors for resources on planned outages scheduled at least 14 days in advance.[13] We summed the outage hours for each resource (using fractional equivalent hours for derates).

Table A8: Alternative Capacity Accreditation Penalties by Resource Class

In Table A8 below, we show the results of the historic accreditation methodology, the modified methodology recently approved by FERC, and the alternative methodology we are recommending by the major resource categories in MISO. We weight the class averages by resource ICAP from the 2019 Planning Year.

11 Docket No. ER19-915-000.

12 Day-ahead margin is the hourly FRAC load forecast subtracted from the sum of max available MWs from online resources and those from offline resources with less than 24 hour offered notification/startup time. We also considered the top 5% real-time margin hours but it produced very similar results.

13 A 14 day exemption for planned outages was discussed in a recent Resource Adaquacy and Need (RAN) meeting: Reliability Subcommittee, May 2, 2019, Outage Coordination RAN Update.

Table A6: Alternative Capacity Accreditation Penalties by Resource Class

Resource Class	Capacity (MW) 1/	Current XEFORd	MISO RAN: Include Other Outages during Emergencies 2/	IMM: Availability in Tightest Hours - excl. Planned Outages > 14 Days Notice
Combined Cycle 3/	16,744	4.0	4.2	6.9
Coal	52,646	8.5	8.6	14.9
Combustion Turbine (Gas)	27,219	6.9	7.2	9.8
Nuclear 3/	11,592	2.9	3.0	4.1
Steam Turbine (Gas)	12,456	18.4	18.9	22.8

1/ Includes units with awarded UCAP in 2019 that is not fully excluded. Excludes a small number of units that have an XEFORd of 0.

2/ Excludes a small number of additional units that are assigned a Class Average XEFORd.

3/ A few additional units are excluded from these categories due to anomalous outage patterns.

IV. Day-Ahead Market Performance

In the day-ahead market, market participants make financially-binding forward purchases and sales of electric energy for delivery in real time. Day-ahead transactions allow LSEs to procure energy for their own demand, thereby managing risk by hedging their exposure to real-time price volatility. Participants also buy and sell energy in the day-ahead market to arbitrage price differences between the day-ahead and real-time markets.

Day-ahead outcomes are important because the bulk of MISO's generating capacity available in real time is actually committed through the day-ahead market, and almost all of the power procured through MISO's markets is financially settled in the day-ahead market. In addition, obligations to FTR holders are settled based on congestion outcomes in the day-ahead market.

A. Day-Ahead Energy Prices and Load

Figure A18 and Figure A19: Day-Ahead Energy Prices and Load

Figure A18 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on non-holiday weekdays) at six representative hub locations in MISO and the corresponding scheduled load (which includes net cleared virtual demand). Differences between the hub prices generally reflects transmission congestion on the MISO system.

Figure A18: Day-Ahead Hub Prices and Load
Peak Hours, 2017–2018

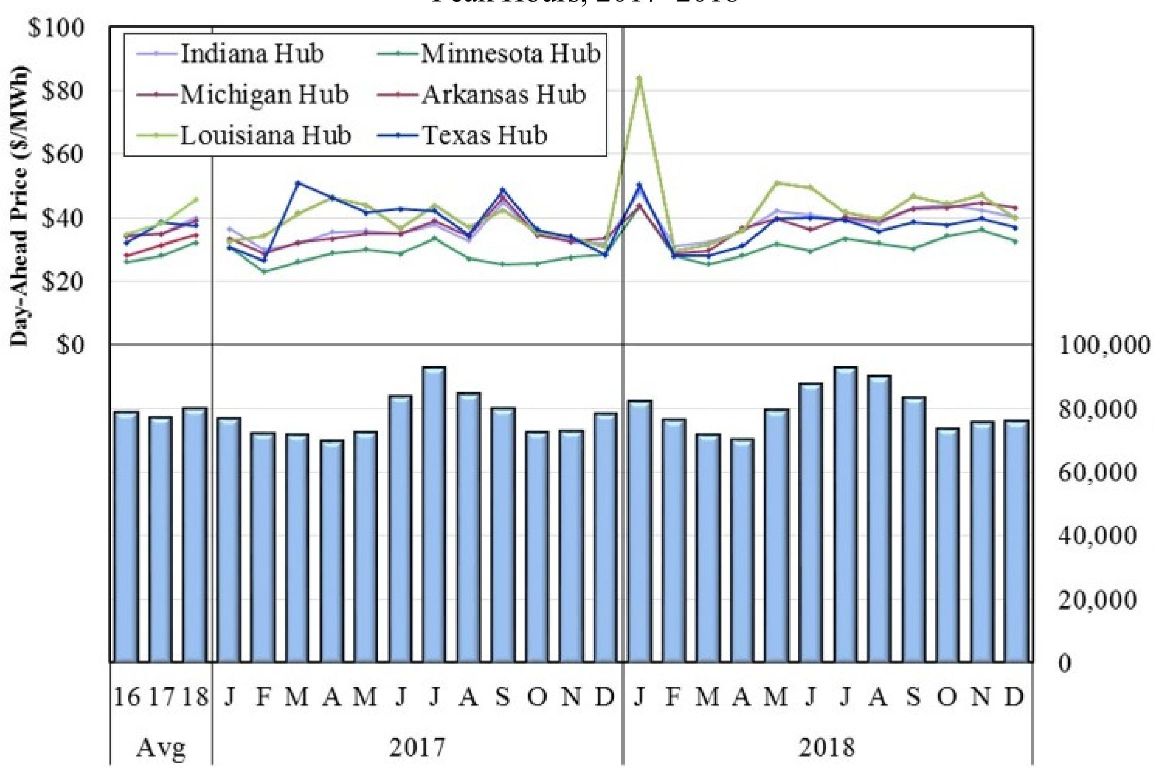
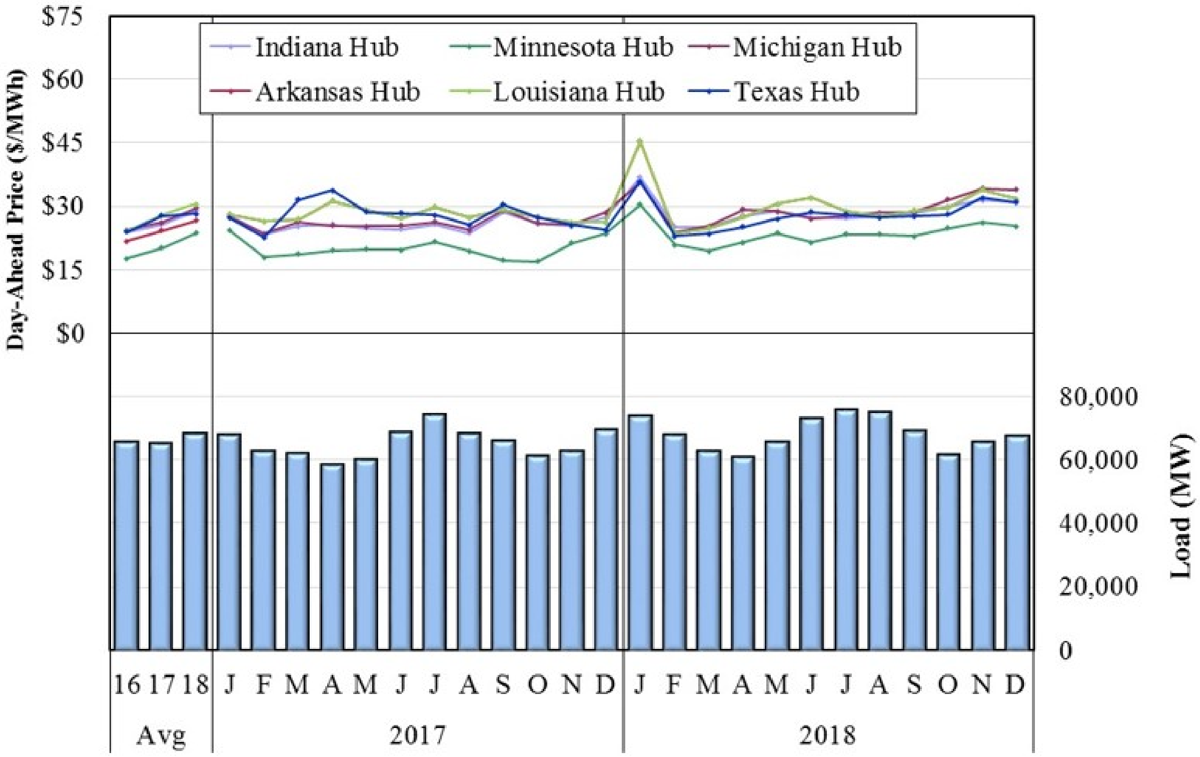


Figure A19 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Differences in prices among the hubs show the prevailing congestion and loss patterns. High prices in one location relative to another location indicate congestion and loss factor differences from a low-priced area to a high-priced area.

Figure A19: Day-Ahead Hub Prices and Load
Off-Peak Hours, 2017–2018



B. Day-Ahead and Real-Time Price Convergence

This subsection evaluates the convergence of prices in the day-ahead and real-time energy and ancillary services markets. 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 anticipated conditions are not being realized in the physical dispatch in real time. 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.

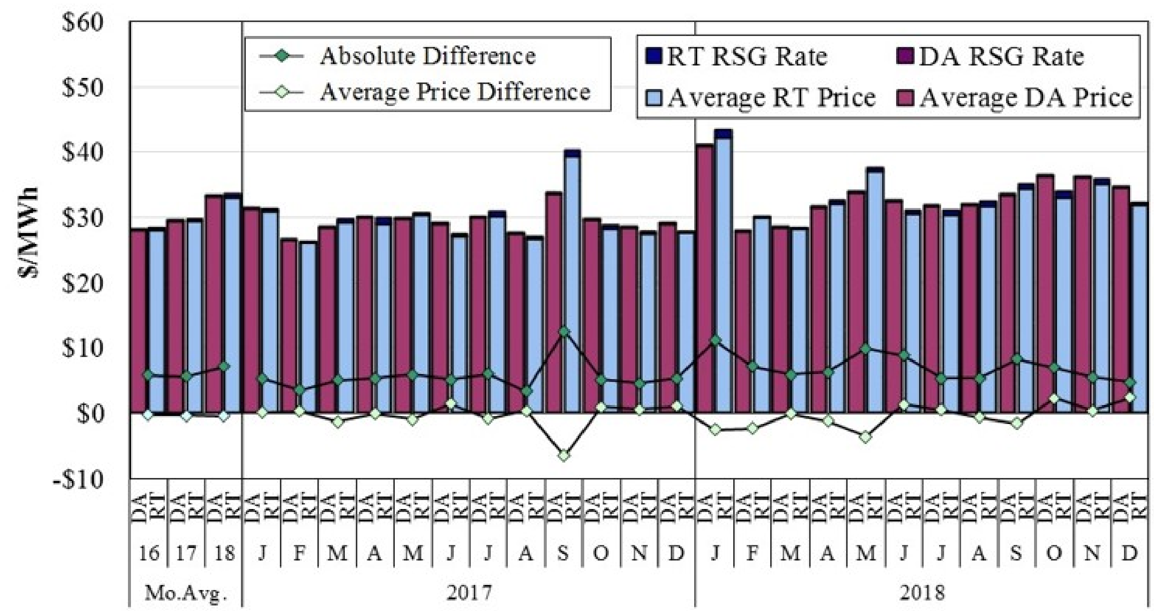
Participants' day-ahead market bids and offers should reflect their expectations of the real-time market the following day. However, a variety of factors can cause real-time prices to be significantly higher or lower than those anticipated in the day-ahead market. While a well-performing market may not 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 A20 to Figure A26: Day-Ahead and Real-Time Prices

The next seven figures show 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.[14] The table below the figures shows the average day-ahead and real-time price difference, which measures overall price convergence. We show it separately for prices 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 A20: Day-Ahead and Real-Time Prices
2017–2018: Indiana Hub

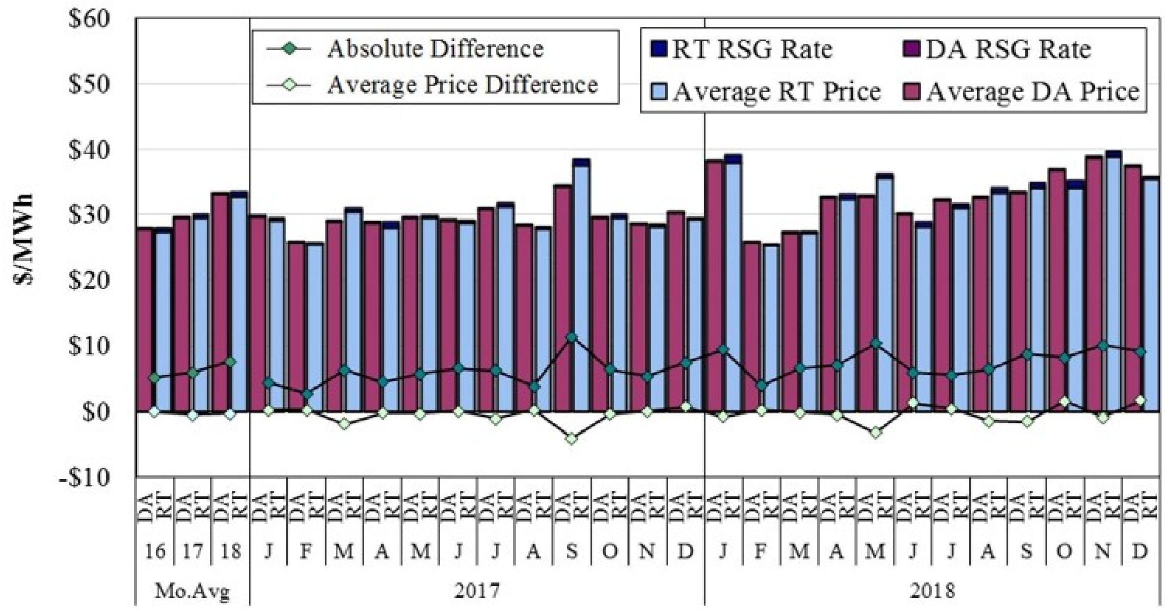


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	1	0	1	2	1	-3	3	-2	7	-1	3	-14	5	3	5	-4	-7	0	-2	-8	7	4	0	-3	10	3	9
Including RSG	-1	-1	-1	0	1	-4	0	-3	5	-3	1	-16	3	2	4	-6	-8	0	-4	-10	4	2	-2	-4	7	1	7

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

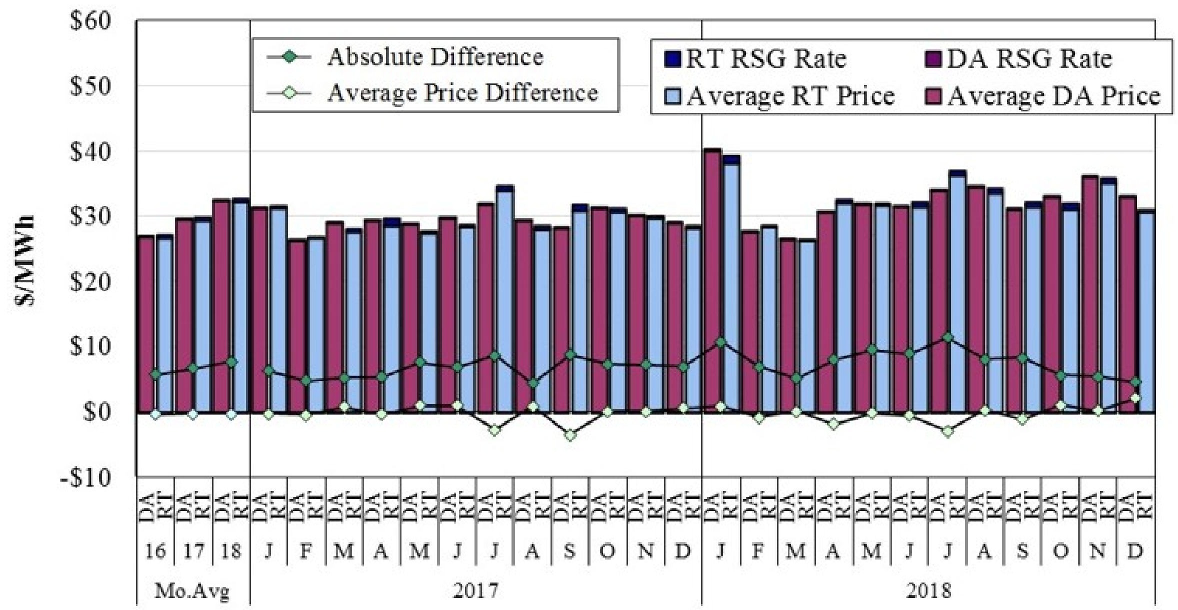
Figure A21: Day-Ahead and Real-Time Prices
2017–2018: Michigan Hub



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

Excluding RSG	1	0	1	2	1	-5	3	0	1	-1	2	-8	0	1	3	1	1	0	0	-8	7	4	-2	-3	7	0	6
Including RSG	0	-2	-1	1	1	-6	-1	-1	0	-3	1	-11	-1	0	2	-2	1	-1	-2	-9	4	1	-4	-5	4	-2	5

Figure A22: Day-Ahead and Real-Time Prices
2017–2018: WUMS Area

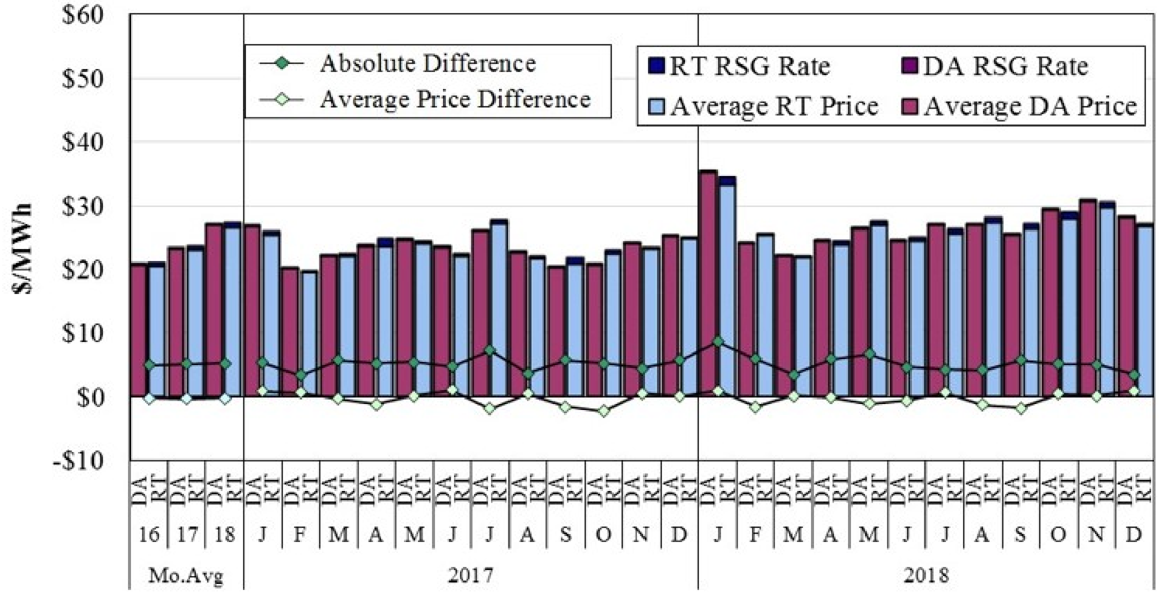


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	0	1	1	0	-2	4	2	4	5	-7	4	-8	2	1	3	5	-3	1	-4	1	0	-6	3	-2	6	3	8
Including RSG	-1	-1	-1	-1	-2	3	-1	3	3	-8	3	-11	0	0	2	2	-3	0	-6	-1	-2	-8	1	-4	3	0	7

Figure A23: Day-Ahead and Real-Time Prices

2017–2018: Minnesota Hub

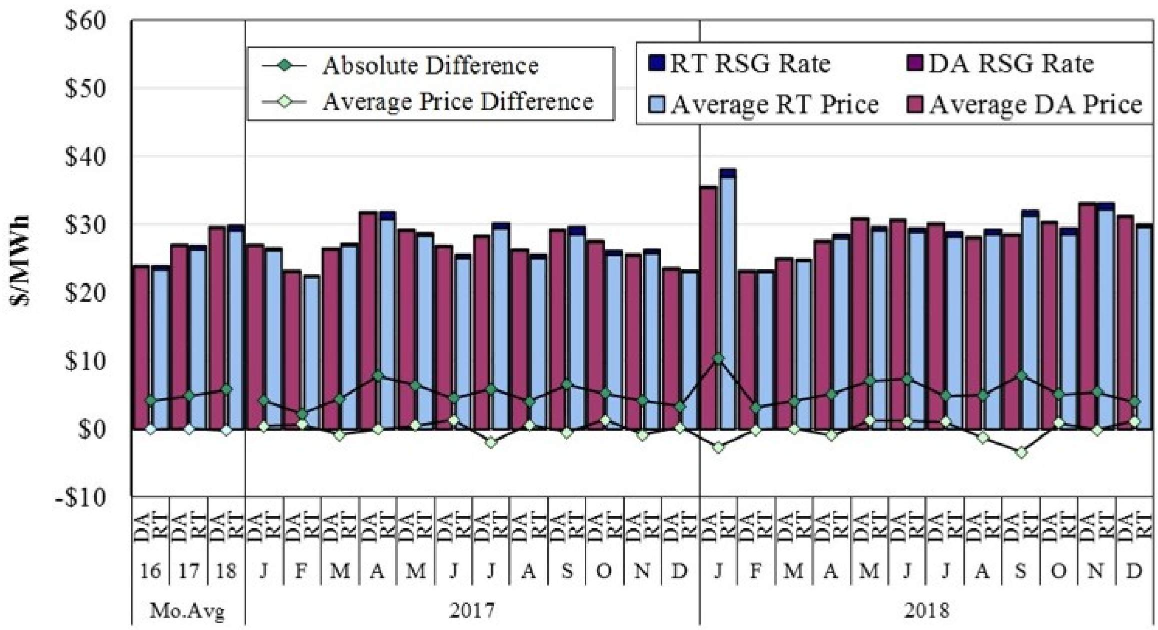


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	1	1	2	5	4	1	-1	2	6	-5	4	-3	-8	4	1	6	-6	1	2	-2	0	6	-2	-4	5	3	5
Including RSG	-1	-1	-1	3	3	-1	-5	1	5	-7	2	-7	-10	3	0	3	-6	1	0	-4	-2	3	-4	-6	2	1	4

Figure A24: Day-Ahead and Real-Time Prices

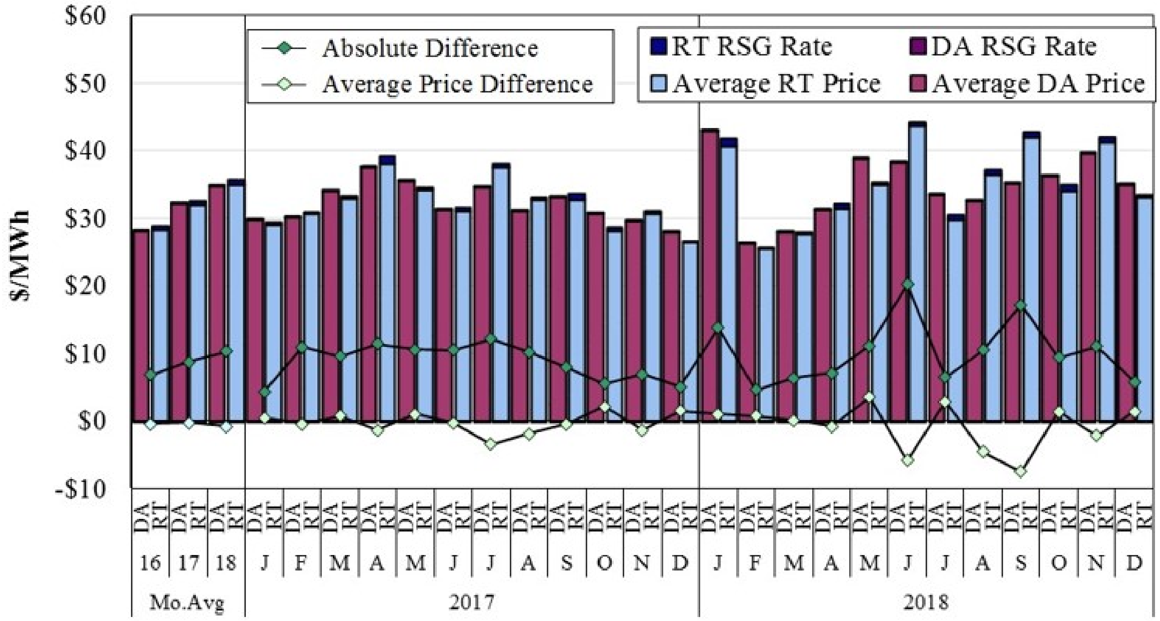
2017–2018: Arkansas Hub



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

Excluding RSG	1	2	1	3	3	-2	3	3	7	-5	4	2	7	-2	2	-5	0	0	-2	6	6	6	-2	-9	6	2	5
Including RSG	0	0	-1	1	3	-3	0	2	5	-7	2	-2	5	-3	1	-7	-1	0	-4	4	4	3	-4	-11	3	-1	4

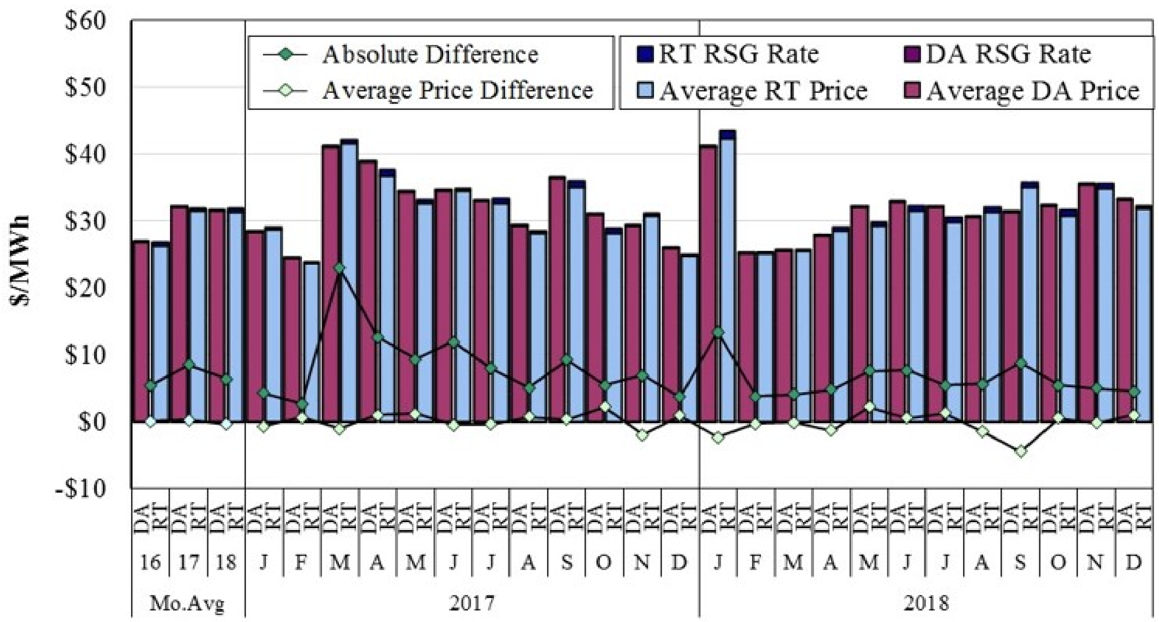
Figure A25: Day-Ahead and Real-Time Prices
2017–2018: Louisiana Hub



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

Excluding RSG	0	0	-1	3	-2	3	-1	4	0	-8	-5	1	9	-4	6	5	3	1	-1	11	-12	12	-11	-16	7	-4	5
Including RSG	-2	-1	-2	1	-2	2	-4	3	-1	-9	-6	-1	7	-5	5	3	3	0	-3	10	-13	9	-12	-18	4	-5	4

Figure A26: Day-Ahead and Real-Time Prices
2017–2018: Texas Hub



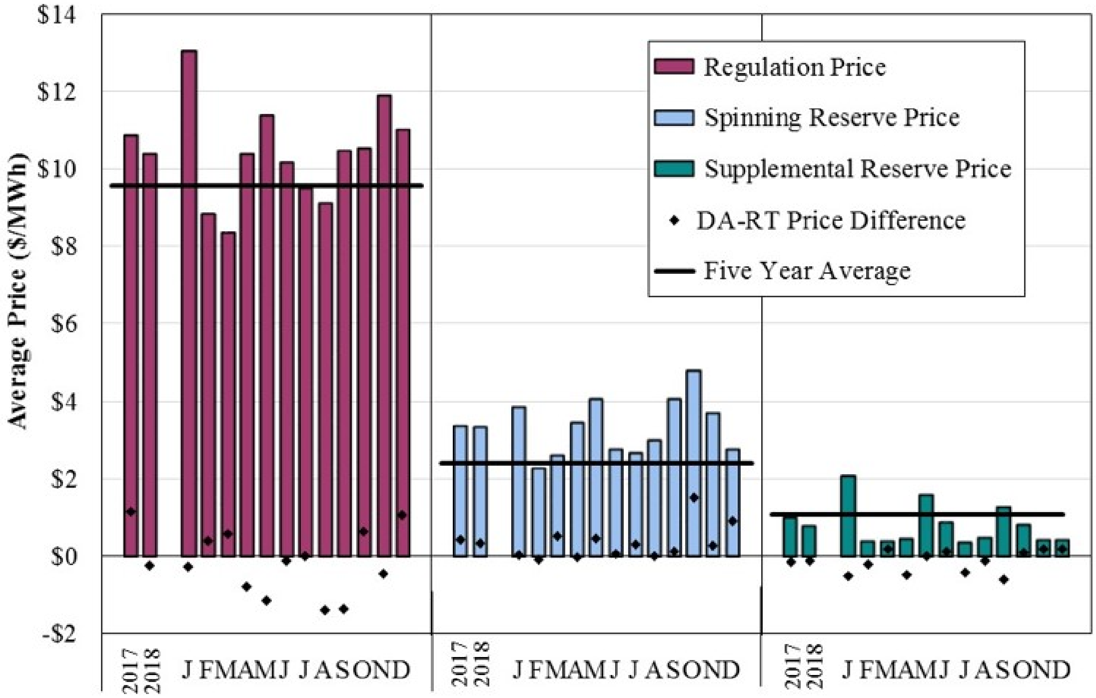
Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	2	2	1	-1	3	-1	5	5	0	1	4	4	10	-5	5	-3	0	0	-3	9	4	7	-2	-11	5	2	4
Including RSG	1	1	-1	-2	3	-2	3	4	-1	-1	3	1	8	-6	4	-5	-1	0	-5	8	2	4	-5	-12	2	-1	3

Figure A27: Day-Ahead Ancillary Services Prices and Price Convergence

The figures above show the convergence of MISO's energy market prices. Price convergence is also important for MISO's ancillary services markets, which are jointly optimized with the energy markets. These markets have operated without significant issues since their introduction in January 2009. Figure A27 shows monthly average day-ahead clearing prices in 2018 for each ancillary services product, along with day-ahead and real-time price differences.

Figure A27: Day-Ahead Ancillary Services Prices and Price Convergence
2018



C. 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 affect commitment patterns and RSG costs because units are committed and scheduled in the day-ahead to satisfy the net day-ahead load.

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. Despite improvements from expansion of ELMP, peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section V.B). 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:

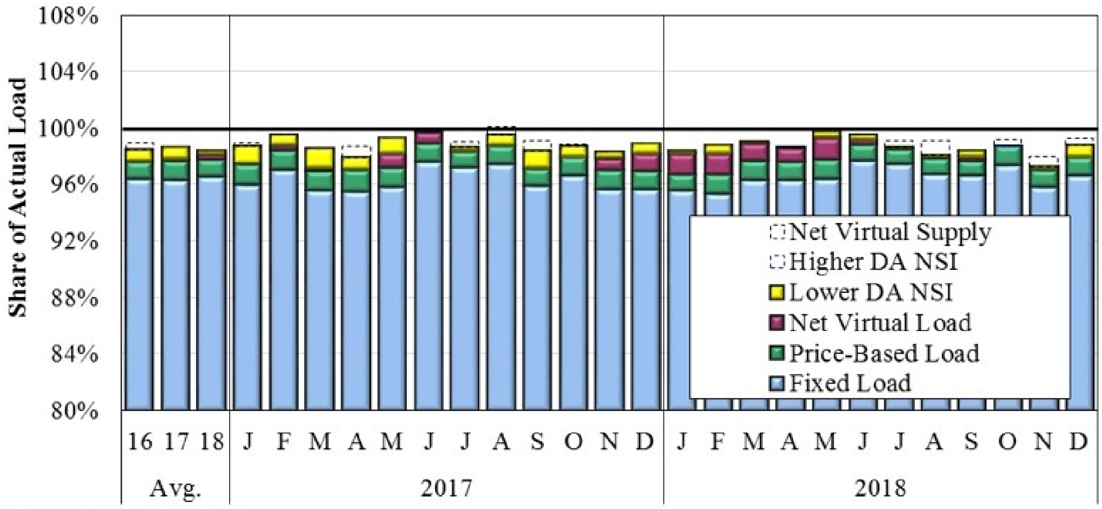
- Supplemental commitments made by MISO for reliability after the day-ahead market;
- Self-commitments made by market participants after the day-ahead market;
- Under-scheduled wind output in the day-ahead market; and
- Real-time net imports above day-ahead schedules.

Figure A28 to Figure A30: Day-Ahead Scheduled Versus Actual Loads

To show net day-ahead load-scheduling patterns, Figure A28 compares the monthly average day-ahead scheduled load to average real-time load. The figure shows only the daily peak hours when under-scheduling is 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 A29 and Figure A30.

Figure A28: Day-Ahead Scheduled Versus Actual Loads

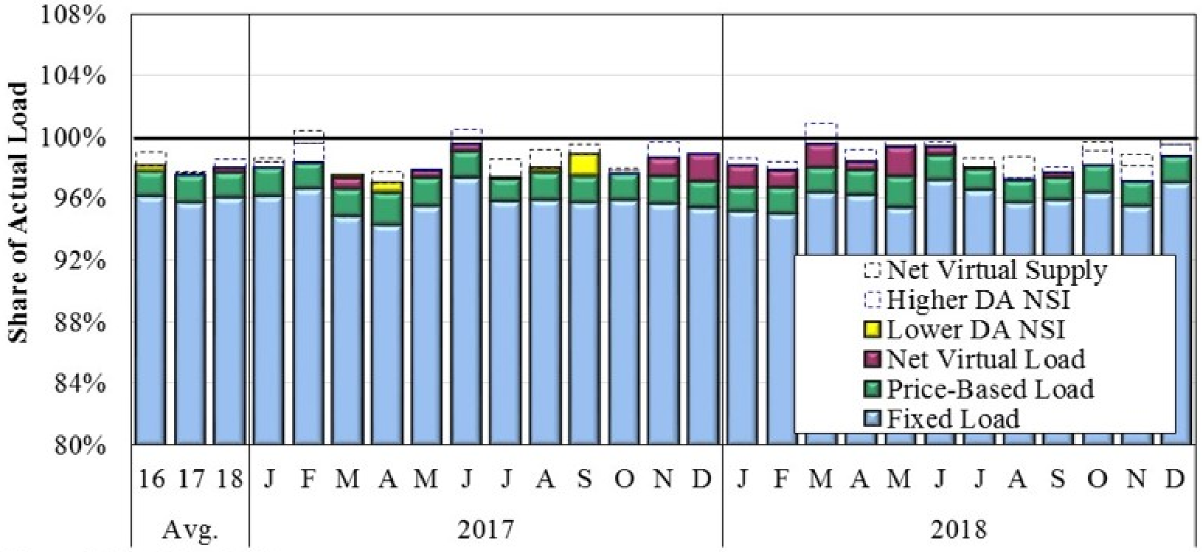
2017–2018, Daily Peak Hour



Share of Actual Load (%)

	Avg. 16	Avg. 17	Avg. 18	2017 J	F	M	A	M	J	J	A	S	O	N	D	2018 J	F	M	A	M	J	J	A	S	O	N	D
All Hours	98.8	99.1	99.0	99.2	98.7	99.1	98.5	99.3	100.2	99.6	99.9	98.9	98.8	98.6	99.2	98.7	98.6	99.3	98.6	100.0	99.7	99.4	99.3	98.9	99.1	97.5	98.8
Peak Hours	98.5	98.6	98.4	98.7	99.5	98.5	97.9	99.3	99.8	98.6	99.5	98.4	98.7	98.3	98.9	98.3	98.8	99.0	98.6	99.7	99.5	98.6	98.0	98.3	98.7	97.2	98.8

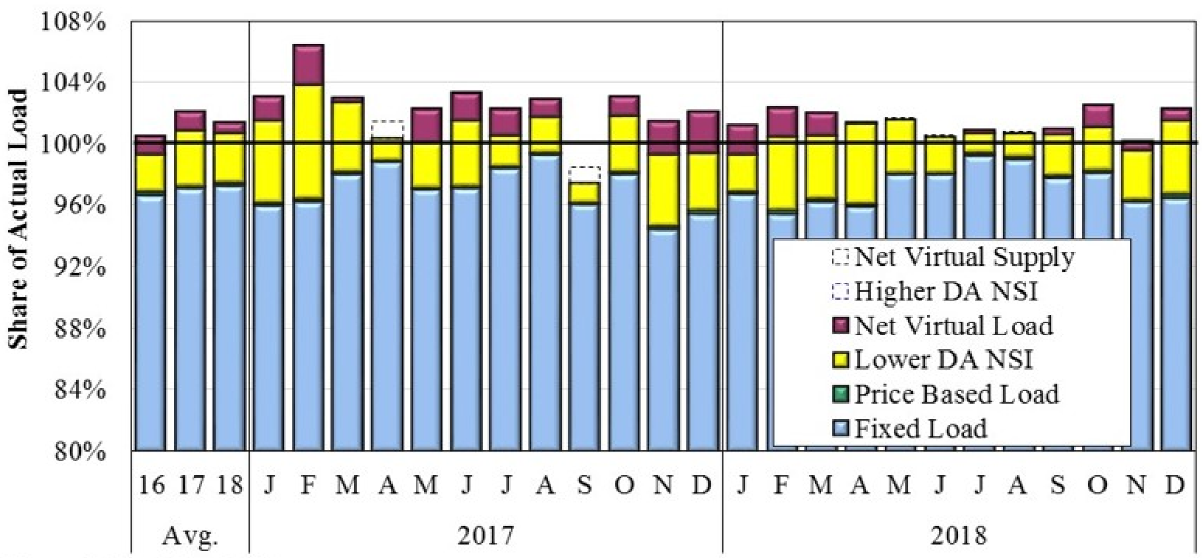
Figure A29: Midwest Region Day-Ahead Scheduled Versus Actual Loads
2017–2018, Daily Peak Hour



Share of Actual Load (%)

All Hours	98.2	98.0	98.2	98.1	97.0	97.7	97.1	97.8	99.3	98.4	98.9	98.8	97.4	97.8	98.7	97.9	97.7	98.7	98.4	98.9	99.0	98.5	98.5	97.8	98.0	96.7	97.9
Peak Hours	98.1	97.5	97.9	98.0	98.3	97.5	97.0	97.8	99.5	97.3	98.0	98.9	97.6	98.6	98.8	98.1	97.8	99.5	98.3	99.4	99.3	97.9	97.1	97.6	98.1	97.1	98.7

Figure A30: South Region Day-Ahead Scheduled Versus Actual Loads
2017–2018, Daily Peak Hour



Share of Actual Load (%)

All Hours	100.7	102.6	101.6	102.6	105.0	103.3	102.2	103.3	103.1	102.7	102.3	99.1	102.6	101.3	101.0	101.3	101.3	101.7	101.7	103.1	101.6	101.9	101.5	101.9	102.1	99.9	101.4
Peak Hours	100.5	102.1	101.3	103.1	106.4	102.9	100.3	102.3	103.2	102.2	102.9	97.4	103.0	101.4	102.1	101.2	102.3	102.0	101.3	101.5	100.4	100.9	100.6	101.0	102.5	100.1	102.2

D. Hourly Day-Ahead Scheduling

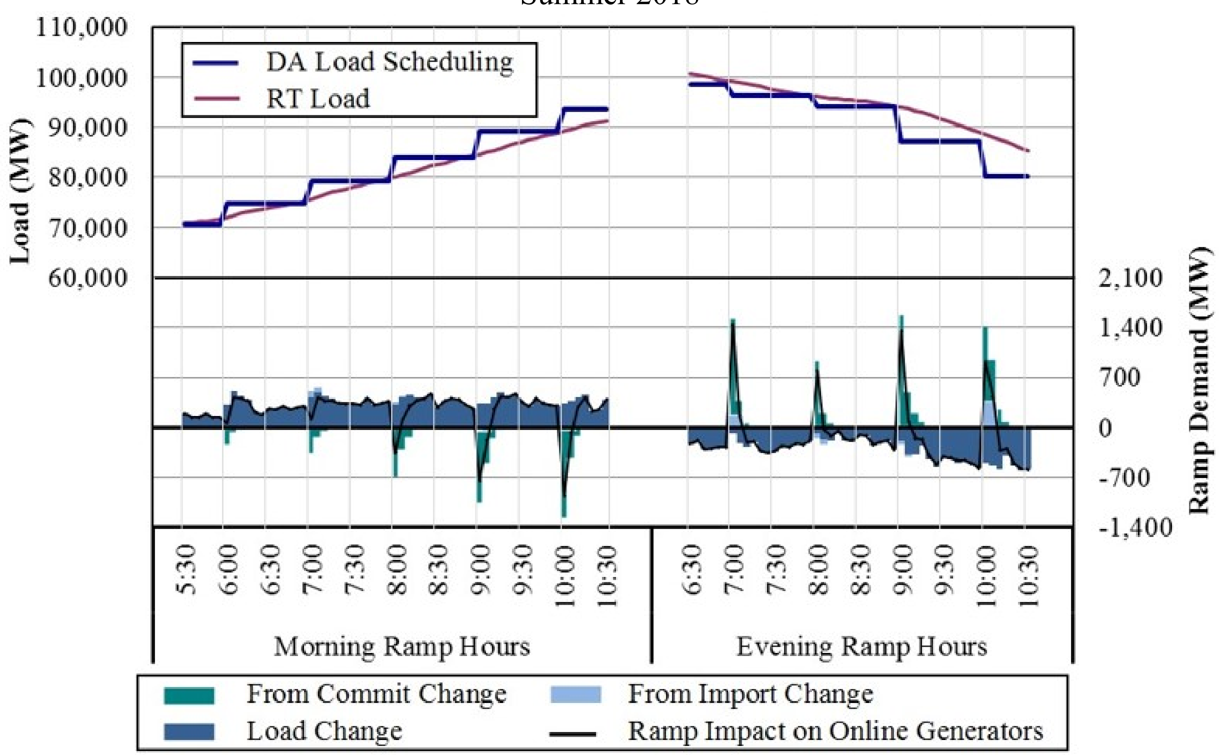
The day-ahead energy and ancillary services markets clear on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of each hour.

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 A31: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A31 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 A31: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2018



E. Virtual Trading Activity

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 the 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, while 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 would sell virtual supply forward and buy it back financially in the real-time market. If they forecast higher real-time prices, they would 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.[15]

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 and the virtual position would be unprofitable.

For example, a participant may submit a high-priced (likely to clear) virtual demand bid at an otherwise unconstrained location that causes artificial day-ahead market congestion. In this case, the participant would buy energy in the day-ahead market at the high (i.e., congested) price and sell the energy back at a lower (i.e., uncongested) price in the real-time market. Although it is foreseeable that the virtual transaction would be unprofitable, the participant could earn net profits if the participant has financial positions (including FTRs) that would benefit. We monitor for such behavior and utilize mitigation authority to restrict virtual activity when appropriate.

Figure A32 and Figure A33: Day-Ahead Virtual Transaction Volumes

Figure A32 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market from 2017 to 2018. Figure A33 separates the 2018 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).

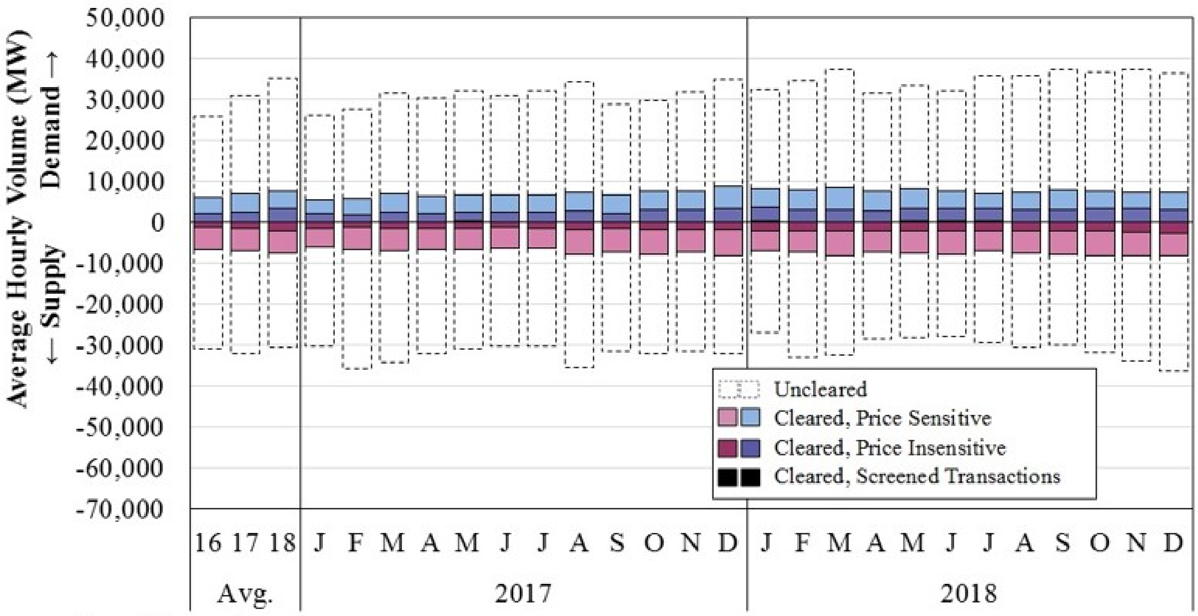
15 Chaves, Jose Pablo and Yannick Perez. 2010. Virtual Bidding: A Mechanism to Mitigate Market Power in Electricity Markets: Some Evidence from New York Market, Working Paper.

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):1107-1125.

Jha, Akshaya, and Frank Wolak. 2014. Testing for Market Efficiency with Transactions Costs: An Application to Convergence Bidding in Wholesale Electricity Markets. Working paper, March 2015.

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

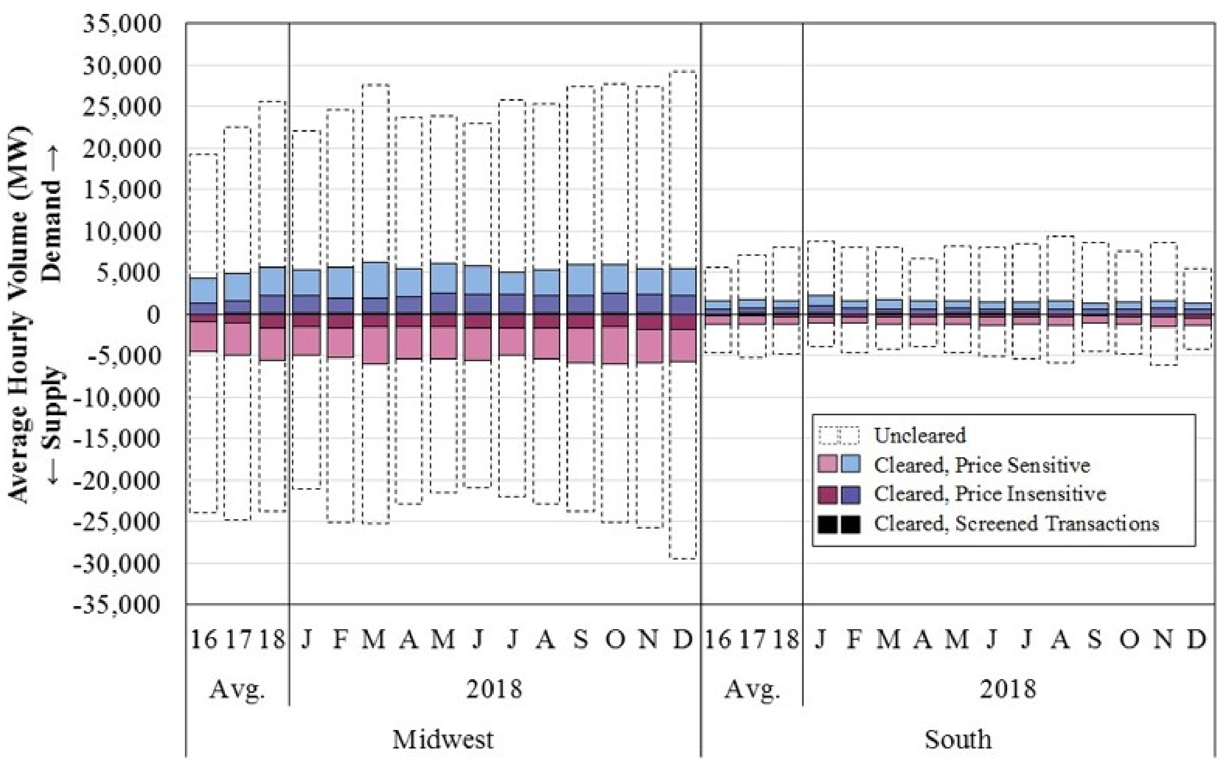
Figure A32: Day-Ahead Virtual Transaction Volumes
2017–2018



Percent Screened

	16	17	18	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Demand	1.2	1.3	1.6	0.9	1.3	1.4	2.1	2.8	1.4	1.2	0.5	1.7	1.4	0.7	0.6	2.3	0.6	1.2	1.3	3.1	2.7	2.3	0.8	1.2	1.9	1.1	0.6
Supply	0.4	0.3	0.4	0.3	0.2	0.4	0.4	0.5	0.3	0.1	0.2	0.5	0.4	0.2	0.3	0.9	0.2	0.3	0.4	0.5	0.5	0.4	0.1	0.2	0.4	0.4	0.2
Total	0.8	0.8	1.0	0.6	0.7	0.9	1.2	1.6	0.8	0.7	0.3	1.0	0.9	0.5	0.4	1.6	0.4	0.7	0.8	1.9	1.6	1.3	0.4	0.7	1.1	0.7	0.4

Figure A33: Day-Ahead Virtual Transaction Volumes by Region
2018



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 purposes 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 the congestion between the day-ahead and real-time markets and warranted further investigation. These volumes are labeled 'Screened Transactions' in the figures.

Figure A34 to Figure A37: 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 A34 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 A35 and Figure A36 show the same values by region, and Figure A37 shows these values by type of location.

Figure A34: Virtual Transaction Volumes by Participant Type
2018

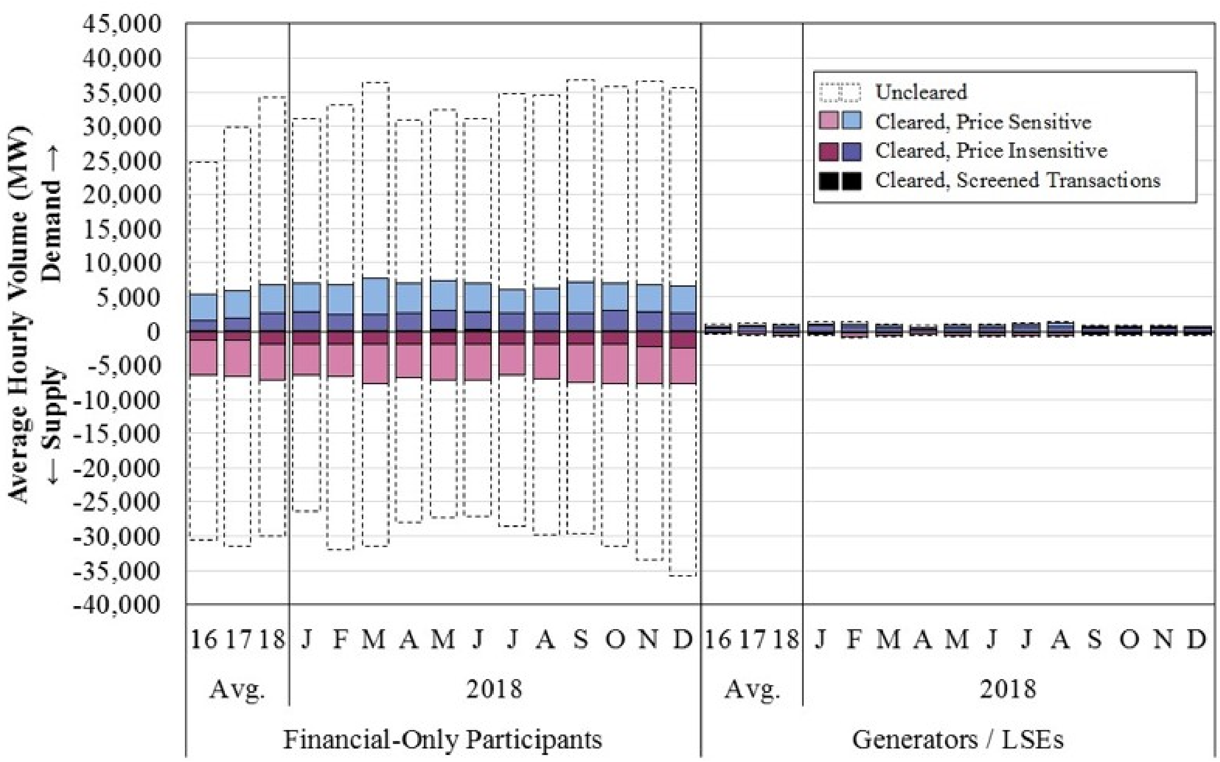


Figure A35: Virtual Transaction Volumes by Participant Type
Midwest Region, 2018

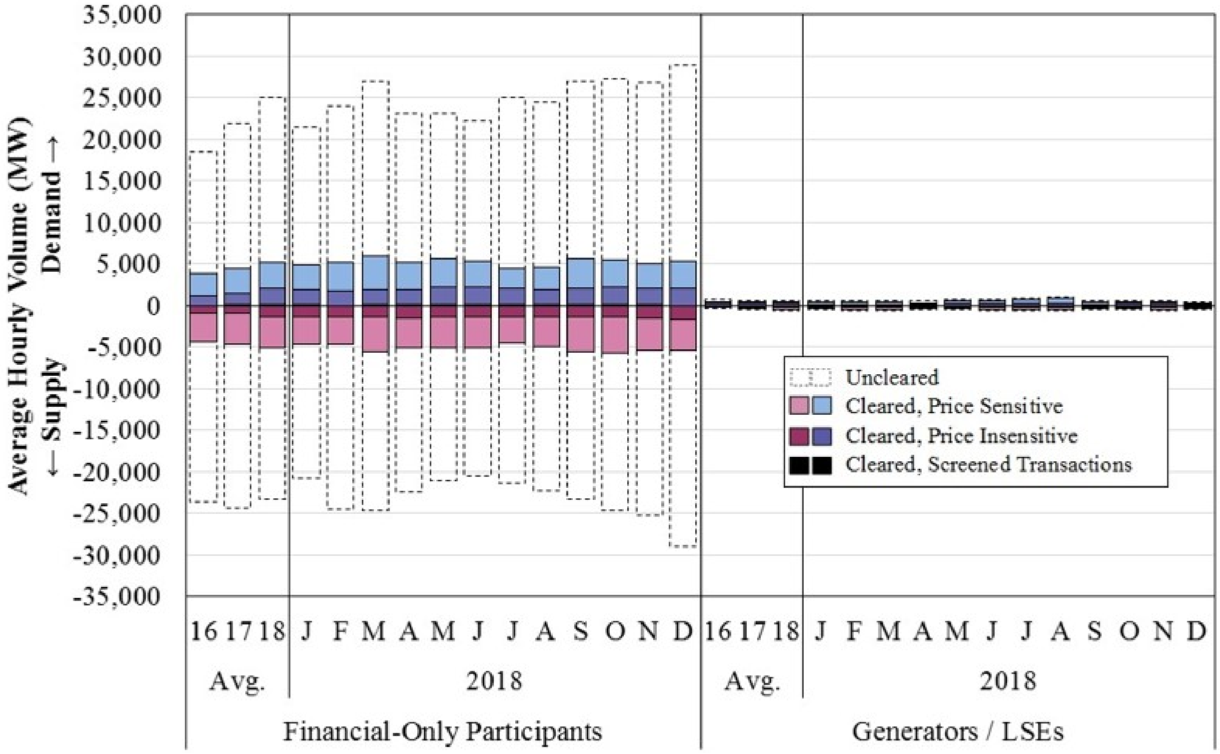


Figure A36: Virtual Transaction Volumes by Participant Type
South Region, 2018

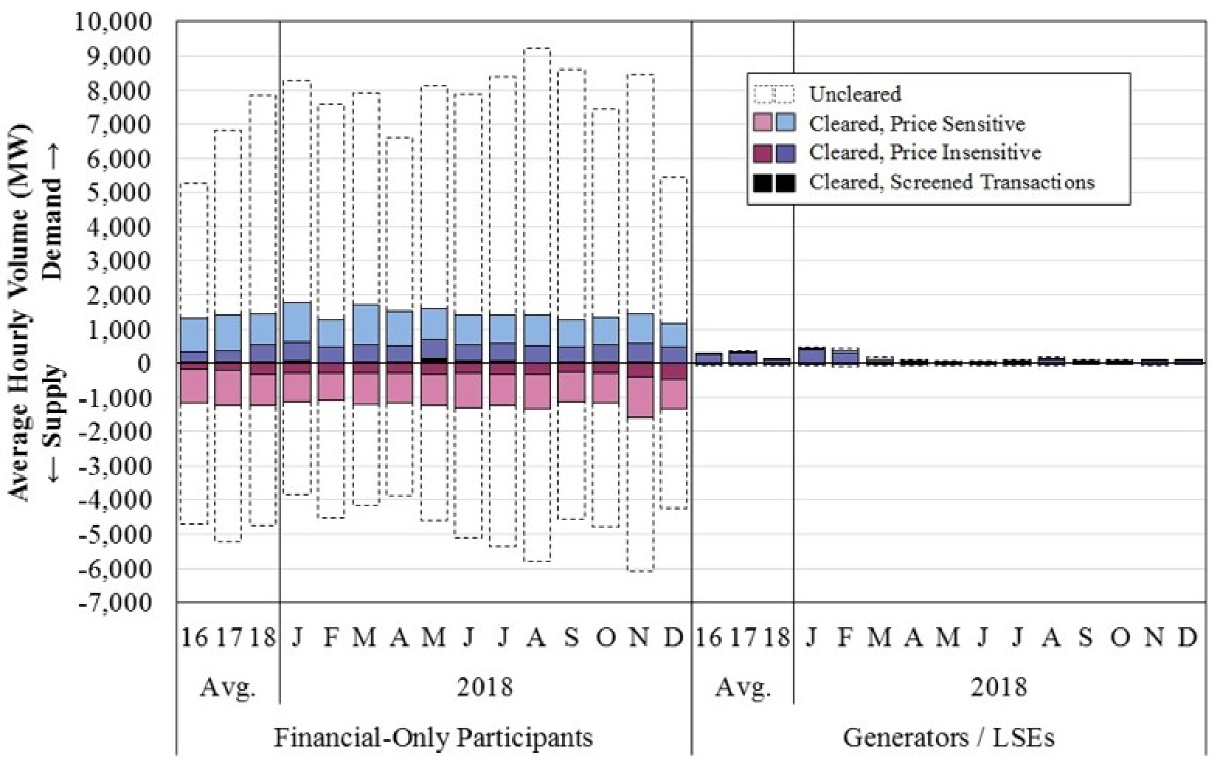


Figure A37: Virtual Transaction Volumes by Participant Type and Location
2016–2018

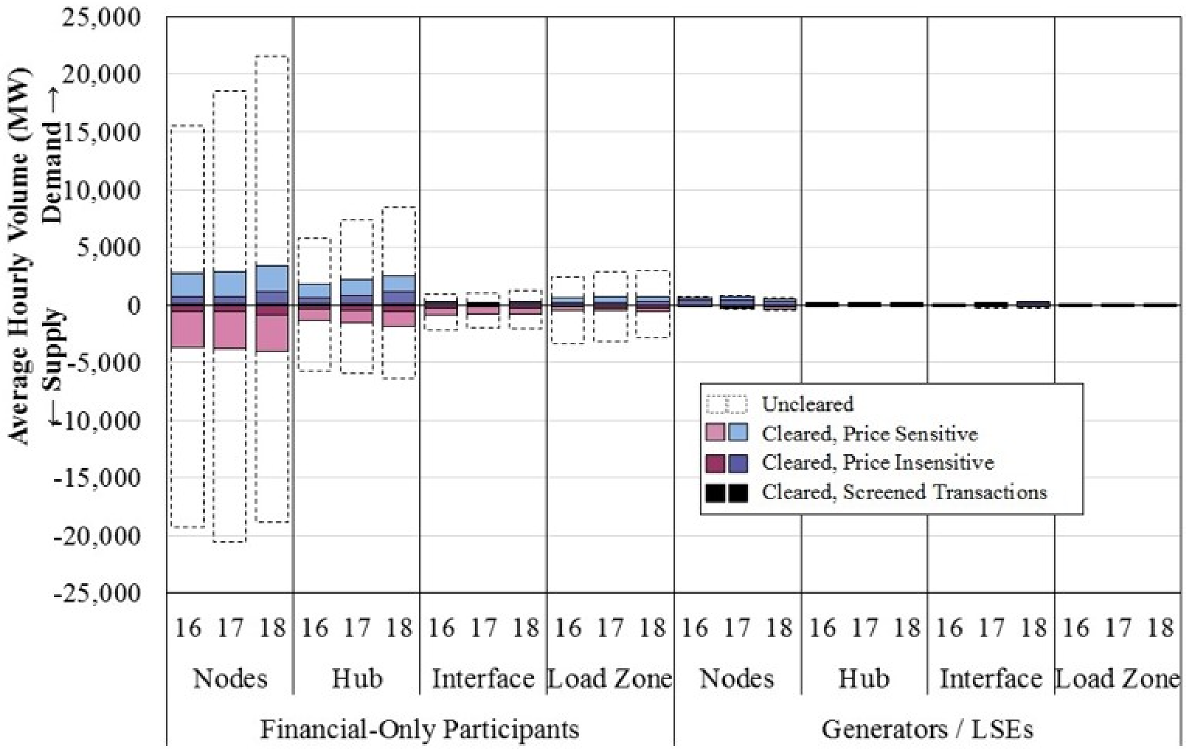


Figure A37 above disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many electrical nodes and, therefore, are less prone to congestion-related price spikes than generator locations.

