2013 State of the Market Report for the MISO Electricity Markets

Analytical Appendix

POTOMAC ECONOMICS

June 2014

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I. Prices and Revenues

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 voluntary capacity auction in June 2009. The Voluntary Capacity Auction (VCA) was replaced by the annual Planning Resource Auction (PRA) in June 2013. In this section, we address the day-ahead and real-time energy markets and summarize prices and revenues associated with these markets.

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 2011 to 2013 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.

Figure A1: All-In Price of Electricity
2012–2013

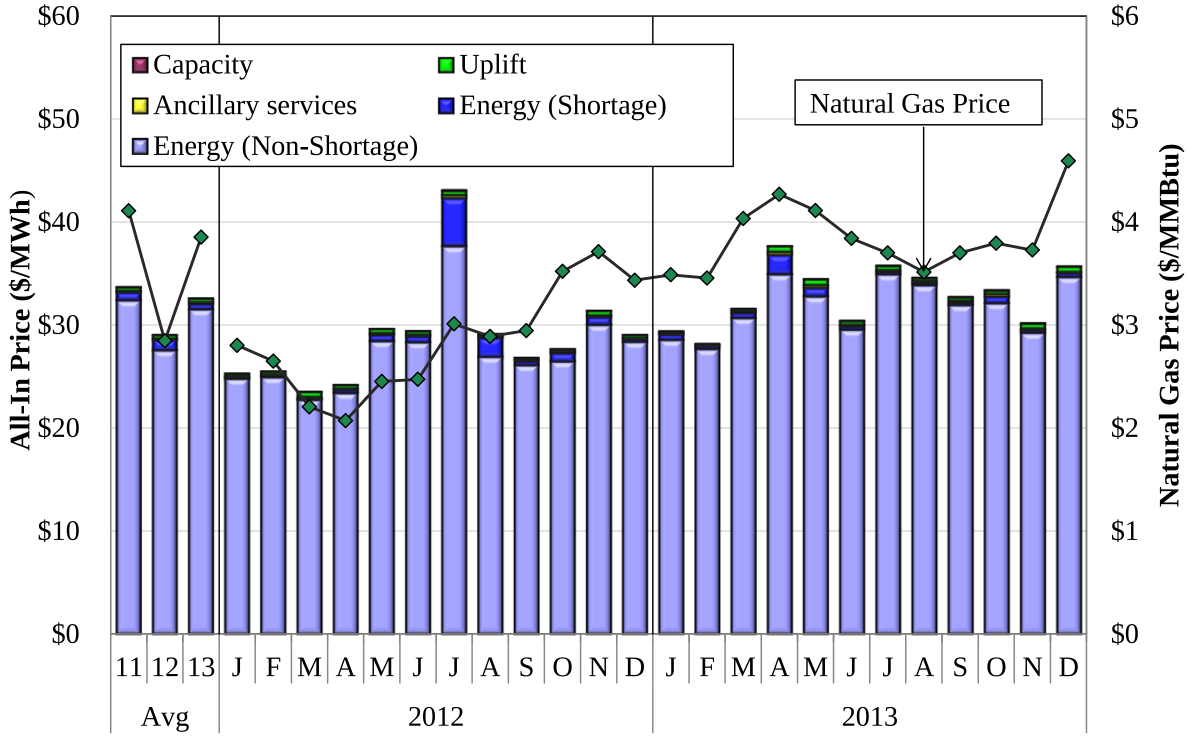
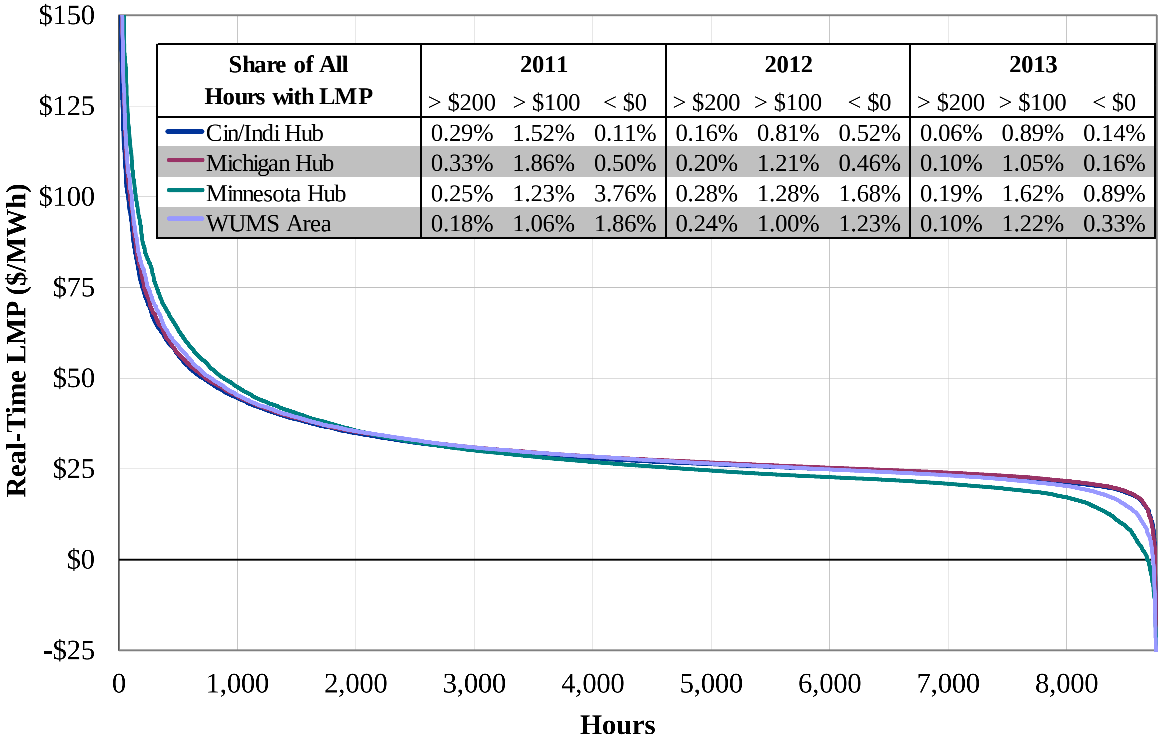


Figure A2: Real-Time Energy Price-Duration Curves

Figure A2 shows the real-time hourly prices at four 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
2013



Share of All Hours with LMP	2011 > $200	2011 > $100	2011 < $0	2012 > $200	2012 > $100	2012 < $0	2013 > $200	2013 > $100	2013 < $0
Cin/Indi Hub	0.29%	1.52%	0.11%	0.16%	0.81%	0.52%	0.06%	0.89%	0.14%
Michigan Hub	0.33%	1.86%	0.50%	0.20%	1.21%	0.46%	0.10%	1.05%	0.16%
Minnesota Hub	0.25%	1.23%	3.76%	0.28%	1.28%	1.68%	0.19%	1.62%	0.89%
WUMS Area	0.18%	1.06%	1.86%	0.24%	1.00%	1.23%	0.10%	1.22%	0.33%

Figure A3: MISO Fuel Prices

As noted previously, 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 2012.[1] The top panel shows nominal prices in dollars per million British thermal units (MMBtu) along with a table showing annual average nominal prices since 2011. The bottom panel shows fuel price changes in relative terms, with each fuel indexed to January 2012.

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

Figure A3: MISO Fuel Prices
2012–2013

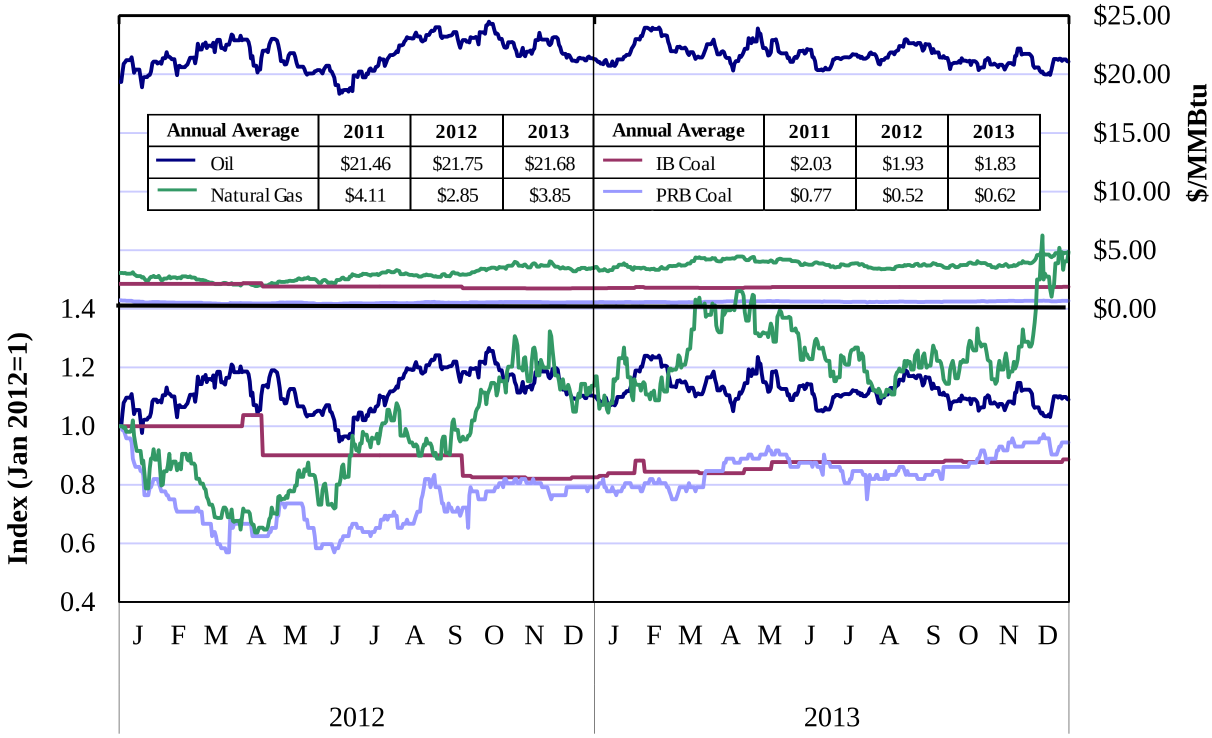
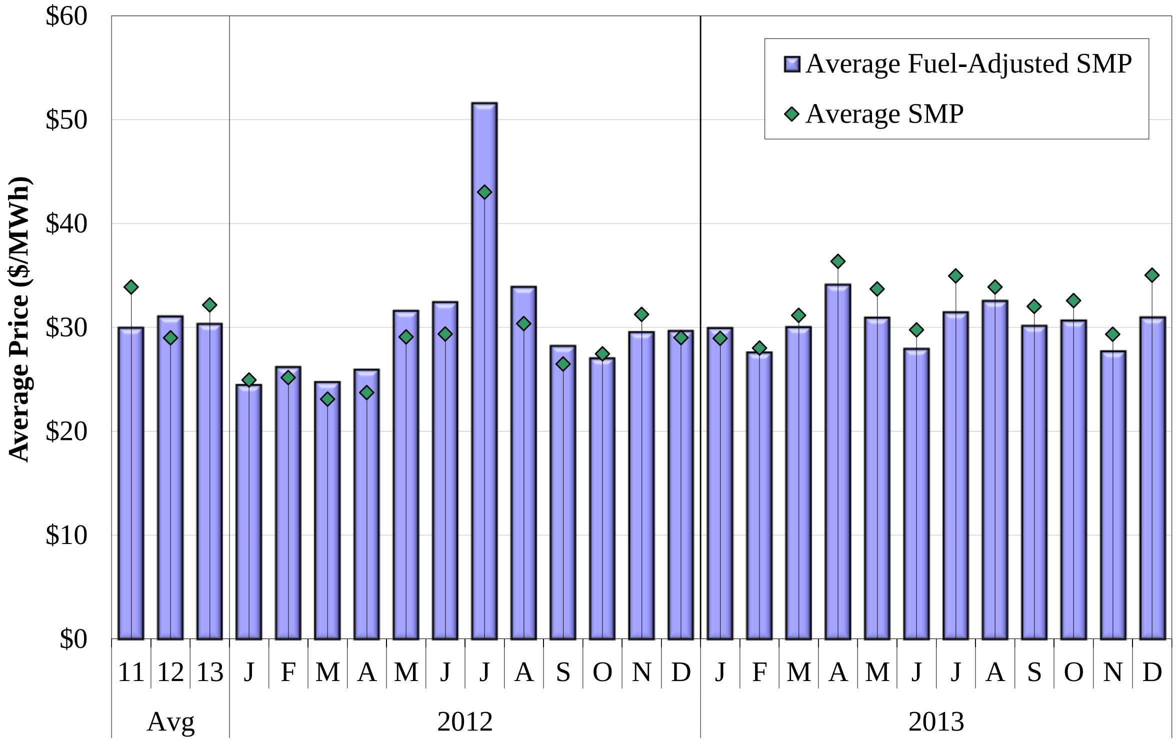


Figure A4: Fuel-Price Adjusted System Marginal Price

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 as a result of unit additions or retirements, 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
2012–2013



Key Observations: Prices

i. Real-time energy prices increased 12.2 percent in 2013 from 2012.

- Natural gas prices rose 35 percent, while Western coal prices rose nearly 20 percent.
- Although load increased slightly, MISO did not experience as hot a summer as it did in 2012 and had fewer shortages.
- Hence, average energy prices did not rise as substantially as fuel prices.
- Real-time energy prices in MISO averaged $32.05 per MWh, with little average price variation across regions.

ii. The all-in price averaged $32.51 per MWh in 2013, a 12.2 percent increase from 2012. The rise was nearly the same as the rise in real-time energy prices, because energy prices constituted almost 99 percent of the all-in price.

- The total contribution to the all-in price from uplift costs, including RSG payments and PVMWP, increased 4 cents to $0.27 per MWh and remained less than 1 percent of the all-in price.

– Ancillary services prices added just $0.17 per MWh to the all-in price. Despite a reduction in the incidence of ancillary services shortages, this is a 4-cent rise from 2012.

  ✓ This amount includes payment for pre-paid regulation mileage, but excludes the $1.8 million in uplift for additional mileage (net of charges for un-deployed mileage).

– The rise in natural gas prices increased the opportunity cost of foregone energy embedded in ancillary service clearing prices.

iii. Capacity costs contributed less than one cent per MWh to the all-in price because of the current capacity market design shortcomings and prevailing near-term capacity surplus in MISO.

iv. Adjusting for changes in fuel prices, the SMP declined 2.3 percent.

– This indicates that non-fuel factors (most notably a milder summer) contributed to a modestly lower SMP. The rise in fuel prices, however, explains the majority of the increase in (unadjusted) energy prices.

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 price in MISO. Since more than one type of unit can be marginal in an interval due to binding transmission constraints, the total for all fuel types exceeds 100 percent. When a transmission constraint is binding, different fuels may be marginal at different locations. 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).

Because approximately one-half of MISO's generation mix—and the majority of its base-load capacity—is coal-fired, these units tend to set 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
2012–2013

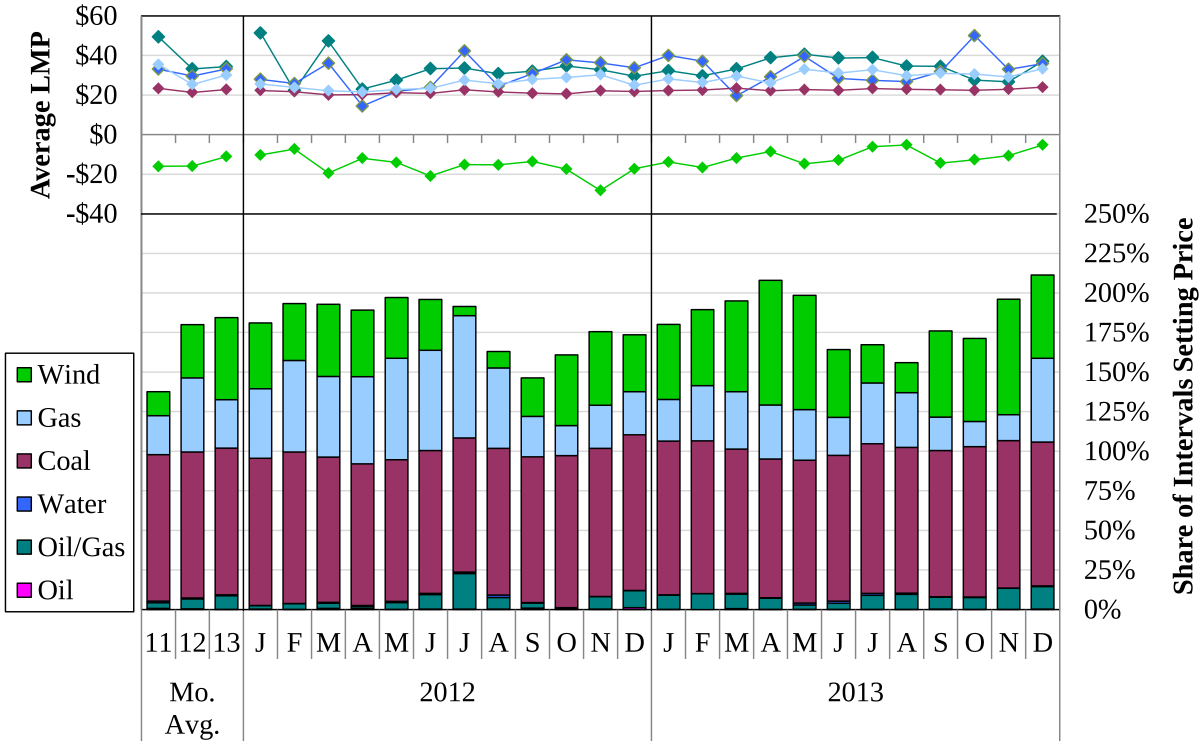
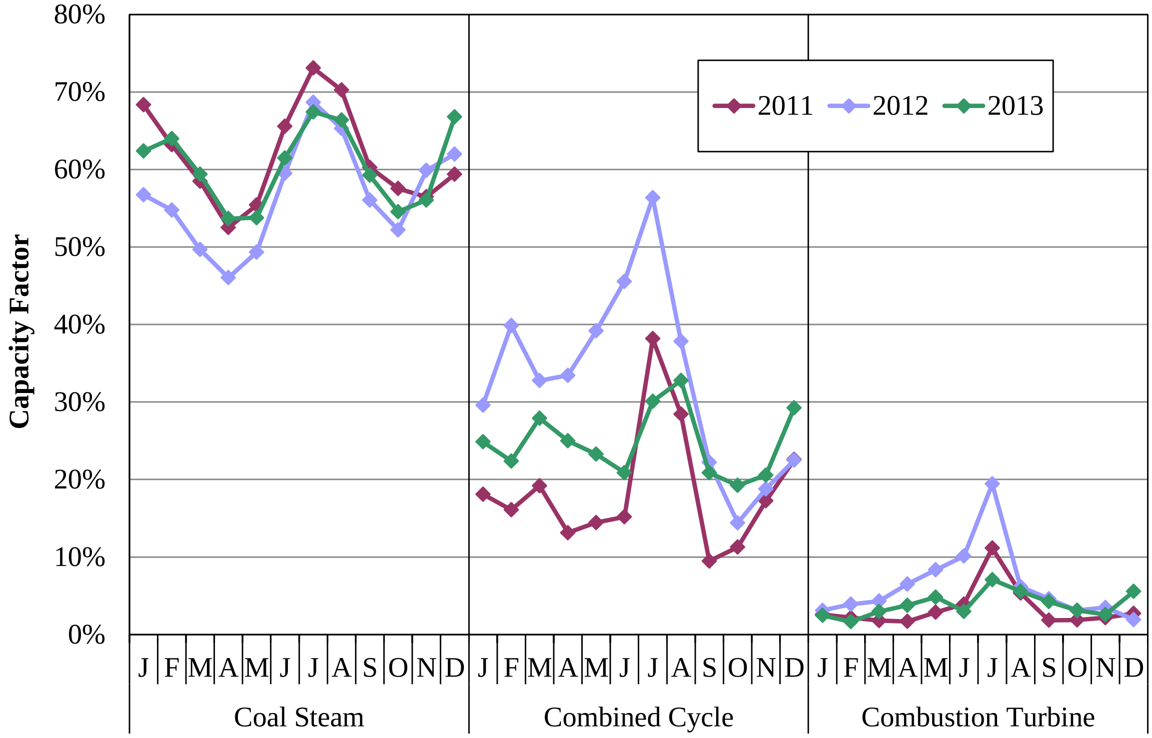


Figure A6: Capacity Factors by Unit Type

Figure A6 shows average monthly capacity factors—the share of total hours that the average unit was generating—for three types of common generators: coal-fired steam, natural gas-fired combined-cycle, and natural gas-fired combustion turbine. Coal-fired steam units provide much of the base-load generation in MISO, while combined-cycle units generally provide intermediate-load capacity. Combustion turbine resources provide much of the system's peaking capacity.

Fluctuations in fuel prices and load will impact the relative competitiveness of each type of resource—in a competitive market, the higher the capacity factor of a unit, the more competitive it is across all hours. We show each year separately, since yearly changes for each month are predominantly due to changes in fuel prices. Monthly fluctuations over the course of a given year, meanwhile, predominantly reflect changes in load.

Figure A6: Capacity Factors by Unit Type
2011-2013



Key Observations: Price Setting and Capacity Factors

i. The rise in natural gas prices reduced the competitiveness of natural gas-fired units relative to coal-fired steam units in 2013.

– Natural gas-fired units were marginal in 31 percent of intervals, down from 47 percent in 2013, and for much of the year operated at capacity factors far lower than those recorded in 2012.

– Although natural gas-fired capacity set prices in less than one-third of the intervals, this capacity is an important driver of energy prices because the intervals in which it sets prices tend to be during the highest-priced periods.

ii. Coal continues to be the most prevalent price-setting fuel in MISO. It was a marginal fuel in at least some locations in MISO in 93 percent of all intervals. Coal-fired units generated two-thirds of all energy in 2013.

– Increased installed capacity and expansion of the participation of wind resources continued in 2013. The majority of wind units, representing approximately 80 percent of capacity, are now DIR, which allows them to economically curtail and set the real-time energy price.

– Wind units set prices in more than one-half of intervals at -$11 per MWh on average.

– However, wind resources typically set prices in relatively small areas where output from wind units is contributing to congestion.

C. 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.

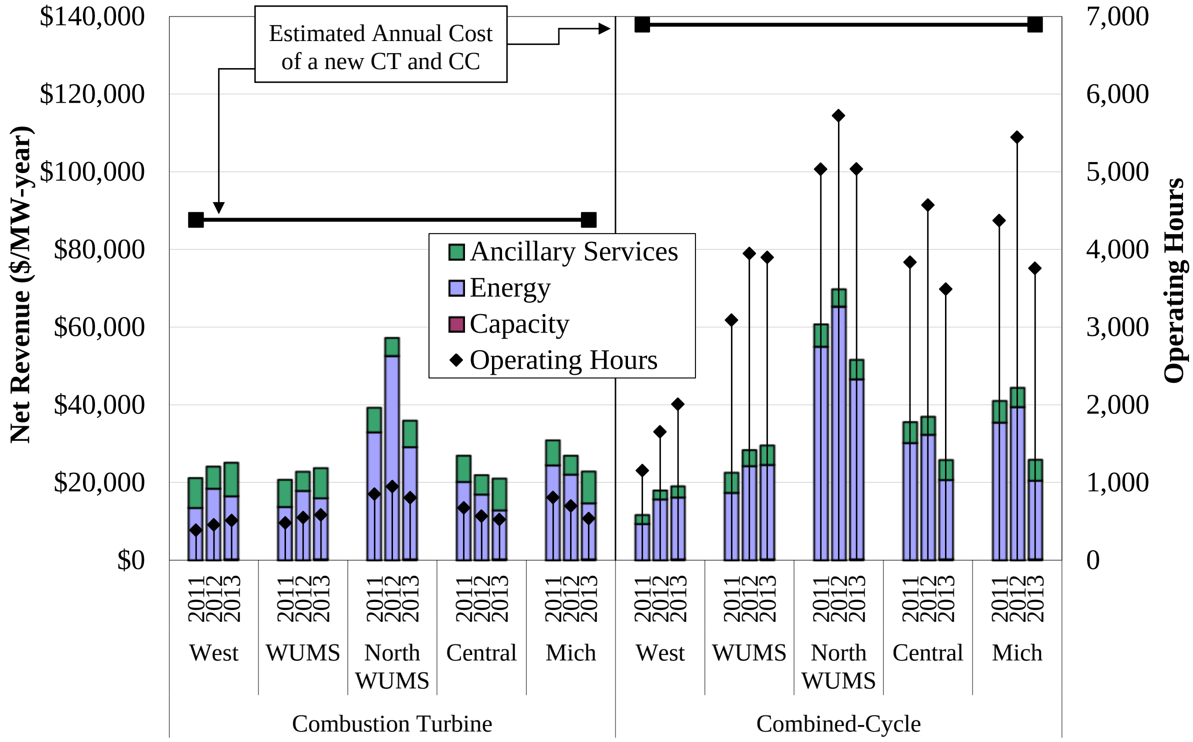
Our analysis examines the economics of two types of new units: a natural gas combined-cycle unit with an assumed heat rate of 7,050Btu per kWh and a natural gas CT unit with an assumed heat rate of 9,750 Btu per kWh. These are comparable to assumptions used in the EIA Annual Energy Outlook. We also incorporate 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 A7: Net Revenue and Operating Hours

The next figure compares the market revenue that would have been received by new CCGT 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. Figure A7 shows 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-cycles 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. Although capacity prices were uniform across the MISO footprint in 2013, they may not be in the future. Zonal requirements under the new capacity construct can result in regional capacity prices higher than the market-wide clearing price. No zonal constraint bound in the 2013-2014 planning year PRA. 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.

Figure A7: Net Revenue and Operating Hours
2011–2013



Key Observations: Net Revenues

i. Estimated net revenues in 2013 for both combined-cycle units and combustion turbine units were substantially less than the cost of new entry in all regions. This is consistent with expectations because the MISO region continues to exhibit a capacity surplus and did not experience a large number of shortages in 2013.

- Estimated net revenues for both types of units were nearly unchanged in the West Region and in WUMS, but declined considerably in the other three areas.

- The decline in net revenues in 2013 in most areas was due to the relative reduction in shortages compared to 2012, particularly during the summer.

- The finding that estimated net revenues are far less than the revenues needed to support new investment is unchanged from prior years and is consistent with expectations because of the prevailing capacity surplus in MISO and the capacity market design flaws we discuss below.

ii. There were only limited periods of shortage pricing in MISO in 2013. When such periods increase in frequency, they can provide economic signals that additional capacity is necessary.

- Future pricing changes will allow peaking and demand response resources to more reliably and efficiently set prices, which will also tend to raise net revenues.

iii. MISO introduced a new Resource Adequacy Construct (RAC) in 2013, which includes the replacement of the VCA with the PRA. The RAC also added zonal requirements to the capacity market that should allow prices to better reflect regional capacity needs.

- Prices in the PRA, like the prior VCA, were very low and none of the zonal constraints bound. Hence, the reformed RAC has not significantly impacted capacity revenues.

- A transitional PRA held late in 2013 for capacity deliverable to the South Region cleared at a zero price in all zones.

- Despite tighter market-power mitigation measures under the new RAC, we did not find significant attempts at physical or economic withholding.

iv. Additional changes are needed to the RAC to ensure that it will provide efficient incentives to invest in new resources when MISO’s surplus capacity dissipates and resources are needed.

- Resources may be needed sooner than previously anticipated due to forthcoming environmental regulations affecting MISO’s coal-fired resources.

  ✓ MISO is forecasting a substantial shortfall as soon as 2016.

- We continue to recommend several changes to MISO’s RAC to improve price signals, including:

  ✓ The adoption of a sloped demand curve in the capacity auction to set more efficient capacity prices based on the quantity of surplus capacity in the market; and

  ✓ Continuing to work with PJM to eliminate barriers to capacity trading between regions.

II. Load and Resources

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

In this section, we distinguish between market participants and reliability-only participants. Prior to the MISO South Integration, there were 88 market participants that either owned generation resources (totaling 128.9 GW of nameplate capacity) or served load in the MISO market.[2] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers. MISO also serves as the reliability coordinator for reliability-only members, such as Manitoba Hydro, which provide an additional 11.5 GW of capacity. These entities do not submit physical bids or offers into MISO's markets, but they may schedule energy into or out of the market.[3] Reliability-only (or coordinating) members are excluded from our analysis unless otherwise noted.

The integration of the MISO's South Region on December 19, 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 this section, we confine ourselves to MISO's Midwest Region because MISO's South Region was integrated into MISO for less than two weeks in 2013. The integration of MISO South is reviewed and discussed in a separate report.

We analyze four geographic areas in this section:

- East—Includes MISO control areas that had been located in the North American Electric Reliability Corporation's (NERC) ECAR region;
- West—Includes MISO control areas that had been located in the NERC MAPP region;
- Central—Includes MISO control areas that had been located in the NERC MAIN region, but excludes MAIN utilities located in the Wisconsin-Upper Michigan System (WUMS) Area; and
- WUMS—MISO control areas located in the Wisconsin-Upper Michigan System Area.

The East, West, and Central regions were coordination regions that MISO used to operate the system up to 2010. In 2011, MISO consolidated the East and Central regions for purposes of reliability coordination. We examine the WUMS area, originally part of the East reliability region, separately due to differences in congestion patterns. These four regions should not be viewed as distinct geographic markets, particularly with respect to market concentration. In reality, binding transmission constraints govern the extent of the geographic markets from a

2 As of December 2013, MISO membership totals 145 entities when including power marketers, brokers, state regulatory authorities, and other stakeholders. There are 393 separate Certified Market Participants.

3 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-MH interchange.

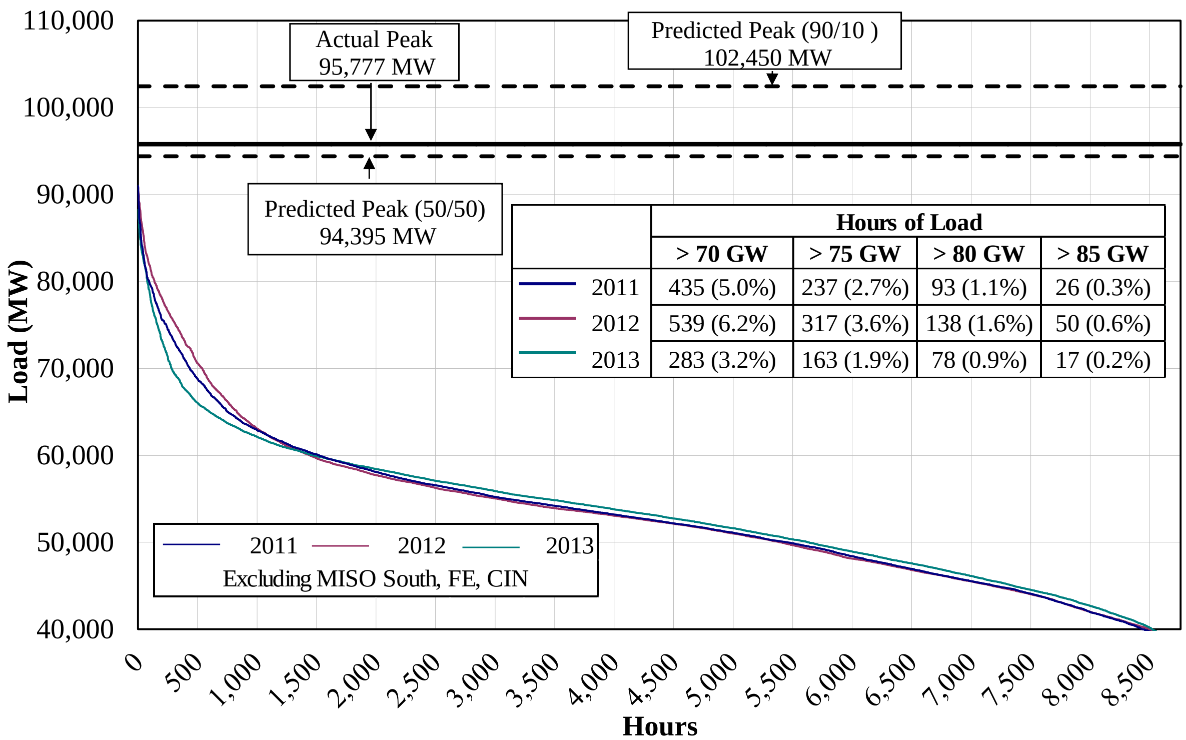
competitive perspective. A detailed analysis of market power is provided in Section VII of this Appendix.

A. Load Patterns

Figure A8: Load Duration Curves

MISO is a summer-peaking market. To show the hourly variation in load, Figure A8 shows load levels for 2013 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 2011, 2012, and 2013 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 70, 75, 80 and 85 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 at this level).

Figure A8: Load Duration Curves
2011–2013



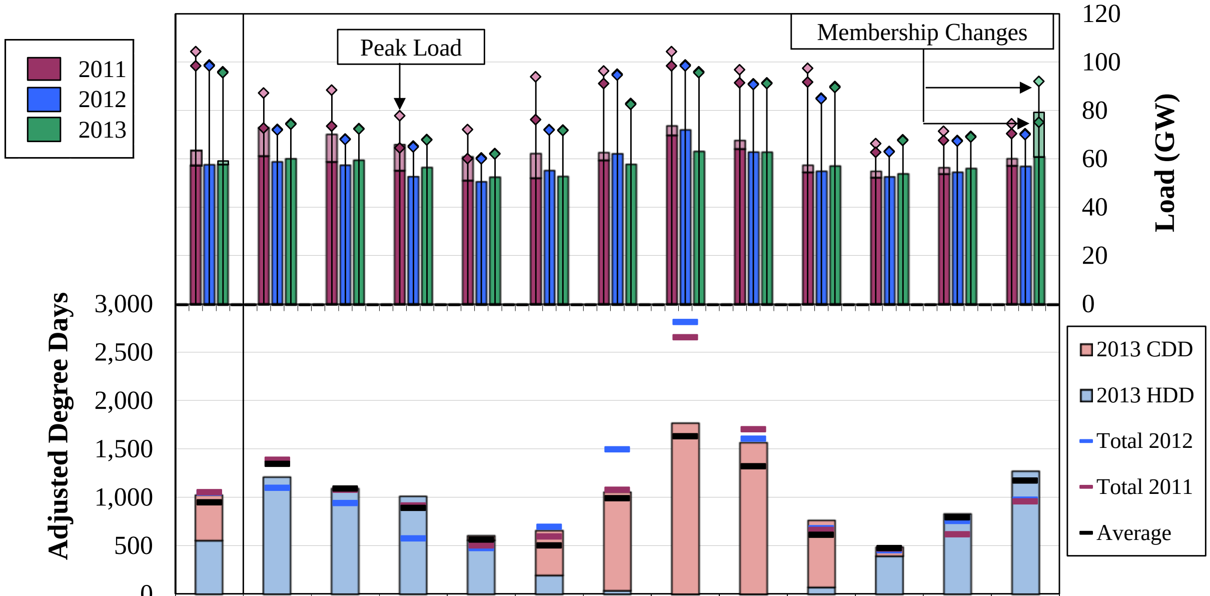
	Hours of Load			
	> 70 GW	> 75 GW	> 80 GW	> 85 GW
2011	435 (5.0%)	237 (2.7%)	93 (1.1%)	26 (0.3%)
2012	539 (6.2%)	317 (3.6%)	138 (1.6%)	50 (0.6%)
2013	283 (3.2%)	163 (1.9%)	78 (0.9%)	17 (0.2%)

Figure A9: Heating and Cooling Degree-Days

MISO's load is temperature-sensitive. Figure A9 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.[4] The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) averaged across four representative locations in MISO.[5] The table at the bottom shows the year-over-year changes in average load and degree-days.

Figure A9: Heating and Cooling Degree-Days
2011–2013



% Chg 12-13	2013	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	0%	2%	4%	7%	4%	-4%	-7%	-12%	0%	4%	2%	3%	7%
Degree Days	-2%	10%	16%	76%	28%	-5%	-29%	-37%	-3%	12%	8%	10%	30%

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

5 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.

Key Observations: Load Patterns

i. After adjusting for changes in membership, there was a distinct flattening of the load duration curve in 2013 compared to the prior two years.

- Average loads in the top 1,000 hours were nearly 5 percent lower than those in 2012 as a result of a much cooler June and July, although loads were slightly higher for the remainder of the year.

- Total degree days in 2013 declined from 2012 by two percent overall, primarily the result of the milder summer temperatures in the May to August months.

  - ✓ In 2013, degree days in summer remained slightly above the historical average but declined as much as 37 percent (in July) from the prior year. Summer 2012 was one of the warmest on record for most of MISO.

- MISO set its annual peak load of 95,777 MW on July 18. This was slightly above the expected "50/50" peak of 94.3 GW, but well below the more extreme "90/10" peak.

  - ✓ We evaluate MISO's performance during the peak load period, which in 2013 occurred from July 15 to 19, in the next subsection.

- There was only a slight increase in economic activity in 2013 compared to 2012 as measured by the Chicago Purchasing Manager's Index, which is a broad metric of economic activity in the region.

  - ✓ By this metric, economic activity barely grew in the first half of the year but solidly increased in the second half of the year.

ii. Over 23 GW of generating capacity was needed solely to meet the energy and operating reserve demands during the highest five percent of load hours, which is a typical pattern for energy demand.

- This generating capacity is needed to satisfy the system's peak energy or operating reserve demands because electricity cannot economically be stored in large quantities.

- This pattern also underscores the importance of efficient energy pricing during peak load hours and capacity pricing to ensure that the system continues to maintain adequate resources.

B. Evaluation of Peak Summer Days

MISO's most demanding period in 2013 occurred in mid-July. Although MISO's system was not as challenged as it was in the repeated and more severe heat waves in 2011 or 2012, MISO experienced a sustained period of above-average temperatures that produced loads above those anticipated in the Summer Assessment. The next subsection evaluates the performance of the markets during this period.

Figure A10: Temperatures on Peak Load Days

Figure A10 shows the high temperature at six cities in the MISO footprint on five high-temperature days during the week of July 15, along with the historical average temperatures for that week. MISO declared Conservative Operations and Hot Weather Alerts on each day of the week. It also declared a Maximum Generation Alert on July 17 (in yellow).

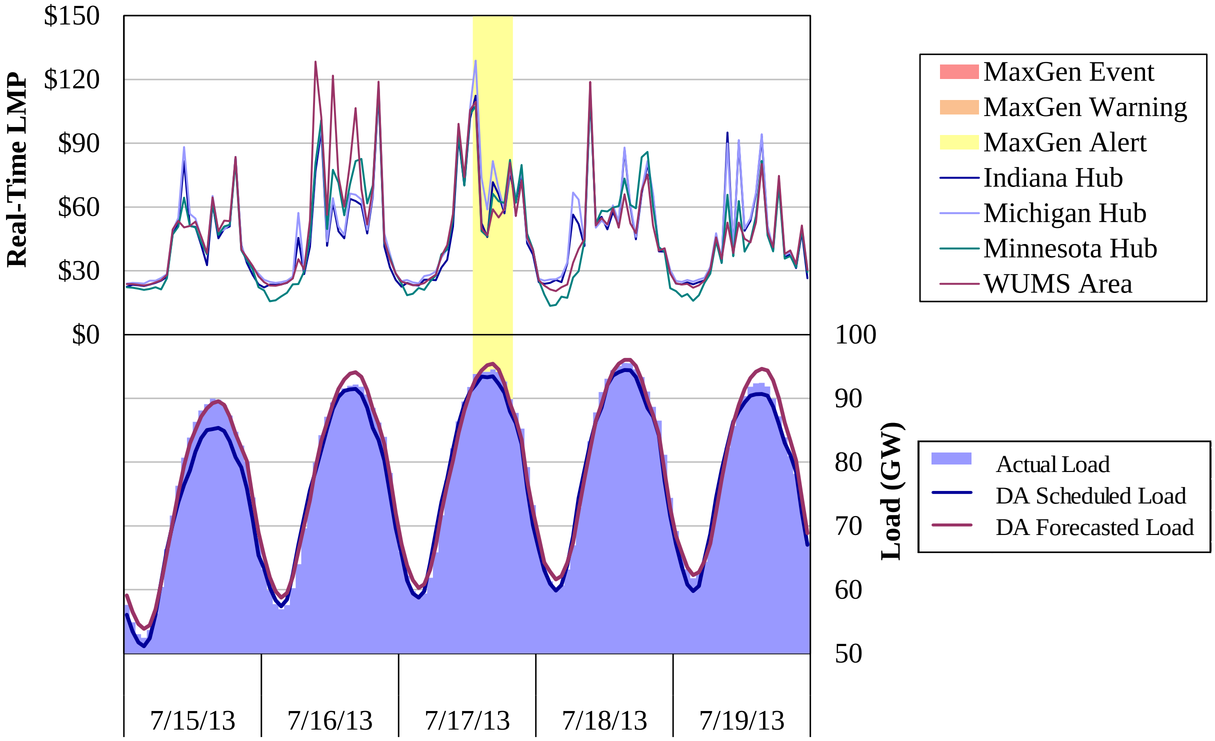
Figure A10: Temperatures on Peak Load Days
July, 2013

	Historical Average	15	16	July 17	18	19
Cincinnati	86	92	93	93	93	89
Detroit	84	93	90	94	94	95
Indianapolis	85	88	93	93	93	92
Milwaukee	80	85	93	95	95	94
St. Louis	89	91	93	94	94	98
Minneapolis	80	87	91	91	93	84

Figure A11: DA Load Scheduling and RT Energy Prices

The top portion of Figure A11 shows a summary of real-time hub prices during these five days. The bottom portion of the figure shows major contributors to real-time prices: the day-ahead forecasted load (maroon line), day-ahead scheduled load (blue line), and real-time load (light blue solid bars). 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 A11: DA Load Scheduling and RT Energy Prices
July 15–19, 2013



In addition to extremely high demand for electricity, there are many other factors not shown in this figure that determine real-time prices. They include unplanned generator and transmission outages and unit deratings; operator actions, such as unit commitments or load offsets; changes in real-time wind generation, changes in net interchange; and changes in other supply factors, such as self-commitments.

