2015 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

ANALYTICAL APPENDIX

POTOMAC ECONOMICS

JUNE 2016

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I. Introduction

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

This Analytical Appendix provides an extended analysis of the topics raised in the main body of Report. We present the methods and motivation for each of the analyses. However, the discussion of our conclusions regarding the performance of various components of the market is contained in the body of our Report. In addition, the body of the report includes a discussion of our recommendations to improve the design and competitiveness of the market.

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. On March 1, 2015, two major changes were implemented in MISO's energy markets. First, MISO introduced Extended Locational Marginal Pricing (ELMP), which allows quick-start units and Emergency Demand Resources (EDRs) to set the price in the energy and operating reserve markets. Second, MISO and SPP began market-to-market coordination.

A. Prices

In a well-functioning, competitive market, suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should be positively correlated with the marginal costs of generation. For most suppliers, fuel constitutes the major portion of these costs. In MISO, coal-fired resources historically have been frequently marginal. However after steep declines in natural gas prices beginning in 2014, natural-gas fired resources are now marginal in most intervals, including the vast majority of the higher-load intervals.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly "all-in" price of electricity from 2013 to 2015 along with the price of natural gas at the Chicago Citygate. The left most section shows the annual average prices for 2013 through 2015. 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 service 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
2014–2015

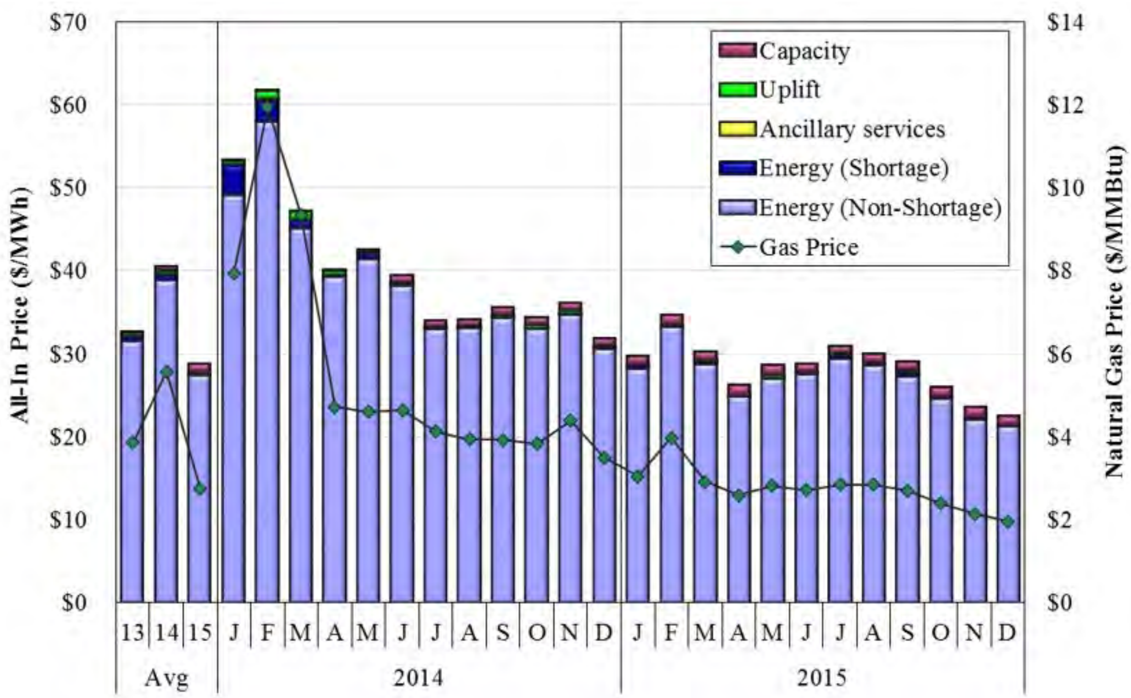


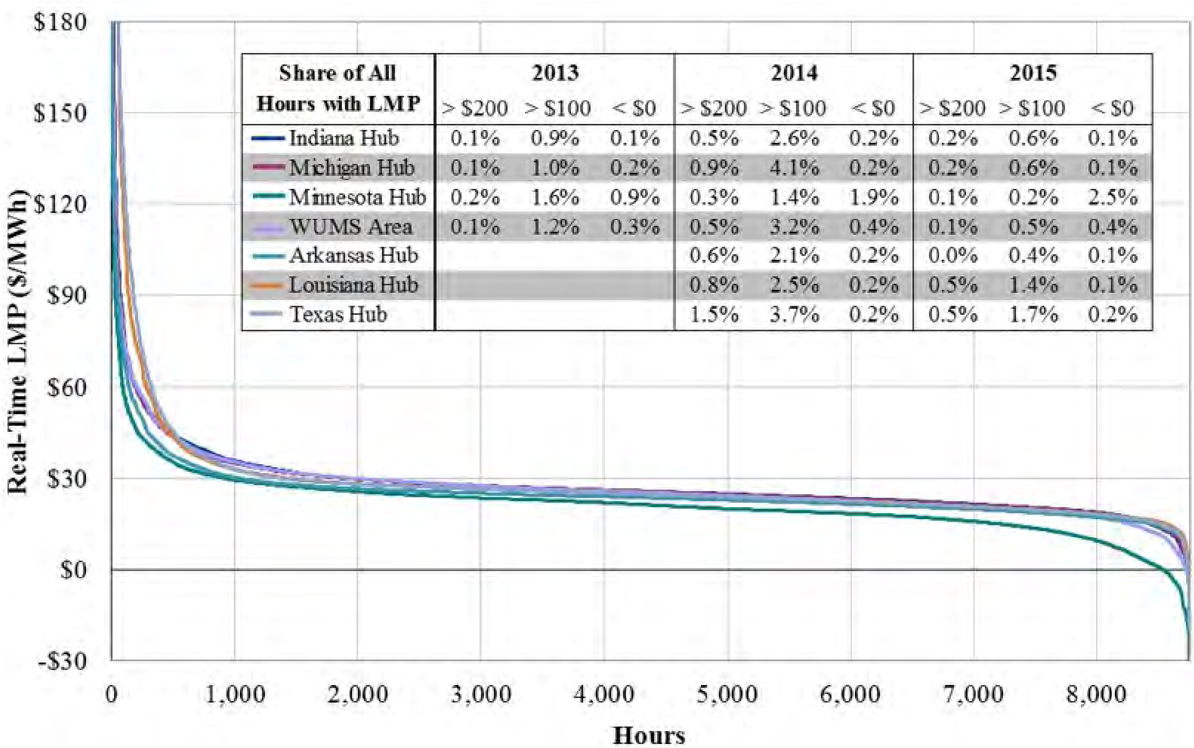
Figure A2: Real-Time Energy Price-Duration Curves

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 as usually attributable to differences in weather-related peak loads that change the frequency of shortage conditions.

Figure A2: Real-Time Energy Price-Duration Curve
2015



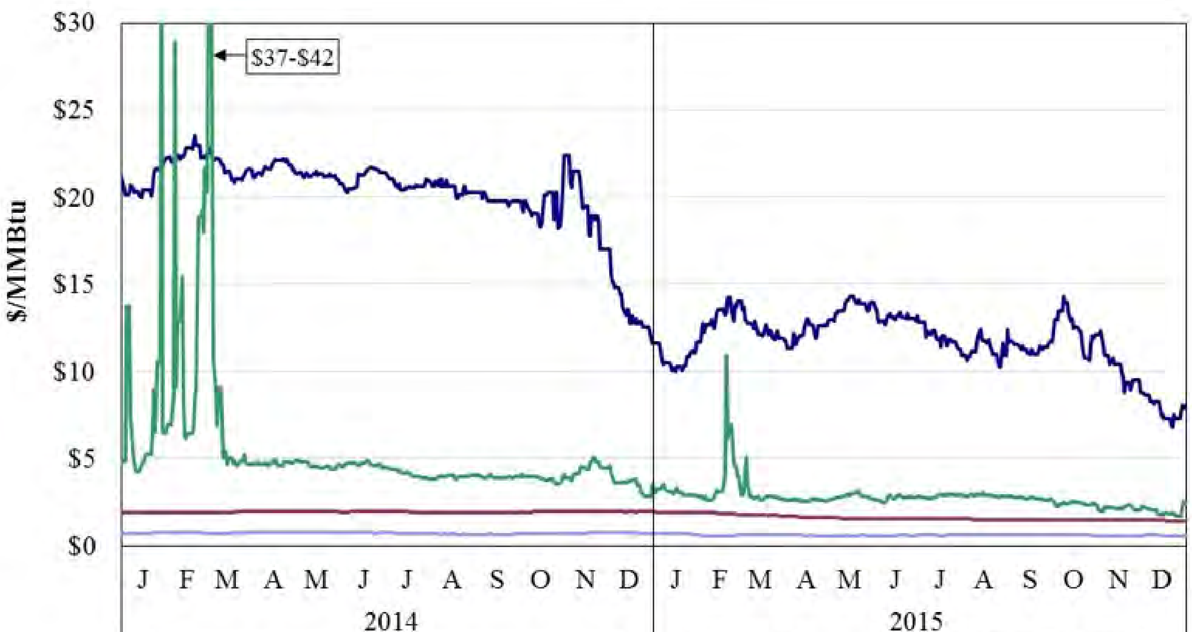
Share of All Hours with LMP	2013			2014			2015		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Indiana Hub	0.1%	0.9%	0.1%	0.5%	2.6%	0.2%	0.2%	0.6%	0.1%
Michigan Hub	0.1%	1.0%	0.2%	0.9%	4.1%	0.2%	0.2%	0.6%	0.1%
Minnesota Hub	0.2%	1.6%	0.9%	0.3%	1.4%	1.9%	0.1%	0.2%	2.5%
WUMS Area	0.1%	1.2%	0.3%	0.5%	3.2%	0.4%	0.1%	0.5%	0.4%
Arkansas Hub				0.6%	2.1%	0.2%	0.0%	0.4%	0.1%
Louisiana Hub				0.8%	2.5%	0.2%	0.5%	1.4%	0.1%
Texas Hub				1.5%	3.7%	0.2%	0.5%	1.7%	0.2%

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 the MISO market has performed very competitively, electricity prices tend to be highly correlated with natural gas prices because natural gas-fired resources set energy prices in a large share of hours. 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 2014.[1] The figure shows nominal prices in dollars per million British thermal units (MMBtu). The table below the figure shows annual average nominal prices since 2013 for each type of fuel.

Figure A3: MISO Fuel Prices
2014–2015



Annual Average	2013	2014	2015
Oil	$21.68	$20.18	$11.68
Natural Gas	$3.85	$5.53	$2.73

Annual Average	2013	2014	2015
IB Coal	$1.83	$1.91	$1.59
PRB Coal	$0.62	$0.71	$0.59

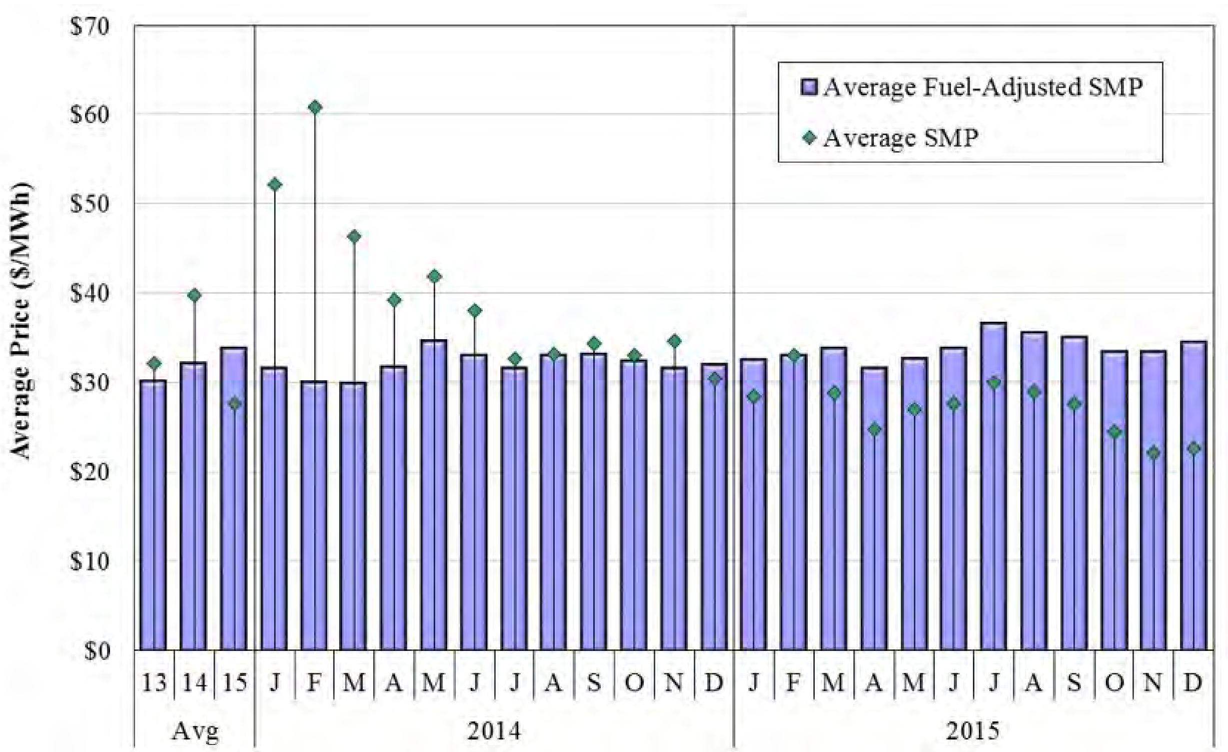
1 Although output from oil-fired generation is typically minimal, it can become significant if natural gas supplies are interrupted during peak winter load conditions. The majority of MISO coal-fired generators receive supplies from the Powder River Basin or other Western supply areas.

Figure A4: Fuel-Price Adjusted System Marginal Price

Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. Hence, 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 due to unit outages or deratings, congestion management needs, or output by intermittent resources.

To calculate this metric, each real-time interval's SMP is indexed to the average three-year fuel price of the marginal fuel during the interval. Hence, downward adjustment is greatest when fuel prices were highest and vice versa. The price-setting distinction was attributed to the most common marginal fuel type during an interval (more than one fuel can be on the margin in a particular interval). 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 (resulting from differences in regional generation mix) that would impact the economics of interchange with neighboring areas.

Figure A4: Fuel-Price-Adjusted System Marginal Price
2014–2015



B. Price Setting and Capacity Factors

Figure A5: Price Setting by Unit Type

Figure A5 examines the frequency that different types of generating resources set the system energy price in MISO. The figure shows the average prices that prevailed when each type of unit was on the margin (in the top panel) and the share of market intervals each type of unit set the real-time price (in the bottom panel).

Prior to the integration of MISO South at the end of 2013, baseload coal-fired units set prices in the majority of hours. After the integration of MISO South, which is mostly natural gas-fired, gas-fired units began setting MISO's energy prices in most hours. This trend continued into 2015 as natural gas prices fell. Natural gas also typically sets prices during the highest-load hours, ramp-up hours, and in constrained areas. Hence, natural gas-fired resources have a greater impact on load-weighted average prices than any other fuel.

Most wind resources can be economically curtailed when contributing to transmission congestion. Because their incremental costs are mostly a function of lost production tax credits (as low as -$35 per MWh), wind units often set negative prices in export-constrained areas when they must be ramped down to manage the congestion.

Figure A5: Price-Setting by Unit Type
2014–2015

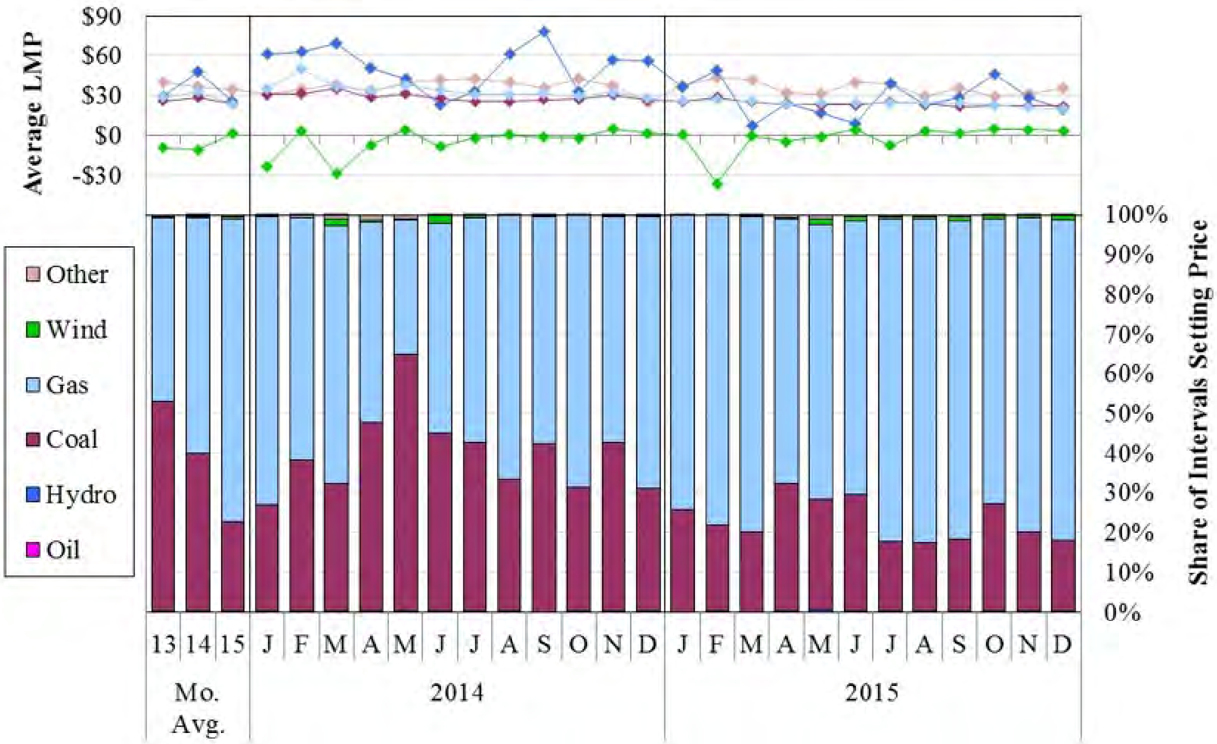


Table A1: Capacity, Energy Output and Price-Setting by Fuel Type

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 2015 compared to 2014. The lowest-cost resources (coal and nuclear) tend to produced most of the energy. Higher-cost resources (natural gas-fired units) tend to produce a lower share of MISO's energy than its share of MISO's installed capacity. Although, their capacity factor and energy production rises as natural gas prices fall.

Table A1: Capacity, Energy Output and Price-Setting by Fuel Type
2014–2015

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015
Nuclear	12,763	12,432	9%	9%	16%	15%	0%	0%	0%	0%
Coal	66,658	59,181	46%	42%	58%	52%	40%	23%	85%	95%
Natural Gas	55,852	58,013	39%	42%	17%	23%	59%	76%	82%	94%
Oil	3,125	2,063	2%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,621	3,603	3%	3%	1%	1%	0%	0%	2%	2%
Wind	1,027	2,412	1%	2%	6%	7%	0%	1%	45%	45%
Other	564	1,688	0%	1%	1%	1%	0%	0%	4%	4%
Total	**143,610**	**139,391**								

C. Load Patterns

Figure A6: Load Duration Curves

Though market conditions can still be tight in the winter periods due to 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 2015 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 or equal to the level indicated on the vertical axis. We separately show curves for 2014 and 2015.

These curves reveal the changes in load 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 2015. The "Predicted Peak (50/50)" is the predicted peak load in 2015 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 2015 Peak Load
2014–2015

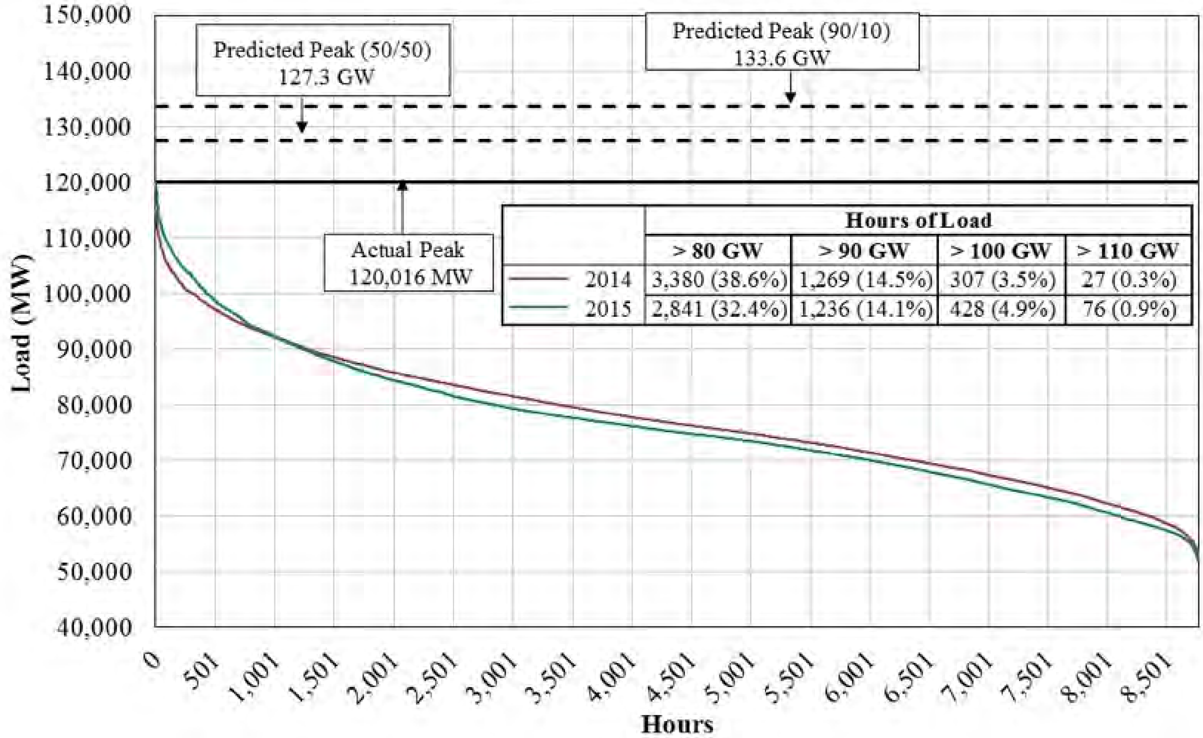


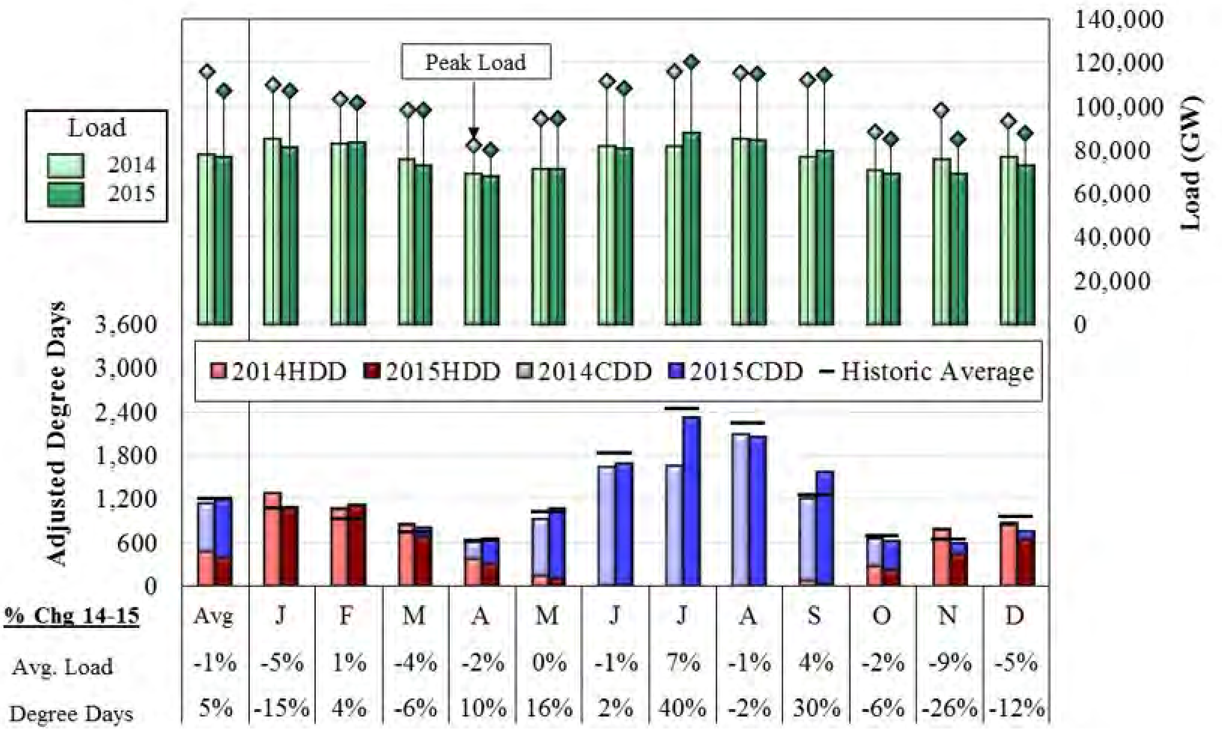
Figure A7: Heating and Cooling Degree-Days

MISO's load is temperature sensitive. Figure A7 illustrates the influence of weather on load by showing heating and cooling degree days (a proxy for weather-driven demand for energy). It is 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 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.

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.

Figure A7: Heating and Cooling Degree-Days
2014–2015



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 new generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. A well-designed market should provide sufficient net revenue 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 changes, outages, or changes in fuel prices) will cause the net revenue 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 7,050 Btu per kWh and a natural gas combustion turbine (CT) unit with an assumed heat rate of 9,750 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.

3 These assumptions are used in the 2015 EIA Annual Energy Outlook.

Figure A8 and Figure A9: Net Revenue and Operating Hours

The next two figures compare the 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 for each type of unit are shown in the figure as horizontal black segments, and is equal to the Cost of New Entry value the IMM estimates each year based on data from EIA and various financing, tax, inflation, and capital cost assumptions. The CONE value for the CT is published each year by the IMM along with the assumptions.

Combined-cycle generators run more frequently (and earn more energy rents) than simple-cycle CTs because CC units have substantially lower production costs per MWh. Hence, the estimated energy net revenues for CC generators are 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. 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.

Figure A8: Net Revenue and Operating Hours
Midwest Region, 2013–2015

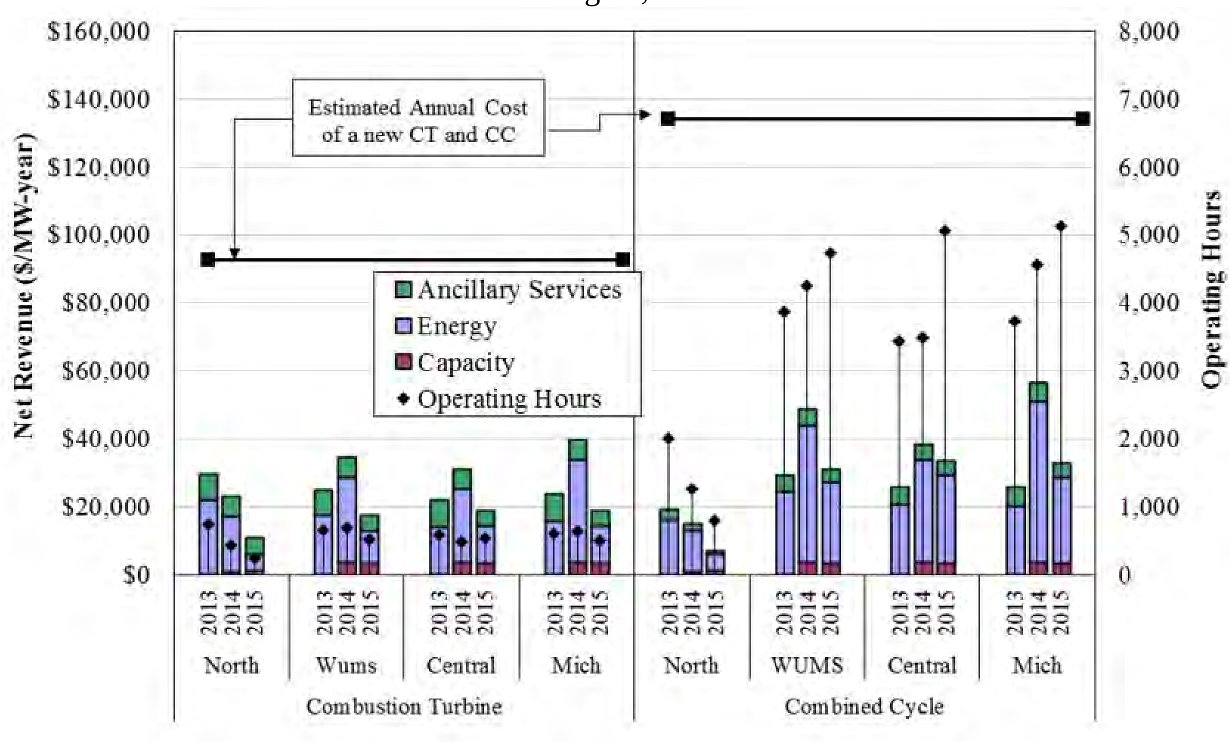
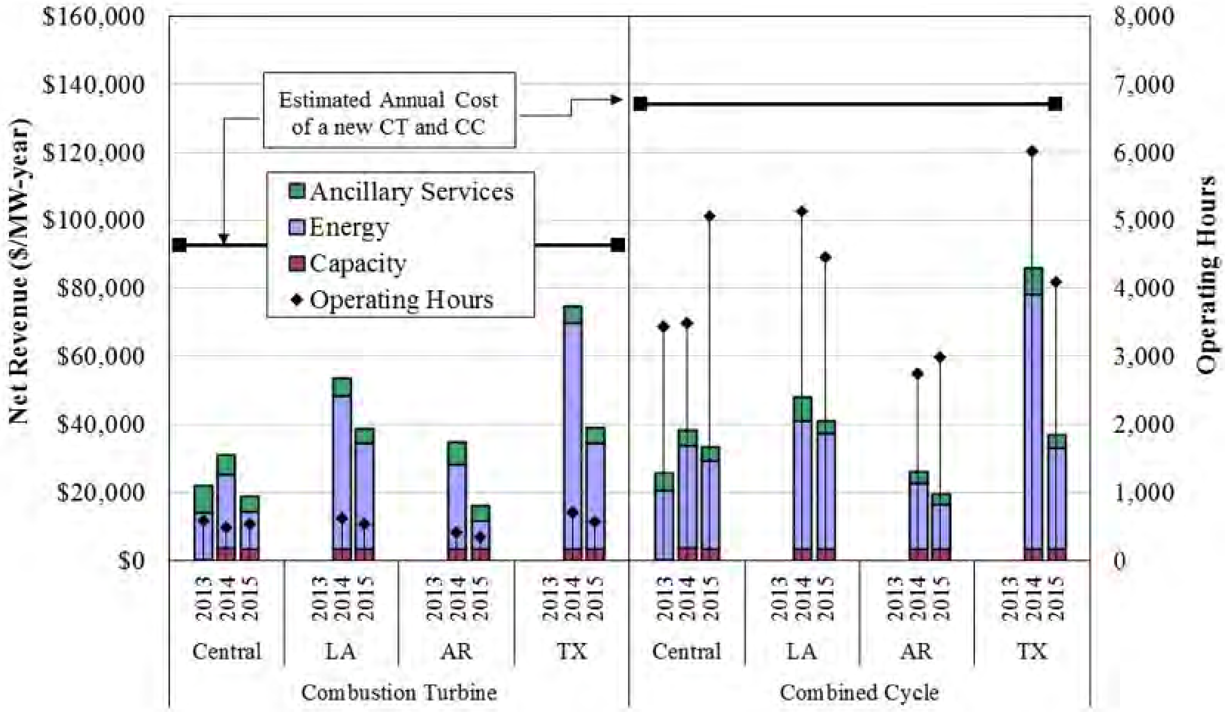


Figure A9: Net Revenue and Operating Hours
South Region, 2013–2015



III. Resource Adequacy

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

In 2015 there were 126 market participants that either owned generation resources (totaling 175 GW of nameplate capacity) or served load in the MISO market.[4] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

MISO also serves as the reliability coordinator for an additional 14.5 GW of capacity. Manitoba Hydro, the largest coordinating member, does not submit physical bids or offers into MISO's markets, but they may schedule energy into or out of the market.[5] In this report, we exclude Manitoba Hydro from our analysis unless otherwise noted.

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 separately review 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.)

4 As of June 2016, MISO membership totals 430 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

5 Manitoba does submit offers for a limited amount of energy under a special procedure known as External Asynchronous Resources (EAR) which permits dynamic interchange with such resources. This EAR essentially allows five-minute dispatch of a limited portion of the MISO-MHEB interchange.

A. Generating Capacity and Availability

Figure A10: Distribution of Generating Capacity by Coordination Region

Figure A10 shows the December 2015 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 are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. Hence, wind capacity does not feature prominently in this figure, even though it makes up more than nine percent of ICAP.

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.

Figure A10: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2015

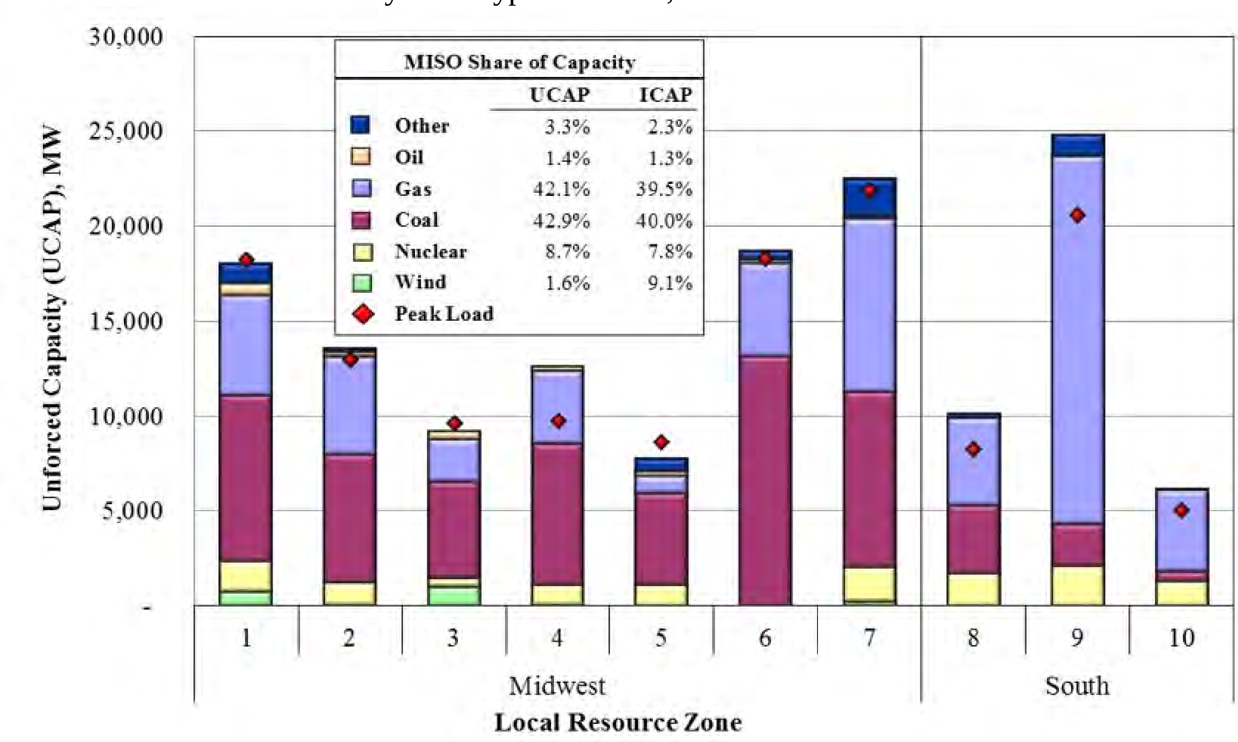
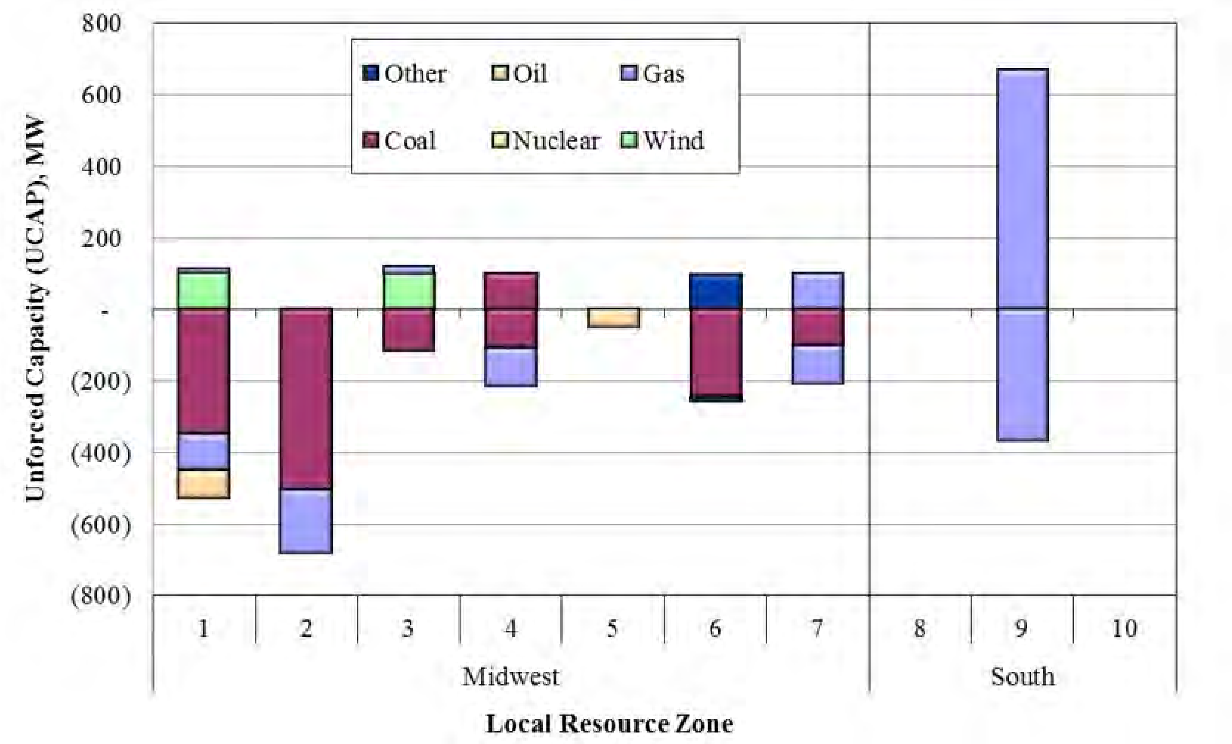


Figure A11: Resource Additions and Retirements

Figure A11 displays the change in the UCAP values during 2015. Negative values indicate retirements and positive values are resource additions. The data is shown by zone. For the same reason as described above, the UCAP values shown for wind resources is much lower than its nameplate or ICAP values.

Figure A11: Distribution of Additions and Retirements Generating Capacity
By Fuel Type and Zone, 2015



Figures A12 and A13: Availability of Capacity during Monthly Peak Load Hour

Figure A12 shows the status of generating capacity during the peak load hour of each month. The load in each of these peak hours is shown as a red diamond. Most of the load is served by MISO resources, whose output is the bottom (blue) segment of each bar. The next three segments are "headroom" (capacity available on online units above the dispatch point), offline quick-start generating capacity, and the emergency output range. These four segments represent the total capacity available to MISO. The other segments are the remaining capacity that cannot be dispatched for the indicated reasons. These categories of deratings and outages are generally shown separately for online and offline units.

The figure shows the quantity of "permanent deratings" (relative to nameplate capacity), which is unavailable in any hour. Many units cannot produce their nameplate output under normal operation, particularly older base-load units in the region. Additionally, wind resources often have ratings in excess of available transmission capability. The height of the bars in Figure A12 is equal to total generating capacity. It reflects additions and retirements of generators. Other monthly differences in total capacity are due to the variability of intermittent generation in each peak hour. Unavailable intermittent capacity between a wind resource's permanently derated level and actual output is not shown on the chart.

Figure A13 is similar, but shows only the unavailable capacity during the monthly peak hour. Planned maintenance scheduling should maximize resource available in the summer peak hours, but greater resource utilization during these periods can produce higher derating levels.

Figure A12: Availability of Capacity During Peak Load Hour
2015

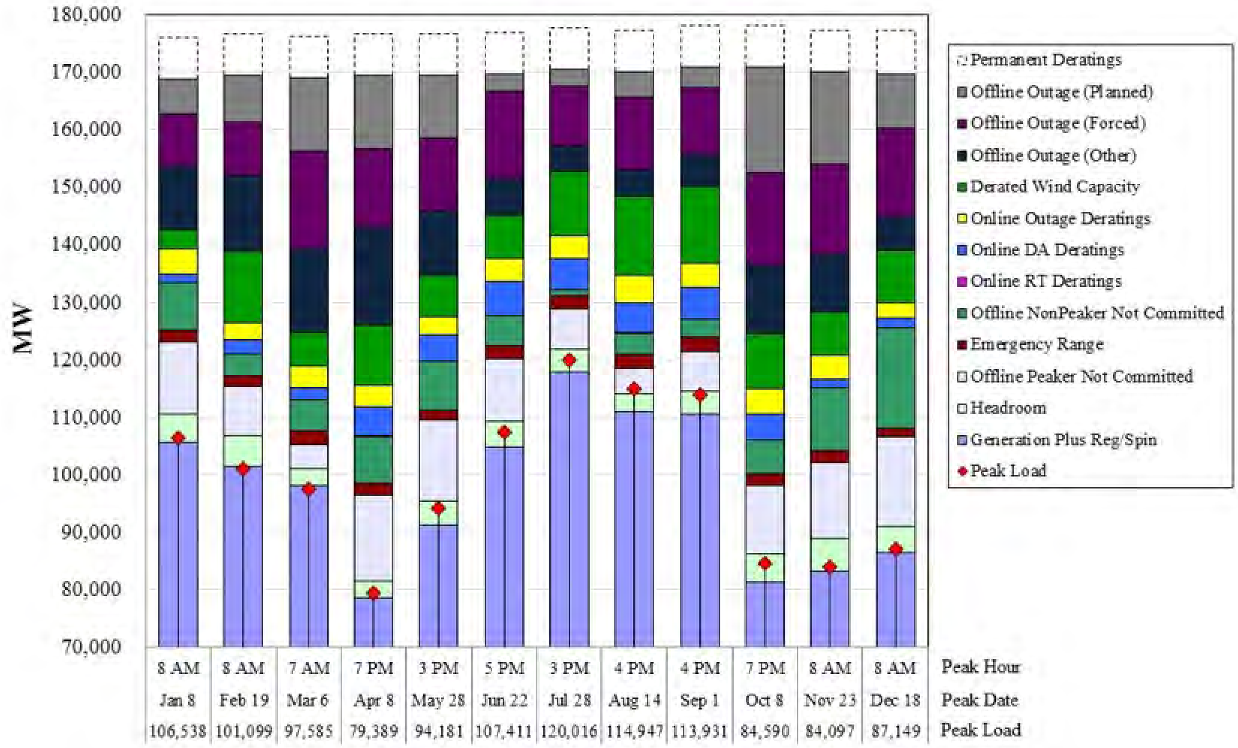


Figure A13: Capacity Unavailable During Peak Load Hours
2015

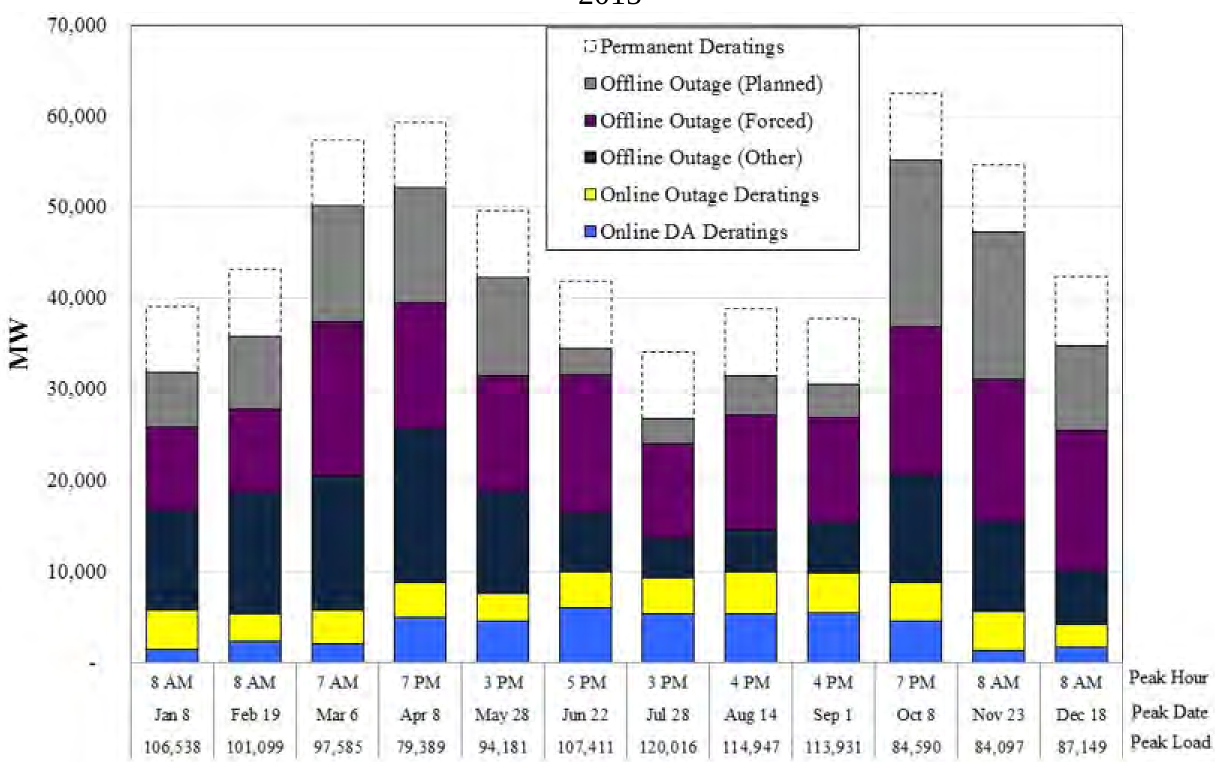
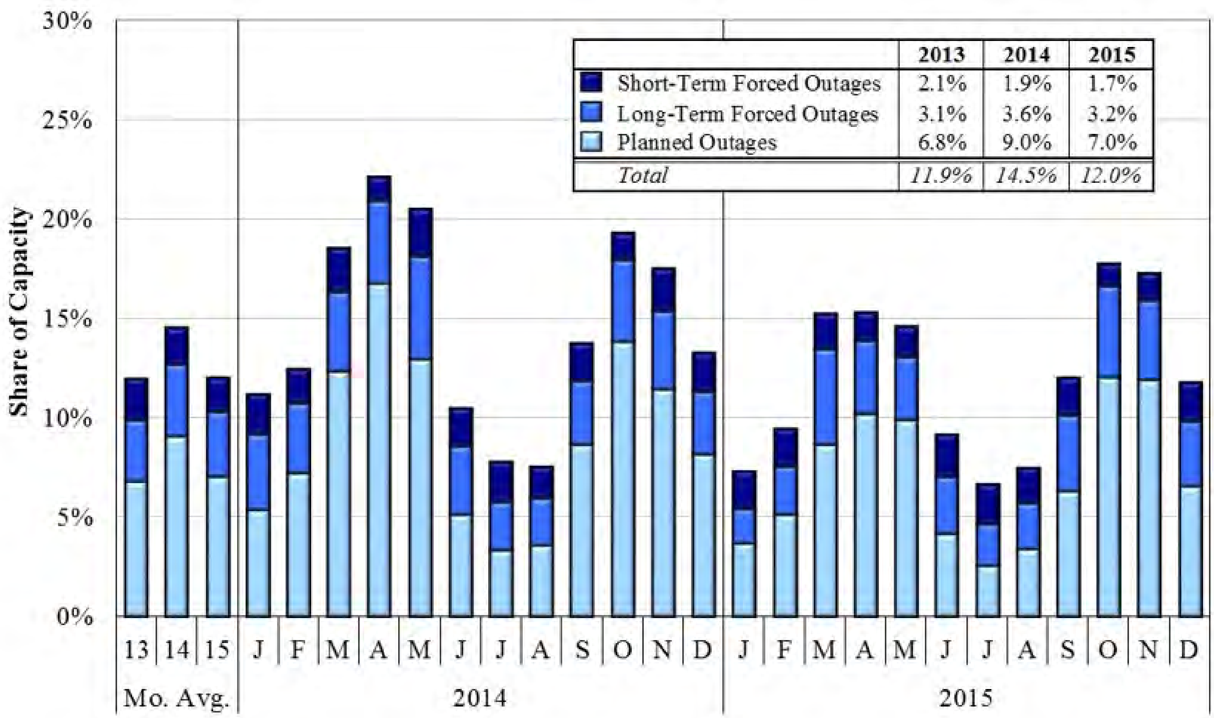


Figure A14: Generator Outage Rates

Figure A14 shows monthly average planned and forced generator outage rates for the three most recent years. Only full outages are included; partial outages or deratings are not shown. The figure also distinguishes between short-term forced outages (lasting fewer than seven days) and long-term forced outages (seven days or longer). Planned outages are often scheduled in low-load periods when economics are favorable for participants to perform maintenance. Conversely, short-term outages are frequently the result of an operating problem.

Short-term outages are also 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.

Figure A14: Generator Outage Rates
2013–2015



B. Planning Reserve Margins and Resource Adequacy

Table A2: Capacity, Load, and Reserve Margins

This subsection evaluates the supply in MISO, including the adequacy of resources for meeting peak needs in 2016. We estimate planning reserve margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. In its 2016 *Summer Resource Assessment*, MISO presented baseline planning reserve margin calculations alongside a number of valuable scenarios that demonstrate the sensitivity to changes in the key assumptions that we evaluate in our planning reserve margin analysis.

The planning reserve margin quantity is the sum of all quantities of capacity, including demand response and firm imports, minus the expected load. The planning reserve margin in percentage terms is then calculated by dividing the margin by load (net of demand response). Our results are shown in Table A2.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[6] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation and imports; and (e) full response from DR resources (behind the meter generation, interruptible load, and direct controllable load management). We have worked with MISO to ensure that our Base Case planning reserve level is consistent with MISO's, with one notable exception. While MISO's transfer limit assumption is based off of the 2016/2017 PRA transfer limit assumed value of 876 MW, we assume a probabilistic derated transfer capability of 2,000 MW, which results in a higher starting planning reserve margin in our base case.

These assumptions tend to cause the base case reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions or if demand response (load-modifying resources or "LMRs") do not perform fully when deployed. Therefore, we include some scenarios that differ from MISO's to show how alternative assumptions regarding DR deployments and unusually hot temperatures would affect MISO's planning reserve margins.

Table A2: Capacity, Load, and Reserve Margins
Summer 2016

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	**Realistic DR (1)**	**Full DR (2)**	**Realistic DR (3)**
Load				
Base Case	125,913	125,913	125,913	125,913
High Load Increase	-	-	6,318	6,318
Total Load (MW)	125,913	125,913	132,231	132,231
Generation				
Internal Generation	140,565	140,565	140,565	140,565
BTM Generation	3,462	3,462	3,462	3,462
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(1,203)	(1,203)	-	-
Total Generation (MW)	142,824	142,824	139,127	139,127
Imports and Demand Response				
Demand Response	6,413	5,130	6,413	5,130
Capacity Imports	2,540	2,540	2,540	2,540
Margin (MW)	25,863	24,581	15,849	14,566
Margin (%)	**20.5%**	**19.5%**	**12.6%**	**11.6%**

Notes:
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.
**The MISO Base Case Reserve Margin assumes that 1,203 MW (50/50 scenario) of capacity in MISO South cannot be accessed due to the 2,000 MW Transfer Limit (applying probabilistic derates on the 2,500 MW Transfer Limit) so this reduces the overall MISO Capacity Margin.

6 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).

Scenarios (1) and (3) are “realistic DR” cases that assume an 80 percent response rate from DR. A reasonably good response rate is expected because MISO has improved its Tariff requirements on DR, which now includes penalty provisions for non-performance and requires an annual demonstration of demand reduction capability for each planning year. We do not use a higher response rate because DR can require up to 12 hours of advanced notice to respond and most DR is not under the direct control of MISO. Additionally, there is a lack of recent historical response data during emergency conditions. However, when DR was deployed in 2006, the response rate was roughly 50 percent.

We also attempt to account for generator derates under higher temperatures than normal in scenarios (2) and (3). MISO’s high-temperature scenario assumes an annual EFORd and monthly net dependable capacities, which doesn’t fully capture the negative correlation between loads and power plant capability under conditions when ambient temperatures are much higher than normal. In addition to the ambient temperature effects, power plants cooled by river water can experience deratings when water temperatures are too high. There is significant uncertainty regarding the size of these derates, so our number in the last two columns of the table is an average of what was observed on extreme peak days in 2006 and 2012 (two years with weather substantially hotter than normal). However, significant supply derates can be a bigger contributing factor to tight reserve margins than an increase in load.

C. Capacity Market Results

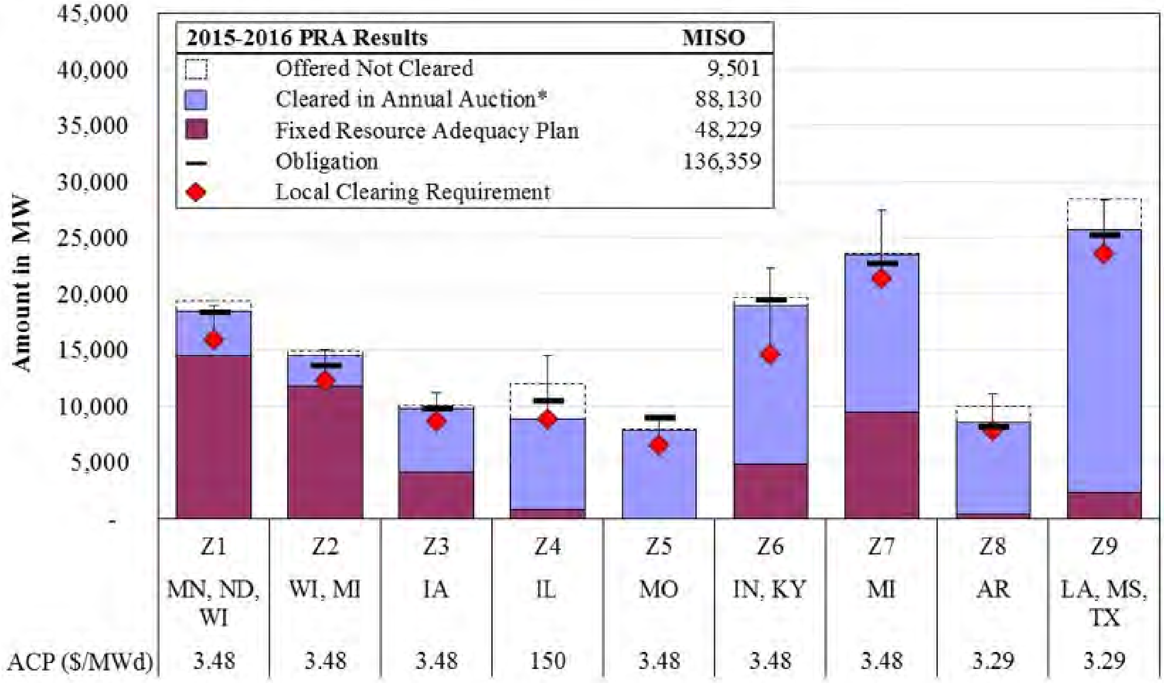
In June 2009, MISO began operating a monthly voluntary capacity auction (VCA) to allow LSEs to procure capacity to meet their Tariff Module E capacity requirements. The VCA was intended to provide a balancing market for LSEs, with most capacity needs being satisfied through owned capacity or bilateral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

Figure A15: Planning Resource Auction Results

Figure A15 shows the zonal results of the 2015–2016 Annual PRA, held in spring 2015 and covering June 2015 to May 2016. The black dash 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 capacity import and export limits.) The local clearing requirement (LCR), which is the minimum amount that must be procured within a zone, is indicated by the red diamond. When the LCR binds so that only the LCR quantity is procured in a zone, the price in the zone will rise. This occurred in 2015 in Zone 4 where the price cleared at $150 per MW-day, far above the $3-$4 price established in other zones. Additionally, the 2015/2016 auction only allowed 1000 MW to be transferred between MISO South to MISO Midwest. This constraint bound in the 2015 auction, causing zones 8 and 9 to clear at a lower price than the zones in the Midwest.

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. They are included in the auction to satisfy the local clearing requirements, but FRAPs cannot set price.

Figure A15: Planning Resource Auction
2015–2016



D. Capacity Market Design: Sloped Demand Curve

The PRA consists of a single-price auction to determine the clearing price and quantities of capacity procured in MISO and in each of the nine zones. The demand in this market is implicitly defined by the minimum resource requirement and a deficiency price, which is based on the Cost of New Entry or CONE that is updated annually. These requirements result in a vertical demand curve (which means demand is insensitive to the price, and MISO is willing to buy the same amount of capacity at any price). 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 this market through the use of 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.

1. Attributes of Demand in a Capacity Market

The demand for any good is determined by the value 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 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 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.

2. Attributes of Supply in a Capacity Market

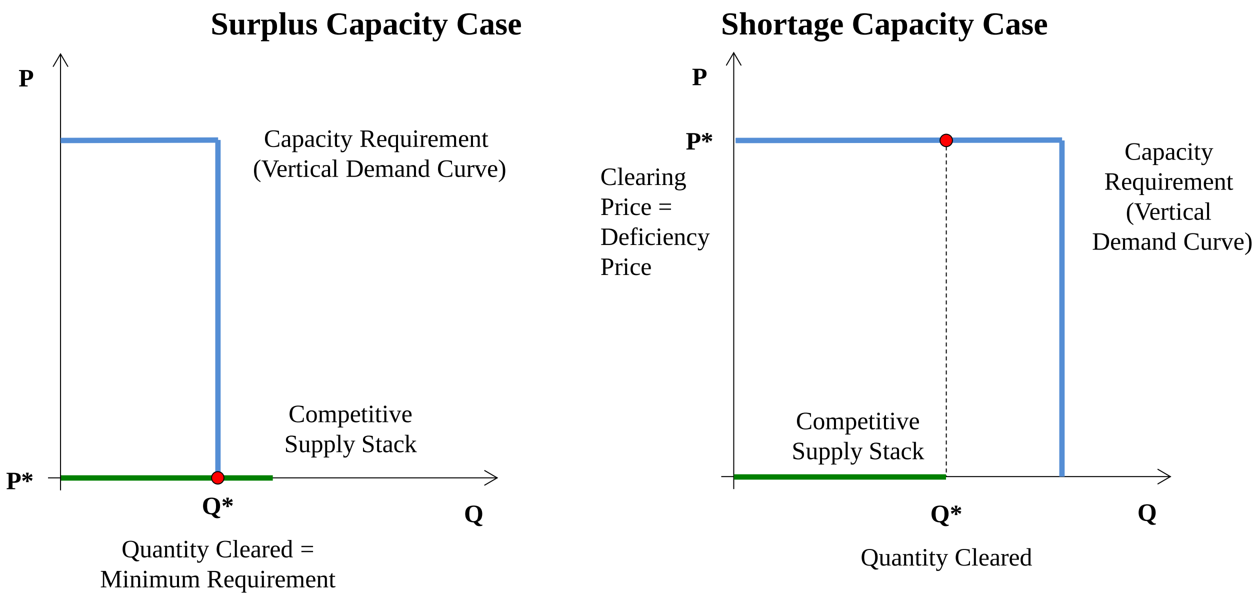
In workably competitive capacity markets, the competitive offer for existing capacity (i.e., the marginal cost of selling capacity) is generally close to zero (ignoring export opportunities). A supplier's offer represents the lowest price it would be willing to accept to sell capacity. This is determined by two factors: (1) the costs the supplier will incur to satisfy the capacity obligations for the resource (the "going-forward costs", or GFC), and (2) whether a minimum amount of revenue is necessary from the capacity market in order to remain in operation (i.e., the expected net revenues from energy and ancillary services markets do not cover GFC).