Figure A38: Matched Price-Insensitive Virtual Transactions

Figure A38 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. Such "matched" transactions rose substantially after RSG revisions in April 2011.

Figure A38: Matched Price-Insensitive Virtual Transactions
2017–2018

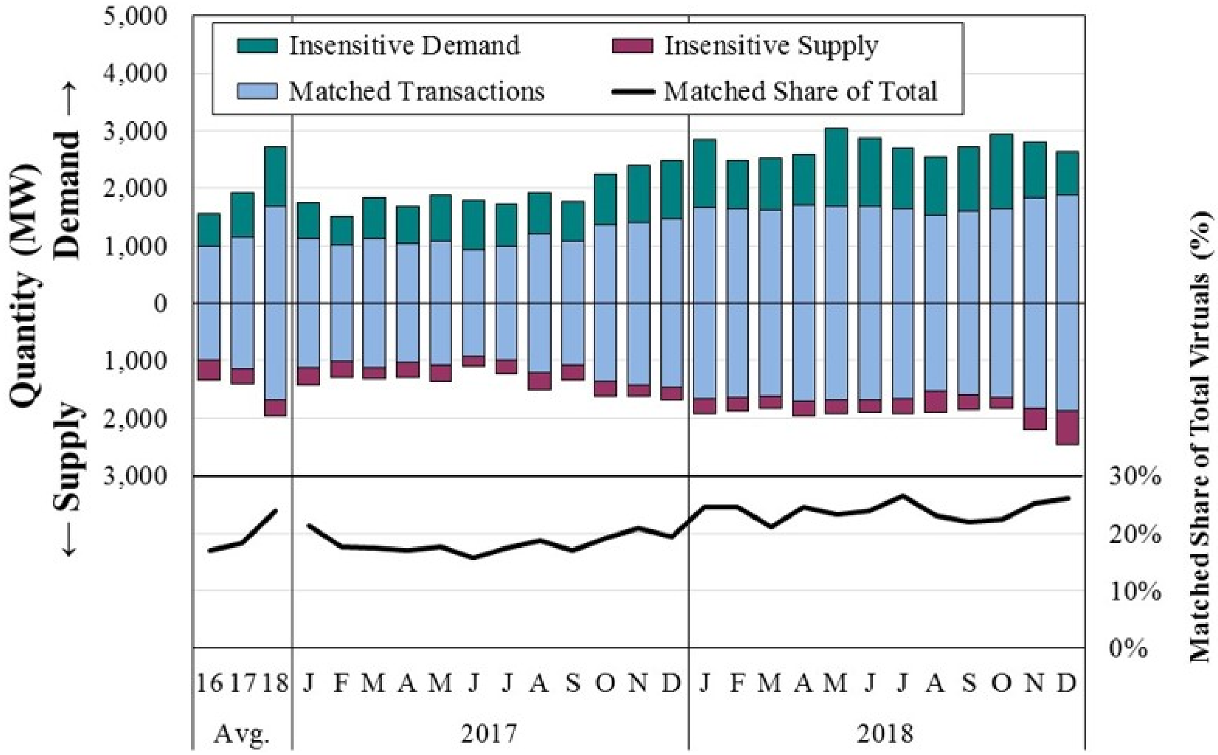
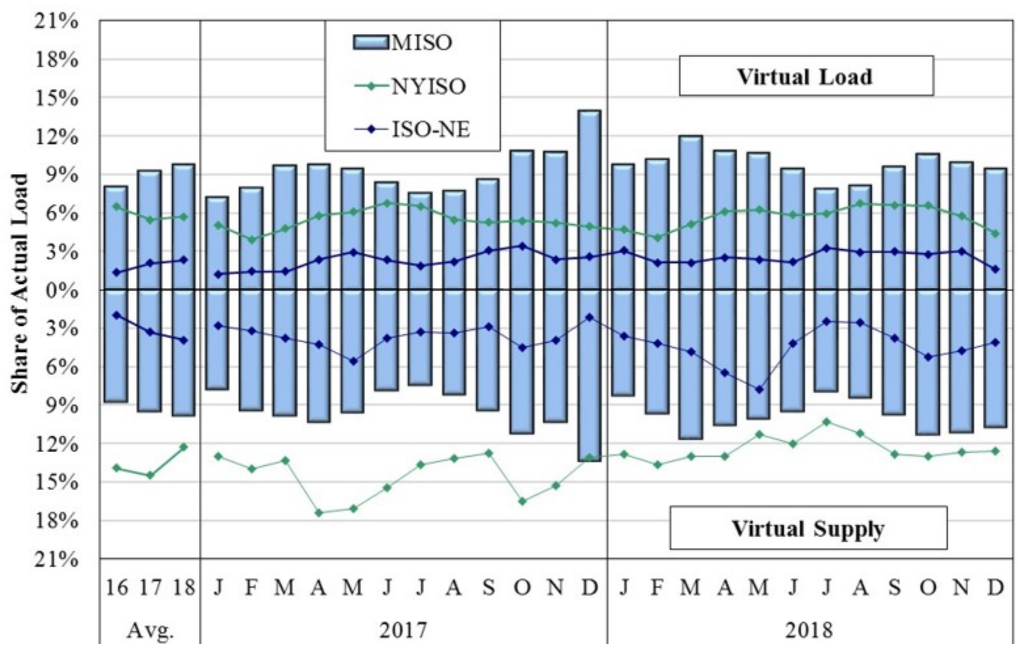


Figure A39: Comparison of Virtual Transaction Levels

To compare trends in MISO to other RTOs, Figure A39 shows cleared virtual supply and demand in MISO, ISO-NE, and NYISO as a share of actual load.

Figure A39: Comparison of Virtual Transaction Levels
2017–2018



F. Virtual Transaction 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.

Figure A40 to Figure A41: Virtual Profitability

Figure A40 shows monthly total profits and average gross profitability of cleared virtual positions. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market and the price at which these positions were covered (i.e., settled financially) in the real-time market. Gross profitability excludes RSG cost allocations, which vary according to the market-wide DDC rate and the hourly net deviation volume of a given participant. Figure A41 shows the same results disaggregated by type of market participant: entities owning generation or serving load and financial-only participants.

Figure A40: Virtual Profitability
2017–2018

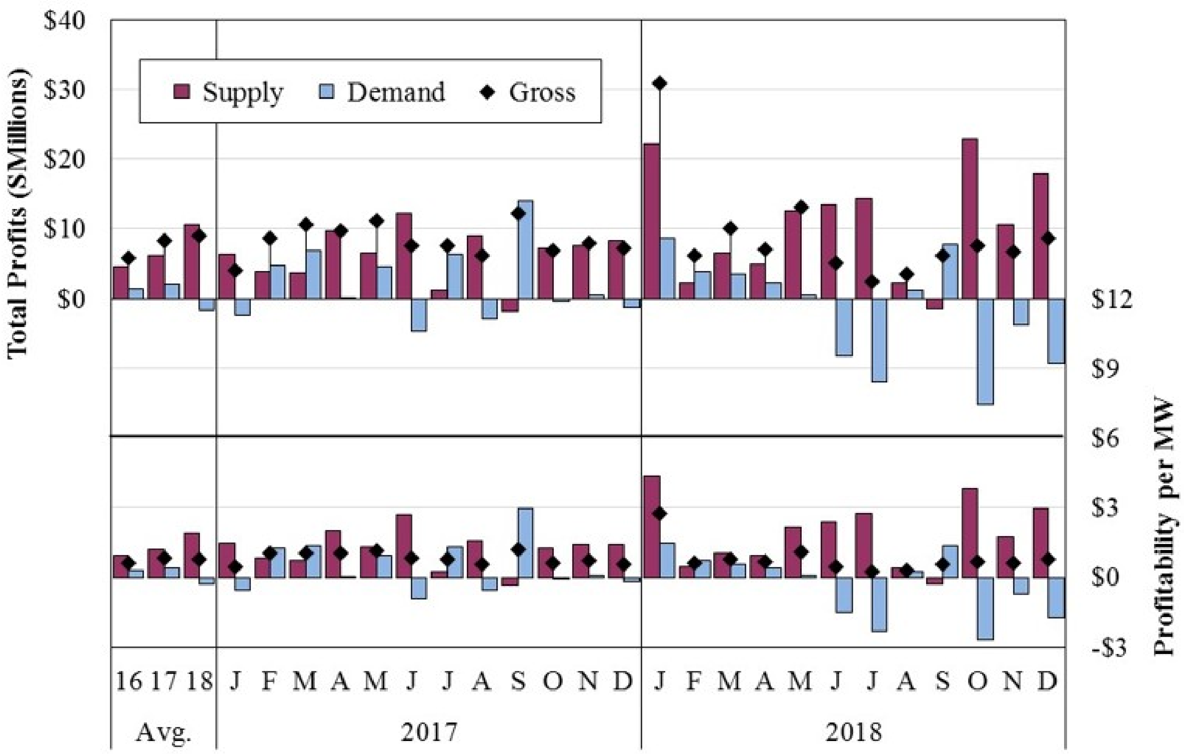
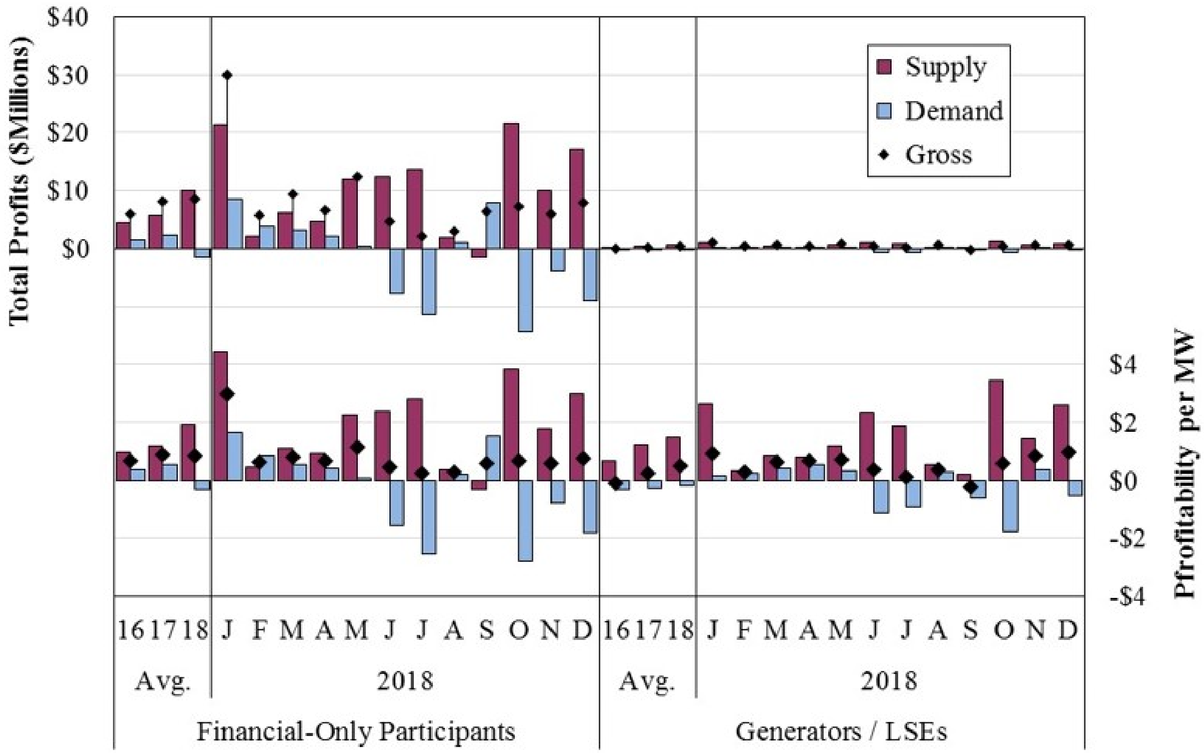


Figure A41: Virtual Profitability by Participant Type
2018



G. Benefits of Virtual Trading in 2018

We conducted an empirical analysis of virtual trading in MISO in 2018 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 that was 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 un-modeled constraints or transactions that were profitable due to 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 – whether the absolute value of the difference between the day-ahead and real-time LMP at time *t* was smaller than the absolute value of the difference between the lagged day-ahead price and the current real-time price.
- Virtual Directional Test: To determine whether the virtual helped move the day-ahead price in the right direction, we test whether 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 A7 and Table A8: Virtual Evaluation Summaries

Table A7 summarizes the virtual transaction quantities in the efficiency-enhancing and non-efficiency-enhancing categories, separated by the type of entity submitting the transactions.

Table A7: Efficient and Inefficient Virtual Transactions in 2018

	Financial Participants		Physical Participants		Total	
	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Total
Efficiency - Enhancing Virtuals	7,800	*58%*	933	*57%*	8,733	*58%*
Non - Efficiency - Enhancing Virtuals	5,675	*42%*	711	*43%*	6,386	*42%*

Table A8 below shows the total profits and losses associated with efficiency-enhancing and non-efficiency-enhancing virtual transactions in MISO in 2018 by market participant type.

Table A8: Analysis of Virtual Profits and Losses of Virtual Transactions in 2018

	Financial Participants		Physical Participants		Total
	Total Profits (Losses)	Share of Class	Total Profits (Losses)	Share of Class	Total Profits (Losses)
Efficiency - Enhancing Virtuals	$ 567,591,049	*92%*	$ 47,692,358	*8%*	$ 615,283,407
Non - Efficiency - Enhancing Virtuals	$ (451,945,968)	*92%*	$ (39,265,742)	*8%*	$ (491,211,711)
Rent	$ 42,635,959	*92%*	$ 3,847,321	*8%*	$ 46,483,280

The profits and losses shown in the table above are useful because they account for the fact that some transactions are relatively more efficient or relatively more inefficient than others. Table A8 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 2018.

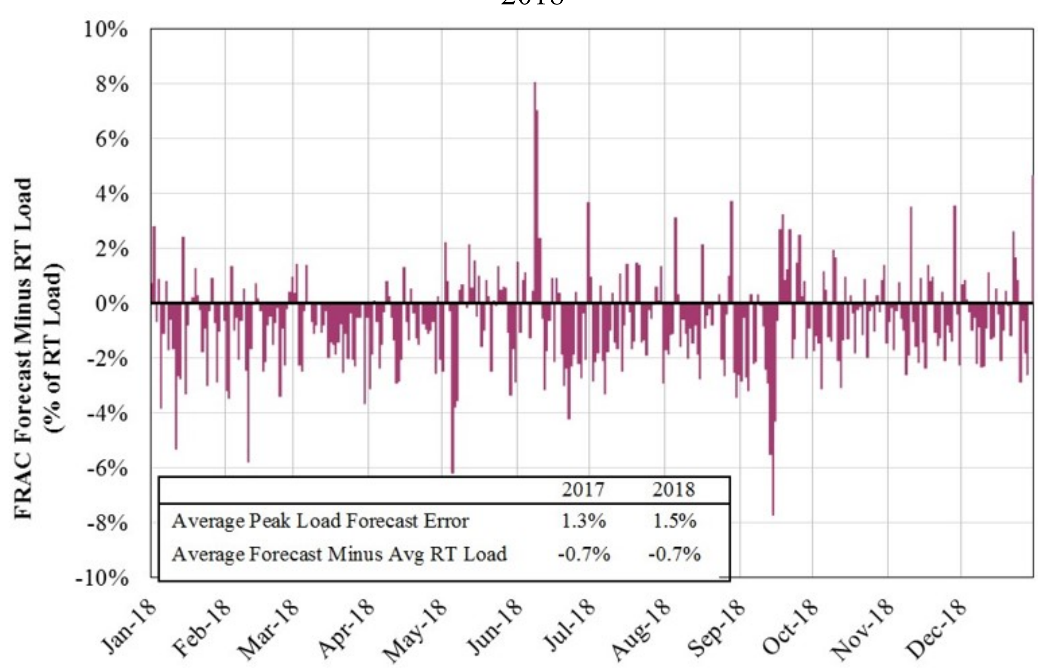
H. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is particularly important because it is an input to the Forward Reliability Assessment Commitment (FRAC) process performed after the day-ahead market closes and before the real-time operating day begins. Inaccurate forecasts can cause MISO to commit more or fewer resources than necessary to meet demand, both of which can be costly.

Figure A42: Daily MTLF Error in Peak Hour

Figure A42 shows the percentage difference between the MTLF used in the FRAC process and real-time actual load for the peak hour of each day in 2018.

Figure A42: Daily MTLF Error in Peak Hour
2018



V. Real-Time Market Performance

In this section, we evaluate real-time market outcomes, including prices, loads, and uplift payments. We also assess the dispatch of peaking resources and the ongoing integration of wind generation. Wind generation has continued to grow and set new output records in 2018, the last of which was March 31 at 15.6 GW.[16]

The real-time market performs the vital role of dispatching resources to minimize the total production cost of satisfying its energy and operating reserve needs, while observing generator and transmission network limitations. Every five minutes, the real-time market utilizes the latest information regarding generation, load, transmission flows, and other system conditions to produce new dispatch instructions and prices for each nodal location on the system.

While some RTOs clear their real-time energy and ancillary services markets every 15 minutes, MISO's five-minute interval permits more rapid and accurate response to changing conditions, such as changing wind output or load. Shortening the dispatch interval reduces regulating reserve requirements and permits greater resource utilization. These benefits sometimes come at the cost of increased price volatility, which we evaluate in this section.

Although most generator commitments are made through the day-ahead market, real-time market results are a critical determinant of efficient day-ahead market outcomes. Energy purchased in the day-ahead market (and other forward markets) is priced based on expectations of the real-time market prices. Higher real-time prices, therefore, can lead to higher day-ahead and other forward market prices. Because forward purchasing is partly a risk-management tool for participants, increased volatility in the real-time market can also lead to higher forward prices by raising risk premiums in the day-ahead market.

A. Real-Time Price Volatility

Substantial volatility in real-time markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by generators' physical limitations. This subsection evaluates and discusses the volatility of real-time prices. Sharp price changes frequently occur when the market is ramp-constrained (when a large share of the resources are moving as quickly as possible), which occurs when the system is moving to accommodate large changes in load, NSI, or generation startup or shutdown. This is exacerbated by generator inflexibility arising from lower offered ramp limits or reduced dispatch ranges.

Figure A43: Fifteen-Minute Real-Time Price Volatility

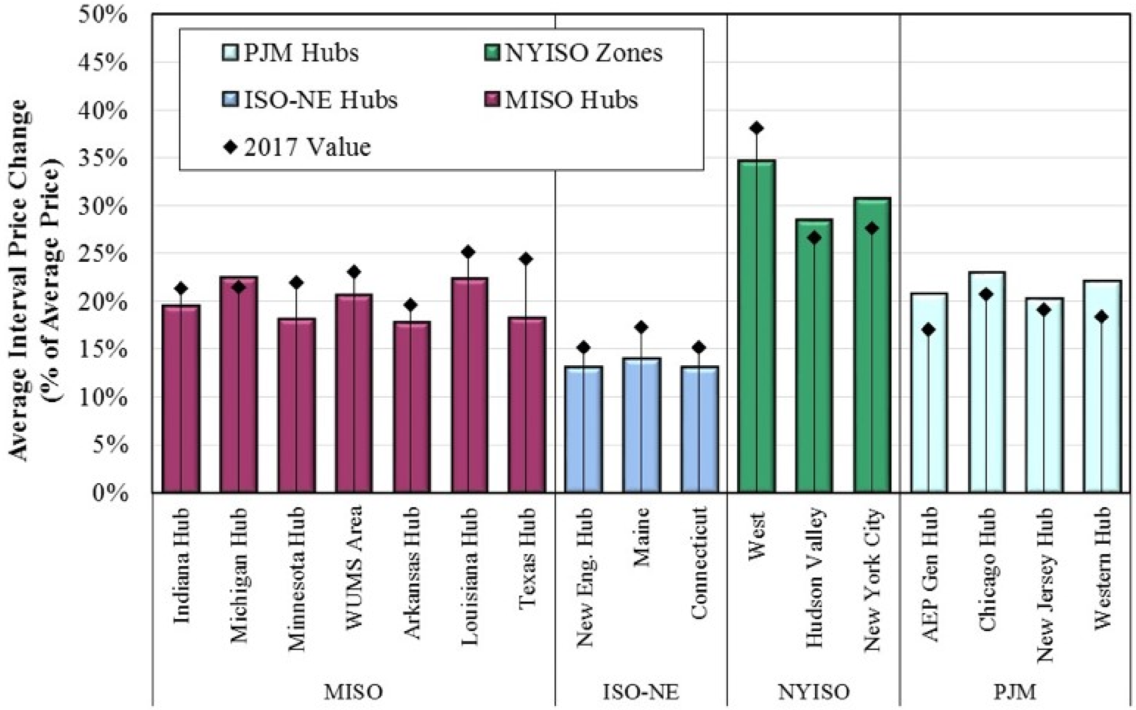
Figure A43 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between 15-minute intervals for several locations in MISO and other RTO markets. Each of these markets has a distinct set of operating characteristics that factor into price volatility. MISO and NYISO are true five-minute markets with a five-minute dispatch horizon. Ramp constraints are more prevalent in these markets as a result of the shorter

16 As of the date of this writing, the all-time peak wind output occurred on March 15, 2019 at 16.3 GW.

time to move generation. However, NYISO's real-time dispatch is a multi-period optimization that looks ahead more than one hour, so it can better anticipate ramp needs and begin moving generation to accommodate them. We are recommending MISO adopt a similar approach.

Although they produce five-minute prices using ex-post pricing models, PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes. As a result, these systems are less likely to be ramp-constrained because they have more ramp capability to serve system demands. Because the systems are re-dispatched less frequently, they are apt to satisfy shorter-term changes in load and supply more heavily with regulation. This is likely to be less efficient than more frequent dispatch cycles—energy prices in these markets do not reflect prevailing conditions as accurately as five-minute markets.

Figure A43: Fifteen-Minute Real-Time Price Volatility
MISO and Other RTO Markets, 2018



B. Evaluation of ELMP Price 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. In May 2017, MISO implemented ELMP Phase 2. ELMP is intended to improve price formation in the day-ahead and real-time energy and ancillary services markets by having LMPs better reflect the true marginal costs of supplying the system at each location. ELMP is a reform of the previous price-setting engine that affects prices but does not affect the dispatch. ELMP reforms pricing in two main ways:

- It allows 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.

- It allows offline Fast-Start Resources to be eligible to set prices during transmission violations or energy shortage conditions.

The first element of ELMP addresses 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 does not always reflect the true marginal cost of the system because inflexible high-cost resources are frequently not recognized as marginal, even though they are 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.

There are several adverse market effects when economic units supplying incremental energy are not included in price setting:

- MISO will generally need to pay RSG to cover these units' full as-offered costs;
- Real-time prices will be understated and will not provide efficient incentives to schedule energy in the day-ahead market, when lower-cost resources could be scheduled that would reduce or eliminate the need to rely on high-cost peaking resources in real time; and
- The market will not provide efficient incentives for participants to schedule exports or imports, which can prevent lower-cost energy from being imported to displace the higher-cost peaking resources.

Accordingly, the objective of the online pricing reforms in ELMP is to allow certain inflexible resources to set prices in the MISO energy markets.

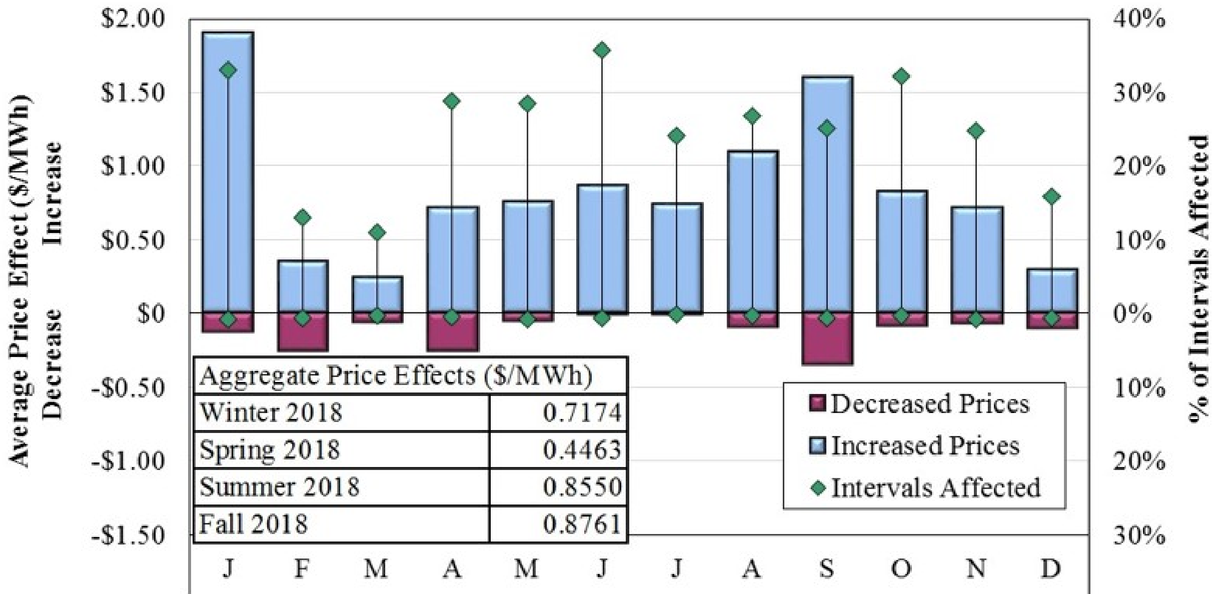
The second element of ELMP allows offline Fast-Start Resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. It is efficient for offline resources to set the price only when a) they are feasible (can be started quickly), and b) they are economic for addressing the shortage. However, when units that are either not feasible or not economic to start are allowed to set energy prices, the resulting prices will be inefficiently low. We review and discuss both of these reforms in this section.

Figure A44 to Figure A46: ELMP Price Effects

Figure A44 to Figure A46 summarize the effects of ELMP by showing the average upward effects via the online pricing, average downward effects via the offline pricing, 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 effected locations (i.e., congestion-related effects). Additionally, to show the size of the ELMP price adjustments, in 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.

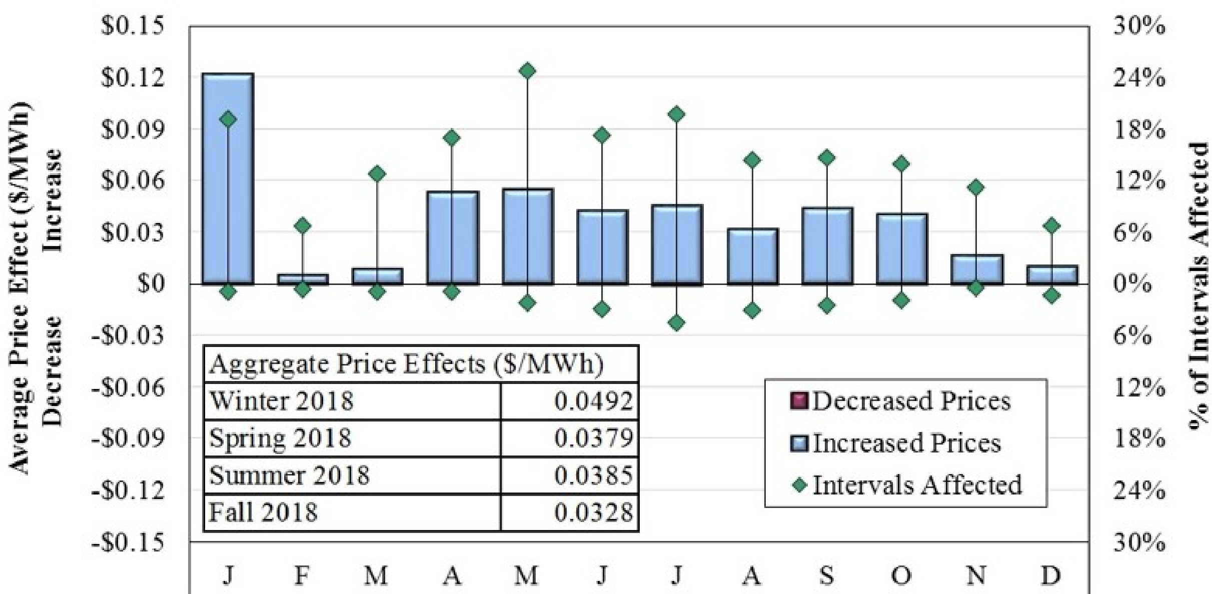
Figure A44: Average Market-Wide Price Effects of ELMP
Real-Time Market, 2018



Change in Affected Intervals ($/MWh) 2018

	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	5.75	2.73	2.26	2.50	2.66	2.44	3.06	4.08	6.37	2.56	2.89	1.89
SMP Decrease	-17.92	-40.59	-20.70	-49.96	-7.67	-2.92	-7.70	-26.84	-55.01	-22.80	-9.75	-19.48

Figure A45: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, 2018



Change in Affected Intervals ($/MWh) 2018

	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	0.64	0.07	0.06	0.31	0.22	0.24	0.23	0.22	0.30	0.28	0.14	0.14
SMP Decrease	-0.03	-0.01	-0.01	-0.01	-0.04	-0.02	-0.03	-0.02	-0.02	-0.02	-0.02	-0.05

Figure A46: Price Effects of ELMP at Most Affected Locations
Real-Time Market, 2018

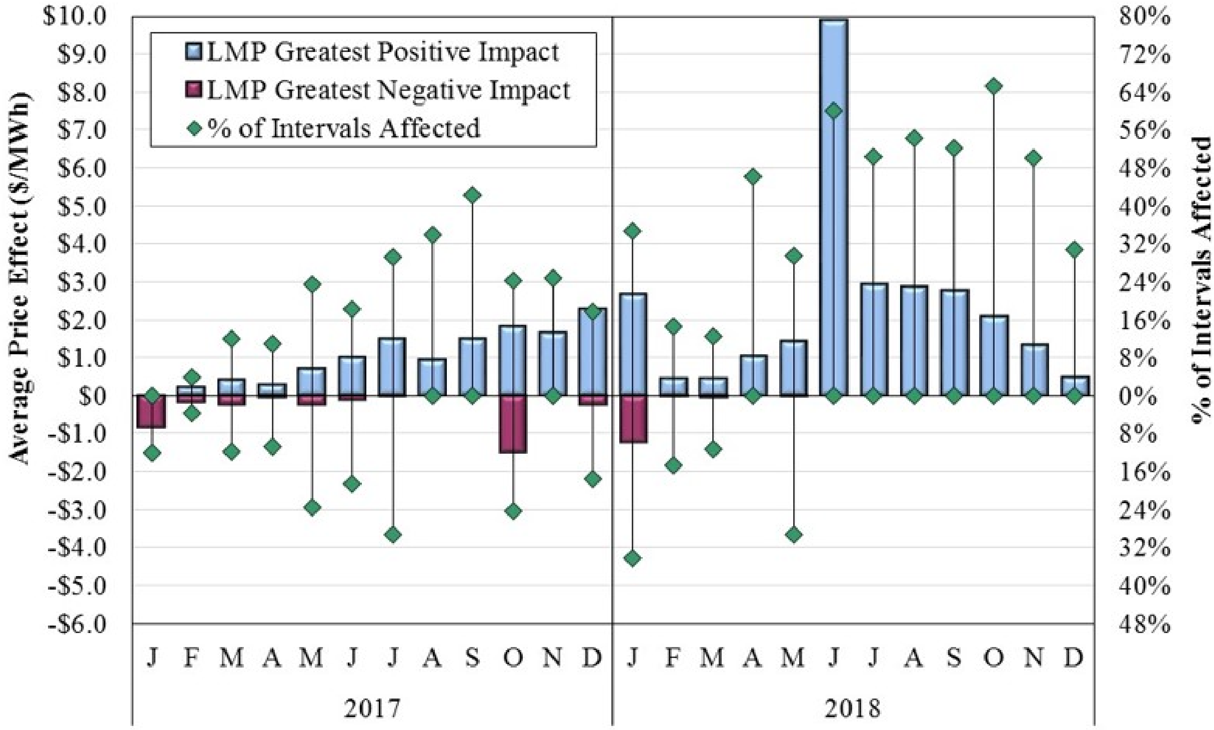


Figure A47: Eligibility of Online Peaking Resource in ELMP

Allowing inflexible online resources to set energy prices increases the effectiveness and efficiency of the markets. The figures above show that the upward price effects of ELMP have been relatively small. We attribute these small effects largely to the ELMP eligibility rules. In this section, we show the portions of MISO's online peaking resources that have been eligible to set prices under the Phase I and II ELMP rules and the portions that remain ineligible.

Figure A47 shows the energy produced by online peaking resources, separated by:

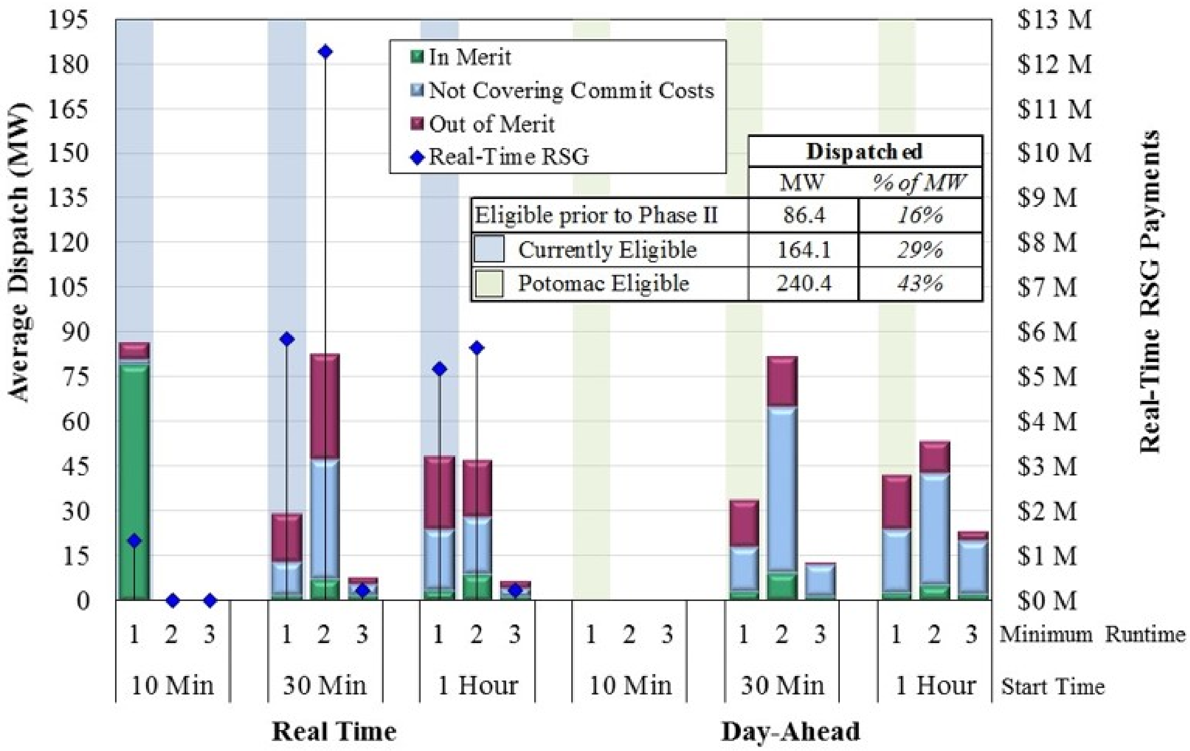
- Whether they were scheduled during or after the day-ahead market;
- Their start-up time; and
- Their minimum run-time.

We show this combination because as of May 1, 2017, only units eligible to set real-time prices in the ELMP pricing model were those not scheduled in the day-ahead market that can start in 60 minutes or less and have a minimum runtime of one hour or less.[17] These units are shaded in blue in the figure below. The IMM proposal would allow peaking resources that are committed in the day-ahead market to be eligible to set prices in ELMP. Hence, we propose that MISO

17 Prior to May 1, 2017, only resources not scheduled in the day-ahead market that were able to start in 10 minutes or less and had a minimum runtime of one hour or less were eligible to set real-time prices in the ELMP pricing model.

evaluate expanding the eligibility rules beyond Phase II of ELMP to include these additional classes of peaking resources.

Figure A47: Eligibility of Online Peaking Resources in ELMP
2018



The primary focus of our recommendation to expand ELMP to date has been selecting which resources should be eligible to set prices in the ELMP model. However, it is equally important to address *how* resources participate in ELMP. The first two phases of ELMP do not allow resources to set prices when the dispatch model seeks to ramp them down at their maximum ramp rate, even if the resources continues to provide marginal energy to the grid. This ramp test substantially reduces the resources that qualify as marginal, price-setting resources. In both the ISO-NE and NYISO variants of ELMP, a resource may be considered marginal and set prices unless it is dispatched to zero. This is a significant advantage over MISO's ELMP approach, which we evaluate below in Figure A48.

Figure A47: Energy Price Effects of ELMP Expansion

The following figure shows the estimated hourly SMP effects of various levels of ELMP expansion in 2018. In each real-time market interval, we modeled energy demand clearing with five different supply curves of available, rampable capacity. The first supply curve replicated the ex-ante capability used in the real-time market dispatch. The remaining four supply curve cases approximated ELMP outcomes with combinations of ramp constraints (unlimited ramp down and five minutes of ramp down capability) and eligible peaking unit definitions (Phase II ELMP and Phase II plus day-ahead committed resources that otherwise meet the Phase II requirements).

The lines on the figure show the average price differences between each of the four ELMP approximations and the ex-ante specification.

The four lines show a similar pattern throughout the day, with almost no effect in off-peak hours and peak-hour effects that track the shape of demand. The dashed blue line represents the effects of the ramp-constrained Phase II participation. The other three cases show larger price effects that grow in proportion to the quantity of participating output.

The IMM's recommended level of expansion is the solid green line showing the unlimited ramp-down scenario with real-time participation from day-ahead committed peaking units. The inset table identifies the average SMP effect for each of the scenarios and the proportion of market intervals when the eligible resources were needed to meet generation demand.

Figure A48: Energy Price Effects of ELMP Expansion
2018

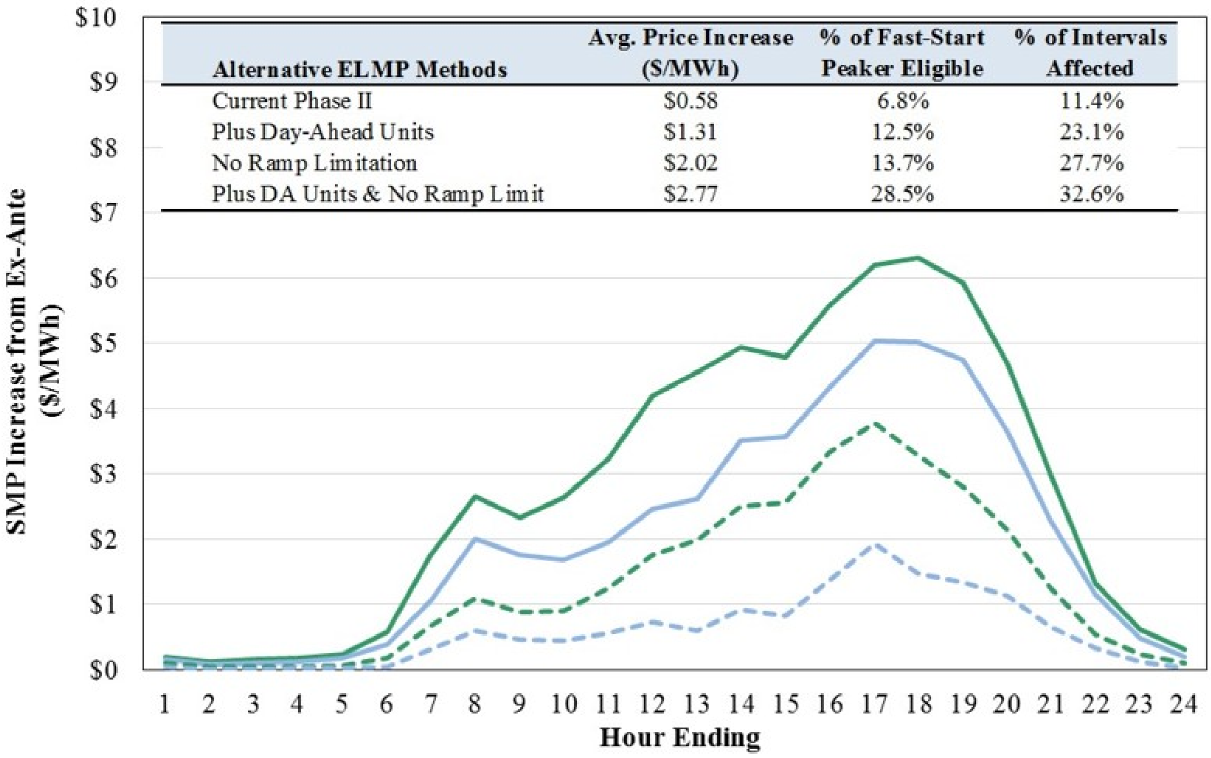


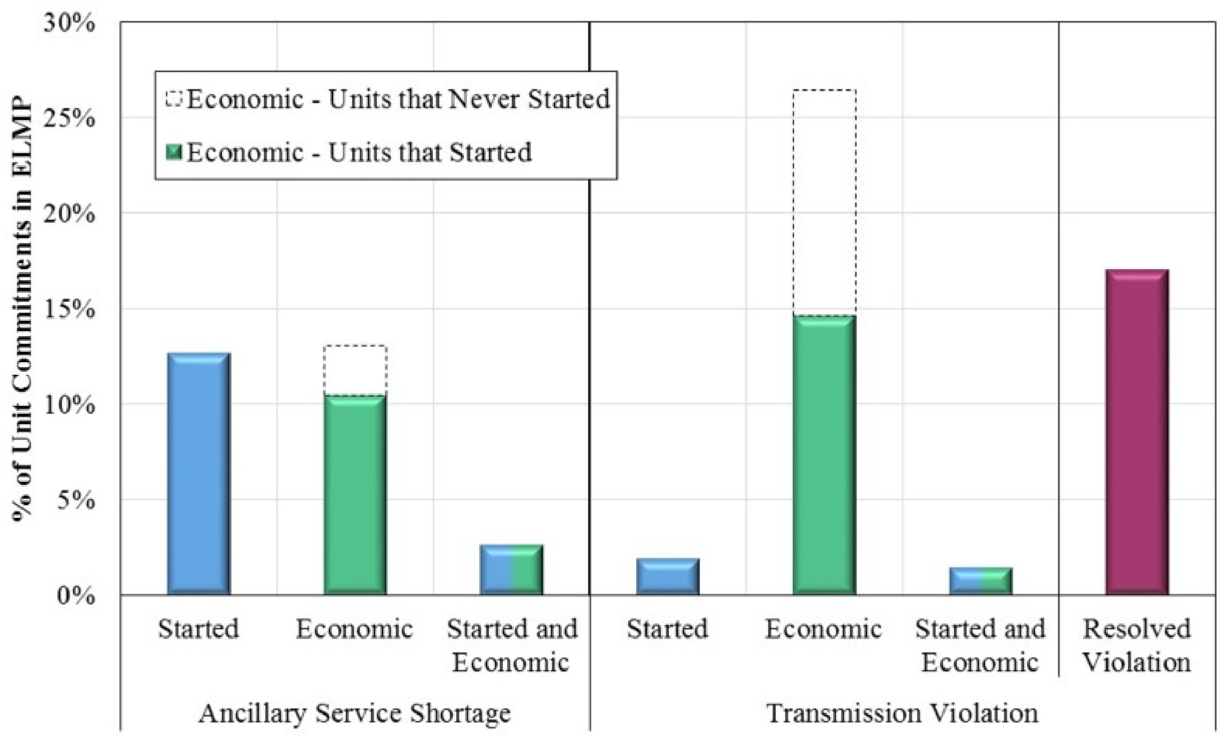
Figure A49: Evaluation of Offline Units Setting Prices in ELMP

ELMP also includes provisions for allowing offline Fast-Start Resources to set price under shortage conditions. Shortages include transmission violations and operating reserves shortages. Prior to the implementation of ELMP, offline units could not set prices because UDS only optimizes the schedules from online resources.

When an operating reserve shortage or a transmission violation occurs, the ELMP software may set prices based on the hypothetical commitment of an offline unit that MISO could utilize to address the shortage. This is only efficient when the offline resource is: a) feasible (can be started quickly enough to help), and b) economic for addressing the shortage. When units that are either not feasible or not economic to start set prices, the prices will be inefficiently low.

When committing an offline unit is feasible and is the economic action to take during a transmission violation or operating reserves shortage, we expect that the unit will be started by MISO. When resources are not started, we infer that the operators did not believe the unit could be online in time to help resolve the shortage and/or that the operator did not expect that the unit would be economic to operate for the remainder of its minimum runtime. Therefore, Figure A49 summarizes whether the offline units that set prices in 2018 were a) economic, b) started by MISO, and c) both started *and* economic. The maroon bar on the right in the figure indicates whether the resources actually resolved a transmission violation. The figure shows operating reserve shortages in the left panel and transmission violations in the right panel.

Figure A49: Evaluation of Offline Units Setting Prices
2018



To determine whether the units were economic (green bar), we compared the real-time market revenues the unit would have received to their total dispatch costs. The total costs included start-up and no-load costs for the units' minimum runtime, starting with the interval after the interval that they were committed. We identified the units that started (blue bar) by whether the UDS recognized the units as online in the three intervals following the recommended commitment intervals. If both of the conditions for economic commitments and MISO starts were met, we determined that the units were both started and economic (blue and green bar).

We also determined whether the offline units setting prices in the ELMP cases for transmission violations were actually resolving the violations (maroon bar). This is important because if an offline unit does not resolve the violation, it may alter the system-wide energy price inefficiently without significantly changing the congestion pricing associated with the violated constraint.

Table A9: Extreme Values of Emergency Offer Floor Prices

During emergency events, MISO can access supply outside of the market that is unavailable during non-emergency conditions, some of which is not dispatchable. In order to prevent the emergency supply from depressing prices, MISO's emergency pricing construct applies Emergency Offer Floor Prices to these emergency MWs in the ELMP pricing engine to allow them to set prices.

An efficient Emergency Offer Floor Price should satisfy the following criteria:

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

Proxy offers are currently formed as the maximum of the resource's offer and either the Emergency Tier I or Tier II Offer Floor Price. The Tier I floor, equal to the highest available economic offer of any resource in the emergency area, applies to emergency resources available under EEA Level 1 events. The Tier II floor applies to EEA Level 2 emergency resources and is calculated as the highest available economic or emergency offer in the area. Because these offer floors are set by a suppliers' offer, the floors can vary widely.

In 2018, MISO declared five emergencies in local areas throughout the footprint. MISO also declared local emergencies in the Central and North Regions on two days in January 2019. In each of these emergency events, Emergency Offer Floor Prices were established. In most of these cases, we believe the floor prices substantially understated the true value of emergency power. However, the risk remains that a single entity could raise a single resource's offer and sharply inflate the proxy Emergency Offer Floor Price.

We conducted an analysis to determine the extent of the volatility of calculated emergency offer floor prices in 2018, based on resource offers. In our analysis, we calculated emergency floor prices for all hours in 2017 and 2018. This analysis shows that emergency floor prices that would have prevailed if MISO were to have declared an emergency in the South or Midwest regions. In Table A9, we show the minimum and maximum values that were calculated by region, as well as the largest inter-hour change.

Table A9: Extreme Values of Emergency Offer Floor Prices
2017–2018

Region	Extreme Values		Largest Inter-hour Change
	Minimum	Maximum	
MIDWEST	$335	$1,081	$593
SOUTH	$109	$525	$198

C. Real-Time Ancillary Service Prices and Shortages

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. The demand curves for the various ancillary services products in 2018 were:

- Regulation: varies monthly according to the prior month's gas prices. It averaged $140.58 per MWh in 2018.
- 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).[18]
- Total Operating Reserves:
  - For cleared reserves less than four percent of the market-wide requirement: Value of Lost Load ($3,500) minus the monthly demand curve price for regulation.
  - For cleared reserves between four and 96 percent of the market-wide requirement: priced between $1,100 (the combined offer caps for energy and contingency reserves) and the above, depending on the estimated probability of loss of load.
  - For cleared reserves more than 96 percent of the market-wide requirement: $200.

Total operating reserves (including contingency reserves plus regulation) is the most important reserve requirement because a shortage of total operating reserves has the greatest potential impact on reliability. Accordingly, total operating reserves 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.

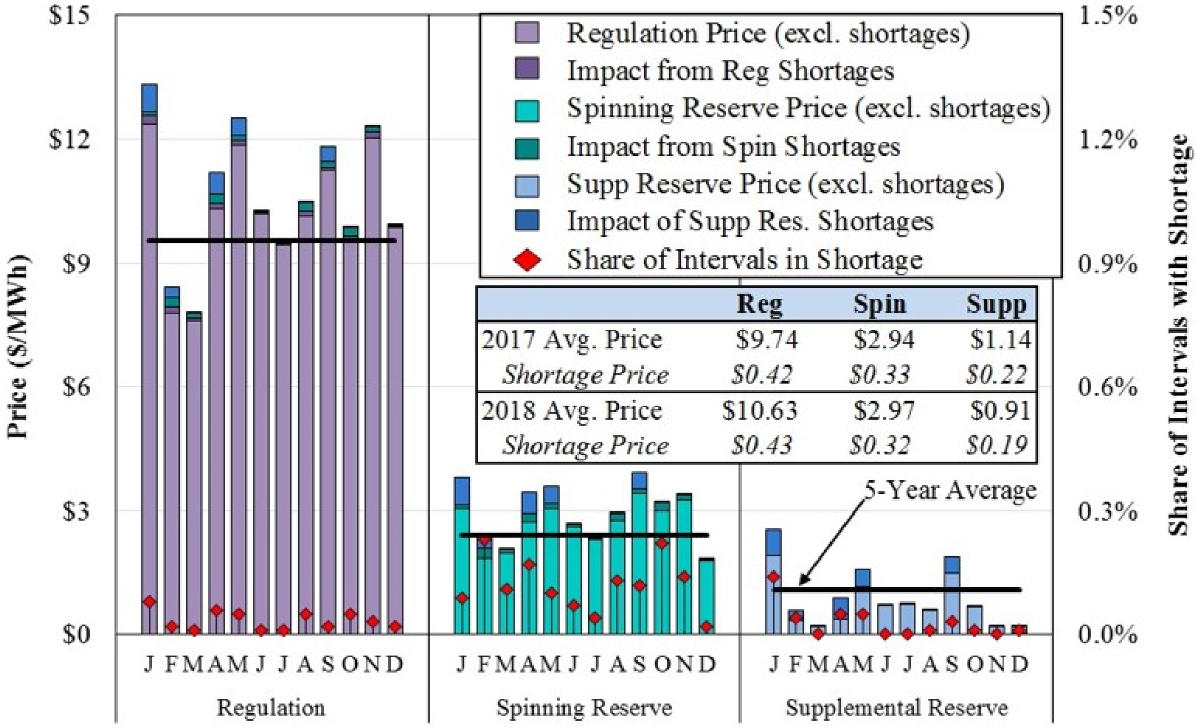
Figure A50: Real-Time Ancillary Services Clearing Prices and Shortages

Figure A50 shows monthly average real-time clearing prices for ASM products in 2018. The price for supplemental reserves, which can be provided by offline fast-start units, is MISO's contingency reserve price.

Contingency reserves are the lowest quality reserve, but because the contingency reserve demand curve is the highest priced, contingency reserve shortages will typically be the largest shortage-pricing component in each of the operating reserve prices and in the energy price. The figure above 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.

18 There is an additional $50 per MWh penalty called the "MinGenToRegSpinPenalty."

Figure A50: Real-Time Ancillary Services Clearing Prices and Shortages
2018



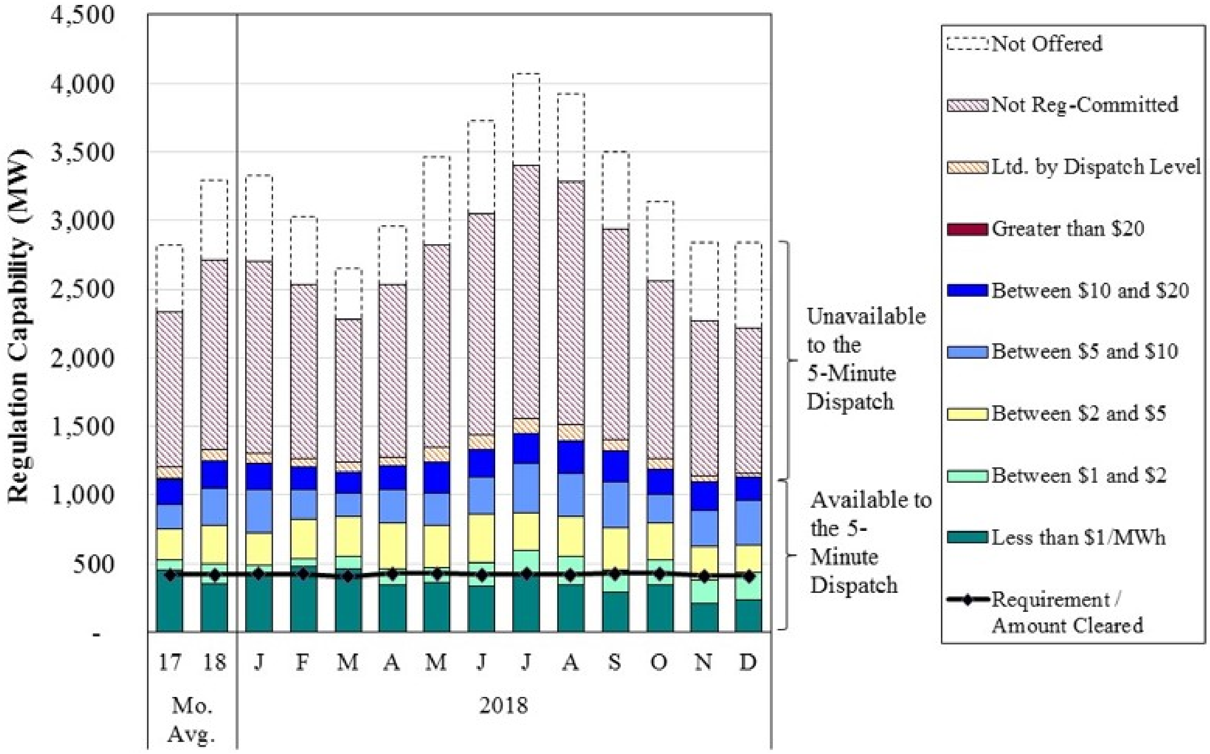
Additionally, higher-quality reserves can always be substituted for lower-quality reserves. Therefore, the price for spinning reserves will always be equal to or higher than supplemental reserves (i.e., contingency reserves). Likewise, when a shortage occurs in a lower-quality reserve product (e.g.,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

Figure A51: Regulation Offers and Scheduling

ASM offer prices and quantities are the primary determinants of ASM outcomes. Figure A51 examines average regulation capability, which 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 the prices 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 A51: Regulation Offers and Scheduling
2018



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).

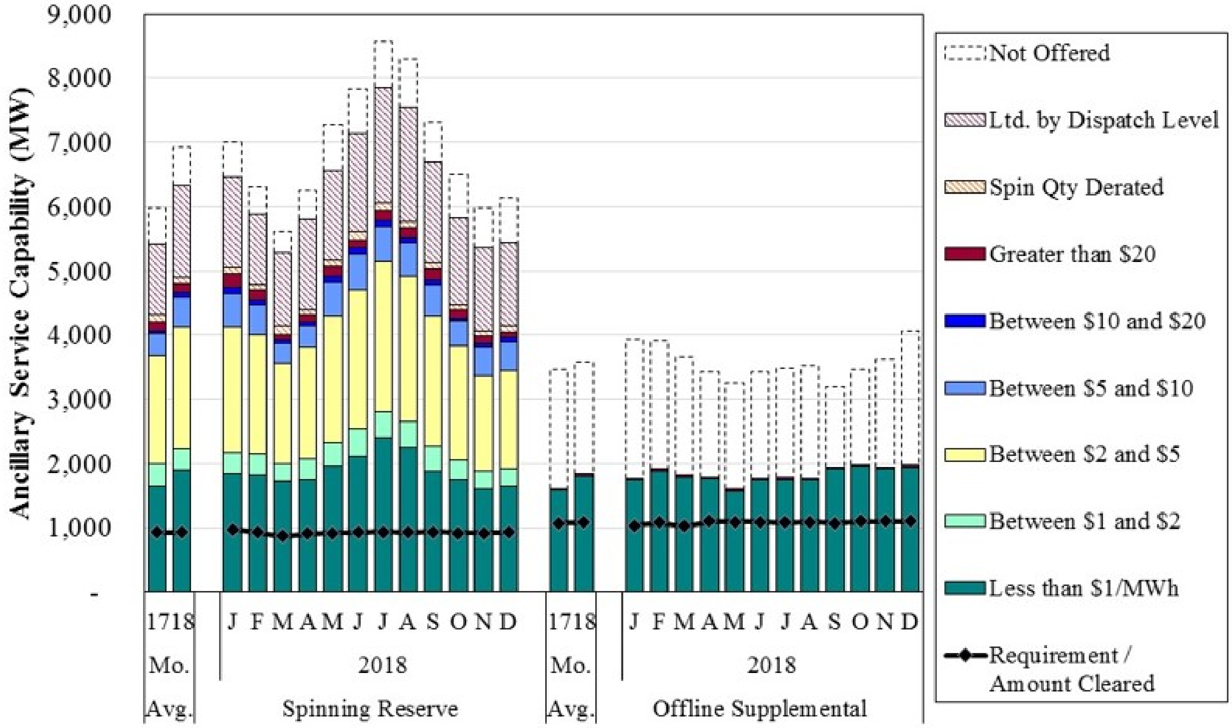
Figure A52: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can only 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 regulating reserves always equal or exceed those for spinning reserves, which in turn always equal or exceed the contingency reserve prices paid to supplemental reserves. As with regulation, spinning and contingency reserve prices can exceed the highest cleared offer as a result of opportunity costs or shortage pricing.