Figure A12 and Figure A13: Contributing Factors to Real-Time Prices, Select Days

In the next chart, we show the cumulative impact of seven primary real-time supply and demand factors that affected the net capacity balance on the afternoon of July 15. These seven factors are: (1) net imports from PJM; (2) net imports from all other areas; (3) load, including any operator offset; (4) wind output; (5) significant generator outages; (6) other rampable capacity[6]; and (7) MISO unit commitments.

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. 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.

6 "Other Rampable Capacity" is additional capacity dispatchable within five minutes that is made available on online units because they are ramping up.

Figure A12: Contributing Factors to Real-Time Prices
July 15, 12:40–16:55

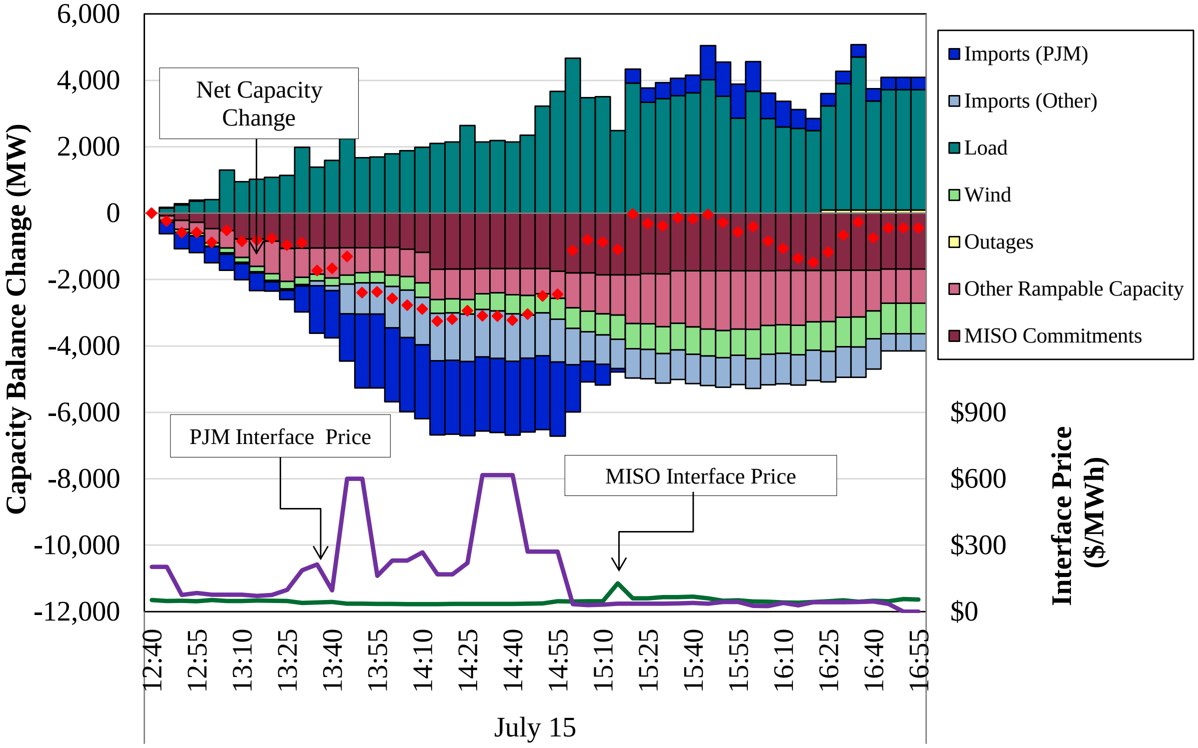
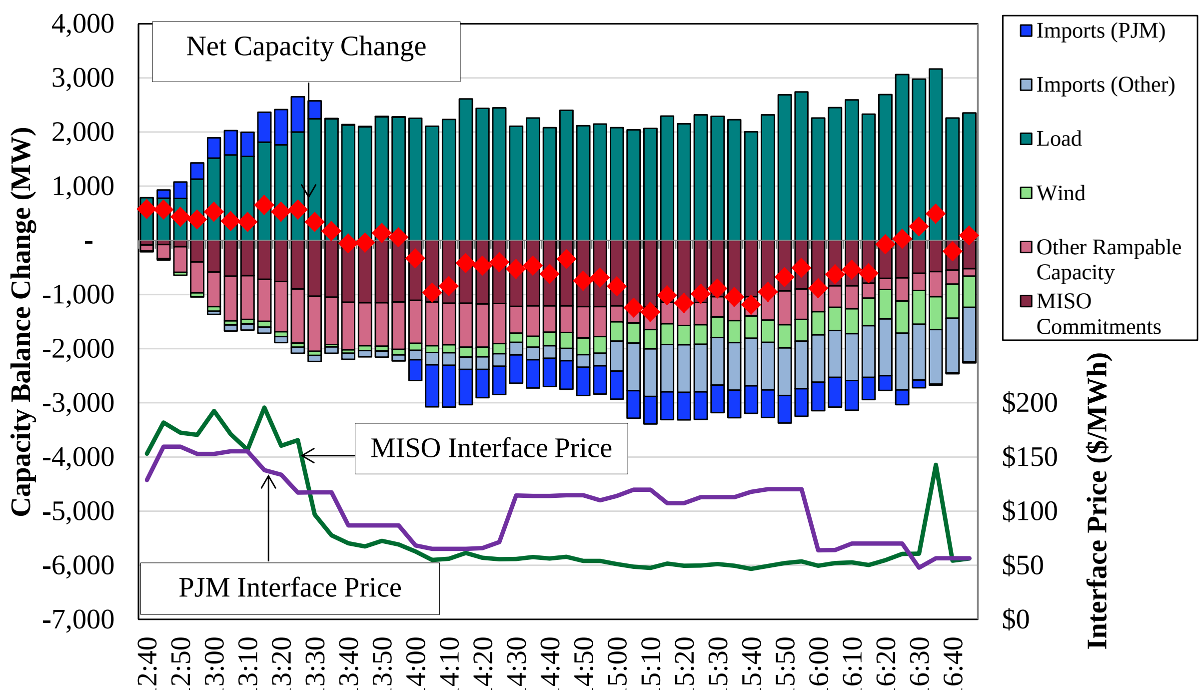


Figure A13: Contributing Factors to Real-Time Prices
July 17, 12:40–16:40



<u>Key Observations: Evaluation of Peak Days</u>

i. Reliability was maintained on each day during the peak period, and the markets accurately signaled the shortages that occurred.

ii. Although load peaked on July 18, supply conditions were tighter on July 17. On this day, wind output during the peak hour was 4 GW lower than it was on July 18.

- Voluntary load curtailments after the Maximum Generation Alert was initiation on July 17 appeared to have truncated the peak load.
- MISO did not call for any demand response to maintain reliability.
- Prices rose sharply between 12:30 and 13:30 as load grew rapidly and net system interchange (NSI) shifted toward PJM by roughly 600 MW.
- In response to the high MISO prices, NSI shifted toward MISO by roughly 1,400 MW from 13:15 to 14:15 and net imports on other interfaces began to grow.
- These shifts, together with (a) MISO's commitments, (b) the fact that load stopped growing after 13:30, and (c) a modest increase in wind output caused MISO's energy prices to remain relatively low ($50-$60 per MWh).
- PJM prices were elevated for much of the period, partly because of the large NSI shift toward MISO, and NSI did not respond to the elevated PJM prices.

iii. Poor interchange scheduling with PJM contributed to tight conditions in PJM on July 15.

- This is the opposite of the events that occurred on several days in 2012, when large swings in NSI precipitated shortages in MISO and periods of very high energy prices.
- Shifts in NSI *into* MISO (i.e., away from PJM) on July 15, in part due to TLR curtailments, led to periods of reserve shortages and high prices in PJM.
- These shifts in NSI into MISO also contributed to very low energy prices in MISO, which increased the RSG payments MISO had to pay to the large quantity of generators committed that day.

iv. Day-ahead scheduled load was generally consistent with the actual peak load on most days, although under-scheduling on July 15 required substantial real-time commitments to meet reliability needs.

- In retrospect, a substantial share of the commitment on these days was not needed and it suppressed real-time prices and inflated RSG costs.
- As discussed further below, operator forecasts of system demands related to NSI changes must be conservative since the external interfaces are not scheduled efficiently and are not optimized by market operators.

v. MISO's reliability mandate and associated operating procedures generally require it to take actions to maintain reliability and avoid shortages.

- When these actions are effective, market prices may not reflect the true costs of taking these actions and lower-cost options may be overlooked.

- The ELMP project will improve MISO's pricing during these conditions, particularly if it can be extended to pricing demand response and other MISO reliability actions.

- MISO's operating procedures warrant review to determine whether reliability actions are taken in the most efficient order. For example, most demand response cannot be called until MISO has exhausted almost all other emergency actions.

vi. Because the current Joint and Common Market (JCM) initiative with PJM to align the business rules will not address the underlying causes of these scheduling inefficiencies, we recommend MISO and PJM make the interchange optimization initiative a high priority.

C. Generating Capacity and Availability

Figure A14: Distribution of Generating Capacity by Coordination Region

Figure A14 shows the summer 2014 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 A14: Distribution of Generating Capacity
By Fuel Type, Summer 2014

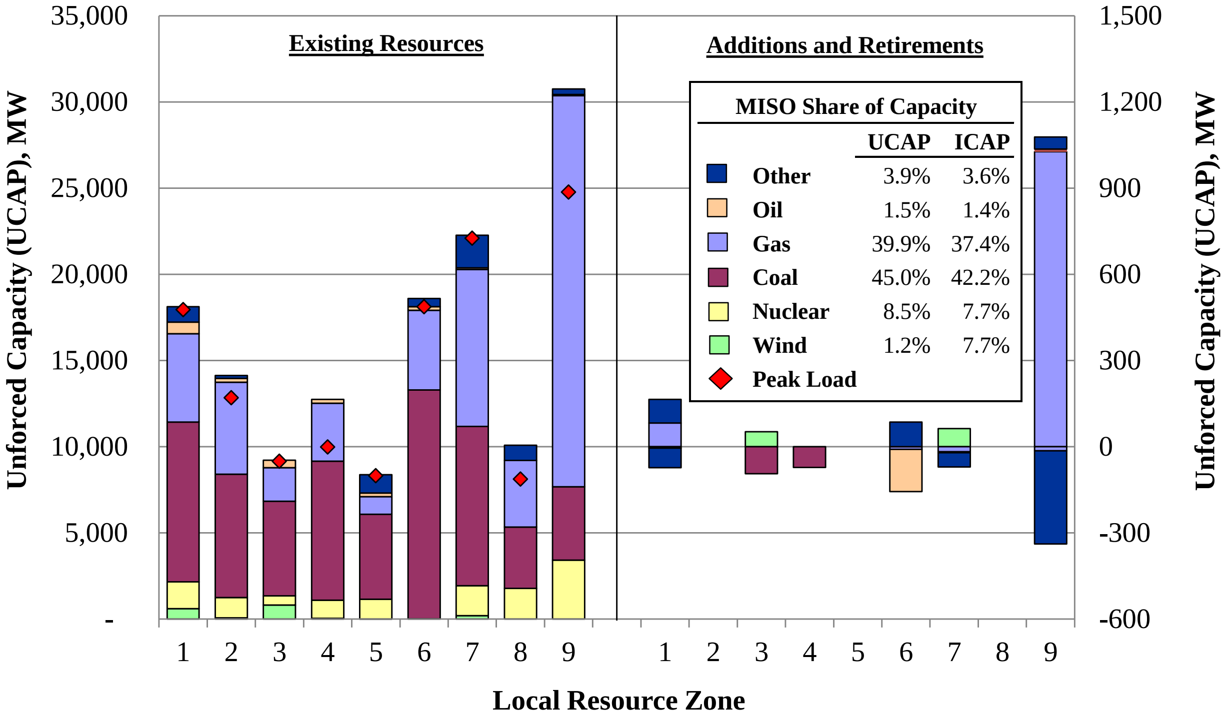


Figure A15: Availability of Capacity during Monthly Peak Load Hour

Figure A15 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 A15: Availability of Capacity During Peak Load Hour
2013

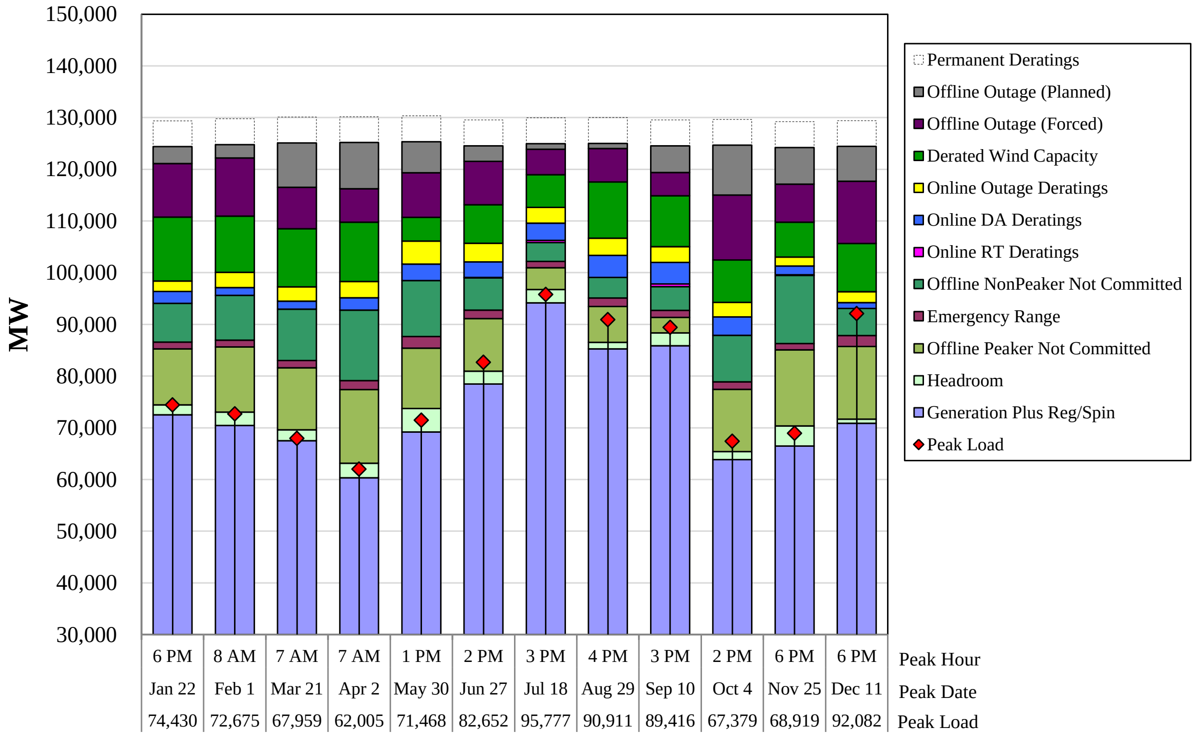


Figure A16: Capacity Unavailable During Peak Load Hours

Figure A16 is very similar to Figure A15 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 A16: Capacity Unavailable During Peak Load Hours
2013

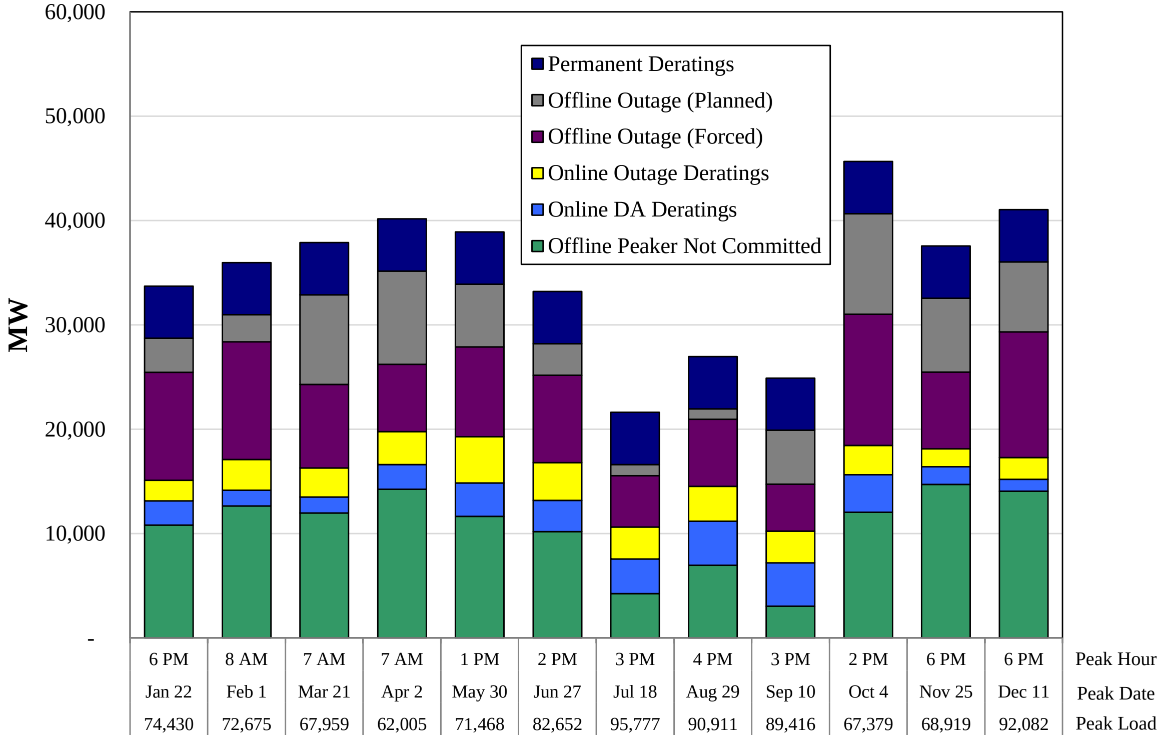
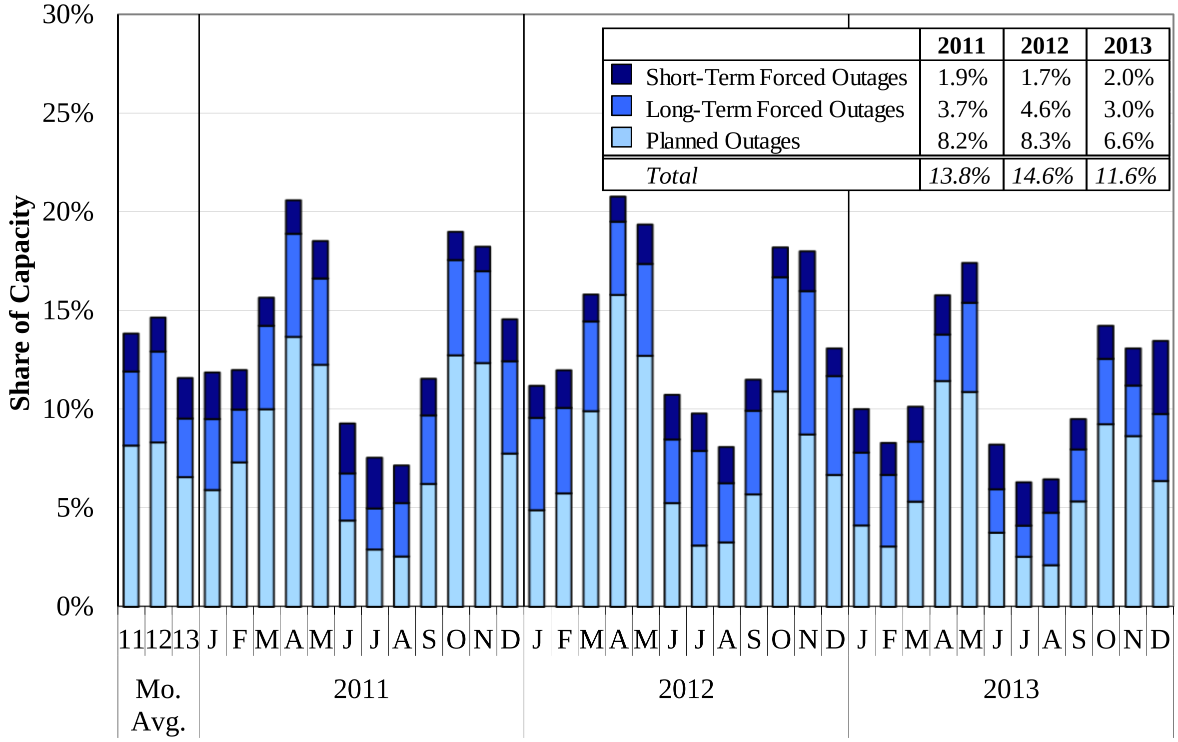


Figure A17: Generator Outage Rates

Figure A17 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 because 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 VII.

Figure A17: Generator Outage Rates
2011–2013



Key Observations: Generating Capacity and Availability

i. Coal-fired generating resources account for a majority of MISO's unforced capacity (adjusted for forced outages and intermittency) in 2013.

– Coal and nuclear resources, which generally provide base-load generation, produced 70 and 12 percent of the energy in 2013, up slightly from 2012.

ii. Energy produced from natural gas-fired units is generally more expensive, but these units provide MISO with the necessary flexibility to manage loads.

– The integration of MISO South in December has significantly increased the share of capacity in the footprint that is fired by natural gas. Nearly 40 percent of MISO's installed capacity expected in summer 2014 is natural gas-fired.

– Natural gas-fired resources were not as competitive relative to coal and nuclear resources in 2013 as they were in 2012. They produced seven percent of total energy generation, down from 10 percent in 2012.

– MISO's unforced capacity exceeds the forecasted *non*-coincident 2014 peak load in each of the nine zones, but only barely (by less than 3 percent) in five of them.

- Because the average output from wind units in western portions of the footprint (e.g., Zones 1 and 3) is usually greater than their UCAP levels, western areas frequently produce substantial surplus energy that is dispatched to serve load in eastern areas.

  - ✓ This pattern produces the west-to-east flows and congestion patterns typically observed in the MISO markets.

  - ✓ The high concentration of wind generating capacity can present operating and reliability challenges, which are discussed in Section IV.J of the Appendix.

iii. MISO is only expecting 66 MW of coal unit retirements and 547 MW of coal unit suspensions between summers 2013 and 2014. The most significant retirement in 2013 was a nuclear unit in Wisconsin.

- The small number of retirements is due to the EPA's Mercury and Air Toxic Standards (MATS) rule, whose April 2015 implementation deadline is frequently and generously deferred, on a case-by-case basis, to April 2016. This prompted many units to suspend instead.

- MISO's Attachment Y process, which participants use to notify MISO of potential unit change of status, requires a 26-week notice, so MISO has not yet been notified of most of the retirements likely to occur before April 2016.

iv. MISO's 2011 EPA Impact Analysis identified 12.6 GW of coal-fired capacity that may need to retire or retrofit in the 2015-2016 to comply with EPA regulations, including MATS and CSAPR, if implemented as proposed.

- The most recent quarterly survey indicated that 92 coal units in the Midwest Region comprising 8.1 GW have already retired or are likely going to retire or suspend, with an additional 1.5 GW converting to another fuel source.

- In the South Region, which has 8.6 GW of coal capacity, very few retirements are expected.

v. Cumulative outages declined to an average of 11.6 percent in 2013.

- Long-term forced outages and planned outages declined significantly, likely due to a postponement of various environmental regulations that contributed to higher planned outage rates in fall 2011 as well as higher levels in 2012.

- Outages were lowest during the summer when capacity needs were greatest because planned outages generally take place in other seasons. As expected, short-term forced outages peaked during this time as a result of greater resource utilization and high ambient temperatures.

D. Planning Reserve Margins and Resource Adequacy

Table A1: 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 *2014 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 A1.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[7] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation and imports; and (e) full response from DR resources (behind the meter generation, interruptible load, and direct controllable load management). These assumptions tend to cause the reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions.

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 a 50 percent response rate from DR. This is consistent with what MISO has received under prior peak conditions—in 2006, it received a response of 2,600 MW, far lower than the more than 6 GW in claimed capability. Most DR is not under the direct control of MISO, and MISO does not directly test this capability, so it is granted a 100 percent capacity credit.

The second difference is that MISO's margin does not fully account for generator derates under peak conditions with higher temperatures than normal. 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.

7 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).

Table A1: Capacity, Load, and Reserve Margins
Summer 2014

	MISO	IMM		
	Base Case	**Realistic DR**	**High Temp Full DR**	**High Temp Realistic DR**
Midwest Region				
Load	**96,244**	**96,244**	**101,276**	**101,276**
High Load Increase	-	-	*5,032*	*5,032*
Capacity	**107,452**	**107,452**	**102,552**	**102,552**
BTM Generation	*3,843*	*3,843*	*3,843*	*3,843*
*Hi Temp Derates**	-	-	*(4,900)*	*(4,900)*
Demand Response	**4,636**	**2,318**	**4,636**	**2,318**
Net Firm Imports	**2,258**	**2,258**	**2,258**	**2,258**
Transfer Limit	1,000	1,000	1,000	1,000
Margin (MW)	**19,101**	**16,784**	**9,169**	**6,852**
Margin (%)	**19.8%**	**17.4%**	**9.1%**	**6.8%**
South Region				
Load	**31,003**	**31,003**	**32,448**	**32,448**
High Load Increase	-	-	*1,444*	*1,444*
Capacity	**39,452**	**39,452**	**39,452**	**39,452**
BTM Generation	*110*	*110*	*110*	*110*
*Hi Temp Derates**	-	-	-	-
Demand Response	**821**	**411**	**821**	**411**
Net Firm Imports	**29**	**29**	**29**	**29**
Transfer Limit	-	1,000	1,000	1,000
Margin (MW)	**9,299**	**9,888**	**8,855**	**8,444**
Margin (%)	**30.0%**	**31.9%**	**27.3%**	**26.0%**

Note: All values are MW unless noted.
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.

Key Observations: Resource Adequacy

i. The baseline capacity margin for the Midwest Region is 28.1 percent, which far exceeds the Planning Reserve Margin Requirement (in ICAP terms) of 14.8 percent.

– The three IMM scenarios use more conservative assumptions that result in much lower planning reserve margins.

✓ A more realistic assumption for demand response reduces the margin by 2.4 percentage points.

– Higher temperatures than assumed in the base case leads to both higher load levels and higher generation deratings.

- ✓ This assumption yields a planning margin as low as 6.8 percent, which would not be sufficient to simultaneously satisfy MISO's operating reserve requirements (2,400 MW) and account for resources that are on forced outage, which generally range from five to eight percent.
- ✓ Under these conditions, MISO would only avoid firm curtailments by utilizing non-firm imports or getting higher than expected response from its wind resources or its demand response.

ii. Unit-level wind capacity credits for Planning Year 2013-2014 ranged from zero to 30.4 percent.

- – Wind output is negatively correlated with load, which means that wind output is often the lowest during peak periods when it is needed most. This presents challenges for developing an appropriate capacity credit for wind resources.

iii. The baseline capacity margin for the South Region is 30.0 percent and 20.2 percent under the most conservative IMM scenario.

- – However, the additional capacity in the South Region is limited in its ability to meet potential supply shortages in the Midwest Region under extreme conditions due to the 1,000-MW transfer limit under the Operations Reliability Coordination Agreement (ORCA).

iv. Overall, these results indicate that the system's resources should be adequate for summer 2014 if the peak summer conditions are not substantially hotter than normal.

- – Capacity margins will likely decrease in the future, and may accelerate as new environmental regulations are implemented. Therefore, it is important for the RAC to provide efficient economic signals to facilitate the investment needed to maintain an adequate resource base.
- – This report includes a number of recommendations designed to better achieve this objective.

E. Capacity Market Results

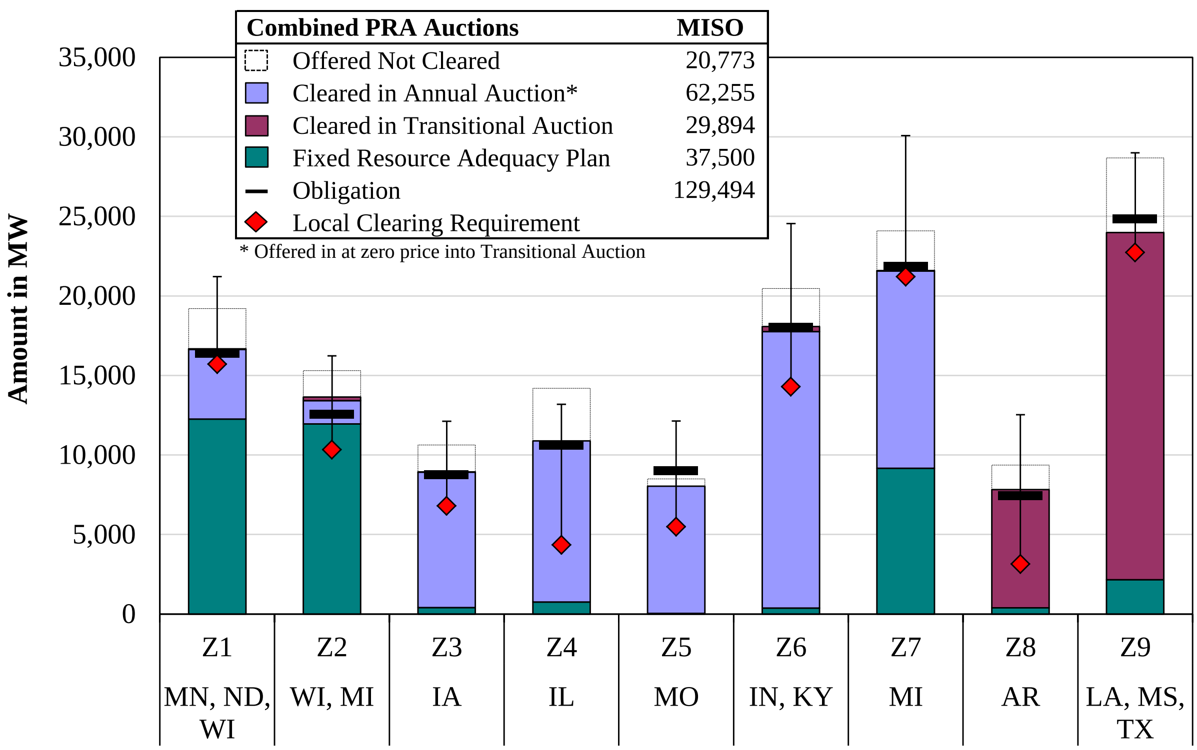
In June 2009, MISO began operating a monthly voluntary capacity auction to allow LSEs to procure capacity to meet their Tariff Module E capacity requirements. The VCA was intended to provide a balancing market for LSEs, with most capacity needs being satisfied through owned capacity or bilateral purchases. 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, will cause price divergence among the zonal clearing prices.

Figure A18: Planning Resource Auction Results

Figure A18 shows the combined results of the 2013 Annual PRA, conducted in April 2013 for the June 2013–May 2014 period and the Transitional PRA, conducted in November 2013 in advance of the MISO South integration. The figure shows the combined results for each of the nine zones: the Annual PRA covered the Midwest Region's Zones 1 through 7, while the transitional PRA covered the South Region's Zones 8 and 9. The surplus capacity not cleared in the annual auction was available for offer into the transitional PRA. The black dash marks the capacity obligation, which is the total amount required to be procured by a zone's resources. (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 have no price impact.

Figure A18: Planning Resource Auction
2013-2014



<u>Key Observations: Capacity Market Results</u>

i. The auctions cleared a cumulative 129,649 MW. There was nearly 21 GW of capacity offered at prices in excess of the clearing price.

– No zonal constraints bound in the auctions, although the cleared amounts in Zones 1 and 7 only slightly exceeded the local clearing requirement.

- In the most recent auction, held in late March for the 2014-2015 Planning Year, Zones 1, 8 and 9 cleared at prices below the system clearing price due to constrained export limits.
- The cleared amount is slightly higher than the capacity obligation (129,494 MW) because there was an excess of price-taking offers (FRAP or offered at zero) in Zone 8.

ii. The Annual PRA cleared at $1.05 per MW-day, while the Transitional PRA cleared at zero. Both outcomes are extremely low and consistent with past VCA results.

- This price is far below the cost of new entry, and is the result of the current capacity surplus in MISO and the continued market design shortcomings discussed below.
- We did not find significant amounts of physical or economic withholding in either auction.

iii. Although the PRA is an improvement to the RAC, several shortcomings remain.

- The most notable is the representation of the demand for capacity as a single fixed amount, or a "vertical demand curve".
- This has been recognized as a problem in other RTO markets and is discussed further in Section II.F below.

iv. We also continue to recommend MISO work actively with PJM to facilitate efficient inter-regional capacity trading between the two areas by eliminating uneconomic barriers.

- These barriers include limited access to firm transmission into PJM, the level of PJM's Capacity Benefit Margin, the ability of long-term firm transmission holders to withhold firm transmission from capacity suppliers seeking to use it to support capacity transfers, and uncertainty regarding obligations on external suppliers that sell capacity into the PJM RPM market.
- In 2013, PJM proposed Capacity Import Limits (CILs) which could further limit trading between the areas. We filed a protest and comments on PJM's proposal.

F. 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). This relationship 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.[8] 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).

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.

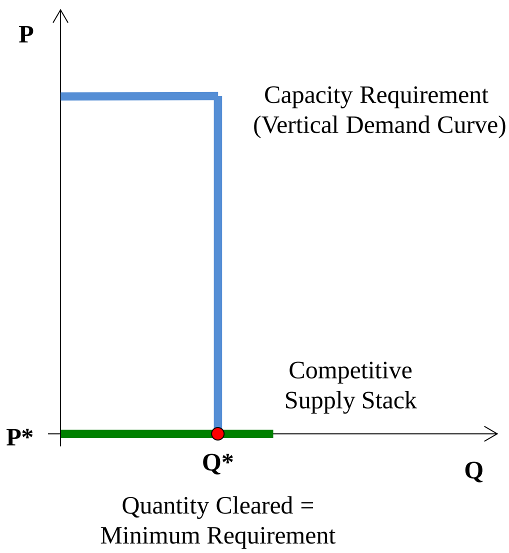
3. Implications of the Vertical Demand Curve for Performance of the Capacity Market

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

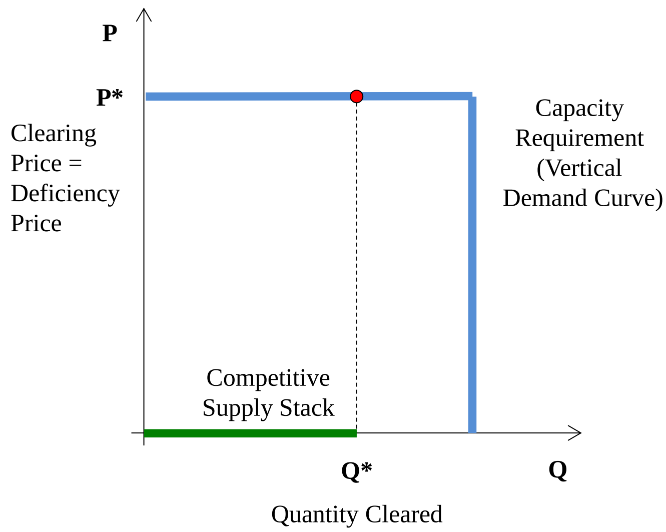
8 This ignores potential opportunity costs of exporting capacity to a neighboring market.

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.

Surplus Capacity Case



Shortage Capacity Case



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.

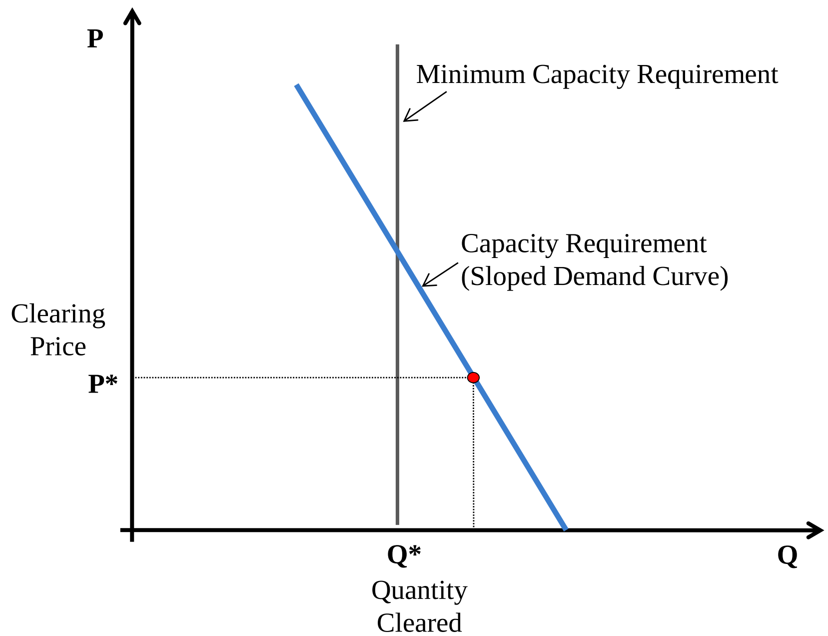
Second, since prices produced by such a construct do not accurately reflect the true marginal value of capacity, the market will not provide efficient long-term economic signals to govern investment and retirement decisions.

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 from withheld capacity 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, the 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 grow 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 2 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 2: 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 is borne by retail customers*. Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds the market's surplus. Under the 3 percent case, for example, the current market would produce almost no wholesale capacity revenue even though the LSE's surplus is improving reliability for the region. Under the sloped demand curve in this case, almost half of the costs of the new unit would be covered by the capacity market revenues.

Hence, although a sloped demand curve could increase costs to non-vertically integrated LSE's that must purchase large quantities of capacity through an RTO's market, the example above shows that this is not the case for the vertically-integrated LSE's that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's 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).

<u>Key Observations: Capacity Market Design</u>

i. Based on both the theoretical and practical concerns with the current vertical demand curve, we recommend that MISO modify the RAC to incorporate a sloped demand curve that would:

- Allow capacity prices to efficiently reflect the marginal reliability value of additional capacity;

- Produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing longer-term price signals and incentives to govern investment and retirement decisions; and

- Reduce the incentive to exercise market power in the capacity market by withholding resources.

ii. The need for a sloped demand curve is particularly acute because MISO is now forecasting a capacity shortage as soon as 2016. Planning reserve margins are forecasted to decline substantially with the retirement of significant amounts of coal-fired capacity.

- These retirements are likely because of a number of factors, including low natural gas prices, increased wind penetration, and the compliance costs associated with new EPA regulations.

- These retirements are expected to outpace net dependable capacity growth from wind units and new installed natural gas-fired capacity.

iii. Improving the performance of the capacity market by implementing a sloped demand curve will provide benefits to the States and the vertically-integrated utilities in the MISO region.

- The sloped demand curve will not raise the expected costs for most regulated LSEs that build capacity to ensure they will not be deficient.

- The sloped demand curve reduces risk for the LSE by stabilizing the costs of having differing amounts of surplus.

- A smaller share of the total capacity 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.

III. Day-Ahead Market Performance

In the day-ahead market, participants make financially-binding forward purchases and sales of power 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 in the day-ahead market.

Day-ahead outcomes are important because the bulk of MISO's generating capacity is committed through the day-ahead market, and much of the power procured through MISO's markets is financially settled day-ahead. 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 A19 and Figure A20: Day-Ahead Energy Prices and Load

Figure A19 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on non-holiday weekdays) at four representative hub locations in MISO and the corresponding scheduled load (which includes net cleared virtual demand). Figure A20 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 throughout the year. High prices in one location relative to another location indicate congestion and loss factor differences from a low.-priced area to a high-priced area.

