2014 State of the Market Report for the MISO Electricity Markets

Analytical Appendix

POTOMAC ECONOMICS

June 2015

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I. Introduction

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, expanded discussion of conclusions regarding market performance as well as recommendations for market design improvement are described in more detail in the body of our Report.

II. Prices and Load trends

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. In this section, we report on MISO's day-ahead and real-time energy markets and summarize prices and revenues associated with these markets. In December 2013, MISO integrated the MISO South Region into these markets.[1]

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 are marginal in most intervals, but natural gas-fired resources tend to set prices at higher load levels and so have a disproportionate impact on load-weighted average energy prices.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly "all-in" price of electricity from 2012 to 2014 along with the price of natural gas at the Chicago Citygate. 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 times 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.

1 Descriptions of the current and historical MISO regions can be found in Section II.

Figure A1: All-In Price of Electricity
2013–2014

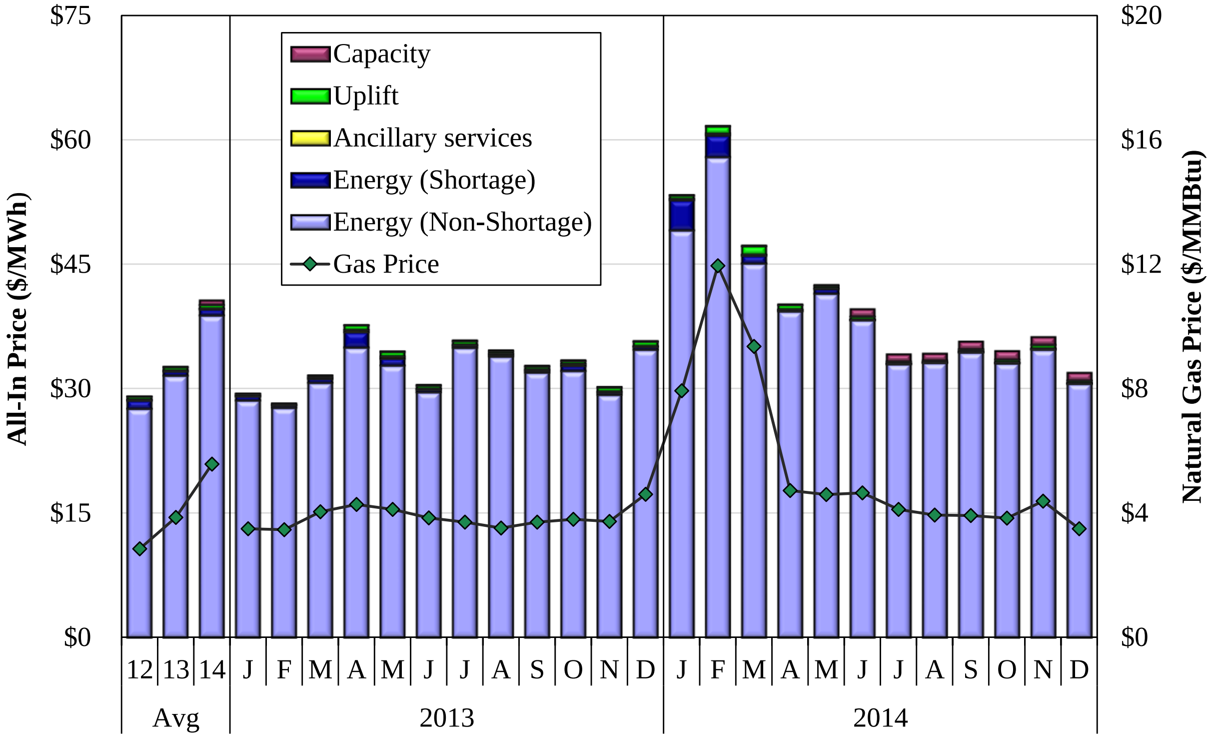
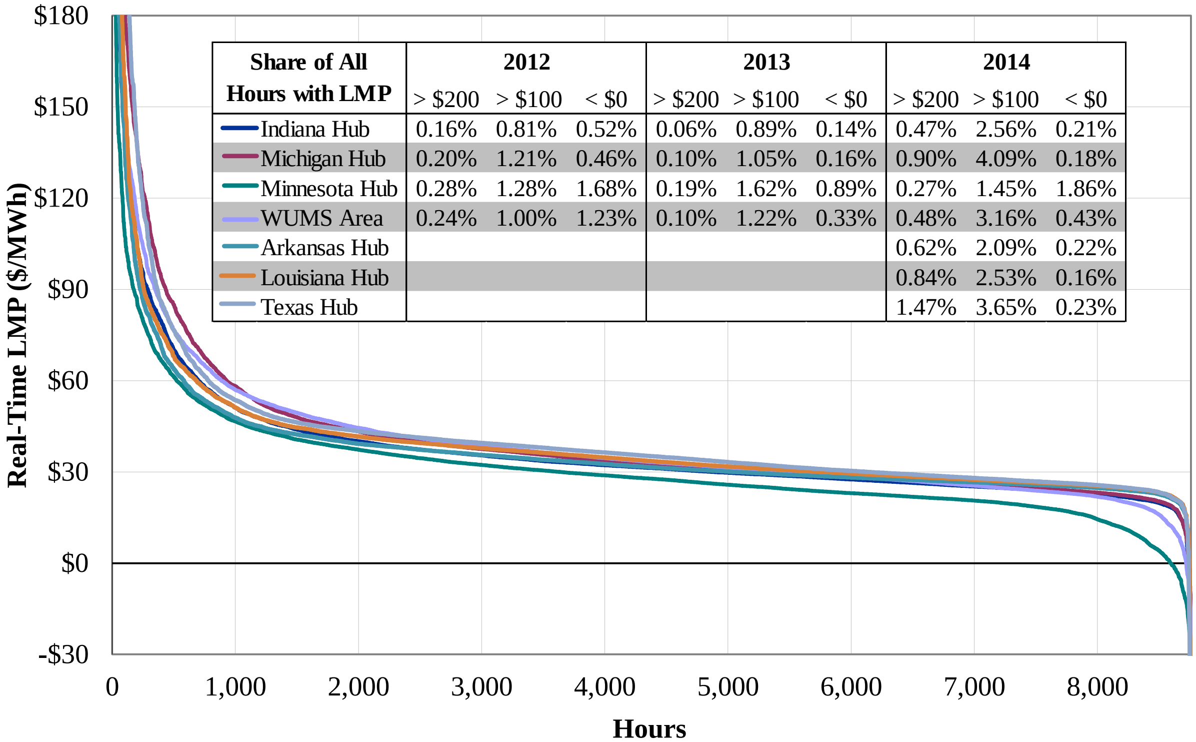


Figure A2: Real-Time Energy Price-Duration Curves

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.

Figure A2: Real-Time Energy Price-Duration Curve
2014



Share of All Hours with LMP	2012 > $200	2012 > $100	2012 < $0	2013 > $200	2013 > $100	2013 < $0	2014 > $200	2014 > $100	2014 < $0
Indiana Hub	0.16%	0.81%	0.52%	0.06%	0.89%	0.14%	0.47%	2.56%	0.21%
Michigan Hub	0.20%	1.21%	0.46%	0.10%	1.05%	0.16%	0.90%	4.09%	0.18%
Minnesota Hub	0.28%	1.28%	1.68%	0.19%	1.62%	0.89%	0.27%	1.45%	1.86%
WUMS Area	0.24%	1.00%	1.23%	0.10%	1.22%	0.33%	0.48%	3.16%	0.43%
Arkansas Hub							0.62%	2.09%	0.22%
Louisiana Hub							0.84%	2.53%	0.16%
Texas Hub							1.47%	3.65%	0.23%

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. Figure A3 shows the prices for natural gas, oil, and two types of coal in the MISO region since 2013.[2] The top panel shows nominal prices in dollars per million British thermal units (MMBtu) along with a table showing annual average nominal prices since 2012. The bottom panel shows fuel price changes in relative terms, with each fuel indexed to January 2013.

2 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 A3: MISO Fuel Prices
2013–2014

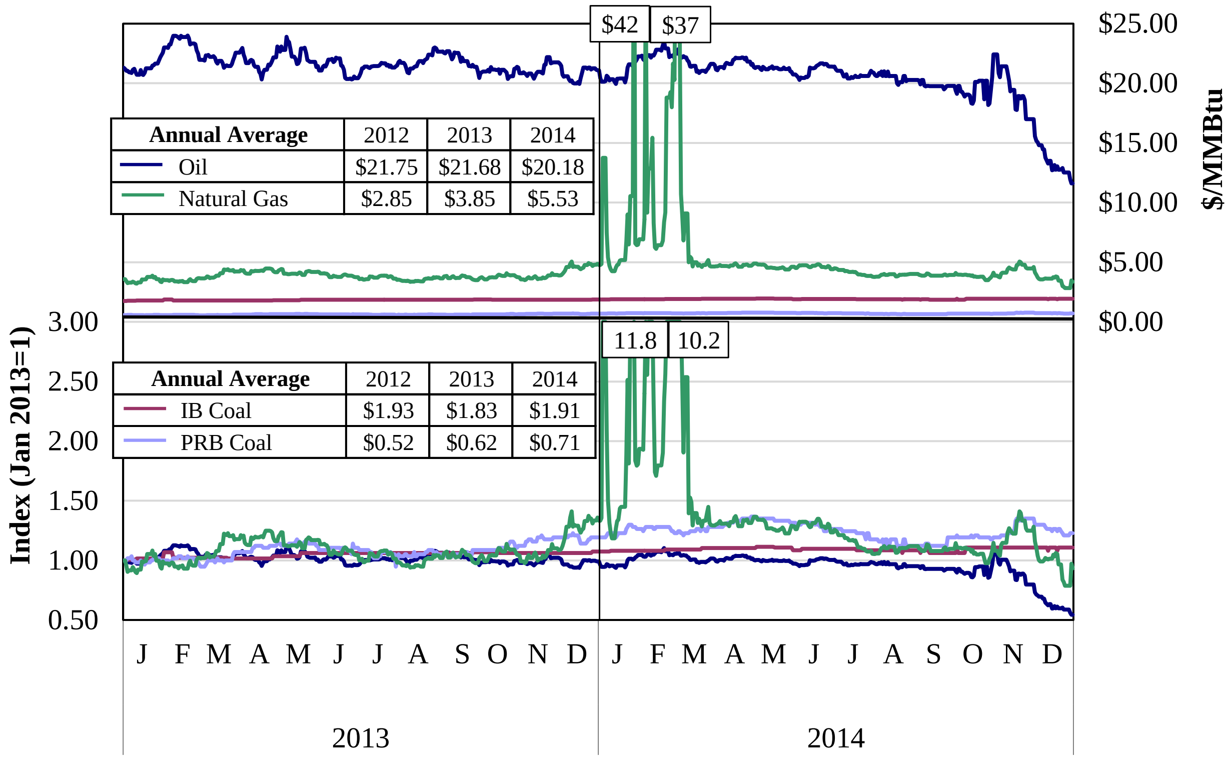
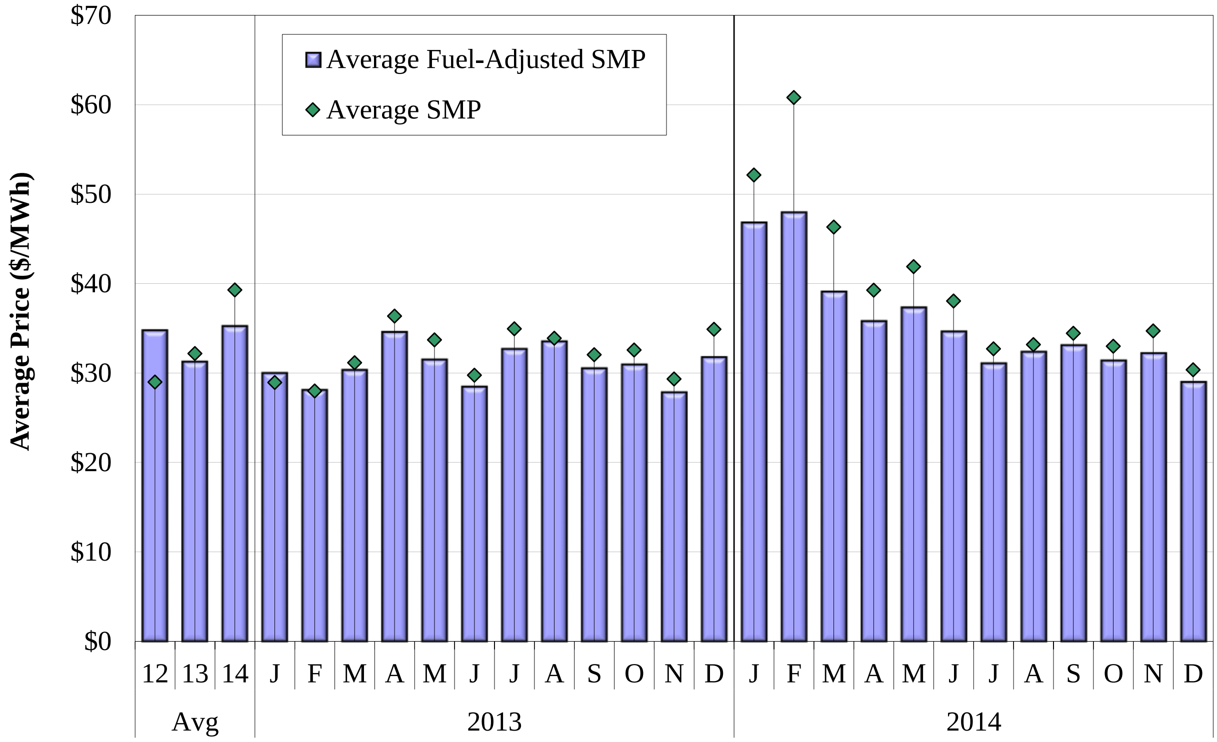


Figure A4: Fuel-Price Adjusted System Marginal Price

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
2013–2014



B. Price Setting and Capacity Factors

Figure A5: Price Setting by Unit Type

Figure A5 examines the frequency with which 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).

Despite the integration of MISO South, which is mostly natural gas-fired, the majority of MISO's base-load capacity remains coal-fired and sets price in most hours. Natural gas and oil resources typically only set prices during the highest-load and ramp-up hours, or in constrained areas. Hence, these resources have a greater impact on load-weighted average prices than their frequency on the margin would suggest. 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 usually set negative prices when they are marginal. Wind resources are generally marginal and setting low (negative) prices in local areas when they are contributing to congestion.

Figure A5: Price-Setting by Unit Type
2013–2014

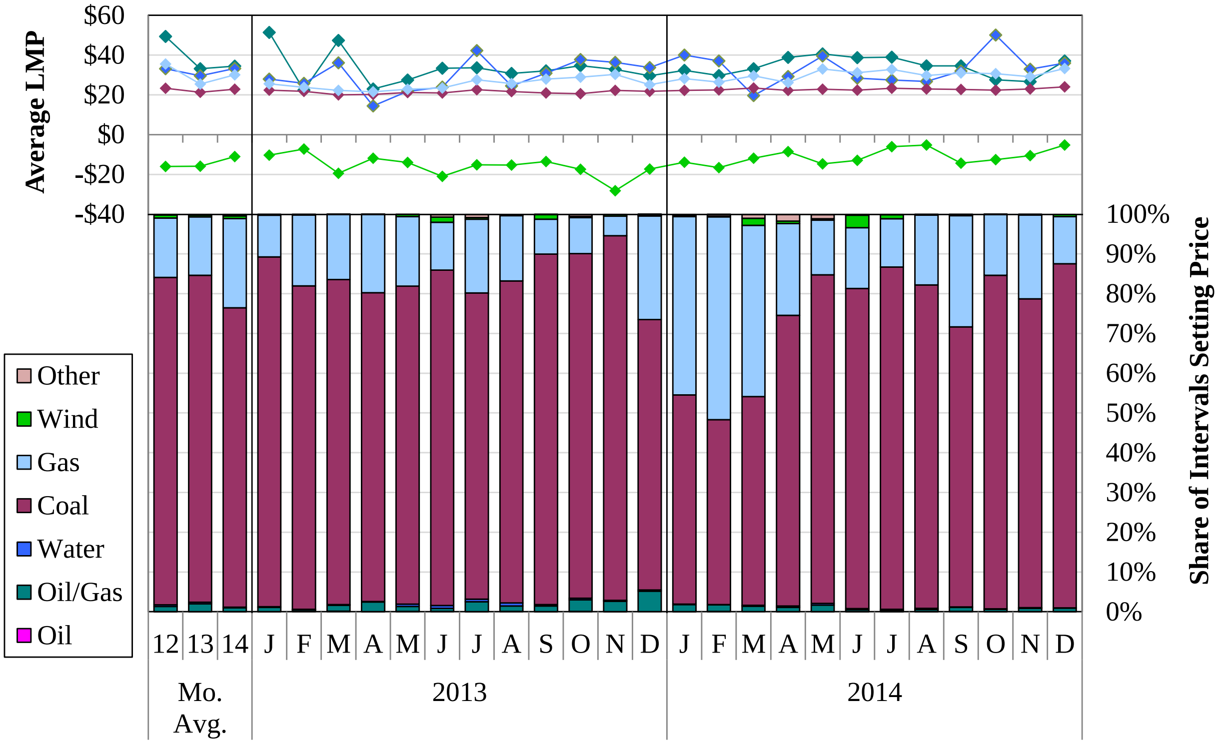


Table A1: Capacity, Energy Output and Price-Setting by Fuel Type

Table A1 shows how these changes affected the share of energy produced by fuel-type as well as the generators that set the real-time energy prices in 2014.

Table A1: Capacity, Energy Output and Price-Setting by Fuel Type
2013–2014

	Installed Capacity (Summer)				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Nuclear	7,299	12,763	7%	9%	12%	16%	0%	0%	0%	0%
Coal	61,234	66,658	57%	46%	71%	58%	82%	75%	90%	90%
Natural Gas	32,415	55,852	30%	39%	8%	17%	17%	23%	30%	84%
Oil	2,391	3,125	2%	2%	0%	0%	0%	0%	2%	4%
Hydro	2,165	3,621	2%	3%	1%	1%	0%	0%	2%	2%
Wind	1,600	1,027	1%	1%	8%	6%	0%	1%	50%	48%
Other	610	564	1%	0%	0%	1%	0%	0%	2%	4%
Total	**107,714**	**143,610**								

The lowest-cost resources (coal and nuclear) produced most of the energy. Natural gas-fired units produced 17 percent of MISO's energy. This was more the double the share produced in 2013, but remains lower than the share of capacity that is gas-fired. The energy share was limited by the sharp rise in natural gas prices from $3.85 per MMBtu in 2013 to $5.53 per MMBtu in 2014.

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 2014 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 2012, 2013, and 2014 adjusted to the membership that existed in all three years, so changes in load due to other factors (e.g., weather and economic activity) are revealed. The inset table indicates the number and percentage of hours when load exceeded 65, 70, 75 and 80 GW of load for the membership-adjusted curves. The figure shows the actual and predicated peak load. The "Predicted Peak (50/50)" is the predicted peak load where MISO expected the load could be higher or lower than this level with equal probability. The "Predicted Peak (90/10)" is the predicted peak load where actual peak will be at or below this level with 90 percent probability (i.e., there is only a 10 percent probability of load peaking above this level).

Figure A6: Load Duration Curves
2012–2014

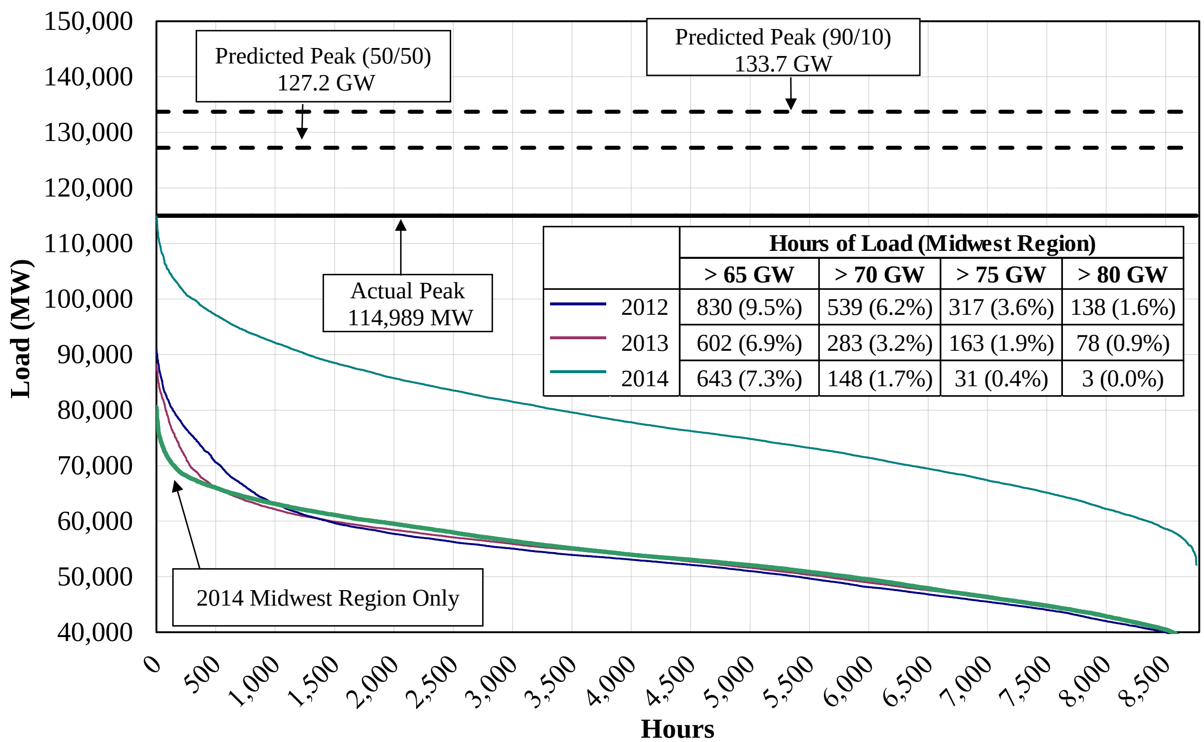
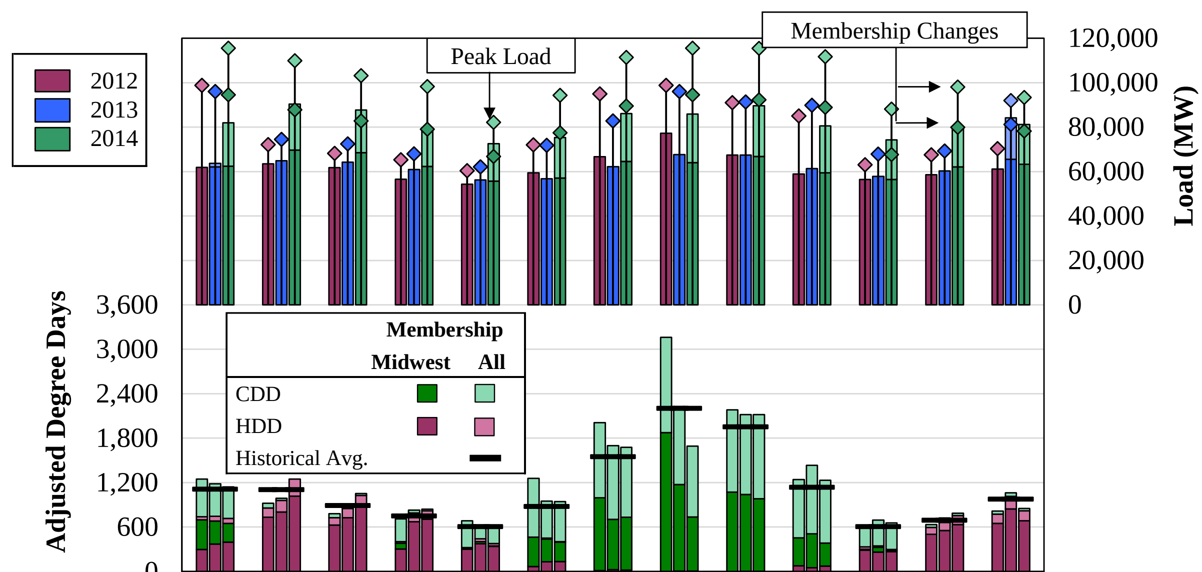


Figure A7: Heating and Cooling Degree-Days

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. We separately indicate changes in peak and average load that are the result of changes in membership.[3] The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) averaged across four representative cities in the Midwest and two cities in MISO South.[4] The table at the bottom shows the year-over-year changes in average load and degree-days.

Figure A7: Heating and Cooling Degree-Days
2012–2014



% Chg 13-14	Avg.	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	1%	8%	7%	2%	-1%	1%	4%	-5%	-1%	-3%	-2%	3%	-4%
Degree Days	-5%	27%	20%	5%	-14%	-10%	4%	-37%	-6%	-24%	-13%	15%	-19%

3 For comparability, we remove FirstEnergy from the load in this figure.

4 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.

D. Evaluation of Polar Vortex

Although MISO is summer-peaking, its most demanding period in 2014 occurred in winter. From early January until mid-March, sustained cold temperatures that caused sharp increases in electricity demand and natural gas prices throughout the Eastern Interconnect. High offer prices caused by extreme gas prices and supply reductions due to gas curtailments caused energy prices to rise sharply. Since the high gas prices were mostly confined to the Midwest region, MISO experienced record levels of congestion driven by large fuel cost differences between the Midwest and South regions. These conditions also resulted in record levels of uplift payments.

The next four charts more closely review market conditions during the first quarter.

Figure A8: Daily Natural Gas Prices

The top panel in Figure A8 shows daily natural gas prices at four locations in the MISO footprint in January and February. We separately show the intraday price at Chicago City Gate, a representative price for many participants. This range is typically small but can be large on “critical” days. The bottom panel shows day-ahead and incremental congestion (visible when real-time congestion value exceeds day-ahead congestion costs) for four constraints between the Midwest and South region.

Figure A8: Daily Natural Gas Prices
January – February, 2014

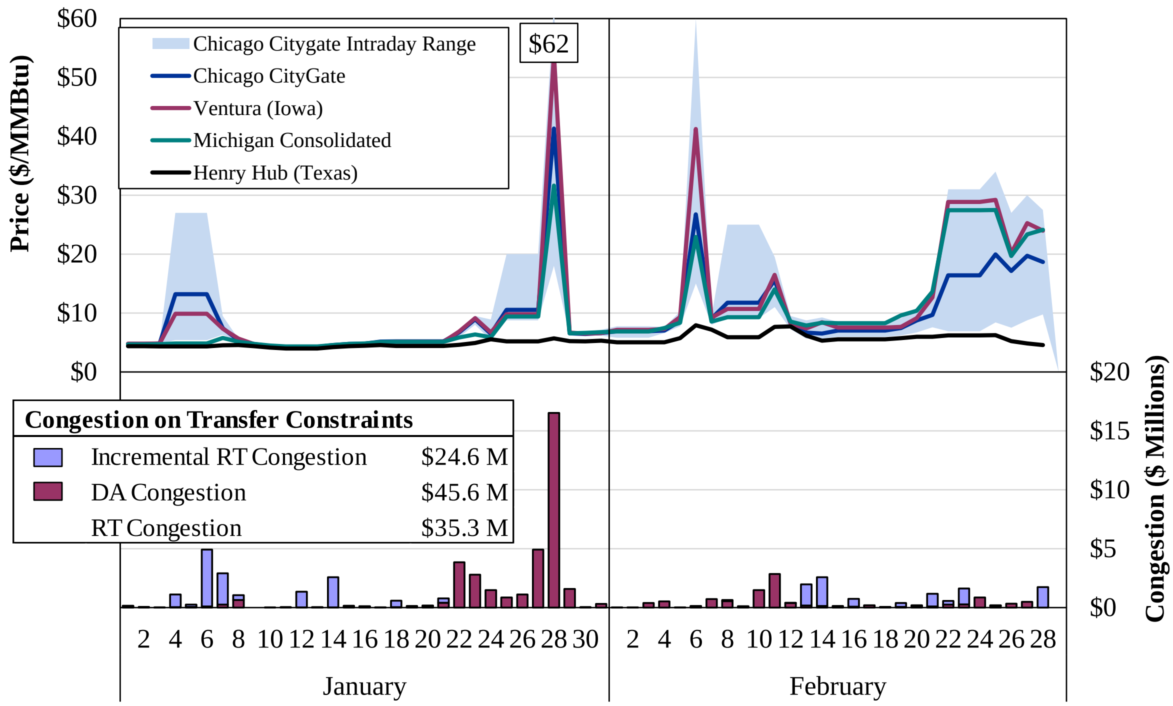


Figure A9: Day-Ahead Prices, January 28, 2014

Figure A9 shows, in the top panel, day-ahead prices at four representative hubs in MISO (two each in the Midwest and South regions) on January 28, when natural gas prices were highest and day-ahead congestion was most significant. Price differences among hubs are primarily due to congestion on the system. The bottom panel shows day-ahead scheduled load as well as actual load. Over-scheduling of load in the day-ahead can depress real-time prices, while under-scheduling can require MISO to make substantial (and expensive) real-time commitments.

Figure A9: Day-Ahead Prices, January 28, 2014

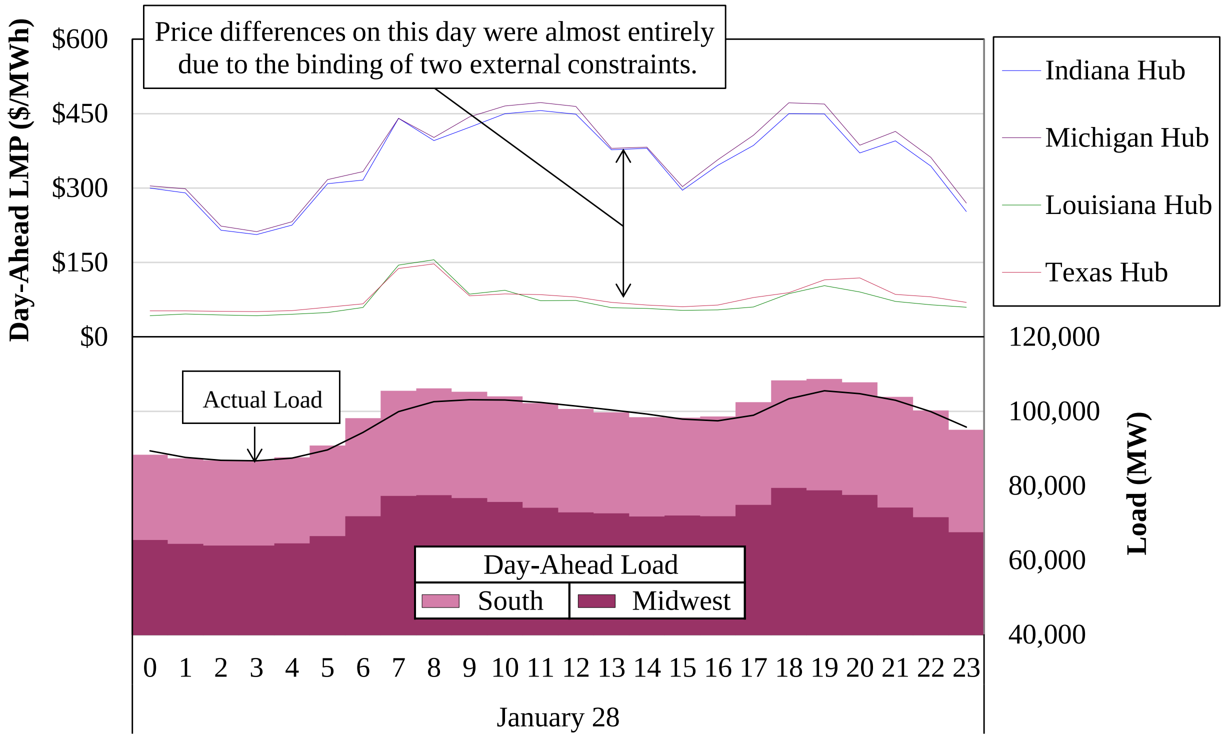


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Figure A10: Contributing Factors to Real-Time Prices

In the next chart, we show the cumulative impact of primary real-time supply and demand factors that affected the net capacity balance on the morning of January 7. These factors are: (1) net imports from PJM; (2) net imports from all other areas; (3) load, including any operator offset; (4) wind output; (5) capacity scheduled day-ahead that failed to show up in real-time ("no-shows"); (6) significant generator outages; (7) other rampable capacity[5]; and (8) MISO unit commitments. We separately identify energy sales to PJM and others that were approved due to emergency conditions in these areas.

In this figure, factors that contribute to higher prices are shown as positive values (reductions in supply or increases in demand), while factors that reduce prices are shown as negative values.

5 "Other Rampable Capacity" is additional capacity dispatchable within five minutes that is made available on online units as they ramp up.

The net capacity change is shown by the red markers. All values are measured against their respective level at the start of the period shown.

Figure A10: Contributing Factors to Real-Time Prices
January 7, 06:00–11:00

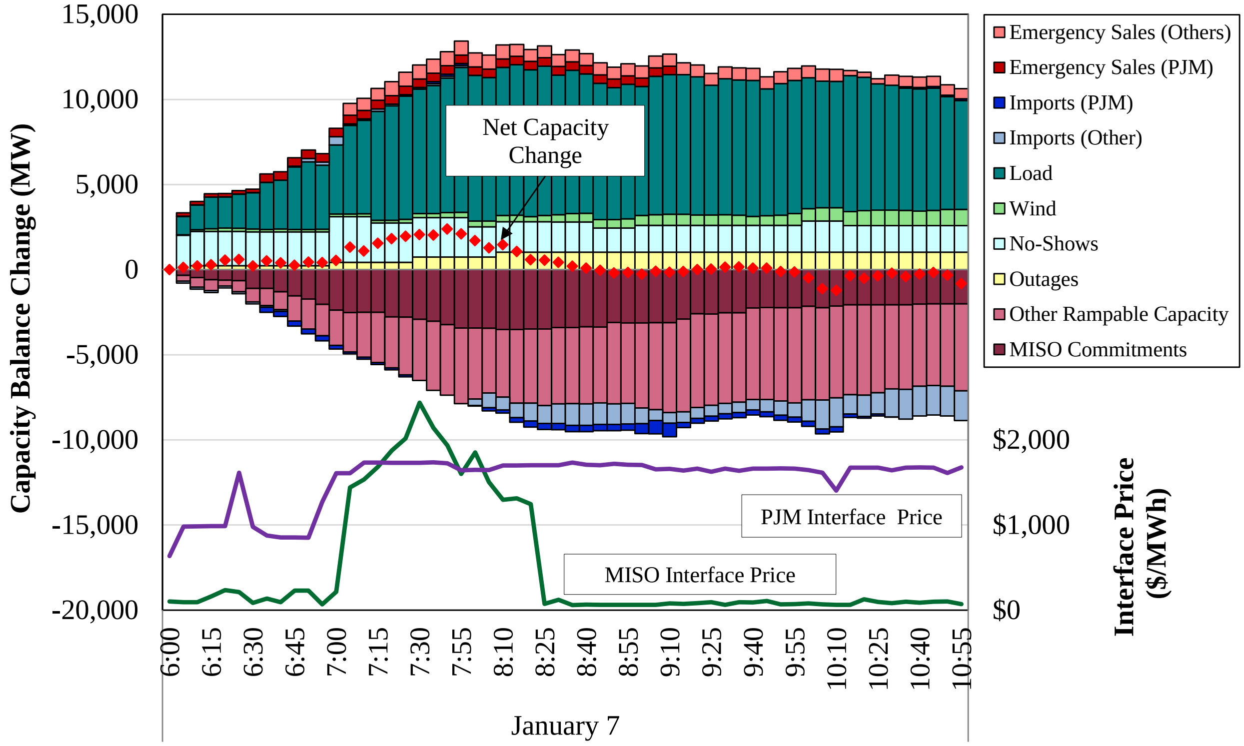


Figure A11 and Figure A12: Daily Price Convergence

The next two figures show daily price convergence for January and February. Each figure shows, in the bars, the day-ahead premium at the two hubs closest to the ORCA interface between the Midwest and South regions (Arkansas and Indiana). The diamonds show the premium at two hubs further away (Michigan and Louisiana). Hence, differences in convergence between the two stacked bars on a particular day is generally due to inter-regional transfer constraints such as ORCA, whereas differences between a bar and a diamond is due to local congestion.

Figure A11: Daily Price Convergence
January 2014

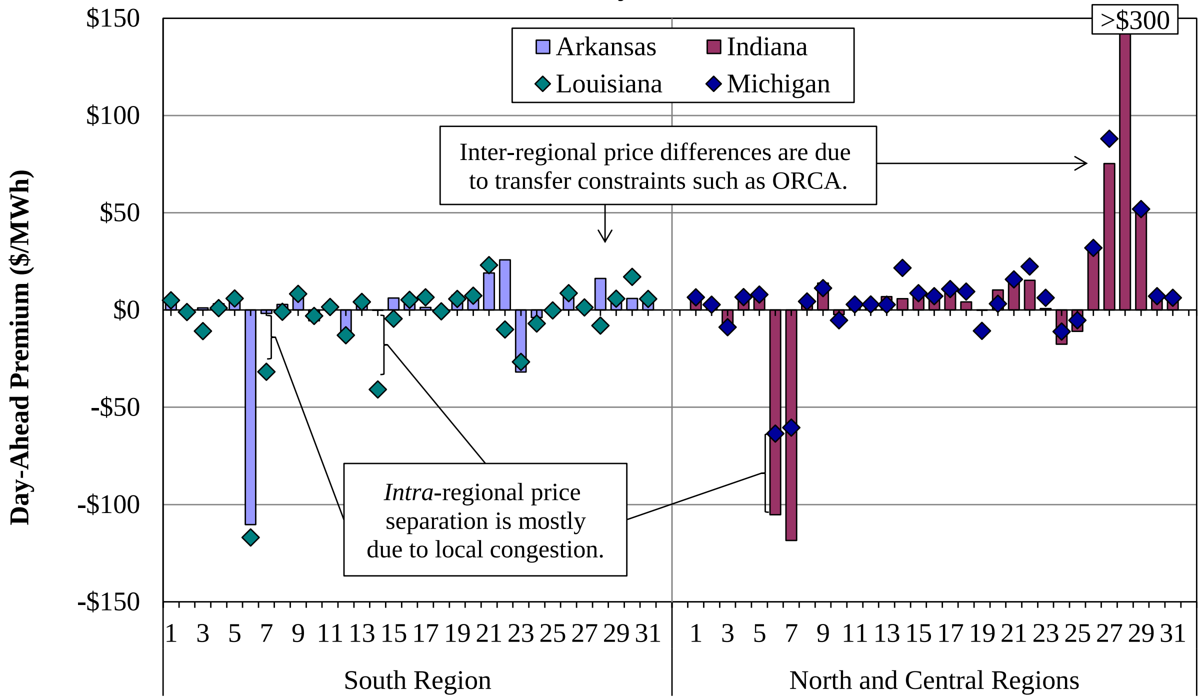
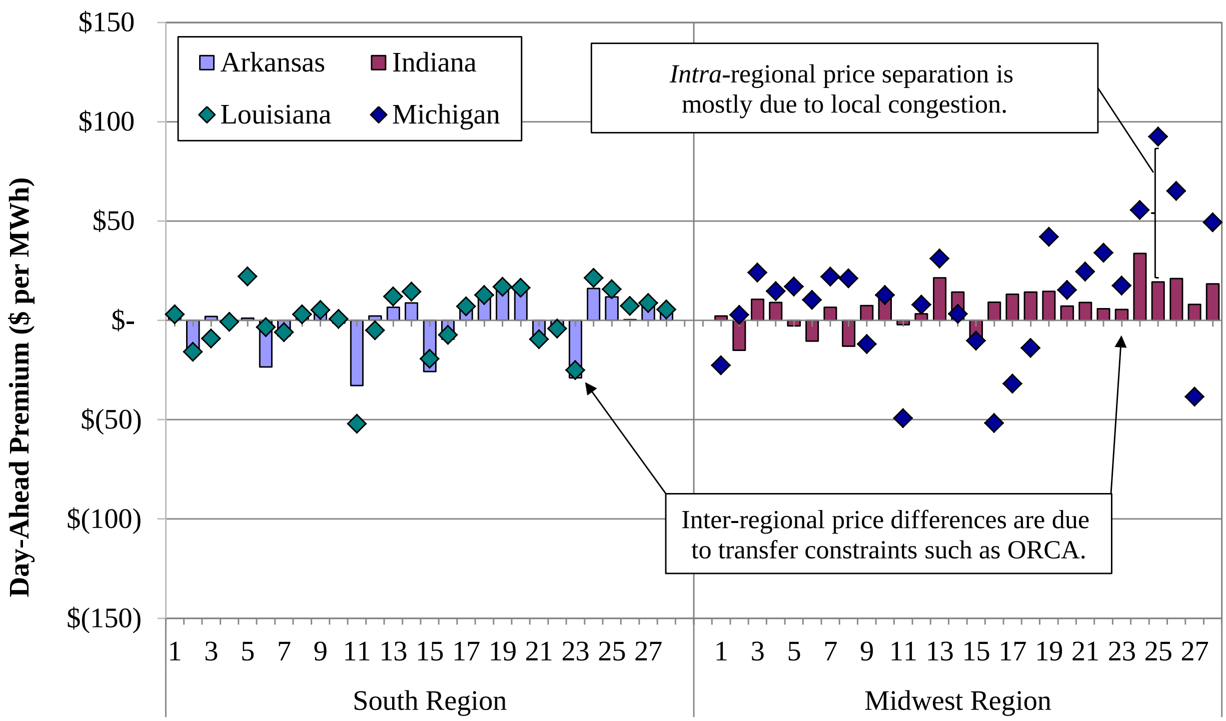


Figure A12: Daily Price Convergence
February 2014



E. 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 unit with an assumed heat rate of 7,050 Btu per kWh and a natural gas CT unit with an assumed heat rate of 9,750 Btu per kWh.[6] We also incorporate standardized assumptions for calculating net revenue put forth by FERC. The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

Figure A13 and Figure A14: 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 or "annual net revenue" a new unit would need to earn in MISO wholesale markets to make the investment economic. The estimated costs of new entry for each type of unit are shown in the figure as horizontal black segments.

Combined-cycle generators run more frequently (and earn more energy rents) than simple-cycle combustion turbine generators because combined-cycle units have substantially lower production costs per MWh. Hence, the estimated energy net revenues for combined-cycle generators are substantially higher than they are for combustion turbines. Conversely, capacity and ancillary services revenues typically account for a comparatively large share of a combustion turbine's net revenues. Capacity requirements and import and export limits enforced in the PRA vary by zone, so capacity revenues vary depending on the clearing price in each zone. The net revenues that we estimated would be earned by these two types of resources in different MISO regions are shown as stacked bars in the figure. The drop lines show the number of hours the resources were estimated to operate during the year.

6 These assumptions are used in the 2014 EIA Annual Energy Outlook.

Figure A13: Net Revenue and Operating Hours
Midwest Region, 2012–2014

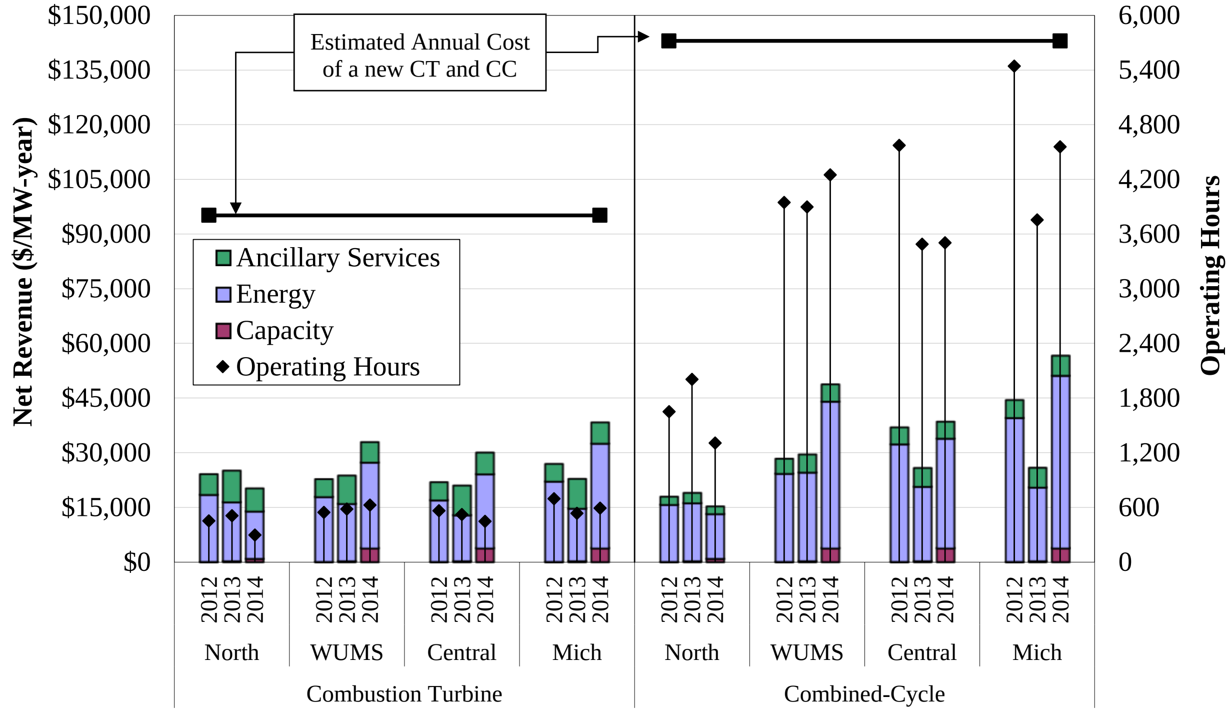
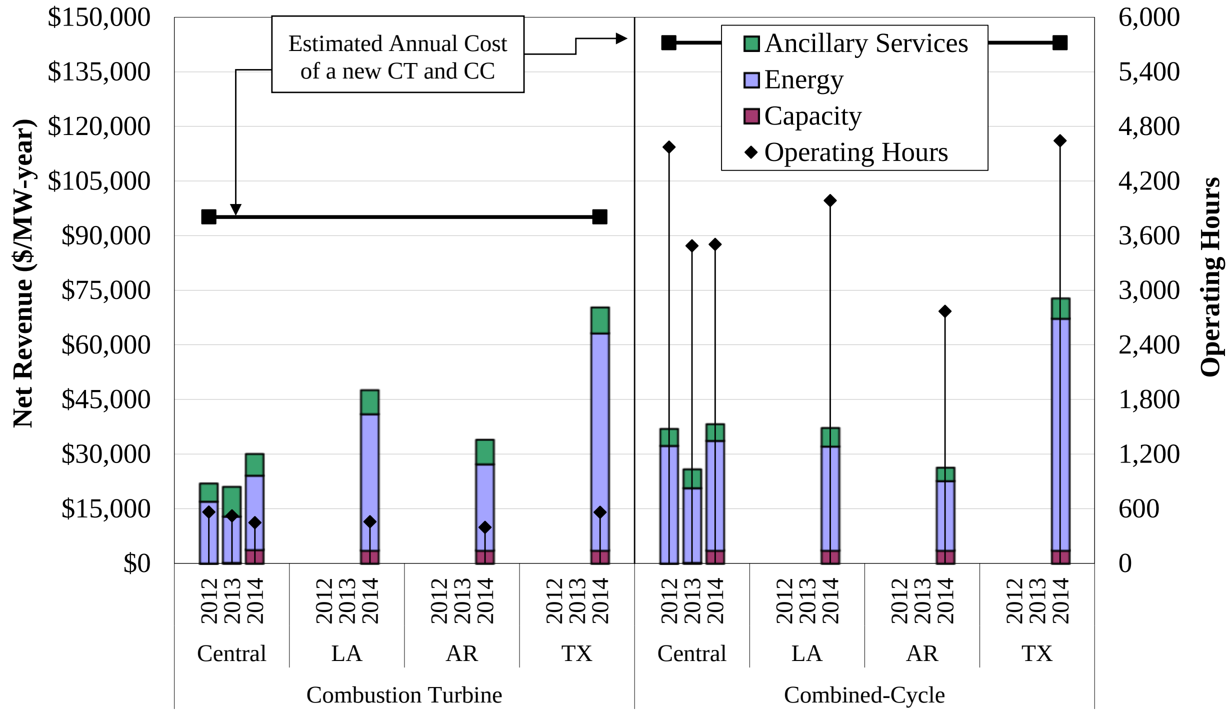


Figure A14: Net Revenue and Operating Hours
South Region, 2012–2014



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.

The integration of the MISO's South Region in late December 2013 added 44.1 GW of generation capacity, ten new transmission-owning companies, six local balancing authorities, and 33 new market participants from Mississippi, Louisiana, Arkansas, Texas, and Missouri, including the Entergy Operating Companies. In 2014 there were 126 market participants that either owned generation resources (totaling 177 GW of nameplate capacity) or served load in the MISO market.[7] This group includes 50 large investor-owned utilities, 25 municipal and cooperative utilities, and 22 independent power producers.

MISO also serves as the reliability coordinator for Manitoba Hydro, which provide an additional 11.5 GW of capacity. As a coordinating member, it does not submit physical bids or offers into MISO's markets, but they may schedule energy into or out of the market.[8] 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.)

7 As of March 2015, MISO membership totals 172 entities when including power marketers. There are an additional 41 non-members when including state regulatory authorities and other stakeholder groups. In all there are 421 separate Certified Market Participants.

8 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 A15: Distribution of Generating Capacity by Coordination Region

Figure A15 shows the summer 2015 distribution of existing generating resources by Local Resource Zone. The left panel shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the annual peak load in each zone. The right panel displays the change in the UCAP values from last summer. 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 nearly 8 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 A15: Distribution of Generating Capacity
By Fuel Type, Summer 2015

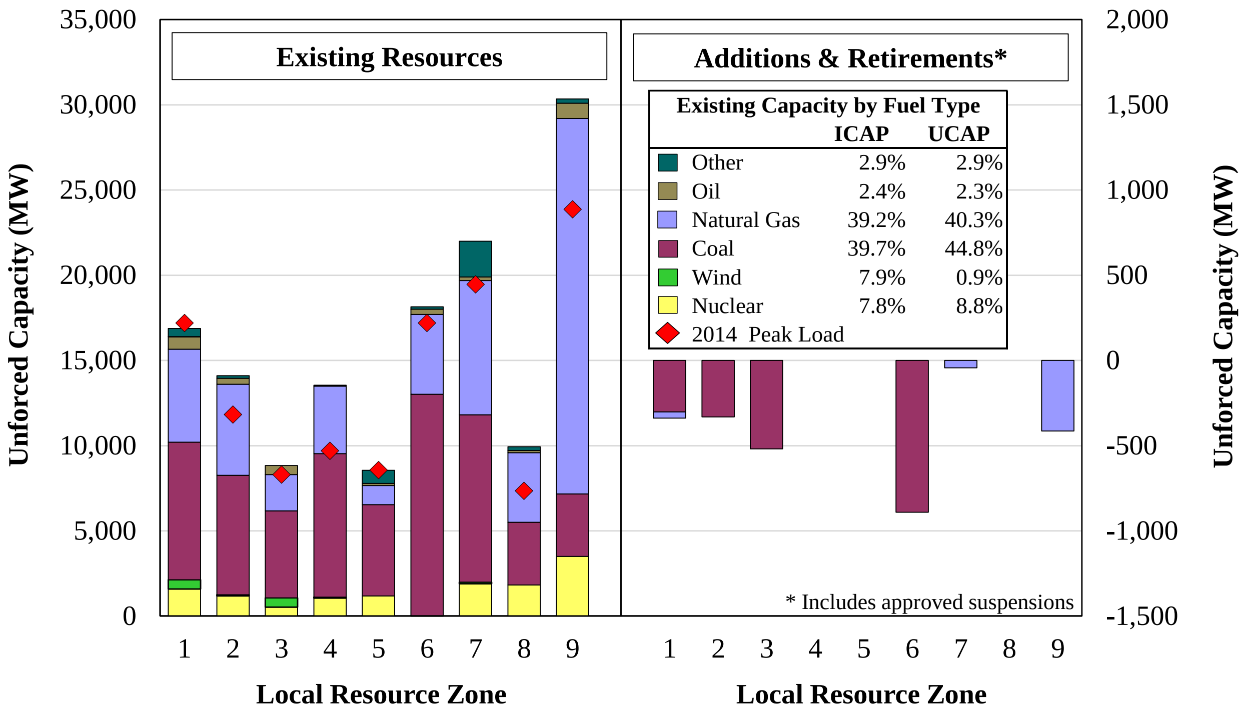


Figure A16: Availability of Capacity during Monthly Peak Load Hour

Figure A16 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.

The height of the bars is equal to total generating capacity. It reflects additions and retirements of generators, as well as market participant entry and exit. 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 A16: Availability of Capacity During Peak Load Hour
2014

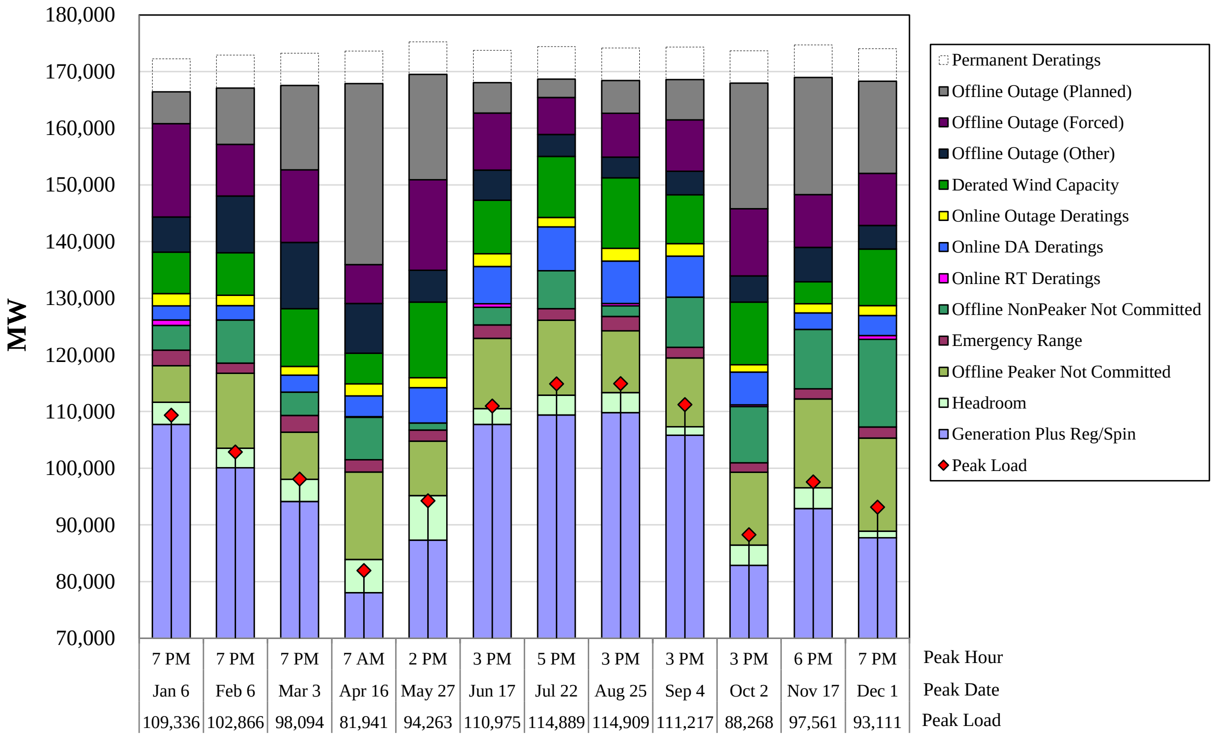


Figure A17: Capacity Unavailable During Peak Load Hours

Figure A17 is very similar to Figure A16 except that it shows only the offline or otherwise unavailable capacity during the peak hour of each month. Maintenance planning should maximize resource availability in summer peak periods when the demands of the system (and prices) are highest. As a consequence of greater resource utilization and environmental restrictions, non-outage deratings are expected to be greatest during these periods.

The figure also 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.