Figure A52 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 A52: Contingency Reserve Offers and Scheduling
2018



D. Spinning Reserve Shortages

Figure A53: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

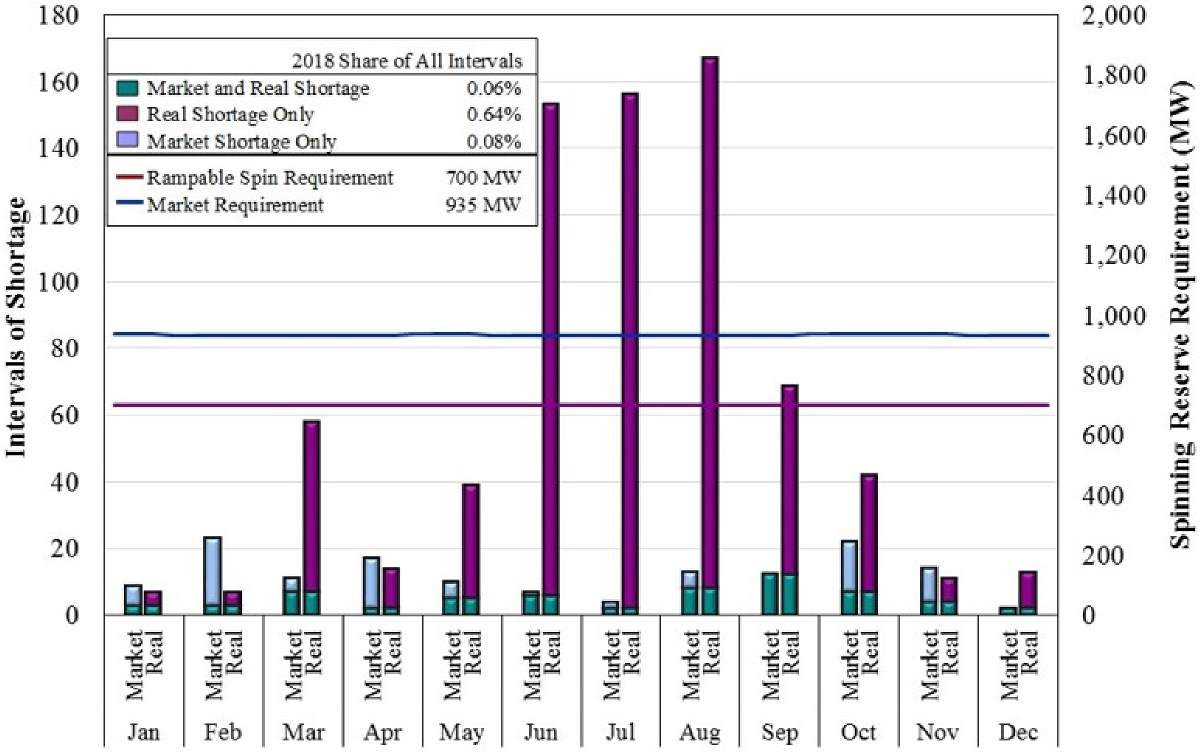
MISO operates with a minimum required amount of spinning reserves that can be deployed immediately for contingency response. Market shortages generally occur because the costs that would be incurred to maintain the spinning reserves exceed the spinning reserve penalty factor (i.e., the implicit value 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 approximately 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.[19] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

Figure A53 shows all intervals in 2018 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements.

19 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 A53: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2018



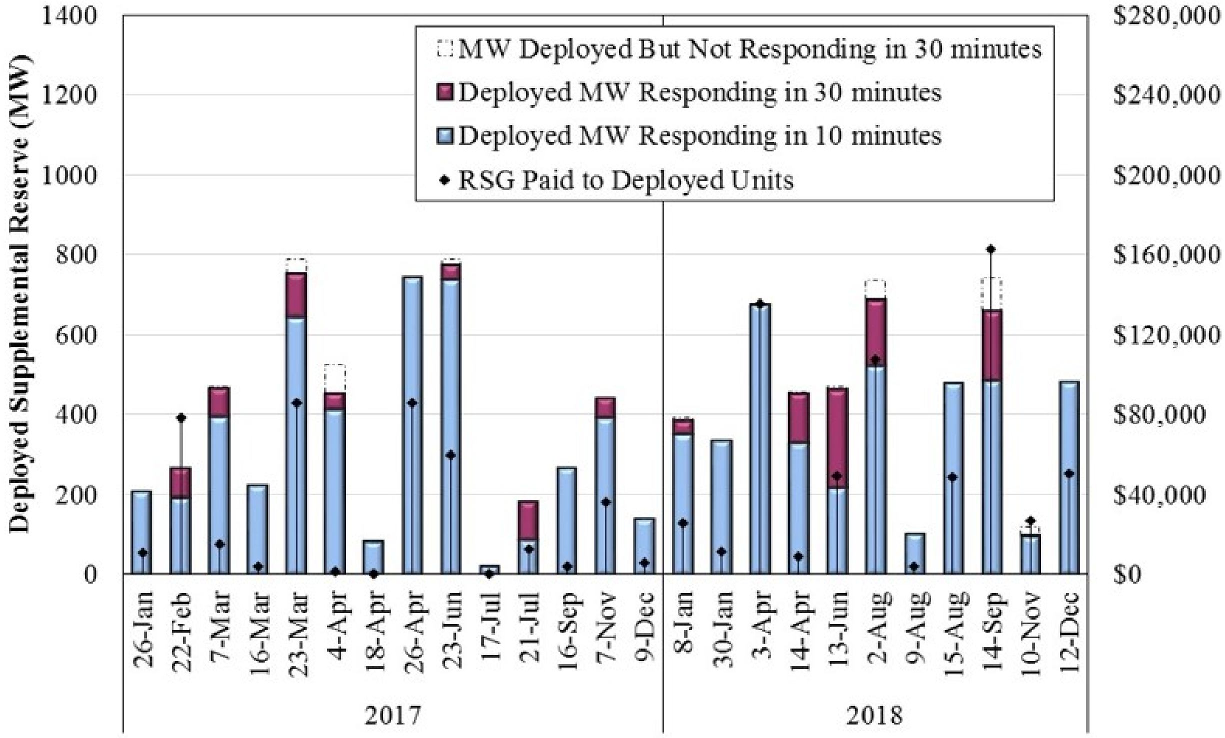
E. Supplemental Reserve Deployments

Figure A54: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A54 shows offline supplemental reserve response during the 11 deployments in 2018 and 14 in 2017, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by the North American Electric Reliability Corporation or "NERC"). The summary is valuable because it indicates how reliably MISO's offline reserves respond when deployed.

The figure also includes the RSG payments paid to deployed offline reserve providers. 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.

Figure A54: Supplemental Reserve Deployments
2017–2018



F. Operating Reserve Demand Curve

Because operating reserve pricing reflects reliability costs of shortages in MISO, efficient market design requires a properly-valued Operating Reserve Demand Curve (ORDC). Efficient shortage pricing is one of the most critical aspects of efficient market design. Efficient shortage prices provide signals for new investment, facilitate optimal commitment and interchange between markets in times of shortage, and balance the value of holding reserves subject to the cost of violating transmission constraints. An efficient ORDC should abide by four principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all significant types of supply-side contingencies;
- Evaluate risks of simultaneous contingencies; and
- Have no discontinuities that lead to volatile outcomes.

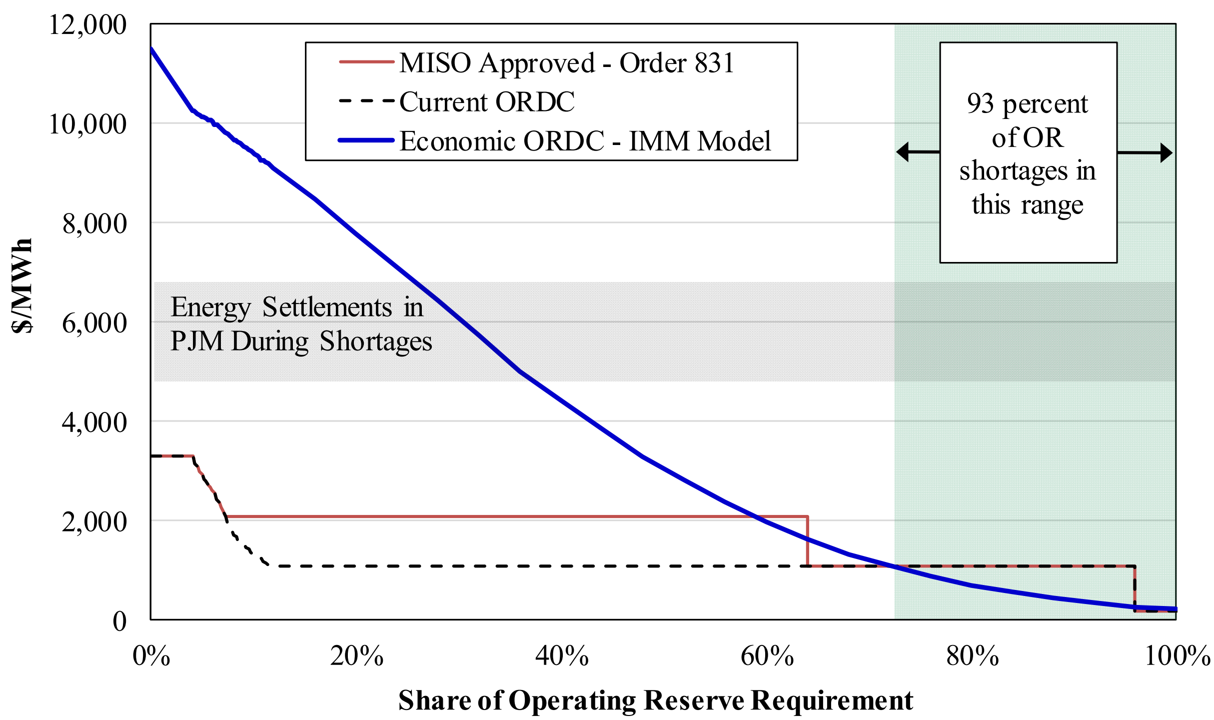
The marginal reliability value of reserves at any shortage level is equal to the expected value of the load that may not be served, which is equal to the product of the net value of lost load (VOLL) and the probability of losing load at that reserve level. As we discuss more fully in the report, MISO's current ORDC includes these factors but is flawed because:

- MISO's current $3,500 VOLL is understated; and
- The slope of the ORDC is not based on the probability of losing load.

Figure A55: Current and Proposed Operating Demand Curve

Figure A55 below shows the current ORDC and a curve that illustrates the IMM's economic ORDC. The shape of the current curve is initially downward-sloping, but it then flattens out for an extended range at $1,100. Small shortages of less than four percent are priced at the lowest step of $200. As shortage levels increase on the $1,100 step of the current ORDC, the prices remain fixed and do not accurately reflect the fact that the probability of losing load is increasing.

Figure A55: Current and Proposed Operating Demand Curve



The IMM's economic ORDC reflects the marginal value of lost load based on an assumed VOLL of $12,000 and a probability of losing load that the IMM estimated using a Monte Carlo simulation.[20] This simulation incorporates the risk of generator forced outages along with other supply-side risks, such as intermittent resource forecast error and changes in net imports. The approach utilizes market participation factors and technology-specific forced outage risks to more accurately reflect the contribution to reliability provided by different types of conventional generating resources. The IMM's recommended simulation approach enables the evaluation of multiple, concurrent risks. These risks are consistent with the actual reliability issues and challenges faced by MISO Operations. The increasing impact of intermittent generation on the MISO market is also better reflected by this model. Our methodology accounts for the fact that these resources impact reliability more through their intermittent nature than forced outages of

20 The simulation will estimate the conditional probabilities across 10,000 iterations. This simulation will be updated once per year using historical data from the prior calendar year where applicable.

conventional resources. The report discusses the differences between these two curves and the benefits of the economic ORDC. Below we review some of the key inputs to the calculation of the current ORDC and the economic ORDC.

Figure A56: 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 Participation Factor (PF) for each generation technology type is similar to the NERC-defined Weighted Service Factor.[21] It equals the sum of the online capacity of that type divided by the sum of the installed capacity of that type across all hours of the historical period.

As shown in Figure A56, these two methodologies result in modest differences. Because all nuclear resources are larger than 100 MW, the current methodology has a 100 percent participation factor. The 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 A56: Participation of Resources in Loss of Load Probability

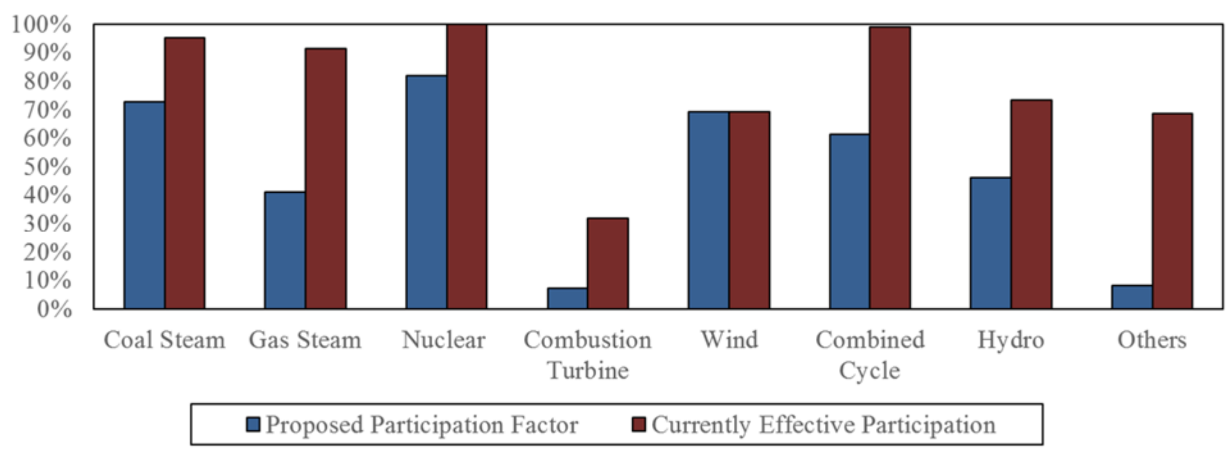


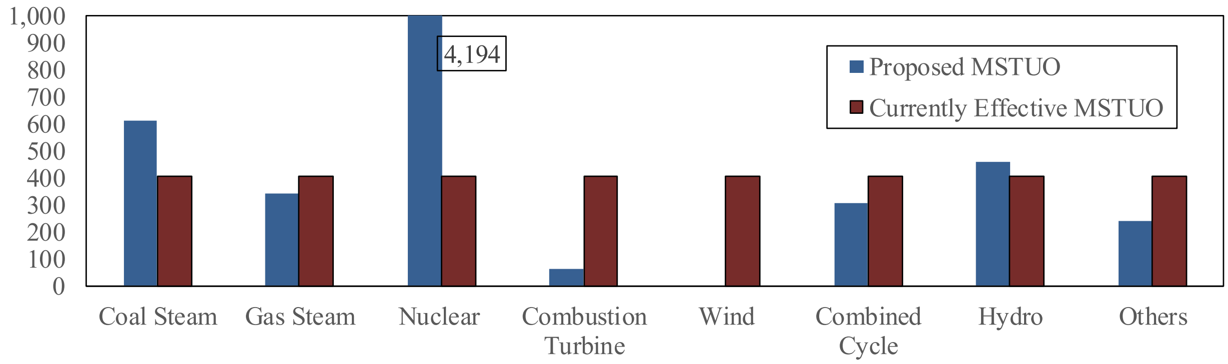
Figure A57: ORDC-Estimated Unit Failure Risk

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

21 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.

generators are assumed to have an equivalent rate of forced outage. As shown in the figure below as the maroon bar, this assumption is inconsistent with resources' actual failure rates.

Figure A57: 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 $1\text{-}e^{(-PF \,*\, ORP \,/\, MSTUO)}$, 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.

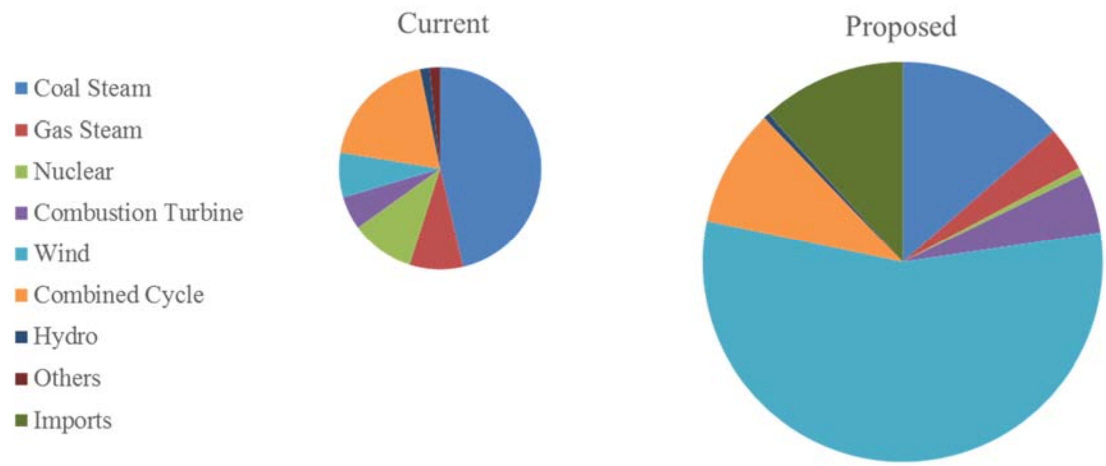
Intermittent resources and net imports were simulated as supply-side forecast risks using similar methodologies. First, a distribution of actual aggregate forecast errors was calculated from the historical period. The errors equaled the difference between actual capability in hour t and the forecasted 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 A58: 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 the 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 A58 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 A58: Distribution of Outage Risks by Technology Type



These results show a four-fold increase in total 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 resources accounted for more than 50 percent of the total outage risk in the proposed model. The volatility of wind, coupled with significant forecasting error, has created unique challenges. As wind and solar penetration increases over time, 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 fail infrequently, so their risk to real-time reliability is greatly reduced under the proposed methodology.

G. 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 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.

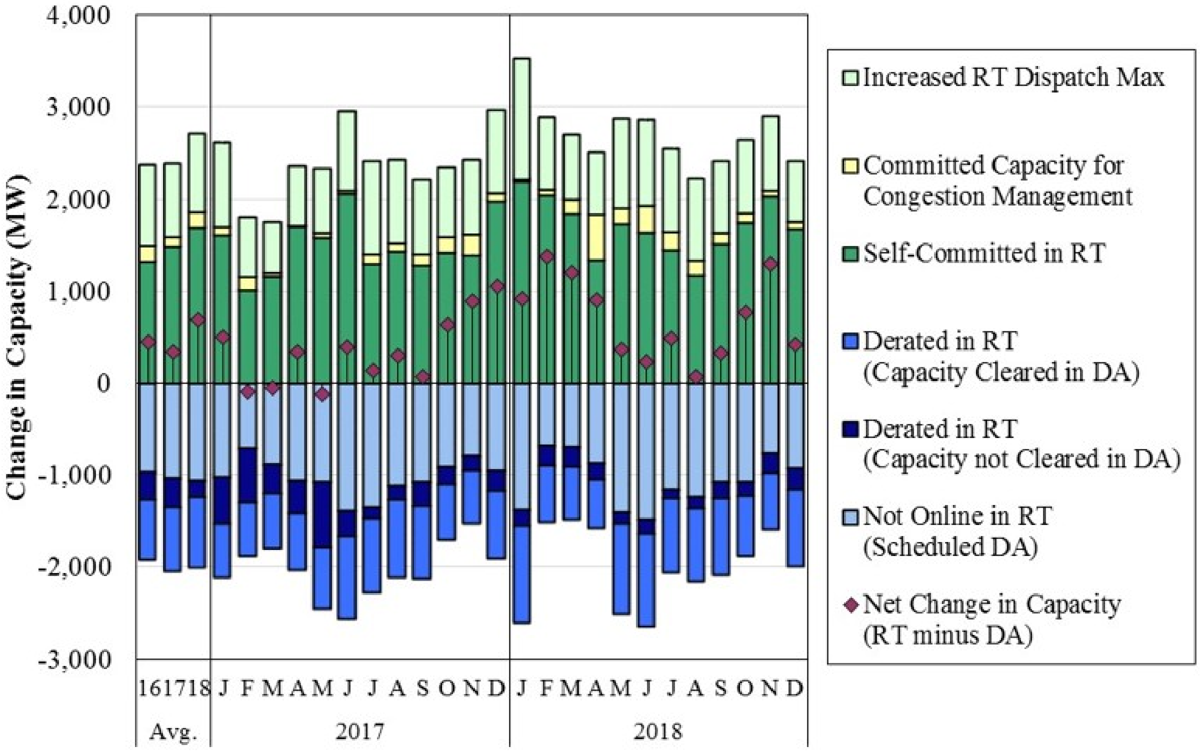
Figure A59: Changes in Supply from Day Ahead to Real Time

Figure A59 summarizes changes in supply availability from day-ahead to real-time markets. Differences between day-ahead and real-time availability are to be expected and are generally attributable to real-time forced outages or derates and real-time commitments and de-commitments by MISO. In addition, suppliers who are scheduled in the day-ahead market sometimes decide not to start their units in real time but instead to buy back energy at the real-time price. Alternatively, suppliers not committed in the day-ahead market may self-commit their generation resources in real time.

The figure shows six types of changes: generating capacity self-committed or de-committed in real time, capacity scheduled in the day-ahead market that is not online in real time; capacity derated in real time (separated by resources cleared and not scheduled in the day-ahead market) and increased available capacity (increases from day-ahead capacity); and units committed for congestion management.

The figure separately indicates the net change in capacity between the day-ahead and real-time markets. A net shortfall indicates that MISO would need to commit additional capacity, while a surplus would allow MISO to de-commit or shorten real-time MISO commitment periods. The amount actually committed for capacity in real time is not included in the figure.

Figure A59: Changes in Supply from Day Ahead to Real Time
2017–2018



H. 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.

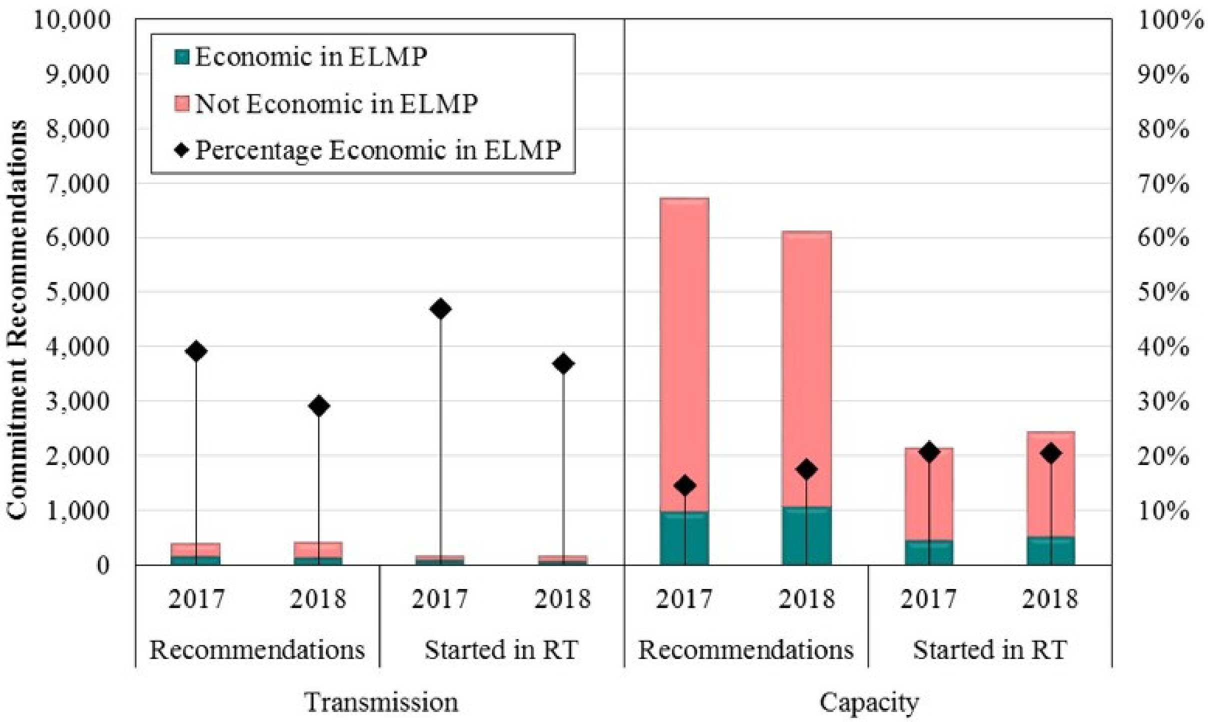
Figure A60: Economic Evaluation of LAC Commitments

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). We determined that a unit was "started in real time" if it came online between the time LAC recommended it start and the end of the unit's minimum runtime.

Figure A60 below 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 2017 and 2018, 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.

Figure A60: Economic Evaluation of LAC Commitments
2018



I. Generator 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. MISO assesses penalties to generators if deviations from these instructions remain outside an eight-percent tolerance band for four or more consecutive intervals within an hour.[22] The purpose of the tolerance band is to permit a level of deviations that balances the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. MISO's criteria for identifying deviations, both the percentage bands and the consecutive interval test, are significantly more relaxed than most other RTOs', including NYISO, CAISO, and PJM.

Having a relatively relaxed tolerance band allows 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 can effectively derate a unit by simply not moving over many consecutive intervals. We discuss these "inferred derates" later in this subsection.

For example, as long as the dispatch instruction is not eight percent higher than its current output, 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 where 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 A61 and Figure A62: Frequency of Net Five-Minute Deviations

Figure A61 shows a histogram of MISO-wide net five-minute deviations from 6 am to 10 pm, which includes MISO's high-ramp and peak hours in the summer and winter seasons. Figure A62 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 are increasing rapidly and resources do not respond, MISO will not be able to satisfy its energy and operating 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.

22 The tolerance band can be no less than six MW and no greater than 30 MW (Tariff section 40.3.4.a.i.).

Figure A61: Frequency of Net Deviations
Ramp and Peak Hours, 2018

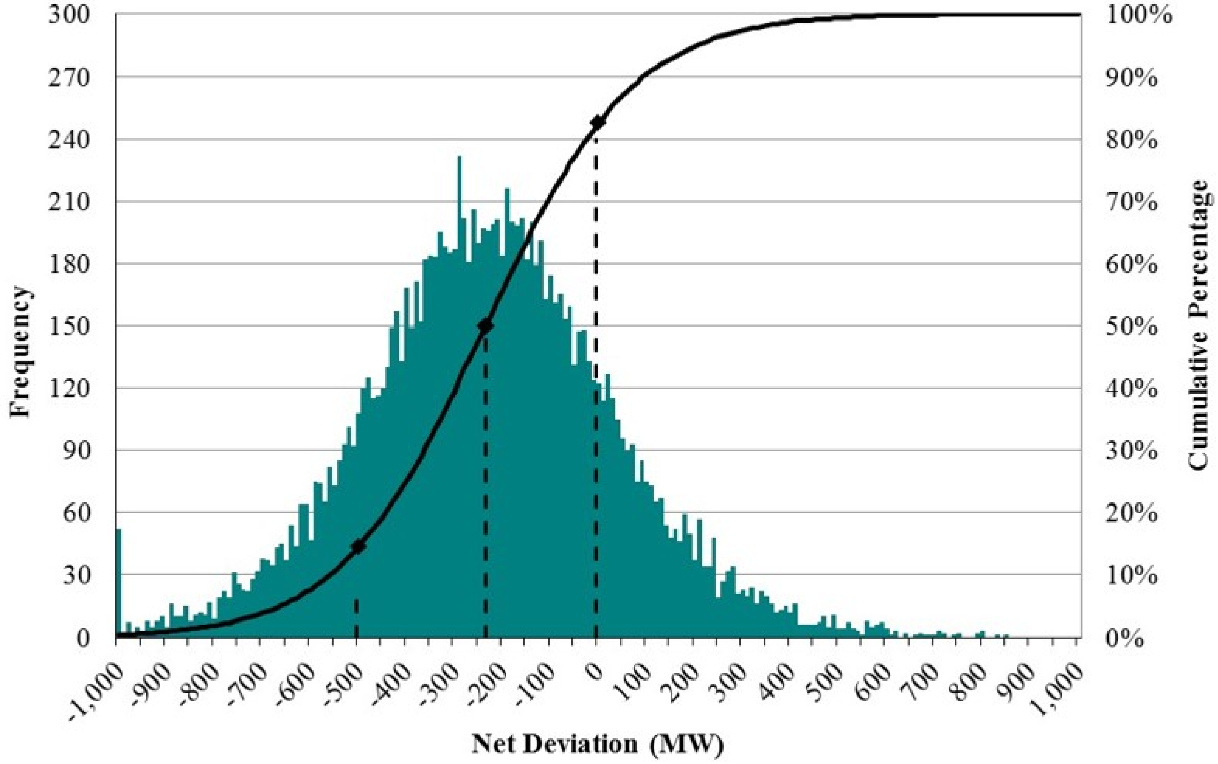


Figure A62: Frequency of Net Deviations
Ramp-Up Hours, 2018

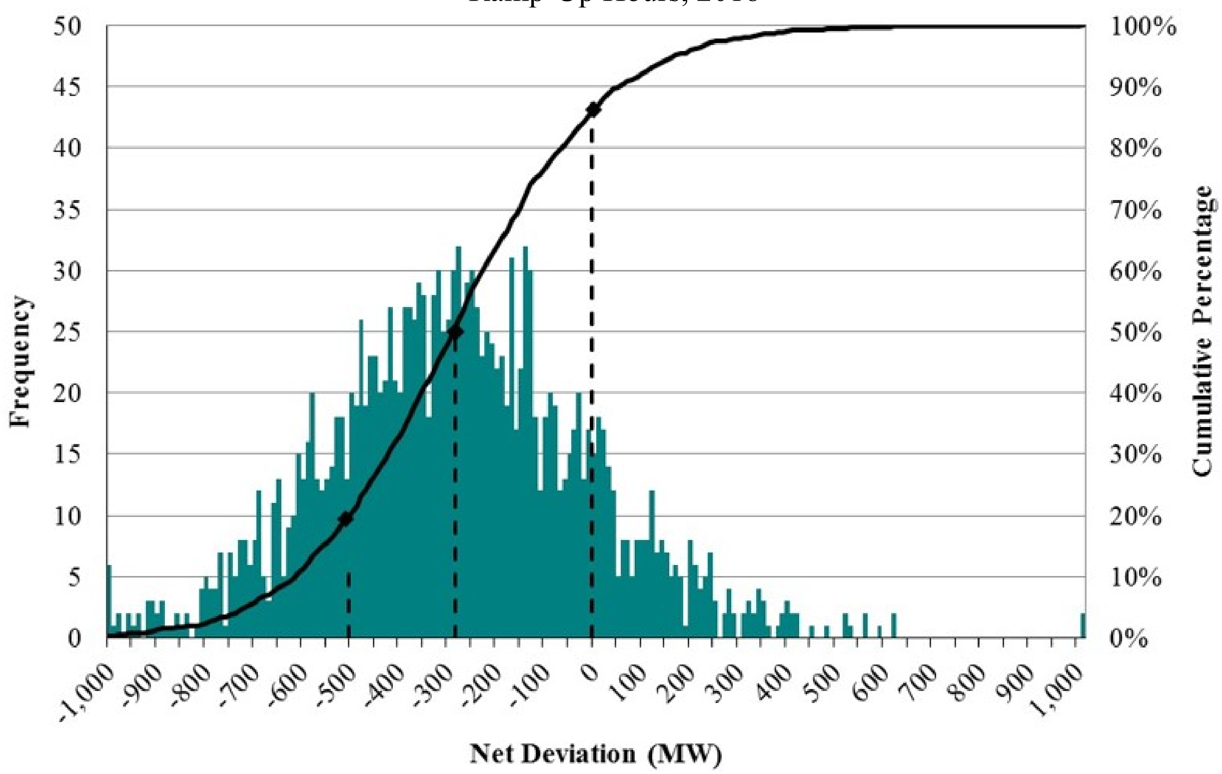


Figure A63: Five-Minute and 60-Minute Deviations by Season

Figure A63 shows the size and frequency of the five-minute and 60-minute net deviations. The figure shows these results by season for steep ramping hours of the day, adjusted for seasonality, when the impact of deviations was most severe on both pricing and reliability.

Figure A63: Five-Minute and 60-Minute Deviations by Season
2018

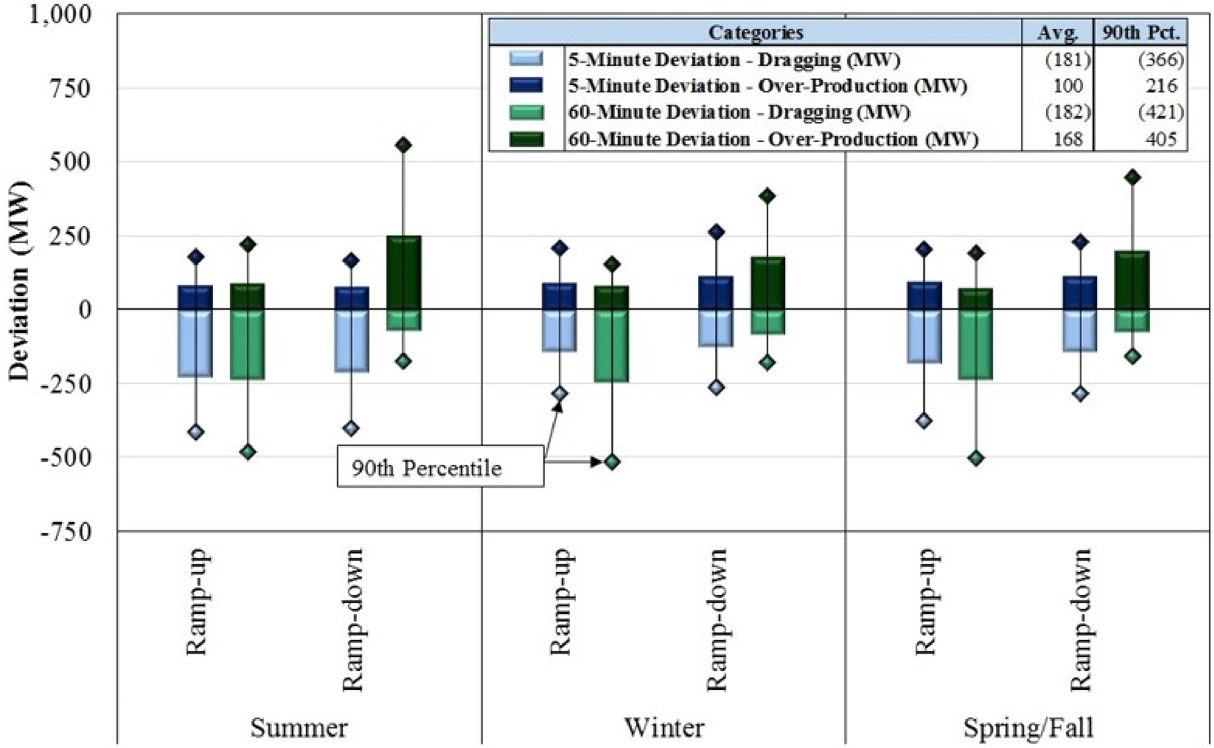


Figure A64: 60-Minute Deviation by Fuel and Hour

In the next three figures, we estimated the sources of 60-minute net deviations by fuel type and its 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. Over 80 percent of the 60-minute deviations in the system are attributed to coal units as compared to gas or wind.

Figure A64: 60-Minute Deviation by Fuel and Hour
2018

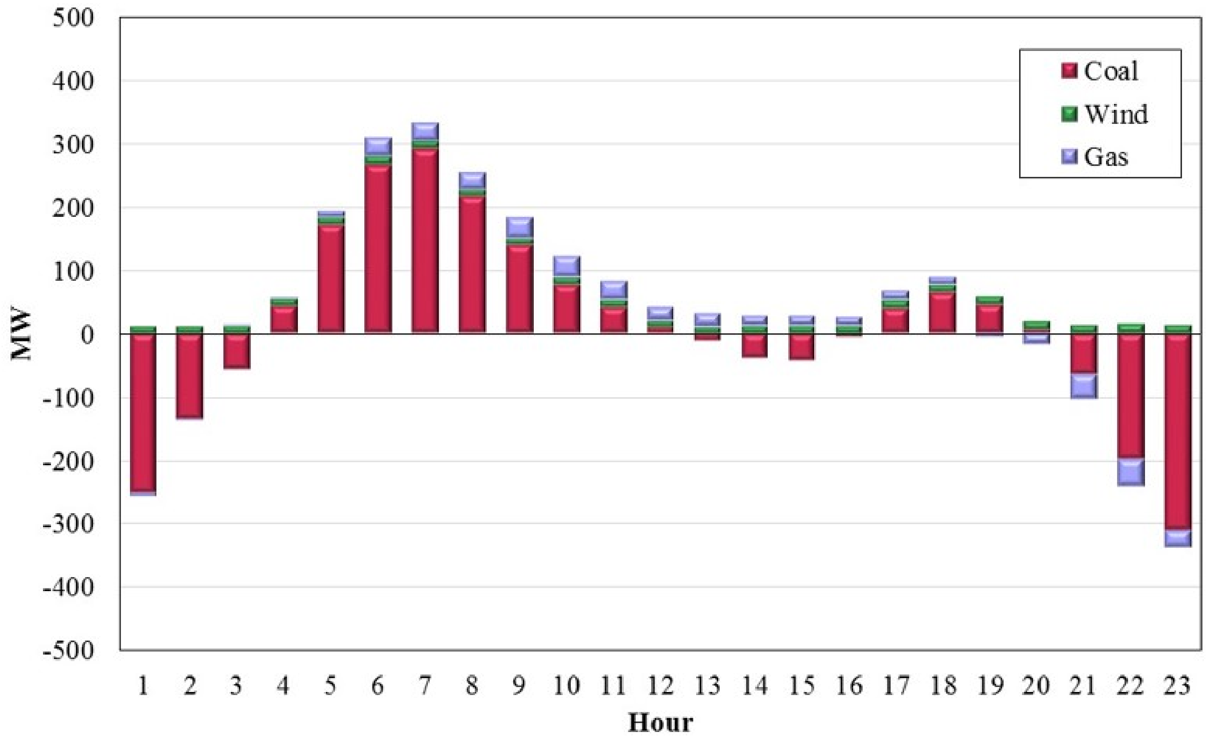


Figure A65: 60-Minute Deviation by Fuel and Hour
Summer 2018

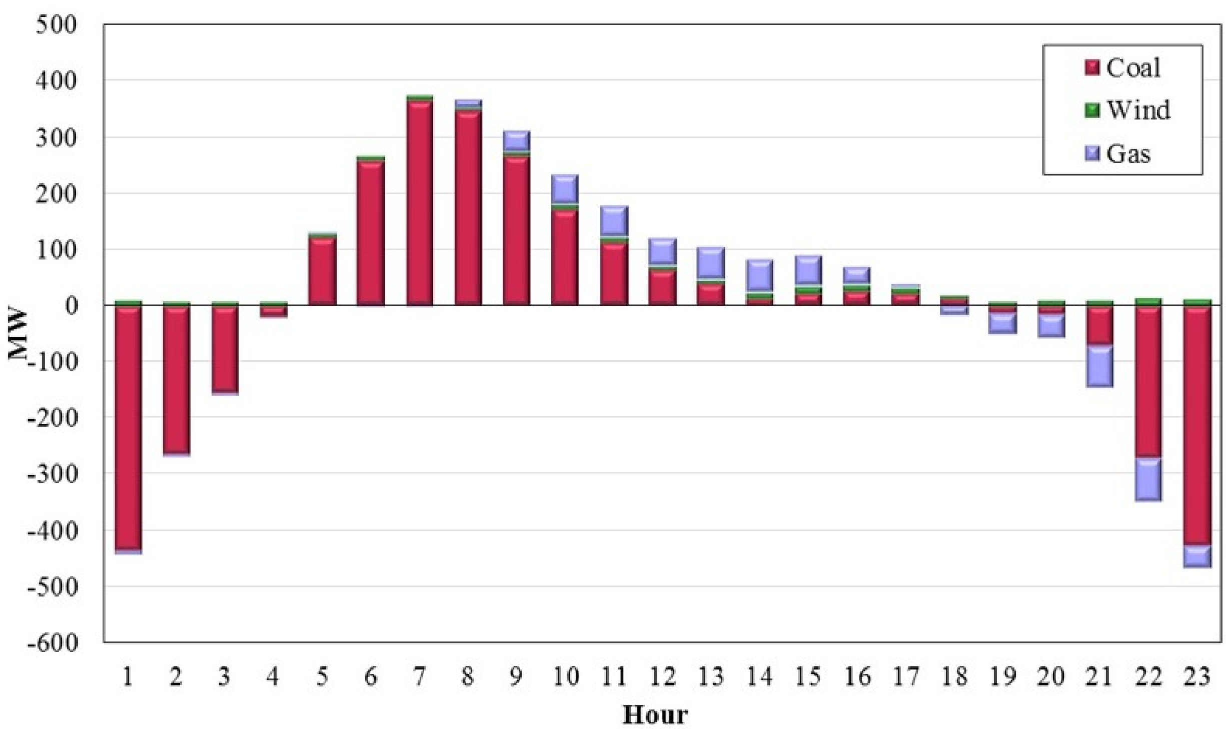


Figure A66: 60-Minute Deviation by Fuel and Hour
Winter 2018

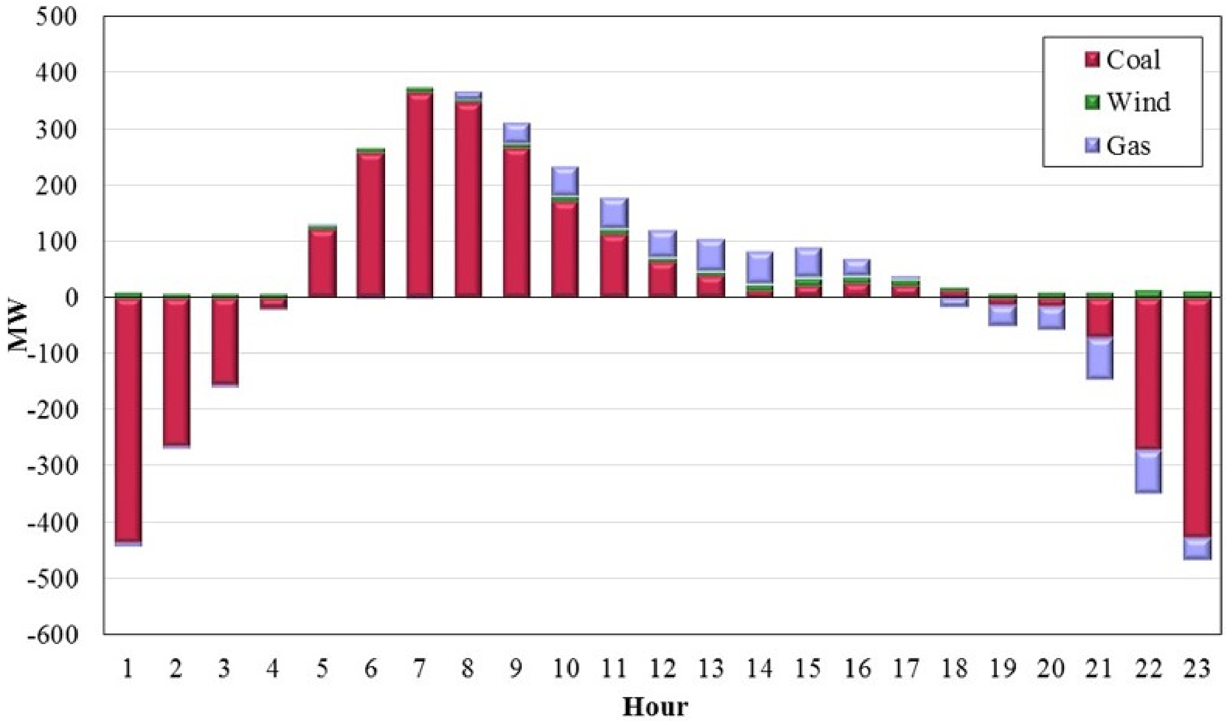


Figure A67: 60-Minute Deviations by Type of Conduct

To better understand the components of the 60-minute deviations, we have estimated the portion of the deviations that was potentially caused by inaccuracies in the State Estimator (SE) model versus various classes of poor generator performance. The SE model can cause deviations when it underestimates a unit's output level. The real-time market uses the SE output to determine how much a generator can move up in the next interval. Therefore, if the SE output is lower than the unit's actual output, this scenario can limit the unit's instructions to ramp up and prevent it from achieving an economic output level.

The categories of poor generator performance shown in this figure include:

- Deviations that would not fail under the IMM's proposed threshold;
- Deviations that would qualify as an uninstructed deviation under the IMM's proposed threshold for "deficient energy" described later in this section; and
- Inferred Derates: Resources effectively derated, because the resource stops moving up at a level well below its economic dispatch level. In some cases, these are units that are violating the Tariff by failing to report a derate condition. We have referred some of these suppliers to FERC enforcement.[23]

23 See EMT Section 39.2.5(c). As MISO notes in the relevant BPM: Any derate, either planned or unplanned, to a Generation Resource's Ramp Rate that causes the unit to be unable to achieve its Offered Economic

Figure A67 show the average of each of the quantities by hour of the day in 2018, as well as the amount of hourly 60-minute deviations in total that prevailed in the worst 10 percent of hours.

Figure A67: Hourly 60-Minute Deviations by Type of Conduct
2018

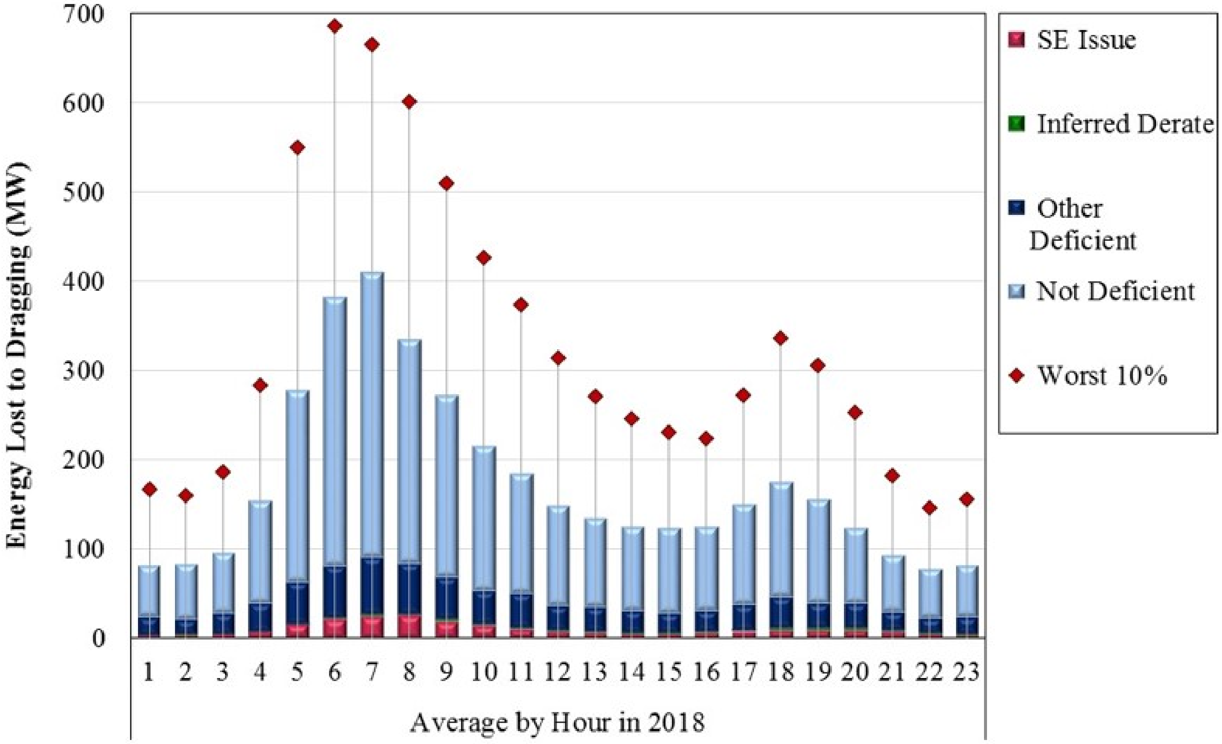
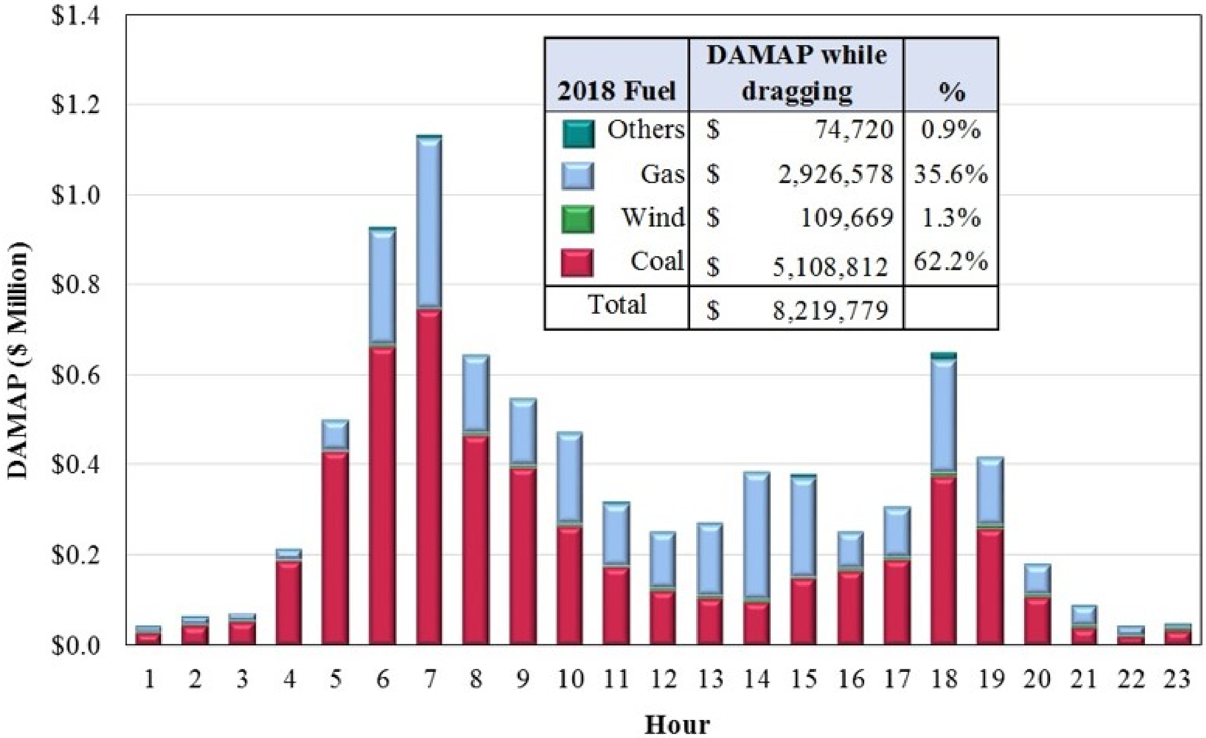


Figure A68: DAMAP to Dragging Units by Fuel Type

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

Minimum/Maximum limit for the Offer Hour will require the GOP to also update the Generation Resource's Hourly Economic Minimum/Maximum to the achievable limits that the derate causes on the Generation Resource's physical capability.

Figure A68: DAMAP to Dragging Units by Fuel Type in 2018



J. Evaluation of the Offset Parameter

The offset parameter is a quantity chosen by the MISO real-time operators to adjust the load to be served by the UDS. A positive offset value is added to the short-term load forecast to increase the generation dispatched, while a negative offset decreases the load and the corresponding dispatched generation. Offset values may be needed for many reasons. For example, operators may use positive offsets when:

- Generator outages occur that are not yet recognized by UDS to increase generation to compensate for the loss in generation;
- Generators are dragging (producing less than MISO's dispatch instruction);
- Wind output is over-forecasted; or
- Operators believe the short-term load forecast is under-forecasted;

Likewise, operators may use negative offsets when:

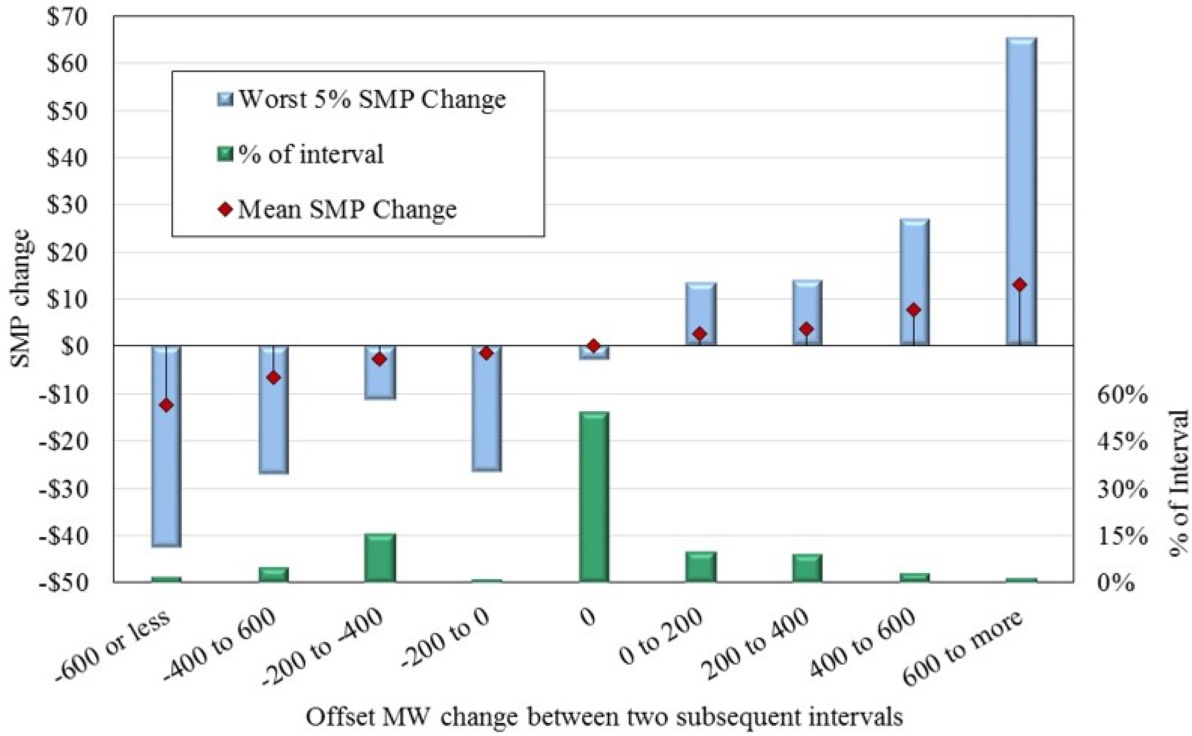
- Generators coming online that are not yet recognized by UDS may require negative offsets to decrease generation (units are not recognized until they are synchronized);
- Generators are overproducing (producing more than MISO's dispatch instruction);
- Wind output is under-forecasted; or
- Operators believe the short-term load forecast is over-forecasted;

Each UDS interval is initialized with a base case and five alternative cases that have different offset values. After the solutions are available, the MISO operators choose the case that they think best represents the market conditions (accounting for factors listed above and others). When large changes in the offset are made from one interval to the next, it can substantially affect the MISO-wide energy prices (i.e., the System Marginal Price or SMP). We evaluated how changes in the offset value affected the SMP.

Figure A69: Impact of Offset Changes on SMP

Figure A69 summarizes our results of this analysis. The horizonal axis shows nine tranches of intervals grouped by the change in offset from the prior interval. The table above the axis shows the portion of the intervals that are in each tranche. The primary vertical axis represents the change in SMP associated with the change in offset for the respective tranches. The drop-lines are the mean change associated with the change in offset and the blue vertical bars are the worst five-percent change in MISO's SMP associated with the change in offset.

Figure A69: Impact of Offset Changes on SMP in 2018



K. Revenue Sufficiency Guarantee Payments

RSG payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[24] Generally, MISO makes most 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

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

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.

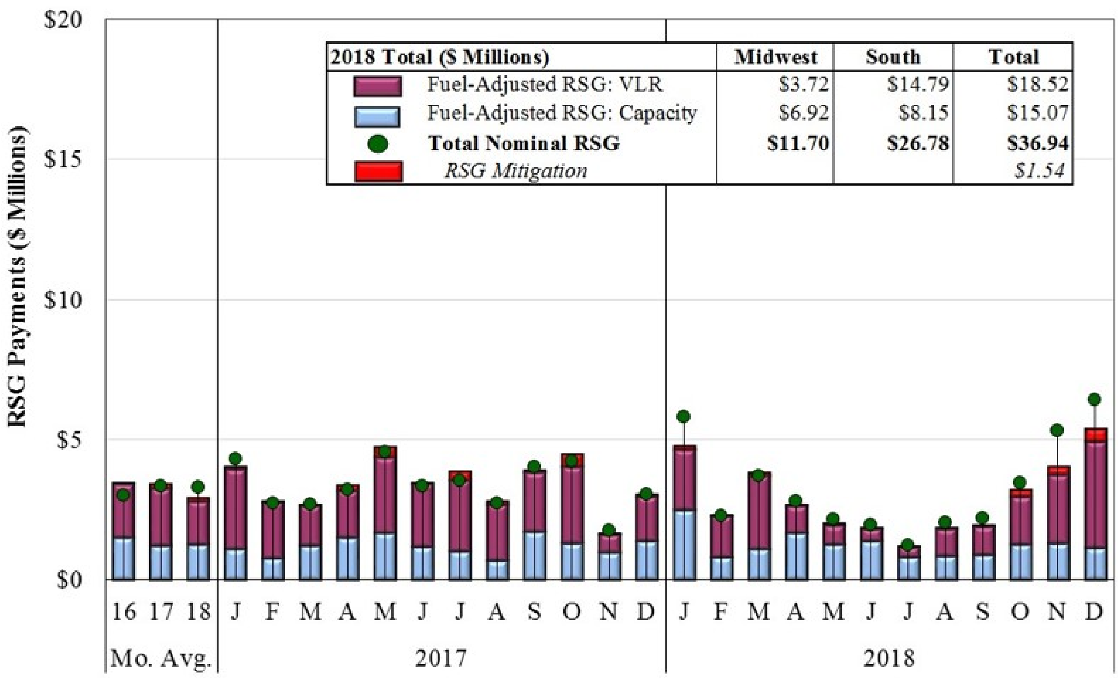
MISO makes many voltage and local reliability (VLR) commitments, predominantly in the day-ahead market. Most VLR commitments occur in the South region to manage load pocket requirements. In order to satisfy these requirements and accommodate the startup times of the required resources, MISO makes reliability 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 A70 and Figure A71: RSG Payment Distribution

Figure A70 shows the total day-ahead RSG payments and distinguishes between payments made for VLR and for 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. The results are adjusted for changes in fuel prices, although nominal payments are indicated separately. Figure A71 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.