For most resources, the net revenues available from RTOs' energy and ancillary services markets are sufficient to keep a resource in operation. Hence, no additional revenue is needed from the capacity market (which would cause the supplier to submit a non-zero capacity offer). With regard to the first factor, suppliers that sell capacity in MISO are not required to accept costly obligations (that could substantially increase the suppliers' costs of selling capacity).

Hence, most suppliers are willing price-takers in the capacity market, accepting any non-zero price for capacity. One factor that could cause internal capacity suppliers to offer non-zero prices is the opportunity to export capacity. If such opportunities exist, suppliers should rationally include this opportunity cost in their capacity offer price. Currently, such opportunities are limited. Experience in the PRA has confirmed that most suppliers are essentially price-takers, submitting offers at prices very close to zero.

3. Implications of the Vertical Demand Curve

When the low-priced supply offers clear against a vertical demand curve, only two outcomes are possible. If the market is not in a shortage, the price will clear close to zero – this is illustrated in the left figure below and characterizes the recent auction results in MISO. If the market is in shortage (so the supply and demand curves do not cross), the price will clear at the deficiency price, as shown in the right figure.



This pricing dynamic and the associated market outcomes raise significant issues regarding the long-term performance of the current capacity market. First, this market will result in significant volatility and uncertainty for market participants. This can hinder long-term contracting and investment by making it extremely difficult for potential investors to forecast the capacity market revenues. In fact, it may be difficult for an investor to forecast with enough certainty that the market will be short in the future and produce forecasted capacity revenues that will be substantially greater than zero. This would undermine the effectiveness of the capacity market in maintaining adequate resources.

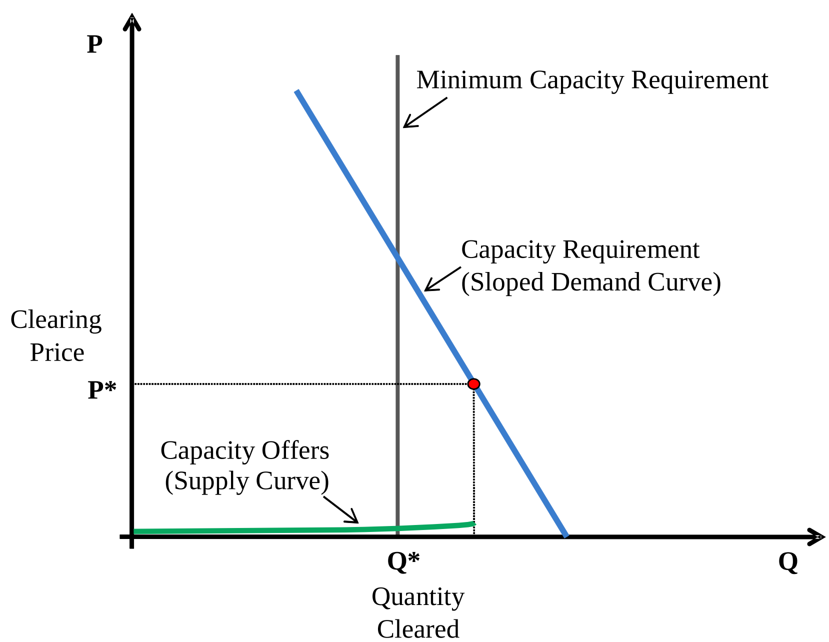
Second, since prices produced by such a construct do not accurately reflect the true marginal value of capacity, the market will not provide efficient long-term economic signals to govern investment and retirement decisions.

Third, a market that is highly sensitive to such small changes in supply around the minimum requirement level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless since the foregone capacity sales would otherwise be priced at close to zero. Therefore, market power is of greater potential concern, even in a market that is not concentrated. These concerns grow with local capacity zones, where the ownership of supply is generally more concentrated.

4. Benefits of a 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.

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 (the vertical line that crosses the “kink” in the demand curve). 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, it would significantly improve suppliers’ incentives. Likewise, the sloped demand curve reduces the incentives for buyers or policymakers to support uneconomic investment in new capacity to lower capacity prices.

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), FERC should recognize that some of the most important parameters are being 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 in the record for why an infinite slope is efficient or reasonable.

5. Effects of a Sloped Demand Curve on Vertically-Integrated LSEs

Load-serving entities (LSEs) and their ratepayers should benefit from a sloped demand curve. LSEs in the Midwest 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. Since 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 A3: Effects on LSEs of Alternative Capacity Demand Curves

Table A3 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 A3: 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 associated with the sloped demand curve:

- The sloped demand curve does not raise the expected costs for most regulated LSEs. In this example, if an LSE fluctuates between 1 and 2 percent surplus (around the 1.5 percent market surplus), its costs will be virtually the same under the sloped and vertical demand curves.
- The sloped demand curve 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 1 and 4 percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.
- A smaller share of the total cost is 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 3 percent case, for example, the current market would produce almost no wholesale 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 LSE's 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 to providing efficient market signals to other types of market participants (unregulated suppliers, competitive retail providers, and capacity importers and exporters).

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

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 A16 and Figure A17: Day-Ahead Energy Prices and Load

Figure A16 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 A16: Day-Ahead Hub Prices and Load
Peak Hours, 2014–2015

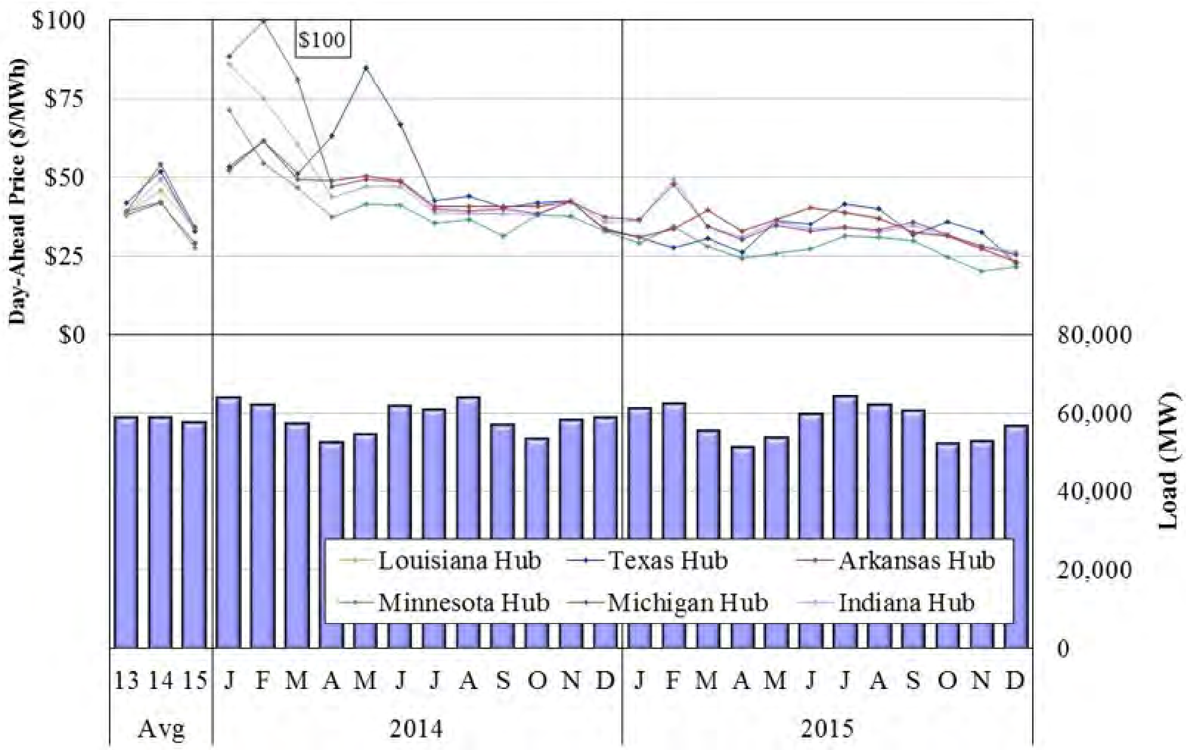
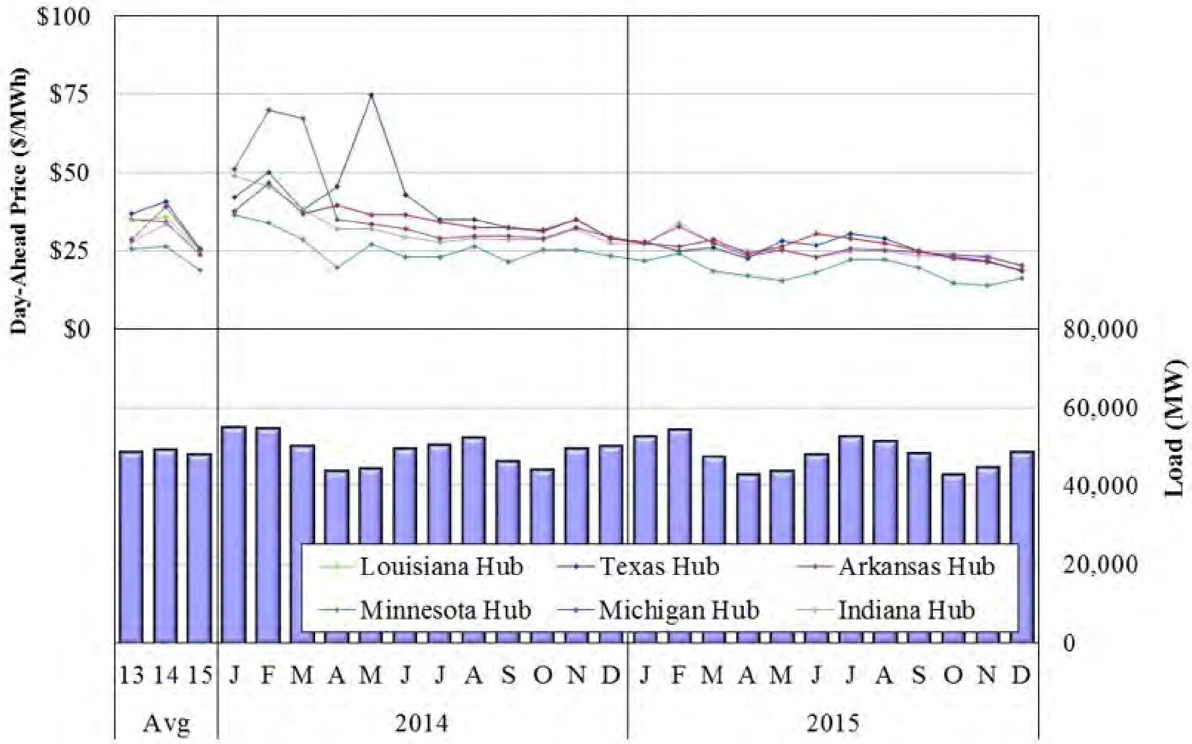


Figure A17 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Differences in prices among the hubs show the prevailing congestion and loss patterns. High prices in one location relative to another location indicate congestion and loss factor differences from a low-priced area to a high-priced area.

Figure A17: Day-Ahead Hub Prices and Load
Off-peak Hours, 2014–2015



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, it means anticipated conditions are not being realized in the physical dispatch in real time. This can result in:

- Generating resources not being efficiently committed since 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 since these payments are determined by day-ahead market outcomes, which will ultimately distort future FTR prices and revenues.

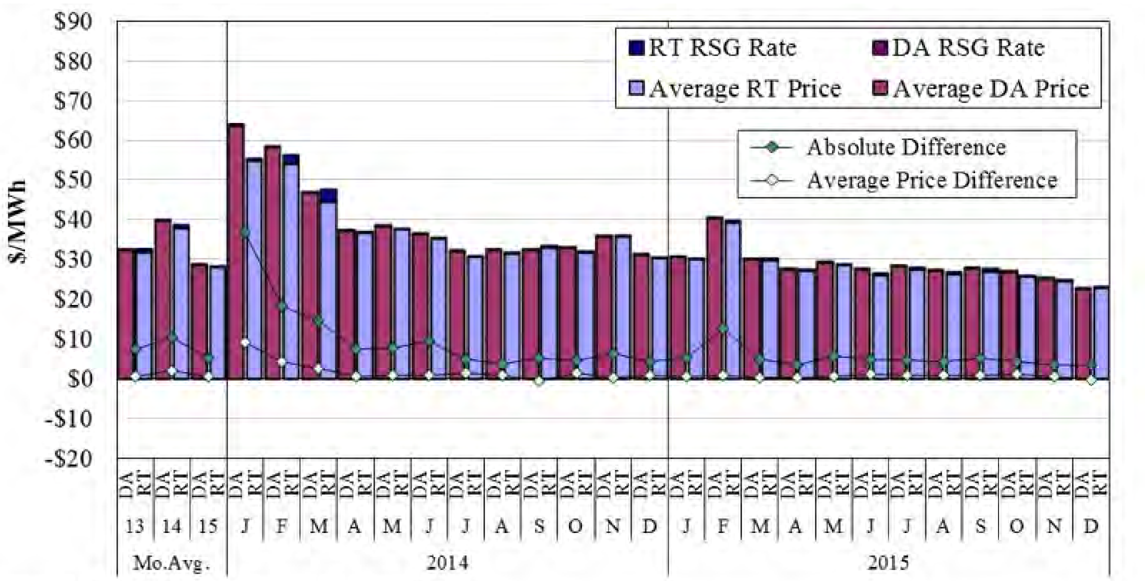
Participants' day-ahead market bids and offers should reflect their expectations of the real-time market the following day. However, a variety of factors can cause real-time prices to be significantly higher or lower than anticipated day-ahead. While a well-performing market may not result in prices 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 allocation of real-time RSG costs (typically much larger than day-ahead RSG charges). Day-ahead RSG costs were relatively high in 2015, but most of these costs were associated with local reliability requirements in MISO South and were allocated locally. Hence, most day-ahead purchases can avoid these RSG costs.

Figure A18 to Figure A24: Day-Ahead and Real-Time Prices

The next seven figures show monthly average prices in the day-ahead and real-time markets at seven representative locations in MISO, along with the average RSG costs allocated per MWh.[7] 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 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 A18: Day-Ahead and Real-Time Price
2014–2015: Indiana Hub

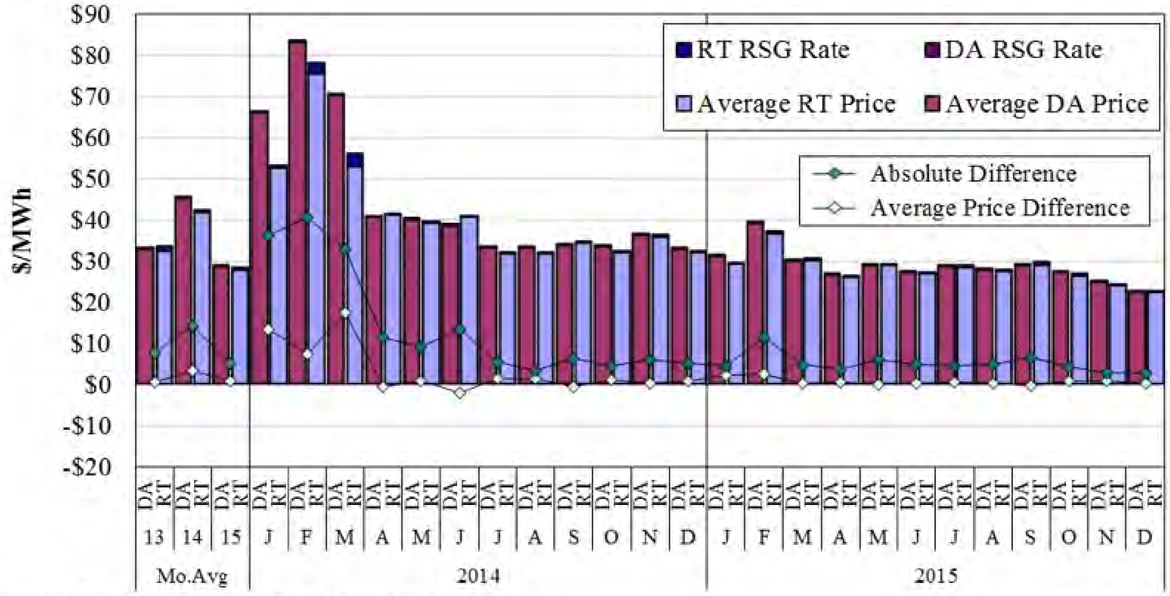


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	2	5	2	16	8	6	2	2	2	4	3	-2	4	1	3	2	2	1	1	2	5	3	3	3	4	2	-1
Including RSG	-1	3	1	16	4	-1	2	2	3	4	2	-2	3	0	2	1	1	0	1	2	3	1	2	0	3	2	-2

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

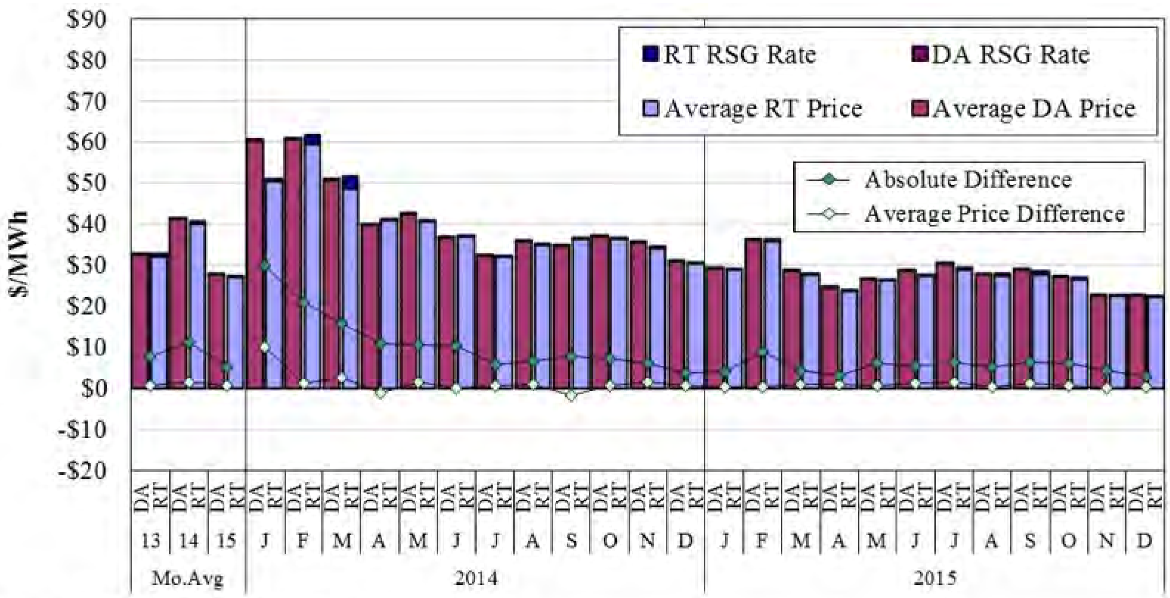
Figure A19: Day-Ahead and Real-Time Price
2014–2015: Michigan Hub



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

	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Excluding RSG	2	8	3	26	10	33	-1	2	-5	4	4	-2	4	1	2	8	7	1	2	0	1	2	1	-1	4	4	1
Including RSG	-1	7	1	25	7	26	-1	2	-5	4	3	-2	3	0	2	7	6	-1	2	0	0	0	0	-3	2	3	0

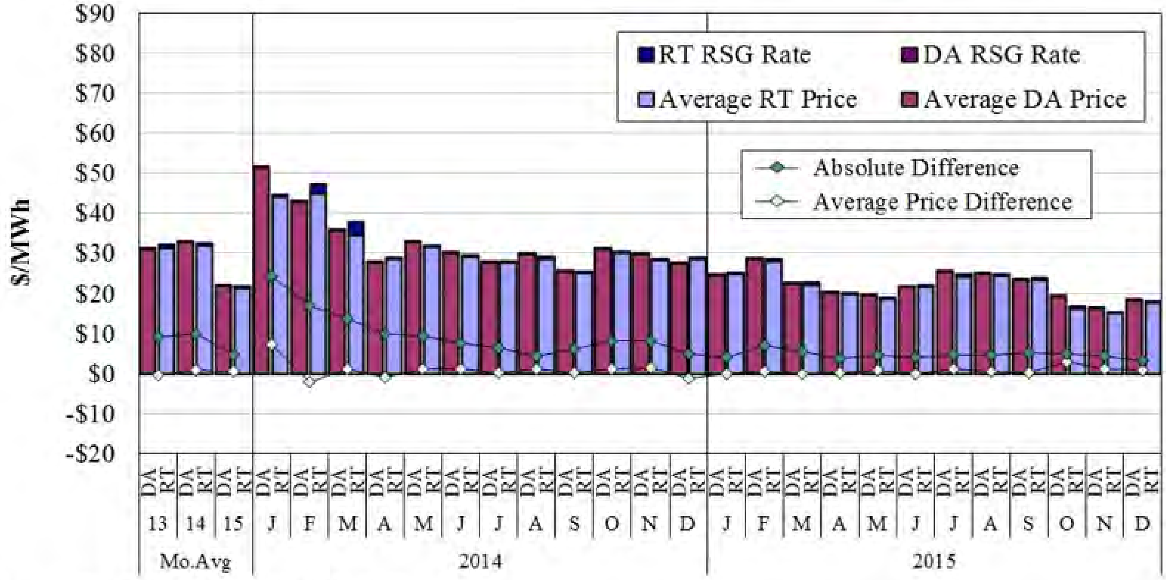
Figure A20: Day-Ahead and Real-Time Price
2014–2015: WUMS Area



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

	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Excluding RSG	2	3	2	20	2	5	-3	4	0	2	2	-5	1	4	1	1	1	3	4	2	4	5	1	4	2	0	1
Including RSG	-1	2	1	19	-2	-1	-3	3	0	2	2	-5	1	3	1	1	0	2	4	1	3	3	0	1	1	-1	0

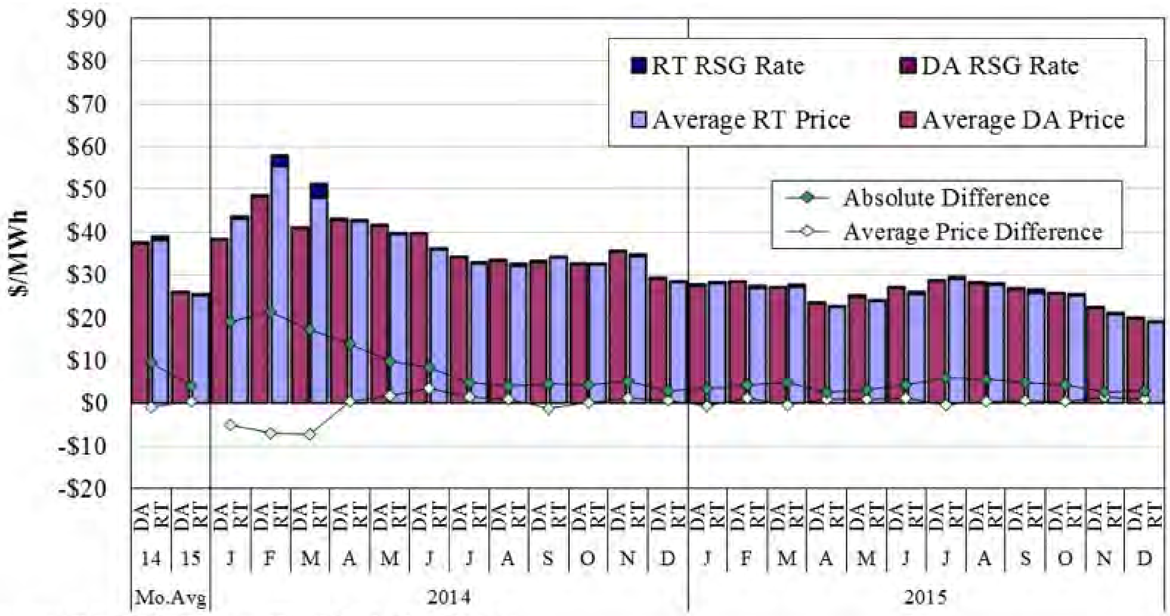
Figure A21: Day-Ahead and Real-Time Price
2014–2015: Minnesota Hub



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

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

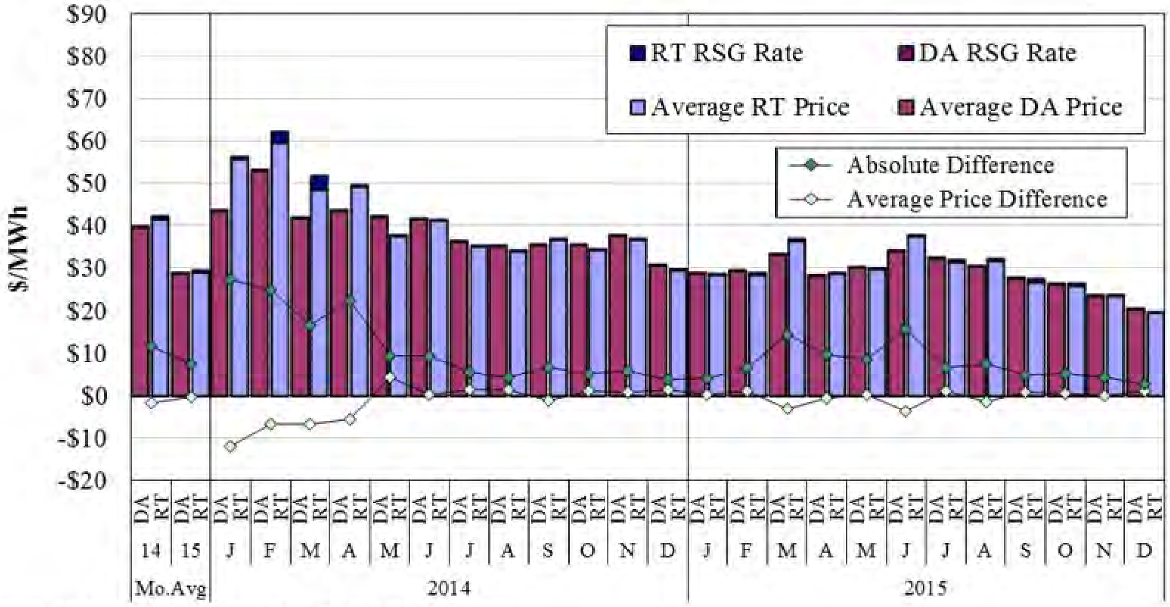
Figure A22: Day-Ahead and Real-Time Price
2014–2015: Arkansas Hub



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

Excluding RSG	-2	2	-12	-13	-15	1	5	10	4	3	-3	0	3	3	-2	5	-2	4	4	5	-2	1	3	2	7	4
Including RSG	-3	1	-12	-16	-20	1	4	10	5	2	-4	-1	3	2	-3	3	-3	4	3	3	-3	0	0	0	6	4

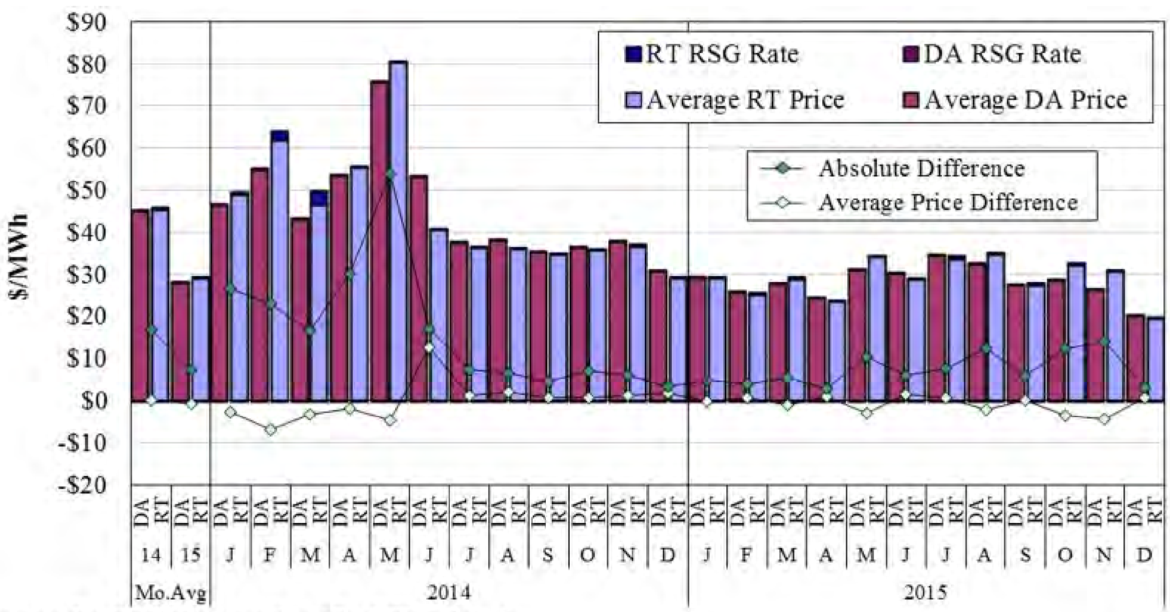
Figure A23: Day-Ahead and Real-Time Price
2014–2015: Louisiana Hub



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

Excluding RSG	-4	-1	-22	-11	-14	-12	11	0	3	4	-4	3	2	4	1	3	-9	-2	1	-10	3	-4	3	1	0	5
Including RSG	-6	-2	-22	-14	-19	-12	11	1	4	3	-4	2	2	4	0	2	-10	-2	0	-10	1	-5	0	0	-1	4

Figure A24: Day-Ahead and Real-Time Price
2014–2015: Texas Hub



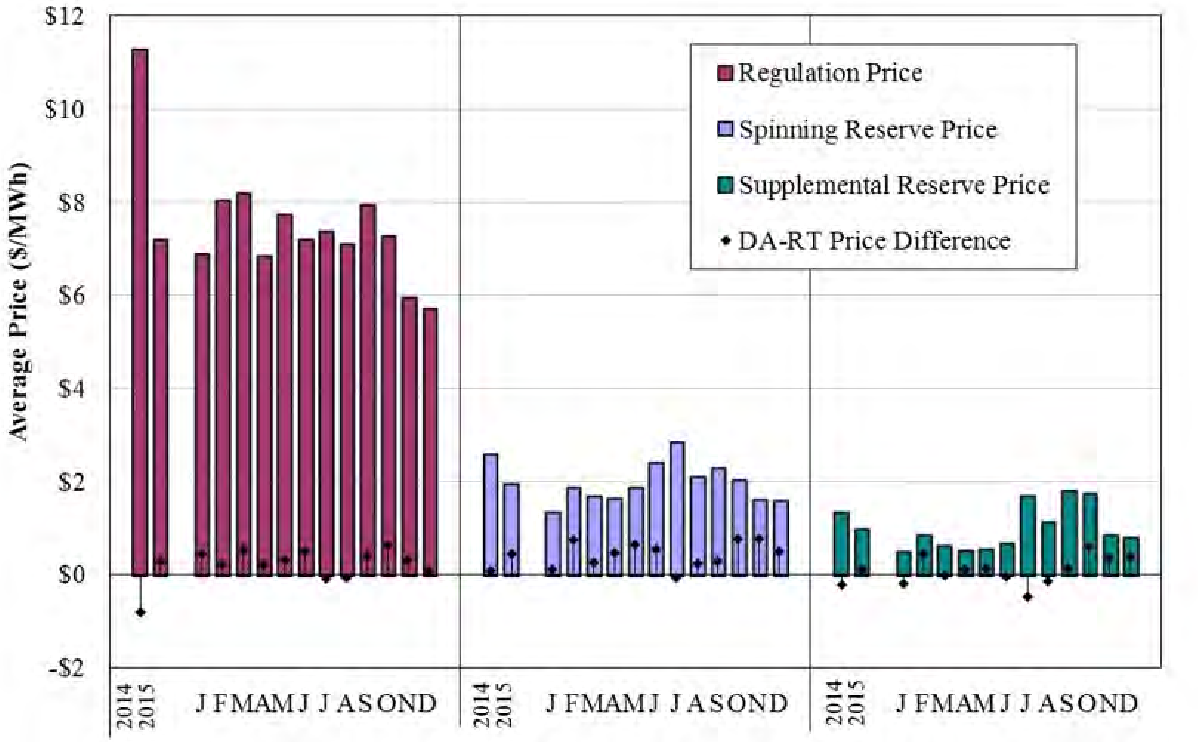
Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	0	-3	-5	-11	-7	-4	-6	31	3	5	2	1	3	6	-1	2	-4	3	-9	5	2	-7	0	-11	-15	3
Including RSG	-1	-4	-6	-14	-13	-4	-6	31	3	5	2	1	2	5	-1	1	-5	4	-10	4	0	-7	-2	-12	-15	3

Figure A25: Day-Ahead Ancillary Services Prices and Price Convergence

The figures above show the convergence of MISO's energy markets. Price convergence is also important for MISO's ancillary service markets, which are jointly optimized with the energy markets. These markets have operated without significant issues since their introduction in January 2009. Figure A25 shows monthly average day-ahead clearing prices in 2015 for each ancillary services product, along with day-ahead to real-time price differences.

Figure A25: Day-Ahead Ancillary Services Prices and Price Convergence
2015



C. Day-Ahead Load Scheduling

Load scheduling, net scheduled interchange (NSI) and virtual trading in the day-ahead market plays 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 scheduled load is defined as physical load plus cleared virtual load minus cleared virtual supply, plus NSI. The differences between net scheduled 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 in real-time to satisfy the system's needs. Peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section V.K). This can contribute to suboptimal real-time pricing and can result in inefficiencies 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.

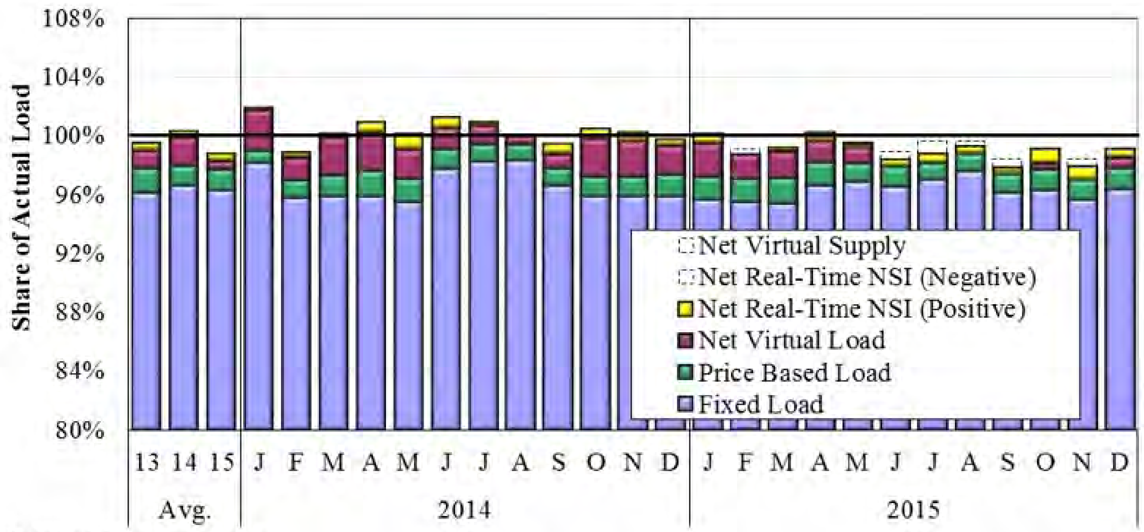
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

- 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 A26 to Figure A28: Day-Ahead Scheduled Versus Actual Loads

To show net load-scheduling patterns in the day-ahead market, Figure A26 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 Figure A27 and Figure A28.

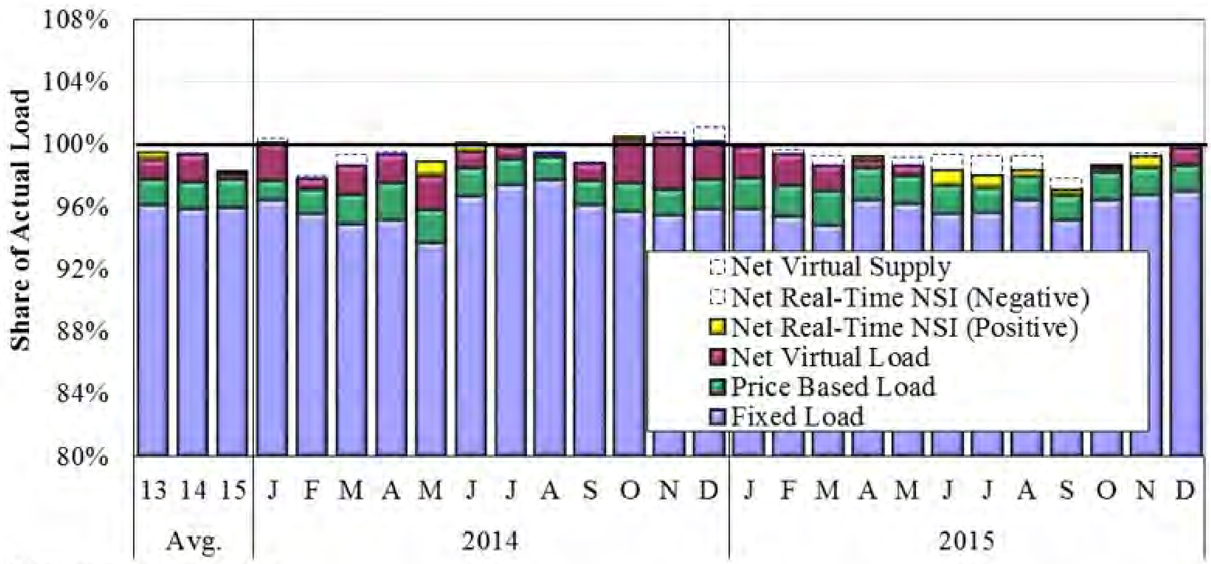
Figure A26: Day-Ahead Scheduled Versus Actual Loads
2014–2015, Daily Peak Hour



Share of Actual Load (%)

	Avg. 13	Avg. 14	Avg. 15	2014 J	2014 F	2014 M	2014 A	2014 M	2014 J	2014 J	2014 A	2014 S	2014 O	2014 N	2014 D	2015 J	2015 F	2015 M	2015 A	2015 M	2015 J	2015 J	2015 A	2015 S	2015 O	2015 N	2015 D
All Hours	99.7	100.7	99.0	102.1	100.0	100.1	101.0	100.8	101.4	101.0	100.3	99.6	100.0	100.6	99.8	99.9	98.9	98.6	99.3	99.4	98.5	99.4	99.6	98.5	98.2	97.9	98.4
Peak Hours	99.5	100.7	99.5	102.1	99.3	100.7	101.4	100.7	101.9	101.5	100.5	99.6	100.8	100.5	100.2	100.3	99.2	99.6	100.6	100.3	99.0	99.1	99.8	98.4	99.5	98.7	99.9

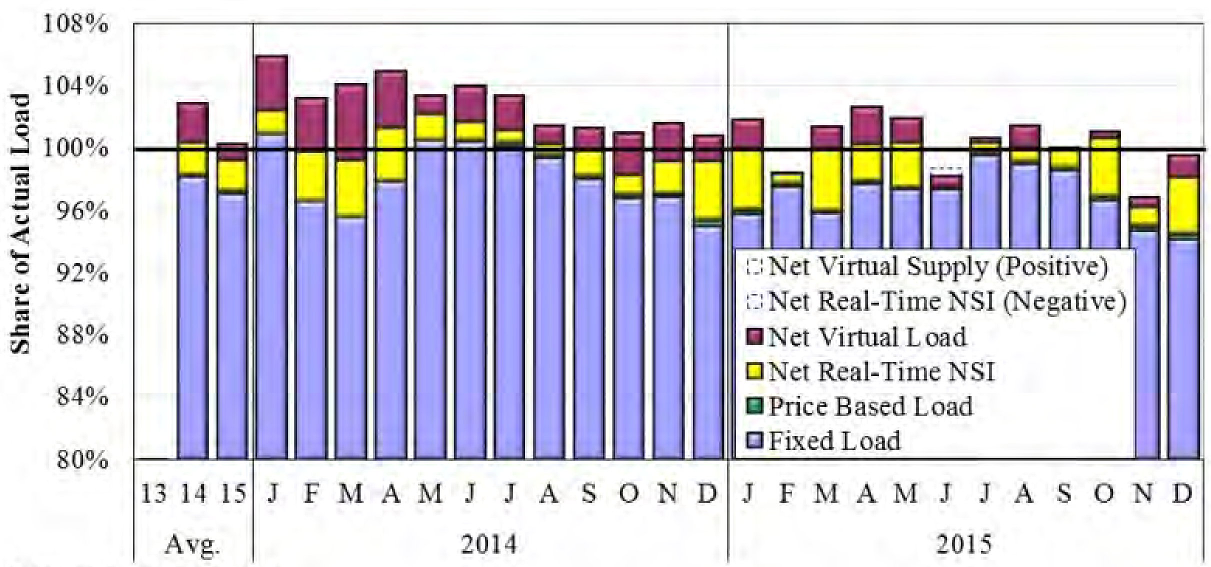
Figure A27: Midwest Region Day-Ahead Scheduled Versus Actual Loads
2014–2015, Daily Peak Hour



Share of Actual Load (%)

	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.7	100.5	98.7	101.9	99.7	99.9	100.3	100.8	101.5	100.8	99.9	99.2	100.0	100.4	99.2	99.5	98.8	98.0	99.0	98.8	98.6	99.2	99.3	98.1	97.9	98.0	98.0
Peak Hours	99.5	99.4	98.7	100.0	97.8	98.6	99.3	98.8	100.1	99.9	99.4	98.7	100.4	100.3	100.1	99.8	99.3	98.6	99.1	98.6	98.3	97.9	98.2	97.0	98.6	99.2	99.7

Figure A28: South Region Day-Ahead Scheduled Versus Actual Loads
2014–2015, Daily Peak Hour



Share of Actual Load (%)

	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours		103.6	100.6	105.9	103.5	103.1	105.6	104.0	104.0	103.4	102.0	101.4	101.5	102.4	100.8	101.8	98.6	101.4	101.6	102.0	99.5	101.3	101.8	100.3	99.9	98.3	100.0
Peak Hours		103.2	100.4	105.8	103.1	104.0	104.9	103.3	103.9	103.3	101.4	101.2	100.9	101.5	100.7	101.8	98.3	101.3	102.6	101.8	98.1	100.6	101.4	99.9	101.0	96.8	99.5

D. Hourly Day-Ahead Scheduling

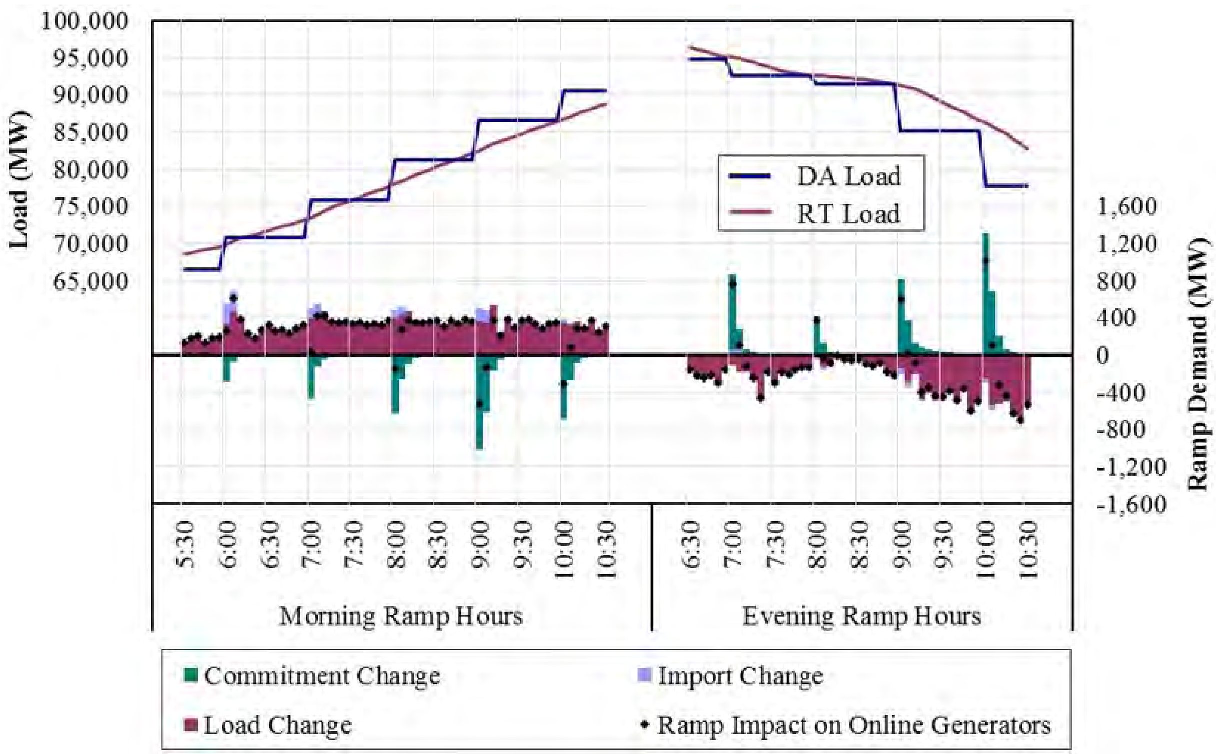
The day-ahead energy and ancillary services markets currently solves on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of the hour.

MISO currently 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. When it has the ability to do so, MISO should consider implementing a shorter time interval in the day-ahead market.

Figure A29: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A29 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 A29: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2015



E. Virtual Transaction Volumes

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 prices established in the real-time market. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. For example, if the market clears 1 MW of supply for $50 in the day-ahead market, virtual supply sellers must then purchase 1 MW in real time to cover the trade. They will incur a loss if the real-time cost (the LMP at the transaction location) exceeds $50 and receive a profit if it is less than $50.

Accordingly, if virtual traders expect real-time prices to be lower than day-ahead prices, they would sell virtual supply in the day-ahead market and buy (i.e., settle financially) the power back based on real-time market prices. Likewise, if virtual traders expect real-time prices to exceed day-ahead prices, they would buy virtual load in the day-ahead market and sell the power back based on real-time prices. This trading is one of the primary means to arbitrage prices between the two markets. Numerous empirical studies have shown that this arbitrage converges prices between the day-ahead and real-time markets and, in doing so, improves market efficiency and mitigates market power.[8]

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 would cause prices to diverge from real-time prices and the virtual transaction to 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 in the day-ahead market at the high (i.e., congested) price and sell the

8 See, for instance:

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.

Isemonger, Alan G. 2006. The Benefits and Risks of Virtual Bidding in Multi-Settlement Markets. The Electricity Journal, 19: 26-36.

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.

Saravia, Celeste. 2003. Speculative Trading and Market Performance: The Effect of Arbitrageurs on Efficiency and Market Power int eh New York Electricity Market, Center for the Study of Energy Markets (CSEM) Working Paper, University of California, Berkeley.

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 payments to its FTRs (or payments through some other physical or financial position) increase as a result of the higher day-ahead congestion. We continually monitor for indications of such behavior and utilize mitigation authority to restrict virtual activity when appropriate.

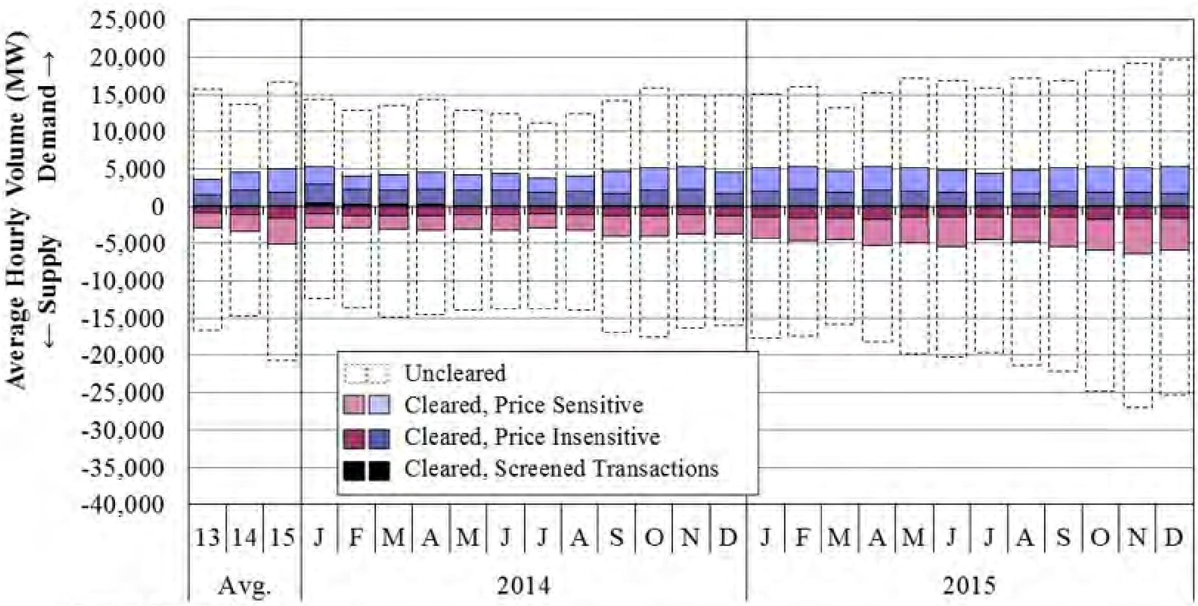
Figure A30 and Figure A31: Day-Ahead Virtual Transaction Volumes

Figure A30 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market from 2014 to 2015. Figure A31 separates these volumes by region in 2015. 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 offers priced at more than the clearing price and demand bids priced below the clearing price).

The figures 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 as calculated by the IMM 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 A30: Day-Ahead Virtual Transaction Volumes

2014–2015



Percent Screened

	Avg.			2014												2015											
	13	14	15	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	2.1	3.5	1.5	8.7	7.7	5.0	4.2	3.1	3.2	1.7	2.0	1.3	1.9	1.8	1.2	1.6	3.0	1.7	1.0	1.7	1.6	1.6	1.7	1.0	1.1	1.4	0.6
Supply	1.2	1.4	0.6	2.1	2.5	2.7	1.8	1.9	1.6	0.7	0.2	0.8	1.4	1.0	1.0	0.6	1.0	1.0	0.9	1.0	0.4	0.4	0.2	0.5	0.5	0.4	0.2
Total	1.7	2.6	1.0	6.4	5.6	4.1	3.2	2.6	2.5	1.3	1.2	1.1	1.7	1.5	1.1	1.1	2.1	1.4	1.0	1.4	0.9	1.0	1.0	0.8	0.8	0.8	0.4

Figure A31: Day-Ahead Virtual Transaction Volumes by Region
2015

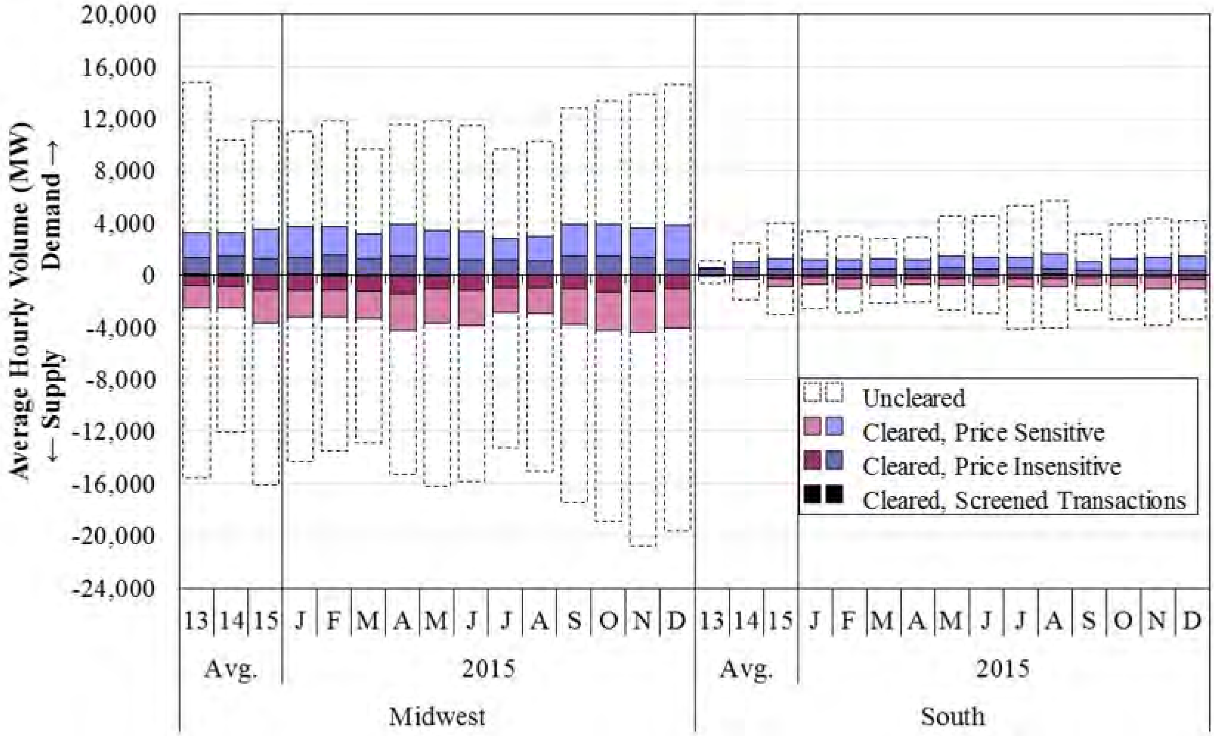


Figure A32 to Figure A35: Virtual Transaction Volumes by Participant Type

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 A32 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 A33 and Figure A34 show the same values by region and Figure A35 shows these values by type of location.

Figure A32: Virtual Transaction Volumes by Participant Type
2015

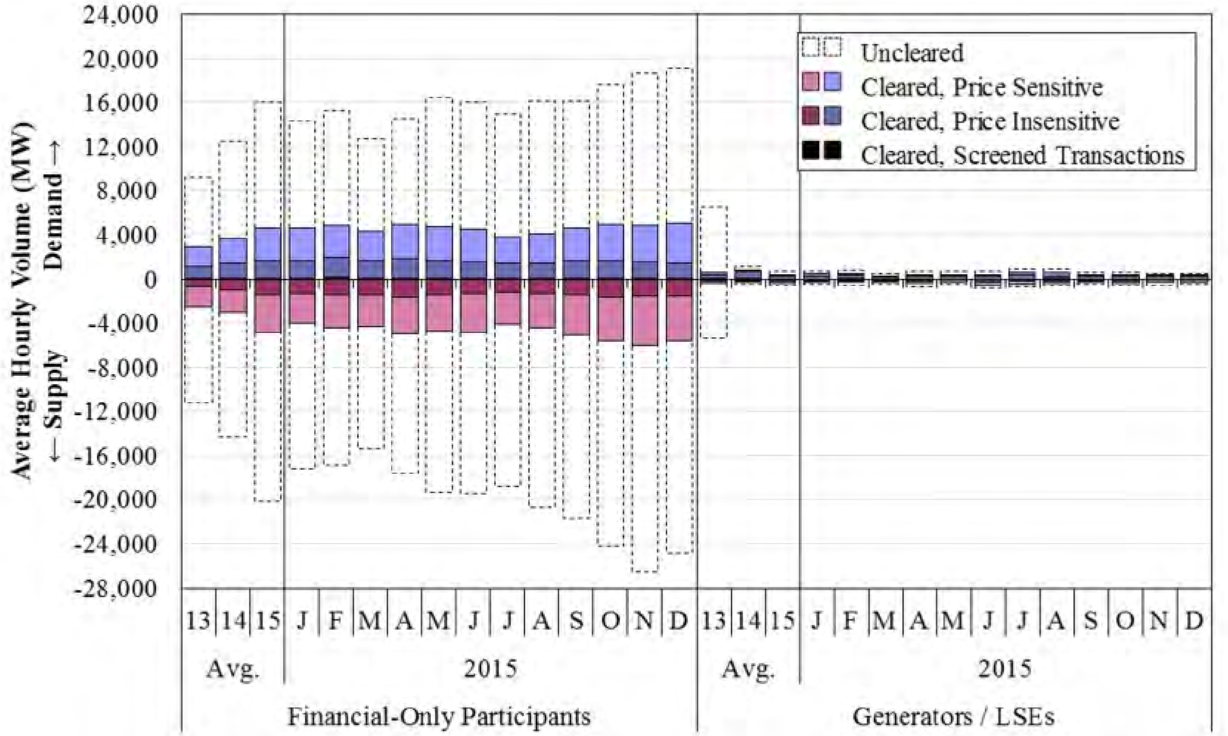


Figure A33: Virtual Transaction Volumes by Participant Type
Midwest Region, 2015

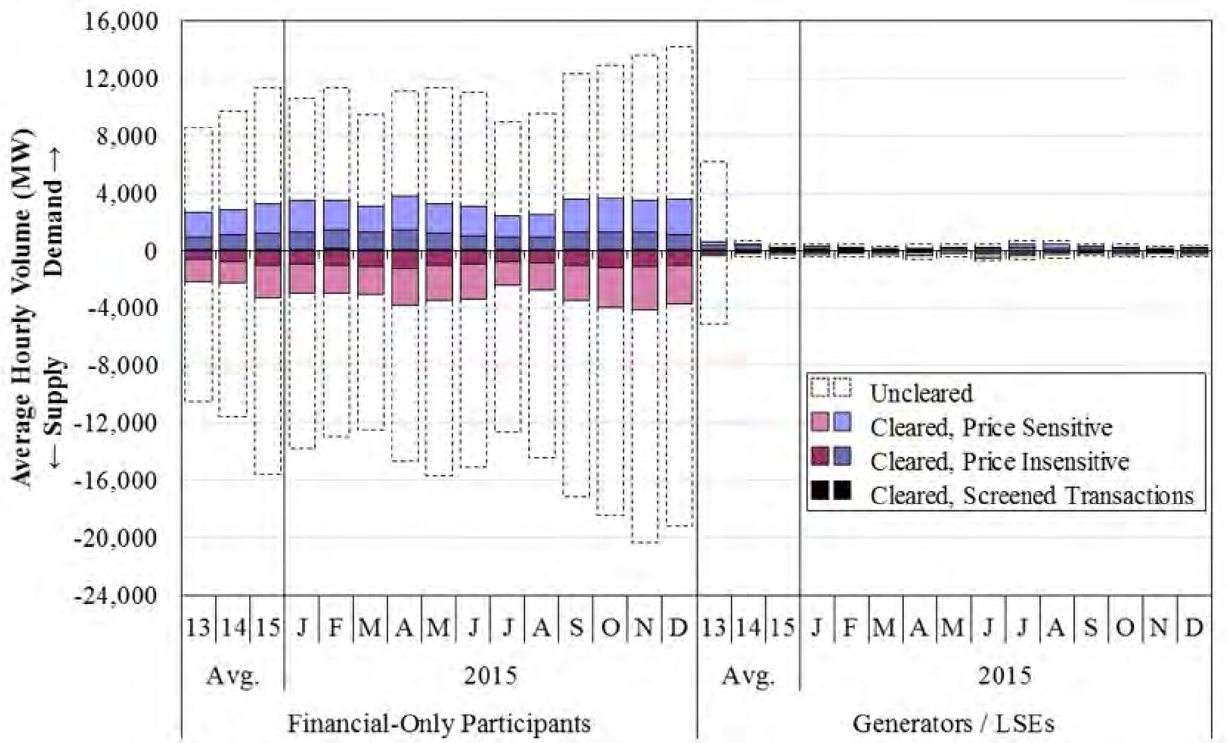


Figure A34: Virtual Transaction Volumes by Participant Type
South Region, 2015

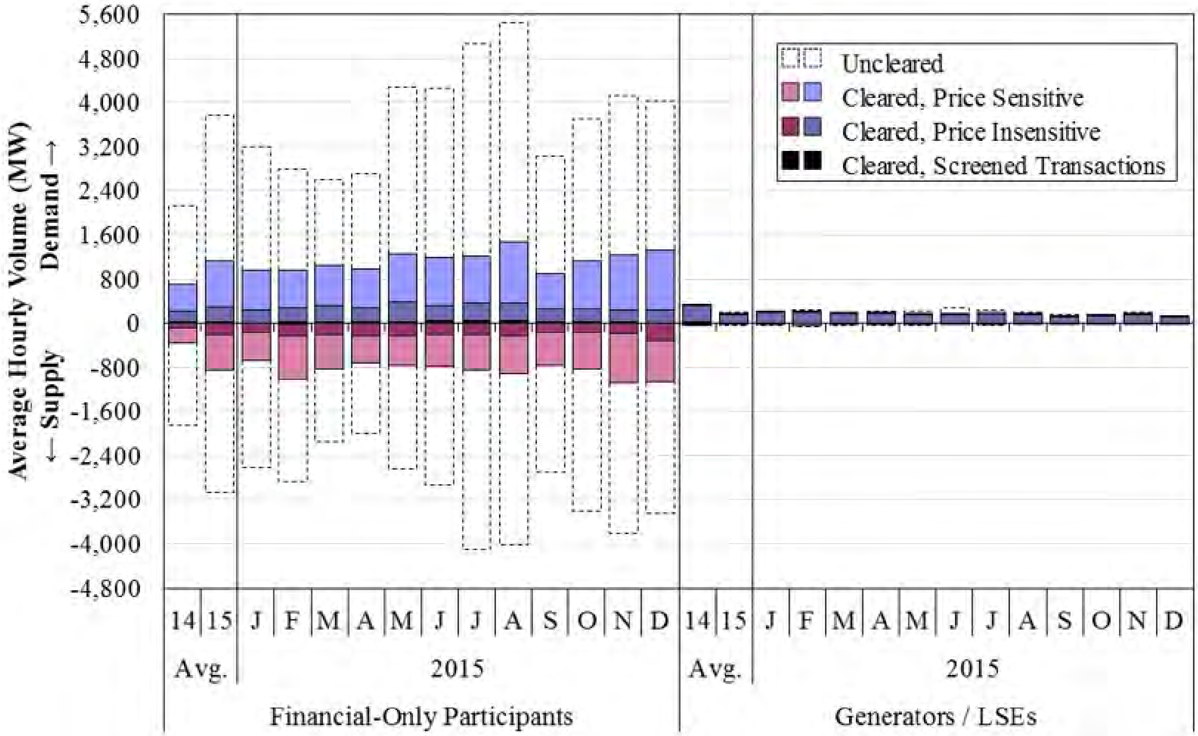


Figure A35: Virtual Transaction Volumes by Participant Type and Location
2013–2015

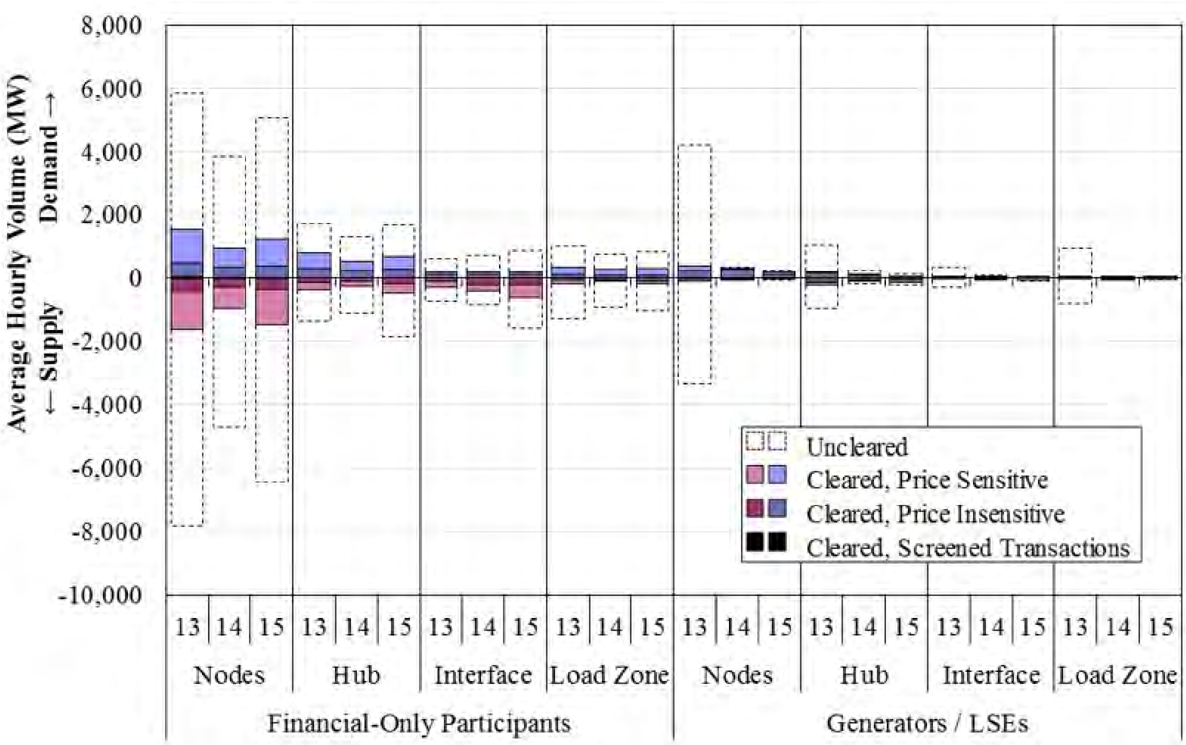


Figure A35 above, disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many nodes and are therefore less prone to congestion-related price spikes than generator locations. The Indiana Hub remained the single most liquid trading point in MISO during 2015.