Figure A17: Capacity Unavailable During Peak Load Hours
2014

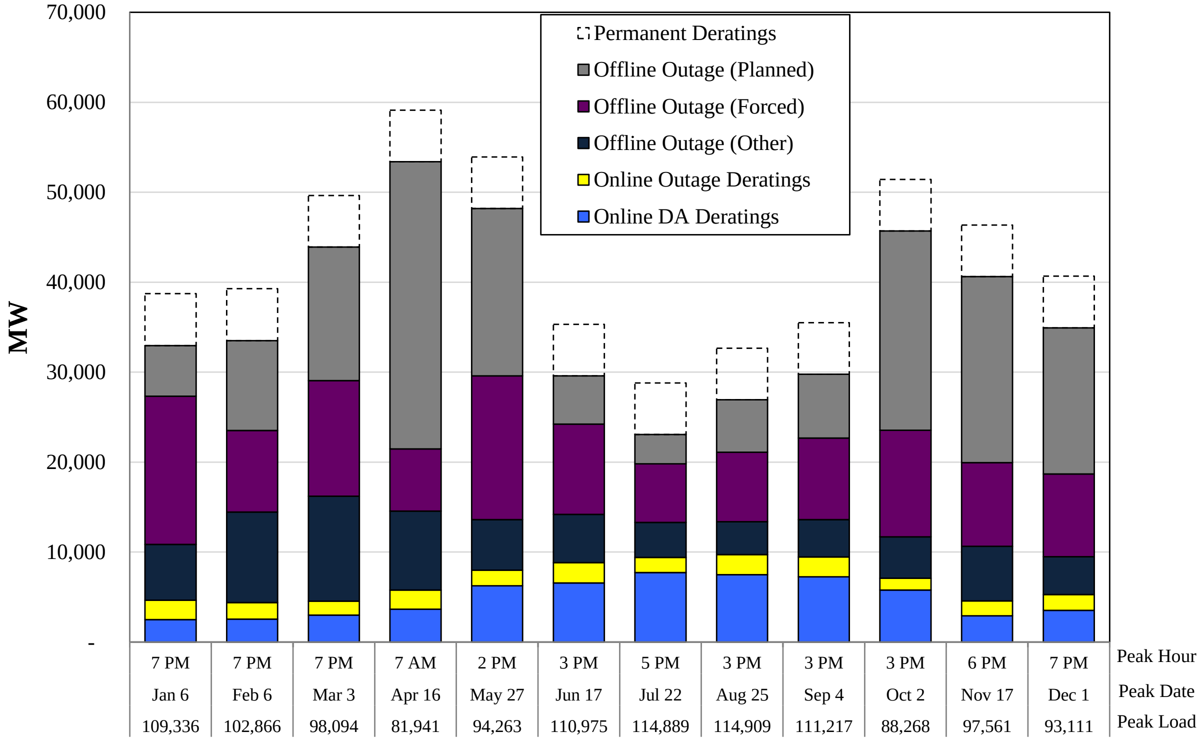
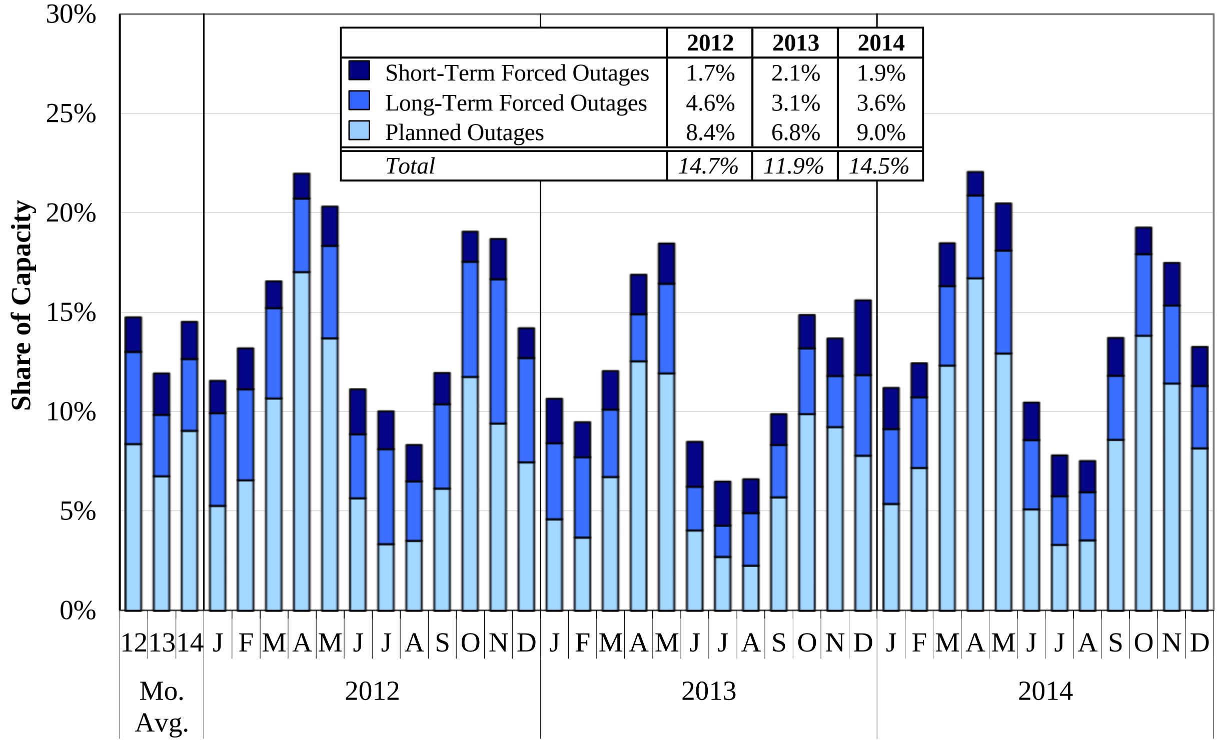


Figure A18: Generator Outage Rates

Figure A18 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 A18: Generator Outage Rates
2012–2014



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 2014. We estimate planning reserve margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. In its 2015 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. Because we use the same capacity data, our results are consistent with the MISO Summer Assessment, although we evaluate some scenarios with different assumptions.

The planning reserve margin quantity is the sum of all quantities of capacity, including demand response and 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;[9] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of

9 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).

wind generation and imports; and (e) full response from DR resources (behind the meter generation, interruptible load, and direct controllable load management). These assumptions tend to cause the reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions.

Table A2: Capacity, Load, and Reserve Margins
Summer 2015

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	**Realistic DR**	**Full DR**	**Realistic DR**
Load				
Base case	127,319	127,319	127,319	127,319
High Load Increase	-	-	6,280	6,280
Total Load (MW)	127,319	127,319	133,599	133,599
Generation				
Internal Generation	143,696	143,696	143,696	143,696
BTM Generation	4,413	4,413	4,413	4,413
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(3,834)	(3,834)	(3,834)	(3,834)
Total Generation (MW)	144,276	144,276	139,376	139,376
Imports and Demand Response				
Demand Response	5,938	4,750	5,938	4,750
Net Firm Imports	56	56	56	56
Margin (MW)	22,951	21,763	11,771	10,583
Margin (%)	**18.0%**	**17.1%**	**9.2%**	**8.3%**

Notes:
* Based on the available capacity on the three hottest days of 2012 and on August 1, 2006. Available capacity can vary substantially based on ambient air and water temperatures, and other factors.
** The MISO Base Case Reserve Margin assumes that 3,834 MW of capacity in MISO South cannot be accessed due to the 1000 MW Transfer Limit, which reduces the overall MISO Capacity Margin.

Our three IMM scenarios in the table account for two major differences between MISO and the IMM's planning reserve margins. The first difference, shown in IMM scenarios 1 and 3, assumes an 80 percent response rate from DR. A strong response rate is expected because the Tariff has penalty provisions in place 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 is far less responsive and flexible than typical generation resources, and there is a lack of historical response data during emergency conditions. DR can require up to 12 hours of advanced notice to respond. Additionally, most DR is not under the direct control of MISO.

The second difference is that MISO's margin does not fully account for generator derates under peak conditions with higher temperatures than normal. The simulation that MISO performs uses an annual EFORd and monthly net dependable capacities, which doesn't fully capture the negative correlation between loads and power plant capability in response to temperature exceeding monthly norms. Power plants are frequently cooled by river water, and experience efficiency losses 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. The estimated impact of this is shown in IMM scenarios 2 and 3.

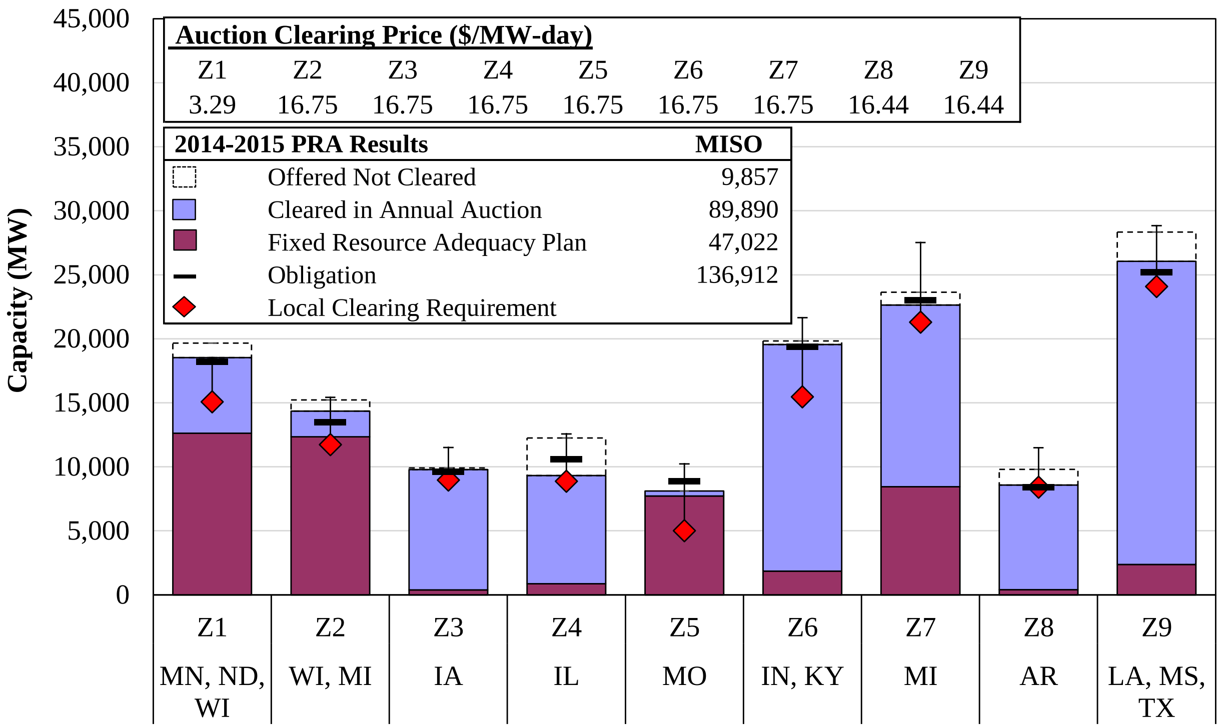
C. Capacity Market Results

In June 2009, MISO began operating a monthly voluntary capacity auction 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 A19: Planning Resource Auction Results

Figure A19 shows the zonal results of the 2014–2015 Annual PRA, held in spring 2014 and covering June 2014 to May 2015.

Figure A19: Planning Resource Auction
2014–2015



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, which is the minimum amount that must be sourced within a zone, is indicated by the red diamond.

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.

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. 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.[10] A supplier's offer represents the lowest price it would be willing to accept to sell capacity. This is determined by two factors: (1) whether there are 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).

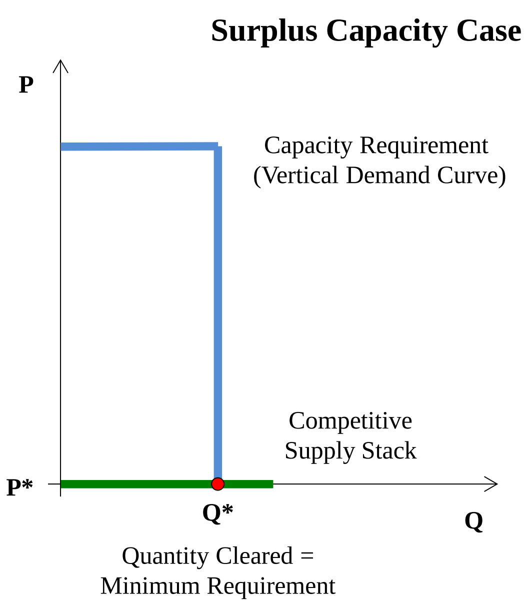
10 This ignores potential opportunity costs of exporting capacity to a neighboring market.

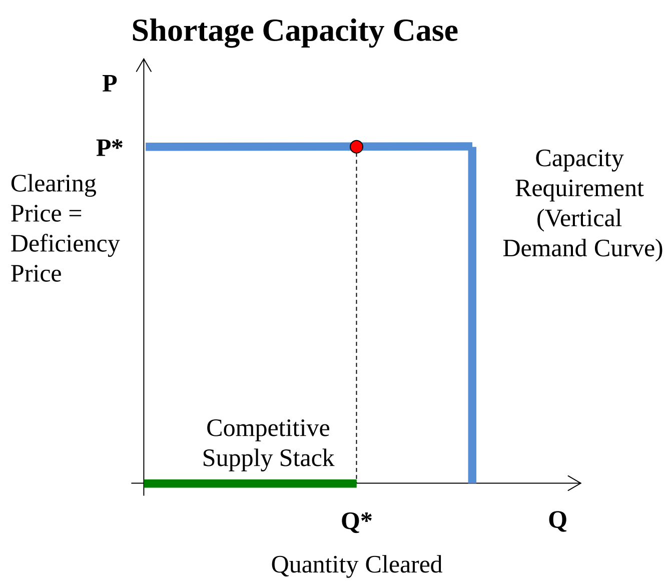
For most resources, the net revenues available from RTOs' energy and ancillary services markets are sufficient to keep a resource in operation. Hence, no additional revenue is needed from the capacity market (which would cause the supplier to submit a non-zero capacity offer). With regard to the first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

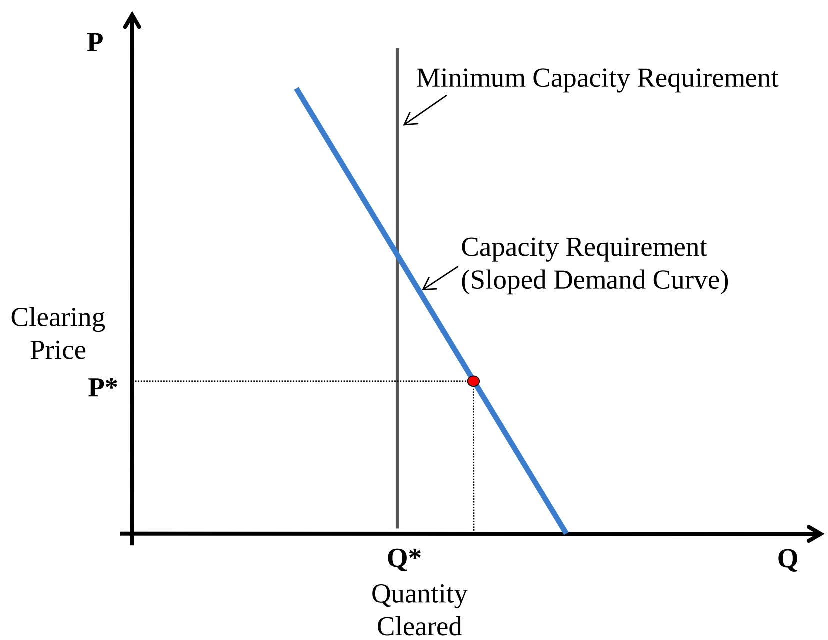
Second, since prices produced by such a construct do not accurately reflect the true marginal value of capacity, the market will not provide efficient long-term economic signals to govern investment and retirement decisions.

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 when local capacity zones are introduced, like in the reformed RAC, 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 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:

1.) 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.

2.) 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 are surplus levels between 1 and 4 percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.

3.) A smaller share of the total costs are 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 LSE's 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).

IV. Day-Ahead Market Performance

In the day-ahead market, participants make financially-binding forward purchases and sales of electric energy for delivery in real time. Day-ahead transactions allow participants to procure energy for their own demand, thereby managing risk by hedging the participant's exposure to real-time price variability, or for arbitraging price differences between the day-ahead and real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing energy in the day-ahead market.

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 most of the power procured through MISO's markets is financially settled based on day-ahead market results. 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 A20 and Figure A21: Day-Ahead Energy Prices and Load

Figure A20 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).

Figure A20: Day-Ahead Hub Prices and Load
Peak Hours, 2013–2014

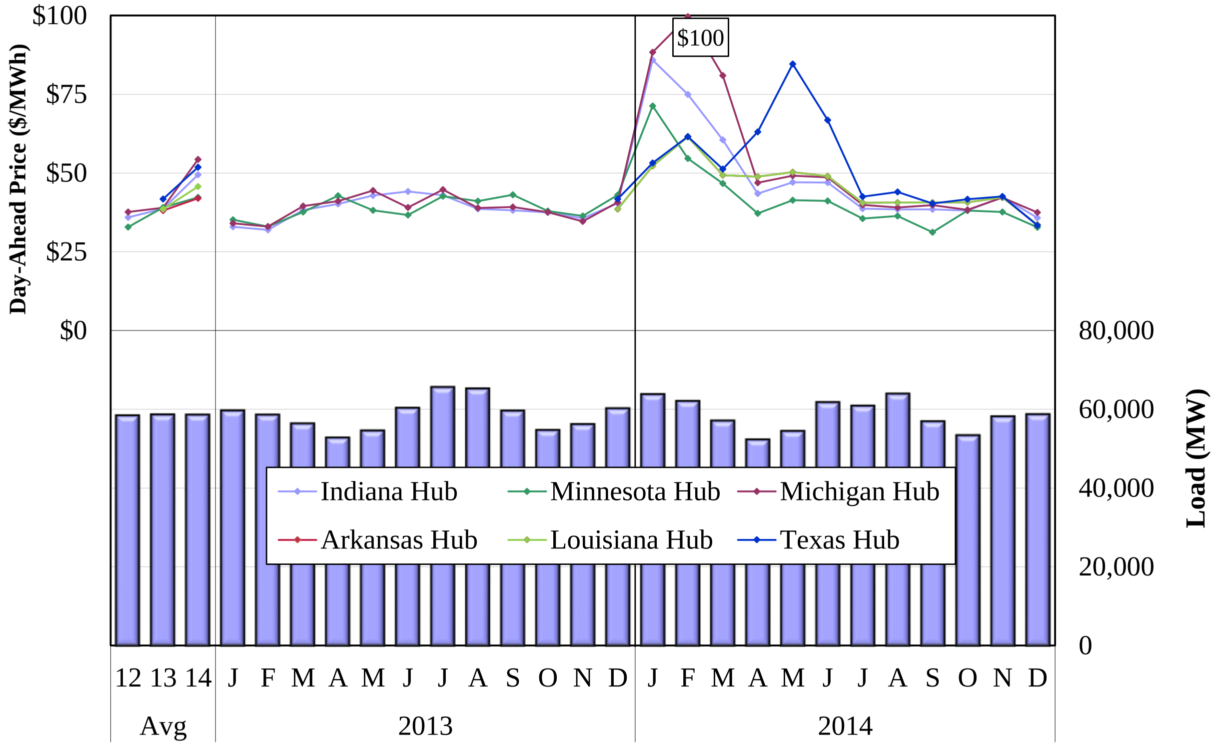
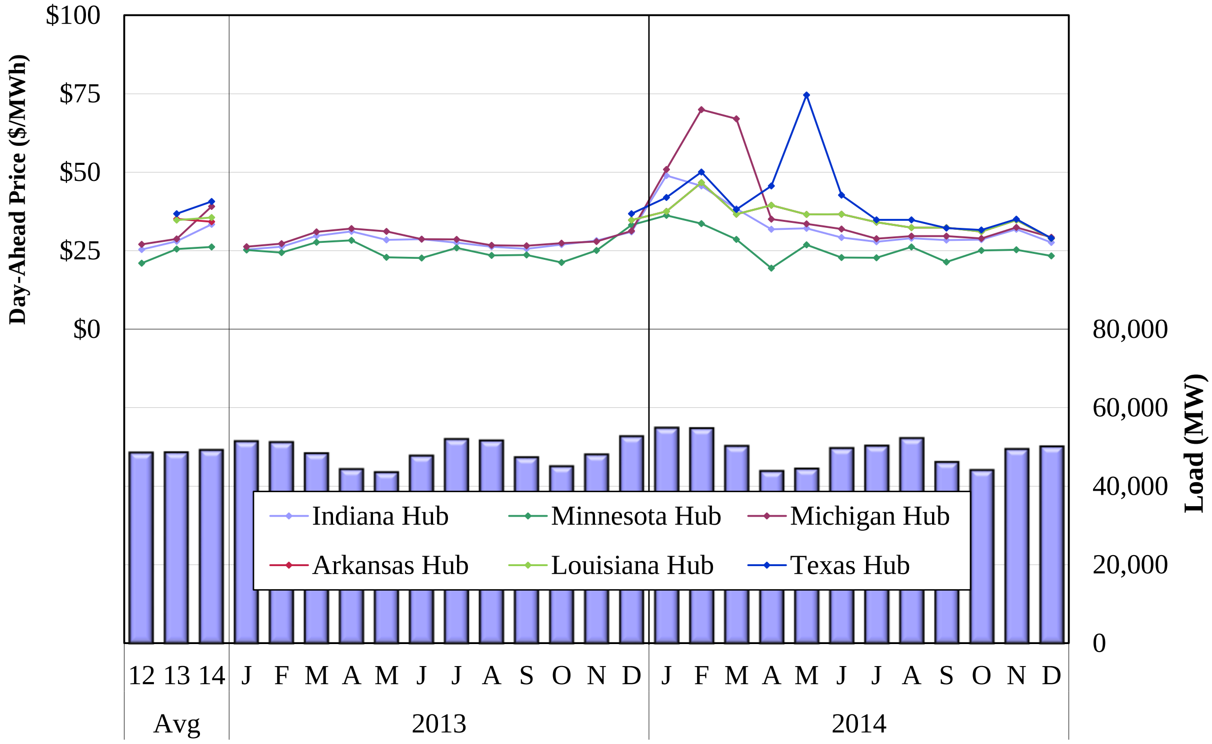


Figure A21 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Differences in prices among the hubs show the prevailing congestion and loss patterns. High prices in one location relative to another location indicate congestion and loss factor differences from a low-priced area to a high-priced area.

Figure A21: Day-Ahead Hub Prices and Load
Off-peak Hours, 2013–2014



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.

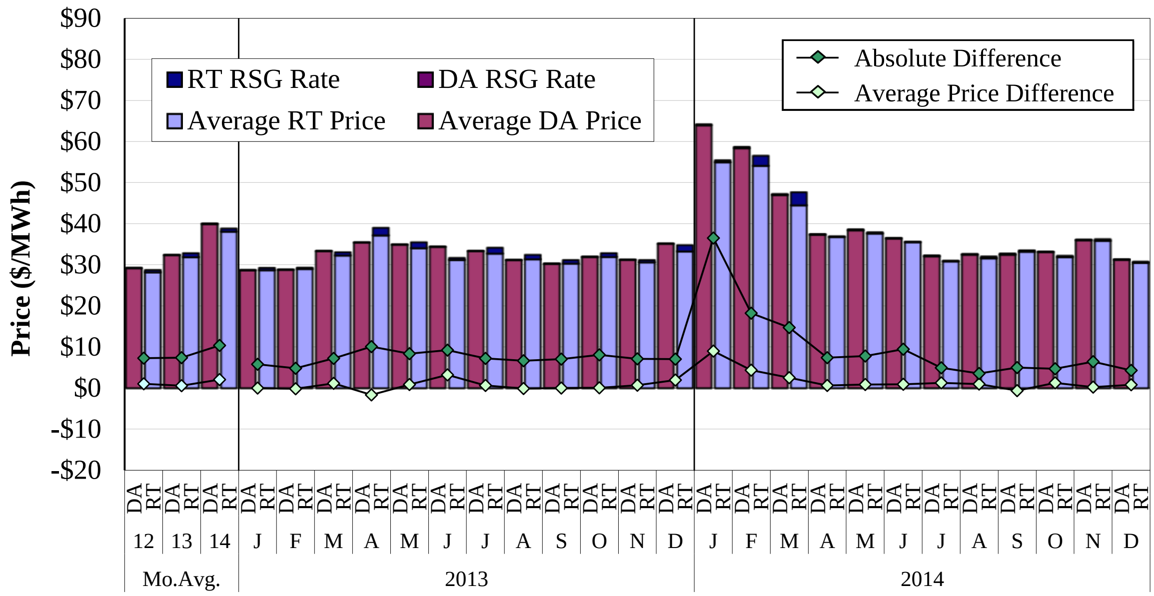
Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day. However, a variety of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While a well-performing market may not result in prices converging on an hourly basis, it should lead prices to converge well on a monthly or annual 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 (which have typically been much larger than day-ahead RSG costs). Although day-ahead RSG costs rose considerably in 2014, particularly in the South region, most of these costs are associated with local reliability requirements and were allocated locally. Hence, most day-ahead purchases can avoid the higher real-time RSG costs.

Figure A22 to Figure A28: 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 cost per MWh.[11] 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 real-time RSG charges (assessed to deviations net of day-ahead schedules, including net virtual supply), which are much higher than day-ahead charges and therefore should contribute to modest day-ahead premiums.

Figure A22: Day-Ahead and Real-Time Price
2013–2014: Indiana Hub

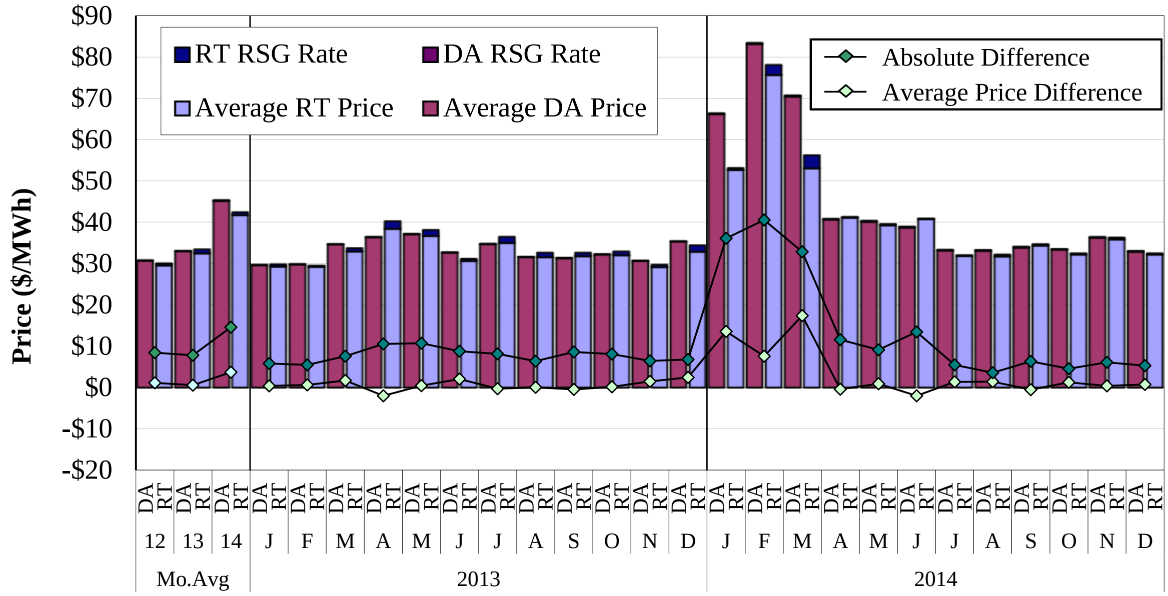


Average DA-RT Difference (% of Real-Time Price)

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

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

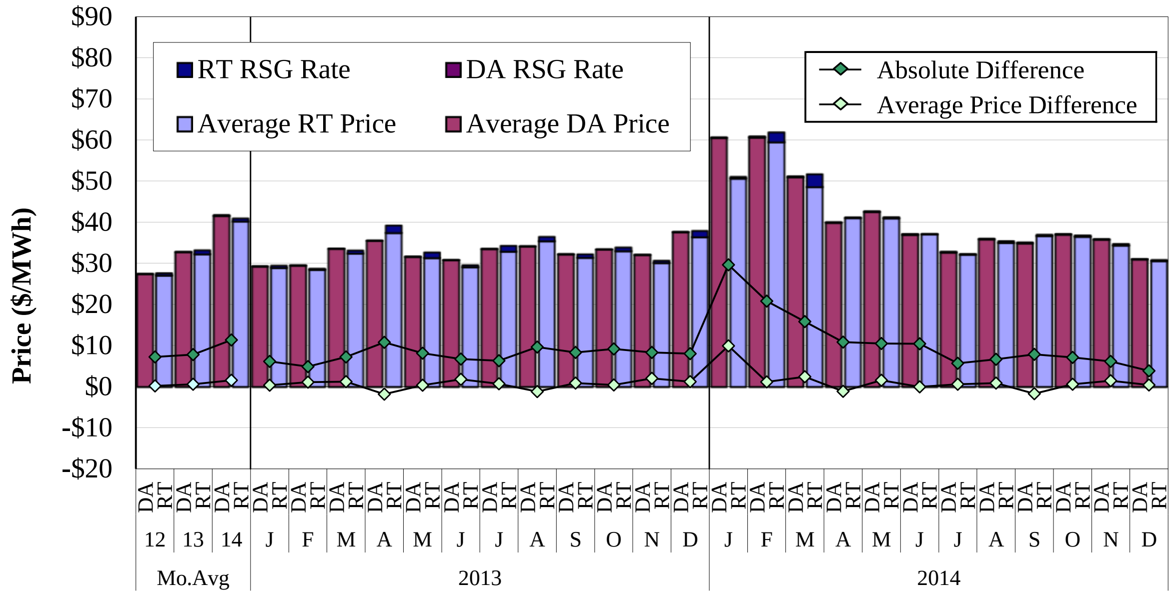
Figure A23: Day-Ahead and Real-Time Price
2013–2014: Michigan Hub



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

Excluding RSG	4	2	9	1	2	5	-5	1	7	-1	0	-2	0	5	7	26	10	33	-1	2	-5	4	4	-2	4	1	2
Including RSG	2	-1	7	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	7	26	-1	2	-5	4	3	-2	3	0	2

Figure A24: Day-Ahead and Real-Time Price
2013–2014: WUMS Area

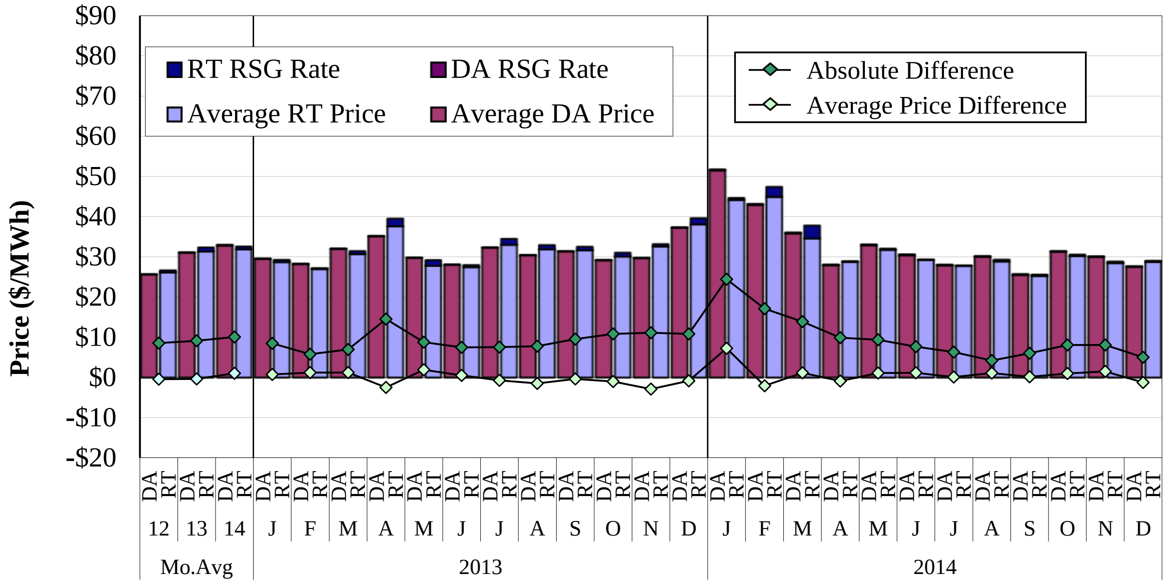


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	1	2	4	1	4	4	-5	1	6	2	-4	3	1	7	3	20	2	5	-3	4	0	2	2	-5	1	4	1
Including RSG	-2	-1	2	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	-2	-1	-3	3	0	2	2	-5	1	3	1

Figure A25: Day-Ahead and Real-Time Price

2013–2014: Minnesota Hub

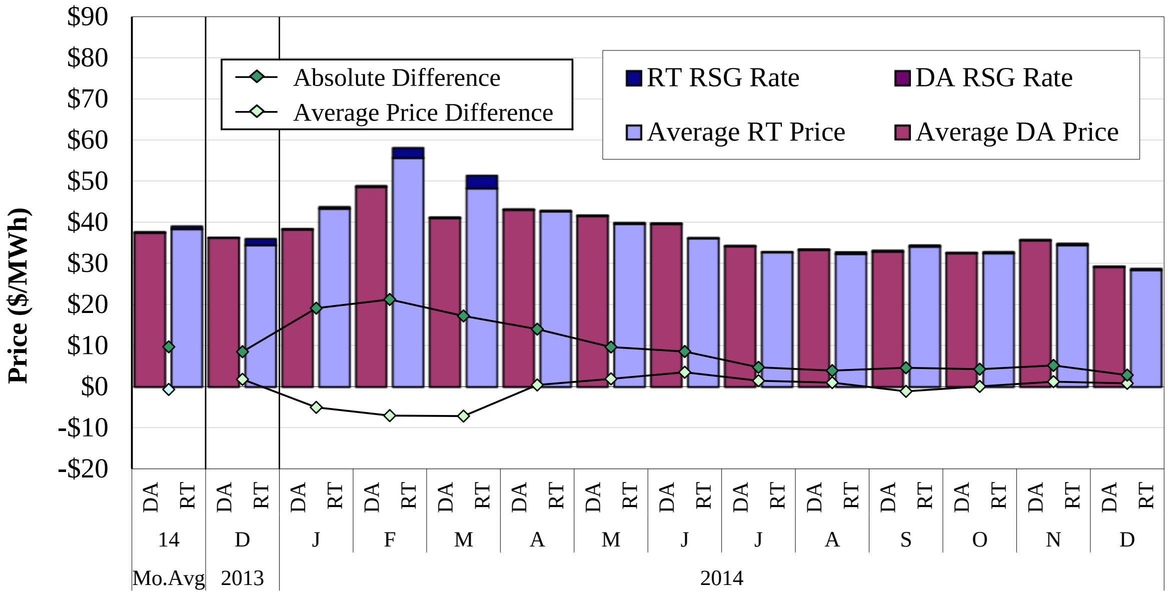


Average DA-RT Difference (% of Real-Time Price)

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

Figure A26: Day-Ahead and Real-Time Price

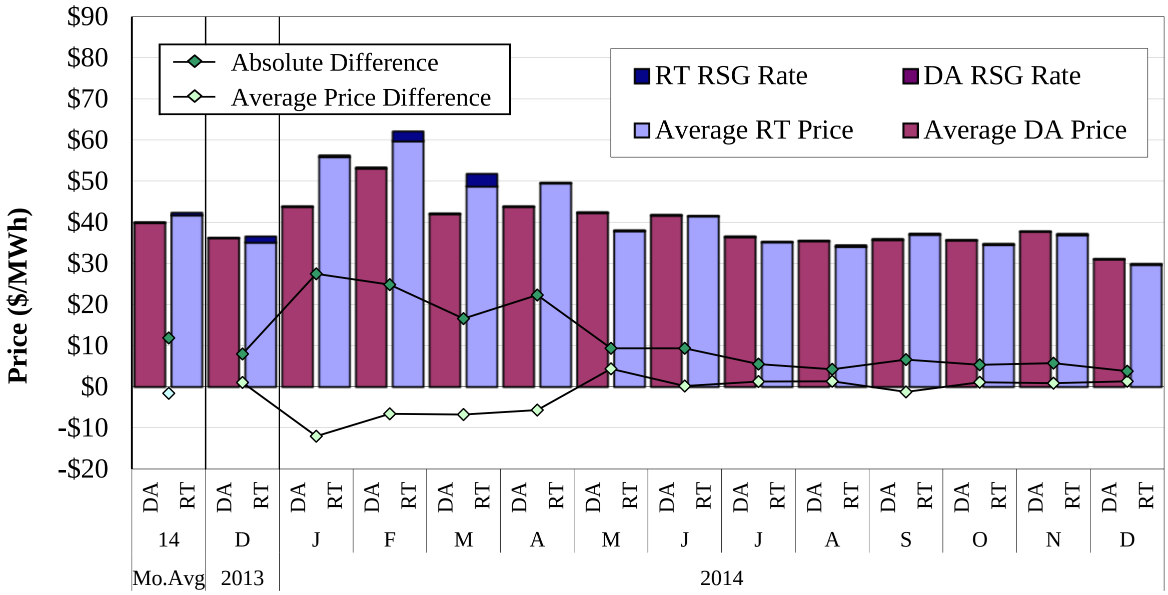
2013–2014: Arkansas Hub



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

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

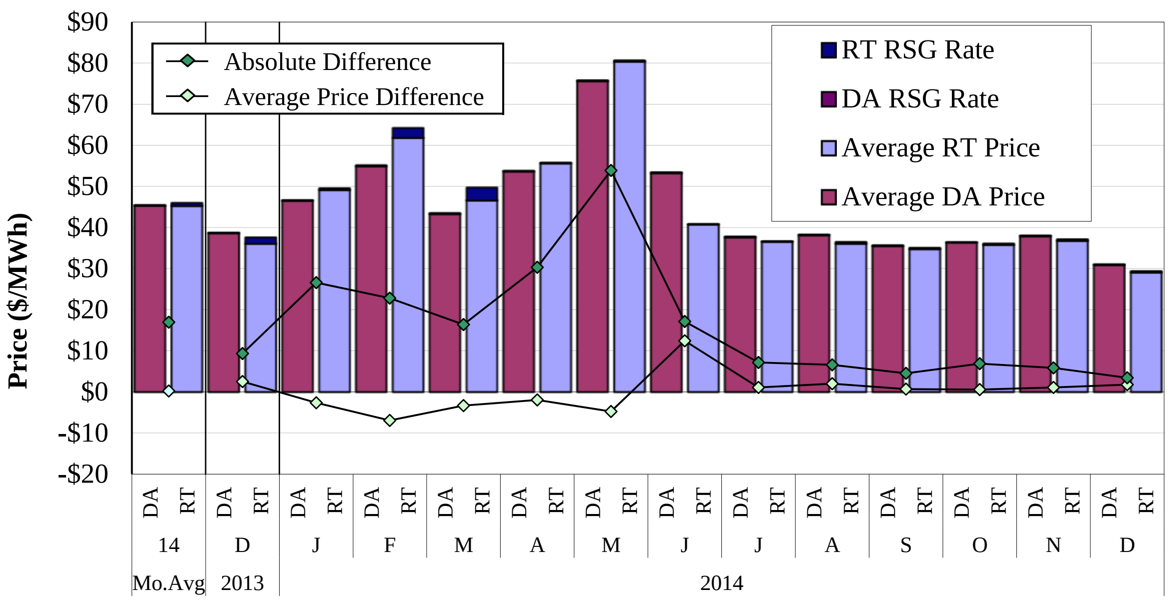
Figure A27: Day-Ahead and Real-Time Price
2013–2014: Louisiana Hub



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

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

Figure A28: Day-Ahead and Real-Time Price
2013–2014: Texas Hub



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

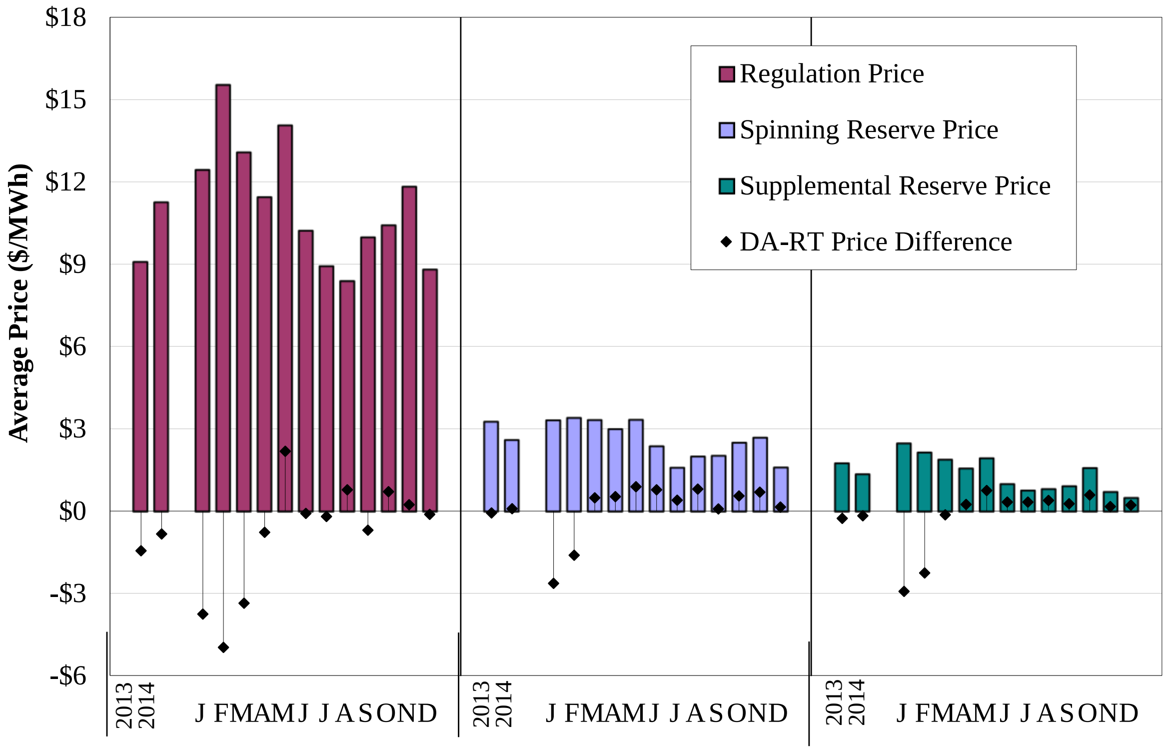
Excluding RSG	0	7	-5	-11	-7	-4	-6	31	3	5	2	1	3	6
Including RSG	-1	3	-6	-14	-13	-4	-6	31	3	5	2	1	2	5

MISO's ancillary service markets consist of day-ahead and real-time markets for regulating reserves, spinning reserves, and supplemental reserves that are jointly optimized with the energy markets. These markets have operated without significant issues since their introduction in January 2009. In mid-December 2012, MISO added regulation mileage compensation to its ancillary services markets in accordance with FERC Order 755.

Figure A29: Day-Ahead Ancillary Services Prices and Price Convergence

Figure A29 shows monthly average day-ahead clearing prices in 2014 for each ancillary services product, along with day-ahead to real-time price differences.

Figure A29: Day-Ahead Ancillary Services Prices and Price Convergence
2014



C. Day-Ahead Load Scheduling

Load scheduling 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. The relationship of net scheduled load to the real-time or actual load affects commitment patterns and RSG costs because units are committed and scheduled in the day-ahead only 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 difference. Peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section V.H). 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.

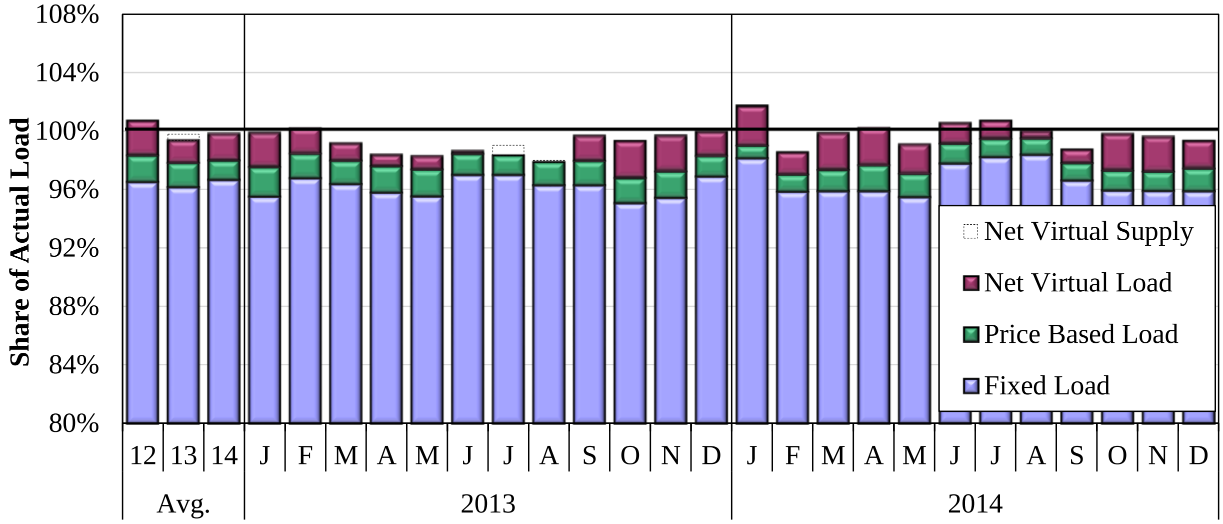
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

- 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 A30- Figure A32: Day-Ahead Scheduled Versus Actual Loads

To show net load-scheduling patterns in the day-ahead market, Figure A30 compares the monthly day-ahead scheduled load to actual load in real time. The figure shows only the daily peak hours, when under-scheduling is most likely to require MISO to commit additional generation. The table below the figure shows the average scheduling levels in all hours and for the peak hour. We show peak hour scheduling separately for the Midwest and South regions in Figure A31 and Figure A32.

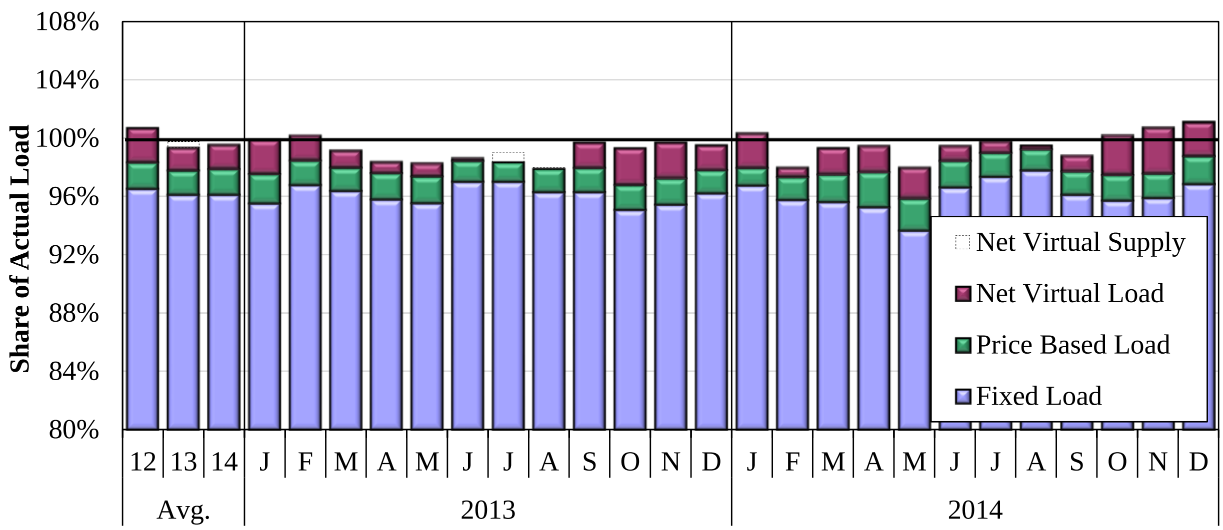
Figure A30: Day-Ahead Scheduled Versus Actual Loads
2013–2014, Daily Peak Hour



Share of Actual Load (%)

	Avg.			2013												2014											
	12	13	14	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.4	99.4	99.6	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.9	101.7	99.3	99.2	99.8	99.1	100.1	100.2	99.8	98.7	99.0	99.7	99.0
Peak Hours	100.4	99.3	99.8	99.9	100.2	99.2	98.4	98.3	98.6	98.3	97.9	99.7	99.3	99.7	100.0	101.7	98.5	99.9	100.2	99.1	100.5	100.7	100.0	98.7	99.8	99.6	99.3

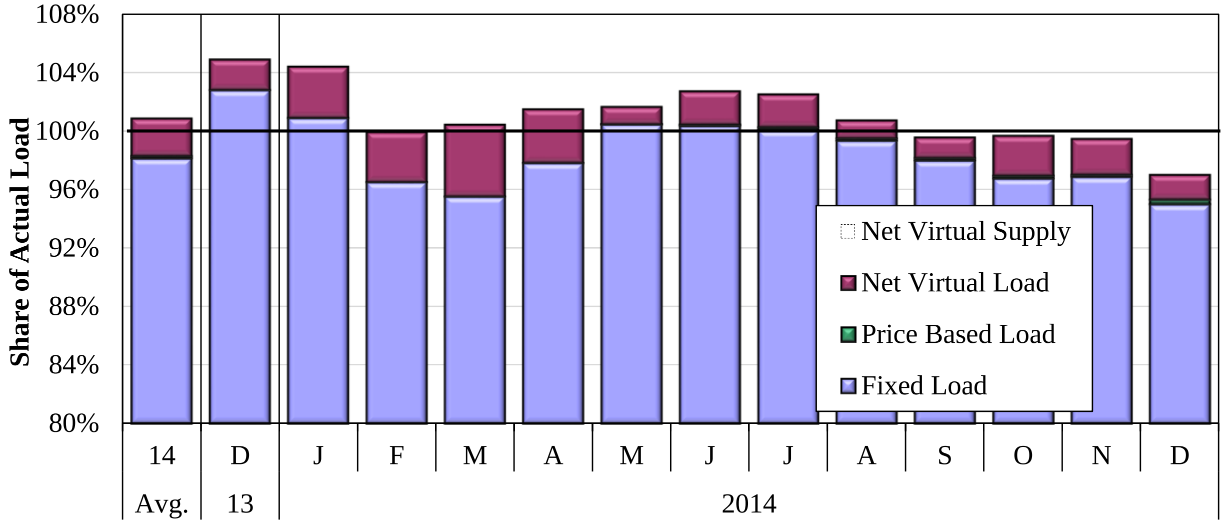
Figure A31: Midwest Region Day-Ahead Scheduled Versus Actual Loads
2013–2014, Daily Peak Hour



Share of Actual Load (%)

	Avg.			2013												2014											
	12	13	14	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.4	99.2	99.0	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.1	100.6	98.6	98.5	98.9	98.0	99.1	99.4	99.6	98.4	98.6	99.3	99.3
Peak Hours	100.4	99.1	99.6	99.9	100.2	99.2	98.4	98.3	98.6	98.3	97.9	99.7	99.3	99.7	99.5	100.4	98.0	99.3	99.5	98.0	99.5	99.8	99.5	98.8	100.2	100.7	101.1

Figure A32: South Region Day-Ahead Scheduled Versus Actual Loads
2013–2014, Daily Peak Hour



Share of Actual Load (%)

	14 Avg.	D 13	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	101.4	107.3	104.8	101.8	101.6	102.4	102.4	102.8	102.2	100.4	99.4	100.3	101.0	97.9
Peak Hours	100.8	104.9	104.4	99.9	100.4	101.5	101.6	102.7	102.5	100.7	99.5	99.7	99.4	97.0

D. Fifteen-Minute Day-Ahead Scheduling

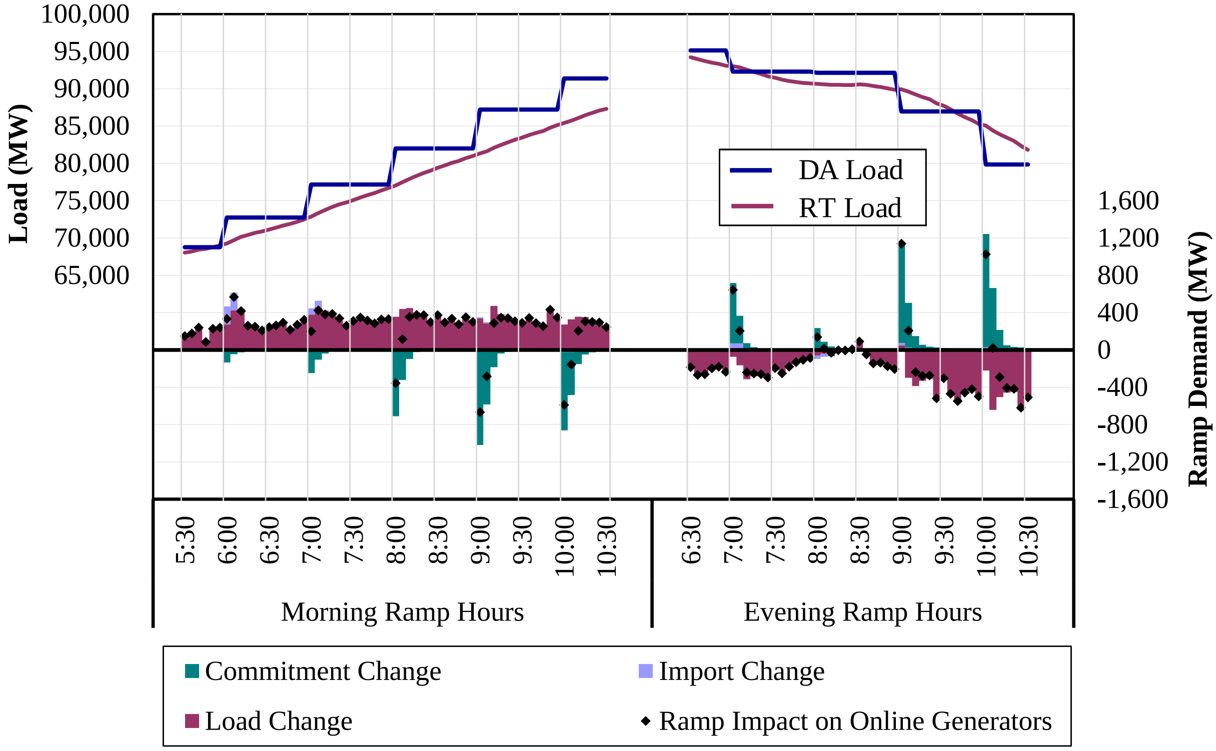
The day-ahead energy and ancillary services markets currently solves on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of the hour.

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.

Figure A33: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A33 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 to balance the market. When the sum is positive, generators are forced to ramp down.

Figure A33: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2014



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 (or produce) 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 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 and causes day-ahead prices to converge with real-time prices. Price convergence resulting from this arbitrage increases efficiency and mitigates market power in the day-ahead market.

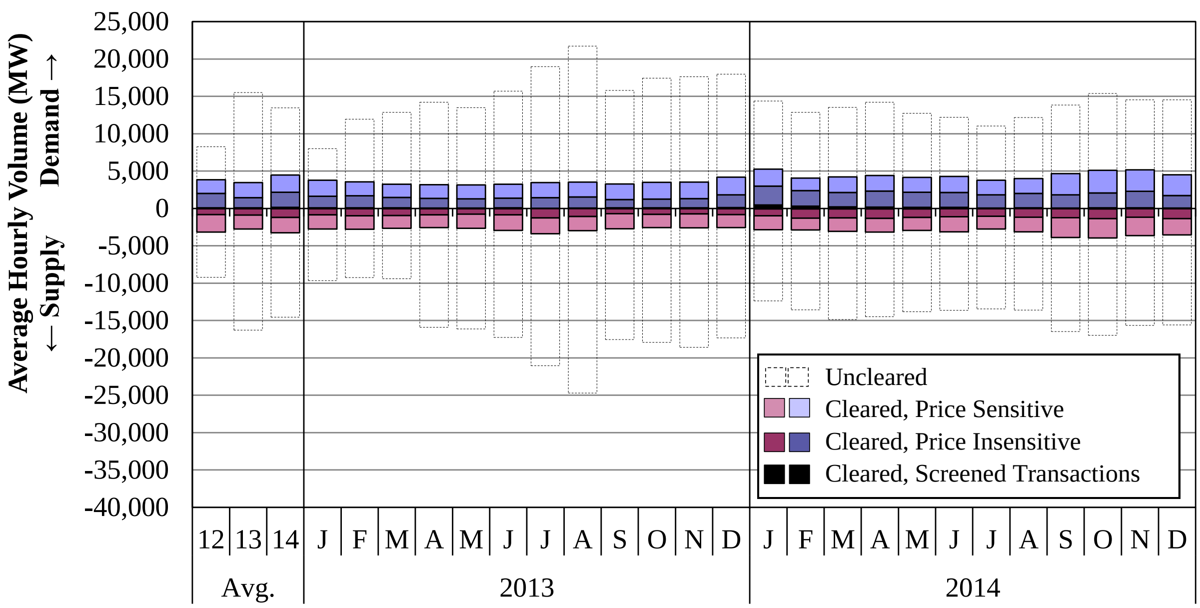
Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies, while large losses may indicate an attempt to manipulate day-ahead prices. Attempts to create artificial congestion or other price movements in the day-ahead market would cause prices to diverge from real-time 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 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 A34 and Figure A35: Day-Ahead Virtual Transaction Volumes

Figure A34 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market from 2013 to 2014. Figure A35 separates these volumes by region in 2014. 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).

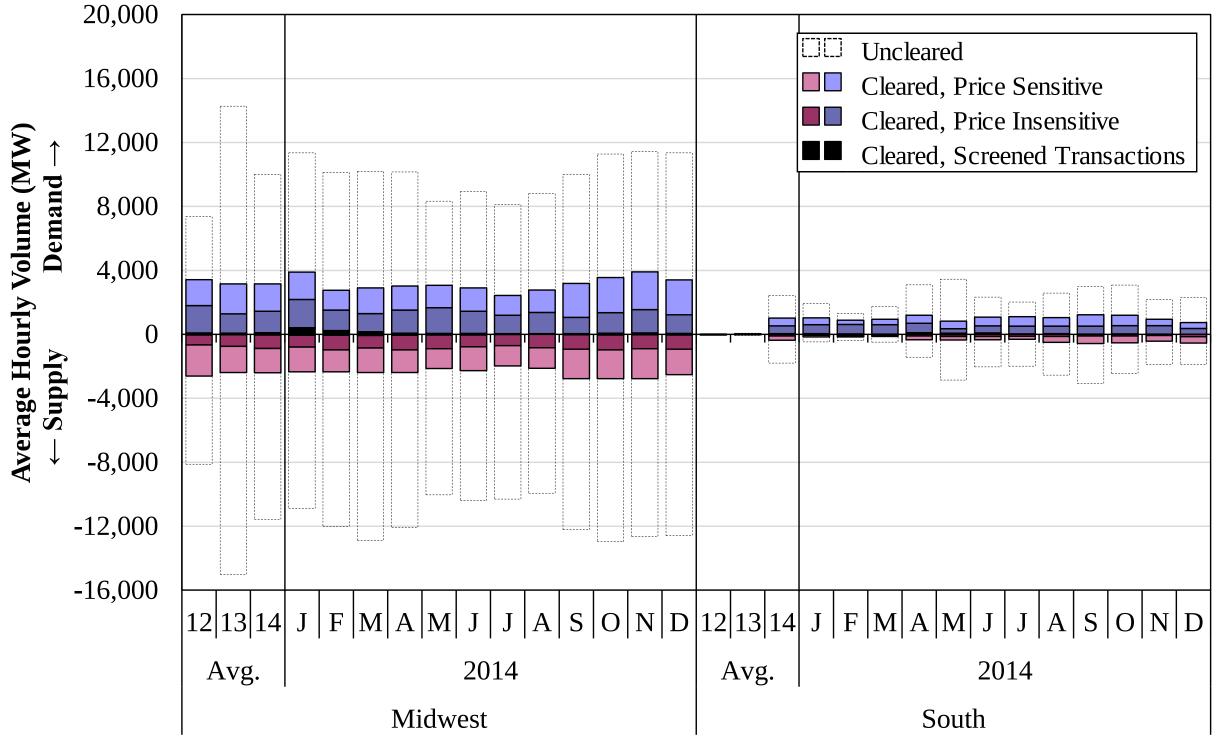
Figure A34: Day-Ahead Virtual Transaction Volumes
2013–2014



Percent Screened

	12	13	14	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	2.2	2.2	3.6	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5	8.9	7.9	5.3	4.3	3.4	3.5	1.8	2.0	1.2	2.0	1.9	1.2
Supply	1.4	1.2	1.6	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3	2.1	2.7	2.7	1.9	2.0	1.6	0.9	0.2	0.7	1.6	1.4	1.1
Total	1.9	1.8	2.7	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1	6.5	5.7	4.2	3.3	2.8	2.7	1.4	1.2	1.0	1.9	1.7	1.2

Figure A35: Day-Ahead Virtual Transaction Volumes by Region
2014



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 A36 - Figure A39: Virtual Transaction Volumes by Participant Type

The next figure show day-ahead virtual transaction by participant type. Figure A36 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 A38 and Figure A39 show the same statistic except separated by region.