Figure A70: Total Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2017–2018



2018 Total ($ Millions)	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$3.72	$14.79	$18.52
Fuel-Adjusted RSG: Capacity	$6.92	$8.15	$15.07
Total Nominal RSG	**$11.70**	**$26.78**	**$36.94**
RSG Mitigation			*$1.54*

Figure A71: Total Real-Time RSG Payments
Fuel-Cost Adjusted, 2017–2018

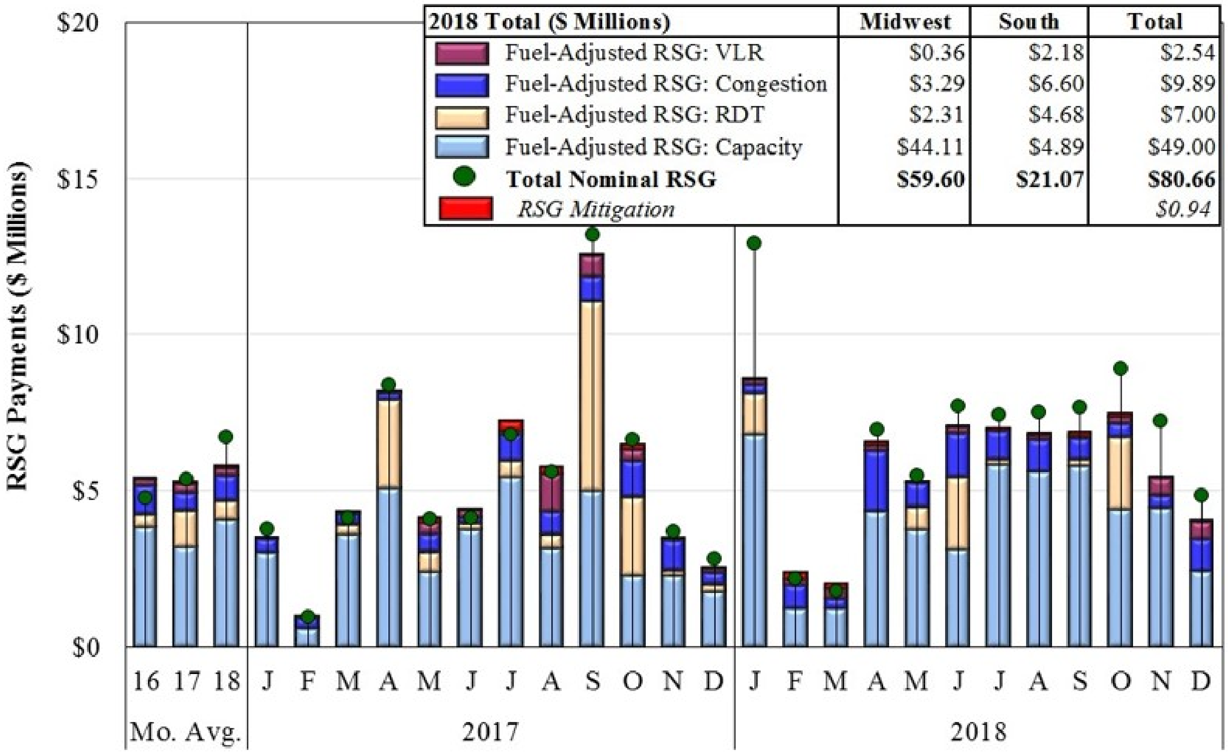


Figure A72: RSG for units committed for RDT

MISO has begun making 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 evaluate the magnitude of these costs to determine the benefit of a regional reserve product, which we have been recommending.

Figure A72 below shows the total RSG that MISO has incurred for these commitments since January 2017 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 A72: RSG for units committed for RDT
2017–2018

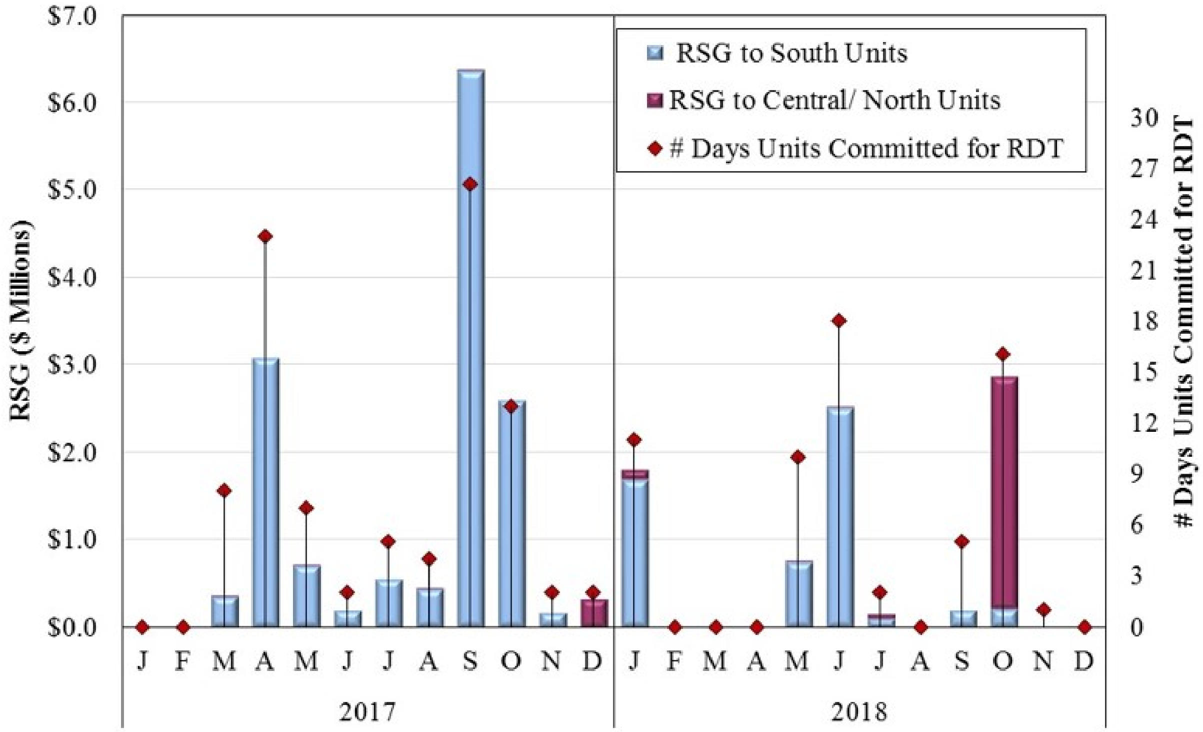


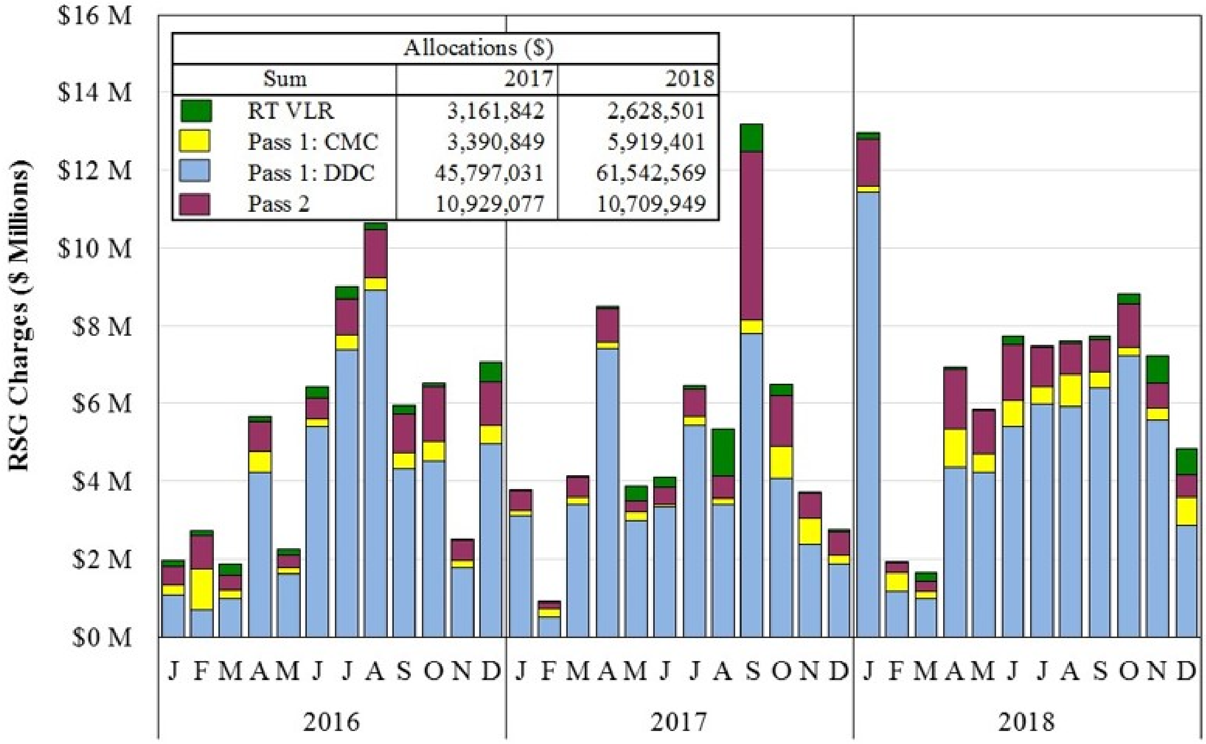
Figure A73: Allocation of RSG Charges

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").[25]

Figure A73 summarizes how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month from 2016 to 2018. 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.

25 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.

Figure A73: Allocation of RSG Charges
By Month, 2016–2018



L. 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 responding to MISO's prices and following its dispatch signals in real time are not financially harmed by doing so, thereby removing a potential disincentive to providing more operational flexibility.

The PVMWP consists of two separate 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.

Figure A74: Price Volatility Make-Whole Payments

Figure A74 shows monthly average PVMWPs for each of the past three years in the left panel. The monthly PVMWPs over the past two years are shown in the two right panels. The figure separately shows two measures of price volatility based on (1) the System Marginal Price (SMP) and (2) the LMP at generator locations receiving PVMWP. It is expected that payments should correlate with price volatility because volatility leads to greater obligations to flexible suppliers. LMP volatility is expected to be higher than SMP volatility because LMPs include the effect of transmission congestion.

Figure A74: Price Volatility Make-Whole Payments
2017–2018

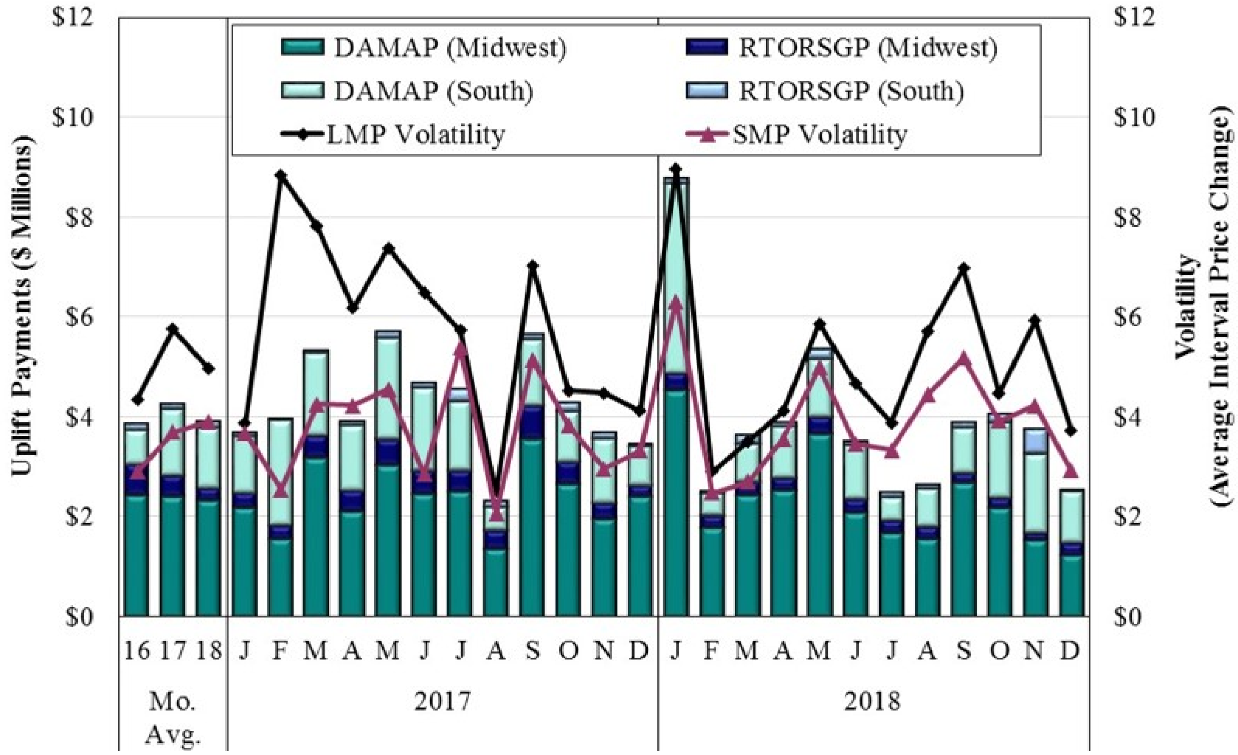


Table A10: Causes of DAMAP

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. Nonetheless, generators generally do not lose eligibility for DAMAP when they perform poorly, a situation we address in our recommendations.

Table A10 shows the total DAMAP in 2018, the shares of DAMAP that are paid to units following MISO's dispatch signals, as well as those that are not performing well in following dispatch signals. These are categorized in the same manner as the prior figure.

Table A10: Causes of DAMAP
2018

Item Description	DAMAP ($ Million)	% Share
Following Instruction	$31.1	74%
SE Issue	$1.1	3%
Inferred Derate	$0.1	0%
Dragging - Failing IMM New Threshold	$2.8	7%
Wind Unjustified	$1.3	3%
Dragging - Not Failing IMM New Threshold	$5.4	13%
Total	$41.9	100%

Note: Excluded Hour Beginning 0 in the Analysis

M. Dispatch of Peaking Resources

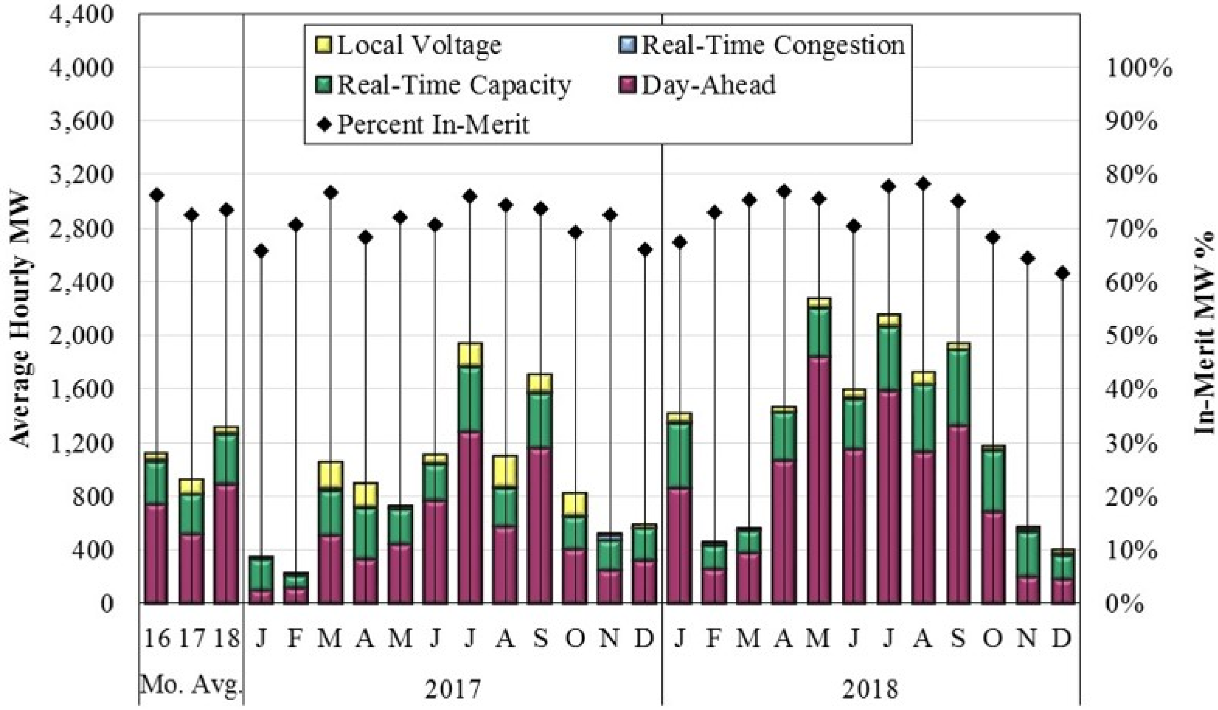
Peak demand is often satisfied by generator commitments in the real-time market. Typically, peaking resources account for a large share of real-time commitments because they are available on short notice and have attractive commitment-cost profiles (i.e., low startup costs and short startup and minimum-run 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 demands 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 A75: Dispatch of Peaking Resources

Figure A75 shows average hourly dispatch levels of peaking units in 2018 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 A75: Dispatch of Peaking Resources
By Commitment Reason, 2017–2018



N. 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.

About 88 percent of MISO's wind capacity is the Dispatchable Intermittent Resource (DIR) type. DIRs are wind resources that are physically capable of responding to dispatch instructions (from nearly zero output to a forecasted maximum) 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.[26]

Figure A76: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A76 shows the hourly average wind scheduled in the day-ahead market and real-time markets by month. Under-scheduling of output in the day-ahead market can create price

26 Capacity credits for wind resources are determined by evaluating a unit's performance during the peak hour of each of the prior seven years' eight highest-load days (56 hours). For the 2018-2019 Planning Year, the system-wide capacity credit for wind is 15.2 percent, while individual credits range from 0 to 26.2 percent.

convergence issues and lead to uncertainty regarding the need to commit resources for reliability. Virtual supply at wind locations is also shown in the figure because the response by virtual supply in the day-ahead market can offset the effects of under-scheduling by the wind resources.

Figure A76: Day-Ahead Scheduling Versus Real-Time Wind Generation
2017–2018

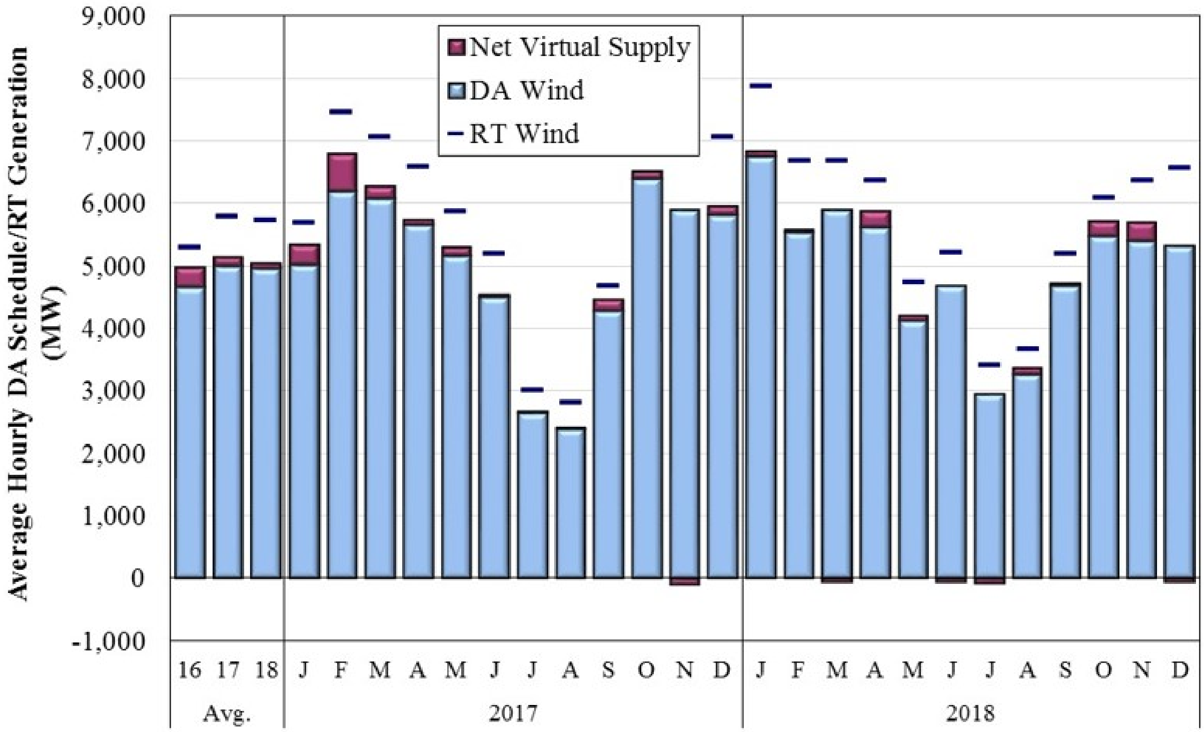


Figure A77: Generation Wind Over-Forecasting Levels

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-forecast resource will produce less than the dispatch instruction. Figure A77 shows the monthly average dispatch deviations from the wind resources in the bars, as well as the average forecast error plotted as a line against the right axis in 2017 and 2018.

Figure A77: Generation Wind Over-Forecasting Levels
2017–2018

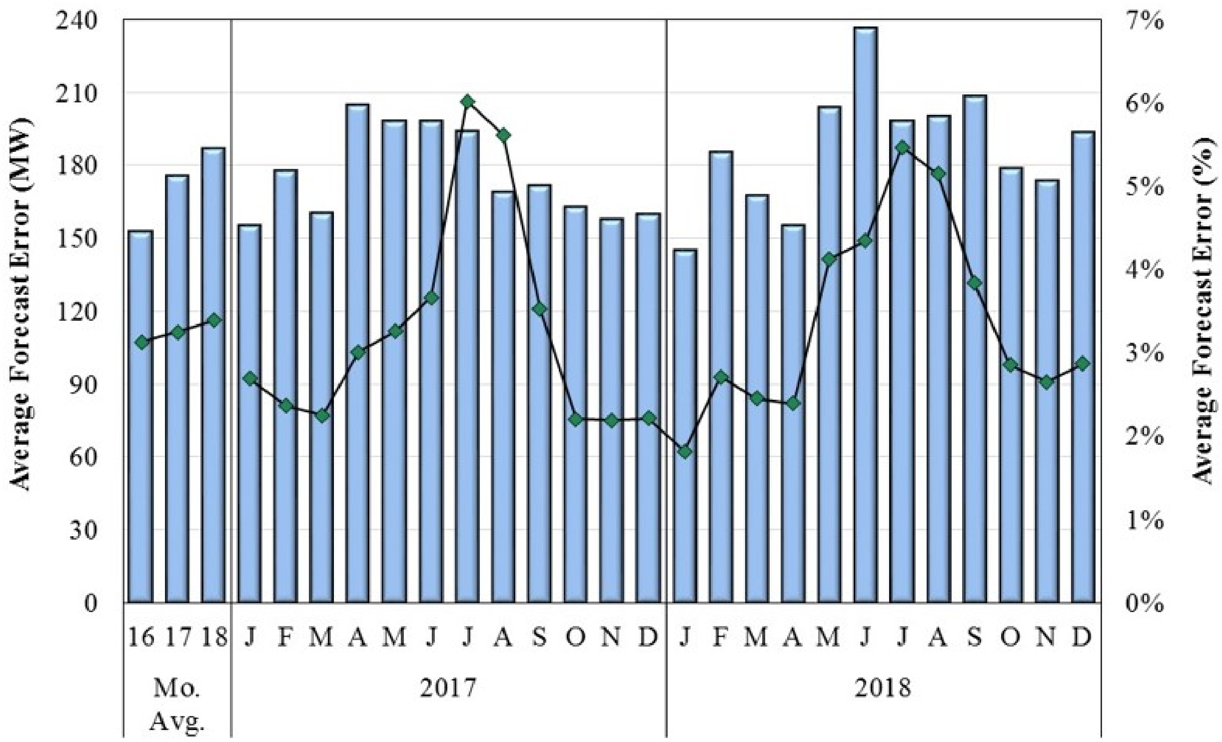


Figure A78: Wind DAMAP Compensation

We determined that one of the factors that led to the over-forecasting concerns is that MISO's current settlement rules provide strong incentives for DIR resources to over-forecast their output in real time. These incentives result from two main factors: DAMAP and uninstructed deviation settlements.

Currently, a flaw in the MISO DAMAP settlements formula allows existing DIR wind resources to receive DAMAP when they are dispatched at their economic maximums, which is unintended. The intent of the Tariff is to only make DAMAP when units are dispatched below their economic maximums. However, the Tariff was written prior to the introduction of DIR, so it does not consider that the economic maximum value for a DIR wind unit can change every five minutes.

To show the extent to which wind resources received DAMAP as a result of the Tariff flaw in 2018, we classified DAMAP paid to wind units as:

- Justified: Payments to resources that were economically curtailed and dispatched by MISO below their forecast maximum. As a result of integrated-hourly settlements and ELMP ex-post pricing, MISO re-dispatch can erode day-ahead margins.
- Unjustified: Payments that are the direct result of the Tariff flaw. In these cases, the wind resources were dispatched at their economic maximum and could not have produced the output on which they recovered DAMAP.

Figure A78 shows DAMAP in these two categories by month in 2017 and 2018. We estimate that $1.31 million (or 52 percent) of DAMAP to wind units was unjustified in 2018, down from $2.75 million in 2017.

Figure A78: Wind DAMAP Compensation
2017–2018

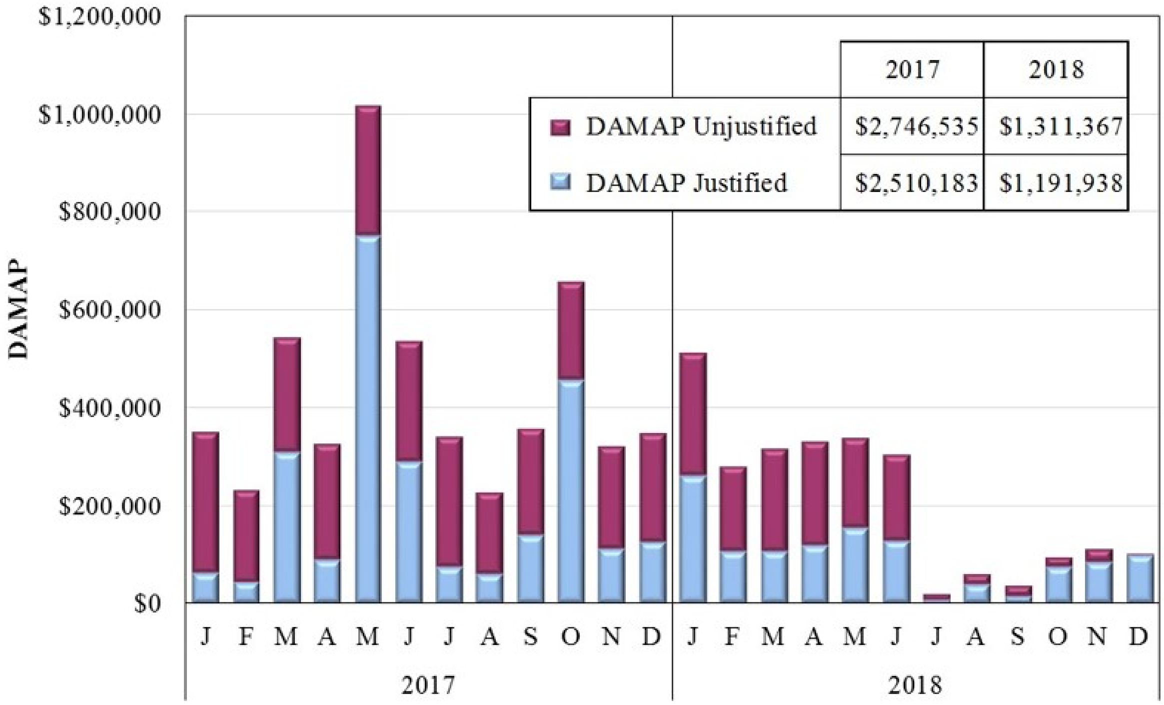


Figure A79: Expected Settlement Value of Forecast Alternatives

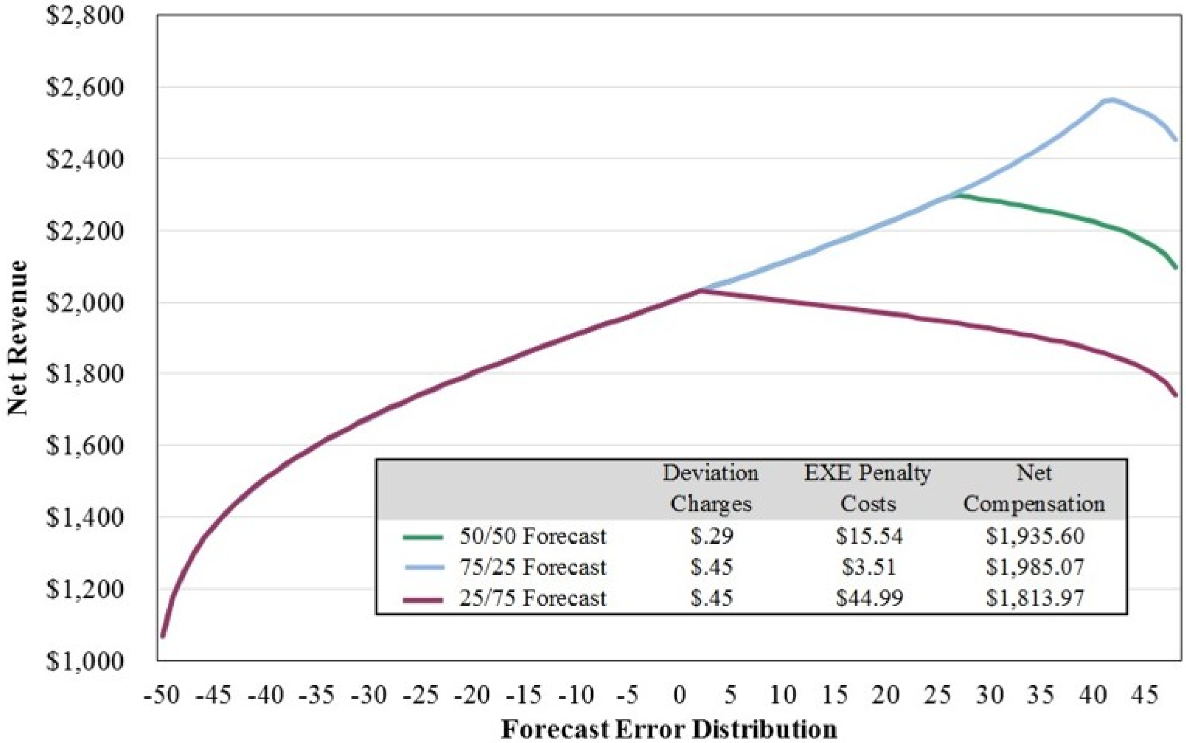
The second potential cause of the persistent over-forecasting by wind resources is that they face asymmetric costs for uninstructed deviations associated with forecast errors. One reason for this is that generators are paid the lower of their offer price or zero for excessive energy. Because of Production Tax Credits, wind resources generally submit substantially negative incremental energy offers, so the penalty for excessive energy is much larger than for other resource types (the penalty is the difference between the LMP and their offer price).

Conversely, wind units are only deficient when the resources' actual generating capabilities are less than their forecasts, a situation that does not cause them to forego any profit margin.[27] These factors combine to yield a relatively strong incentive to over-forecast wind resources' output. This is evaluated in the figure below, which shows the settlements for a wind resource under three wind forecast alternatives: a 25/75 low forecast (75 percent chance output will exceed the forecast), a 50/50 forecast (even likelihood high or low), and a 75/25 high forecast (75 percent chance output will fall short of forecast). These scenarios depict a theoretical resource with a known wind speed forecast and standard deviation of forecast errors.

27 In fact, wind resources will generally receive a DAMAP settlement that will provide this profit margin on the energy they are unable to produce.

The net revenues shown in the figure as lines include LMP payments less excessive energy penalties and deviation charges, primarily in the form of Day-Ahead Headroom and Deviation Charges, at the differing levels of forecast errors shown on the x-axis. An assumed price elasticity was included to reflect the expected reduction in LMP revenues from higher forecasts.

Figure A79: Expected Settlement Value of Forecast Alternatives
2018



These results are equivalent when the wind speed and output is lower than forecasted (i.e., negative forecast error). However, the net revenues differ substantially when the wind speed and output is higher than forecast because they are exposed to substantial excessive energy penalty costs if they produce significantly more than their forecast economic maximum. Hence, the most profitable forecast of the three is the 75/25 over-forecast scenario. In this scenario, the risk of excessive energy charges outweighs the cost of more deviation charges and lower LMPs. The market rules should incent unbiased forecasting.

Figure A80: Hours when Proposed Wind EXE Threshold Exceeds Current Threshold

We have recommended that MISO should also consider other approaches to promote unbiased wind resource forecasts, including adopting Excessive Energy (EXE) thresholds for wind resources that recognize the potential for congestion to arise if wind resources over-produce.[28] In addition to receiving basepoint instructions from MISO, wind resources could receive not-too-exceed limits that would allow wind resources to exceed their dispatch instructions up to a

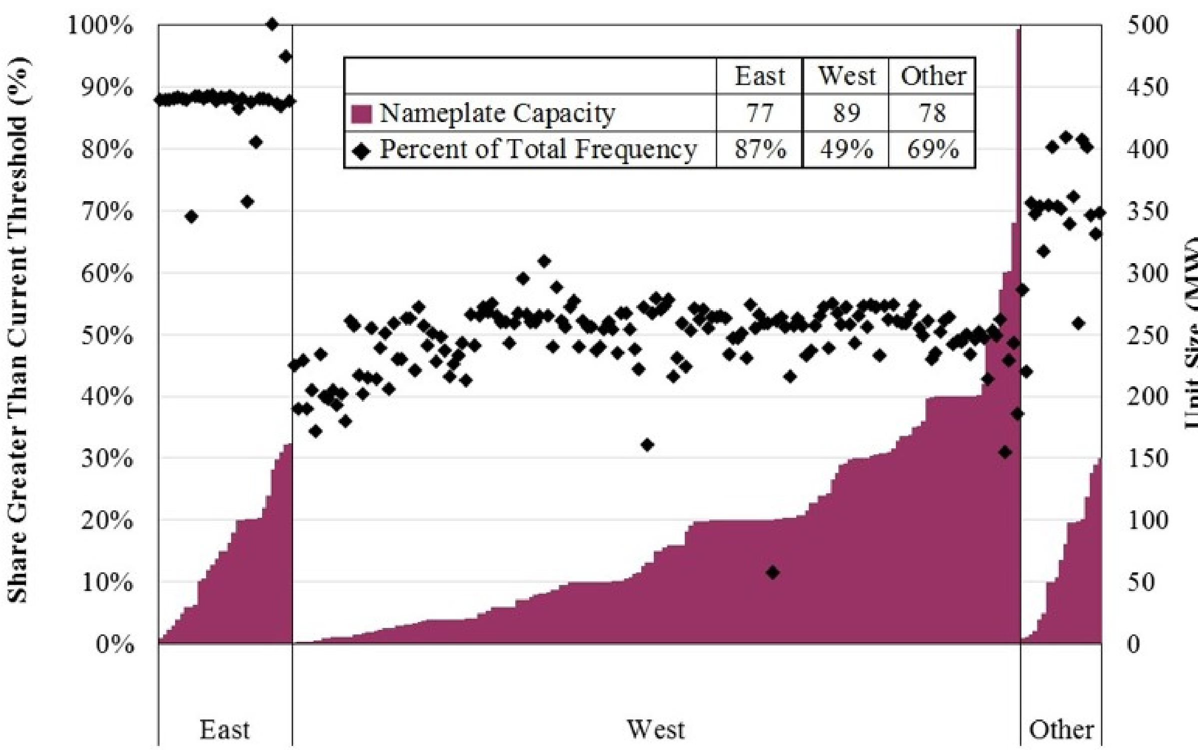
28 ISO New England employs a similar approach.

reliable maximum level. This solution would maximize the economic value of these low-cost resources while mitigating reliability concerns associated with wind output volatility.

We conducted an analysis to determine how frequently wind generation thresholds would exceed the current thresholds under this type of approach. We define the proposed EXE threshold equal to the headroom on constraints affected by the wind resources – the difference in the defined flow limit and the actual flow on the constraint – divided by the aggregate GSF of all wind units loading that constraint. This approach allows the threshold to vary with the headroom on the constraint, tightening the threshold in congested periods.

In Figure A80, we compared the proposed threshold to the existing EXE threshold (the greater of six MW or eight percent of the unit's output) to determine when the proposed threshold was greater than or equal to the current threshold. When the proposed threshold is higher, wind units could increase their output without incurring penalties or having a negative impact on reliability. Figure A80 shows wind unit size in the bars and how frequently the proposed threshold is greater than or equal to the current threshold is shown in the diamonds by resource and region.

Figure A80: Hours in 2018 when Proposed EXE Threshold Exceeds Current Threshold



The results vary considerably by region. Resources in the Other and East legacy regions would benefit the most from transmission-dependent EXE thresholds. In these regions, the proposed threshold is greater or equal to the current threshold 69 and 87 percent of the time, respectively. Units in the West legacy region benefit less, with expanded thresholds occurring approximately 49 percent of the time on average because of the higher wind output and more persistent congestion in this region.

Figure A81: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

Wind capacity factors that are measured as actual output as a percentage of nameplate capacity vary substantially year-to-year, as well as by region, hour, season, and temperature. Figure A81 shows average hourly wind capacity factors by load-hour percentile, shown separately by season and for two MISO Coordination regions (North and Central). This breakdown shows how capacity factors changed with overall load. The horizontal axis in the figure shows tranches of data by load level. For example, the "<25" bars show the capacity factor during the 25 percent of hours when load was lowest.

Figure A81: Seasonal Wind Generation Capacity Factors by Load-Hour Percentile
2018

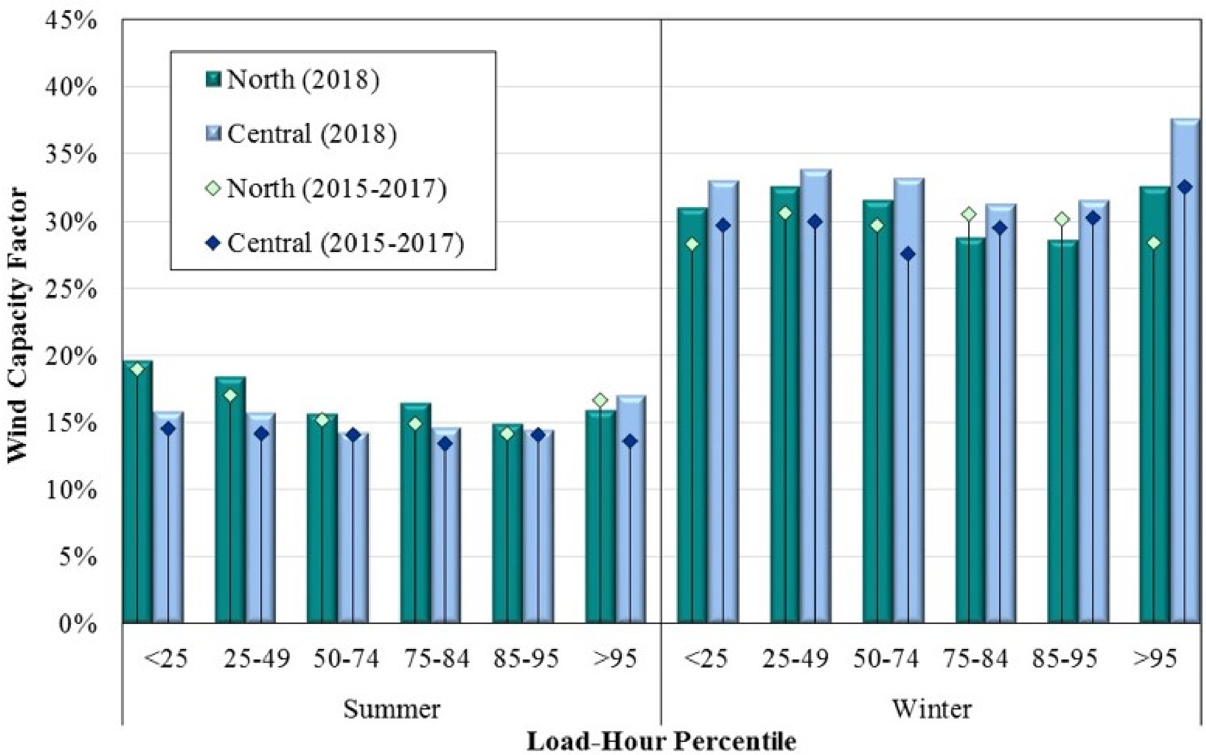
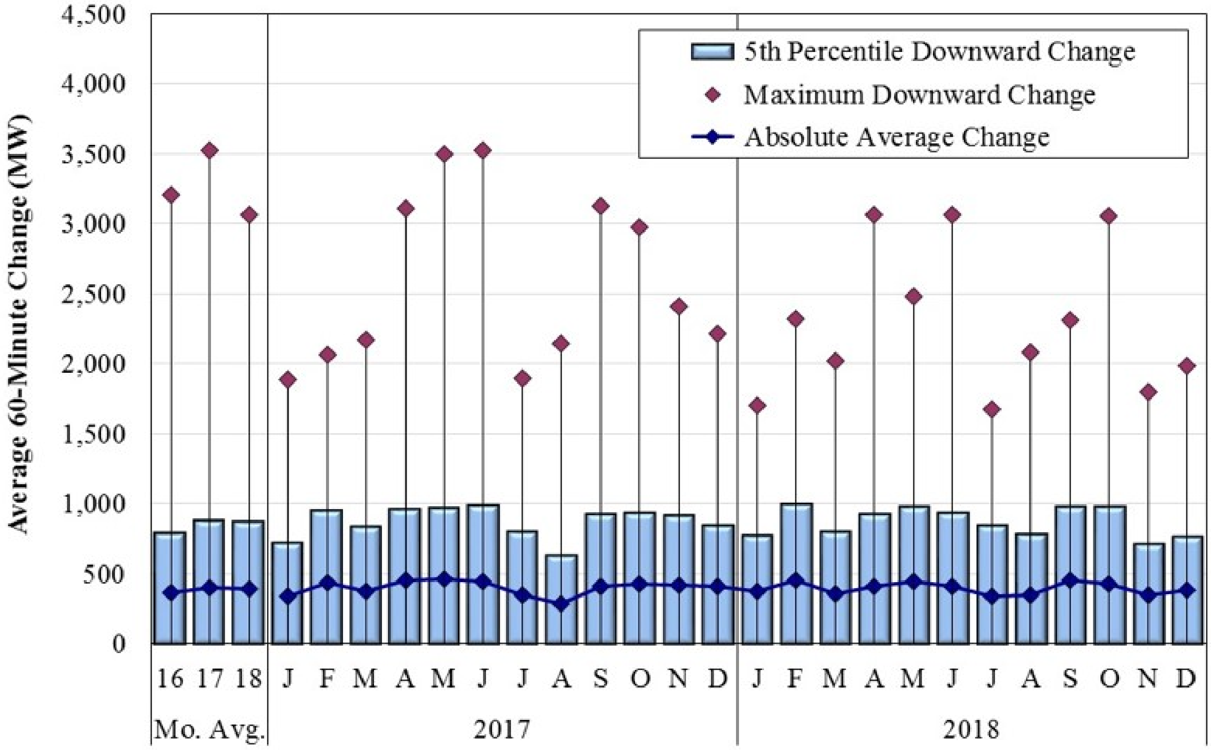


Figure A82: Wind Generation Volatility

Wind output can be highly variable and must be managed through curtailment, the re-dispatch of other resources, or commitment of peaking resources. Figure A82 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 purple bars; and
- The maximum hourly decrease in each month in the drop lines.
- Changes in wind output that are due to MISO economic curtailments are excluded from this analysis.

Figure A82: Wind Generation Volatility
2017–2018



VI. Transmission Congestion and FTR Markets

Congestion management 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") that 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 the 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, it 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 A83: Value of Real-Time Congestion by Coordination Region

Figure A83 shows the total monthly value of real-time congestion by MISO's Reliability Coordination regions in 2017 and 2018. The bars on the left panel of the chart show the average monthly value of the past three years.

Figure A83: Value of Real-Time Congestion by Coordination Region
2017–2018

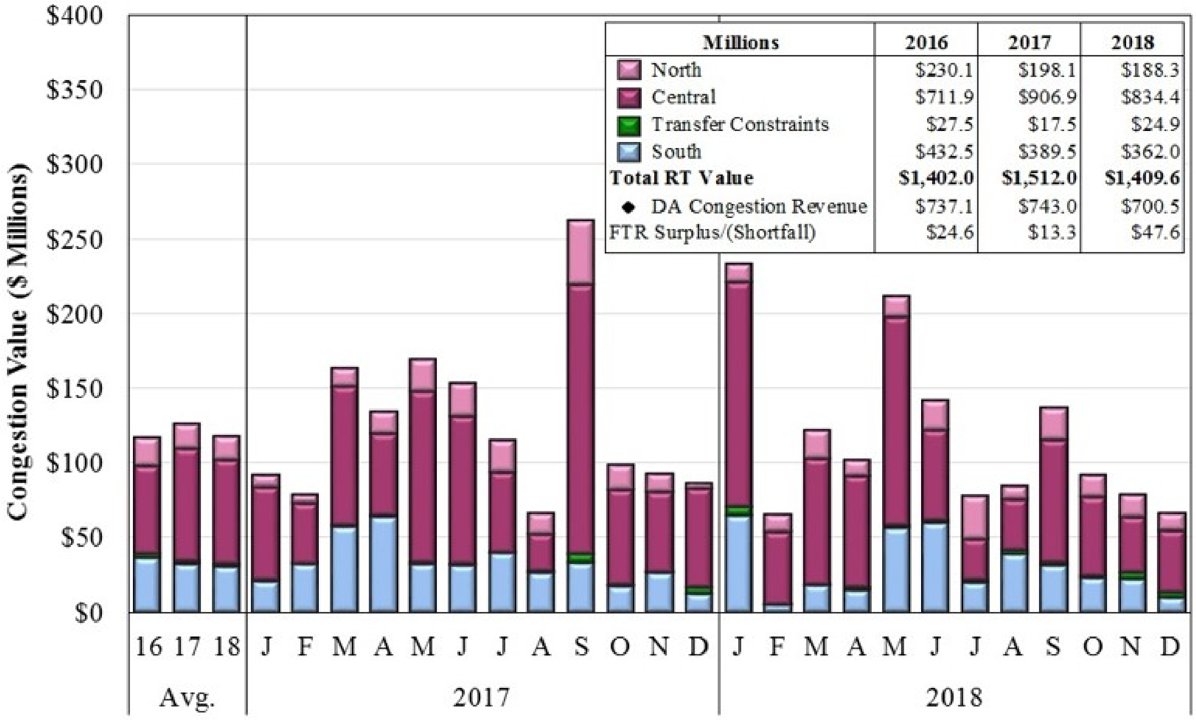


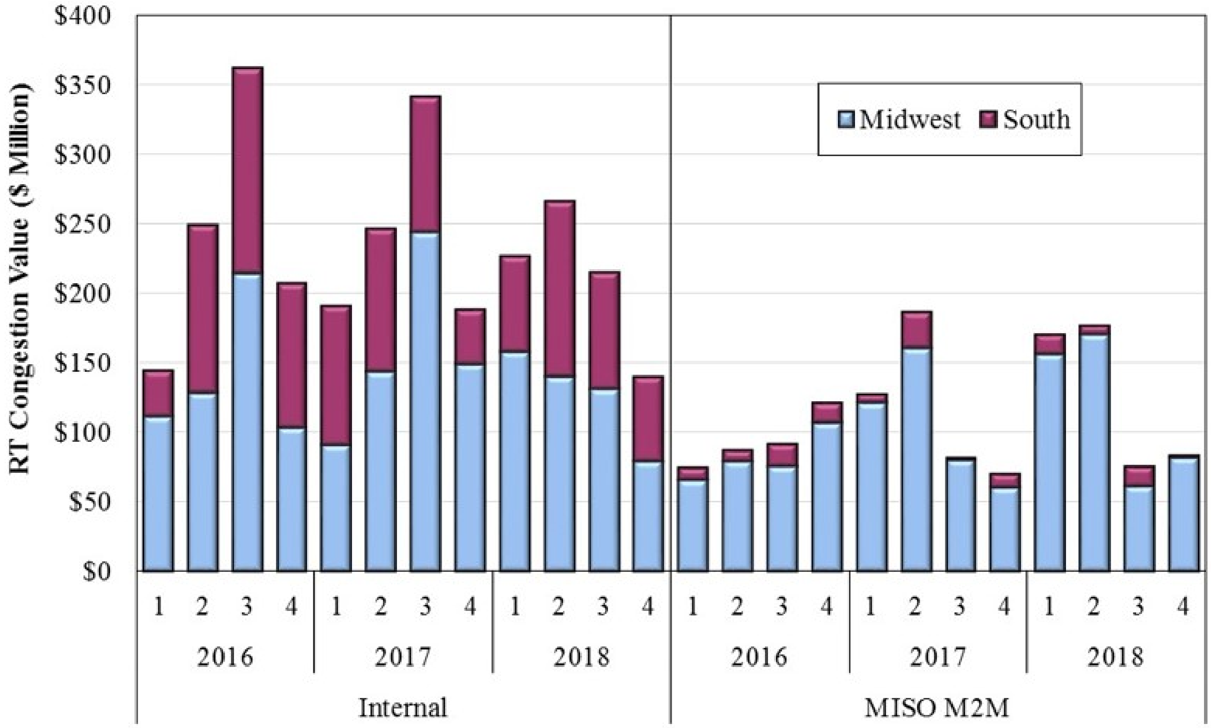
Figure A84: Value of Real-Time Congestion by Type of Constraint

To better identify the drivers of the real-time congestion value, Figure A84 disaggregates the results by the type of constraint and by the MISO subregion. We define four constraint types:

- Internal Constraints: Those 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.
- PJM and SPP M2M Constraints: M2M constraints coordinated with MISO and monitored by either PJM or SPP.
- External Constraints: Constraints located on other systems that MISO must help relieve by re-dispatching generation. These include non-M2M PJM and SPP constraints and those coordinated by other Transmission Operators such as TVA and Southern Company.

The flow on PJM and SPP M2M constraints and on external constraints represented in the MISO dispatch is limited to the MISO market flow, and this flow is used in our measure of congestion value. Market flow is limited to MISO’s flow on the constraints in MISO’s dispatch model and does not represent the total flow on these constraints. The internal and MISO M2M constraints represented in the MISO dispatch model include the total flow. Therefore, the value of congestion on external constraints (but not their impact on LMP congestion components) appears to be significantly smaller than the value of congestion of internal constraints in Figure A84 below.

Figure A84: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2016–2018



B. Day-Ahead Congestion Costs 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.

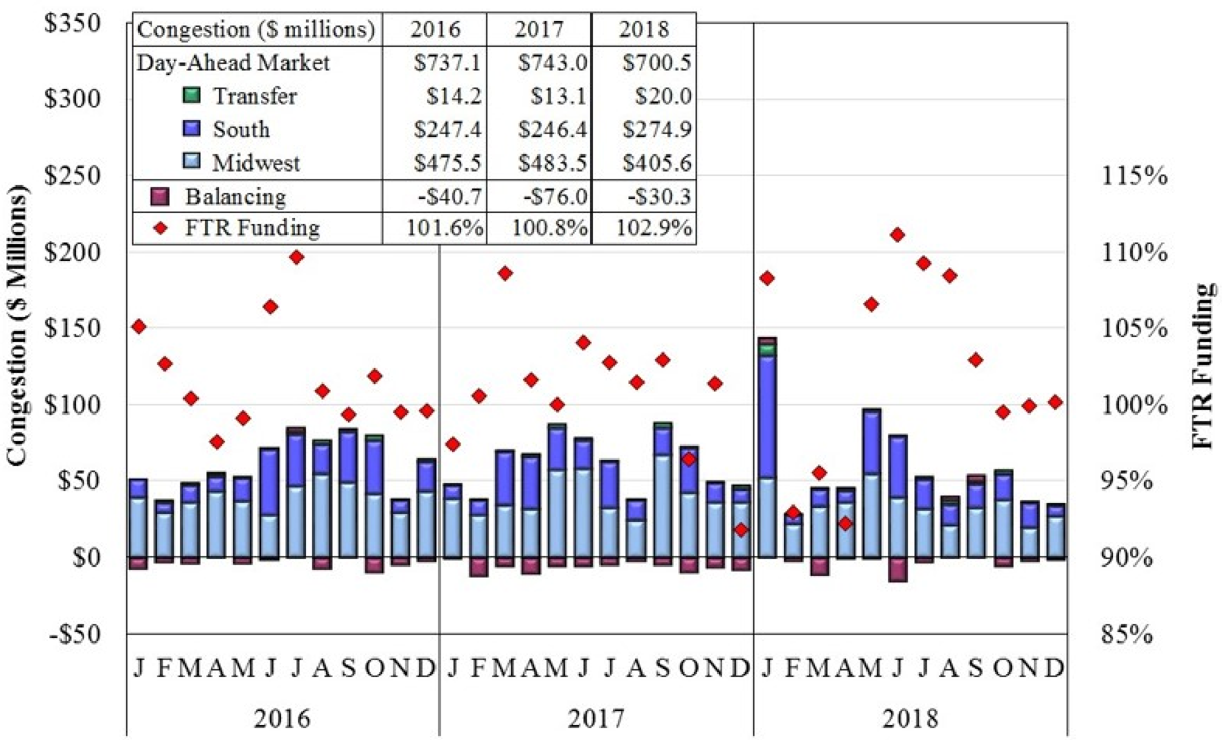
The resulting congestion revenue is paid to holders of Financial Transmission Rights (FTRs). FTRs represent the economic property rights of the transmission system, entitling the holder to the day-ahead congestion revenues between two points on the network. A large share of the value of these rights 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 the expected 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 them 100 percent of the FTR entitlement.

Figure A85: Day-Ahead and Balancing Congestion and Payments to FTRs

Figure A85 shows total day-ahead congestion revenues for constraints in the Midwest subregion, South subregion, and the transfer constraints between the Midwest and South regions for the last three years. It also shows balancing congestion revenue (net congestion collections in real time), as well as the funding level of the FTRs.

Figure A85: Day-Ahead and Balancing Congestion and Payments to FTRs
2016–2018



C. FTR Auction Revenues and Obligations

An FTR represents 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 transmission system and, therefore, are entitled to the economic property rights to the network. 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.

FTRs can be bought and sold in the seasonal and monthly auctions. 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. MISO also operates the Multi-Period Monthly Auction (MPMA), which permits Market Participants to purchase (or sell) FTRs for the next month and several future months in the current planning year.

MISO is obligated to pay FTR holders the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[29] Congestion revenues collected in MISO's day-ahead market fund the FTR obligations. Surpluses and shortfalls are expected to be limited when participants hold FTR portfolios that are consistent with the capability of the network. When MISO sells FTRs that reflect a different transmission capability than what is ultimately available in the day-ahead market, shortfalls or surpluses can occur. Reasons for differences between FTR capability and day-ahead capability include:

- 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; or
- Generators and loads outside the MISO region that contribute to loop flows that use more or less transmission capability than what is assumed in the FTR market model.[30]

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. Recent changes include new tools and procedures for the FTR modeling process, more conservative assumptions on transmission derates in the auction model, updated constraint forecasting and identification procedures, and more complete modeling of the lower-voltage network.

Figure A86: FTR Funding by LBA

At an aggregate level, MISO's FTRs were fully funded in 2018. 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.

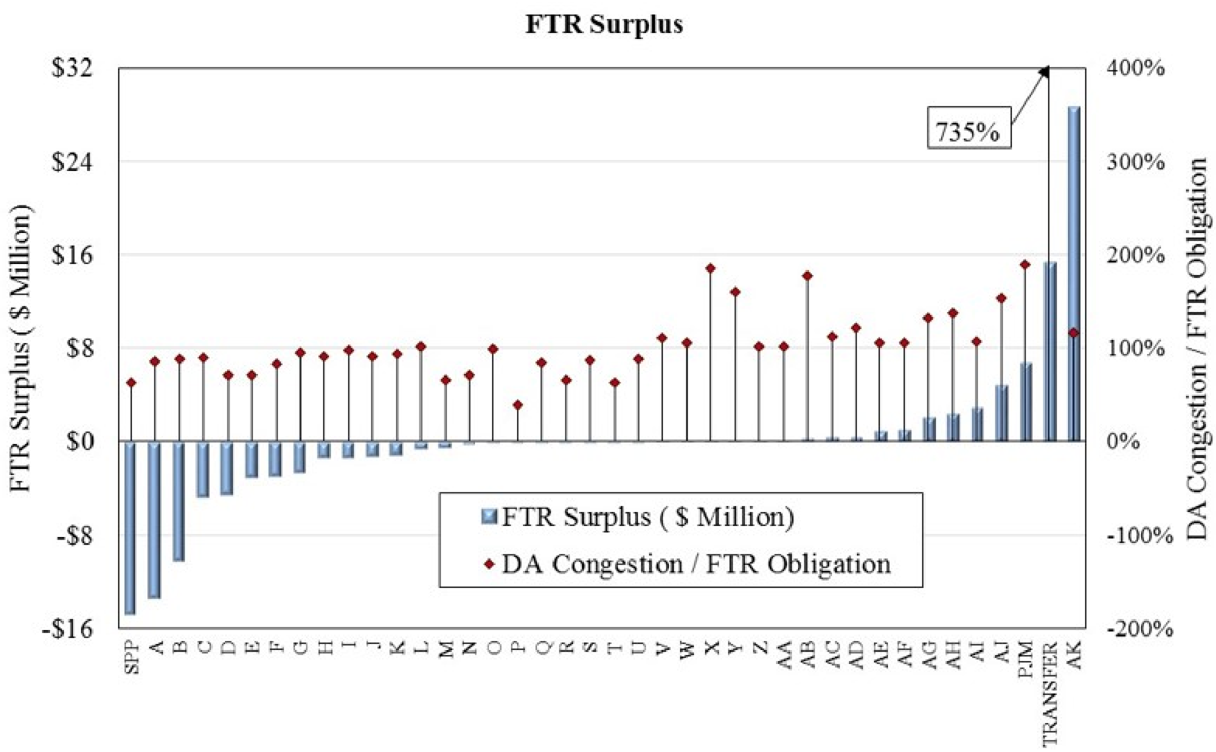
Figure A86 shows the monthly FTR surpluses and shortfalls (in both dollars and percentage terms) by LBA for 2018. The LBAs are masked with sequential letters. The constraints in each

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

30 "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.

LBA include all internal and MISO-coordinated M2M constraints. External M2M constraints are summarized by the coordinating RTO. The RDT constraint and external constraints that impact transfers between the South and Midwest regions are shown as "Transfer" constraints. Other external TLR constraints are categorized as Non-MISO.

Figure A86: FTR Funding by Type of Constraint and Control Area
2018



D. Balancing Congestion Revenues

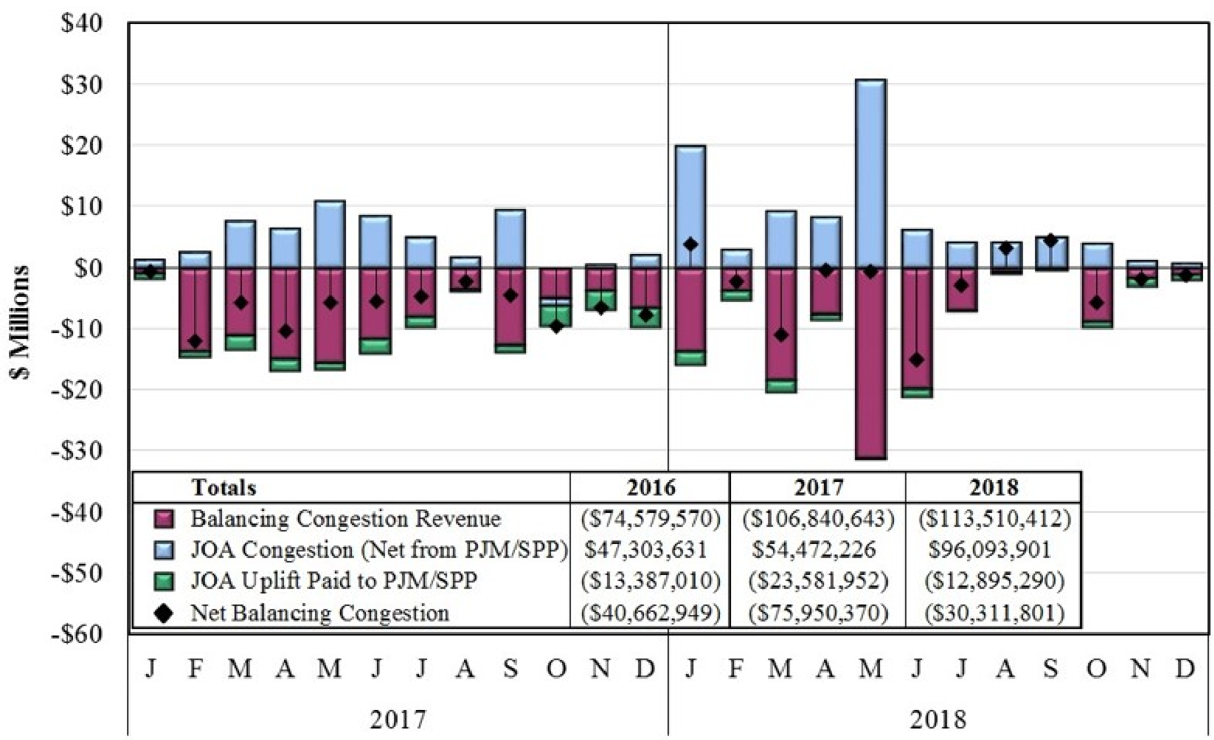
Balancing congestion revenues are congestion collections in the real-time market based on deviations from day-ahead congestion outcomes. The magnitude of balancing revenues should be small if the day-ahead market accurately forecasts the real-time network capabilities. However, balancing congestion revenue shortfalls can be large and result in substantial costs to MISO's customers if the day-ahead model is not fully consistent with the real-time topology of the system.