Figure A36: Matched Virtual Transactions

Figure A36 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 seeking an energy-neutral position across a particular constraint. This allows the participant to arbitrage differences in congestion and losses between locations.

- A participant seeking to balance their portfolio. RSG day-ahead deviation or "DDC" charges 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 A36: Matched Price-Insensitive Virtual Transactions
2014-2015

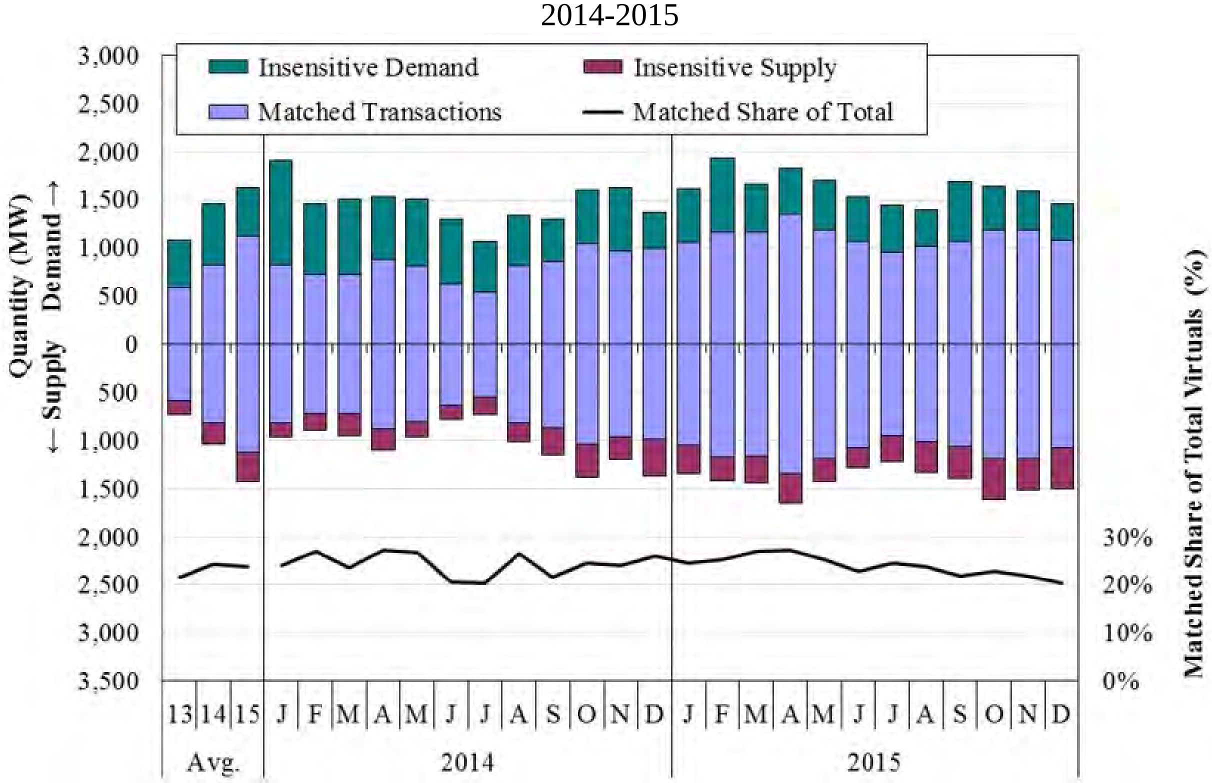
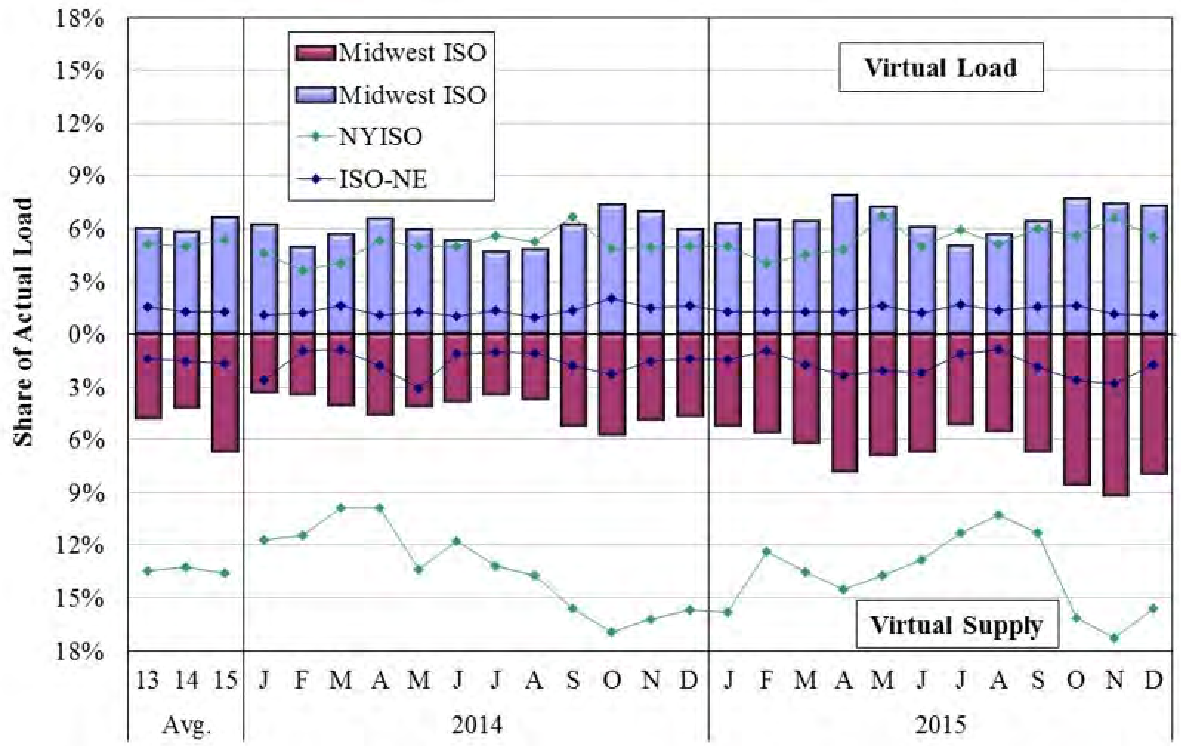


Figure A37: Virtual Transaction Volumes, MISO and Neighboring RTOs

To compare trends in MISO to other RTOs, Figure A37 shows cleared virtual supply and demand in MISO, ISO New England (ISO-NE), and New York ISO (NYISO) as a percent of actual load.

Figure A37: Comparison of Virtual Transaction Volumes
2014–2015



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 A38 to Figure A39: Virtual Profitability

Figure A38 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 A39 shows the same results disaggregated by type of market participant: entities owning generation or serving load, and financial-only participants.

Figure A38: Virtual Profitability
2014–2015

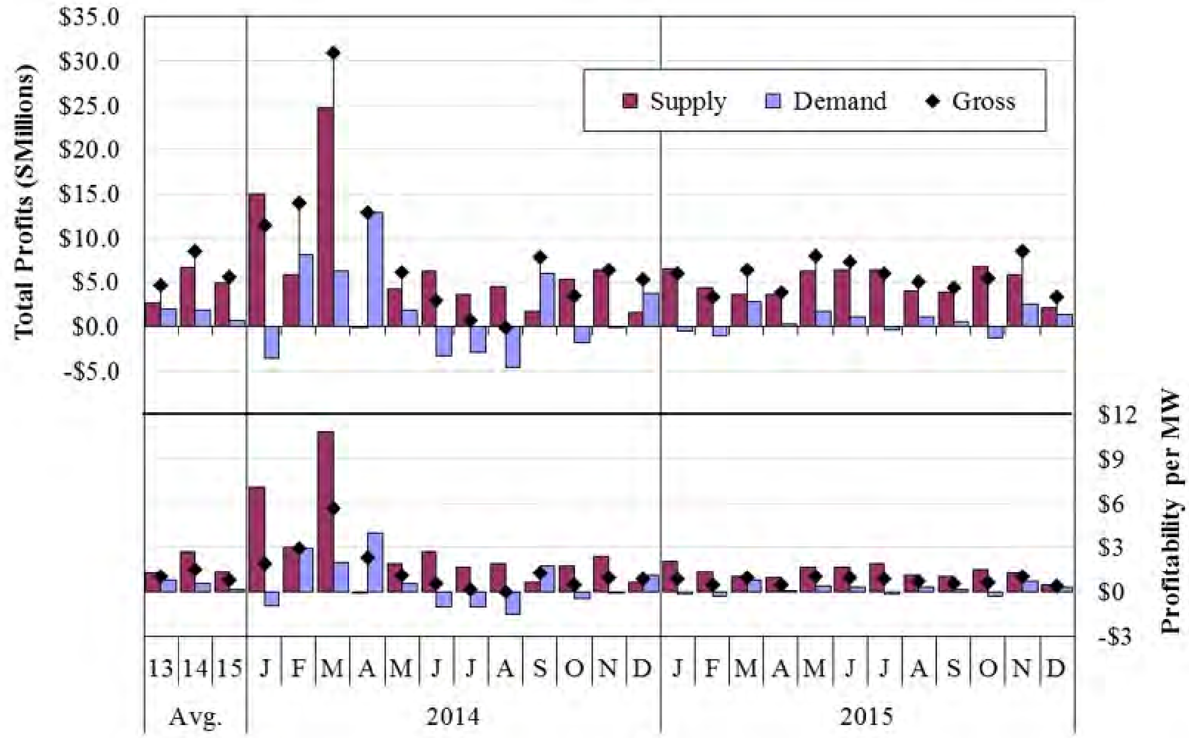
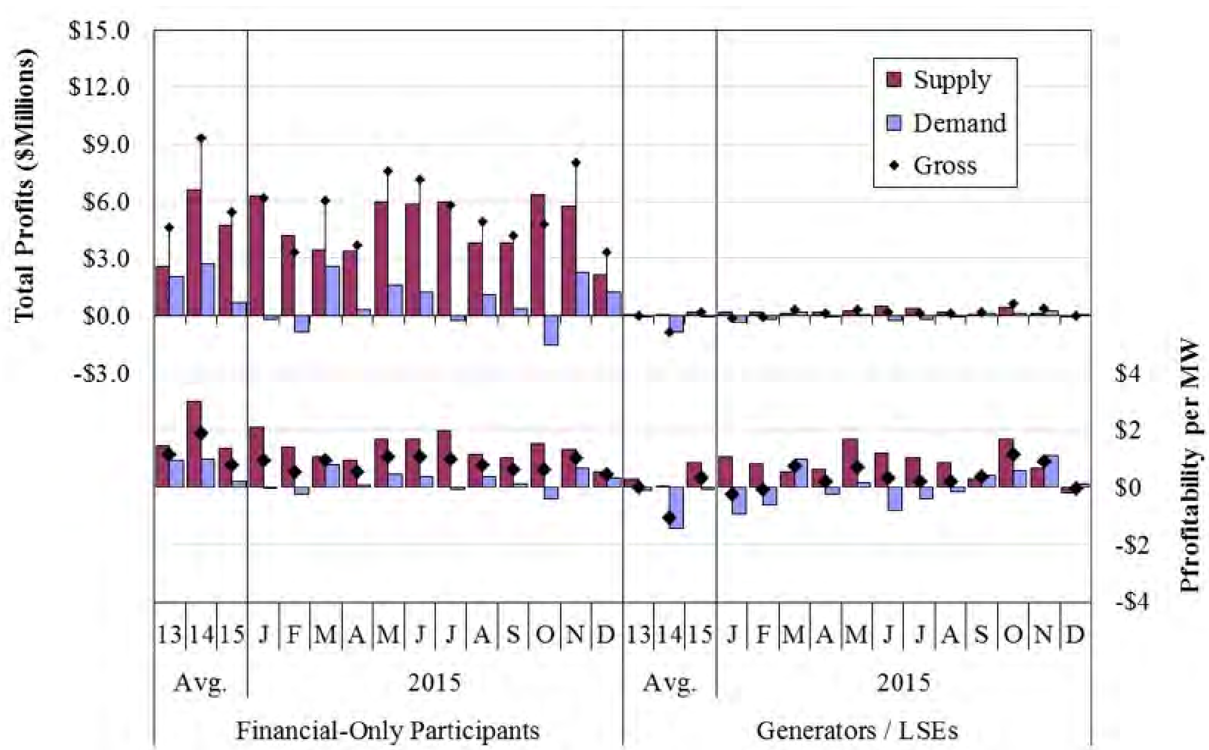


Figure A39: Virtual Profitability by Participant Type
2015



G. Benefits of Virtual Trading in 2015

We conducted an empirical analysis of virtual trading in MISO in 2015 that evaluated virtuals' 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 volumes (MWhs) and net profits.

The volumes of 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 on the margin virtuals contributed to better market efficiency in MISO by providing incrementally better commitments in the day-ahead and leading to better convergence.

To conduct our analysis, we first identified constraints that were modeled consistently in the day-ahead and real-time and those that were not. We categorized efficiency-enhancing virtuals as those that were profitable based on congestion that was modeled in the day-ahead and real-time market, and the marginal energy component (system-wide energy price). We did not include transactions that were profitable because of un-modeled constraints or the marginal loss factors, because profits on 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. 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.

We designed three tests in order to accurately identify unprofitable efficiency-enhancing virtual transactions. The tests were based on time *t* and a lagged time (*t-24* for hours 0-11 and *t-48* for hours 12-24 of the time *t* day). These lags correspond to the real-time prices a participant would observe by the time it must submit its bid or offer for the following day-ahead market.

- 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.

Table A4 and Table A5: Virtual Evaluation Summaries

Table A4 summarizes the virtual transaction quantities that fall in the efficiency-enhancing and not efficiency enhancing categories, divided by the type of entity submitting the transactions.

Table A4: Efficient and Inefficient Virtual Transaction Volumes by Type of Participant
2015

	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 Virtual Transactions	5329	*57%*	424	*56%*	5752	*56%*
Non-Efficiency-Enhancing Virtual Transactions	4097	*43%*	333	*44%*	4430	*44%*

Table A5 below shows the total profits and losses associated with efficiency-enhancing and non-efficiency-enhancing virtuals in MISO in 2015 by market participant type. This is important because the profits and losses account for the fact that some transactions are more efficient or more inefficient than others. The table shows rents earned by virtual transactions, which are profits that do not produce efficiency benefits. The rents include profits associated with un-modeled day-ahead constraints and differences in the loss components between the two markets. These rents do not 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.

Table A5: Efficient and Inefficient Virtual Profits and Losses by Type of Participant
2015

	Financial Participants		Physical Participants		Total
	Total Profits/ (Losses) $M	**Share of Class**	**Total Profits/ (Losses) $M**	**Share of Class**	**Total Profits/ (Losses) $M**
Efficiency-Enhancing Virtual Transactions	$340	*52%*	$18	*50%*	$358
Non-Efficiency-Enhancing Virtual Transactions	-$286	*43%*	-$16	*46%*	-$302
Rent	$34	*5%*	$2	*4%*	$36

It is important to recognize, however, that the total net benefits are much larger than indicated by these marginal benefit and losses. This is the case because:

- The profits of efficient virtual transactions become smaller as prices converge.
- The losses of inefficient virtual transactions get larger as prices diverge.
- Hence, the total net benefit of virtual transactions were much larger than $56 million in 2015 shown in the table above.

To accurately calculate this total benefit would require one to rerun all of the day-ahead and real-time market cases for the entire year. However, our analysis allows us to establish with a high degree of confidence that virtual trading was highly beneficial in 2015.

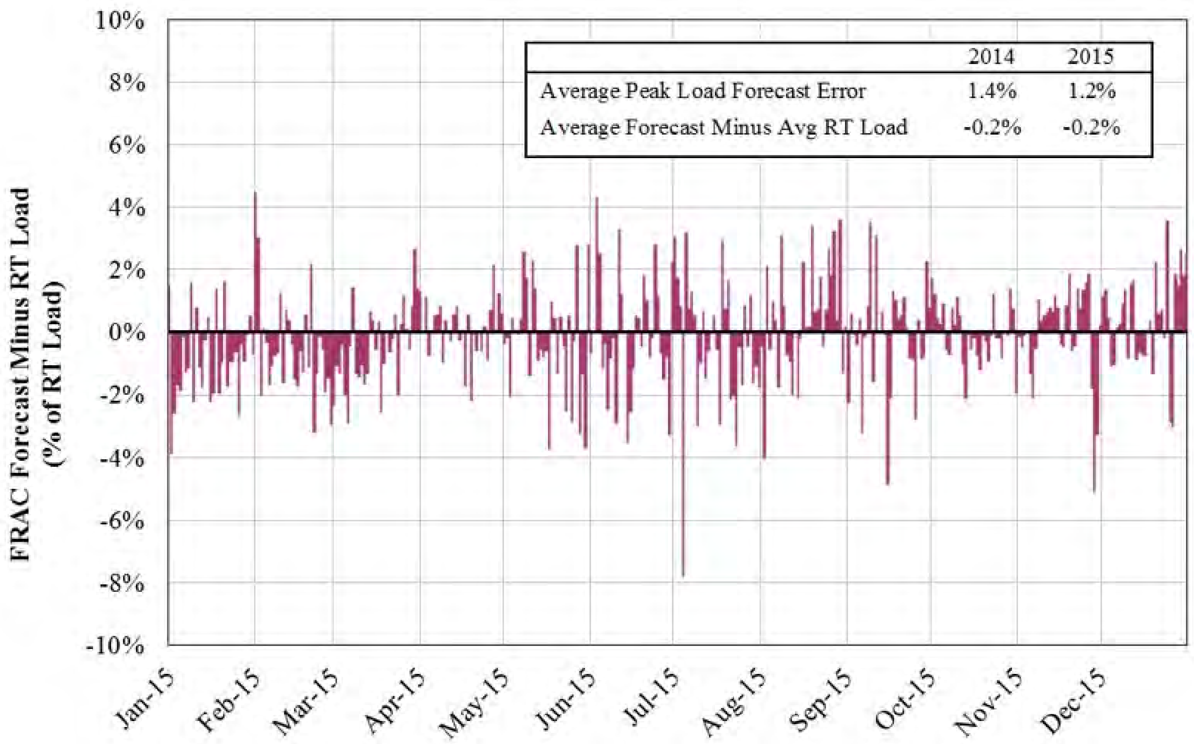
H. Load Forecasting

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, which is 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 A40: Daily MTLF Error in Peak Hour

Figure A40 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 2015.

Figure A40: Daily MTLF Error in Peak Hour
2015



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 in real time and the ongoing integration of wind generation. Wind generation has continued to grow and MISO set a number of new records in 2015 and early 2016.

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 for each resource and prices for each nodal location on the system.

While some RTOs clear their real-time energy and ancillary service 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 wholesale electricity markets is expected because the demands of the system can change rapidly and supply flexibility is restricted by generators' physical limitations. However, an RTO's real-time software and operating actions can help manage real-time price volatility.

This subsection evaluates and discusses the volatility of real-time prices. Sharp price movements 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, Net Scheduled Interchange (NSI), or generation startup or shutdown. This is exacerbated by generator inflexibility arising from lower offered ramp limits or reduced dispatch ranges.

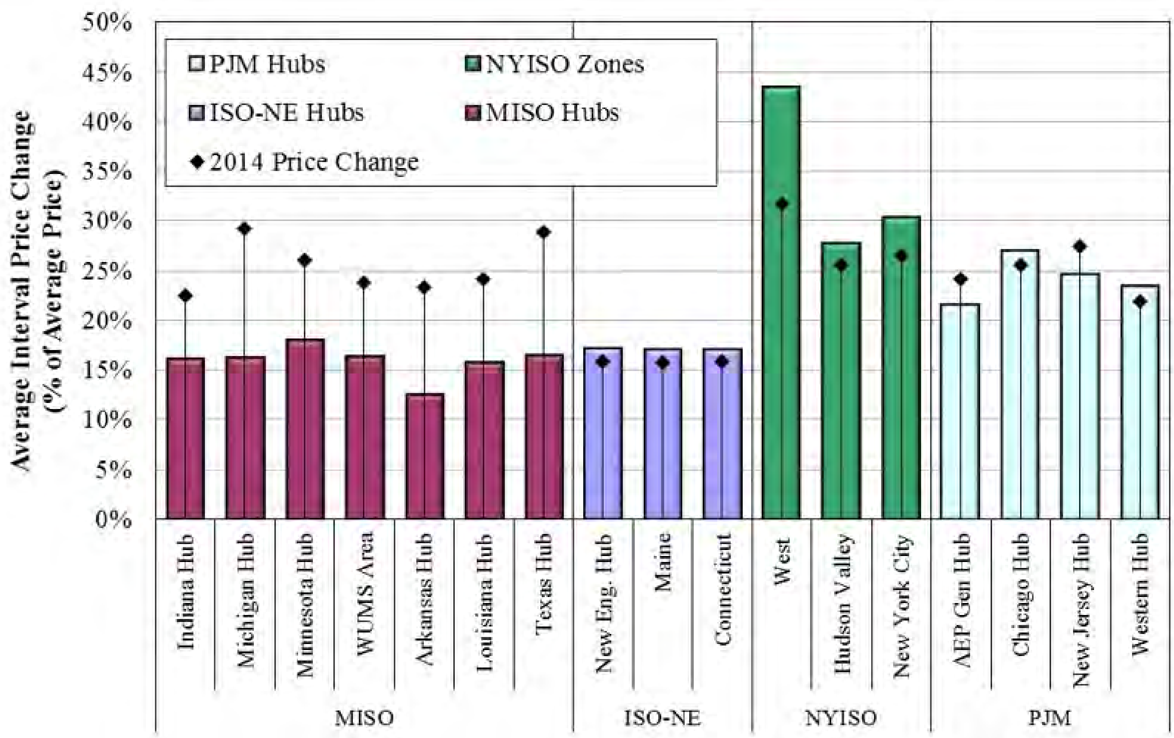
Figure A41: Fifteen-Minute Real-Time Price Volatility

Figure A41 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between fifteen-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 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. Since the systems are redispatched 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 do.

Figure A41: Fifteen-Minute Real-Time Price Volatility
MISO and Other RTO Markets, 2015



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). ELMP is intended to improve price formation in the day-ahead and real-time energy and ancillary services markets by having LMPs prices better reflect the true marginal costs of supplying the system at each location. ELMP is a reform of the current 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 are online "Fast-Start Resources"[9] and demand response resources.

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

The first of these reforms is intended to address 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 needs. 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 a number of adverse market effects when economic units supplying incremental energy are not included in price setting:

- MISO will generally need to pay Revenue Sufficiency Guarantee payments to cover these units' full as-offered costs;
- Real-time prices are understated and do not provide efficient incentives to schedule energy in the day-ahead market when lower-cost resources could potentially be scheduled that would reduce or eliminate the need to rely on high-cost peaking resources in real time;
- 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 reform allows offline Fast-Start Resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. It is efficient for

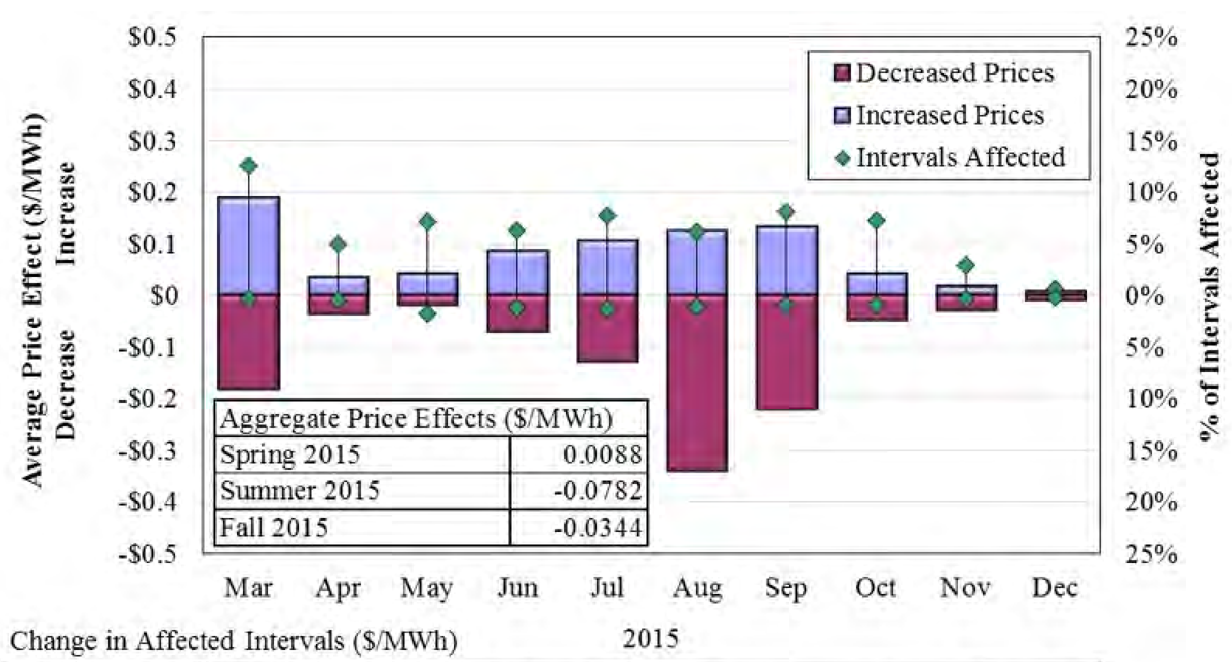
9 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff term as: a "Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less…."

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 A42 to Figure A44: ELMP Price Effects

Figure A42 to Figure A44 summarize the effects of ELMP by showing the average upward effects (via the online pricing), average downward effects (via offline pricing) along with the frequency that the ELMP model alters 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, the table below the first two figures shows the size of the adjustments in those intervals that the ELMP model adjusts the price.

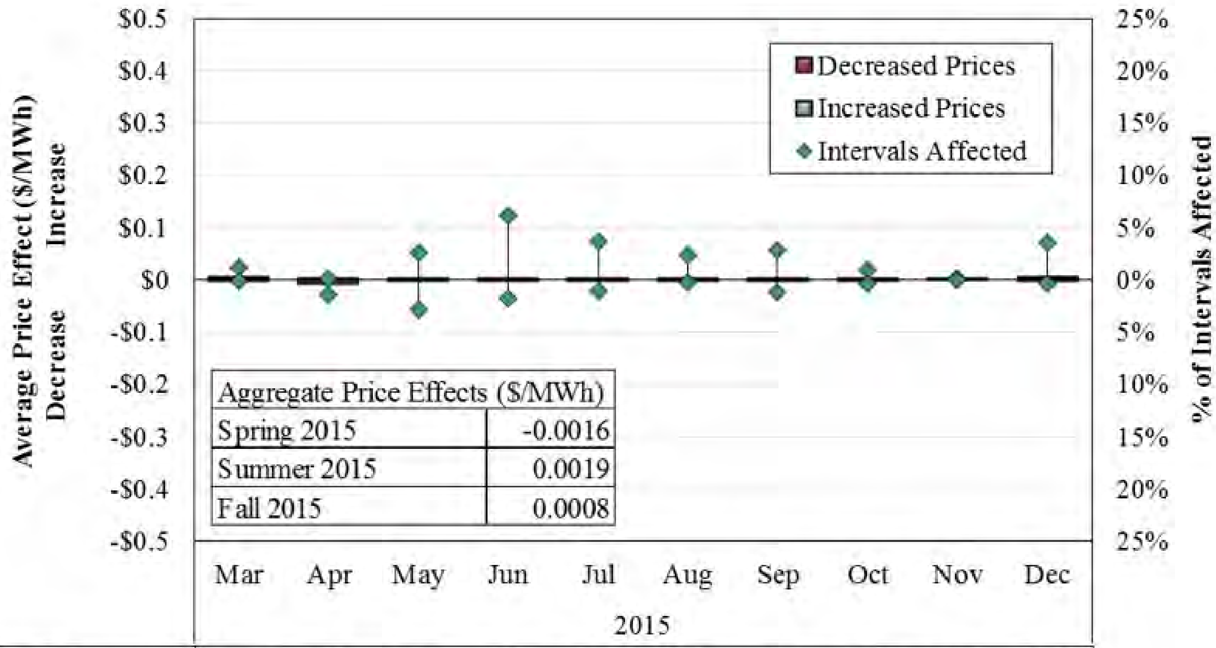
Figure A42: Average Market-Wide Price Effects of ELMP
Real-Time Market, March 2015 to December 2015



Change in Affected Intervals ($/MWh)

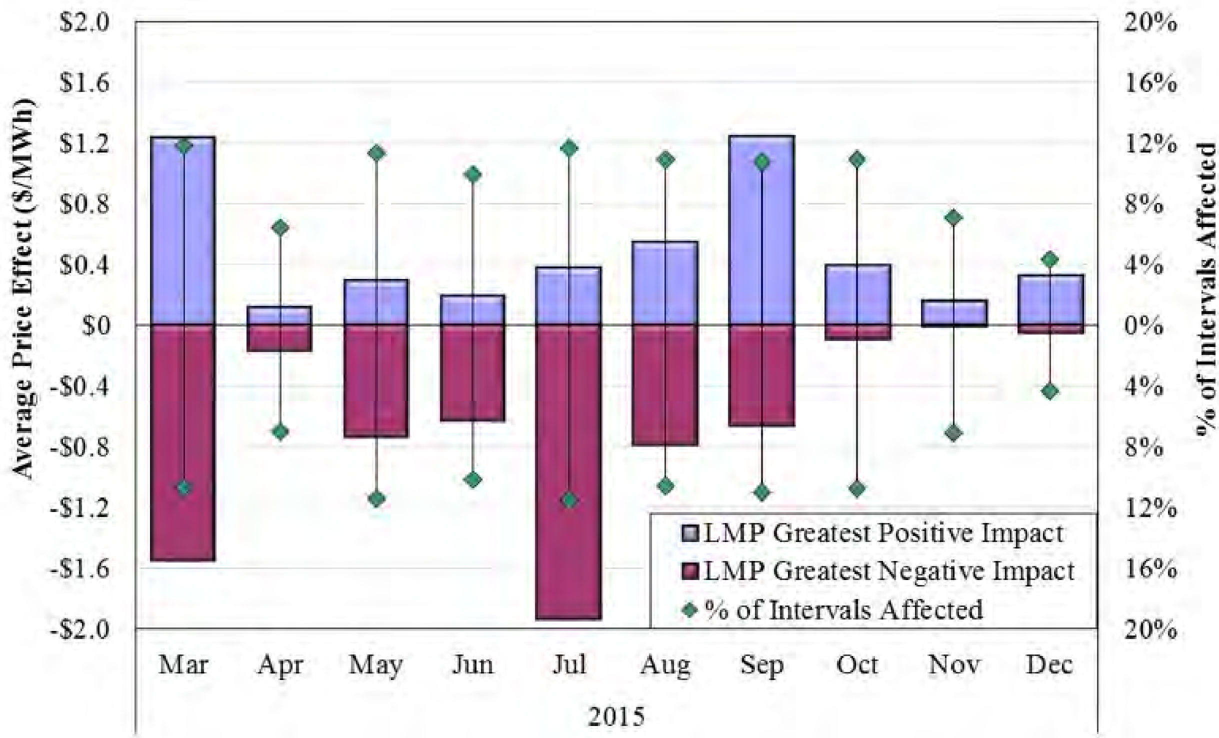
SMP Increase	1.51	0.71	0.61	1.37	1.37	2.03	1.64	0.60	0.69	1.50
SMP Decrease	-63.99	-8.04	-1.21	-6.19	-10.44	-33.45	-23.18	-5.35	-9.01	-7.24

Figure A43: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, March 2015 to December 2015



	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMP Increase	0.29	0.37	0.04	0.02	0.08	0.13	0.11	0.15	0.01	0.10
SMP Decrease	-0.01	-0.58	-0.07	-0.04	-0.09	-0.12	-0.06	-0.26	0.00	-0.08

Figure A44: Price Effects of ELMP at Most Affected Locations
Real-Time Market, March 2015 to December 2015



1. Online Price Setting by Peaking Resources

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 1 ELMP rules and the portions that have been ineligible.

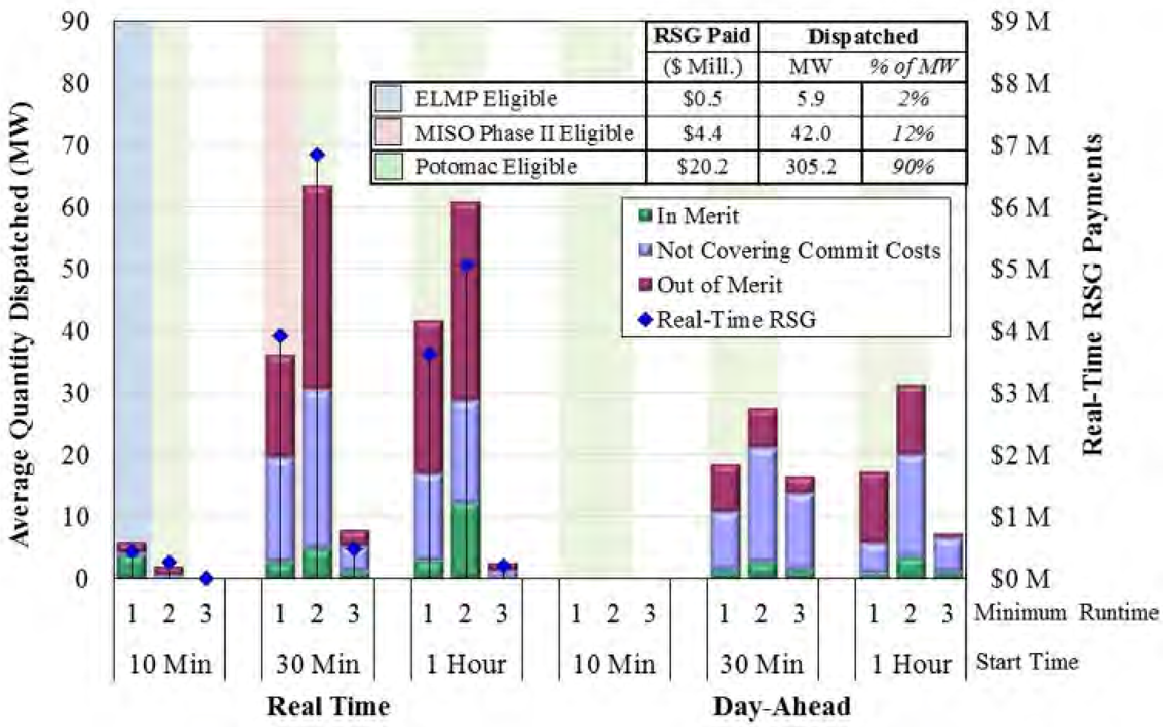
Figure A45: ELMP Eligibility and RSG Costs

Figure A45 shows all of the energy produced by online peaking resources, divided 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 only units not scheduled day-ahead, that can start in 10 minutes or less, and have a minimum runtime of 1 hour or less are eligible to set real-time prices in the ELMP pricing model. These units are shown to the left of the figure (shaded in blue). The additional units that MISO has proposed be eligible to set prices under Phase 2 of ELMP is shaded in red, while the units the IMM proposes be eligible to set prices in Phase 2 are shaded in green. The IMM proposal would allow most of the remaining peaking resources that receive RSG payments to be eligible to set prices in ELMP. Hence, we propose that MISO expand the eligibility rules under Phase 2 of ELMP to include these additional classes of peaking resources.

Figure A45: Eligibility for Online Peaking Resources in ELMP
March 2015 to December 2015



	RSG Paid ($ Mill.)	Dispatched MW	Dispatched % of MW
ELMP Eligible	$0.5	5.9	2%
MISO Phase II Eligible	$4.4	42.0	12%
Potomac Eligible	$20.2	305.2	90%

2. Price-Setting by Offline Units

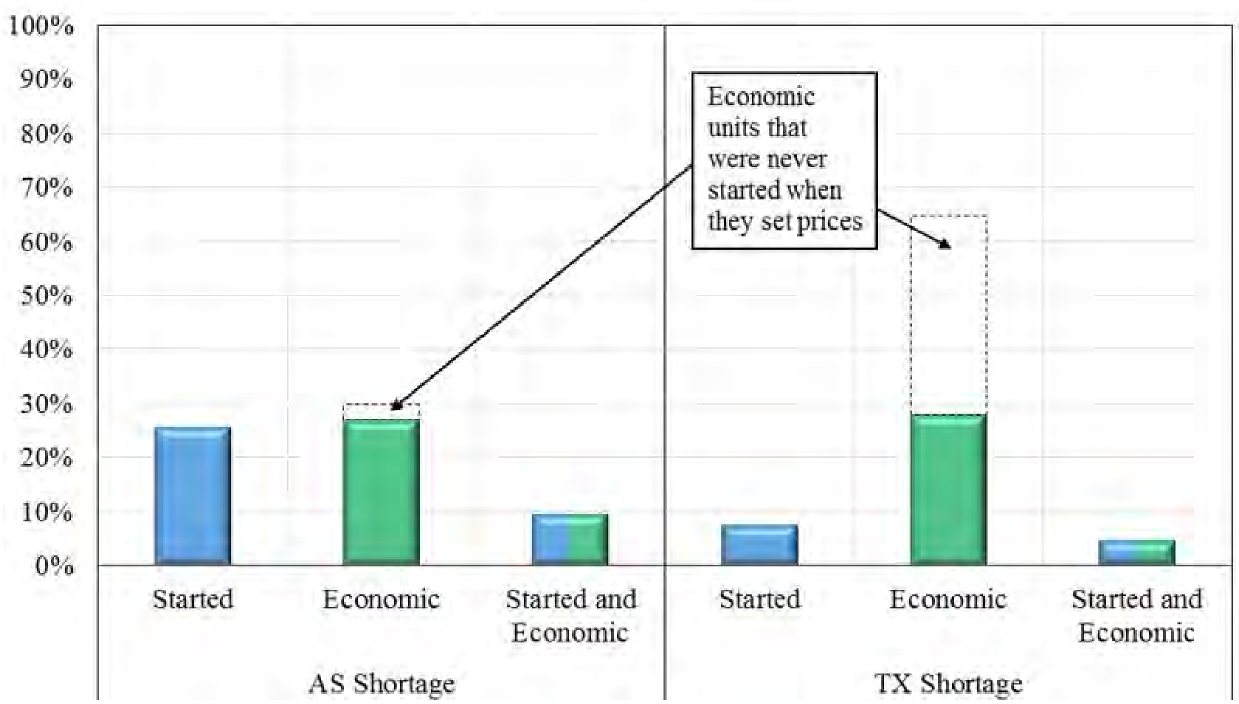
ELMP also includes provisions for allowing offline Fast-Start Resources to set price under shortage conditions. Shortages include transmission violations and operating reserves shortages. Prior to the implementation of ELMP, offline units could not set prices because UDS only optimizes the schedules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

When an operating shortage or a transmission violation occurs, the ELMP software may now set prices based on the hypothetical commitment of an offline unit that MISO could theoretically utilize to address the shortage. This is only efficient when the offline resource is: a) feasible (can be started quickly), and b) 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.

Figure A46: Evaluation of Offline Units that Set Price in ELMP

When committing an offline unit is feasible and is the economic action to take during a transmission violation or operating reserve 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 on in time 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 A46 summarizes whether the offline units that set prices are economic and whether they are started by MISO, as well as the combination of whether the unit is started and economic. The figure separately shows transmission shortages and operating reserve shortages.

Figure A46: Evaluation of Offline Units Setting Prices in ELMP
March 2015 to December 2015



To determine whether the unit is economic, we compare the real-time market prices and revenues paid to the unit to its total dispatch costs, including start-up and no load costs, for its minimum runtime starting with the interval after the current interval. To determine whether the unit was started, we identify whether UDS recognized the unit as online in the three intervals following the current interval.

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 service products, the demand curve for that product will set the market-wide price for that product and be included in the price of higher value reserves and energy.[10] The demand curves for the various ancillary services products in 2015 were:

- Spinning Reserves: $65 per MWh (for shortages between 0 and 10 percent of the market-wide requirement) and $98 per MWh (for shortages greater than 10 percent).[11]
- Regulation: varies monthly according to the prior month's gas prices. It averaged $105 per MWh in 2015.
- Total Operating Reserves:
  - For cleared reserves less than 4 percent of the market-wide requirement: Value of Lost Load ($3,500) minus the monthly demand curve price for regulation.
  - For cleared reserves between 4 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 per MWh.

Total operating reserves (includes contingency reserves plus regulation) is the most important reserve requirement because a shortage of total operating reserves has the biggest 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.

10 There are additional requirements for regulation and spinning reserves for each reserve zone in MISO.

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

Figure A47: Real-Time Ancillary Service Prices and Shortages

Figure A47 shows monthly average real-time clearing prices for ASM products in 2015. The price for supplemental reserves, which are provided from offline fast-start units, is MISO's contingency reserve price because this is the only product that it can sell.

Contingency reserves is 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 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.

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 A47: Real-Time Ancillary Services Clearing Prices and Shortages
2015

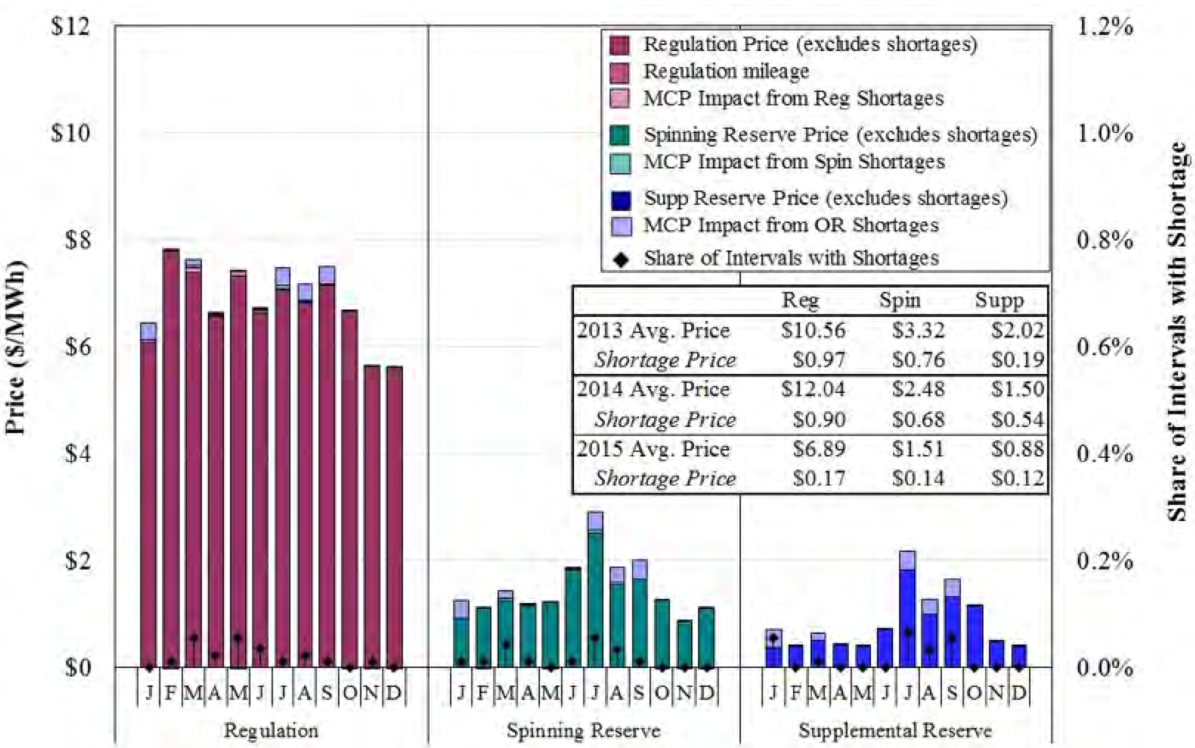


Figure A48: Regulation Offers and Scheduling

ASM offer prices and quantities are primary determinants of ASM outcomes. Figure A48 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.

The figure distinguishes between quantities of regulation that are available to the five-minute dispatch (in the solid bars) and quantities that are unavailable (in the hashed bars). Of the unavailable quantities, the figure shows separately those that are not offered by participants, not committed by MISO, and limited by dispatch level (i.e., constrained by a unit's operating limits).

Figure A48: Regulation Offers and Scheduling
2015

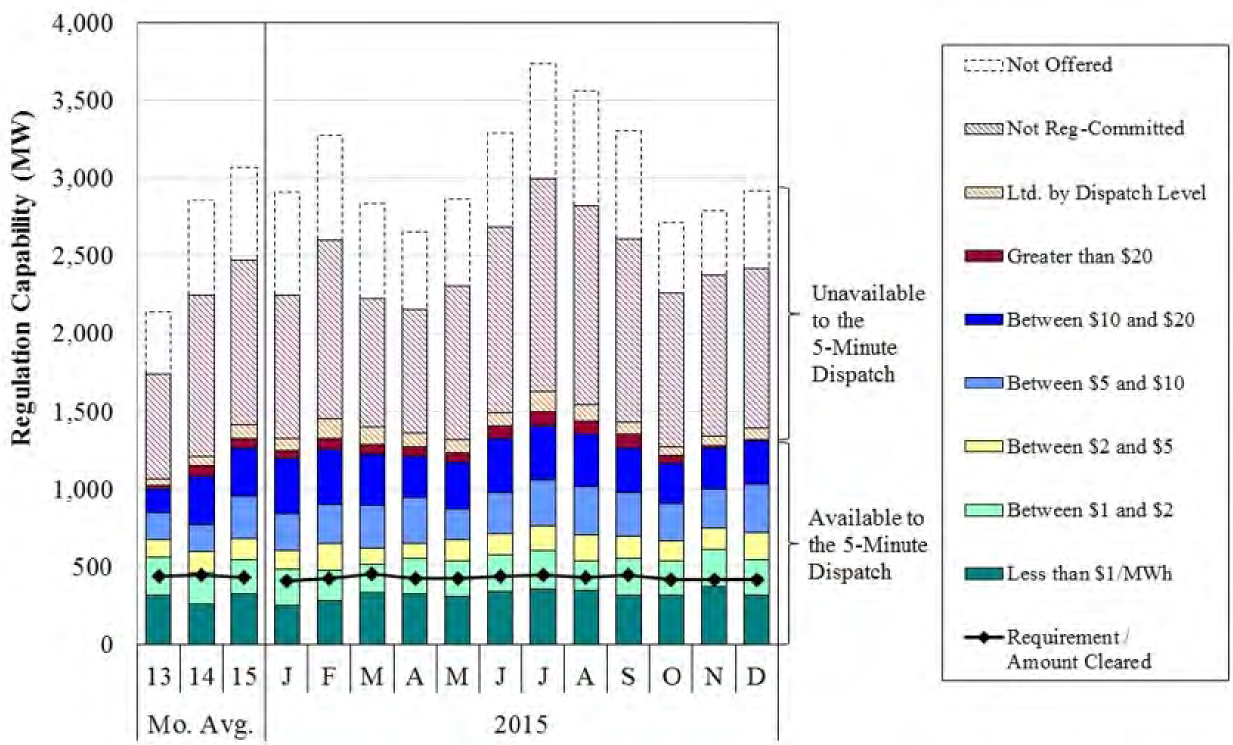


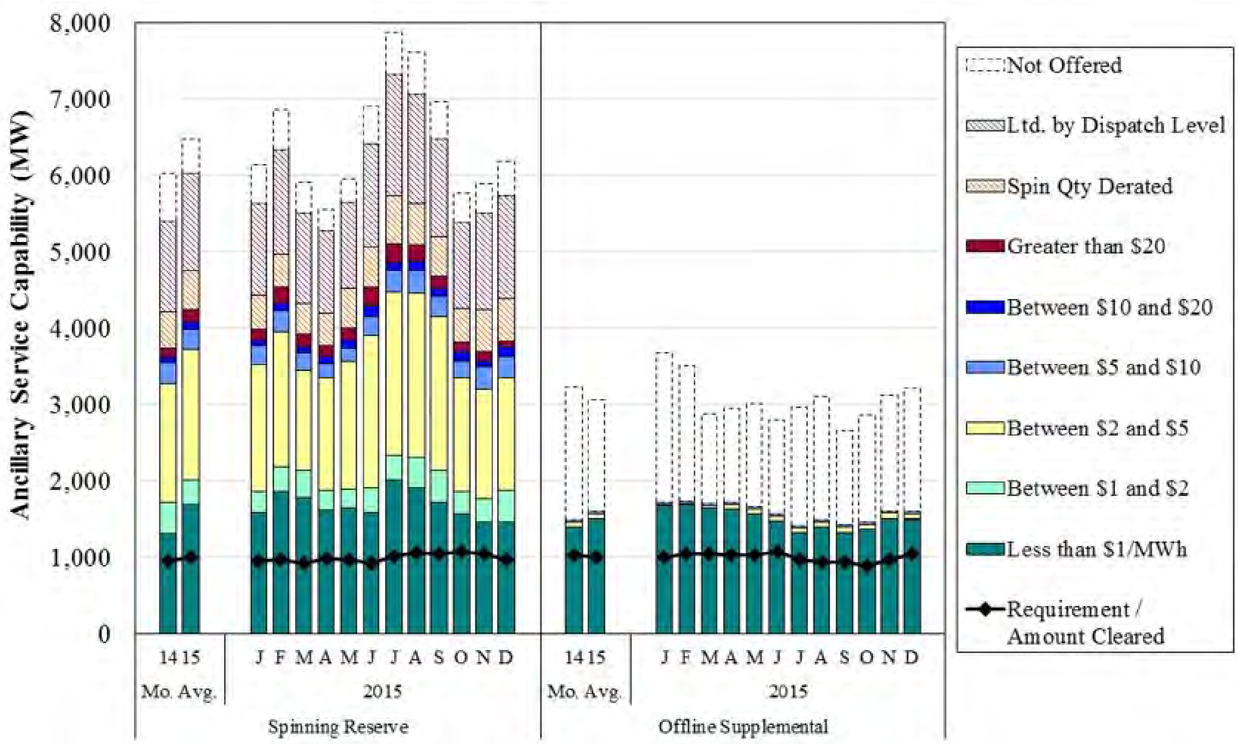
Figure A49: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can only be provided by online resources for up to ten minutes of ramp capability (and limited by available headroom above their output level). Supplemental reserves are provided by offline units that can respond within 10 minutes (including 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 will 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 A49 shows the quantity of spinning and supplemental reserve offers by offer price. Of the capability not available to the dispatch, the figure distinguishes between quantities not offered, derated, and limited by dispatch level.

Figure A49: Contingency Reserve Offers and Scheduling
2015



D. Spinning Reserve Shortages

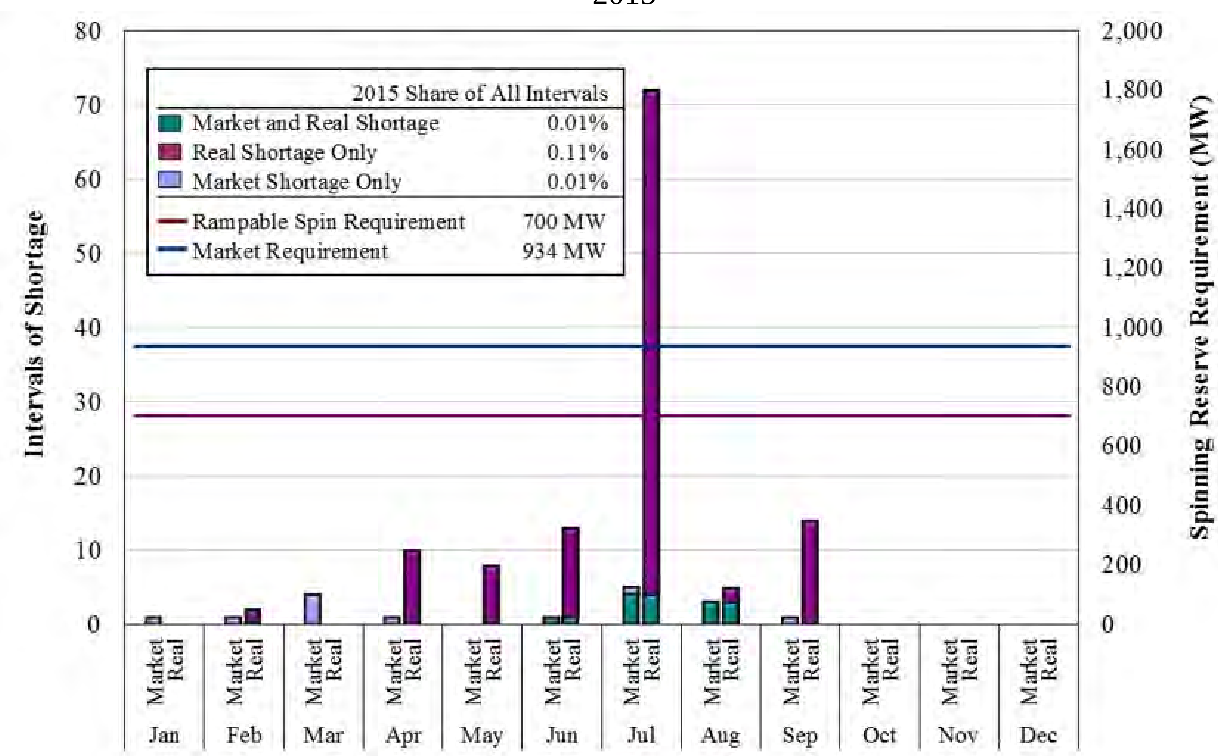
Figure A50: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

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.[12] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

Figure A50 shows all intervals in 2015 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements.

Figure A50: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2015



12 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.

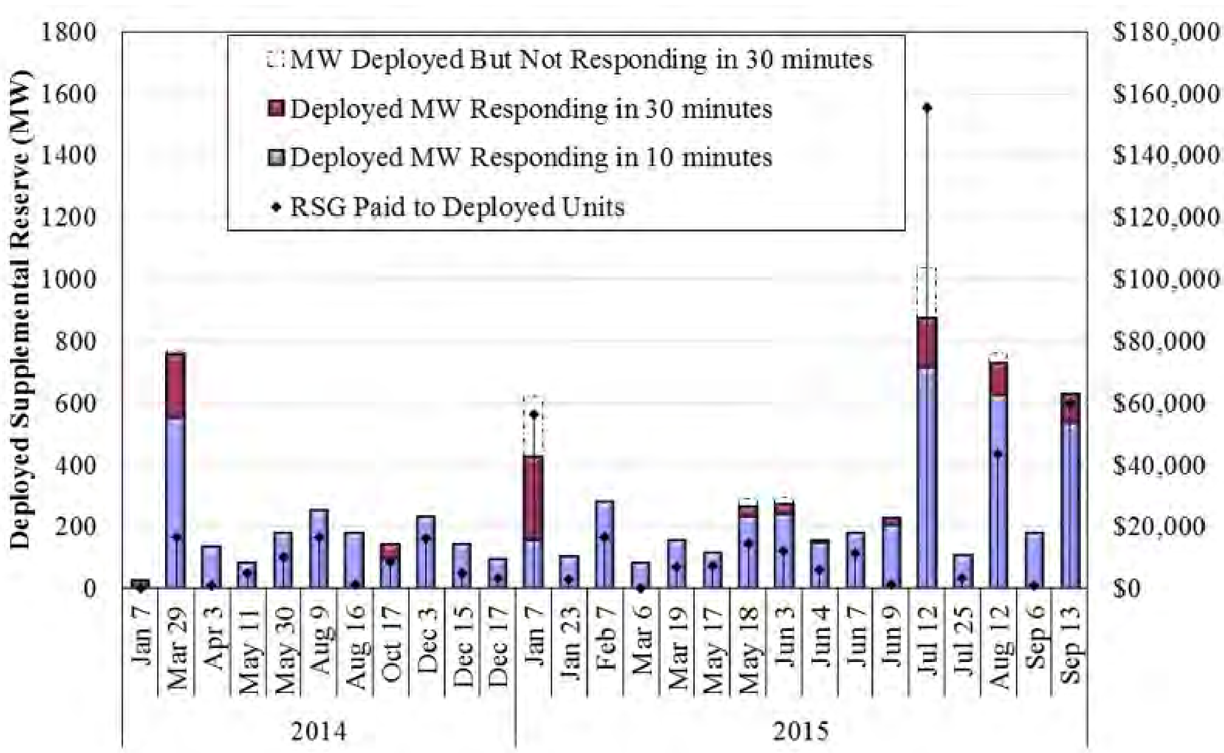
E. Supplemental Reserve Deployments

Figure A51: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A51 shows offline supplemental reserve response during the 17 deployments in 2015, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC).