Figure A19: Day-Ahead Hub Prices and Load
Peak Hours, 2012–2013

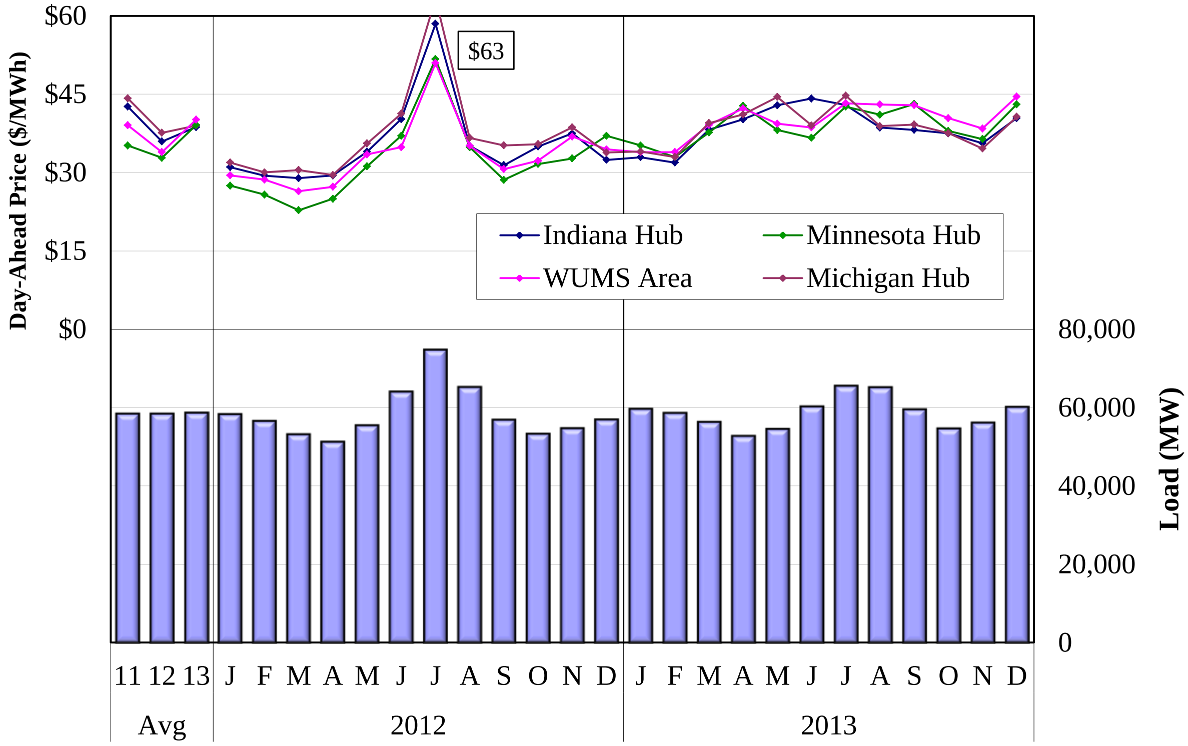
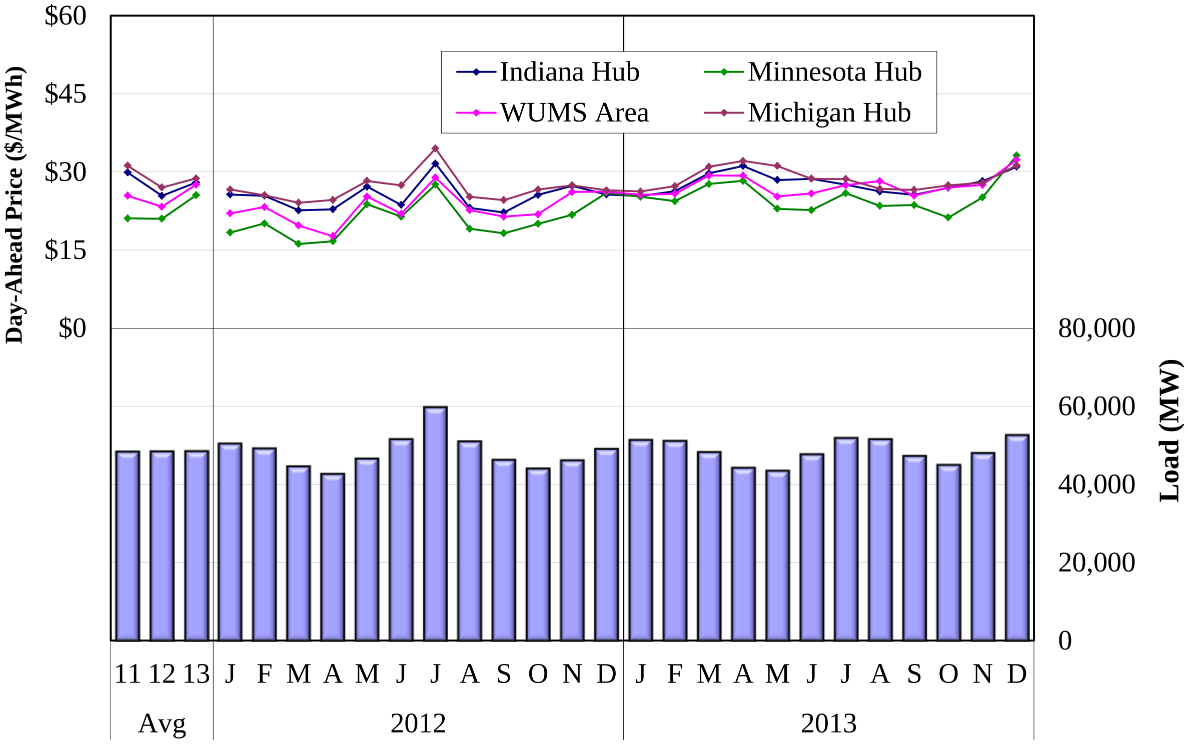


Figure A20: Day-Ahead Hub Prices and Load
Off-peak Hours, 2012–2013



Key Observations: Day-Ahead Energy Prices and Load

i. Prices continue to be moderately correlated with load, generally exhibiting the highest prices in the summer months and, to a lesser extent, in winter months. However, as discussed in Section I.B, fuel costs generally play a significant role in determining energy prices.

ii. Colder than average weather contributed to elevated day-ahead prices in March and April 2013.

iii. Price differences are the result of congestion and transmission losses on the network.

- The pattern of increasing prices from west to east held only during off-peak hours in 2013, and was most apparent in the second half of the year.
  - ✓ Scheduled wind output increased 24 percent in 2013, which explains why this pattern continued in many hours.
  - ✓ However, outages and changes in interchange patterns mitigated the west to east congestion pattern in many hours in 2013.
  - ✓ Off-peak congestion out of Minnesota was most apparent in October, when it averaged nearly $6 per MWh.
- During peak hours, prices were mostly uniform throughout MISO. The most apparent patterns of congestion were into Indiana in June and into WUMS after July.
  - ✓ The retirement of the Kewaunee nuclear station in June contributed to a shift in congestion patterns affecting WUMS.

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.

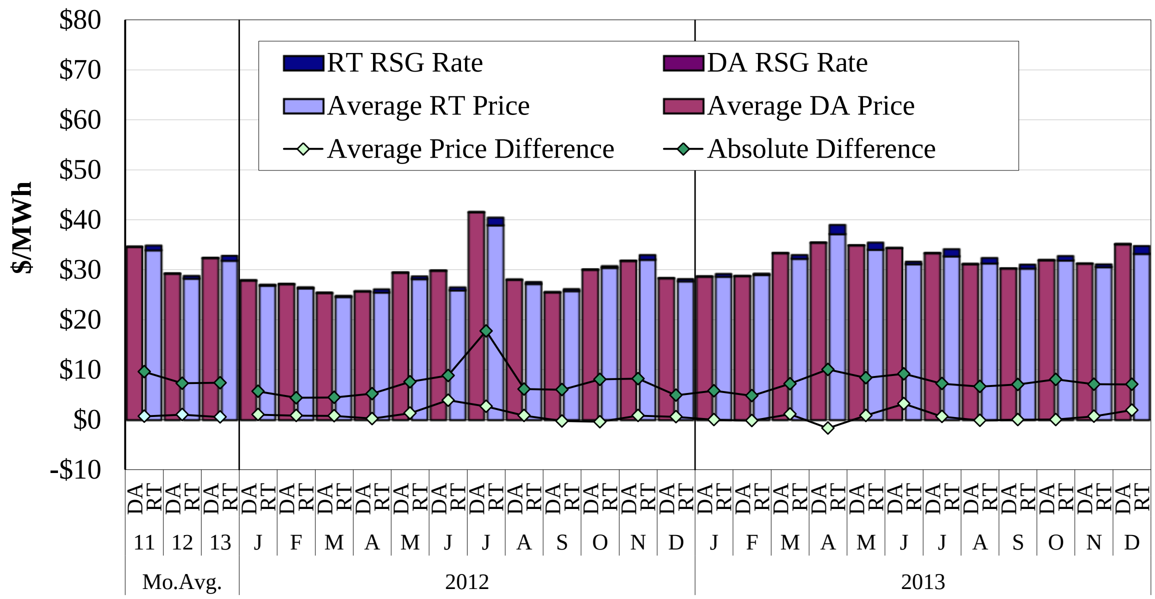
Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day. However, a variety of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While a well-performing market may not result in prices 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 typically are much larger than day-ahead RSG costs). Hence, day-ahead purchases can avoid these higher RSG costs.

Figure A21 to Figure A24: Day-Ahead and Real-Time Prices

The next four figures show monthly average prices in the day-ahead and real-time markets at four representative locations in MISO, along with the average RSG cost per MWh.[9] 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 A21: Day-Ahead and Real-Time Price
2012–2013: Indiana Hub

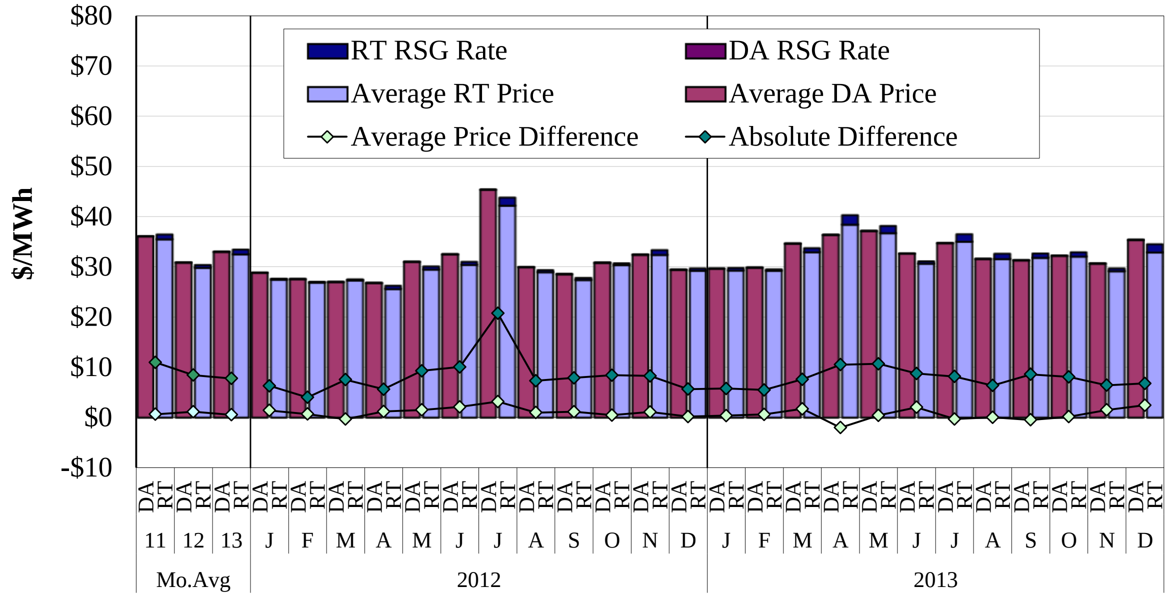


Average DA-RT Difference (% of Real-Time Price)

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

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

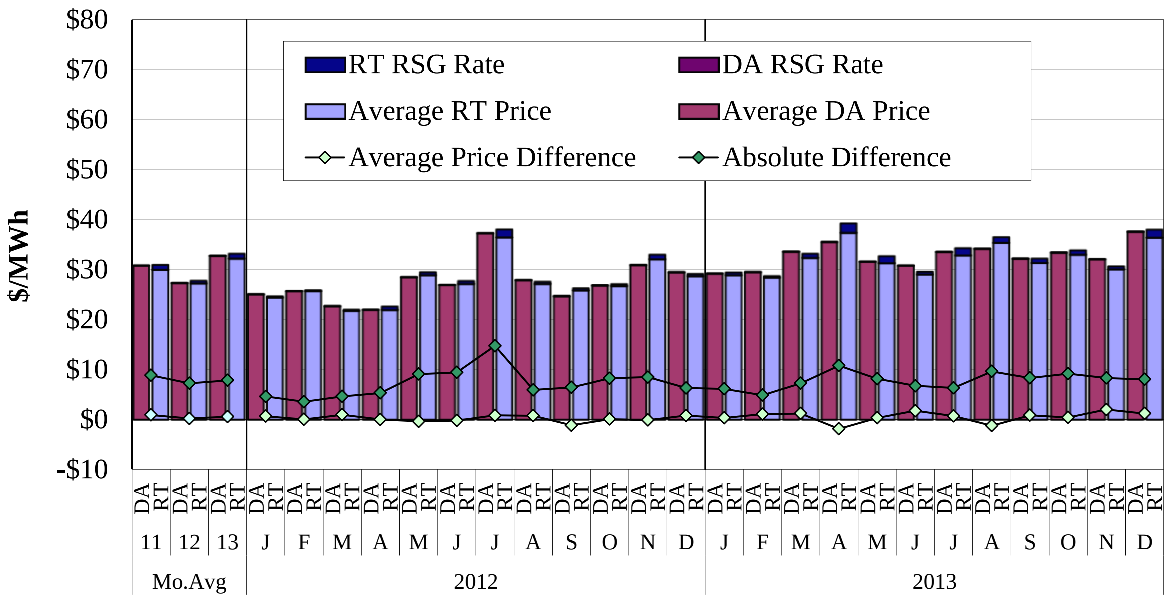
Figure A22: Day-Ahead and Real-Time Price
2012–2013: Michigan Hub



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

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

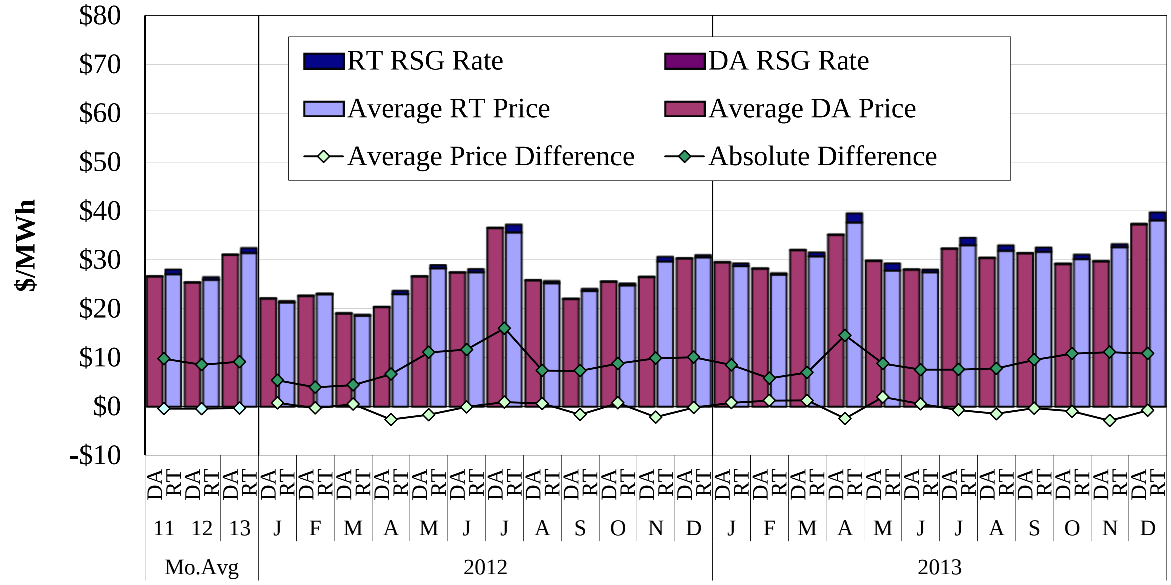
Figure A23: Day-Ahead and Real-Time Price
2012–2013: WUMS Area



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

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

Figure A24: Day-Ahead and Real-Time Price
2012–2013: Minnesota Hub



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

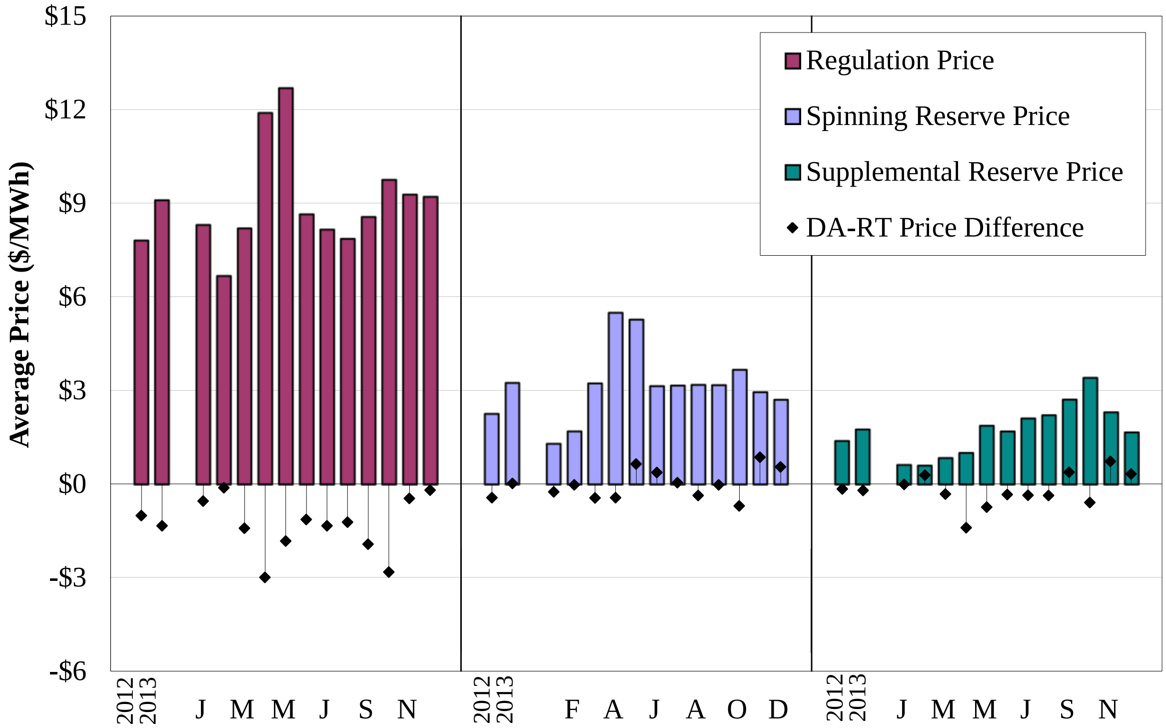
Excluding RSG	-2	-2	-1	3	-2	2	-12	-6	0	2	2	-7	3	-8	-1	3	4	4	-7	7	2	-2	-5	-1	-3	-9	-2
Including RSG	-5	-4	-4	2	-2	1	-14	-8	-3	-2	1	-8	2	-10	-2	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6

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 A25: Day-Ahead Ancillary Services Prices and Price Convergence

Figure A25 shows monthly average day-ahead clearing prices in 2013 for each ancillary services product, along with day-ahead to real-time price differences.

Figure A25: Day-Ahead Ancillary Services Prices and Price Convergence
2013



Key Observations: Day-Ahead and Real-Time Price Convergence

i. In 2013, there was a modest day-ahead energy price premium of 1.7 percent at the Indiana Hub, which is expected given the real-time RSG allocated to net real-time purchases and the lower volatility of prices in the day-ahead market. This is a decline from 3.6 percent in 2012.

– Convergence was poorest in April and May, when real-time prices at all hubs exceeded day-ahead prices due to real-time operating reserve shortages not anticipated by the day-ahead market.

– The real-time premium in June was mostly due to a low day-ahead limit on a market-to-market constraint impacted by a PJM FFE calculation error that caused a transmission limit to bind more severely than it should have.

ii. After accounting for $0.99 per MWh in average real-time RSG cost allocations to day-ahead deviations, there was a slight real-time premium of 1.3 percent at Indiana Hub.

– Real-time RSG costs nearly doubled from 2012, when they averaged $0.58 per MWh, but are nearly the same as costs in 2011.

– As in prior years, modest day-ahead premiums prevailed in all of the MISO regions except at the Minnesota Hub, where it exceeded 4 percent (including RSG costs).

- This was most significant in late summer because of outage-related congestion that was unanticipated by the day-ahead market.

- Over the long term, we expect small day-ahead premiums because scheduling load day-ahead reduces risk associated with higher real-time price volatility and because of higher RSG cost allocations to real-time deviations.

iii. Day-ahead market clearing prices for ancillary services products rose 15 to 45 percent, and tracked reasonably well with real-time clearing prices.

- Prices rose primarily due to increases in the opportunity cost of providing energy.

- There was a persistent real-time premium for regulation. It was greatest during shoulder seasons when Minimum Generation situations can occur.

  - ✓ During low-priced, low-load periods, units must remain above their minimum output levels to satisfy the bidirectional requirement of regulation.

  - ✓ These periods are not well foreseen by the day-ahead market.

  - ✓ Additionally, regulation prices can rise during these periods because fewer regulation-capable resources are committed.

- Real-time premiums for supplemental reserves were highest in April, May and October, when operating reserve shortages were greatest (six in each month).

  - ✓ These are often not anticipated well by the day-ahead market, which resulted in an average real-time premium for all products since higher-quality reserves can be substituted for lower-quality reserves.

C. Day-Ahead Load Scheduling

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

Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or resources. Similar to price-sensitive load, virtual load is cleared if the day-ahead price is equal to or less than the virtual load bid. Net 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 IV.I). This can contribute to suboptimal real-time pricing and can result in inefficiencies when lower-cost generation scheduled in the day-ahead market is displaced by peaking units committed in real time. Because these peaking units frequently do not set real-time prices (even though they are more expensive than other resources), the economic feedback and incentive to schedule more fully in the day-ahead market will be diluted.

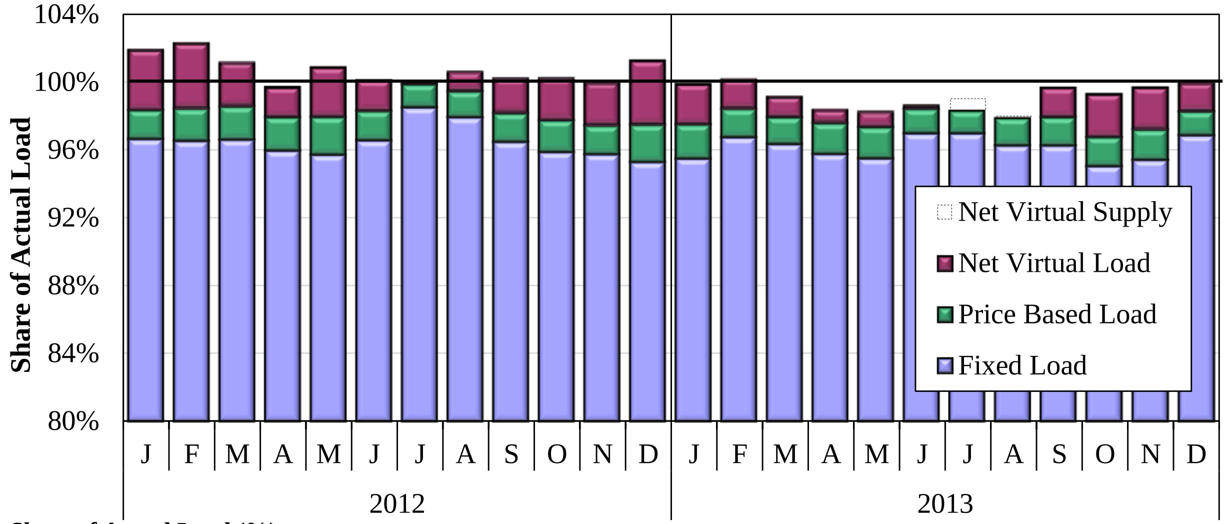
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

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

Figure A26: Day-Ahead Scheduled Versus Actual Loads

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

Figure A26: Day-Ahead Scheduled Versus Actual Loads
2012–2013, Daily Peak Hour



Share of Actual Load (%)

All Hours	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4	100.1	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.9
Peak Hours	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6	100.2	100.2	100.0	101.3	99.9	100.2	99.2	98.4	98.3	98.6	98.3	97.9	99.7	99.3	99.7	100.0

Key Observations: Load Scheduling

i. Load scheduling during the peak hour averaged 99.1 percent, down from 100.7 percent in 2012. Under-scheduling was most apparent in spring and in summer.

- The reduction in net load scheduling was consistent with the slight real-time price premium discussed in the prior section.
- Net virtual load declined in 2013, while fixed and price-based load scheduling as a share of actual load were unchanged from 2012.
- Under-scheduling of load during the peak hour often causes MISO to make additional real-time commitments, which generally increase RSG payments.

ii. Load scheduling during all hours averaged 99.2 percent, comparable to the 99.4 percent last year.

- Under-scheduling of load in off-peak hours often does not result in additional real-time commitments since day-ahead headroom is usually adequate in off-peak hours.

D. Fifteen-Minute Day-Ahead Scheduling

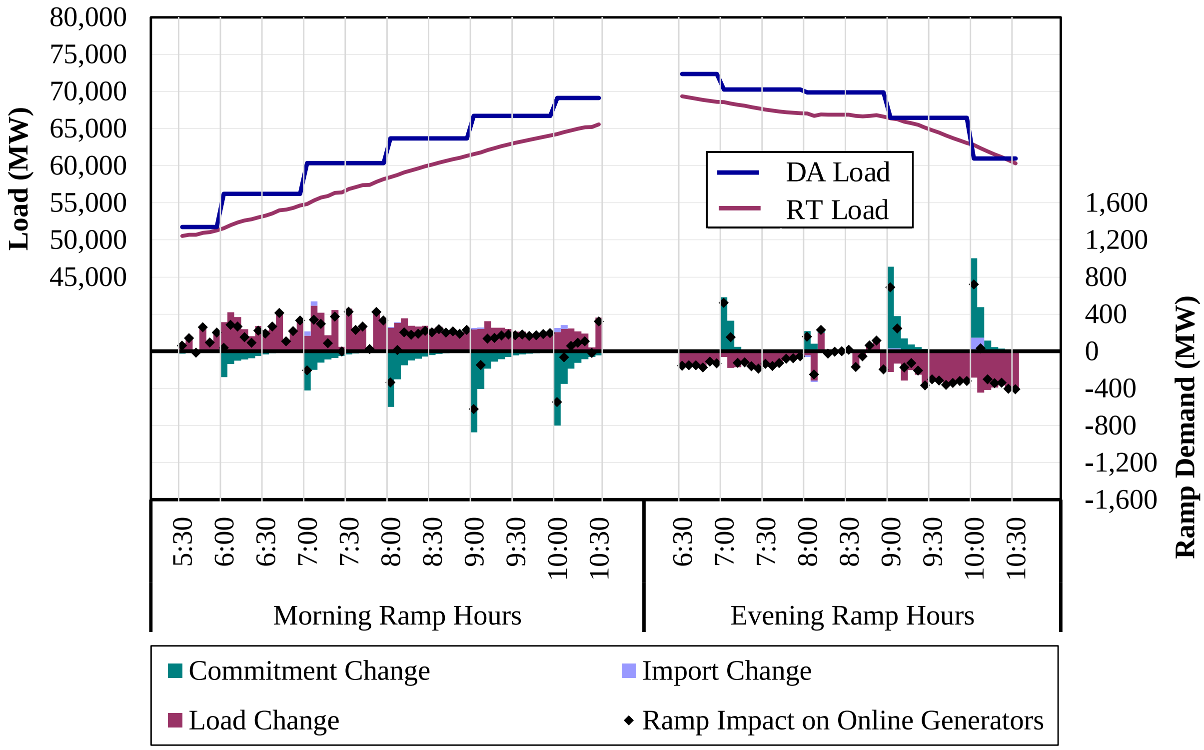
The day-ahead energy and ancillary services markets currently solves on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of the hour.

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), and 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 A27: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A27 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 A27: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2013



<u>Key Observations: Fifteen-Minute Scheduling</u>

i. Absent actions taken by MISO operators, online generators would be forced to ramp down at the top of morning ramp-up hours, and vice versa during evening hours to accommodate losses of physical schedules and unit de-commitments.

- Since MISO is generally a net importer, commitment and physical schedule changes are usually in the same direction (i.e., reduce generation demand in the morning ramp hours and increase generation demand in the evening ramp hours).
- Although improved from 2012, the average implied ramp demand during the first two intervals in an hour averaged -252 MW in morning ramp hours and nearly 600 MW in evening ramp hours, and sometimes it exceeded 1 GW.
- These ramp demands can contribute to transitory operating reserve shortages and inflated production costs during these periods, plus increased wear on physical facilities.

ii. Running the day-ahead market based on fifteen-minute intervals would result in more flexible commitments and schedules that could better align scheduled ramp with actual ramp demand in real time.

- The information technology limitations that had once prevented a more granular day-ahead market have dissipated over time. Hence, MISO should evaluate the costs and benefits of revising its day-ahead market to schedule energy and ancillary services on a 15-minute basis.

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 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, sellers must then purchase (or produce) 1 MW in real time to cover the trade. They will incur a loss if their 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 be unprofitable.

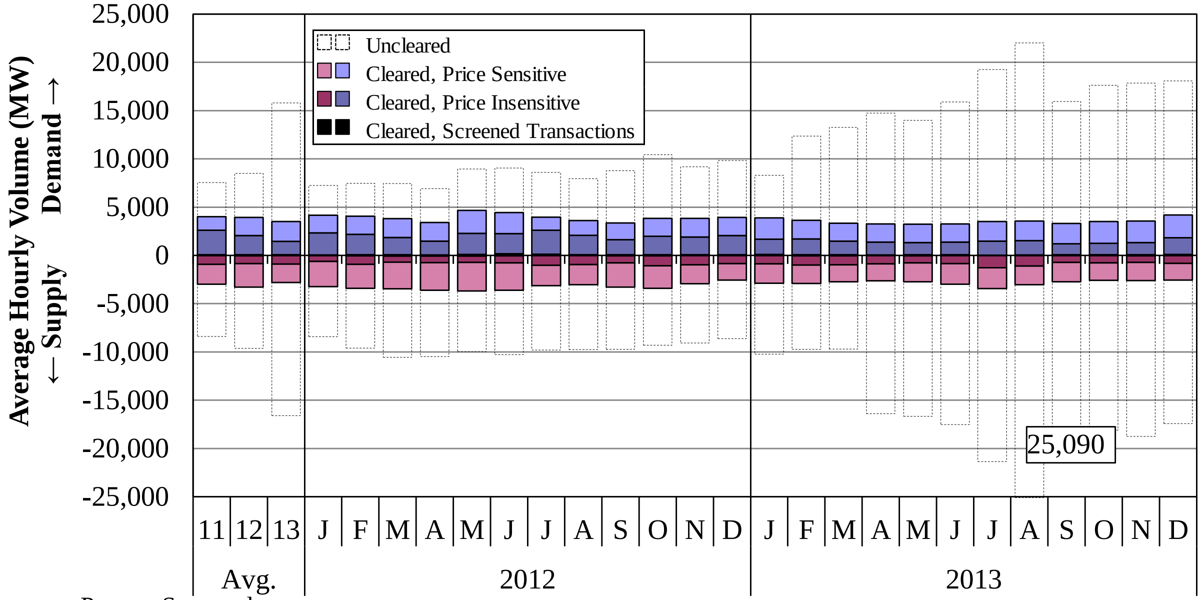
For example, a participant may submit a high-priced (likely to clear) virtual demand bid at an otherwise unconstrained location that causes artificial day-ahead market congestion. In this case, the participant would buy in the day-ahead market at the high (i.e., congested) price and sell the energy back 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 A28: Virtual Transaction Volumes

Figure A28 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It shows components of daily virtual bids and offers and net virtual load (i.e., cleared virtual load less virtual supply) in the day-ahead market from 2011 to 2013. The virtual bids and offers that did not clear are shown as dashed areas at the end points (top and bottom) of the solid bars. These are virtual bids and offers that were not economic based on the prevailing day-ahead market prices (supply offers priced at more than the clearing price and demand bids priced below the clearing price).

The figure separately distinguishes 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 this figure, bids and offers submitted at more than $20 above or below an expected real-time price, respectively, are considered price-insensitive. A subset of these volumes that contributed materially to an unexpected difference in the congestion at the location between the day-ahead and real-time markets warrant closer investigation. These volumes are labeled ‘Screened Transactions’ in the figure.

Figure A28: Virtual Transaction Volumes
2012–2013



Percent Screened

Demand	1.6	2.2	2.2	1.5	2.0	1.7	1.6	2.1	4.0	3.1	1.8	2.1	2.2	2.1	2.1	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5
Supply	1.2	1.4	1.2	0.9	1.2	2.4	1.9	2.2	1.4	1.2	1.0	1.2	1.3	1.0	1.4	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3
Total	1.4	1.9	1.8	1.2	1.6	2.0	1.7	2.2	2.9	2.3	1.4	1.6	1.8	1.6	1.8	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1

Figure A29: Virtual Transaction Volumes by Participant Type

Figure A29 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 A29: Virtual Transaction Volumes by Participant Type
2013

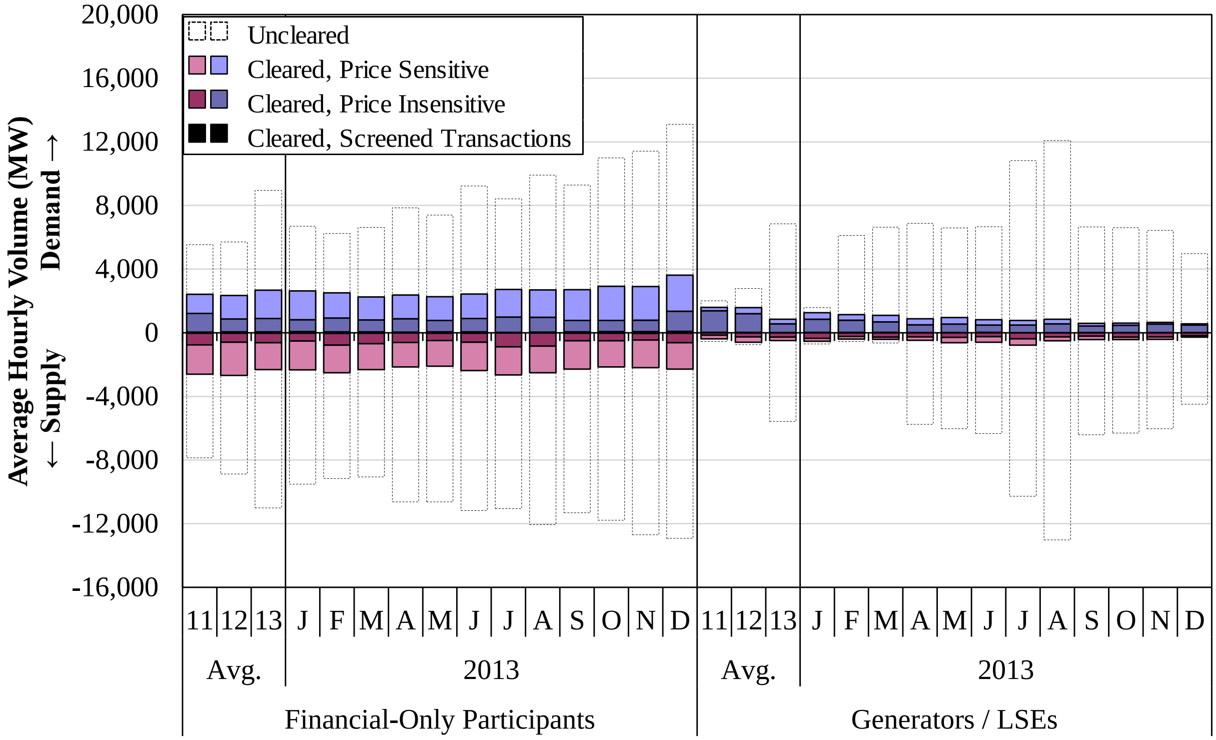


Figure A30: Virtual Transaction Volumes by Participant Type and Location

Figure A30 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 2013.

Figure A30: Virtual Transaction Volumes by Participant Type and Location
2011–2013

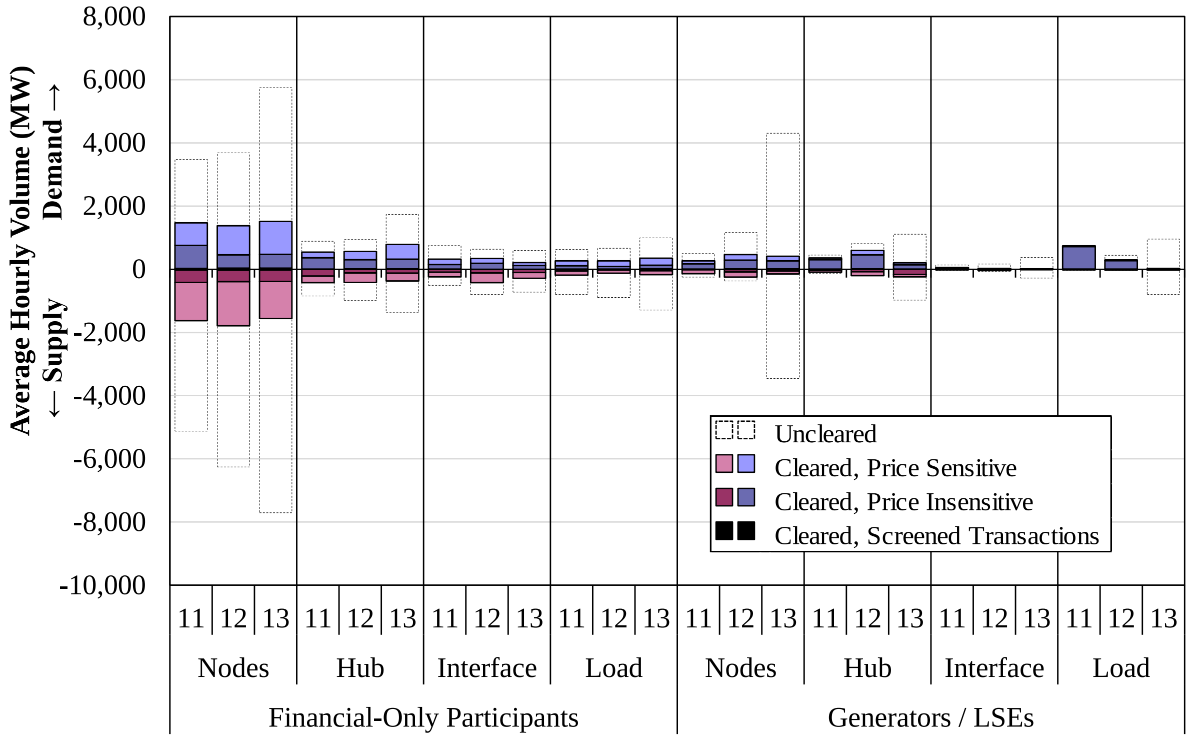


Figure A31: Matched Virtual Transactions

Figure A31 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 A31: Matched Price-Insensitive Virtual Transactions
2012-2013

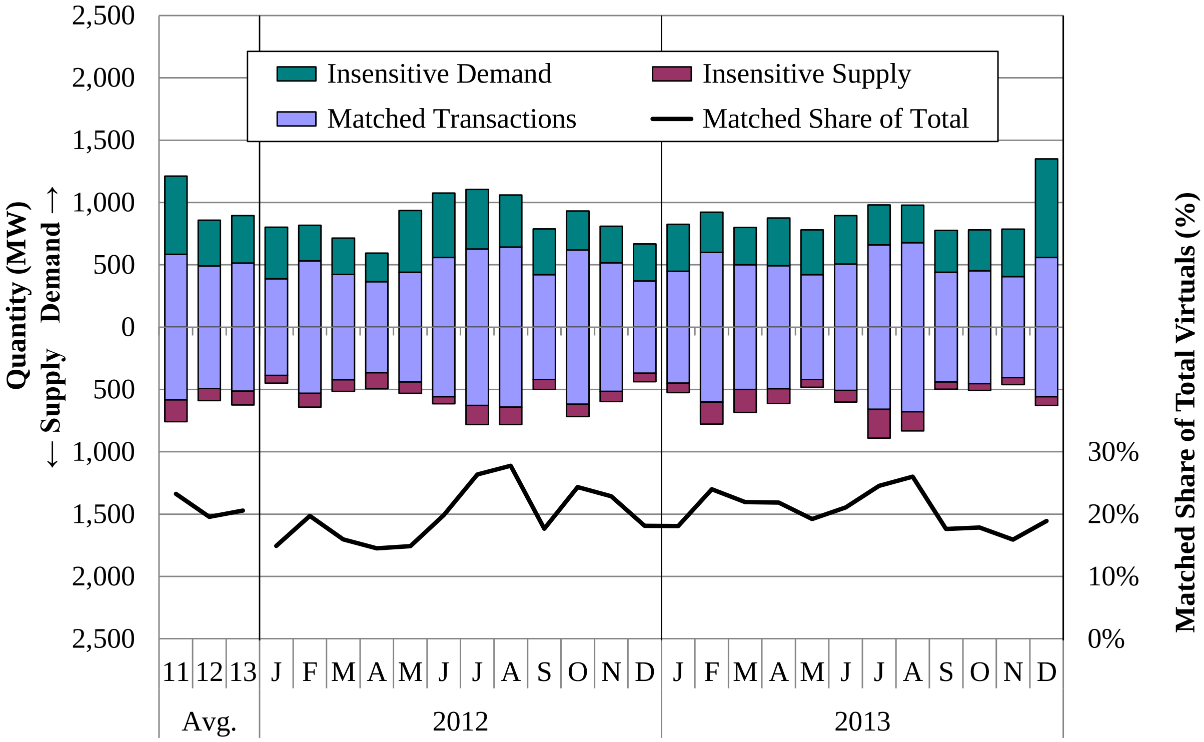
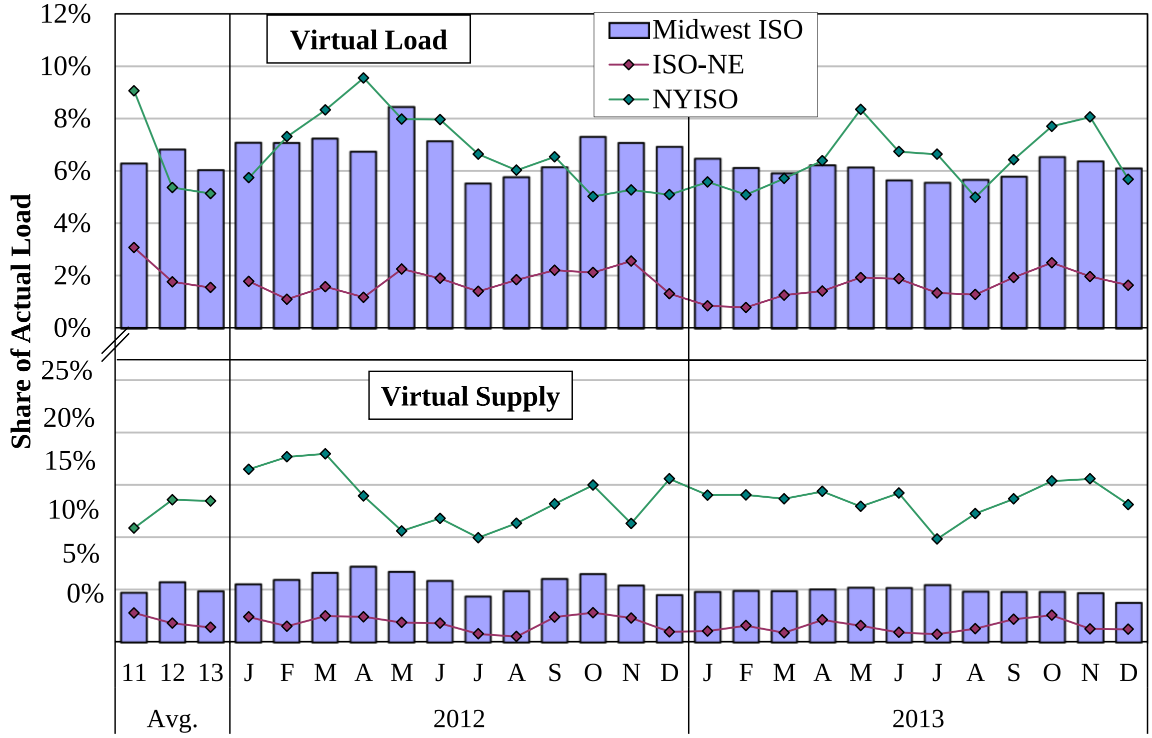


Figure A32: Virtual Transaction Volumes, MISO and Neighboring RTOs

To compare trends in MISO to other RTOs, Figure A32 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 A32: Comparison of Virtual Transaction Volumes
2011–2013



Key Observations: Virtual Transaction Volumes

i. Offered total virtual demand and supply rose 79 percent from 2012. Much of this is due to an increase in volumes that were offered well above (for demand) or below (for supply) the expected price range, so they rarely cleared.