For example, if MISO does not model a particular constraint in the day-ahead market and it binds in real time, MISO can accumulate a substantial amount of negative balancing congestion costs. This occurs because the failure to model the constraint can allow participants to schedule more flows over the constraint in the day-ahead market than can be accommodated in real time. The negative revenues incurred by MISO to "buy back" the day-ahead flows, or balancing congestion costs, must be collected through an uplift charge to MISO's customers.

Figure A87: Balancing Congestion Revenues

To understand balancing congestion revenues, Figure A87 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 A87: Balancing Congestion Revenues
2016–2018



Totals	2016	2017	2018
Balancing Congestion Revenue	($74,579,570)	($106,840,643)	($113,510,412)
JOA Congestion (Net from PJM/SPP)	$47,303,631	$54,472,226	$96,093,901
JOA Uplift Paid to PJM/SPP	($13,387,010)	($23,581,952)	($12,895,290)
Net Balancing Congestion	($40,662,949)	($75,950,370)	($30,311,801)

Figure A88: Value of Additional Available Relief

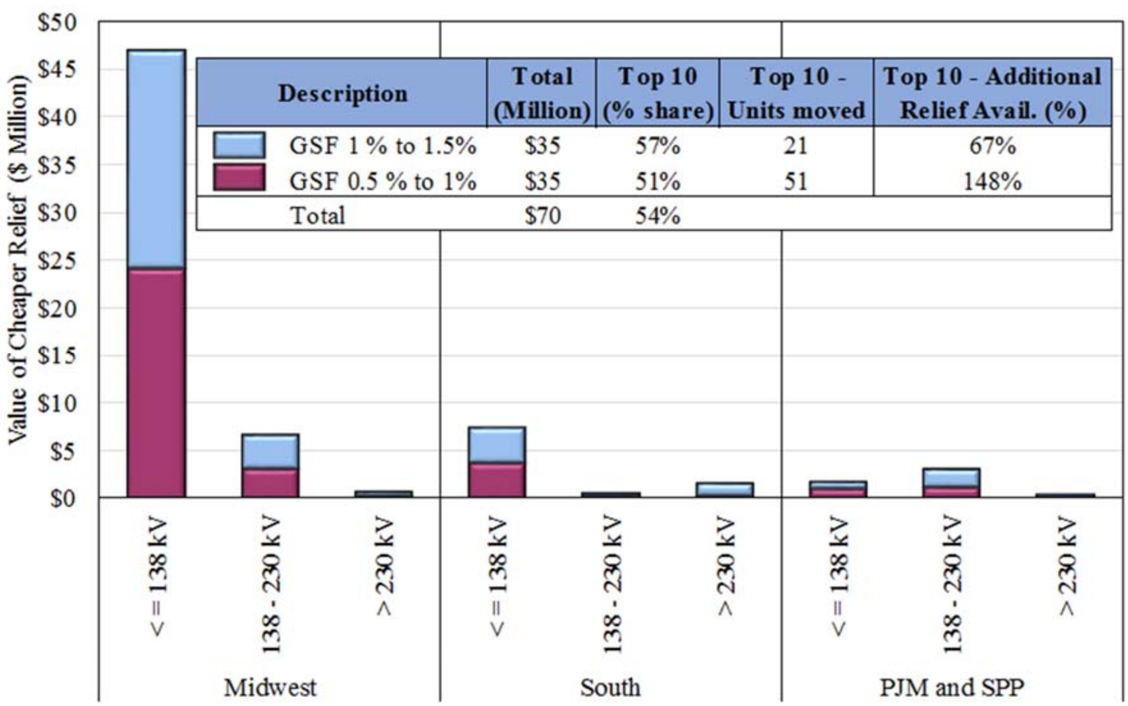
A generation shift factor ("GSF") indicates how changes in net injections at a given node will impact flows on the constraint. The GSF cutoff is a GSF level below which MISO's dispatch software assumes a generator or load's effect on a constraint is zero. MISO employs a GSF cutoff of 1.5 percent to reduce the complexity and solution time of its market optimization models, preventing electrically-distant generators from being re-dispatched to manage congestion. The flows created by these generators and loads are unpriced and treated as loop flow for purposes of market settlements.

While we believe that the use of the 1.5 percent GSF cutoff is generally reasonable, it forecloses valuable congestion relief on some constraints and can adversely affect reliability. Additionally, the RTOs engage in M2M settlements based on all market flows (down to a zero GSF level). Hence, the GSF cutoff can prevent MISO from efficiently reducing its market flows and raise the resulting M2M settlement costs. Finally, the FTR markets do not employ a GSF cutoff and this inconsistency can lead to FTR surpluses and shortfalls.

To evaluate the effects of employing a lower GSF cutoff, we recalculated GSFs down to 0.5 percent for all market days in 2018. Active real-time transmission constraints were mapped to the day-ahead GSFs, although we removed binding periods when significant differences existed between the day-ahead and real-time constraints from our analysis. This information was used to calculate the additional economic relief available from online dispatchable units and offline fast start resources with GSFs between 0.5 and 1.5 percent, and we summarize our results by voltage class and region.

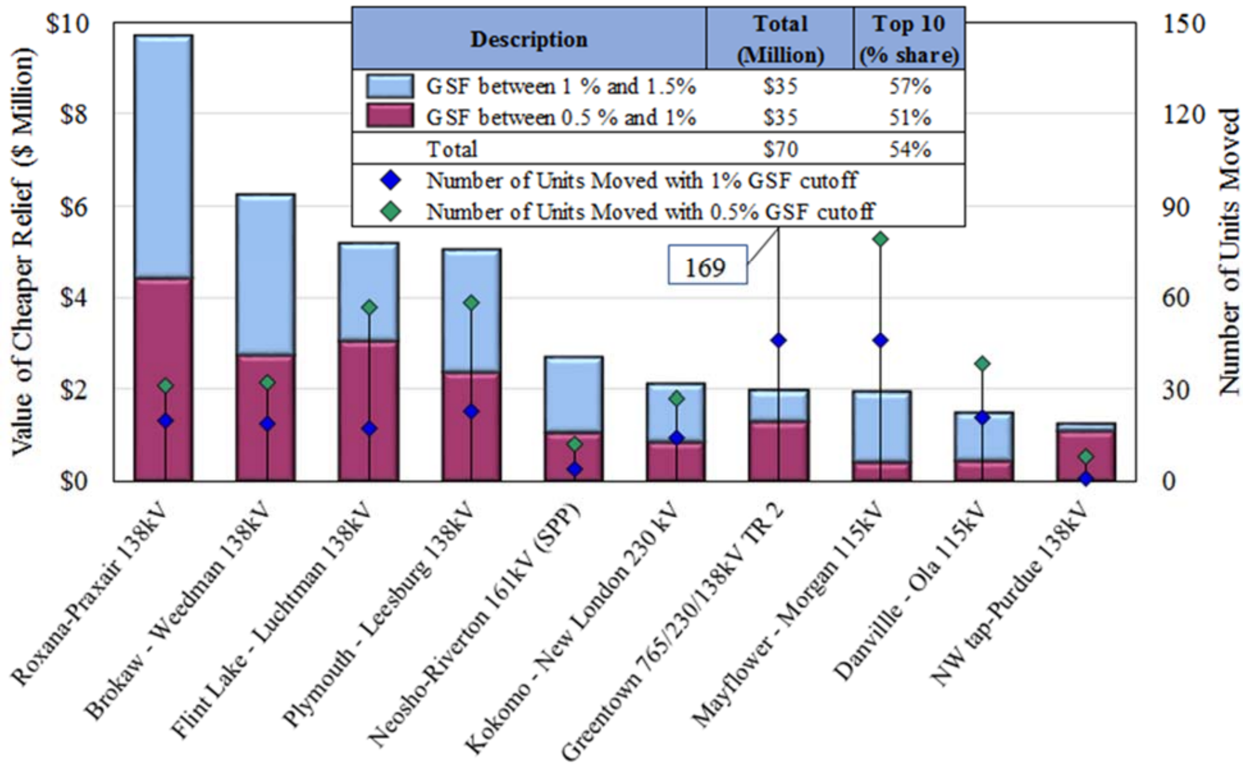
We calculate the value of the additional relief by multiplying the shadow price by the relief capability on the constraint that is available at a cost less than the shadow price of the constraint. In Figure A88, we show the value of cutoff relief by region and constraint voltage class category. In the table insert, we indicate the incremental value of relief gained by reducing the cutoff from 1.5 percent to 1 percent and separately the additional relief by further lowering the GSF cutoff to 0.5 percent. The three columns on the right indicate the percentage of additional relief that pertains to the top 10 constraints that would be affected by this change, how many additional units would move on average for those constraints, and the average percentage of total additional relief available. In Figure A89 we illustrate the top 10 constraints that would be most affected by this recommended change.

Figure A88: Value of Additional Available Relief
2018



Description	Total (Million)	Top 10 (% share)	Top 10 - Units moved	Top 10 - Additional Relief Avail. (%)
GSF 1 % to 1.5%	$35	57%	21	67%
GSF 0.5 % to 1%	$35	51%	51	148%
Total	$70	54%		

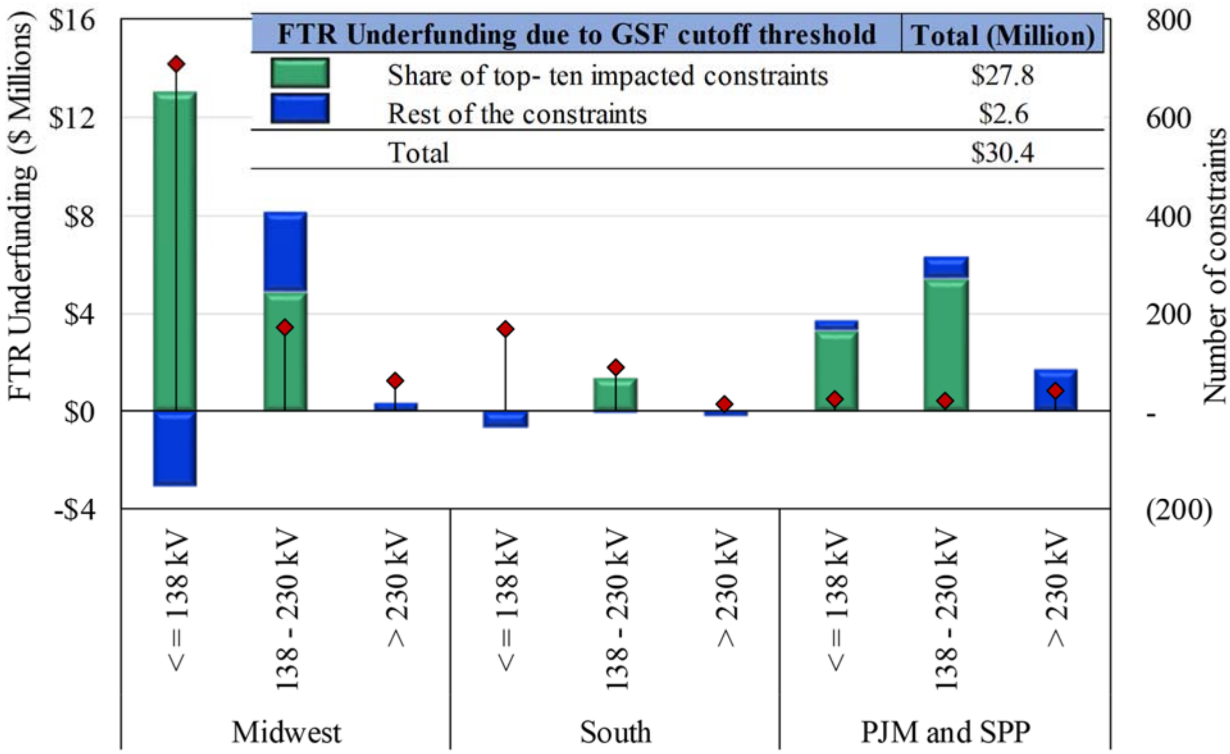
Figure A89: Value of Additional Available Relief
Top 10 Constraints



In Figure A90 below, we calculate the FTR underfunding value due to the 1.5 percent GSF cutoff threshold in the day-ahead market by multiplying the congestion component of the constraints at the affected nodes (nodes with GSF values between 0.5 and 1.5 percent) by the corresponding FTR volumes that were sold in the FTR auction. No GSF cutoff is employed for FTRs in the FTR auctions, so the FTR volumes tend to be higher than the revenues collected in the day-ahead market.

We show the FTR underfunding by region and constraint voltage class category. The green column represents the top 10 most impacted constraints, whereas the blue column represents all other constraints. In the table insert, we indicate the FTR underfunding that pertains to the top 10 constraints that would be affected by this change in comparison to the rest of the constraints.

Figure A90: FTR Underfunding Due to GSF Cutoff Threshold
2018



E. Improving the Utilization of the Transmission System

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 assumption used for rating the facilities, additional power flows can be accommodated.[31] Therefore, if transmission owners develop and submit temperature-adjusted transmission ratings, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most transmission owners do not provide temperature-adjusted ratings.

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.[32] However, we have identified

31 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.

32 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

some transmission owners that provide only normal ratings for most facilities. Some of these transmission owners may have legitimate concerns regarding the actions MISO will be able to take after a contingency occurs to reduce the flows over the facility. In such cases, it would be useful for MISO to develop the ability to evaluate in real time its ability to respond after a contingency occurs and to develop operating guides that would ensure such a response.

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.

Figure A91: Potential Value of Additional Transmission Capability

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.

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.

To estimate the benefits of providing emergency ratings, we identified transmission elements whose normal and emergency ratings were identical. 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 on average for each facility type and voltage class combination.

Figure A91 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.

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.

Figure A91: Potential Value of Additional Transmission Capability
2017–2018

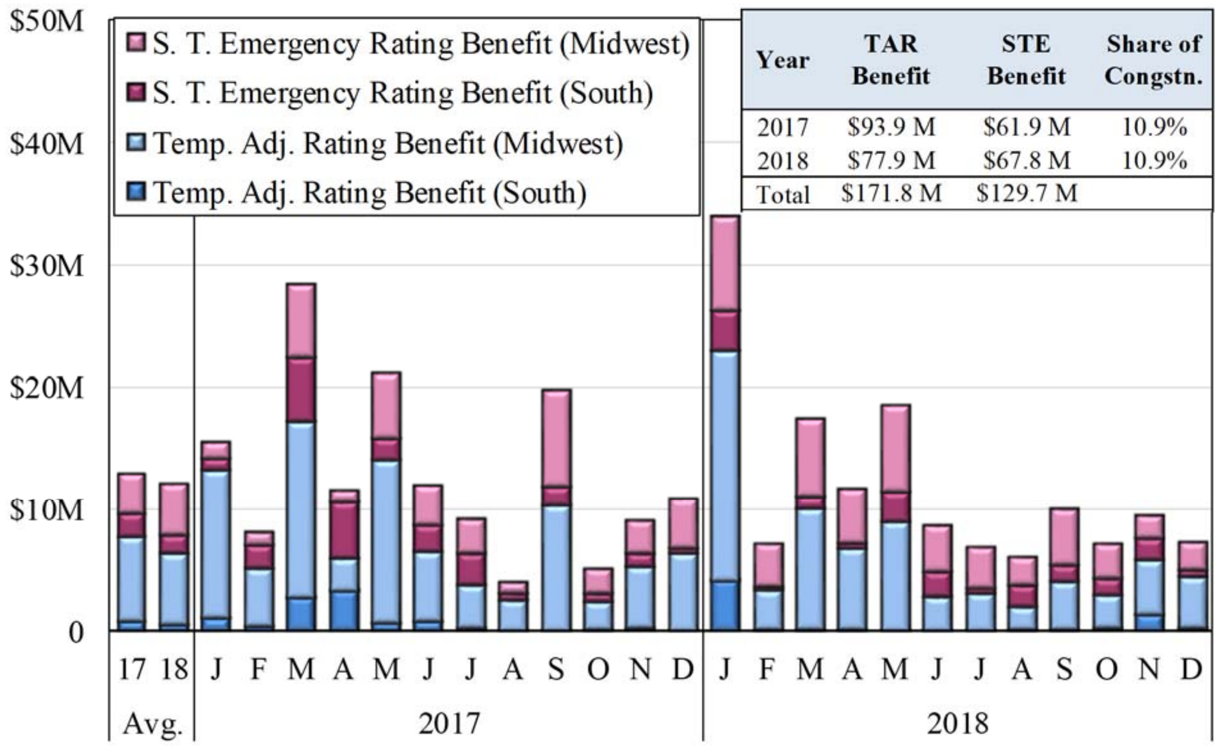
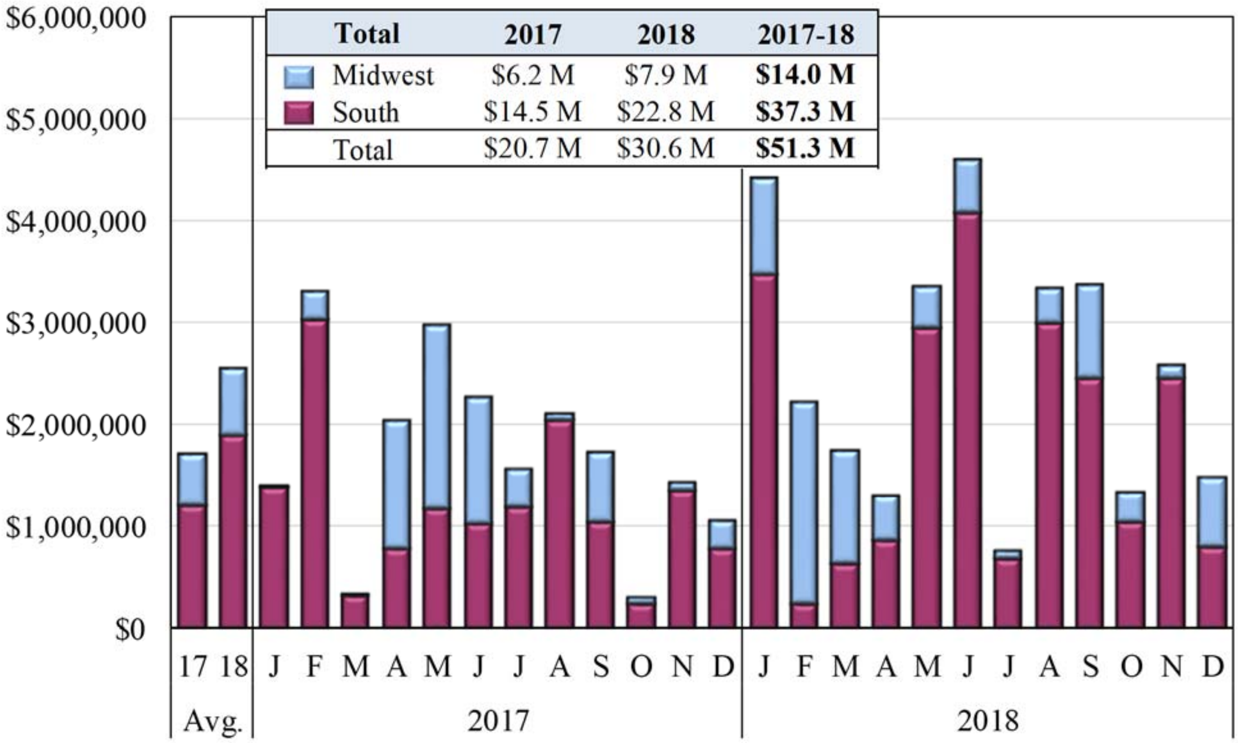


Figure A92: Estimated Actual Savings of Temperature-Adjusted Ratings

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 A92 summarizes our estimates of the congestion savings that have actually been realized from these two transmission owners' use of temperature-adjusted ratings by region. 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 was controlling to a lower, non-adjusted rating.

Figure A92: Estimated Actual Savings of Temperature-Adjusted Ratings
2017–2018



The adoption of temperature-adjusted ratings on the most congested facilities can achieve a large share of the potential benefits. For example, by selectively targeting 36 of its most congested transmission elements for the Entergy pilot program, Entergy was able to recover more than 50 percent of the potential benefits of applying temperature-adjusted limits across its entire network.

Figure A93: Area-Specific Savings Potential of Ratings Enhancement

Figure A93 organizes the potential savings by transmission area for the 24 most congested areas in MISO. The bars indicate the relative 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 A93: Area-Specific Savings Potential of Ratings Enhancement
2017–2018

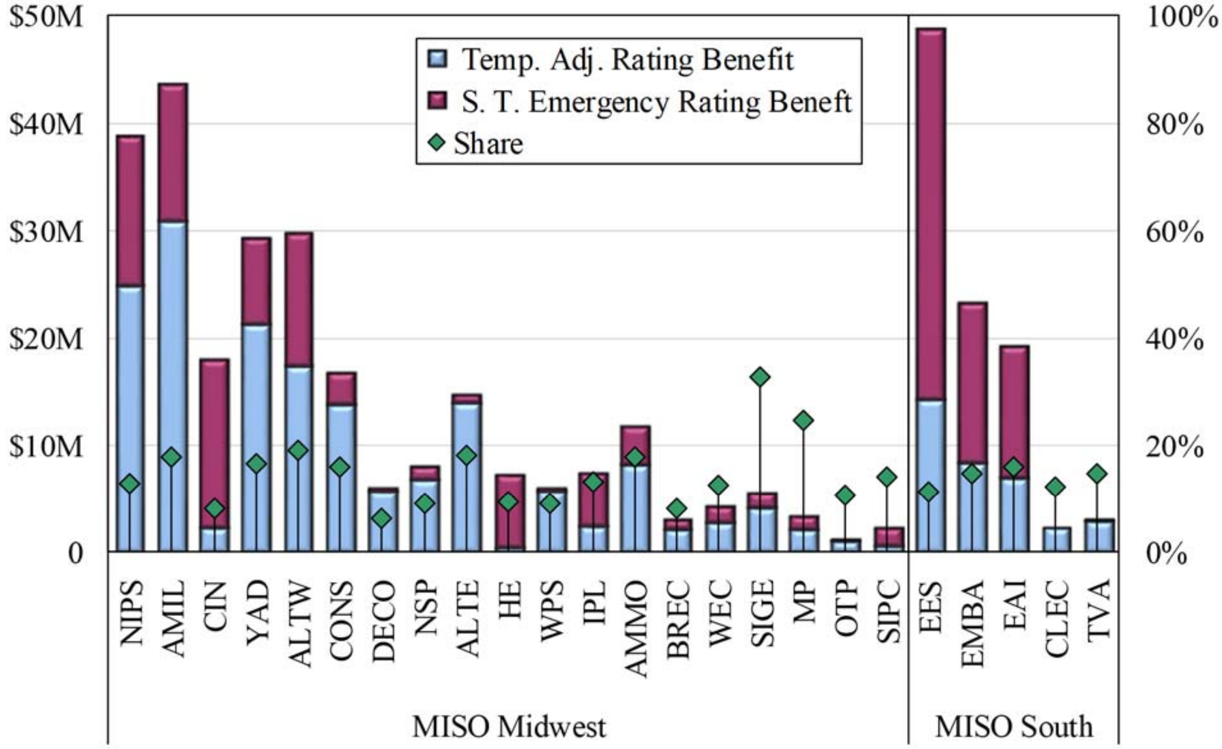


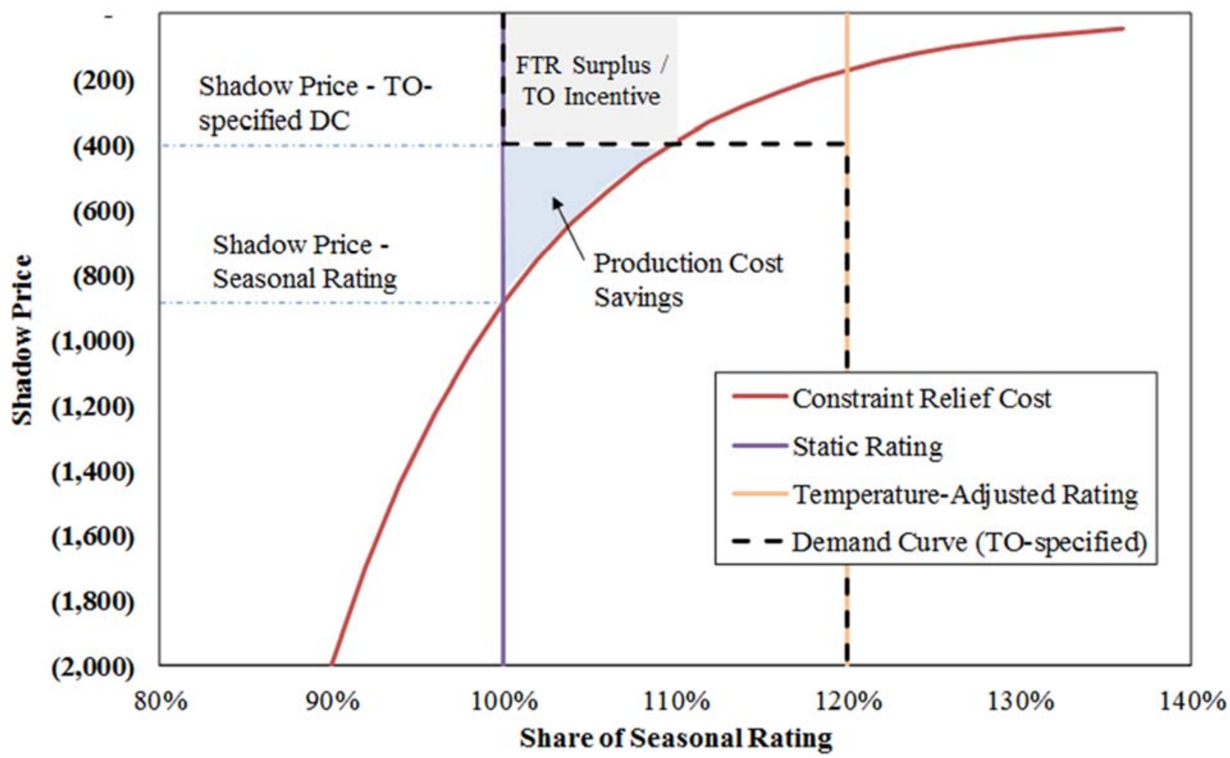
Figure A94: Potential Incentive for Transmission Operators

We believe that at least one of the reasons why most transmission owners do not provide temperature-adjusted ratings is that there is little economic incentive to do so. One means to address this issue is to provide an economic incentive to the TOs that is related to the benefits of the additional transmission capability. This is reasonable because using higher transmission limits would reduce congestion costs and benefit the loads.

Assuming the FTR market continued to limit flows to the current static seasonal ratings, use of temperature-adjusted day-ahead ratings will result in day-ahead congestion surpluses. These surpluses are equal to the increase in the limit times the shadow price of the constraint. A portion of this surplus could be used to compensate the TOs. There could also be opportunities for TOs to determine the Transmission-Constraint Demand Curve price above the static rating. This would align their expectation of incremental risk with surplus compensation.

Figure A94 illustrates the potential savings of the higher ratings and the incentive that could be created for MISO's transmission owners. This figure shows the cost of relieving the constraint in the orange line. The shadow price at the static rating level is where this relief curve intersects the static rating. It also shows the reduced shadow price of enforcing a higher rating or utilizing a transmission demand curve that allows the use of additional transmission above the static rating.

Figure A94: Potential Incentive for Transmission Operators
2017–2018



F. Transmission Line Loading Relief Events

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)[33] 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 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.

33 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 on flowgates to the IDC for use by Reliability Coordinators in the TLR process.

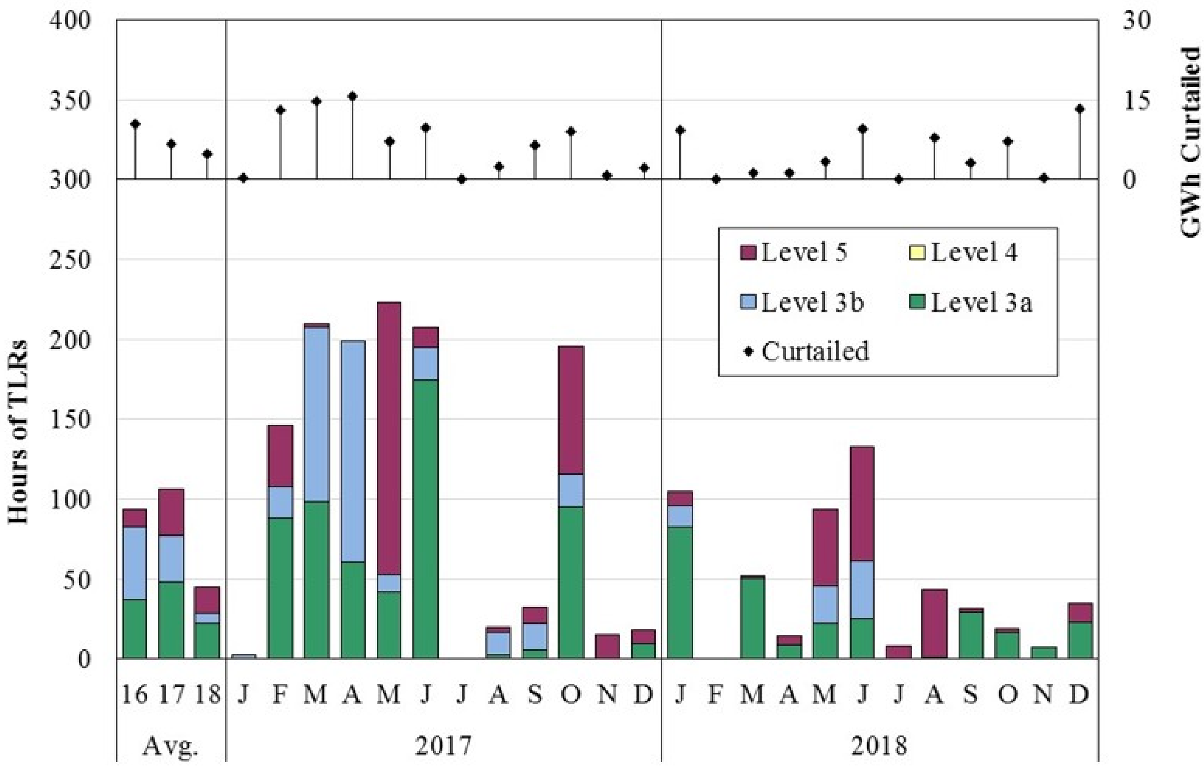
External entities not dispatched by MISO also contribute to total flows on MISO flowgates. If external transactions contribute more than five percent of the total flow on a MISO binding facility, MISO can invoke a TLR to ensure that these transactions are curtailed to reduce the flow over the constrained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

Figure A95 and Figure A96: Periodic TLR Activity

Figure A95 shows monthly TLR activity on MISO flowgates in 2017 and 2018. The top panel of the figure shows quantities of scheduled energy curtailed by MISO in response to TLR events called by other RTOs. The bottom panel of the figure provides the total number of hours of TLR activity called by MISO, grouped by TLR level.

Figure A95: Periodic TLR Activity
2017–2018



These NERC TLR levels shown in both figures are defined as follows:

- Level 3—Non-firm curtailments;[34]

34 Level 3 (3a for next hour and 3b for current hour) allows for the reallocation of transmission service by curtailing interchange transactions to allow transactions using higher priority transmission service.

- Level 4—Commitment or re-dispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[35]

Figure A96 shows the total number of TLR hours aggregated by the Reliability Coordinator declaring the TLR.

Figure A96: TLR Activity by Reliability Coordinator
2017–2018

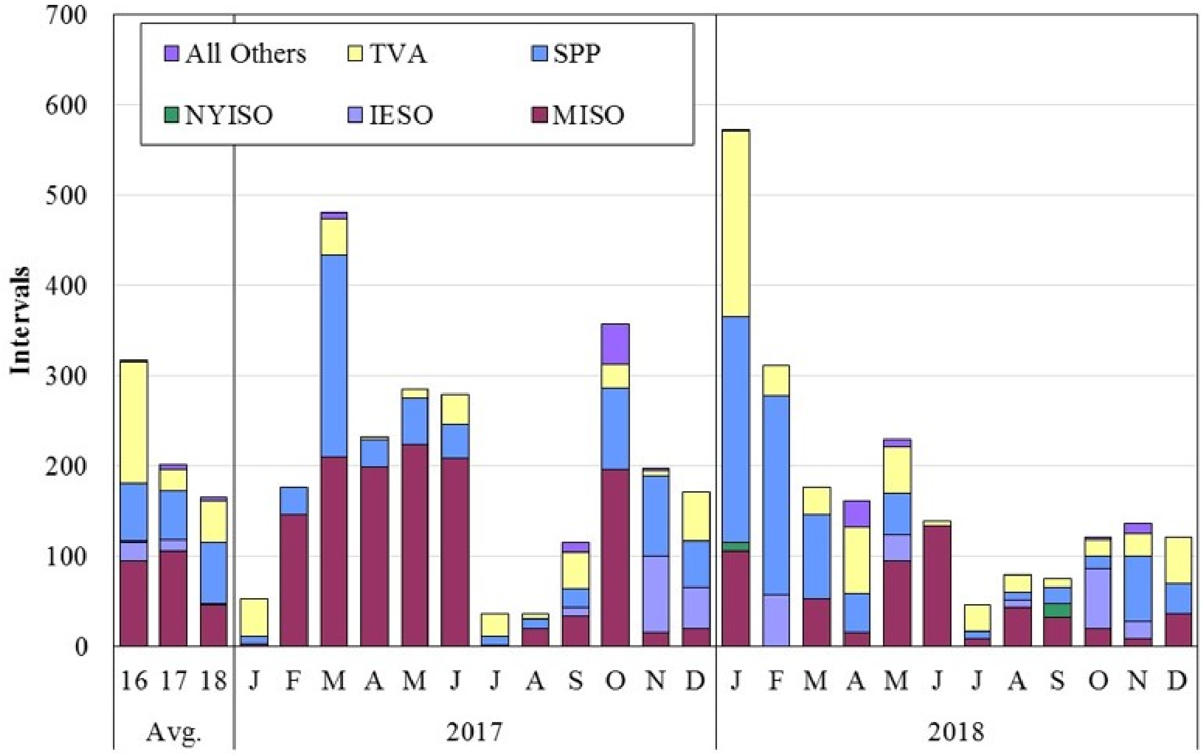


Table A11: Economic Congestion Relief from TVA Generators

Table A11 illustrates the potential savings that could be achieved by utilizing TVA generation to provide lower cost relief on constraints binding in MISO. Our analysis focuses on economic relief on two types of constraints:

- MISO internal constraints; and
- TVA constraints binding in MISO's real-time market because TVA has called a TLR.

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, while the right

35 NERC's TLR procedures include four additional levels: Level 1 (notification), Level 2 (holding transfers), Level 6 (emergency procedures), and Level 0 (TLR concluded).

column indicates the potential savings that could have been realized through economic coordination.

Table A11: Economic Congestion Relief from TVA Generators
2018

Status	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$272.5 M	$26.8 M
TVA (TLR) Constraints binding in MISO	$3.3 M	$2.0 M
Total	$275.8 M	$28.8 M

G. Congestion Manageability

MISO monitors the flows on all the transmission facilities throughout its network. It 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 nears or is expected to near the limit in real time, the constraint is activated in the market model. This causes MISO's energy market to economically alter the dispatch of generation that affects the transmission constraint, especially the dispatch of generators with high Generation Shift Factors (GSFs).[36]

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 re-dispatch capability is reduced when:

- Generators that are most effective at relieving the constraint are not online;
- Generator flexibility is reduced (e.g., generators set operating parameters lower than actual physical capabilities); or
- Generators are already at their limits, operating at the maximum or minimum points of their dispatch range.

When available relief capability is insufficient to control the flow over the transmission line in the next five-minute interval, we refer to the transmission 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 to stakeholders is triggered. Constraints most critical to system reliability (e.g., those that could lead to cascading outages) are operated more conservatively.

Figure A97 - Figure A99: Constraint Manageability

36 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.

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 2017 to 2018.

Figure A97: Constraint Manageability
2017–2018

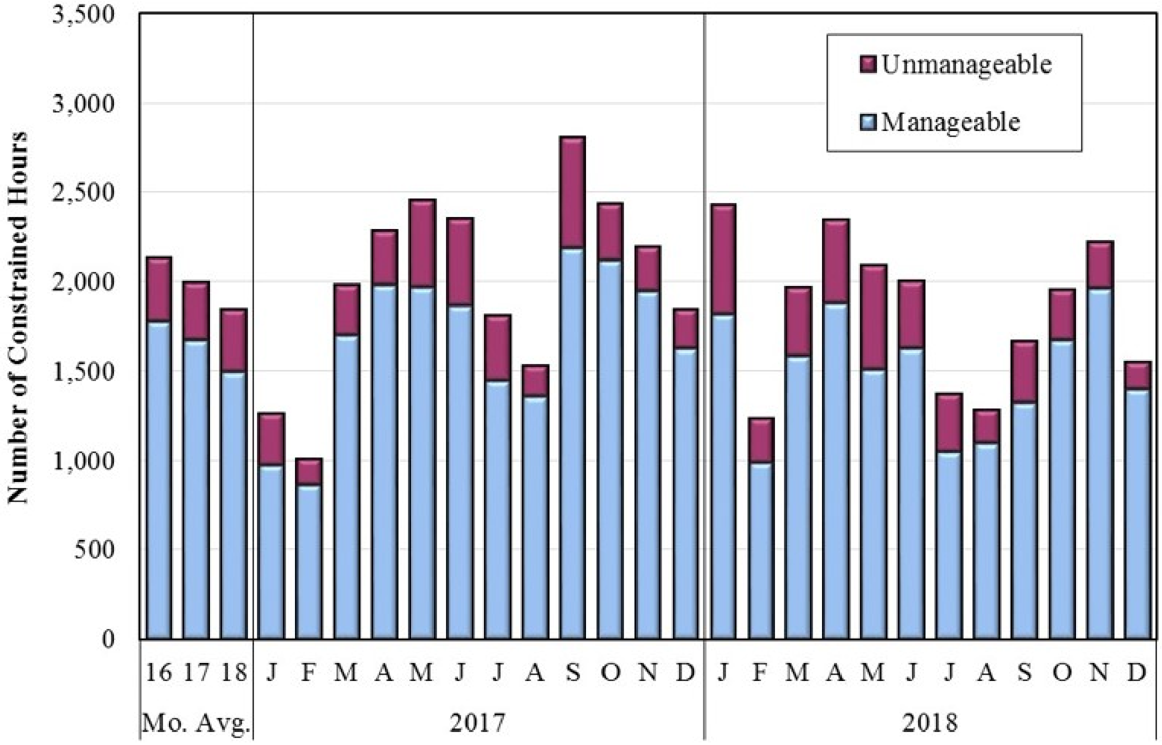


Figure A98: Real-Time Congestion Value by Voltage Level

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. Efficient market performance requires the TCDC to reflect the reliability cost of violating the constraint.

When the constraint is violated (i.e., unmanageable), the most efficient shadow price is the TCDC of the violated constraint. This produces an efficient result because the LMPs will reflect MISO's expressed value of the constraint. Prior to February 2012, an algorithm was used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs when a constraint's flow exceeded its limit. This constraint relaxation algorithm often produced LMPs that were inconsistent with value of unmanageable constraints. Its sole function was to produce a shadow price for unmanageable constraints that was lower than the TCDC. No economic rationale supports setting prices on the basis of relaxed shadow prices. Although this practice was discontinued for internal non-M2M constraints, it remains in place for all M2M constraints.

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.[37]

Figure A98: Real-Time Congestion Value by Voltage Level
2016–2018

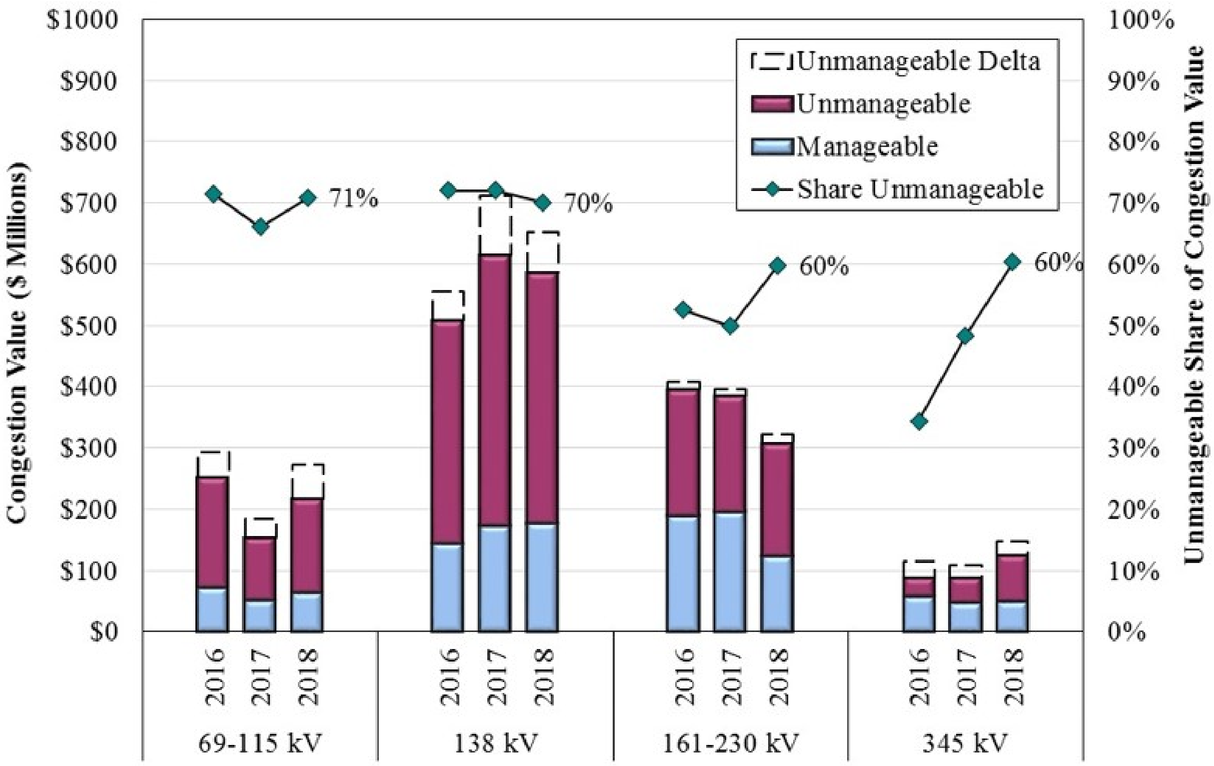


Figure A99: Congestion Affected by Multiple Planned Generation Outages

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.

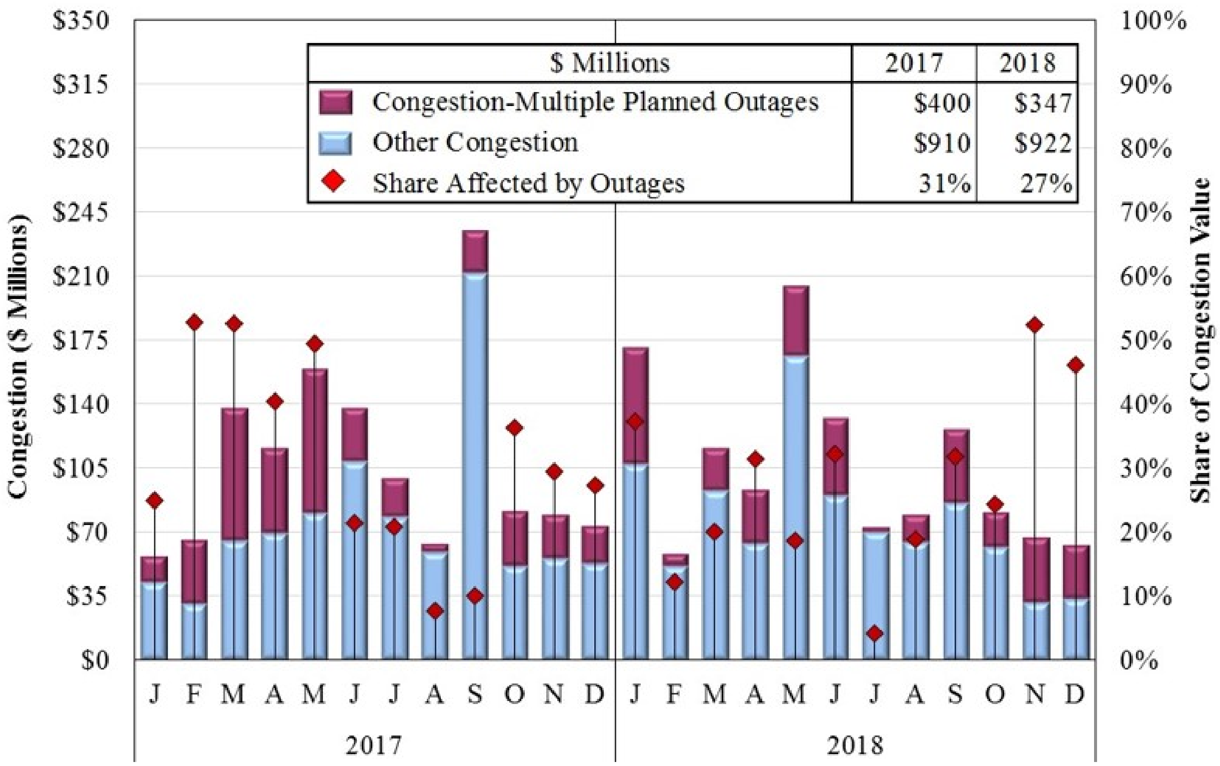
Participants tend to consolidate planned outages in the spring and fall shoulder-load months, assuming opportunity costs are lower if taking outages when load is mild, and prices are

37 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.

relatively low. However, this is not always true. Different participants may schedule multiple generation outages in a constrained area or schedule transmission outages into the area at the same time without knowing what others are doing. 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 A99 provides a high-level evaluation of how uncoordinated planned outages may affect congestion. It shows the real-time congestion value incurred from January 2017 through December 2018. 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 A99: Congestion Affected by Multiple Planned Generation Outages
2017–2018



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 was launched in November 2013 and facilitates FTR trading for future months or seasons remaining in the planning year.

Figure A100: FTR Profits and Profitability

Figure A100 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 A100: FTR Profits and Profitability
2017–2018

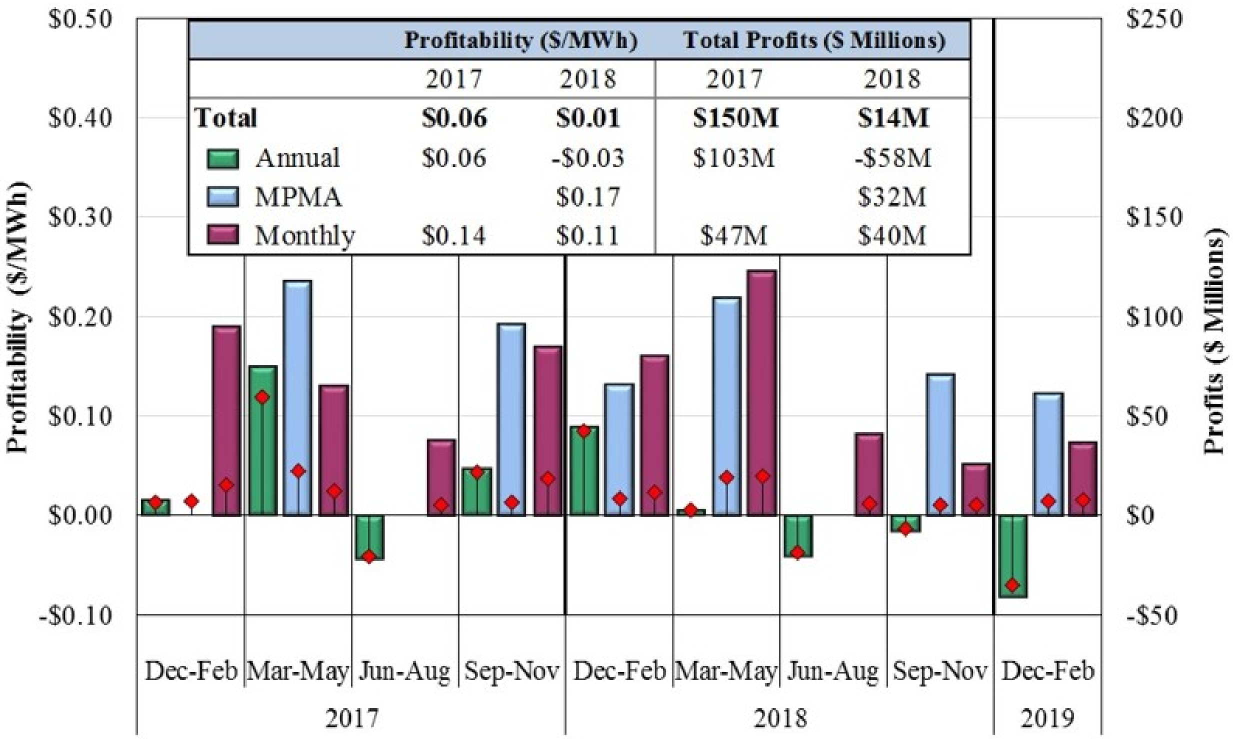


Figure A101 to Figure A103: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly FTR auctions in more detail for 2016 to 2018. The bottom panels show the total profits and losses, while the top panel shows the profits and losses per MWh.

The results in the figure include FTRs sold as well as purchased. FTRs sold are netted against FTRs purchased. For example, if an FTR purchased during round one of the annual auction is sold in round two, the purchase and sale of the FTR in round two would net to zero.

Figure A101: FTR Profitability
2016–2018: Annual Auction

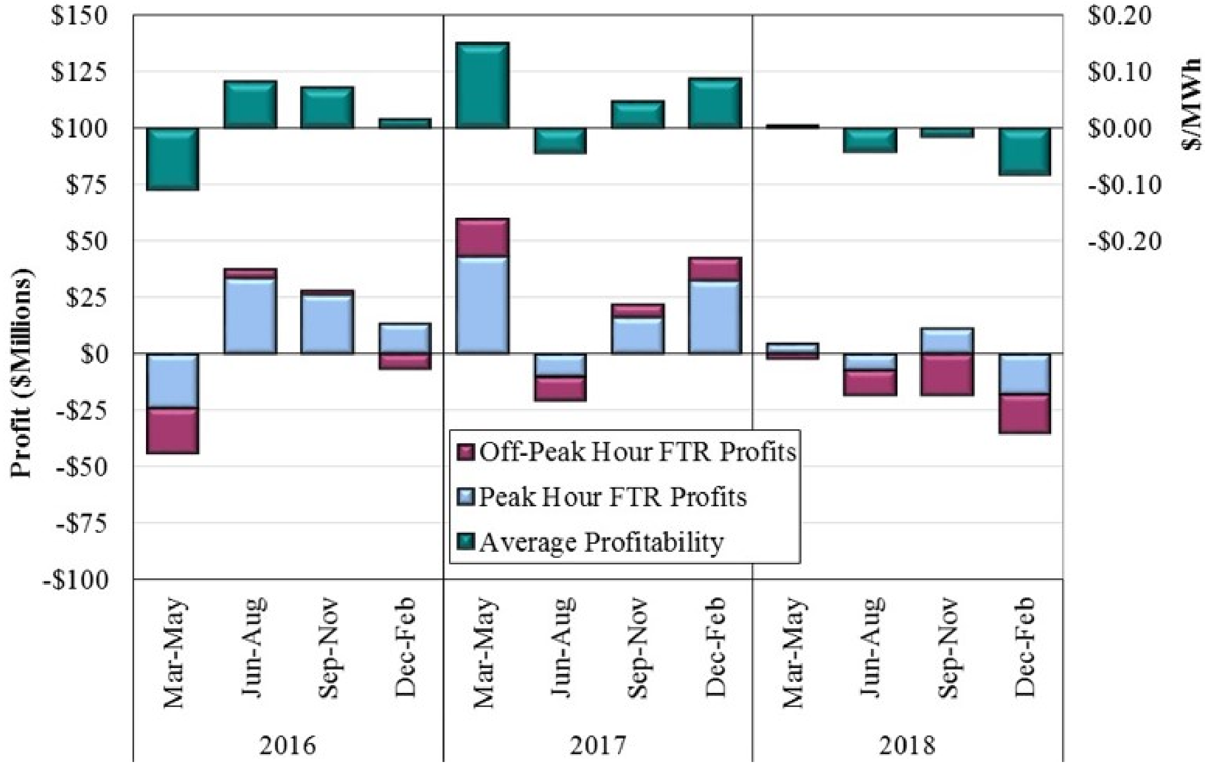


Figure A102: FTR Profitability
2017–2018: Monthly Auction

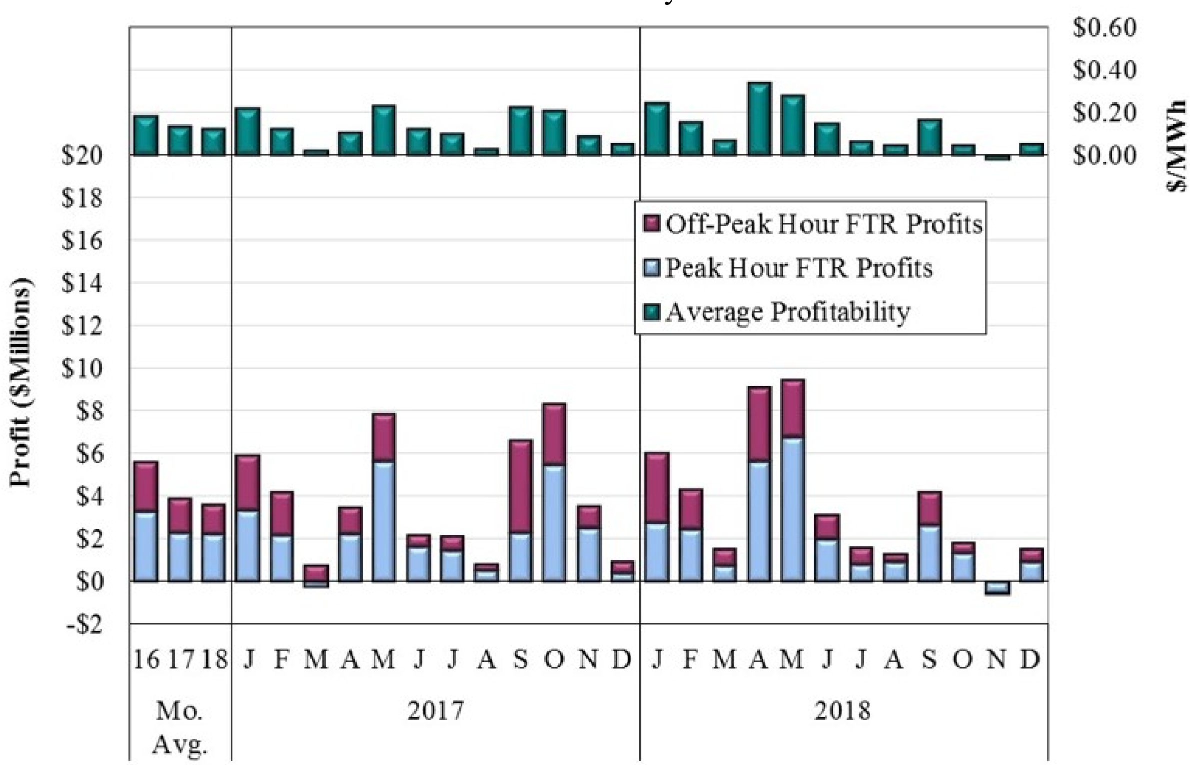


Figure A103: FTR Profitability
2016–2018 Seasonal Auction MPMA

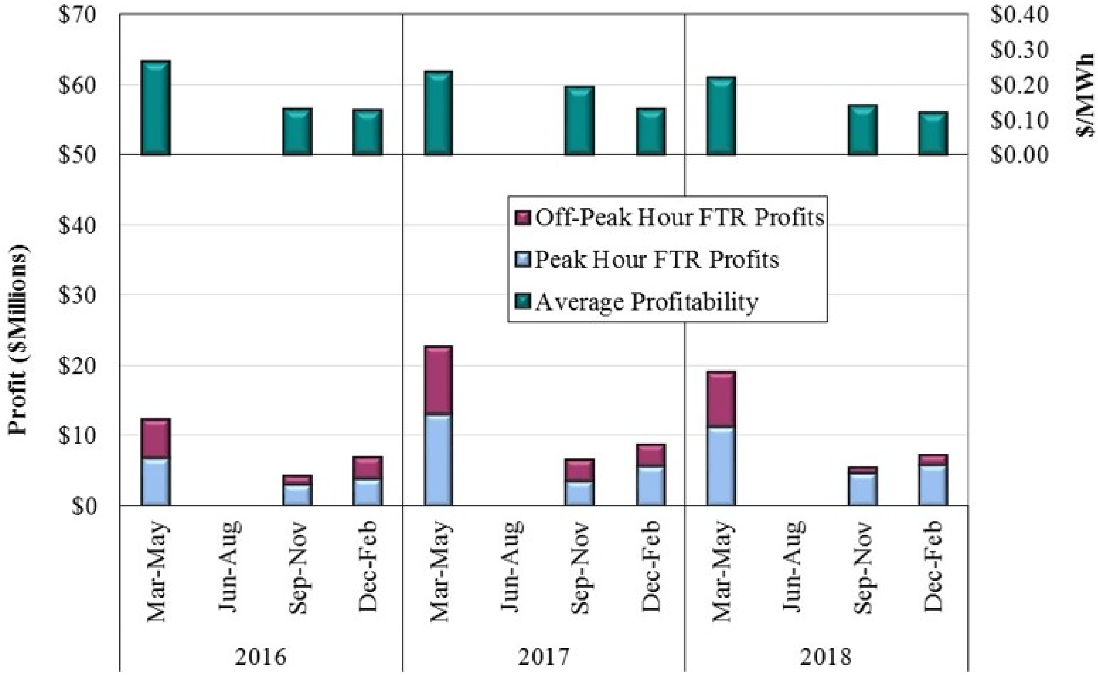


Figure A104 to Figure A117: Comparison of FTR Auction Prices and Congestion Value

The next 14 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 A104: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2017–2018: Off-Peak Hours

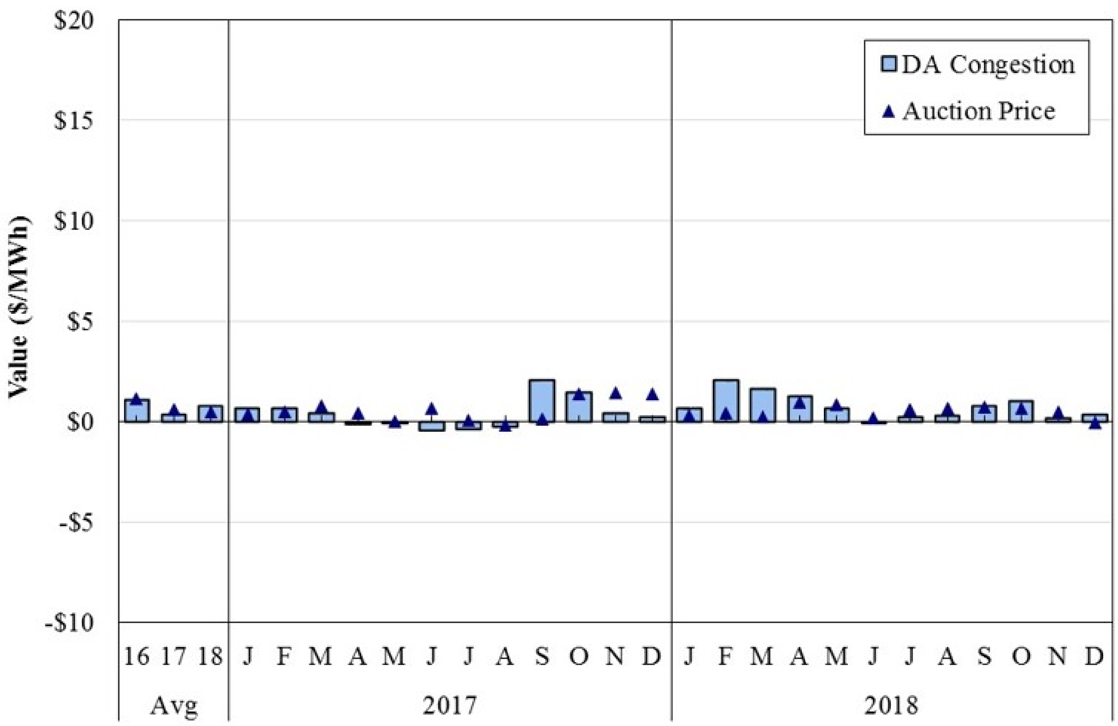


Figure A105: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2017–2018: Peak Hours