The summary is valuable because it indicates how reliably MISO's offline reserves start when MISO needs them.

Figure A51: Supplemental Reserve Deployments
2015



F. 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.

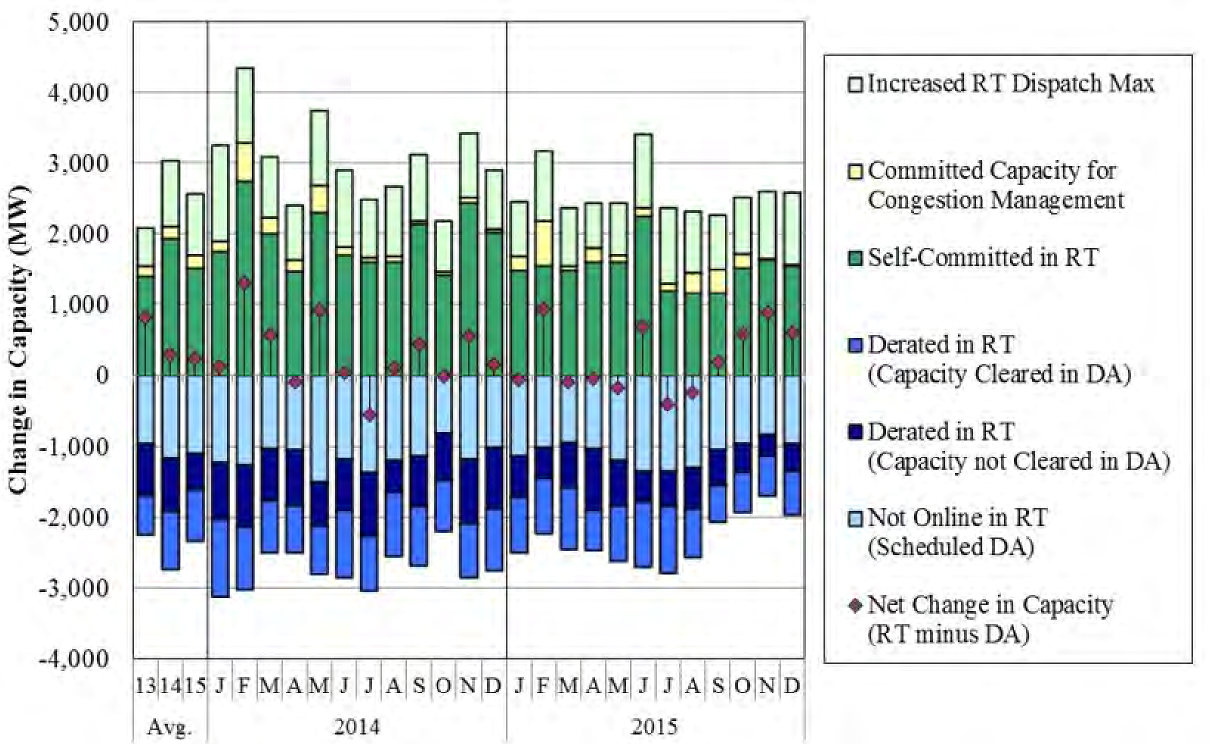
Figure A52: Changes in Supply from Day Ahead to Real Time

Figure A52 summarizes changes in supply availability from day-ahead to real time. 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 decommitments by MISO. In addition, suppliers who are scheduled day-ahead 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 may self-commit their generation resources in real time.

The figure shows six types of changes: generating capacity self-committed or decommitted in real time, capacity scheduled day-ahead that is not online in real time; capacity derated in real time (separated by resources cleared and not scheduled day-ahead) and increased available capacity (increases from day-ahead); 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 decommit or shorten real-time MISO commitment periods. The amount actually committed for capacity in real time is not included in the figure.

Figure A52: Changes in Supply from Day Ahead to Real Time
2014–2015



G. Generator Performance

MISO sends dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. It 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.[13] 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 refer to this as "inferred derates" and it is discussed 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 unjustified DAMAP payments 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. The figures in this subsection show how much energy is lost through sustained dragging and inferred derates.

Figure A53 and Figure A54: Frequency and Quantity of 5-Minute Net Deviations

Figure A53 shows a histogram of MISO-wide net 5-minute deviations and accumulates hourly dragging (60-minute deviations) from 6 am to 10 pm, which includes MISO's high-ramp and peak hours in the summer and winter seasons. The hourly dragging is calculated based on the difference between each resource's actual output and the output it would be producing if it followed MISO's dispatch instructions over the prior hour.

Figure A54 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, if 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 0 MW; and the median deviation.

13 The tolerance band can furthermore be no less than six MW and no greater than 30 MW (Tariff section 40.3.4.a.i.). This minimum and maximum were unchanged for this analysis.

Figure A53: Frequency of Net Deviations
Ramp and Peak Hours, 2015

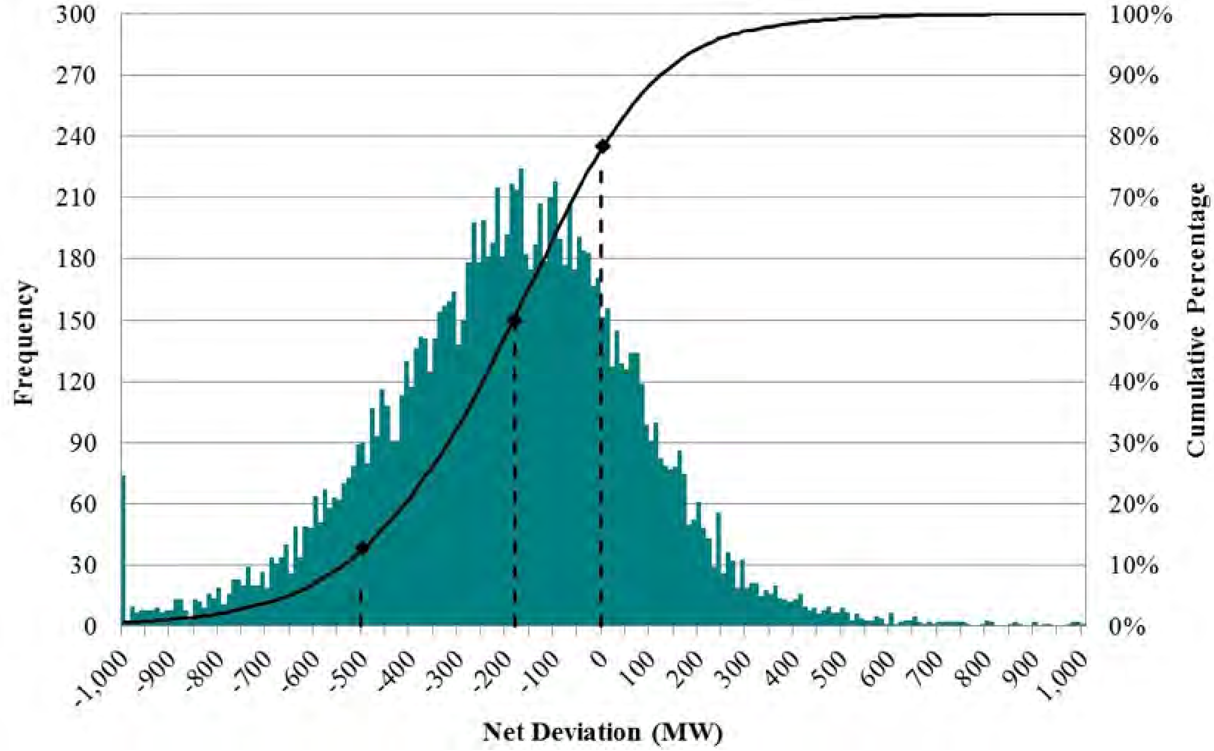


Figure A54: Frequency of Net Deviations
Ramp-Up Hours, 2015

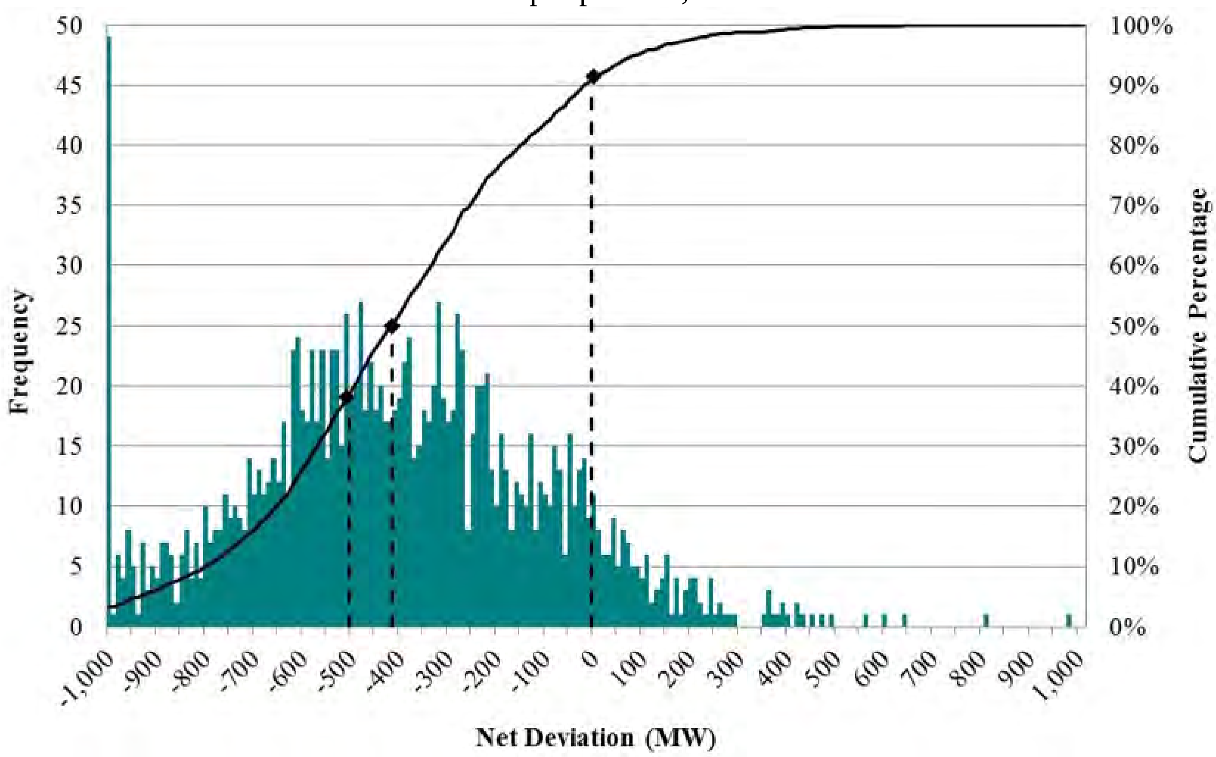


Figure A55: 5-Minute and 60-Minute Deviations by Season and Type of Hour

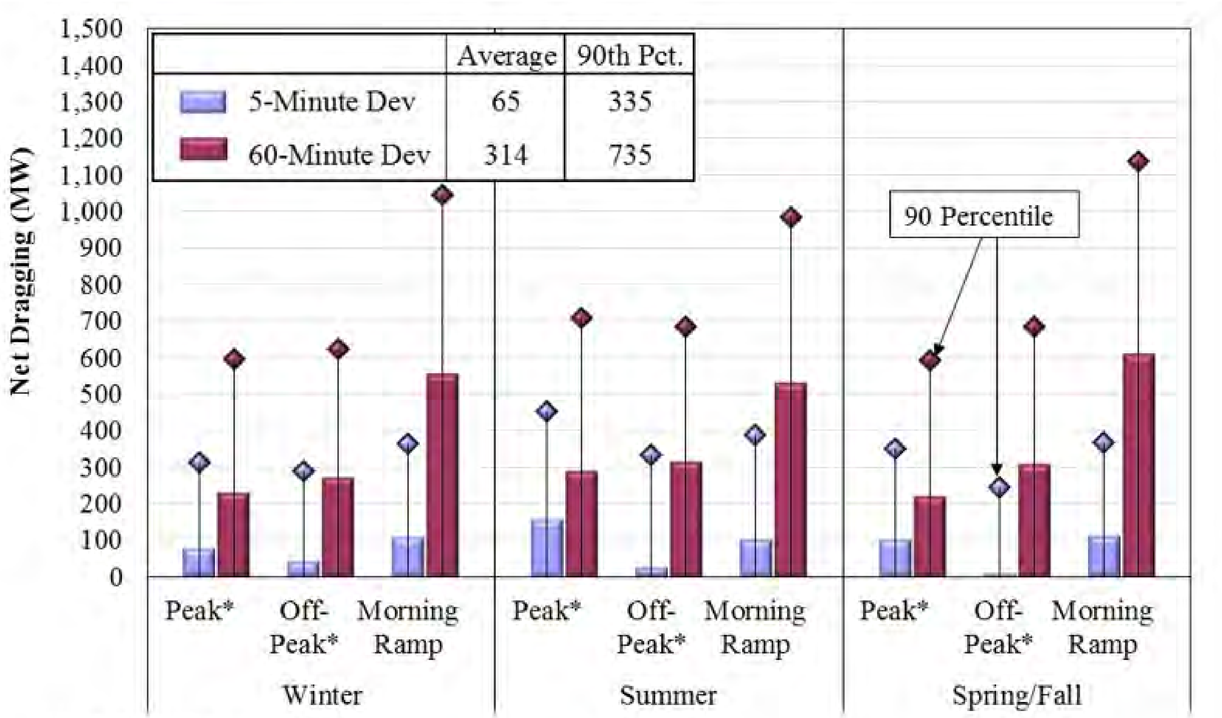
When generators do not respond to MISO's dispatch instruction, it will affect the generator's dispatch instruction in the following interval. Hence, a poorly performing unit over an extended period can cause a generator to produce at a much different output level than the level it would be producing if it had followed dispatch instructions.

Figure A55 shows the size and frequency of the two types of net deviations:

- 5-minute deviation is the difference between MISO's dispatch instructions and the generators' response in each interval.
- 60-minute deviation is the effect over 60 minutes of generators not following MISO's dispatch instructions.

The methodology for calculating the net 60 minute deviation is described in more detail in Section V of the Analytical Appendix. It is essentially the difference between where the energy the generator would be producing had it followed MISO's dispatch instructions over the prior 60 minutes versus the energy it is actually producing. The figure shows these results by season and type of hour, including the typically steep ramping hours of 6, 7, and 8 a.m, when the impact of deviations are most severe on both pricing and reliability.

Figure A55: 5-Minute and 60-Minute Deviations by Season
2015



* Excludes morning ramp hours.

Figure A56: Causes of 60-Minute Generator Deviations

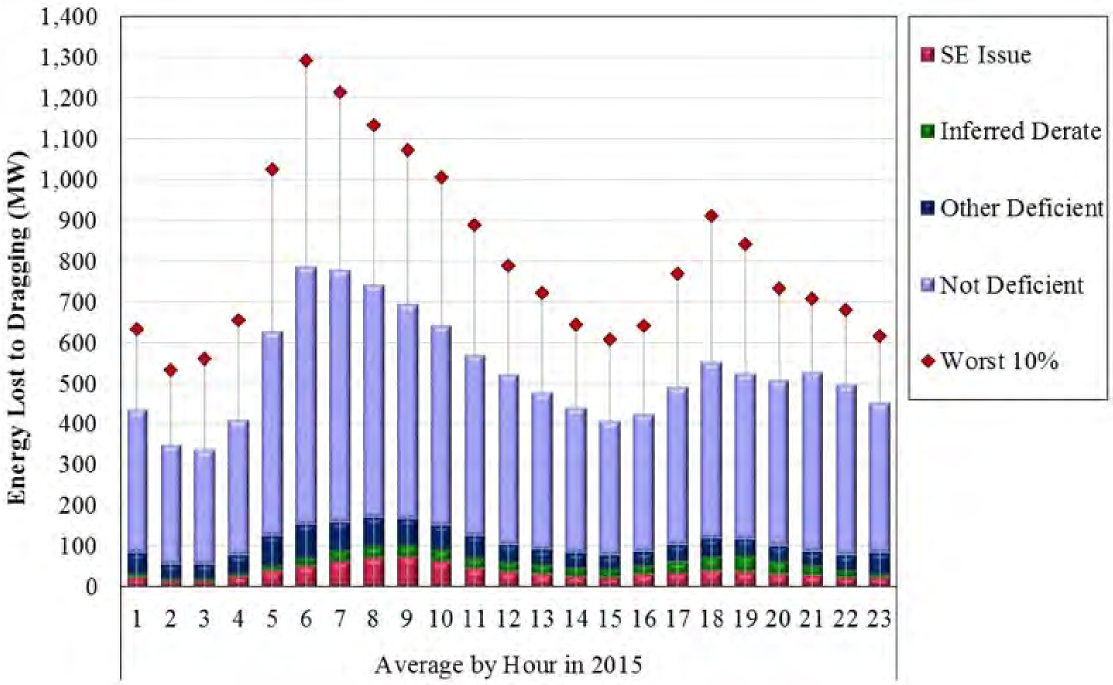
To better understand the components of the 60-minute deviations, we have estimated how much of the deviations is potentially caused by inaccuracies in the State Estimator model, versus various classes of poor generator performance. The state estimator model can cause deviations when it estimates an output level for a resource that is less than the generators actual output. The real-time market uses the SE output to determine how much a generator can move up in the next interval. Therefore, if it is lower than the unit's actual output, it 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 are:

a. Inferred derates: Resources effectively derated because they stop moving at a level well below its economic output level. When unit are physically derated, suppliers are violating the tariff by not reporting the derate and we have referred some to FERC enforcement;[14]
b. Other dragging that would qualify as an uninstructed deviation under the IMM's proposed threshold for "deficient energy" described later in this section; and
c. Dragging that would not fail under the IMM's proposed threshold.

Figure A56 show the average of each of the quantities by hour of the day in 2015, as well as the amount of hourly dragging in total that prevailed in the worst 10 percent of the hours.

Figure A56: Hourly Dragging by Type of Conduct



14 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 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 A57: DAMAP Payments caused by Dragging

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 economic output level and it causes their margins earned in the day-ahead market to fall.

This payment was intended to provide incentives for generators to be flexible and to be held harmless if MISO directs them to dispatch down temporarily in response to volatile prices. It was not intended to hold generators harmless when they produce less output than is economic because they are performing poorly. Nonetheless, because generators remain eligibility for DAMAP even when they perform poorly, a situation we address in our recommendations.

Figure A57 shows the total DAMAP in 2015 along with the shares of DAMAP that are paid to units following MISO's dispatch signals, as well as those there are not performing well in following dispatch signals (categorized in the same manner as the prior figure).

Figure A57: Causes of DAMAP
2015

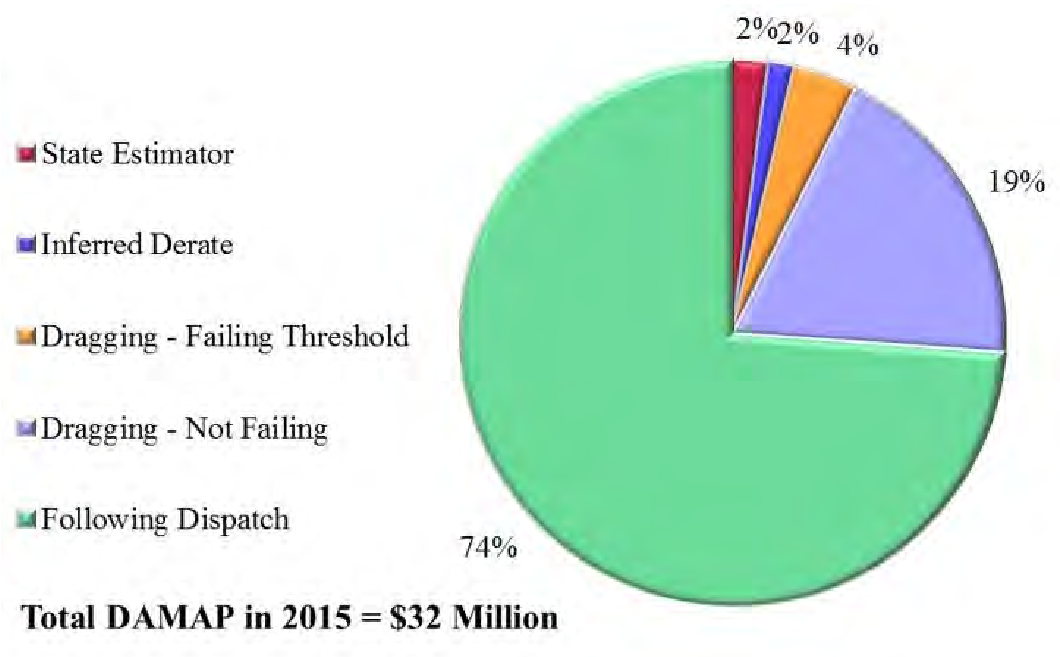


Figure A58: Proposed Change in Uninstructed Deviation Thresholds

We continue to recommend a specific approach to tighten the tolerance bands for uninstructed deviations (Deficient and Excessive Energy) that would be more effective at identifying units that are not following dispatch. This approach is based on units' ramp rates. The specific threshold calculation we propose equals one-half of the resource's five-minute ramp capability plus a value that corresponds to the base-point change for the direction in which the unit is moving (i.e., base-point change included for deficient energy when the unit is moving up and for excess energy when the unit is moving down).

This specification provides increased tolerance only in the ramping direction so units that are dragging slightly or responding with a lag will not violate the threshold. Additionally, since the current thresholds require that a unit fail in four consecutive intervals, the IMM proposed threshold would similarly require that a resource be unresponsive for four consecutive intervals before it would be considered to be deviating or not following dispatch. This approach has a number of advantages compared to the current output-based thresholds, to include:

- The threshold will be the same regardless of the output level (ability to follow dispatch does not change as the output level increases);
- It will more readily identify units who are not responding to dispatch signals (resources that do not move, or move in opposition to the dispatch instruction will be identified);
- Making thresholds proportional to offered ramp rate will eliminate the current incentive to provide an understated ramp rate; and
- Output-based thresholds enable a resource to avoid being flagged for not following dispatch if it offers low ramp rates.

Figure A58 illustrates how these thresholds would be calculated and applied in three cases. Each of the cases assumes a unit that has been operating at 350 MW, has a 2 MW-per-minute ramp rate, and is receiving dispatch instructions to increase output at its ramp rate. In the first case, the unit is not moving. In the second and third cases, the unit is ramping up at 50 percent and 100 percent of the unit's ramp rate. The lighter areas are the existing thresholds while the darker areas are our proposed thresholds. A unit is producing excessive or deficient energy when the diamond marker, indicating the unit's output level, falls outside a particular tolerance band for four consecutive intervals.

Figure A58: Proposed Generator Deviation Methodologies

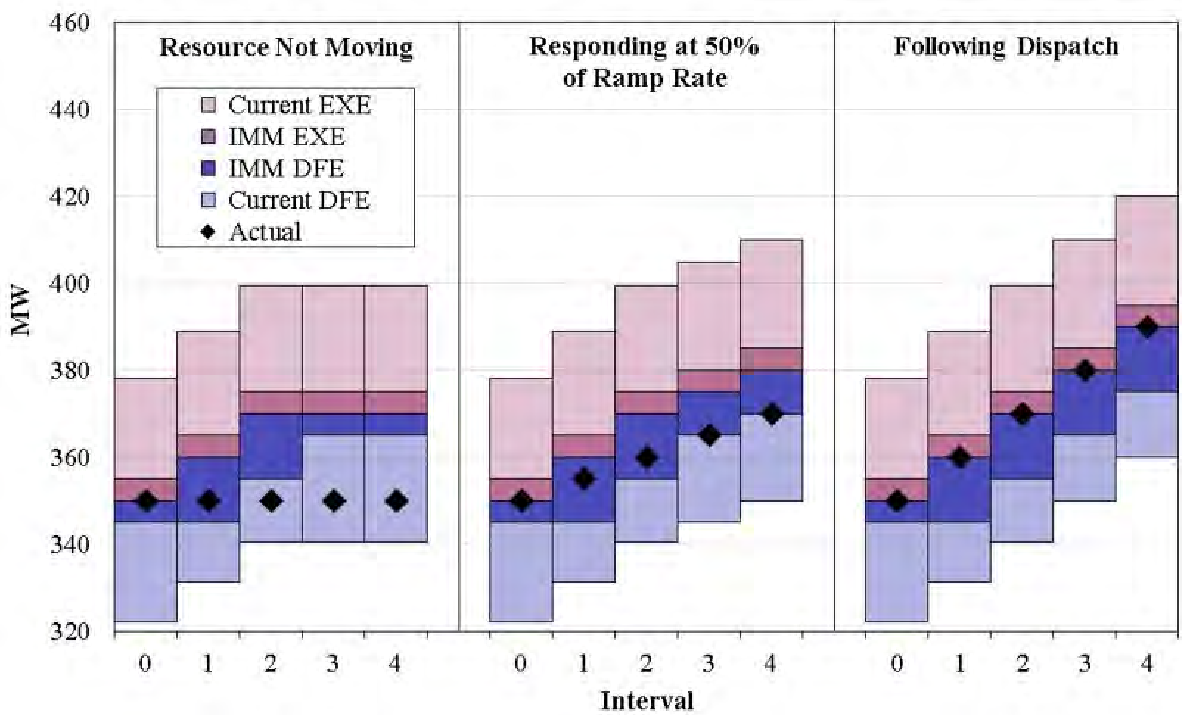
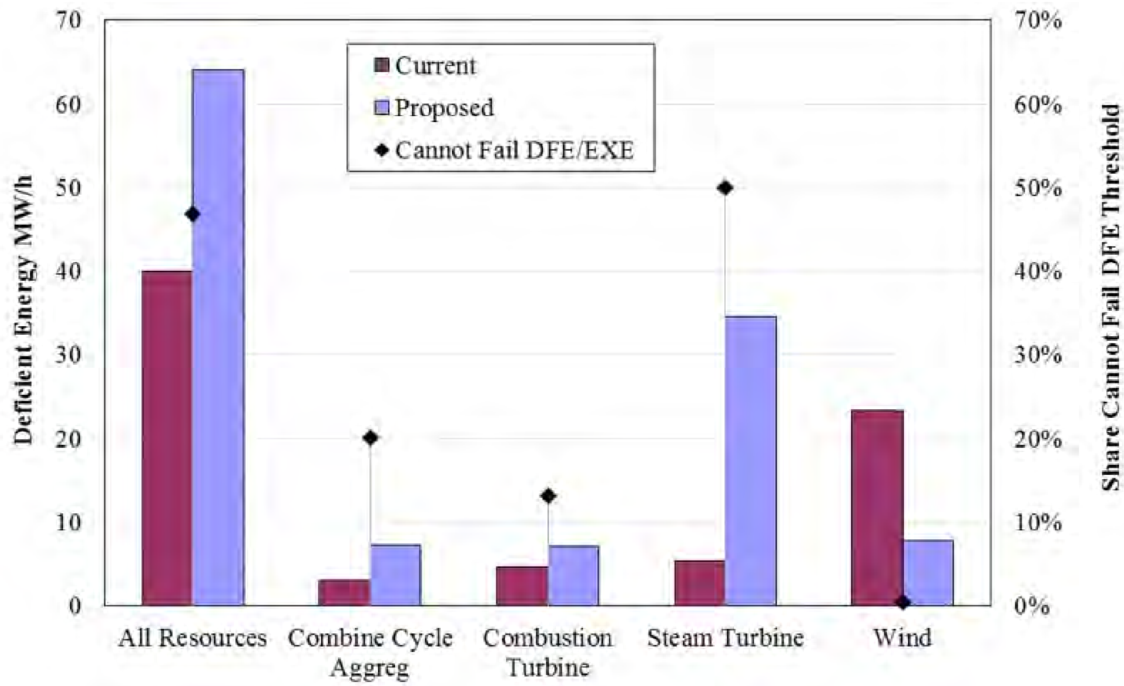


Figure A59: Impacts of Proposed Reform

Figure A59 illustrates the consequence of implementing the proposed tolerance bands to identify the deficient energy from different types of units. The maroon bars show the results of the current threshold while the blue bars show the results under the IMM threshold. The proposed ramp-based threshold will more effectively identify units that are dragging for most types of units, which is why it results in higher levels of deficient energy. However, this threshold will reduce deviations identified from wind resources because they tend to have fast ramp rates (so most will be subject to a higher threshold under the IMM proposal). This figure also shows the share of each kind of technology that can ignore MISO's dispatch signal entirely without failing under MISO's current deviation threshold.

Figure A59: Impacts of IMM-Proposed Deviation Thresholds
2015



H. Revenue Sufficiency Guarantee Payments

Revenue Sufficiency Guarantee (RSG) payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[15] 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. Since these commitments receive market revenues from the real-time market, their production costs in excess of these revenues are recovered under "real-time" RSG payments. MISO commits resources in real time for many reasons; including to meet (a) capacity needs that can arise during peak load or sharp ramping periods, (b) real-time load under-scheduled day-ahead, or (c) to secure a transmission constraint or a local reliability need or to maintain the system's voltage in a location.

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

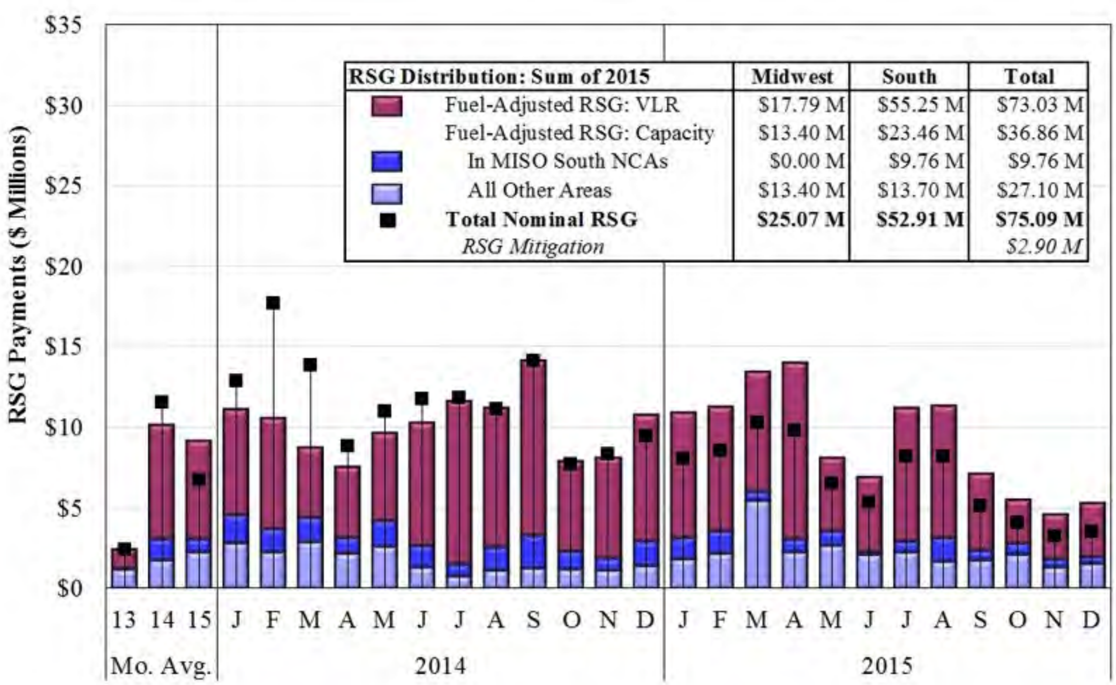
Beginning in the fall of 2012, MISO began making many voltage and local reliability ("VLR") commitments, predominately in the day-ahead market. VLR commitments increased after the South region integration, due to the implementation of new operating procedures in South load pockets. To satisfy the requirements of these operating guides and due to the startup times of the required resources, MISO makes the associated reliability commitments in advance of, or in the day-ahead markets. Consequently day-ahead RSG payments are now larger than real-time payments in most months.

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

Figure A60 and Figure A61: RSG Payment Distribution

Figure A60 shows total day-ahead RSG payments, and distinguishes between payments made for VLR or 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 A61 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.[16]

Figure A60: Total Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2014–2015



16 We examine market power issues related to commitments for voltage support in Section VIII.

Figure A61: Total Real-Time RSG Payments
Fuel Adjusted, 2014–2015

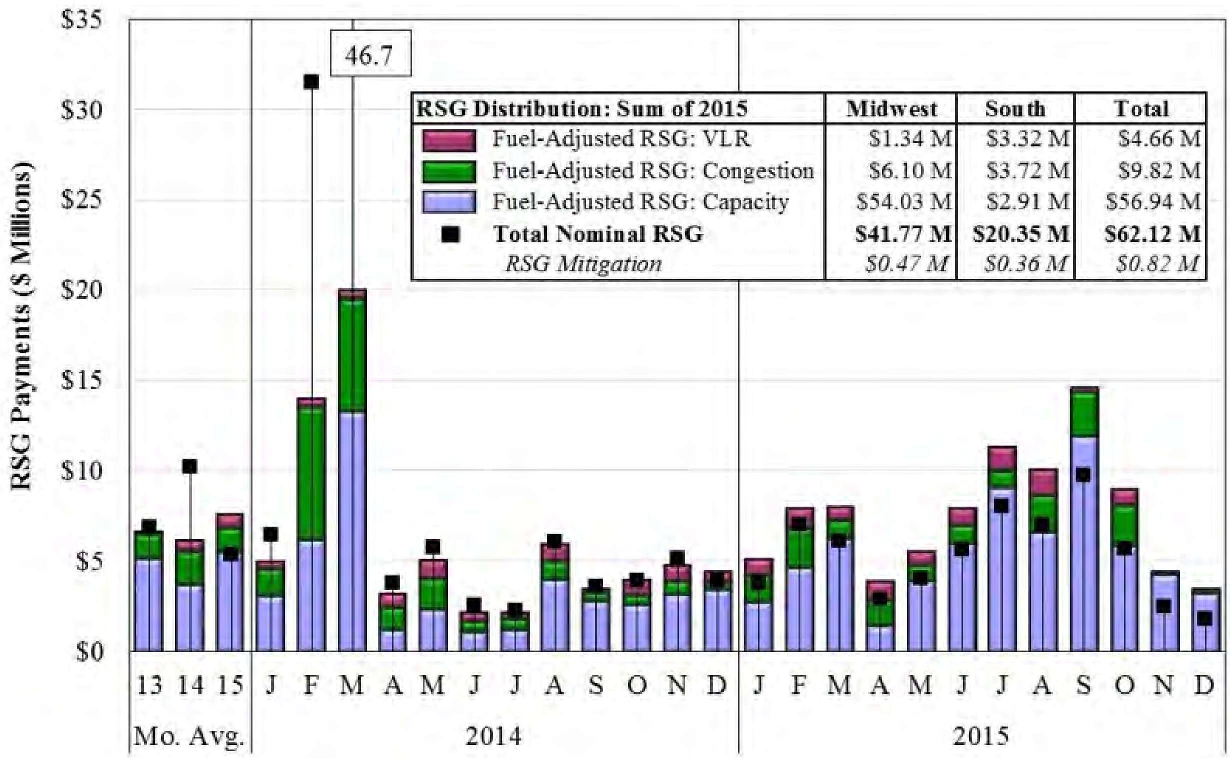


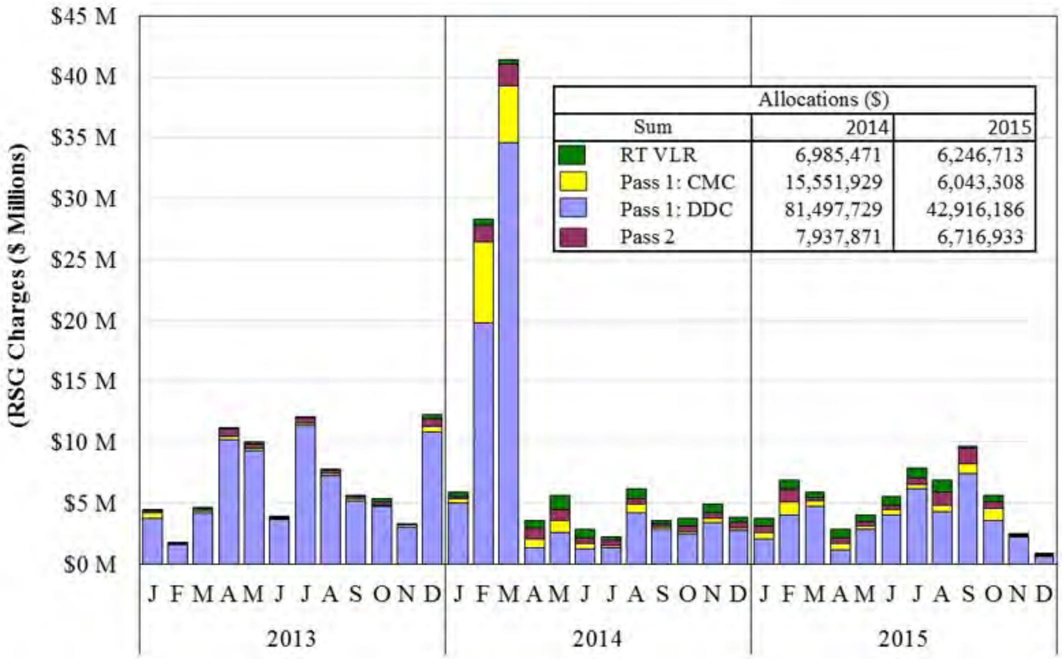
Figure A62: Allocation of RSG Charges

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 (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").[17]

Figure A62 summarizes how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month during 2013 - 2015. Until March 2014, the CMC allocations were inappropriately limited based on the GSF of the committed unit. This caused a significant portion of constraint-related RSG costs to be allocated under the DDC charge. This is more closely examined in the next figure.

17 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 A62: Allocation of RSG Charges
By Month, 2013–2015



I. Price Volatility Make-Whole Payments

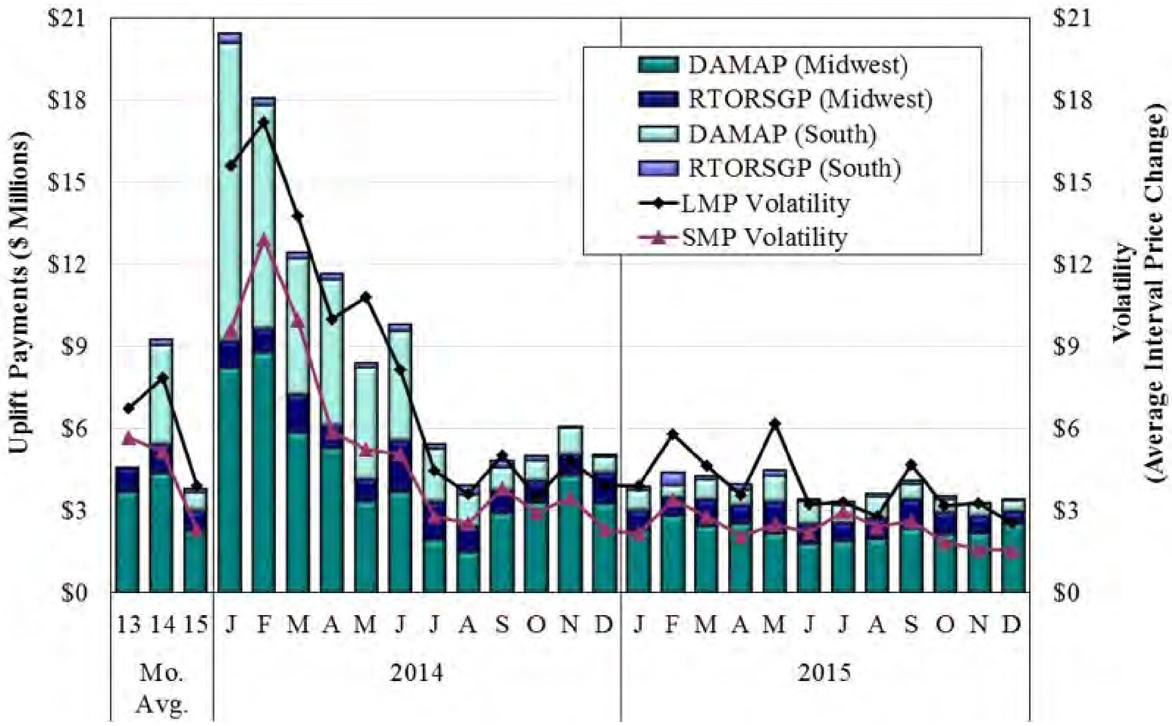
MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers responding to MISO's prices and following its dispatch signals in real time are not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

The PVMWP consists of two payments: Day-Ahead Margin Assurance Payment (DAMAP) and Real-Time Operating Revenue Sufficiency Guarantee Payment (RTORSGP). The DAMAP is paid when a resource's day-ahead margin is reduced because it is dispatched in real time below the level that would have been most economic based on the hourly integrated price. Often, this is due to volatile real-time prices associated transmission constraints. In contrast, the RTORSGP is made to resources that are unable to recover their energy costs when dispatched above their day-ahead schedule. Opportunity costs for potential revenues are not included in the payment.

Figure A63: Price Volatility Make-Whole Payments

Figure A63 shows monthly average PVMWPs for each of the past three years in the left panel. The monthly PVMWPs by month for the past two years is shown in the right panel. 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, since volatility leads to greater obligations to flexible suppliers. Volatility at recipients' locations is expected to be higher because they will be relied upon for redispatch more so than other suppliers due to larger price fluctuations and because the SMP volatility does not include volatility related to transmission congestion.

Figure A63: Price Volatility Make-Whole Payments
2014–2015



J. Five-Minute Settlement

While MISO clears the real-time market in five-minute intervals and schedules physical transactions on a 15-minute basis, it settles generation on an hourly basis[18] The five-minute real-time market produces prices that more accurately reflect system conditions and aides in more rapid response to system ramp and congestion management needs than longer intervals used in some other markets. Hourly settlement, however, creates financial incentives that are often in opposition to the five-minute dispatch signals for generators. When an hourly settlement value is anticipated to be higher than a resource's incremental cost, the resource has the incentive to dispatch up regardless of MISO's base point instruction, provided it stays within MISO's deviation tolerances.

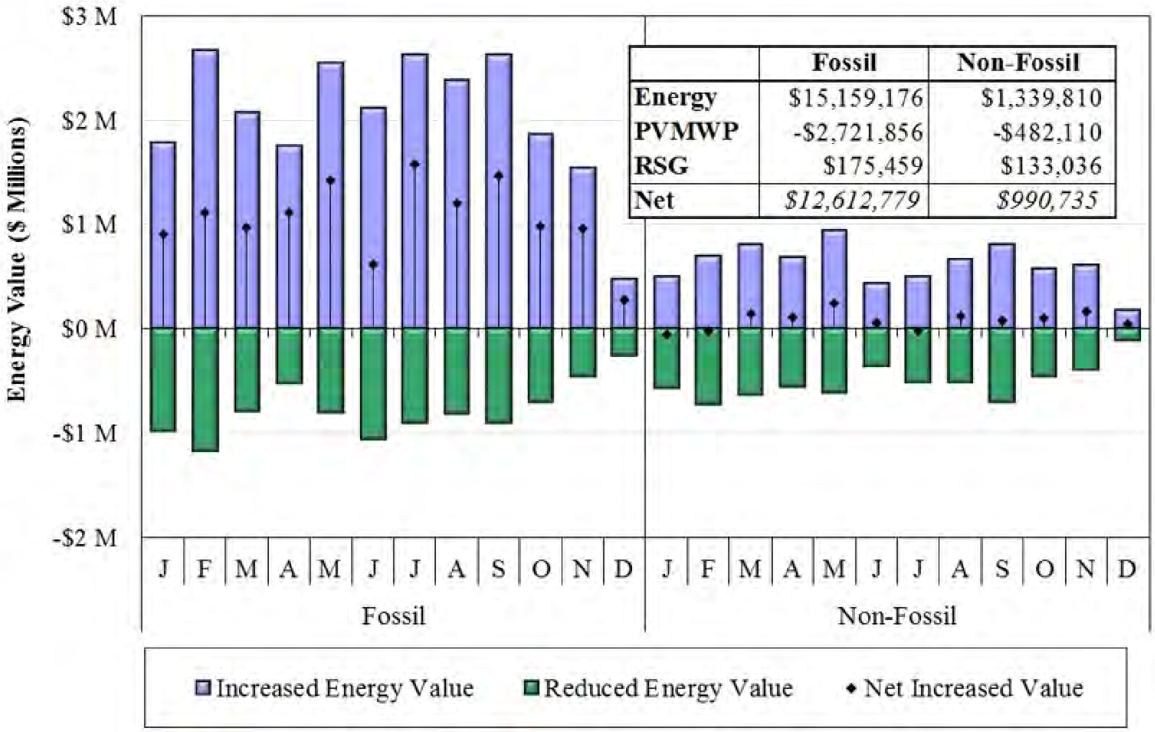
MISO has attempted to address the discrepancy between the five-minute dispatch and the hourly settlement incentives with the PVMWP. The PVMWP is intended to induce generators to provide dispatch flexibility and to respond to five-minute dispatch signals. While the PVMWP removes some of the disincentives a generator would have to follow five-minute dispatch signals under the hourly settlement, settling on a five-minute basis for generation would provide a much stronger incentive for generators to follow five-minute dispatch. It would also remove incentives for generators to self-commit in hours following price spikes to profit from hourly settlements and it would be compatible with other MISO initiatives (e.g., a ramp product).

[18] In response to Order 764, MISO implemented 15-minute settlement for physical transactions in June, 2015.

Figure A64: Net Energy Value of Five-Minute Settlement

The next figure examines the over- and under-counting of energy value associated with the hourly settlement of the five-minute dispatch in 2015. The hourly settlement is based on a simple average of the five-minute LMPs and is not weighted by the output of the resource. A resource tends to be undervalued when its output is positively correlated with LMP and vice versa. For example, a resource that produces more output in intervals when five-minute prices are lower than the hourly price would be overvalued. The figure shows the differences in energy value in the five-minute versus hourly settlement for fossil-fueled and non-fossil resources.

Figure A64: Net Energy Value of Five-Minute Settlement
2015



Fossil-fueled resources tend to provide more flexibility and therefore tend to produce more in intervals with higher five-minute prices. Some non-fossil fuel types such as nuclear provide little dispatch flexibility, so the average output across a given hour is consistent and seldom results in any discernible difference in valuation.

Wind resources, on the other hand, can only respond to price by curtailing output; normally they cannot ramp up in response to price increases because they typically operate at their maximum. Additionally, wind resource output is negatively correlated with load and often contributes to congestion at higher output levels, so hourly-integrated prices often overstate the economic value of its generation.

FERC issued a NOPR in RM15-24 calling for consistency between settlement intervals and dispatch intervals. MISO has agreed with our related recommendation to implement 5-minute settlement and filed supporting comments in response to the Commission's NOPR.

K. 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.

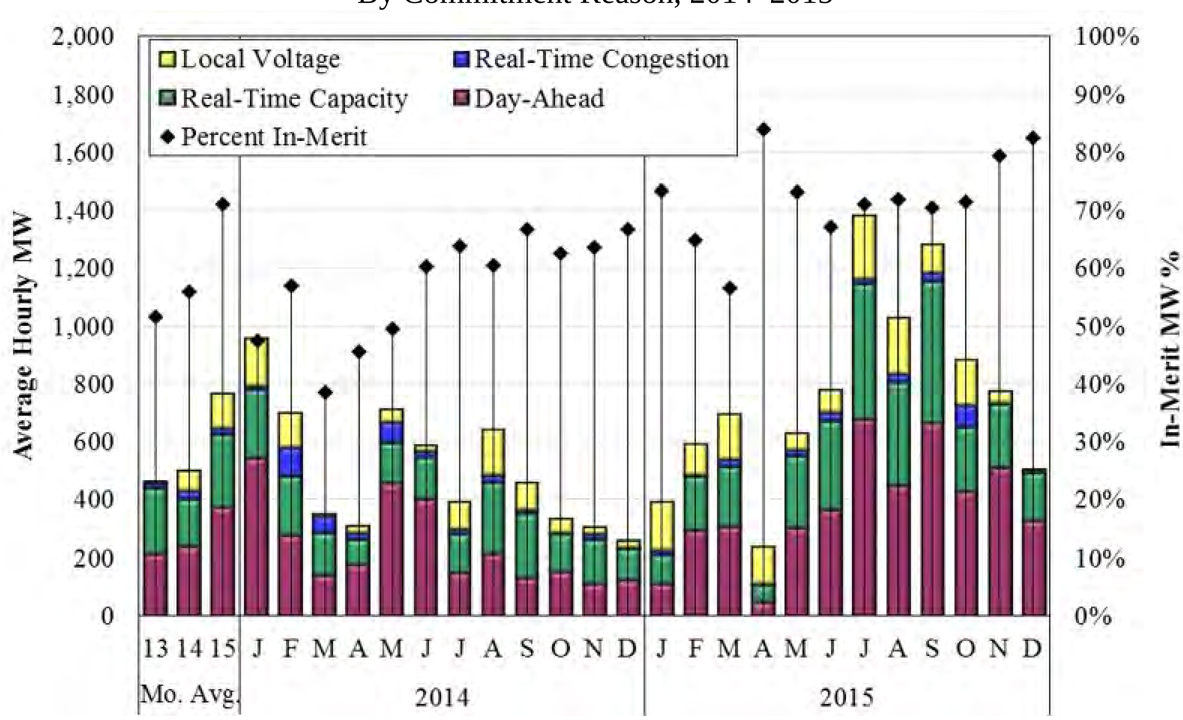
While low commitment costs make peaking resources attractive for meeting capacity needs, they generally have high incremental energy costs and frequently do not set the energy price because they are often dispatched at their economic minimum level (causing them to run "out-of-merit" with an offer price higher than their LMP). When a peaking unit runs out-of-merit order, it will receive RSG payments to cover its as-bid energy, start-up and minimum-generation costs.

Since MISO's aggregate load peaks in the summer, 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 A65: Average Hourly Peaking Unit Dispatch and Prices

Figure A65 shows average hourly dispatch levels of peaking units in 2015 and evaluates the consistency of peaking unit dispatch and market outcomes. The figure is disaggregated by the unit's commitment reason. It separately indicates the share of the peaking resource output that is in-merit order (i.e., the LMP exceeds its offer price).

Figure A65: Dispatch of Peaking Resources
By Commitment Reason, 2014–2015



L. 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 particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind's portion of total generation increases.

MISO introduced the Dispatchable Intermittent Resource (DIR) type in June 2011. DIRs are wind resources that are physically capable of responding to dispatch instructions (from nearly zero to a forecasted maximum) and can, therefore, set the real-time energy price. DIRs are treated comparable to other dispatchable resources. Nearly 85 percent (13.8 GW) of MISO's wind capacity—149 out of 212 units—is currently capable of responding to dispatch instructions; the rest generally lack the physical capabilities (such as blade feathering) to participate as DIRs. DIRs can submit offers in the day-ahead market (accompanied by generation forecasts). For both DIR and non-DIR, MISO utilizes short and long-term forecasts to make assumptions about wind output. With the expanded DIR capability, MISO now rarely needs to utilize manual curtailments to ensure reliability.

Figure A66: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A66 shows a seven-day moving average of wind scheduled in the day-ahead market and dispatched in the real-time market since 2014. Under-scheduling of output in the day-ahead market can create price convergence issues in western areas 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 offsets the effects of under-scheduling by the wind resources.

Figure A66: Day-Ahead Scheduling Versus Real-Time Wind Generation
2014–2015

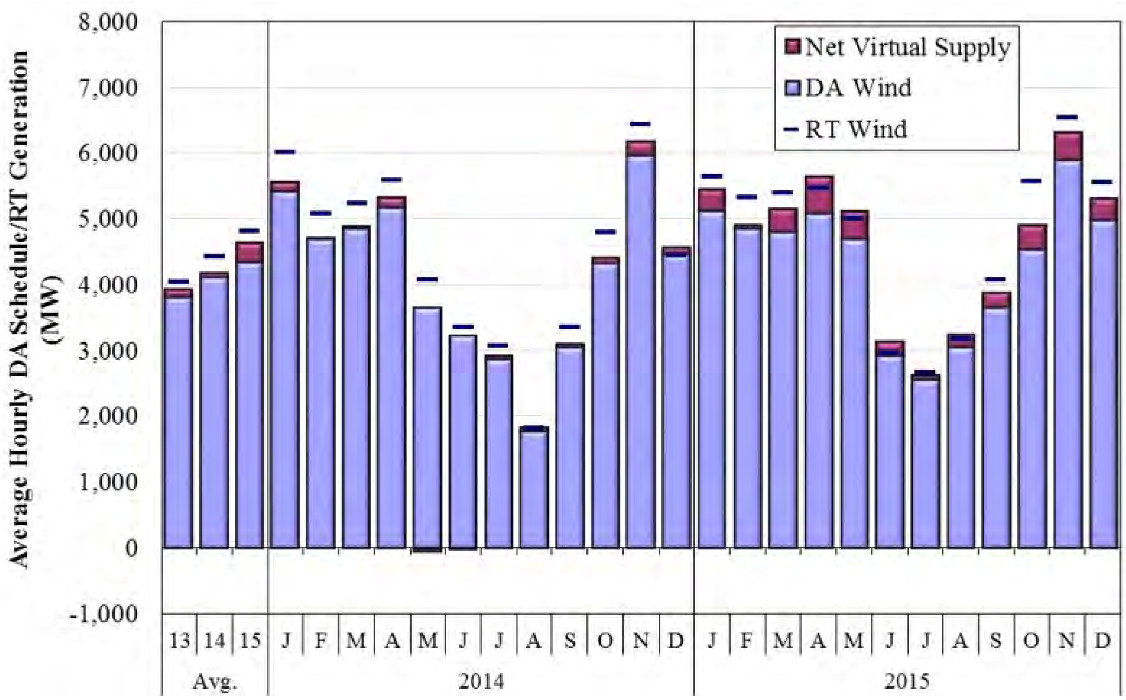


Figure A67: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

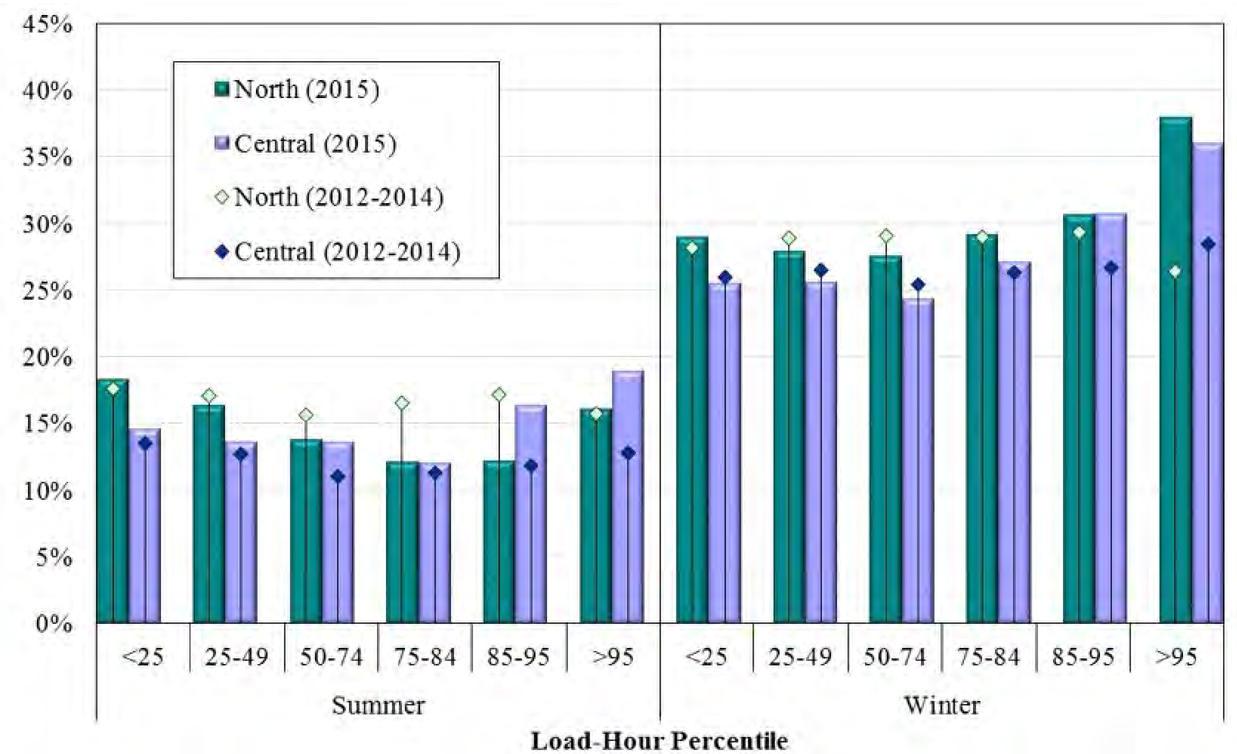
Wind capacity factors (measured as actual output as a percentage of nameplate capacity) vary substantially year-to-year, and by region, hour, season, and temperature. Wind resources can be designated as capacity resources under Module E of the Tariff, but their capacity value is adjusted for their capacity or capacity factors).[19]

Figure A67 shows average hourly wind capacity factors by load-hour percentile, shown separately by season and region. The figure also shows the three-year average from 2012 - 2014. This breakdown shows how capacity factors have 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 A67: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

2015



19 Module E capacity credits for wind resources are determined by MISO's annual Loss of Load Expectation (LOLE) Study. It is established on a unit basis by evaluating a resource's performance during the peak hour of each of the prior seven years' eight highest peak load days, for a sample size of 56 peaks. For the upcoming 2016–2017 Planning Year, the system-wide capacity credit for wind is 15.6 percent, up from 14.7 percent last year. Excluding resources that received no credit, individual credits range from 1.4 to 27.4 percent.

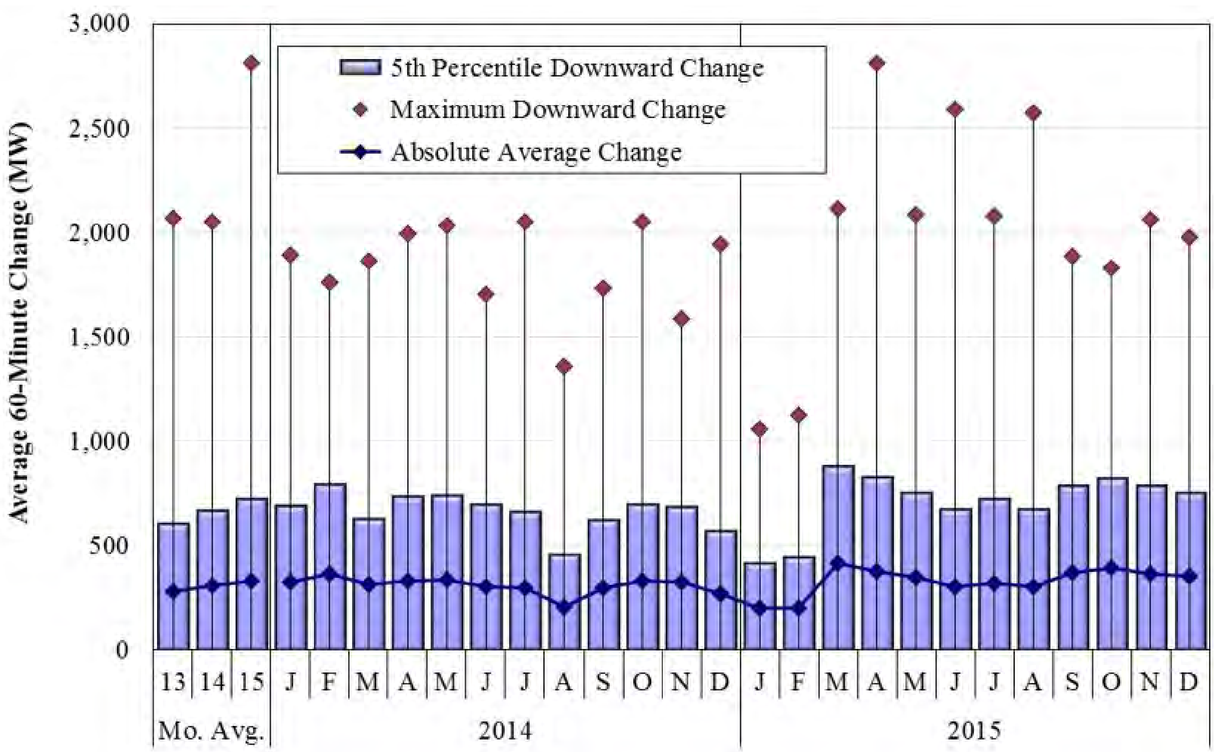
Figure A68: Wind Generation Volatility

Wind output can be highly variable and must be managed through the redispatch of other resources, curtailment of wind resources, or commitment of peaking resources. Figure A68 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 due to MISO economic curtailments are excluded from this analysis.