- This "backstop" strategy accounted for almost all of the increase from 2012, although less than 1 percent of these cleared.
- When they did clear, they were substantially profitable and beneficial for the market because they mitigated particularly large day-ahead price deviations.

ii. Cleared transactions declined 10 to 14 percent.

- Physical participants in particular cleared half as much demand as they did in 2012.
- Nearly half of all cleared transactions are by financial participants at generator locations, with financial participants clearing a further 18 percent at hub locations.
- Interface and load zone transactions make up just fewer than 10 percent each of financial participants' volumes. Physical participants rarely transact at these locations.

- The price-sensitivity of cleared transactions improved modestly in 2013. Nearly two-thirds of all cleared transactions were price-sensitive, up from 60 percent in 2012 and 50 percent in 2011.

iii. Over two-thirds of insensitive volumes and 21 percent of all virtual volumes were "matched" transactions.

- These transactions are most likely to benefit from a virtual spread bid product.
- The substantial rise in matched transactions from 2010 (when just four percent of all volumes were matched) is most likely due to RSG allocation revisions.
  - ✓ In determining a participant's deviations that will be the basis for allocating RSG costs, MISO now nets a participant's virtual load and virtual supply. This has increased the incentive for participants to balance their portfolio.
- A virtual spread product would be a more efficient means of arbitraging congestion-related price differences than matched virtual supply and demand transactions. This product could facilitate improved price convergence between the day-ahead and real-time markets. PJM and ERCOT both have similar products.
  - ✓ Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (up to which they are willing to schedule a transaction).
  - ✓ The transaction would be profitable if the difference in real-time congestion between the source and the sink is greater than the day-ahead difference, and would lose money if it is less.
  - ✓ The product would settle only on the difference in the congestion component of the LMP, so there is no energy risk. In addition, since it would only clear as a spread, there is no execution risk comparable to the risk participants face today of only one side of the "matched" transactions clearing.
  - ✓ We continue to recommend and MISO continues to discuss a potential virtual spread product with MISO stakeholders.
- Fewer than two percent of cleared volumes were "screened" as contributing to a material divergence in prices.
- No virtual bid restrictions were imposed in 2013.

iv. In 2013, MISO received approval to modify its Tariff to correct the CMC rate sign error, which had caused congestion-related RSG costs to be misallocated to virtual transactions.

- An additional filing was made in 2013 to modify RSG allocations, including both CMC and DDC charges, to be better aligned with cost-causation.

– These changes are addressed more fully in Section IV.F.

v. Financial-only participants continued to provide most of the virtual liquidity in the day-ahead market and offered much more price-sensitively than physical participants.

– Approximately 70 percent of financial-only participant volumes were price-sensitive, compared to just one-third of physical participant volumes. Both shares are modest improvements from 2012.

– Much of the virtual trading by financial-only participants occurred at individual nodes, which allows them to arbitrage price differences related to congestion.

– Demand volumes by physical participants at hub locations declined by two-thirds.

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 A33-34: Virtual Profitability

Figure A33 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 A34 shows the same results disaggregated by type of market participant: entities owning generation or serving load, and financial-only participants.

Figure A33: Virtual Profitability
2012–2013

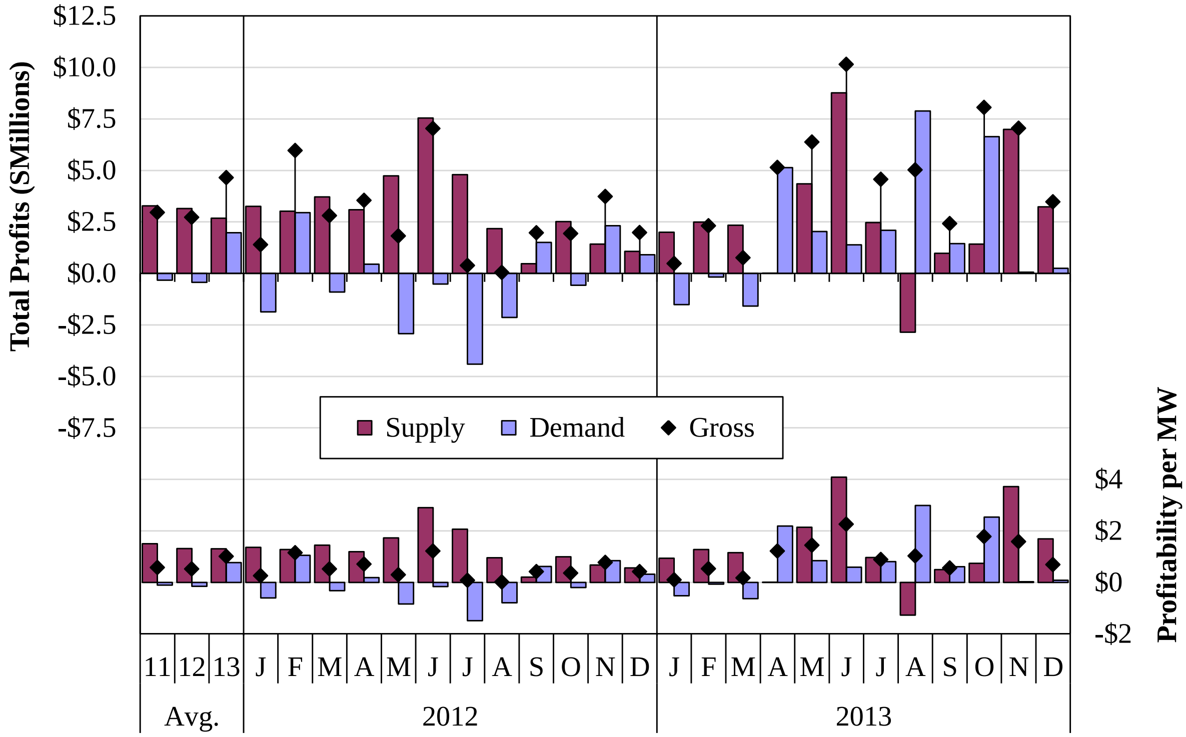
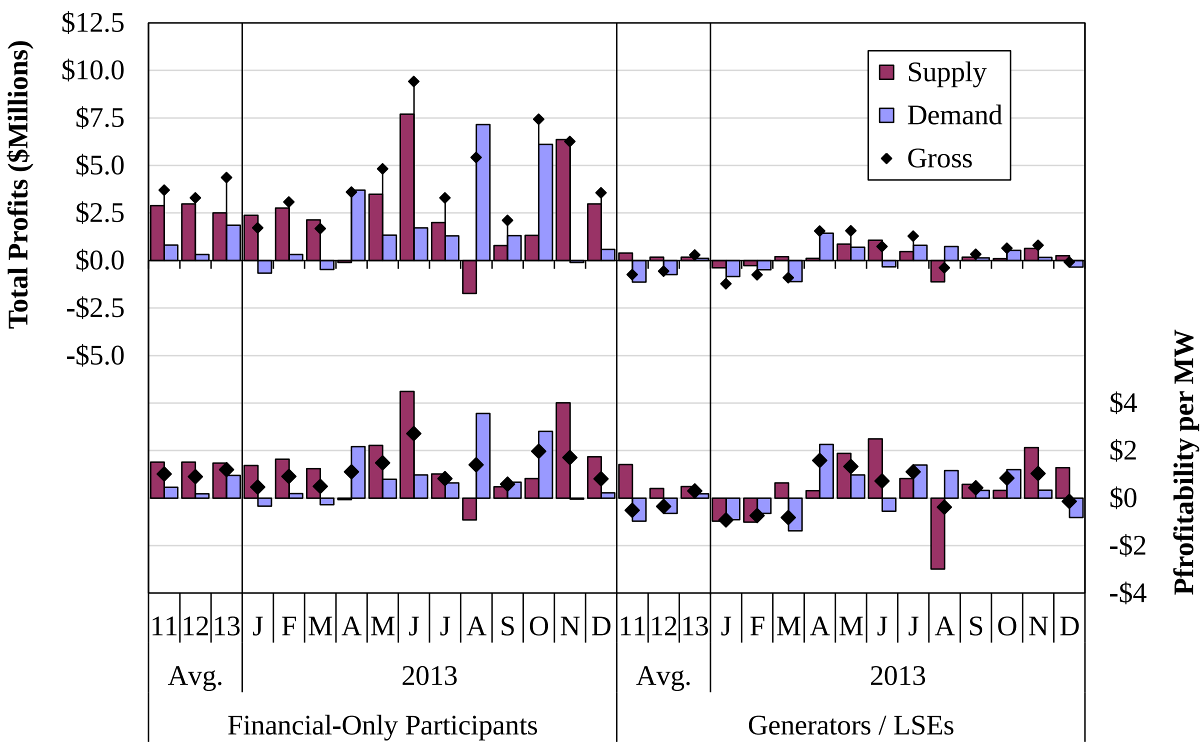


Figure A34: Virtual Profitability by Participant Type
2013



Key Observations: Virtual Profitability

i. Gross virtual profitability nearly doubled from 2012 to $1.01 per MW.

- Demand in particular was more profitable than usual: it averaged $0.77 per MW, up from a slight loss in prior years. This is consistent with the increase in periods exhibiting real-time price premiums in 2013.

- Supply profitability was nearly unchanged at $1.30 per MW.

- Total virtual profits increased from $32.6 million to $55.8 million.

ii. The real-time RSG costs allocated to deviations, including net virtual supply, under the DDC rate averaged $0.99 per MW, which lowered the net profitability of virtual supply transactions.

- Low virtual profitability is consistent with a competitive and liquid day-ahead market, which allows the market to efficiently schedule MISO's generating resources.

iii. Transactions by financial-only participants continued to be more profitable (at $1.20 per MW) than those by physical participants, which were also profitable at $0.30 per MW for the first time in years.

- Physical participants in 2013 were less willing to consistently incur losses on virtual demand than in prior years.

iv. In August, demand was unusually profitable—and supply unusually unprofitable—in part because of significant and volatile congestion on constraints in the Central region.

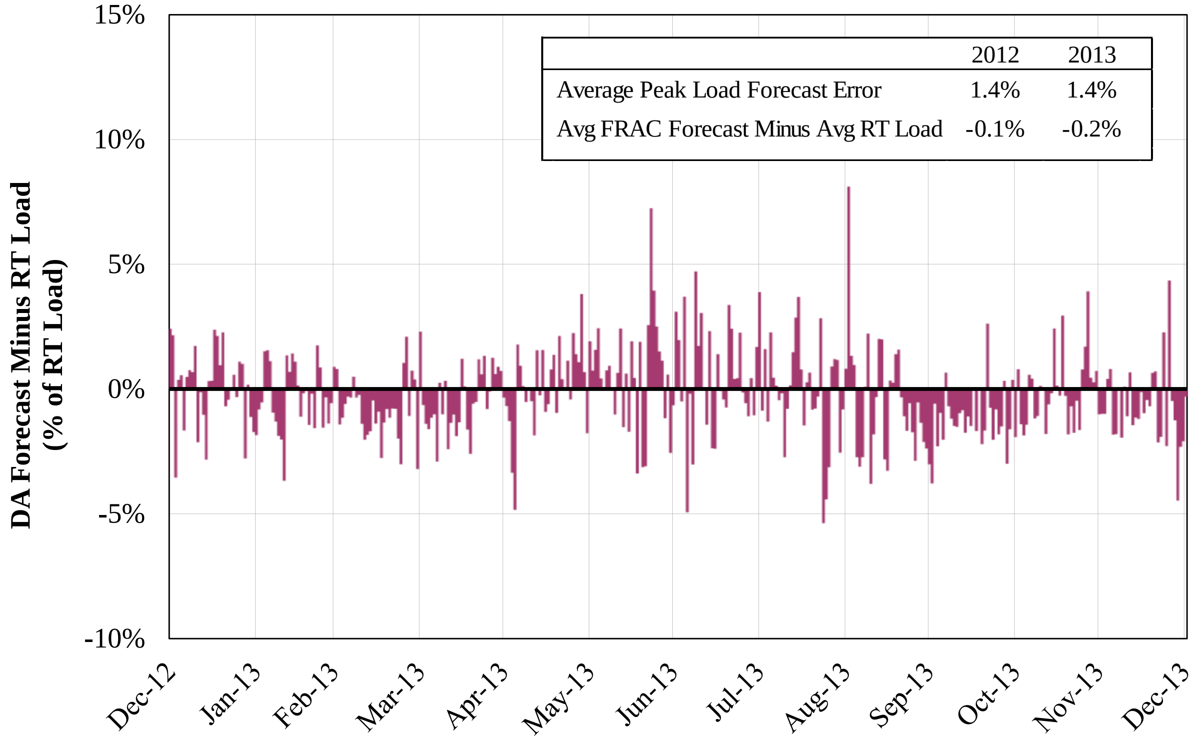
G. Load Forecasting

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 A35: Daily MTLF Error in Peak Hour

Figure A35 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 2013.

Figure A35: Daily MTLF Error in Peak Hour
2013



Key Observations: Load Forecasting

i. In 2013, MISO generally forecasted peak-hour loads accurately. Several observed patterns continued from previous years:

– The average forecast error was considerably greater in absolute terms in summer months because of the higher uncertainty associated with weather-related loads.

✓ The timing of weather changes that can substantially increase or decrease temperatures contributes to the load forecast errors.

✓ Load forecasting on peak load days improved in 2013—it was generally over-forecasted by less than 2 percent.

✓ This improvement may have partially been due to the milder summer temperatures, which reduces the weather-related load uncertainty.

– Load was modestly under-forecasted in shoulder seasons.

✓ Roughly half of this impact is attributable to misalignment of the forecasted and actual peak hour, which biases these results toward under-forecasting.

ii. Overall, we find that MISO's load forecasting was consistent with the performance of other RTOs and did not generally raise significant concerns.

IV. 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 dispatch range.

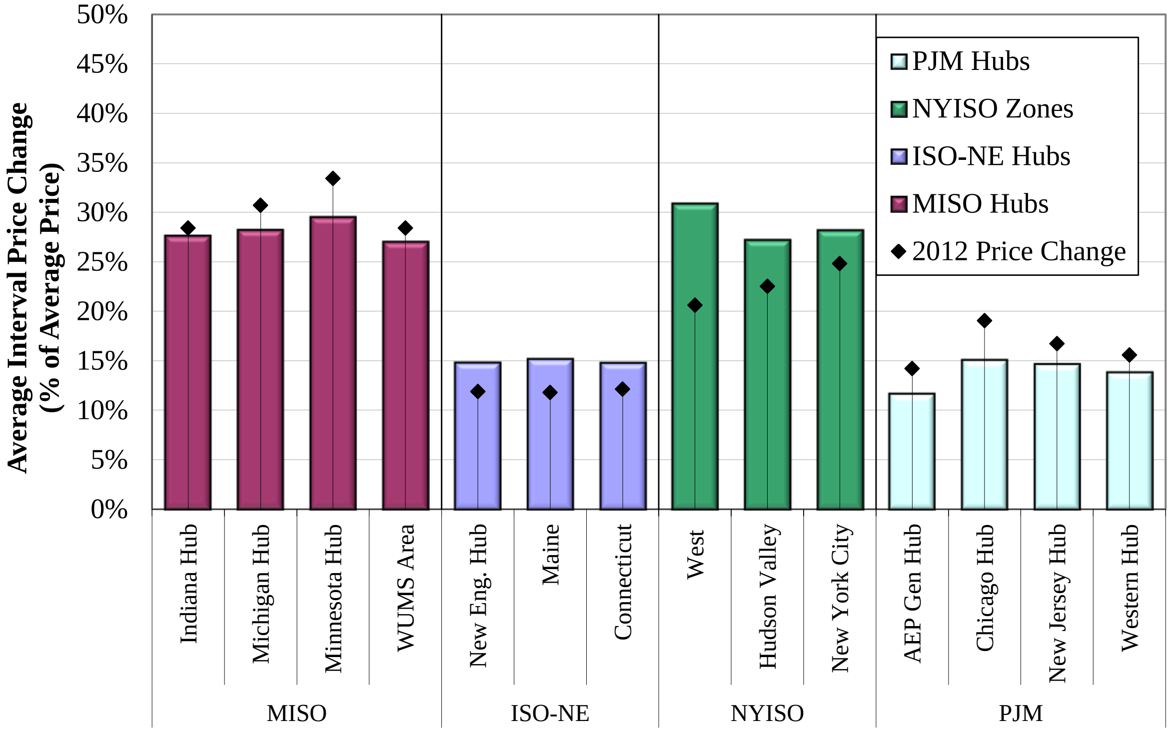
Figure A36: Five-Minute, Real-Time Price Volatility

Figure A36 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between five-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 A36: Five-Minute, Real-Time Price Volatility
MISO and Other RTO Markets, 2013



Key Observations: Real-Time Price Volatility and High Priced Events

i. Price volatility rose to $5.71 per interval, which is 10 percent higher than in 2012. This increase is largely due to the rise in fuel prices in 2013 that led to higher overall prices.

- As a share of the average price, price volatility declined slightly from 2012 to 18 percent.

- The 35 percent rise in natural gas prices also increased price volatility because it increased the slope of the energy supply curve.

- Volatility remained highest in absolute terms ($6.45 per interval) and in percentage terms (21 percent) at the Minnesota Hub, where fluctuations in wind output have the greatest impact on congestion.
  - ✓ The increase in DIR penetration, however, improved manageability and contributed to the largest regional decline in volatility (11 percent).
- Overall, price volatility in MISO remains considerably higher than in neighboring RTOs.
- One reason volatility is higher in MISO is that it runs a true five-minute real-time market (producing a new real-time dispatch every five minutes).
  - ✓ NYISO does so as well, but it has a look-ahead dispatch system that optimizes over multiple intervals.
  - ✓ Other RTOs dispatch every 10 to 15 minutes, which tends to provide more flexibility (which lowers volatility), but maintains less control of the system (by relying more on regulation to balance supply with demand between intervals).
- MISO has improved the efficiency of real-time commitments with the introduction of the Look-Ahead Commitment (LAC) tool.
- It is also considering a ramp product to better manage the ramp demands of the system, which are greatest at the top of the hour. We believe this product will be beneficial and continue to recommend its adoption.
- We also support MISO's decision to evaluate the remaining benefits of a Look-Ahead Dispatch after deployment of the ramp product.

B. ASM Prices and Offers

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.[10] The demand curves for the various ancillary services products in 2013 were:

- Spinning Reserves: $65 per MWh (for shortages between 90 and 100 percent of the market-wide requirement) and $98 per MWh (for shortages less than 90 percent).[11]

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

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

- Regulation: Varies monthly according to the prior month's gas prices. It averaged $183.97 per MWh in 2013 and ranged from $169 to $210.

- Total Operating Reserves: In May 2013 MISO introduced a demand curve that corresponds to the severity of the shortage, as follows:

  - 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 A37: Real-Time Ancillary Service Prices and Shortages

Figure A37 shows monthly average real-time clearing prices for ASM products in 2013. 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.

Figure A37: Real-Time Ancillary Services Clearing Prices and Shortages
2013

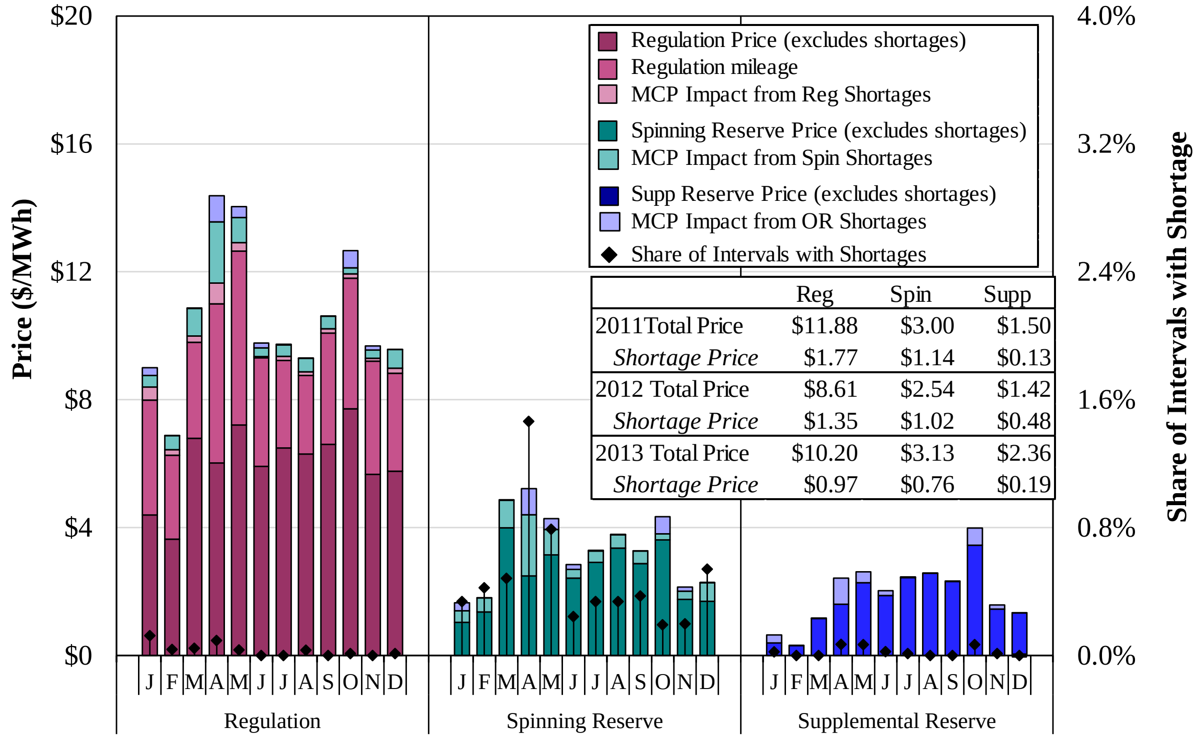


Figure A38: Regulation Offers and Scheduling

ASM offer prices and quantities are primary determinants of ASM outcomes. Figure A38 examines average regulation capability, which is the smallest of the three products 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 are 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 A38: Regulation Offers and Scheduling
2013

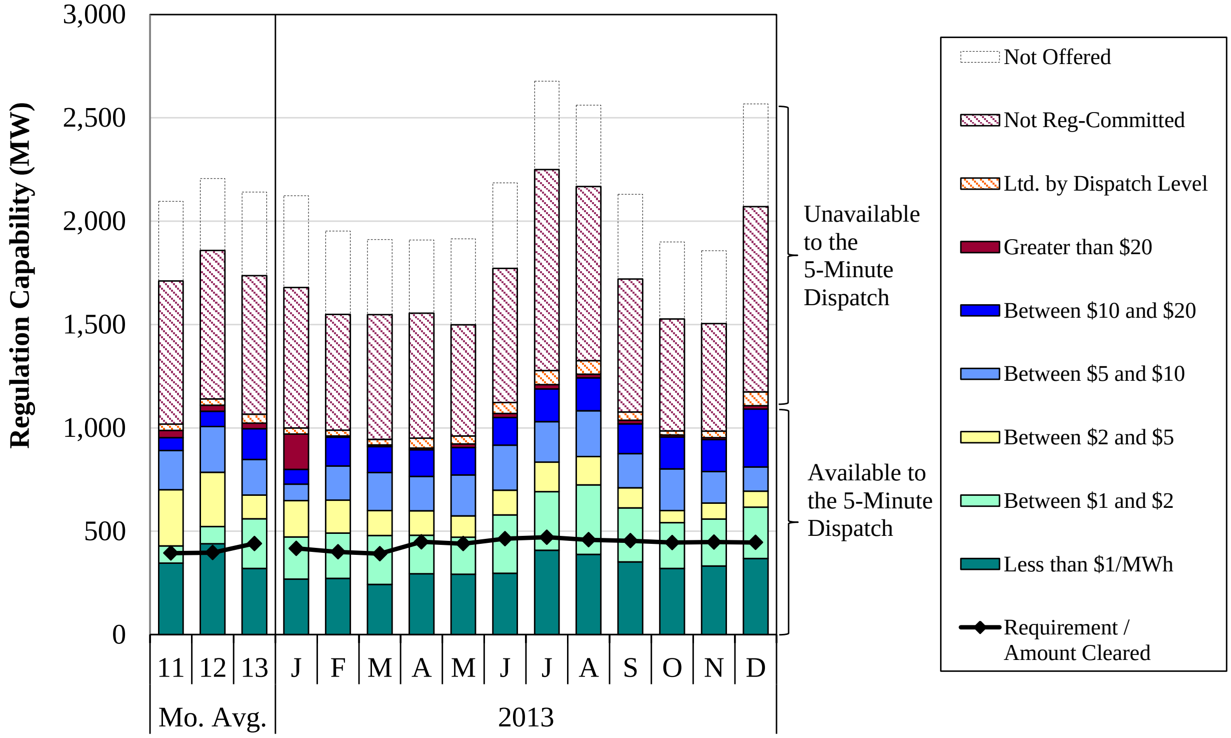
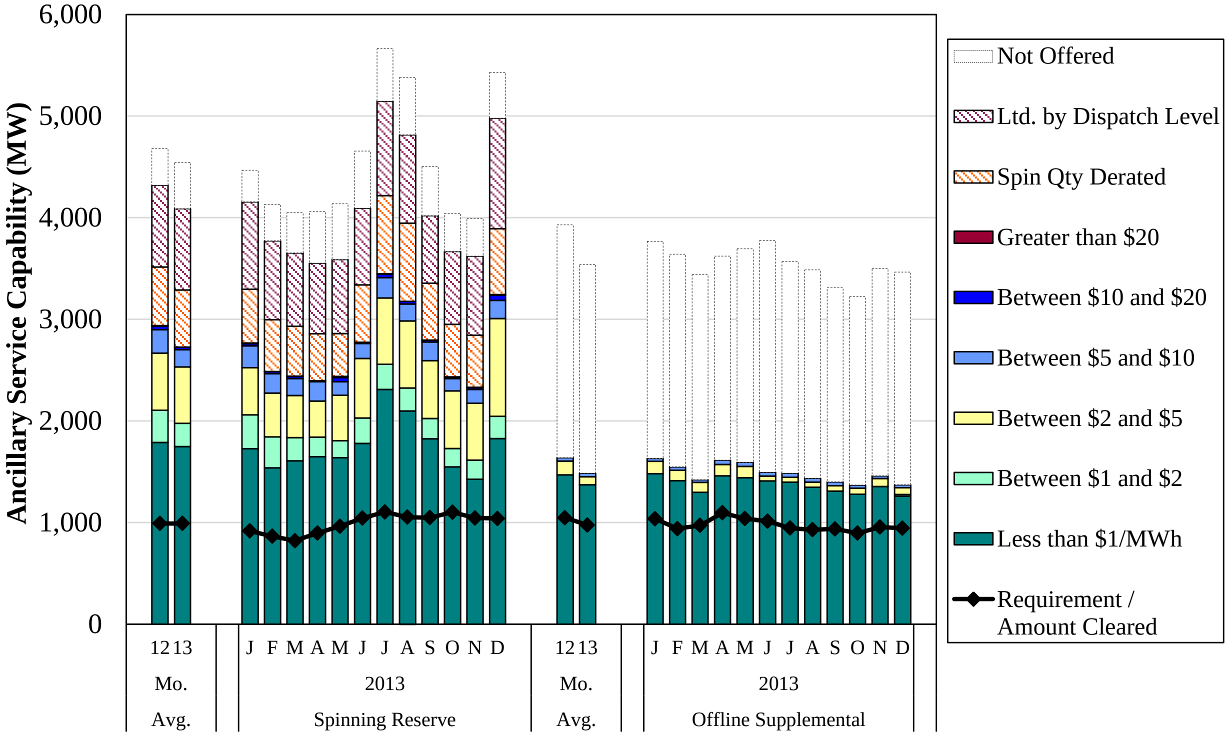


Figure A39: Contingency Reserve Offers and Scheduling

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 A39 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 A39: Contingency Reserve Offers and Scheduling
2013



Key Observations: ASM Prices and Offers

i. Monthly average market clearing prices for all ancillary services products rose in 2013 because of considerably higher energy prices driven by higher natural gas prices (higher energy prices increase the opportunity cost of providing reserves).

- The impact of higher energy prices on ASM prices was offset by a reduction in shortages in 2013. In particular, operating reserve shortages declined by 44 percent from 2012.

ii. Shortage pricing was most significant in April, when there were 126 intervals of spinning reserve shortage and 6 intervals of operating reserve shortage.

- These were due primarily to factors that increased the ramp demands on the system.
- Limited offline supplemental resources on several days in spring caused MISO to procure spinning reserves at costs well above the spinning reserve demand curve price to meet the contingency reserve requirement.
- Shoulder seasons (spring and fall) can experience shortages because MISO often has fewer units online providing ramp capability (due to low load) and may have fewer offline reserves (due to increased planned outages taken in off-peak seasons).

– Per FERC Order 755, MISO introduced a two-part compensation formula for pricing regulation in late 2012 that paid participants separately for regulation capacity and for "mileage" service (actual up and down movement).

– Many participants' regulation offer prices rose considerably after this change due to a lack of familiarity with the two-part offers. This had a moderate impact on regulation prices in January, but a minimal impact thereafter.

iii. Although the average clearing price for regulation was over $10 per MWh, sufficient capability was generally available to meet the requirement with offers less than $1.

– Similar conditions prevailed for spinning and supplemental reserves, where the average clearing price was considerably higher than the marginal unit's offer price.

– As discussed previously, prices can and generally do clear higher than the highest cleared ASM offers because they reflect opportunity costs of not providing energy and, to a lesser extent, the impact of shortage pricing.

iv. December includes partial month information for MISO's South Region and the rise in spinning reserve offers in December reflects the integration of MISO South.

– MISO's South Region has very few resources capable of providing supplemental reserves.

C. Spinning Reserve Shortages

Figure A40: 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).

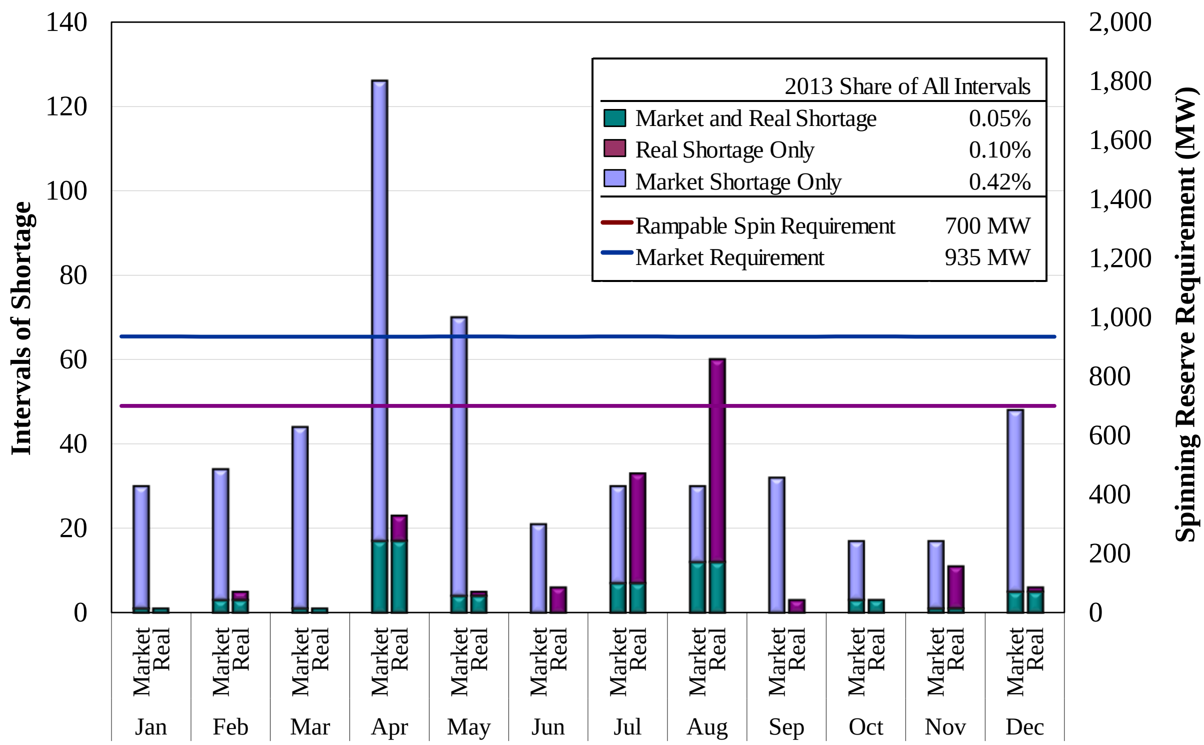
Units scheduled for spinning reserves may temporarily be unable to provide the full quantity in 10 minutes if the real-time energy market is instructing them to ramp up to provide energy. To account for concerns that ramp-sharing between ASM products could lead to real ramp shortages, MISO maintains 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.[12] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

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

Figure A40 shows all intervals in 2013 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.[13]

Figure A40: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

2013



Key Observations: Spinning Reserve Shortages

i. Inconsistencies between market and real (capacity or ramp-limited) spinning reserve shortages persisted in 2013.

- For nearly 90 percent of intervals with market shortages, there was no accompanying real shortage.
  - ✓ This indicates that the market requirement continues to be set too high.
- Real shortages occurred in approximately 100 intervals, predominantly in July and August, and predominantly reflect inferred unit derates.

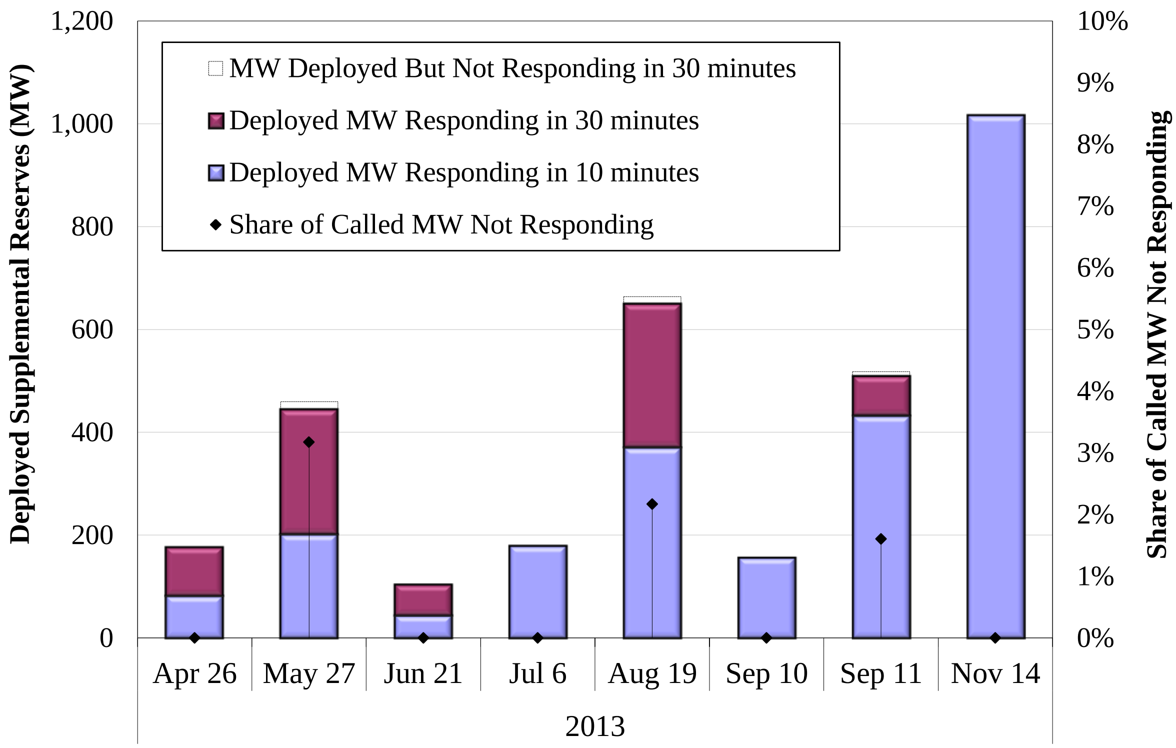
13 For a more complete discussion on inferred derates, see Section IV.K.

D. Supplemental Reserve Deployments

Figure A41: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A41 shows offline supplemental reserve response during the eight deployments in 2012 and 2013, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC).

Figure A41: Supplemental Reserve Deployments
2012–2013



Key Observations: Supplemental Reserve Deployments

i. There were eight supplemental reserve deployments in 2013. The large majority of responses were delivered within 10 minutes, and nearly all deployments responded within 30 minutes.

ii. When quick-start units carrying offline supplemental reserves are committed for energy, MISO does not account for either energy or reserves until it is fully synchronized, which can take 5 to 15 minutes. In the interim, the capacity loss can contribute to reserve shortages and energy price spikes.

- This accounting discrepancy affected 2.5 percent of market intervals in 2013 by an average of 108 MW, caused four operating reserve shortages, and contributed at least $100 to operating reserve prices in five additional periods.

- MISO should pursue changes to its reserve accounting that would retain reserve capability during the period when a quick-start unit is coming online.