Figure A36: Virtual Transaction Volumes by Participant Type
2014

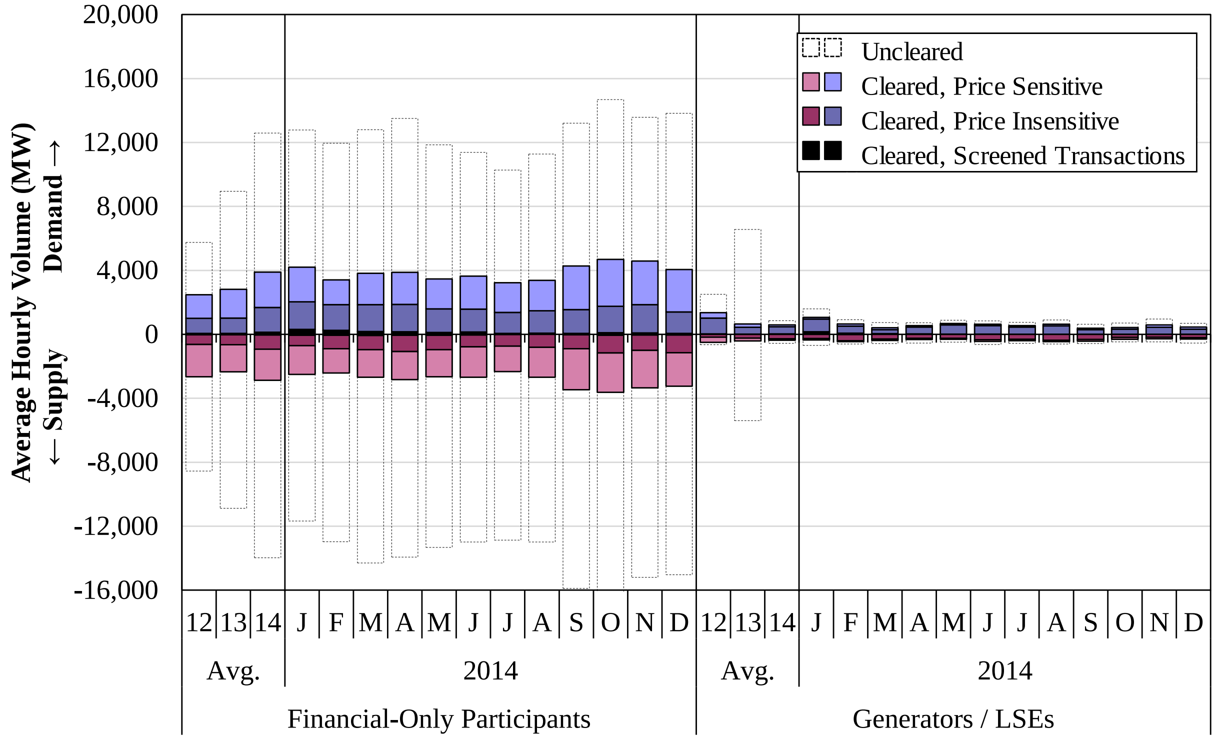


Figure A37: Virtual Transaction Volumes by Participant Type
Midwest Region, 2014

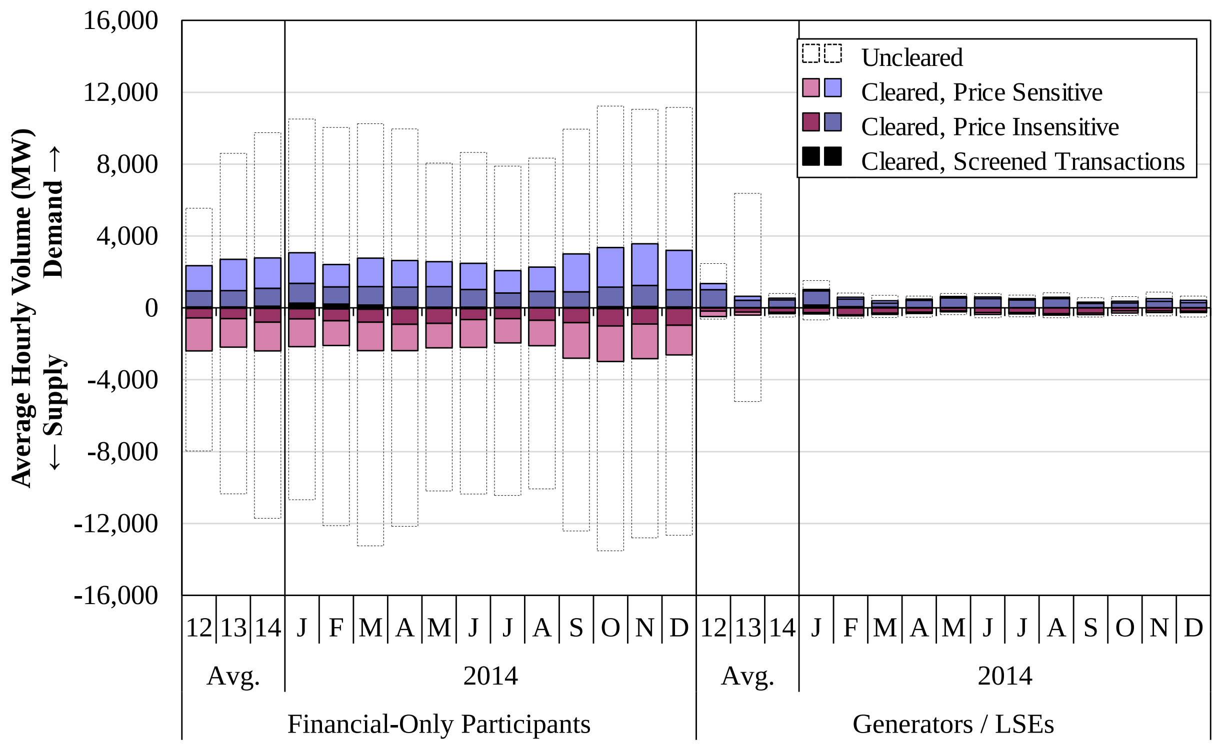


Figure A38: Virtual Transaction Volumes by Participant Type
South Region, 2014

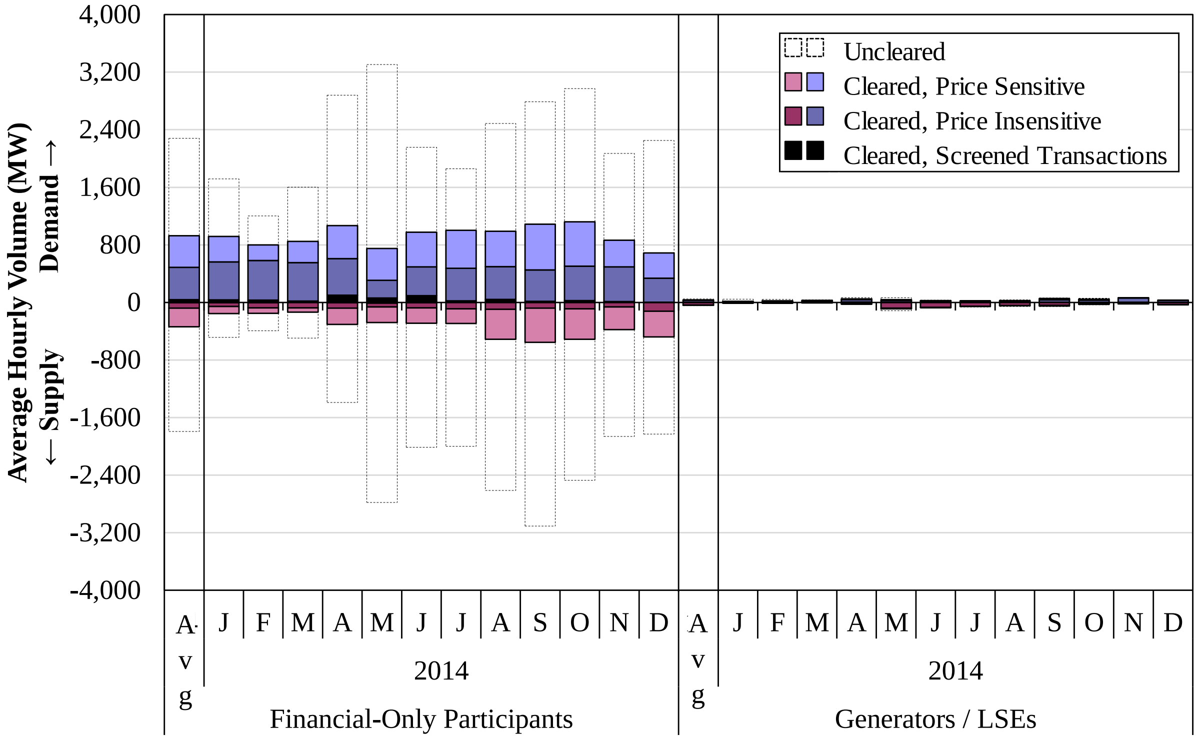


Figure A39: Virtual Transaction Volumes by Participant Type and Location
2012–2014

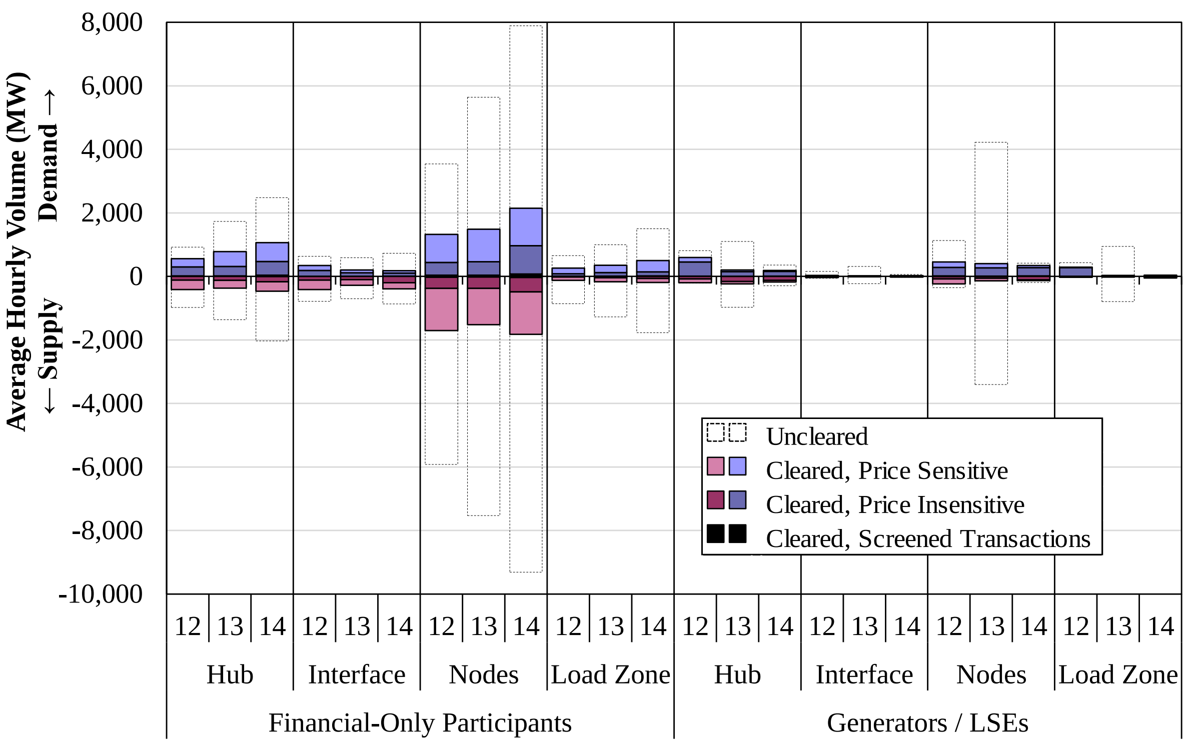


Figure A39, above, disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many nodes and are therefore less prone to congestion-related price spikes than generator locations. The Indiana Hub remained the single most liquid trading point in MISO during 2014.

Figure A40: Matched Virtual Transactions

Figure A40 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.
- 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 A40: Matched Price-Insensitive Virtual Transactions
2013-2014

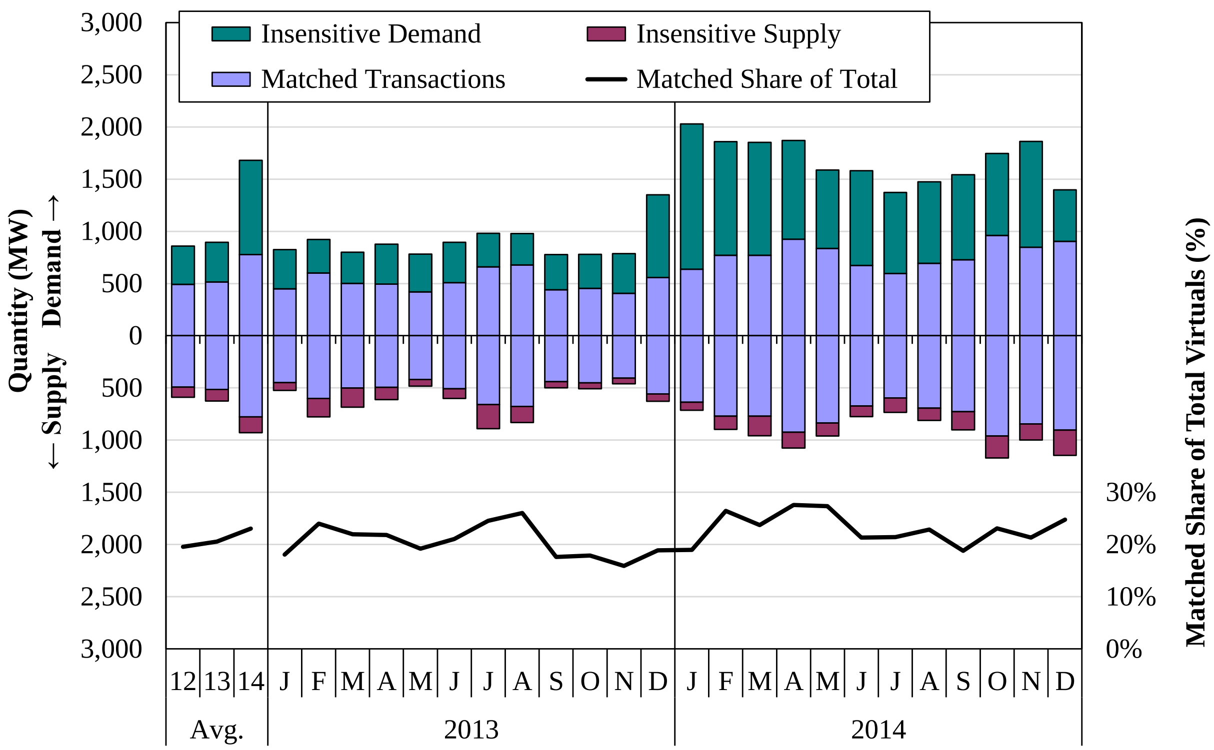
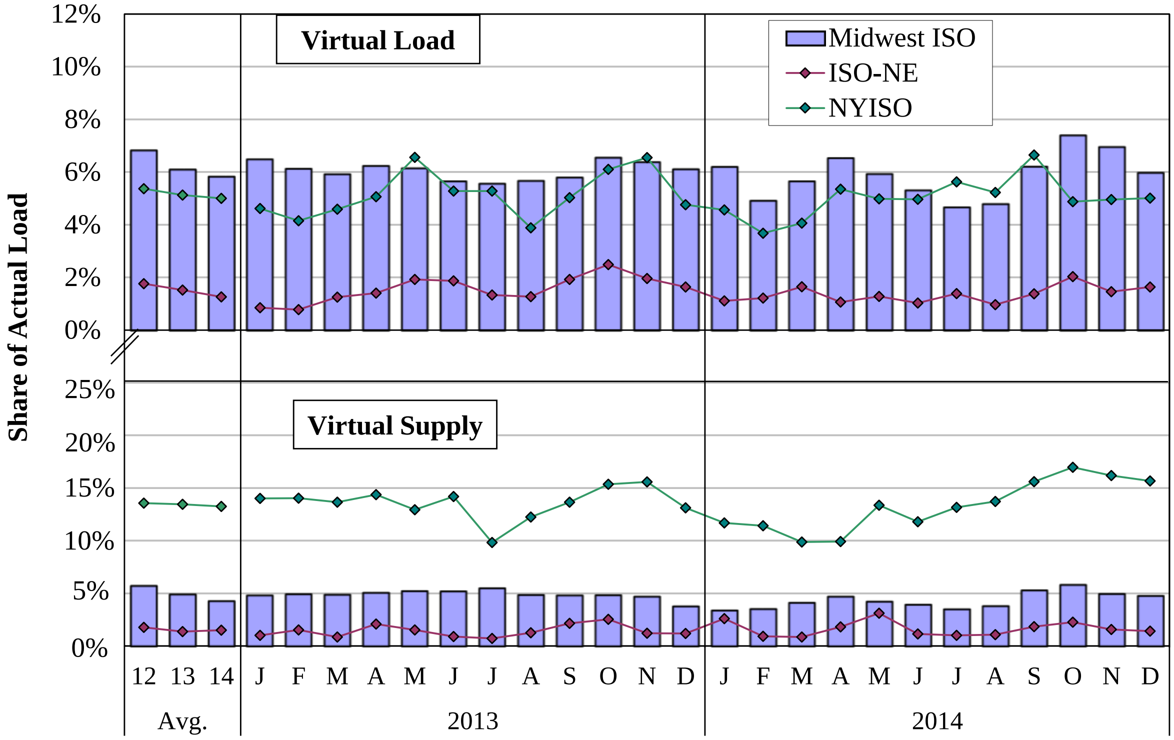


Figure A41: Virtual Transaction Volumes, MISO and Neighboring RTOs

To compare trends in MISO to other RTOs, Figure A41 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 A41: Comparison of Virtual Transaction Volumes
2012–2014



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 A42 -- Figure A43: Virtual Profitability

Figure A42 shows monthly average gross profitability of virtual purchases and sales. 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 A43 shows the same results disaggregated by type of market participant: entities owning generation or serving load, and financial-only participants.

Figure A42: Virtual Profitability
2013–2014

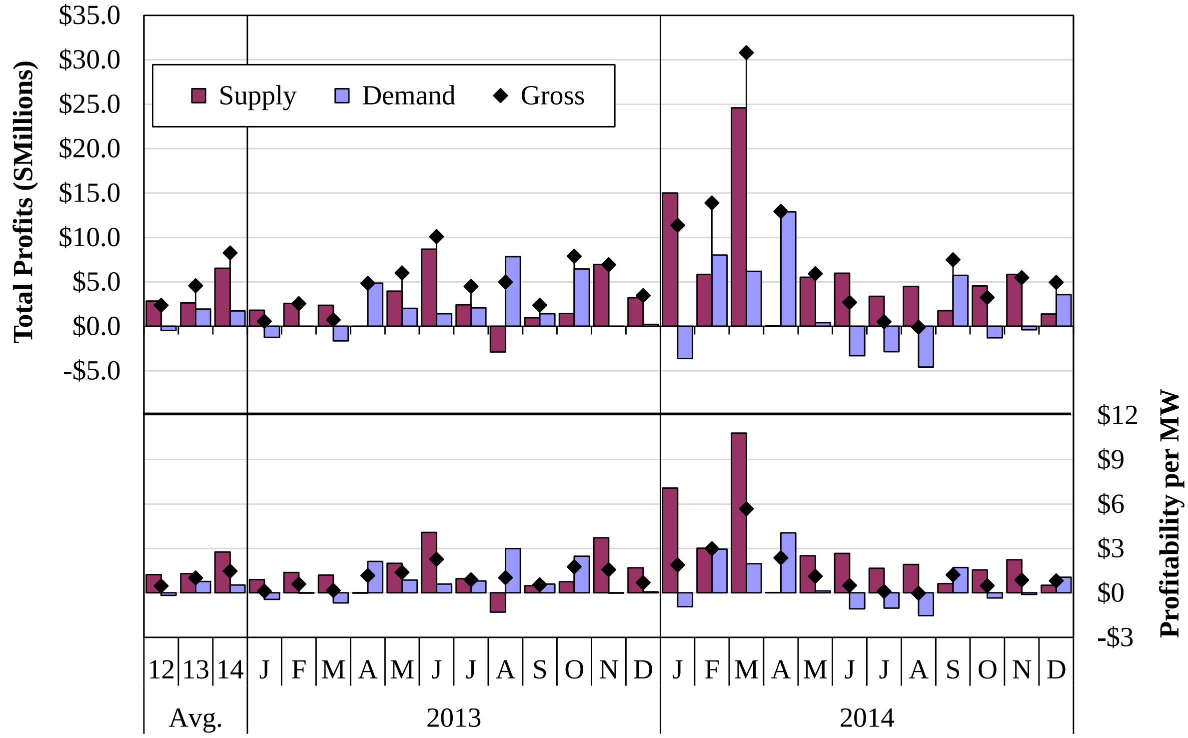
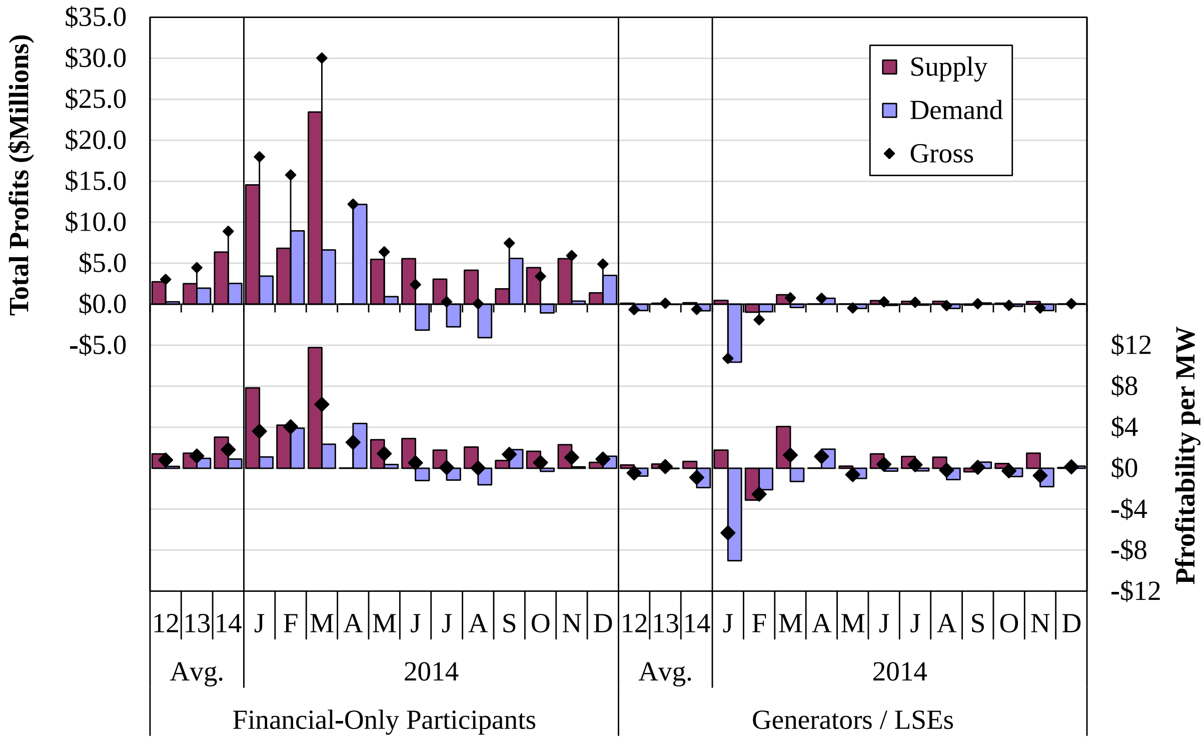


Figure A43: Virtual Profitability by Participant Type
2014



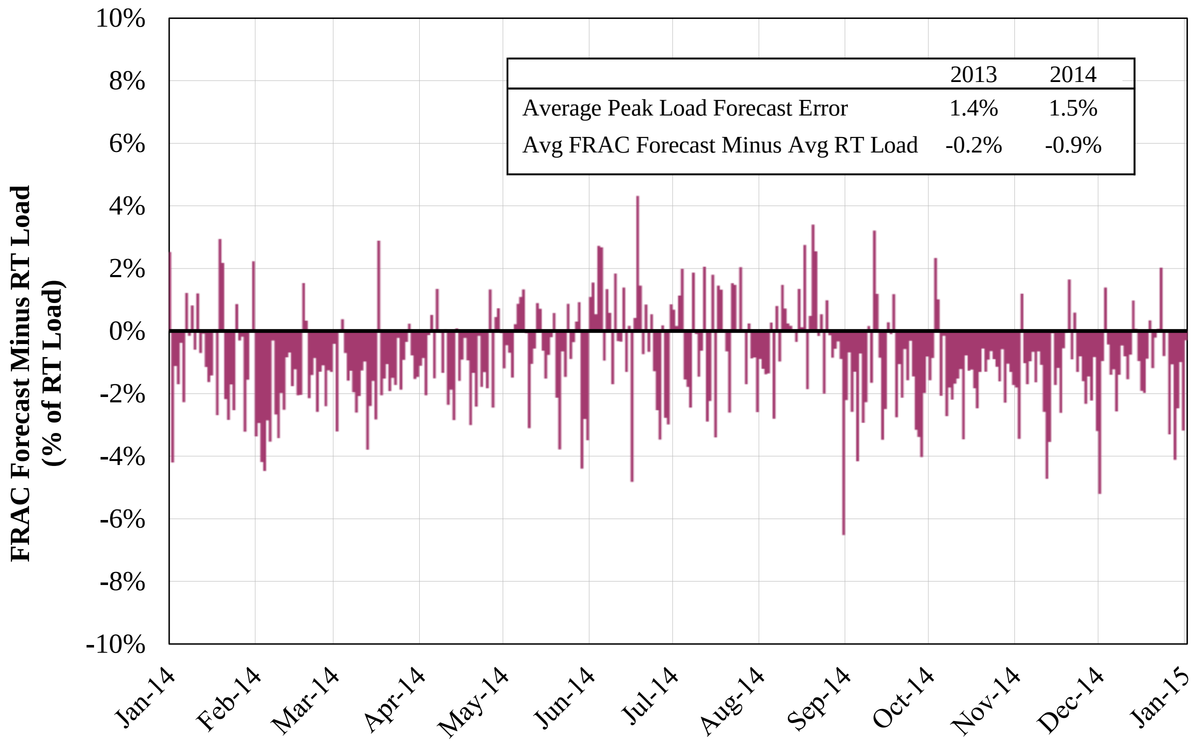
G. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is particularly important for 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 A44: Daily MTLF Error in Peak Hour

Figure A44 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 2014.

Figure A44: Daily MTLF Error in Peak Hour
2014



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.

The real-time market performs the vital role of dispatching resources to minimize the 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 a primary 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 A45: Fifteen-Minute Real-Time Price Volatility

Figure A45 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 A45: Fifteen-Minute Real-Time Price Volatility
MISO and Other RTO Markets, 2014

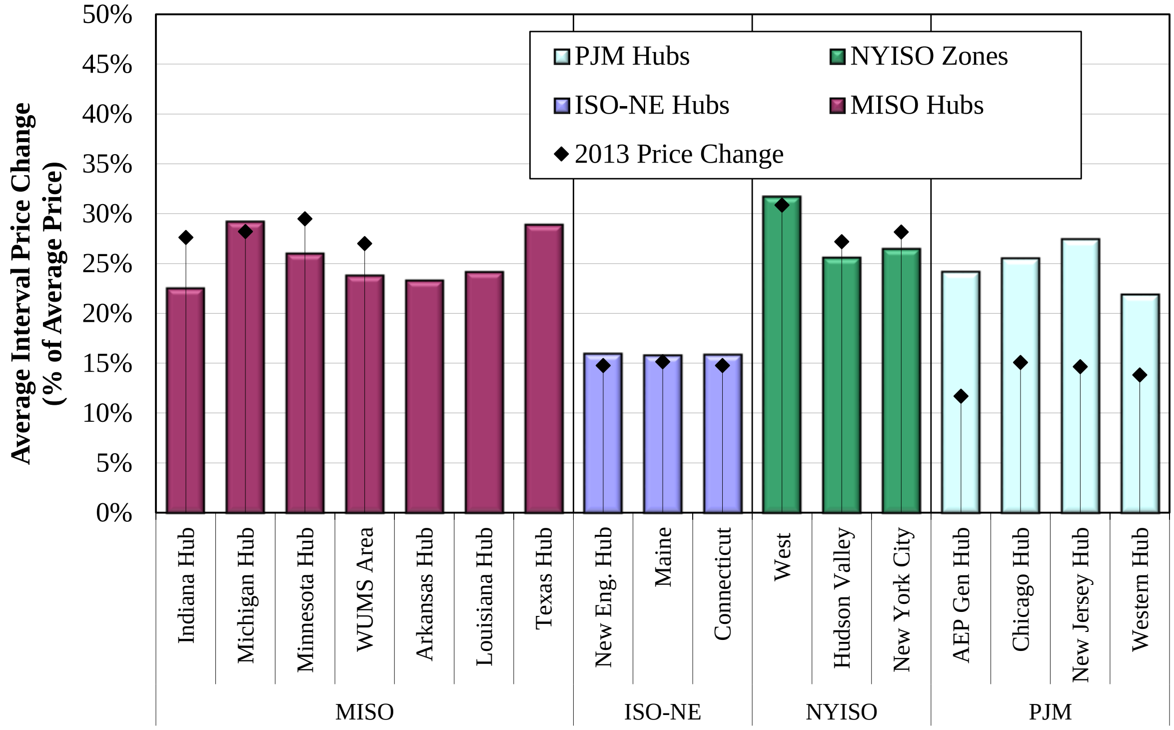


Figure A46: Real-Time Ancillary Service Prices and Shortages

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 ASM prices are additionally affected by reserve shortages. When the market is short of one or more ancillary service product, 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.[12] The demand curves for the various ancillary services products in 2014 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).[13]
- Regulation: Varies monthly according to the prior month's gas prices. It averaged $203.74 per MWh in 2014 and reached nearly $400 in March.
- 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.

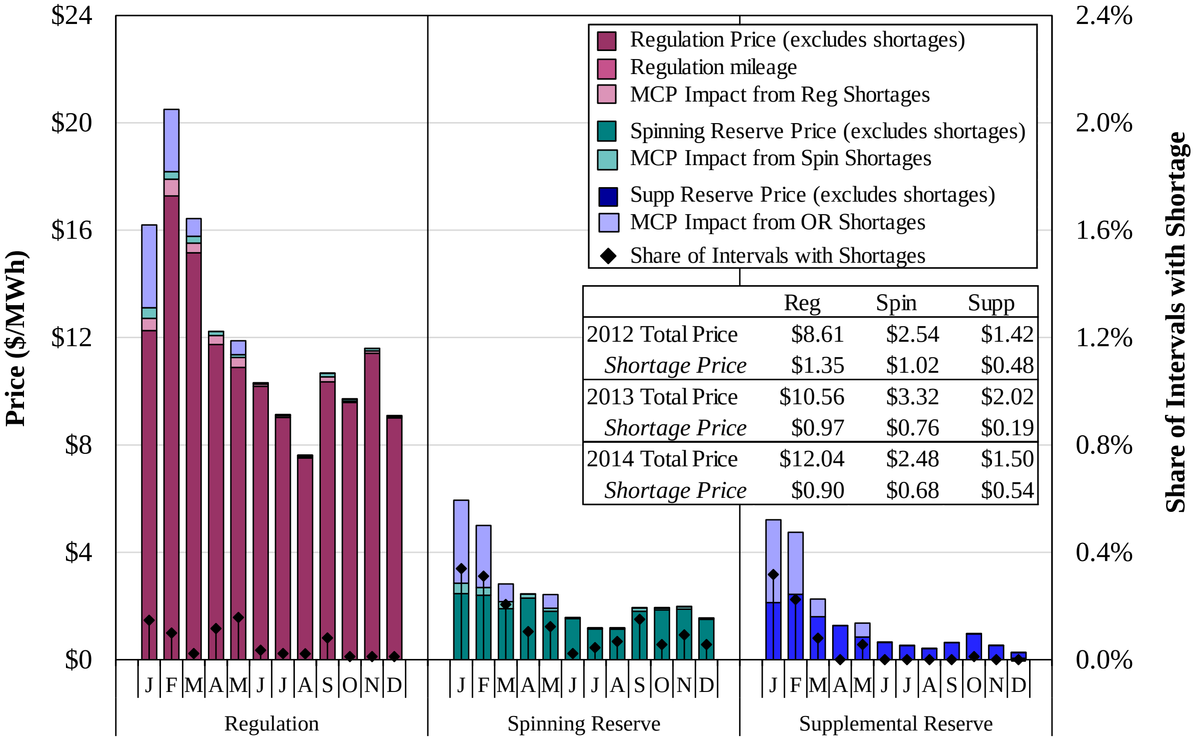
Total operating reserves (includes contingency reserves plus regulation) is the most important reserve requirement because a shortage of total operating reserves has the biggest potential impact on reliability. Accordingly, total operating reserves has the highest-priced reserve demand curve. To the 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.

Figure A46 shows monthly average real-time clearing prices for ASM products in 2014. It also shows the frequency with which the system was short of each class of reserves. We show separately the impact of each product's shortage pricing.

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

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

Figure A46: Real-Time Ancillary Services Clearing Prices and Shortages
2014



	Reg	Spin	Supp
2012 Total Price	$8.61	$2.54	$1.42
Shortage Price	$1.35	$1.02	$0.48
2013 Total Price	$10.56	$3.32	$2.02
Shortage Price	$0.97	$0.76	$0.19
2014 Total Price	$12.04	$2.48	$1.50
Shortage Price	$0.90	$0.68	$0.54

Figure A47: Regulation Offers and Scheduling

ASM offer prices and quantities are primary determinants of ASM outcomes. Figure A47 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 offers 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 A47: Regulation Offers and Scheduling
2014

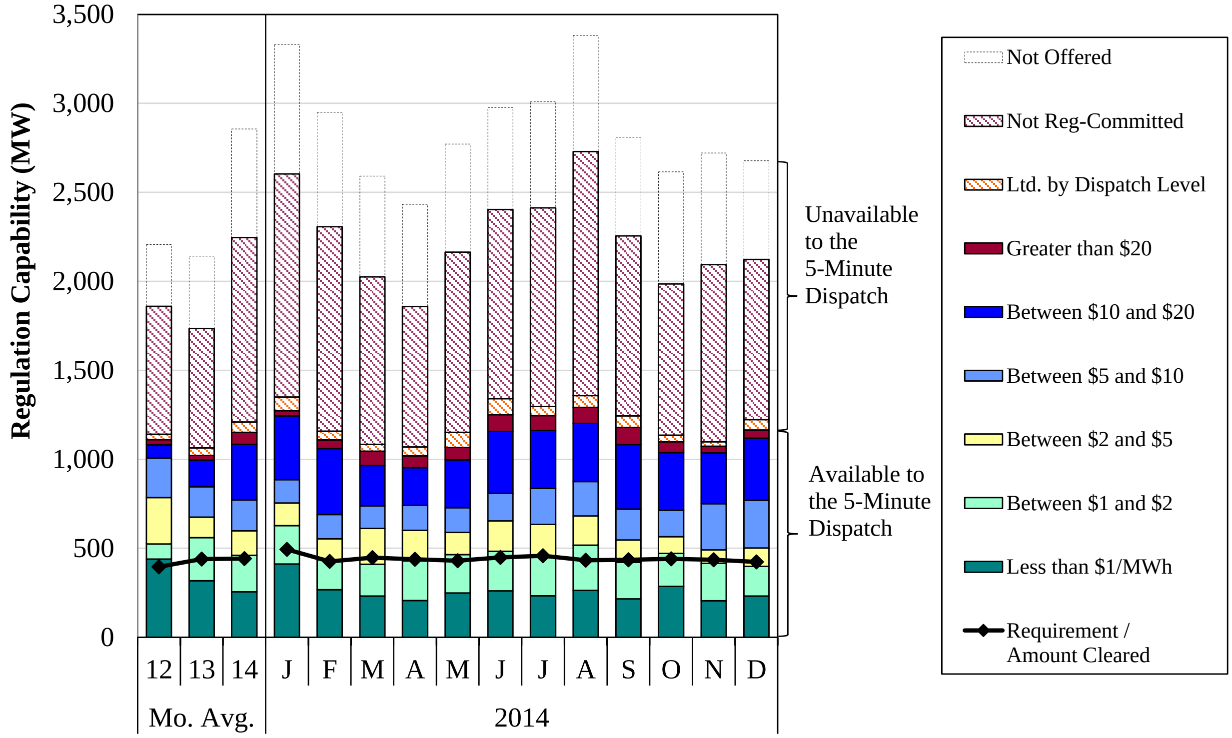
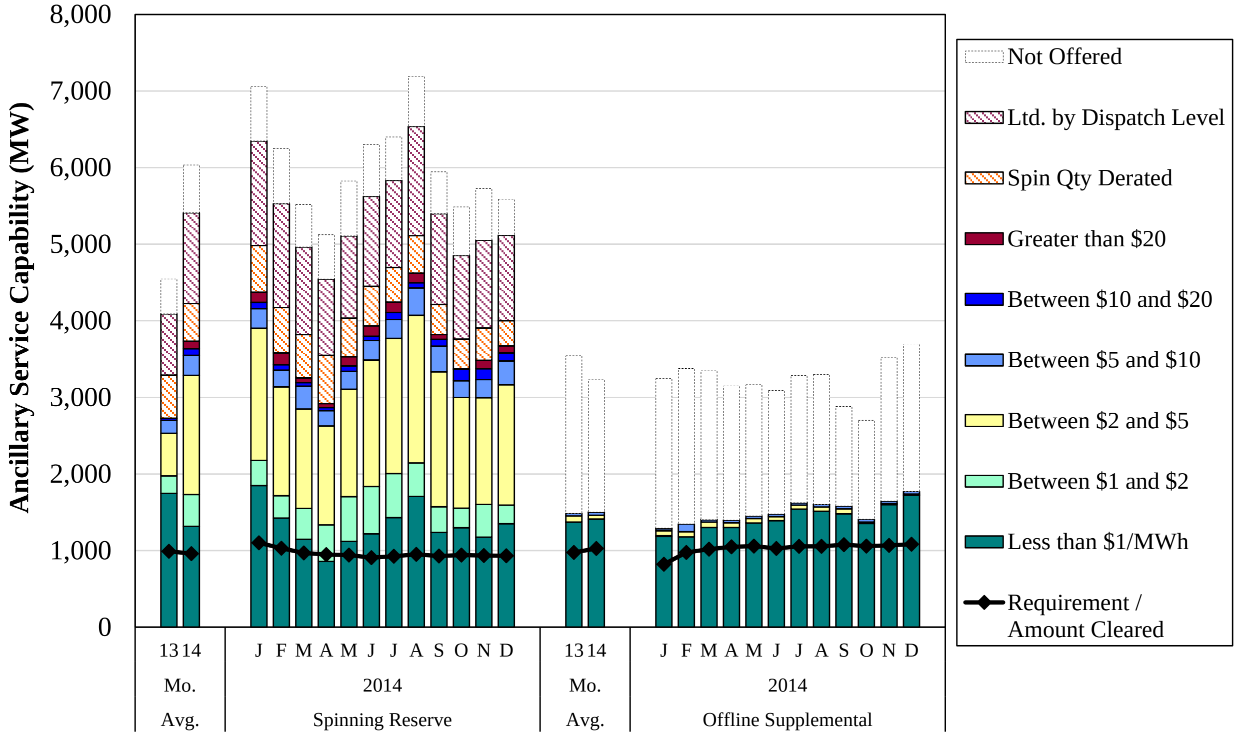


Figure A48: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can be provided by only 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 A48 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 A48: Contingency Reserve Offers and Scheduling
2014



B. Spinning Reserve Shortages

Figure A49: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

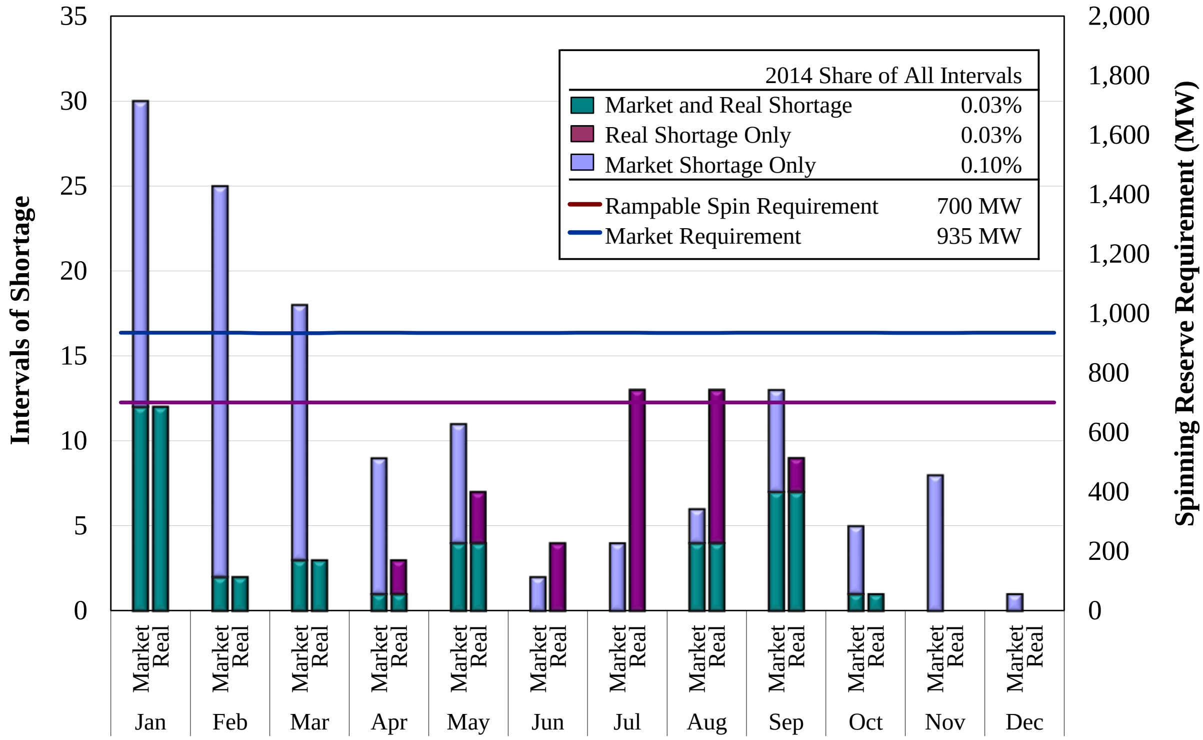
MISO operates with a minimum required amount of spinning reserves that can be deployed immediately for contingency response. Market shortages generally occur because the costs that would be incurred to maintain the spinning reserves exceed the spinning reserve penalty factor (i.e., the implicit value 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 the real-time energy market is instructing them to ramp 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.[14] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

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

Figure A49 shows all intervals in 2014 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements. Most real-only shortages are associated with "inferred derates"—unachievable capacity on units that MISO is counting as part of its headroom or reserves that are not reflected in market outcomes.[15]

Figure A49: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2014



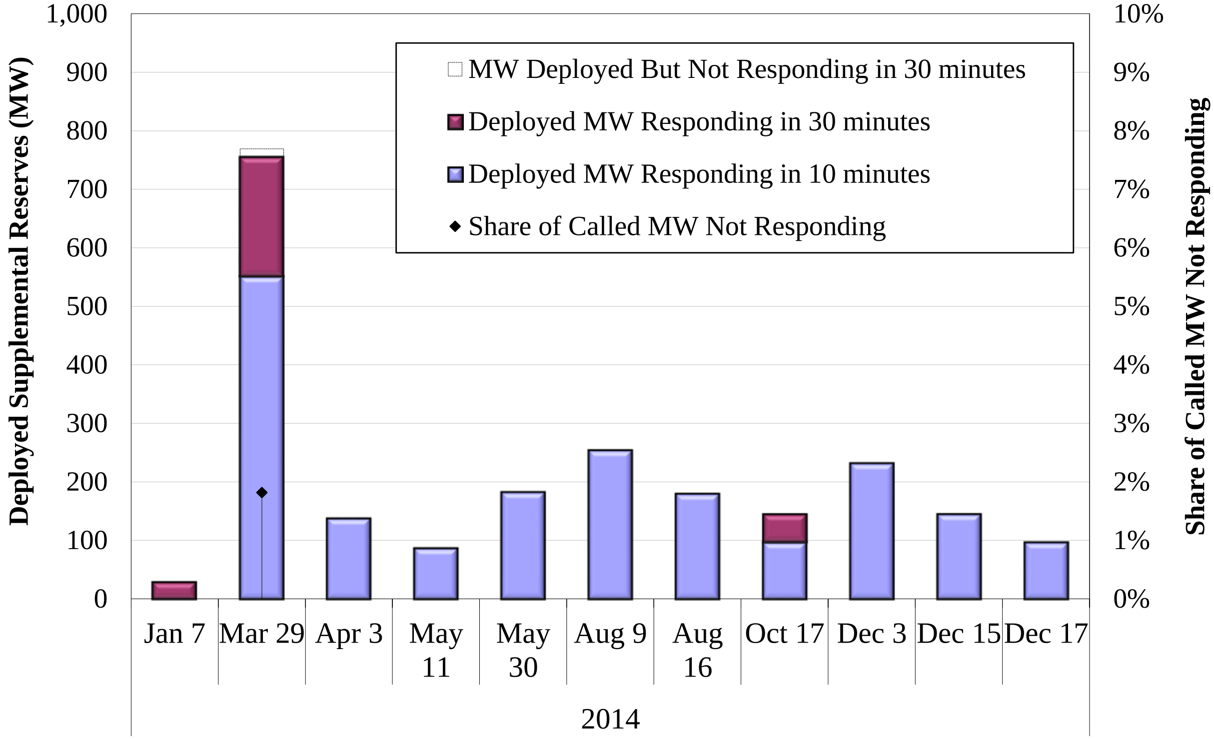
C. Supplemental Reserve Deployments

Figure A50: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A50 shows offline supplemental reserve response during the 11 deployments in 2014, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC).

15 For a more complete discussion on inferred derates, see Section V.J.

Figure A50: Supplemental Reserve Deployments
2013–2014



D. Generation Availability and Flexibility in Real Time

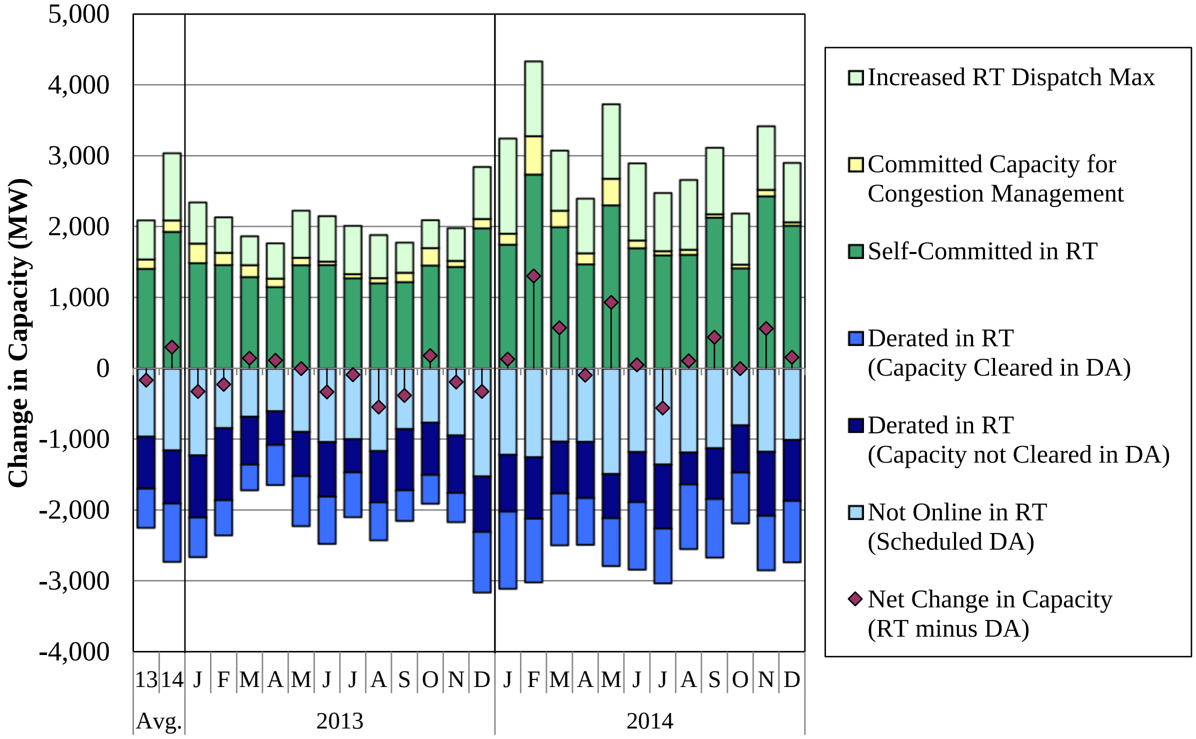
The flexibility of generation available to the real-time market provides MISO the ability to manage transmission congestion and satisfy energy and operating reserve obligations. In general, the day-ahead market coordinates the commitment of most generation that is online and available for real-time dispatch. 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 A51: Changes in Supply from Day Ahead to Real Time

Figure A51 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 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 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; derated capacity (cleared and not cleared in day-ahead) and its inverse, increased available capacity; and units committed for congestion management. The figure separately indicates the net change in capacity between the day-ahead and real-time markets. A net shortfall indicates that MISO would need to commit additional capacity, while a surplus would allow MISO to decommit or shorten real-time MISO commitment periods. The amount actually committed for capacity in real time is not included in the figure.

Figure A51: Changes in Supply from Day Ahead to Real Time
2013–2014



E. 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.[16] 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.

Beginning in the fall of 2012, MISO began making many voltage and local reliability ("VLR") commitments in the day-ahead market. VLR commitments increased after South region integration, due to 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-

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

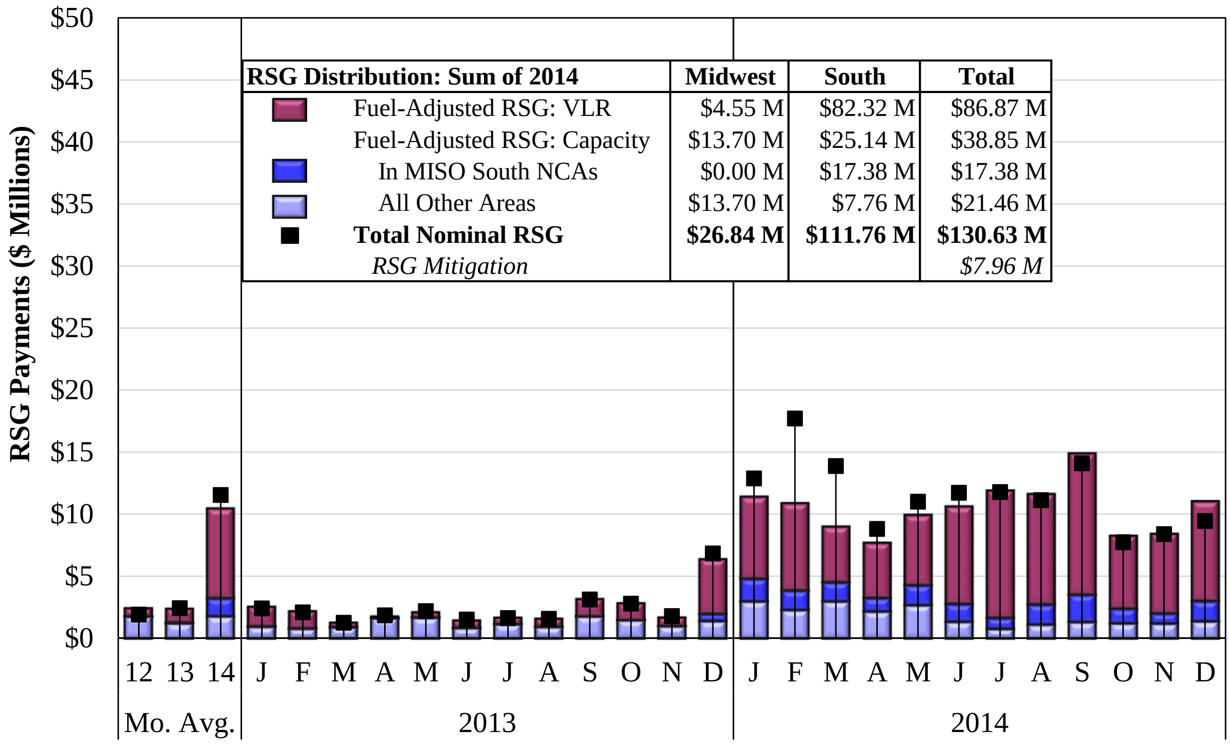
ahead markets. Consequently day-ahead RSG payments are now larger than real-time payments in most months.

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 A52 and Figure A53: RSG Payment Distribution

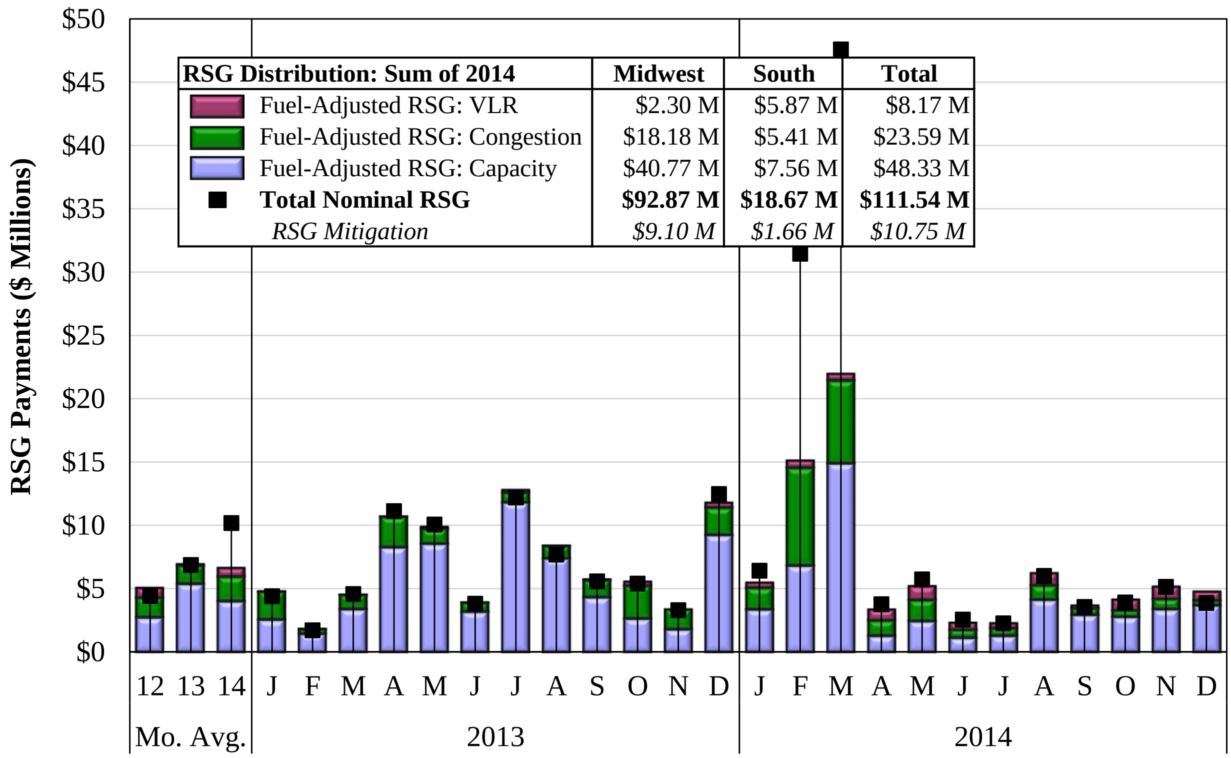
Figure A52 shows total day-ahead RSG payments, and distinguishes between payments made for VLR or for capacity needs. In addition, capacity payments made to units in MISO South NCAs are separately identified because these units are typically committed for VLR and are frequently subject to the tighter VLR mitigation criteria. The results are adjusted for changes in fuel prices, although nominal payments are indicated separately. Figure A53 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.[17]

Figure A52: Total Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2013–2014



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

Figure A53: Total Real-Time RSG Payments
Fuel Adjusted, 2013–2014



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 CMC rate. Most constraint-related RSG costs not allocated under the CMC rate were allocated to net participant deviations (negative net deviations pre-notification deadline (NDL) and all deviations post-NDL) under the DDC rate. Any residual RSG cost is then allocated market-wide on a load-ratio share basis (“Pass 2”).[18]

Figure A54: Allocation of RSG Charges

Figure A54 summarizes, in the top panel, how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month of 2014. 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.