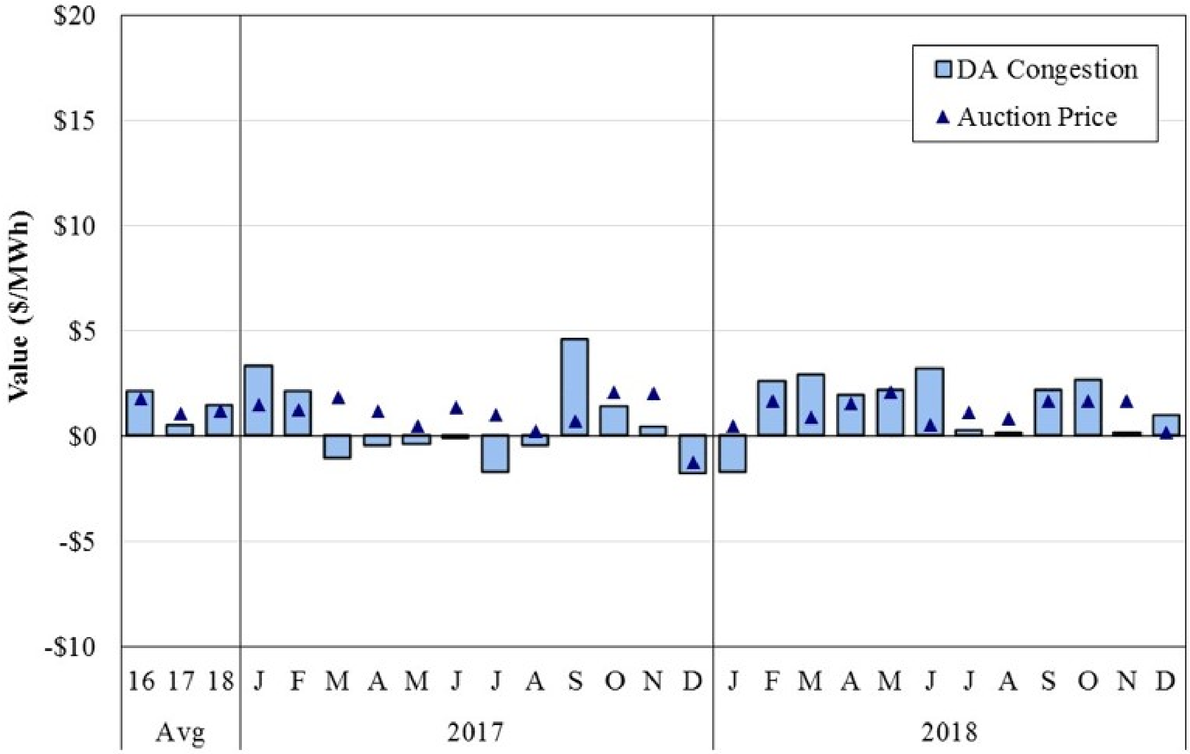


Figure A106: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2017–2018: Off-Peak Hours

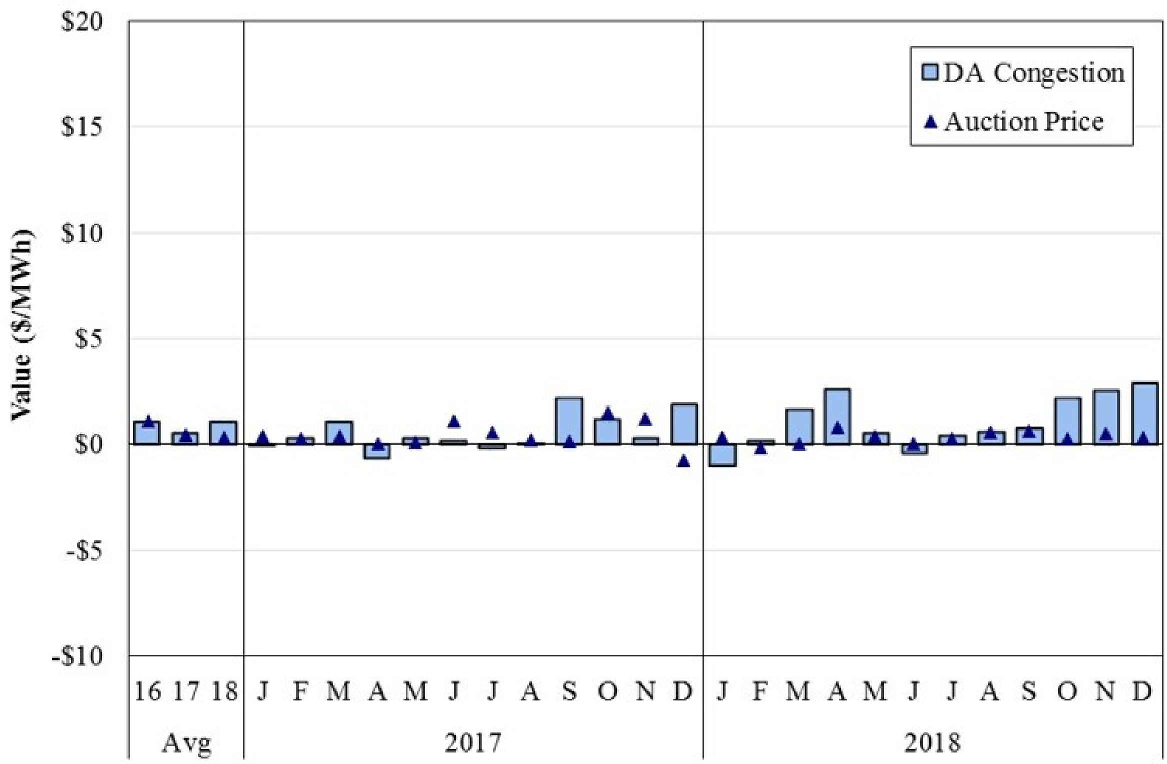


Figure A107: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2017–2018: Peak Hours

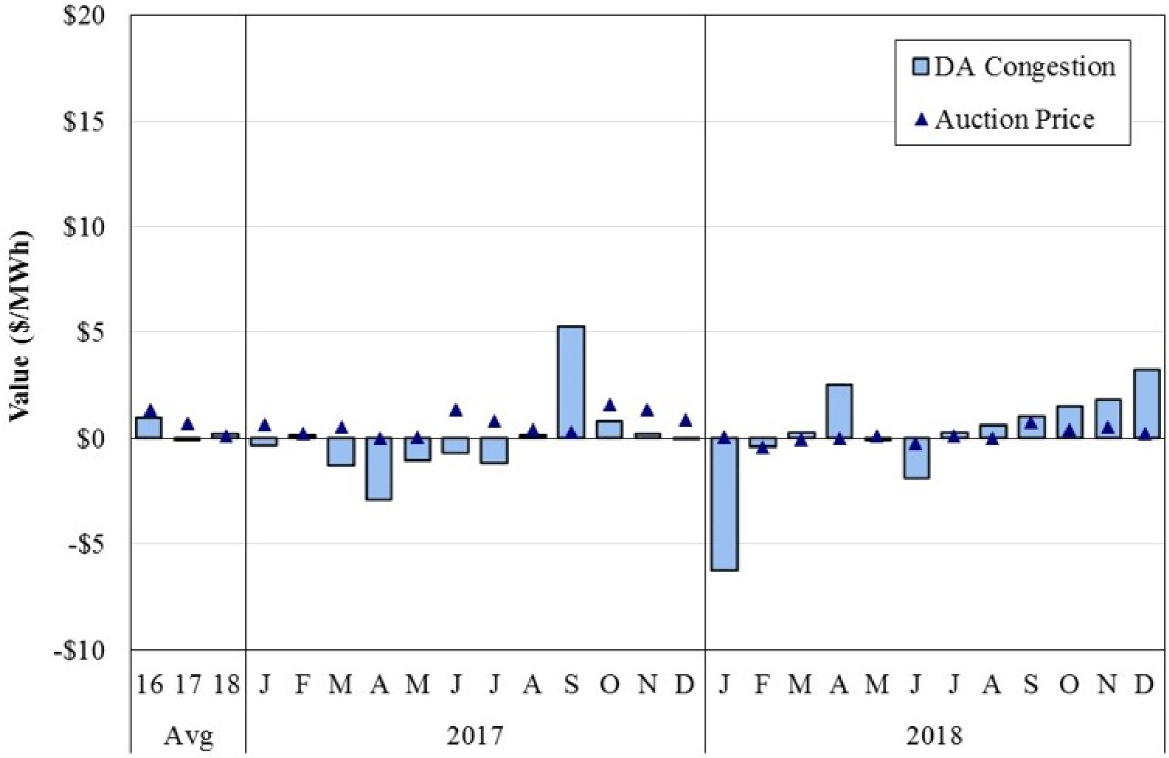


Figure A108: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2017–2018: Off-Peak Hours

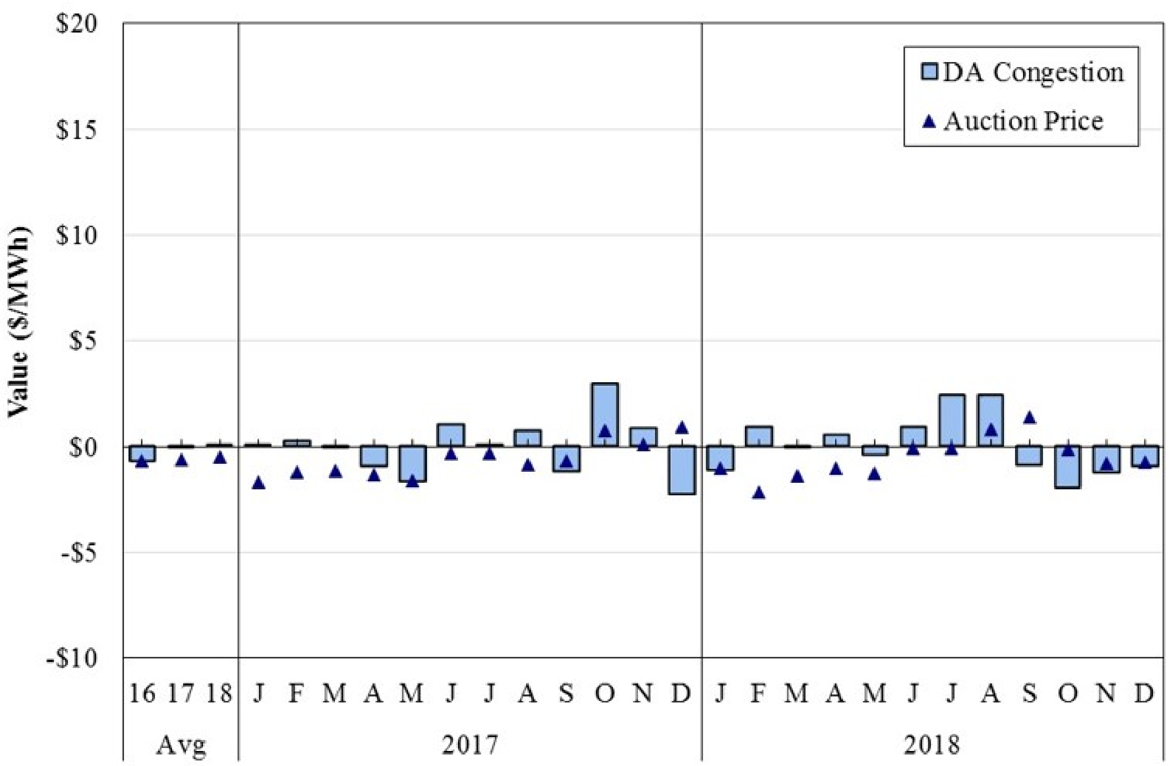


Figure A109: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2017–2018: Peak Hours

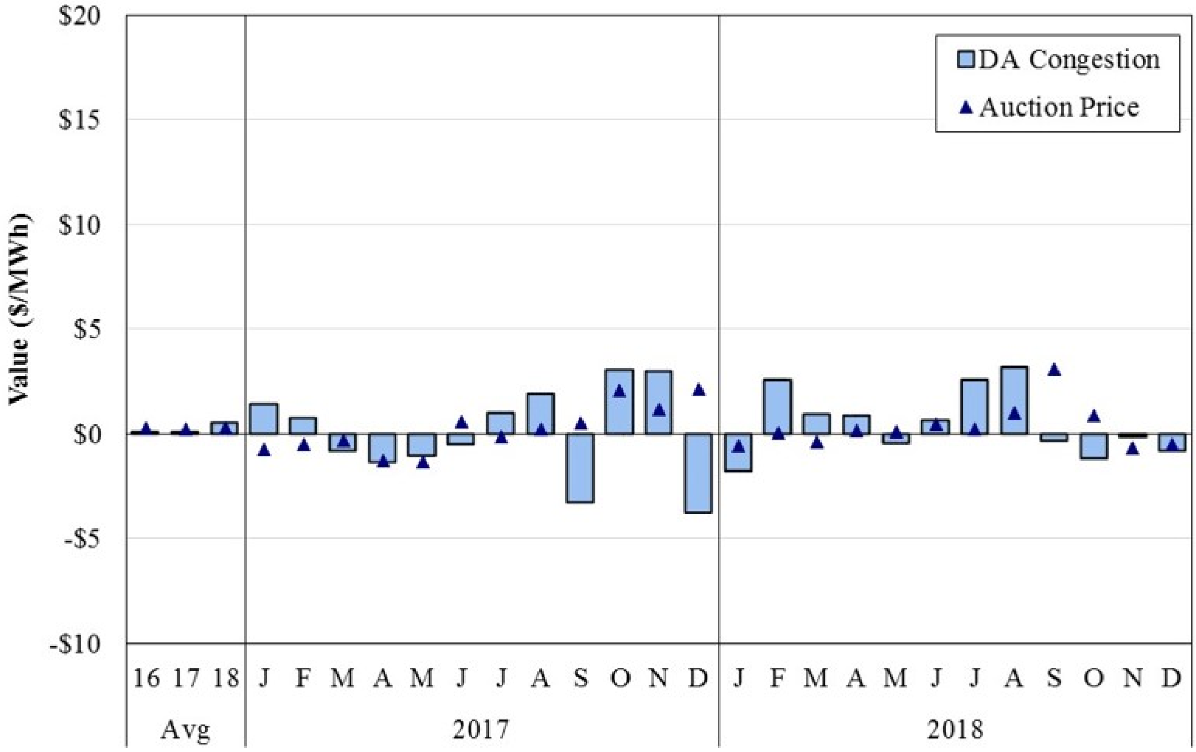


Figure A110: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2017–2018: Off-Peak Hours

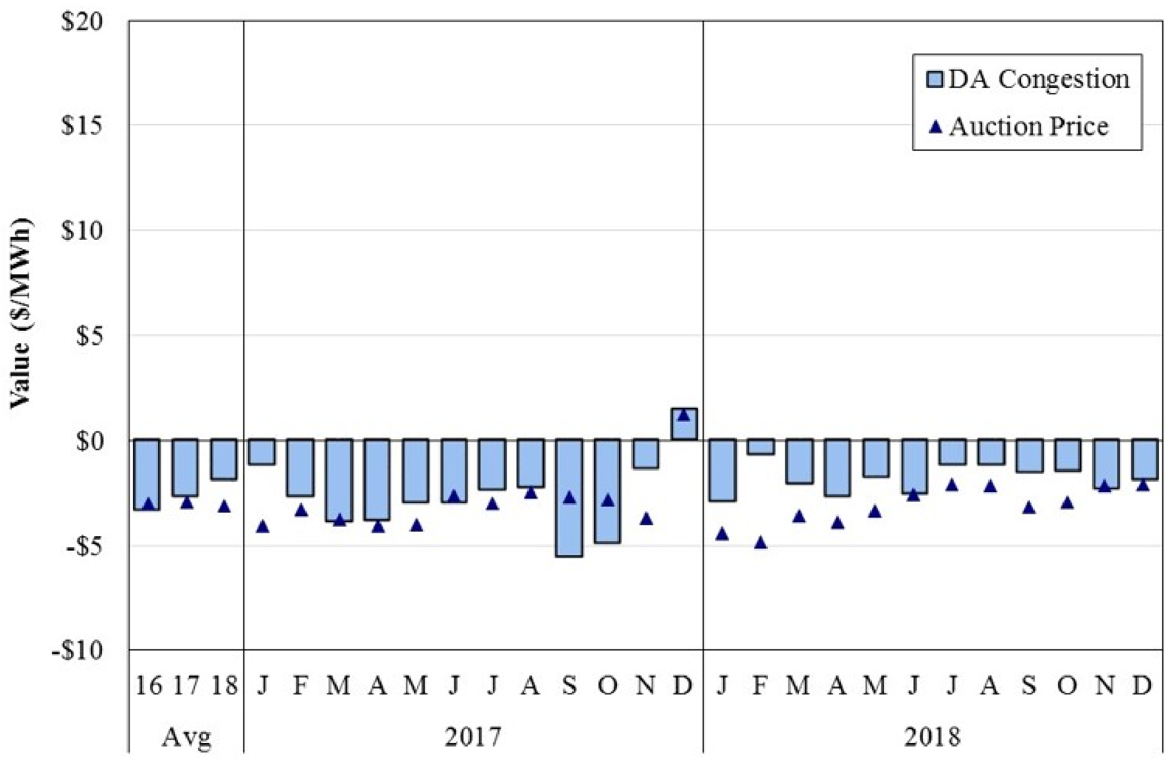


Figure A111: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2017–2018: Peak Hours

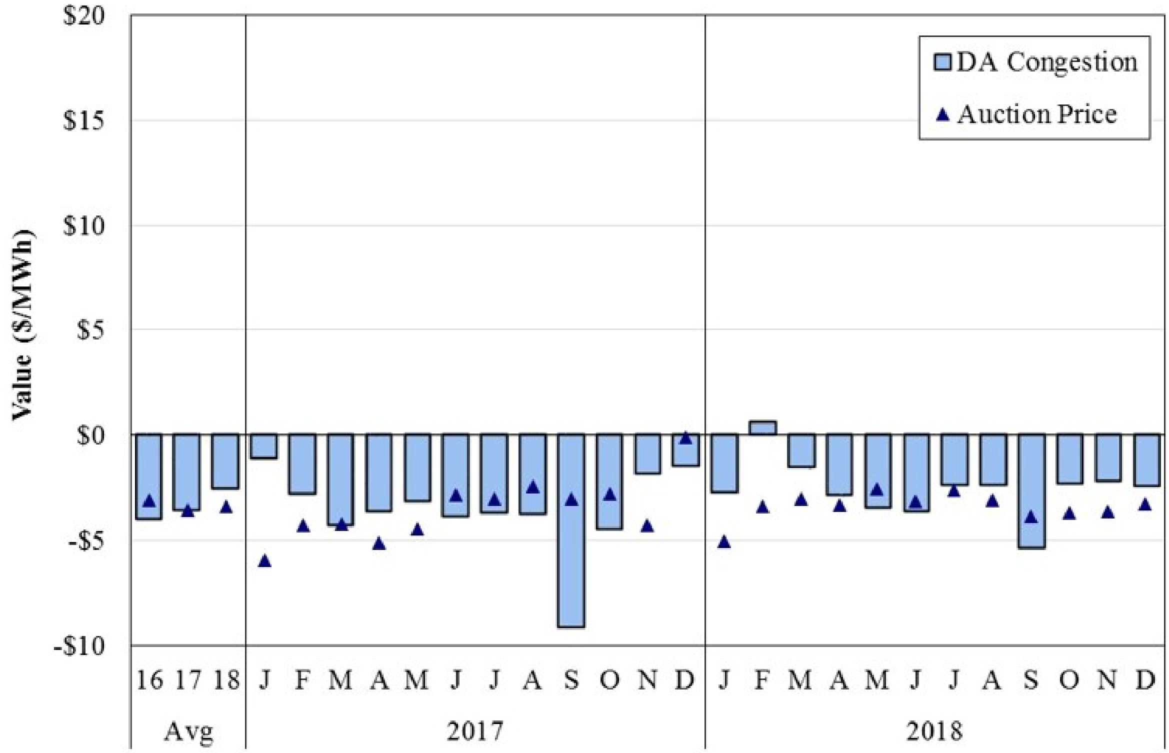


Figure A112: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2017–2018: Off-Peak Hours

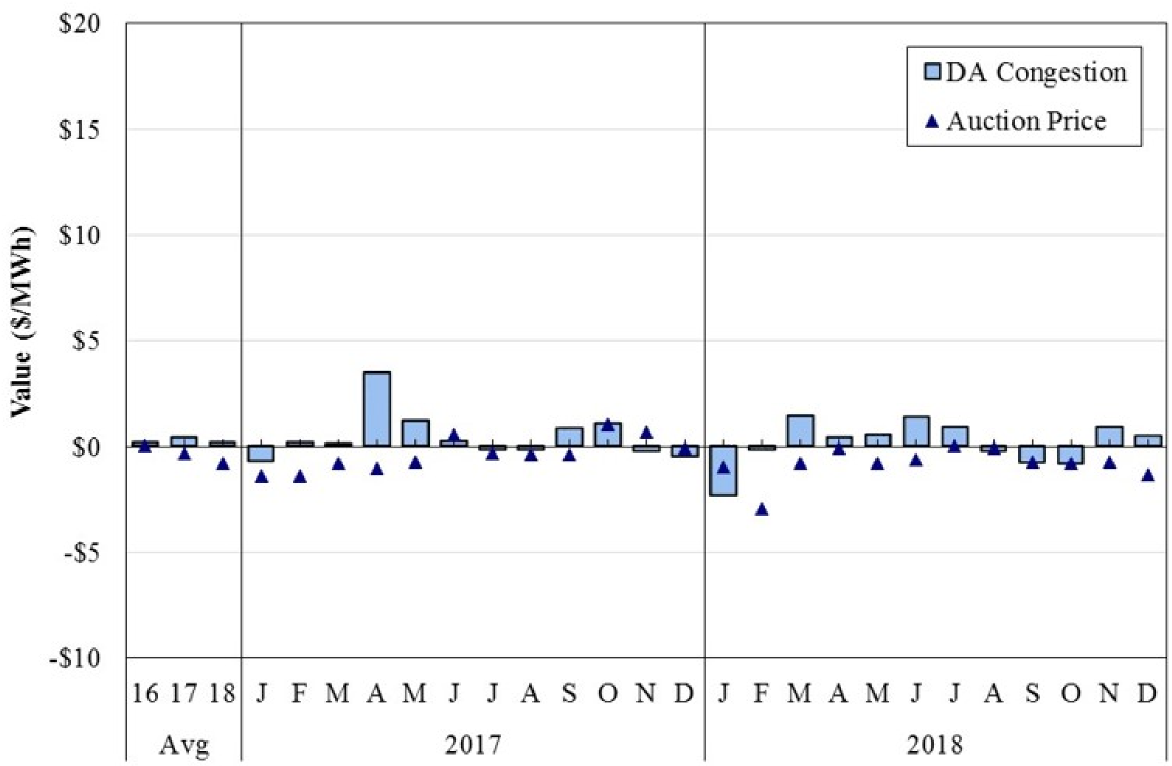


Figure A113: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2017–2018: Peak Hours

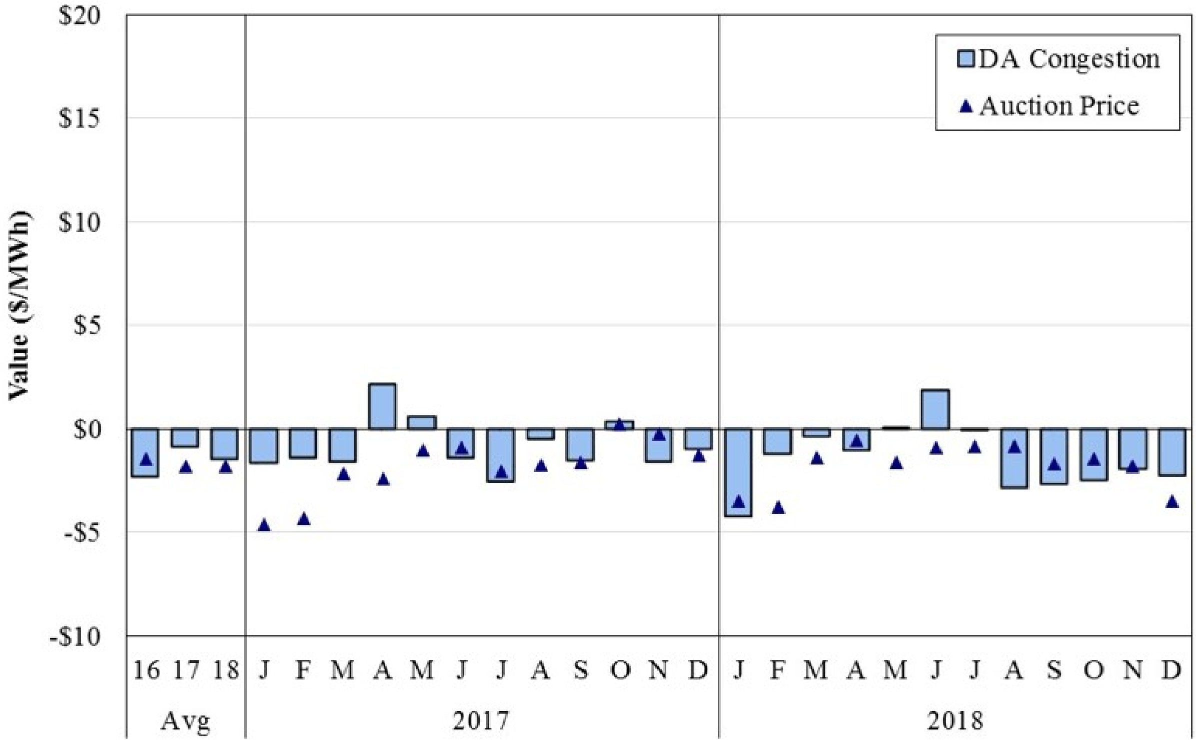


Figure A114: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2017–2018: Off-Peak Hours

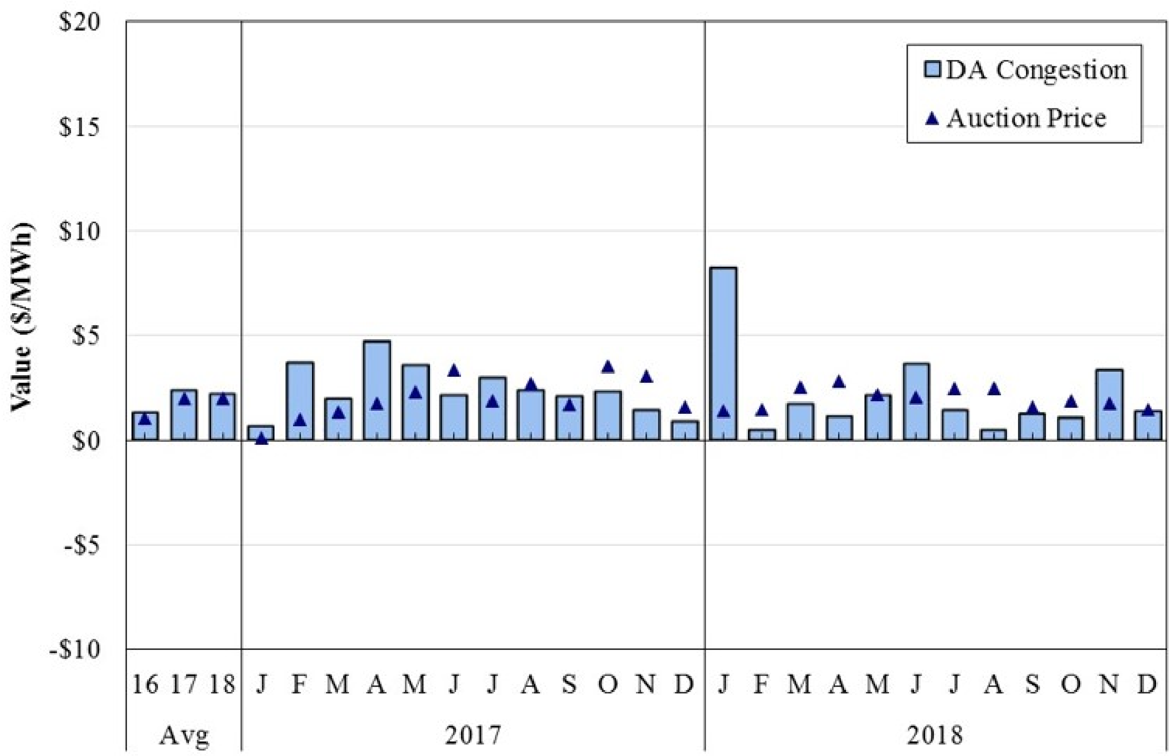


Figure A115: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2017–2018: Peak Hours

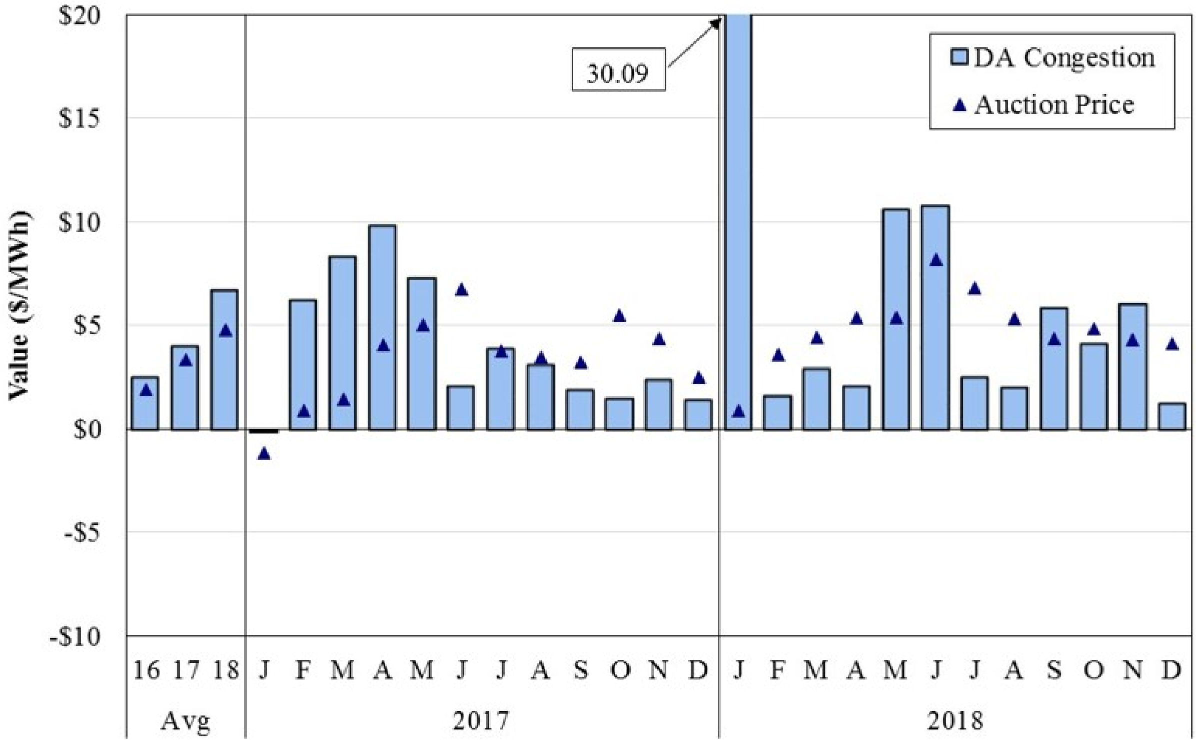


Figure A116: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2017–2018: Off-Peak Hours

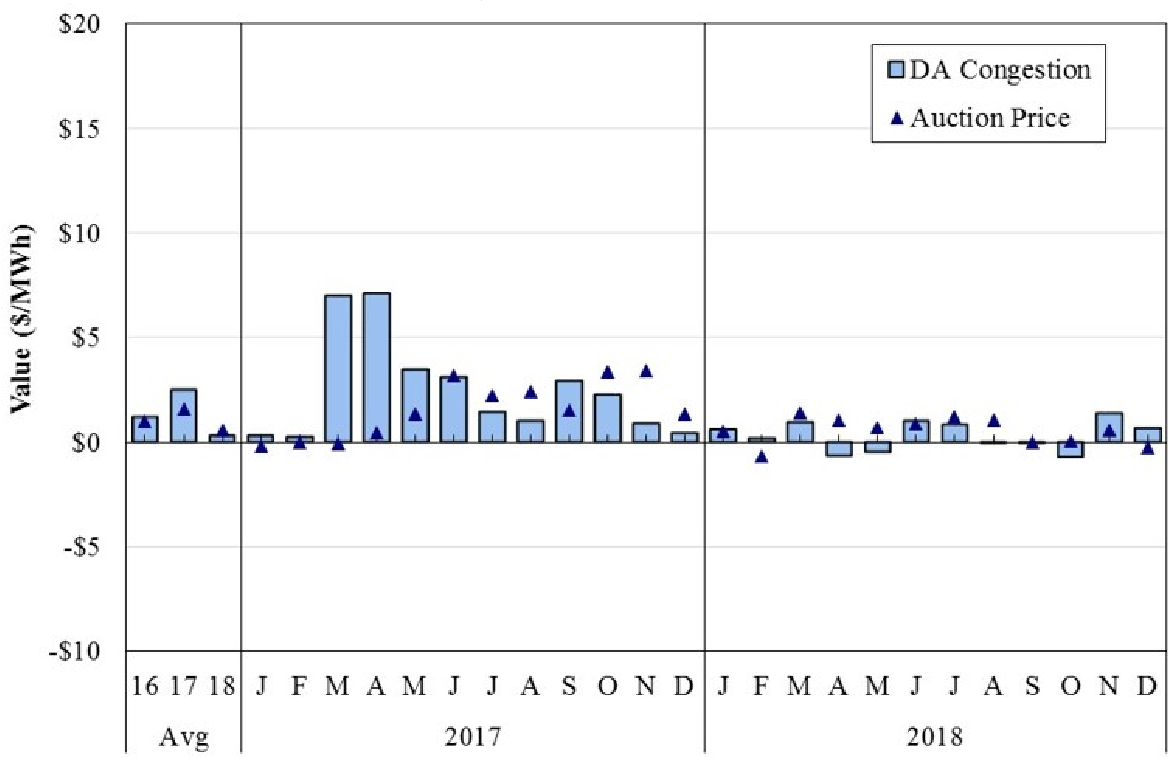
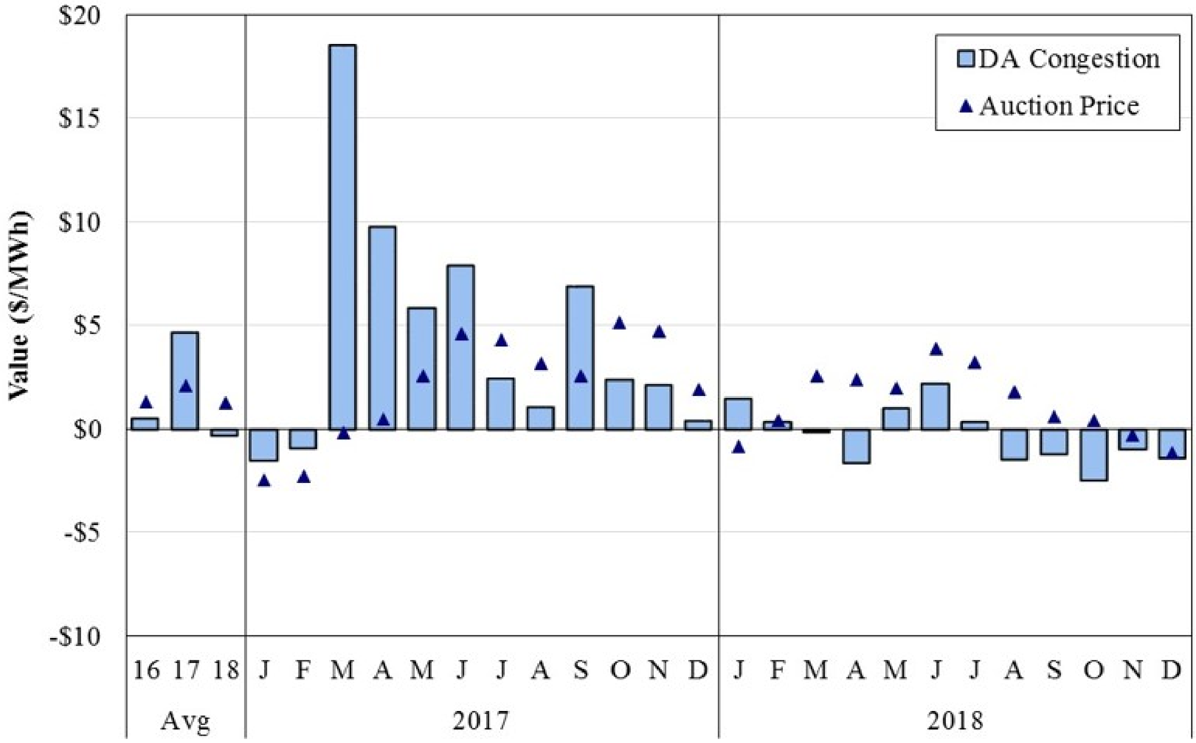


Figure A117: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2017–2018: Peak Hours



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.

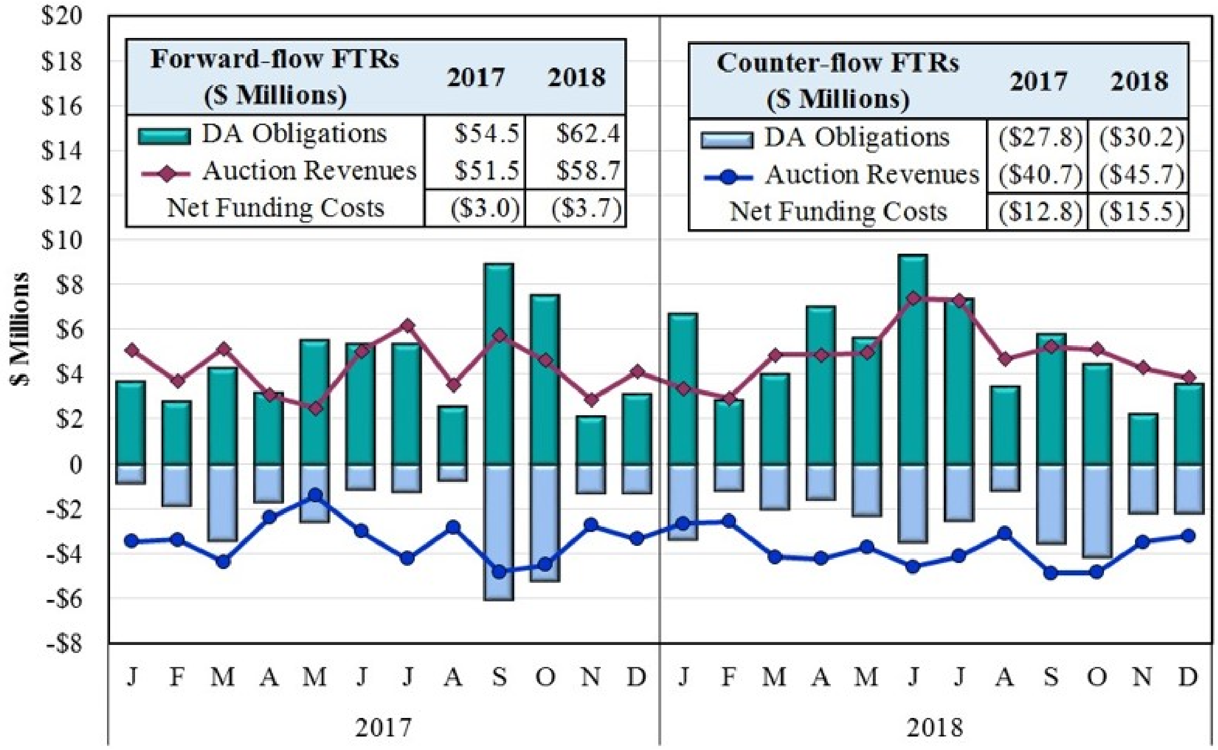
MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative financial residual. Hence, it can sell counter-flow FTRs to the extent that it has sold forward-flow FTRs in the same auction. This limits MISO's ability to resolve feasibility 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 A118: Monthly FTR Auction Revenues and Obligations

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A118 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 A118: Monthly FTR Auction Revenues and Obligations
2017–2018



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

The JOAs between MISO and both PJM and SPP establish M2M processes for coordinating congestion management of designated transmission constraints on each of the RTO's systems. The objectives of these processes are to pursue reliable congestion management and efficient generation re-dispatch on these constraints and consistent prices between the markets.[38]

When an M2M constraint is activated, the monitoring RTO (the RTO responsible for the security and monitoring the physical flow on the FG) 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 monitoring RTO'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 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 monitoring RTO's shadow price. From a settlement perspective, each market is allocated FFE on each of the M2M constraints. Settlements between the RTOs are based on their flows over the constraint relative to their FFEs.

38 MISO has separate JOAs with PJM and SPP.

Figure A119 and Figure A120: PJM and SPP Market-to-Market Events

Figure A119 and Figure A120 shows 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 A119: Market-to-Market Events: MISO and PJM
2017–2018

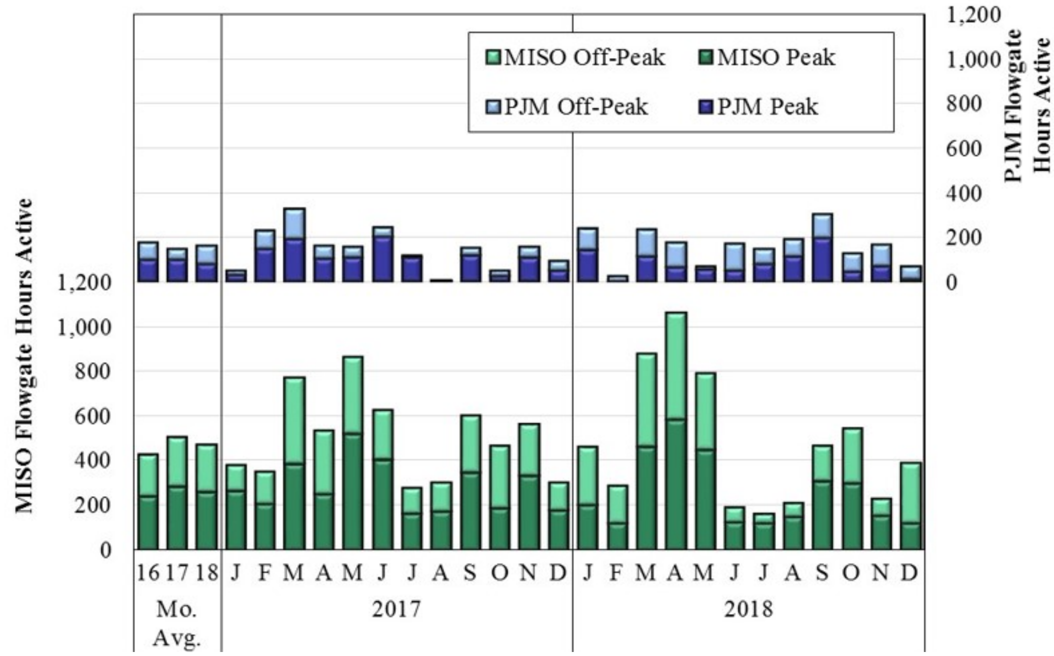


Figure A120: Market-to-Market Events: MISO and SPP
2017–2018

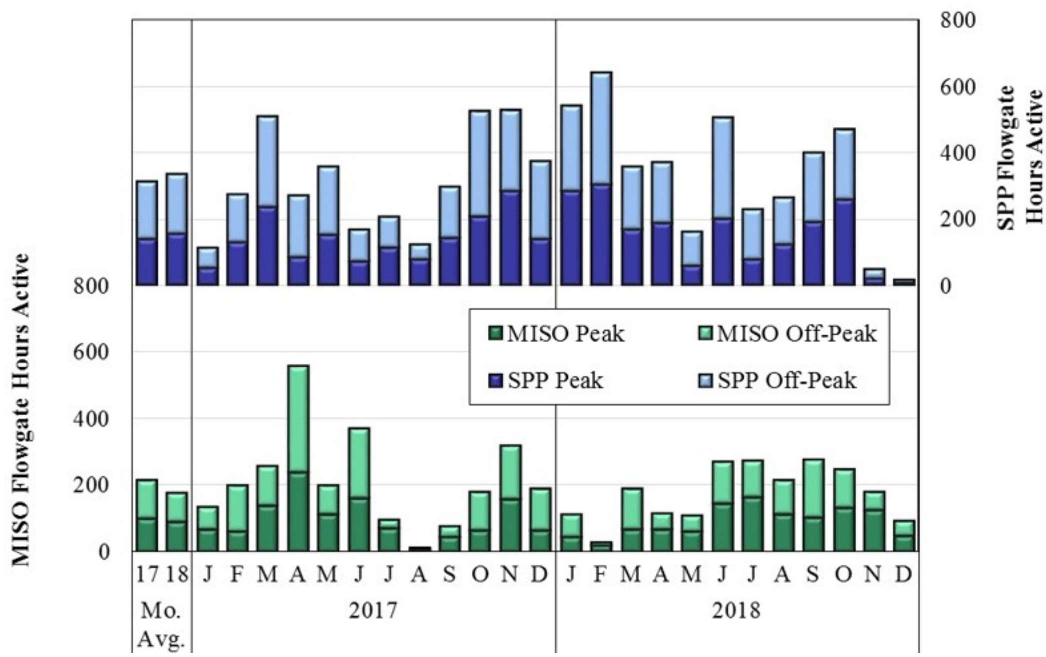


Figure A121: Market-to-Market Settlements

Figure A121 summarizes MISO's financial settlement of M2M coordination with SPP and PJM. Settlement is based on the non-monitoring RTO's actual market flow compared to its FFE. If the non-monitoring RTO's market flow is below its FFE, then it is paid for any unused entitlement at its internal cost of providing relief. Alternatively, if the non-monitoring RTO's flow exceeds its FFE, then it owes the cost of the monitoring RTO's congestion for each MW of excess flow. 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.

Figure A121: Market-to-Market Settlements
2017–2018

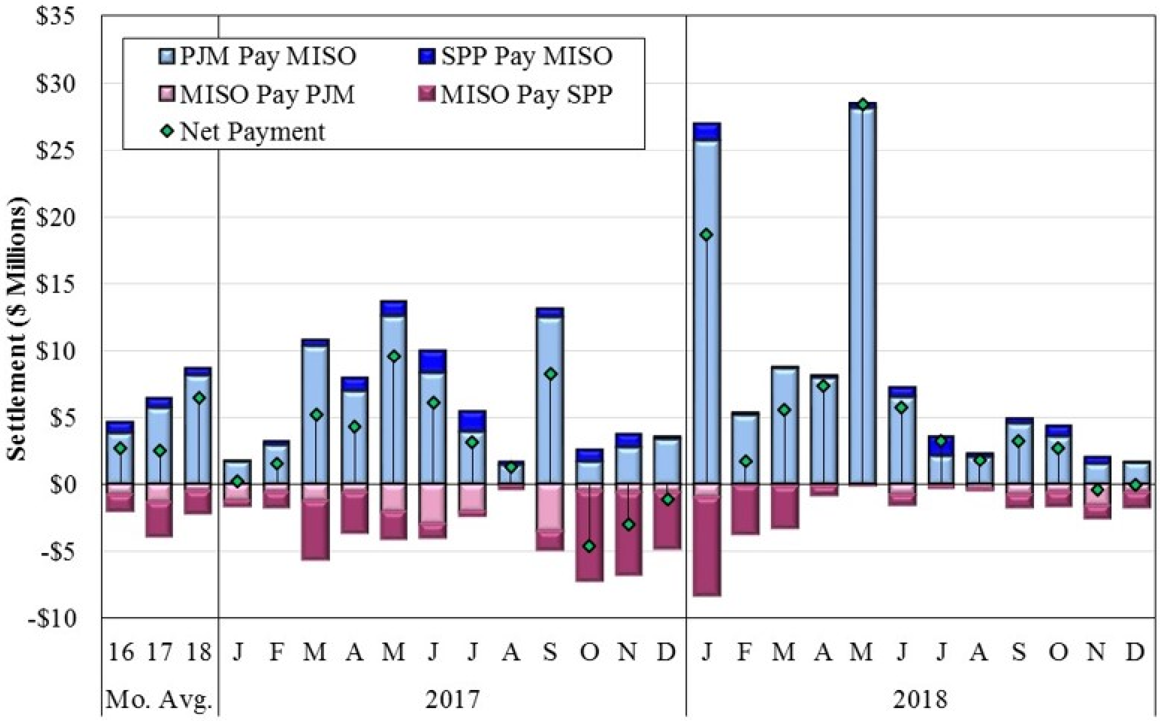


Table A12: Evaluation of the Market-to-Market Coordination

We evaluate the effectiveness of the market-to-market process by tracking the convergence of the shadow prices of market-to-market constraints in each market. When the process is working well, the non-monitoring RTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the monitoring RTO's relief. Our analysis shows that for the most frequently binding market-to-market constraints, the market-to-market process generally contributes to shadow price convergence over time and substantially lowers the monitoring RTO's shadow price after the market-to-market 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 market-to-market 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 market-to-market constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as market-to-market; and
- Delays in activating market-to-market constraints for coordination after they have been classified as market-to-market.

These issues can result in a failure to coordinate M2M congestion, causing inefficient dispatch and generating inappropriately high congestion costs. Serious equity concerns can also arise if the external area exceeds its flow entitlement on the constraint without compensating the monitoring RTO. We developed a series of screens to identify constraints that should have been coordinated but were not because of these issues. These screens identified 36 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. We then quantified the congestion on these constraints, which is shown in Table A12.

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

- *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 not been previously identified as 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.

Table A12: Evaluation of the Market-to-Market Coordination
2017–2018

Item Description	PJM ($ Millions)	SPP ($ Millions)	Total ($ Millions)
Never classified as M2M	$5	$15	$21
M2M Testing Delay	$22	$8	$29
M2M Activation Delay	$11	$7	$18
Total	$38	$30	$68

Figure A122 and Figure A123: Market-to-Market Outcomes with PJM

Successful M2M coordination should lead to two outcomes: a) the RTOs' shadow prices should converge after activation of a coordinated constraint; and b) the shadow prices should decrease from the initial value as the two RTOs jointly manage the constraint. The next two figures show five frequently-active M2M constraints coordinated by PJM and MISO, respectively. The analysis shows the extent to which the RTOs' shadow prices on these constraints converge. We calculate the average shadow prices and relief requested during M2M events, including:

1. An initial shadow price representing the average shadow price of the monitoring RTO that was logged prior to the first response from the reciprocating RTO; and
2. Post-activation shadow prices for both the monitoring and reciprocating RTOs, which are the average prices in each RTO after the requested relief was provided.

The share of active constraint periods that were coordinated is shown below the x-axis. When coordinating, the reciprocating RTO provides relief by limiting flows in its real-time dispatch.

Figure A122: PJM Market-to-Market Constraints in 2018

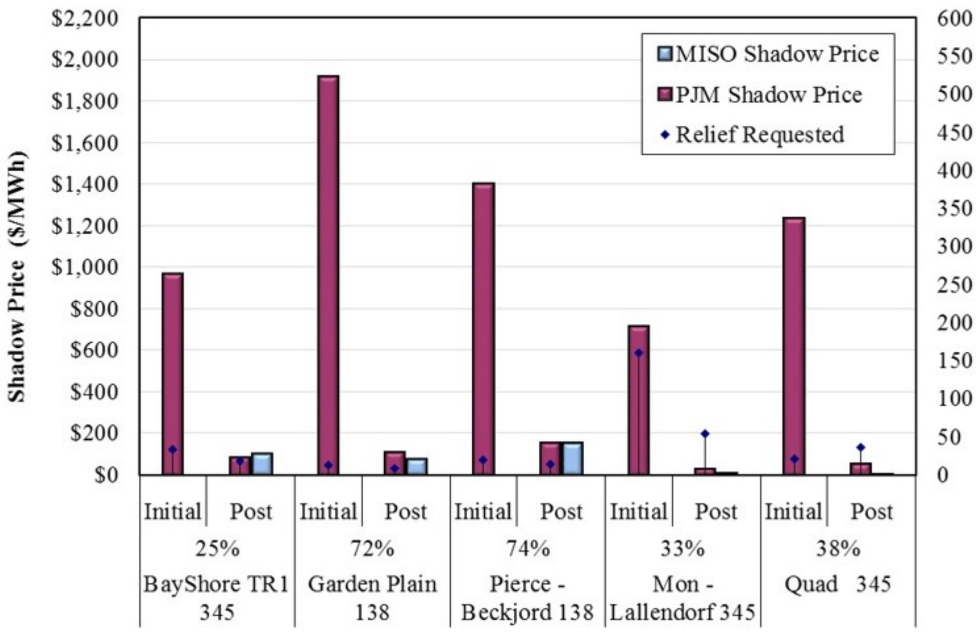


Figure A123: MISO Market-to-Market Constraints with PJM in 2018

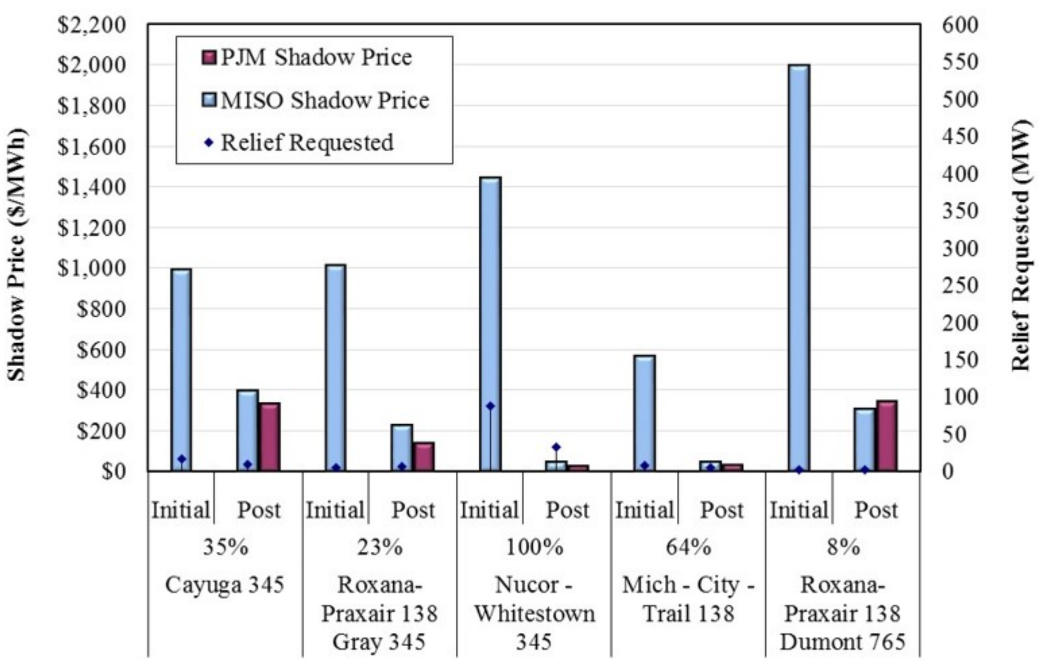


Figure A124 and Figure A125: Market-to-Market Outcomes with SPP

On March 1, 2015, MISO implemented M2M coordination with SPP and began coordinating with SPP in the WAPA Basin region after October 2015. Early issues arose, and MISO is working with SPP to develop procedures to address these issues. These procedures involve transferring control of M2M constraints to the neighboring RTO if the neighboring RTO has the most effective relief for the constraint. In late June 2017, MISO and SPP executed a Memorandum of Understanding (MOU), and the RTOs reached agreement on the most important aspects of coordination under the JOA. The MOU should help the RTOs avoid future issues similar to those that occurred in 2015.

The next two figures examine five frequently coordinated M2M constraints between SPP and MISO, respectively. As with the prior two figures, the analysis is intended to show the extent to which shadow prices on coordinated constraints converge between the two RTOs. The figures show the same results for the constraints coordinated with SPP as the prior two figures showed for the constraints coordinated with PJM.