E. Generation Availability and Flexibility in Real Time

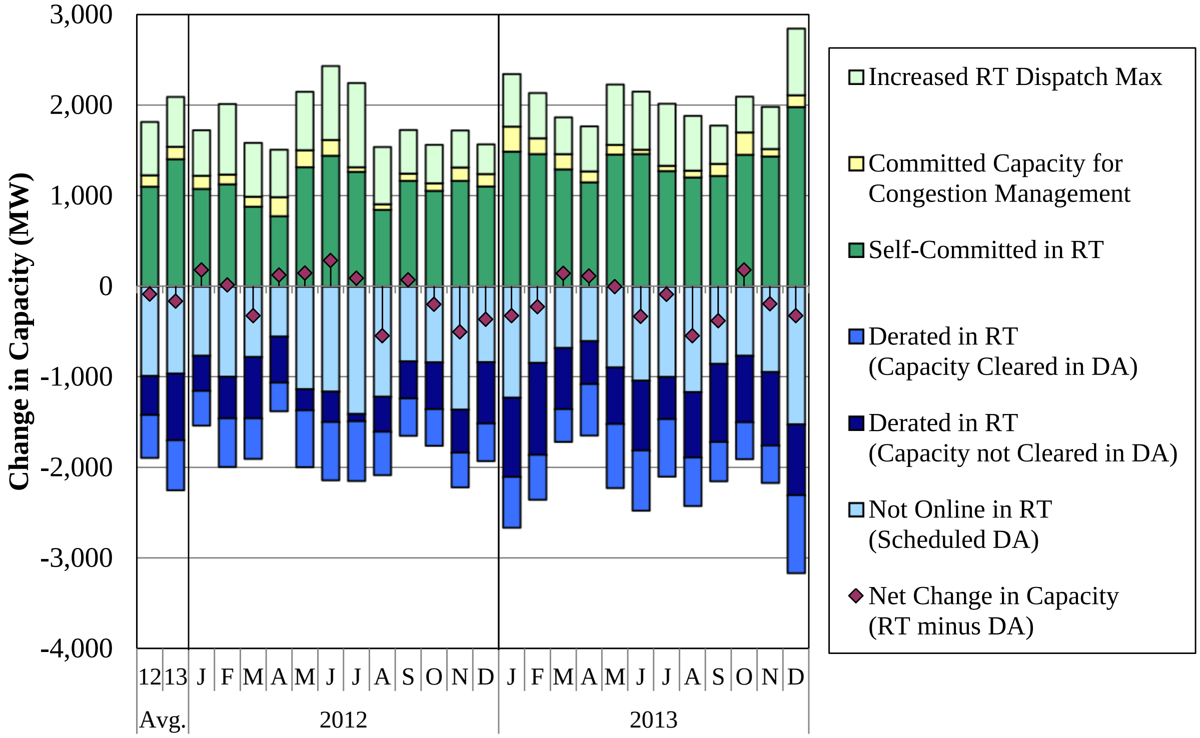
The flexibility of generation available to the real-time market provides MISO the ability to manage transmission congestion and satisfy energy and operating reserve obligations. In general, the day-ahead market coordinates the commitment of most generation that is online and available for real-time dispatch. 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 A42: Changes in Supply, Day-Ahead Market to Real-Time Market

Figure A42 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 A42: Changes in Supply, Day-Ahead Market to Real-Time Market
2012–2013



Key Observations: Generation Availability and Flexibility in Real Time

i. On average, 2.25 GW (3.7 percent) of capacity scheduled in the day-ahead market was unavailable in real time, a modest rise from the 1.9 GW (3.1 percent) recorded last year.

– Participants that decide not to start their units in real time due to unfavorable economics remain financially responsible for their day-ahead scheduled output.

ii. This lost capability was offset by 547 MW of capacity increases from suppliers increasing their dispatch maximum in real time and over 1.5 GW of self-scheduled or MISO-committed resources.

– Changes in commits by suppliers in real time can add or subtract significant amounts of available real-time capacity as suppliers self-commit (units not committed in the day-ahead market), or decommit (units committed in the day-ahead market) based on their forecast of real-time prices.

– Most of MISO's dispatch flexibility continues to be provided by steam units. However, steam units provide similar flexibility to most other types of resources (i.e., dispatch ranges from 30 to 45 percent of their economic maximums).

– The continued expansion of the DIR type by wind resources has increased MISO's dispatch flexibility.

- ✓ While DIR flexibility helps to manage congestion, its benefits for ramp management are limited to periods with sharp decreases in load or low absolute load levels such as Minimum Generation Events.

F. 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.[14] In 2013, resources committed after the day-ahead market received most of the RSG payments in MISO. 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) a local reliability need to manage congestion or maintain the system's voltage in a location. Beginning in the fall of 2012, MISO began making many voltage and local reliability commitments in the day-ahead market. Nonetheless, the majority of RSG costs associated with reliability commitments remain in real time.

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.

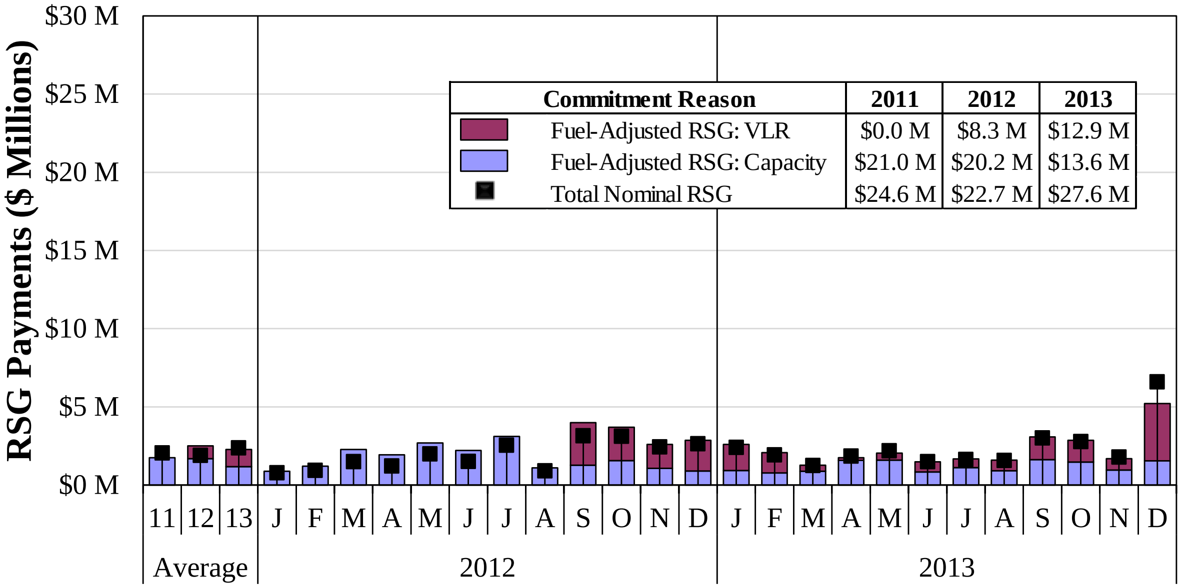
Figure A43 and Figure A44: RSG Payment Distribution

Figure A43 shows total day-ahead RSG payments. The results are adjusted for changes in fuel prices, although nominal payments are indicated separately. The table below the figures indicates the share of payments made to peaking and non-peaking units. Figure A44 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.[15]

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

15 We examine market power issues related to commitments for voltage support in Section VII.

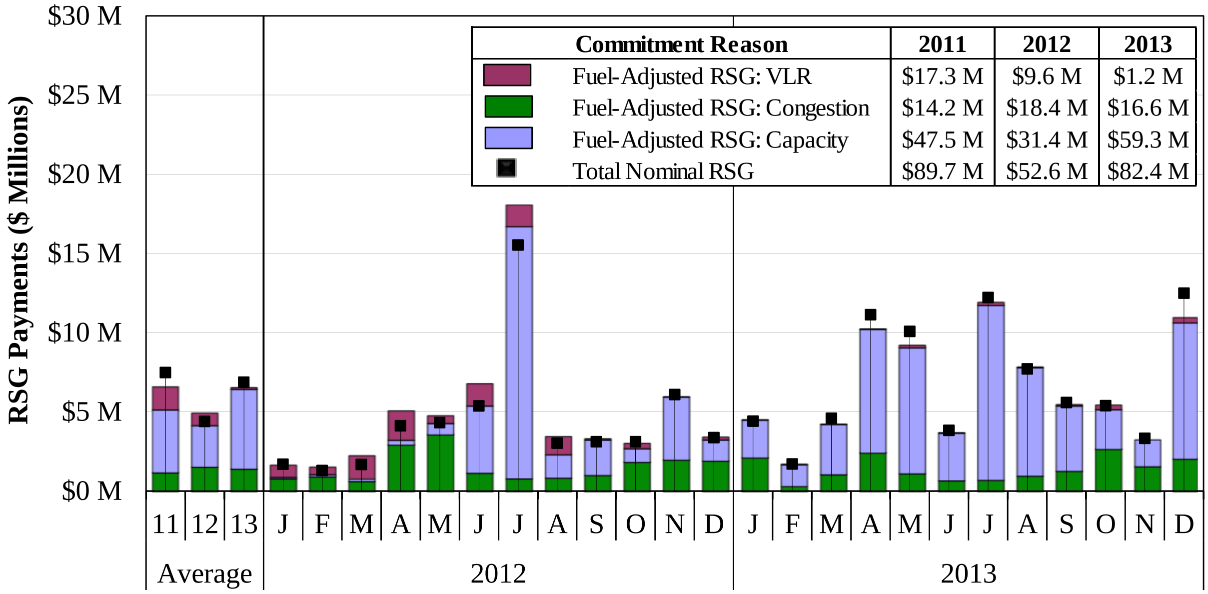
Figure A43: Total Day-Ahead RSG Payments
Fuel Adjusted, 2012–2013



Share of Day-Ahead RSG Costs by Unit Type (%)

Peaker	14	13	7	2	1	2	9	21	14	60	35	8	1	2	6	1	0	1	10	6	6	9	17	9	10	4	3
Non-Peaker	86	87	93	98	99	98	91	79	86	40	65	92	99	98	94	99	100	99	90	94	94	91	83	91	90	96	97

Figure A44: Total Real-Time RSG Payments
Fuel Adjusted, 2012–2013



Share of Real-Time RSG Costs by Unit Type (%)

Peaker	60	68	76	29	31	27	43	73	65	82	42	68	71	74	76	82	56	75	81	76	74	85	81	73	50	63	80
Non-Peaker	40	32	24	71	69	73	57	27	35	18	58	32	29	26	24	18	44	25	19	24	26	15	19	27	50	37	20

The RSG process was substantively revised in April 2011 in an attempt 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").[16]

Figure A45: Allocation of RSG Charges

Figure A45 summarizes, in the top panel, how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each week of 2013. The bottom panel shows daily average total net deviations from the day-ahead, for each week in 2013, as well as the total deviations that are paying the DDC charge. Since the CMC allocations are inappropriately limited based on the GSF of the committed unit, a significant portion of RSG costs that should be allocated to CMC deviations are passed on to the DDC charge. We have recommended that MISO eliminate the GSF factor from the numerator of the CMC allocation formula. In August 2013 MISO filed tariff modifications with the FERC to implement this and other IMM recommendations to modify the allocation formulae to bring them more in line with cost-causation principles. After a technical conference, these recommendations were approved by FERC effective March 17, 2014.[17]

16 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.

17 Midcontinent Indep. Sys. Operator, Inc., 146 FERC ¶ 61,165 (2014) (March 7 Order), in Docket No. ER13-2124-000.

Figure A45: Allocation of RSG Charges
By Week, 2013

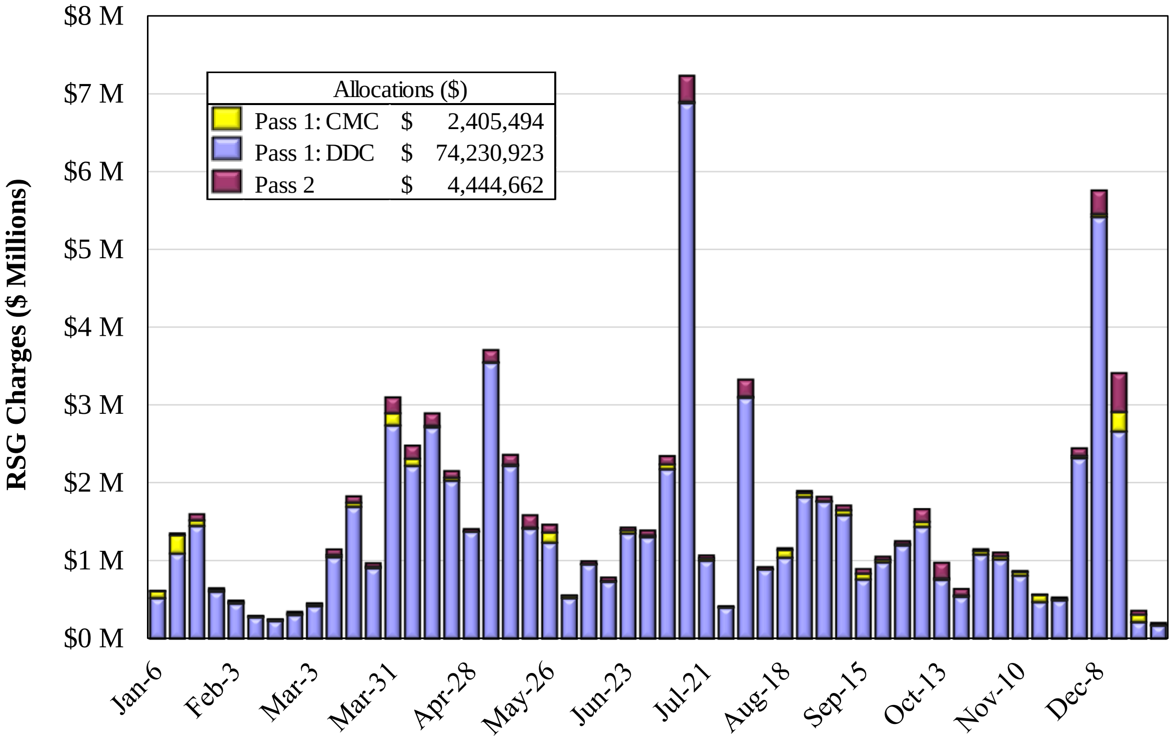
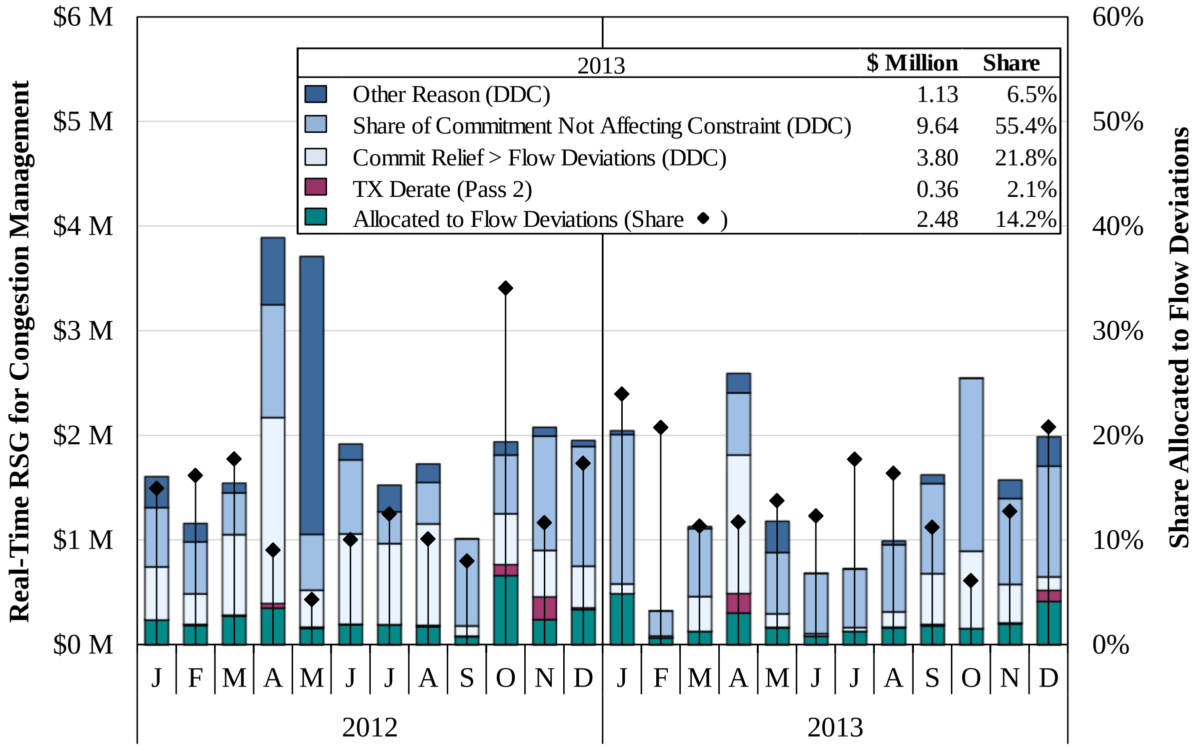


Figure A46: Allocation of Constraint-Related RSG Costs

Figure A46 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 allocates 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. As noted, this was changed per our recommendation in mid-March 2014. 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 A46: Allocation of Constraint-Related RSG Costs
2012–2013



Key Observations: RSG Payments

i. Real-time RSG payments rose 55 percent from 2012 to 2013 to $82.4 million.

- Nearly half of this increase is due to the significant rise in fuel prices. Adjusted for fuel price increases, real-time RSG payments rose 30 percent compared to 2012.

- Real-time capacity needs in shoulder seasons were greater than in 2012 because of lower load scheduling.

  ✓ In the spring, peak-hour load scheduling of just over 98 percent resulted in real-time RSG payments of over $18 million to units committed for capacity.

- Nominal payments were greatest in December, when the various effects of extremely cold temperatures (e.g., increased demand, fuel supply issues) required substantial commitments in the first half of the month.

ii. Real-time payments for capacity needs rose fastest, and made up three-quarters of the total.

- Lower load scheduling in the first half of the year compared to 2012 (when load was over-scheduled), resulted in MISO committing a larger number of RSG-eligible units in the real-time, particularly in April.

iii. Commitments for voltage and local reliability (VLR) support, which used to be made in real time, were mostly shifted to the day-ahead market in September 2012.

- Day-ahead VLR payments rose to nearly $13 million, and were greatest in December because of significant local needs in the newly-integrated South Region.

- VLR commitments are subject to tighter mitigation measures because a supplier facing little or no competition to resolve local reliability issues has the ability to extract substantial market-power rents.

iv. Payments for commitments made to resolve congestion declined 10 percent to a fuel-adjusted $16.6 million.

- Many of the most substantial payments for congestion were related to outages, particularly in October, when much of the $2.3 million in payments went to expensive oil-fired units.

v. Our analysis indicates that the prevailing allocation of real-time RSG costs in 2013 remained inconsistent with principles of cost-causation because:

- Costs associated with managing congestion were allocated under the DDC rate when the current methodology did not allocate those costs to the CMC rate.

- The share of the costs allocated under the CMC rate could not exceed the GSF of the resource committed for the constraint.

  - ✓ This component of the allocation failed to recognize that the constraint in most cases caused all of the costs, regardless of the magnitude of the GSF.

  - ✓ This inappropriately reduced CMC charges and correspondingly increased DDC charges by $15 million in 2013.

vi. The lack of market-wide netting and other rules related to the calculation of deviations to allocate RSG costs also contributed to the over-allocation of costs to deviations.

- Negative net deviations, if calculated in a manner consistent with cost causation, should reduce the need for MISO to commit resources for capacity, and therefore would not contribute to any real-time RSG costs.

vii. Changes filed by MISO in 2013 to address these flaws were largely approved and implemented in mid-March 2014. However, FERC has required a change in MISO market-wide netting proposal that is not sound.

G. Price Volatility Make-Whole Payments

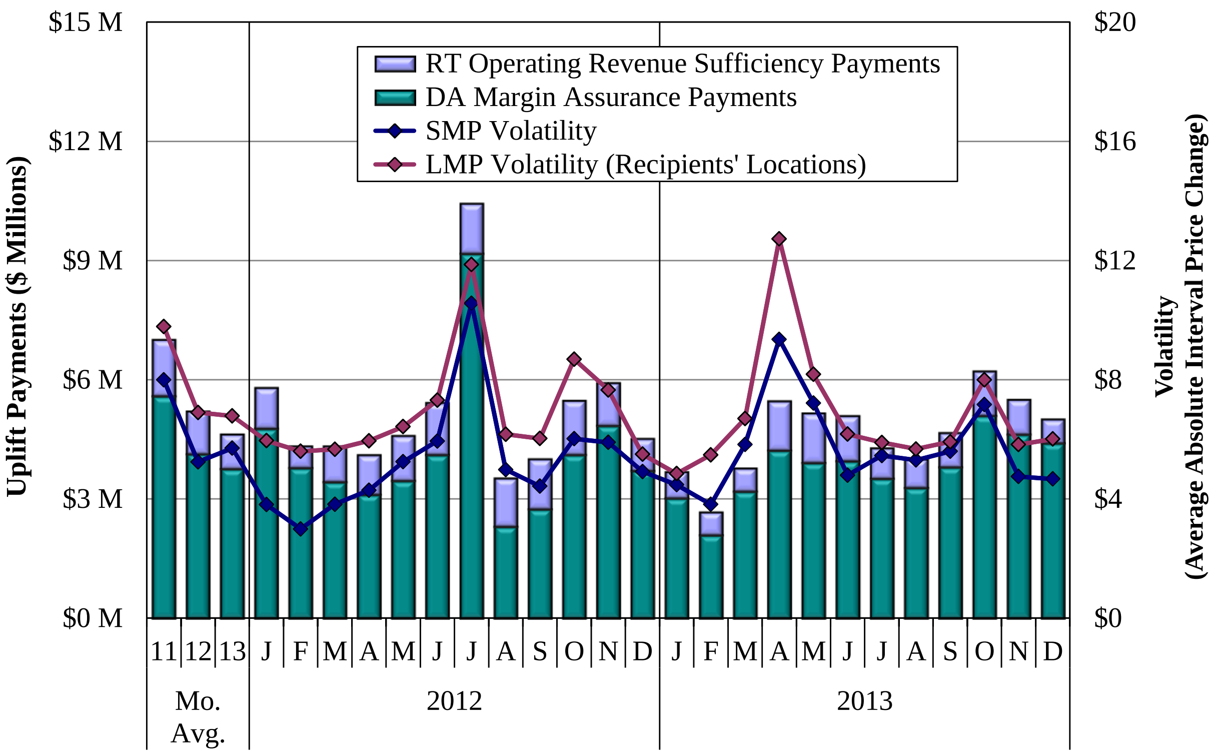
MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers responding to MISO's prices and following its dispatch signals in real time are not 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 its incremental energy costs when dispatched to a level above its day-ahead schedule. Opportunity costs for avoided revenues are not included in the payment.

Figure A47: Price Volatility Make-Whole Payments

Figure A47 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 A47: Price Volatility Make-Whole Payments
2012–2013



Key Observations: Price Volatility Make-Whole Payments

i. Total PVMWP declined 10 percent to $55.5 million in 2013, consistent with the modest declines in SMP and LMP volatility.

- Volatility was greatest in April due to significant spinning and operating reserve shortages, although payments peaked in October.

- Payments rose substantially after the integration of the MISO South Region.

- DAMAP, which declined 9 percent in 2013 to $45.1 million, continued to be paid predominantly to flexible coal units during ramping hours. RTORSGP declined 19 percent to $10.4 million.

ii. In 2012 and 2013, the IMM made a number of referrals to FERC regarding resources that were inappropriately paid DAMAP for energy that was scheduled in the day-ahead but was unavailable in real time.

- These resources remained eligible in real time in part because they did not update their real-time offers to reflect derated capacity.

- In addition, MISO PVMWP eligibility rules generally do not identify when resources are "dragging" and not following base point instructions.

iii. IMM screening of operational and market data has identified significant quantities of unit derates that went unreported by market participants to MISO, which resulted in significant quantities of inappropriate DAMAP payments and avoided RSG allocations.

- The quantity of unreported derates declined in 2013 after the IMM identified this concern.

- MISO also held a number of stakeholder discussions with participants on the expectations and procedures for updating offers in real time to reflect derates and other operating issues.

iv. In 2012, the IMM recommended several changes to the DAMAP eligibility rules and MISO operating procedures.

- MISO has agreed with these recommendations and will be implementing new operating procedures beginning in the spring of 2014 with additional improvements in the spring of 2015.

- In addition, MISO filed on October 16, 2013 changes in eligibility rules to address potential gaming issues related to the PVMWPs. FERC approved these changes effective immediately.

H. 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 remove 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 A48: 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 2013. 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 in the downward direction; 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 A48: Net Energy Value of Five-Minute Settlement
2013

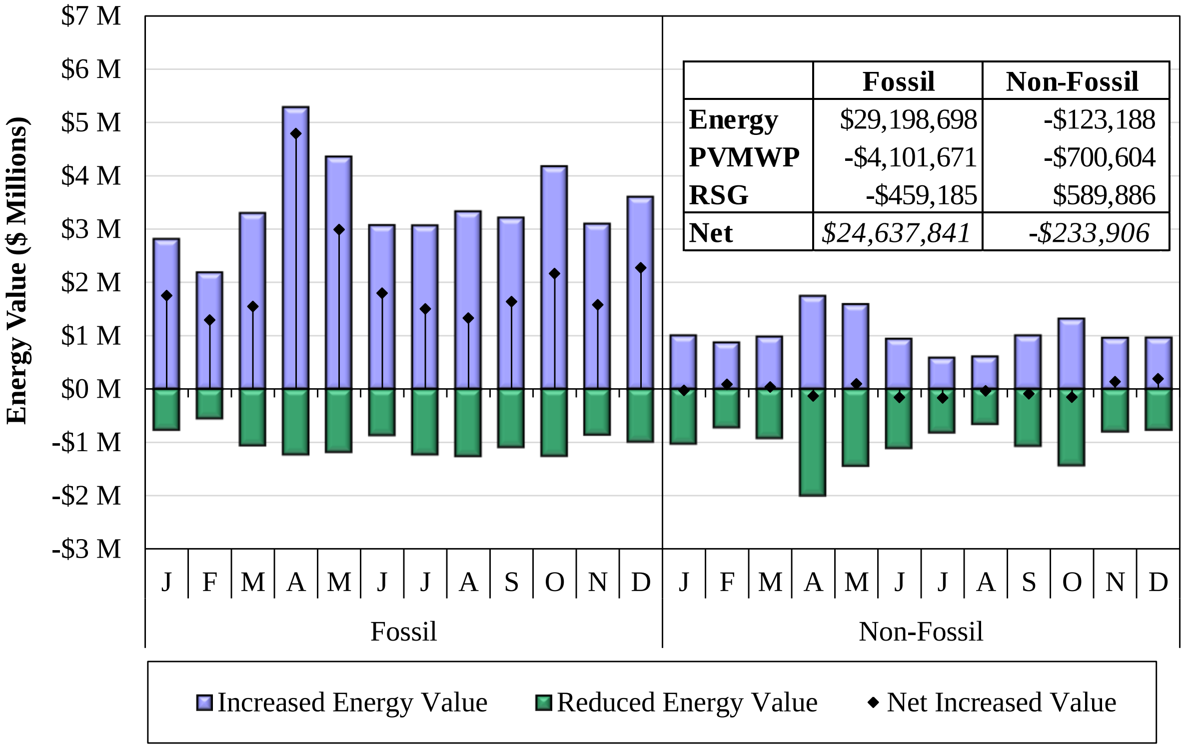
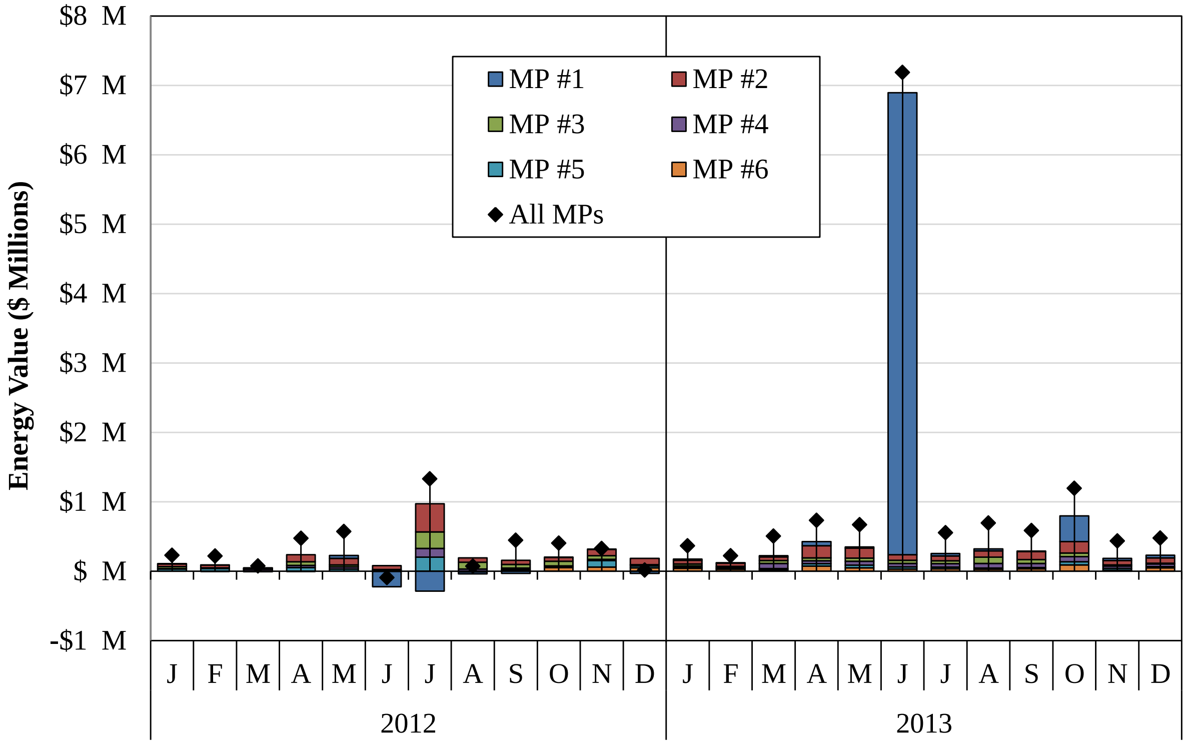


Figure A49: Net Energy Value of Physical Schedules Settlement

The figure below shows a similar analysis for physical scheduling. As noted above, these transactions may be scheduled to start and stop every fifteen minutes (thirty minutes in advance) 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 A49: Net Energy Value of Physical Schedules Settlement
2013



<u>Key Observations: Five-Minute Settlement</u>

i. In 2013, fossil-fueled resources produced $24.4 million more in actual energy value than was reflected in their real-time energy revenues.

- The additional energy value was fairly uniform across the year.
- The underpayment of fossil resources peaked in April at over $5 million when units responded quickly to price spikes produced by shortages.
- Some of this underpayment for energy (about $4 million, or 14 percent) not paid to these resources was paid as PVMWP.
- Combustion turbines were underpaid by $3.5 million, or $0.42 per MWh, on average while combined-cycle units were underpaid by $6.4 million, or $0.25 per MWh.

ii. For the same period, non-fossil fueled resources were paid nearly the same in energy revenues with hourly settlement as they would have with their actual five-minute energy value.

- This is a considerable reduction from the overpayment in 2012, when they were overpaid nearly $5 million.
- These resources were also paid an additional $700,000 in PVMWP.

– Wind resources were overpaid by $1.4 million.

iii. In contrast to generation, which was consistently undervalued in aggregate, physical schedules are consistently overvalued.

– In 2013, physical schedules in aggregate were overvalued under the current hourly settlement by nearly $13.6 million, up from $4 million in 2012.

✓ Most of this, including nearly $8 million on the afternoon of June 20, accrued to one participant whose schedules on several days were vastly overvalued because of TLR-5 events.

– Excluding this and a similar discrepancy in October, twice as many schedules were overvalued than undervalued in each month in 2013.

✓ Overvalued schedules averaged a cumulative $1.1 million, while undervalued schedules averaged $550,000.

– To improve the incentives of suppliers and physical schedulers, we continue to recommend that MISO move to a five-minute settlement.

– MISO has indicated a willingness to implement this change to comply with FERC Order 764, which among other things requires fifteen-minute transmission scheduling capability.

I. 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.

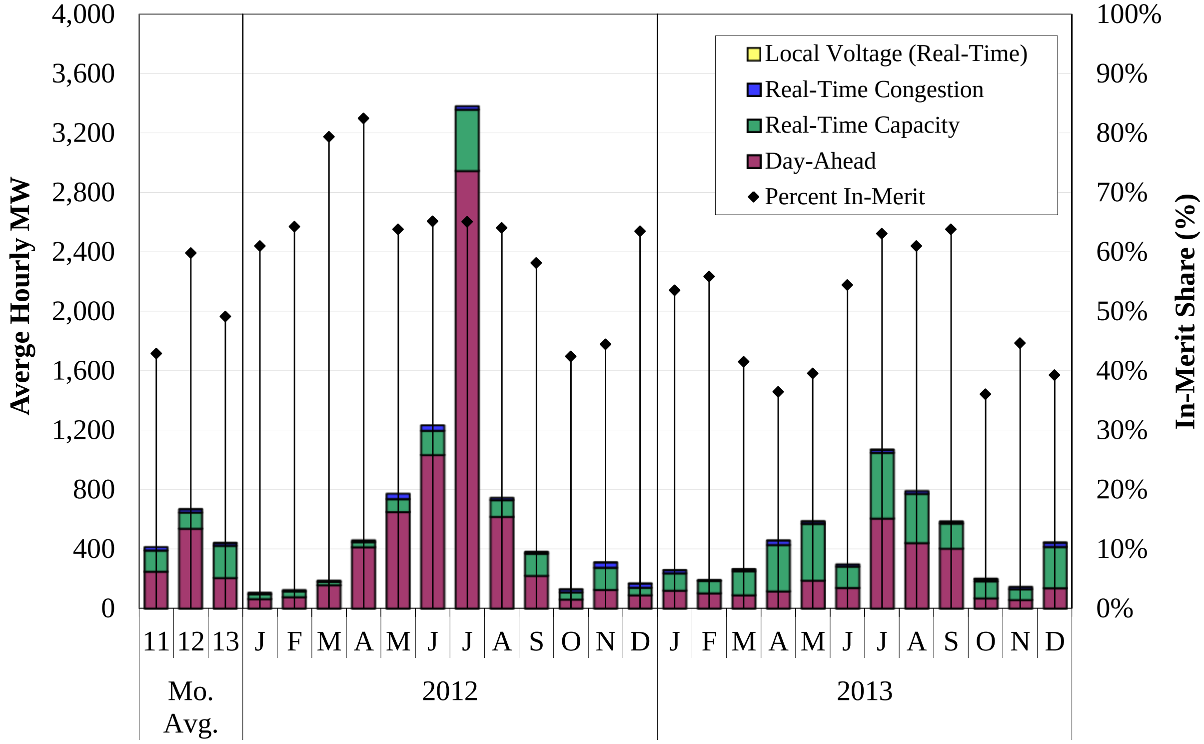
While low commitment costs make peaking resources attractive for meeting capacity needs, they generally have high incremental energy costs and frequently do not set the energy price because they are often dispatched at their economic minimum level (causing them to run "out-of-merit" order with an offer 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 A50: Average Daily Peaking Unit Dispatch and Prices

Figure A50 shows average daily dispatch levels of peaking units in 2013 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 (LMP exceeds its offer price).

Figure A50: Dispatch of Peaking Resources
By Commitment Reason, 2012–2013



Key Observations: Dispatch of Peaking Resources

i. The average hourly dispatch quantities of peaking resources declined 34 percent in 2013 to 443 MW in 2012.

– Fewer periods of extreme heat reduced peaking needs by nearly 70 percent in July 2013 compared to July 2012.

– The decline in 2013 was mostly of peaking resources committed day-ahead, which fell 62 percent to 139 MW on average.

– Real-time capacity commitments doubled to 277 MW because of less than full load scheduling.

ii. The in-merit share averaged 49 percent in 2013, a decline from 60 percent last year.

- Higher gas prices in 2013 and lower peak loads resulted in fewer peaking units being committed economically in the day-ahead market.

- This indicates that peaking units frequently do not set energy prices.

- MISO's continuing efforts to implement a new "Extended LMP", expected in October 2014, will allow quick-start peaking resources to set prices more often when they are needed to satisfy the system's energy and ASM requirements. This will improve MISO's real-time and day-ahead energy pricing, and reduce RSG payments.

J. 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, and most wind units that were required to convert did so by the April 2013 deadline.[18] DIRs are wind resources that are physically capable of responding to dispatch instructions (from 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 of MISO's wind capacity—115 of 176 units—is currently capable of responding to dispatch instructions.

Intermittent resources 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] In real time, some wind resources are unable to become DIR and remain limited in their ability to be dispatched by the real-time market. As a result, the real-time market software does not control the production of a share of these resources. 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 curtailments when necessary to ensure reliability.

Figure A51: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A51 shows a seven-day moving average of wind scheduled in the day-ahead market and dispatched in the real-time market since 2012. Under-scheduling of output in the day-ahead

18 Wind resources placed in service prior to April 2005 are exempt from this requirement.

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 2014–2015 Planning Year, this credit averages 14.1 percent, comparable to prior years. Excluding several resources that received no credit, individual credits range from 5 to 25 percent.