18 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 A54: Allocation of RSG Charges
By Month, 2013–2014

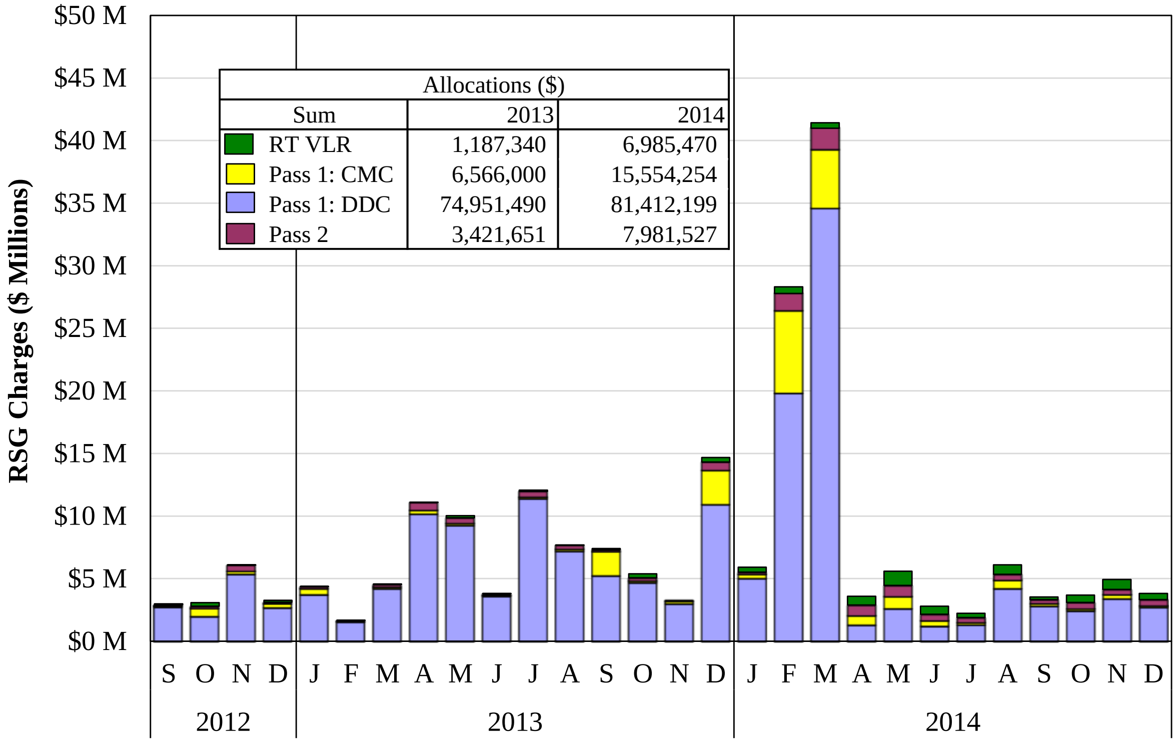
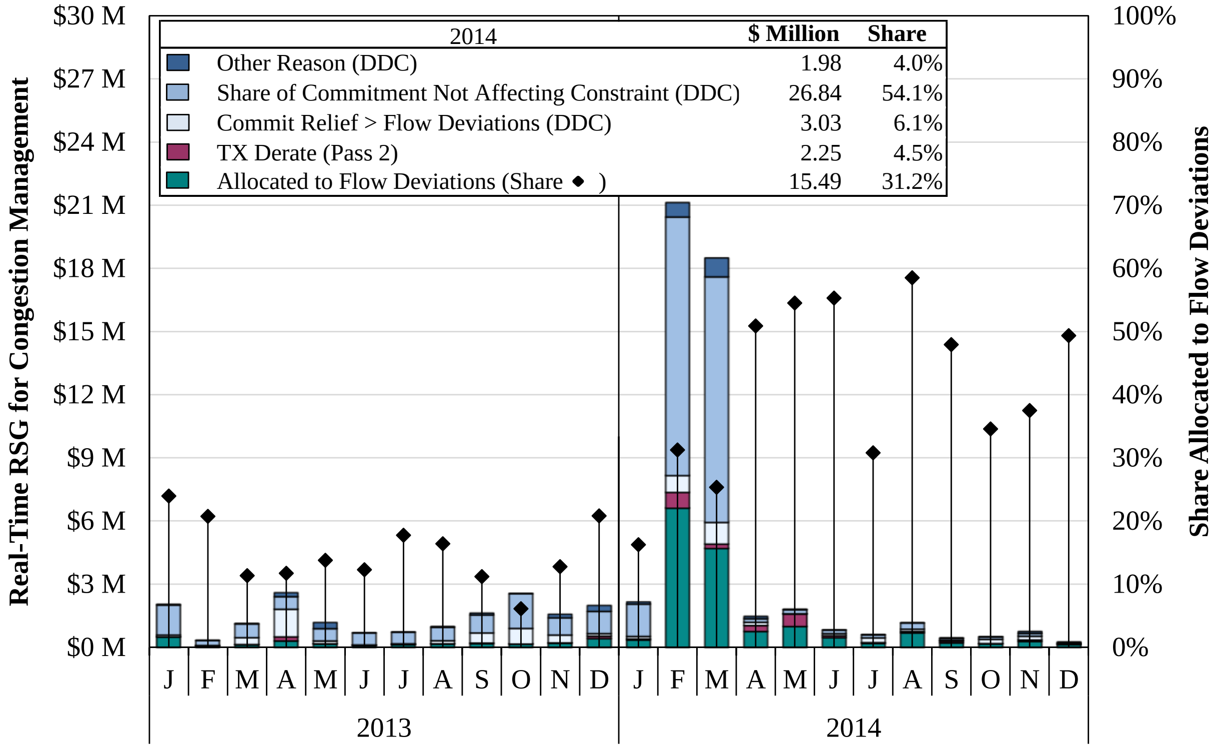


Figure A55: Allocation of Constraint-Related RSG Costs

Figure A55 examines more closely how RSG costs associated with commitments to manage constraints and other local issues are allocated. The green portion of the bar is the portion allocated to those deviations that create a flow deviation on the constraint for which the resource is committed. The maroon block corresponds to costs incurred because of a transmission derate and is allocated to load through "Pass 2". Each of the three blue blocks is allocated to market-wide deviations under the DDC rate. The lightest blue block shows allocations that occur when the committed capacity exceeds the deviation flow (i.e., more committed relief is procured than the contribution of the harming deviations to the constraint flows).

As discussed previously, the second block occurs because MISO allocated only the portion of the costs based on the GSF of the committed unit that corresponds to its actual relief (counter-flows) over the constraint, and not the full cost. After adopting the IMM changes in March, this bar declines substantially. The darkest blue block is allocated under the DDC rate for reasons we cannot identify, but may be due to errors in logging or the definition of the constraint.

Figure A55: Allocation of Constraint-Related RSG Costs
2013–2014



F. Price Volatility Make-Whole Payments

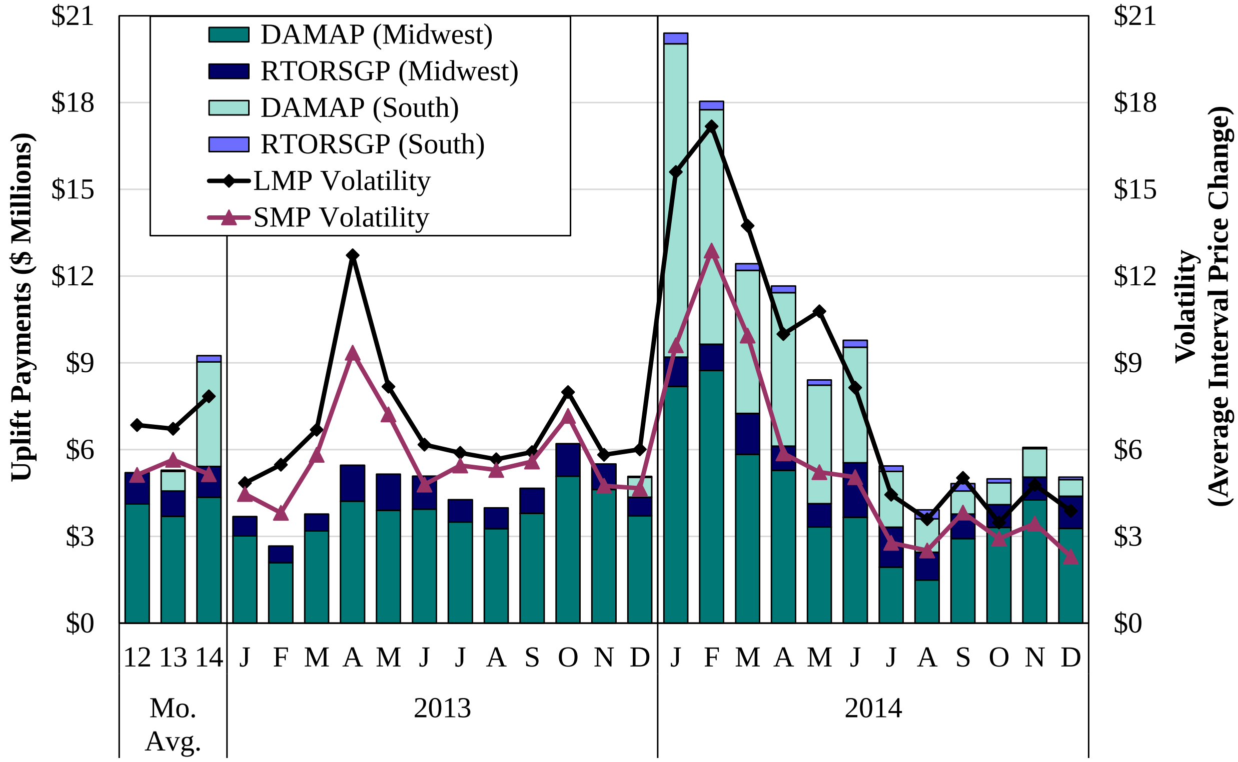
MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers responding to MISO's prices and following its dispatch signals in real time are not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

The PVMWP consists of two separate payments: 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 to a level below its day-ahead schedule and has to buy its day-ahead scheduled output back at real-time prices. Often, this payment is the result of short-term price spikes in the real-time market due to binding transmission constraints or ramp constraints. Conversely, the RTORSGP is made to a qualified resource that is unable to recover incremental energy costs when dispatched to a level above its day-ahead schedule. Opportunity costs for potential revenues are not included in the payment.

Figure A56: Price Volatility Make-Whole Payments

Figure A56 shows total monthly PVMWP statistics for the prior three years. 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. 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 A56: Price Volatility Make-Whole Payments
2013–2014



G. 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 both physical transactions and generation on an hourly basis. 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). The five-minute settlement of physical schedules would remove similar harmful incentives for physical schedules.

Figure A57: 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 2014. 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. 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.

Figure A57: Net Energy Value of Five-Minute Settlement
2014

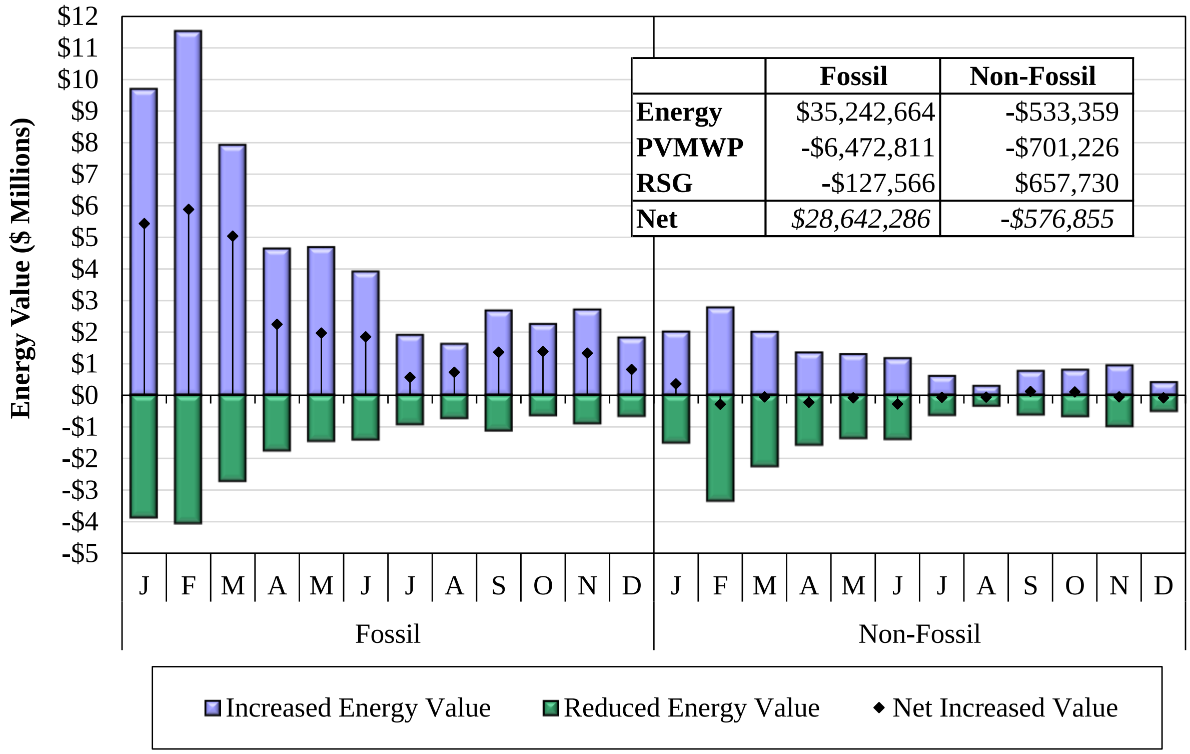
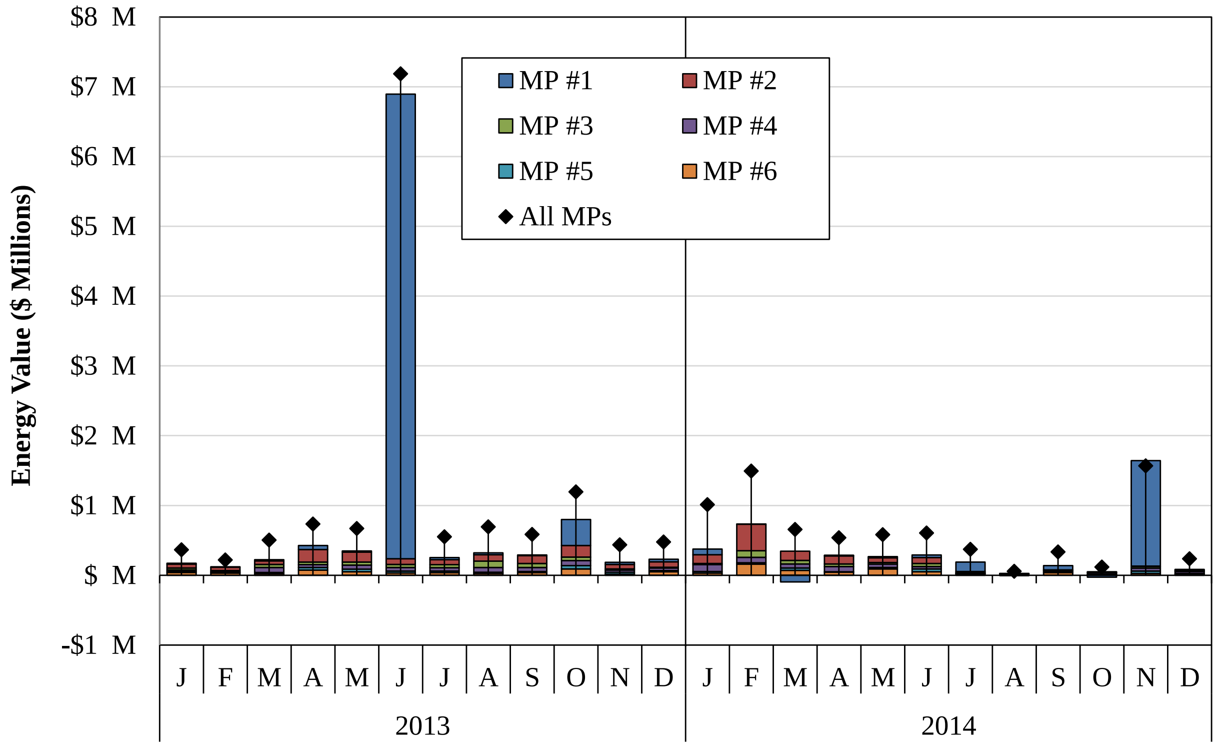


Figure A58: Net Energy Value of Physical Schedules Settlement

The next figure shows a similar analysis for physical scheduling. As noted above, these transactions may be scheduled at least twenty minutes in advance to start and stop in fifteen minute increments, but similar to generation are settled based on average hourly interface prices. Consequently, like generation, these schedules may be paid more or less than their value depending upon whether the five-minute interval prices during the scheduled interval are more or less than the hourly average price.

This chart shows overvalued transactions as positive values and undervalued transactions as negative values. The stacked bar shows the total for the top six market participants in terms of settlement values, and the drop line shows the net relative five-minute to hourly valuation for all participants.

Figure A58: Net Energy Value of Physical Schedules Settlement
2014



H. 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.

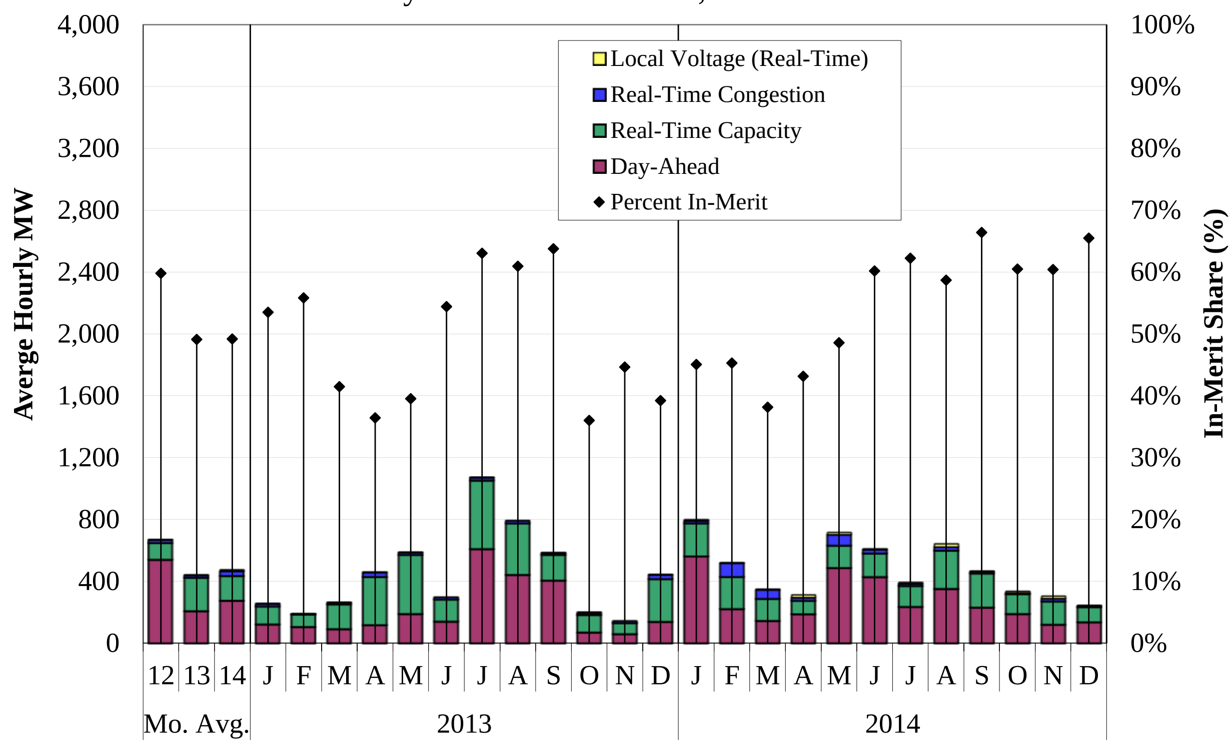
While low commitment costs make peaking resources attractive for meeting capacity needs, they generally have high incremental energy costs and frequently do not set the energy price because they are often dispatched at their economic minimum level (causing them to run "out-of-merit" order with an offer price higher than their LMP). When a peaking unit does not set the energy price, or runs out-of-merit, it will be revenue-inadequate because it receives no energy rents to cover its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

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 A59: Average Daily Peaking Unit Dispatch and Prices

Figure A59 shows average daily dispatch levels of peaking units in 2014 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 A59: Dispatch of Peaking Resources
By Commitment Reason, 2013–2014



I. 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 generation. They are eligible for all uplift payments and are subject to all requisite operating requirements. Nearly 80 percent (10.5 GW) of MISO's wind capacity—118 out of 183 units—is currently capable of responding to dispatch instructions; the rest generally lack the physical capabilities (such as blade feathering) to do so.

DIRs can submit offers in the day-ahead market (accompanied by generation forecasts) and can be designated as capacity resources under Module E of the Tariff (adjusted for capacity factors).[19] For both DIR and non-DIR, MISO utilizes short and long-term forecasts to make assumptions about wind output. Despite the expanded DIR capability, MISO continues to utilize manual curtailments when necessary to ensure reliability.

Figure A60: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A60 shows a seven-day moving average of wind scheduled in the day-ahead market and dispatched in the real-time market since 2013. 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.

19 Module E capacity credits for wind resources are determined by MISO's annual Loss of Load Expectation 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 2015–2016 Planning Year, this credit averages 14.7, percent, up slightly from the prior year's 14.1 percent. Excluding resources that received no credit, individual credits range from 1 to 25 percent.

Figure A60: Day-Ahead Scheduling Versus Real-Time Wind Generation
2013–2014

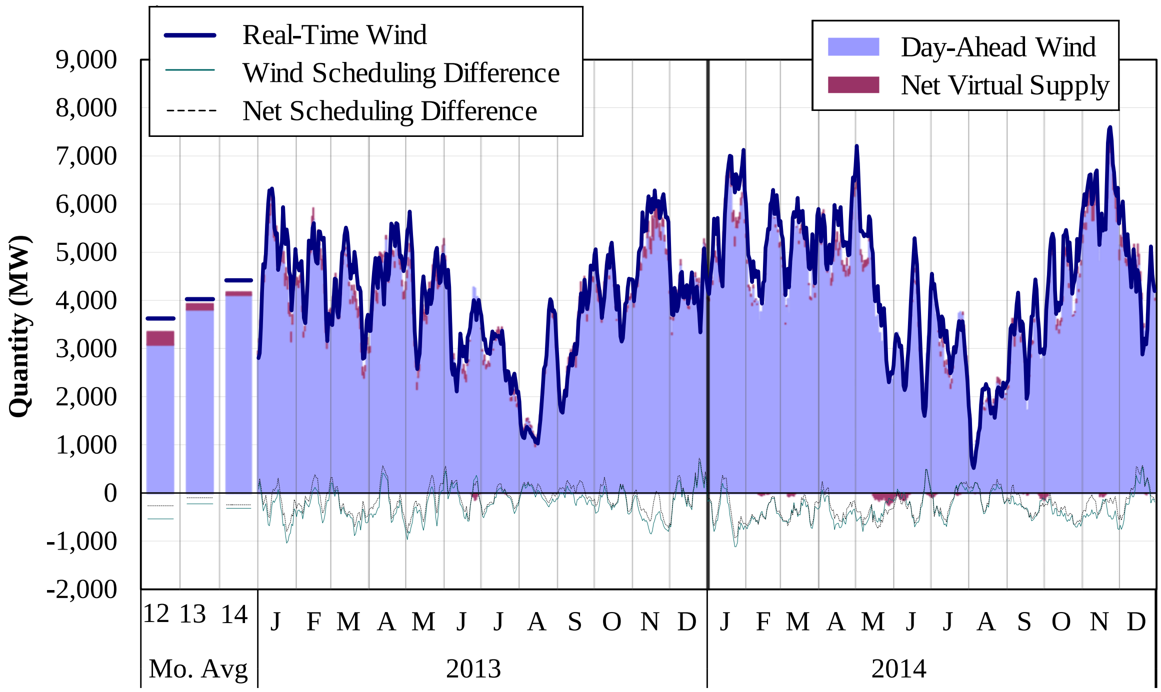


Figure A61: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

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.

Figure A61 shows average hourly wind capacity factors by load-hour percentile, shown separately by season and region. The figure also shows the four-year average. 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 A61: Seasonal Wind Generation Capacity Factors by Load Hour Percentile
2014

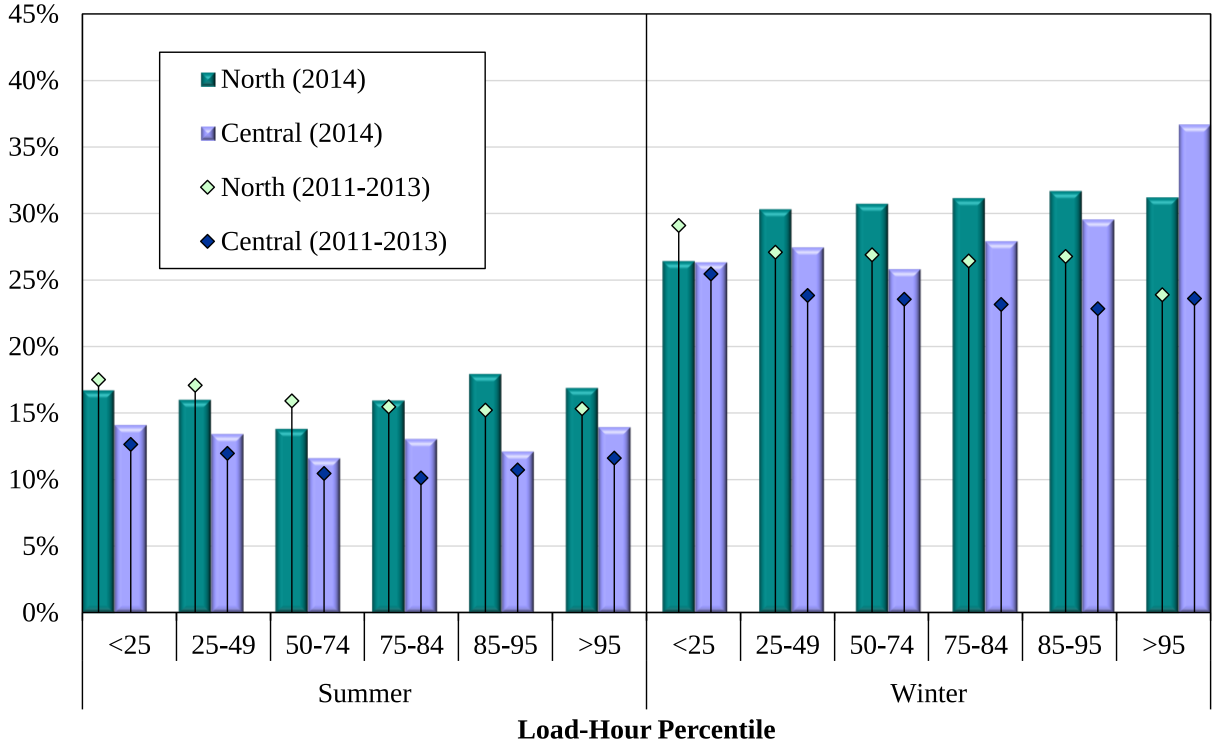


Figure A62: Wind Curtailments by MISO

Since much of the wind capacity is located in the North region and its output impacts lower voltage transmission constraints, the growth in wind output over time has resulted in increased congestion out of western areas. Before the phased introduction of DIR beginning in June 2011, MISO operators manually curtailed wind resource output regularly to manage congestion and address local reliability issues. Manual curtailments are an inefficient means to relieve congestion because the process does not allow prices to reflect the marginal costs incurred to manage the congestion. This inefficiency is eliminated when DIR units are economically curtailed.

In addition to MISO-issued curtailments, wind resource owners at times choose to curtail their output in response to very low prices. Owner-instructed curtailments are not coordinated with or tracked by MISO, and appear to the market operator as a sudden reduction in wind output. These actions, which contribute to wind generation volatility (discussed later in this section), have declined as DIR integration has expanded.

Figure A62 shows the average wind curtailments since 2012. The figure distinguishes between MISO-issued manual and economic (DIR) curtailments. Manual curtailments of units that have since become DIR are indicated by the lighter color.

Figure A62: Wind Curtailments
2013–2014

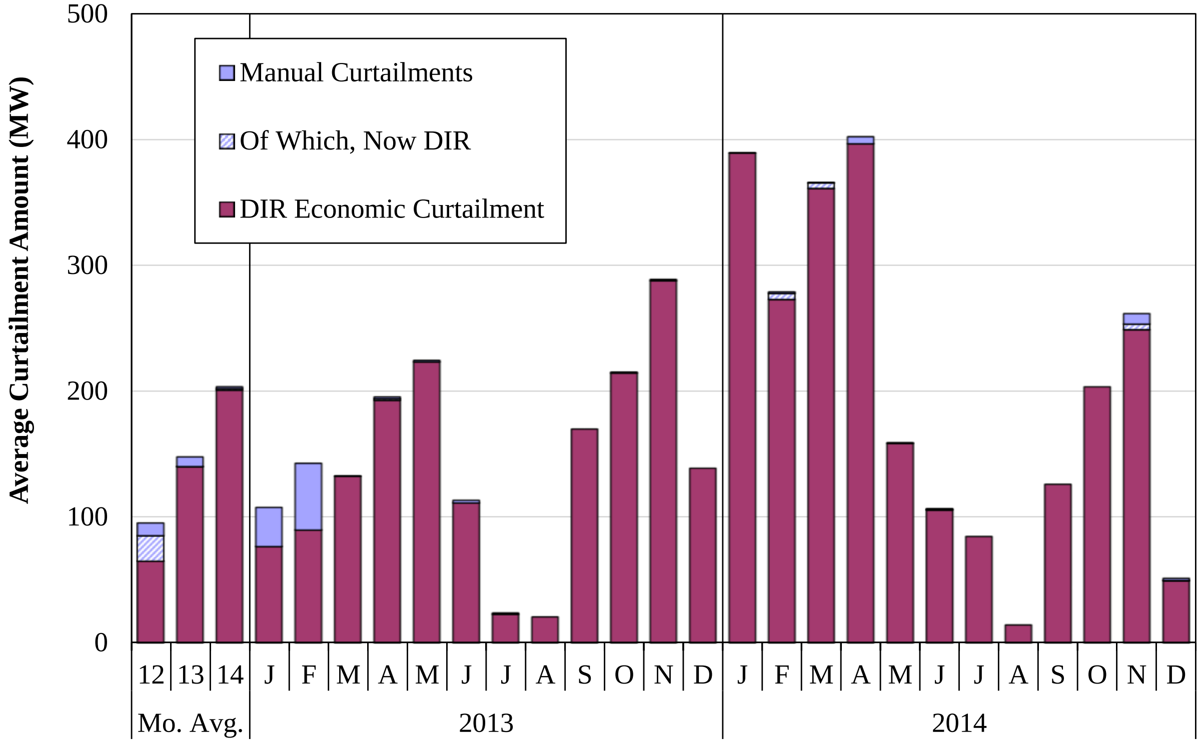


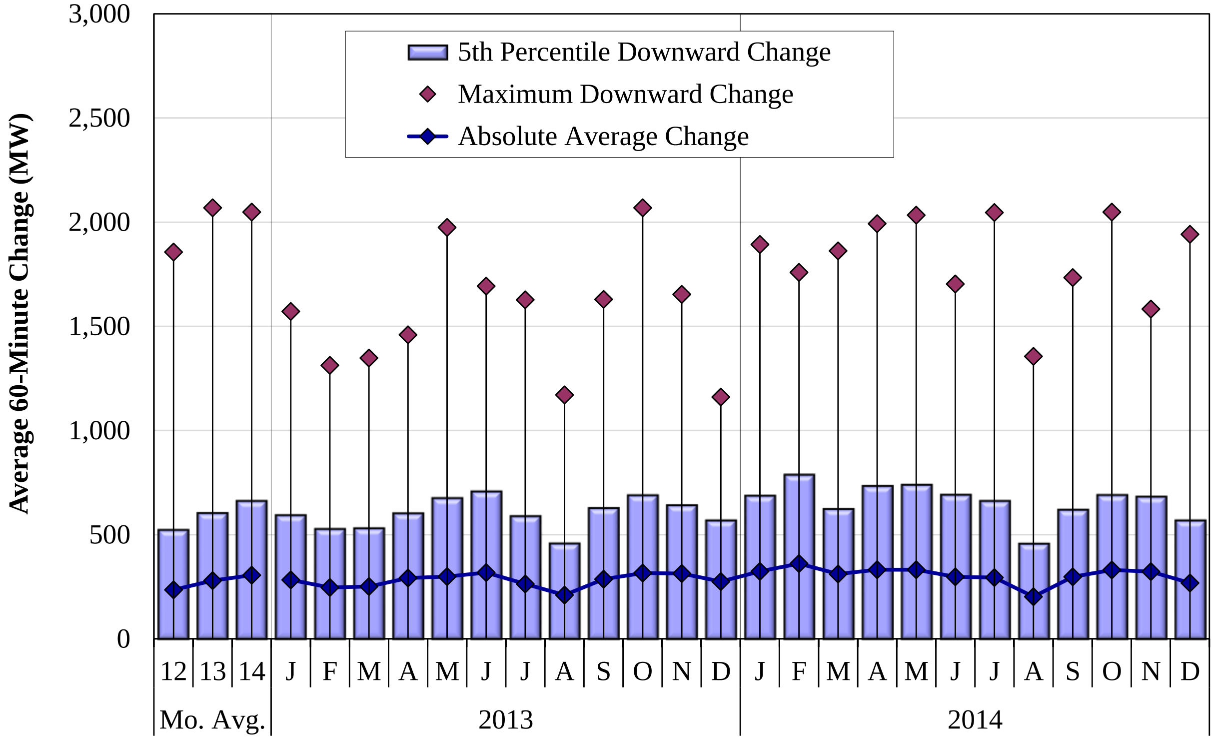
Figure A63: Wind Generation Volatility

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 A63 summarizes the volatility of wind output on a monthly basis over the past two years by showing:

- The average absolute value of the 60-minute change in wind generation in the blue line;
- The largest five percent of hourly decreases in wind output in the blue bars; 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 A63: Wind Generation Volatility
2013–2014



J. Inferred Derates

As noted above, in 2014 MISO implemented a new screening procedure intended to identify resources experiencing an unreported derate condition, or failing to adequately follow dispatch signals. MISO's criteria are established by boundaries seven percent above and below dispatch instructions for units that are deviating for three or more 5-minute instruction intervals.[20] Operators at MISO review the results of these screens in real-time and contact deviating generators and may take the units off control if the behavior persists. During MISO's design phase for this procedure and related tools, the IMM informed MISO that the tools were not designed to identify units that may be chronically not responding to dispatch signals over multiple intervals. The current system focuses on a very short time frame and is designed to support control area criteria, such as ACE. Consequently, a unit that may be effectively derated by large amounts that accumulate over multiple intervals and is unable to follow dispatch may not be identified by MISO's current tools and procedures. Additionally, the new screen has similar shortfalls to the tolerance bounds that are used in the settlement's process where units operating at high output levels and low ramp rates are not detected when not follow dispatch instructions.

[20] This is compared to the eight percent threshold that is currently used for the Failure to Follow Dispatch Flag in the settlements process.

Resources are required to update their real-time offer parameters and report derates under MISO's Tariff.[21] We have in recent years found numerous examples where resources were operating well below their economic output levels (often reflected in their DA schedules). In these cases, the resources were effectively derated in real time, but were not put off control or derated in real time.

This can undermine reliability by causing operators to believe they have more available capacity than they actually do. It can cause less effective dispatch and congestion management since the derated units would not provide the energy or congestion relief the dispatch is seeking. It directly impacts the resource's eligibility to receive DAMAP payments and allows the resource to avoid RSG charges. Finally, in some cases the derated capacity was actually selected to provide spinning reserves, which results in MISO meeting its requirements with capacity that cannot respond if needed in an emergency.

Figure A64 and Figure A65: Unreported Inferred Derates.

Figure A64 summarizes our review of instances in 2014 when units were effectively derated in real time and did not update their economic maximums in their offers. The bottom panel shows the average hourly quantity of unreported derates for all on-peak hours. Derates are shown separately for capacity that was unavailable but was scheduled for regulation, spinning reserves, or credited for providing headroom (latent reserves) in MISO's reliability analysis. The diamond marker shows the maximum hourly quantity in the month. The top panel shows the cumulative DAMAP and ASM clearing payments that were made in each month that should not have been made, and RSG charges that were avoided because the resource did not report the derate to MISO.

Figure A65 shows a histogram of cumulative inferred derate quantities in each hour in 2014. The curve shown by the black line indicates the share of inferred derates (on the right vertical axis) that are less than the derate amount (on the horizontal axis). The marker indicates the median derate.

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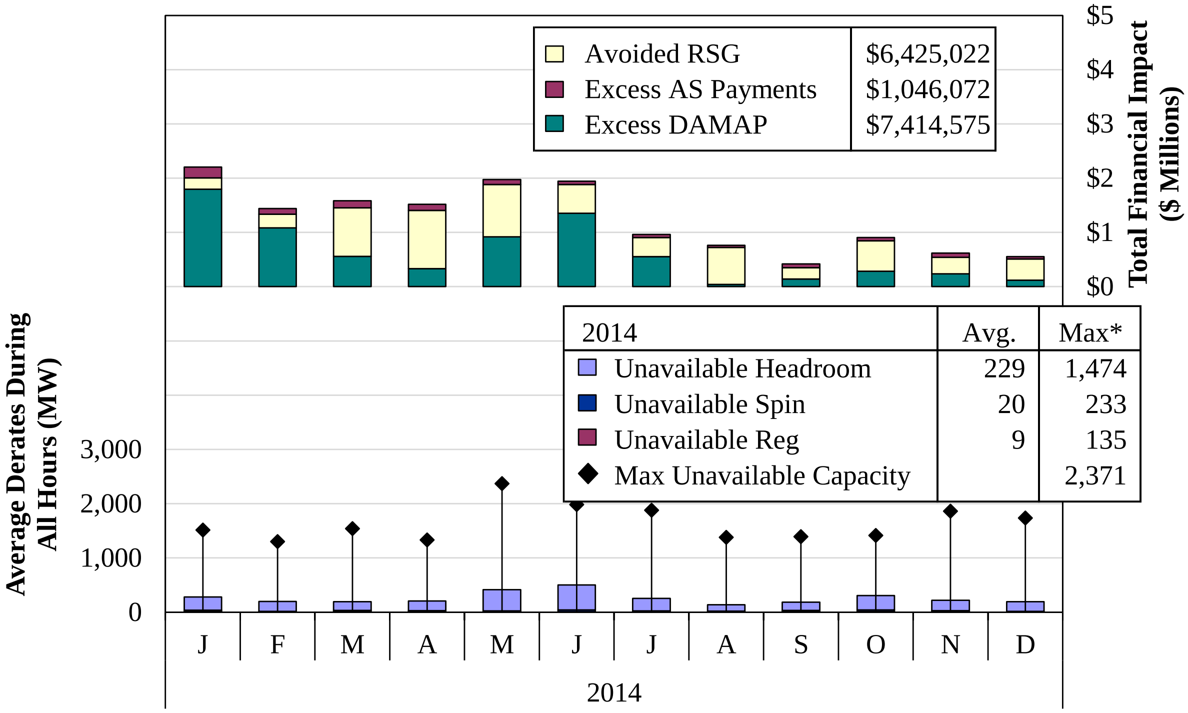
21 As MISO notes in the relevant BPM, under Generator Derate Procedure Instructions:

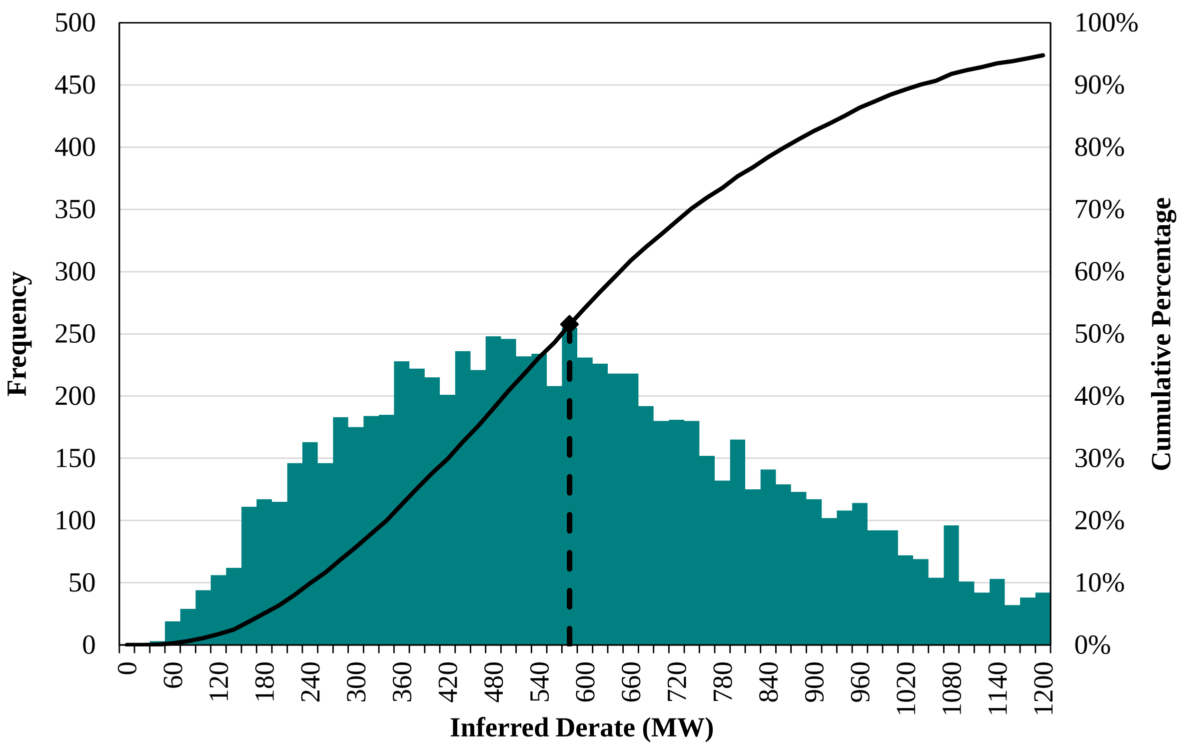
> Under the EMT Section 39.2.5(c), the values in Generation Offers shall reflect the actual known physical capabilities and characteristics of the Generating Resource [or Dynamic Dispatchable Resource (DRR)] on which the Offer is based. As defined in the EMT, the Economic Minimum and Economic Maximum is the minimum and maximum achievable MW level at which a Generation Resource may be dispatched by the UDS in real time under normal system conditions for an Hour on a particular Operating Day.
>
> 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. Unit derates should not be managed solely with an adjustment to the ramp rate offer.

Figure A64: Unreported ("Inferred") Derates
2014



* Daily Average Maximum

Figure A65: Distribution of Unreported ("Inferred") Derates
2014



K. Generator Deviations

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.[22] The purpose of the tolerance band is to permit a level of deviations that balances the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. MISO's criteria for identifying deviations, both the percentage bands and the consecutive interval test, are significantly more relaxed than most other RTOs including NYISO, CAISO, and PJM.

Having a relatively relaxed tolerance band allows resources to effectively derate themselves by simply not moving over many consecutive intervals, which is discussed in the previous subsection. 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.

Figure A66 and Figure A67: Frequency of Net Generator Deviations

Figure A66 shows a histogram of MISO-wide interval deviations during peak hours in summer months without applying any deviation tolerance rules. Figure A67 shows the same results for peak hours on only the 10 highest-load days. 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.

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, which has a number of advantages compared to the current output-based thresholds:

22 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.

- 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 A66: Frequency of Net Deviations
Peak Summer Hours, 2014

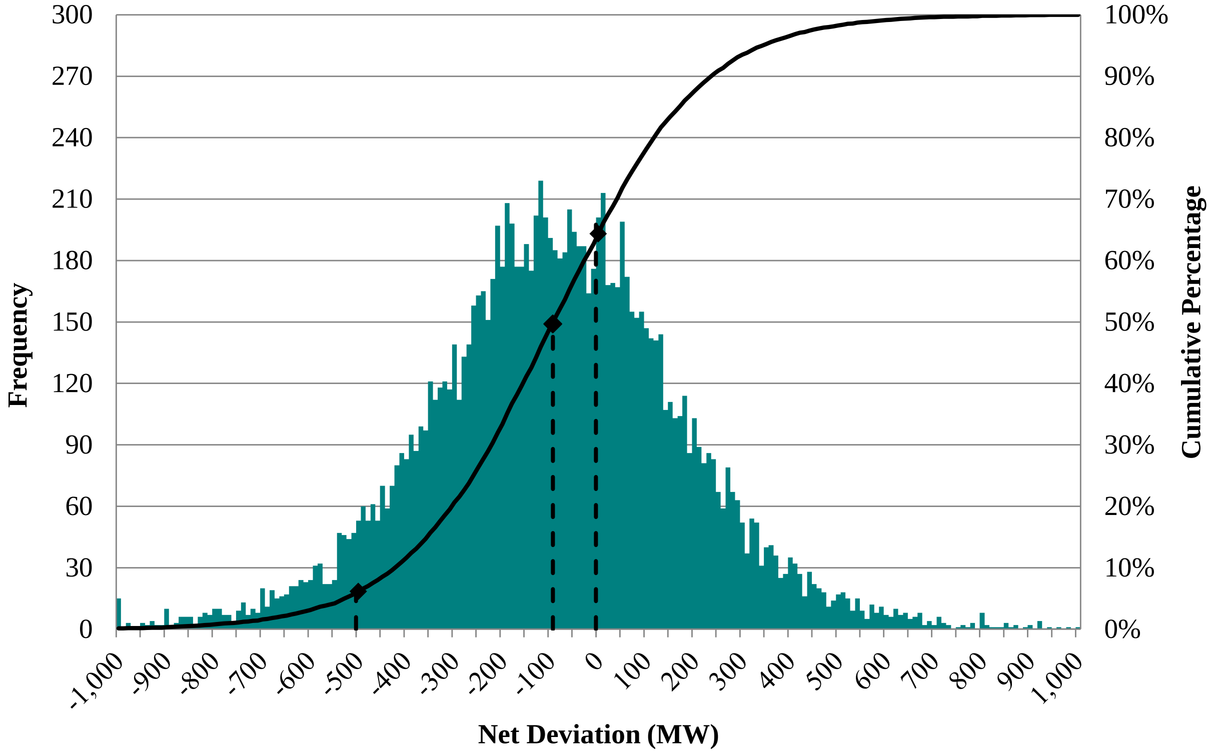
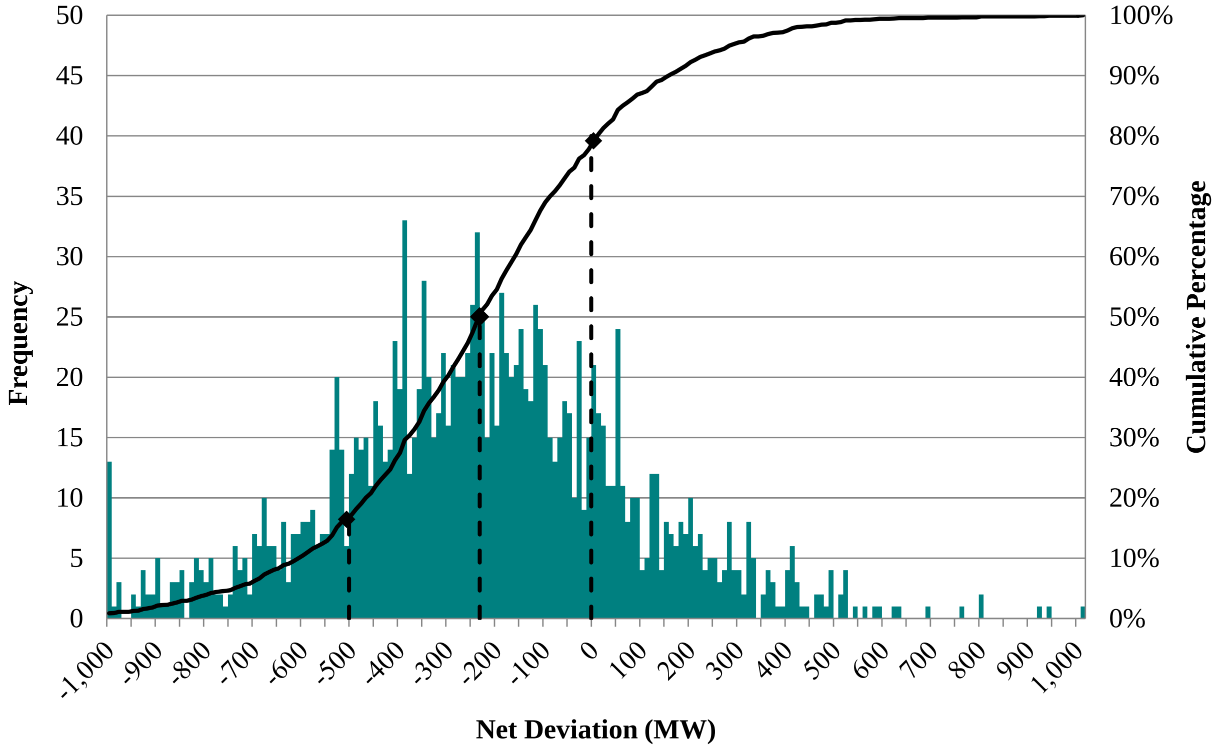


Figure A67: Frequency of Net Deviations
Top 10 Summer Hours, 2014



The specific threshold calculation we propose equals one-half of the resource's five-minute ramp capability plus a value that corresponds to the set-point change for the direction in which the unit is moving (i.e., set-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.

Figure A68: Average Deviations by Month

Figure A68 shows monthly average gross deviations (both excessive and deficient) and net deviations by month. This figure shows the deviations using MISO's current deviation tolerance rules as well as under the proposed rules.

Figure A68: Average Deviations by Month

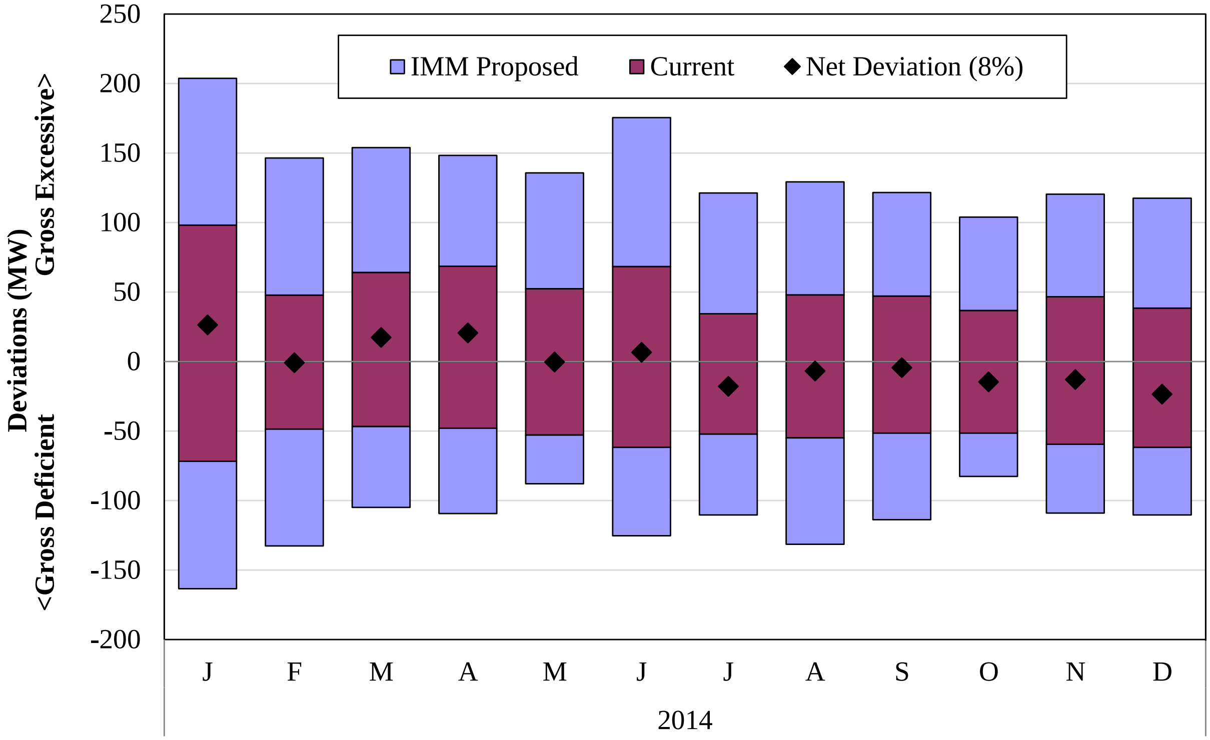


Figure A69: Proposed Change in Uninstructed Deviation Thresholds

Figure A69 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 A69: Proposed Generator Deviation Methodologies

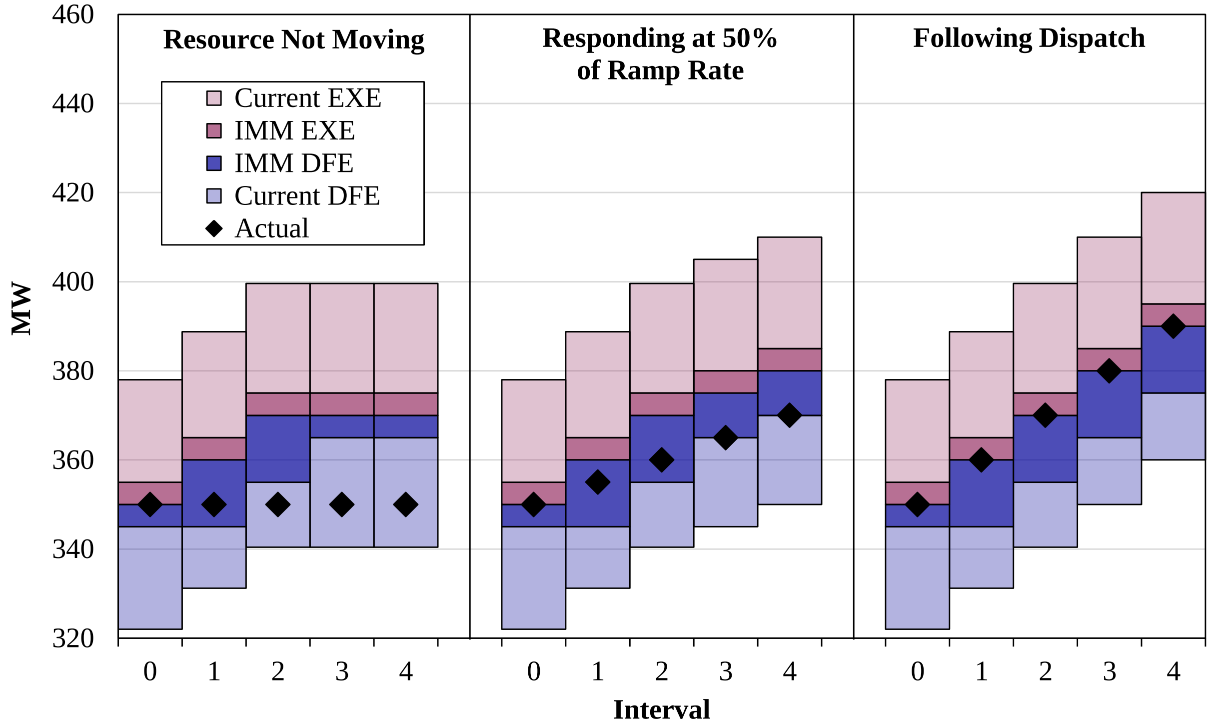
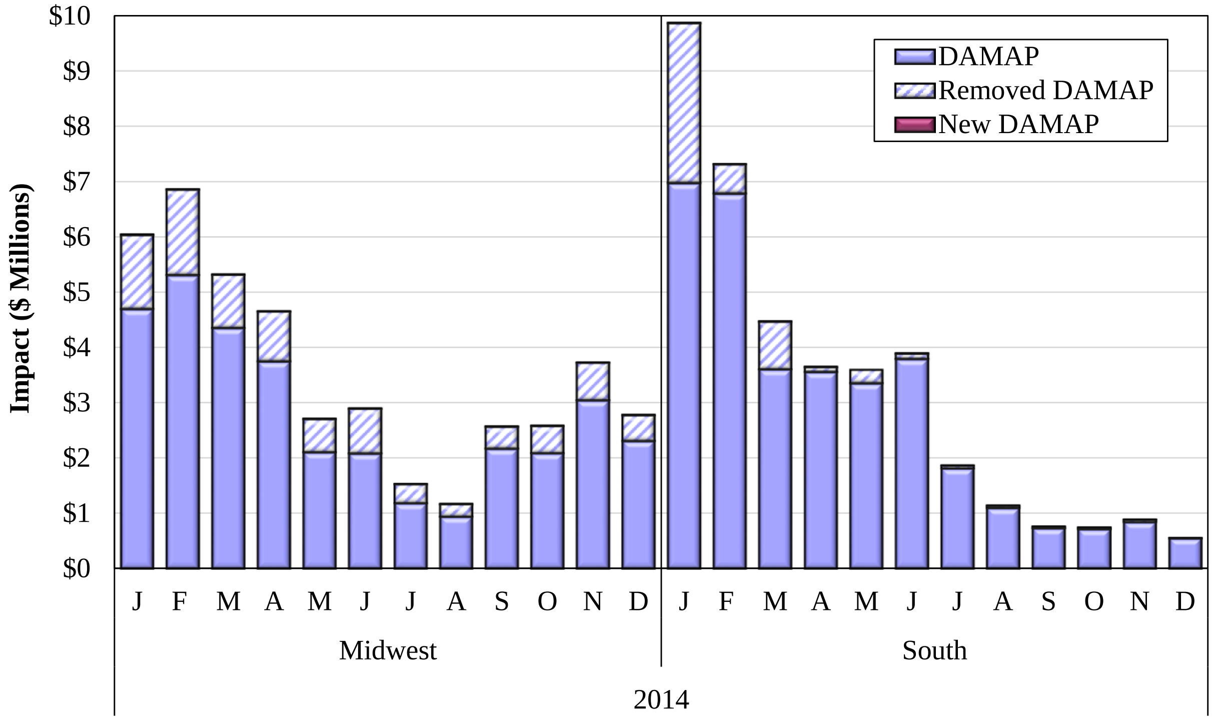


Figure A70: DAMAP Impacts of Proposed Reform

Figure A70 illustrates the consequence of implementing the proposed tolerance bands and using these bands to determine eligibility for DAMAP. The figure shows the results of applying this eligibility criteria to DAMAP paid in 2014. The solid royal blue bar and the hatched region indicates the total amount of DAMAP paid in 2014, the hatched royal blue area is the amount of DAMAP that was paid but would not have been if IMM proposed criteria were in place, and the maroon bar indicates the DAMAP that would be paid under the proposed criteria but was not paid this year.

Figure A70: Impact of IMM-Proposed Eligibility Rules on DAMAP



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 LMPs to be higher 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. 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 this revenue contributing to the recovery of the costs of the network. FTRs provide an instrument for market participants to use to hedge 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 and balancing congestion costs and payments to FTR holders for the last two years. As mentioned above, 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.