Figure A68: Wind Generation Volatility
2014–2015



VI. Transmission Congestion and FTR Markets

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources. 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 transmission capability is limited – so higher-cost units must be dispatched in place of lower-cost units to avoid overloading transmission facilities. In LMP markets, this generation redispatch 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, rather than congestion revenues collected by MISO. The value of congestion is defined as the marginal value (e.g., shadow price) of the constraint times the power flow over the constraint. If the 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. There are two primary reasons why MISO does not collect the full value of the congestion on its system.

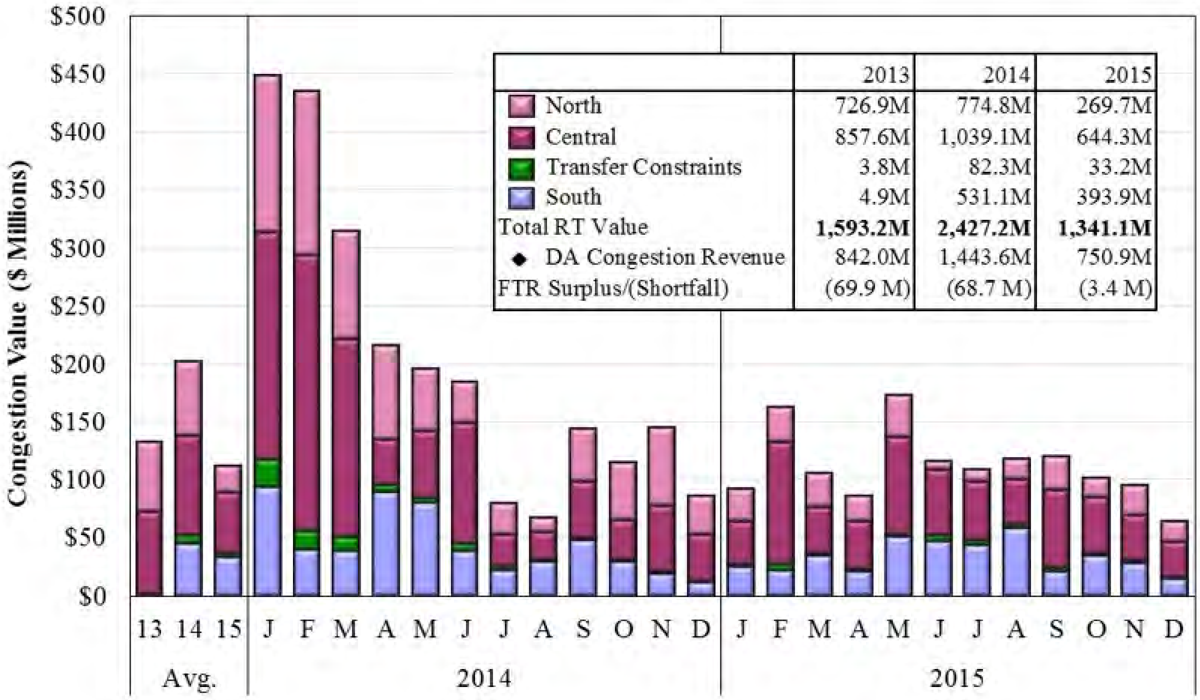
First, the congestion value is based on the total flow over the constraint and MISO settles with only part of the flows on its constraints. Generators and loads outside MISO contribute to flows over MISO’s system (known as “loop flows”) that do not pay MISO for their congestion value. Additionally, some neighboring entities have entitlements to flow power over MISO’s system (e.g., PJM and SPP).

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 (which settles only deviations from the day-ahead market). Therefore, when congestion is not foreseen and, therefore, not fully anticipated in day-ahead prices, MISO will collect less congestion revenue than the real-time value of congestion on its system.

Figure A69: Value of Real-Time Congestion by Coordination Region

Figure A69 shows the total monthly value of real-time congestion by region and the average number of binding constraints per interval in 2014 and 2015. The bars on the bottom of the chart show the average monthly value against the left axis in each of the past three years.

Figure A69: Value of Real-Time Congestion by Coordination Region
2014–2015



	2013	2014	2015
North	726.9M	774.8M	269.7M
Central	857.6M	1,039.1M	644.3M
Transfer Constraints	3.8M	82.3M	33.2M
South	4.9M	531.1M	393.9M
Total RT Value	**1,593.2M**	**2,427.2M**	**1,341.1M**
◆ DA Congestion Revenue	842.0M	1,443.6M	750.9M
FTR Surplus/(Shortfall)	(69.9 M)	(68.7 M)	(3.4 M)

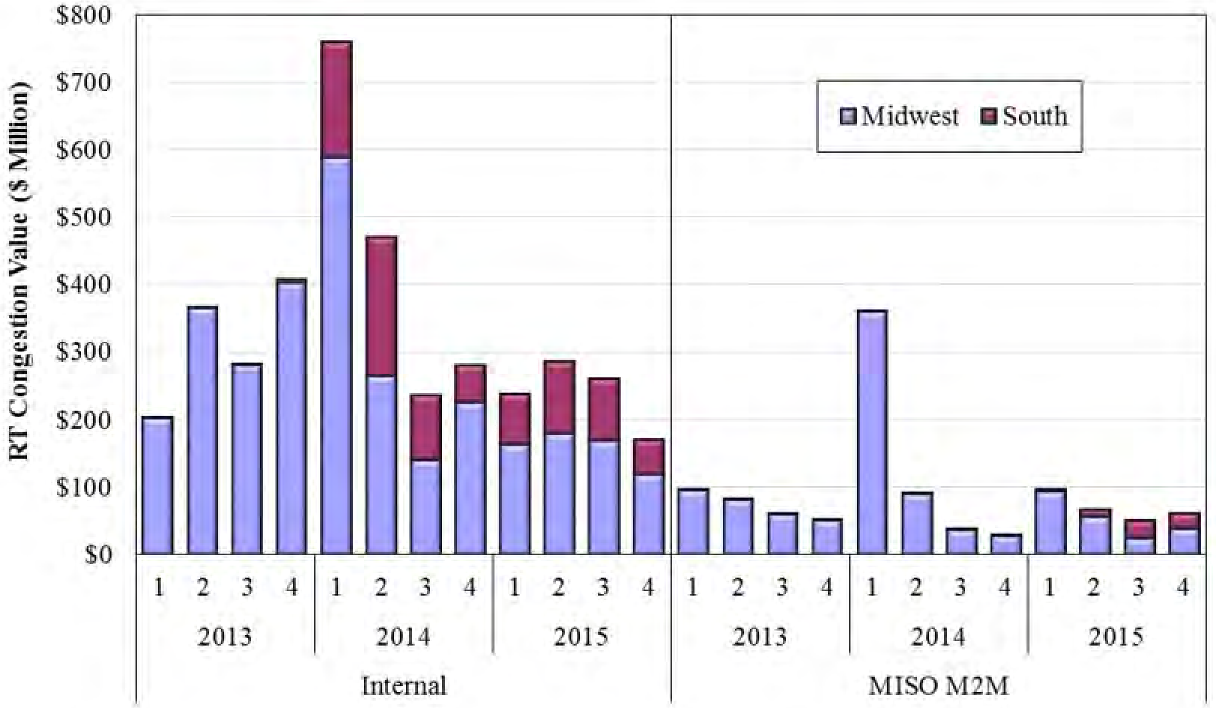
Figure A70: Value of Real-Time Congestion by Type of Constraint

To better identify the nature of constraints and the congestion value, Figure A70 disaggregates the results by type of constraint. We define four constraint types:

- Internal Constraints: Those constraints internal to MISO (where MISO is the reliability coordinator) and not coordinated with PJM or SPP.
- MISO M2M Constraints: MISO-coordinated market-to-market constraints. Many of these are substantially impacted by generation in the Commonwealth Edison (ComEd) area of PJM and beginning in March 2015 these include constraints coordinated with SPP.
- PJM and SPP M2M Constraints: PJM and SPP -coordinated market-to-market constraints.
- External Constraints: Constraints located on other systems that MISO must help relieve by redispatching generation when Transmission Line Loading Relief (TLR) procedures are invoked by a neighboring system. These include PJM and SPP constraints that are not market-to-market constraints.

The flow on PJM and SPP M2M constraints and on external constraints represented in the MISO dispatch is only the MISO market flow; whereas, internal and MISO market-to-market constraints include the total flow. The estimated value of congestion on external constraints (but not their impact on LMP congestion components) is therefore reduced.

Figure A70: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2013–2015



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 associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets, with the 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 (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 A71: Day-Ahead and Balancing Congestion and Payments to FTRs

Figure A71 shows total day-ahead congestion revenues for constraints in the Midwest region, South region, and the transfer constraints between the Midwest and South regions for the last three years. It also shows the balancing congestion costs (these are costs because they are actually negative revenues), as well as the funding level of the FTRs.

Figure A71: Day-Ahead and Balancing Congestion and Payments to FTRs
2013–2015

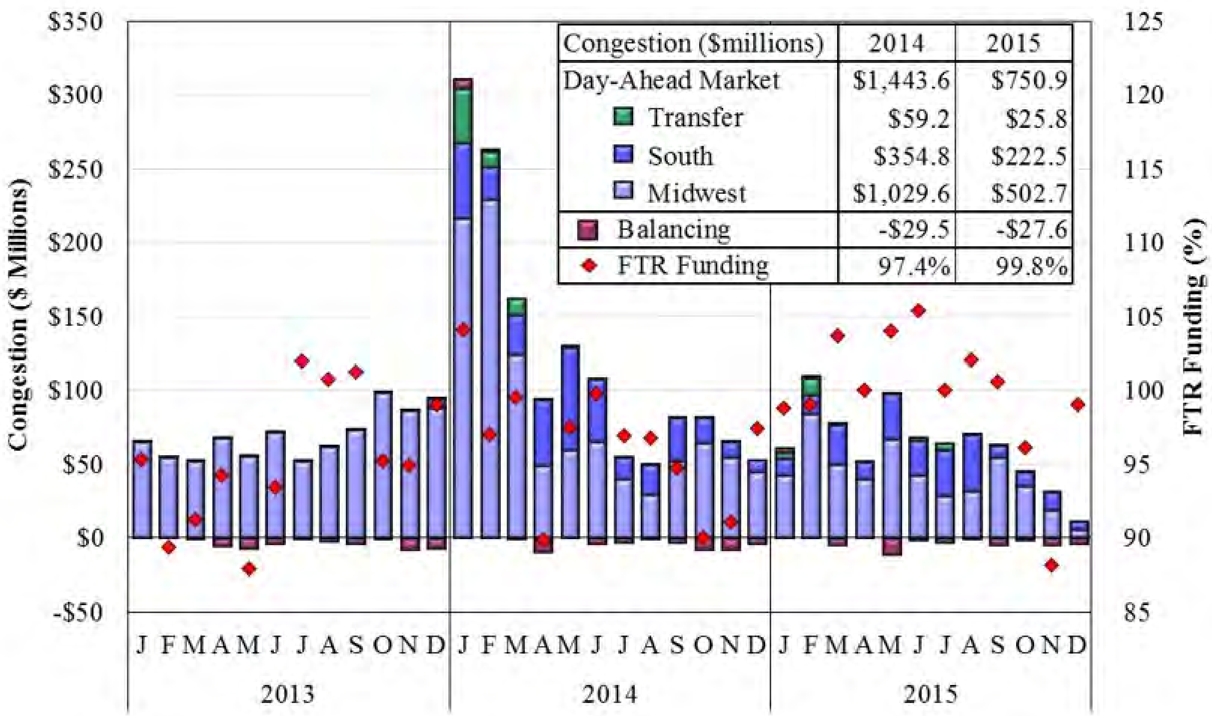
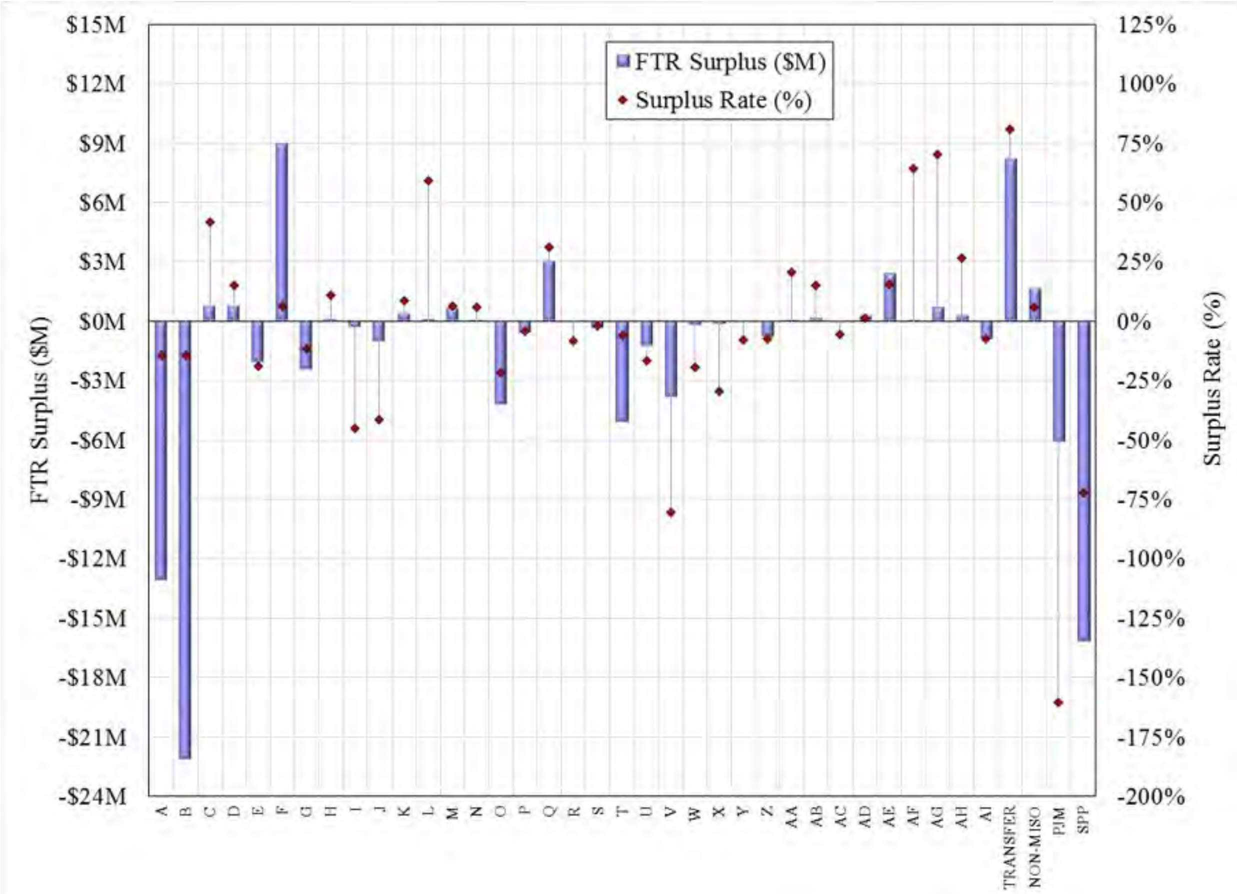


Figure A72: FTR Funding by Balancing Area

At an aggregate level, FTR funding is good (over 99 percent). 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 control area can illuminate any potential cost-shifting that may be occurring between participants.

Figure A72 shows the monthly FTR surpluses and shortfalls (in dollars and percentage terms) by type of constraint and by control area for 2015 (actual control area is masked with sequential letters). The types of constraints include internal, market-to-market and external constraints.

Figure A72: FTR Funding by Type of Constraints and Control Area
2015



C. Balancing Congestion Costs

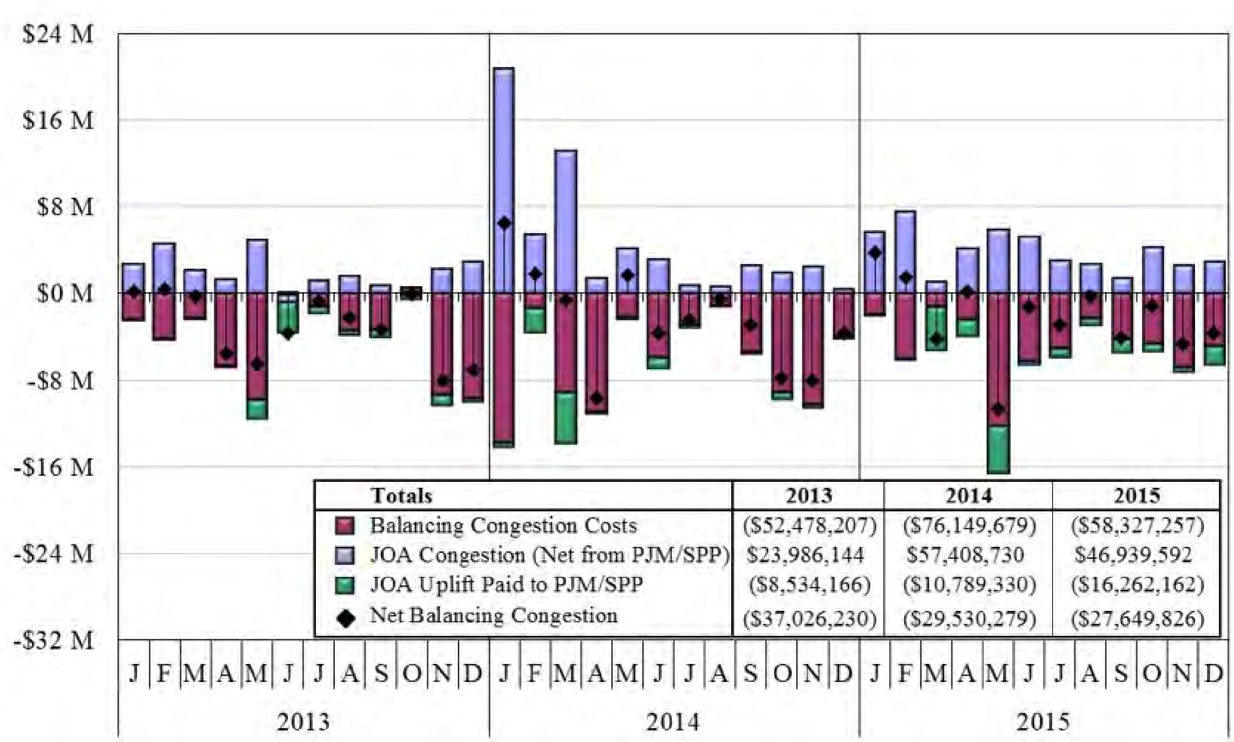
Balancing congestion costs are real-time costs incurred based on deviations from day-ahead congestion outcomes. They should be small if the day-ahead accurately forecasts the real-time network capabilities. However, balancing congestion can be large and result in substantial costs to the RTO's customers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

For example, if the RTO does not model a particular constraint in the day-ahead market and it ultimately binds in real time, the RTO can accumulate a substantial amount of balancing congestion. 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 costs incurred by the RTO to "buy-back" the day-ahead flows are negative balancing congestion revenues (or balancing congestion costs) that must be collected through an uplift charge to MISO's customers.

Figure A73: Balancing Congestion Costs

To understand balancing congestion costs, Figure A73 shows these costs disaggregated into (1) the real-time congestion costs incurred to reduce (or increase) the MISO flows over binding transmission constraints and (2) the market-to-market payments made by (or to) PJM under the JOA. For example, when PJM exceeds its flow entitlement on a MISO-managed constraint, MISO will redispatch to reduce its flow and generate a cost (shown as negative in the figure), while PJM's payment to MISO for this excess flow is shown as a positive revenue to MISO. We have also included JOA uplift in real-time balancing congestion costs. JOA uplift results from MISO exceeding its FFE on PJM market-to-market 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 A73: Balancing Congestion Costs
2013–2015



D. FTR Auction Revenues and Obligations

Because FTR holders are entitled to congestion costs collected in the day-ahead market, an FTR represents a forward purchase of day-ahead congestion costs that allows participants to manage day-ahead price risk from congestion. Transmission customers have and are continuing to pay for the embedded costs of the transmission system and are therefore 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 network load and resources. ARRs give customers the right to receive the FTR revenues MISO receives when it sells FTRs that correspond to their ARRs, or to convert their ARRs into FTRs directly in order to receive day-ahead congestion revenues. FTRs can be bought and sold in the seasonal and monthly auctions. Residual transmission capacity not sold in the seasonal auction is sold in monthly auctions. This affords participants an opportunity to trade monthly obligations for seasonal rights. Beginning in the fall of 2013, MISO began operating 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 value of day-ahead congestion over the path that defines each FTR. In particular, the FTR payment obligation is the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[20] Congestion revenues collected in MISO's day-ahead market fund FTR obligations. Surpluses and shortfalls are expected to be limited when participants hold FTR portfolios that match power flows over the transmission system. When FTRs exceed the transmission system's physical capability or loop flows from activity outside MISO uses its transmission capability, MISO may collect less day-ahead congestion revenue than it owes to FTR holders.[21] 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 year end, when they are prorated to reduce any remaining FTR shortfalls.

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 are similar to those discussed previously between the day-ahead and real-time markets. They 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.

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.

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.

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

21 "Loop Flows" cannot be directly calculated and in this context would be measured real-time flows less the calculated real-time market flows from PJM, and SPP, and the MISO commercial flows (which include the 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.

E. Multi-Period Monthly FTR Auction Revenues and Obligations

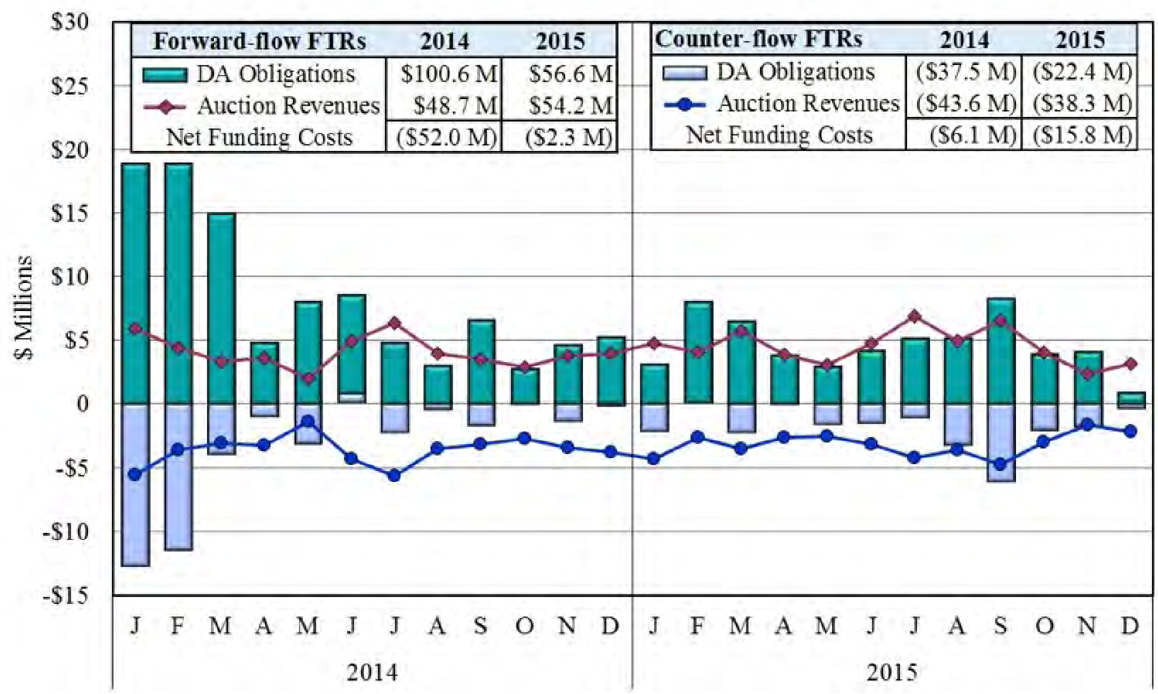
In the MPMA FTR auctions, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on an interface. For example, imagine MISO has issued 250 MW of FTRs over an interface 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 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 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 more costly to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

Figure A74: Monthly FTR Auction Revenues and Obligations

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A74 compares the auction revenues from the monthly FTR auction to the day-ahead FTR obligations associated with the FTRs sold. It 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 ultimate value.

Figure A74: Monthly FTR Auction Revenues and Obligations
2014–2015



F. Improving the Utilization of the Transmission System

Substantial savings could be achieved through wide-spread use of temperature-adjusted transmission ratings for all types of transmission constraints. For most transmission constraints, the ability flow power through the facility is related to the heat caused by the power flow. When ambient temperatures are cooler than the typical assumption when rating the facilities, additional power flows can be accommodated. Therefore, if transmission owners develop and submit temperature-adjusted transmission ratings, it would allow MISO to operate to higher transmission limits and achieve 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 both normal and emergency limits as called for under the Transmission Owner's Agreement.[22] However, we have identified some transmission owners that provide only normal ratings. 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/or develop operating guides that would assure such a response.

We worked with MISO and one transmission owner in 2015 to implement a pilot program to make use of temperature-adjusted, short-term emergency ratings on a number of key facilities. Preliminary results indicate clear benefits with no reliablity issues.

Finally, there are substantial potential savings with more wide-spread use of Voltage and Stability Analysis Tools (VSAT) in real time. In January 2015, the VSAT software was implemented and successfully used to reduce costs of managing stability constraints in the MISO North region. In 2014, the congestion on a key interface exceeded $31 million in real-time. After implementation of VSAT, this was reduced to less than $1 million. We support MISO's efforts to work with transmission providers in other MISO regions or neighboring regions that call TLRs that affect MISO to adopt such software.

The analysis in this section examines the potential value that may be available by more fully utilizing the transmission network. This can be accomplished by operating to higher transmission limits that would result from consistent use of improved ratings for MISO's transmission facilities, including:

- Temperature-adjusted transmission ratings; Emergency ratings; and
- Use of dynamic Voltage and Stability ratings.

22 The Transmission Owners Agreement calls for transmission owners to submit normal transmission ratings on base (non-contingency) constraints and emergency ratings on contingency constraints ("temporary" flow levels that can be reliability accommodated for 2-4 hours). Because most constraints are contingent constraints (i.e., the limit is less than the rating to make room for the flows that will occur if the contingency happens), it is generally safe to use the emergency ratings.

Figure A75: Potential Value of Additional Transmission Capability

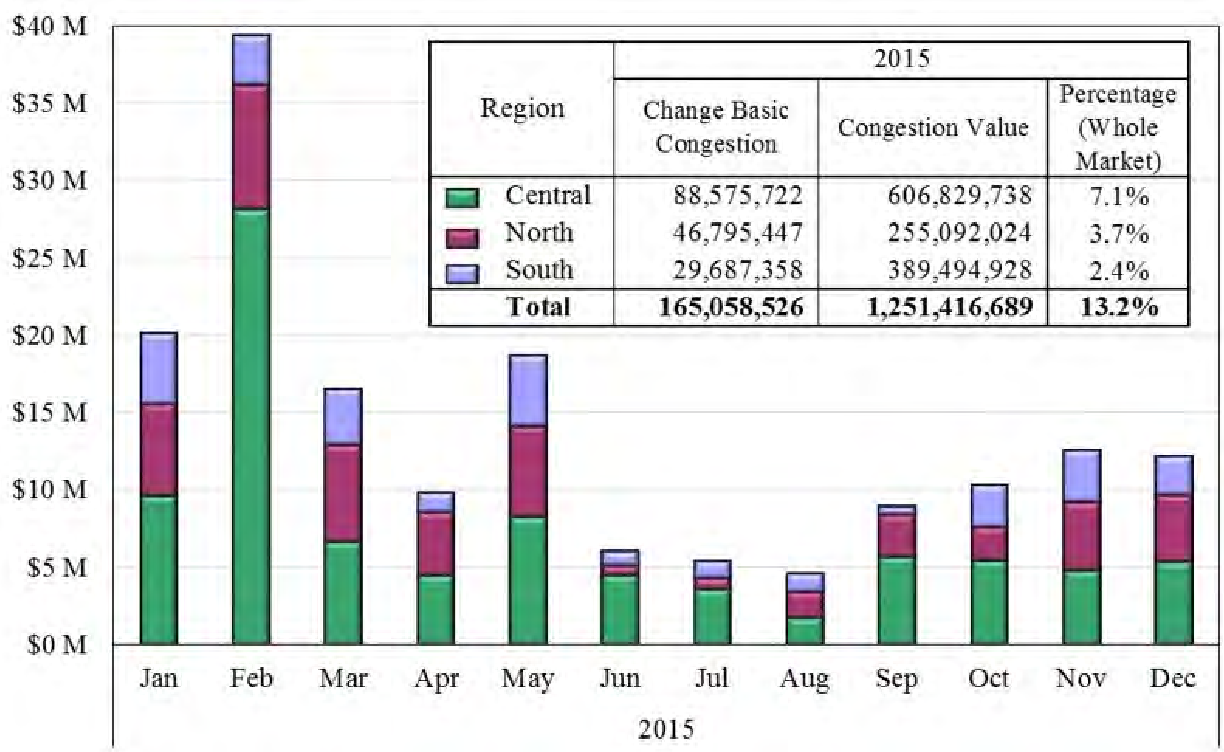
Figure A75 shows our estimate of the congestion value of the incremental transmission capability that could potentially be made available by consistently utilizing temperature-adjusted emergency ratings.

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 class of transmission elements (e.g. Forced Air-Cooled Transformers, Self-Cooled Transformers, Overhead Conductors).

We used the most conservative class of ratings (e.g. the lowest permissible ratings increase under the Standard) for the type of element (Line or Transformer). We then used the highest ambient temperatures prevailing at the nearest temperature measurement location for each market date during 2015 to calculate an adjusted transmission limit consistent with the temperature adjusted ratings.

The value of increasing the transmission limits was then calculated by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint. The results of this analysis are shown by region and month in the figure below.

Figure A75: Potential Value of Additional Transmission Capability
2015



Region	2015		
	Change Basic Congestion	Congestion Value	Percentage (Whole Market)
Central	88,575,722	606,829,738	7.1%
North	46,795,447	255,092,024	3.7%
South	29,687,358	389,494,928	2.4%
Total	**165,058,526**	**1,251,416,689**	**13.2%**

Another class of relevant constraints are those limited by voltage or voltage stability concerns. These constraints cannot be accurately modeled as thermal constraints and require a more detailed analysis. Absent a real-time tool and the ability to calculate dynamic limits based on current or near-term expected operating conditions, operators must use what can be very conservative ratings.

MISO has developed real-time tools including the Voltage Stability Analysis Tool (VSAT) and Transient Stability Analysis Tool (TSAT) which has been used successfully to reliably calculate ratings on Interregional Operating Limits (IROL) constraints (e.g. the Minnesota-Wisconsin Export (MWEX) constraint). These dramatically reduced the frequency and cost of binding this interface in 2015.

G. Transmission Line Loading Relief Events

With the exception of market-to-market coordination between MISO and PJM, MISO and SPP, and between NYISO and PJM, reliability coordinators in the Eastern Interconnect continue to rely on Transmission Line Loading Relief (TLR) procedures and the NERC Interchange Distribution Calculator (IDC)[23] to manage congestion on their systems that is 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 entities in other areas 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 redispatch its resources to reduce MISO's market flows over the constrained transmission facility by the amount requested.

On MISO flowgates, external entities not dispatched by MISO also contribute to total flows. If external transactions contribute more than five percent of their 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.

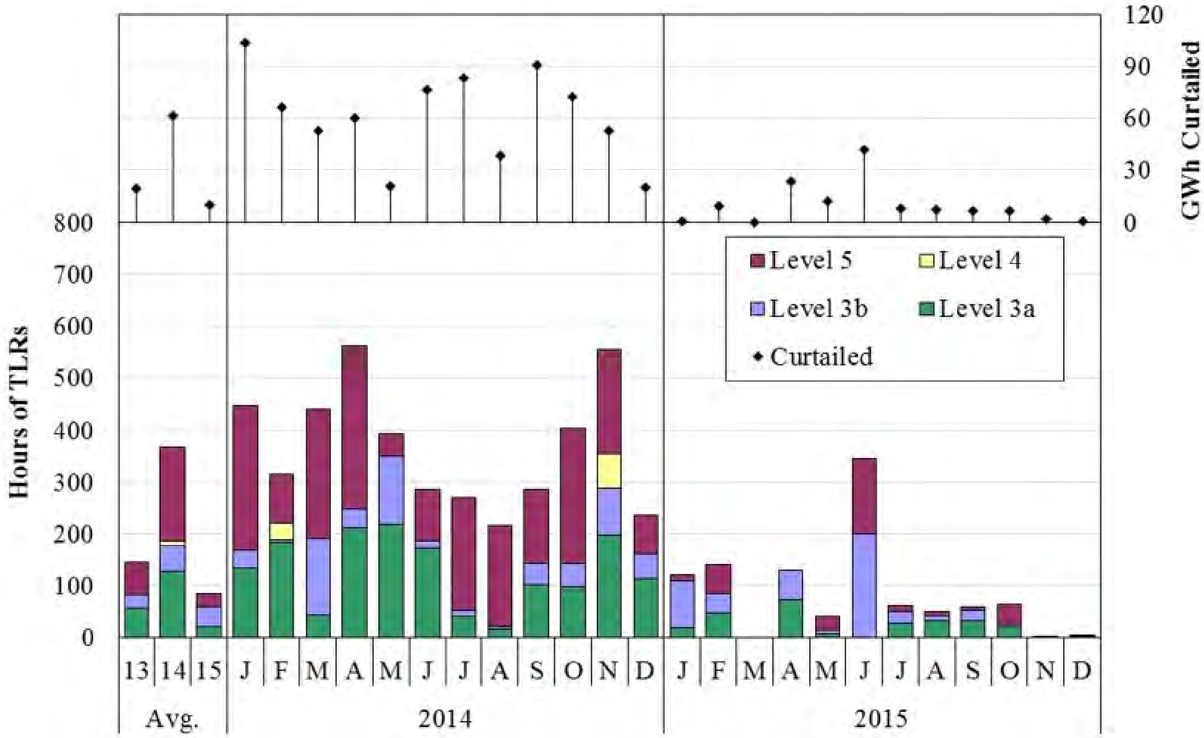
When compared to economic generation dispatch through LMP markets, the TLR process is an inefficient and rudimentary means to manage congestion. TLR provides less timely and less certain control of power flows over the system. We have found in prior studies that the TLR process resulted in approximately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

23 To implement TLR procedures on defined Flowgates, Reliability Coordinators (RCs) depend upon the IDC. The IDC provides RCs with the 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 RCs in TLR.

Figure A76 and Figure A77: Periodic TLR Activity

Figure A76 shows monthly TLR activity on MISO flowgates in 2014 and 2015. 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 hourly TLR activity called by MISO, shown by the various TLR levels.

Figure A76: Periodic TLR Activity
2014–2015



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

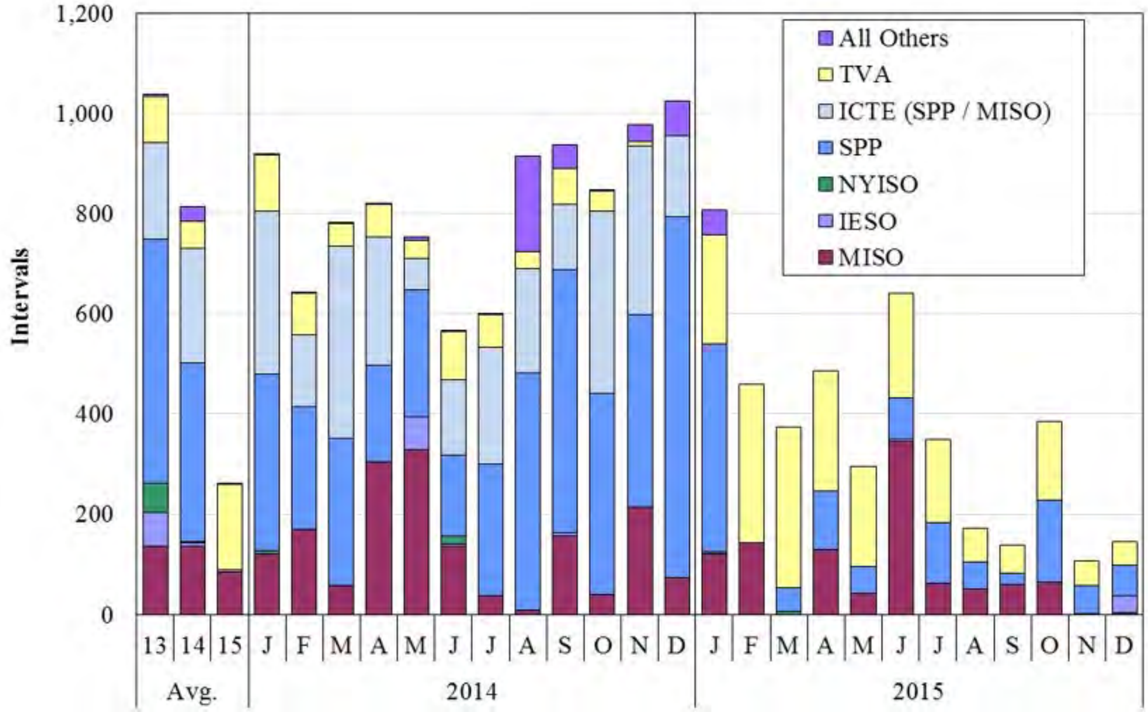
- Level 3—Non-firm curtailments;[24]
- Level 4—Commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[25]

Figure A77 shows TLR hours disaggregated by the Reliability Coordinator declaring the TLR.

24 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.

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

Figure A77: TLR Activity by Reliability Coordinator
2014–2015



H. Congestion Management

Congestion management is among MISO's most important roles. MISO monitors thousands of potential network constraints throughout its system using 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).[26]

While this is intended to reduce the flow on the constraint, some constraints can be difficult to manage if the available relief from the generating resources is limited. The available redispatch 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, such as dispatch range or ramp rate, lower than actual physical capabilities); or
- Generators are already at their limits (i.e, operating at the maximum or minimum points of their dispatch range).

26 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.

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, since MISO's performance criteria allow for twenty minutes to restore control on most constraints. If control is not restored within thirty minutes, a reporting criterion to stakeholders is triggered. Constraints most critical to system reliability (e.g., constraints that could lead to cascading outages) are operated more conservatively.

Figure A78: Constraint Manageability

The next set of figures show manageability of internal and MISO-managed market-to-market constraints. Figure A78 shows how frequently binding constraints were manageable and unmanageable in each month from 2014 to 2015.

Figure A78: Constraint Manageability
2014–2015

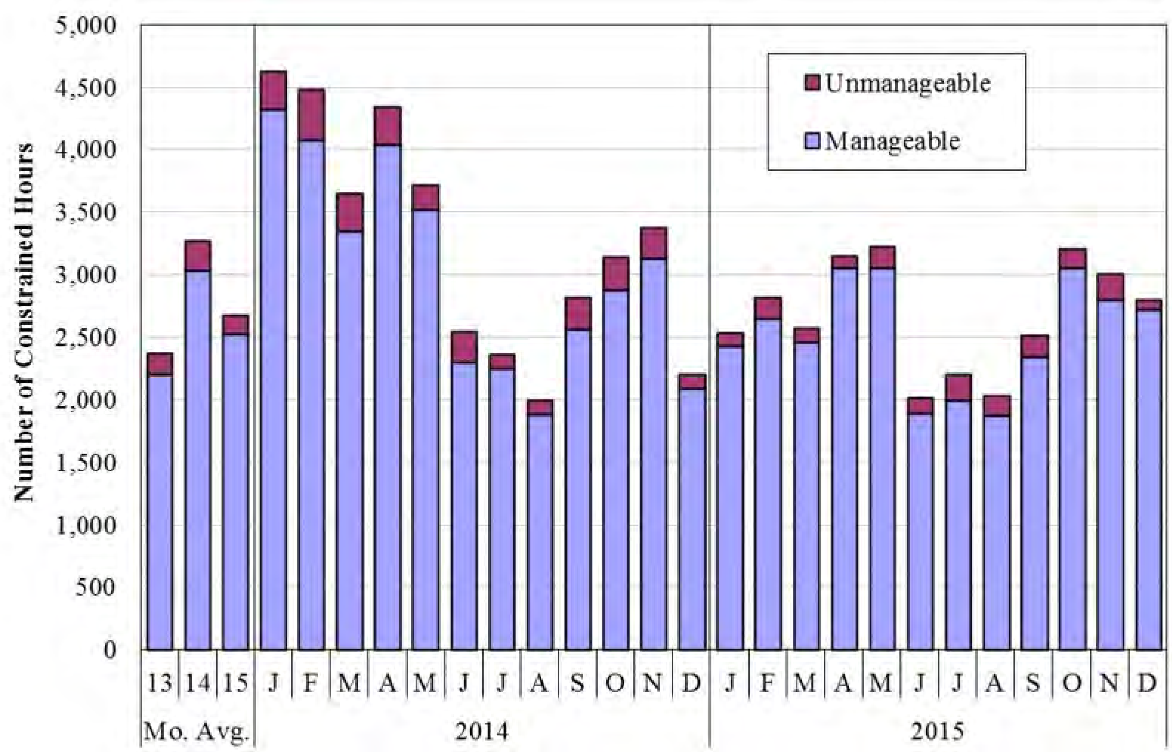


Figure A79: Value of Real-Time Congestion by Voltage Level

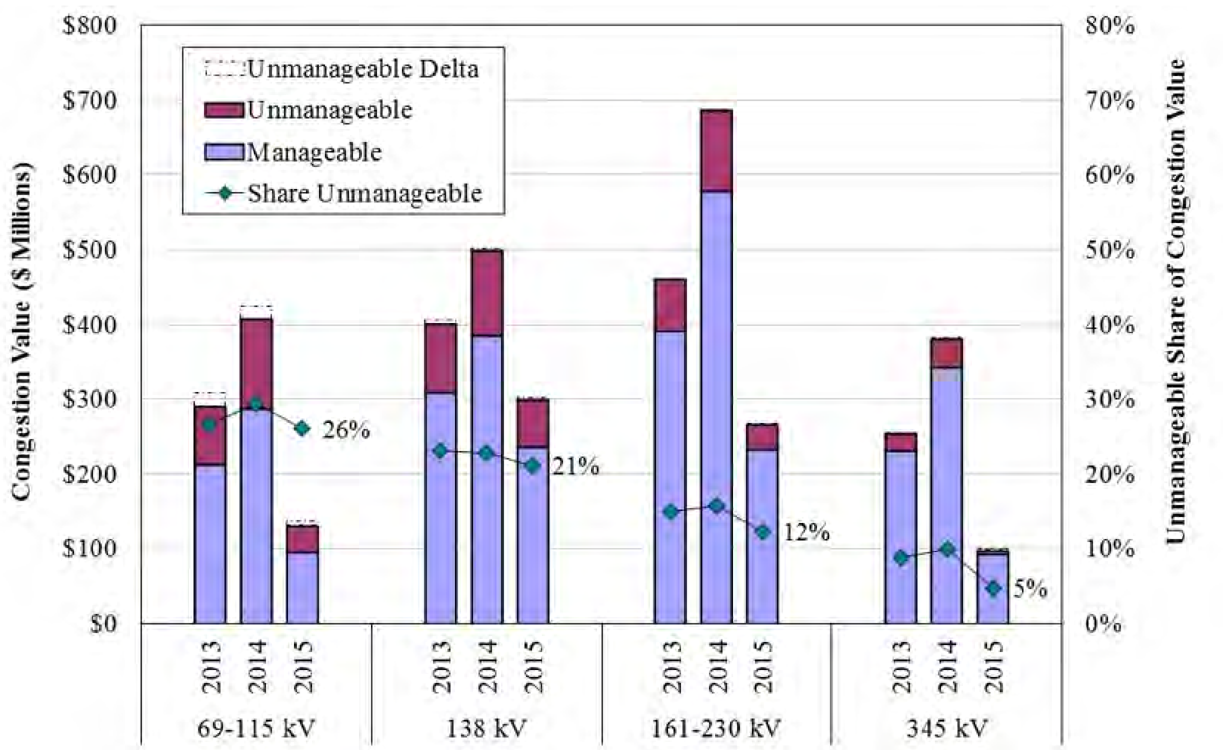
Given the frequency that constraints are unmanageable, it is critical that unmanageable congestion be priced efficiently and reflected in MISO's LMPs. The real-time market model utilizes Marginal Value Limits (MVLs) that cap the marginal cost (i.e., the shadow price) that the energy market will incur to reduce constraint flows to their limits. For the MISO markets to perform efficiently, the MVL must reflect the full reliability cost of violating the constraint.

When the constraint is violated (i.e., unmanageable), the most efficient shadow price would be the MVL 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, when a constraint's flow exceeded its limit an algorithm was used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs. 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 is lower than the MVL. No economic rationale supports setting prices on the basis of relaxed shadow prices. Although this practice was discontinued for internal non-market-to-market constraints, it remains in place for all market-to-market constraints.

Figure A79 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 A79 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 MVL) and the relaxed shadow price used to calculate prices.[27]

Figure A79: Real-Time Congestion Value by Voltage Level
2013–2015



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

I. FTR Market Performance

Because an FTR is a forward purchase of day-ahead congestion costs, FTR markets perform well when they establish prices that accurately reflect the expected value of day-ahead congestion. When this occurs, FTR profits are low (profits = the FTR price minus the day-ahead congestion payments). It is important to recognize 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 values established in the FTR markets. MISO runs the FTR market in two timeframes: annual (for the June to May planning year) and the current and future months via the Multi-Period Monthly Auction (MPMA). The MPMA was launched in November 2013 and facilitates FTRs trading for future months or seasons remaining in the planning year.

Figure A80: FTR Profits and Profitability

Figure A80 shows our evaluation of the profitability of these auctions by showing 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 future months.

Figure A80: FTR Profits and Profitability
2014–2015

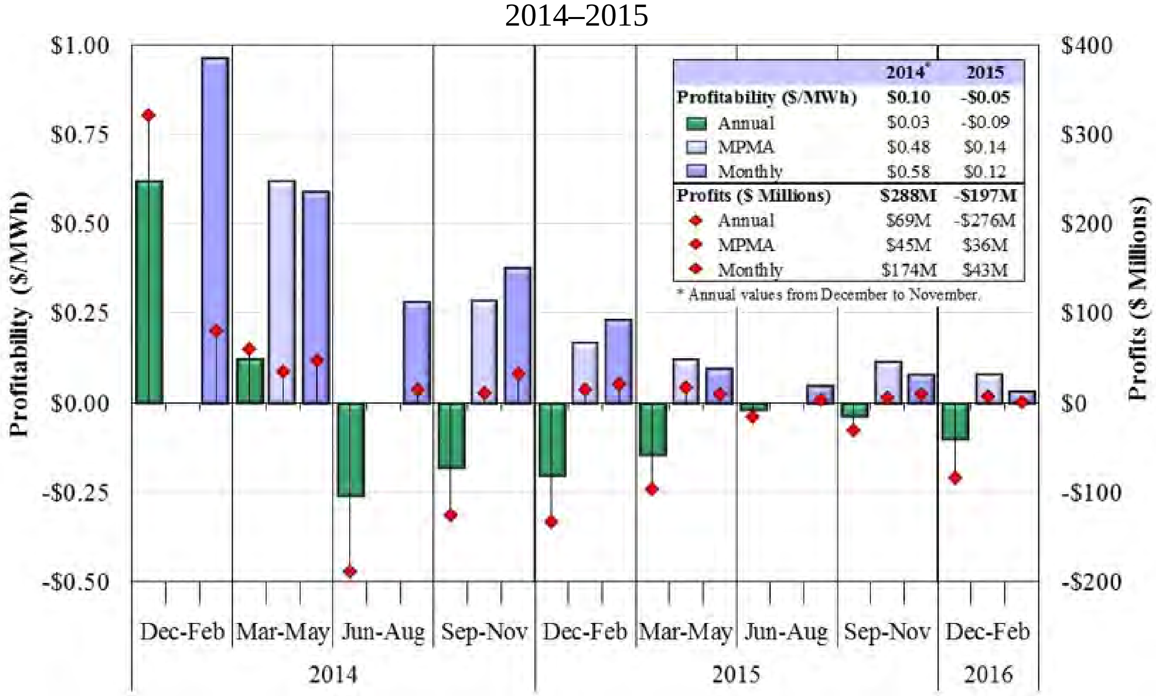


Figure A81 to Figure A83: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly FTR auctions in more detail for 2013-2015. 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 A81: FTR Profitability
2013–2015: Annual Auction

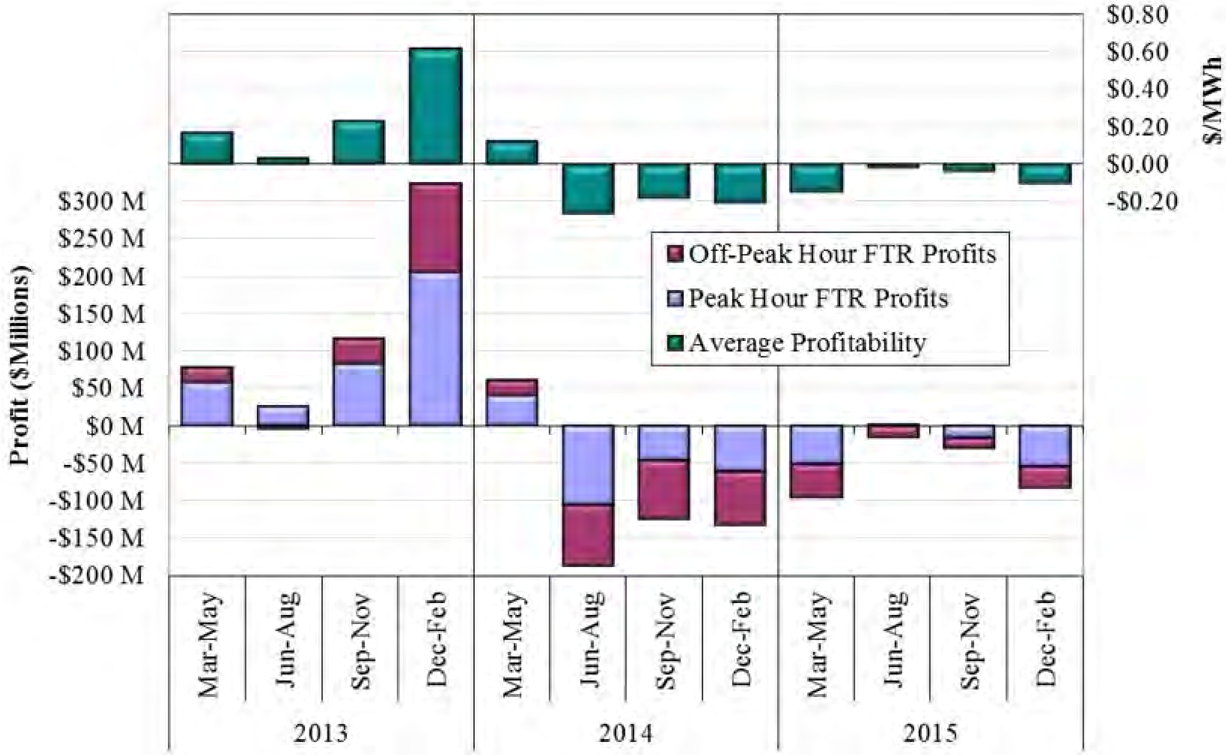


Figure A82: FTR Profitability
2014–2015: Monthly Auction

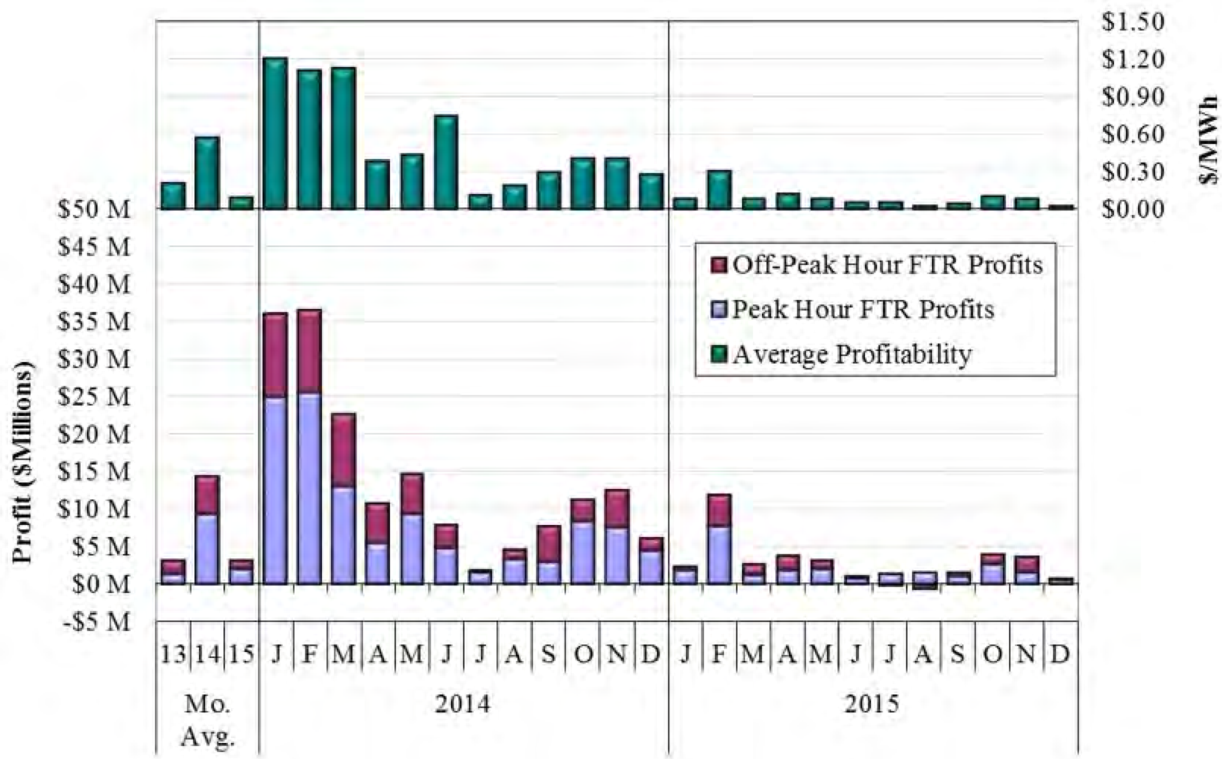


Figure A83: FTR Profitability
2014–2015 Seasonal Auction MPMA

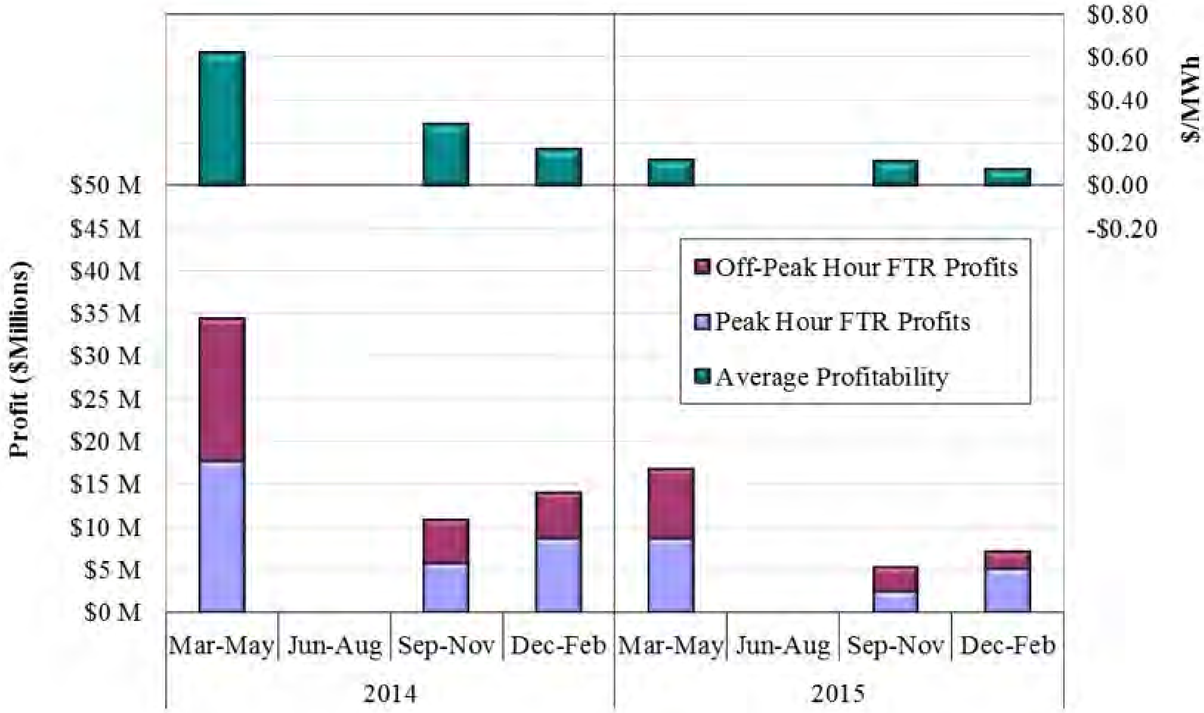


Figure A84 to Figure A97: Comparison of FTR Auction Prices and Congestion Value

The next 14 figures examine auction revenues from the monthly FTR auction to the day-ahead FTR obligations at representative locations in MISO. We analyze values for the Indiana, Michigan and Minnesota Hubs and for the WUMS Area in the Midwest Region, as well as for Texas, Louisiana and Arkansas Hubs in the South Region. Results for the seven locations are shown separately for peak and off-peak hours.

The purpose of this analysis is to show how well correlated the FTR market prices are to the actual congestion that occurs in the day-ahead market and is the basis for the payments to the FTRs. In a well performing FTR market, the FTR prices should accurately reflect expected day-ahead congestion. However, we note that actual congestion is subject to substantial uncertainty so these values will not be equal.