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

Figure A51: Day-Ahead Scheduling Versus Real-Time Wind Generation
2012–2013

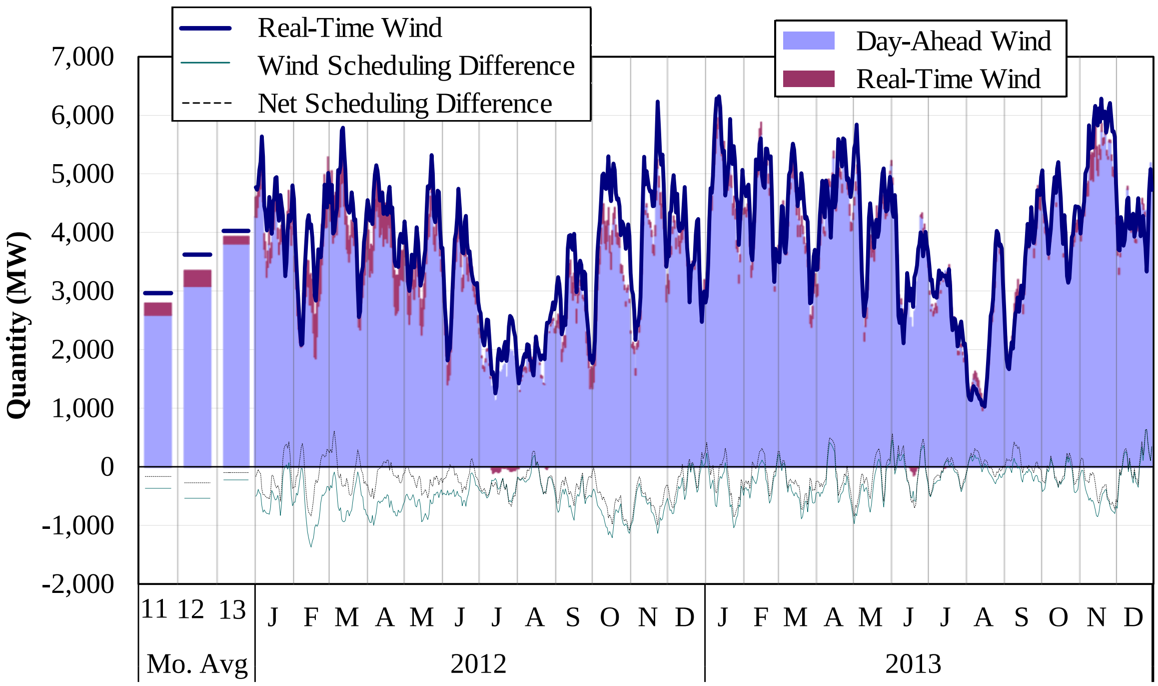


Figure A52: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

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 A52 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 A52: Seasonal Wind Generation Capacity Factors by Load Hour Percentile
2013

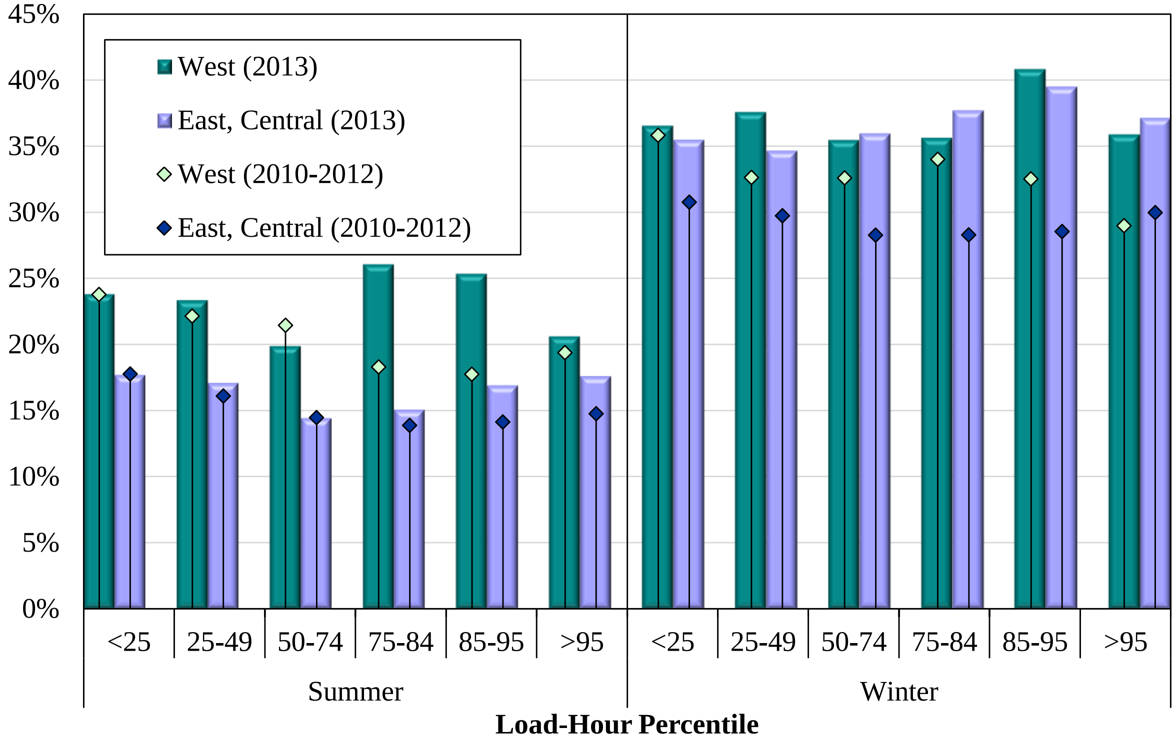


Figure A53: Wind Curtailments by MISO

Since much of the wind capacity is located in the West 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 A53 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 A53: Wind Curtailments
2012–2013

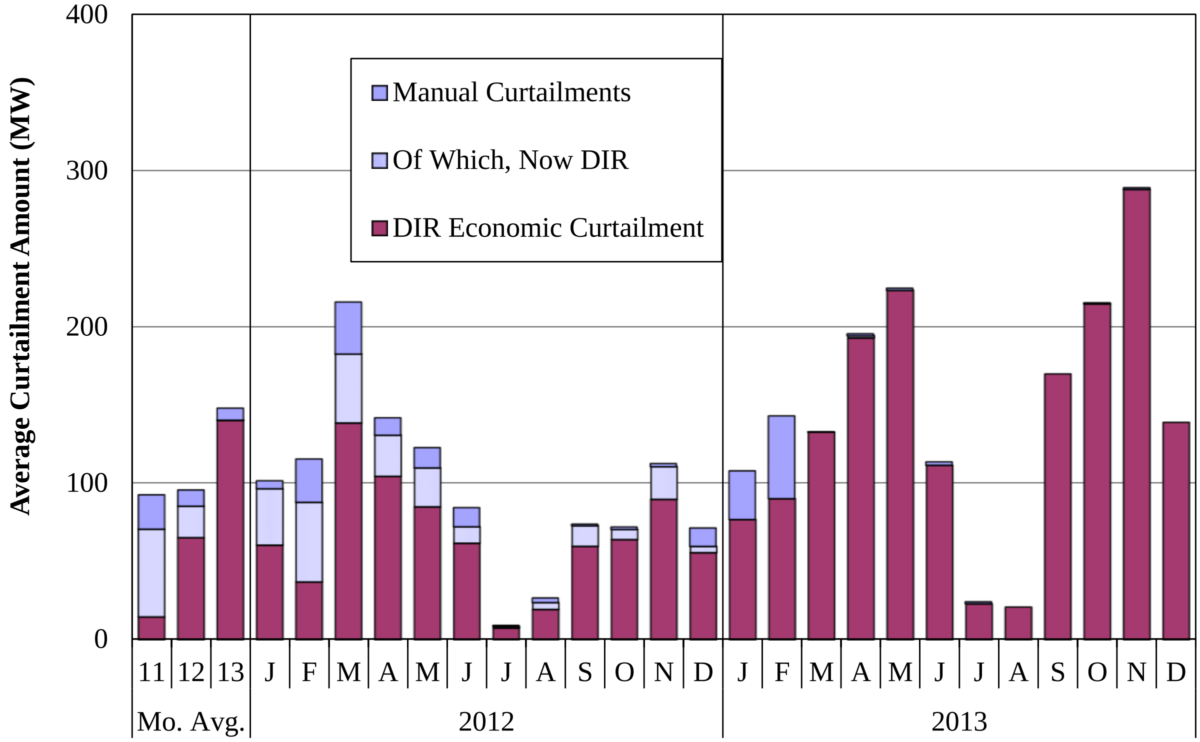


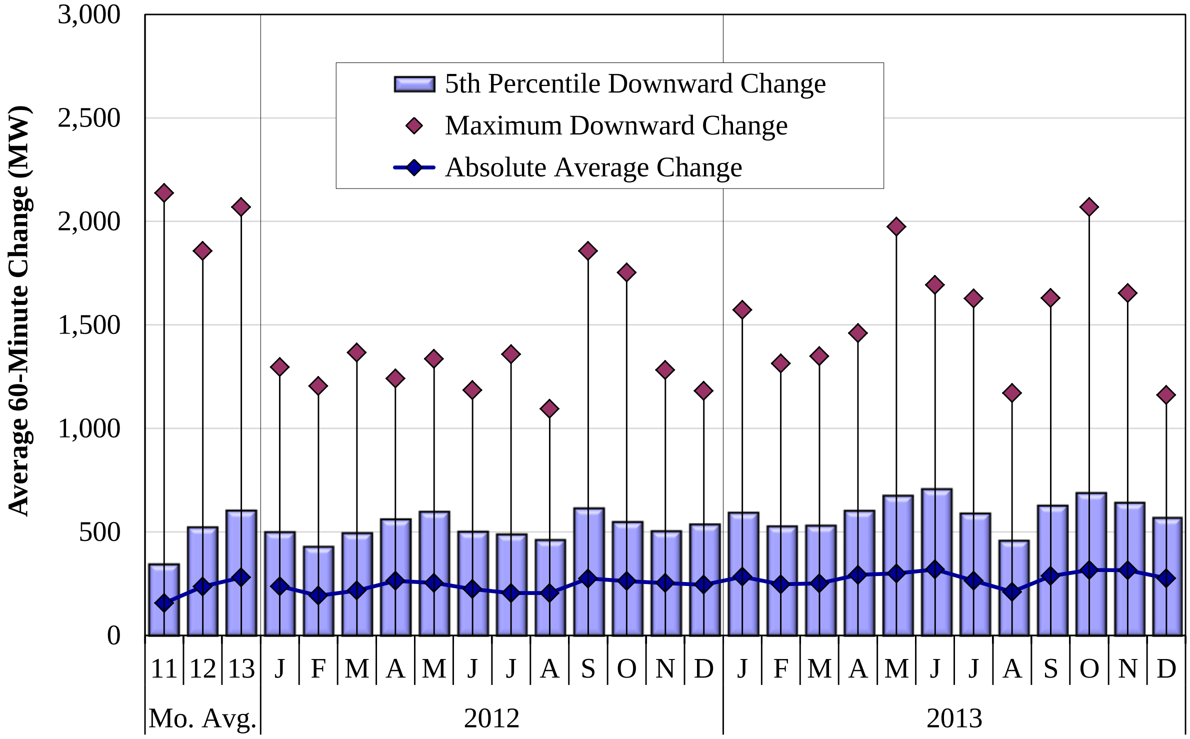
Figure A54: Wind Generation Volatility

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 A54 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 A54: Wind Generation Volatility
2012–2013



Key Observations: Wind Generation

i. Real-time wind generation in MISO in 2013 increased 11 percent to an average of 4,028 MW per hour, which accounted for 7 percent of total generation for the year.

– As of December, wind resources accounted for 9 percent of installed capacity (over 12 GW), a 5 percent increase from 2012, although the integration of MISO South, which has no wind capacity, has reduced this share to 7 percent.

– This growth trend is expected to continue because of the wind capability in western areas of MISO, state mandates, and various subsidies and tax incentives.

✓ Most units placed into service in 2013 received production tax credits that provide an incentive to wind resources to produce energy as low as -$35 per MWh.[20] This exacerbates congestion affected by wind output.

✓ Investment tax credits were also available in 2013 and only required the beginning of production on a new wind resource. Hence, continued increases in wind capacity are likely in the next several years.

20 Since the PTC is an after-tax credit, its pre-tax equivalent (assuming a tax rate of 35 percent) is: $23 / (1 – tax rate) = $35.

✓ Both have expired, however, and there is substantial uncertainty as to whether they will be renewed for future years.

ii. Wind scheduling in the day-ahead improved considerably in 2013. It was under-scheduled in the day-ahead by just 221 MW, and net virtual supply made up more than half of the deficit.

iii. Wind capacity factors were highest in the West region, where the resource potential is greatest.

iv. Wind output is substantially lower during summer months than during shoulder months, particularly during the highest load hours, which reduces its value from a reliability perspective.

– The capacity factor of wind resources continues to be inversely correlated with load, as expected because wind tends to be strongest in shoulder seasons and at night.

– For this reason, wind resources receive capacity credits toward satisfying Module E requirements that are only a fraction of their installed capacity.

– The capacity credit value is determined separately for each wind unit and is based on its output during prior peak demand days over the past several years.

v. The continued adoption of DIR has greatly improved MISO's ability to manage wind output and price it efficiently.

– Nearly 80 percent of all wind units were dispatchable under the DIR program for most of 2013. They set price in over half of all intervals, although typically in narrow areas, and did so at an average as-offered cost of -$11 per MWh.

– This added flexibility has nearly eliminated the amount of manual wind curtailments made by MISO. In 2013, manual wind curtailments averaged just 8 MW per interval, a fraction of what was curtailed prior to the DIR adoption.

– Economic curtailments rose to 140 MW and at times exceeded 1 GW per interval.

vi. In 2013, 60-minute wind volatility (excluding economic DIR curtailments) rose 19 percent to an average hour-to-hour change of 280 MW.

– Five percent of the time, the average hour-to-hour decline in wind output exceeded 600 MW, and in October declined by nearly 2.1 GW in one 60-minute period.

– MISO is working to develop changes in procedures and evaluate market design changes that may be beneficial for managing the changes in wind output.

K. Inferred Derates

MISO's current set of tools used to monitor the performance of units in real time are not designed to identify units that may be chronically not responding to dispatch signals over multiple intervals. The current system focuses on single interval results and is designed to support control area criteria, such as ACE. Consequently, a unit that may be effectively derated by large amounts and unable to follow dispatch may not be identified by MISO's current tools and procedures. Resources are required to update their real-time offer parameters and report derates under MISO's Tariff.[21] In 2012 we 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.

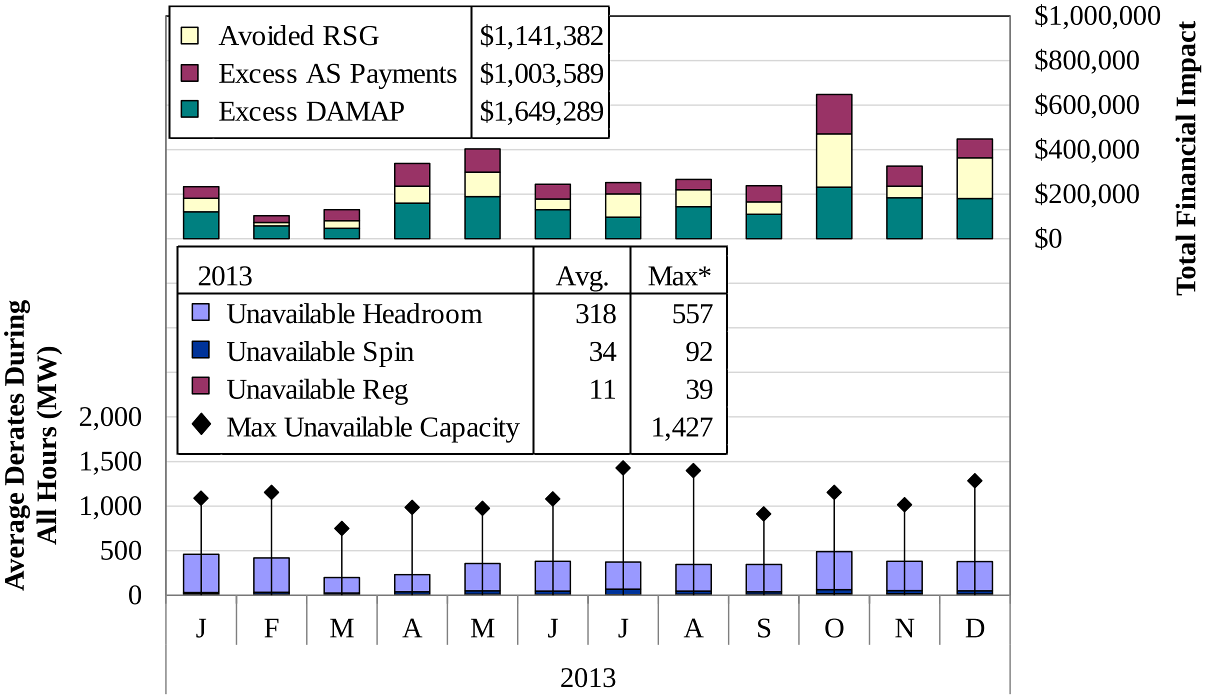
Figure A55: Unreported ("Inferred") Derates

Figure A55 summarizes our review of instances in 2013 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.

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 A55: Unreported ("Inferred") Derates
2013

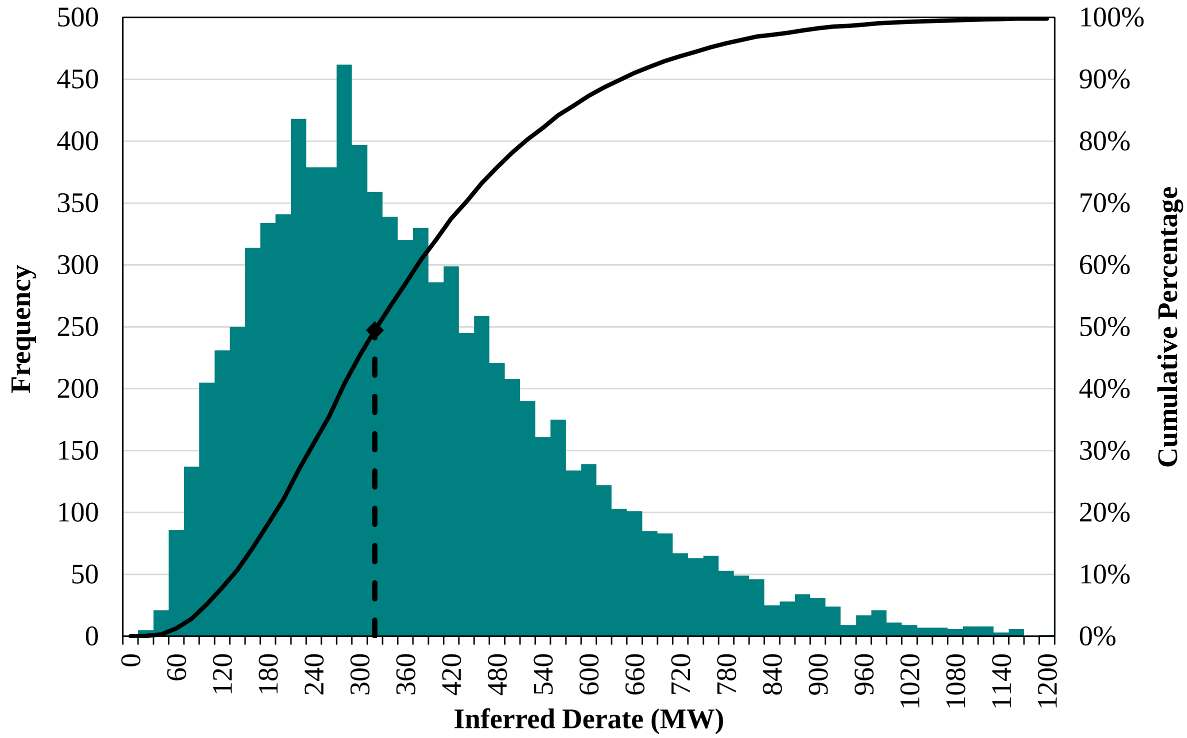


* Daily Average Maximum

Figure A56: Distribution of Unreported ("Inferred") Derates

Figure A56 shows a histogram of cumulative inferred derate quantities in each hour in 2013. 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.

Figure A56: Distribution of Unreported ("Inferred") Derates
2013



<u>Key Observations: Inferred Derates</u>

i. Cumulative derated quantities averaged 361 MW, and caused MISO to be short of its rampable spinning reserve requirement in 130 hours, or 1.5 percent of all hours.

- These quantities peaked at over 1,400 MW in one hour on July 9.

ii. In 2013, resources were operating below their day-ahead schedules due to unreported (or "inferred") derates:

- Were paid nearly $1.7 million in DAMAP;
- Avoided $1.1 million in RSG; and
- Were paid over $1 million for scheduled ancillary services that they likely could not have provided if deployed.

iii. In our 2012 *State of the Market Report*, we made a number of recommendations to address this issue, including:

- MISO improving its screening and reporting of these types of derates, as well as its operating procedures for designating a resource off-control or derated; and

– Tightening the tolerances for uninstructed generator deviations, which would make it more difficult for resources to fail to follow MISO's dispatch instructions without (a) incurring deviation penalties, (b) being placed off dispatch, (c) losing eligibility for DAMAP payments, and (d) charged RSG costs. This is discussed more fully in the next subsection.

iv. MISO has agreed to these recommendations and will begin implementing new procedures in real time beginning spring 2014.

L. 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 vast majority of deviation quantities from significant settlement penalties.

Figure A57 and Figure A58: Frequency of Net Generator Deviations

Figure A57 shows a histogram of MISO-wide interval deviations during peak hours in summer months *without* applying any deviation tolerance rules. Figure A58 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.

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.

Figure A57: Frequency of Net Deviations
Peak Summer Hours, 2013

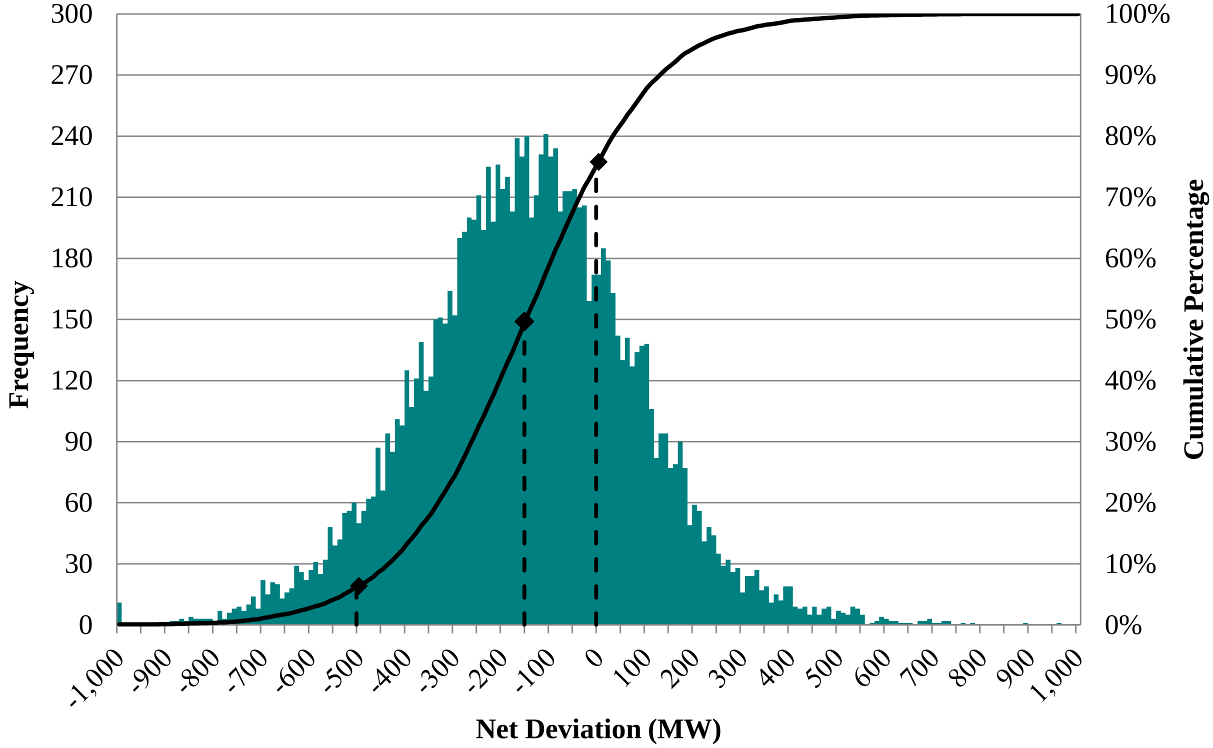
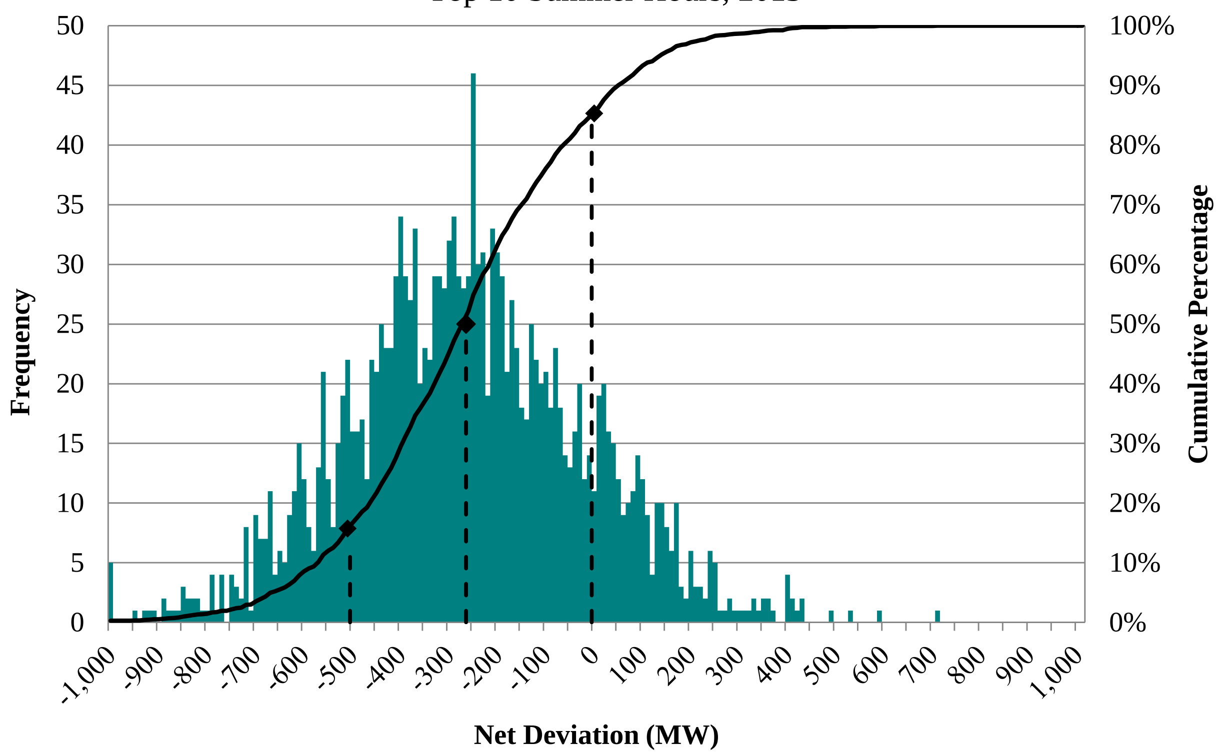


Figure A58: Frequency of Net Deviations
Top 10 Summer Hours, 2013



In our *2012 State of the Market Report*, we recommended that MISO tighten the tolerance bands for uninstructed deviations (Deficient and Excessive Energy). In this report, we recommend a specific approach for establishing the tolerance bands 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:

- 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.

The 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 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 A59: Average Deviations by Interval

Figure A59 shows interval average gross deviations (both excessive and deficient) and net deviations by interval of the hour. This figure shows the deviations using MISO's current deviation tolerance rules as well as under the proposed rules.

Figure A59: Average Deviations by Interval
2013

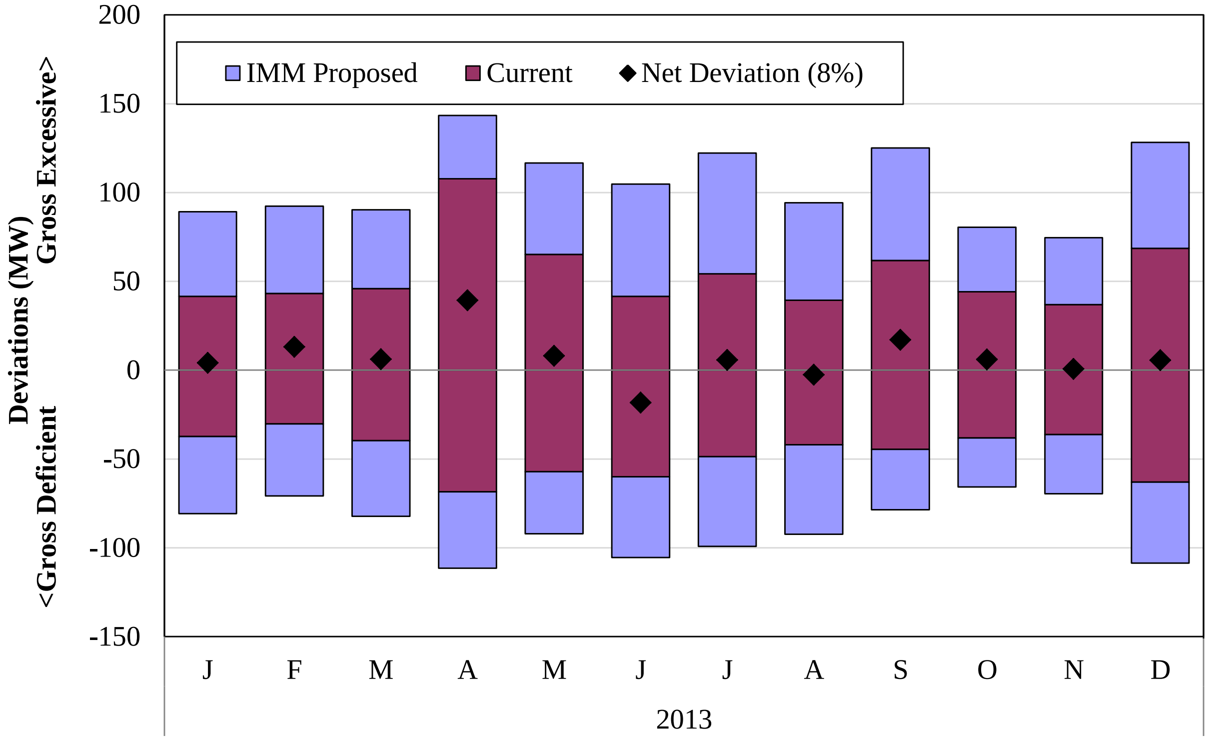
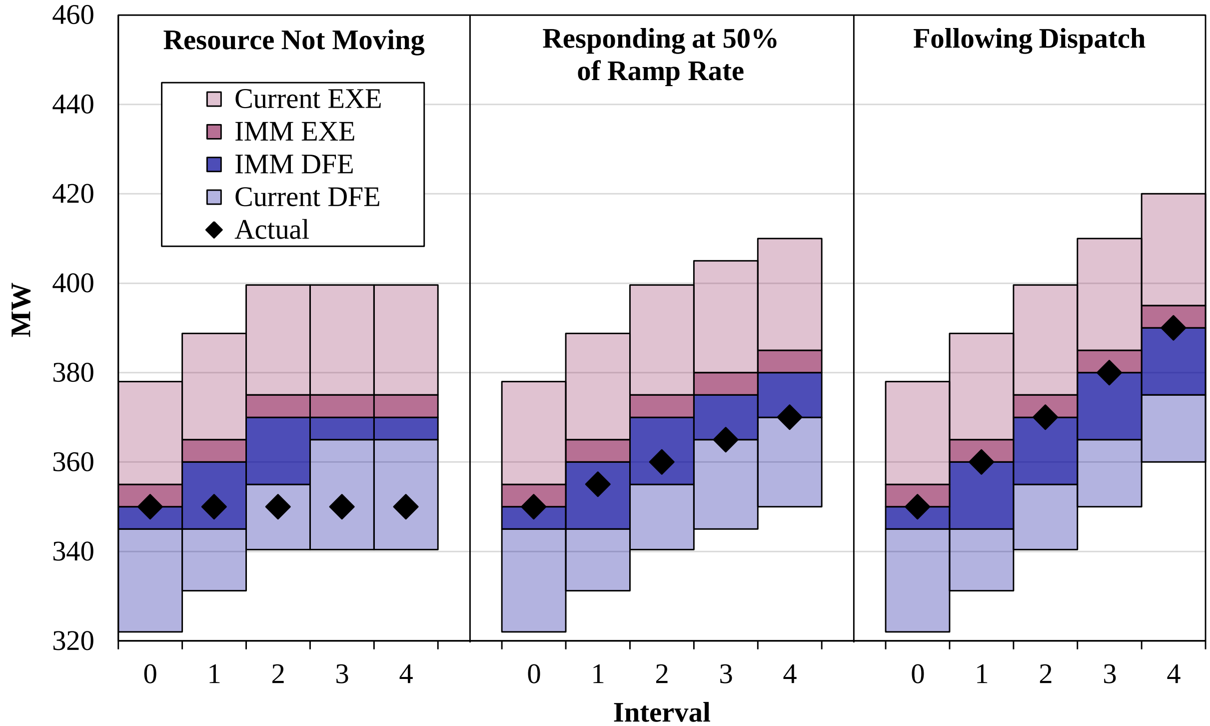


Figure 60: Proposed Generator Deviation Methodologies

Figure 60 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 60: Proposed Generator Deviation Methodologies



Key Observations: Generator Deviations

i. The average gross negative deviation (before applying any tolerance tests) in 2013 was 545 MW, while gross positive deviations averaged 502 MW.

– Gross positive deviations were greatest during ramping hours and in hour beginning 0 (when units get new day-ahead schedules), and lowest during the middle of the afternoon.

✓ This is expected because units are moving most often in these hours to accommodate changes in demand or generation commitments.

✓ Gross negative deviations were slightly larger during peak hours, when units are more likely to be dispatched above their minimum output.

✓ Under the current rules, a unit that is deviating beyond the eight percent threshold for only the six consecutive intervals that span across the hour (i.e., intervals 45, 50, 55, 0, 5 and 10) is not considered to be producing excessive or deficient energy.

ii. While net deviations are modest on the whole, they are greater when loads are highest.

– MISO was net deficient in over 75 percent of peak summer intervals, and by more than 150 MW in one-half of those intervals.

- In 6.4 percent of peak summer intervals, MISO was net deficient by more than 500 MW. On the top 10 load days, this percentage exceeded 15 percent.

- Significant net negative deviations can contribute to shortage situations, particularly when supply conditions are tight.

iii. The results suggest that MISO should consider adopting tighter thresholds for excessive and deficient energy quantities to improve suppliers' adherence to dispatch instructions.

- Adopting the IMM-proposed deviation rules would nearly double the quantity of deviations considered excessive or deficient in 2013.

iv. Our case study shows that a representative 350-MW unit that is entirely unresponsive to dispatch instructions would still not be considered deviating under MISO's existing rules.

- Under the IMM-proposed revisions, such a unit would be producing deficient energy if it ramps up at less than 50 percent of its ramp rate or is unresponsive.

- When such a unit moves at its ramp rate, it will have a wider deficient energy tolerance threshold because the unit is moving upward.

V. Congestion and Financial Transmission Rights

MISO's energy markets are designed to serve load and meet reserve obligations with the lowest-cost resources, subject to the limitations of the transmission network. The locational market structure in MISO is designed to ensure that transmission capability is used efficiently and that energy prices reflect the marginal value of energy at each location. Congestion costs arise when transmission line flow limits prevent lower-cost generation on the unconstrained side of a transmission interface from replacing higher-cost generation on the constrained side of the interface. This results in diverging LMPs that reflect the value of transmission.[23] An efficiently designed system typically will have some congestion because transmission investment to alleviate congestion should only occur when the production cost savings from eliminating the congestion exceed the cost of investment.

When congestion arises, the price difference between two locations represents the marginal value of transmission capability between them. When the power transferred across the interface or constraint[24] between the locations reaches its limit, the cost of the resulting congestion is equal to the marginal value of relieving the constraint (the cost of controlling one MW of flow on the constraint) multiplied by the total flow over the constraint. MISO collects these congestion costs in the settlement process through the congestion component of the LMP. In a constrained location (where generation cannot be imported to replace higher-cost generation), the congestion component will be positive and increase the LMP, causing higher-cost generators to produce; conversely, in locations where additional generation contributes to *increased* flow on constraints, the congestion component will decrease the LMP, causing generators to lower production.[25]

In a congested location, load will generally exceed generation. Therefore, when the net load in the constrained location settles at the higher constrained location price and the net generation in the unconstrained location settles at the lower unconstrained price, MISO will receive more revenue from the load than it pays to the generators. The difference is the cost of congestion, or "congestion revenues". Locational prices that reflect congestion provide economic signals important for managing transmission network congestion in both the short run and long run. In the short run, these signals allow generation to be efficiently committed and dispatched to manage network flows; in the long run, they facilitate investment and retirement decisions that can significantly affect network congestion.

This section of the Appendix evaluates congestion costs, FTR market results, and congestion management.

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23 Transmission losses will still cause prices across the footprint to vary even absent any congestion.

24 Throughout this report the terms "interface" and "constraint" are used interchangeably and refer to transmission constraints in the market clearing software that limit transfers of power from generation to load based on the network configuration and status. These constraints (and transmission losses) account for all the locational price differences.

25 This signifies that power injected at that location is less valuable because it aggravates the constraint.

A. Total Day-Ahead and Real-Time Congestion Costs

Most congestion revenues are collected through the settlement of the day-ahead market because day-ahead schedules utilize the vast majority of the system's transmission capability. As described above, congestion revenues are collected because the prices at load locations affected by congestion will generally be higher than the prices at generator locations (because some of the generation is outside the constrained location and transmitted into the location over the constraint).

Real-time balancing congestion costs are settled based on real-time market results. In particular, real-time market settlements are based on deviations from the day-ahead market. Among other reasons, real-time balancing congestion can occur when transmission limits change from the day-ahead market model or when "loop flows" (flows across the MISO network created by generation and load on other systems) deviate from levels forecasted in the day-ahead market.

For example, suppose a transmission interface (or constraint) is fully scheduled in the day-ahead market. If in real time the limit is decreased (e.g., the interface is derated) or loop flows increase over the congested interface, MISO would incur real-time congestion costs to redispatch generation to achieve the required reduction in real-time interface flows. Absent these changes, no balancing congestion costs would be incurred.[26]

We distinguish between congestion *costs* or *revenues* collected by MISO via the congestion component of the LMP, and the *value* of real-time congestion of a particular constraint. The value of real-time congestion is the MW amount of flow on a constraint multiplied by the marginal value, or shadow price, of relieving one MW of flow.[27] The difference is important because MISO does not collect congestion costs for all actual flows over its system (e.g., loop flows incur no congestion costs). In addition, the Joint Operating Agreement between PJM and MISO entitles PJM to use a certain portion (its "Firm Flow Entitlement," or FFE) of transmission capability on market-to-market flowgates. Therefore, PJM only compensates MISO for congestion associated with power flows that exceed PJM's entitlement on a market-to-market constraint. For these reasons, congestion costs collected by MISO are often significantly less than the total value of real-time congestion on the MISO network.

Figure A61: Total Congestion Costs

Figure A61 shows total congestion costs incurred by month in the day-ahead and real-time markets since 2011.

26 In MISO, these costs are incurred as negative Excess Congestion Funds, or "ECF".

27 The marginal value (or shadow price) is the amount of production cost that would be saved if the limit of the constraint could be increased by 1 MW.

Figure A61: Total Congestion Costs
2011–2013

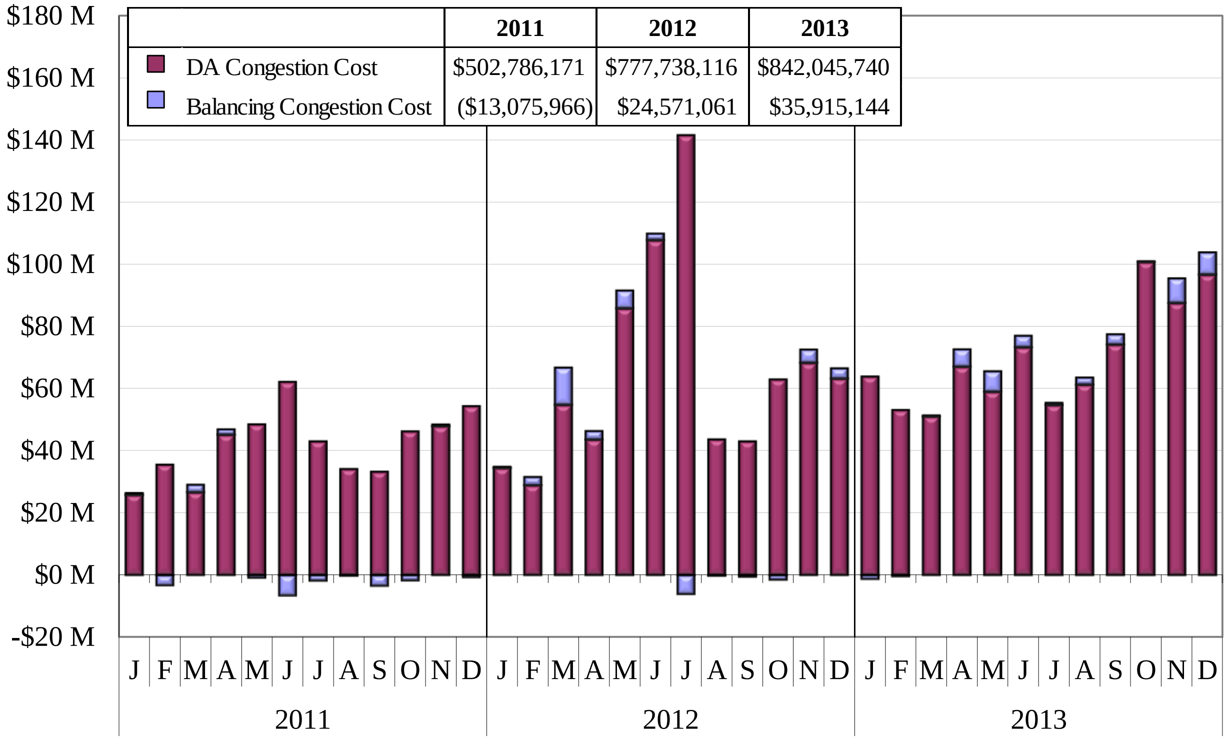
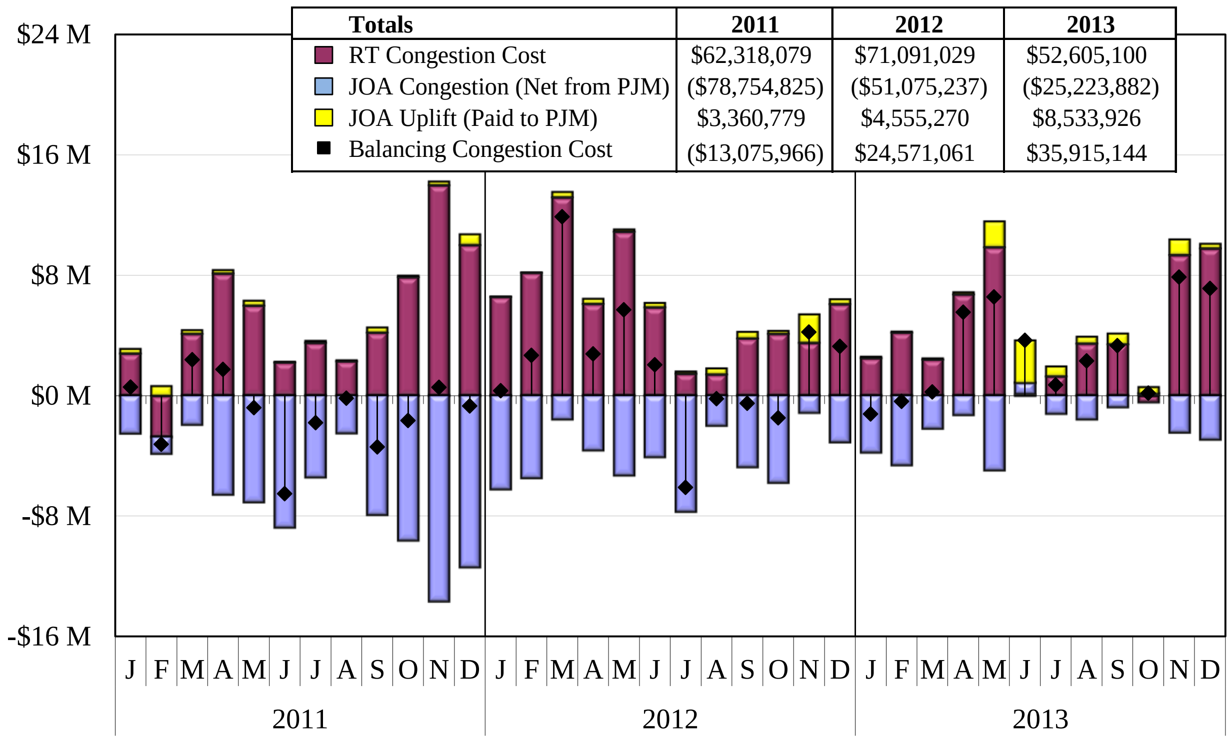


Figure A62: Balancing Congestion Costs

To better understand balancing congestion costs, Figure A62 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 A62: Real-Time Congestion Costs
2011–2013



Key Observations: Congestion Costs

i. Day-ahead congestion costs rose over 8 percent from $778 million in 2012 to $842 million in 2013. Costs were 67 percent greater than in 2011.

– MISO continues to improve its day-ahead processes to better align them with the real-time energy and FTR markets.

✓ Better alignment contributes to relatively low levels of real-time balancing congestion and FTR underfunding (shown later in this section).

ii. Congestion revenues collected through the MISO markets remain substantially less than the value of real-time congestion on the system, which totaled $1.59 billion (see Section C below).

– This difference is caused primarily by loop flows and PJM entitlements that do not pay MISO for use of its network.

– In addition, since most transmission capability is scheduled through the day-ahead market, when day-ahead prices do not fully reflect the real-time congestion on an interface, congestion revenue collected by MISO will be less than the real-time congestion value.

iii. Balancing congestion costs in 2013 were a small share of total congestion costs collected by MISO, which is favorable because these costs generally occur when the transmission capability available in the real-time market is less than what was assumed in the day-ahead market.