Figure A71: Day-Ahead and Balancing Congestion and Payments to FTRs
2012–2014

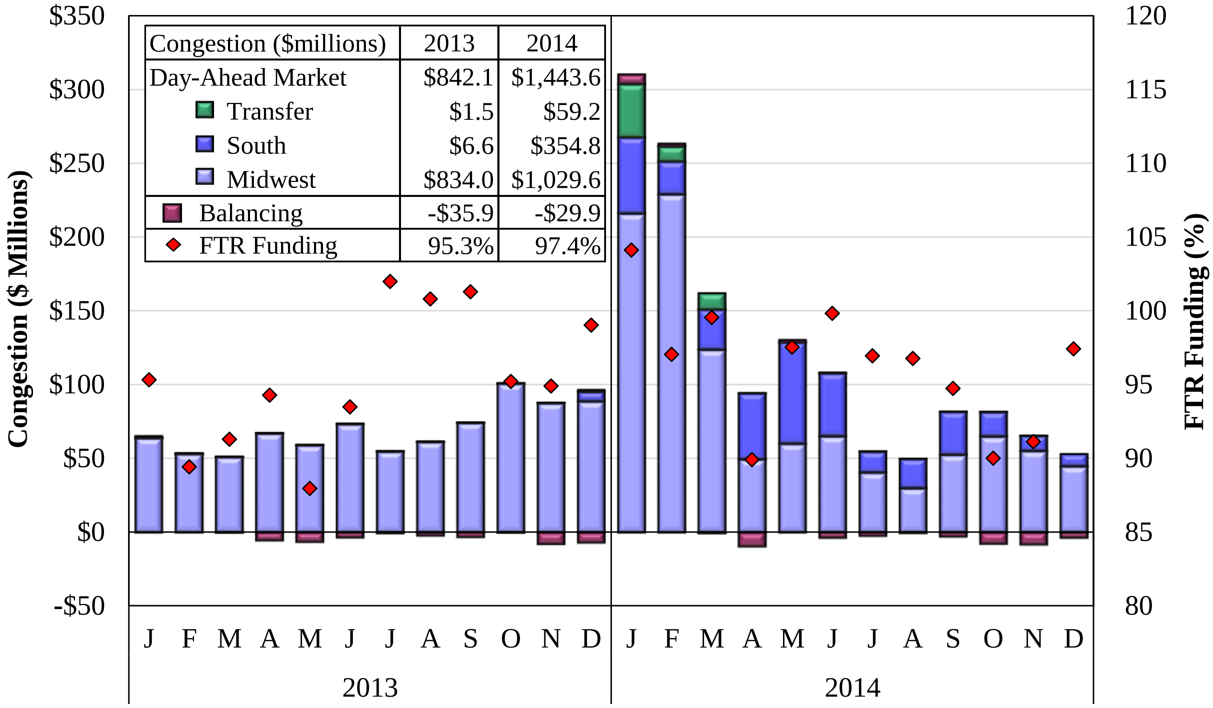
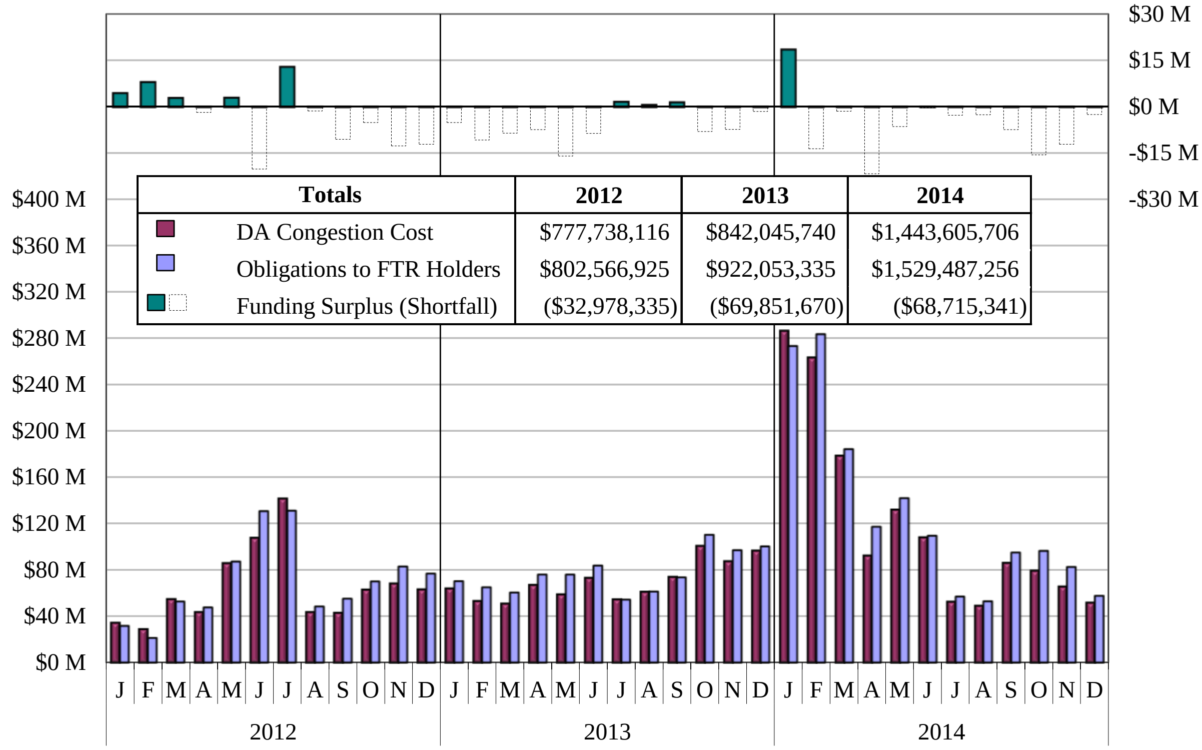


Figure A72 and Figure A73: Payments to FTR Holders

Figure A72 compares monthly day-ahead congestion revenues to FTR obligations for 2012 to 2014. The top panel shows the FTR funding shortfall or surplus in each month. Significant shortfalls are undesirable because they introduce uncertainty and can distort FTR values. Significant funding surpluses are similarly undesirable because they indicate that the capability of the transmission system was not fully available in the FTR market.

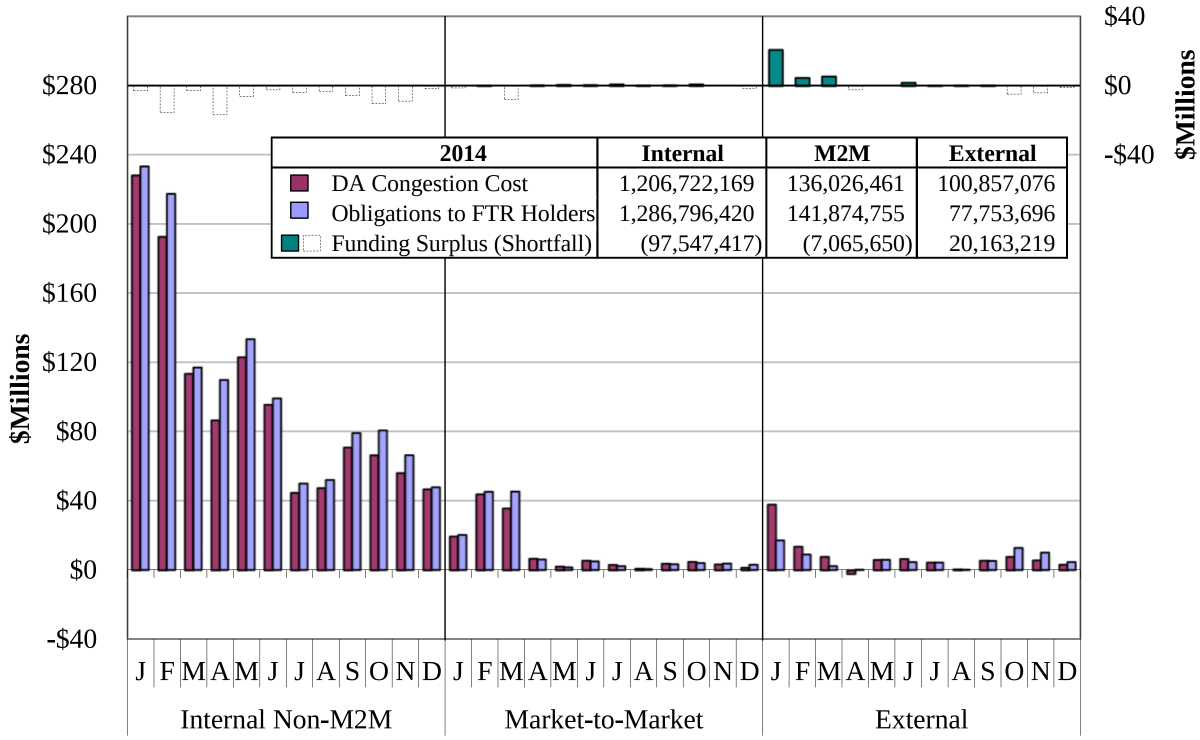
Figure A73 compares monthly total day-ahead congestion revenues to monthly total FTR obligations in 2014 by type of constraint (i.e., internal, market-to-market or external). As in the prior figure, the top panel shows the FTR funding shortfall or surplus in each month.

Figure A72: Day-Ahead Congestion Revenue and Obligations to FTR Holders
2012–2014



Totals	2012	2013	2014
DA Congestion Cost	$777,738,116	$842,045,740	$1,443,605,706
Obligations to FTR Holders	$802,566,925	$922,053,335	$1,529,487,256
Funding Surplus (Shortfall)	($32,978,335)	($69,851,670)	($68,715,341)

Figure A73: Day-Ahead Congestion Revenue and Payments to FTR Holders
2014

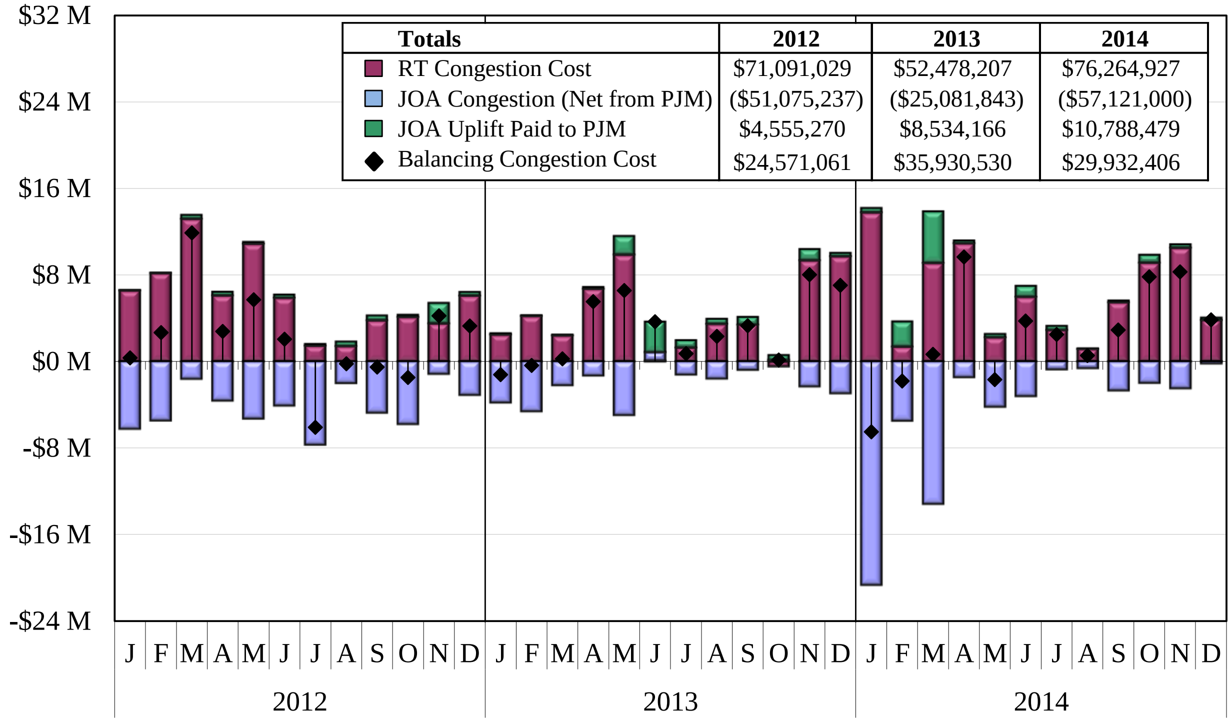


2014	Internal	M2M	External
DA Congestion Cost	1,206,722,169	136,026,461	100,857,076
Obligations to FTR Holders	1,286,796,420	141,874,755	77,753,696
Funding Surplus (Shortfall)	(97,547,417)	(7,065,650)	20,163,219

Figure A74: Balancing Congestion Costs

To better understand balancing congestion costs, Figure A74 shows these costs disaggregated into (1) the real-time congestion costs incurred to reduce (or increase) the MISO flows over certain 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 positive in the figure), while PJM's payment to MISO for this excess flow is shown as a negative cost (i.e., 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.

Figure A74: Real-Time Congestion Costs
2012–2014



B. 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.[23] 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.[24] 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.

Figure A75: FTR Auction Revenues and Obligations

In the MPMA and Monthly FTR auctions, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths.

23 An FTR obligation can be in the "wrong" direction (counter flow) and can require a payment from the FTR holder.

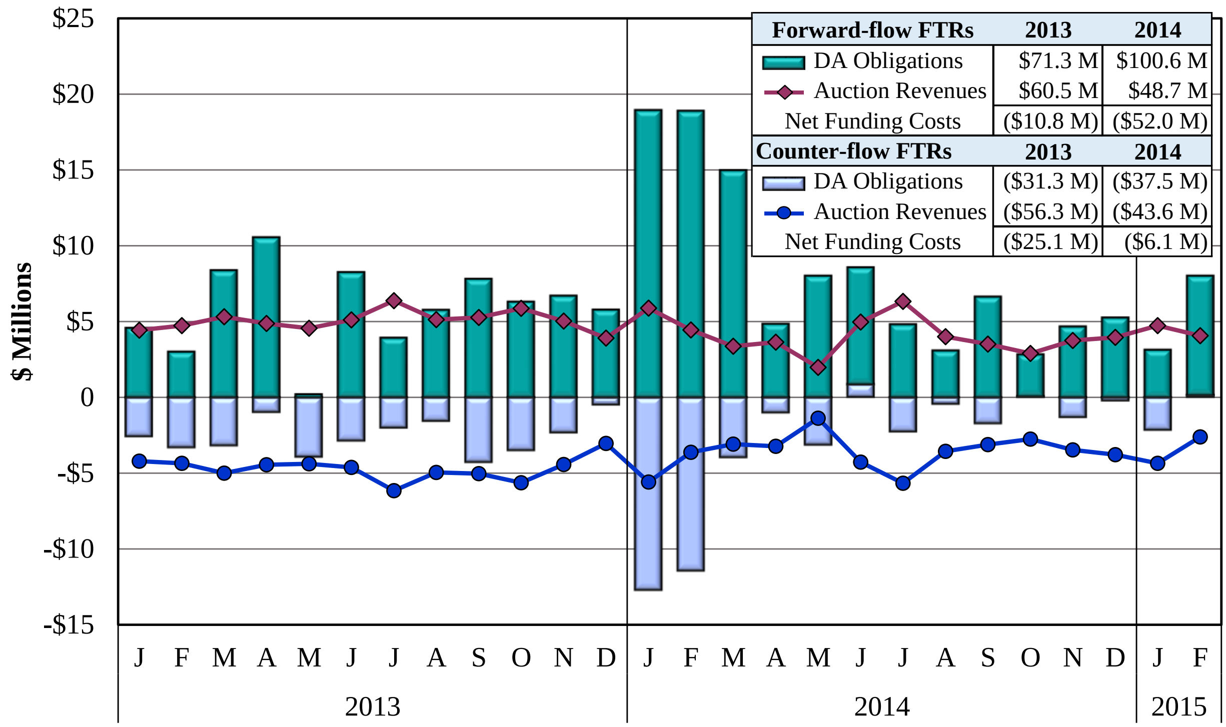
24 The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

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 monthly and 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.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A75 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 A75: Monthly FTR Auction Revenues and Obligations
2013–2014



Forward-flow FTRs	2013	2014
DA Obligations	$71.3 M	$100.6 M
Auction Revenues	$60.5 M	$48.7 M
Net Funding Costs	($10.8 M)	($52.0 M)
Counter-flow FTRs	**2013**	**2014**
DA Obligations	($31.3 M)	($37.5 M)
Auction Revenues	($56.3 M)	($43.6 M)
Net Funding Costs	($25.1 M)	($6.1 M)

C. Value of Congestion in the Real-Time Market

This section reviews the value of real-time congestion, rather than collected congestion costs. As discussed previously, 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.

Figure A76: Value of Real-Time Congestion by Coordination Region

Figure A76 shows the total monthly value of real-time congestion by region and the average number of binding constraints per interval in 2013 and 2014. The bars on the bottom of the chart show the average monthly value against the left axis in each of the past three years. The average number of binding constraints per interval are shown by the colored lines against the right axis.

Figure A76: Value of Real-Time Congestion by Coordination Region
2013–2014

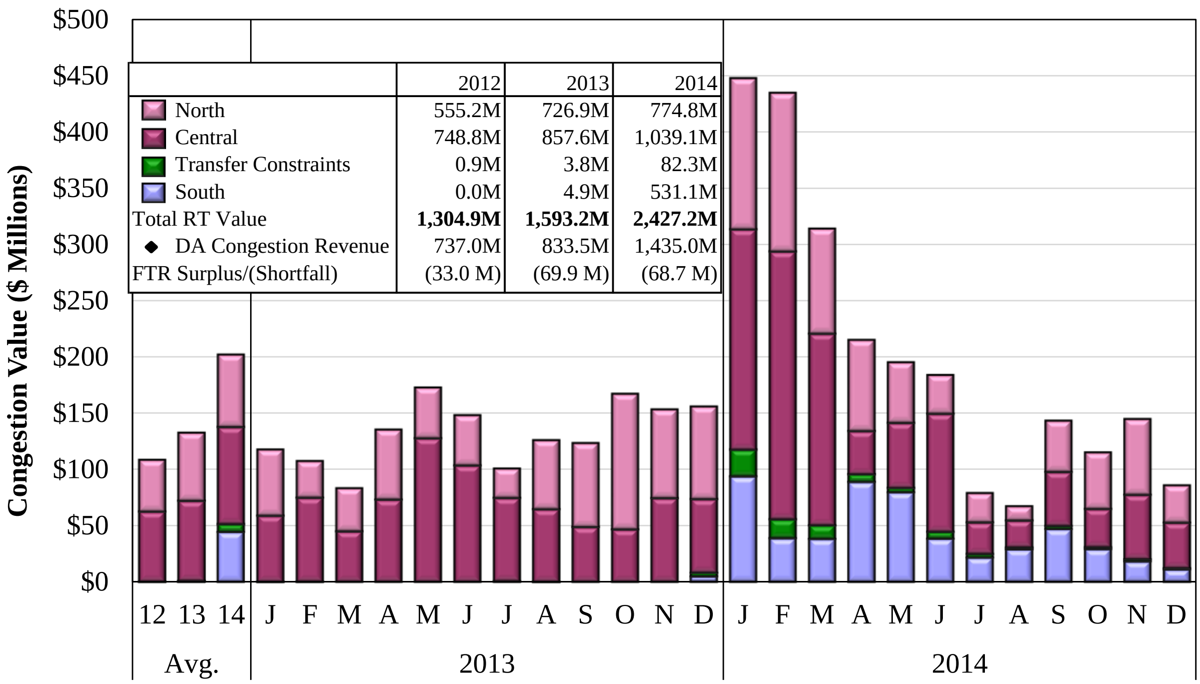


Figure A77: Value of Real-Time Congestion by Type of Constraint

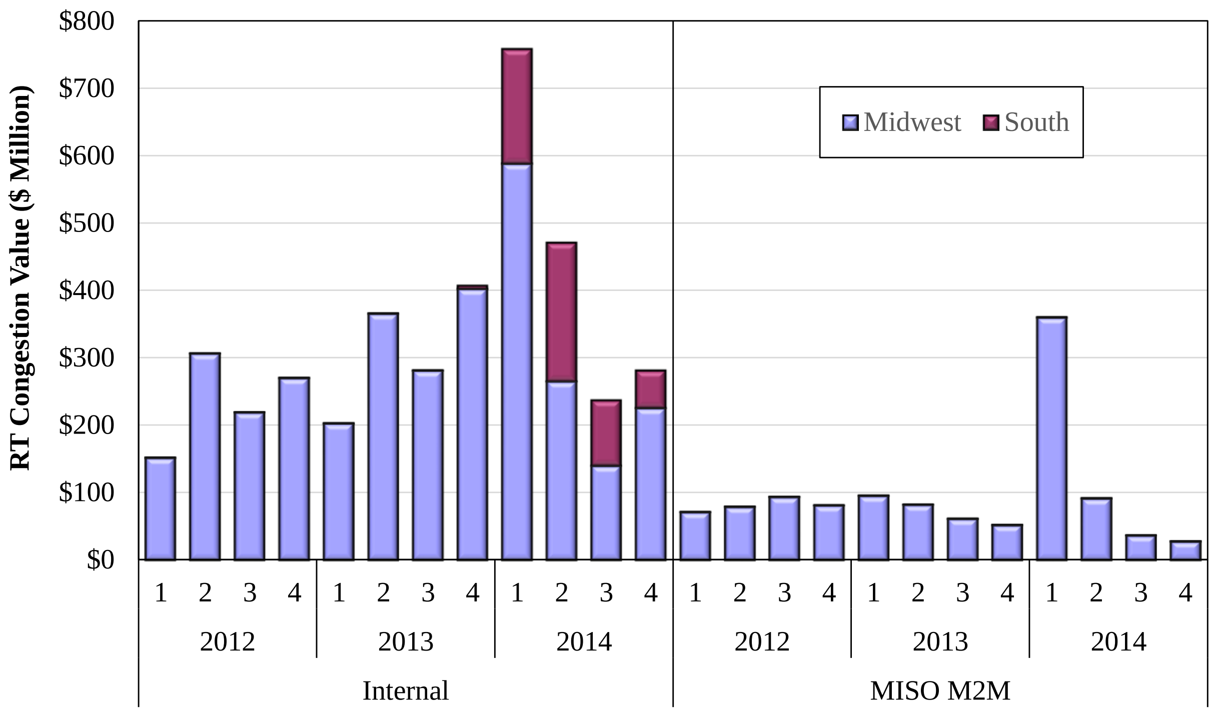
To better identify the nature of constraints and the congestion value, Figure A77 disaggregates the results by type of constraint. We define four constraint types:

- <u>Internal Constraints:</u> Those constraints internal to MISO (where MISO is the reliability coordinator) and not coordinated with PJM.

- 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.
- PJM M2M Constraints: PJM-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 constraints that are not market-to-market constraints.

The flow on PJM 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 A77: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2012–2014



D. Transmission Line Loading Relief Events

With the exception of market-to-market coordination between MISO and PJM and between NYISO and PJM, reliability coordinators in the Eastern Interconnect continue to rely on TLR procedures and the NERC Interchange Distribution Calculator (IDC) 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

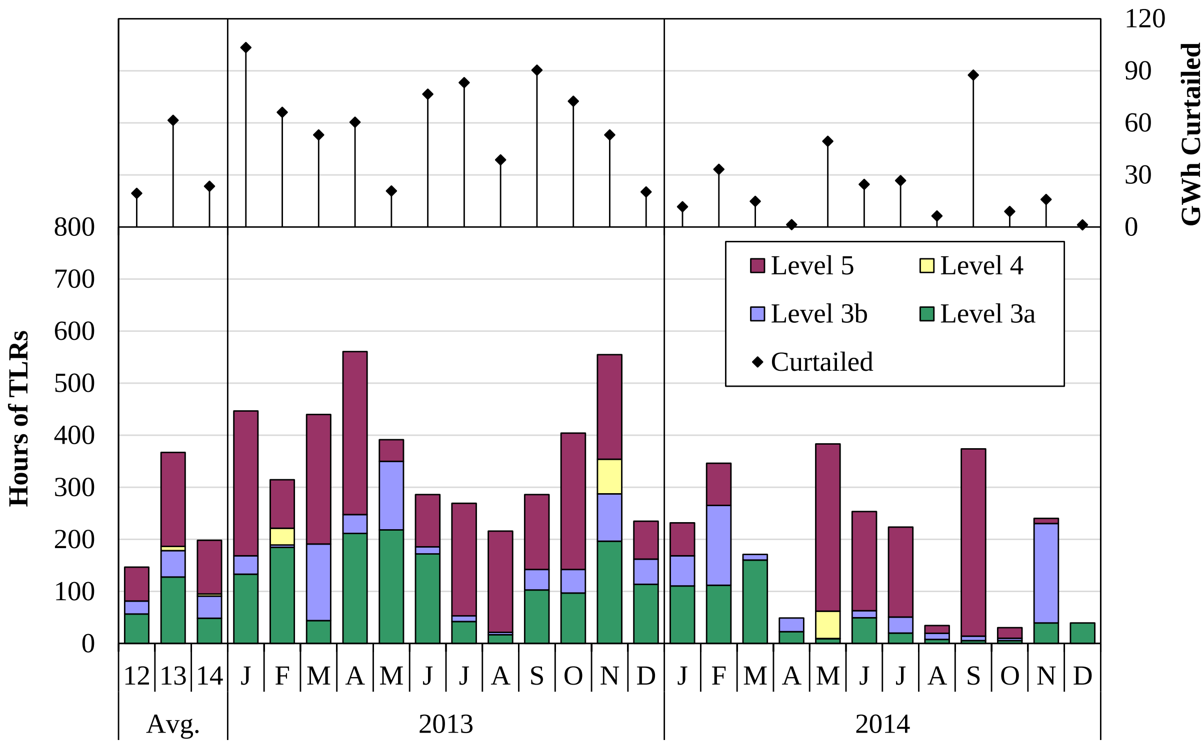
Interconnection-wide process that allows reliability coordinators to obtain relief from entities in other areas that have scheduled transactions that load the constraint. When an external (non-PJM market-to-market) constraint is binding and a TLR is called, MISO receives a relief obligation from the 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 can 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.

Figure A78 and Figure A79: Periodic TLR Activity

Figure A78 shows monthly TLR activity on MISO flowgates in 2013 and 2014. 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 A78: Periodic TLR Activity
2013–2014

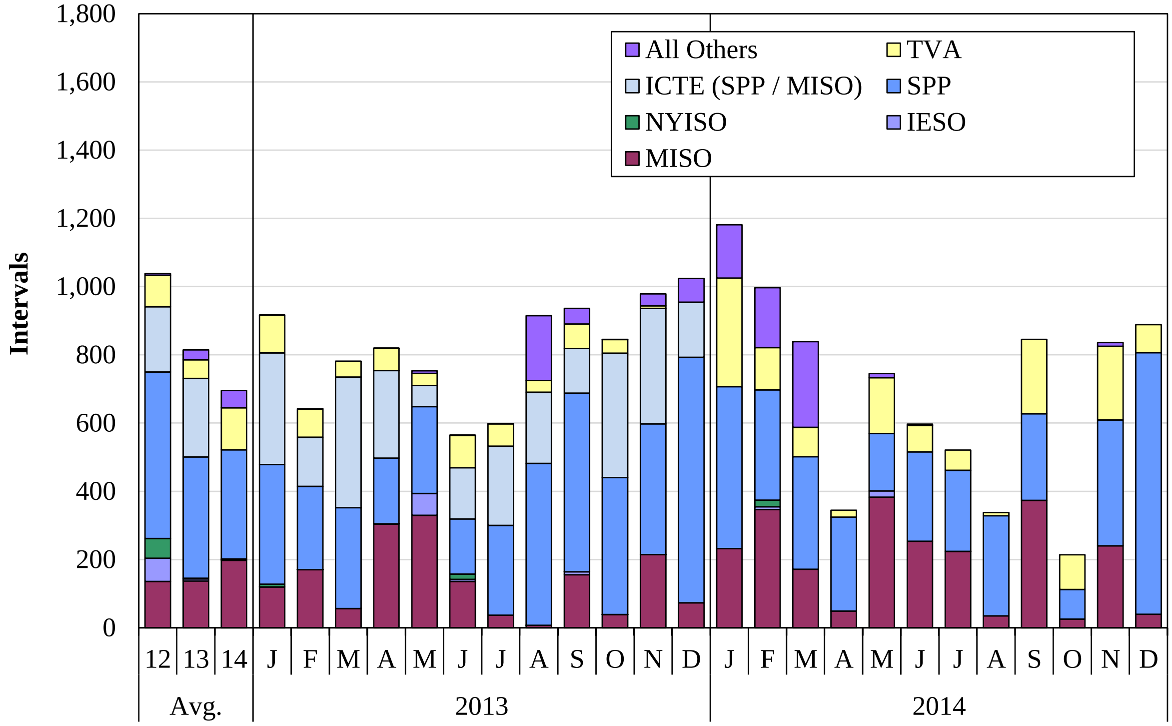


These NERC TLR levels shown in both figures are defined as follows:

- Level 3—Non-firm curtailments;[25]
- Level 4—Commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[26]

Figure A79 shows TLR hours disaggregated by the Reliability Coordinator declaring the TLR.

Figure A79: TLR Activity by Reliability Coordinator
2013–2014



E. 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).

25 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.

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

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).

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 A80: Constraint Manageability

The next set of figures show manageability of internal and MISO-managed market-to-market constraints. Figure A80 shows how frequently binding constraints were manageable and unmanageable in each month from 2013 to 2014.

Figure A80: Constraint Manageability
2013–2014

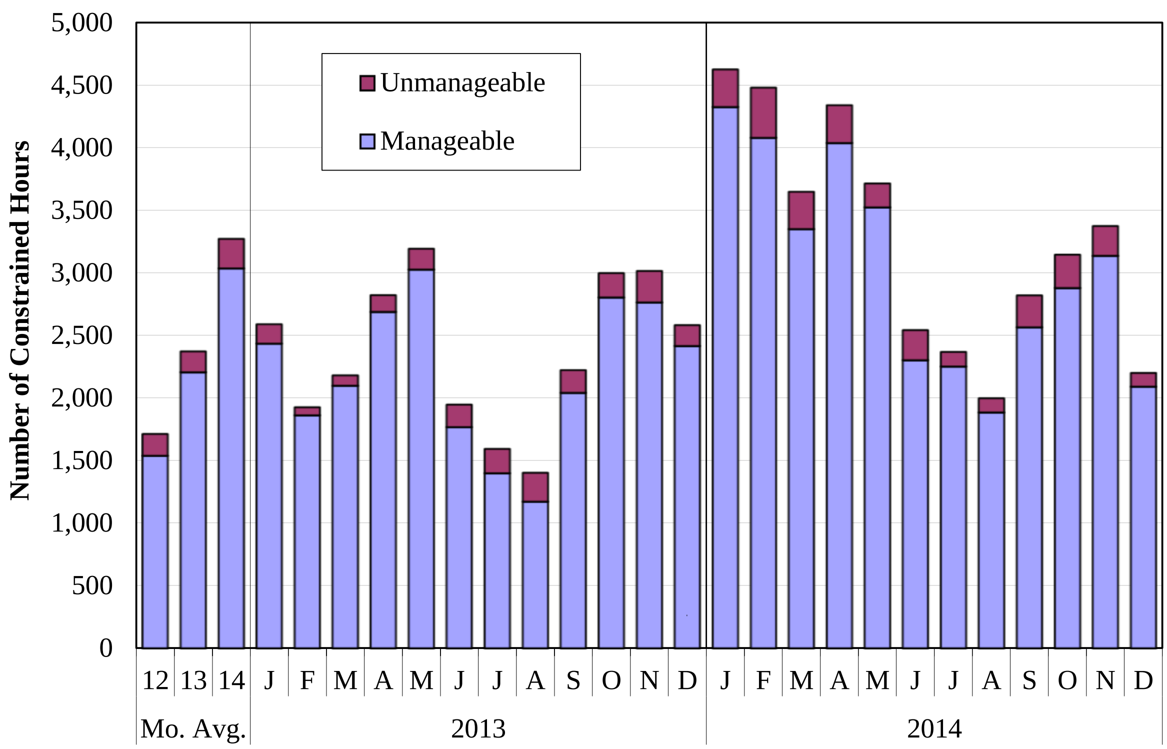


Figure A81: Value of Real-Time Congestion by Voltage Level

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. In order for the MISO markets to perform efficiently, the MVL must reflect the full reliability cost of violating the constraint.

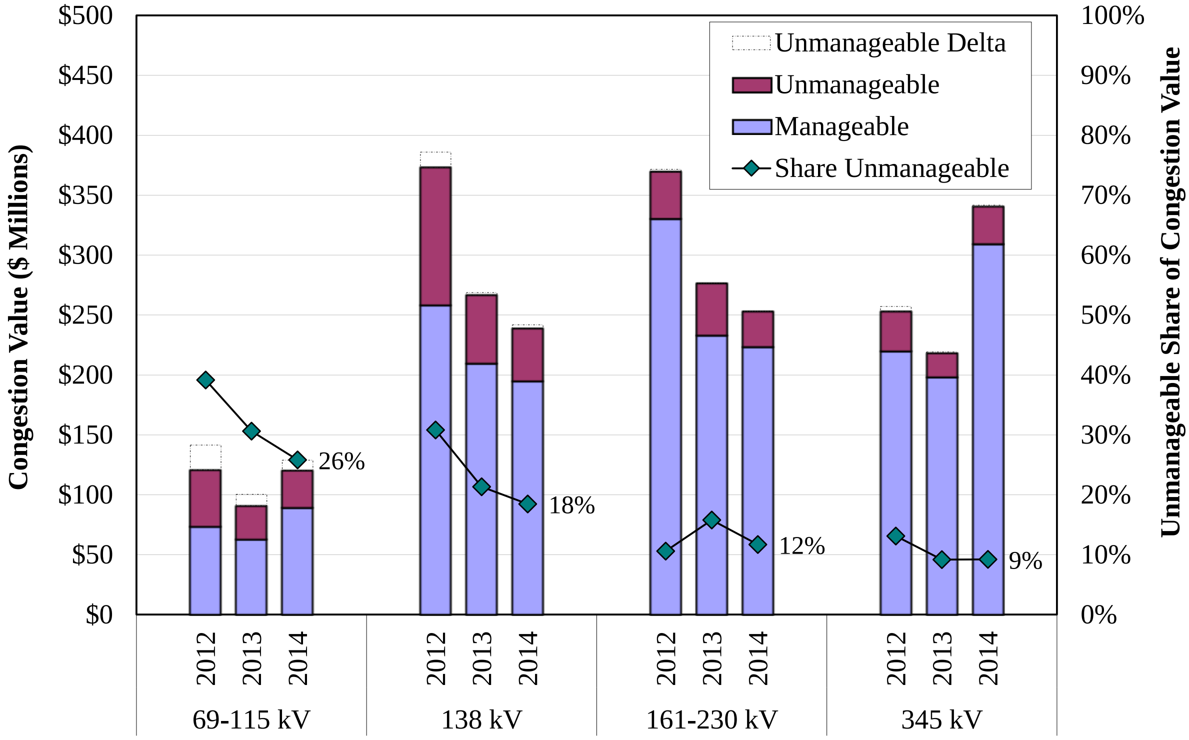
When the constraint is violated (i.e., unmanageable), the most efficient shadow price would be the MVL of the violated constraint. This produces an efficient result because the LMPs will reflect MISO's expressed value of the constraint. Prior to February 2012, when a constraint's flow exceeded its limit 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 A81 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 A81 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]

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.

Figure A81: Real-Time Congestion Value by Voltage Level
2012–2014



F. FTR Market Performance

Because and FTR represents a forward purchase of day-ahead congestion costs, FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion. When this occurs, FTR profits are low (profits = the FTR price minus the day-ahead congestion payments). It is important to recognize, however, that even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may cause actual congestion to be much higher or much lower than values established in the FTR markets. MISO currently runs the FTR market in three timeframes: annual (from June to May), monthly, and a recently implemented Multi-Period Monthly Auction (MPMA). The MPMA was launched in November 2013 and facilitates FTRs trading for future months or seasons in the planning year.

Figure A82: FTR Profits and Profitability

Figure A82 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.

Figure A82: FTR Profits and Profitability
2013–2014

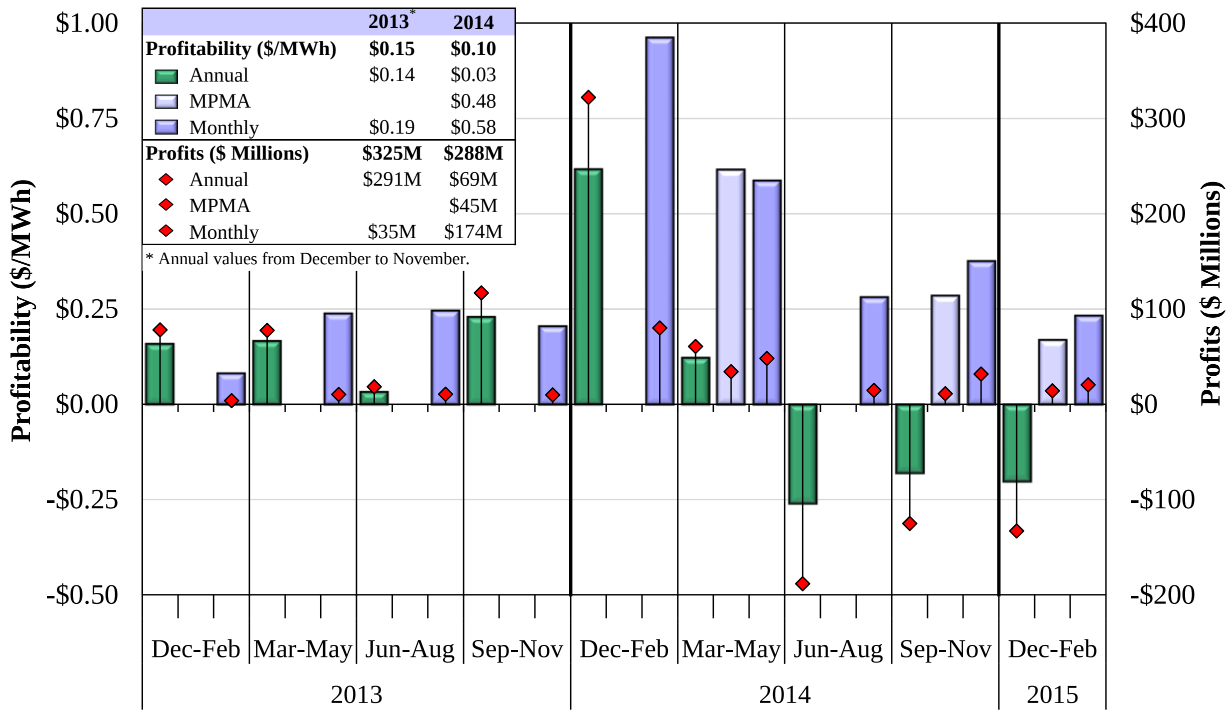


Figure A83 – Figure A85: FTR Profitability

The next four figures show the profitability of FTRs purchased in the annual, seasonal, and monthly FTR auctions in more detail for 2012-2014. 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 A83: FTR Profitability
2012–2014: Annual Auction

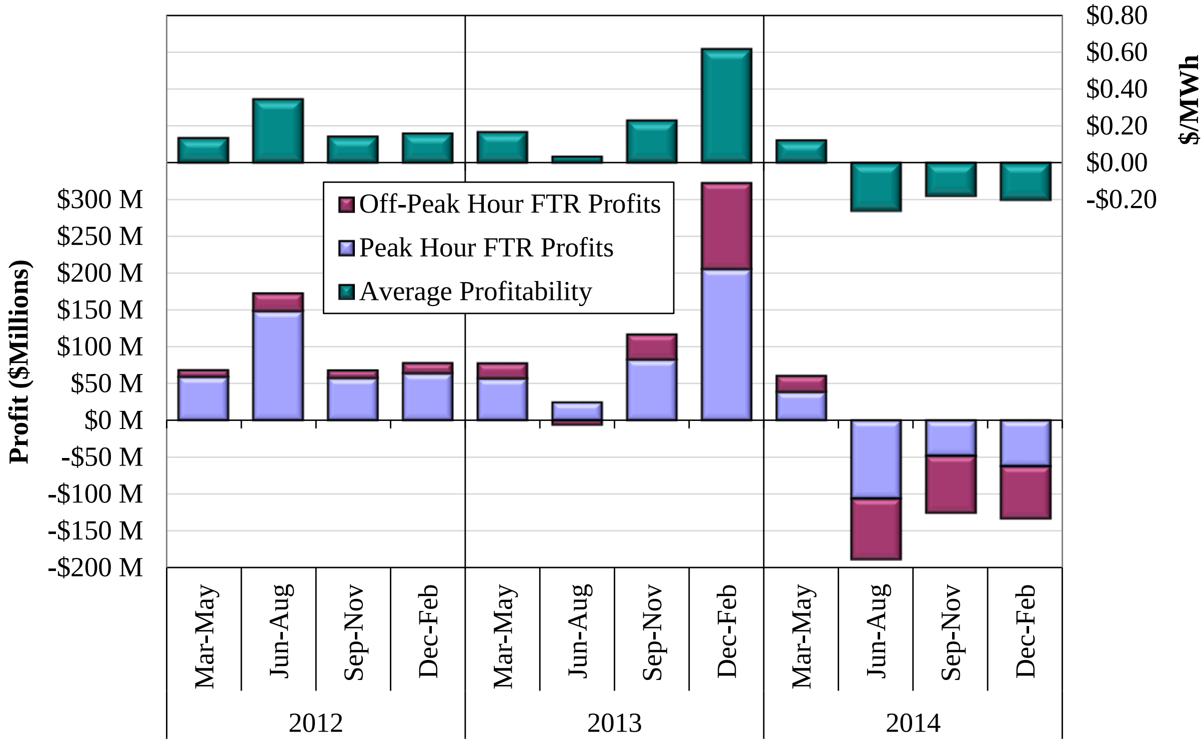


Figure A84: FTR Profitability
2013–2014: Monthly Auction

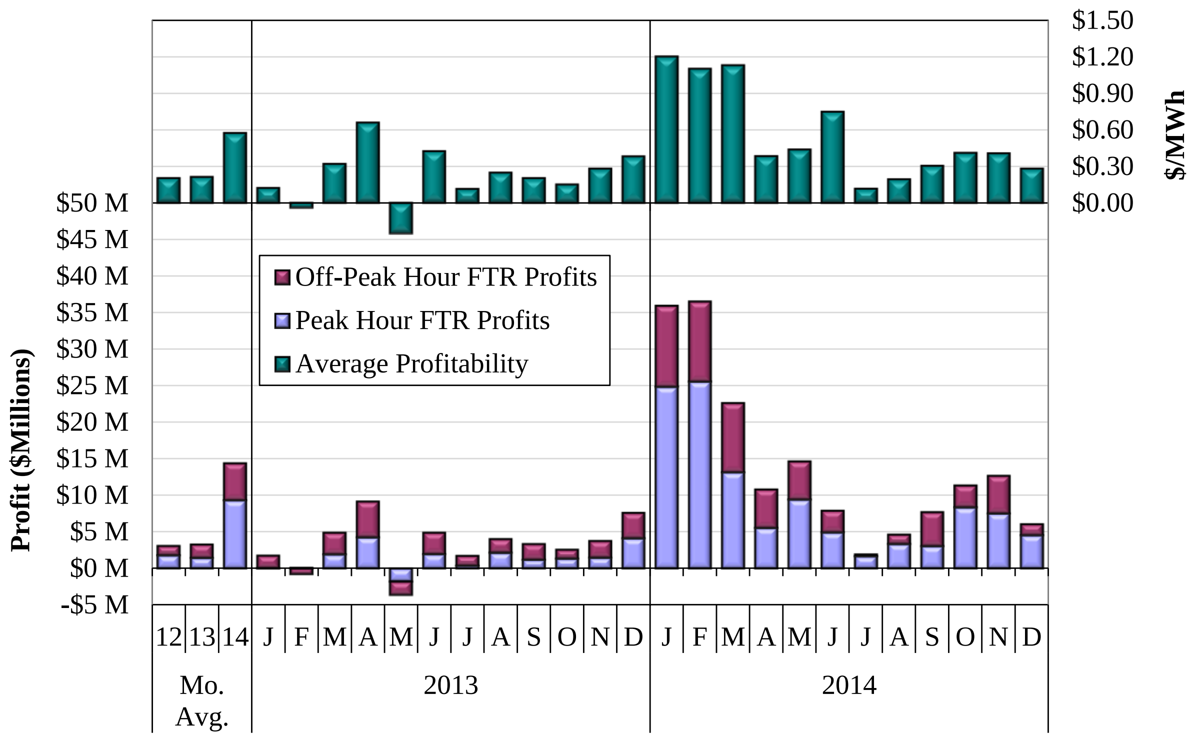


Figure A85: FTR Profitability
2014 Seasonal Auction MPMA

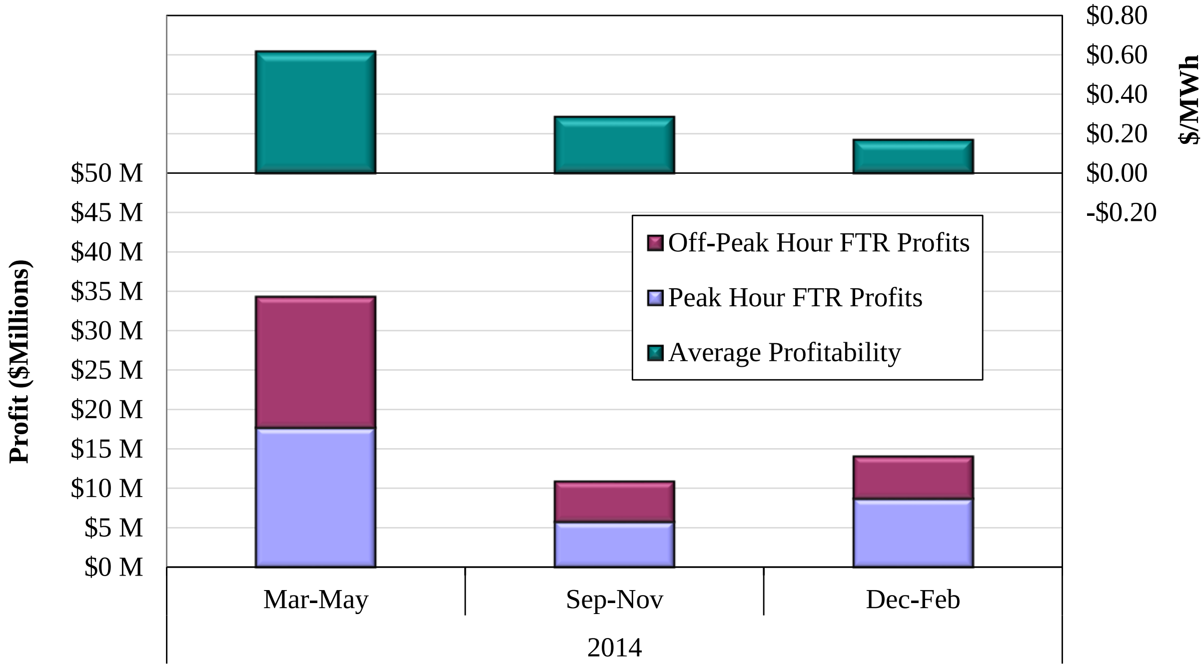


Figure A86 to Figure A99: Comparison of FTR Auction Prices and Congestion Value

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.

Figure A86: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2013–2014: Off-peak Hours

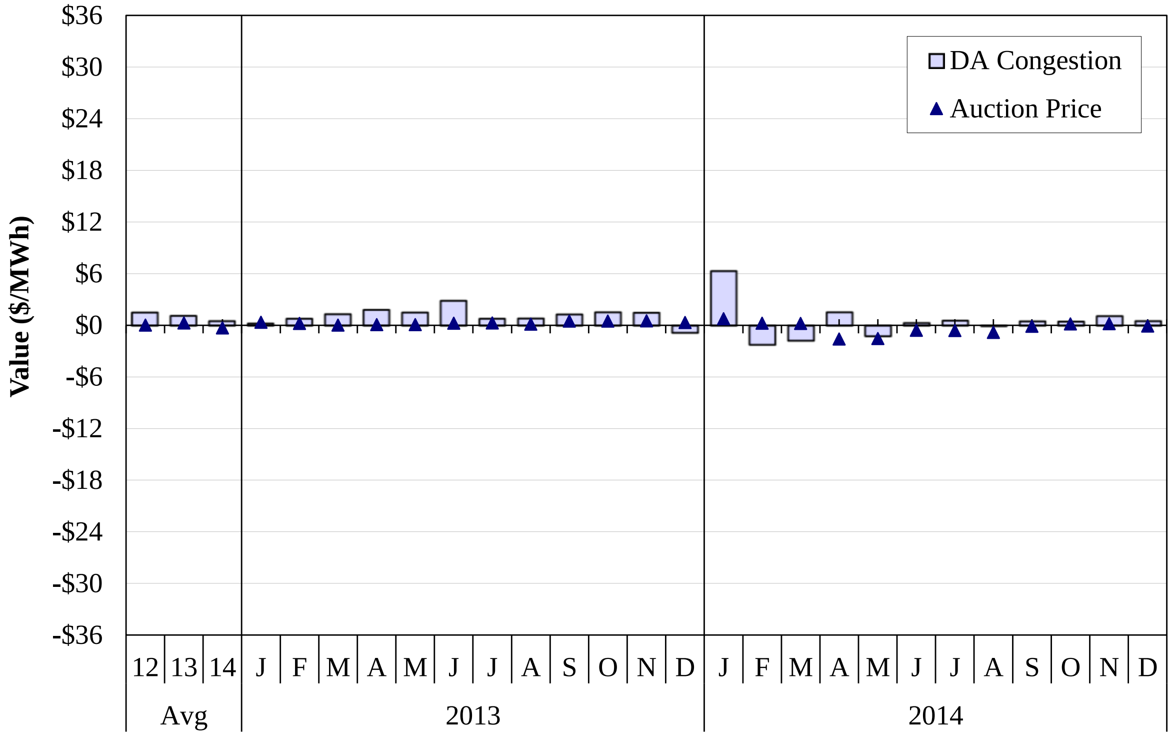


Figure A87: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2013–2014: Peak Hours

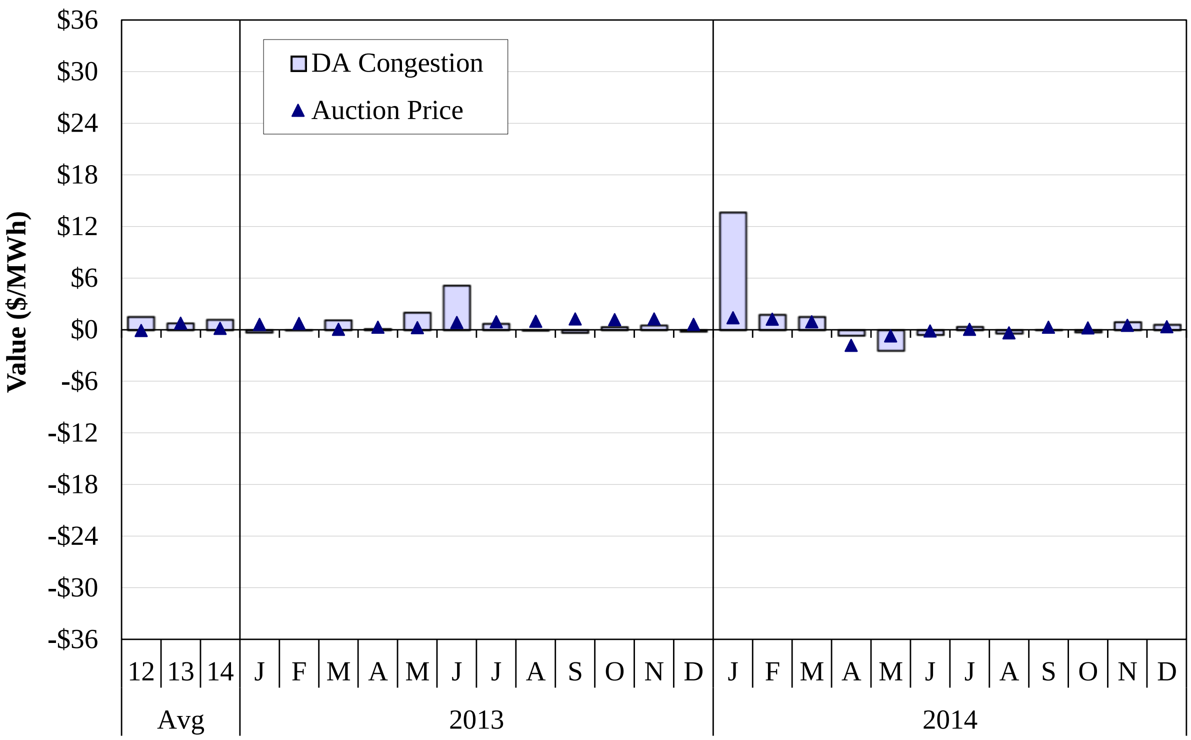


Figure A88: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2013–2014: Off-peak Hours

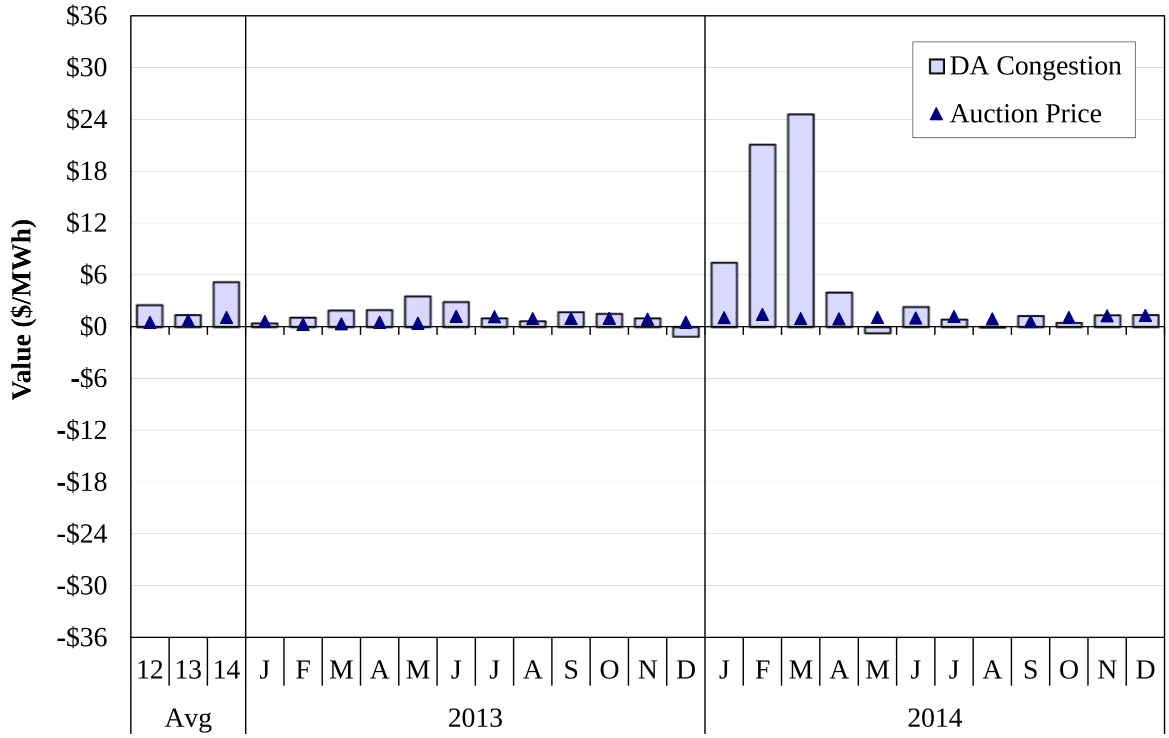


Figure A89: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2013–2014: Peak Hours

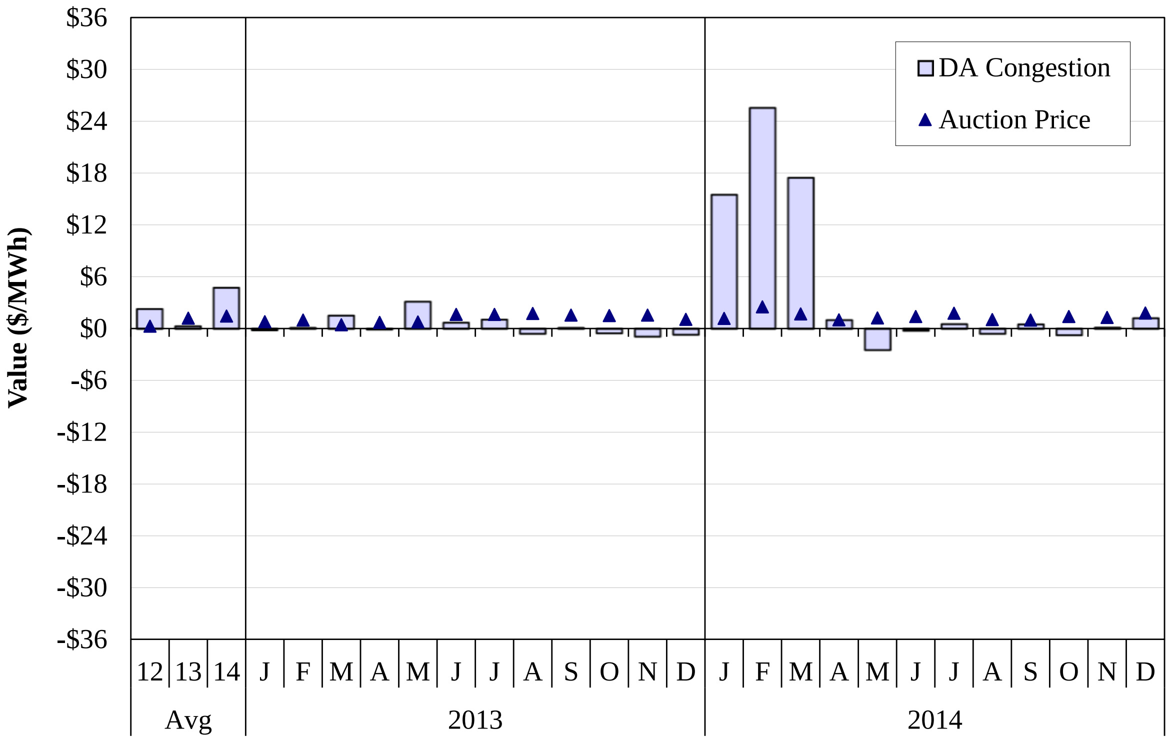


Figure A90: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2013–2014: Off-peak Hours