Figure A84: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2014–2015: Off-Peak Hours

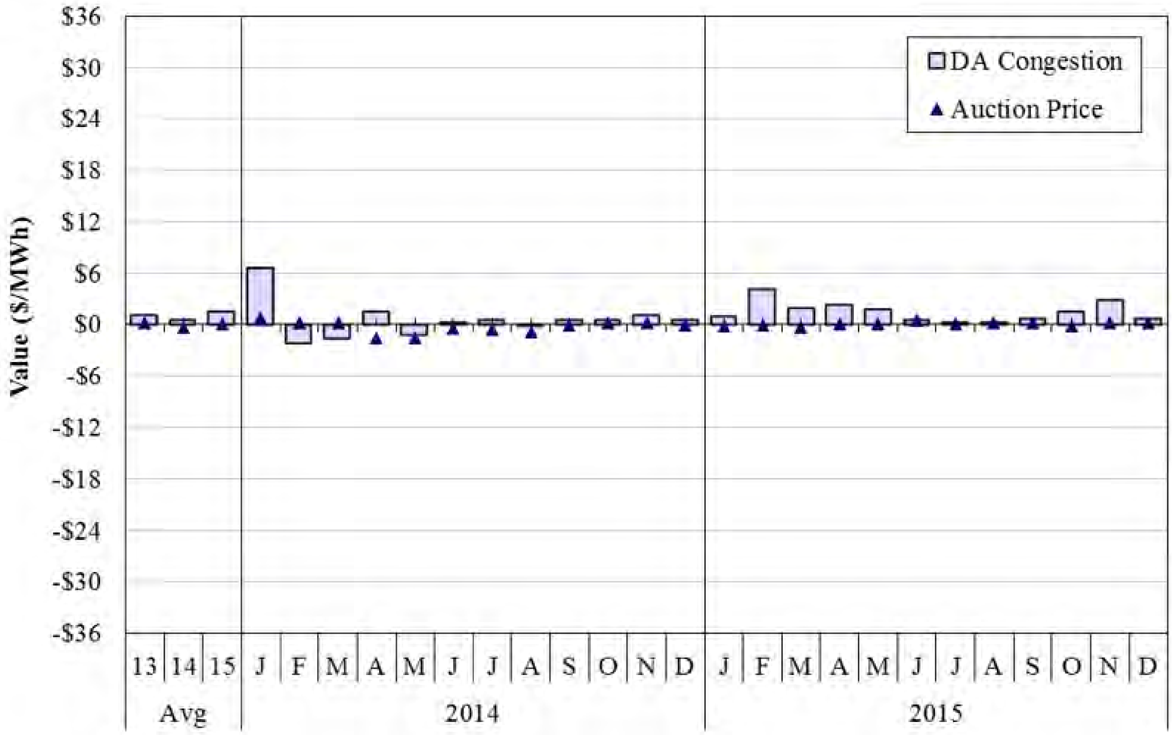


Figure A85: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2014–2015: Peak Hours

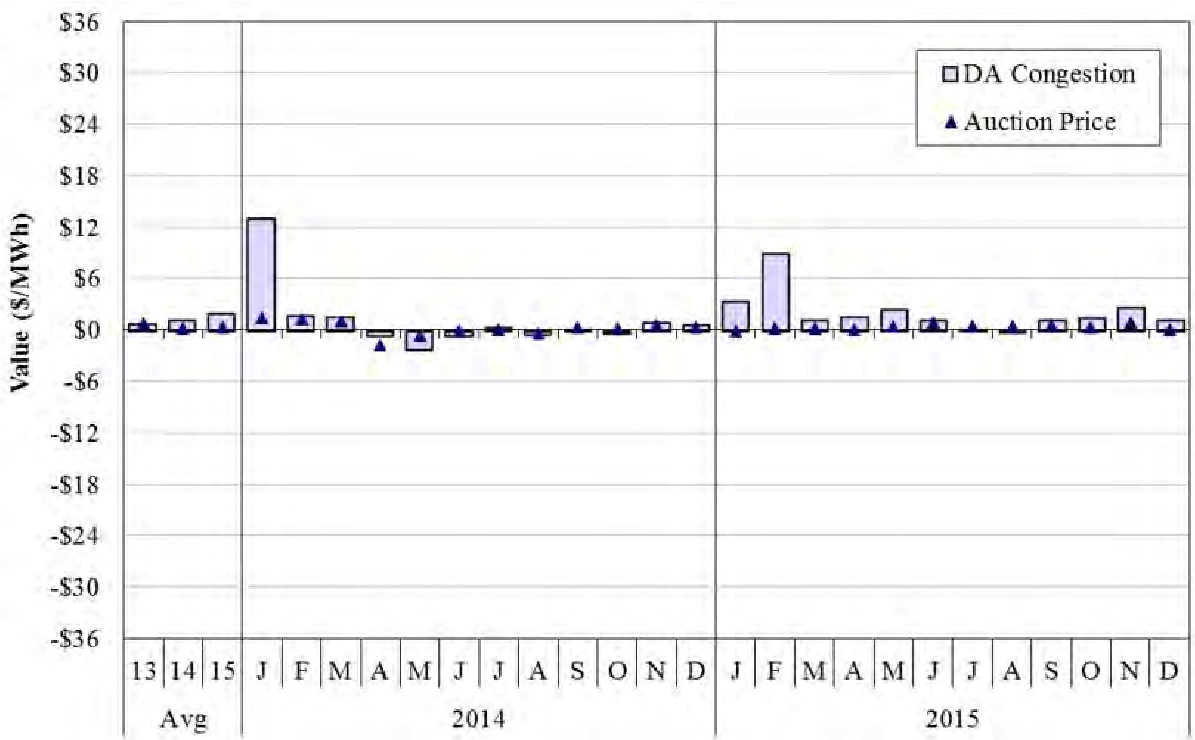


Figure A86: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2014–2015: Off-Peak Hours

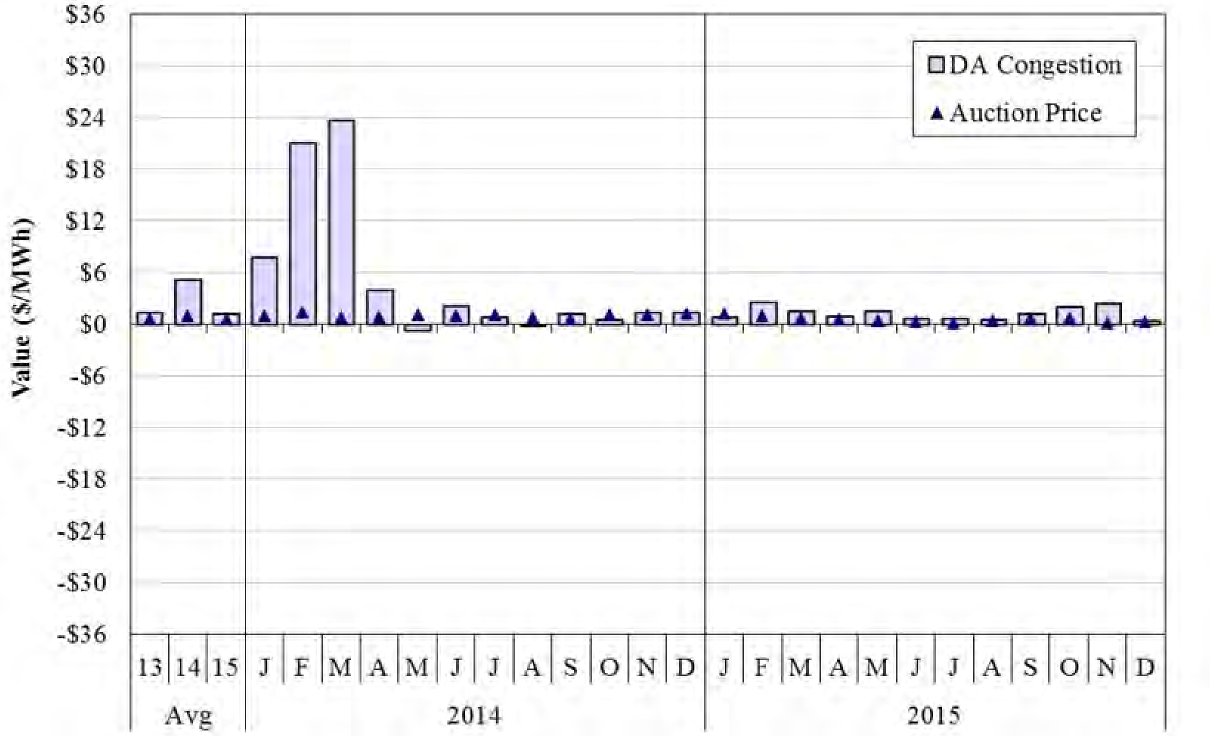


Figure A87: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2014–2015: Peak Hours

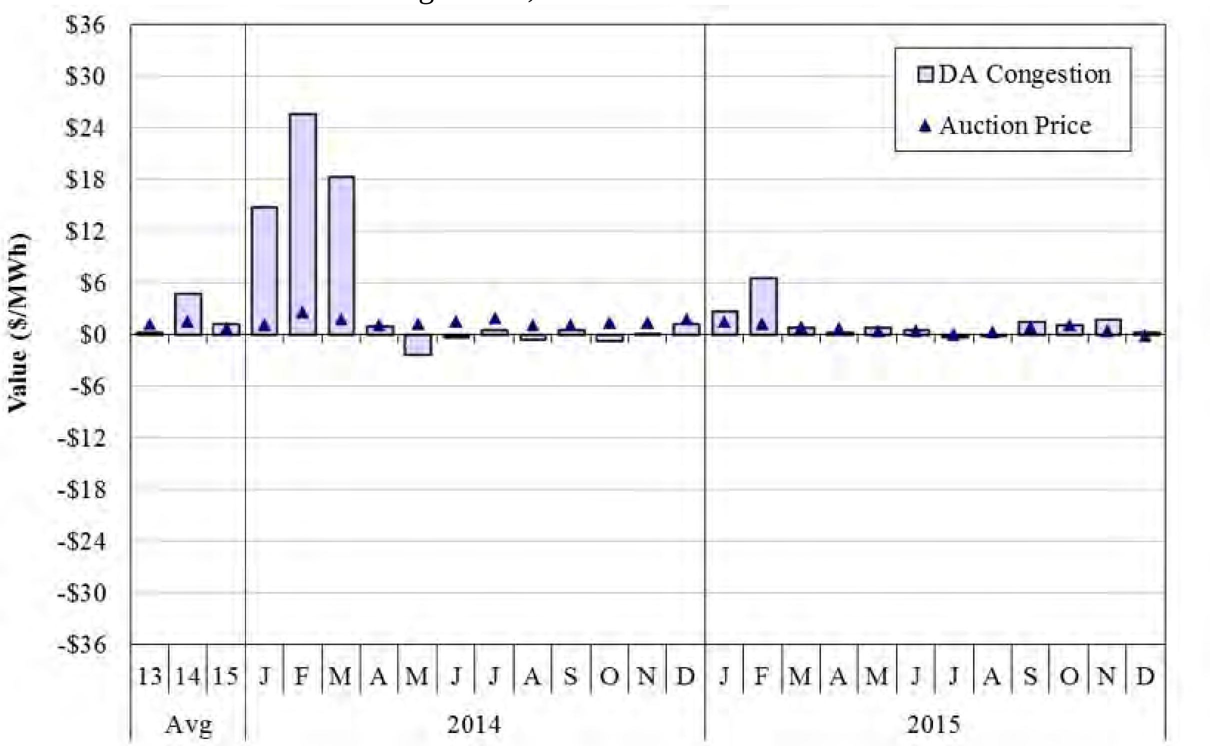


Figure A88: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2014–2015: Off-Peak Hours

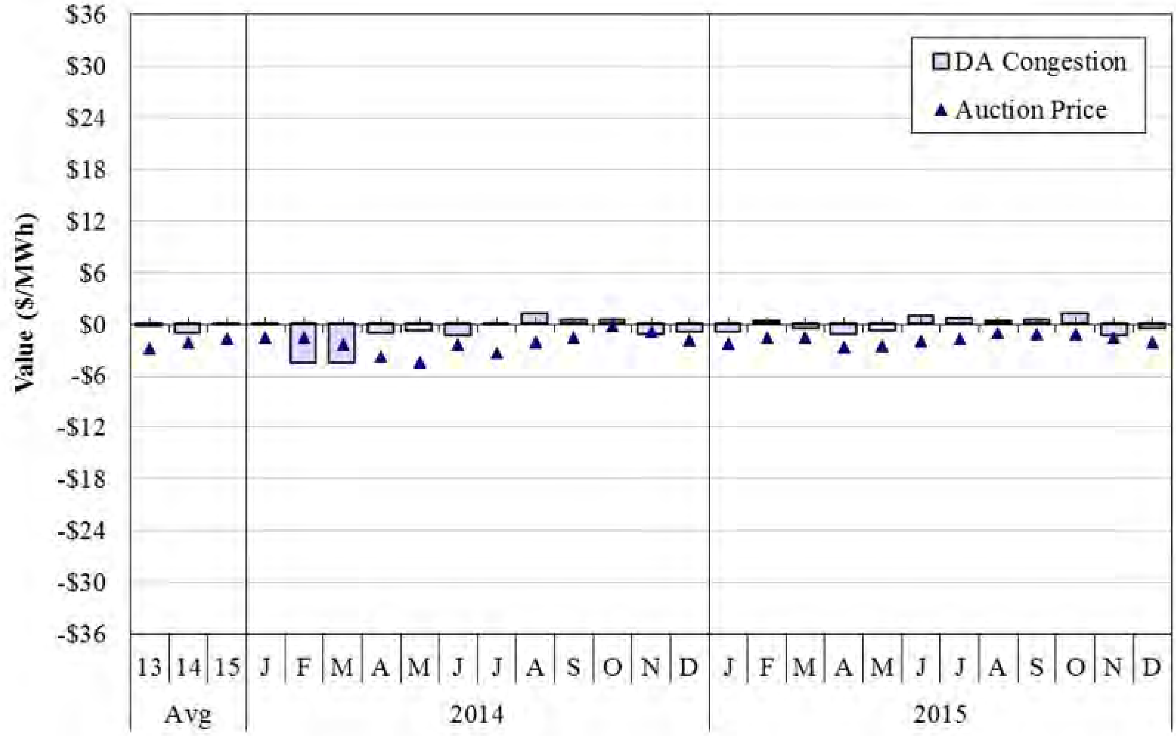


Figure A89: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2014–2015: Peak Hours

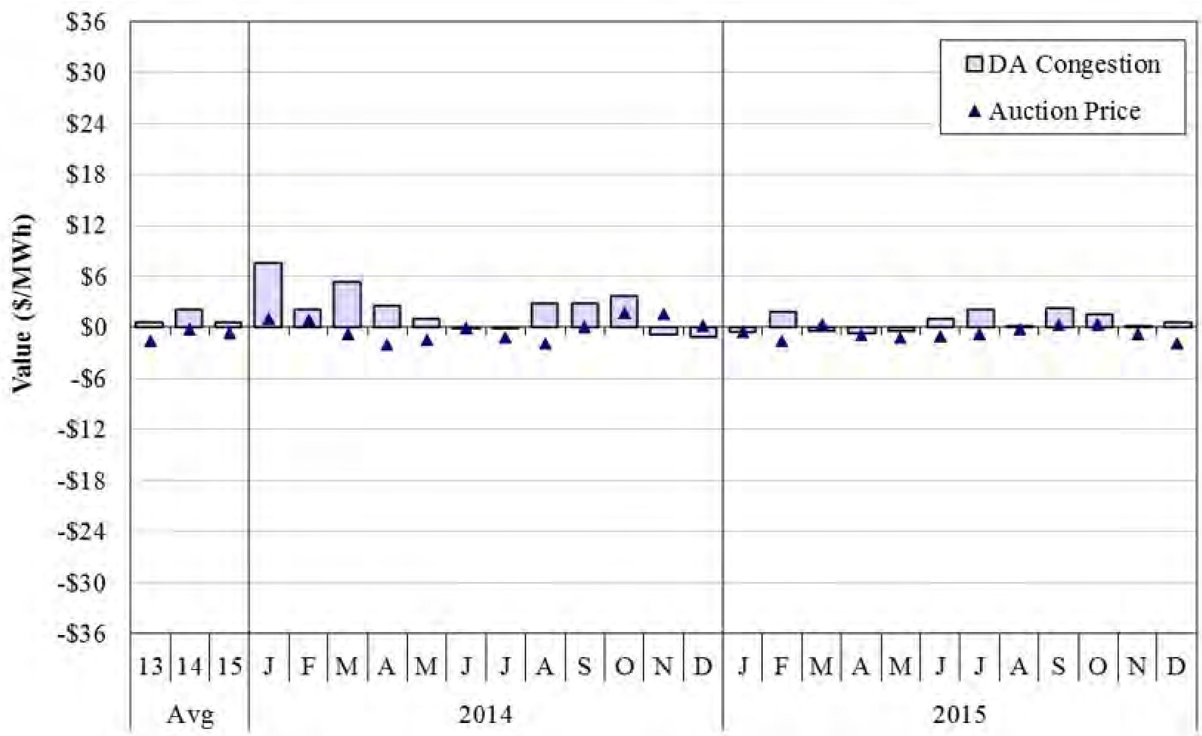


Figure A90: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2014–2015: Off-Peak Hours

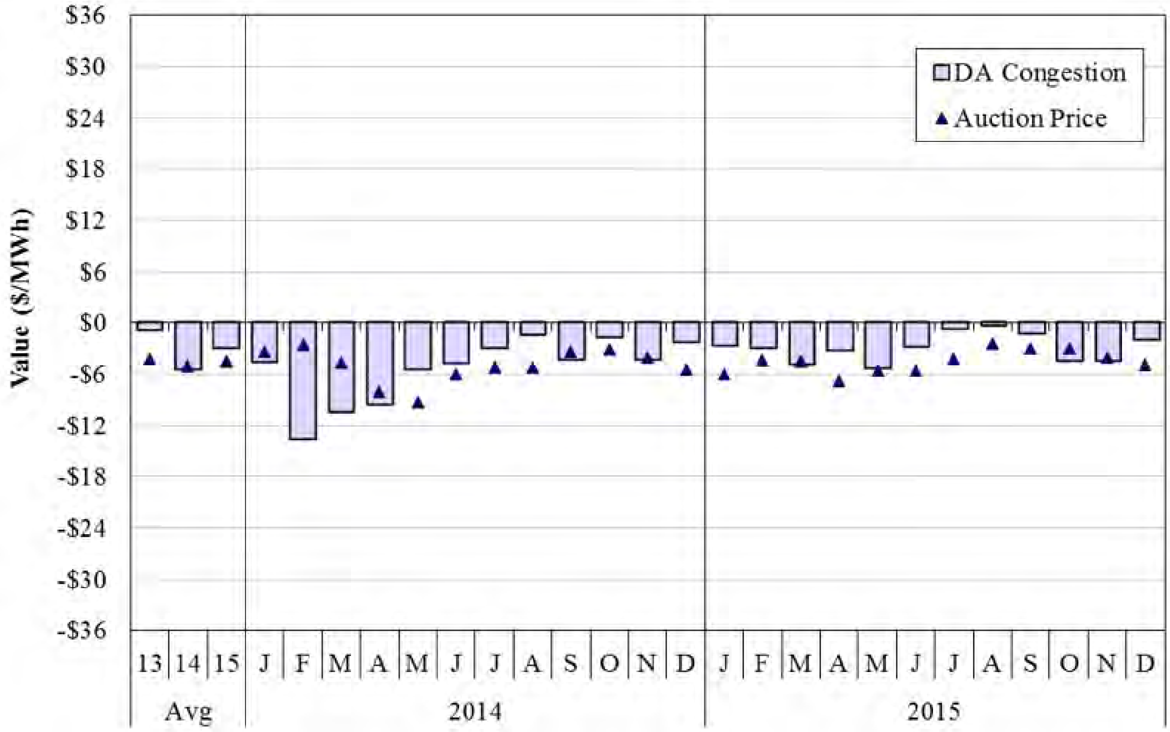


Figure A91: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2014–2015: Peak Hours

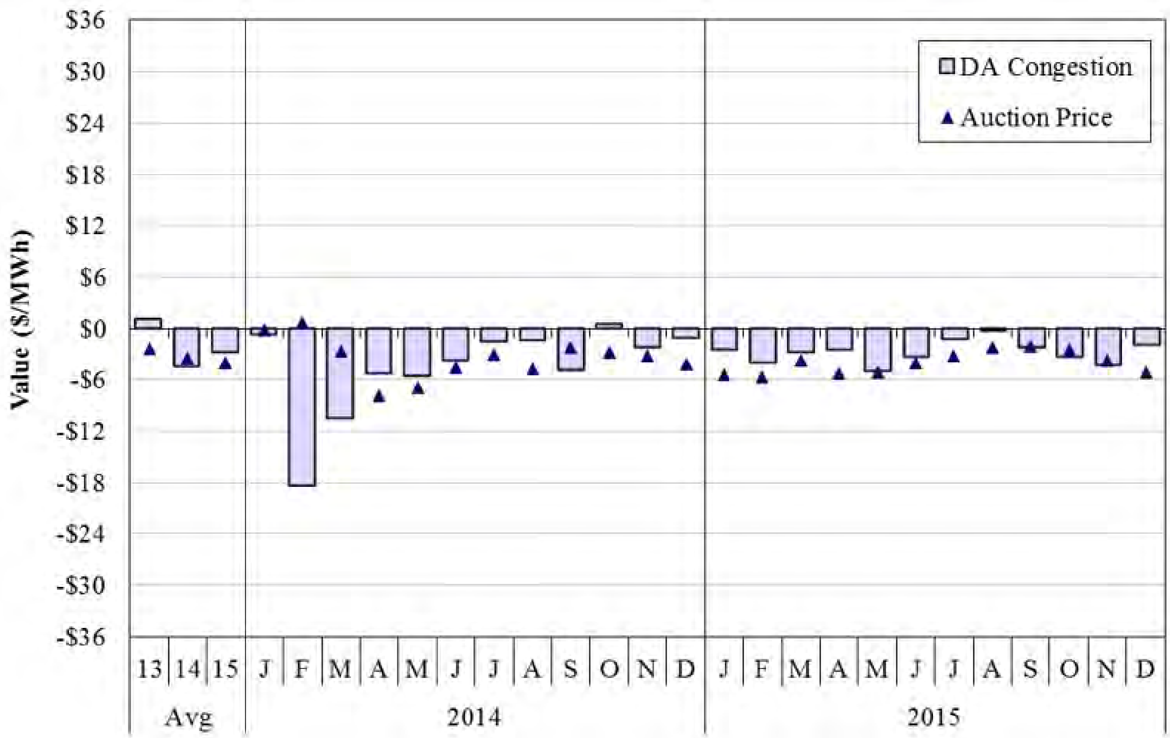


Figure A92: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2014–2015: Off-Peak Hours

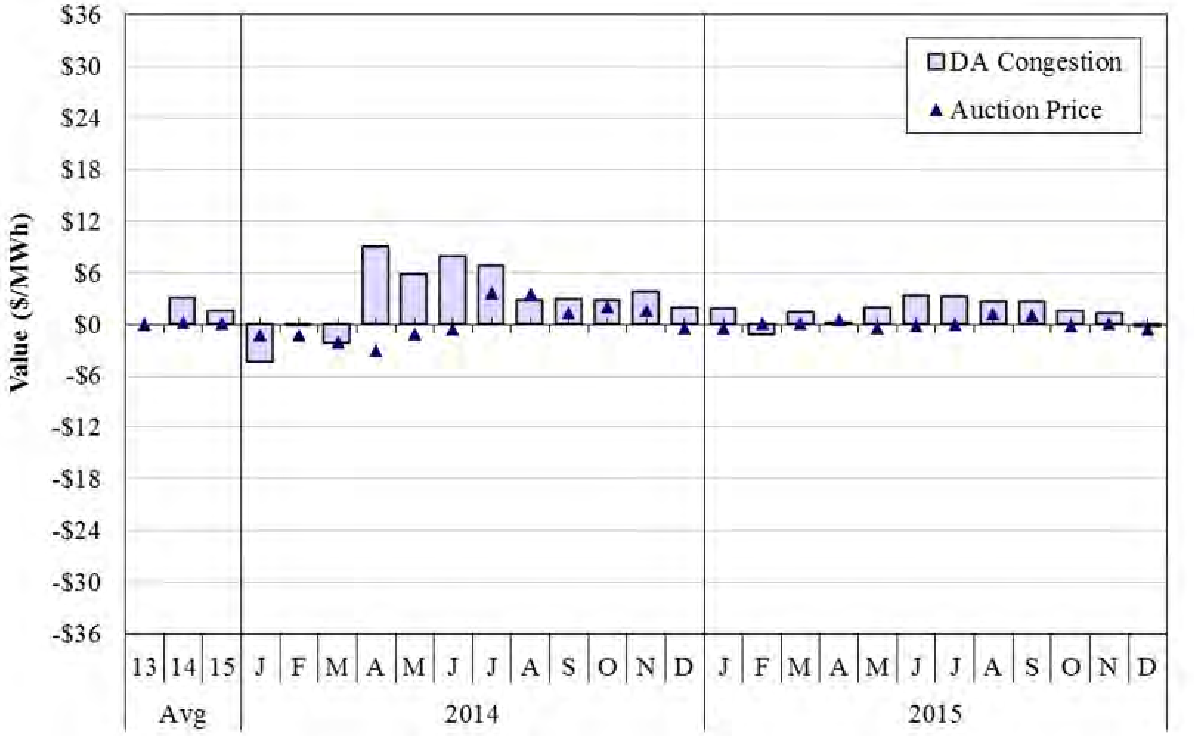


Figure A93: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2014–2015: Peak Hours

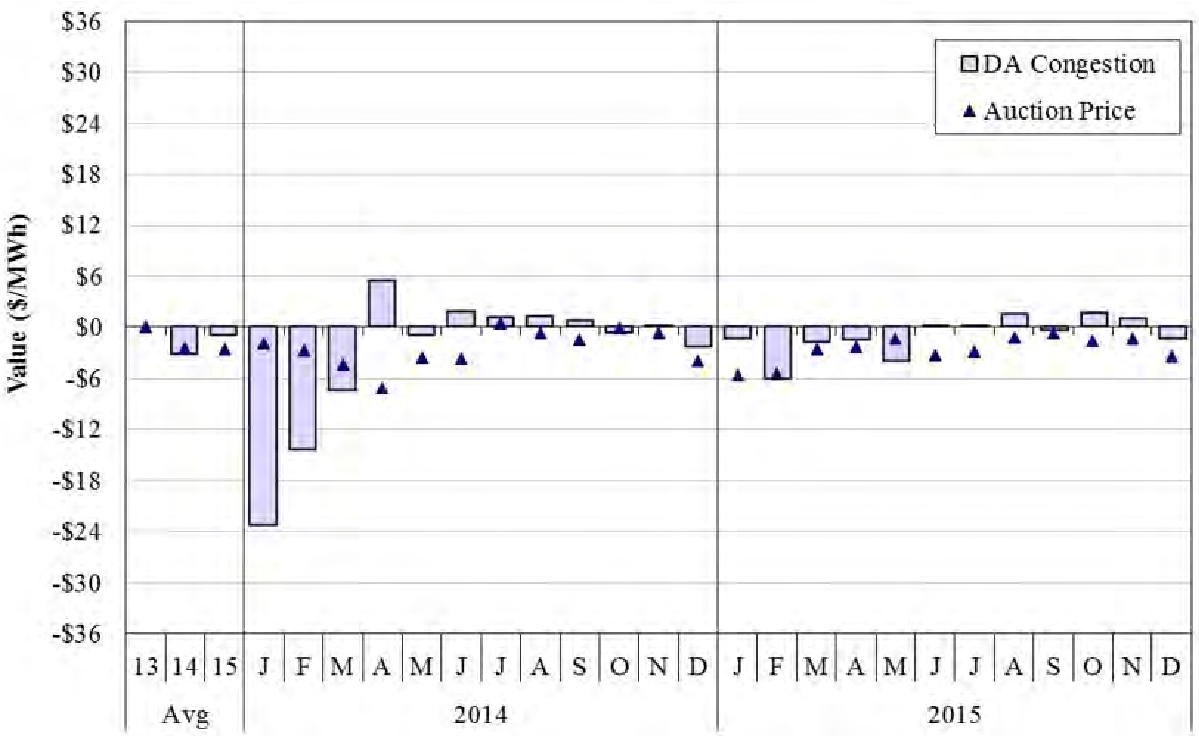


Figure A94: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2014–2015: Off-Peak Hours

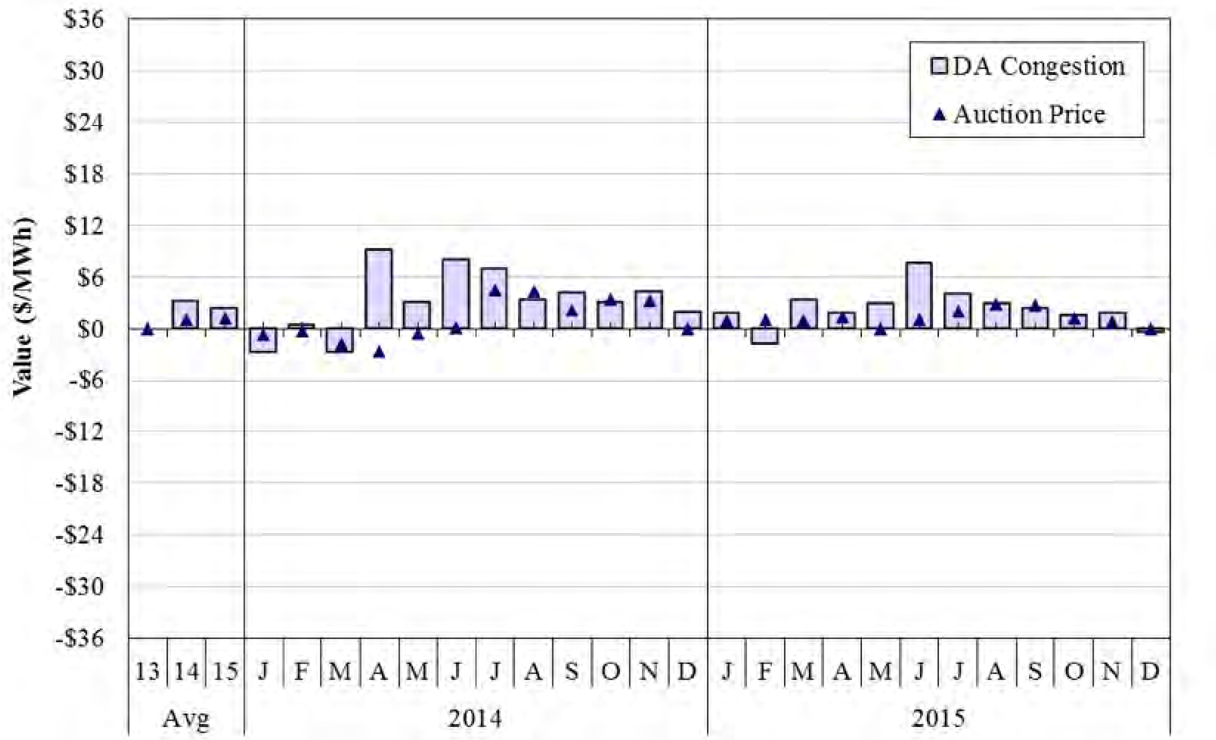


Figure A95: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2014–2015: Peak Hours

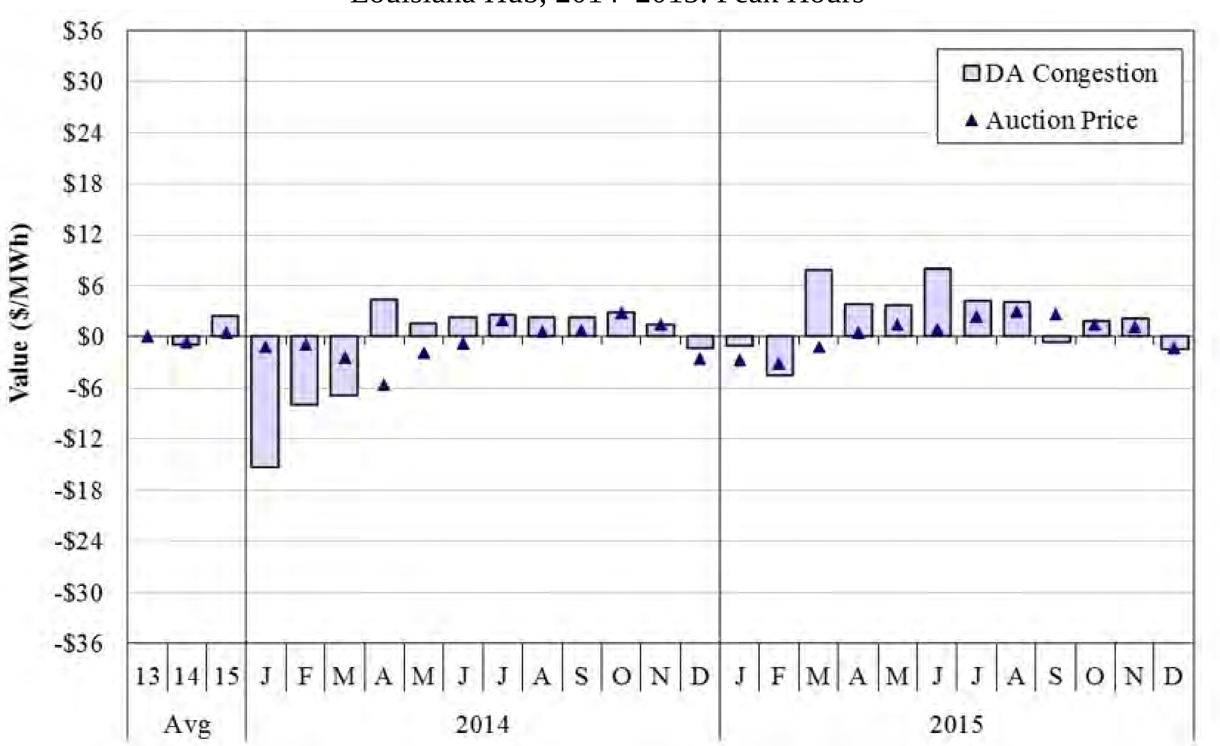


Figure A96: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2014–2015: Off-Peak Hours

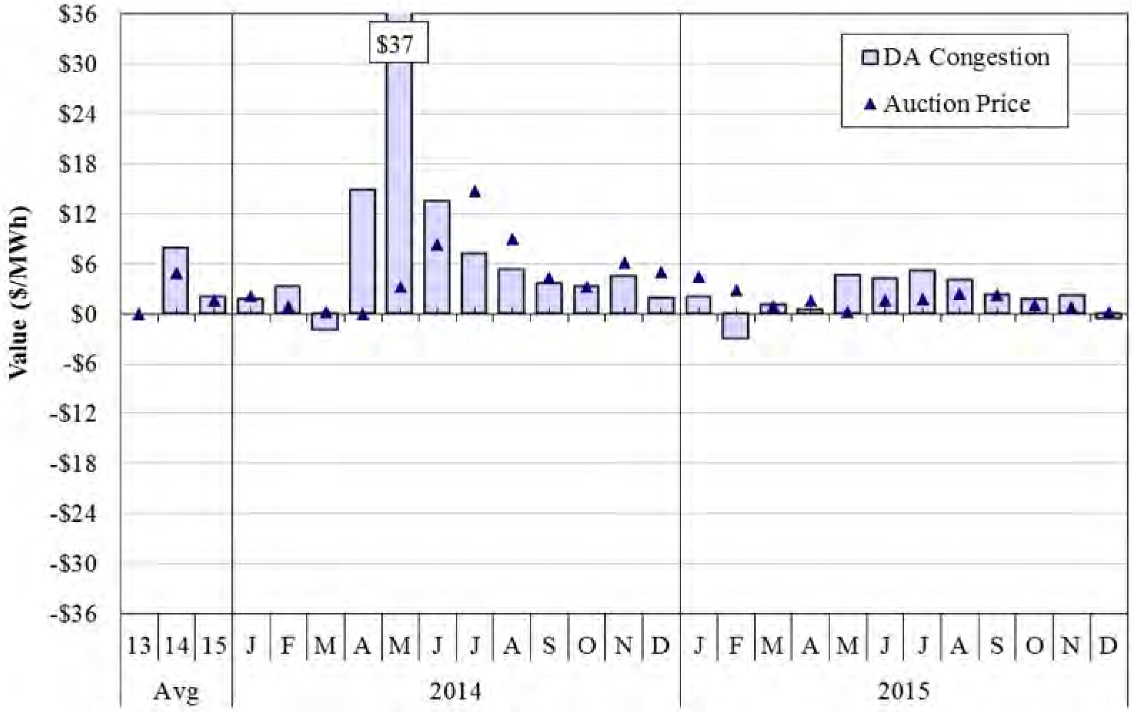
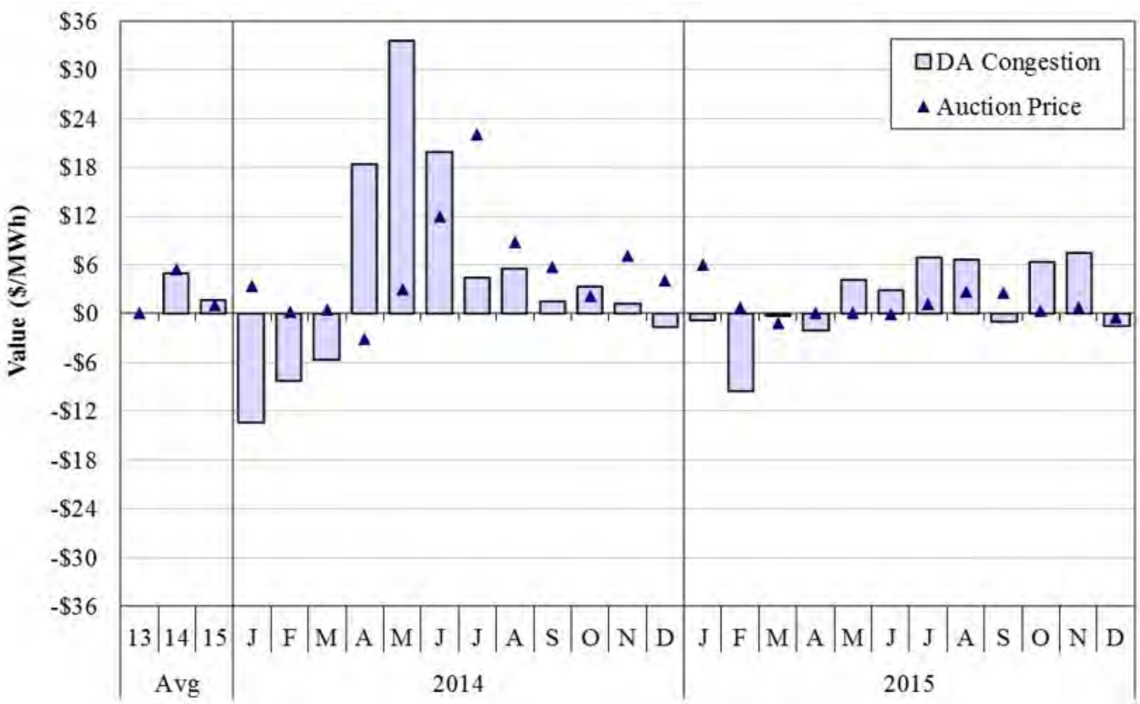


Figure A97: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2014–2015: Peak Hours



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

The Joint Operating Agreement (JOA) between MISO and PJM establishes a market-to-market process for coordinating congestion management of designated transmission constraints on each of the RTO's systems. The objective of this process is to pursue efficient generation dispatch on these constraints and consistent prices between the markets.

When a market-to-market constraint is activated, the monitoring RTO responsible for the constraint provides its shadow price and the quantity of relief requested (i.e., the desired reduction in flow) from the other market. This shadow price measures the monitoring RTO's marginal cost for relieving the constraint. The process to determine the appropriate relief request is based on prevailing market conditions and is generally automated (though it can be manually selected by Reliability Coordinators). When the reciprocating RTO receives the shadow price and relief request, it incorporates both values into its real-time market to provide as much of the requested relief as possible at a cost up to the monitoring RTO's shadow price. For settlements, the RTOs are allocated a Firm Flow Entitlement (FFE) on each market-to-market constraint. Settlements are based on the RTOs' constraint flows relative to their FFEs.

Figure A98: PJM Market-to-Market Events

Figure A98 shows the total number of market-to-market constraint-hours (i.e., instances when a constraint was active and binding) in 2014 and 2015. The top panel represents coordinated flowgates located in PJM and the bottom panel represents flowgates located in MISO. The darker shade in the stacked bars represents the total number of peak hours in the month when coordinated flowgates were active. The lighter shade represents the total for off-peak hours.

Figure A98: Market-to-Market Events
2014–2015

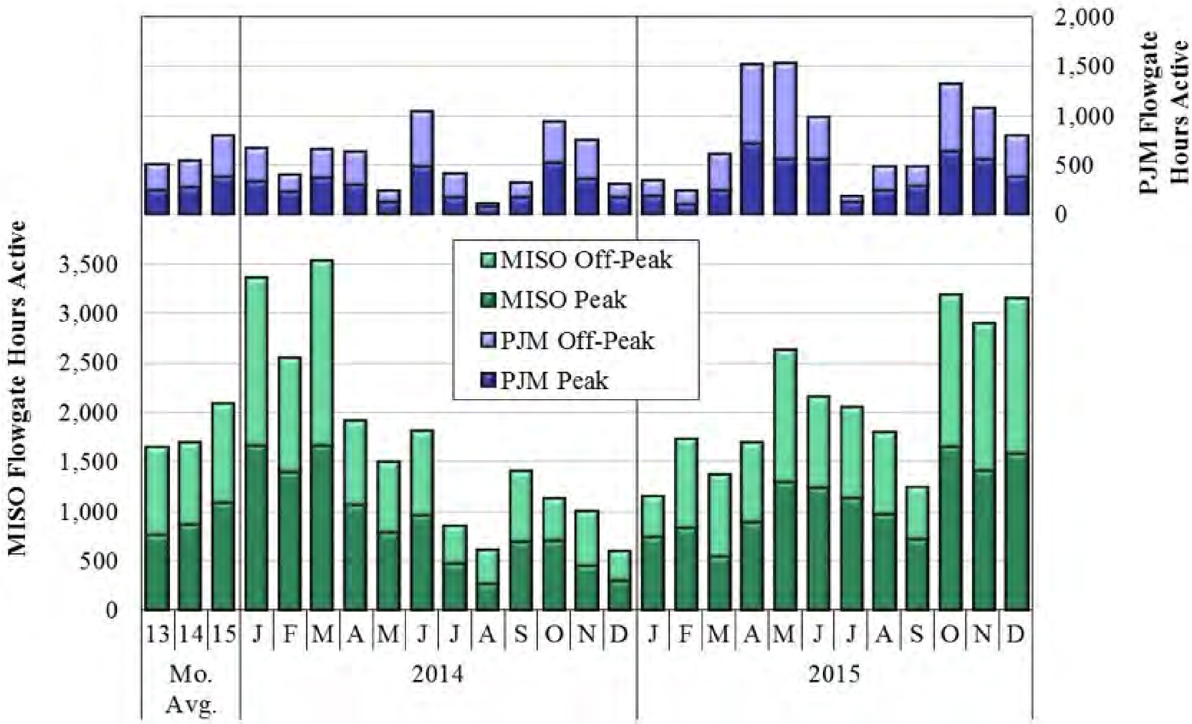


Figure A99: Market-to-Market Settlements

Figure A99 summarizes the settlement of market-to-market coordination, which is based on the reciprocating RTO's market flows compared to its FFE. If its market flow is below its FFE, then it is paid for the unused entitlement at its own cost of providing relief. If its flow exceeds its FFE, then it pays the monitoring RTO's congestion cost for each MW of excess flow. Positive values in the figure represent payments made to MISO and negative values represent payments to PJM and SPP. The diamond marker shows net payment to (or from) MISO in each month.

Figure A99: Market-to-Market Settlements
2014–2015

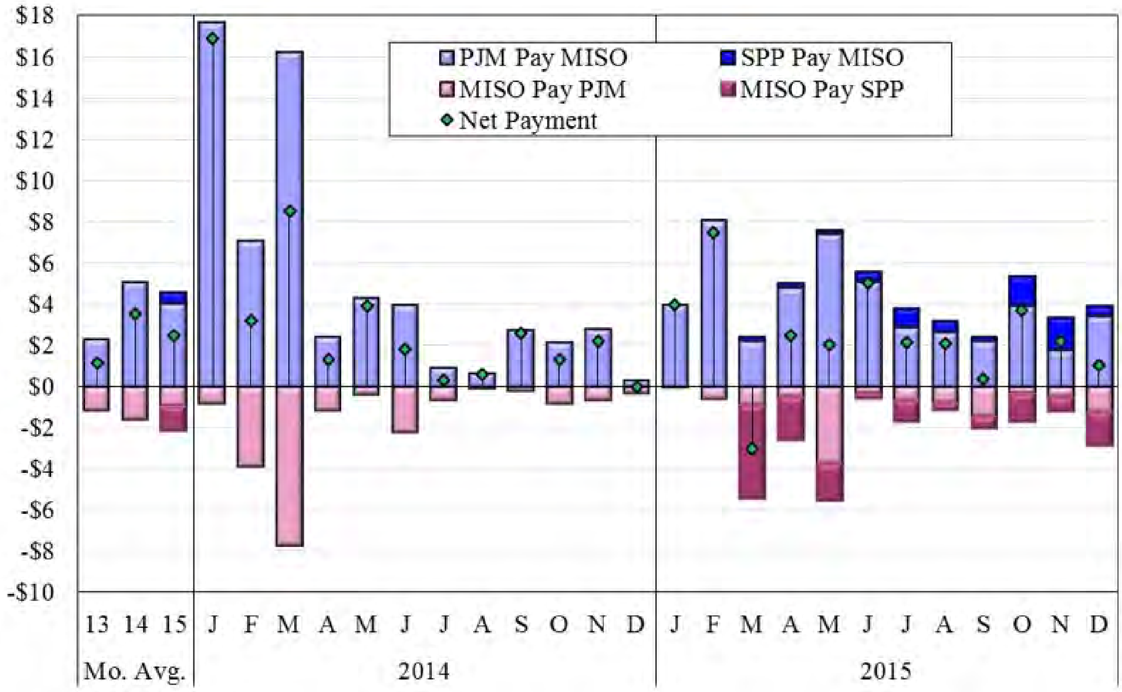


Figure A100 and Figure A101: Market-to-Market Outcomes with PJM

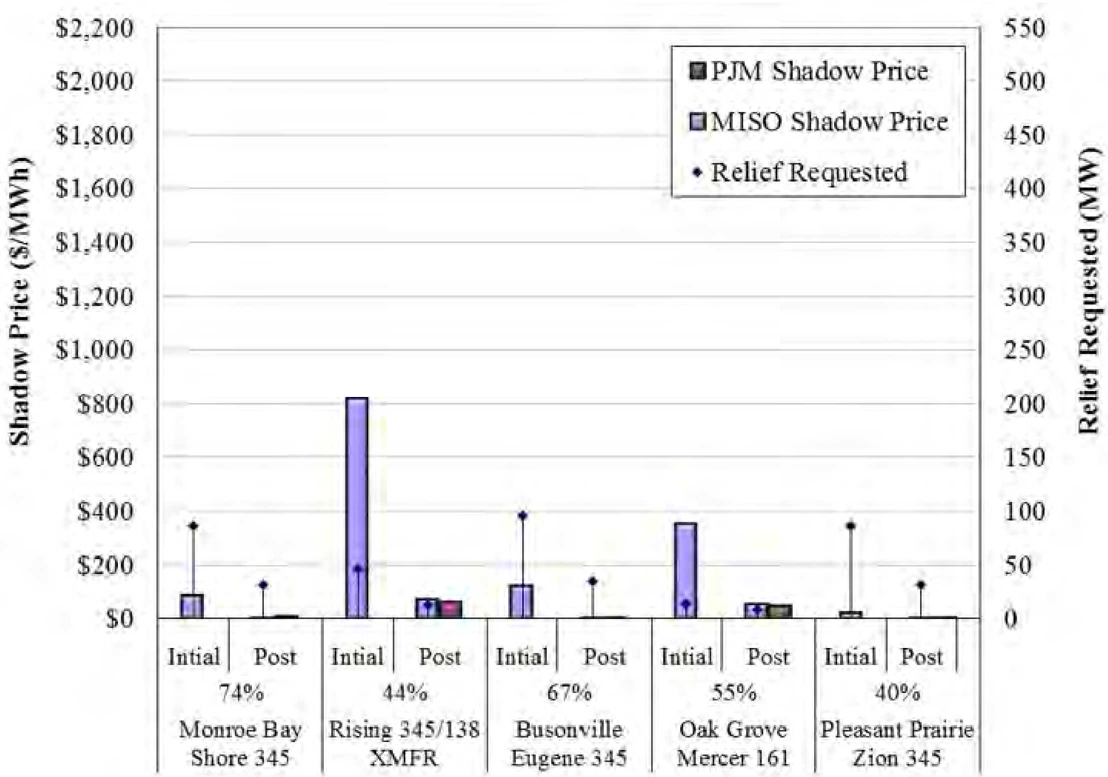
Successful market-to-market coordination should lead to two outcomes. First, the RTOs' shadow prices should converge after activation of a coordinated constraint. Second, the shadow prices should decrease from the initial value as the two RTOs jointly manage the constraint. The next two figures examine the five most frequently coordinated market-to-market constraints by PJM and MISO, respectively. The analysis is intended to show the extent to which shadow prices on coordinated constraints converge between the two RTOs. We calculated average shadow prices and the amount of relief requested during market-to-market 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 A100: PJM Market-to-Market Constraints
2015

Figure A101: MISO/PJM Market-to-Market Constraints
2015



K. Market-to-Market Coordination with SPP

On March 1, MISO implemented market-to-market coordination with SPP, and began coordinating with SPP in the WAPA Basin region after October. The implementation was successful overall and has lowered the impact of SPP constraints on MISO's dispatch and prices. However, early issues arose that will likely require resettlement and procedures are being developed to address these issues. These procedures involve transferring control of M2M constraints to the neighboring RTO if it has the most effective relief for the constraint.

Figure A102 and Figure A103: Market-to-Market Outcomes with SPP

The next two figures examine the five most frequently coordinated market-to-market constraints by SPP and MISO, respectively. As with the prior two charts, the analysis is intended to show the extent to which shadow prices on coordinated constraints converge between the two RTOs. We calculated average shadow prices and the amount of relief requested during market-to-market events in the initial period and the Post-activation shadow prices for both the monitoring and reciprocating RTOs, which are the average prices in each RTO after the requested relief associated with the market-to-market process was provided. The share of active constraint periods that were coordinated is shown below the horizontal axis. When coordinating, the reciprocating RTO can provide relief by limiting market flow in its real-time dispatch.

Figure A102: SPP Market-to-Market Constraints
2015

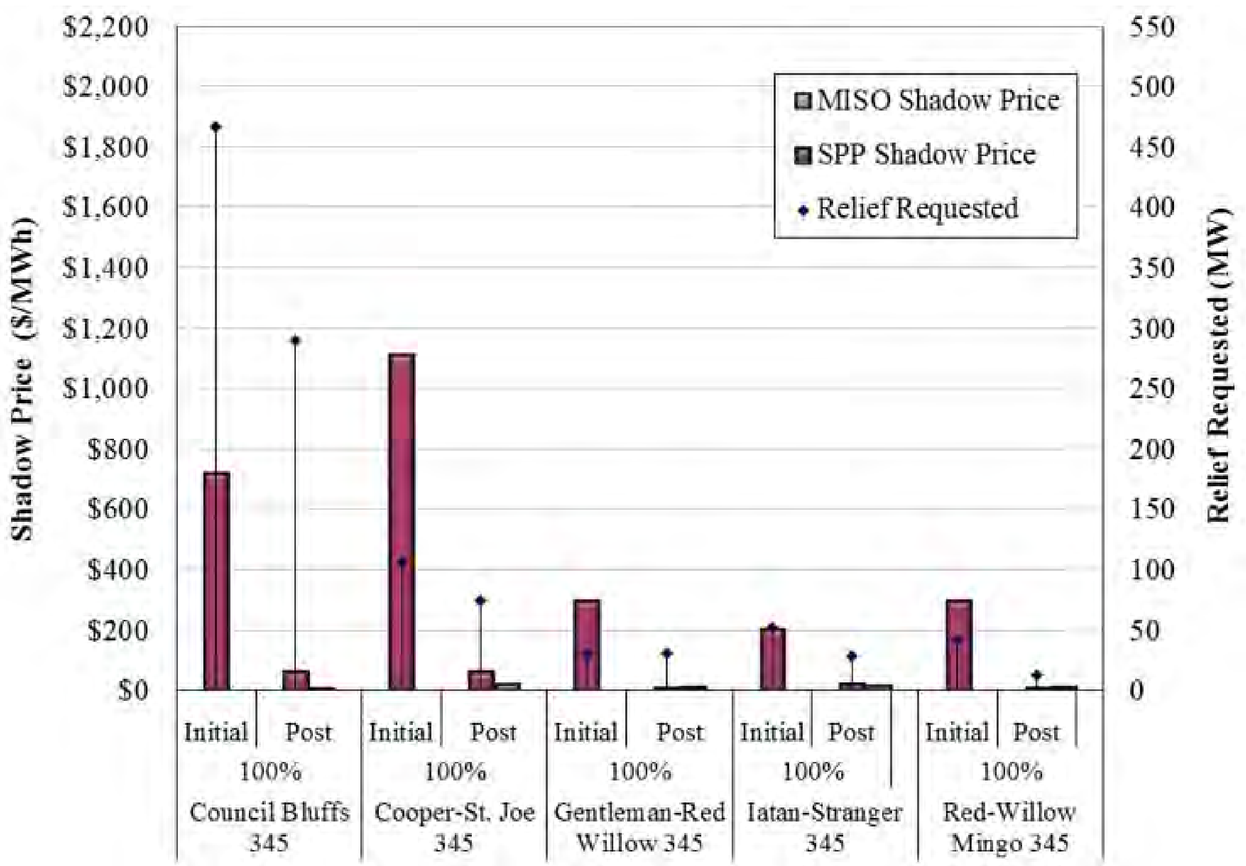


Figure A103: MISO/SPP Market-to-Market Constraints
2015

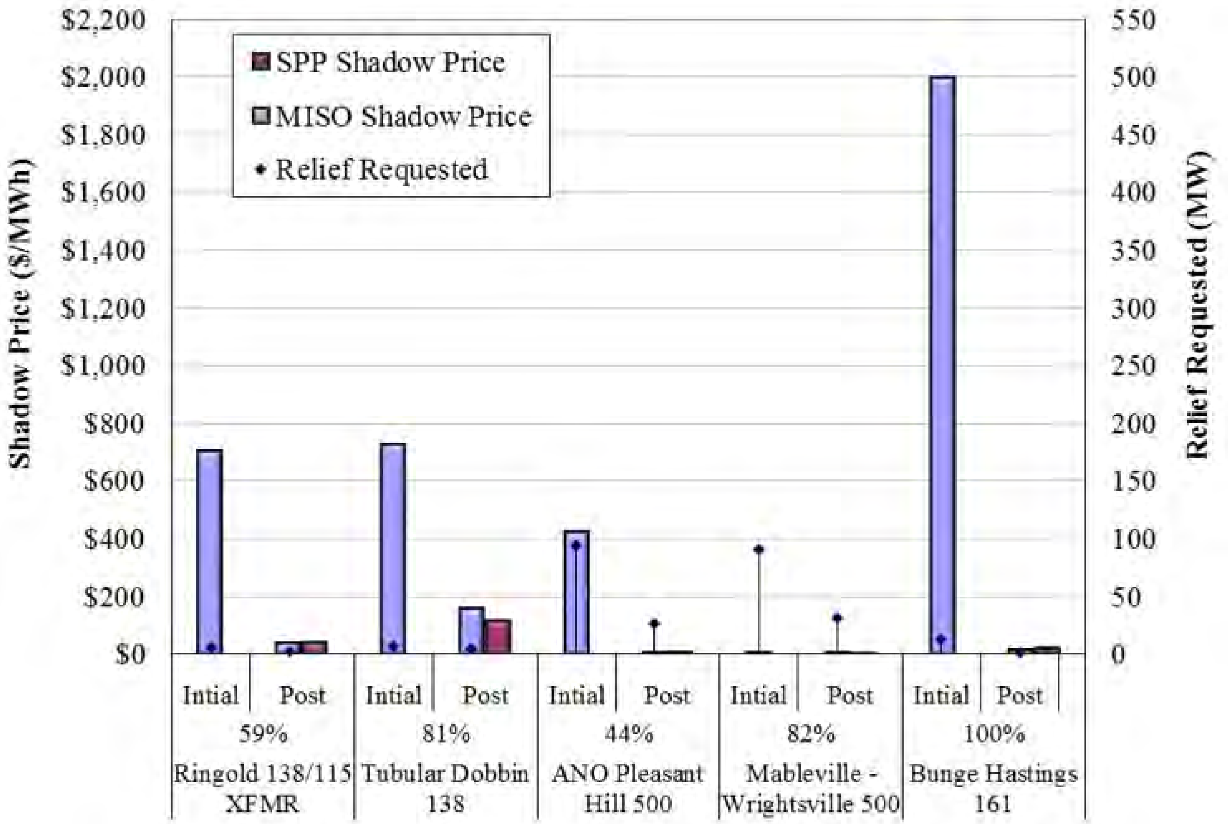


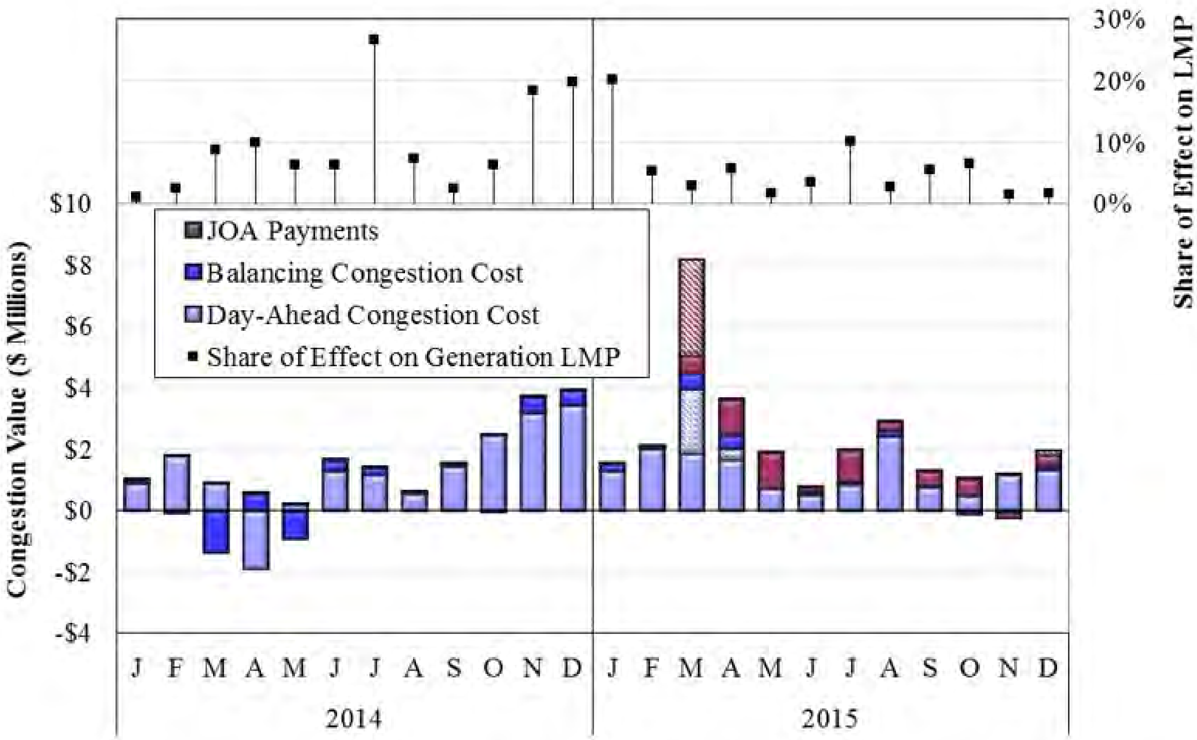
Figure A104: Congestion on SPP Flowgates

The following figure shows the congestion incurred in the MISO markets associated with SPP transmission constraints. MISO began market-to-market coordination with SPP in March 2015, which results in coordinated congestion management any time a coordinated SPP flowgate is binding. Prior to this time, MISO activated constraints in its market when SPP would invoke the Transmission Line-Loading Relief (TLR) process for an SPP constraint and request relief from MISO.

The bottom panel of this figure shows the congestion cost incurred by MISO in its day-ahead market and the balancing congestion costs incurred in real time. After market-to-market coordination began, the RTOs engage in JOA settlements that are shown in the figure.

The upper panel of the figure shows the total share of the locational congestion costs in MISO's LMPs that are attributable to SPP's constraints. This share could be large before market-to-market coordination because MISO would incur any cost up to its transmission constraint demand curve level to provide the requested relief (even though the constraints were often not binding in SPP).

Figure A104: Congestion Cost on SPP Flowgates
2014-2015



L. Effects of Pseudo-Tying MISO Generators

Figure A105: Effects of Pseudo-Tying MISO Resources to PJM

In recent years, increasing quantities of MISO capacity have been exported to PJM. Regrettably, PJM has recently implemented rules to require external capacity to be pseudo-tied to PJM. We have raised serious concerns about this trend because allowing PJM to take dispatch control of large numbers MISO generators will:

- Remove dispatch control and commitment/decommitment authority over generators that cause forward flows over a large number of MISO transmission facilities; and
- Remove dispatch and commitment authority over generators that provide relief over other MISO constraints.