- Much of the real-time congestion, pre-JOA settlement, was attributable to PJM exceeding its entitlements on MISO market-to-market flowgates or MISO reducing its flow below its entitlement on PJM market-to-market flowgates.

- Balancing congestion costs of $27.4 million (excluding JOA uplift of $8.5 million) indicate that the real-time binding constraint flows were slightly less than the amount cleared in the day-ahead market.

B. FTR Obligations and Funding

In the MISO market, the economic value of transmission capacity is reflected in Financial Transmission Rights (FTRs). FTR holders are entitled to congestion costs collected in the day-ahead market between the source and sink locations that define a particular FTR. Hence, FTRs allow participants to manage day-ahead price risk from congestion. FTRs are distributed through an annual allocation process as well as through seasonal and monthly auctions. Prior to June 2008, most FTRs were allocated based on the physical usage of the system. Since then, most transmission rights have been auctioned seasonally while the rights to the associated auction revenue are allocated via Auction Revenue Rights (ARRs). Holders of ARRs may receive the auction revenue or self-schedule the ARRs to receive the underlying FTRs. 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.[28] 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.[29] 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.

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

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

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 A63: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A63 compares monthly day-ahead congestion revenues to FTR obligations for 2011 to 2013. 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 A63: Day-Ahead Congestion Revenue and Payments to FTR Holders
2011–2013

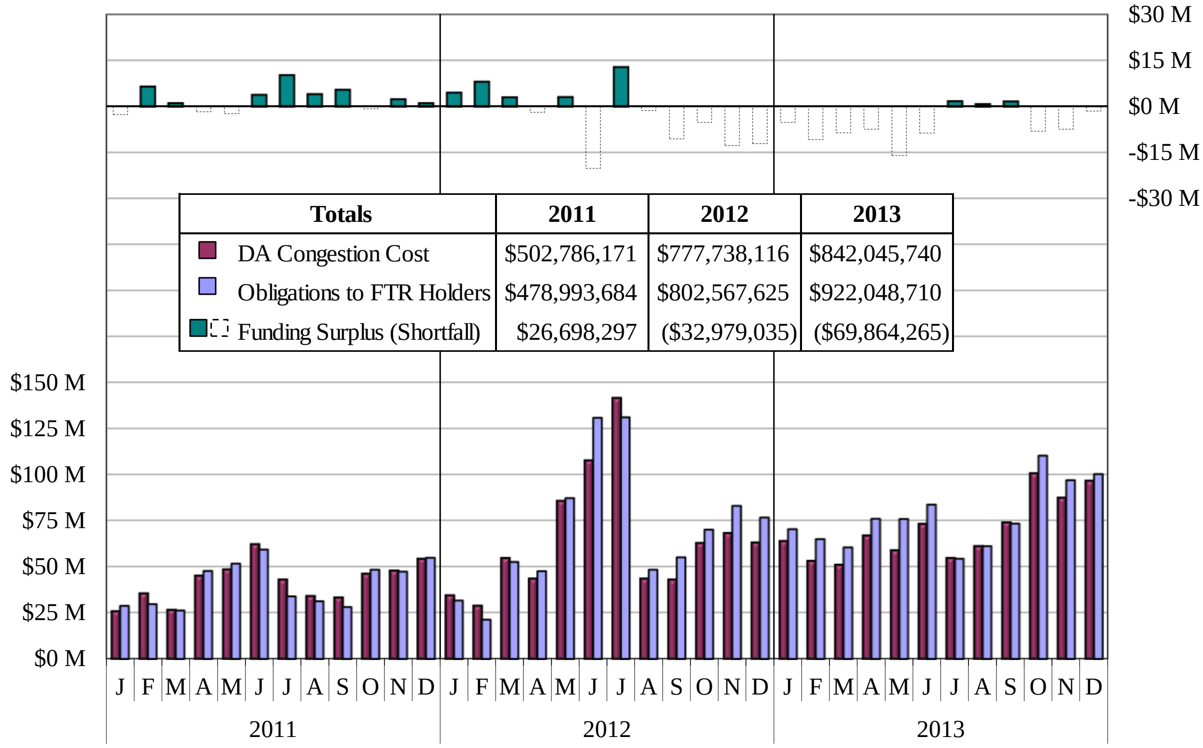


Figure A64: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A64 compares monthly total day-ahead congestion revenues to monthly total FTR obligations in 2013 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 A64: Day-Ahead Congestion Revenue and Payments to FTR Holders
2013

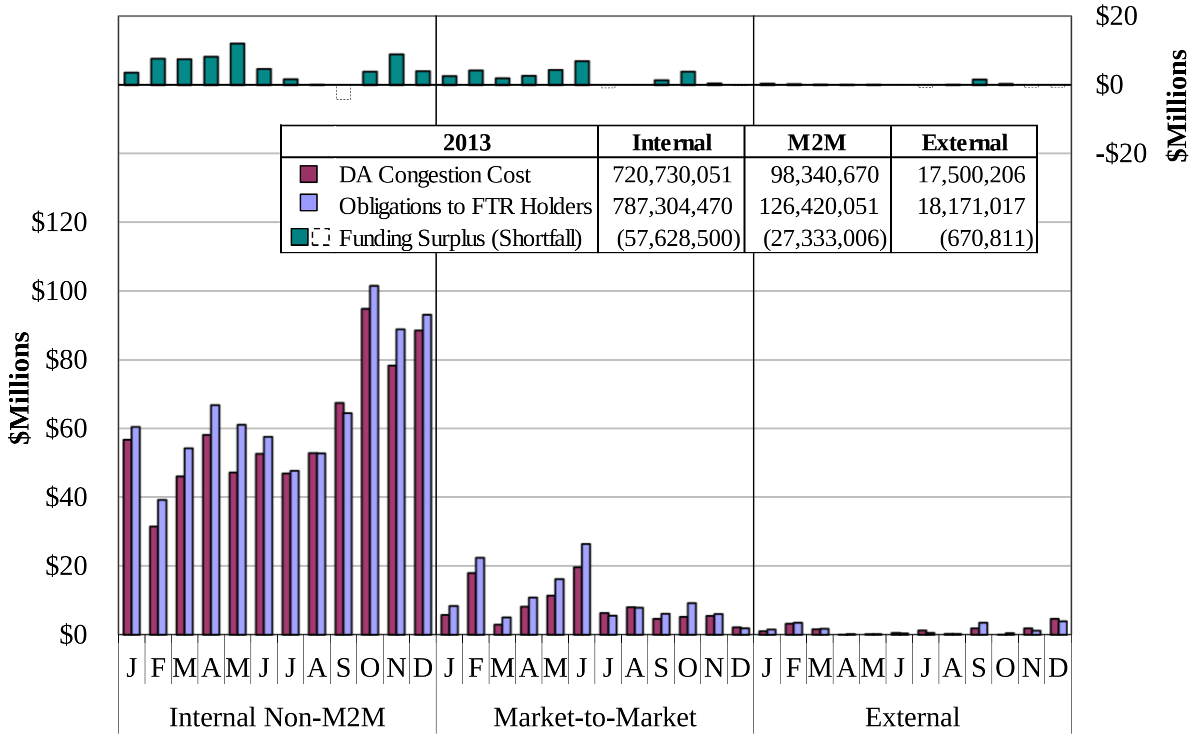
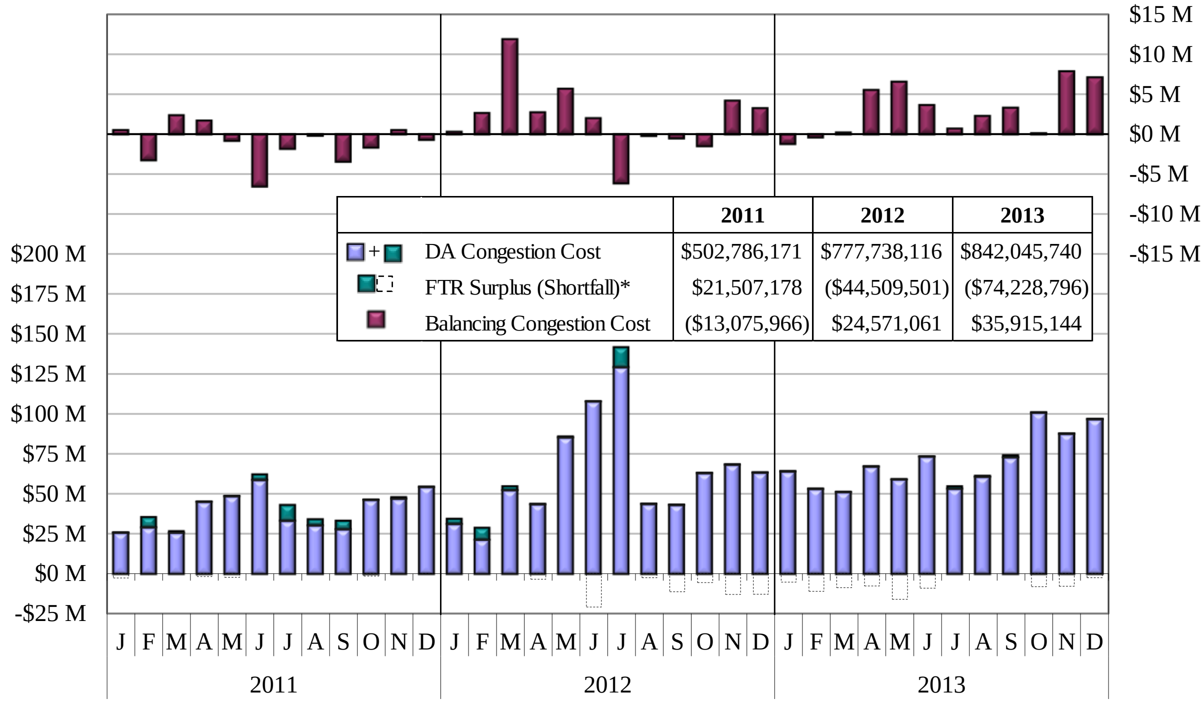


Figure A65: Payments to FTR Holders

In order to protect entities with transmission arrangements that predate the market, MISO established Grandfathered Agreements (GFAs). Holders of these rights receive rebates that refund any congestion charges incurred on a specified path in the day-ahead or real-time markets. The rights include an alternative type of FTR with use-it-or-lose-it characteristics (known as “Option B”) and rebates to “Carve-Out” GFAs. These only comprise a small portion of total transmission rights and do not provide the same incentives as conventional FTRs.

Figure A65 shows monthly payments and FTR obligations, along with Option B and day-ahead and real-time Carve-Out rebates. The figure also shows the funding surplus or shortfall in each month.

Figure A65: Payments to FTR Holders
2011–2013



Note: * Excludes contributions of monthly auction residual collections which totaled $4.36 million in 2013.

Key Observations: FTR Obligations and Funding

i. In 2013, MISO recorded a $74 million FTR shortfall, which means FTRs were underfunded by over 8 percent.

– Shortfalls were far greater in the first half of 2013 and accrued on both market-to-market and internal constraints. A large share of the underfunded obligations was annual FTRs that expired at the end of the planning year on May 31, 2013.

– FTRs were nearly fully funded in the second half of 2013, indicating that the FTRs better reflected the physical capability of the system in the planning year beginning June 1.

– While overall funding levels were relatively high, the most significant causes for underfunding continue to be planned and unplanned transmission outages and derates that do not get modeled in the FTR auction.

✓ Forced transmission outages are the largest driver of underfunding.

✓ Short-duration scheduled outages that are not included in the FTR auction also contribute to underfunding.

- ✓ MISO's procedures have been modified over time to include the effects of shorter-term planned outages in the FTR auction. There is a trade-off, however, between being more conservative to produce higher funding levels and being overly restrictive.

- ✓ The impact on FTR funding associated with derates from physical inspections via Light Detection and Radar (LIDAR) surveys was much reduced from 2012 because the related derates and outages were anticipated in the auctions.

- ✓ Impacts of underestimated loop flows and underestimated firm-flow entitlements by JOA entities also contributed to underfunding.

– In March 2013, MISO filed a permanent Tariff change that does not award FTRs that source and sink at the same station (without limit or cost).

- ✓ These "Same-Bus" or "Zero-Cost" FTRs led to $7 million in underfunding in 2012 when there was a congestion component difference between locations in the day-ahead market (generally when one is identified as a contingency).

ii. MISO continues to pay out the vast majority of its day-ahead congestion via FTRs, but this share declined to just 83 percent in 2013. This is down from 95 percent in 2010.

– Most Carve-Out and Option B rights exist in the West region, so payments in recent years to these holders have risen along with congestion and growth in wind generating capacity.

– Higher levels of congestion in Iowa in 2013 resulted in one participant being paid over $47 million in rebates.

– These alternative transmission rights do not provide incentives as efficiently as FTRs do.

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 A66: Value of Real-Time Congestion by Coordination Region

Figure A66 shows the total monthly value of real-time congestion by region and the average number of binding constraints per interval in 2012 and 2013. The bars on the left show the average monthly value in each of the past three years.

Figure A66: Value of Real-Time Congestion by Coordination Region
2012–2013

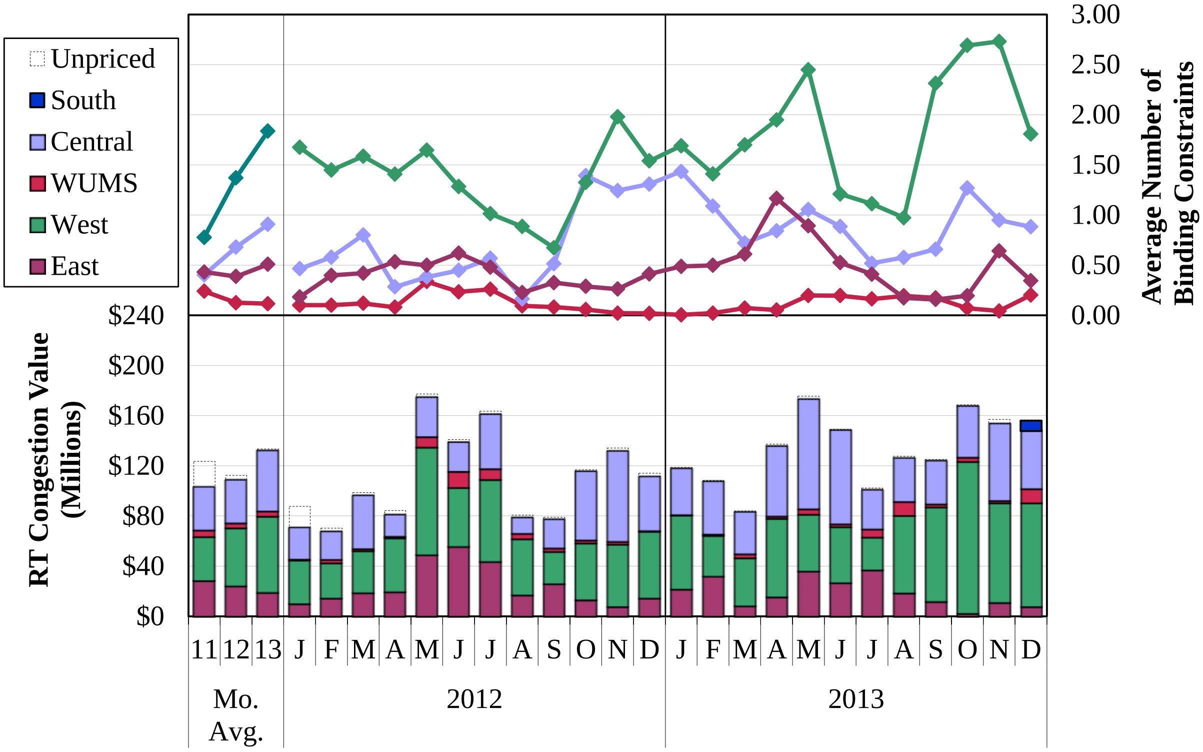


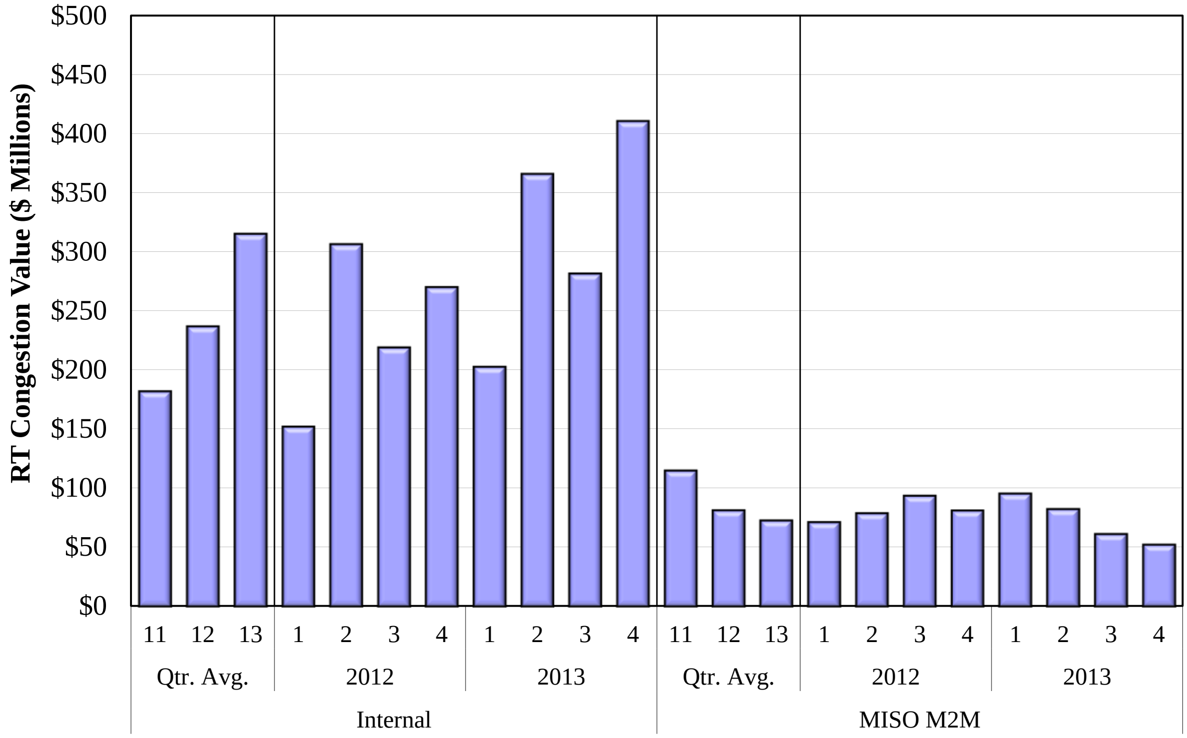
Figure A67: Value of Real-Time Congestion by Type of Constraint

To better identify the nature of constraints and the congestion value, Figure A67 disaggregates the results by type of constraint. We define four constraint types:

- Internal Constraints: Those constraints internal to MISO (where MISO is the reliability coordinator) and not coordinated with PJM.
- 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 A67: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2011–2013



Key Observations: Congestion Value

i. Real-time congestion value increased 22 percent in 2013 from 2012 to $1.59 billion.

– Congestion on internal constraints rose by one-third and accounted for nearly 80 percent of the total congestion value.

– Congestion on internal constraints was greatest in the fourth quarter because of significant seasonal outages in the West region and because of the integration of the South Region late in December.

ii. Congestion rose fastest in the Central (41 percent) and West regions (31 percent), whereas it declined by 21 percent in the East region.

– Transmission derates and outages associated with upgrades and LIDAR surveys accounted for a large share of 2012 congestion in East region, and particularly in the Northern Lower Peninsula of Michigan. This congestion was greatly reduced in 2013.

– Increased wind generation and DIR participation in the West allowed wind resources to more frequently set the LMP and made congestion more manageable.

– MISO continued to control a greater number of low-voltage constraints, most of which are situated in the West region.

iii. Congestion on MISO-managed market-to-market constraints declined 10 percent and was most significant in December.

D. Congestion on External Constraints

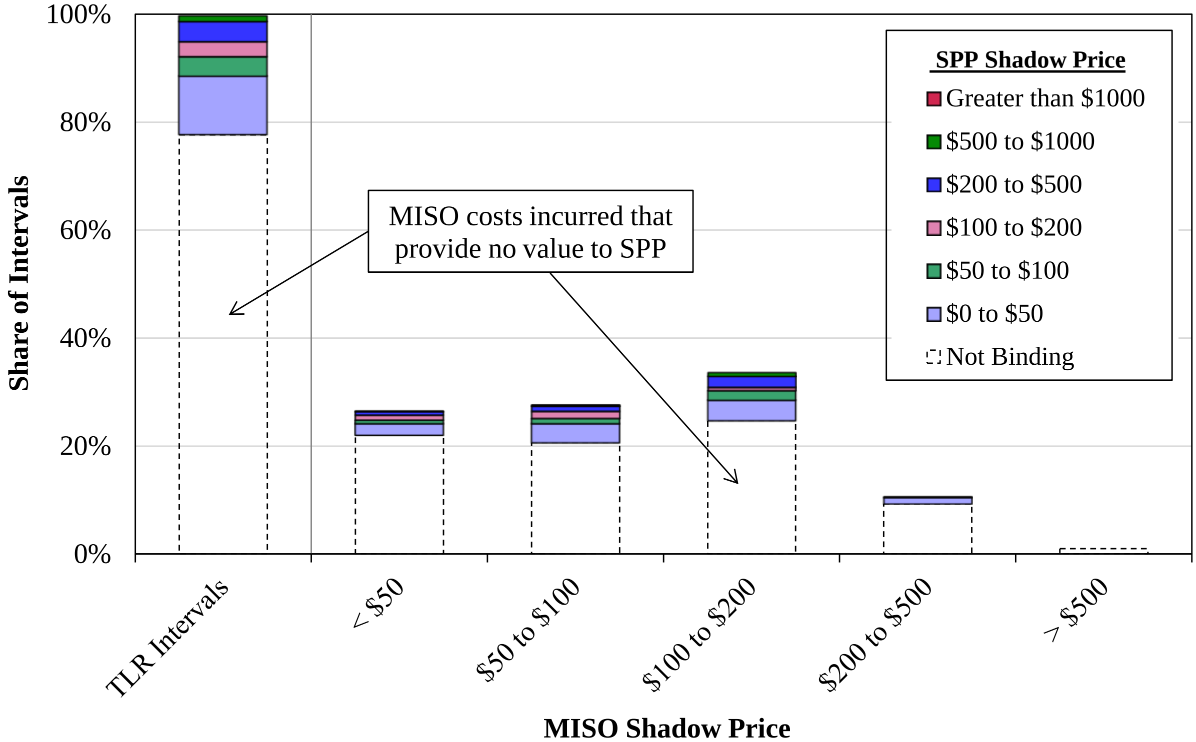
This subsection discusses congestion that occurs on external constraints, which are constraints monitored by adjacent RTOs or control area operators. MISO incurs congestion on external constraints when a neighboring system calls Transmission Line-Loading Relief (TLR) procedures for a constraint. When 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 A68: Average MISO and SPP Shadow Prices

To evaluate the efficiency of this process, Figure A68 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.

Figure A68: Average MISO and SPP Shadow Prices
SPP TLR Flowgates, March 2014

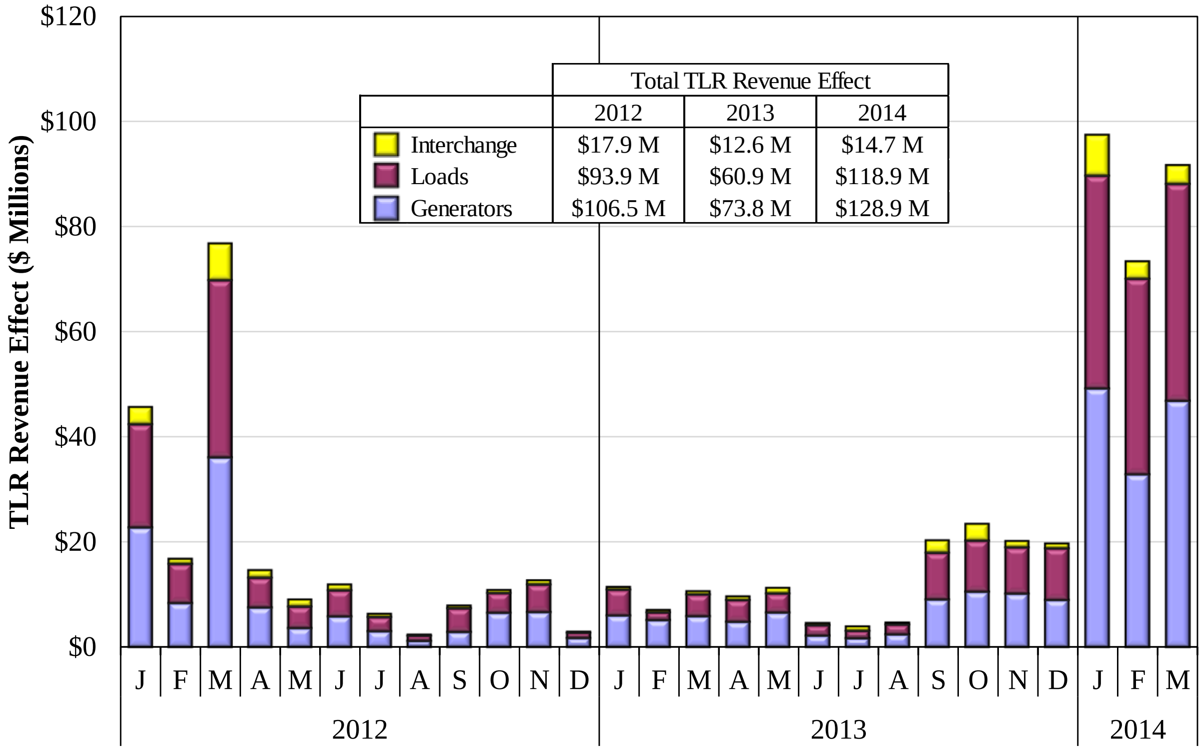


Because external constraints can cause substantial changes in LMPs within MISO, we estimate the effects of these changes by calculating the total increase in real-time payments by loads and the reduction in payments to generators caused by the external constraints. External constraints also affect interface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

Figure A69: Real-Time Valuation Effect of TLR Constraints

Figure A69 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 A69: Real-Time Valuation Effect of TLR Constraints
2013



Key Observations: Congestion on External Constraints

i. Our analysis shows that when an SPP TLR constraint is active, MISO's shadow cost is on average 2.3 times higher than SPP's shadow cost.

- In 78 percent of the periods when such constraints are binding in MISO, the constraints are not binding in SPP. During 46 percent of periods, the TLR flowgate is not even active in SPP's real-time market.
- Case studies suggest that a $100 shadow price on the most-frequently activated SPP TLR flowgates results in a 1 percent increase in market-wide dispatchable energy production costs.
- The redispatch by MISO for external constraints is highly inefficient.

ii. The price and settlement impacts at affected locations of TLR constraints are also large.

- Generator locations impacted by all TLR constraints received $74 million less in revenue, while loads paid an additional $61 million as a result of these inefficiencies.
- On net, most of this is offset by windfall payments to other generators and avoided charges by other loads. Nevertheless, this is a significant transfer of payments among MISO participants.

- Similarly, certain generators receive lower payments due to the price effects of the TLR constraints, which reduced payments by $9 million in 2013.

iii. This inefficiency is due in part to the outsized relief obligation that MISO received based solely on its forward direction flows.

- MISO can receive relief obligations when its total market flow is in the reverse direction (opposite to the prevailing flow).
- MISO is working with NERC and other RTOs to address this issue. In such cases, even small relief obligations (based on forward-only direction flows, rather than net flows) can cause significant price and market settlement impacts.
- We continue to recommend that MISO work to improve the calculation of its relief obligations, which would greatly reduce the inefficiencies of this process.

iv. One way to address these inefficiencies is to cap the cost that the MISO market will incur to provide the requested relief.

- MISO filed proposed transmission demand curves for TLR constraints that are at the same price levels as high-voltage internal constraints.
- This is unjustified because the reliability implication of not providing the full quantity of relief for a TLR constraint is not comparable to violating internal constraints.
- We have filed for rehearing of FERC's November 15 order approving the transmission demand curves for TLR constraints.

E. 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 A70 and Figure A71: Periodic TLR Activity

Figure A70 shows monthly TLR activity on MISO flowgates in 2012 and 2013. 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. These NERC TLR levels are:

- Level 3—Non-firm curtailments;[30]
- Level 4—Commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[31]

Figure A71 shows TLR hours disaggregated by the Reliability Coordinator declaring the TLR.

30 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.

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

Figure A70: Periodic TLR Activity
2012–2013

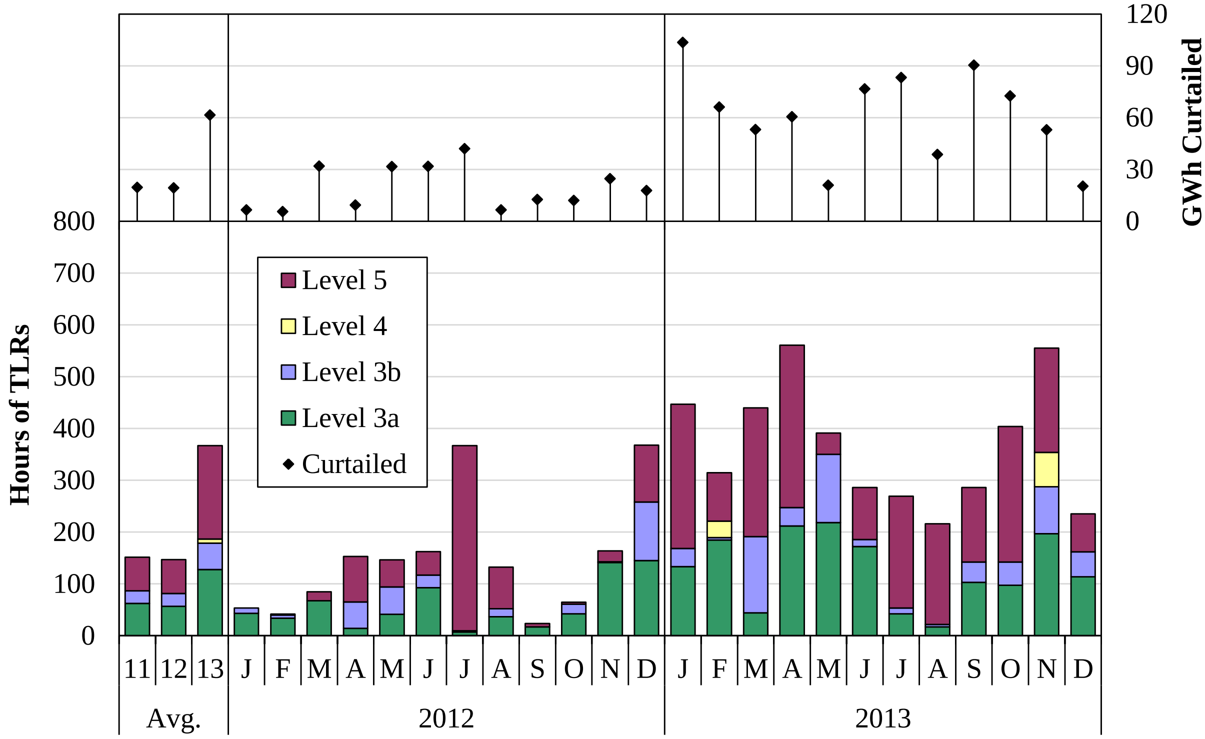
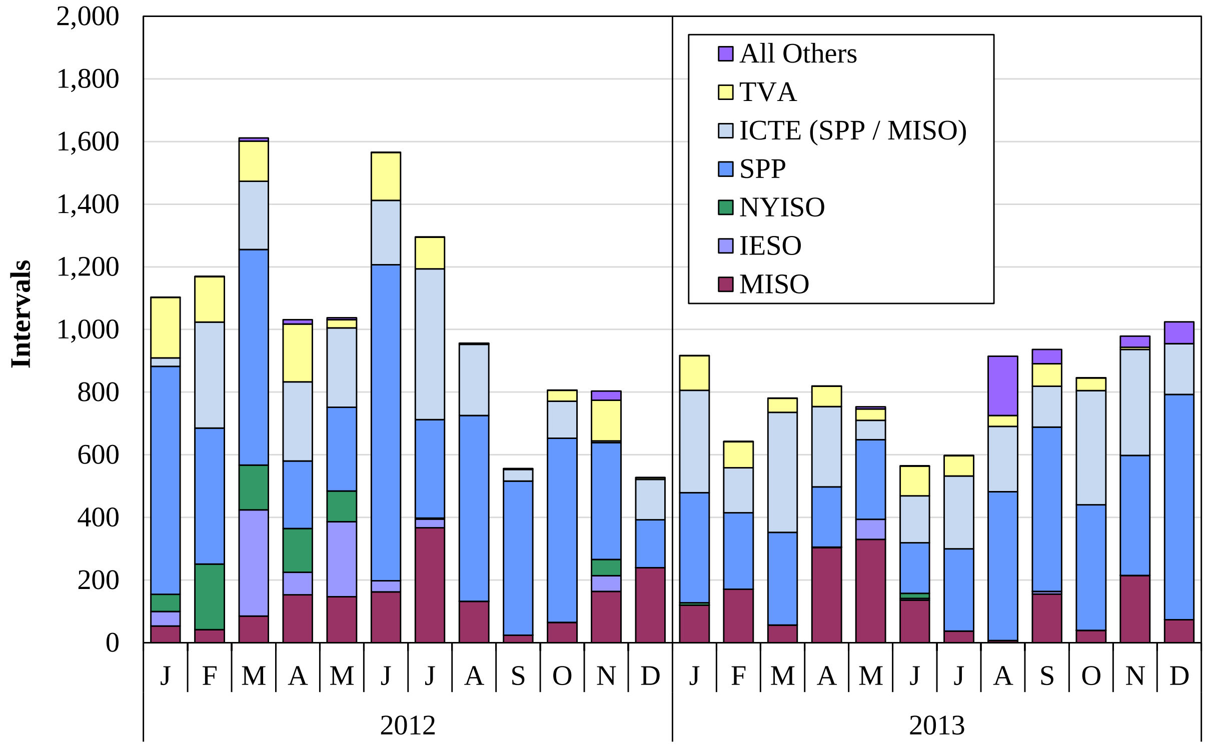


Figure A71: TLR Activity by Reliability Coordinator
2012–2013



Key Observations: TLR Events

i. TLR quantities rose 150 percent from 2012 to 367 hours per month. Curtailed quantities similarly rose from 19 to 62 GWh per month.

– This is primarily because MISO became the Reliability Coordinator for Entergy (ICTE) in December 2012.

ii. The increase was most apparent for TLR-5 declarations, which nearly tripled to an average of 180 hours per month. TLRs by neighboring system operators affecting MISO declined 44 percent from 2012. Of the neighboring entities, only PJM recorded an increase.

– The full operation of the PARs since July 2012 to control the flow around Lake Erie has reduced the number of TLR hours and quantities declared by Ontario and NYISO by over 90 percent.

F. 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).

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 A72: Constraint Manageability

The next set of figures show manageability of internal and MISO-managed market-to-market constraints. Figure A72 shows how frequently binding constraints were manageable and unmanageable in each month from 2012 to 2013.

Figure A72: Constraint Manageability
2012–2013

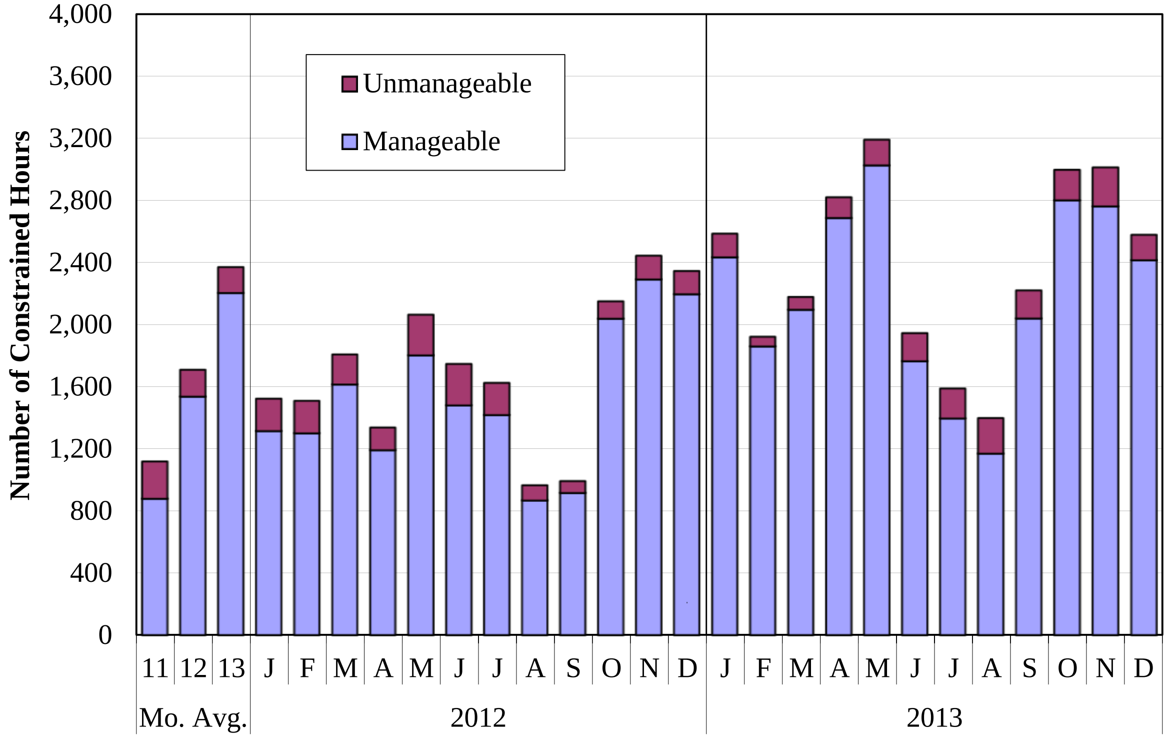


Figure A73: Value of Real-Time Congestion by Voltage Level

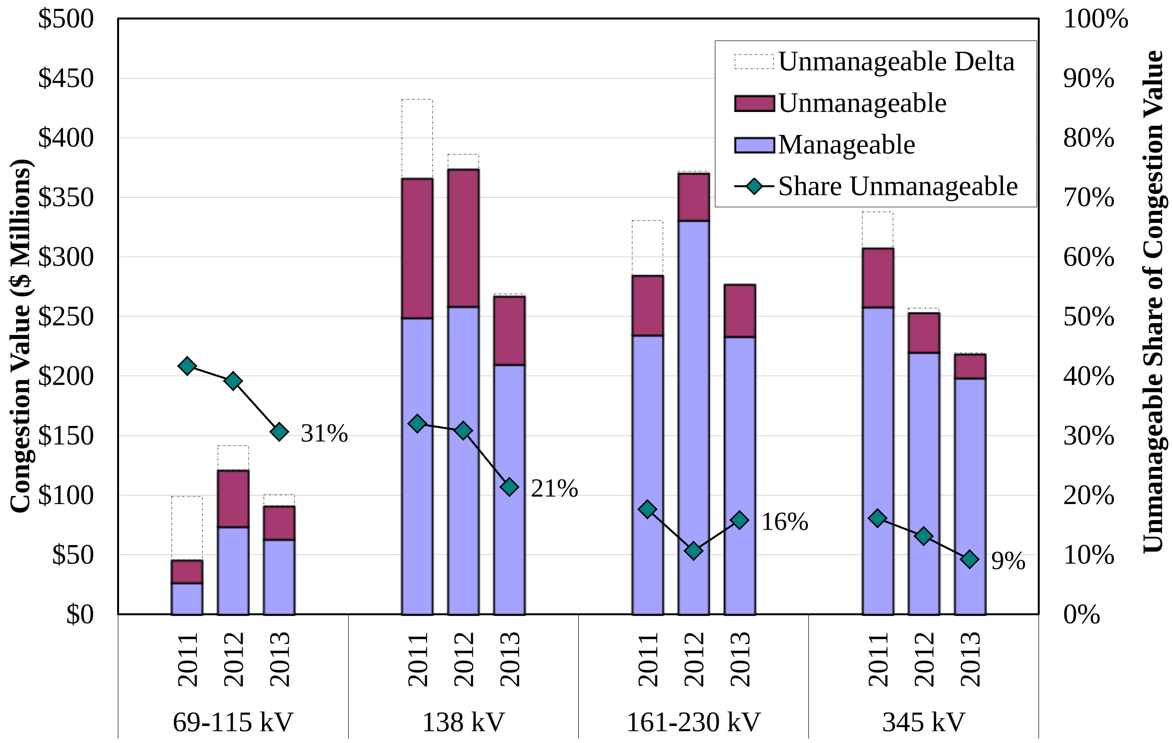
Given the frequency that constraints are unmanageable, it is critical that unmanageable congestion be priced efficiently and reflected in MISO's LMPs. The real-time market model utilizes Marginal Value Limits (MVLs) that cap the marginal cost (i.e., the shadow price) that the energy market will incur 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 A73 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 A73 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.[32]

Figure A73: Real-Time Congestion Value by Voltage Level
2011–2013



32 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.

Key Observations: Congestion Management

i. The manageability of congestion improved modestly in 2013.

- Just over 19 percent of congestion value (and 7 percent of binding constraint hours) were considered unmanageable in 2013. This is down from 21.4 and 10 percent, respectively, in 2012.