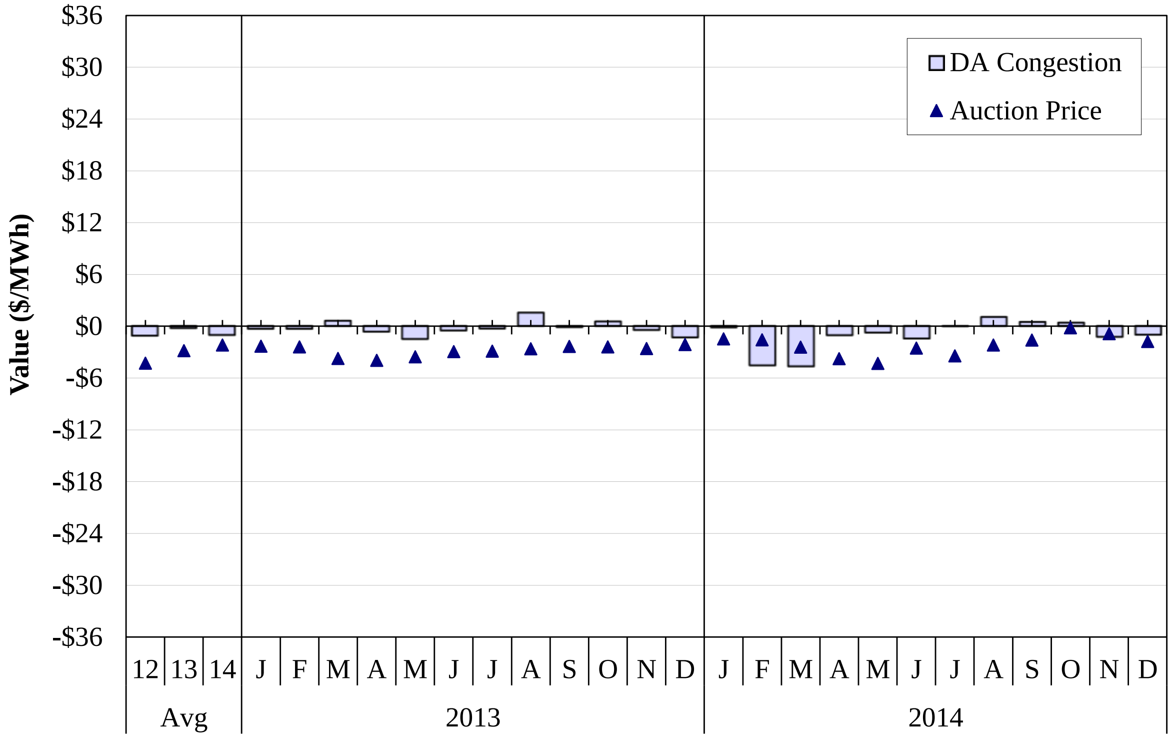


Figure A91: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2013–2014: Peak Hours

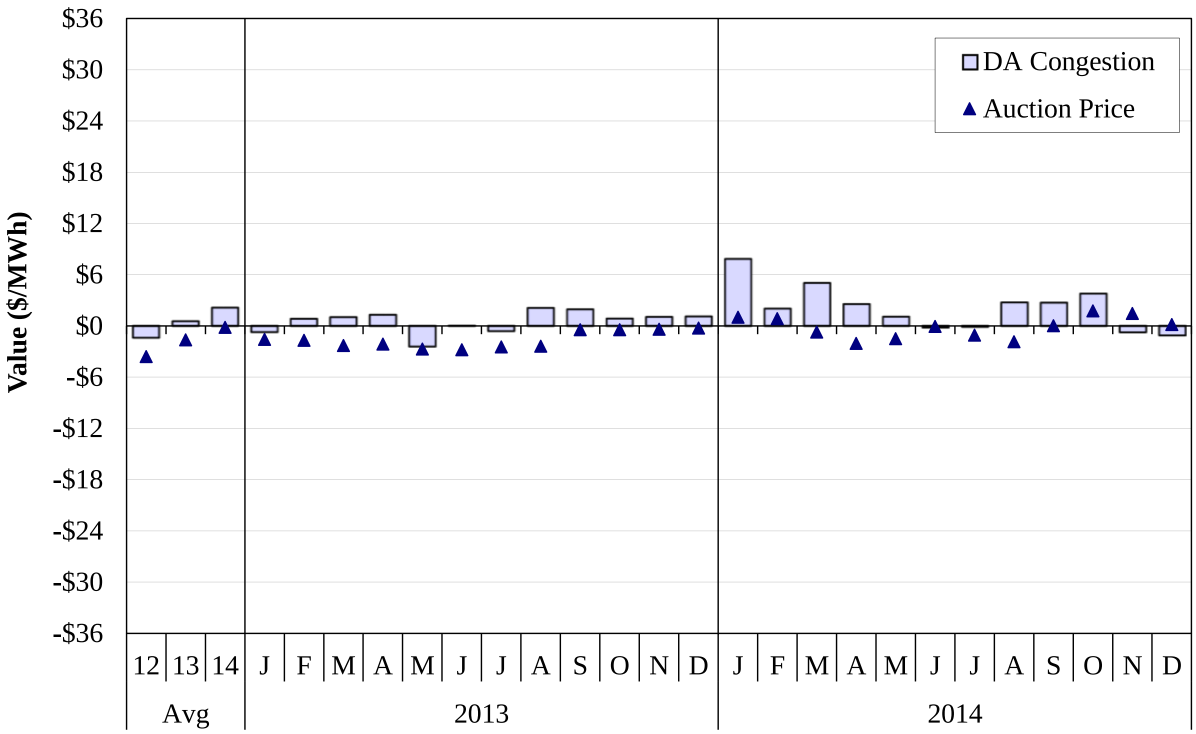


Figure A92: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2013–2014: Off-peak Hours

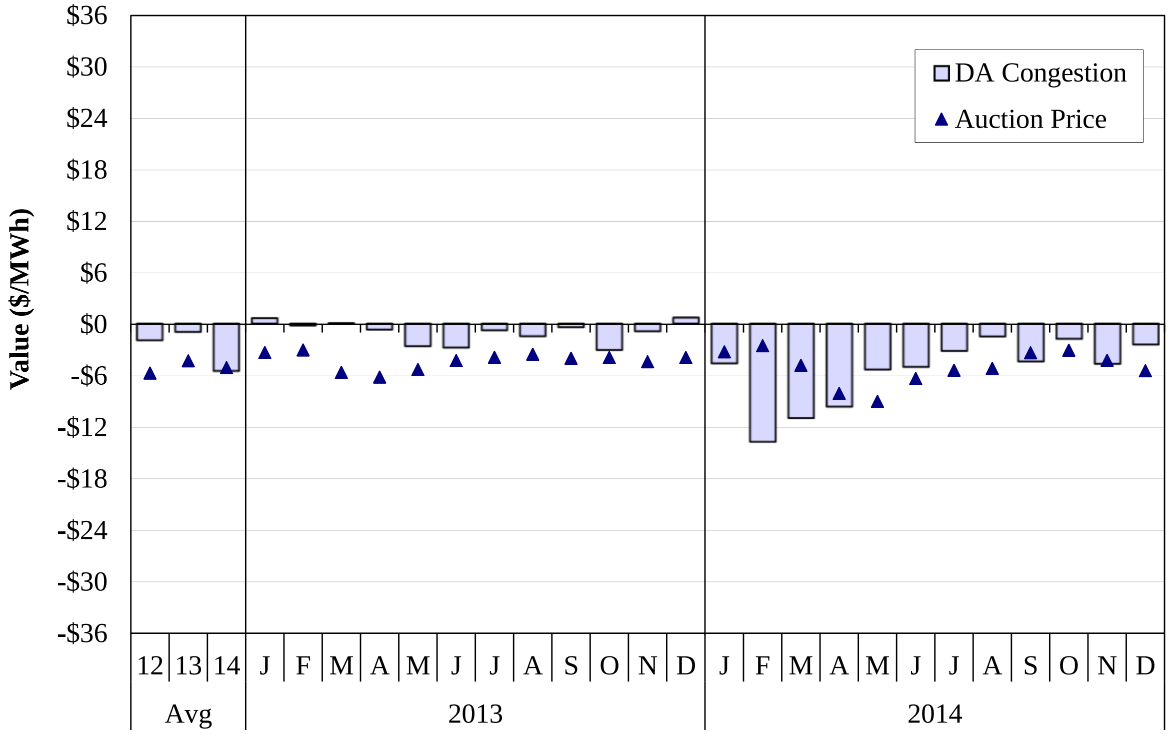


Figure A93: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2013–2014: Peak Hours

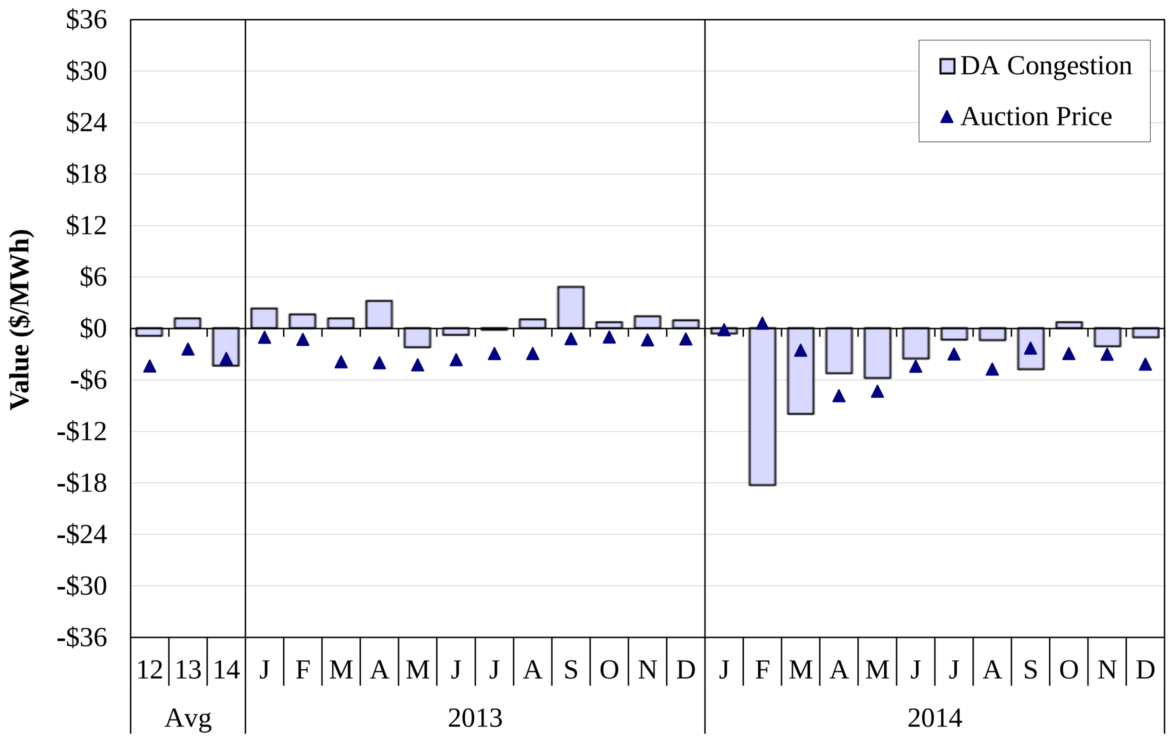


Figure A94: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2013–2014: Off-Peak Hours

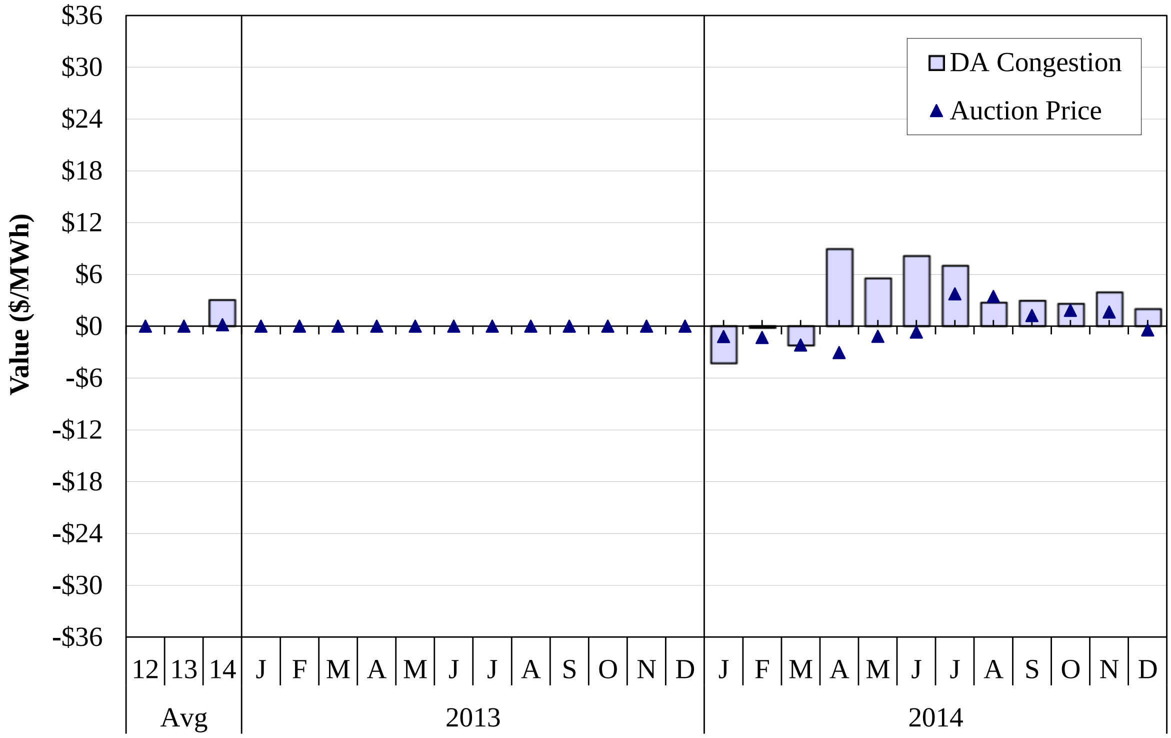


Figure A95: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2013–2014: Peak Hours

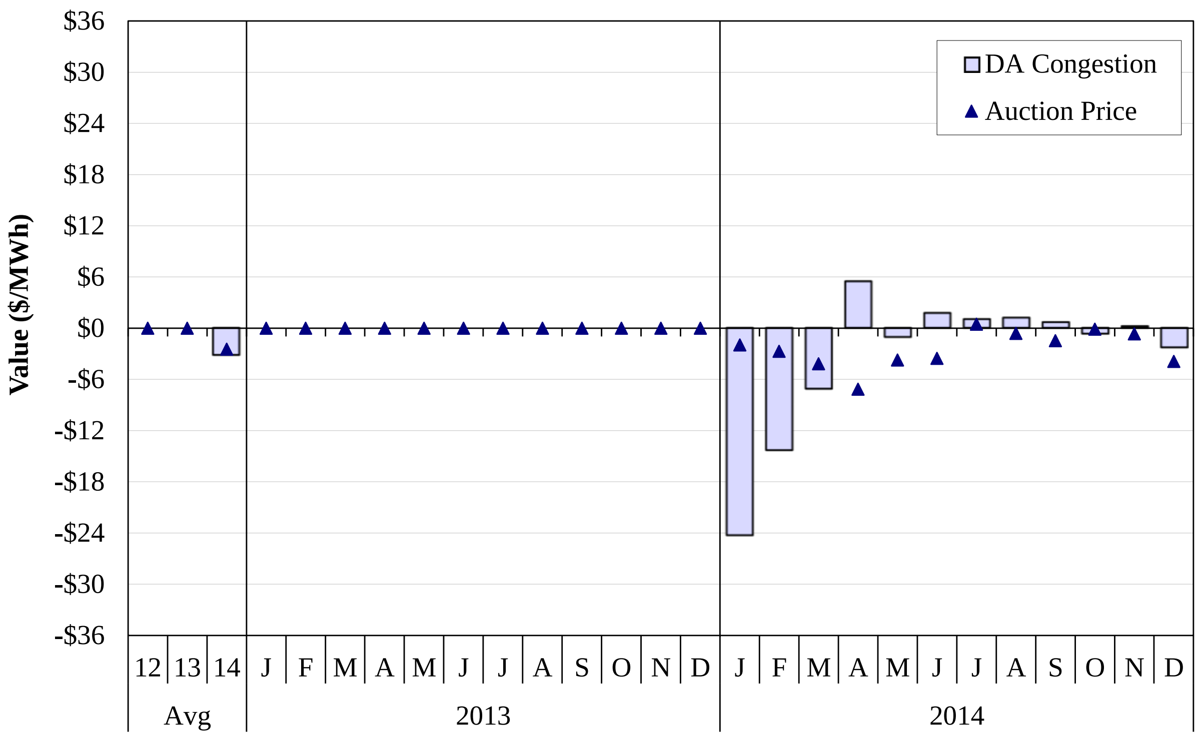


Figure A96: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2013–2014: Off-Peak Hours

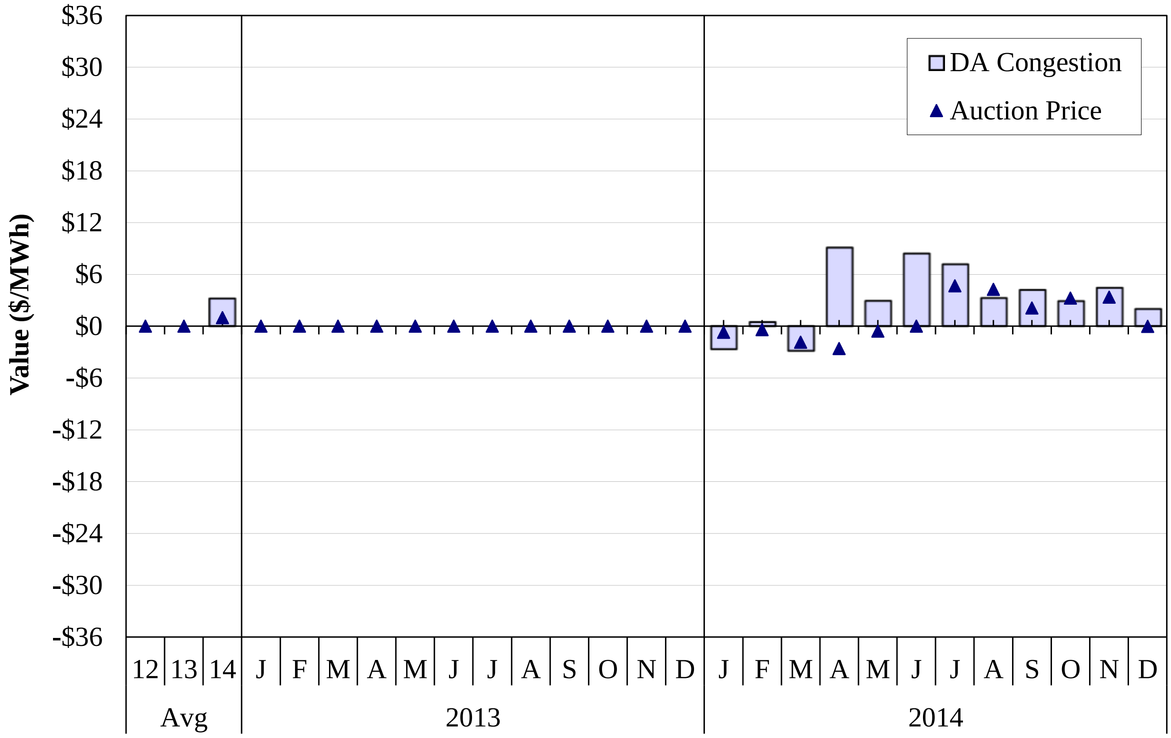


Figure A97: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2013–2014: Peak Hours

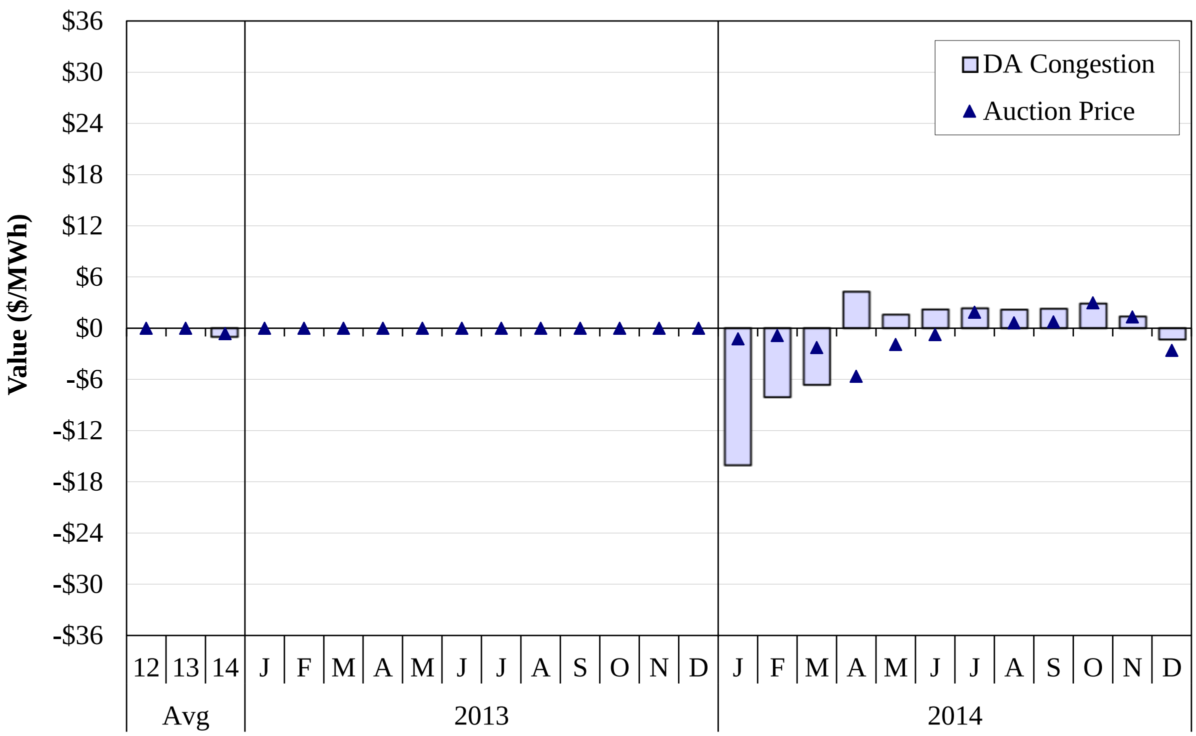


Figure A98: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2013–2014: Off-Peak Hours

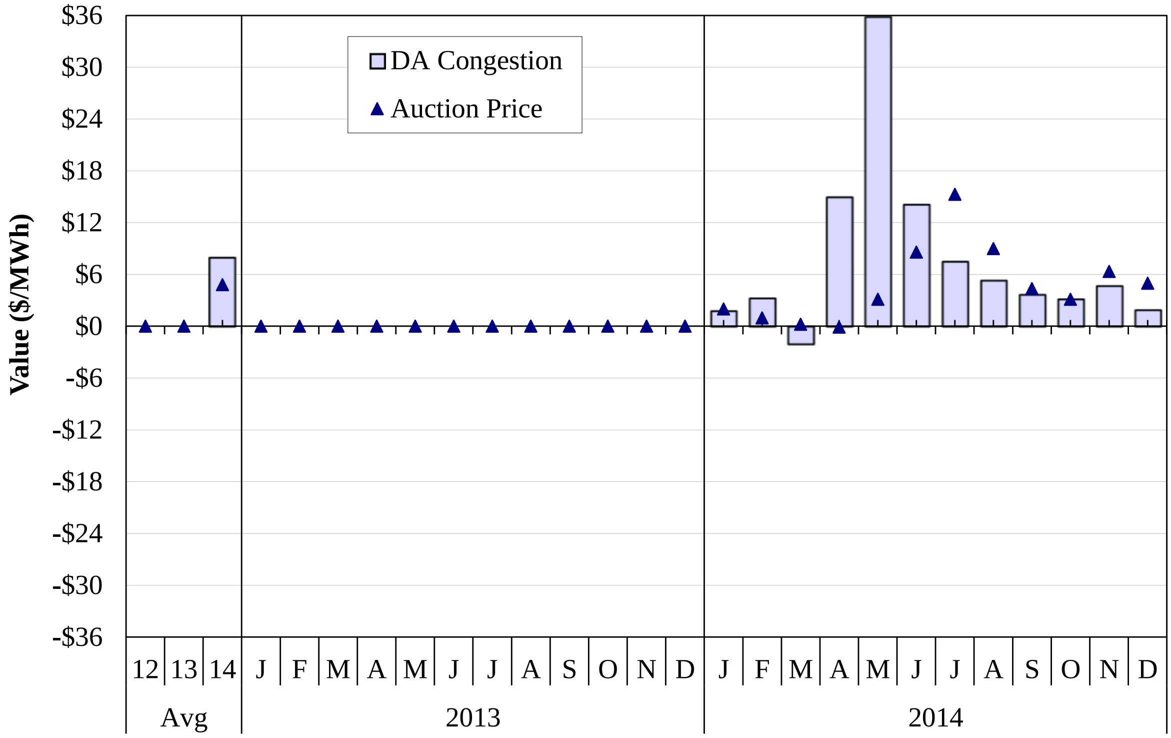
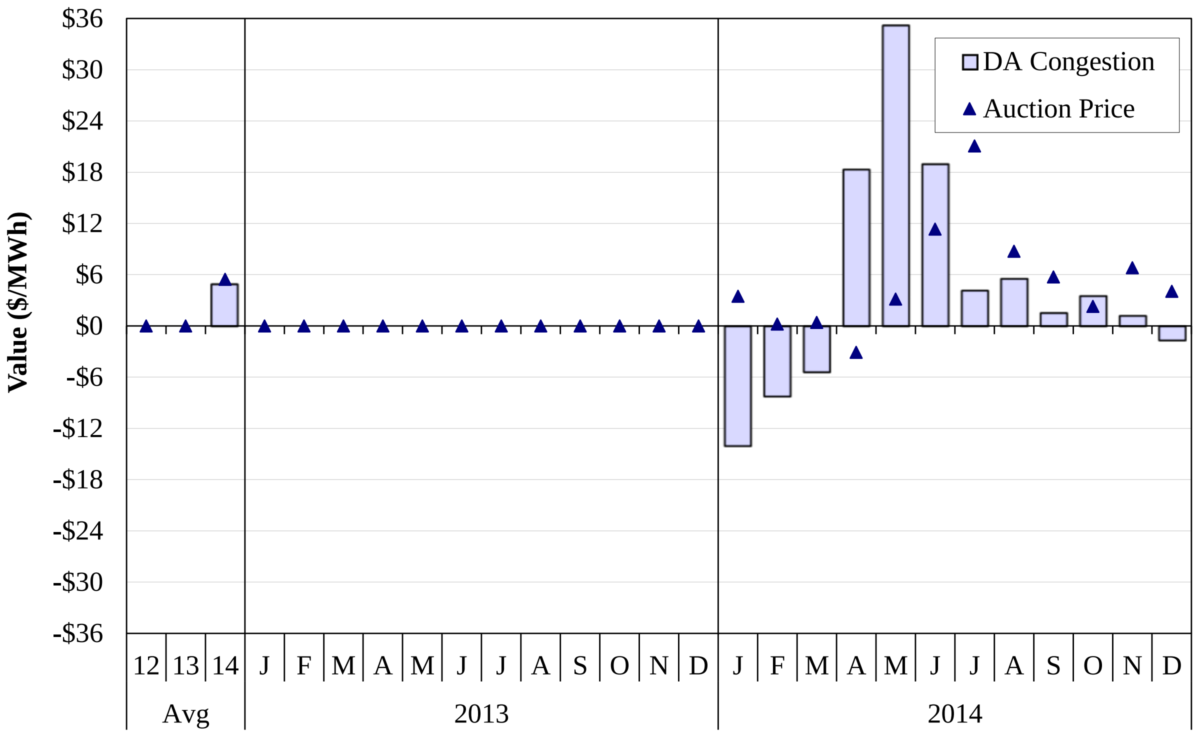


Figure A99: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2013–2014: Peak Hours



G. Market-to-Market Coordination with PJM

The Joint Operating Agreement 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 process provides congestion management relief on coordinated flowgates in a least-cost manner, ensures efficient generation dispatch on these constraints, and ensures that prices are consistent between the markets.

Under the terms of the JOA, when a market-to-market constraint is activated, the monitoring RTO is responsible for coordinating reliability for the constraint and 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 marginal cost of the monitoring RTO for relieving the constraint. The relief requested varies considerably by constraint as well as over the course of the coordinated hours for each 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). The RTOs continue to make gradual improvements in the market-to-market process, including improved real-time data exchange and better communication procedures.

When the reciprocating RTO receives the shadow price and requested relief quantity, 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. From a settlement perspective, each market is allocated a Firm Flow Entitlement (FFE) on each of the market-to-market constraints. Settlements are made between the RTOs based on their actual flows over the constraint relative to their FFE.

Figure A100: Market-to-Market Events

Figure A100 shows the total number of market-to-market constraint-hours (i.e., instances when a constraint was active and binding) in 2013 and 2014. 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 A100: Market-to-Market Events
2013–2014

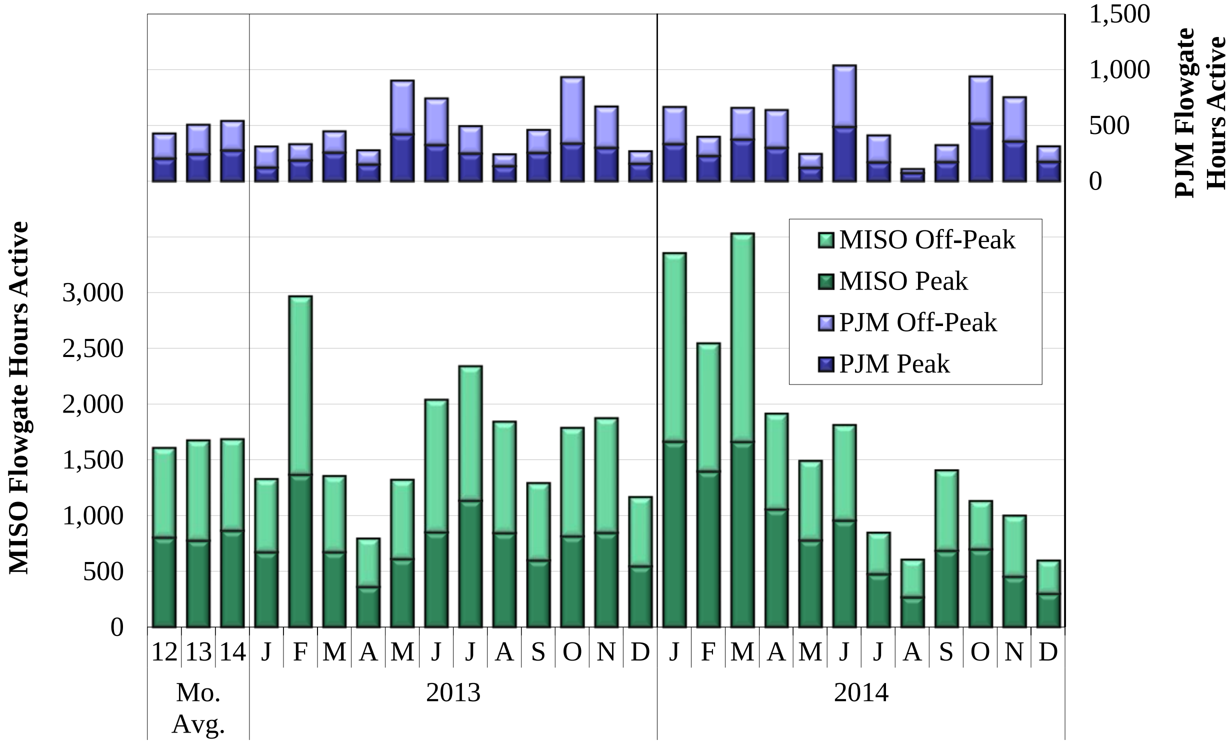


Figure A101: Market-to-Market Settlements

Figure A101 summarizes the financial settlement of market-to-market coordination. Settlement is based on the reciprocating RTO's actual market flows compared to its FFE. If the reciprocating RTO's market flow is below its FFE, then it is paid for any unused entitlement at its internal cost of providing relief. Alternatively, if the reciprocating RTO's flow exceeds its FFE, then it owes the cost of the monitoring RTO's congestion for each MW of excess flow.

In the figure, positive values represent payments made to MISO on coordinated flowgates and negative values represent payments to PJM on coordinated flowgates. The diamond marker shows net payment to (or from) MISO in each month.

Figure A101: Market-to-Market Settlements
2013–2014

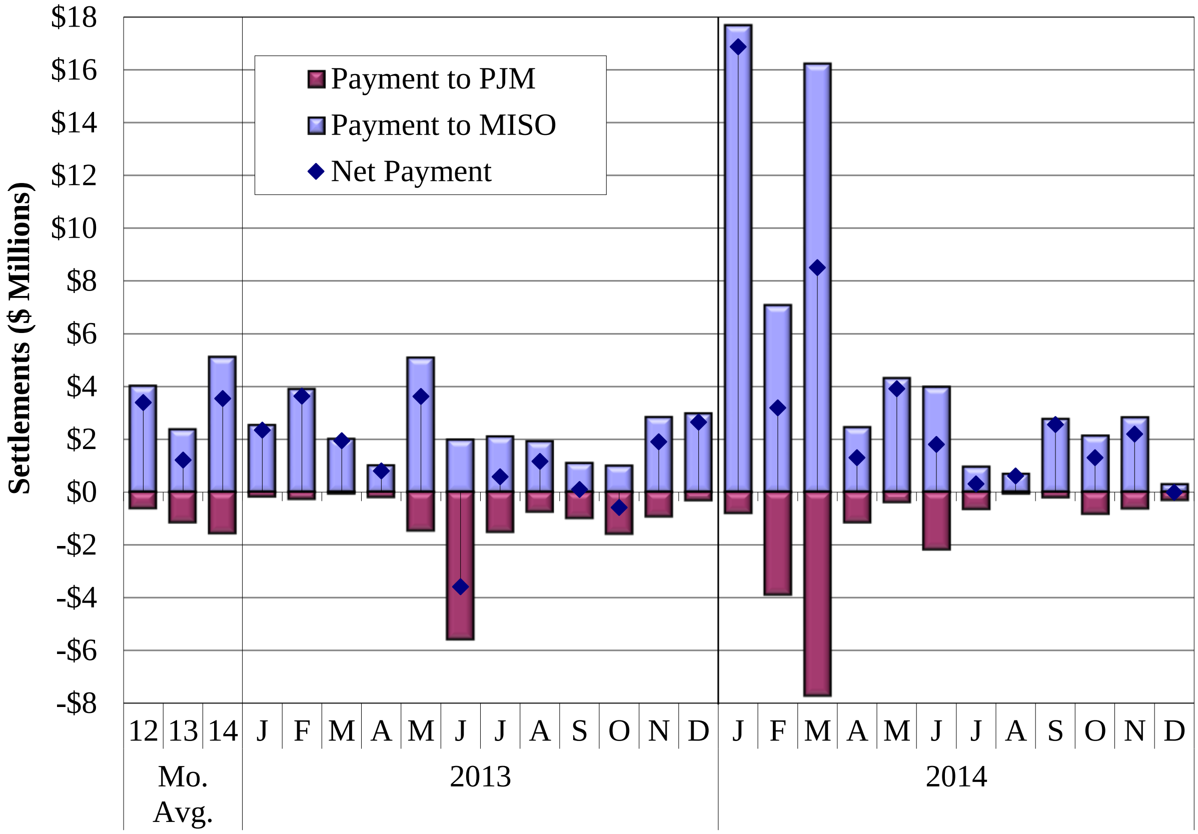


Figure A102 and Figure A103: Market-to-Market Outcomes

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:

- 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
- 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: PJM Market-to-Market Constraints
2014

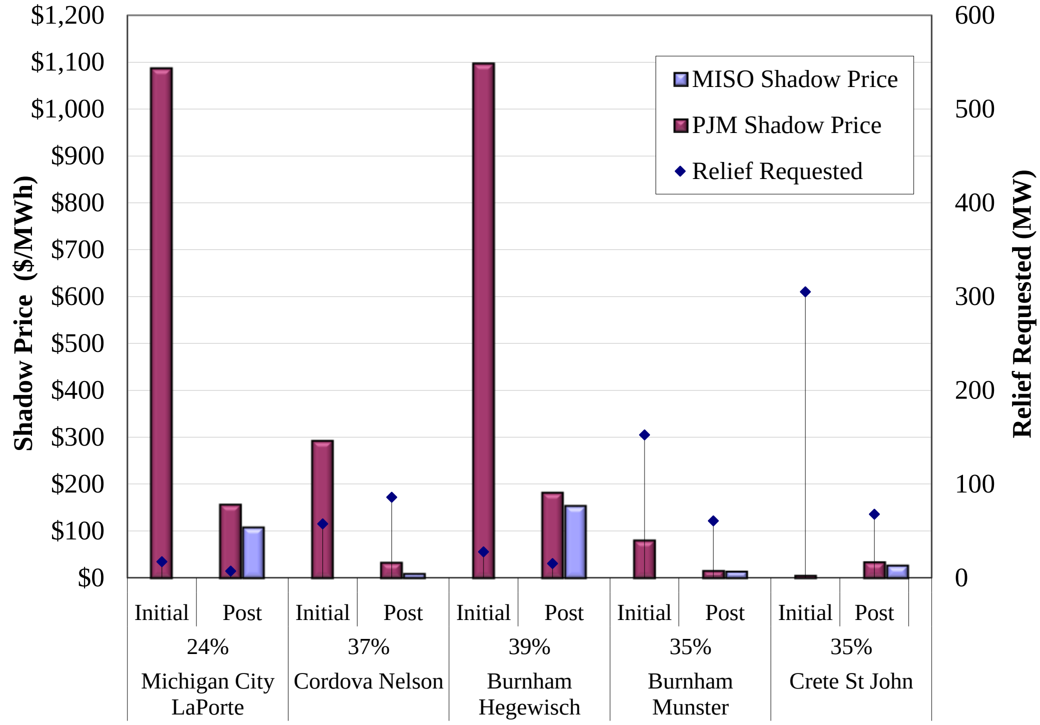
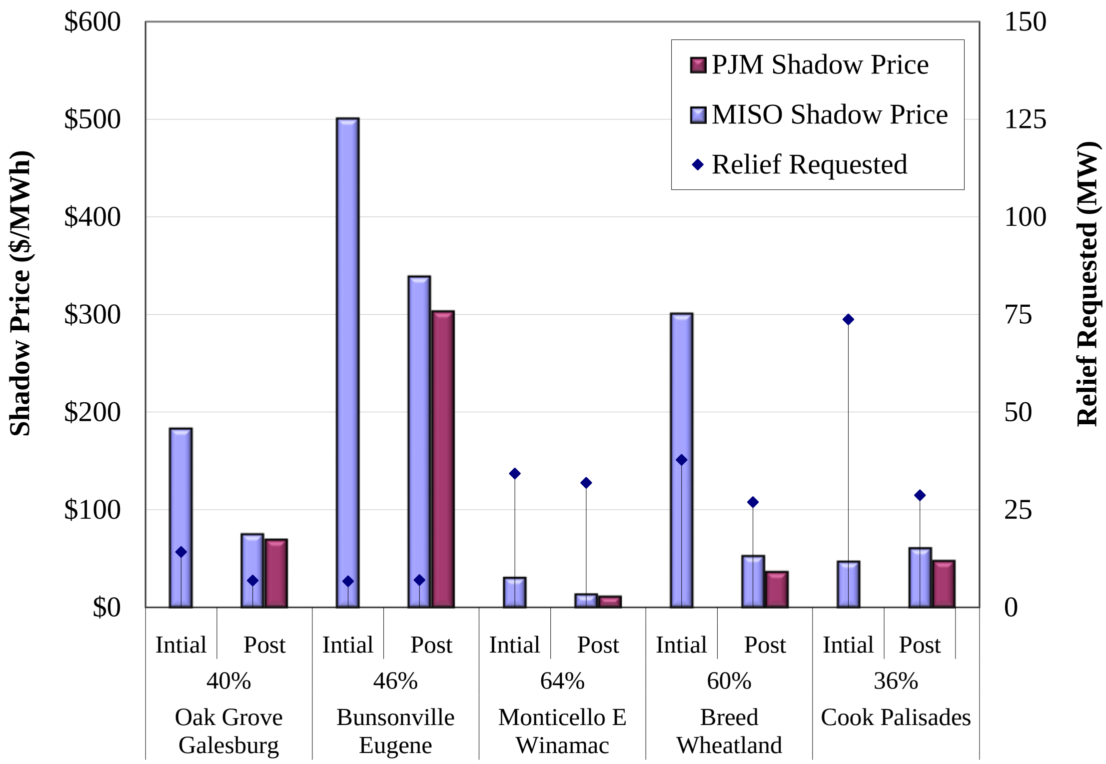


Figure A103: MISO Market-to-Market Constraints
2014



H. Congestion on External Constraints

This subsection provides analysis of congestion that occurs on external constraints, which are constraints monitored by adjacent RTOs or control area operators. MISO incurs congestion on external constraints when a neighboring system calls Transmission Line-Loading Relief (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 equal to or less than the cost of the neighboring system operator to manage the flow on the constraint. Unfortunately, this has historically not been true. One contributing factor is the fact that MISO receives relief obligations based on its forward-only flows. In other words, generators that are running to serve MISO's needs that are reducing the flows on the TLR constraints are ignored when the relief obligation is calculated. It is possible that the net of all of MISO's load and generation is reducing the flow on the TLR constraint and MISO will still receive a relief obligation. Because the relief obligation is outsized, it is frequently very costly for MISO to provide the relief requested and MISO's marginal cost of providing the relief is included in its LMPs.

Figure A104 and Figure A105: TLR Process

To evaluate the efficiency of this process, Figure A104 compares MISO's shadow costs for SPP's TLR flowgates compared to SPP's shadow costs for these flowgates when activated for TLR. The horizontal axis in the figure groups observations by MISO shadow price level, while the bars associated with each MISO shadow price level show the distribution of corresponding flowgate shadow prices in SPP's market. The chart excludes any periods when the given flowgate was binding in SPP but MISO did not receive a TLR obligation.

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.H.

Figure A105 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 A104: Average MISO and SPP Shadow Prices
SPP TLR Flowgates, March 2014

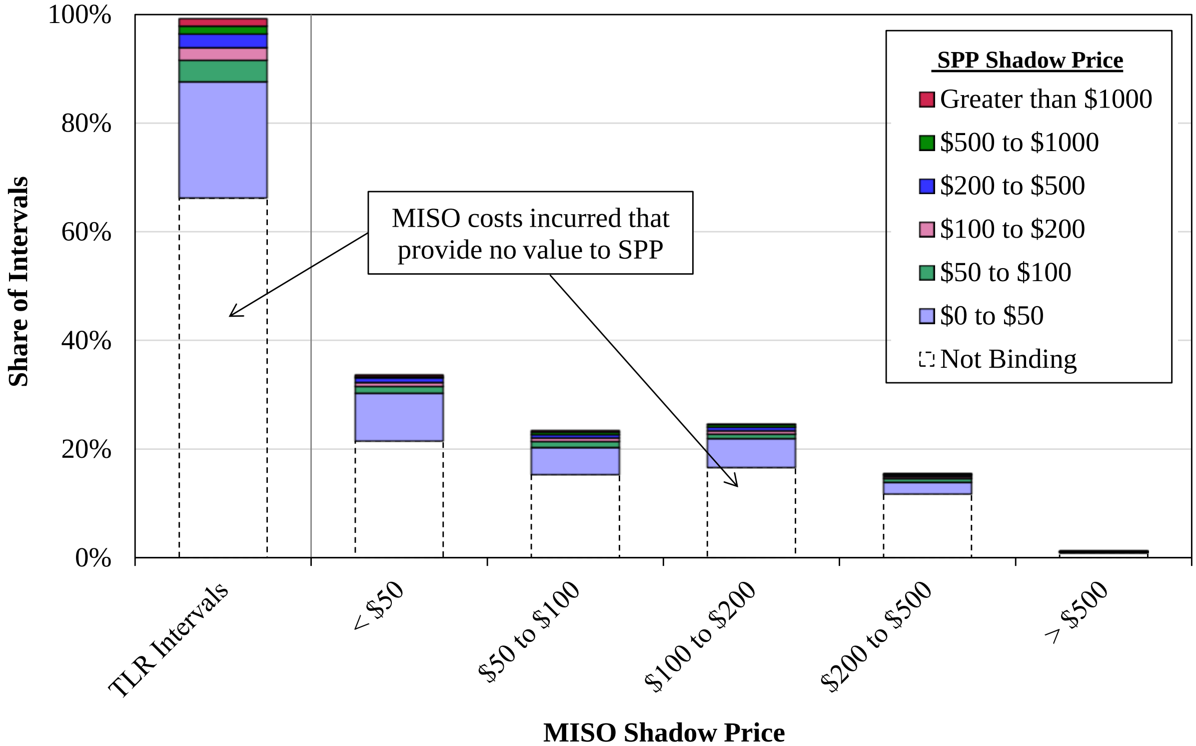
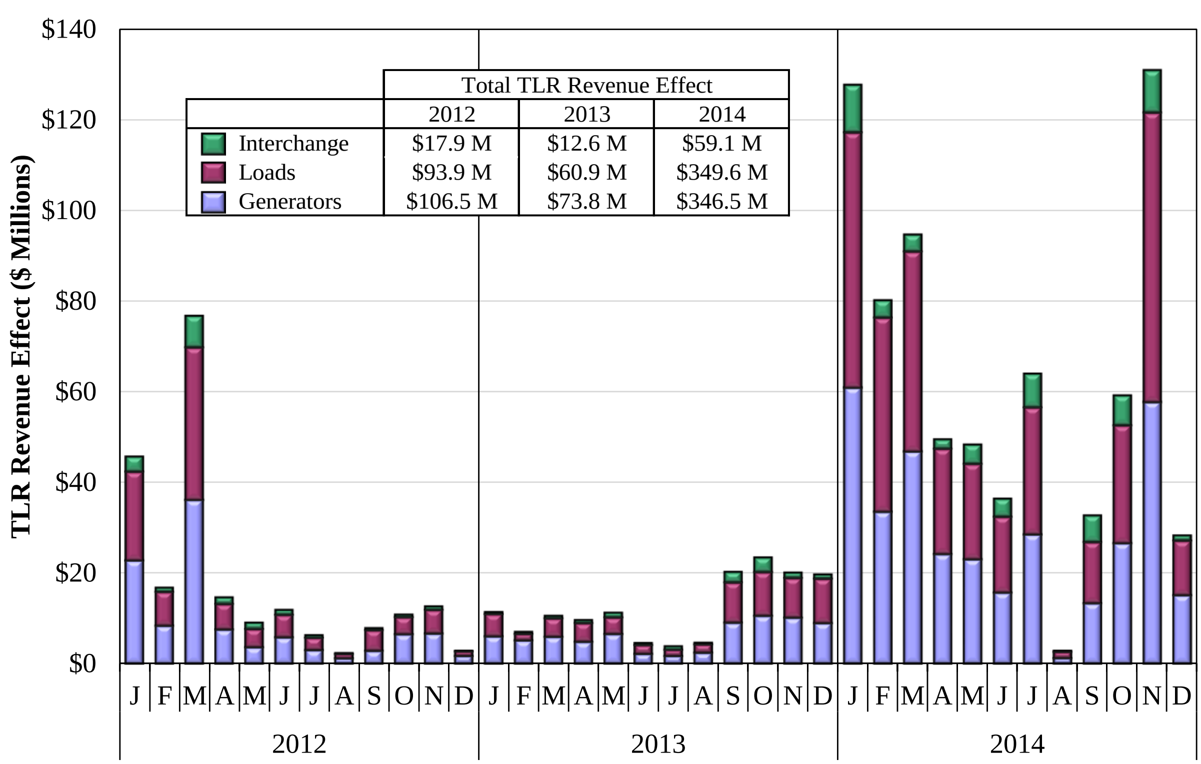


Figure A105: Real-Time Valuation Effect of TLR Constraints
2014



VII. External Transactions

MISO relies on imports to supply the energy and capacity markets and 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.

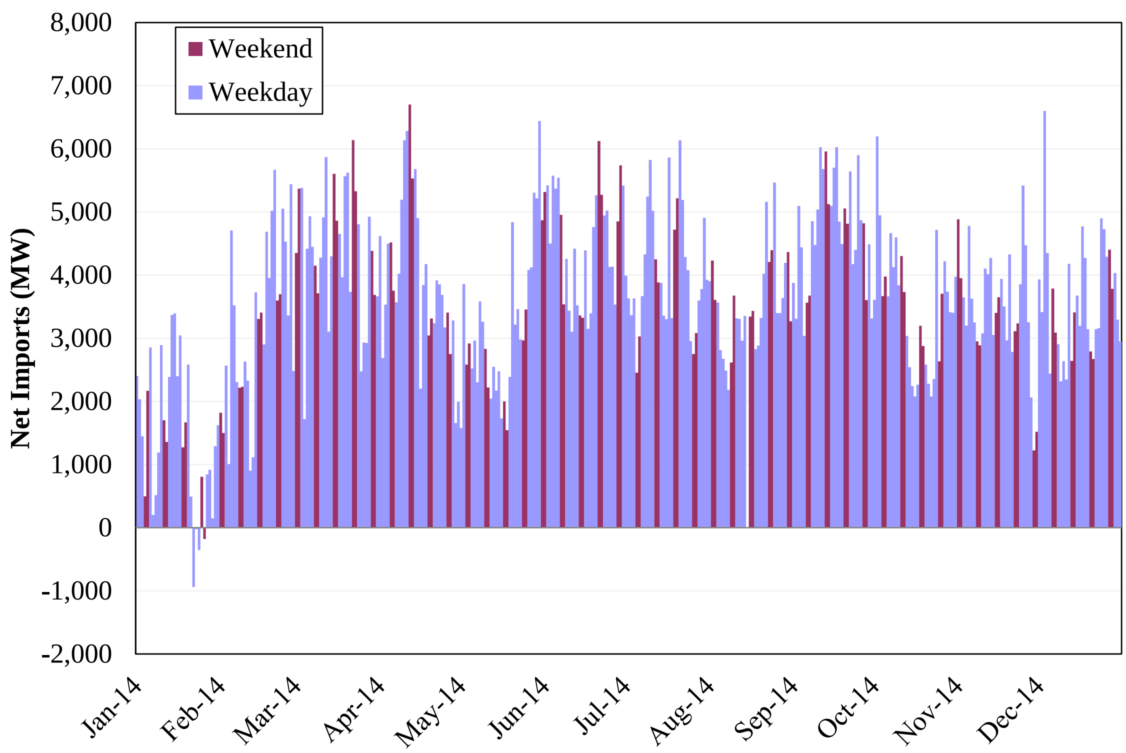
Imports and exports can be scheduled on a 15-minute basis, although the schedules are fixed 30 minutes before the transactions occur. The scheduling notification period was reduced from 30 minutes to 20 minutes on October 15, 2013, to satisfy the requirements of FERC's Order 764. Participants must reserve ramp capability in order to schedule a transaction and MISO will refuse transactions that place too large a ramp demand on its system. 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 A106 to Figure A109: 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 A106: Average Hourly Day-Ahead Net Imports
2014



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 A107: Average Hourly Real-Time Net Imports
2014

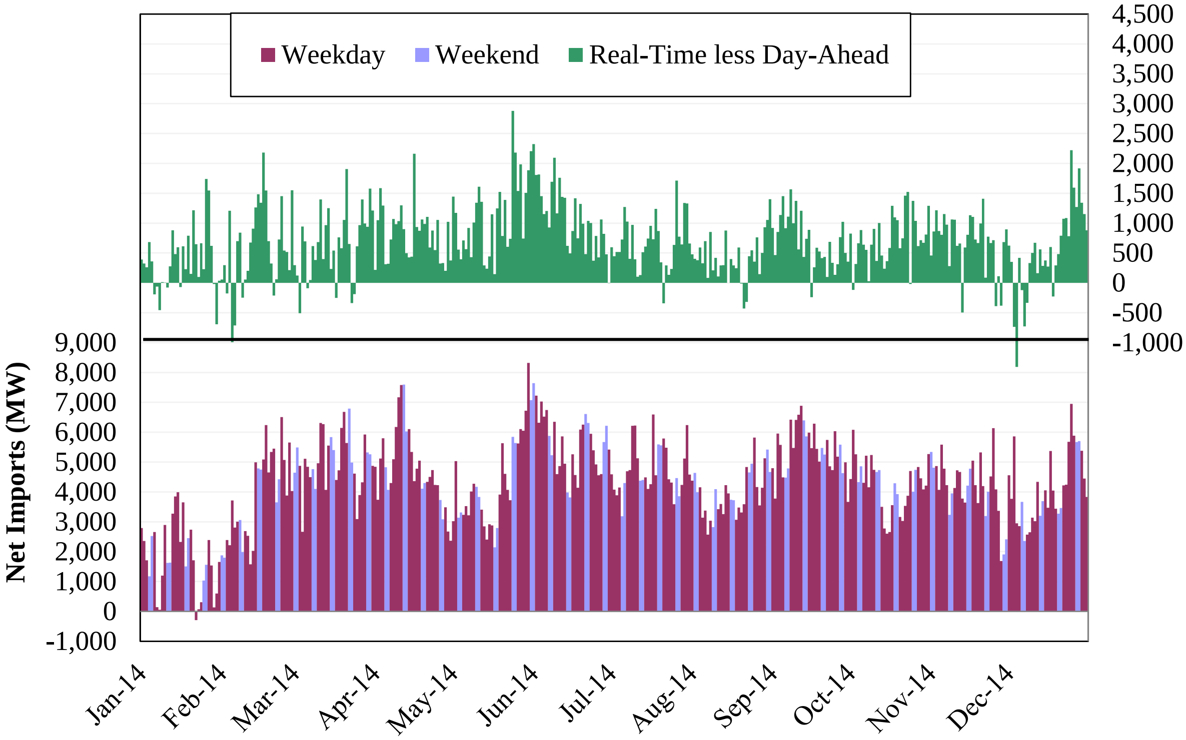


Figure A108: Average Hourly Day-Ahead Net Imports
2014, by Interface

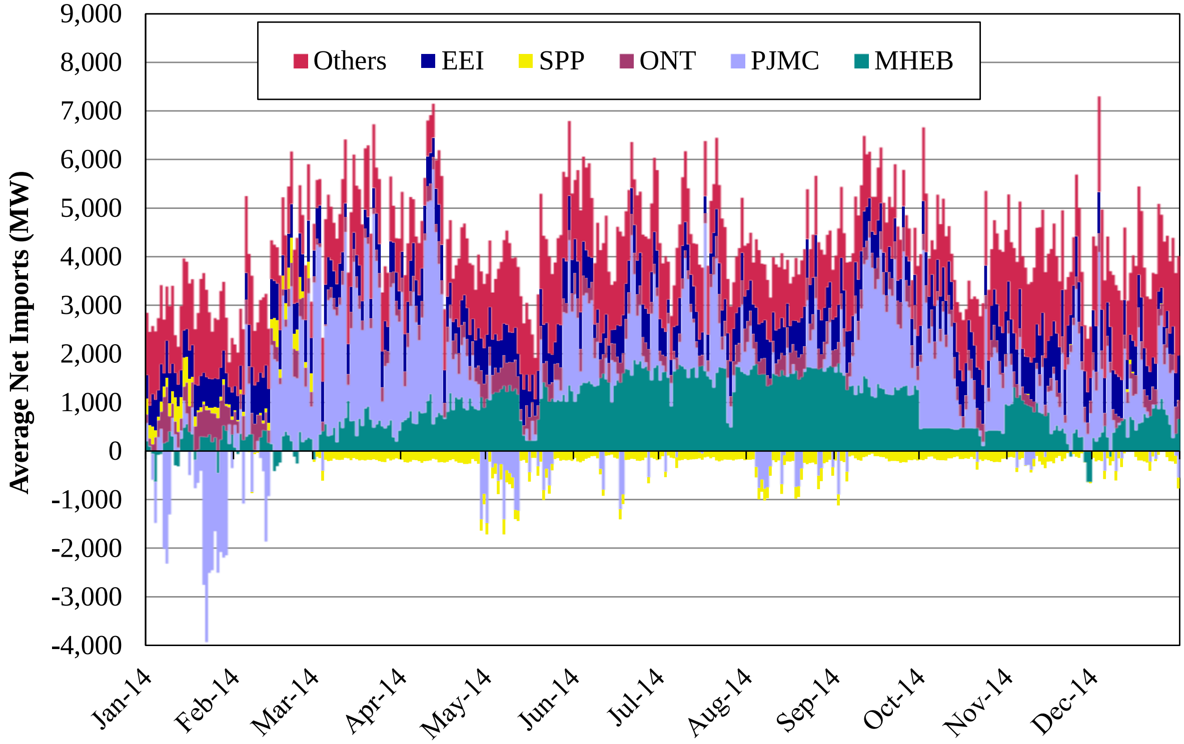


Figure A109: Average Hourly Real-Time Net Imports
2014, by Interface

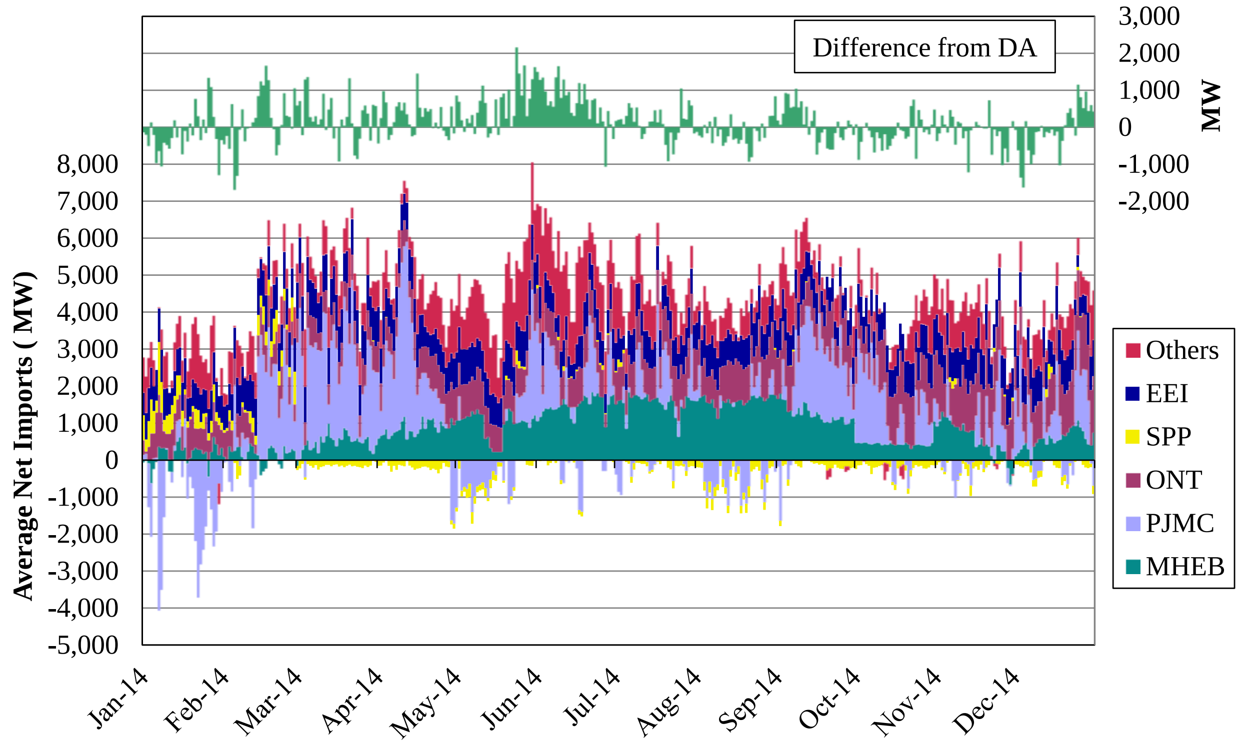
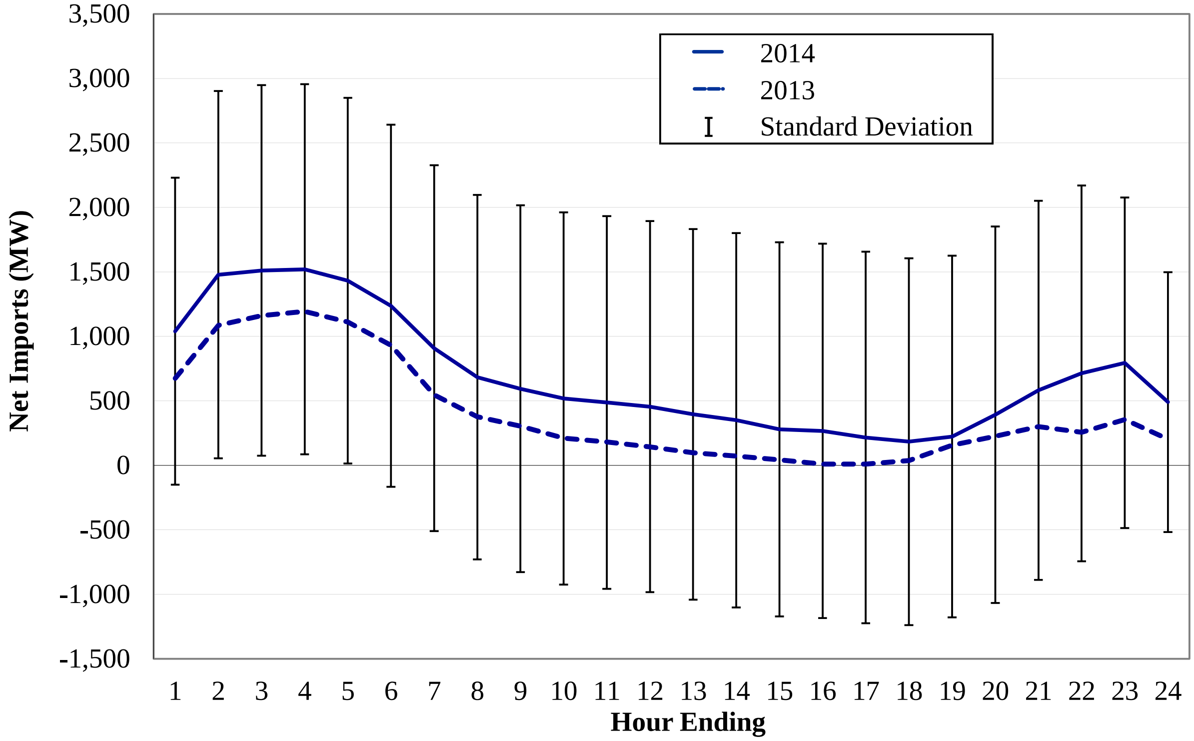


Figure A110 and Figure A111: Hourly Average Real-Time Net Imports by Interface

The next two figures examine net real-time imports by interface. 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.