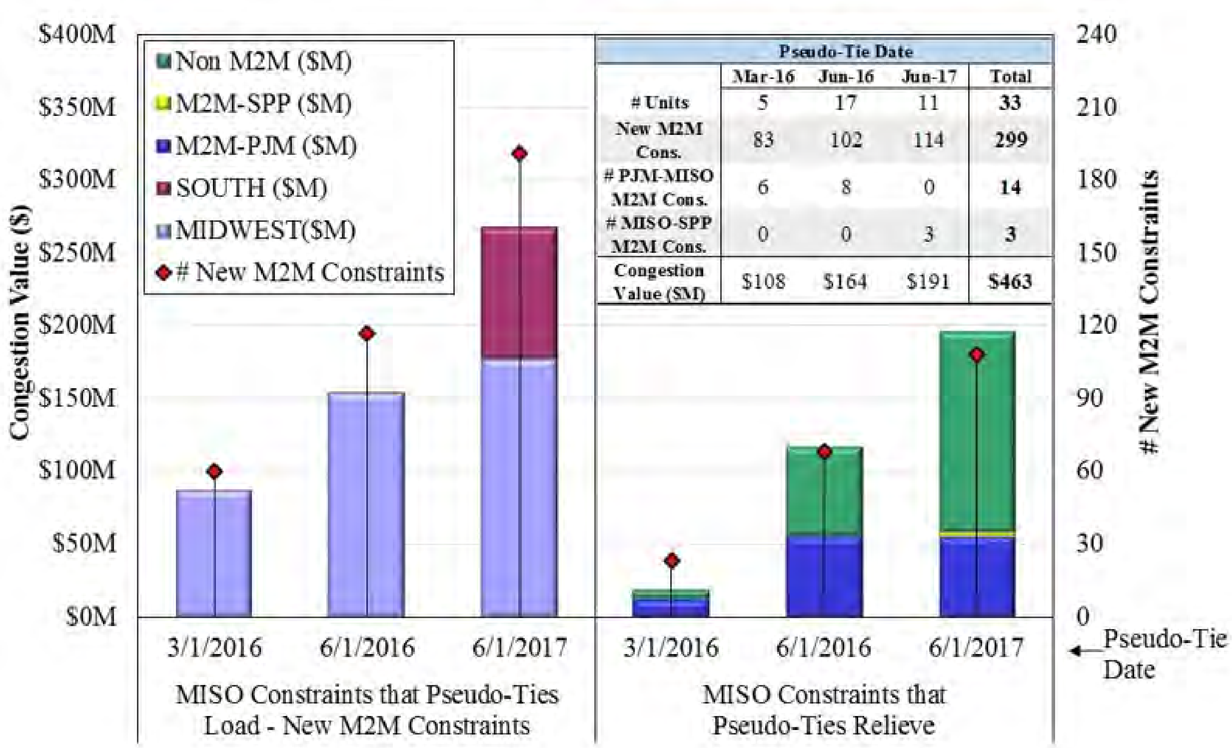
Both of these issues can be partially addressed to the extent that the constraints loaded or unloaded by these generators are defined as market-to-market constraints and, therefore, are coordinated with PJM. However, market-to-market coordination is not nearly as effective as full dispatch control and many of the constraints will remain non-market-to-market constraints. Based on our analysis, a large number of MISO constraints will be affected and will now qualify as market-to-market constraints that would not qualify absent the pseudo ties.

With regard to the second issue, MISO will also lose direct control of the counterflow (i.e., the dispatch relief the units provide). In addition, MISO will lose the ability to commit or decommit these resources for congestion management unless it declares an operating emergency.

Figure A105 shows our evaluation of the effects of pseudo-tying the generators to PJM. In the left panel, it shows how many of MISO's constraints in 2015 would have qualified as new market to market constraints (the red diamond) assuming that the groups of resources that currently plan to pseudo tie to PJM, which are in tranches dated March 2016, June 2016, and June 2017. It also shows the value of the congestion on these constraints, which is calculated as the shadow price of the constraint times the flow caused by the pseudo-tied resources. This amount could rise in the future as gas prices rise and the congestion becomes more poorly managed because of the pseudo ties.

The right panel shows the number of constraints for which direct control of the redispatch relief would be lost because of the pseudo ties. The green bars shows the value of congestion on the constraints where MISO may still have some access to the relief because the constraints will qualify as market to market constraints. The remaining bars show where direct control will be transferred to PJM (on PJM M2M constraints). The yellow bar shows that on a small number of SPP M2M constraints relief will be lost to SPP and MISO under M2M, since PJM and SPP do not coordinate with each other under a M2M process.

Figure A105: Effects of Pseudo-Tying MISO Resources to PJM
2015



M. Congestion on External Constraints

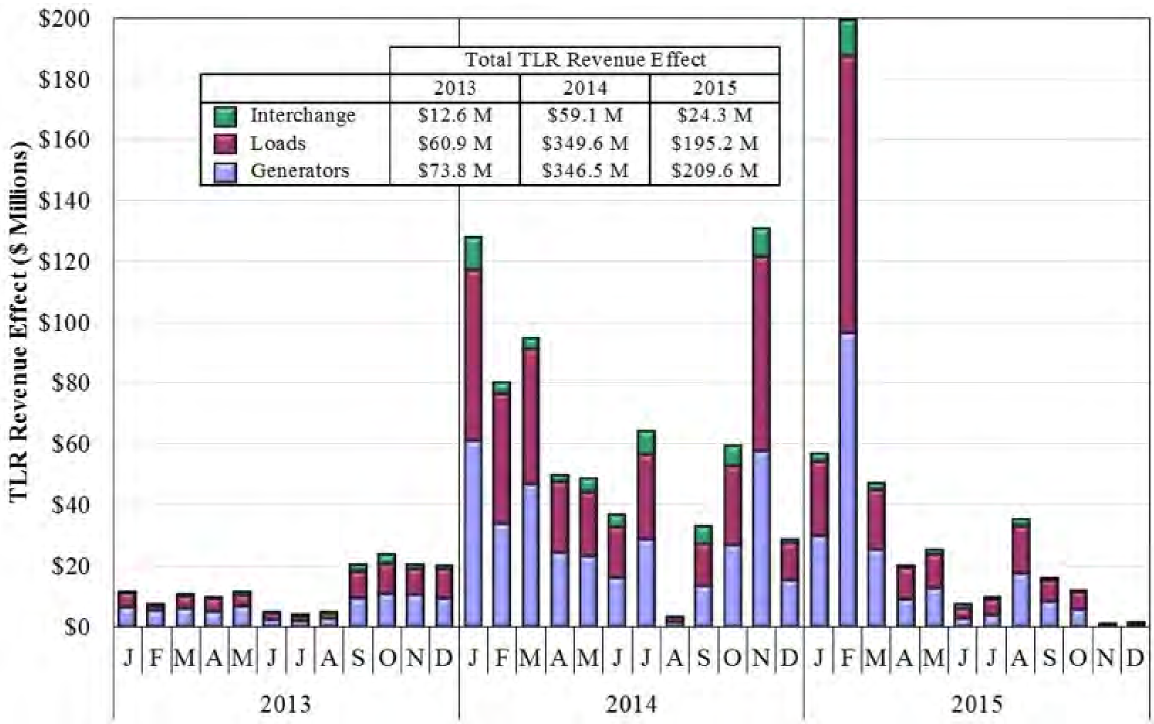
This subsection provides analysis of congestion that occurs on external constraints that are monitored by adjacent RTOs or control area operators. MISO incurs congestion on external constraints when a neighboring system calls TLR procedures for a constraint. When this occurs, MISO activates the constraint as it would an internal constraint, seeking to reduce its flow over the constraint by the amount of the required relief. This process will be efficient only if the cost of the relief provided by MISO is less costly than the adjacent system's cost to manage the flow on the constraint. Unfortunately, this has historically not been true. One contributing factor is that MISO receives relief obligations based on its forward flows, not the net flows it is actually causing. Because the relief obligation is outsized, it is often very costly for MISO to provide the relief requested and MISO's marginal cost of providing the relief is included in its LMPs.

Figure A106: TLR Process

Because external constraints can cause substantial changes in LMPs within MISO, we estimate the effects of these changes by calculating the total increase in real-time payments by loads and the reduction in payments to generators caused by the external constraints. External constraints also affect interface prices and the payments made to participants scheduling imports and exports, an issue that is further evaluated in Section VI.K.

Figure A106 shows increases and decreases in hourly revenues that result from TLR constraints binding in MISO. Since MISO's market flow on external flowgates is generally low or negative, the reported congestion value for these constraints is correspondingly low. That metric masks the larger impact that these constraints have on MISO's dispatch and pricing.

Figure A106: Real-Time Valuation Effect of TLR Constraints
2013–2015



VII. External Transactions

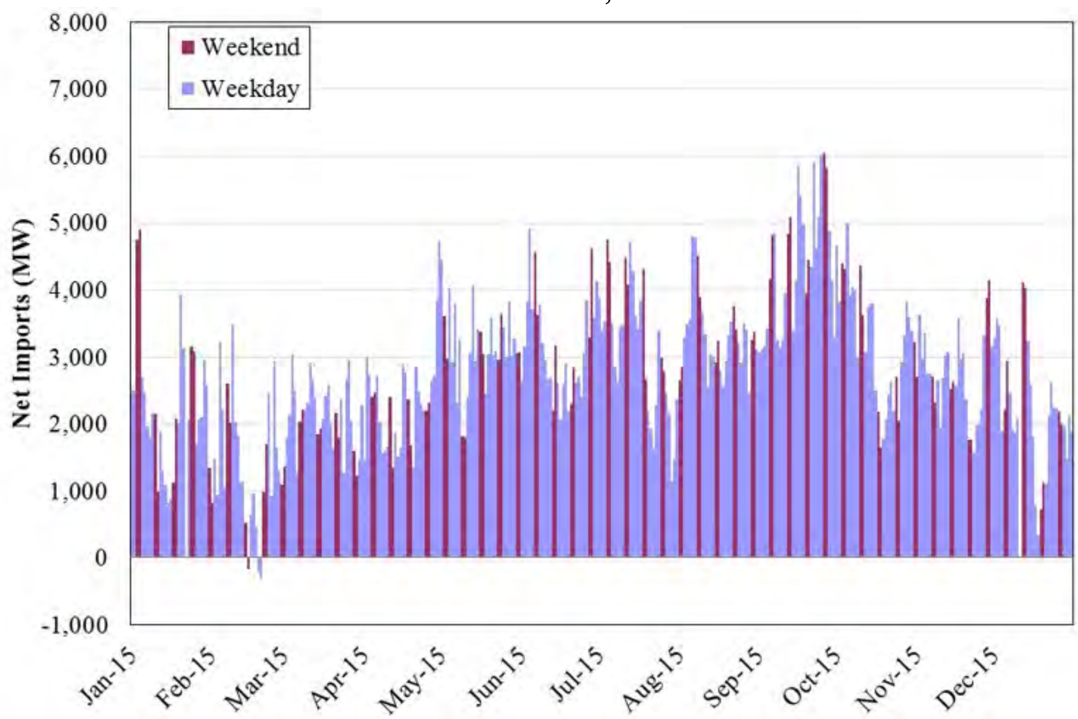
MISO is a net importer of power during nearly all hours and seasons. Given its reliance on imports, the processes to schedule and price interchange transactions can have a substantial effect on the performance and reliability of MISO's markets. Imports and exports are scheduled on a 15-minute basis and are fixed 20 minutes before they flow. The scheduling deadline was reduced from 30 minutes to 20 minutes in October 2013. 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. Currently, participants cannot submit a price-sensitive offer for external transactions in the real-time market. This section of the Appendix reviews the magnitude of these transactions and the efficiency (or inefficiencies) of the scheduling process.

A. Import and Export Quantities

Figure A107 to Figure A110: Average Hourly Imports

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

Figure A107: Average Hourly Day-Ahead Net Imports
All Interfaces, 2015



The second figure shows real-time net-imports and changes from day-ahead net import levels. When net imports decline substantially in real time, MISO may be compelled to commit additional generation (often peaking resources) to satisfy the system's needs. The third and fourth figures show the same information by interface.

Figure A108: Average Hourly Real-Time Net Imports
2015

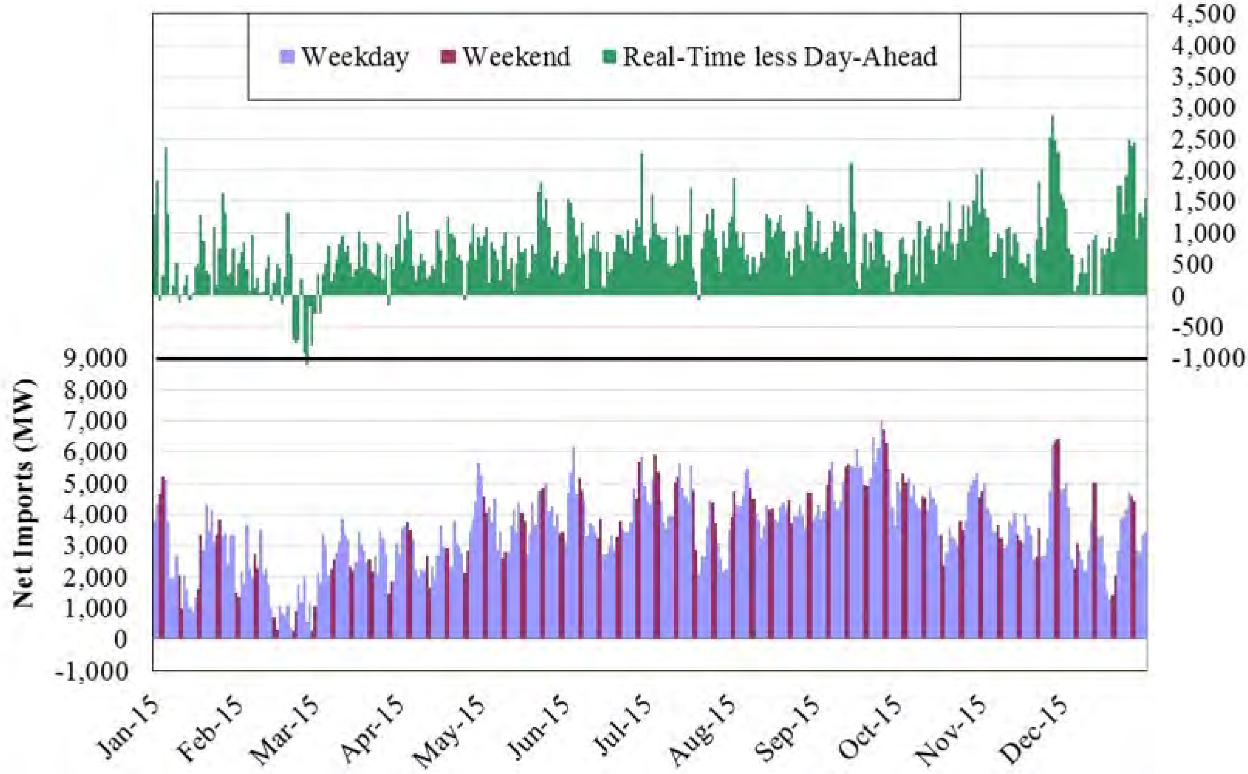


Figure A109: Average Hourly Day-Ahead Net Imports
2015, by Interface

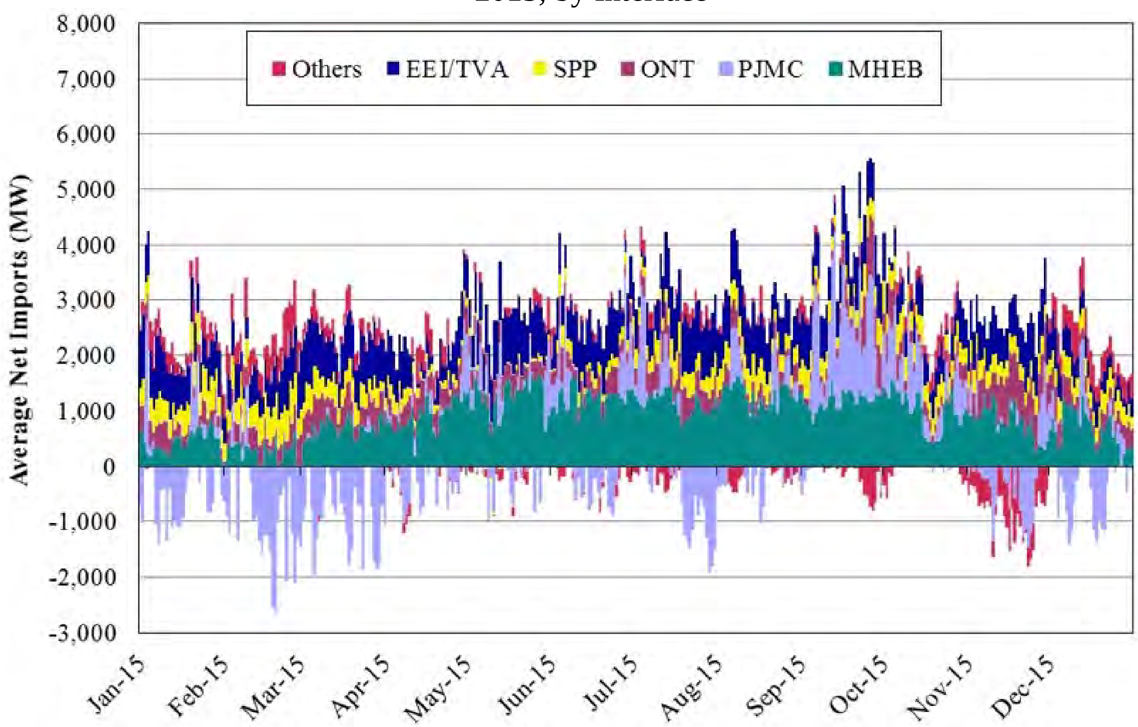


Figure A110: Average Hourly Real-Time Net Imports
2015, by Interface

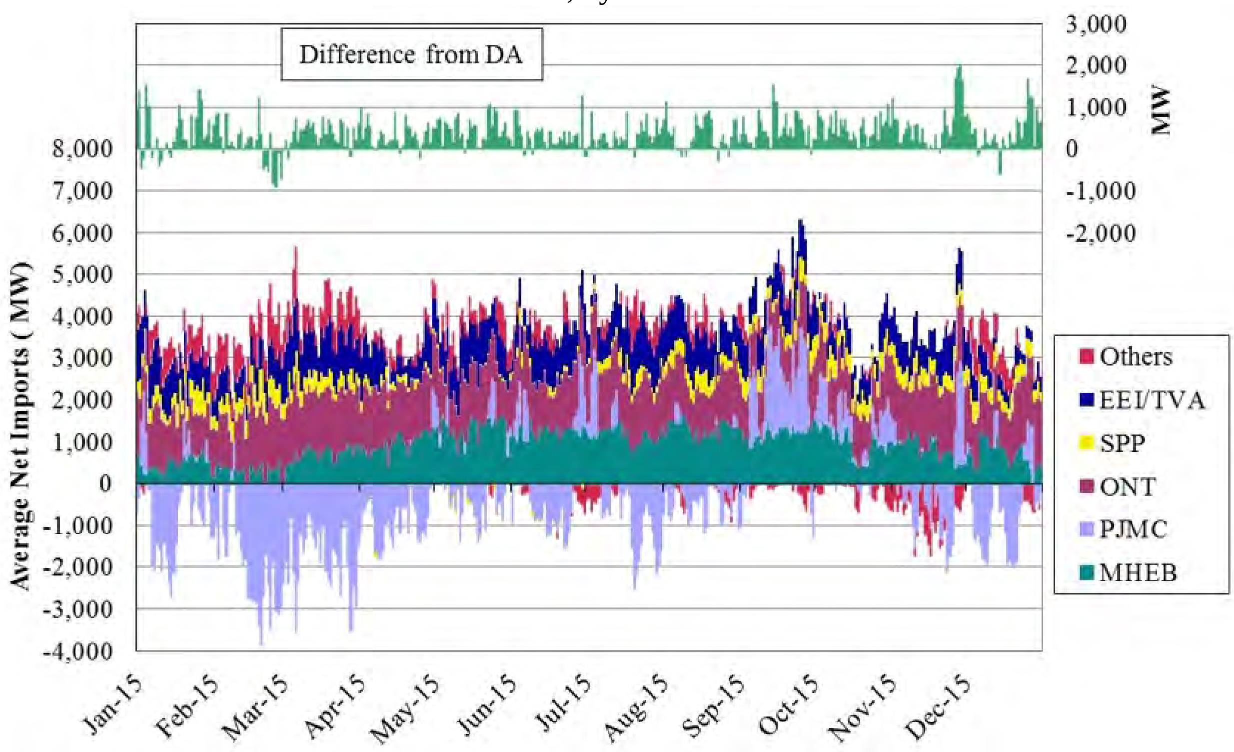


Figure A111 and Figure A112: Hourly Average Real-Time Net Imports by Interface

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

Accordingly, Figure A111 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2014 and 2015, along with the standard deviation of such imports.[28] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

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

Figure A111: Average Hourly Real-Time Net Imports from PJM
2014–2015

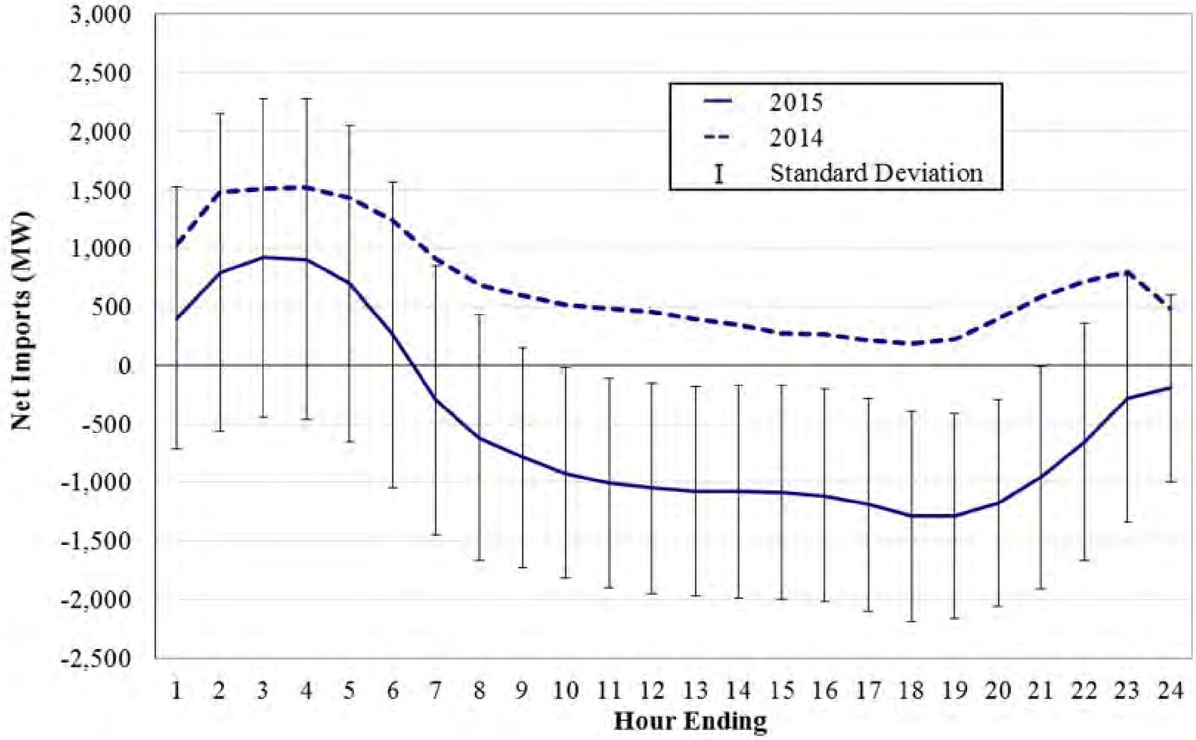
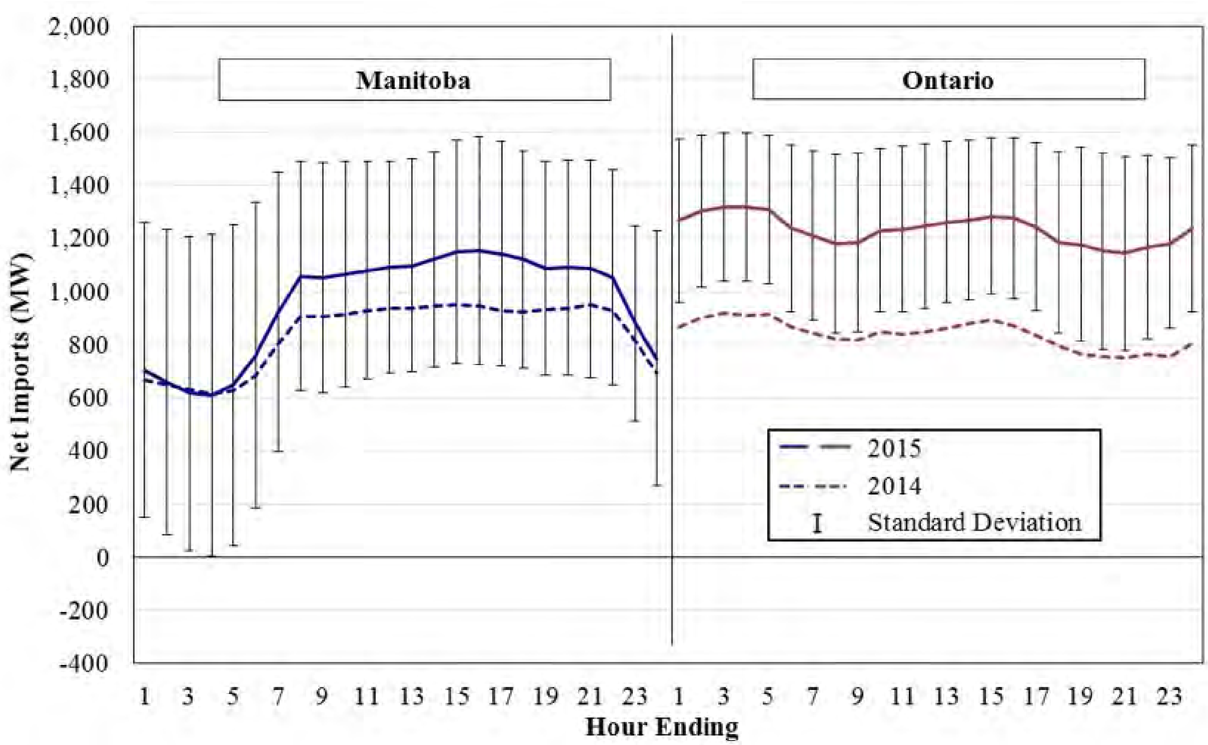


Figure A112: Average Hourly Real-Time Net Imports, from Canada
2014–2015

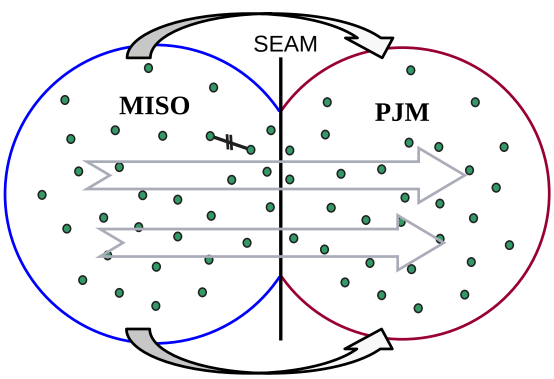


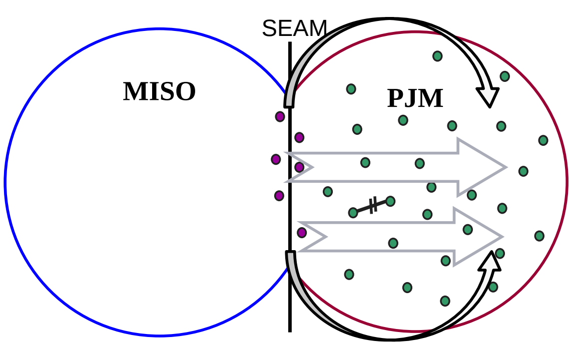
B. Interface Pricing and External Transactions

Each RTO posts its own interface price at which it will settle with participants selling and buying power from the neighboring RTO. It provides incentives for participants to engage in external transactions -- participants will schedule between the RTOs to arbitrage the differences between the interface prices. Like the LMPs at all generation and load locations, the interface price includes: a) the SMP; b) a marginal loss component; and c) a congestion component.

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 system marginal prices come into equilibrium (and generation costs equalized). However, congestion is pervasive on these systems and so the fundamental issue with interface pricing is estimating the congestion costs and benefits of external transactions (imports and exports).

For generators, the source of the power is known so 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". Using this interface definition, the RTOs use transmission models to calculate the flow effects for imports and exports. These flow effects (i.e., the "shift factor") times the value of the binding transmission constraints is the congestion component that will be included in the interface price. If the interface definition is 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.





In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units) as shown in the figure below. This figure is consistent with MISO's current interface pricing, which calculates flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.

However, PJM assumptions are much different. It assumes the power sources and sinks from the border with MISO as shown in the second figure. This 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 identied the location of MISO's marginal generators 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.

1. Interface Pricing and External Market-to-Market Constraints

We raised a separate concern in our *2012 State of the Market Report*, that MISO and PJM are including redundant congestion component in their interface prices for M2M constraints. When MISO and PJM independently calculate interface prices that include the cost of congestion on the same "coordinated" market-to-market flowgate, the total settlement will over-pay or over-charge the market participant for the congestion effects of the transaction.

We have also quantified some of the related inefficiencies and costs to both PJM and MISO related to this pricing flaw. We estimate that the two RTOs together incurred costs of $51.5 million in net overpayments on market-to-market constraints in 2015, of which $44.7 million was incurred by PJM. These amounts do not include overpayments made for other external constraints (only for the PJM and MISO M2M constraints).

In addition to the overpayments for transactions that are expected to help relieve the constraint, this issue causes transactions to be overcharged for congestion when they are expected to aggravate a constraint. Although this effect will not result in uplift, it serves as an economic barrier to efficient external transactions.

Table A6: Analysis of Near-Term Proposals

We continue to work with MISO and PJM, and their respective stakeholders through the JCM process to address the problem and have now largely achieved a consensus between the RTOs on the problem. We continue to discuss two potential near-term solutions:

- The non-monitoring RTO could simply stop including its neighbor's M2M constraints in its interface prices. This would ensure that the incentive to transact reflects the value of the relief to MISO who is managing the constraint. This solution resolves all of the efficiency and equity concerns associated with this pricing flaw, and can be applied to all external constraints for all interfaces.

- PJM proposes that both RTOs adopt a common interface comprised of limited number of nodes close to the MISO-PJM seam. While this may have intuitive appeal, our analysis indicates that it would produce less efficient, more volatile interface prices.

Ultimately, these near-term alternatives should be judged by the correctness of the incentive provided to participants to import and export. To evaluate this, we establish a baseline that represents the ideal amount of congestion to include in the settlement of an import or export (i.e., the difference in the two RTOs' congestion components). Since MISO and PJM use their load-weighted centroids as their reference buses to calculate congestion at all locations, the objective for the interface pricing proposals should be to produce congestion components that are efficient relative to these reference buses – i.e., the reference-to-reference flow effect times the shadow price of each constraint. The results of two metrics we use to evaluate the proposals are shown in Table A6:

- "Difference from Ideal" is the average deviation (absolute value) of the congestion incentive from our benchmark. The benchmark is the congestion price you would get assuming transactions source at one reference bus, sink at the other reference bus, and the shadow price equals the monitoring RTO's shadow price.

- "Volatility" is change in the congestion incentive from the prior hour in the day-ahead market or 30 minutes prior in the Real-Time.

Table A6: Analysis of Near-Term Proposals

	Average Difference from Ideal			Volatility			Preferred Approach	
	Status Quo	Common Interface	MISO Increm.	Status Quo	Common Interface	MISO Increm.	Difference from Ideal	Volatility
Real-Time Market								
Total Effects -- All Constraints	**1.40**	**1.58**	**1.29**	**1.86**	**1.82**	**1.63**	Incremental	Incremental
MISO M2M Constraints	1.95	1.49	1.95	2.70	2.92	2.70	Common	Incremental
PJM M2M Constraints	2.95	1.97	2.53	4.37	3.60	2.84	Common	Incremental
MISO Internal Constraints	0.14	0.86	0.14	0.03	0.02	0.03	Incremental	-
Day-Ahead Market								
Total Effects -- All Constraints	**2.55**	**2.11**	**1.83**	**2.20**	**1.95**	**2.02**	Incremental	Common
MISO M2M Constraints	1.63	1.60	1.63	1.25	1.25	1.25	-	-
PJM M2M Constraints	1.21	0.88	0.49	0.88	0.68	0.46	Incremental	Incremental
MISO Internal Constraints	0.33	0.89	0.33	0.80	0.70	0.80	Incremental	Common

Similar discussions have begun with SPP because MISO implemented a market-to-market process with SPP in March of 2015. However, SPP has not yet taken a position on any particular interface pricing proposal.

2. Interface Pricing and External TLR Constraints

Market-to-market constraints activated by PJM or SPP are one type of external constraint that MISO activates in its real-time market. It 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 because this enables MISO to respond to TLR relief requests as efficiently as possible. While redispatching 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.[29] 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 the inequity of these congestion payments, they motivate participants to schedule transactions inefficiently for three reasons. In most cases, these beneficial transactions are already being fully compensated by the area where the constraint is located. For example, when an SPP constraint binds and it calls a TLR, it will establish an interface price for MISO that

29 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.

includes the marginal effect of the transaction on its own constraint. Hence, 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.

Finally, MISO's shadow cost for external TLR constraints is frequently overstated times over versus the monitoring system operator's true marginal cost of managing the congestion on the constraint. As shown in Section VI.K, this causes the congestion component associated with TLR constraints that is included in the interface prices to be highly distortionary and provide inefficient scheduling incentives. One should expect that is will result in inefficient schedules and higher costs for MISO customers.

C. Price Convergence Between MISO and Adjacent Markets

Like other markets, MISO relies on participants to increase or decrease net imports to cause prices between MISO and adjacent markets to converge. Given uncertainty regarding price differences at the time transactions are scheduled, perfect convergence is not be expected.

Transactions can start and stop at 15 minute intervals during an hour, but are settled on an hourly basis. This discrepancy between the hourly settlement and the scheduling timeframe can create incentives for participants to schedule transactions that are uneconomic when flowing, but are nonetheless profitable under hourly settlement.

MISO and PJM modified their scheduling rules in 2009 to address problems caused by allowing participants to schedule 15-minute transactions at the end of the hour after they have observed prices at the beginning of the hour that would be included in the hourly settlement. MISO prohibited changes to schedules within the hour while PJM limited the duration of schedules to no less than 45 minutes. To comply with FERC's Order 764, MISO reduced its scheduling deadline in October 2013 to 20 minutes in advance of the operating period. It filed to continue restricting intra-hour schedule changes, however, until it can implement five-minute settlements.

Figure A113 and Figure A114: Real-Time Prices and Interface Schedules

Our analysis of these schedules is presented in two figures, each with two panels. The left panel is 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 (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 A113: Real-Time Prices and Interface Schedules
PJM and MISO, 2015

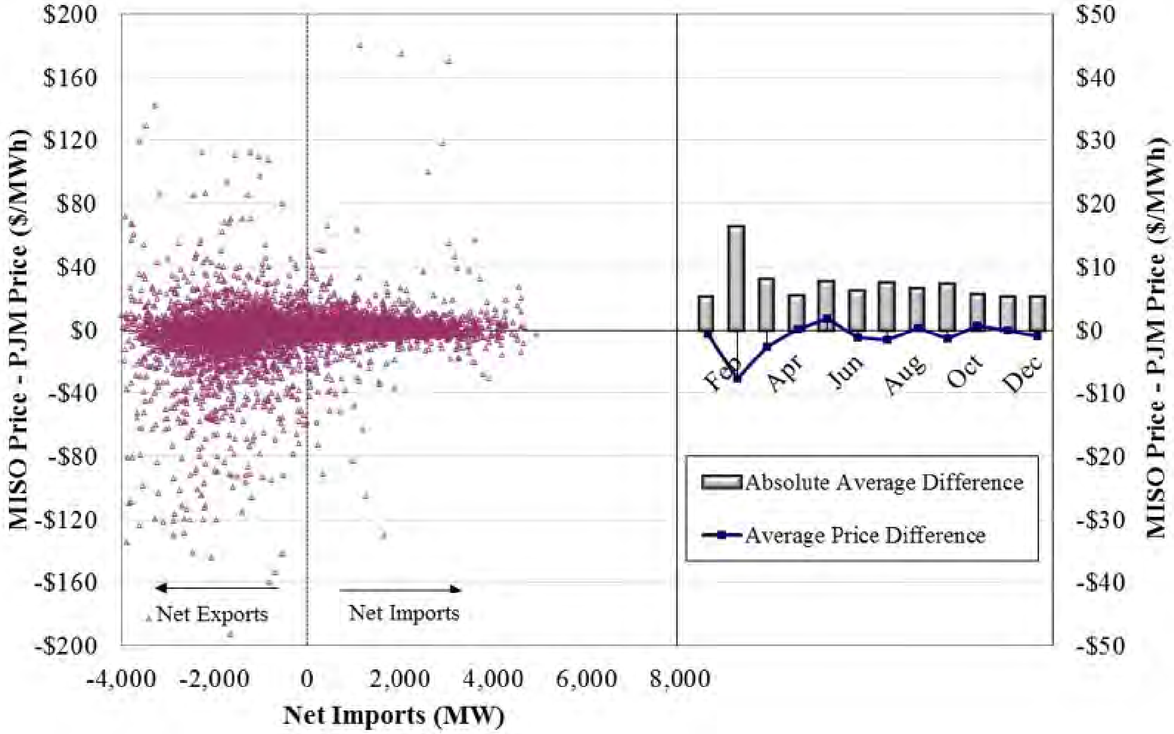
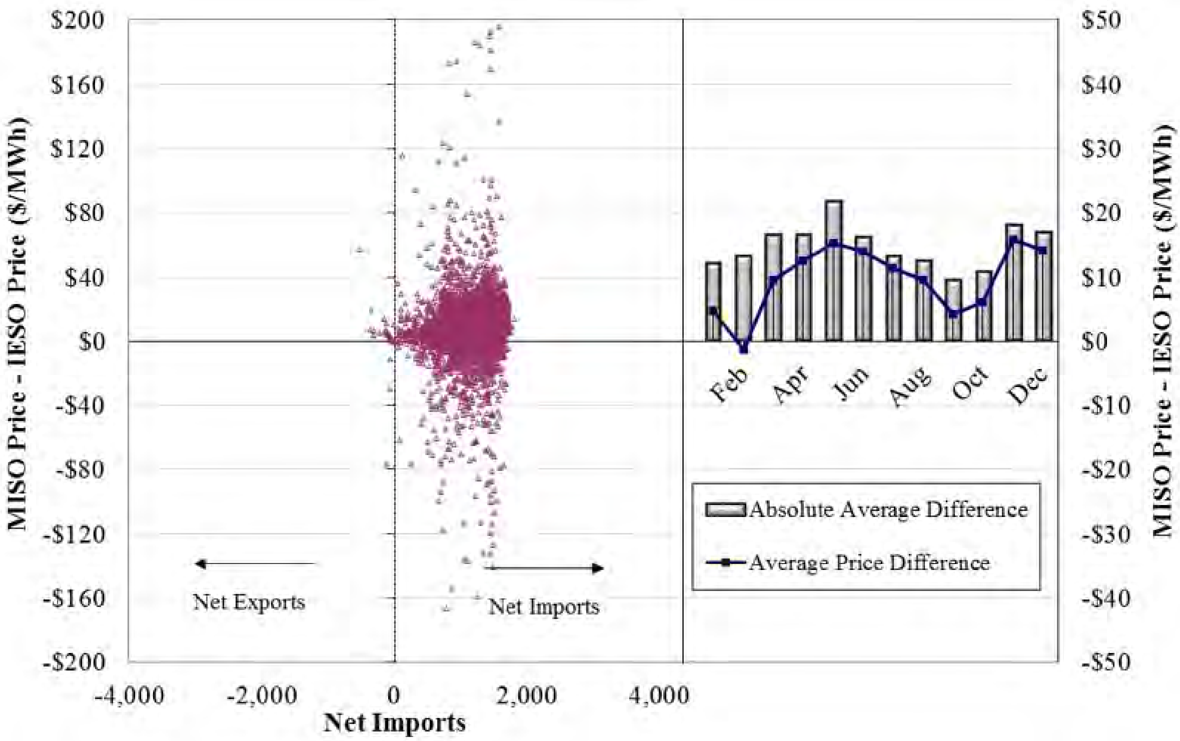


Figure A114: Real-Time Prices and Interface Schedules
IESO and MISO, 2015



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 highly susceptible to the exercise of market power.

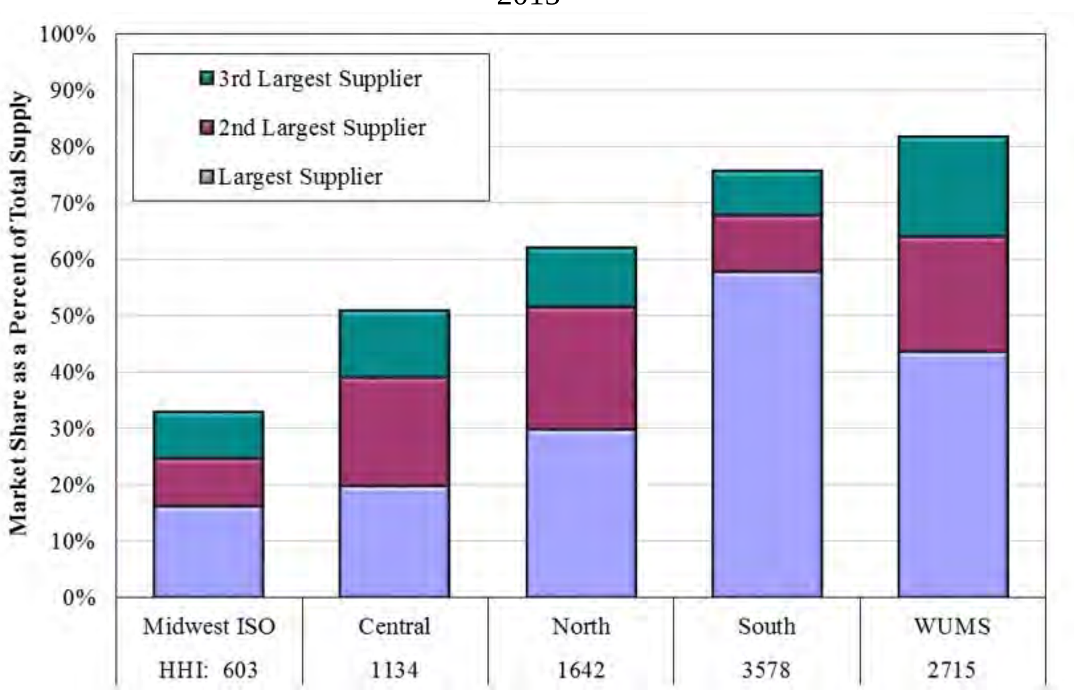
A. Market Structure

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 A115: Market Shares and Market Concentration by Region

The first analysis evaluates the market concentration using the Herfindahl-Hirschman Index (HHI). The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share (in percentage terms). Antitrust agencies generally characterize markets with an HHI greater than 1,800 to be moderately concentrated, while those with an HHI in excess of 2,500 are considered to be highly concentrated. Figure A115 shows generating capacity-based market shares and HHIs for MISO and its subregions.

Figure A115: Market Shares and Market Concentration by Region
2015



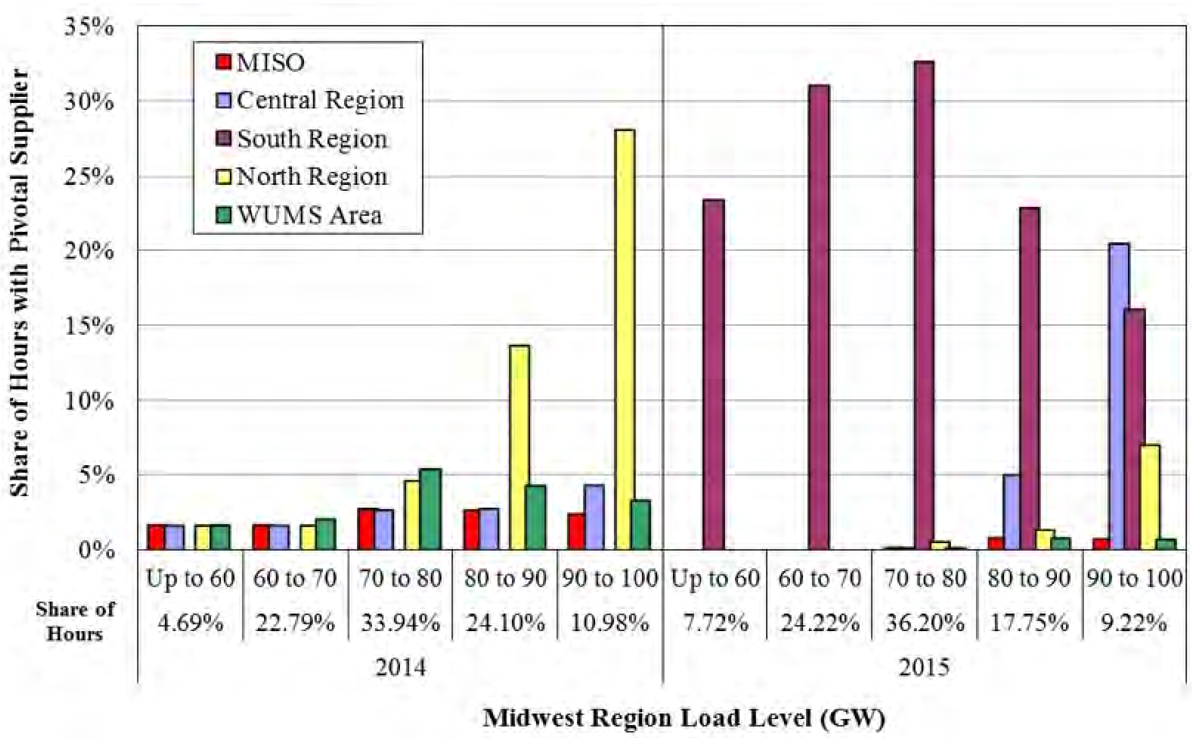
The HHI is only a general indicator of market concentration and not a definitive measure of market power. The HHI's most significant shortcoming for identification of market power in electricity markets is that it generally does not account for demand or network constraints. In wholesale electricity 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 A116: Pivotal Supplier Frequency by Load Level

The first pivotal supplier metric is the Residual Demand Index (RDI), which measures the part of the load in an area that can be satisfied without the resources of its largest supplier. The RDI is calculated based on the internal capacity and all import capability into the area, not just the imports actually scheduled. In general, the RDI decreases as load increases. An RDI greater than one means that the load can be satisfied without the largest supplier's resources. An RDI less than one indicates that a supplier is pivotal and a monopolist over some portion of the load.

Figure A116 summarizes the results of this analysis, showing the percentage of total hours with a pivotal supplier (e.g., RDI less than 1) 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 tranche.

Figure A116: Pivotal Supplier Frequency by Region and Load Level
2014–2015



While the 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, measure 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 overload 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). 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[30], and the North WUMS NCA) and two in the South Region (WOTAB and Amite South NCAs).

Market power associated with BCA constraints can also be significant. A BCA is defined dynamically when non-NCA transmission constraints bind, and includes all generating units with significant impact on power flows over the constraint. BCA constraints are not chronic like NCA constraints are; however, they can raise competitive concerns. Due to 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 A117 to Figure A120: Pivotal Suppliers

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 A117 to Figure A118 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 A119 and Figure A120 show, by region, the percentage of the intervals with active constraints in each month with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs in Midwest region are combined.

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30 Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, the thresholds that applied to the NCAs for most of 2015 ranged from $19.04 per MWh in WOTAB to $50.74 per MWh in Amite South. The Minnesota, WUMS, and North WUMS thresholds were $31.88, $47.86, and $26.74 per MWh, respectively.

Figure A117: Percent of Intervals with at Least One Pivotal Supplier
Midwest Region, 2015

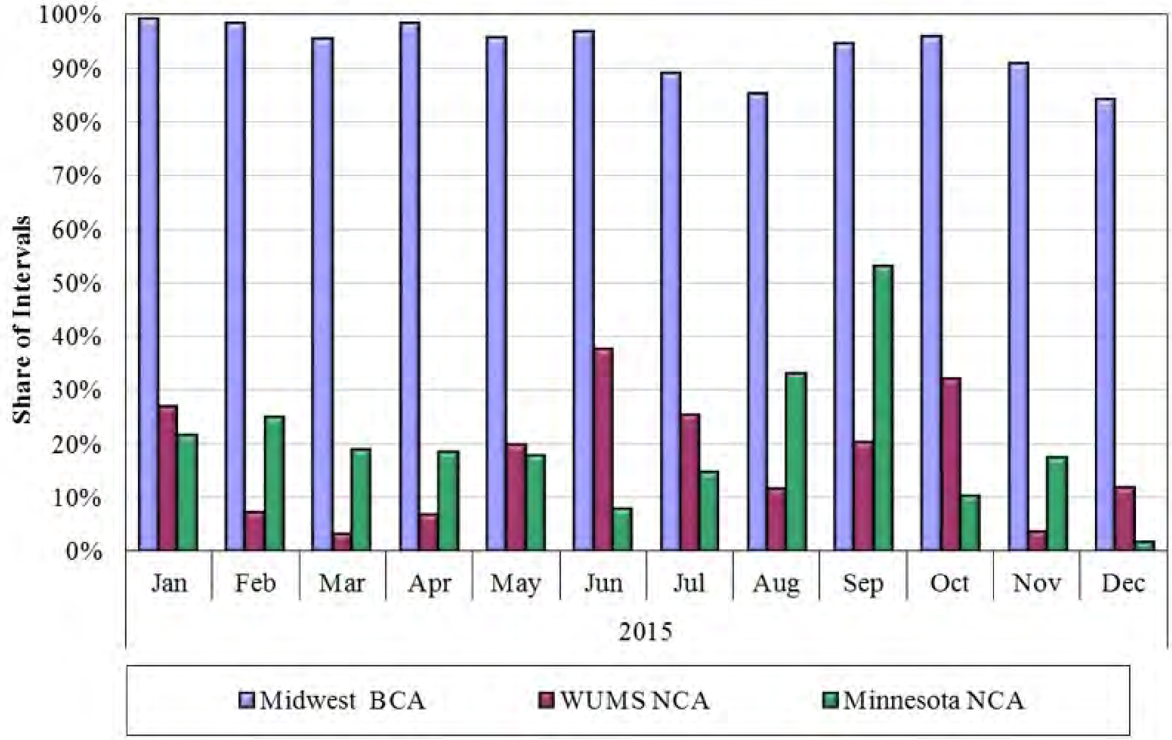


Figure A118: Percent of Intervals with at Least One Pivotal Supplier
South Region, 2015

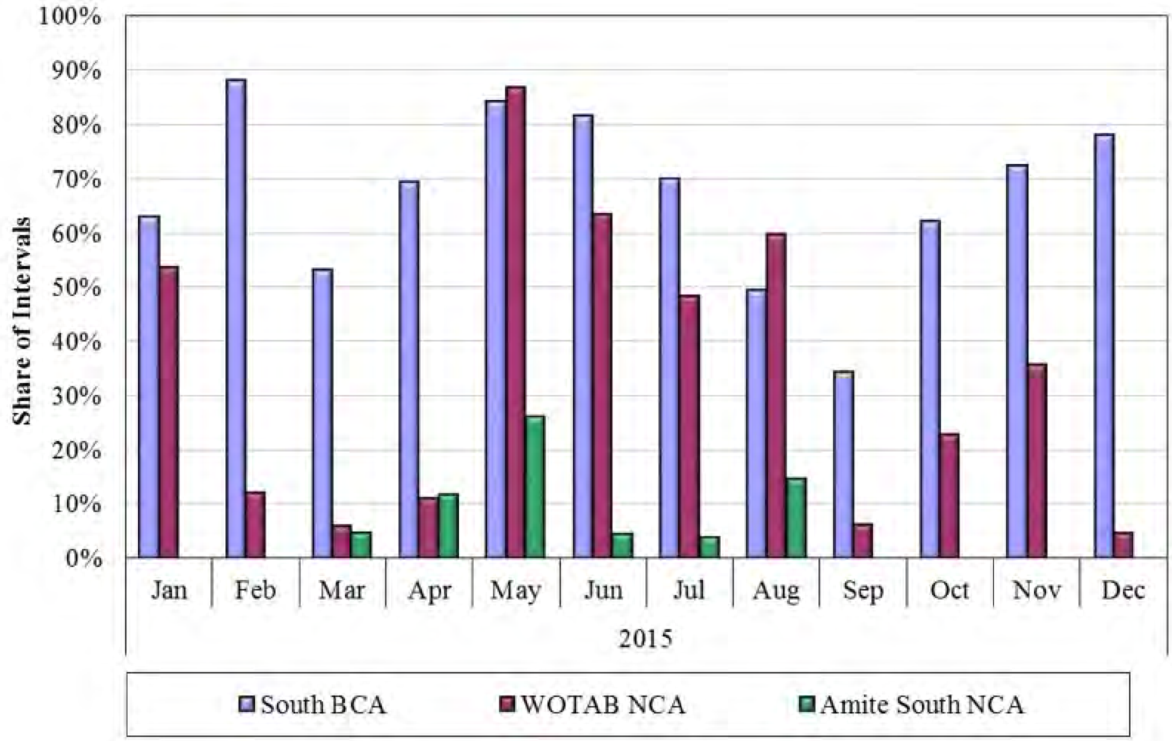


Figure A119: Percentage of Active Constraints with a Pivotal Supplier
Midwest Region, 2015

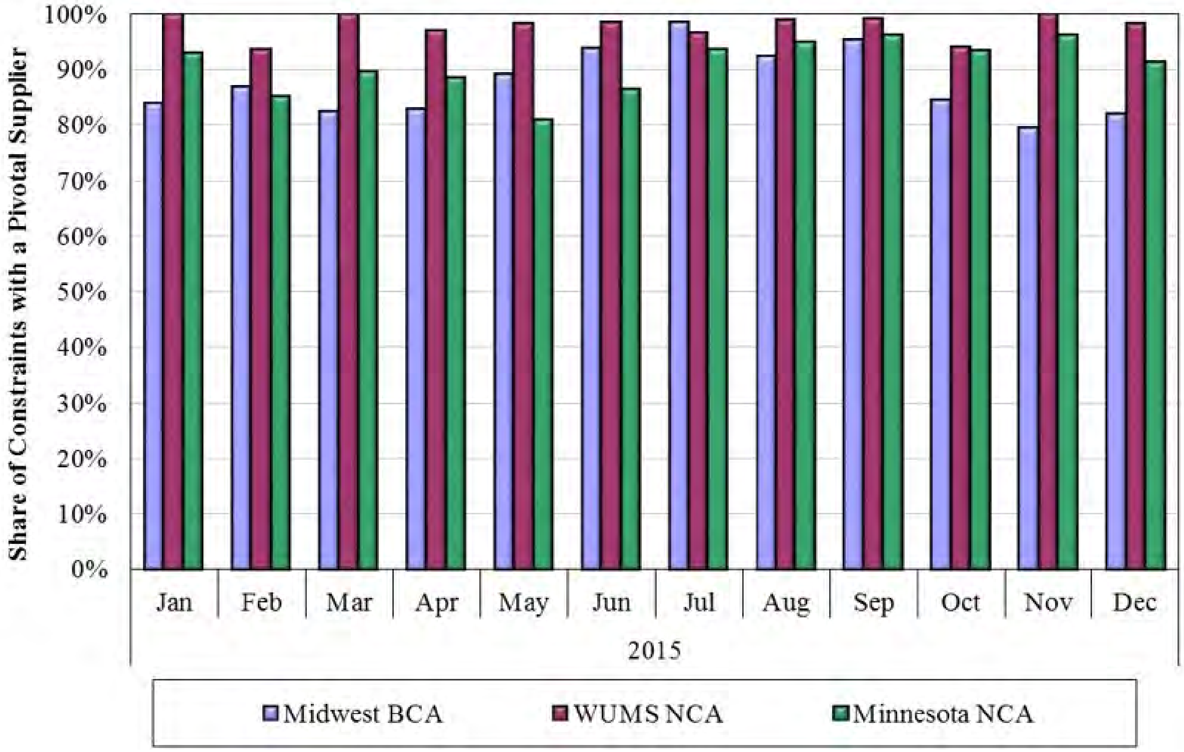
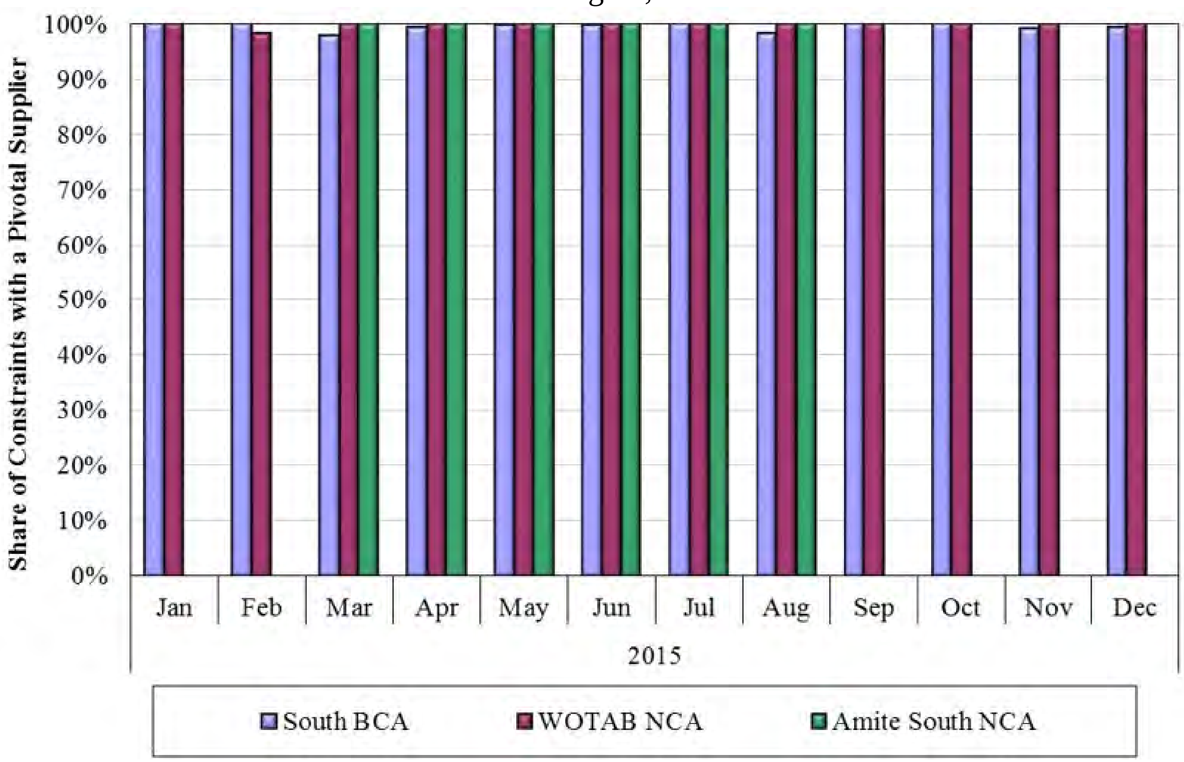


Figure A120: Percentage of Active Constraints with a Pivotal Supplier
South Region, 2015



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 resources at prices substantially above competitive levels 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.

This 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 cost. (Offering above marginal costs would be expected to result in lost revenue contribution to cover fixed costs.) Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so we would not expect to see a mark-up exactly equal to zero. The average price-cost mark-up for 2015 was approximately zero, which 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 cost. 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 O&M, and other costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by variable production costs (primarily 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 units with output restrictions due to 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 the market power mitigation. The second prerequisite is the "impact test", which requires that the identified conduct significantly affect market prices or guarantee payments.[31]

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 true 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 its 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

31 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 would indicate due to operational considerations, including ramp rate limitations. 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.

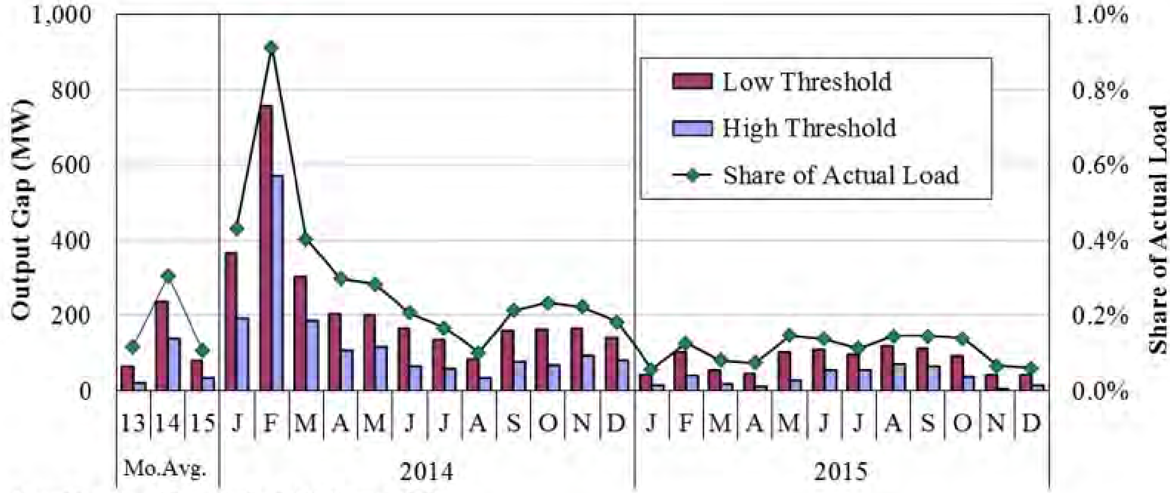
By using the greater of actual production or the output level offered at the clearing price, infeasible energy due to ramp limitations is excluded from the output gap.