Figure A124: SPP Market-to-Market Constraints
2018

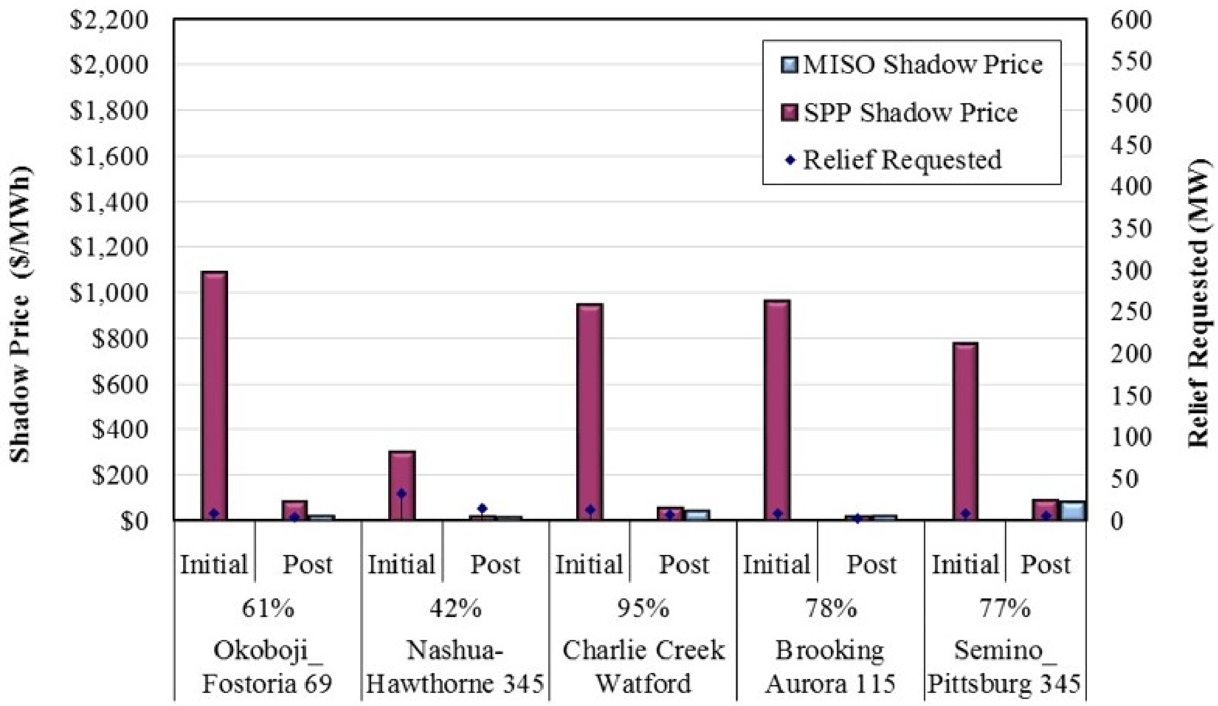


Figure A125: MISO Market-to-Market Constraints with SPP
2018

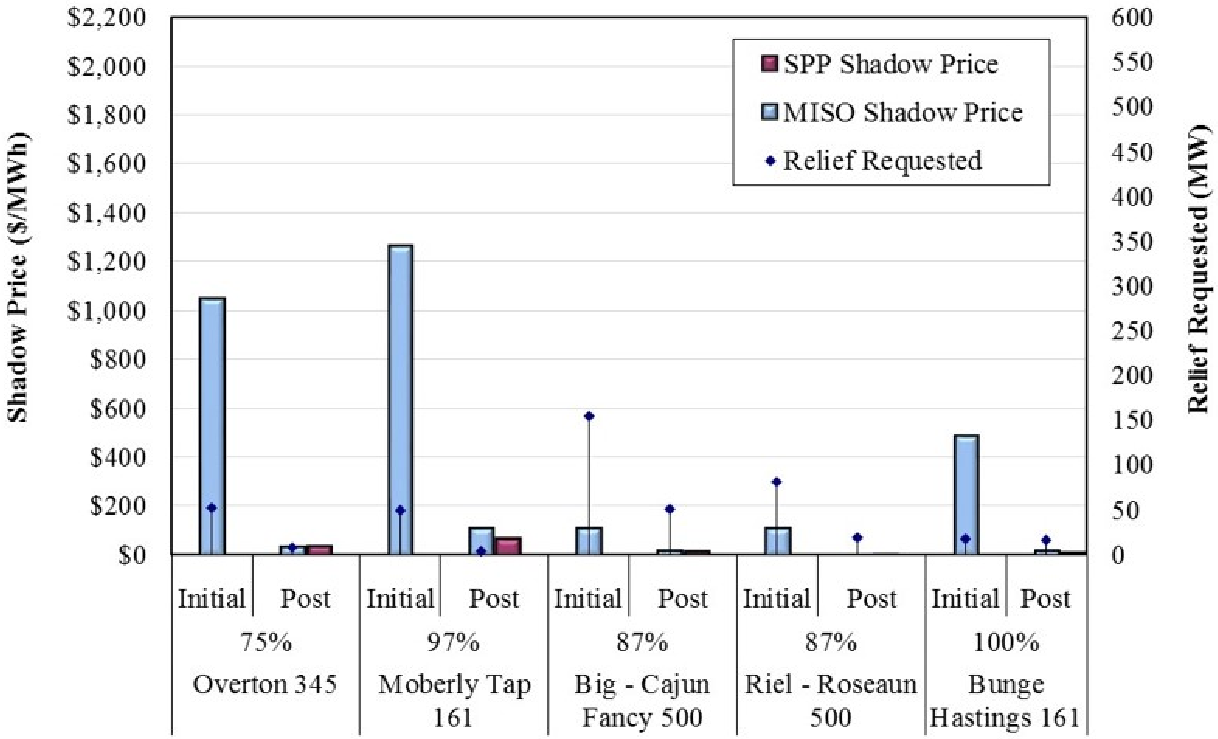
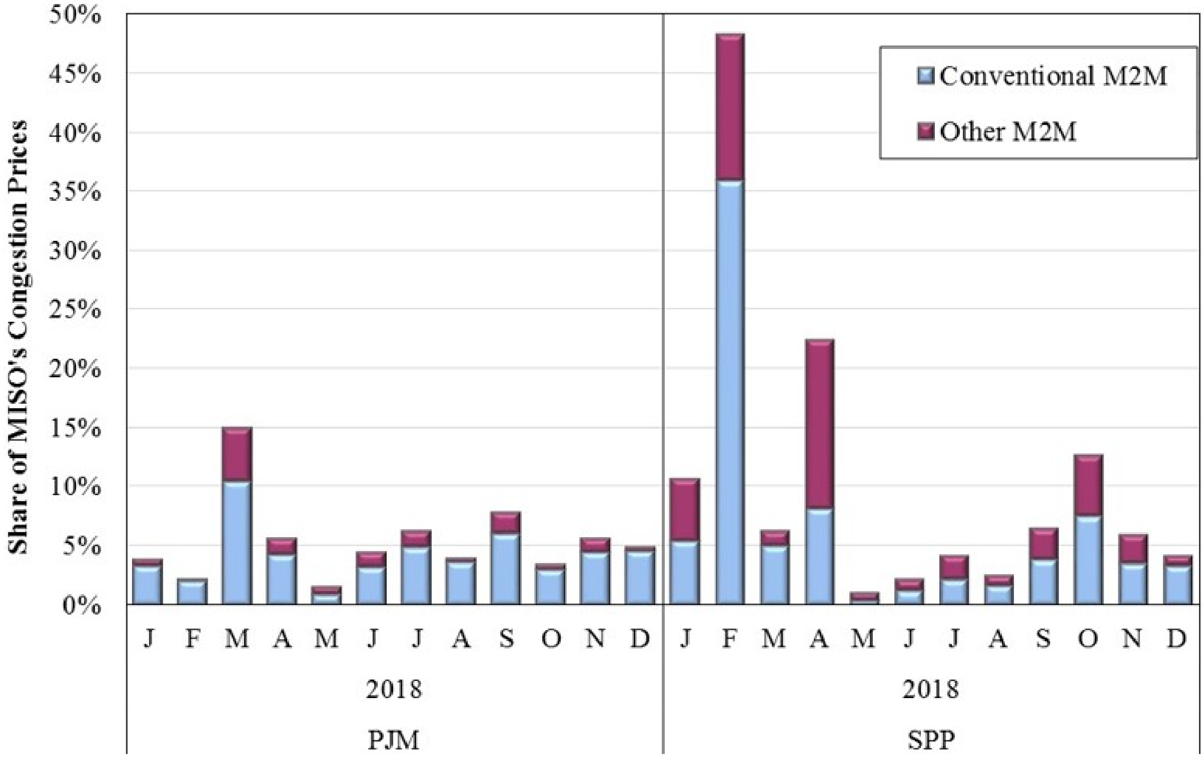


Figure A126: Congestion Costs on PJM and SPP Flowgates

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 A126 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 A126: Congestion Costs on PJM and SPP Flowgates
2018



K. Effects of Pseudo-Tying MISO Generators

In recent years, increasing quantities of MISO capacity have been exported to PJM. PJM implemented rules that require external capacity to be pseudo-tied to PJM, which started to impact the MISO markets in 2016. Beginning in 2015 and continuing into 2018, we have been raising serious concerns about this trend because allowing PJM to dispatch many MISO generators will:

- Cause forward flows over many MISO transmission facilities that are difficult to manage; and
- Transfer control of generators that relieve other MISO constraints so that MISO will no longer have access to them to manage congestion on these constraints.

The first issue can be partially addressed to the extent that these constraints will be defined as market-to-market constraints and, therefore, coordinated with PJM. However, this coordination is not as effective as dispatch control, and many constraints will not be coordinated.

Figure A127: Effects of Pseudo-Tying MISO Resources to PJM

Figure A127 shows our evaluation of the effects of pseudo-tying generators to PJM. This shows the value of real-time congestion on constraints that qualified as new market-to-market constraints only because of the resources that are pseudo-tied to PJM. The purpose of this analysis was to determine whether the pseudo ties are leading to less efficient congestion management and higher resulting congestion costs. The left side of the figure shows the monthly congestion on these constraints for the year that preceded the initiation of the first tranche of pseudo-ties on March 1, 2016. The second tranche of pseudo-ties began on June 1, 2016. The red shading to the right shows the real-time congestion value on the same constraints in those months that these pseudo-ties were in place. The inset indicates the average congestion on the constraints per month prior to the pseudo-ties and the average congestion on the same constraint.

Figure A127: Effects of Pseudo-Tying MISO Resources to PJM
2018

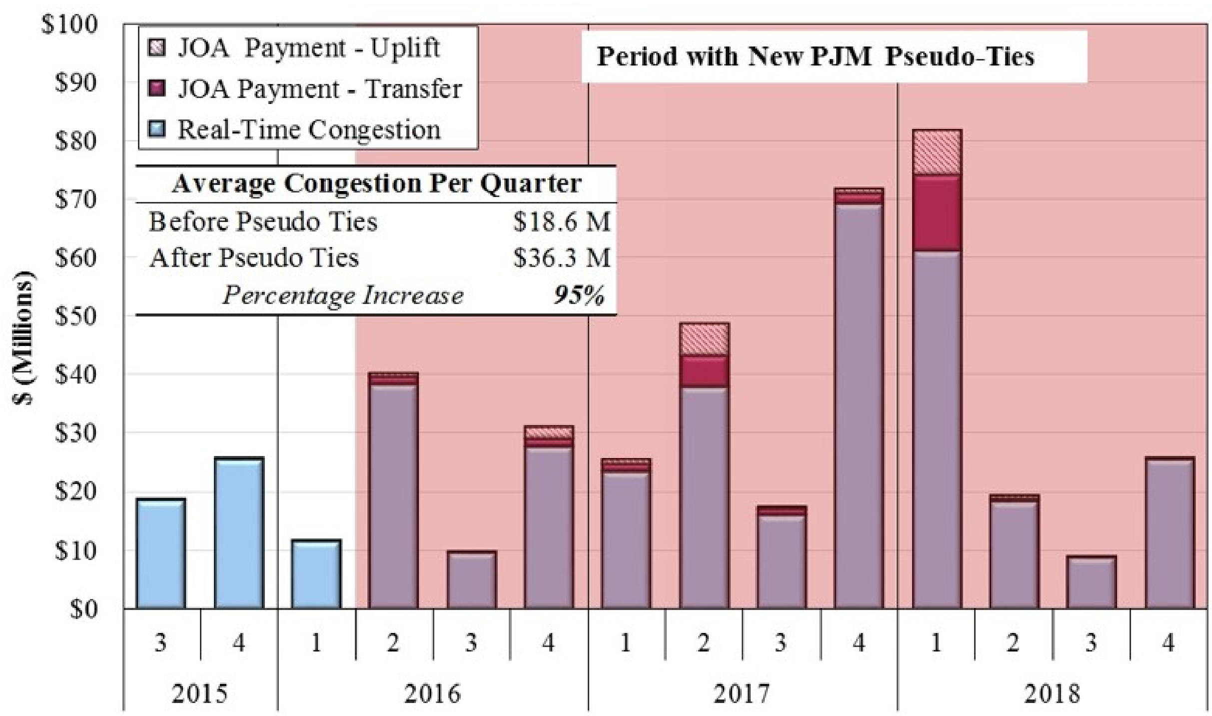


Table A13: Potential Pseudo-Tie Impacts on MISO Constraints

We conducted an analysis to determine how many constraints have been or will need to be defined as M2M constraints solely because resources in MISO have been pseudo-tied to PJM. Pseudo-tied units located on MISO's transmission system are now under the dispatch control of PJM, so the flows they cause on MISO's constraints have become PJM's market flows. The market-to-market process is necessary to manage these flows. Unfortunately, the market-to-market coordination is not nearly as effective as full dispatch control, and many of the constraints remain non-market-to-market constraints.

In Table A13, we identified a number of new M2M constraints that resulted from the March 2016 and June 2016 pseudo ties. The middle column of the table shows the annual number of binding constraints that bound between 2016 and 2018 that qualified as M2M because of pseudo-tied resources and that first qualified to be M2M constraints as a result of the pseudo ties.. The right column indicates the value of the real-time congestion on those constraints since they were classified as M2M constraints.

Table A13: Potential Pseudo-Tie Impacts on MISO Constraints in 2016–2018

Year	Number of constraints that became M2M with PJM this year due to Pseudo-tie units *only*	Number of constraints became M2M with PJM previous years due to Pseudo-tie units *only*	Congestion on constraints that became M2M with PJM this year due to Pseudo-tie units *only* ($ Million)	Congestion on constraints became M2M with PJM previous years due to Pseudo-tie units *only* ($ Million)	Total Congestion
2016	9	0	$1.4	$0.0	$1.4
2017	22	9	$2.4	$17.6	$20.0
2018	28	31	$16.1	$9.2	$25.3

L. Congestion on External Constraints

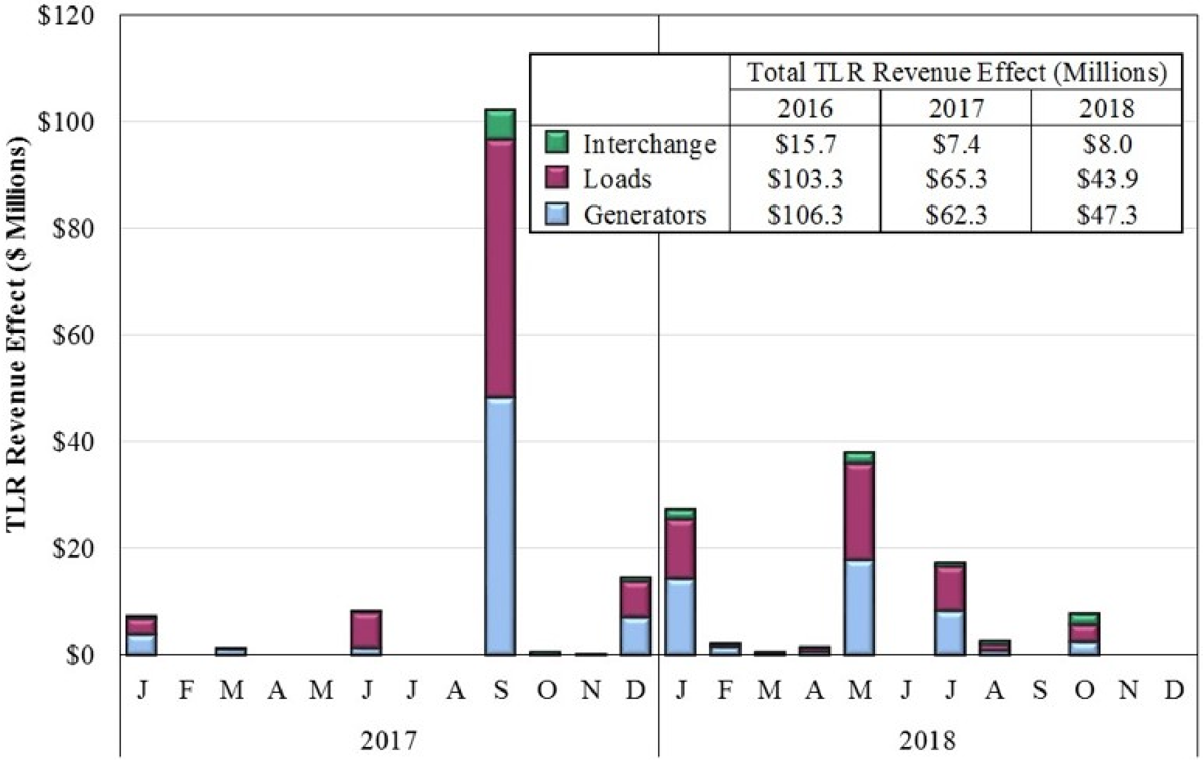
This subsection provides an analysis of congestion that occurs on external constraints located in adjacent systems. MISO incurs congestion on external constraints when a neighboring system calls a TLR for a constraint or initiates M2M coordination. When this occurs, MISO activates the constraint as it 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 due to counterflow on the constraint. Because the relief obligation is 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 A128: 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.[39] Figure A128 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.

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

Figure A128: Real-Time Valuation Effect of TLR Constraints
2016–2018



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 its 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. Import and Export Quantities

Figure A129 to Figure A132: 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. 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 A129: Average Hourly Day-Ahead Net Imports
All Interfaces, 2018

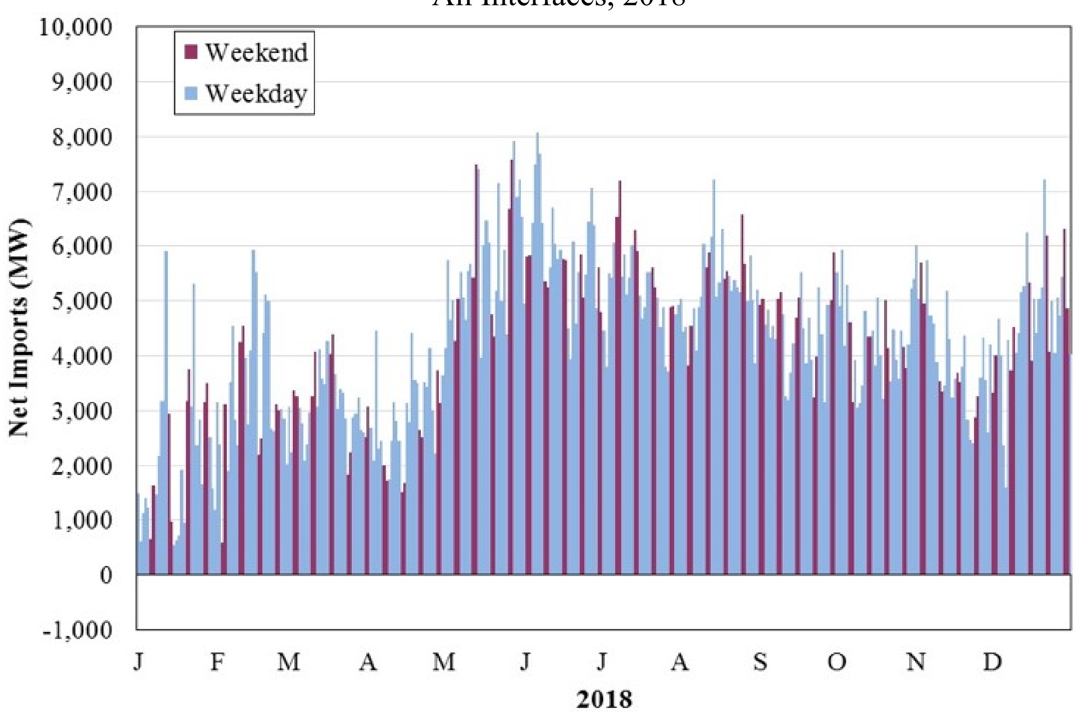


Figure A130: Average Hourly Real-Time Net Imports
2018

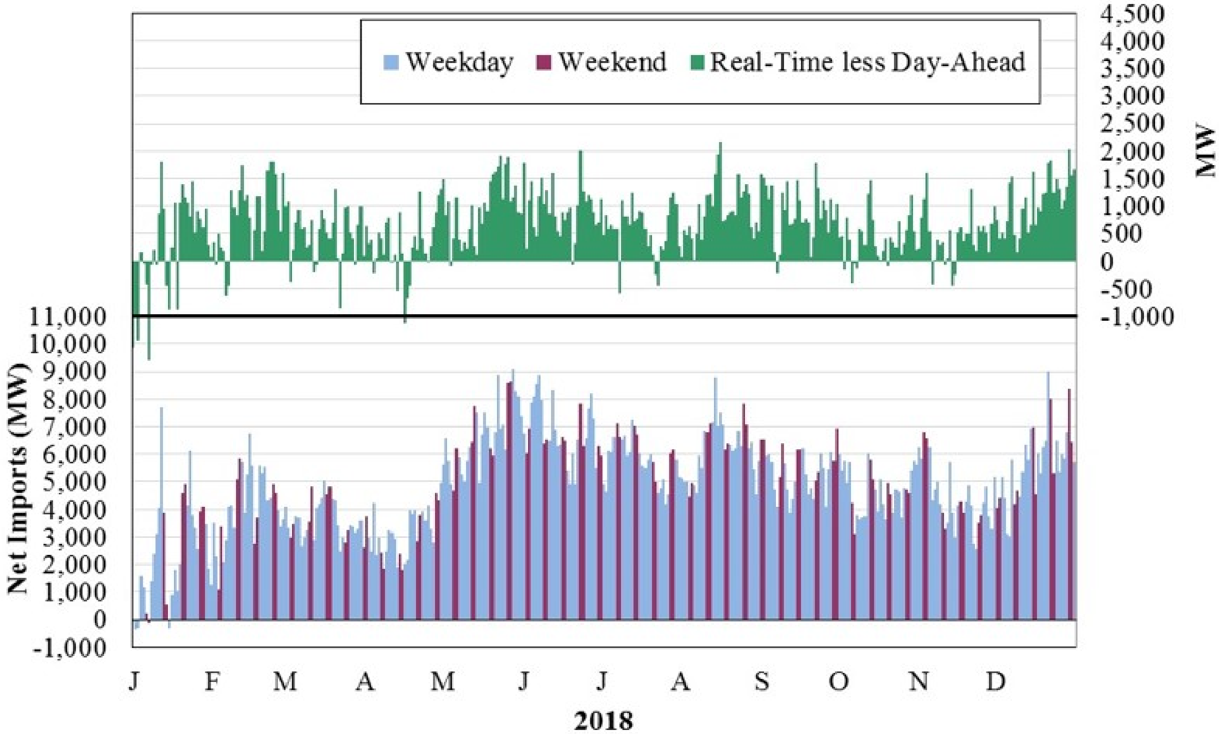


Figure A131: Average Hourly Day-Ahead Net Imports
2018, by Interface

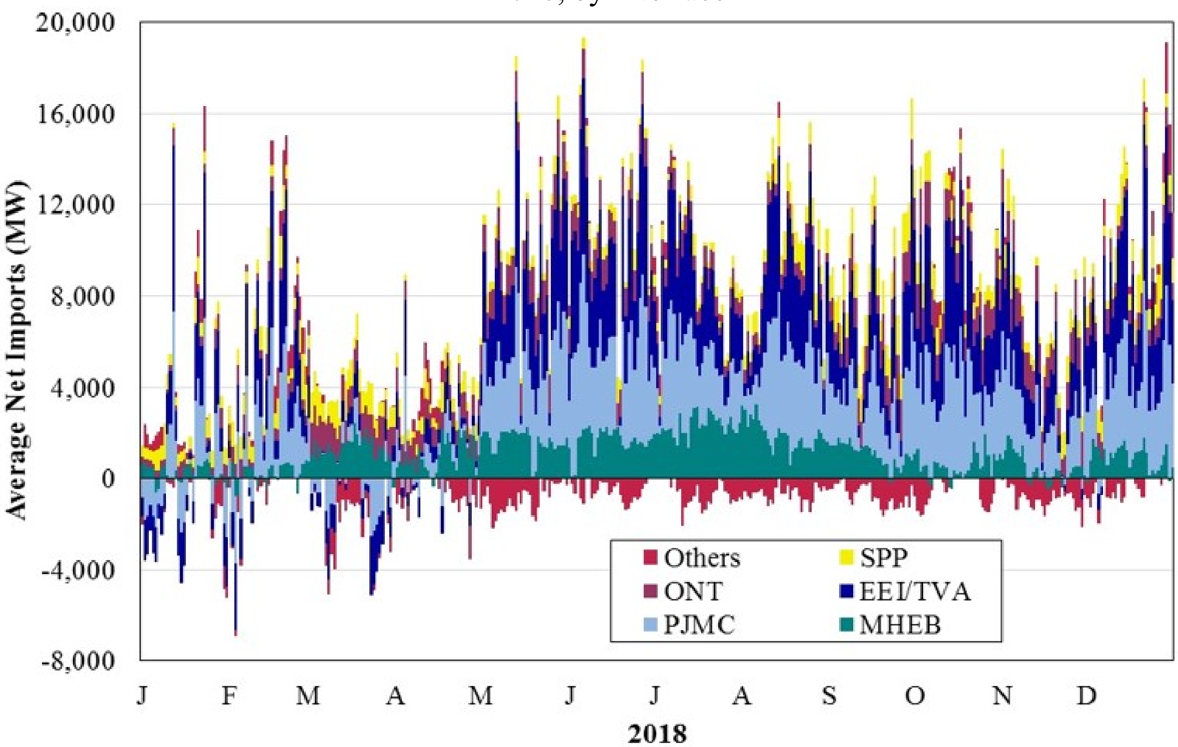


Figure A132: Average Hourly Real-Time Net Imports
2018, by Interface

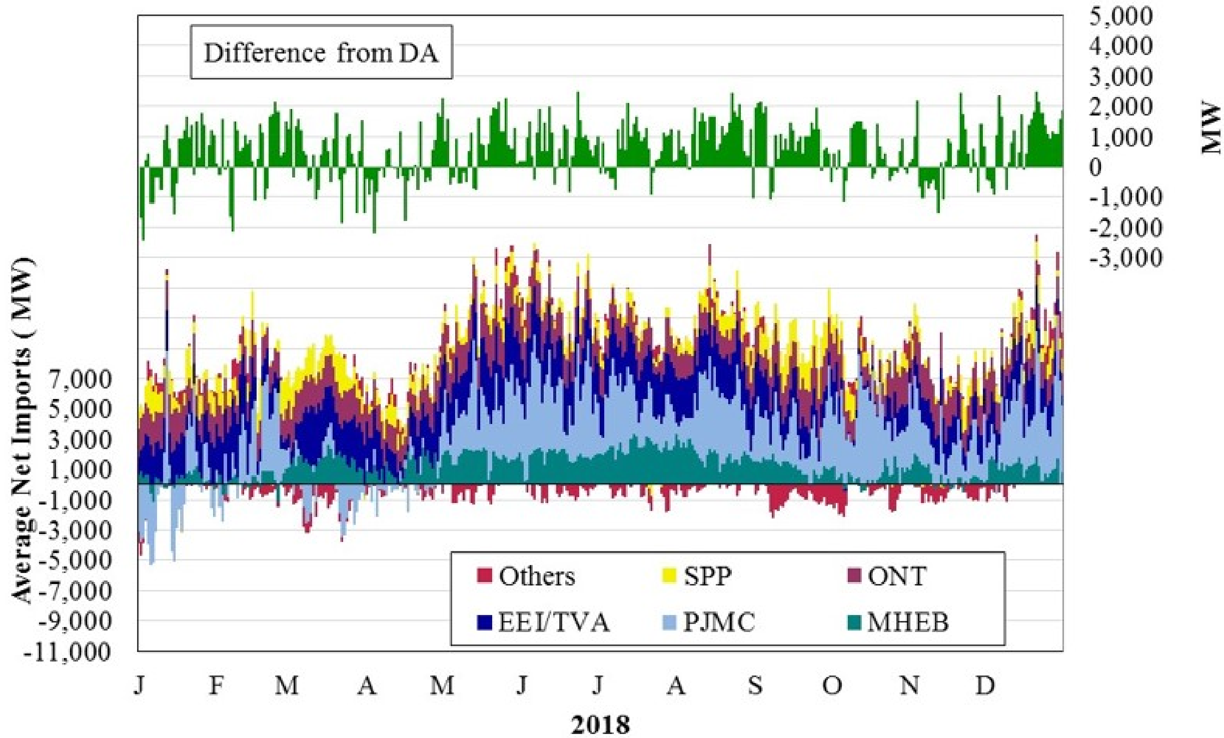


Figure A133 and Figure A134: Average Hourly Real-Time Net Imports by Interface

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 five 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 A133 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2017 and 2018, along with the standard deviation of such imports.[40] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

40 Wheeled transactions, predominantly from Ontario to PJM, are included in the figures.

Figure A133: Average Hourly Real-Time Net Imports from PJM
2017–2018

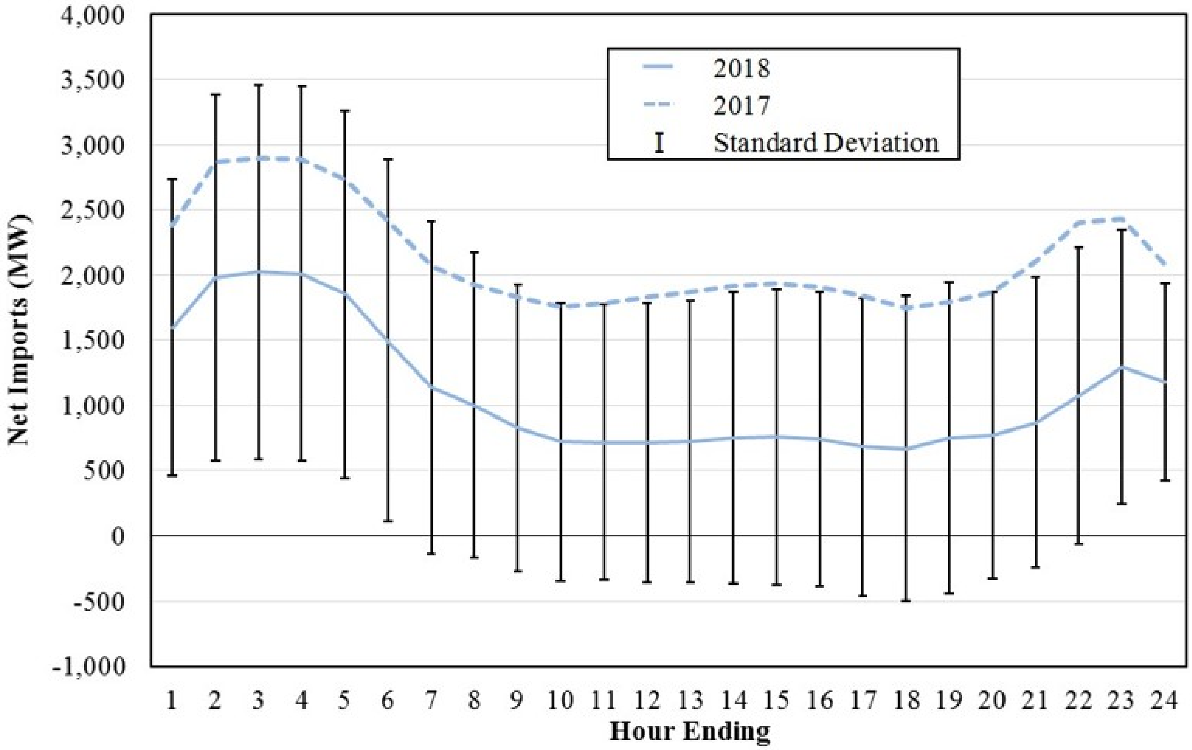
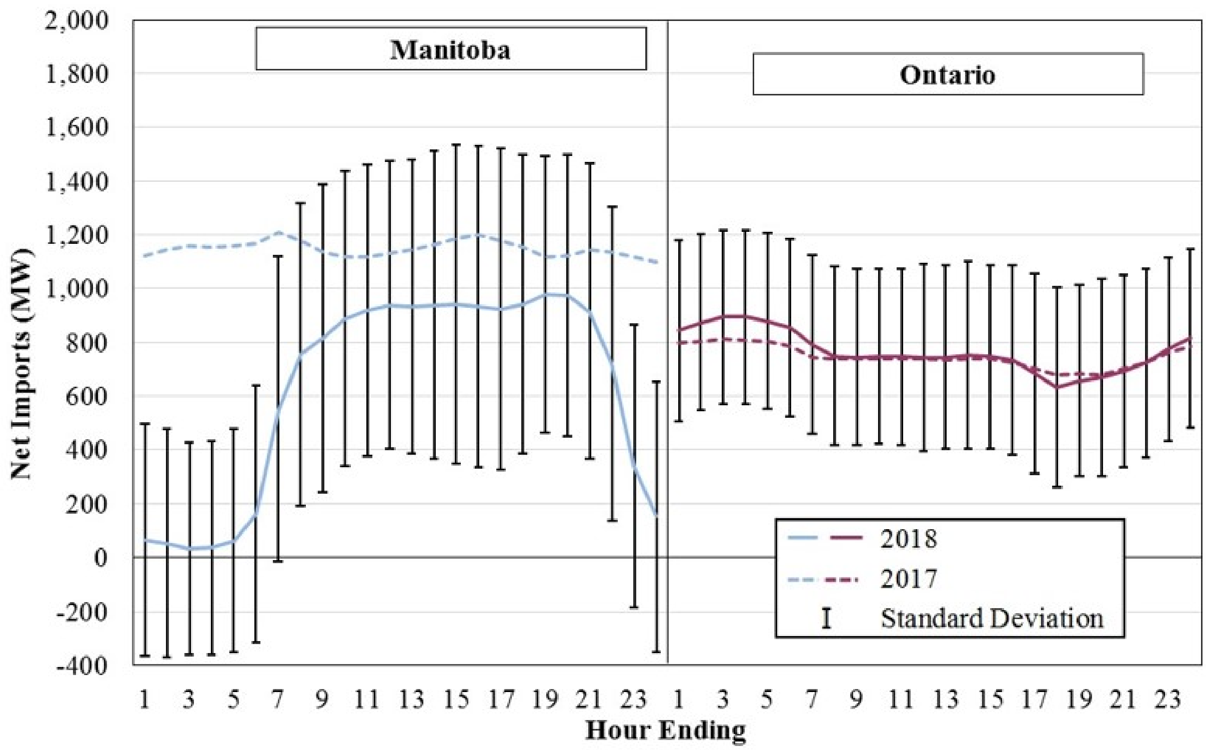


Figure A134: Average Hourly Real-Time Net Imports from Canada
2017–2018



B. 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 schedule between the RTOs to arbitrage the difference between the two interface prices. Interface pricing is essential because:

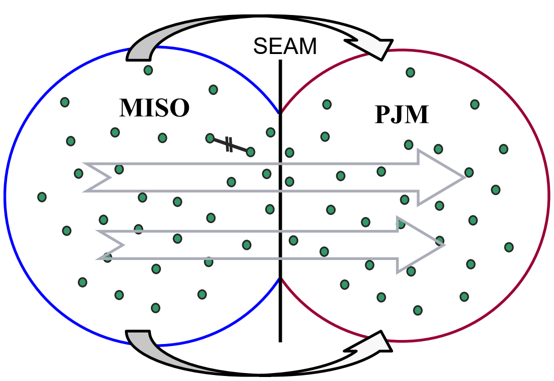
- It is the sole means to facilitate efficient power flows between RTOs;
- It coordinates schedules efficiently and can avoid significant uplift costs and other inefficient outcomes; and
- It is an essential basis for CTS to maximize the utilization of the interface.

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 come into equilibrium (and generation costs are equalized). However, congestion is pervasive, so the fundamental interface pricing challenge is estimating the congestion costs and benefits from cross-border transfers (imports and exports).

Like the locational marginal price 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.

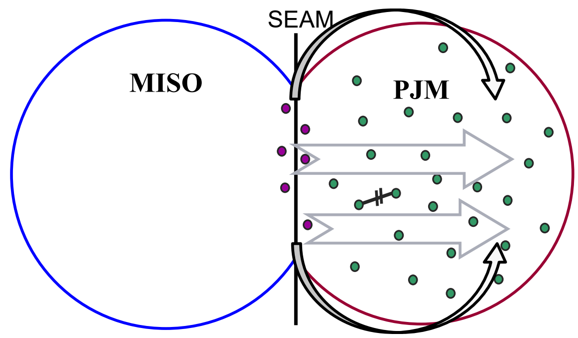
In contrast, the source of an import (or sink for an export) is not known, so it must be assumed in order to calculate the congestion effects. This is known as the "interface definition." If the interface definition reflects where the power is actually coming from (import) or going to (export), the interface price will provide an efficient incentive to transact, and traders' responses to these prices will lower the total costs for both systems.

Interface Pricing with PJM



In reality, when power moves from one area to another other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. Before June 2017, MISO's interface pricing was consistent with this reality, calculating flows for exports to PJM by assuming power is sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.

However, PJM's assumptions are much different. It assumes the power sources and sinks from specific buses at the border with MISO, as shown in the figure to the right. There is no good basis for this assumption and, indeed, it tends to exaggerate the flow effects of imports and exports on any constraint 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 that physically support imports and exports and confirmed that they are distributed throughout MISO, so we remain concerned that PJM's interface definitions on all of its interfaces tend to set inefficient interface prices. MISO agreed to use PJM's interface definition beginning in June 2017, which we evaluate in this report.

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.[41] 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.

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 transaction over its interface with MISO that includes the effect of the transaction on its own constraint. MISO's additional payment is duplicative 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 encourages and compensates additional relief from physical schedulers that benefits the flowgate owner at the expense of MISO.

41 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.

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 VI, this causes the congestion component of the interface prices associated with TLR constraints to be highly distortionary and provides inefficient scheduling incentives. One should expect that it will result in inefficient schedules and higher costs for MISO customers.

C. Summary CTS Usage

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 A135: CTS vs. 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).

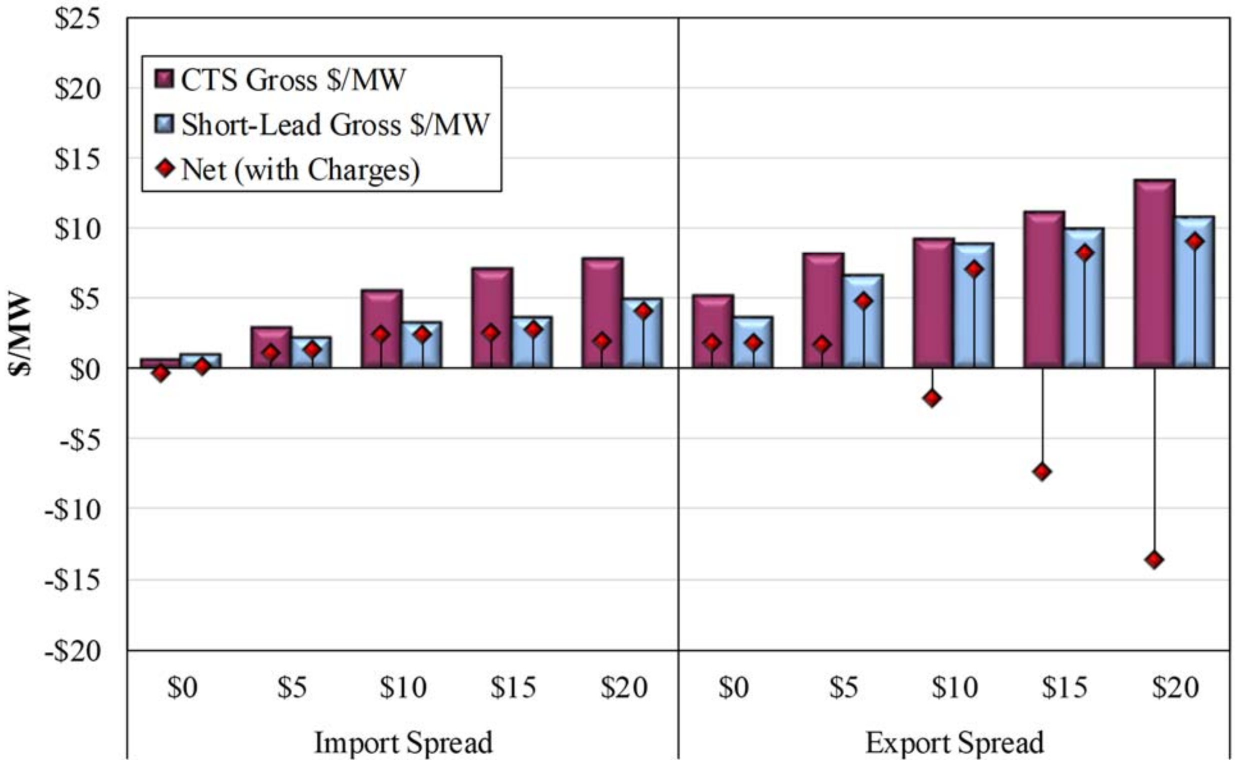
Excluding the charges applied to CTS transactions, the CTS transactions should be more profitable if the mechanism operates effectively because participants are able to submit an offer price. In contrast, the traditional scheduling mechanism requires participants to submit transactions that are not price-sensitive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

We limited the time period of our analysis to October 2, 2017 through June 12, 2018 because a significant forecasting bias was introduced after that time frame that was not resolved until March 2019. The results of our analysis are shown in Figure A135 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 $0.73 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 A135, 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 A135: CTS vs. Traditional NSI Scheduling
October 2017 – June 2018



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 A136 and Figure A137: 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. The first figure shows these results for the MISO-PJM interface; the second figure shows the same for the IESO-MISO interface.

Figure A136: Real-Time Prices and Interface Schedules
PJM and MISO, 2018

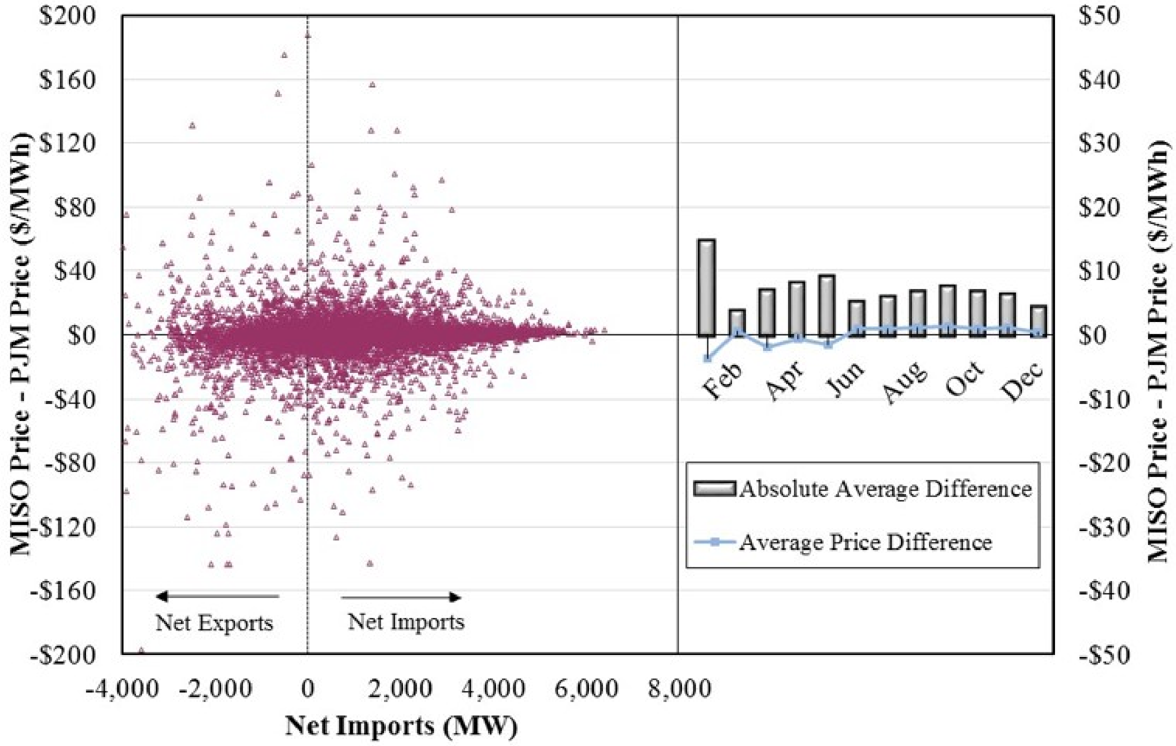
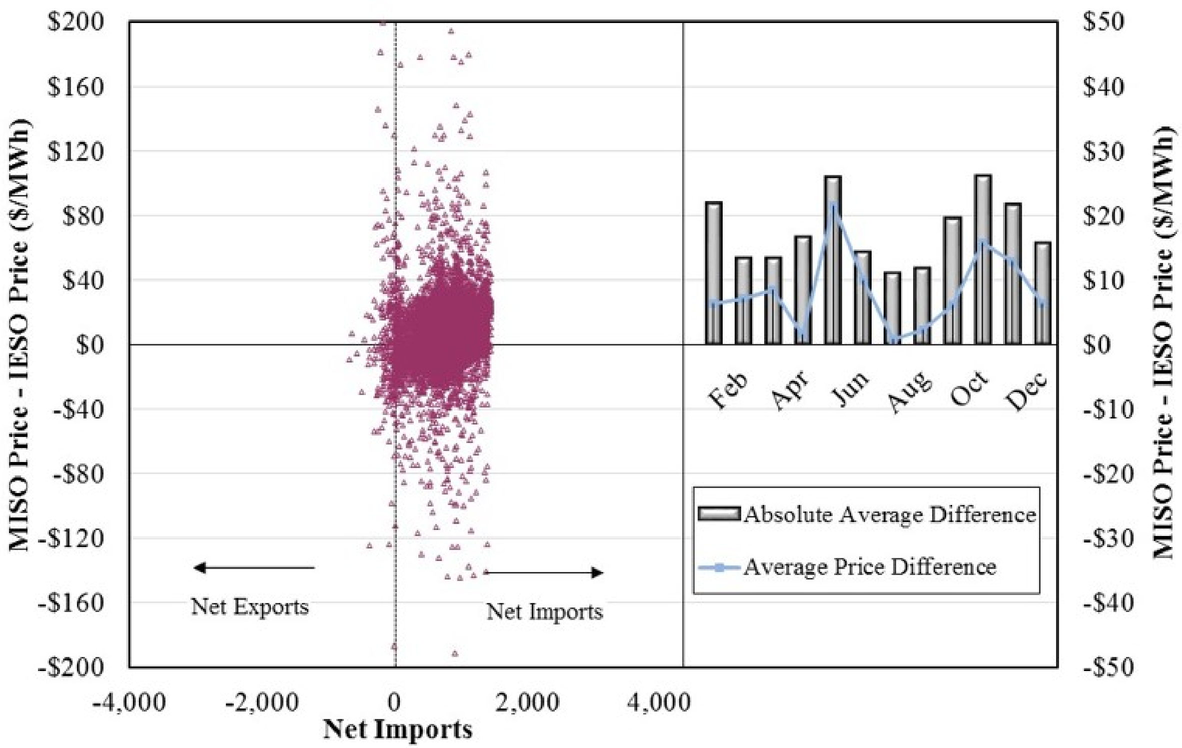


Figure A137: Real-Time Prices and Interface Schedules
IESO and MISO, 2018



VIII. Competitive Assessment

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.

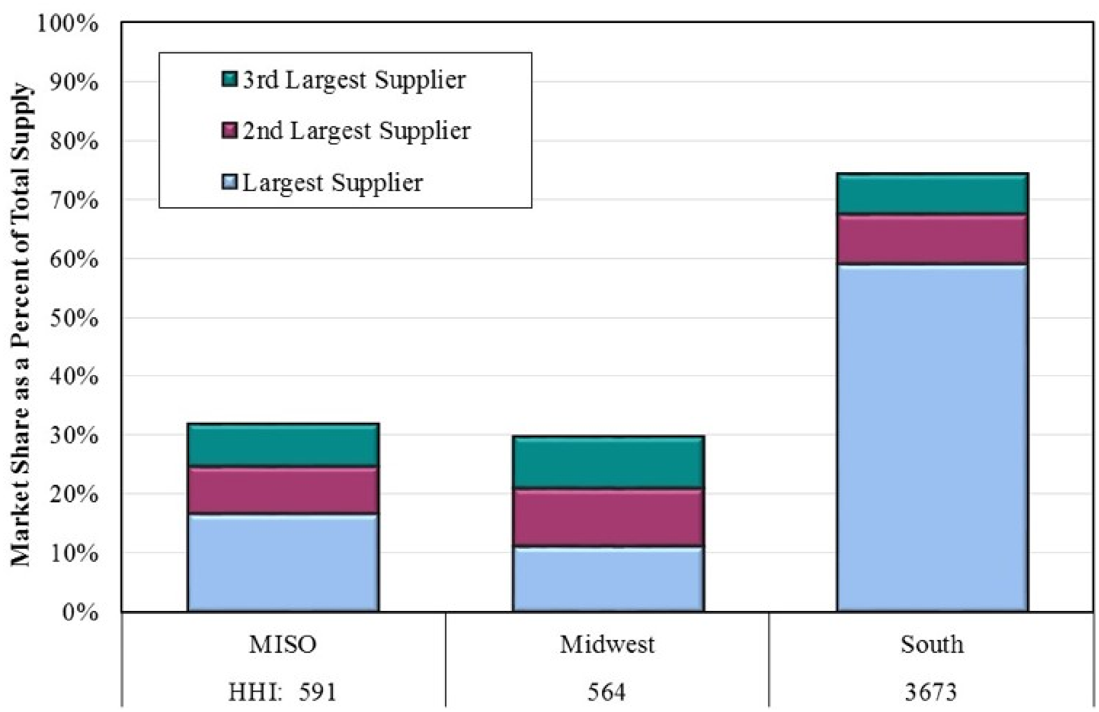
A. Structural Market Power Analyses

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 A138: 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 1200 as unconcentrated and those with an HHI in excess of 2,500 as highly concentrated. Figure A138 shows generating capacity-based market shares and HHIs for MISO and its subregions.

Figure A138: Market Shares and Market Concentration by Region
2018



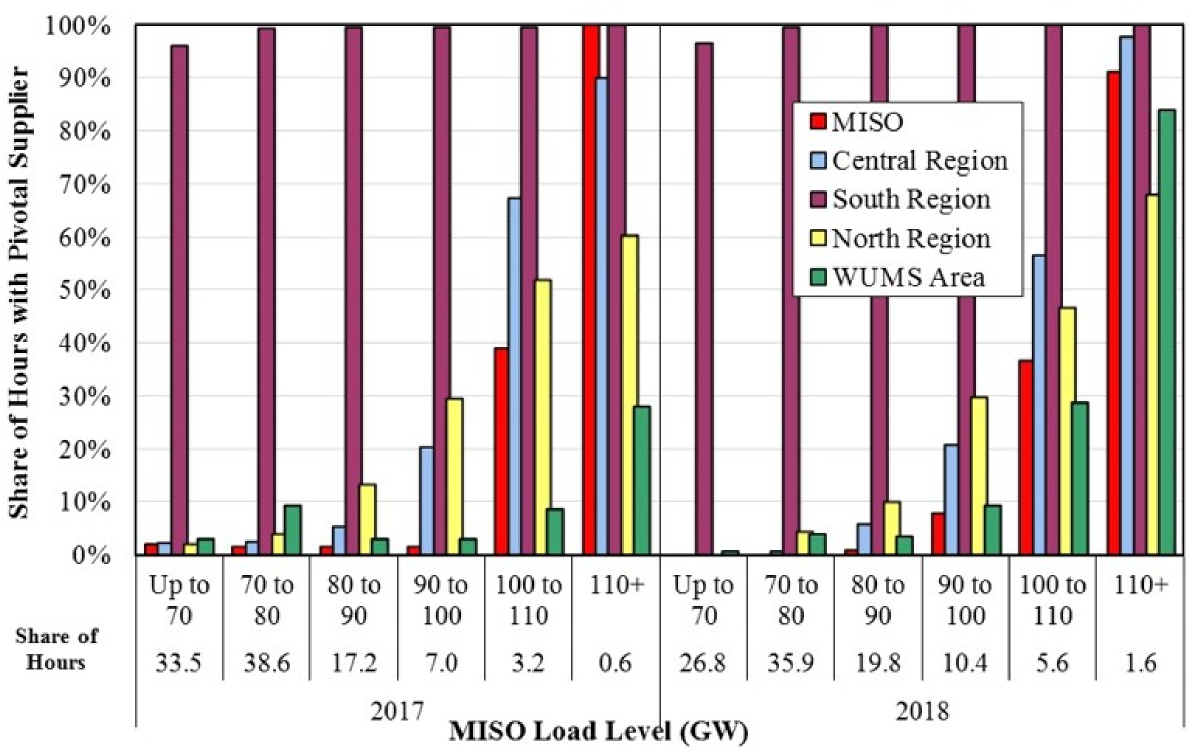
The HHI is only a general indicator of market concentration and not a definitive measure of market power. The HHI's most significant shortcoming for identification of market power in electricity markets is that it generally does not account for demand or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness. Because the HHI does not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, the HHI alone does 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 A139: 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 A139 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 A139: Pivotal Supplier Frequency by Region and Load Level
2017–2018



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 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).[42] 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 the Midwest Region (the Minnesota NCA, the WUMS NCA, and the North WUMS NCA) and two in the South Region (WOTAB and Amite South NCAs).[43]

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 affect 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 A140 to Figure A143: Pivotal Suppliers on Transmission Constraints

The next four figures evaluate potential local market power by showing the frequency with which suppliers are pivotal on individual NCA and BCA constraints. Figure A140 to Figure A143 show, by region, the percentage of all market intervals by month during which at least one supplier was pivotal for each type of constraint. Figure A142 and Figure A143 show the percentage of the intervals with active constraints in each month by region with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs in the Midwest region are combined.

42 Beginning in 2018 FERC approved a new Dynamic Narrow Constrained Area authority.

43 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 most of 2018 ranged from \$19.63 per MWh in North WUMS to \$100.00 per MWh in Amite South. The WUMS, WOTAB, and Minnesota thresholds were \$27.74, \$53.19, and \$61.52 per MWh, respectively.

Figure A140: Percent of Intervals with at Least One Pivotal Supplier
Midwest Region, 2018

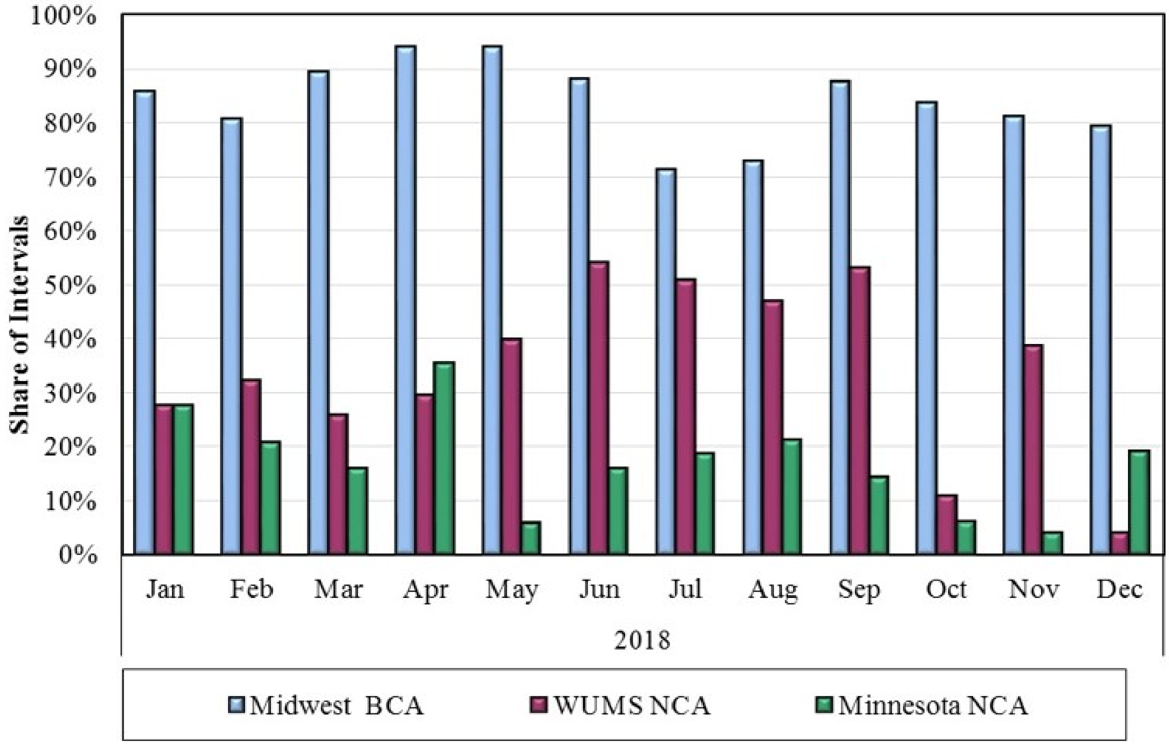


Figure A141: Percent of Intervals with at Least One Pivotal Supplier
South Region, 2018

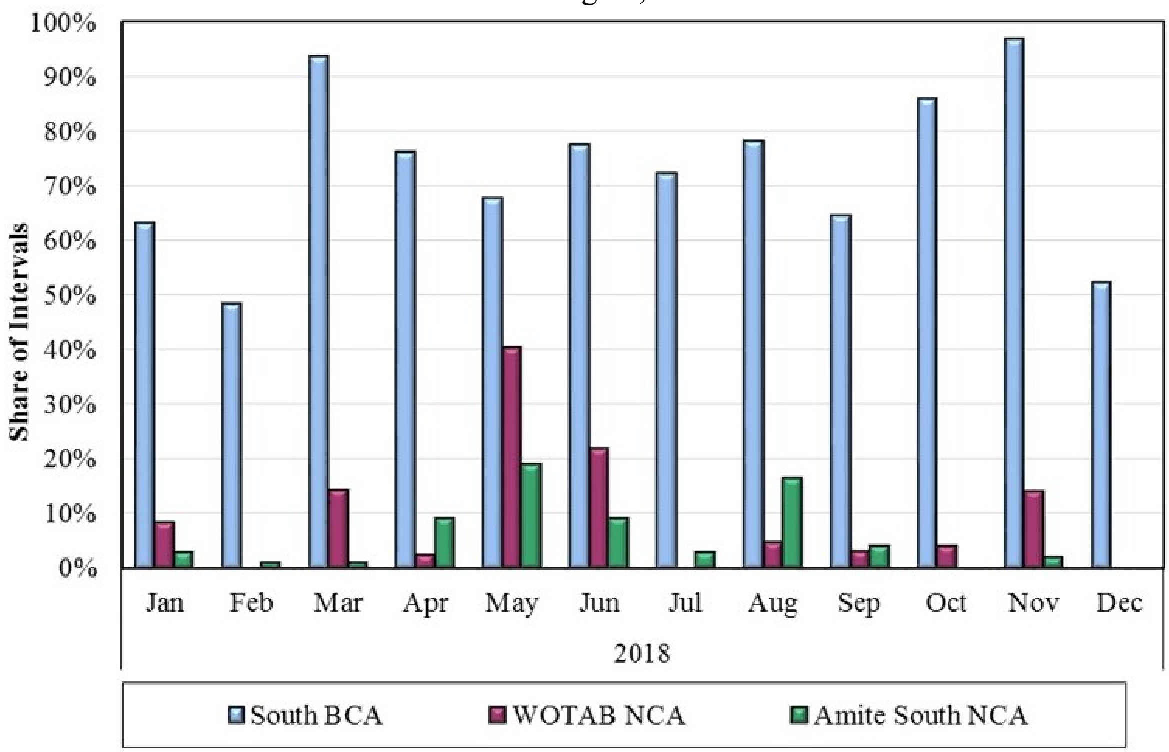


Figure A142: Percentage of Active Constraints with a Pivotal Supplier
Midwest Region, 2018

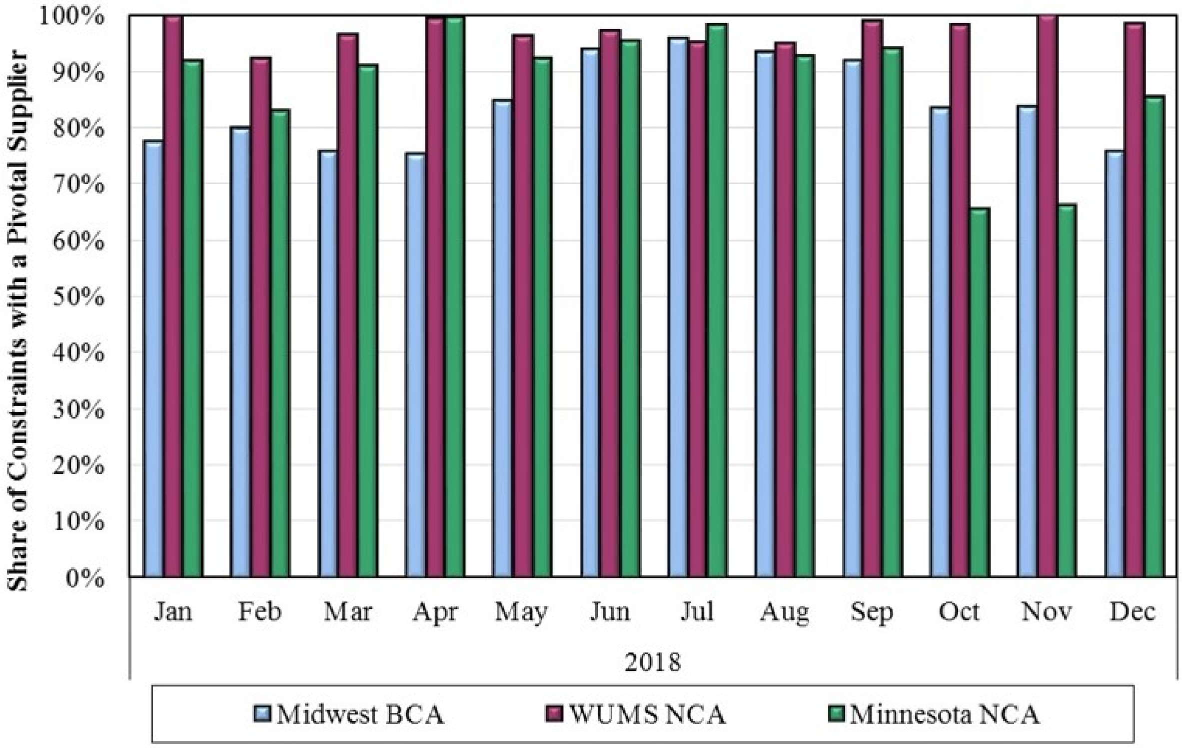
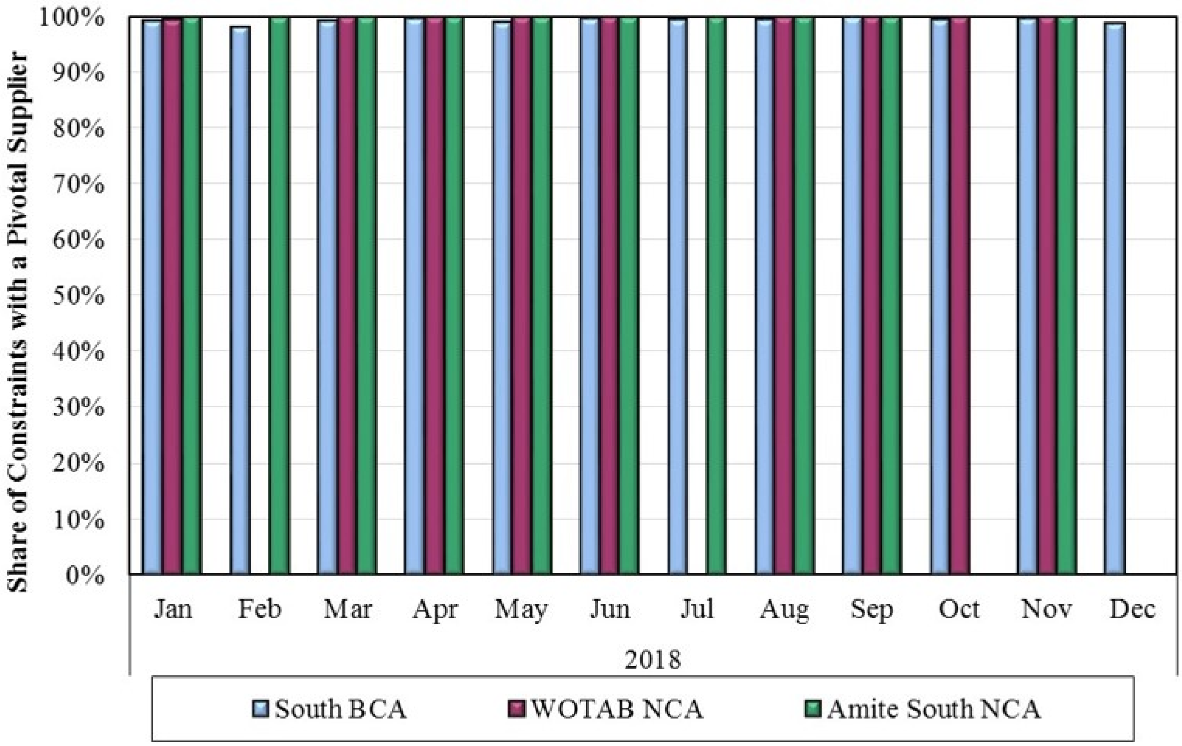


Figure A143: Percentage of Active Constraints with a Pivotal Supplier
South Region, 2018



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: *the average price-cost mark-up for 2018 was approximately zero*. This indicates that MISO markets were highly competitive. Mark-ups of less than three percent lie within the bounds of highly competitive expectations.