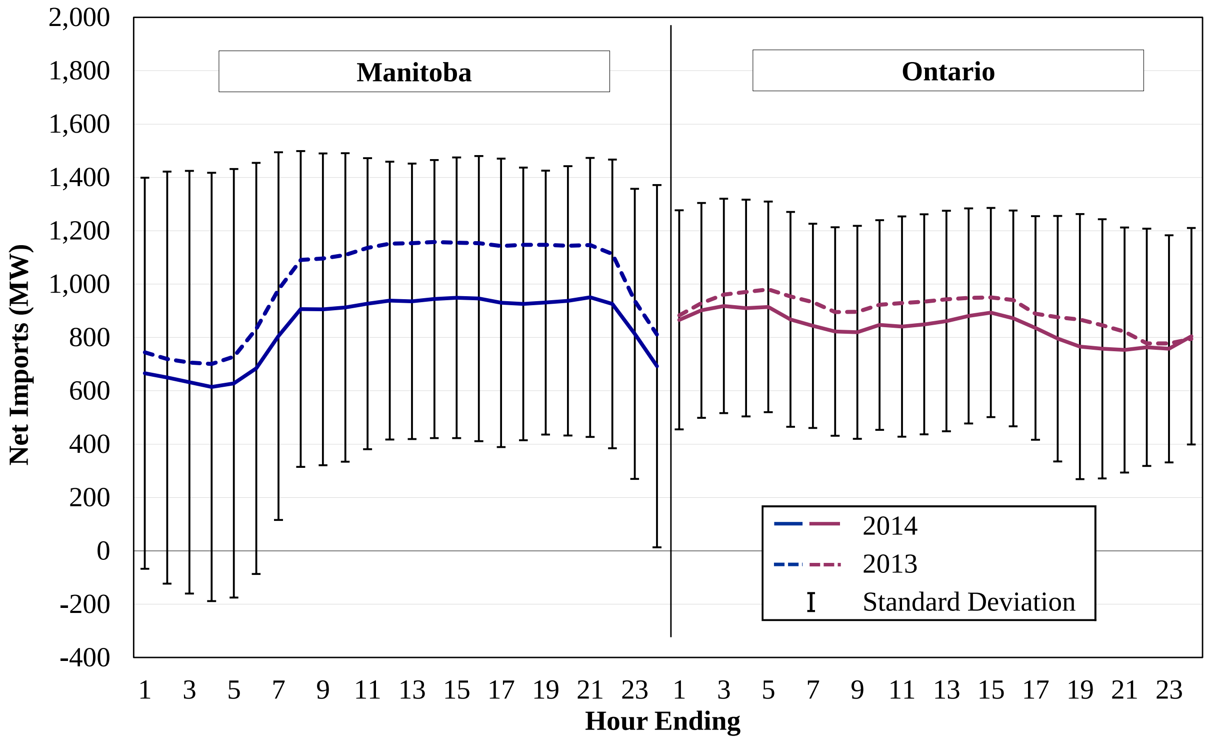
Accordingly, Figure A110 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2013 and 2014, along with the standard deviation of such imports.[28] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

Figure A110: Average Hourly Real-Time Net Imports from PJM
2013–2014



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

Figure A111: Average Hourly Real-Time Net Imports, from Canada
2013-2014



B. Interface Pricing and External Transactions

Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to take advantage of differentials between the two interface prices. 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 from cross-border transfers (imports and exports). Like the locational marginal price at all generation and load locations, the interface price includes: a) the SMP; b) a marginal loss component; and c) a congestion component.

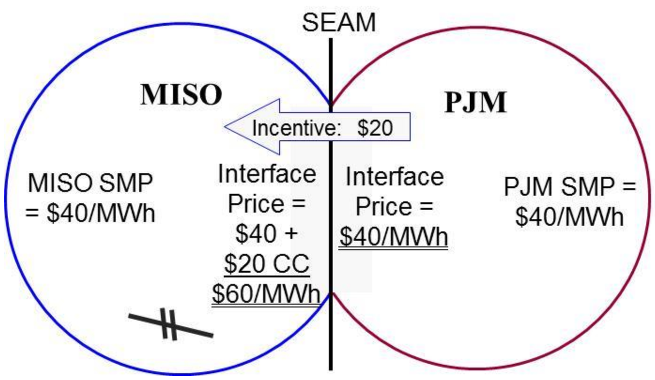
For generators, the source of the power is known so congestion effects can be accurately calculated. In contrast, the source of an import (or sink for an export) is not known so it must be assumed in order to calculate the congestion effects. This is known as the "interface definition". Using this interface definition, the RTOs calculate the congestion effects for imports and exports by running a power flow model that includes a representation of both their network and portions of the Eastern Interconnect surrounding their network.

This approach to setting interface prices is efficient as long as the congestion components of the prices estimated by each RTO on their own system are reasonably accurate, which depends entirely on the interface definition. If they are accurate, the interface price will reflect the marginal benefit (or cost) of a transfer into or out of the system. In other words, the congestion component is the net congestion cost incurred (or relieved) on the RTO's own system by the transfer from or to its neighboring RTO. As power moves from one RTO area to the other, it will change the flow on the RTOs' transmission networks and can relieve congestion or aggravate congestion on multiple constrained transmission facilities. The sum of the net congestion effects from a transfer is the congestion component of the interface price. When calculated accurately, traders' responses to these prices will help the system converge to an efficient outcome and lower the total costs for both systems.

Figure A112 and Figure A113: Illustration of Interface Pricing

The following two figures illustrate the purpose and application of interface prices by showing prices and settlements for a non-market-to-market constraint binding in MISO. Although it is not material to the example, for simplicity we assume each RTO's region-wide "system marginal price" (SMP) is equal to $40 per MWh.

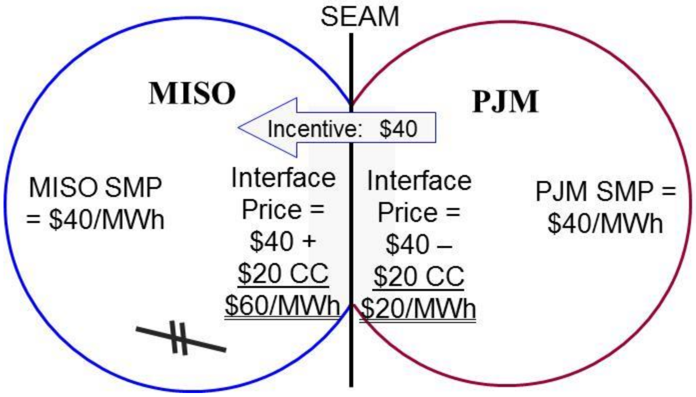
Figure A112: Interface Pricing for a Non-Market-to-Market Constraint



In this example, we assume that a binding constraint in MISO is relieved by an import into MISO from PJM. MISO estimates the value of the relief ($20 in this example) and the interface price will include a congestion component to create an efficient incentive for participants to schedule the transaction. PJM's interface price would not include a congestion component for this because it is a MISO constraint.

However, 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. This is illustrated in the Figure A113. Under market-to-market and the RTO's current interface pricing protocols, this constraint will appear in both RTOs' interface prices to reflect each of their estimates of the relief the transaction will provide.

Figure A113: Interface Pricing for a Market-to-Market Constraint



MISO's settlement is unchanged, but PJM's settlement now includes the $20 congestion component in its interface price, which is redundant. This doubles the incentive to $40 per MWh for participants to schedule the transaction ($60-$20). PJM makes a $20 payment to the participant by charging it only $20 per MWh to leave the PJM system (rather than the $40 per MWh it costs to generate the power being exported). PJM's $20 congestion payment will be uplifted to its customers because the impact of the transaction is not included in its market flow calculation. In other words, PJM (as the non-monitoring RTO or "NMRTO") would get no credit in the market-to-market settlement process for this real-time transaction or the payment it has made to motivate it to be scheduled.

One solution to this problem, which we believe resolves all of the efficiency and equity concerns associated with this pricing flaw, is for PJM to simply stop making the $20 payment in this example. This would ensure that the incentive to transact reflects the value of the relief to MISO who is managing the constraint and eliminates the need for settlement rules that would give PJM credit for making these types of payments. While there has been wide agreement that interface pricing should be coordinated in order to rectify this over-payment of congestion costs, the RTOs have not achieved a consensus on the preferred solution.

For example, if MISO estimates a shift factor on the constraint for an export of -10 percent (it provides relief) and the constraint has a shadow cost of $500 per MWh, MISO congestion component for the PJM interface will be -$50. This will encourage the export. If PJM estimates the same shift factor and has the same shadow cost for the MISO market-to-market constraint, it will have also calculated a congestion component for the MISO interface of $50. Assuming the internal system marginal prices are the same, this participant will receive a congestion payment of $100 per MWh to schedule this transaction even though it is only providing relief on the constraint worth $50 per MWh.

Examples of Interface Price Distortions

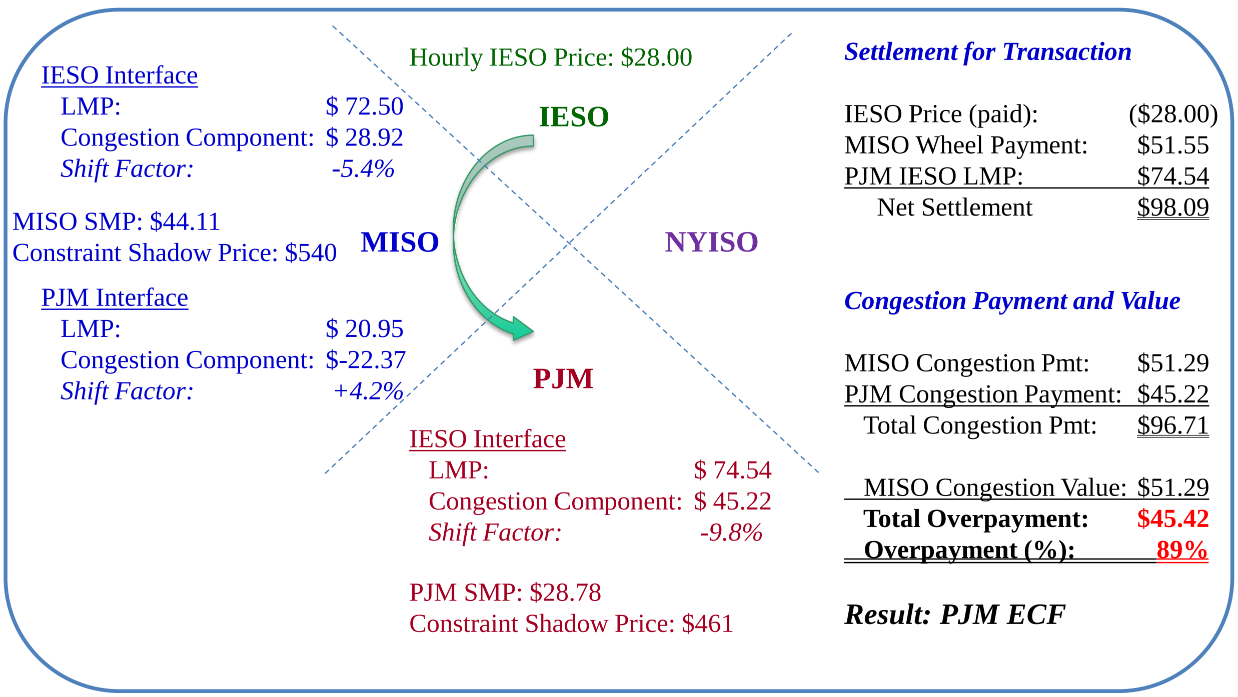
To establish empirically this double settlement, we identified hours when no constraints were binding in PJM or MISO except a single common market-to-market constraint. The following two examples are such cases. By focusing on the prices in these cases, it is relatively straightforward to evaluate this issue because the congestion component of the interface prices in both PJM and MISO will solely reflect the estimated effects related to the single binding market-to-market constraint.

In the first example below, we show an hour where the only binding constraint was a MISO market-to-market constraint. The example then shows the settlements that would result for a transaction scheduled from IESO to PJM (wheeled through MISO). This transaction would help relieve the MISO constraint so it would receive congestion payments from MISO and PJM.

In the second example, we show an hour where the only binding constraint was a PJM market-to-market constraint. The example then shows the settlements that would result for a transaction scheduled from PJM to MISO. This transaction would help relieve the PJM constraint so it would receive congestion payments from MISO and PJM.

To better understand the prices and settlements, we show each interface LMP along with the congestion component of the LMP and the Generation Shift Factor (GSF). The GSF indicates the marginal constraint-flow impact of transactions over that interface. The congestion component of the interface price should equal the GSF times the shadow price of the constraint. The LMP also includes a marginal loss component that is not shown.

Example #1: MISO as Monitoring RTO for a Wheel from IESO-PJM Wheel
M2M Constraint: Monroe–Wayne flo Monroe - Brownstown
Date: 8/7/2012 in Hour-Ending 11pm



Example #2: MISO as Non-Monitoring RTO for an Import from PJM
M2M Constraint: Crete-St. John's Tap flo Dumont – Wilton Center
Date: 4/14/2012 in Hour-Ending 3am

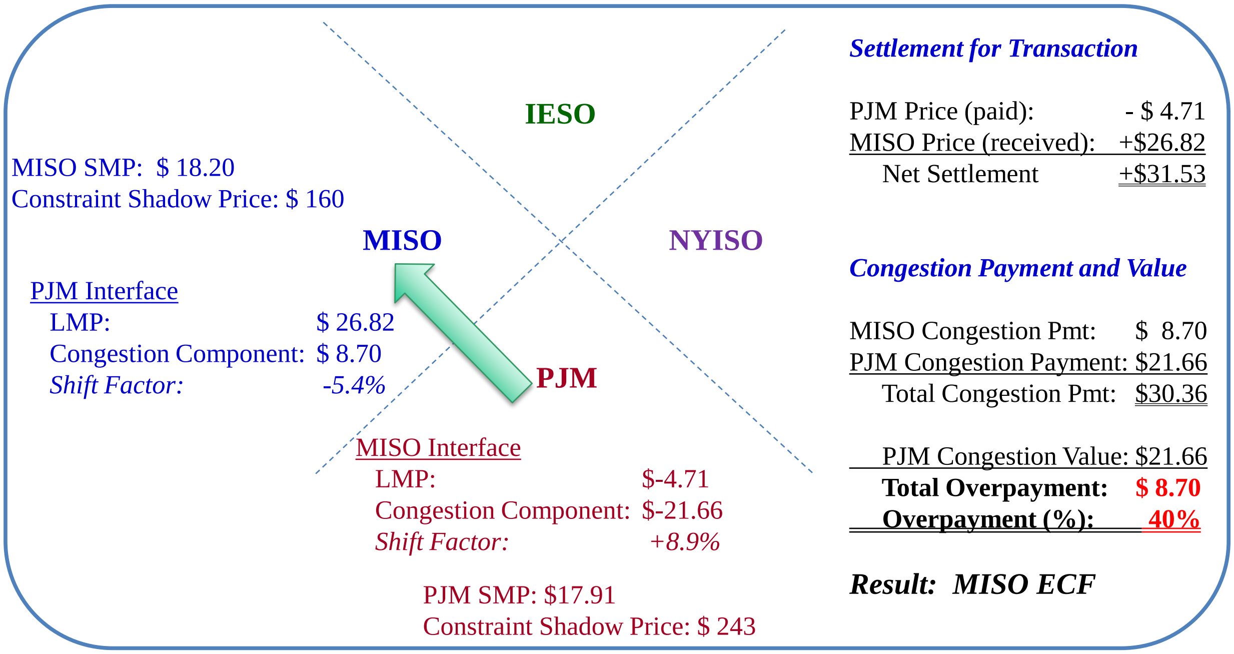
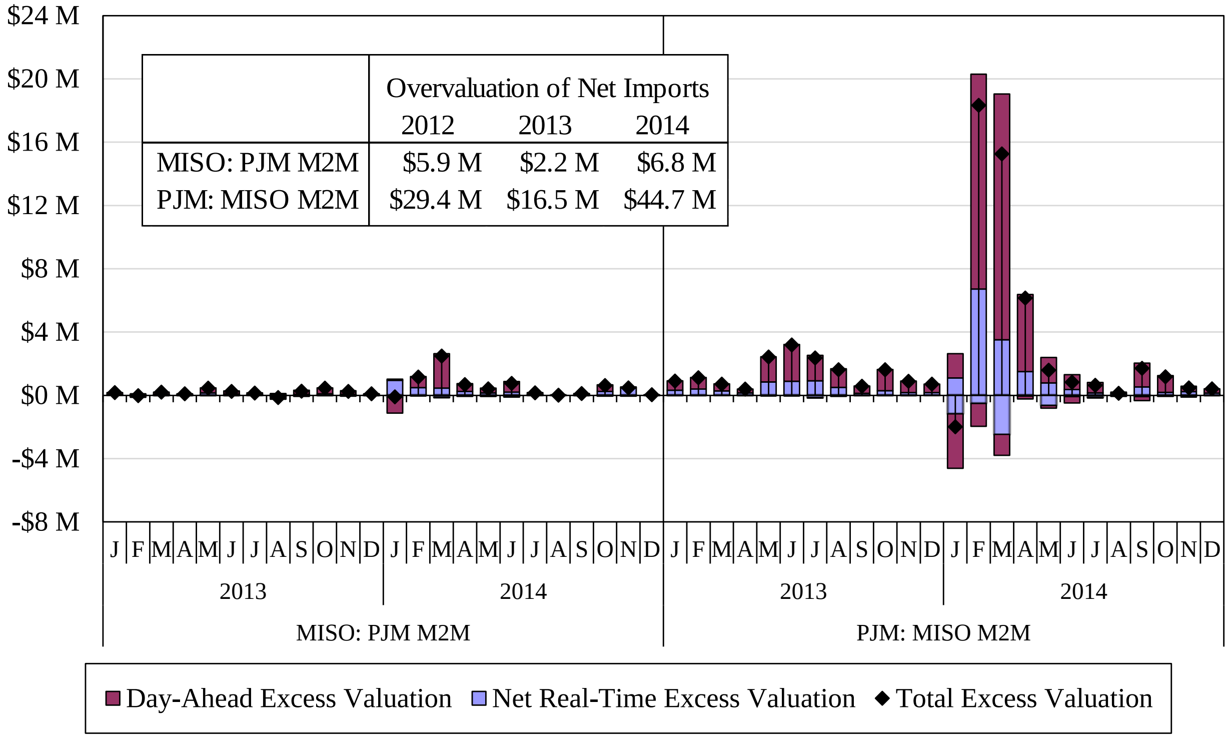


Figure A114: Excess M2M Congestion Settlements

Figure A114 summarizes the overpayments and overcharges that we estimate occurred in 2014 by type of market-to-market constraint. Positive values are overpayments and negative values are transactions that were over-charged.

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.

Figure A114: Excess M2M Congestion Settlements
By Type of Constraint, 2013 –2014



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 and continue to discuss potential solutions. We have taken the lead in using actual data to examine the benefits and unintended consequences of the two solutions advanced by MISO and PJM. These are the only two solutions that have been proposed – no other ones have been proposed by the stakeholders in either area. We discuss the two alternatives below.

1. MISO IMM Proposed Solution

Our proposed interface definition is based on sourcing imports and sinking exports at the non-monitoring RTO's load-weighted reference bus.[29] Effectively, this assumes an interface definition where the power would source from locations throughout the non-monitoring RTO's footprint. By calculating the congestion component assuming power is injected in the exporting RTO across a broad range of locations and is withdrawn in the importing region across a broad range of locations, the congestion effects will reflect how power actually flows between the areas. In reality, the source of the power for an export will be every marginal unit in the exporting RTO's area, which are generally distributed throughout its footprint.

This approach is consistent with the way all RTOs measure locational congestion effects (for generation and load buses and interfaces) relative to a central common "reference bus." To calculate the congestion component of the interface price for a constraint, the RTO first

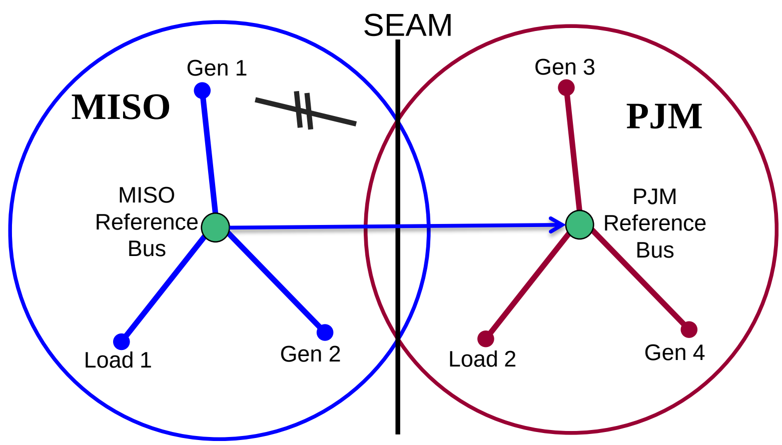
29 The load-weighted reference bus is used by the non-monitoring RTO to calculate the congestion effects for all of its own generation and load.

calculates the marginal flow impact on the constraint (i.e., the "shift factor") of injecting a megawatt at the MISO reference bus and withdrawing it at specified locations (known as the "interface definition") in the adjacent area.

Figure A115: MISO Interface Pricing Proposal

Figure A115 shows MISO using the PJM reference bus as its interface definition. This results in congestion effects that correspond to moving power from the reference bus in one area to the reference bus in the other area.

Figure A115: MISO Interface Definition



The congestion component is equal to the shift factor multiplied by the shadow price for the constraint. At any given time, the interchange transaction may affect multiple binding constraints, relieving some and aggravating others. The congestion component shows the net impact of all of these individual effects.

By establishing an interface price that includes the congestion effects of a transfer between MISO and PJM, the congestion benefits and costs will be fully priced and settled. This is essential because it provides efficient incentives for participants to schedule transactions between the two areas. Our proposed solution, which has been endorsed by MISO, would simply call for each RTO to estimate and price the full congestion effects for their own constraints, and remove the interface congestion effects associated with the other RTO's coordinated flowgates. This interface price would conform directly to the efficient interface pricing described above, i.e., it represents the marginal value to the system of an import or export and would eliminate the redundant settlement by the non-monitoring RTOs.

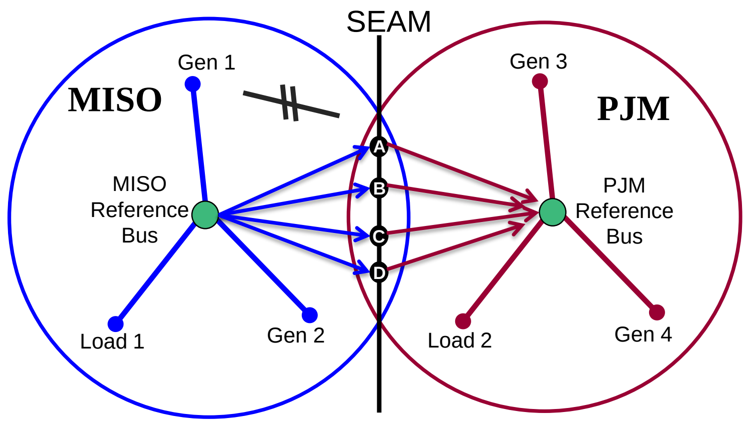
In addition, the MISO IMM proposal also is straightforward and would ensures efficient pricing. As we explain below, the PJM proposal also solves the double-settlement problem, but introduces other potentially serious problems.

2. The PJM Proposed Solution

Figure A116: PJM Interface Pricing Proposal

As an alternative to the MISO IMM proposal, PJM proposes to define a common set of interface buses that would act as the assumed sources and sinks for estimating transfers. This would eliminate the "double-counting" of congestion in the settlements, but introduces other potentially severe problems. The PJM proposal is illustrated in Figure A116.

Figure A116: PJM Interface Definition



We agree that utilizing a common interface definition can eliminate the redundant congestion pricing because the ultimate source and sink are the same as in the MISO IMM proposal – the reference buses of the two RTOs. However, under this proposal, MISO would price the congestion effects from its Reference Bus to A, B, C, and D, while PJM prices the same effects from the seam to its Reference Bus. In reality, what happens under this proposal is the RTOs calculate shift factors that tend to be larger and offsetting so they sum to the same shift factor (i.e., flow effect on the constraint) as injecting at one reference bus and withdrawing at the other.

While this may have intuitive appeal, this solution will produce an efficient settlement only if both RTOs' markets produce the same shadow prices for the constraint. Remember that the congestion component for each RTO is equal to the shift factor times the shadow price. With the inflated shift factors this proposal produces, it is very important that both RTOs are using the same shadow price. We have evaluated this solution and found that this necessary condition often does not hold, particularly in the day-ahead market. Therefore, this solution would distort the incentive to schedule imports and exports when market-to-market constraints are binding.

It also introduces serious concerns for some of the constraints that are not coordinated as market-to-market constraints because only the monitoring RTO settles the congestion effects of transactions with the participant for these constraints. Assuming power sources/sinks at a small number of points at the seam sharply inflates the congestion payments for some constraints and reverses the sign of the congestion settlement for others. PJM has shown power flow analysis results that demonstrate these concerns on the PJM system as well.

Ultimately, the distorted and volatile congestion settlements that would occur under the PJM proposal would result in two significant problems:

- They would cause participants to schedule transactions inefficiently over the PJM-MISO interface; and

- They will create balancing congestion uplift for the RTOs' customers because the RTOs would make payments for flow relief that the transactions will not produce.

We do not believe these problems can be effectively addressed under the PJM proposal and no party has identified any legitimate concerns with the MISO proposal. Therefore, we continue recommend that both PJM and MISO implement the approach we have developed.

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.

Table A4 and Table A5: Illustration of Interface Pricing Alternatives

The PJM solution produce an efficient settlement if two conditions are satisfied:

- First, the flow effects of each half of the transaction must sum to equal the total effect. In other words, MISO shift factor plus PJM's shift factor should equal the shift factor that MISO would have calculated under Alternative #1 discussed above (where MISO would price the entire path from reference bus to reference bus).
- Second, for the pricing to be efficient, both RTOs' real-time markets must estimate similar shadow prices for the constraint.

If these two conditions hold, Alternative #1 (our recommendation) and Alternative #2 (PJM's proposal) will produce the same congestion settlement with the transaction, which is illustrated in the tables below.

Table A4: Illustrations of Alternative Interface Pricing

Example 1- Alternative #1

	MISO	PJM	Balancing Congestion/FTR Underfunding
Shadow Cost	$500	0	
Shift Factor	-10%	0	
Congestion Payment	$50	0	None
Total Payment	**$50**		**Payment is efficient**

Example 2- Alternative #2 with Equal Shadow Prices

	MISO	PJM	Balancing Congestion/FTR Underfunding
Shadow Cost	500	500	
Shift Factor	-20%	10%	
Congestion Payment	$100	($50)	MISO= $50 shortfall, PJM= $50 surplus
Total Payment	**$50**		**Payment is efficient**

The table above showing the example for Alternative #2 exhibits larger shift factors in absolute value terms. They sum to the -10 percent in Alternative #1 because they have offsetting effects (opposite signs). These larger shift factors are consistent with our evaluation of PJM's proposed interface definition, which consists of 10 points on the seam between MISO and PJM. For example, MISO calculated shift factors for one of the Benton Harbor-Palisades constraints (the most valuable market-to-market constraint in early 2014. The shift factor was 0.46 percent under MISO's current interface definition for PJM based on all generators in PJM. Using PJM's proposed interface definition, where the shift factors are based on select buses at the seam, the shift factor was 9.20 percent.

This indicates that MISO's congestion component when this constraint is binding will be 20 times larger under PJM's proposed definition than MISO's current definition. Therefore, in hours when this constraint is binding, it would increase the interface price by $6 per MWh, while under PJM's proposal the interface price would increase by $120 per MWh.

The inflation in the interface price described above will not necessarily create an inefficient incentive to engage in external transactions if it is offset by a comparable change in PJM's interface price. There are at least three problems with relying on this offsetting change:

- The RTO that overpays due to the inflated shift factors would generate balancing congestion or FTR underfunding. There is not settlement mechanism for the RTO that is benefiting from the inflated shift factors to provide a reimbursement.
- The non-monitoring RTO's shadow price (PJM's in this example) is often lower than the monitoring RTO's shadow price. When that happens, the settlement will not be efficient because the non-monitoring RTO's congestion component will not offset the inflated congestion component of the monitoring RTO.
- If the constraint is a not a market-to-market constraint, there will be no offsetting settlement by the non-monitoring RTO so the inflated shift factor will simply provide an inefficient incentive to schedule transactions. This will generate balancing congestion or FTR underfunding for the monitoring RTO.

These latter two problems are illustrated in the following table.

Table A5: Issues Associated with Alternative #2

Example 3- Alternative #2 with Non-Convergent Shadow Prices

	MISO	PJM	Balancing Congestion/FTR Underfunding
Shadow Cost	500	100	
Shift Factor	-20%	10%	
Congestion Payment	$100	($10)	MISO= $50 shortfall, PJM= $10 surplus
Total Payment	**$90**		**Transaction overpaid**

Example 4- Alternative #2 for Non-M2M Constraints

	MISO	Balancing Congestion/FTR Underfunding
Shadow Cost	500	
Shift Factor	-20%	
Congestion Payment	$100	MISO= $50 shortfall
Total Payment	**$100**	**Transaction significantly overpaid**

We do not believe these problems can be effectively addressed under the PJM proposal to establish a common interface at the seam. Further, we have yet to identify any potential issues or inefficiencies with MISO proposal (Alternative #1).

3. Interface Pricing and External TLR Constraints

Market-to-market constraints activated by PJM 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.[30] 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 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.H, 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.

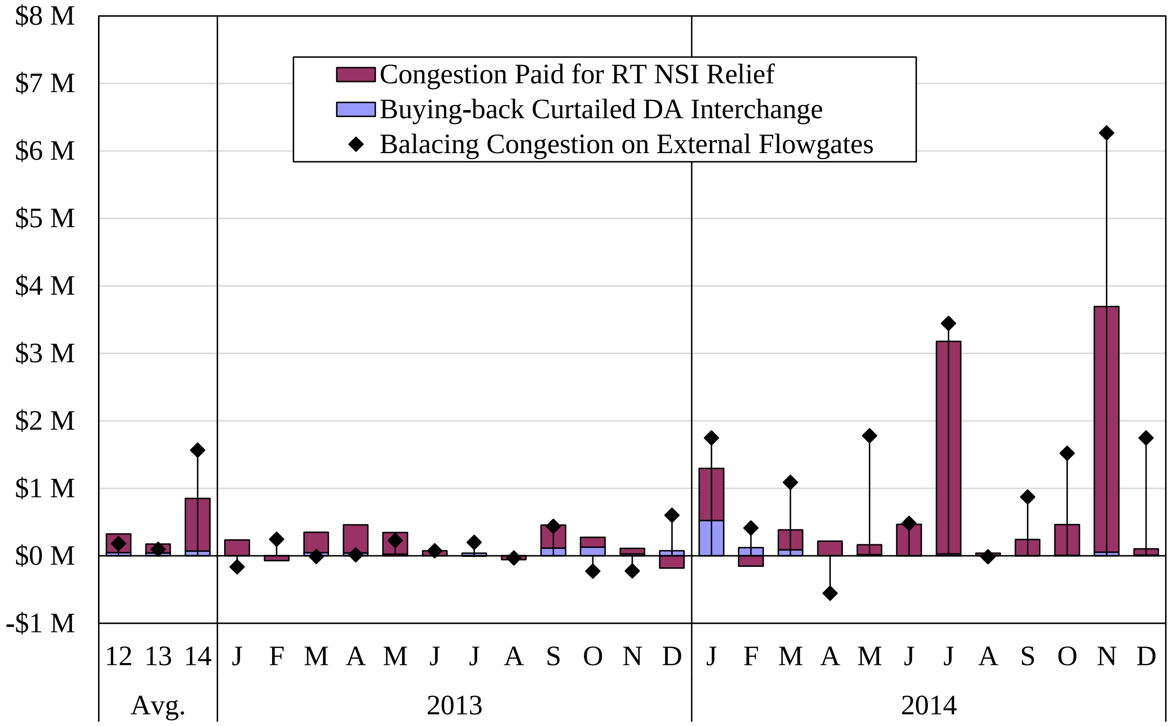
Figure A117: Excess TLR Congestion Settlements for External Transactions

Figure A117 shows the costs incurred by MISO customers associated with the external TLR congestion embedded in MISO's interface prices. These costs are subdivided into two categories. The first category contains costs to buyback day-ahead physical schedules curtailed in real time. Since the LMPs at affected interfaces during TLR events will be reduced,

30 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.

schedulers often profit from being curtailed. The second category shows payments to real-time physical schedulers for TLR constraint relief. Both categories contribute to balancing congestion costs since the impact of these schedules is not considered in MISO market flow.

Figure A117: Excess TLR Congestion Settlements for External Transactions
2012-2014



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 from transactions being scheduled in advance, perfect convergence should 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 on October 15, 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 A118 and Figure A119: 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 A118: Real-Time Prices and Interface Schedules
PJM and MISO, 2014

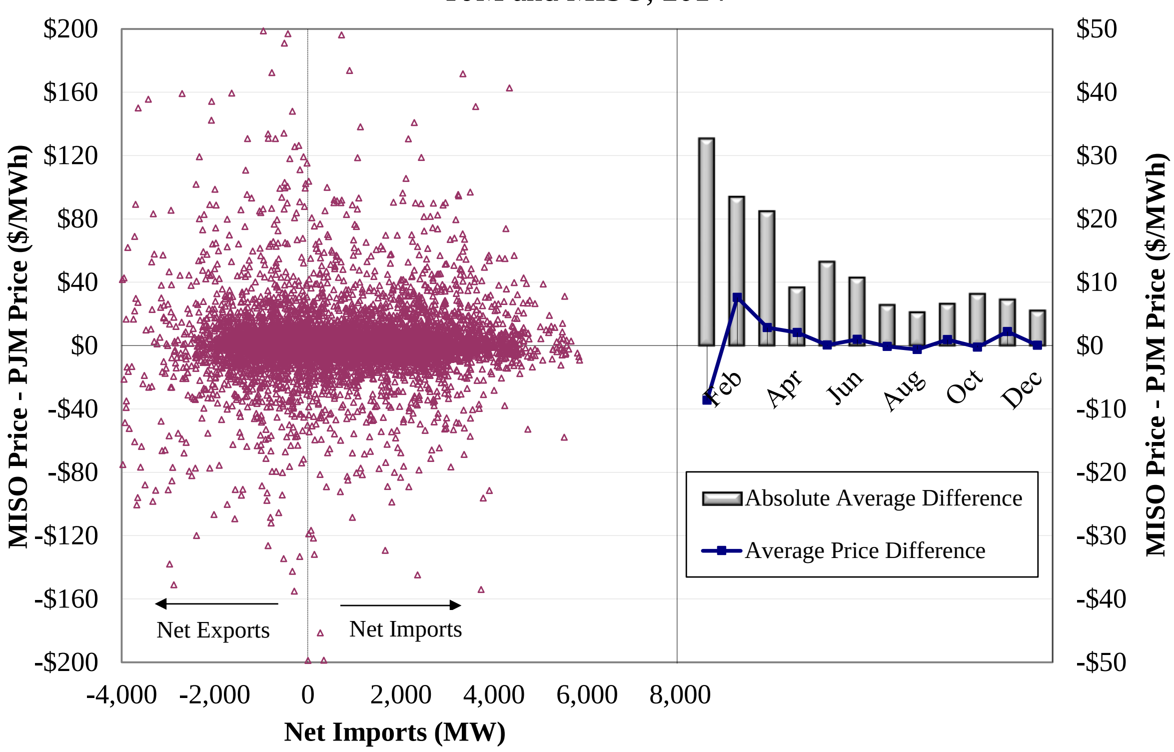
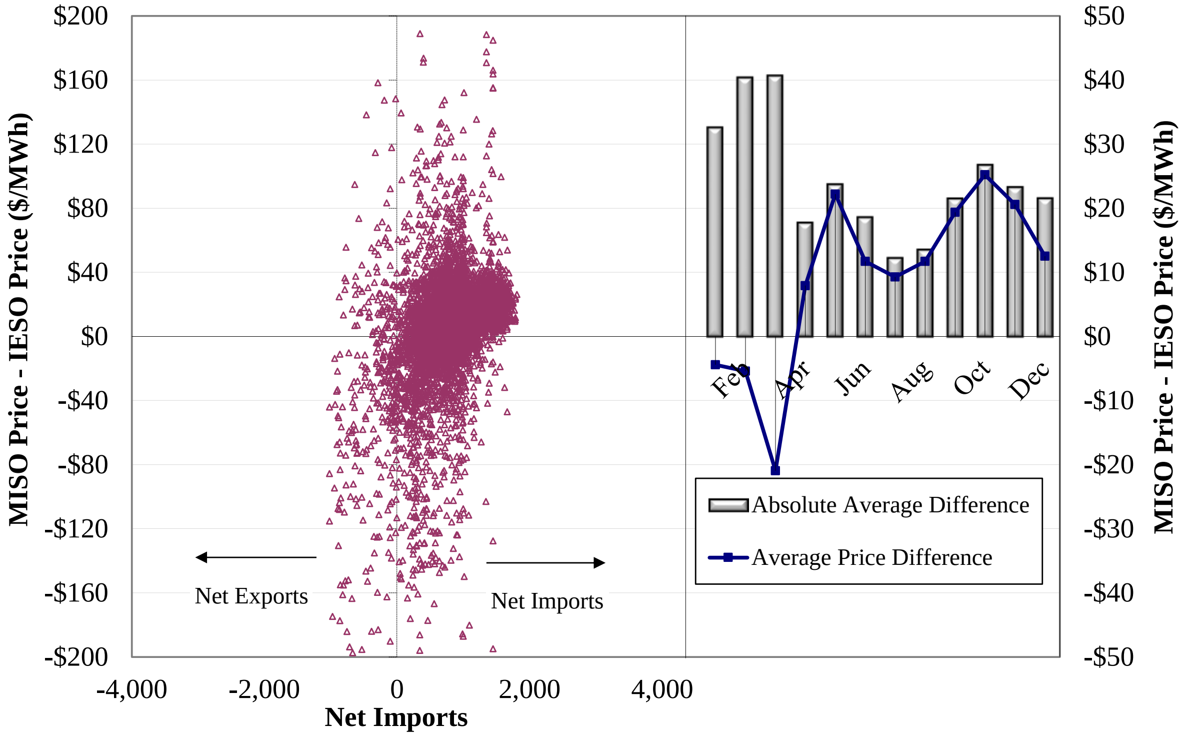


Figure A119: Real-Time Prices and Interface Schedules
IESO and MISO, 2014



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 a market power indicator based on the concentration of generation 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.

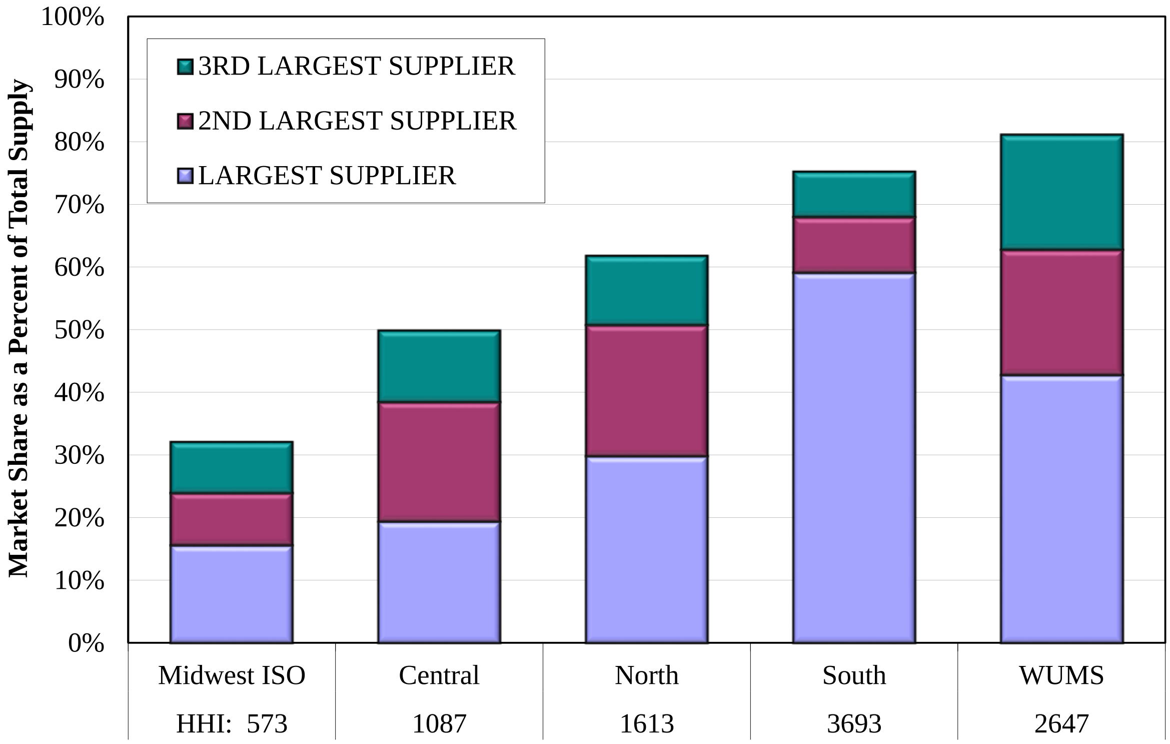
Figure A120: Market Shares and Market Concentration by Region

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.

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. We also calculate a three-firm concentration ratio which calculates the total share of capacity of the largest three suppliers.

Figure A120 shows generating capacity-based market shares and HHI calculations for MISO as a whole and within each region.

Figure A120: Market Shares and Market Concentration by Region
2014



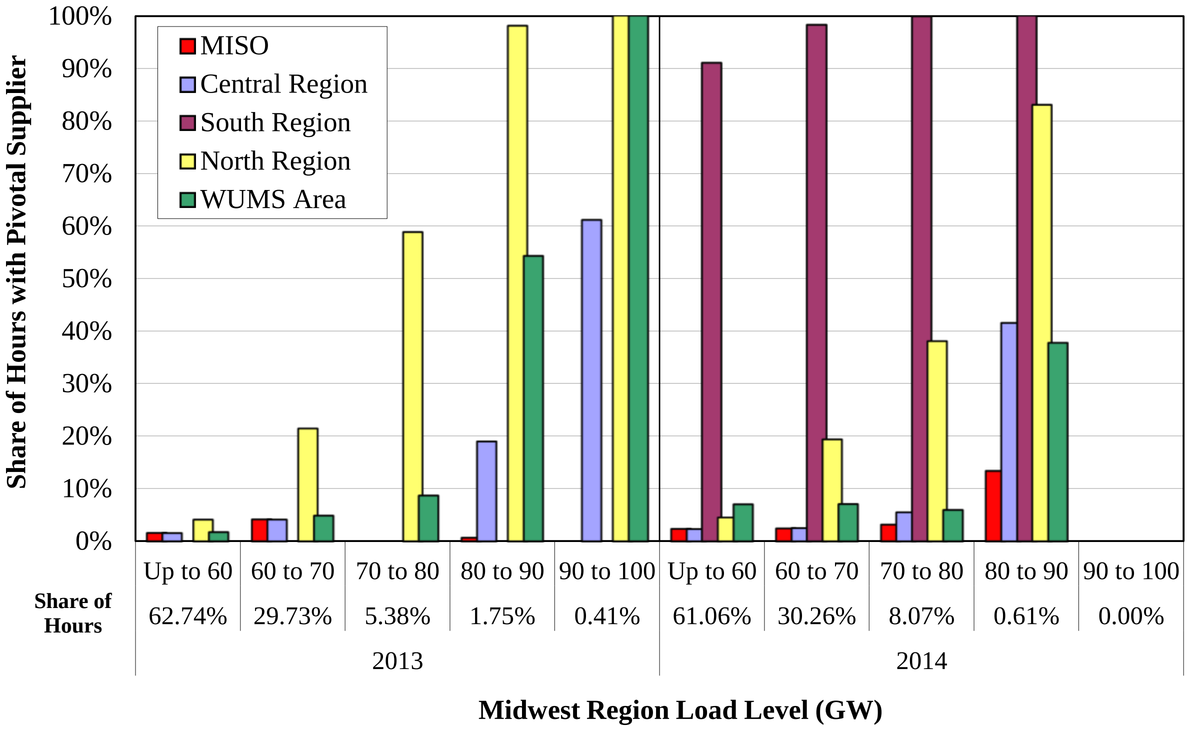
Because the subregions of MISO analyzed above do not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, the HHI alone does not allow for conclusive inferences regarding the overall competitiveness of electricity markets. The next two analyses more accurately reveal potential competitive concerns in the MISO markets.

Figure A121: 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 A121 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 A121: Pivotal Supplier Frequency by Region and Load Level
2013–2014



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

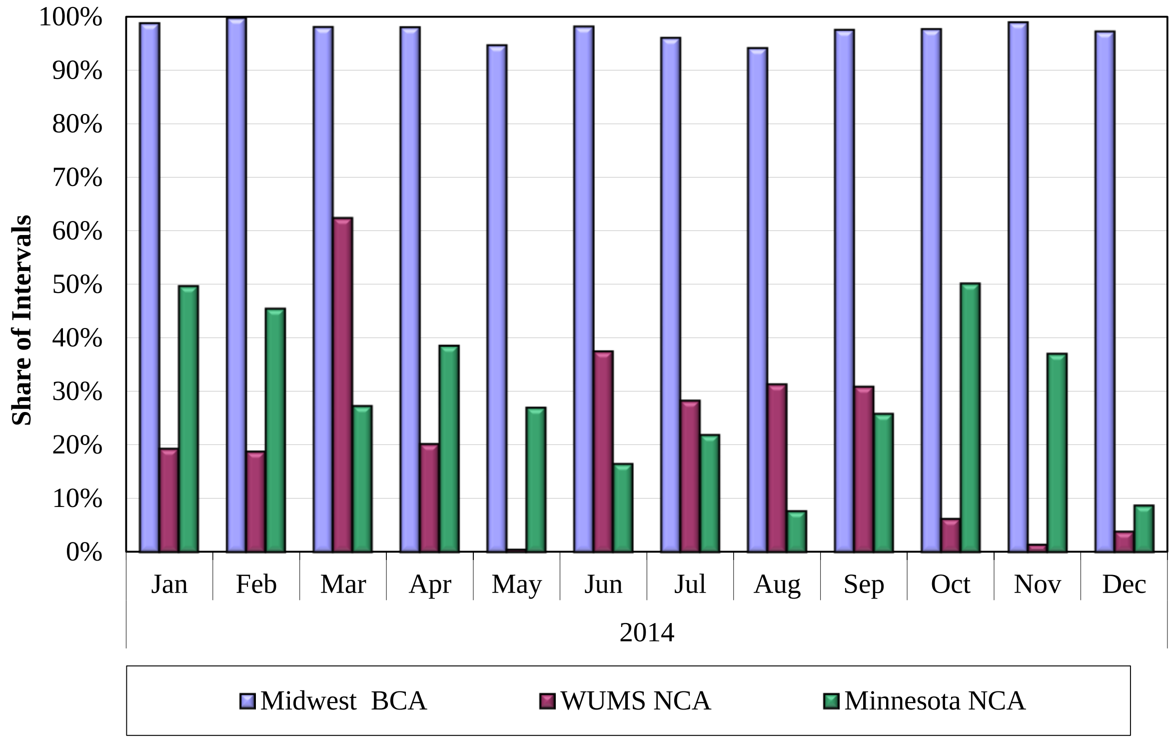
Minnesota NCA, the WUMS NCA[31], and the North WUMS NCA) and two in the South Region (WOTAB and Amite South NCAs).

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 A122 to Figure A125: 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 A122 and A106 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 A123 show, of the intervals with active constraints in each month, the percentage with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs are combined.

Figure A122: Percent of Intervals with at Least One Pivotal Supplier
Midwest Region, 2014



31 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 2014 ranged from $23.78 per MWh in Minnesota to $87.31 per MWh in WUMS. The WOTAB and Amite South NCA thresholds were $30.89 and $31.20 per MWh, respectively.

Figure A123: Percent of Intervals with at Least One Pivotal Supplier
South Region, 2014

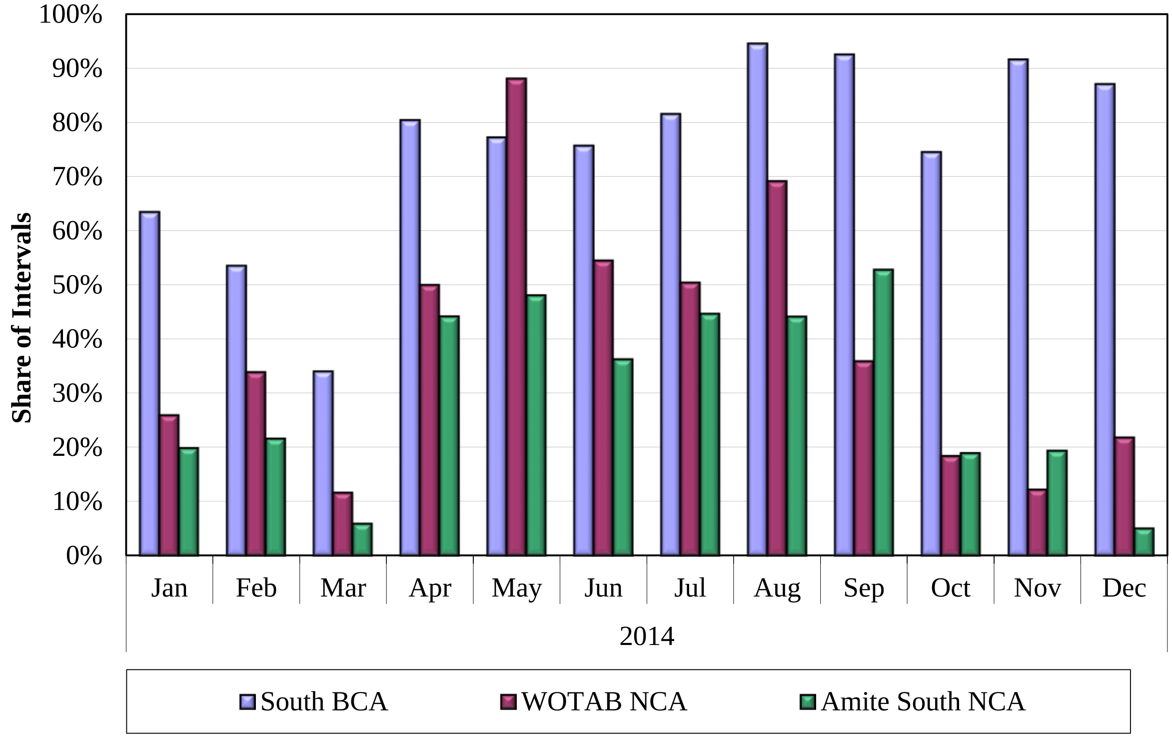


Figure A124: Percentage of Active Constraints with a Pivotal Supplier
Midwest Region, 2014

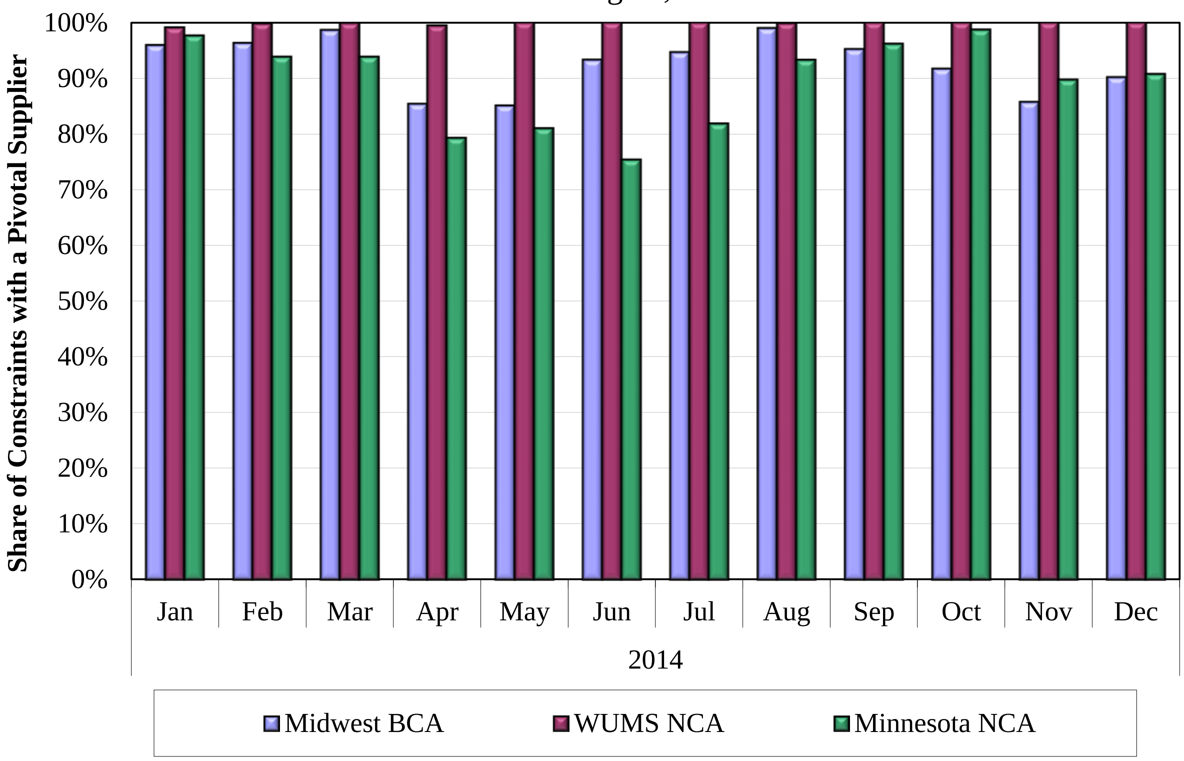
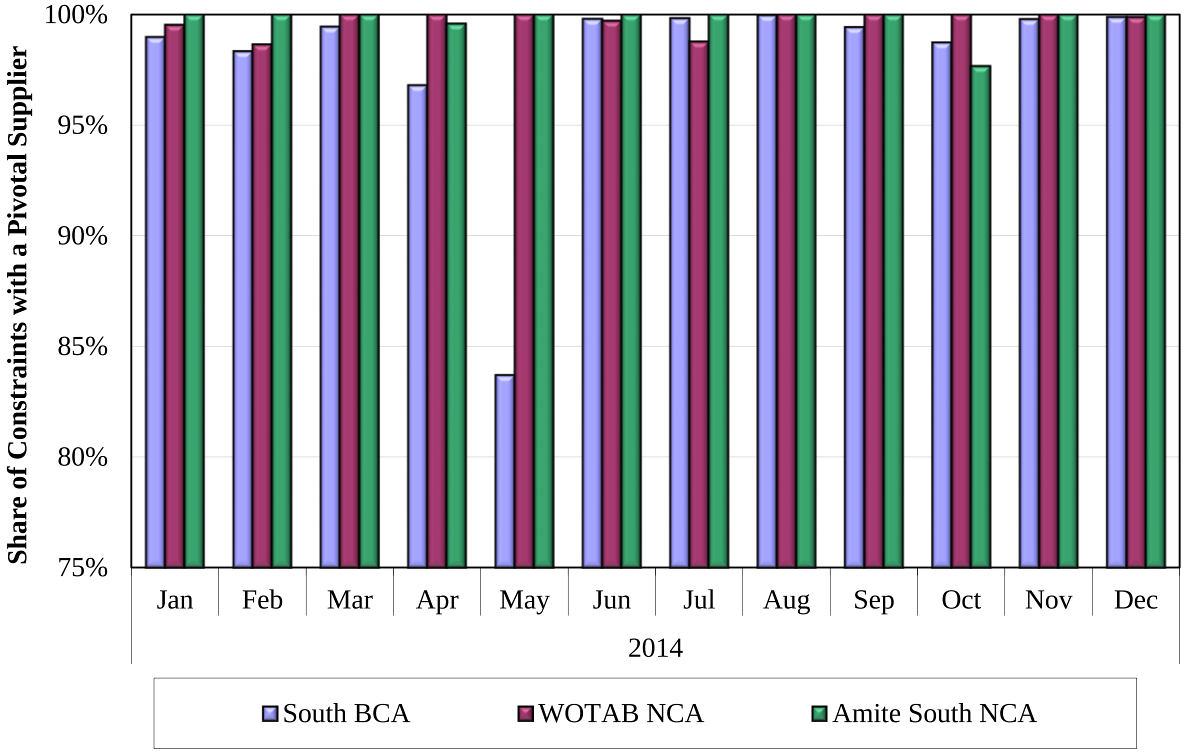


Figure A125: Percentage of Active Constraints with a Pivotal Supplier
South Region, 2014



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 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 price-cost mark-up for 2014 was 1.0 percent, which is very small. Mark-ups of less than three percent lie within the bounds of 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 includes 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, forego revenues in future periods to produce in the current period. These units 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", 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.[32]

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:

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32 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.