Figure A121: Real-Time Monthly Average Output Gap

Figure A121 shows monthly average output gap levels for the real-time market in 2014 and 2015. 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 is arranged to show the output gap using the mitigation threshold in each area (i.e., "high threshold"), and one-half of the mitigation threshold (i.e., "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 effective during most of 2015 were \$47.86 per MWh for resources located in the WUMS NCA, \$26.74 for those in the North WUMS NCA, \$31.88 for those in the Minnesota NCA, and \$19.04 and \$50.74 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 \$25.38 per MWh (50 percent of \$50.74). 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 A121: Economic Withholding -- Output Gap Analysis
2014–2015



Low Threshold Results by Unit Status (MW)

Offline	4	13	99	8	2	6	0	12	1	9	0	26	11	4	70	140	519	154	99	82	18	29	22	32	14	21	52
Online	26	55	140	69	25	62	79	104	53	30	22	55	42	50	74	228	236	150	105	120	150	107	65	131	149	147	92

High Threshold Results by Unit Status (MW)

Offline	3	10	82	7	1	4	0	10	1	6	0	23	7	2	59	106	451	130	83	71	13	21	15	20	9	19	50
Online	5	14	57	27	4	11	20	22	14	5	5	14	11	11	20	89	116	57	26	46	54	41	21	60	62	75	36

Figure A122 to Figure A125: Real-Time Market Output Gap

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), separately showing the two largest suppliers in the region versus all other suppliers. The figures also show the average output gap at the mitigation thresholds (high threshold) and at one-half of the mitigation thresholds (low threshold).

Figure A122: Real-Time Average Output Gap
Central Region, 2015

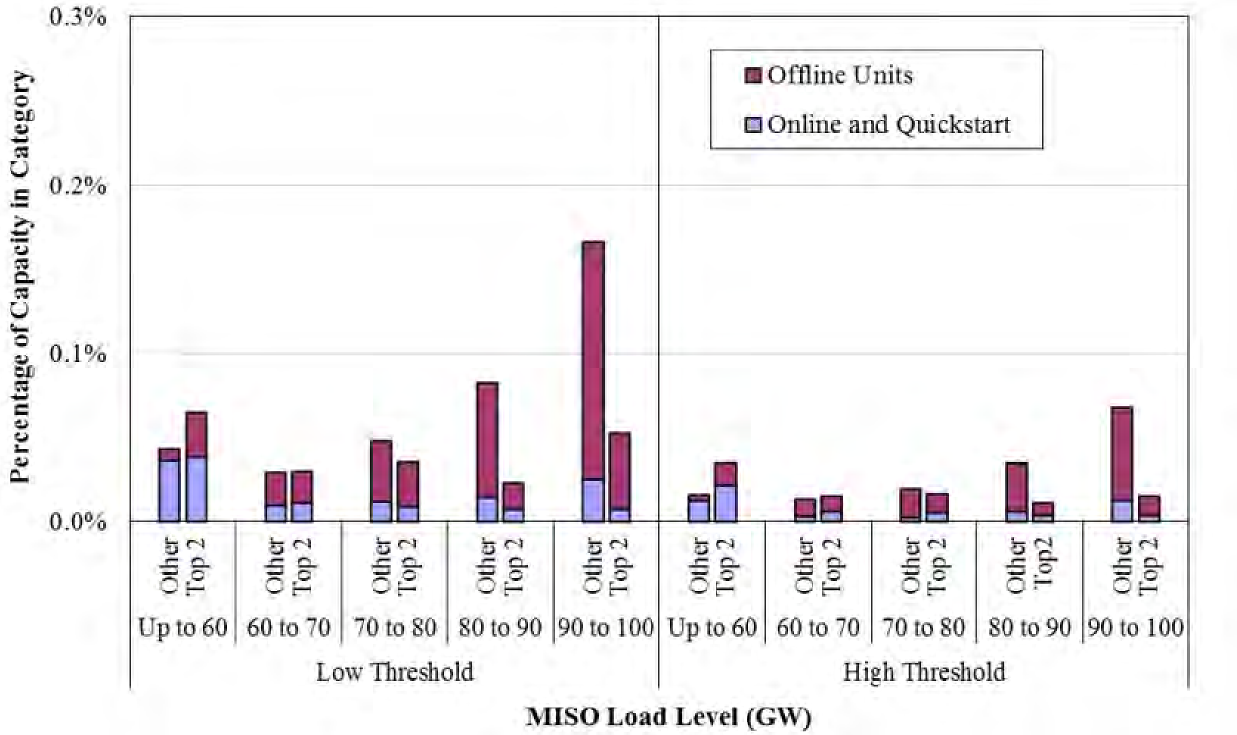


Figure A123: Real-Time Average Output Gap
South Region, 2015

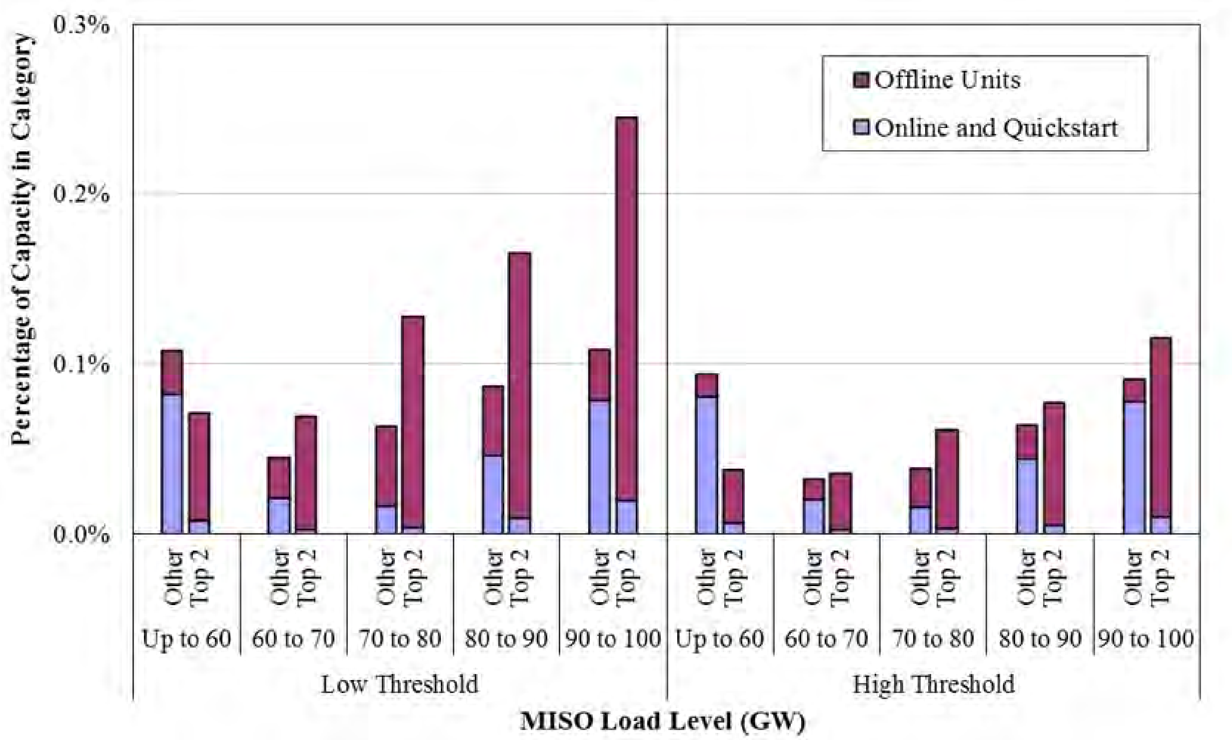


Figure A124: Real-Time Average Output Gap
North Region, 2015

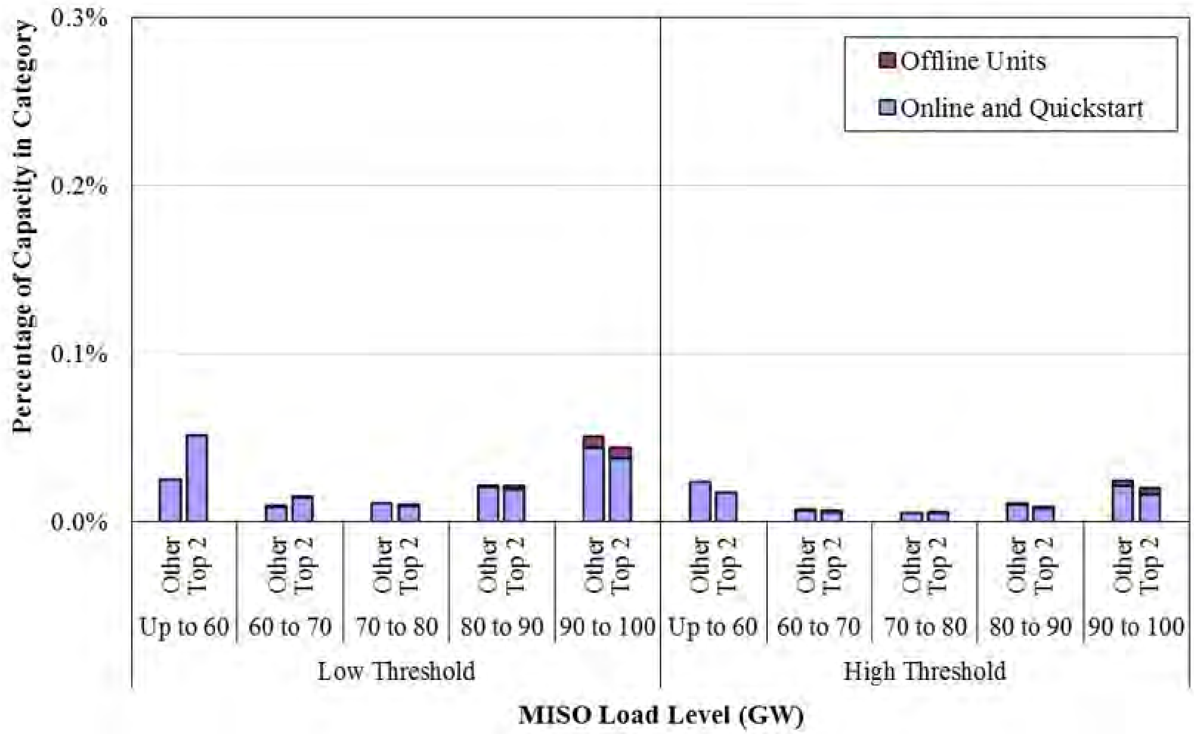
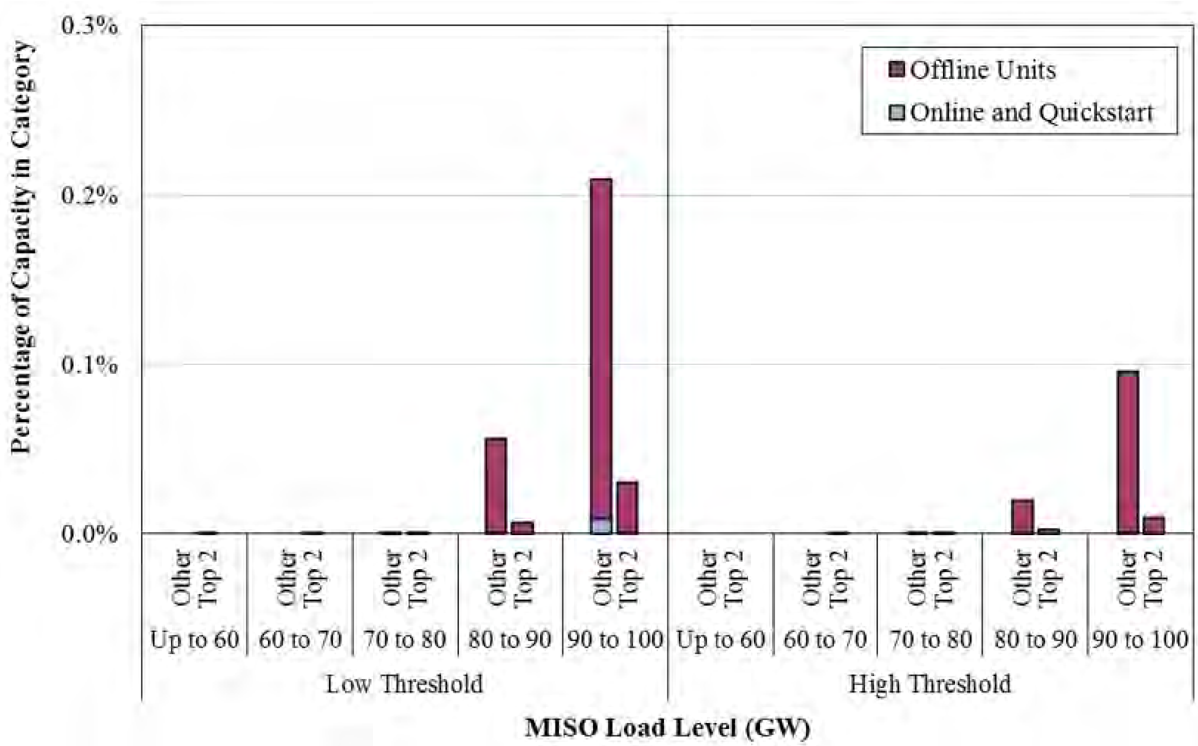


Figure A125: Real-Time Average Output Gap
WUMS Area, 2015



D. Market Power Mitigation

This subsection summarizes the frequency with which market power mitigation measures were imposed in 2015. When Tariff-specified criteria are met, a mitigated unit's offer price is capped at its reference level, a benchmark designed to reflect a competitive offer. MISO only imposes mitigation when suppliers' conduct exceeds defined conduct thresholds and when the effect of the conduct exceeds 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 binding transmission constraints that can result in locational market power because the competitive alternatives to service the load in congested areas and manage network flows are often limited. 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 A126: Day-Ahead and Real-Time Energy Mitigation by Month

Figure A126 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 since the day-ahead market has virtual participants and many more commitment and dispatch options available to provide liquidity. This makes the day-ahead market much less vulnerable to withholding and market power.

Figure A126: Day-Ahead and Real-Time Energy Mitigation by Month
2015

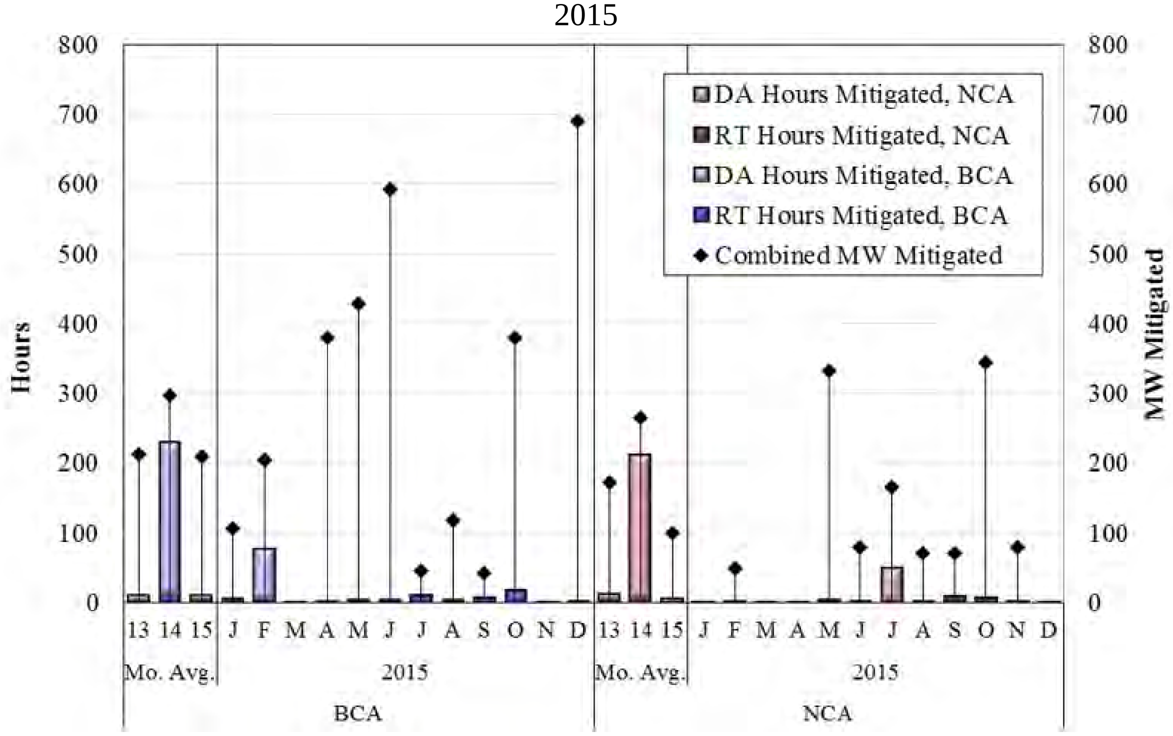
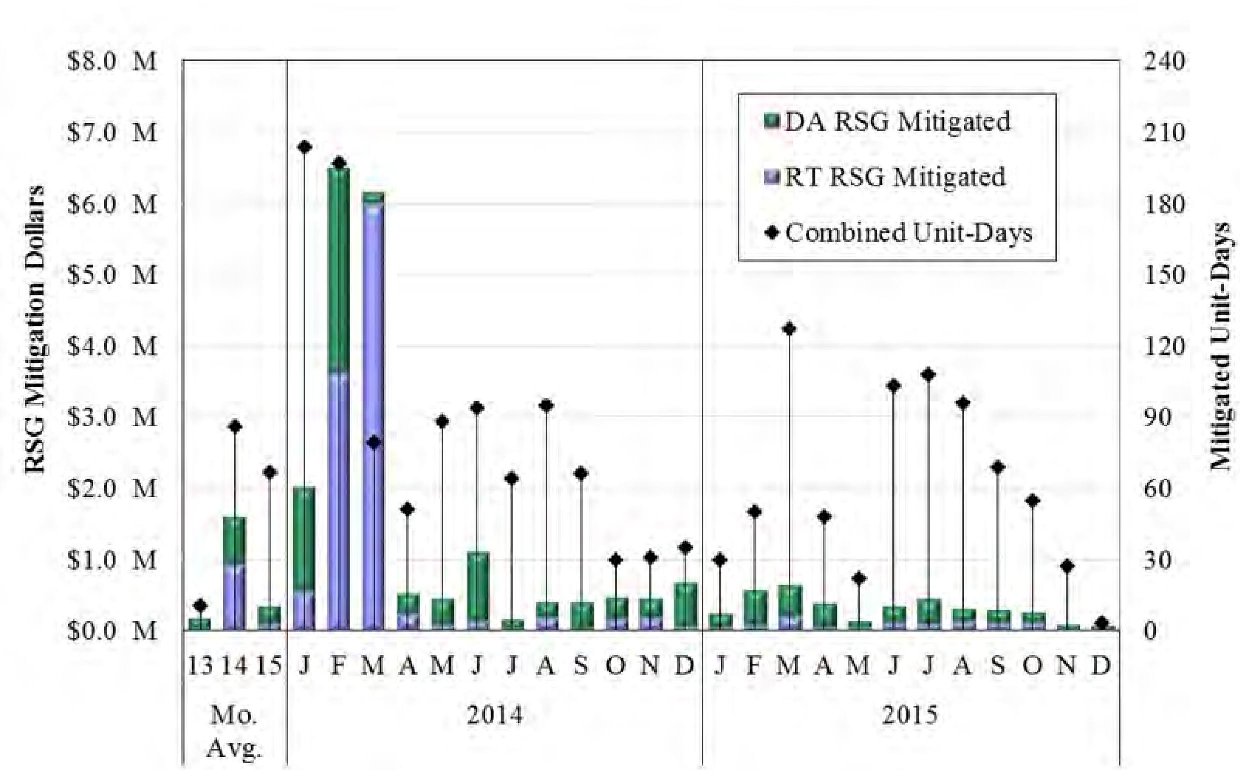


Figure A127: Day-Ahead and Real-Time RSG Mitigation by Month

Participants can also exercise market power by raising their offers when their resources 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 the following three criteria are met: (1) the unit must be committed for a constraint or a local reliability issue; (2) its offer must exceed the conduct threshold; and (3) the effect of the inflated offer must exceed the RSG impact threshold (i.e., by $50 per MWh for BCA and NCAs). In late June, the conduct threshold was changed to the greater of $25 or a 25% increase in production costs with a zero impact threshold. Figure A127 shows the frequency and amount by which RSG payments were mitigated in 2014 and 2015.

Figure A127: Day-Ahead and Real-Time RSG Mitigation by Month
2014–2015



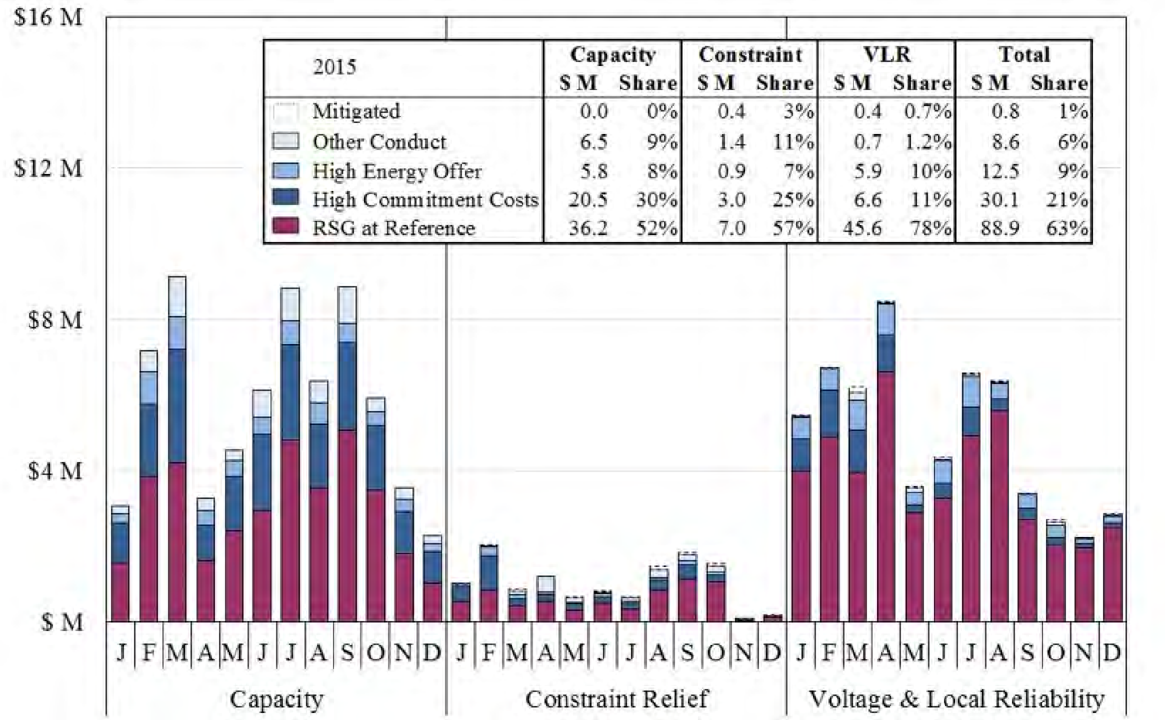
E. Evaluation of RSG Conduct and Mitigation Rules

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

Figure A128 to Figure A130: Real-Time RSG Payments

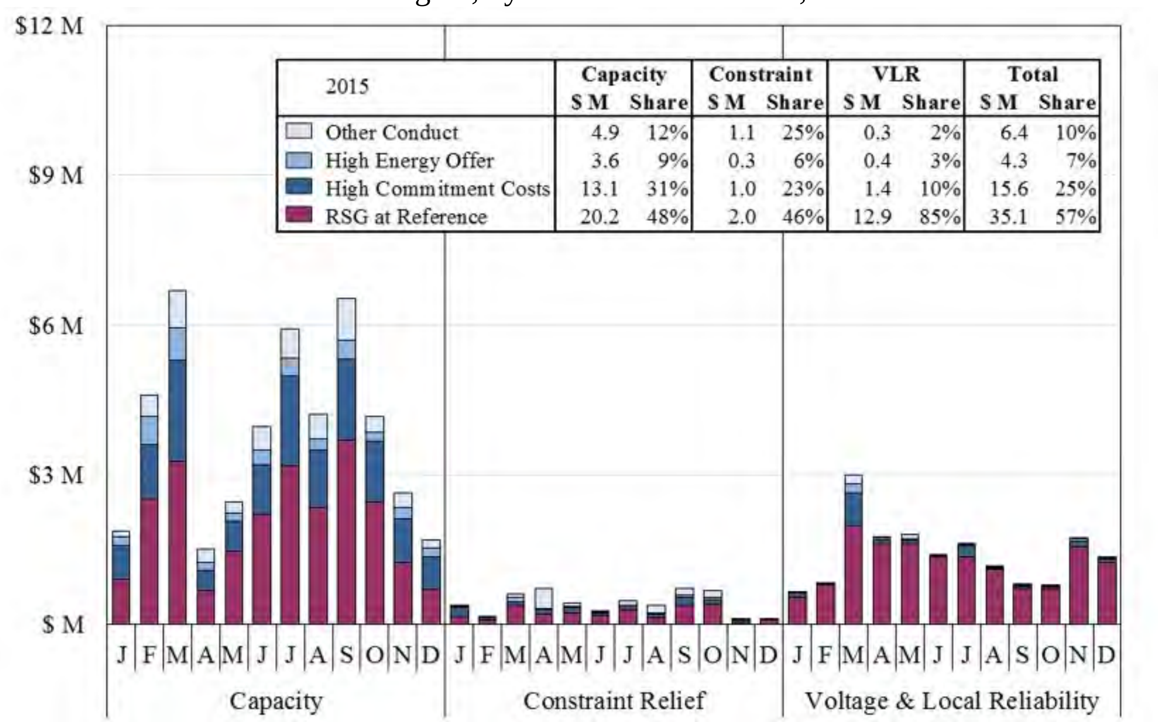
We evaluate conduct associated with RSG payments in the following figure, separating the payments associated with resources' reference levels, and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceed their reference levels. The results are shown separately for units committed for capacity and for congestion management. We also distinguish between the Midwest and South Regions. For Figure A128, the category "Mitigated" includes both day-ahead and real-time amounts.

Figure A128: Real-Time RSG Payments by Conduct
By Commitment Reason, 2015



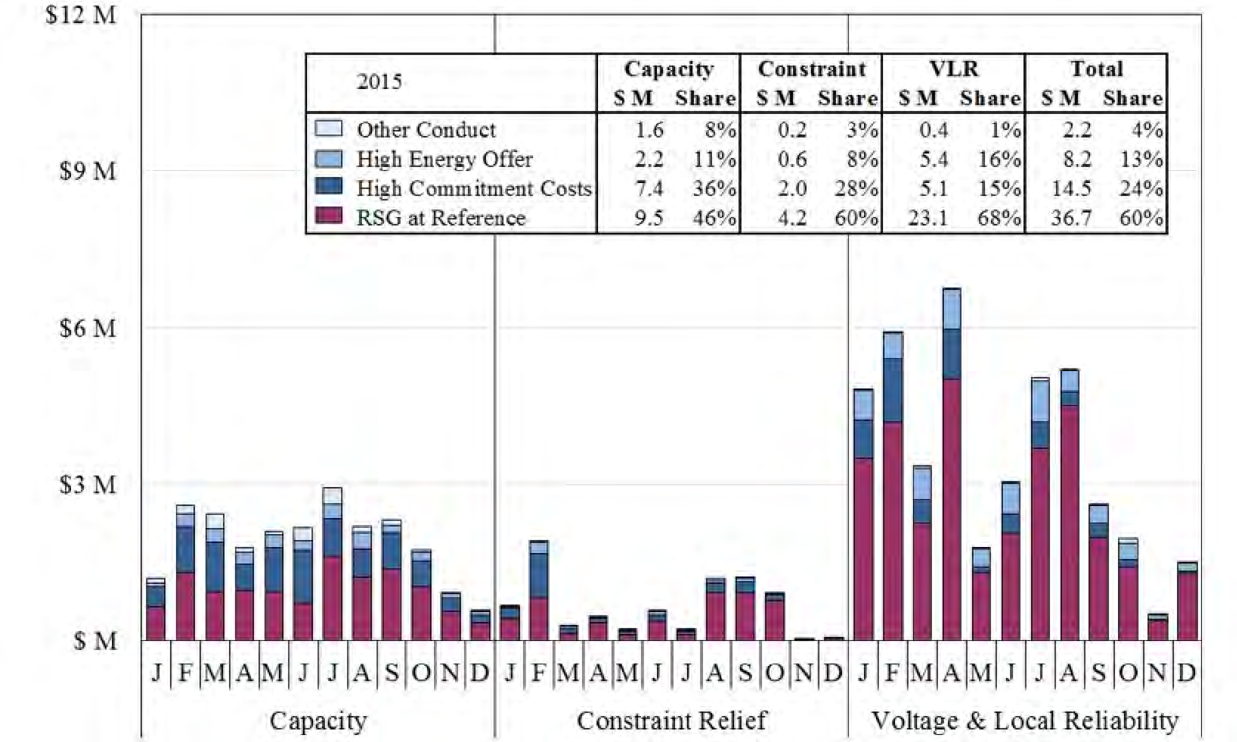
2015	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Mitigated	0.0	0%	0.4	3%	0.4	0.7%	0.8	1%
Other Conduct	6.5	9%	1.4	11%	0.7	1.2%	8.6	6%
High Energy Offer	5.8	8%	0.9	7%	5.9	10%	12.5	9%
High Commitment Costs	20.5	30%	3.0	25%	6.6	11%	30.1	21%
RSG at Reference	36.2	52%	7.0	57%	45.6	78%	88.9	63%

Figure A129: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2015



2015	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Other Conduct	4.9	12%	1.1	25%	0.3	2%	6.4	10%
High Energy Offer	3.6	9%	0.3	6%	0.4	3%	4.3	7%
High Commitment Costs	13.1	31%	1.0	23%	1.4	10%	15.6	25%
RSG at Reference	20.2	48%	2.0	46%	12.9	85%	35.1	57%

Figure A130: Real-Time RSG Payments by Conduct
South Region, by Commitment Reason, 2015



2015	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Other Conduct	1.6	8%	0.2	3%	0.4	1%	2.2	4%
High Energy Offer	2.2	11%	0.6	8%	5.4	16%	8.2	13%
High Commitment Costs	7.4	36%	2.0	28%	5.1	15%	14.5	24%
RSG at Reference	9.5	46%	4.2	60%	23.1	68%	36.7	60%

Up 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 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, FERC approved a $25 or 25 percent conduct patterned after the VLR mitigation framework and eliminated the impact test. This approach has improved the effectiveness of the RSG mitigation framework.

F. Dynamic NCAs

There are times when severe constraints arise that require mitigation thresholds that are tighter than BCA thresholds, but for which an NCA definition is not appropriate. The current Tariff provisions related to the designation of NCAs are focused only on sustained congestion affecting an area and these require a Section 205 filing and stakeholder consultation process to define (or rescind). An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period.

Consequently, when transitory conditions arise that create a severely-constrained area with one or more pivotal suppliers, this would not be defined as an NCA because it would not be expected to bind for 500 hours in a 12-month period. In addition, even if an NCA is defined, the conduct and impact thresholds are based on historical congestion so they would not reflect the recent congestion because it would be based on the prior 12 months of data.

Although the conditions described above are transitory, they can result in substantial market power when an area is chronically constrained for a period of time. This often occurs when system changes occur related to transmission outages or generation outages. Once the congestion pattern begins, suppliers may quickly recognize that their units are needed to manage the constraints. To address this concern, we have recommended MISO establish a dynamic NCA. When a dynamic NCA triggers, we recommend MISO employ conduct and impact thresholds of $25 per MWh rather than the default BCA thresholds of $100 per MWh.

To identify when a dynamic NCA may have been beneficial, we have reviewed mitigation scenarios that we have conducted at thresholds that are 50 percent of the BCA thresholds (effectively $50 per MWh). Since this threshold is higher than what we would propose for the dynamic NCA, this analysis identifies fewer instances of potential mitigation. Nonetheless, it identified a number of instances over the past year when mitigation would have been warranted under a Dynamic NCA approach. However, the frequency of egregious cases of severe transitory congestion that allows a supplier to exercise market power was lower in 2015 that was due in part to the low prevailing fuel prices. Nonetheless, we believe that the need remains for this dynamic NCA authority to respond to transient market power. We provide two of the more egregious examples of the need for this authority that have occurred over the past few years.

Example 1: Overton Transformer

The first example involves the Overton Transformer constraint, which was frequently binding from mid-April to early June 2013. This constraint was binding much more frequently than usual because of a nuclear outage during this timeframe. The output of the nuclear unit typically reduces the power flows over the Overton Transformer.

During this 50-day timeframe, there were more than 80 hours that would have been mitigated at the $50 per MWh threshold. The average price effect of the conduct detected during this period at the locations most affect by the Overton Transformer constraint was more than $150 per MWh in the hours that would have been mitigated. For the entire period, this conduct raised average prices by roughly $10 per MWh.

Example 2: Benton Harbor-Palisades

The second example involves the Benton Harbor-Palisades constraint, which was frequently binding from January 19, 2014 to the beginning of March. This is one of a number of constraints in this area that were affected by a nuclear outage and transmission outages. As described above in the report, these conditions also led to substantial increases in RSG payments. We are proposing changes to more effectively mitigate conduct designed to inflate RSG costs. The dynamic NCA recommendation, however, proposes mitigation measures to address conduct associated with energy and ancillary services offers.

During this 41-day timeframe, there were almost 30 hours that would have been mitigated at the $50 per MWh threshold. The average price effect of the conduct detected during this period at the locations most affected by the Benton Harbor-Palisades constraint was more than $152 per MWh in the hours that would have been mitigated. For the entire period, this conduct raised average prices by almost $4 per MWh.

G. Participant Conduct – Ancillary Services Offers

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

Figure A131 to Figure A133: Ancillary Services Market Offers

Figure A131 to Figure A133 evaluate the competitiveness of ancillary services offers. It shows 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 A131 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 (i.e., the marginal cost of supplying the service). We exclude supplemental (contingency reserves) from this figure since this product is almost never offered at more than $10 per MWh above reference levels.

Figure A131: Ancillary Services Market Offers
2014–2015

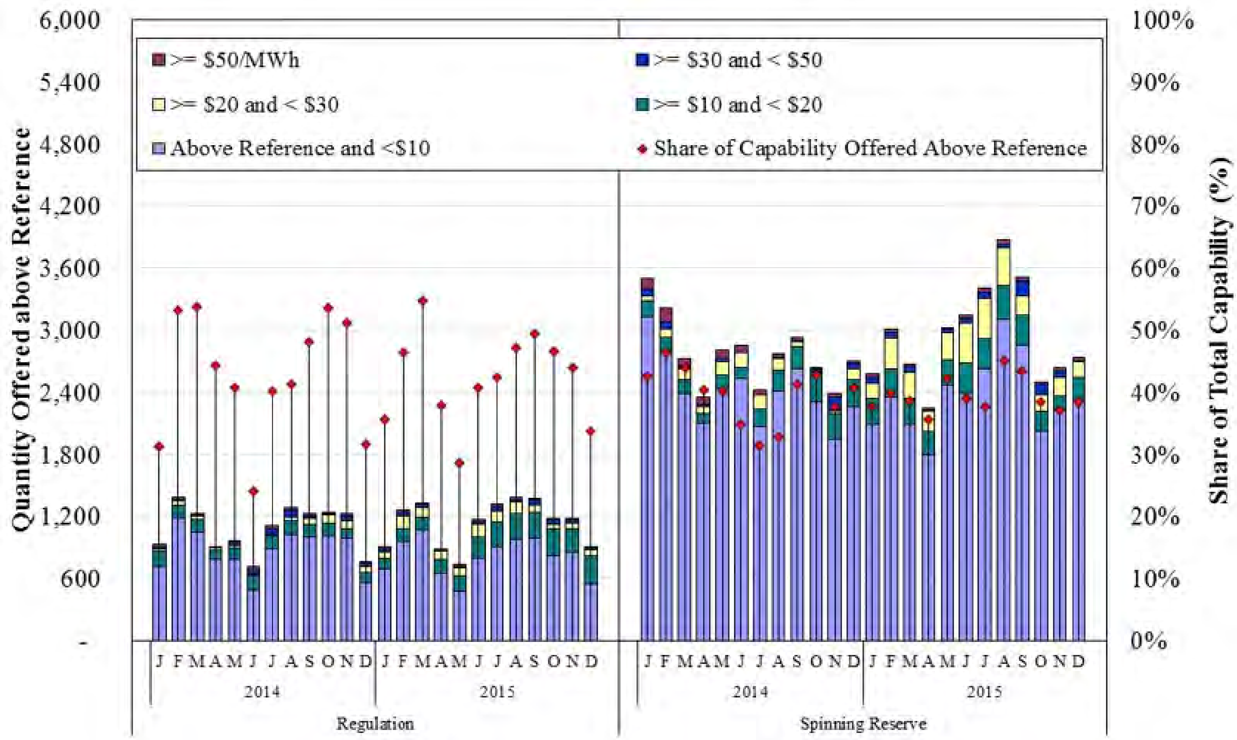


Figure A132: Ancillary Services Market Offers
Midwest Region, 2014-2015

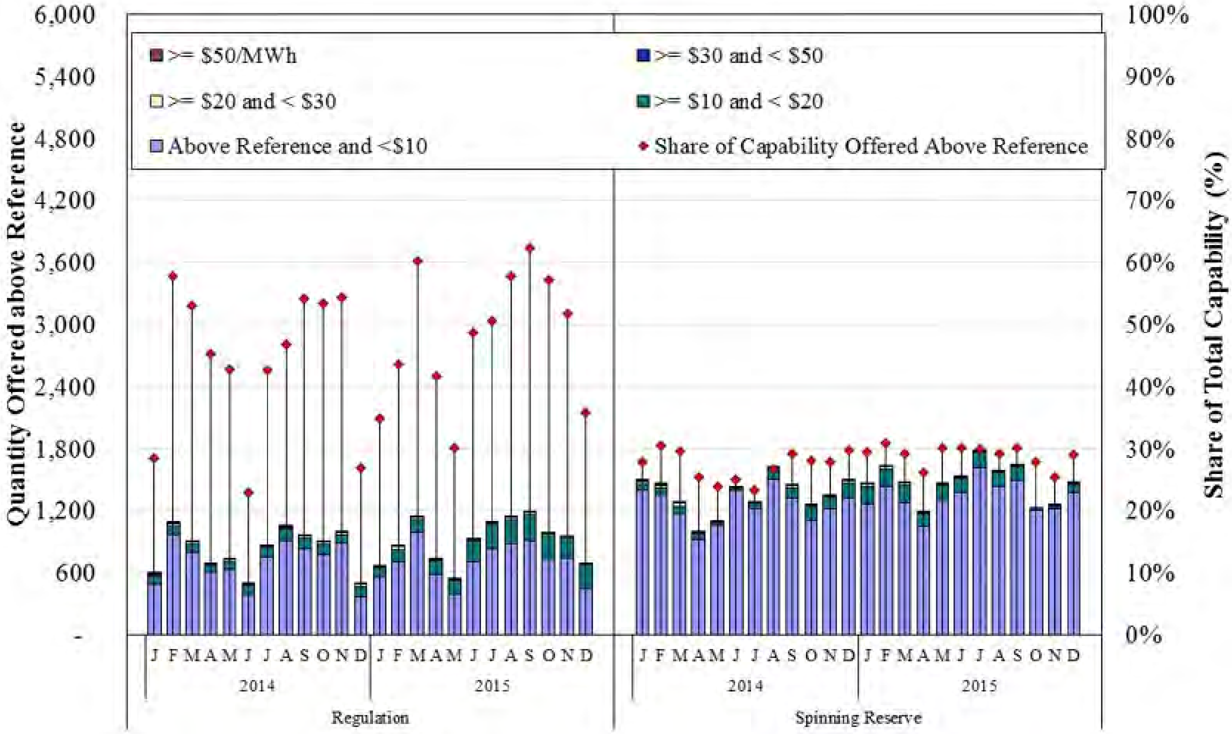
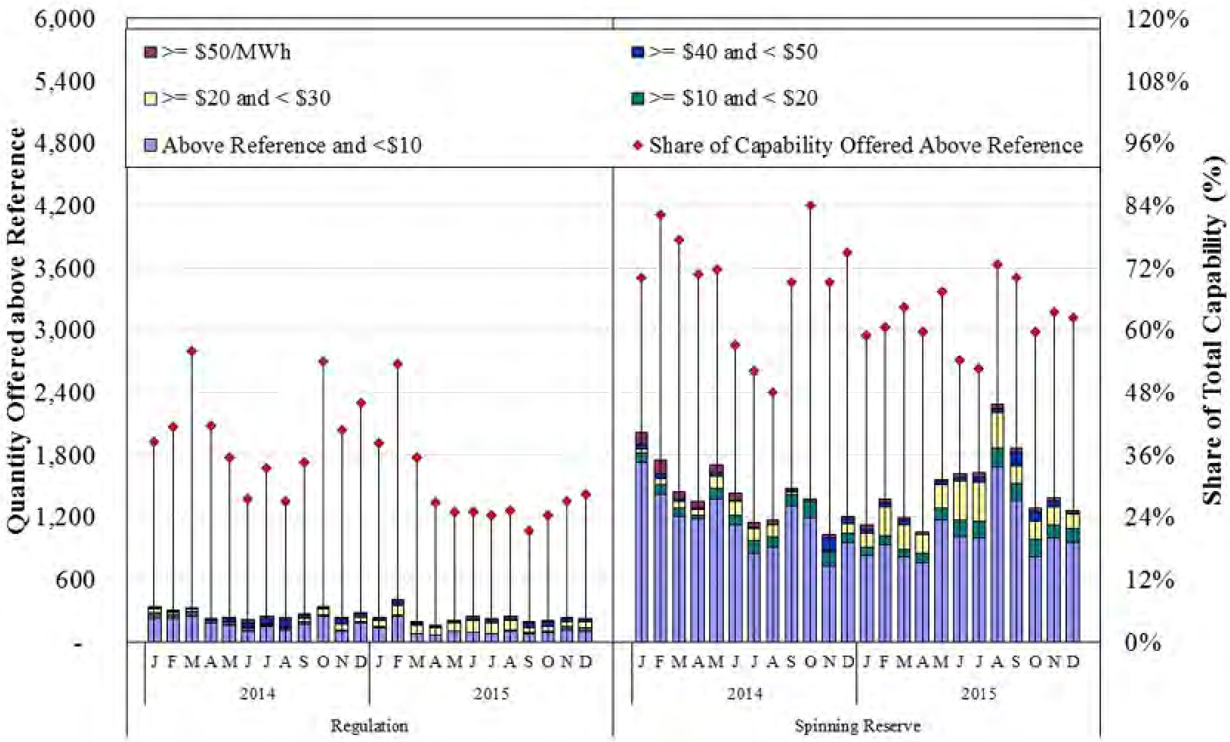


Figure A133: Ancillary Services Market Offers
South Region, 2014-2015



H. 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 market price is unavailable to produce some or all of its output as a result of offering non-economic parameters or declaring other conditions. For instance, this form of withholding may be accomplished by a supplier unjustifiably claiming an outage or derating of the resource. 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 A134 to Figure A137: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2015 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 (lasting fewer than seven days) and short-term deratings because long-term forced outages are less likely to be profitable withholding strategies. Taking a long-term, forced outage of an economic unit would likely cause the supplier to forego greater 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 A134: Real-Time Deratings and Forced Outages
Central Region, 2015

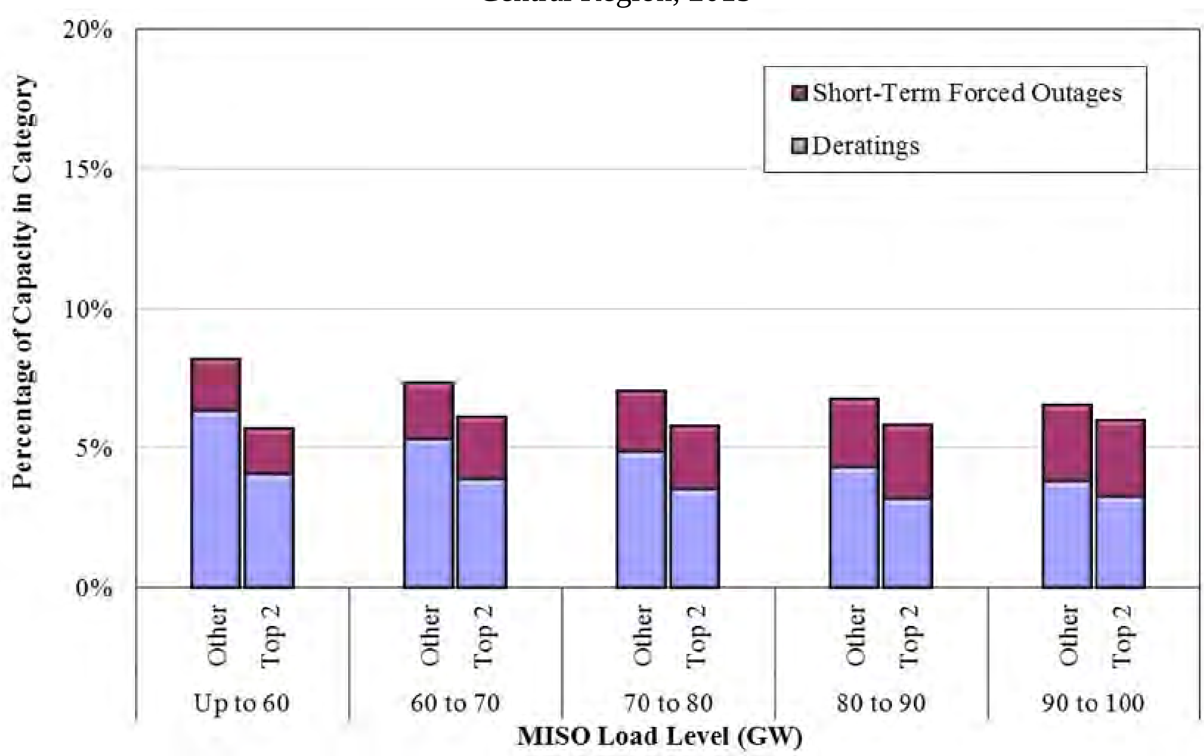


Figure A135: Real-Time Deratings and Forced Outages
South Region, 2015

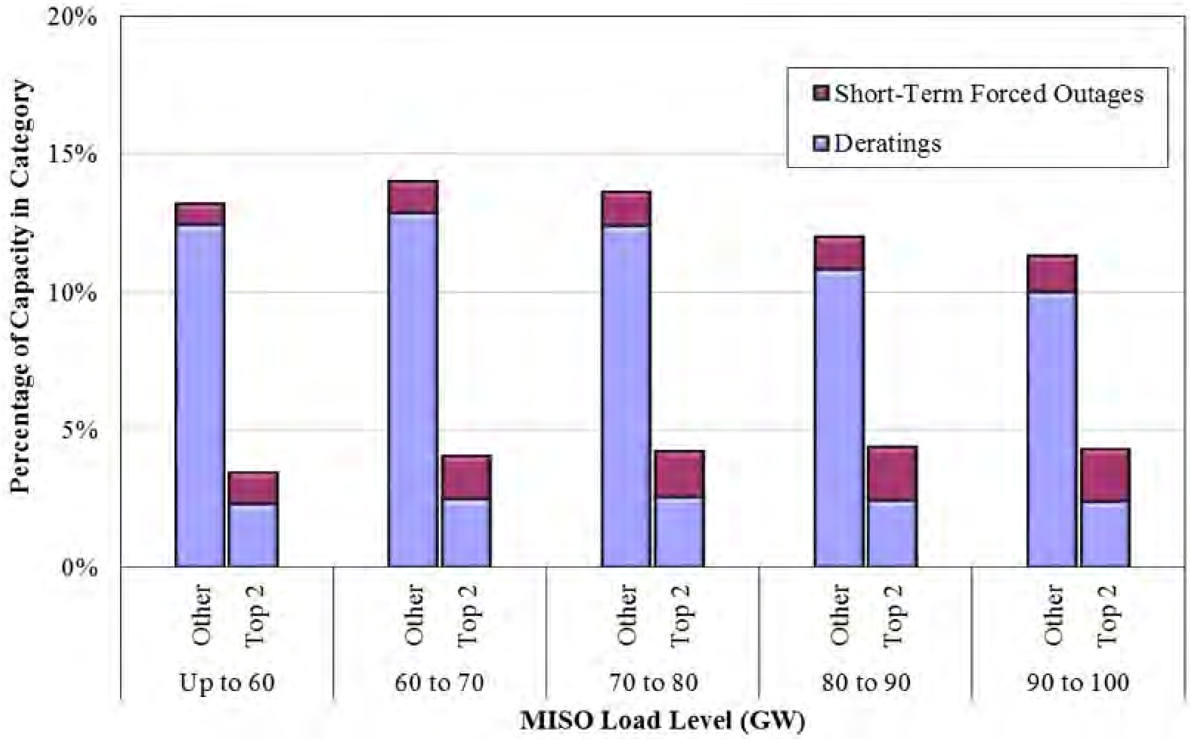


Figure A136: Real-Time Deratings and Forced Outages
North Region, 2015

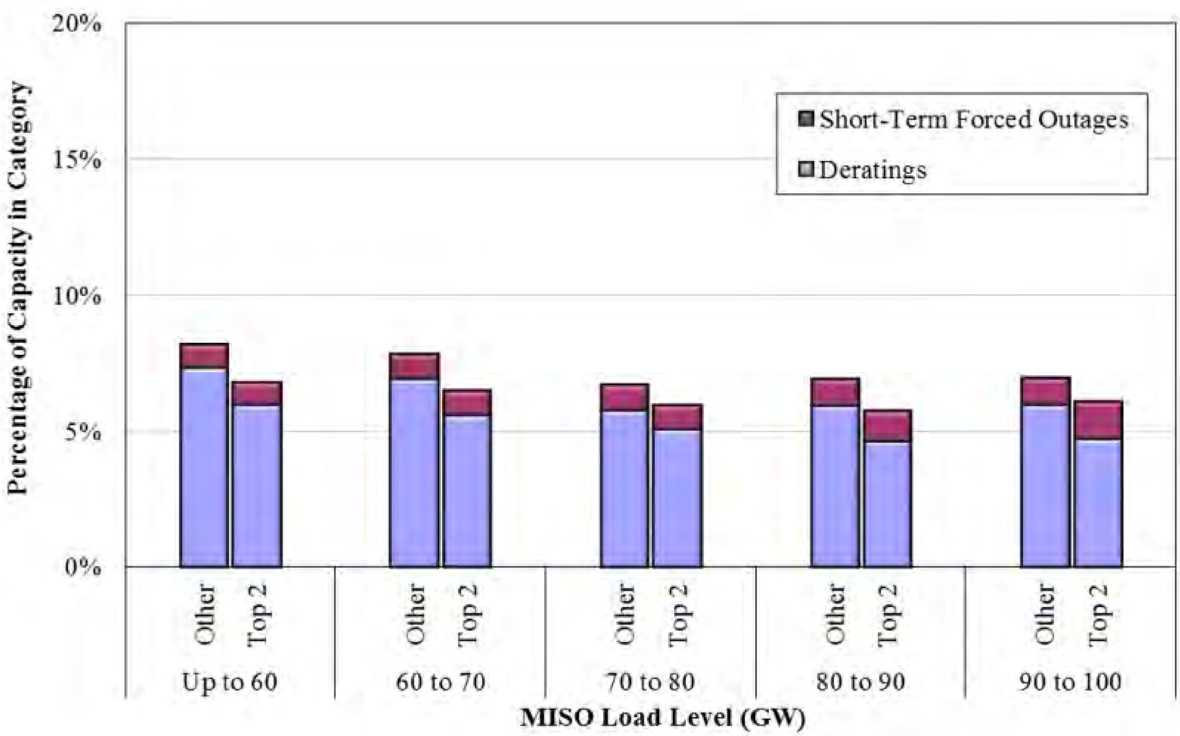
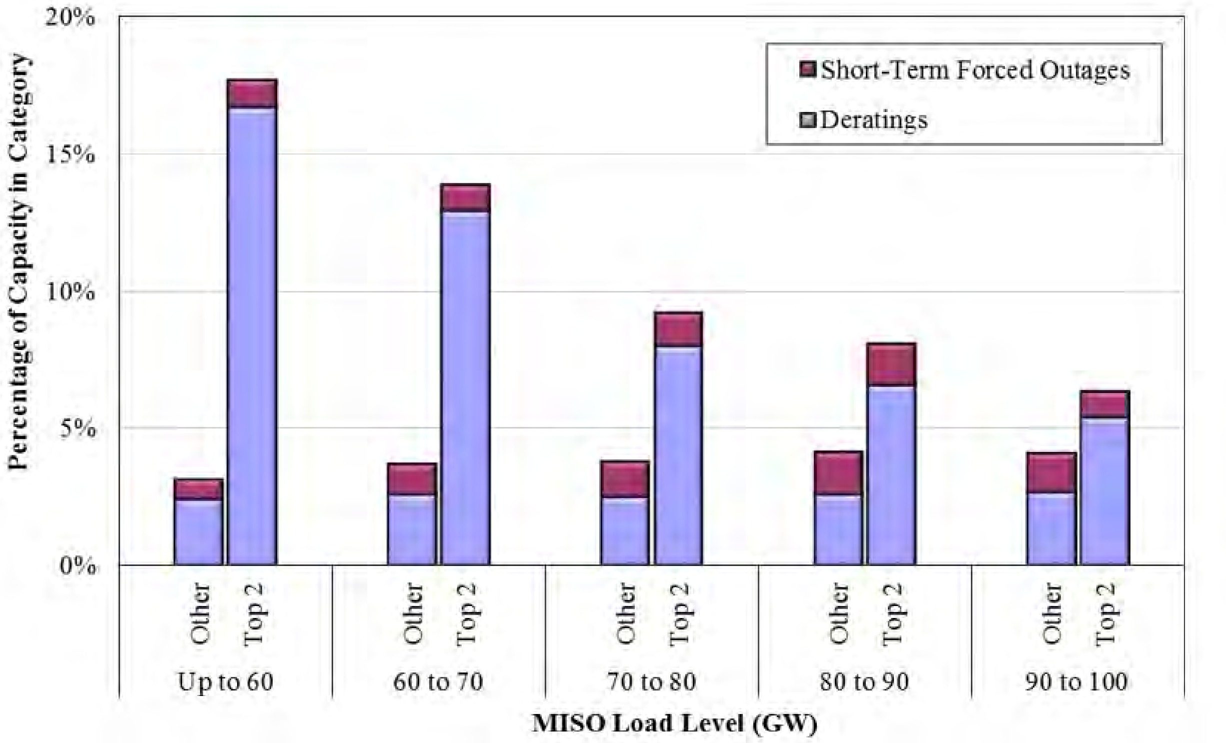


Figure A137: Real-Time Deratings and Forced Outages
WUMS Area, 2015



I. 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;
- Reduced price volatility and other market costs; and
- Reduced supplier market power.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-priced periods can significantly reduce the costs of committing and dispatching generation to satisfy system needs. 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.[32] 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 (e.g., 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 (from peak to off-peak periods, thereby flattening the load curve). These actions improve the overall efficiency and reliability of the system.

32 A large share of the demand response capability in MISO cannot be called directly by MISO because it exists under legacy utility arrangements in the form of interruptible load or behind-the-meter generation (BTMG).

A. DR Resources in MISO

MISO’s demand response capability rose slightly in 2015 to approximately 10.5 GW. The majority of this takes the form of legacy DR programs administered by LSEs, either through load interruptions (Load-Modifying Resources, or LMR) or through behind-the-meter-generation (BTMG). These resources are beyond the control of MISO, but can reduce the overall demand of the system. The share of DR that can respond actively through MISO dispatch instructions comprises a small minority of MISO’s DR capability. Such resources are classified as Demand Response Resources (DRRs) and were eligible to participate in all of the MISO markets this year, 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. Type I resources are capable of supplying a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. Conversely, Type II resources are capable of supplying varying levels of energy or operating reserves on a five-minute basis. MISO had 20 Type I resources and two Type II resources – one of which exited in March 2015 - available to the markets in 2015, and 13 of them cleared on average 18 MW of energy.

Type I resources are inflexible in that they 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 can set prices because they are capable of supplying energy or operating reserves in response to five-minute instructions, and are therefore treated comparably to generation resources. These price-based resources are referred to as “dynamic pricing” resources. Dynamic pricing is the most efficient form of DR because rates formed under this approach provide customers with accurate price signals that vary throughout the day to reflect the higher cost of providing electricity during peak demand conditions. These customers can then alter their usage efficiently in response to such prices. Significant barriers to implementing dynamic pricing include the minimum required load of the participating customer, extensive infrastructure outlays, and potential retail rate reform. Only one 20-MW Type II resource was active the entire year in MISO in 2015.

LSEs are also eligible to offer DRR capability into ASM. 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 2015, one unit provided 17 MW of regulating reserves, two units provided an average of 50 MW of spinning reserves, and ten units provided an average of 4 MW of supplemental reserves.

B. Other Forms of DR in MISO

Most other DR capacity comes from interruptible load programs aimed at large industrial customers. 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 are targeted toward residential and small commercial and industrial customers. In the event of a contingency, the LSE manually reduces the load of this equipment (e.g., air-conditioners or water heaters) to a predetermined level.

Module E of MISO's Tariff allows DR resources to count toward fulfillment of an LSE's capacity requirements. DR resources can also be included in MISO's long-term planning process as comparable to generation. DRR units are treated comparably to generation resources in the PRA, while load modifying resources (LMR) must meet additional Tariff-specified criteria prior to their participation. The ability for all qualified DR resources to provide capacity under Module E goes a long way toward addressing economic barriers to DR and ensuring comparable treatment with MISO's generation.

The EDR initiative began in May 2008 and allows MISO to directly curtail load in specified emergency conditions if DRR is dispatched in the ancillary services market and LSE-administered DR programs are unable to meet demand under non-emergency conditions. EDR is supplementary to existing DR initiatives and requires the declaration of a NERC Energy Emergency Alert (EEA) 2 or EEA 3 event. During such an event, resources that do not qualify as DRR, or DRR units that are not offered into the markets, are still eligible to reduce load and be compensated as EDRs.

EDR offers (curtailment prices and quantities, along with other parameters such as shutdown costs) are submitted 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 cap. EDR participants who reduce their demand in response to dispatch instructions 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.

Table A7: DR Capability in MISO and Neighboring RTOs

Table A7 shows total DR capabilities of MISO and neighboring RTOs. Due to differences in their requirements and responsiveness, individual classes of DR capability are not readily comparable.

Table A7: DR Capability in MISO and Neighboring RTOs
2012-2015

		2015	2014	2013	2012
MISO[1]		**10,563**	**10,356**	**9,798**	**7,196**
	Behind-The-Meter Generation	4,213	4,072	3,411	2,969
	Load Modifying Resource	5,121	4,943	5,045	2,882
	DRR Type I	330	372	372	372
	DRR Type II	116	76	76	71
	Emergency DR	782	894	894	902
NYISO[3]		**1,325**	**1,211**	**1,306**	**1,925**
	ICAP - Special Case Resources	1,251	1,124	1,175	1,744
	Of which: Targeted DR	385	369	379	421
	Emergency DR	75	86	94	144
	Of which: Targeted DR	14	14	40	59
	DADRP	0	0	37	37
ISO-NE[4]		**2,685**	**2,487**	**2,101**	**2,769**
	Real-Time DR Resources	692	796	793	1,193
	Real-Time Emerg. Generation Resources	300	255	279	588
	On-Peak Demand Resources	1,222	997	629	629
	Seasonal Peak Demand Resources	471	439	400	359

[1] Registered as of December 2015. All units are MW. Source: MISO website, published at: www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/DemandResponse.aspx.

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

[3] Registered as of July 2014. Retrieved January 15, 2015. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

[4] Registered as of Jan. 1, 2015. Source: ISO-NE Demand Response Working Group Pesentation, Jan. 7, 2015.