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. 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.[44]

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} = Economic level of output for unit i; and
Q_i^{prod} = 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

44 Module D, Section 62.a 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, infeasible energy that is due to ramp limitations is excluded from the output gap.

Figure A144: Economic Withholding -- Output Gap Analysis

Figure A144 shows monthly average output gap levels for the real-time market in 2017 and 2018. The output gap shown in the figure and summarized in the table includes two types of units:

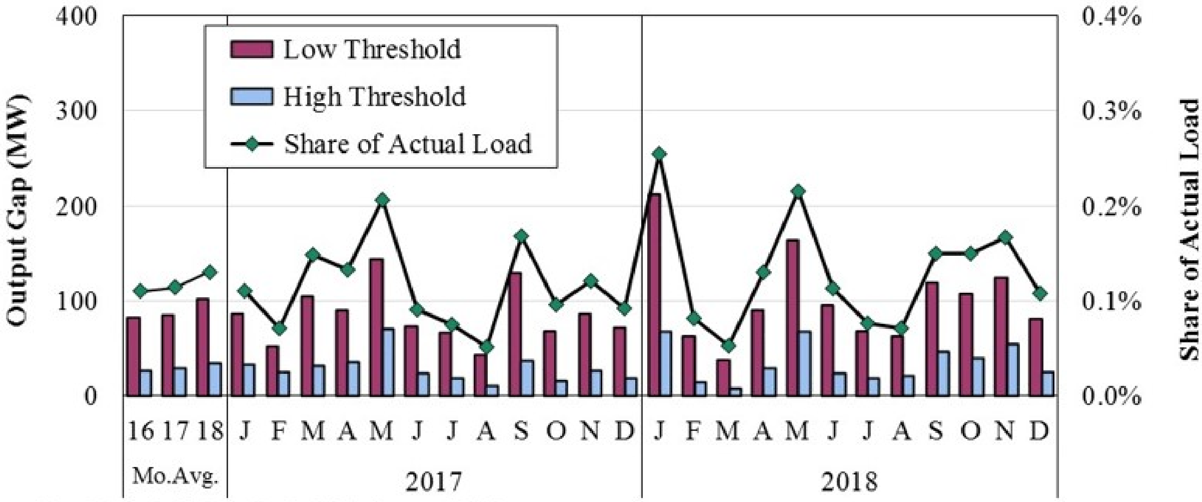
(1) online and quick-start units available in real time, and

(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, 2018 were $27.74 per MWh for resources located in the WUMS NCA, $19.63 for those in the North WUMS NCA, $61.52 for those in the Minnesota NCA, and $53.19 and $100.00 for the WOTAB and Amite South NCAs, respectively. 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 A144: Economic Withholding -- Output Gap Analysis
2017–2018



Low Threshold Results by Unit Status (MW)

Offline	12	6	12	10	6	5	11	14	4	2	2	16	0	0	0	30	0	0	3	40	11	4	8	17	17	6	3
Online	71	79	90	77	46	100	79	130	69	65	41	114	68	86	72	182	63	37	88	124	85	64	55	102	90	118	78

High Threshold Results by Unit Status (MW)

Offline	10	5	10	10	6	5	11	14	4	2	2	12	0	0	0	20	0	0	2	33	8	3	8	16	16	5	3
Online	15	23	24	22	19	27	24	55	20	16	9	24	15	26	19	46	14	7	26	33	15	15	13	30	24	48	21

Figure A145 to Figure A148: 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 A145: Real-Time Average Output Gap and Load
Central Region, 2018

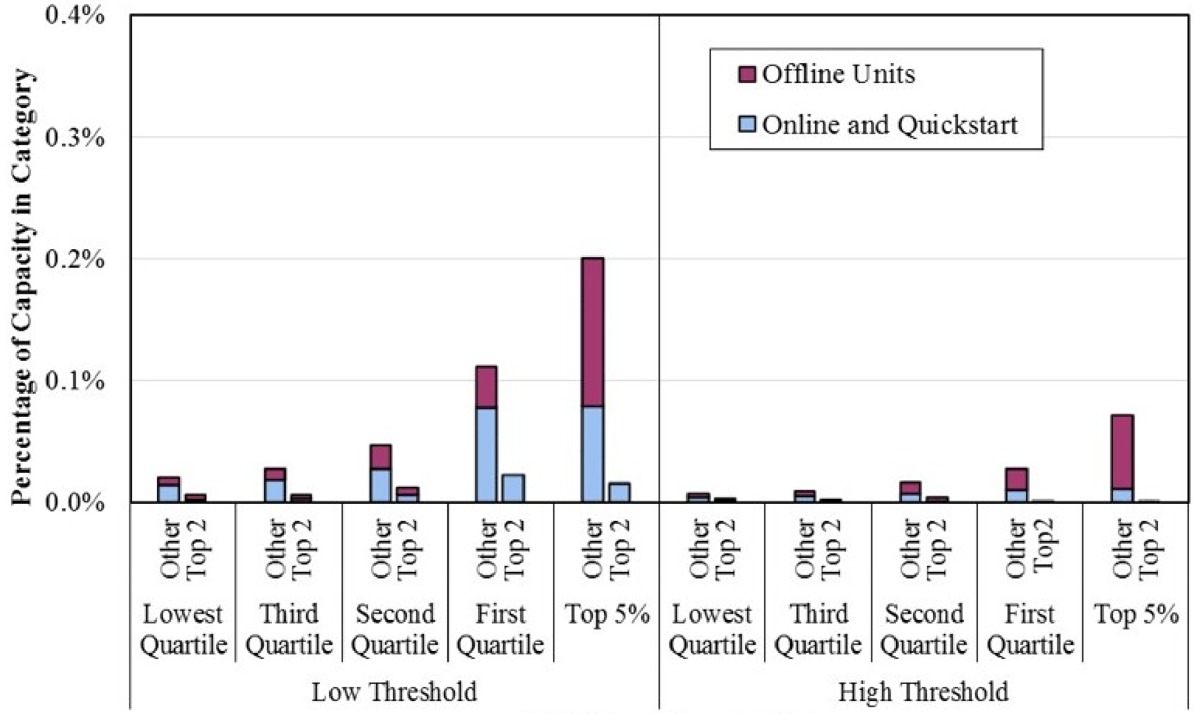


Figure A146: Real-Time Average Output Gap and Load
South Region, 2018

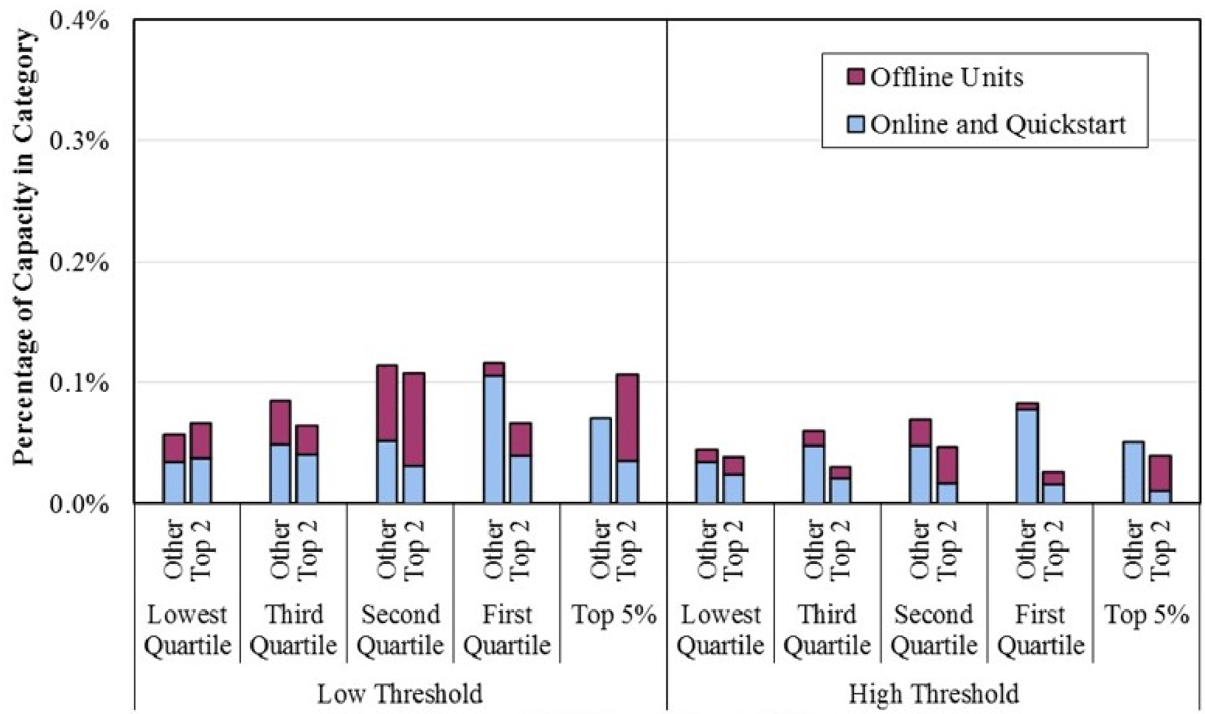


Figure A147: Real-Time Average Output Gap and Load
North Region, 2018

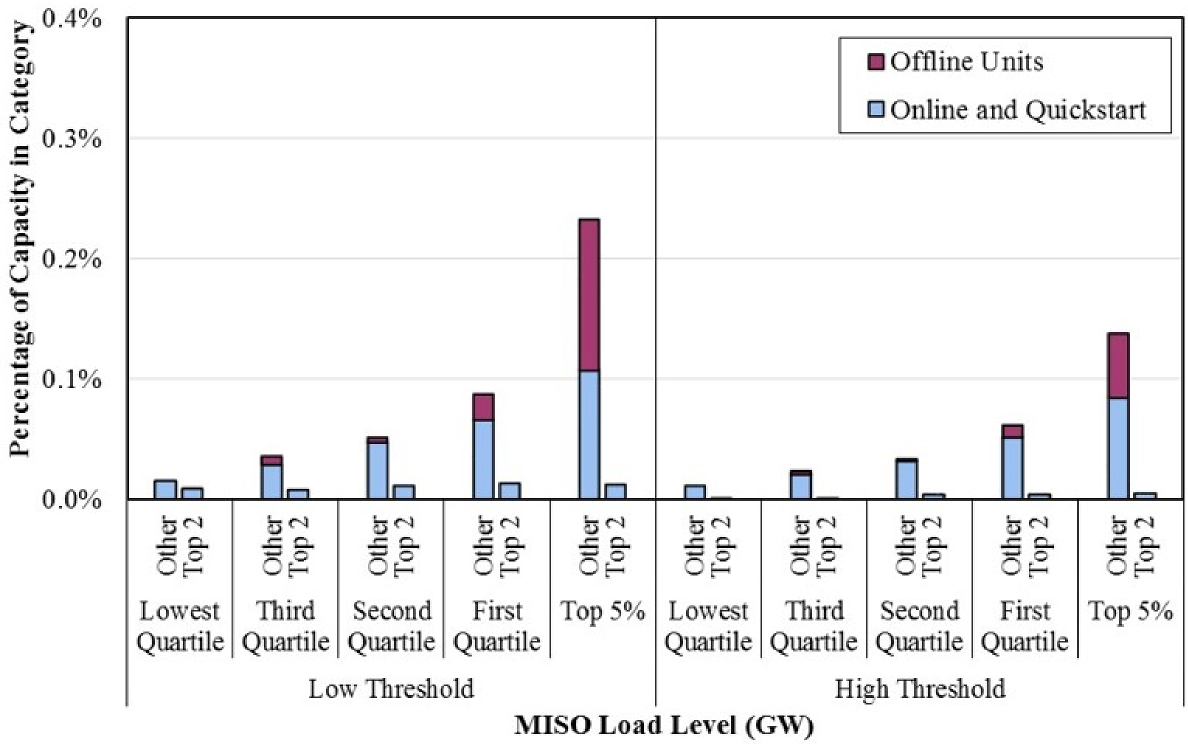
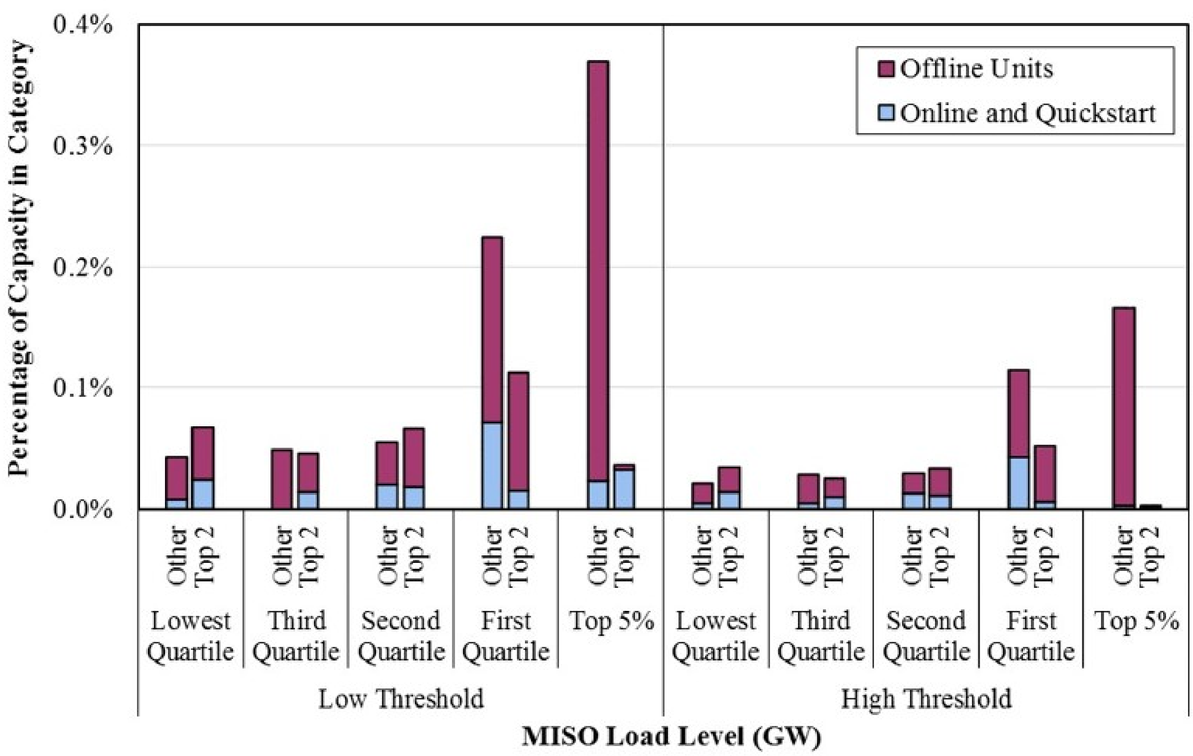


Figure A148: Real-Time Average Output Gap and Load
WUMS Area, 2018



D. Market Power Mitigation

In this next subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2018. 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 effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas.

Market participants are subject to potential mitigation when transmission constraints bind that can result in local market power. The mitigation thresholds differ depending on the two types of constrained areas: BCAs and NCAs. Market power concerns are greater in NCAs because the congestion is chronic, and a supplier is typically pivotal when the congestion occurs. 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 A149: Day-Ahead and Real-Time Energy Offer Mitigation by Month

Figure A149 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month. 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 A149: Day-Ahead and Real-Time Energy Offer Mitigation by Month
2018

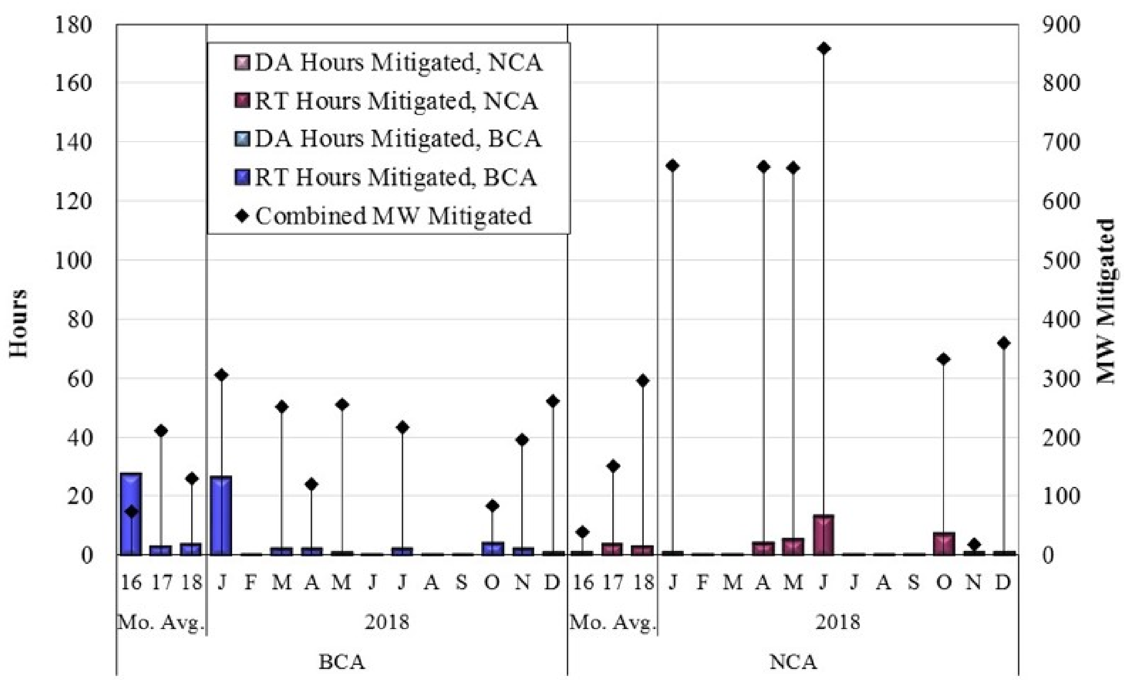
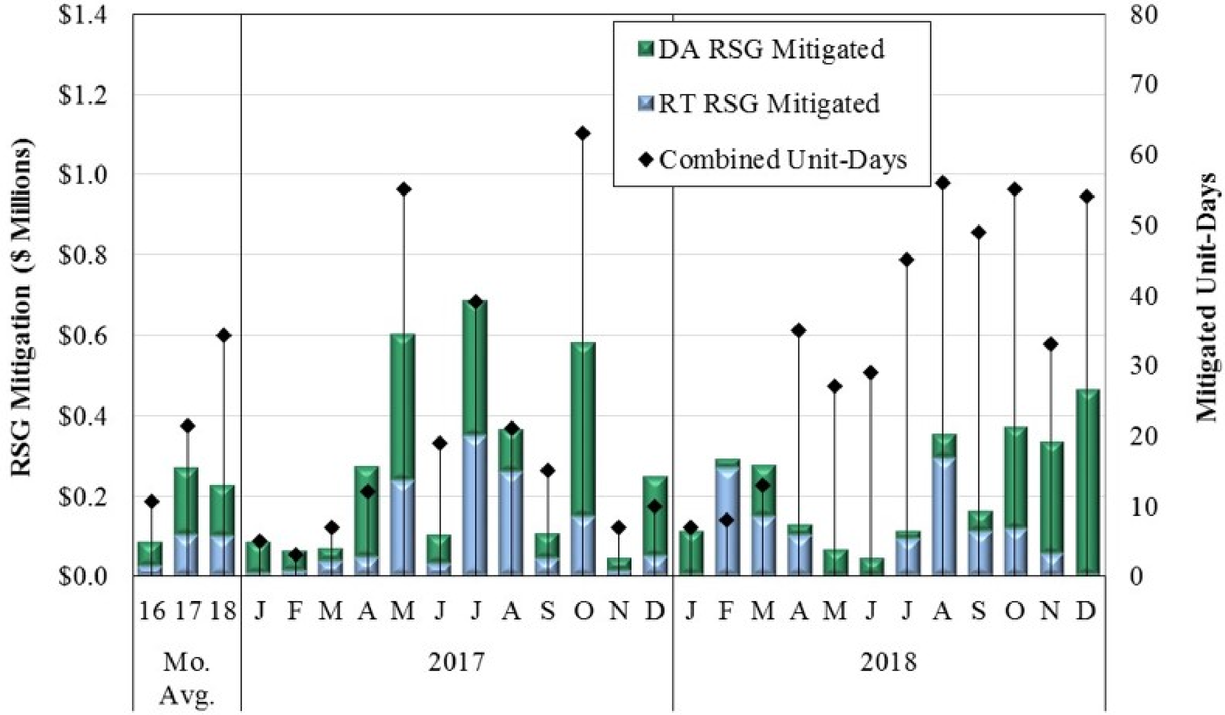


Figure A150: Day-Ahead and Real-Time RSG Mitigation by Month

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 A150 shows the frequency and amount by which RSG payments were mitigated by month in 2017 and 2018 and average monthly values for the last three years.

Figure A150: Day-Ahead and Real-Time RSG Mitigation by Month
2017–2018



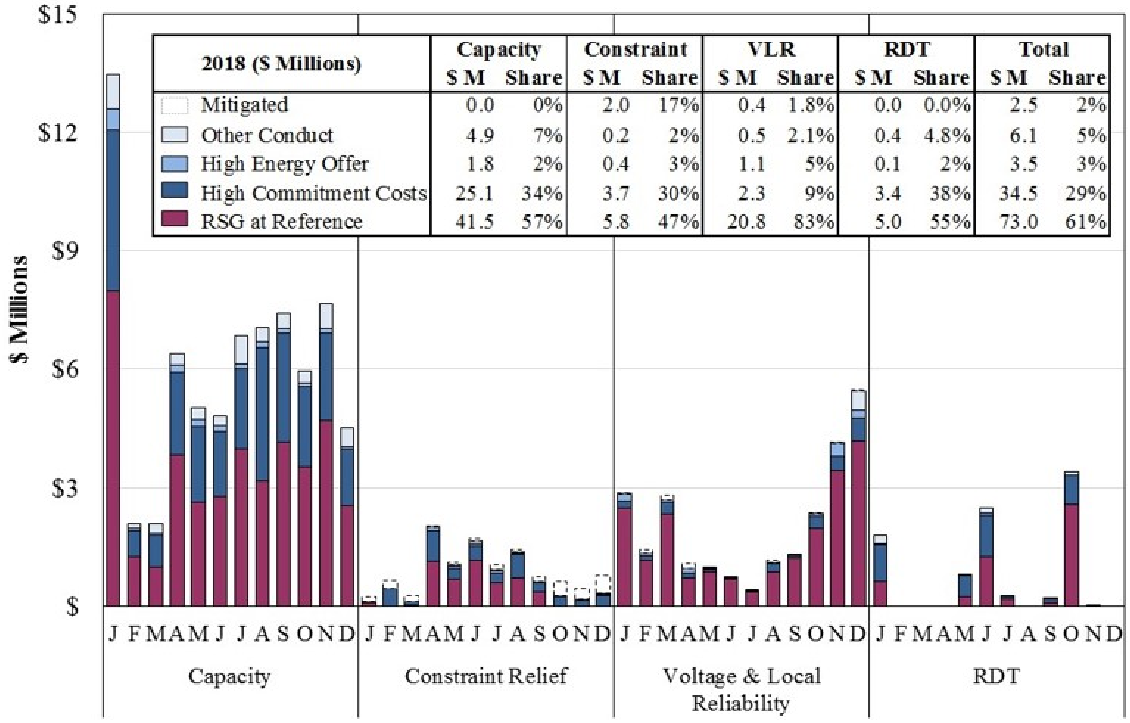
E. Evaluation of RSG Conduct and Mitigation Rules

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

Figure A151 to Figure A153: Real-Time RSG Payments by Conduct

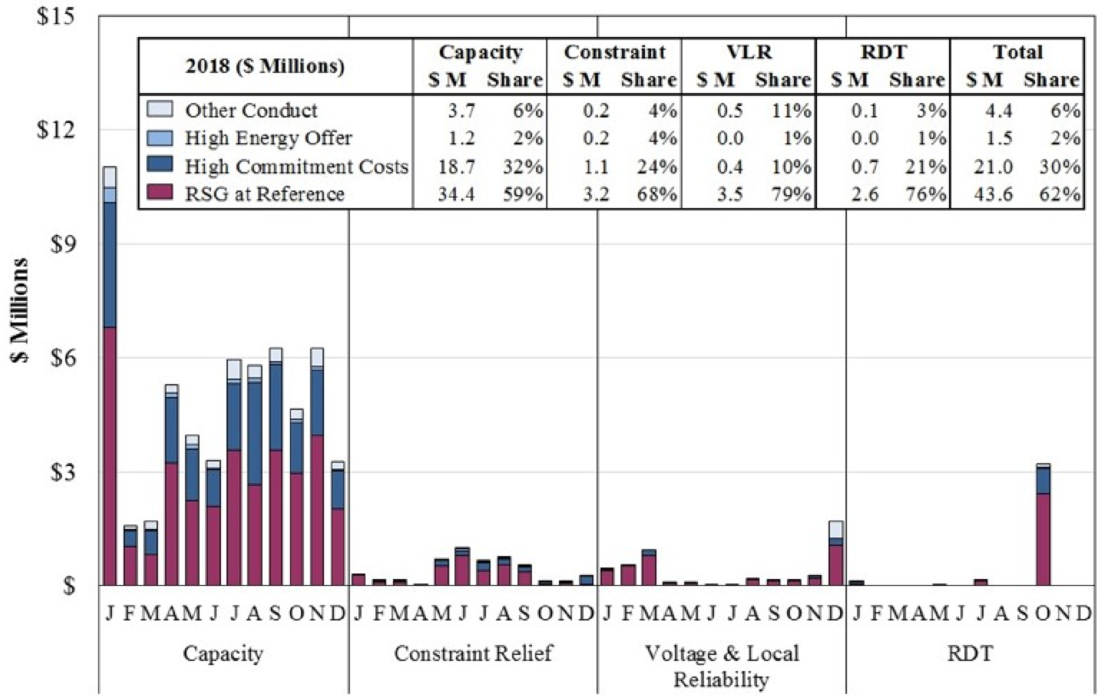
We evaluate conduct associated with RSG payments in the following figure, separating the payments associated with resources' reference levels and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceed their reference levels. The results are shown separately for units committed for capacity, regional capacity needs (i.e., the RDT), for VLR requirements, and for congestion management. We also distinguish between the Midwest and South Regions. For Figure A151, the category "Mitigated" includes both day-ahead and real-time amounts.

Figure A151: Real-Time RSG Payments by Conduct
By Commitment Reason, 2018



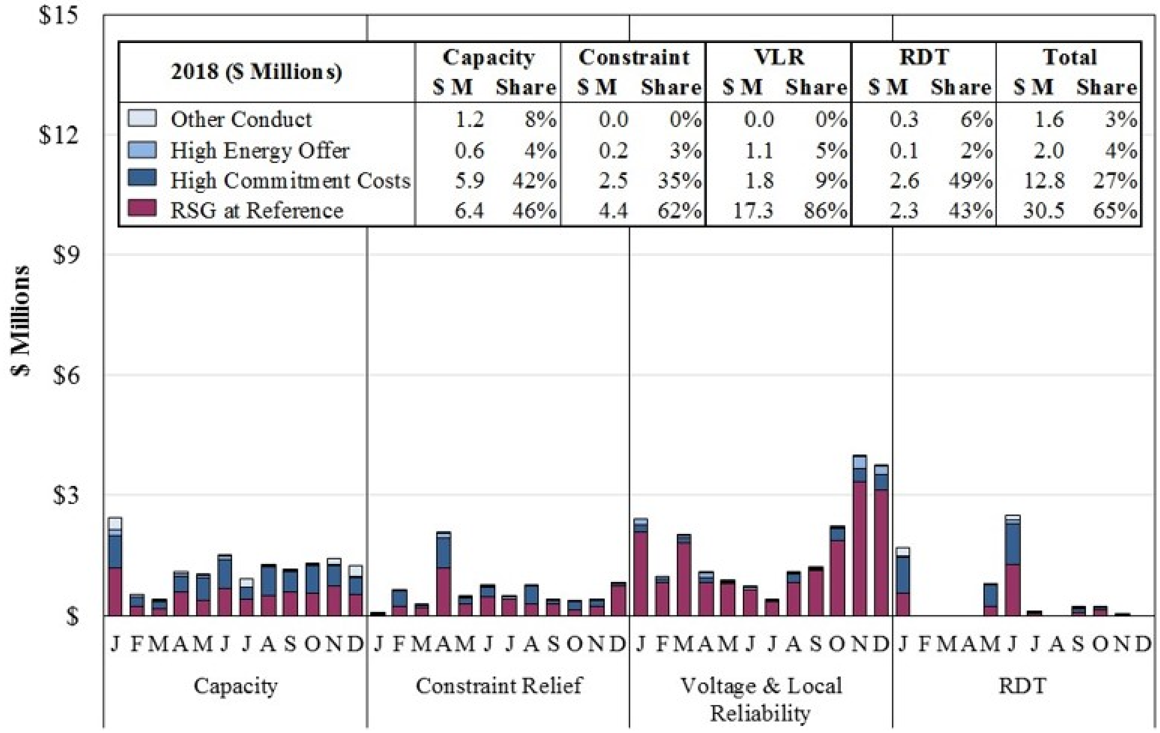
2018 ($ Millions)	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	RDT $ M	RDT Share	Total $ M	Total Share
Mitigated	0.0	0%	2.0	17%	0.4	1.8%	0.0	0.0%	2.5	2%
Other Conduct	4.9	7%	0.2	2%	0.5	2.1%	0.4	4.8%	6.1	5%
High Energy Offer	1.8	2%	0.4	3%	1.1	5%	0.1	2%	3.5	3%
High Commitment Costs	25.1	34%	3.7	30%	2.3	9%	3.4	38%	34.5	29%
RSG at Reference	41.5	57%	5.8	47%	20.8	83%	5.0	55%	73.0	61%

Figure A152: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2018



2018 ($ Millions)	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	RDT $ M	RDT Share	Total $ M	Total Share
Other Conduct	3.7	6%	0.2	4%	0.5	11%	0.1	3%	4.4	6%
High Energy Offer	1.2	2%	0.2	4%	0.0	1%	0.0	1%	1.5	2%
High Commitment Costs	18.7	32%	1.1	24%	0.4	10%	0.7	21%	21.0	30%
RSG at Reference	34.4	59%	3.2	68%	3.5	79%	2.6	76%	43.6	62%

Figure A153: Real-Time RSG Payments by Conduct
South Region, by Commitment Reason, 2018



2018 ($ Millions)	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	RDT $ M	RDT Share	Total $ M	Total Share
Other Conduct	1.2	8%	0.0	0%	0.0	0%	0.3	6%	1.6	3%
High Energy Offer	0.6	4%	0.2	3%	1.1	5%	0.1	2%	2.0	4%
High Commitment Costs	5.9	42%	2.5	35%	1.8	9%	2.6	49%	12.8	27%
RSG at Reference	6.4	46%	4.4	62%	17.3	86%	2.3	43%	30.5	65%

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 of the resources' offer parameters. When units committed for VLR require an RSG payment, every dollar of increased production costs 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. This approach has 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.

Figure A154 to Figure A156: Ancillary Services Market Offers

Figure A154 to Figure A156 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 A154 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 A154: Ancillary Services Market Offers
2017–2018

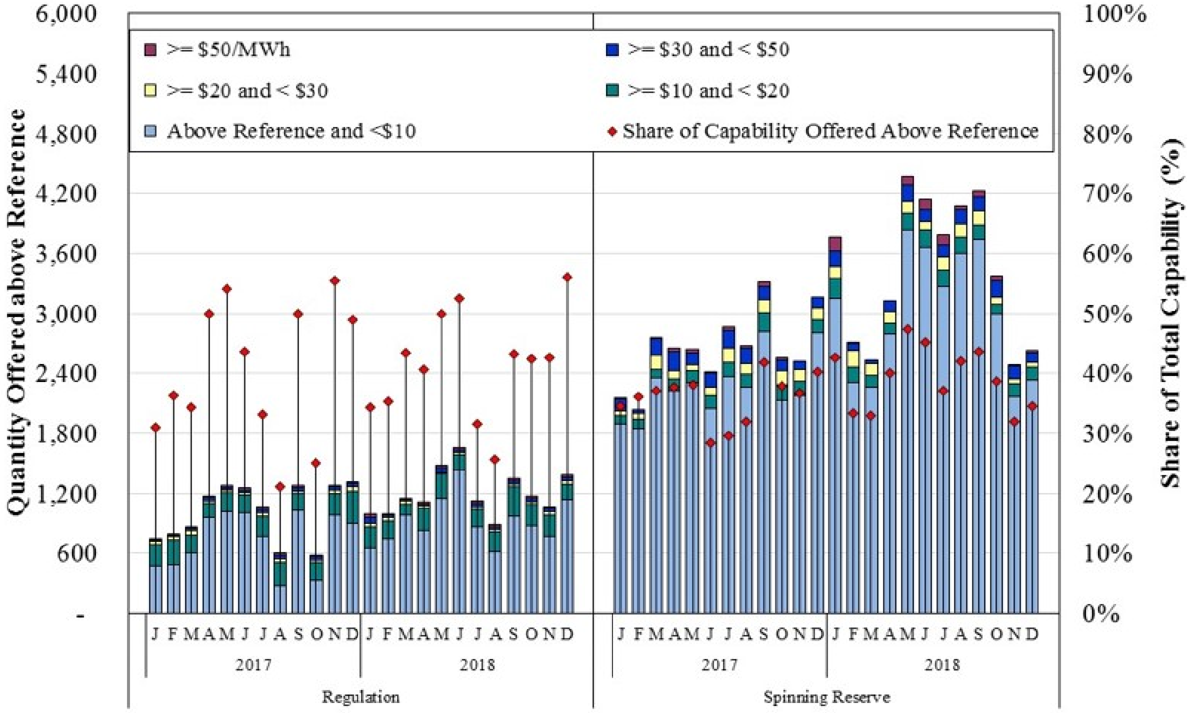


Figure A155: Ancillary Services Market Offers
Midwest Region, 2017–2018

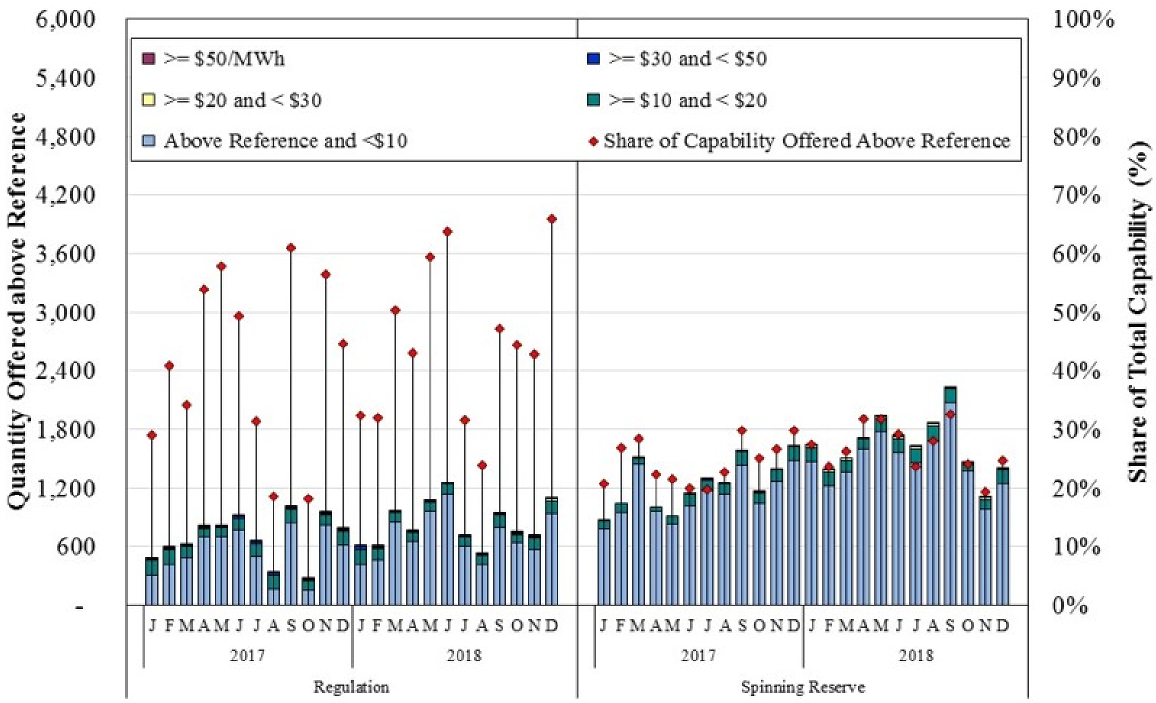
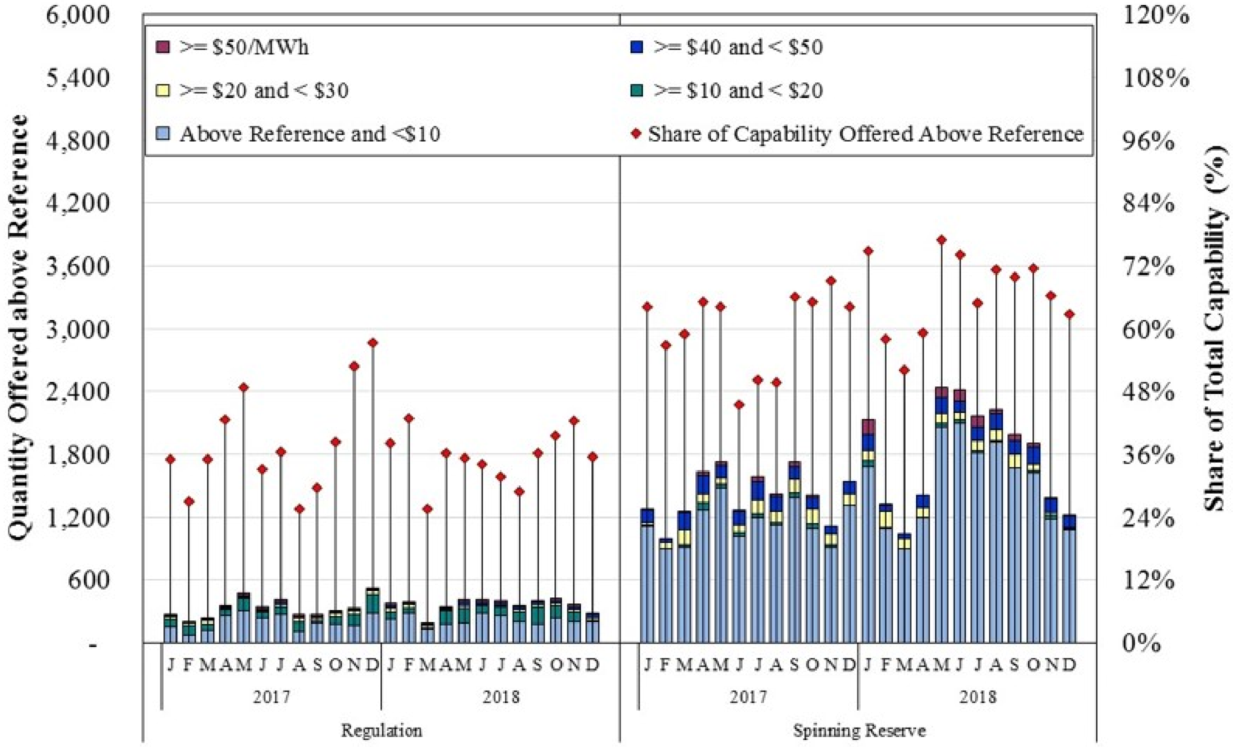


Figure A156: Ancillary Services Market Offers
South Region, 2017–2018



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 of 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 A157 to Figure A160: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2018 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 A157: Real-Time Deratings and Forced Outages
Central Region, 2018

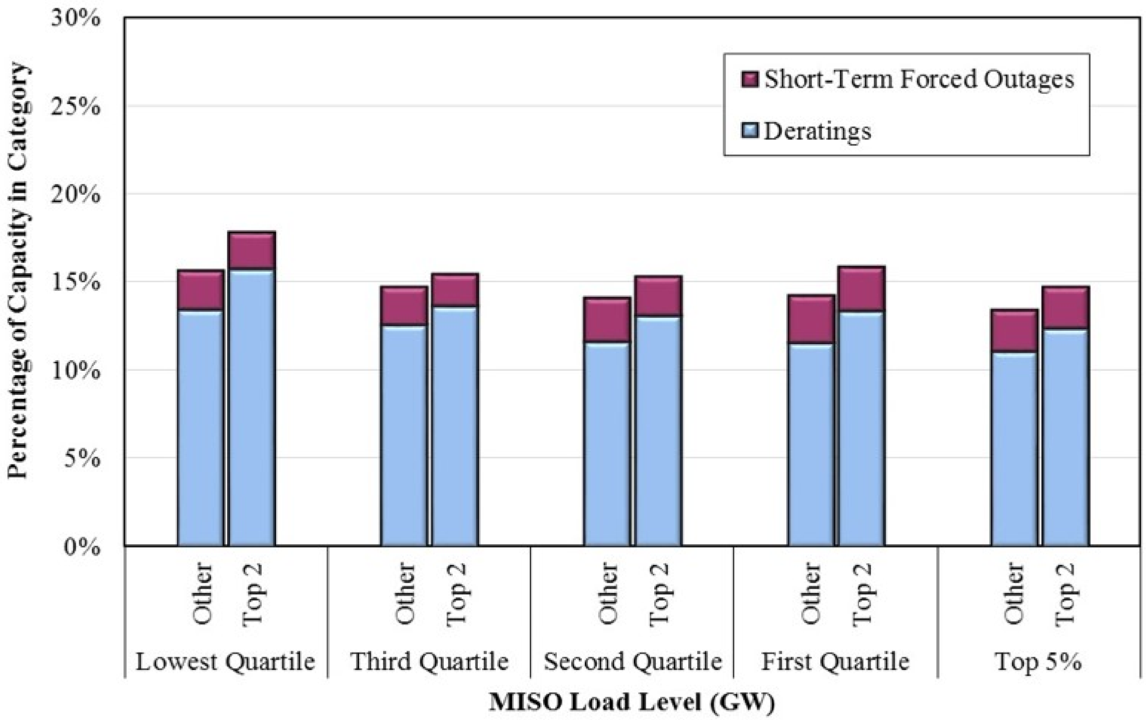


Figure A158: Real-Time Deratings and Forced Outages
South Region, 2018

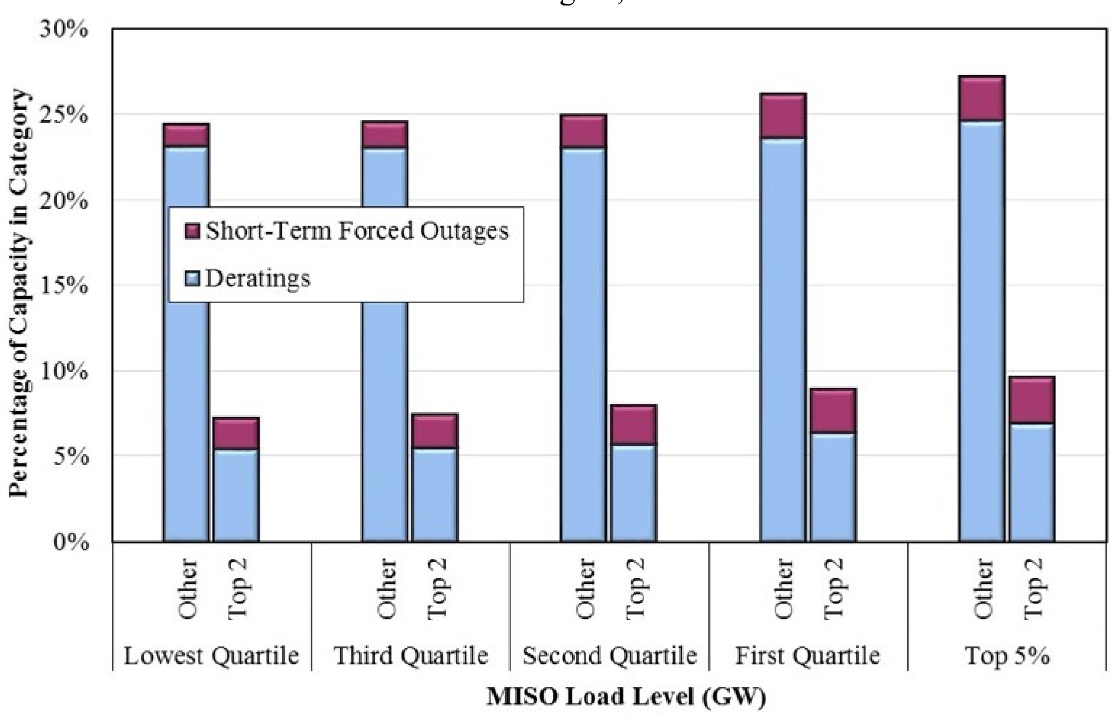


Figure A159: Real-Time Deratings and Forced Outages
North Region, 2018

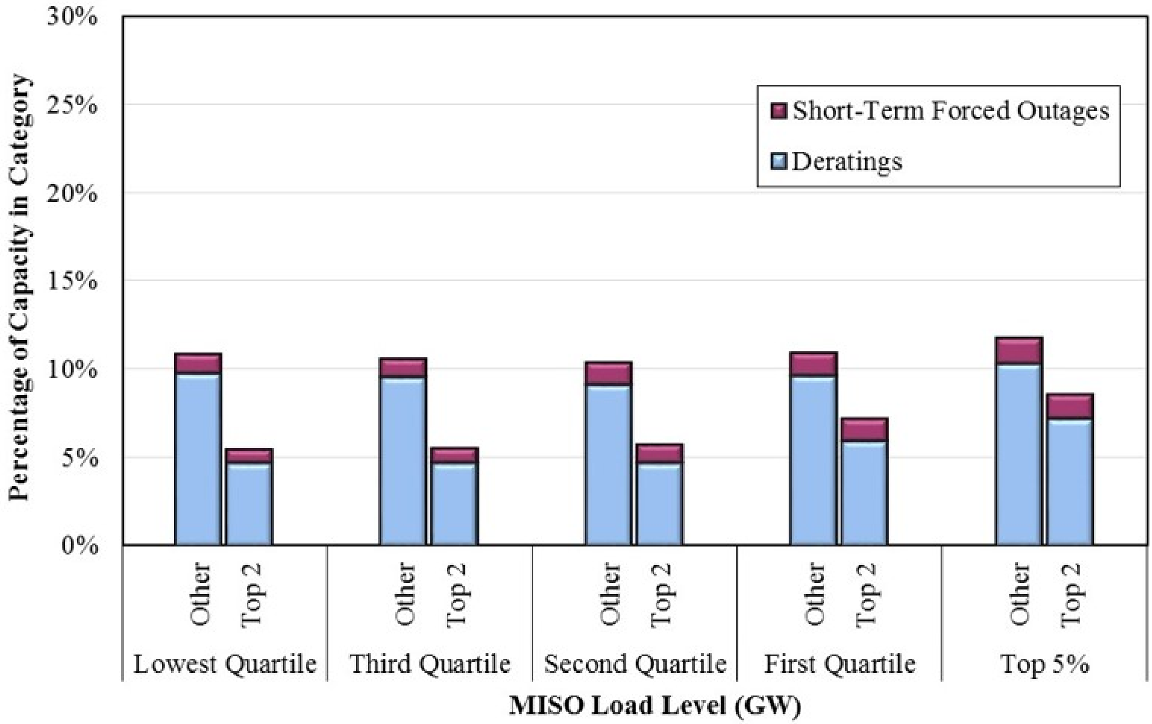
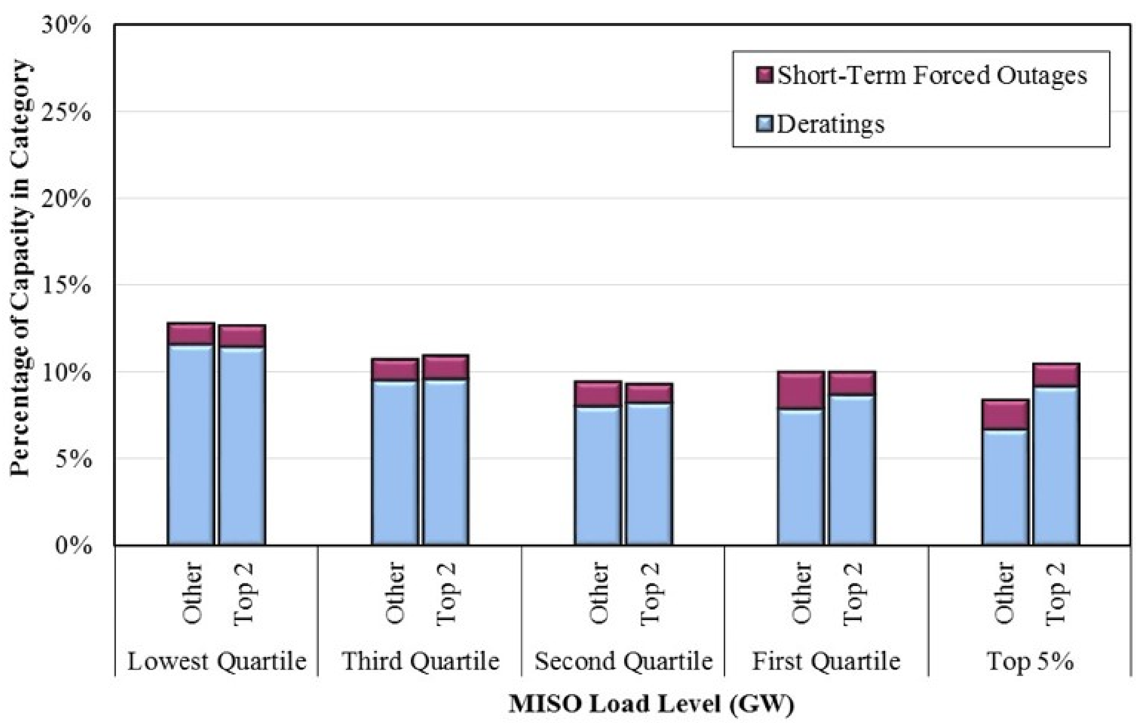


Figure A160: Real-Time Deratings and Forced Outages
WUMS 2018



IX. DEMAND RESPONSE PROGRAMS

Demand Response (DR) involves actions taken to reduce consumption when the value of consumption is less than the marginal cost to supply the electricity. DR allows for participation in the energy markets by end users and contributes to:

- Reliability in the short term;
- Least-cost resource adequacy in the long term; and
- Reductions in price volatility and other market costs.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-priced periods can greatly reduce the costs of committing and dispatching generation. These benefits underscore the need to facilitate DR through wholesale market mechanisms and transparent economic signals.

DR resources can broadly be categorized as either:

- Emergency DR (EDR), which responds to capacity shortages; or
- Economic DR, which responds to high energy market prices.

MISO can call for EDR resources to be activated in advance of a forecasted system emergency, thereby supporting system reliability. By definition, however, EDR is not price-responsive and does not yet participate directly in the MISO markets. Economic DR 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 and interchange, as well as contingencies, such as generator or transmission outages. Given the high value of most electricity consumption, 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.

A. DR Resources in MISO

MISO's DR capability rose in 2018 to approximately 13 GW. The majority of the DR takes the form of Load-Modifying Resources (LMRs), generally comprised of:

- Legacy DR programs administered by load-serving entities (LSEs), or
- Behind-the-meter-generation (BTMG).

These resources are not under MISO's direct control but can reduce the overall demand of the system. The share of DR that can respond actively through MISO dispatch instructions comprises a small portion of MISO's DR capability. Such resources are classified as Demand

Response Resources (DRRs) and are eligible to participate in all of the MISO markets, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff.

MISO characterizes DRRs that participate in the MISO markets as Type I or Type II resources. MISO had 23 Type I resources and 3 Type II resources available to the markets in 2018, and 17 of them cleared an average of 15.7 MW of energy.

Type I resources. Type I resources can supply a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. These resources provide either no response or their "Target Demand Reduction Amount." Therefore, they cannot set energy prices in the MISO markets, although they can set the price for ancillary services. In this respect, MISO treats Type I resources in a similar fashion as generation resources that are block-loaded for a specific quantity of energy or operating reserves. As noted previously in the context of the ELMP Initiative, MISO is developing a pricing methodology to allow Type I and other "fixed-block" offers to establish market prices.

Type II resources. Type II resources can supply varying levels of energy or operating reserves on a five-minute basis; therefore, they are treated comparable to generating resources and can set prices. These resources are "dynamic pricing" resources. Dynamic pricing is the most efficient form of DR because prices formed under this approach provide customers with accurate price signals throughout the day. These customers can then alter their usage in response the prices. Significant barriers to implementing dynamic pricing include the minimum required load of the participating customer, infrastructure outlays, and retail rate regulation.

LSEs are also eligible to offer DRR capability into the ASM markets. Type II resources can currently offer all ancillary services products, whereas Type I units are prohibited from providing regulating reserves. Physical requirements for regulating reserve-eligible units (namely, the ability to respond to small changes in instructions within four seconds) are too demanding for most Type I resources. In 2018, 10 DRR Type I resources provided an average of 4.2 MW per hour of contingency reserves.

Other Forms of DR in MISO. Most other DR capacity in MISO are registered as LMRs, comprised of interruptible load programs registered or BTMG. Enrollment typically requires minimum amounts of reduction in load and a minimum level of peak demand. In an interruptible load program, customers agree to reduce consumption by or to a predetermined level in exchange for a small, per-kWh reduction in their fixed rate. MISO does not directly control this load. Therefore, such programs are ultimately voluntary, although penalties exist for noncompliance. Direct Load Control (DLC) programs also exist that target residential and small commercial and industrial customers. In the event of a contingency, the LSE manually reduces the load of this equipment to a predetermined level. LMRs allow MISO to directly curtail load in specified emergency conditions. LMR scheduling requires the declaration of a NERC Energy Emergency Alert level 2 or 3 event.[45]

45 In December 2018, MISO filed tariff language changes with FERC to allow MISO to call upon LMRs before the declaration of an emergency event.

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 can set price as of the March 1, 2015, go-live of ELMP.

Finally, Module E of MISO's Tariff allows all types of DR resources to count toward fulfillment of an LSE's capacity requirements. To qualify as capacity resources, LMRs must be able to curtail load within 12 hours and must be available during the summer months.

Table A14: DR Capability in MISO and Neighboring RTOs

Table A14 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 A14: DR Capability in MISO and Neighboring RTOs
2016–2018

		2016	2017	2018
MISO[1]		**10,454**	**11,495**	**12,931**
	Behind-The-Meter Generation	3,822	3,822	4,496
	Load Modifying Resource	4,616	6,112	7,137
	DRR Type I	525	620	621
	DRR Type II	75	0	3
	Emergency DR	1,416	941	674
NYISO[3]		**1,267**	**1,237**	**1,314**
	ICAP - Special Case Resources	1,192	1,221	1,309
	Of which: Targeted DR	372	392	494
	Emergency DR	75	16	5
	Of which: Targeted DR	14	1	1
	DADRP	0	0	0
ISO-NE[4]		**2,600**	**2,657**	**2,988**
	RT DR Resources/DR Assets	702	683	262
	RT Emerg. Generation Resources	2	2	
	On-Peak Demand Resources	1,386	1,418	2,214
	Seasonal Peak Demand Resources	510	554	512

[1] Registered as of December 2018. All units are MW.

[2] Roughly 1/3 of the EDR are also LMRs.

[3] Registered as of July 2018. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

[4] Registered as of December 1, 2018. Source: ISO-NE Demand Response Working Group
On June 1, 2018, a new Price-Responsive Demand structure went into effect, with RTEG removed and RTDR replaced with "Demand Response Assets"

B. LMR Availability during Emergency Conditions

Prior to 2017, LMRs had not been called upon in MISO since 2007 but they have an increasingly important role in planning for and operating during emergency events. LMRs were deployed once in April 2017, and twice in January and once in September 2018 in MISO South. We discuss the events in detail in Section III of the Report.

While LMRs have no capacity obligations outside of the summer months, LMRs are required to update their availability to curtail load daily through the MISO Communication System (MCS). During Maximum Generation Events declared by MISO at the emergency level of 2b or higher (more severe), LMRs may receive scheduling instructions (to reduce load for DR and increase output for BTMGs) from MISO via the MCS. The instructions are limited by the availability reported to MISO. LMR performance during Emergency Events is based on measurement and verification criteria outlined in Module E.

LMRs are unique planning resources, in that their participation is limited to declared emergencies when all other available generation resources are in use. In the past two years, MISO has declared emergencies seven times. As MISO moves through the emergency procedure steps, it has access to increasing quantities of emergency MWs. For instance, in an Emergency Event Step 1, MISO can access emergency generation and emergency dispatch ranges of online generating resources. In declaring an Emergency Event Step 2, MISO can access the LMRs and LMM.

Because emergencies tend to occur when there are multiple concurrent contingencies and/or higher than expected load, the tightest conditions tend not to be foreseen far in advance and occur early in the event. For this reason, emergency resources with longer notification times provide much less value in most emergency events. Additionally, DR resources with long notification times generally must continue to be served along with other firm load.

Hence, procuring capacity from long-notification LMR-DRs tend to degrade reliability because LMR-DRs receive capacity credit for the curtailment quantity *plus* transmission losses and the Planning Reserve Margin. Providing a capacity credit that exceeds the curtailment quantity is only reasonable if the RTO is confident that it will not have to serve this load during emergencies. The long notification times offered by many of these resources invalidate this assumption.

Figure A161: Availability of Emergency-Only Resources

We conducted an analysis of the three main LMR events that occurred in MISO South, one on April 4, 2017, a second on January 17, 2018, and a more recent event on September 15, 2018, as well as an emergency event in MISO Central and North on January 30, 2019. We analyzed the amount of time that emergency resources had to prepare for the events, based on the timing of the declarations of the events. Based on MISO's declarations for the these emergency events, we identify which emergency resources that cleared in the 2018-2019 and 2019-2020 capacity auctions would have been available to be scheduled based on the resources' notification and startup or shutdown times.

We divided the associated MW into tranches, based on the offered notification times on the emergency days (for AME resources) or registered notification times (for LMRs). In the case of the cleared LMRs, we included the notification times for a peak hour on a peak day (Monday through Friday) since some resources have notification times that vary. For AME resources, we included the average capacity offered with the various notification times at the time of the declarations during the actual emergency events. The green bars represent the demand response UCAP that cleared in the 2018-2019 and 2019-2020 capacity auctions. The blue bars represent the cleared UCAP of the BTMG resources in the 2018-2019 and 2019-2020 capacity auction. The maroon bars represent the average offered emergency-only generation across all declared emergencies.

Figure A161: Availability of Emergency-Only Resources During Emergency Events
2018–2019 Capacity Resources