$Q_i^{econ} - Q_i^{prod}$ 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 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 inherently 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 transmission constraints, reserve considerations, or other changes in market conditions between the unit commitment and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. Hence the output gap formula used for this report is:

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

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

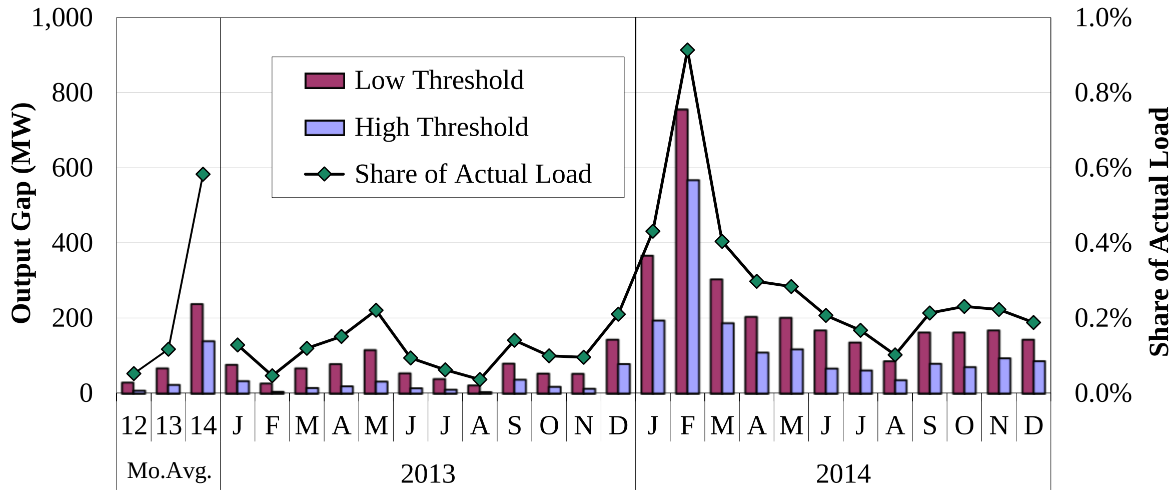
By using the greater of actual production or the output level offered at the clearing price, infeasible energy due to ramp limitations is excluded from the output gap.

Figure A126: Real-Time Monthly Average Output Gap

Figure A126 shows monthly average output gap levels for the real-time market in 2013 and 2014. 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 2014 were $87.31 per MWh for resources located in the WUMS NCA, $62.08 for those in the North WUMS NCA, $23.78 for those in the Minnesota NCA, and $30.89 and $31.20 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 Minnesota NCA, the low threshold would be $11.89 per MWh (50 percent of $23.78). 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 A126: Economic Withholding -- Output Gap Analysis
2013–2014



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 A127 to Figure A130: 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 A127: Real-Time Average Output Gap
Central Region, 2014

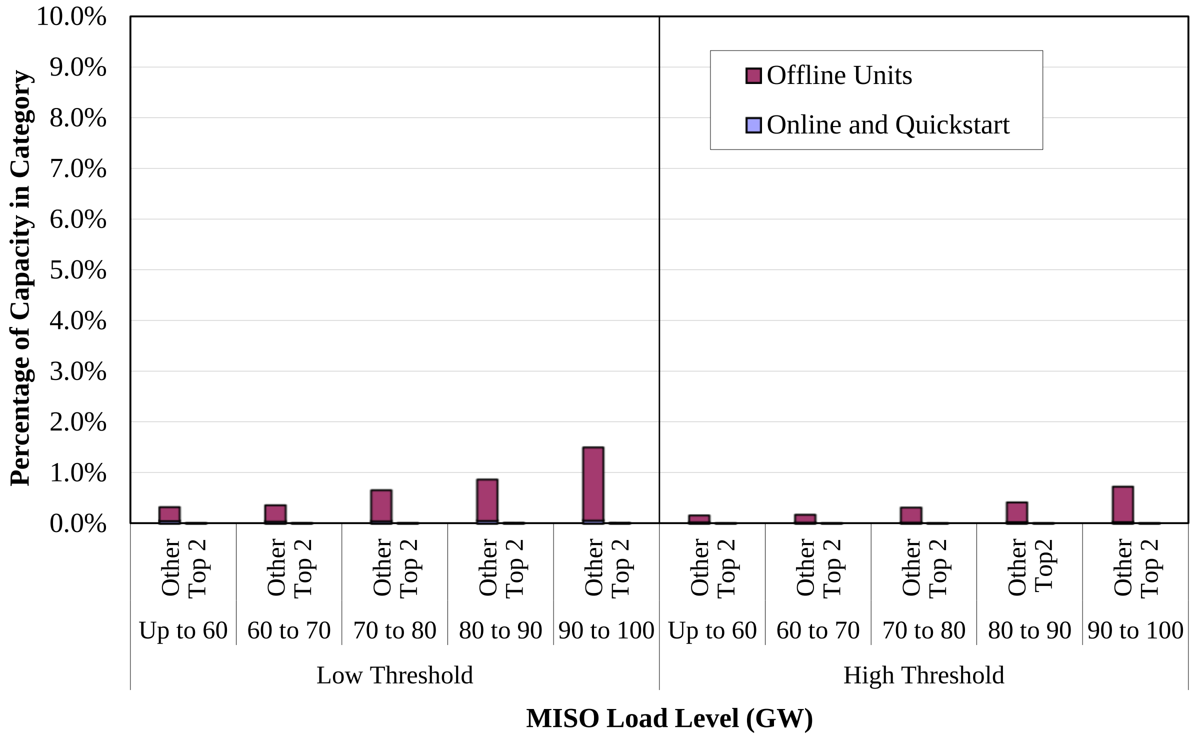


Figure A128: Real-Time Average Output Gap
South Region, 2014

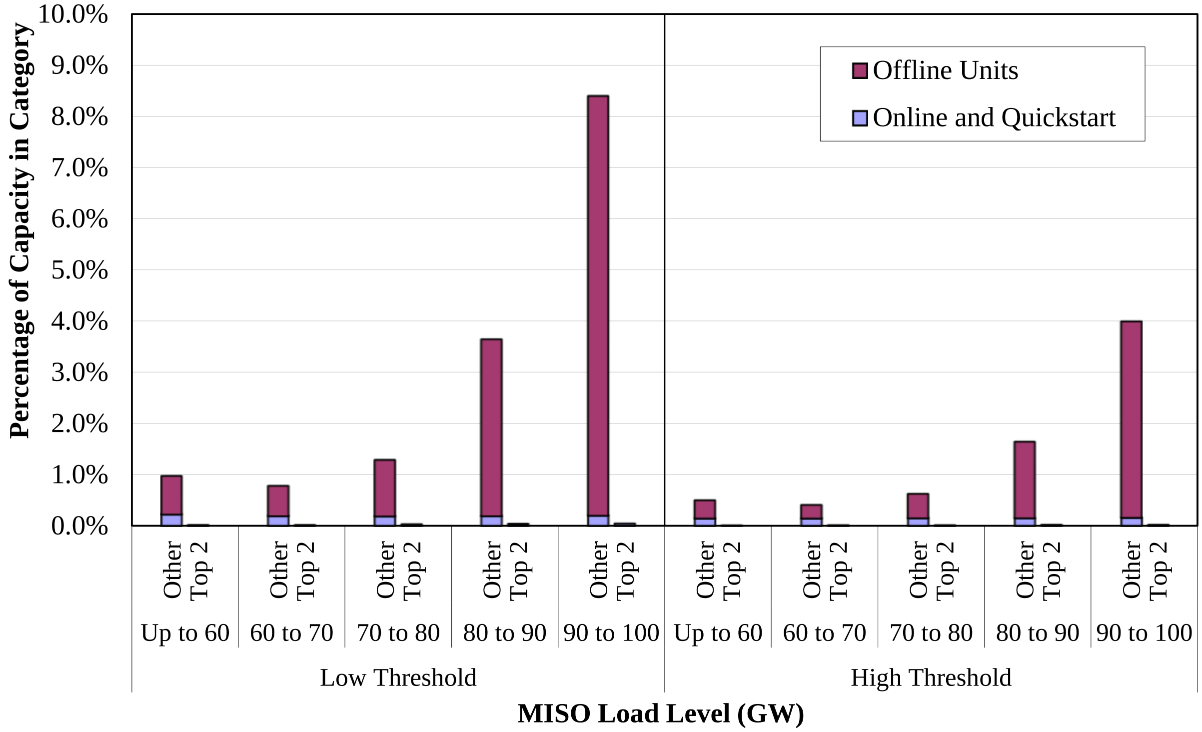


Figure A129: Real-Time Average Output Gap
North Region, 2014

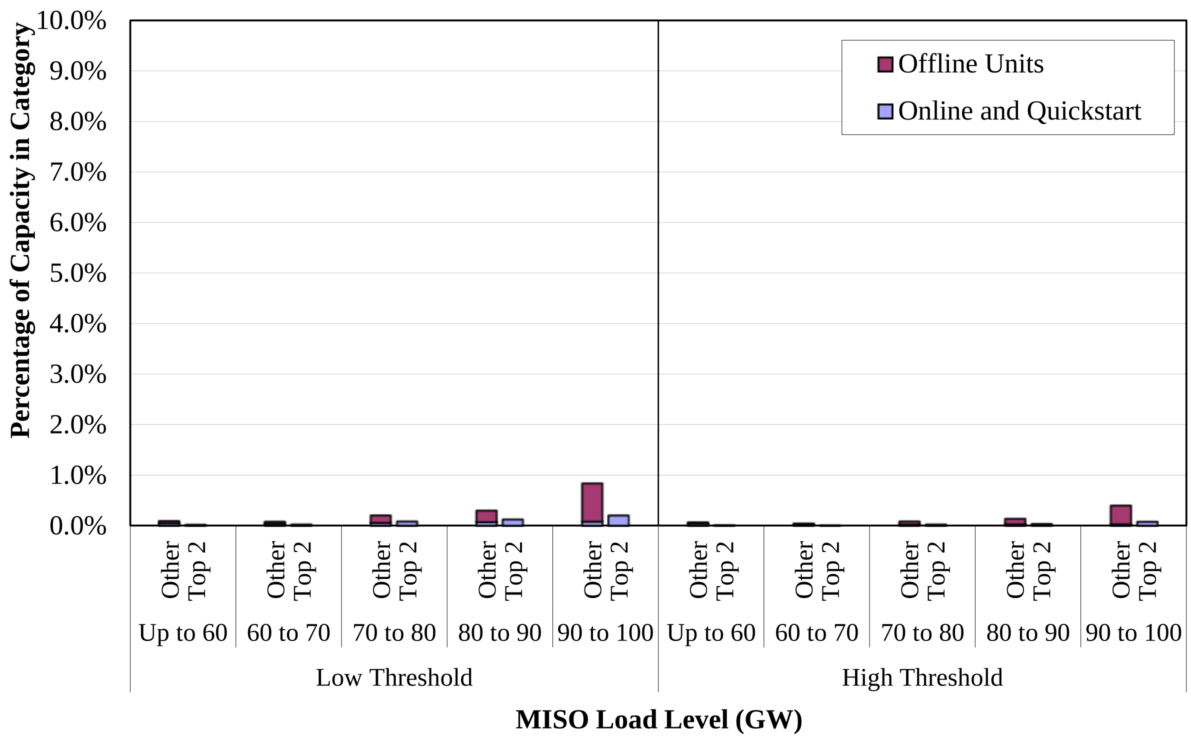
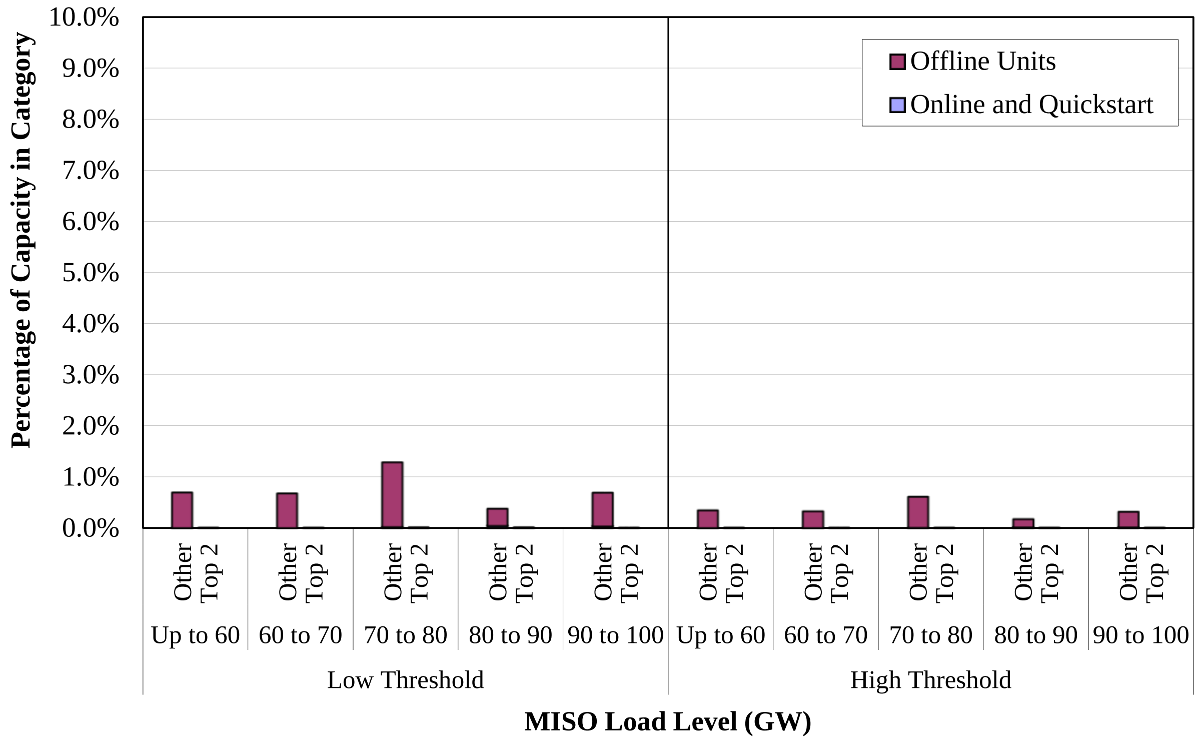


Figure A130: Real-Time Average Output Gap
WUMS Area, 2014



D. Market Power Mitigation

In this next subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2014. When the set of Tariff-specified criteria are met, a mitigated unit's offer price is capped at its reference level, which is a benchmark designed to reflect a competitive offer. MISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas.

Market participants are subject to potential mitigation specifically when binding transmission constraints result in substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in a position to exercise market power if competitive alternatives are not available. The mitigation thresholds differ depending on the two types of constrained areas that may be subject to mitigation: BCAs and NCAs.

Market power concerns are greater in NCAs because the congestion affecting these areas is chronic and a supplier is typically pivotal when the congestion occurs. As a result, conduct and impact thresholds for NCAs, which are calculated annually as a function of the frequency with which NCA constraints bind, are generally lower than for BCAs.

Figure A131: Day-Ahead and Real-Time Energy Mitigation by Month

Figure A131 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month. Mitigation in 2014 was much more frequent in the day-ahead market because VLR commitments, which are subject to tighter thresholds, are most often made day-ahead. For non-VLR commitments, 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 A131: Day-Ahead and Real-Time Energy Mitigation by Month
2014

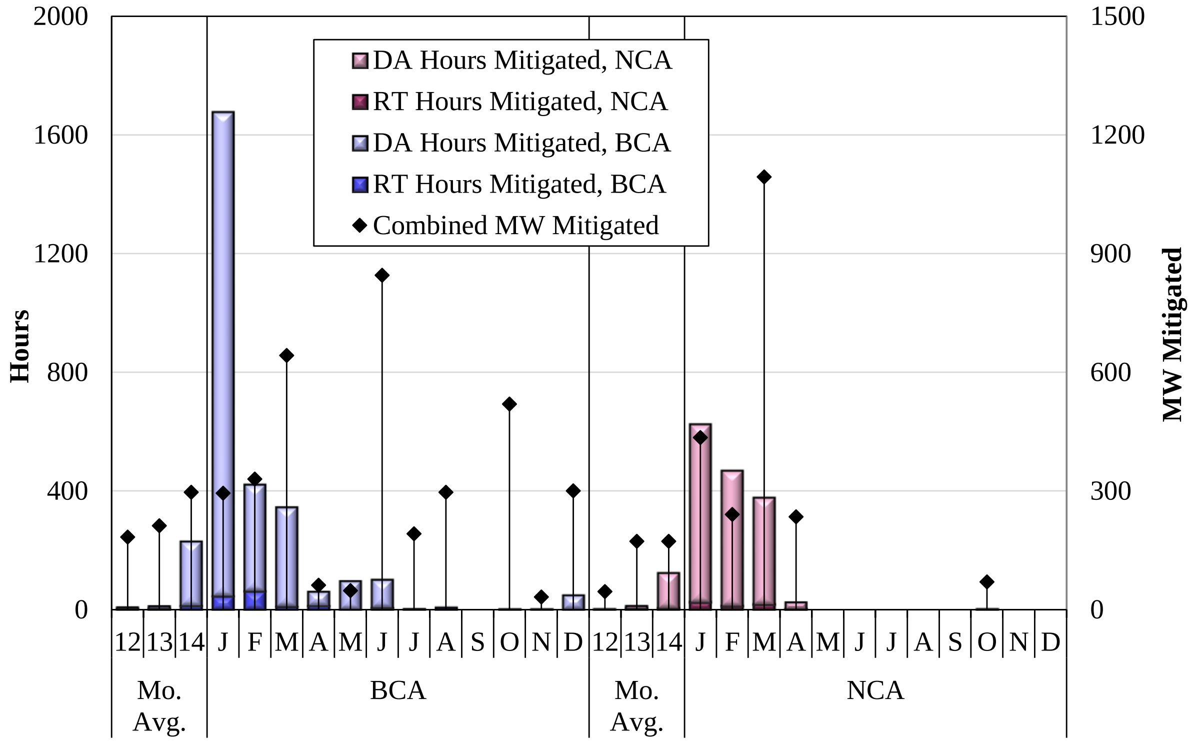
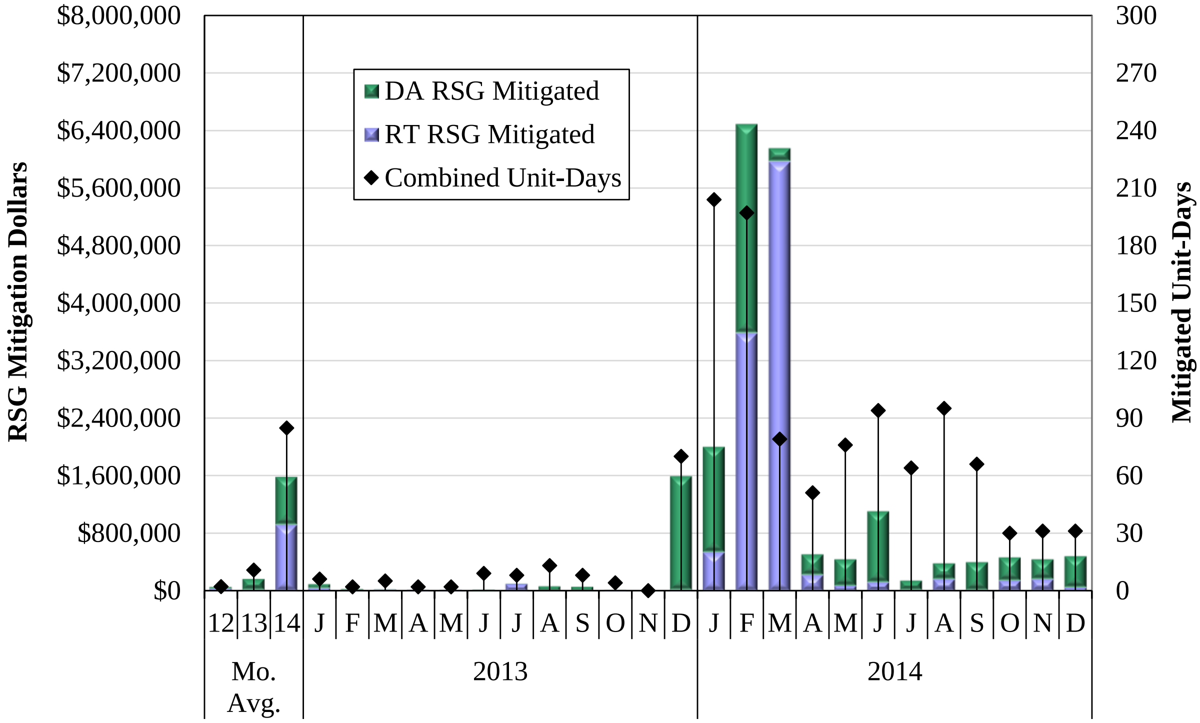


Figure A132: Day-Ahead and Real-Time RSG Mitigation by Month

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 designed mitigation measures to address this conduct. These mitigation measures are triggered when the following three criteria are met: (1) the unit must be committed for a constraint or a local reliability issue; (2) the unit's offer must exceed the conduct threshold; and (3) the effect of the inflated offer must exceed the RSG impact threshold (i.e., raise the unit's RSG payment by $50 per MWh for BCA and NCAs). Figure A132 shows the frequency and amount by which RSG payments were mitigated in 2013 and 2014.

Figure A132: Day-Ahead and Real-Time RSG Mitigation by Month
2013–2014



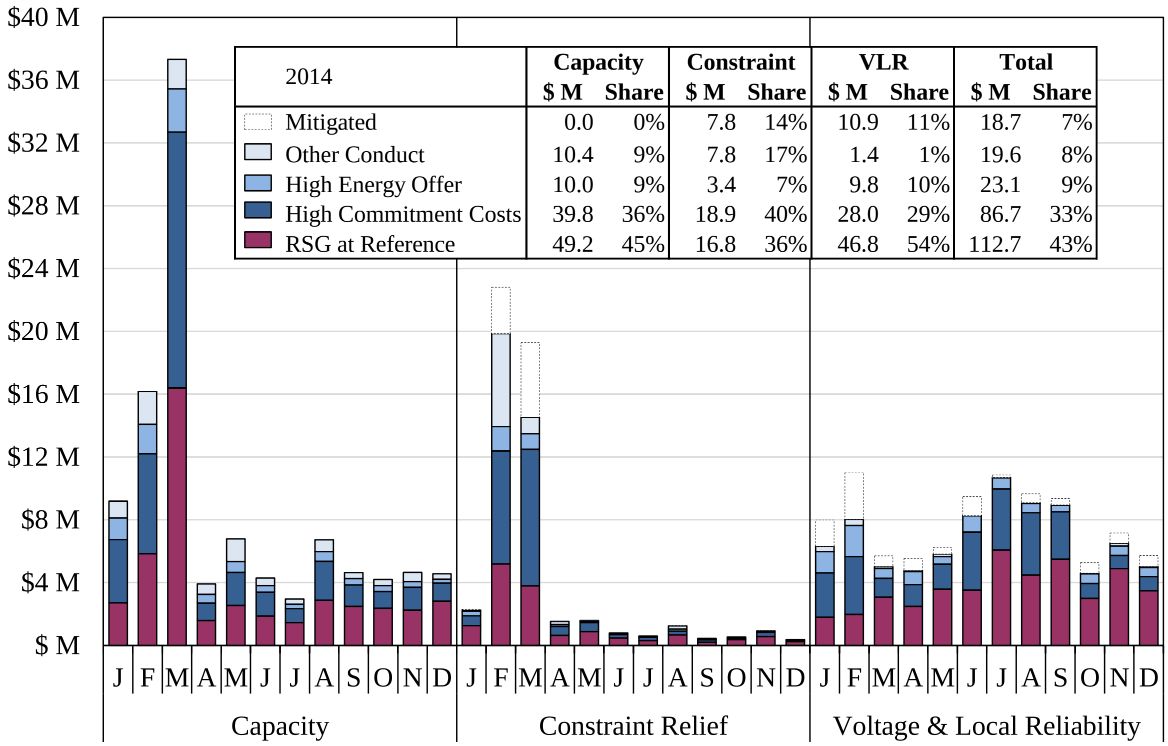
E. Evaluation of RSG Conduct and Mitigation Rules

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 A133 - Figure A135: Real-Time RSG Payments

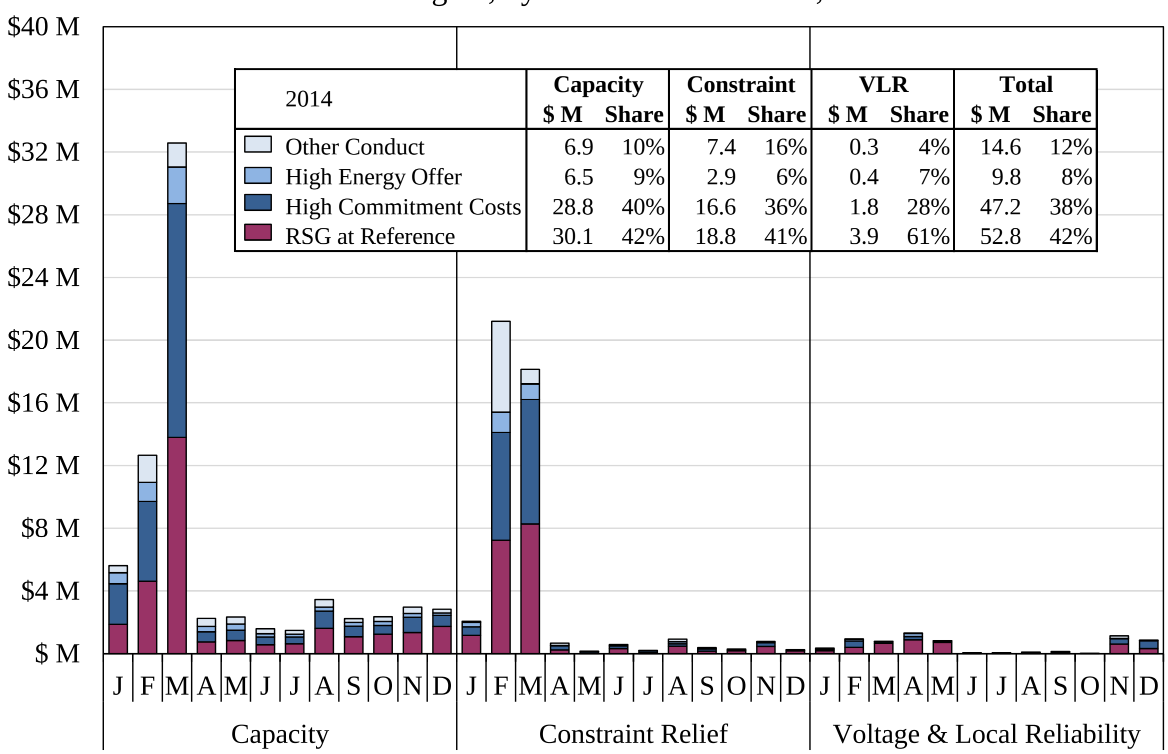
We evaluate conduct associated with RSG payments in the following figure, separating the payments associated with resources' reference levels, and the payments associated with the portions of resources' bid parameters (e.g., energy, commitment costs, and physical parameters) that exceed their reference 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 A132, the category "Mitigation" includes both day-ahead and real-time amounts.

Figure A133: Real-Time RSG Payments by Conduct
By Commitment Reason, 2014



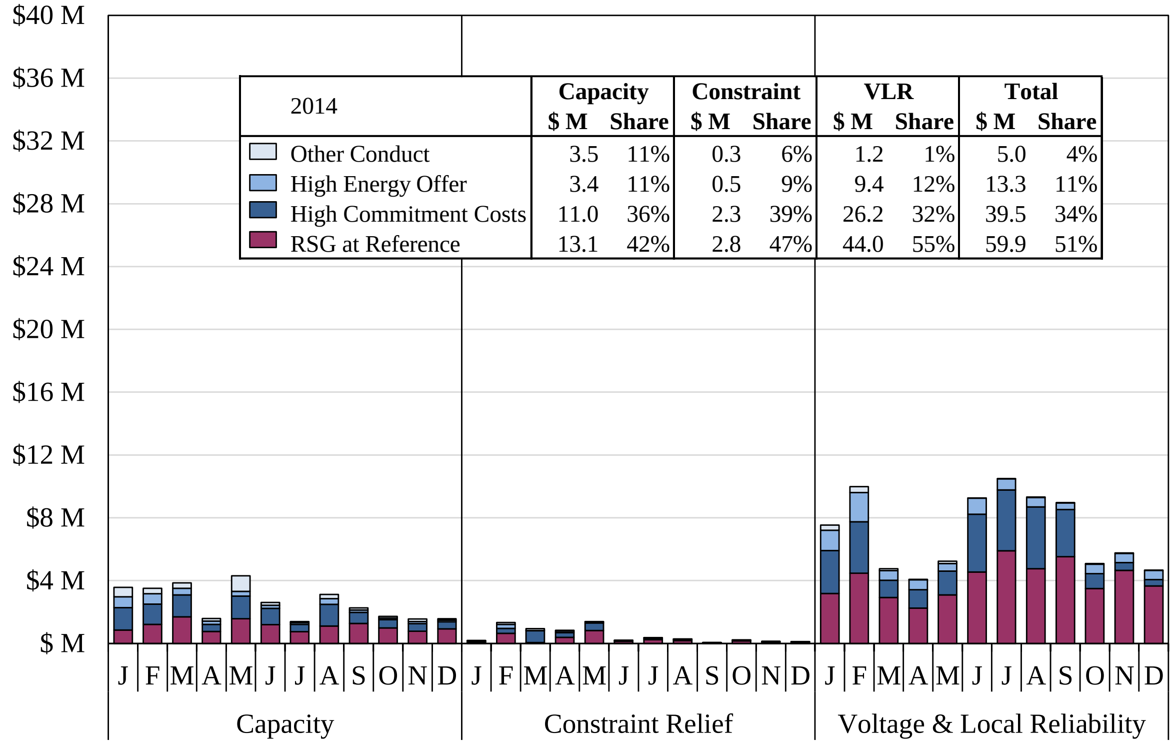
2014	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Mitigated	0.0	0%	7.8	14%	10.9	11%	18.7	7%
Other Conduct	10.4	9%	7.8	17%	1.4	1%	19.6	8%
High Energy Offer	10.0	9%	3.4	7%	9.8	10%	23.1	9%
High Commitment Costs	39.8	36%	18.9	40%	28.0	29%	86.7	33%
RSG at Reference	49.2	45%	16.8	36%	46.8	54%	112.7	43%

Figure A134: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2014



2014	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Other Conduct	6.9	10%	7.4	16%	0.3	4%	14.6	12%
High Energy Offer	6.5	9%	2.9	6%	0.4	7%	9.8	8%
High Commitment Costs	28.8	40%	16.6	36%	1.8	28%	47.2	38%
RSG at Reference	30.1	42%	18.8	41%	3.9	61%	52.8	42%

Figure A135: Real-Time RSG Payments by Conduct
South Region, by Commitment Reason, 2014



One of the attributes of the current mitigation measures is that the conduct tests are performed on each bid parameter individually. 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.

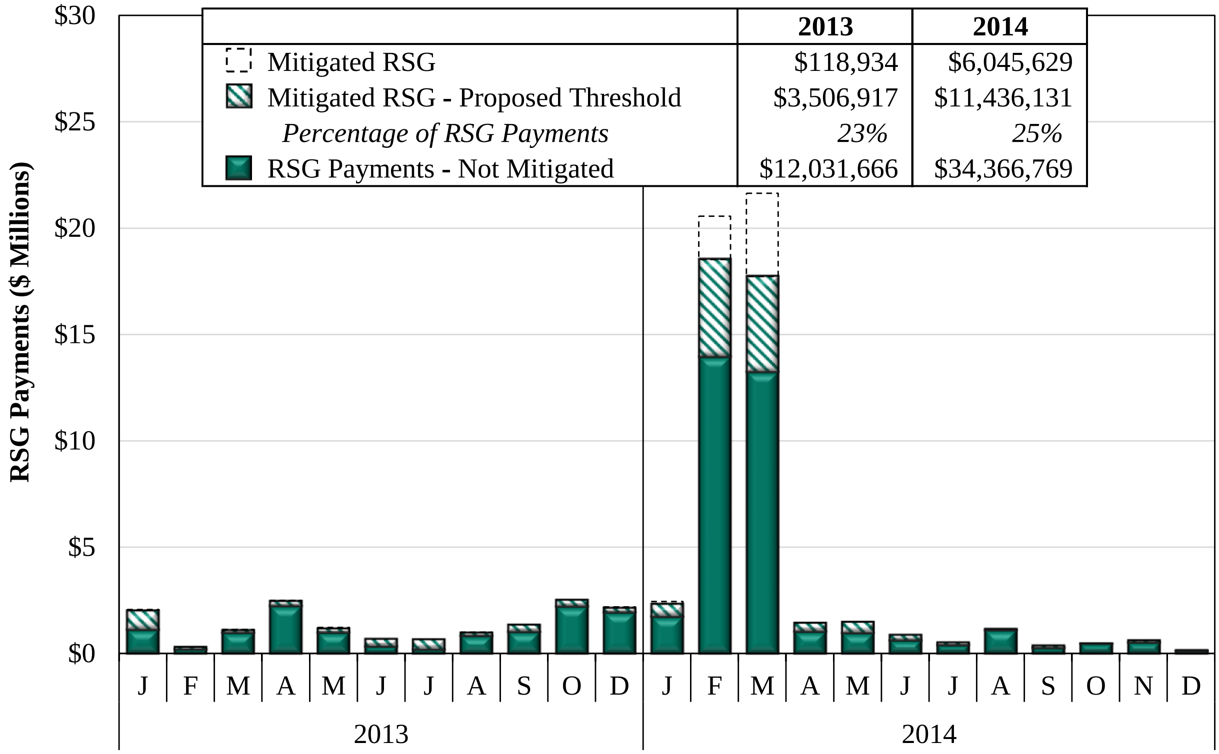
Additionally, the current RSG mitigation measures include an impact test with a $50-per-MW impact threshold to determine when conduct identified through the conduct test should be mitigated. The VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments. Therefore, we have studied whether applying the VLR RSG mitigation framework to all RSG would be more effective than the current RSG mitigation rules. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a tighter threshold for VLR mitigation than for other RSG mitigation. Therefore, we evaluated a conduct an impact threshold equal to the lower of $25 per MWh or 25 percent (rather than the 10 percent threshold applied to VLR commitments). This threshold should balance the need for suppliers to modify their offers to reflect changes in actual costs, while more effectively mitigating market power that may allow them to inflate their RSG payments. The percentage provision allows for reasonable treatment of all units regardless of cost, since a fixed threshold is far more accommodative to a $40 per MWh natural gas-fired unit than to a $500 per MWh oil-fired unit.

Figure A136: Real-Time RSG Payments

Figure A136 total real-time RSG payments in each month in 2013 and 2014. It also shows the payments mitigated under the existing framework, as well as the additional mitigation that would have occurred under the proposed production-cost framework.

Figure A136: Real-Time RSG Payments By Mitigation Classification
2013–2014



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. 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, these results will identify fewer mitigation instances that would be mitigated by the dynamic NCA.

Nonetheless, we have identified a number of instances over the past year when mitigation would have been warranted. Two examples are discussed below.

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

Figure A137 to Figure A139: Ancillary Services Market Offers

Figure A137 to Figure A139 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. 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 A137: Ancillary Services Market Offers

2014

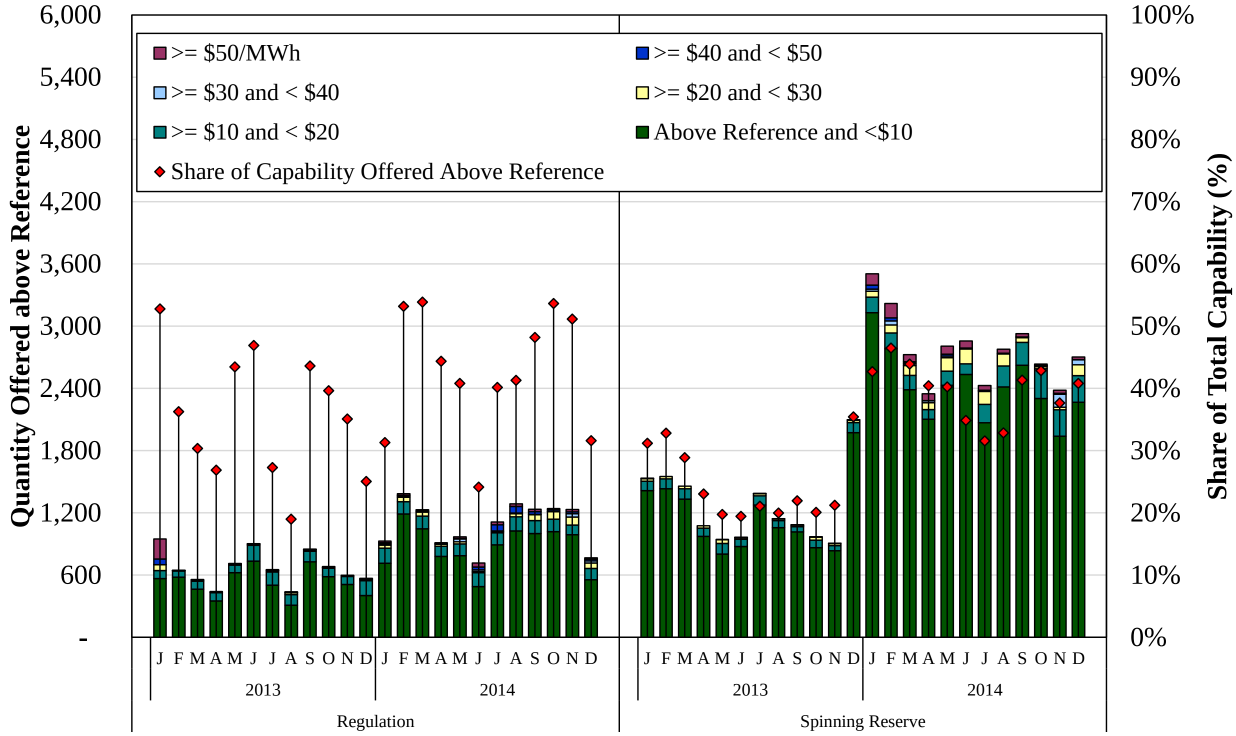


Figure A138: Ancillary Services Market Offers
Midwest

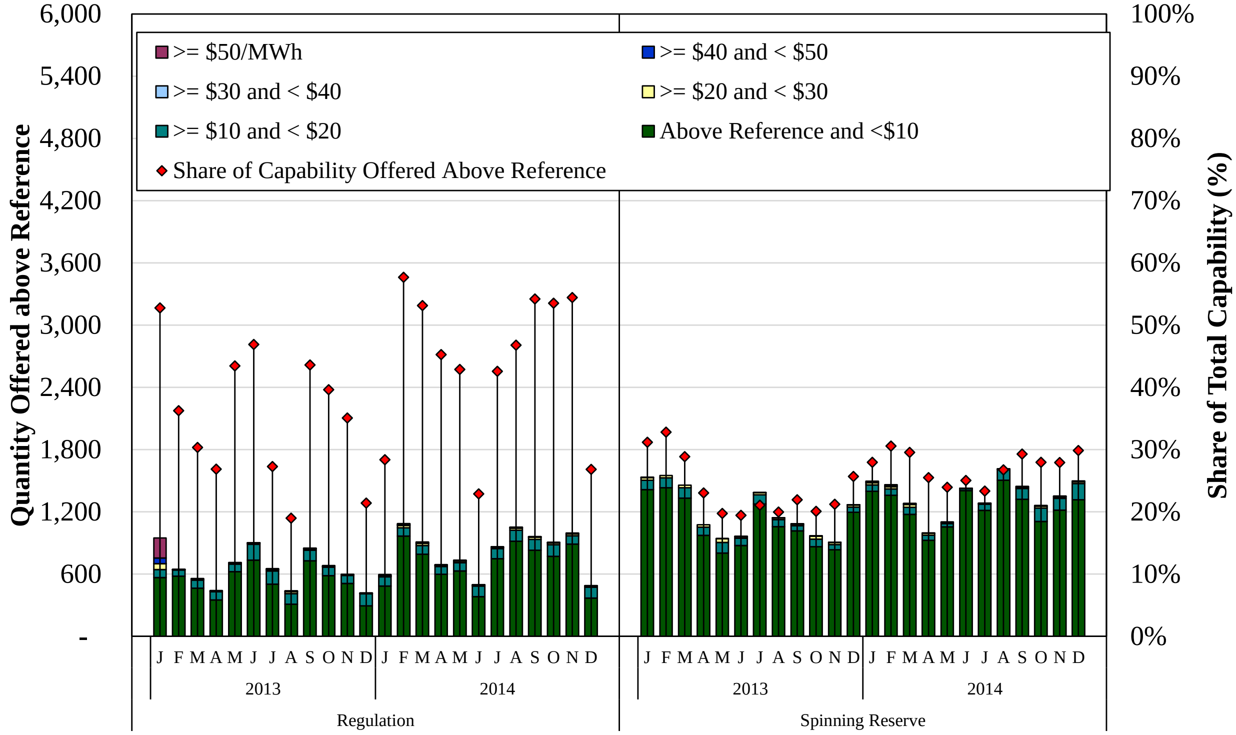
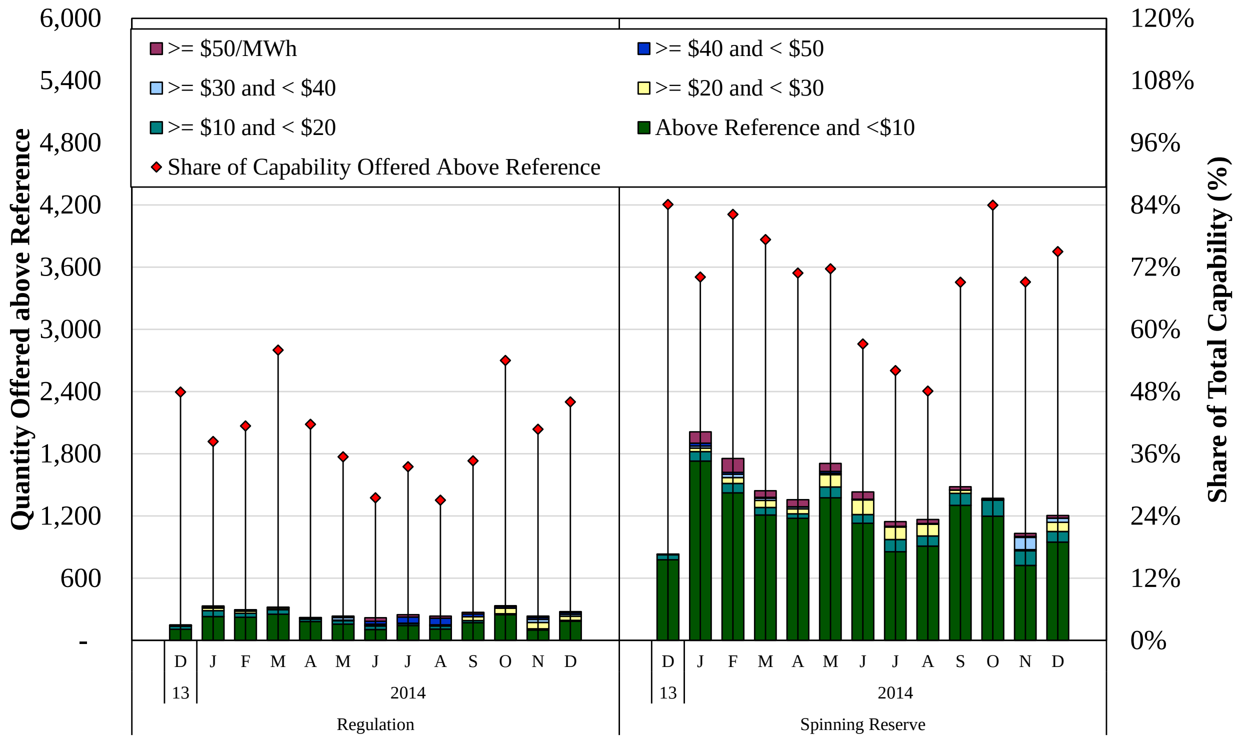


Figure A139: Ancillary Services Market Offers
South



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 A140 to Figure A143: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2014 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 A140: Real-Time Deratings and Forced Outages
Central Region, 2014

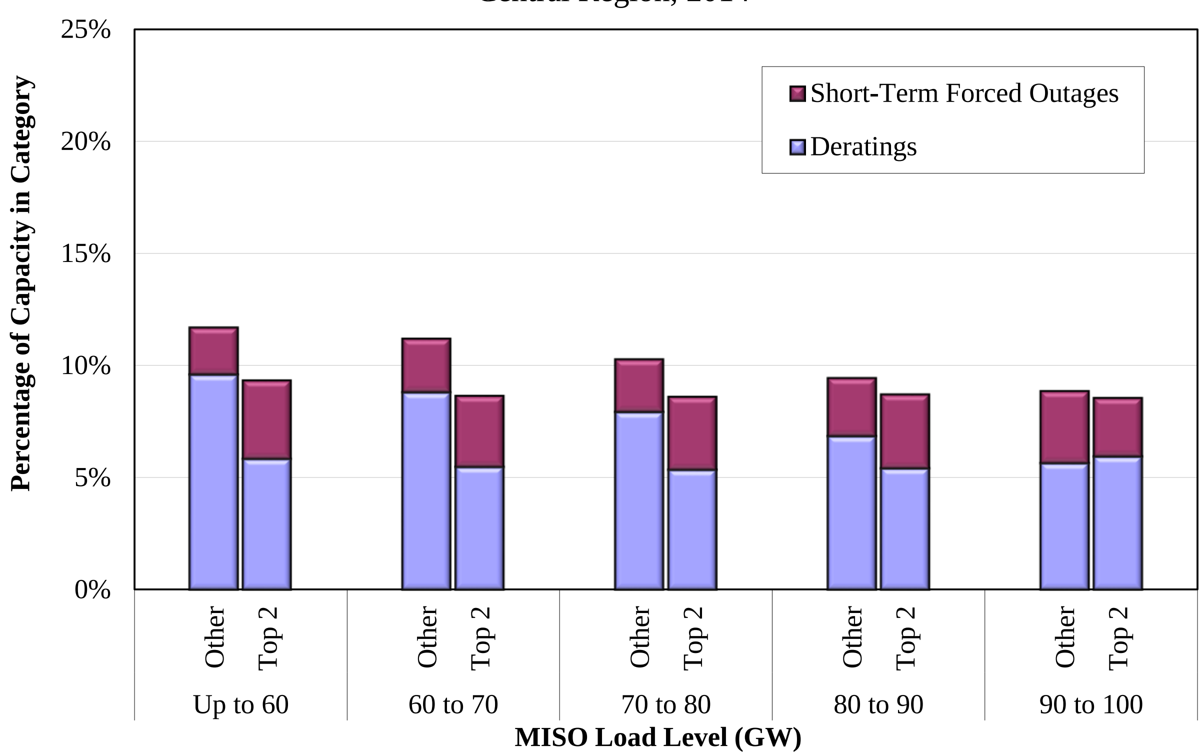


Figure A141: Real-Time Deratings and Forced Outages
South Region, 2014

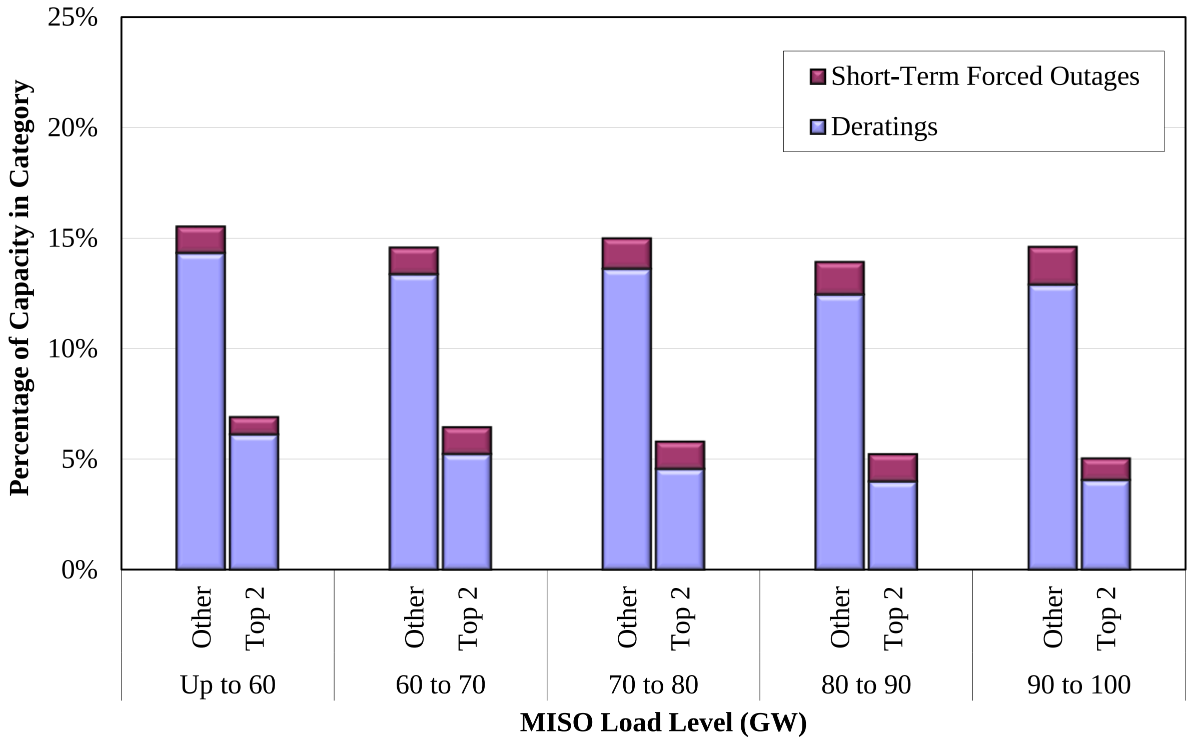


Figure A142: Real-Time Deratings and Forced Outages
North Region, 2014

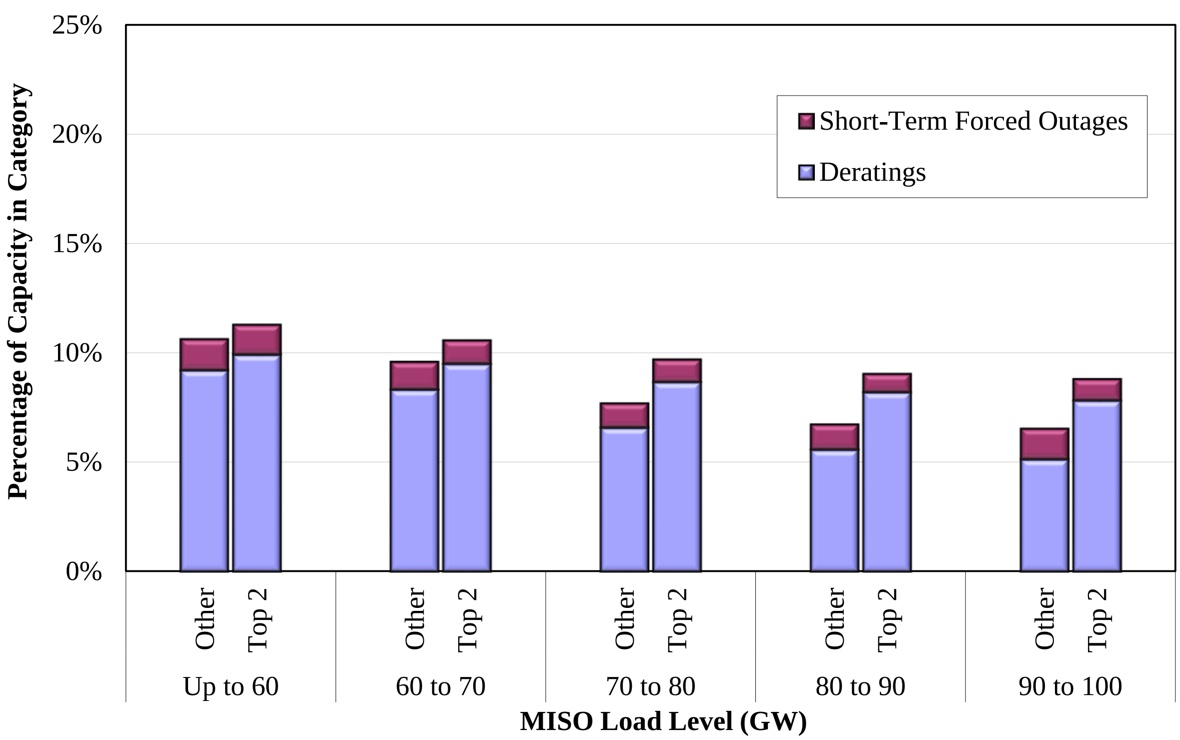
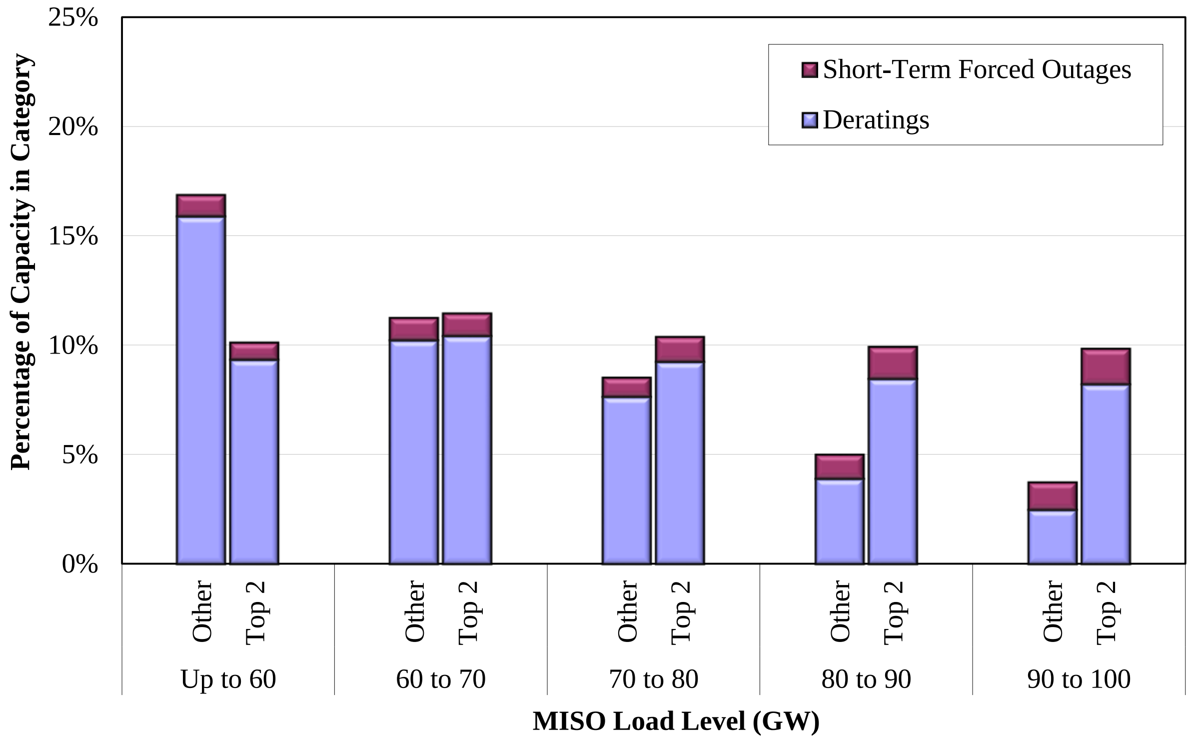


Figure A143: Real-Time Deratings and Forced Outages
WUMS Area, 2014



IX. Demand Response Programs

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

- Reliability in the short term;
- Least-cost resource adequacy in the long term;
- 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.[33] 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.

33 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.

A. DR Resources in MISO

MISO's demand response capability rose slightly in 2013 to approximately 10.2 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 22 Type I resources—three of these exited in March—and one Type II resource available to the markets in 2014, and 13 of them cleared on average less than 4 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 75-MW Type II resource was active in MISO in 2014.

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 2014, one unit provided 4.6 MW of regulating reserves, three units provided 42 MW of spinning reserves, and three units provided less than 1 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 VCA, while 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 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 A6: DR Capability in MISO and Neighboring RTOs

Table A6 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 A6: DR Capability in MISO and Neighboring RTOs
2009–2014

	2014	2013	2012	2011
MISO[1]	**10,356**	**9,798**	**7,196**	**7,376**
Behind-The-Meter Generation	4,072	3,411	2,969	3,001
Demand Resources	4,943	5,045	2,882	2,898
DRR Type I	372	372	372	472
DRR Type II	76	76	71	75
Emergency DR	894	894	902	930
NYISO[3]	**1,211**	**1,306**	**1,925**	**2,161**
ICAP - Special Case Resources	1,124	1,175	1,744	1,976
Of which: Targeted DR	*369*	*379*	*421*	*407*
Emergency DR	86	94	144	148
Of which: Targeted DR	*14*	*40*	*59*	*86*
DADRP	0	37	37	37
ISO-NE[4]	**2,487**	**2,101**	**2,769**	**2,755**
Real-Time DR Resources	796	793	1,193	1,227
Real-Time Emerg. Generation Resources	255	279	588	650
On-Peak Demand Resources	997	629	629	562
Seasonal Peak Demand Resources	439	400	359	316

[1] Registered as of December 2014. All units are MW. Source: MISO webite, published at: www.misoenergy.org/WhatWe Do/StrategicInitiatives/Pages/DemandResponse.aspx. MISO has indicated that the total amount of DR may actually be as high as 11,329 at the end of 2014.

[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 DR Working Group Presentation, Jan. 7, 2015.