- Although significantly improved, lower-voltage constraints remain the most unmanageable category of constraints.

- Much of the improvement on lower-voltage constraints is on constraints affected by wind generation. The full implementation of the DIR capability has significantly improved MISO's ability to manage constraints affected by its wind resources.

- The deactivation of MISO's transmission constraint deadband also likely contributed to the improved manageability of congestion late in 2013.

ii. Very little of MISO congestion is now unpriced since MISO disabled constraint relaxation on internal constraints.

- Although very little of the congestion on M2M constraints was unpriced in 2013, MISO should disable this algorithm on market-to-market constraints because there remains the potential for significant distortion of congestion prices in MISO.

  - ✓ When MISO exceeds its FFE on a PJM market-to-market flowgate, its marginal cost is the PJM shadow price since the JOA payment to PJM will equal the product of MISO's excess flow and PJM's shadow cost for the constraint.

  - ✓ When MISO fails to fully price this congestion, it results in an out-of-market cost uplifted to load.

iii. After an extended market trial evaluation of our prior recommendation on deactivation of the transmission constraint deadband, MISO extended the deactivation to all constraints in November 2013.

- This has resulted in greater utilization of the transmission system, reduced LMP volatility, and improved congestion manageability.

G. FTR Auction Prices and Congestion

A well-functioning FTR market should produce FTR prices that reflect a reasonable expectation of day-ahead congestion. Therefore, a key indicator of FTR market liquidity is profitability of FTR purchases. FTR profits are the difference between the costs to purchase an FTR and the payout its holder receives from congestion in the day-ahead market. In a liquid FTR market, profits should be close to zero because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR holder.

Figure A74 and Figure A75: FTR Profitability

The next two figures show the profitability of FTRs purchased in the seasonal and monthly FTR auctions, respectively. The bottom panels show the total profits and losses, while the top panel shows the profits and losses per MWh.

The results in Figure A74 and Figure A75 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 A74: FTR Profitability
2011–2013: Seasonal Auction

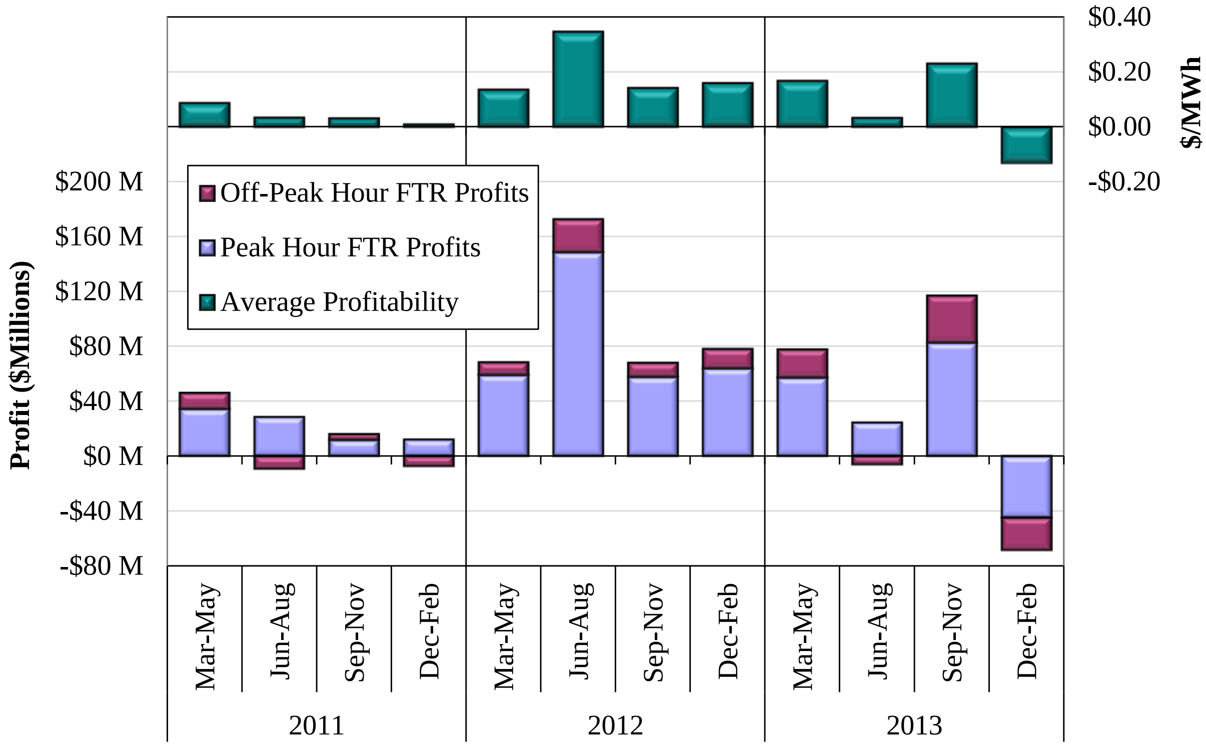
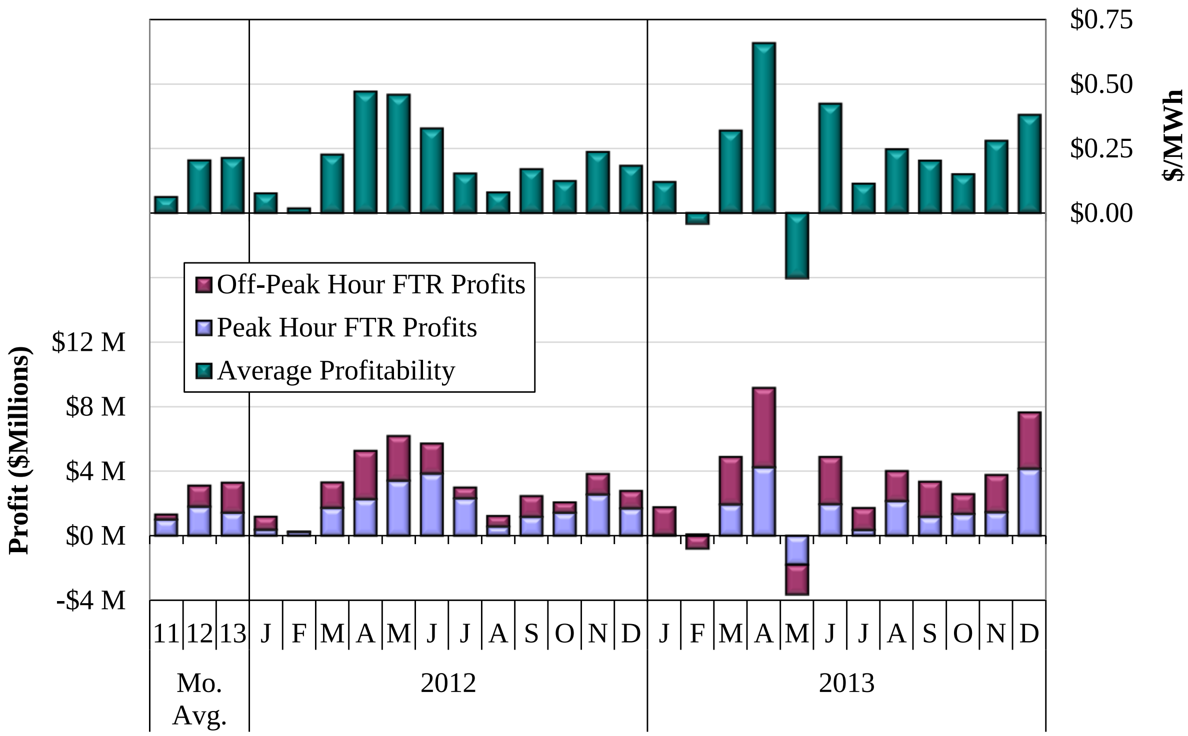


Figure A75: FTR Profitability
2012–2013: Monthly Auction



Another method to evaluate the monthly FTR market is to compare the amount paid for incremental transmission capability to the resulting FTR obligations received. When monthly obligations exceed the auction residuals collected by MISO, funding for all FTRs is reduced or, if the market remains fully funded, distributions to transmission owners decline.

Figure A76 to Figure A83: Comparison of FTR Auction Prices and Congestion Value

The next eight figures examine the performance of the FTR markets by comparing monthly FTR auction prices to day-ahead congestion payable to FTR holders at representative locations in MISO. These differences between prices and congestion values should generally be small in a well-functioning market. We analyze values for the Indiana, Michigan and Minnesota Hubs and for the WUMS Area. Results are shown separately for peak and off-peak hours.

Figure A76: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2012–2013: Off-peak Hours

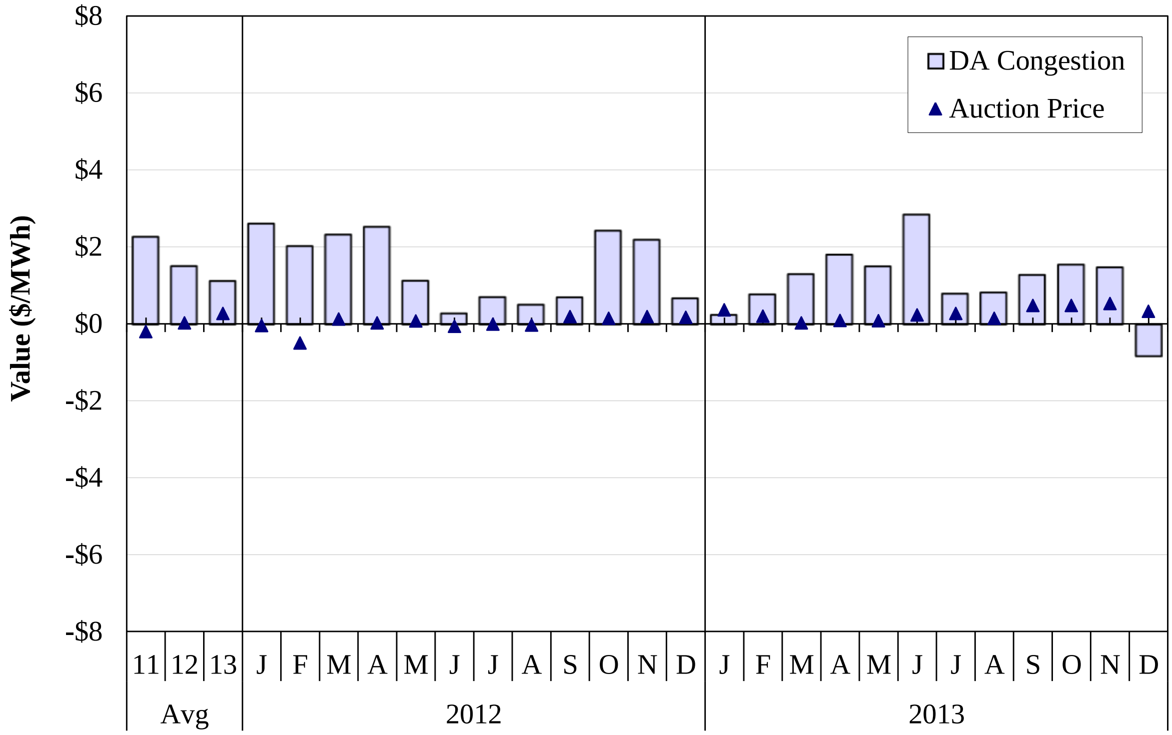


Figure A77: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2012–2013: Peak Hours

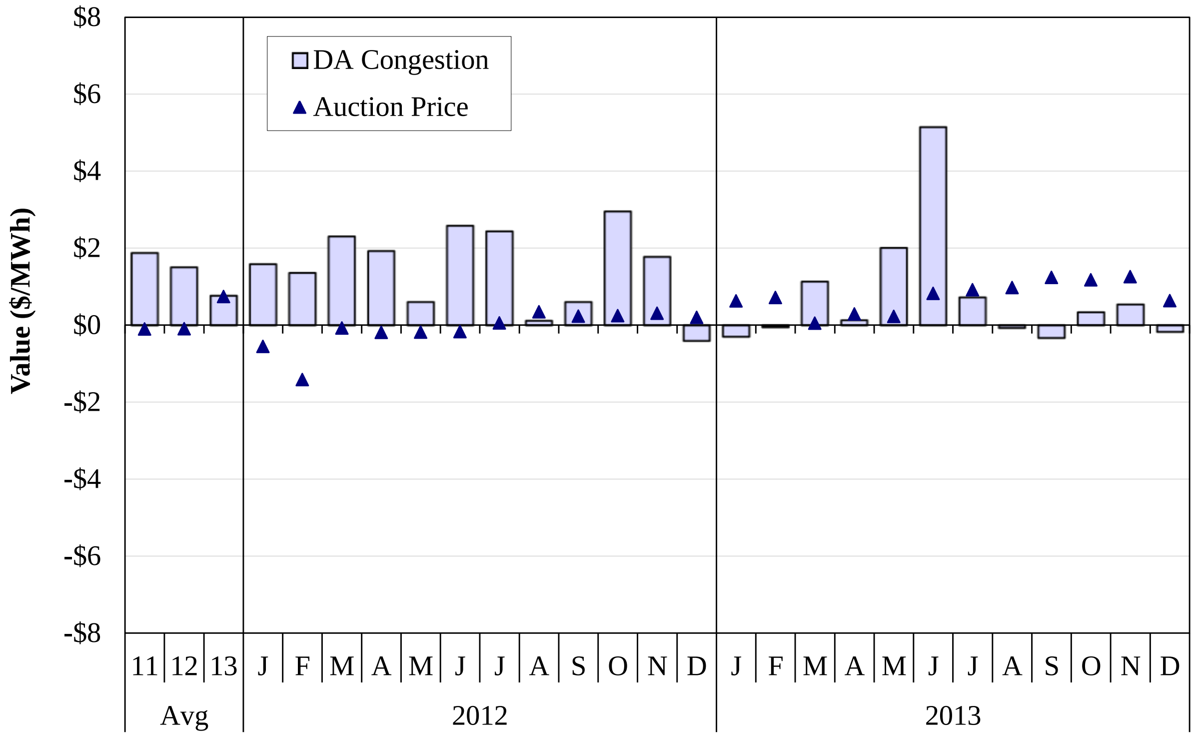


Figure A78: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2012–2013: Off-peak Hours

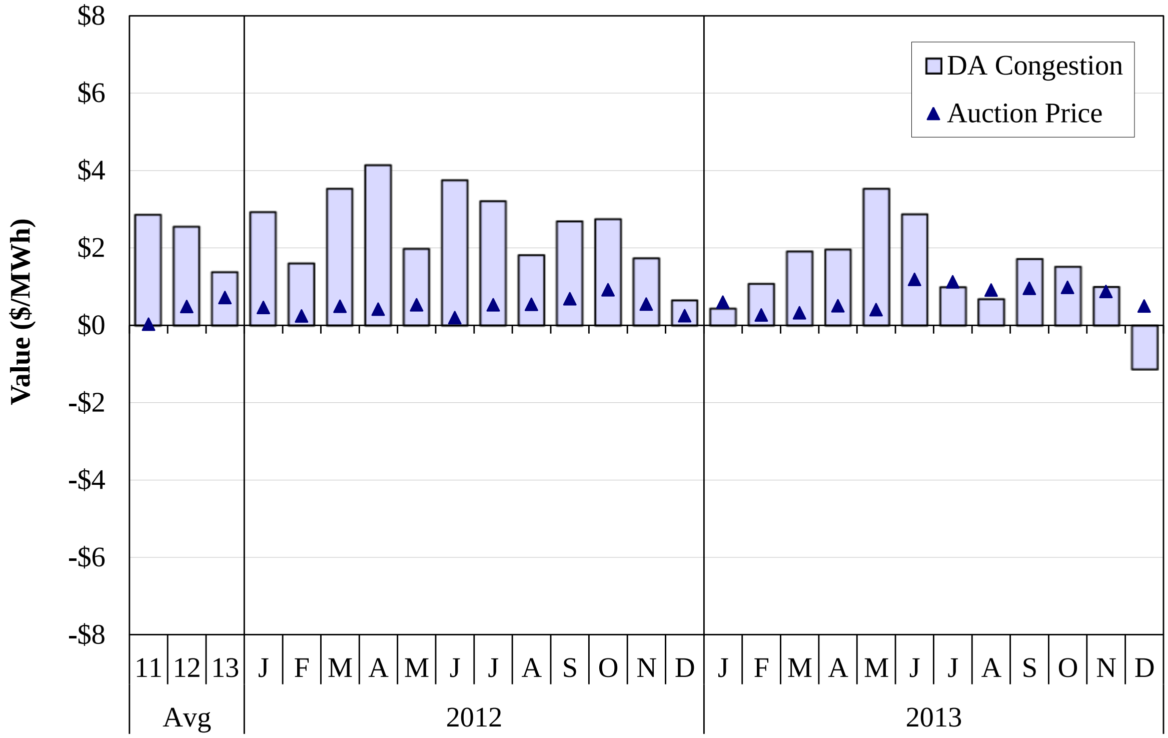


Figure A79: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2012–2013: Peak Hours

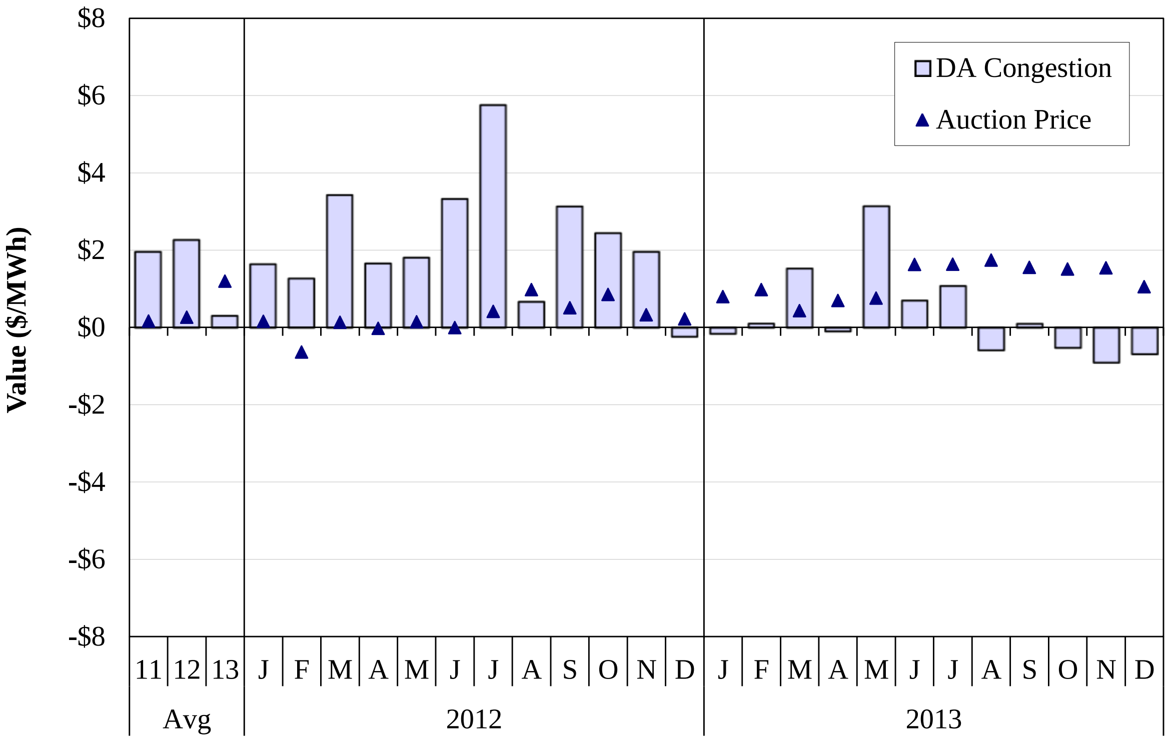


Figure A80: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2012–2013: Off-peak Hours

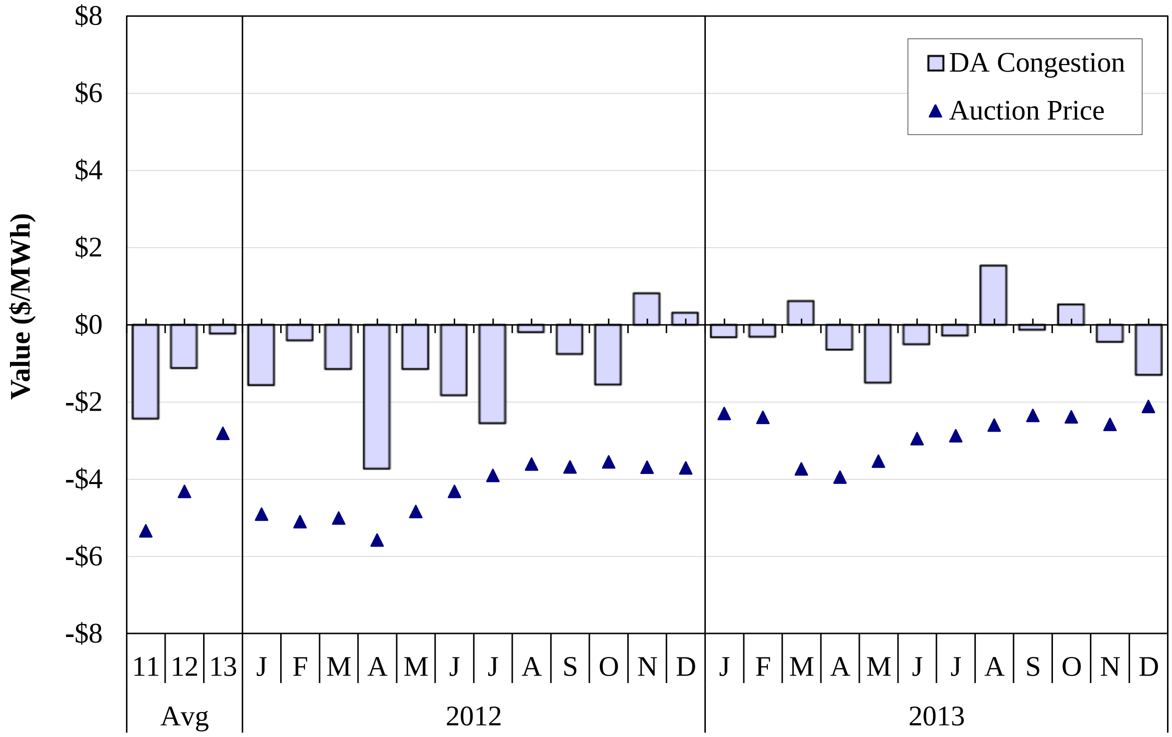


Figure A81: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2012–2013: Peak Hours

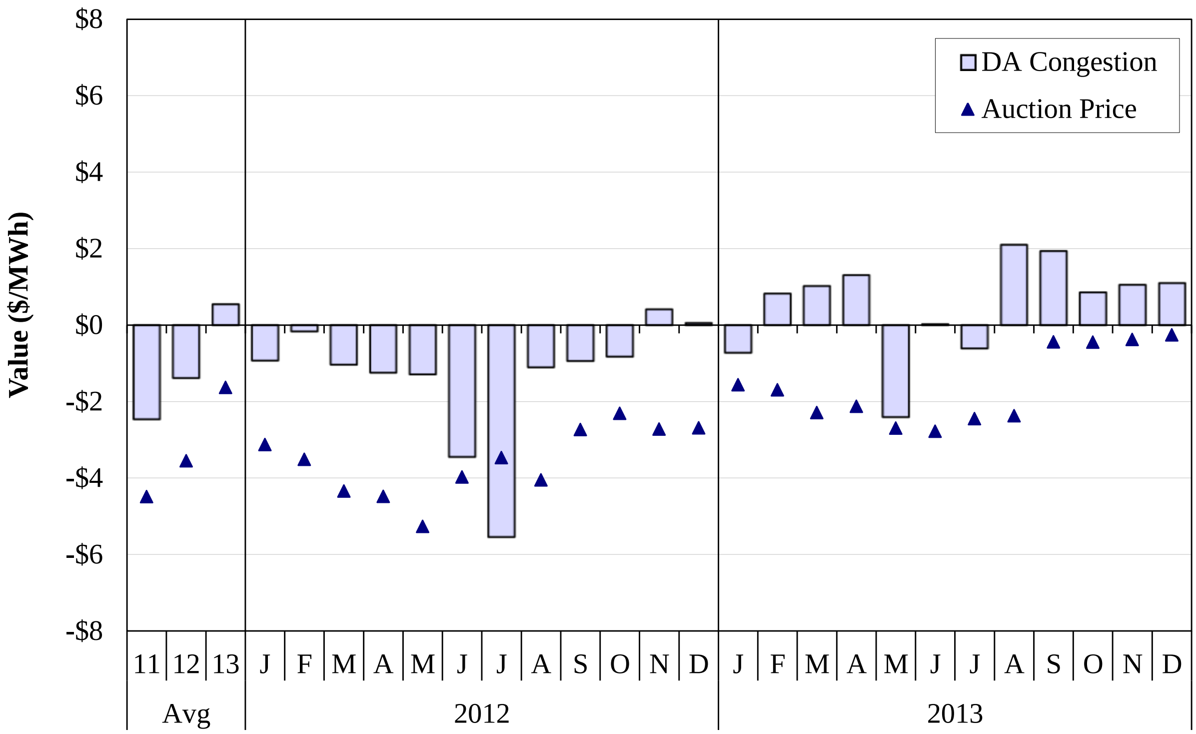


Figure A82: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2012–2013: Off-peak Hours

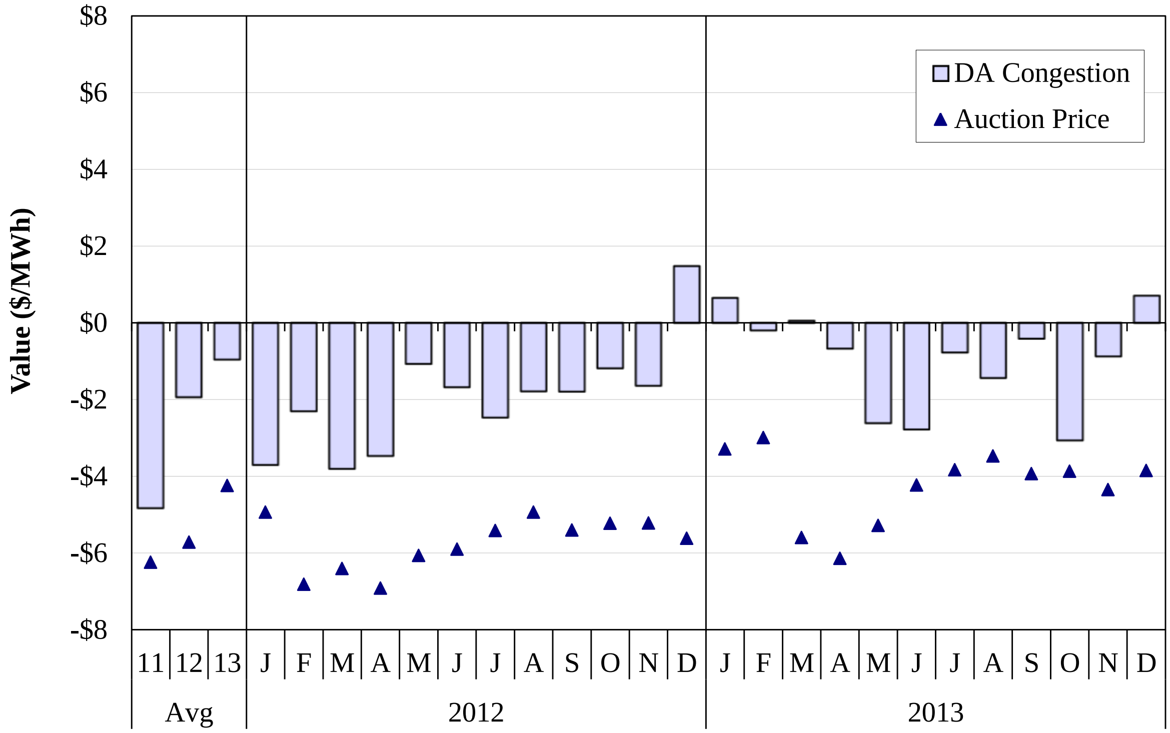
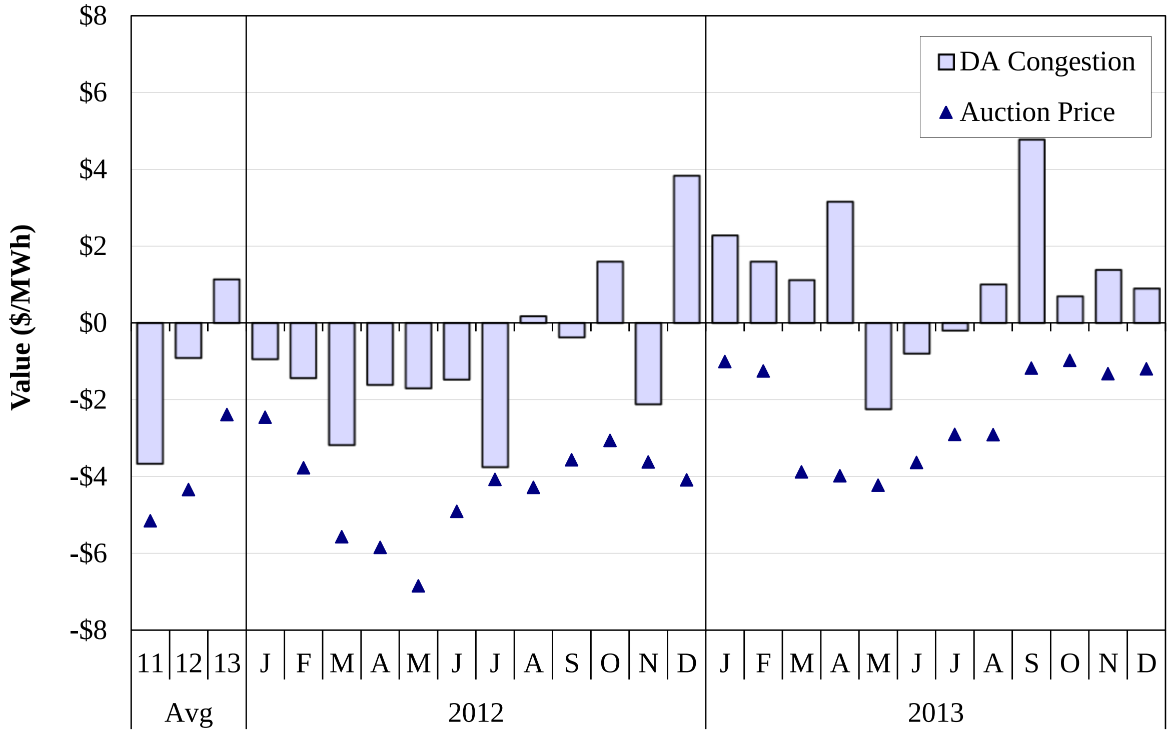


Figure A83: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2012–2013: Peak Hours



Key Observations: FTR Auction Prices

i. Seasonal FTR profitability declined from $0.20 per MWh in 2012 to $0.07 in 2013.

- FTRs were only slightly profitable in summer at $0.03, and lost $0.13 in winter 2013.
- Over 90 percent of FTRs cleared in the annual auction. The remaining incremental capacity, sold in the monthly auctions, was slightly more profitable at $0.22 per MWh.
- The incremental capability transacted in the monthly FTR market resulted in over $47 million of obligations but netted only $4.3 million in residual collections.

ii. Monthly FTR prices significantly under-forecasted congestion in Minnesota and WUMS.

- The generally prevailing pattern of west-to-east congestion was not as significant in 2013. This has yet to be reflected in FTR prices, which sold for several dollars per MWh less than the day-ahead congestion that prevailed.

iii. As noted above, MISO introduced a Multi-Period Monthly Auction in late 2013 that allows participants to trade FTRs for all future months within the planning year.

- This should improve participants' ability to manage congestion risk and, in turn, the correlation between auction prices and congestion value.

H. 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 entitled to its 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 entitlements.

Figure A84: Market-to-Market Events

Figure A84 shows the total number of market-to-market constraint-hours (i.e., instances when a constraint was active and binding) in 2012 and 2013. 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 A84: Market-to-Market Events
2012–2013

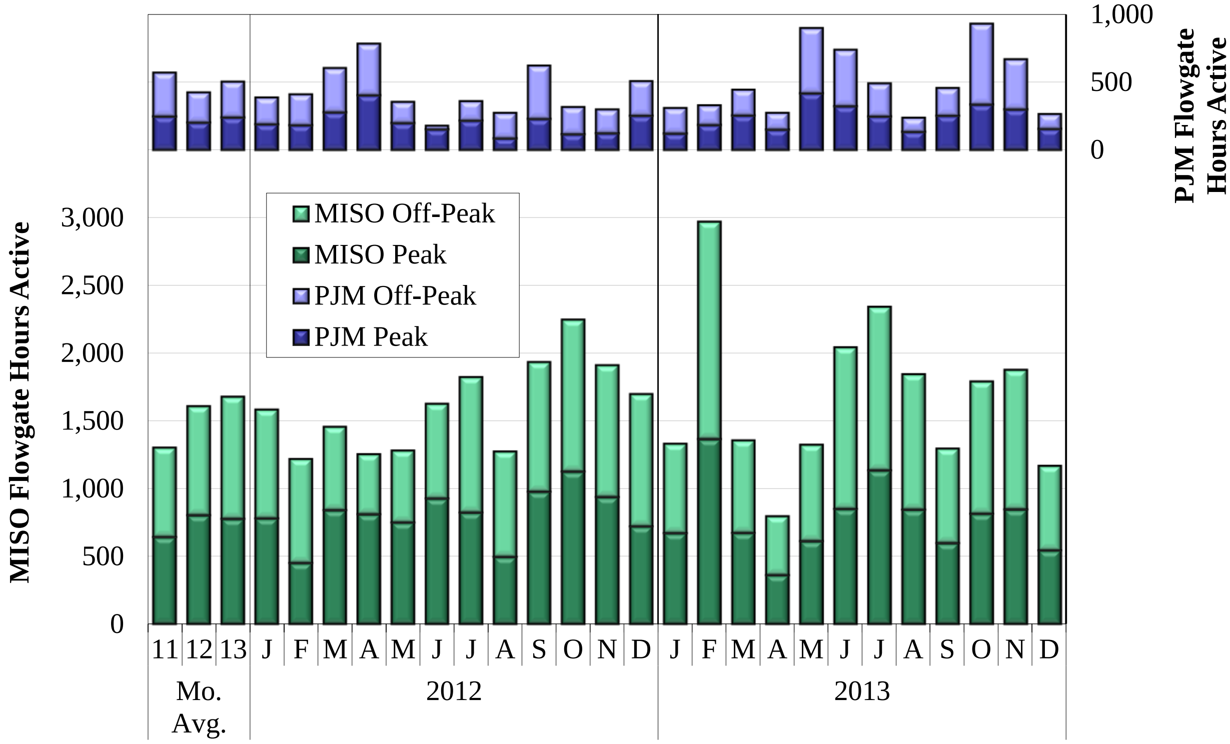


Figure A85: Market-to-Market Settlements

Figure A85 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 A85: Market-to-Market Settlements
2012–2013

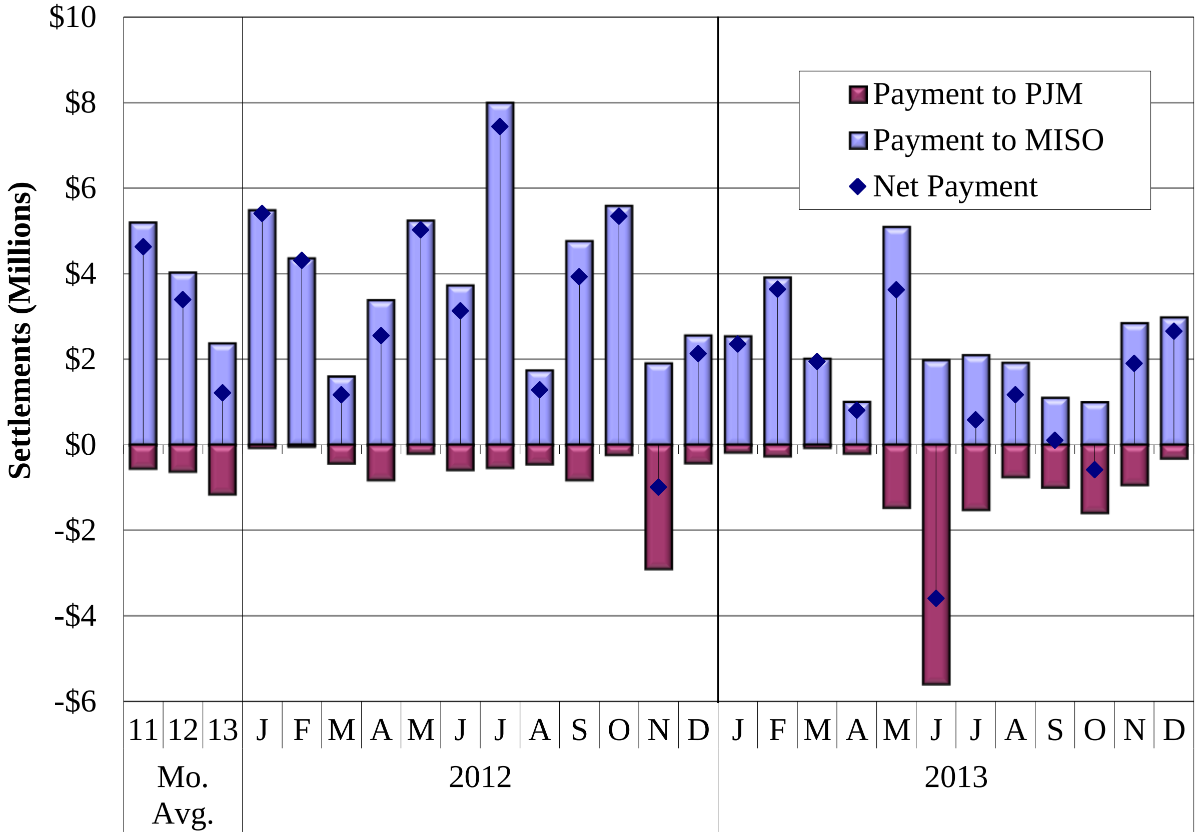


Figure A86 and Figure A87: Market-to-Market Outcomes

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 A86: PJM Market-to-Market Constraints
2013

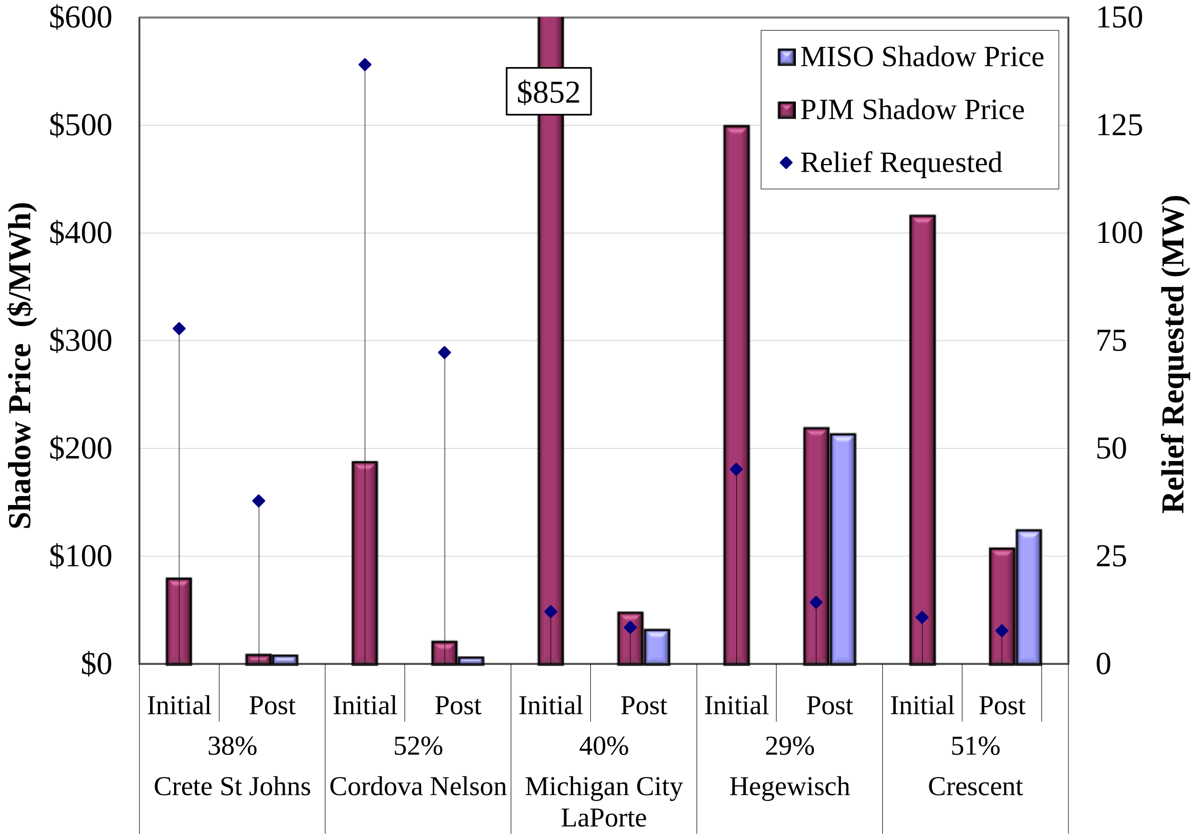
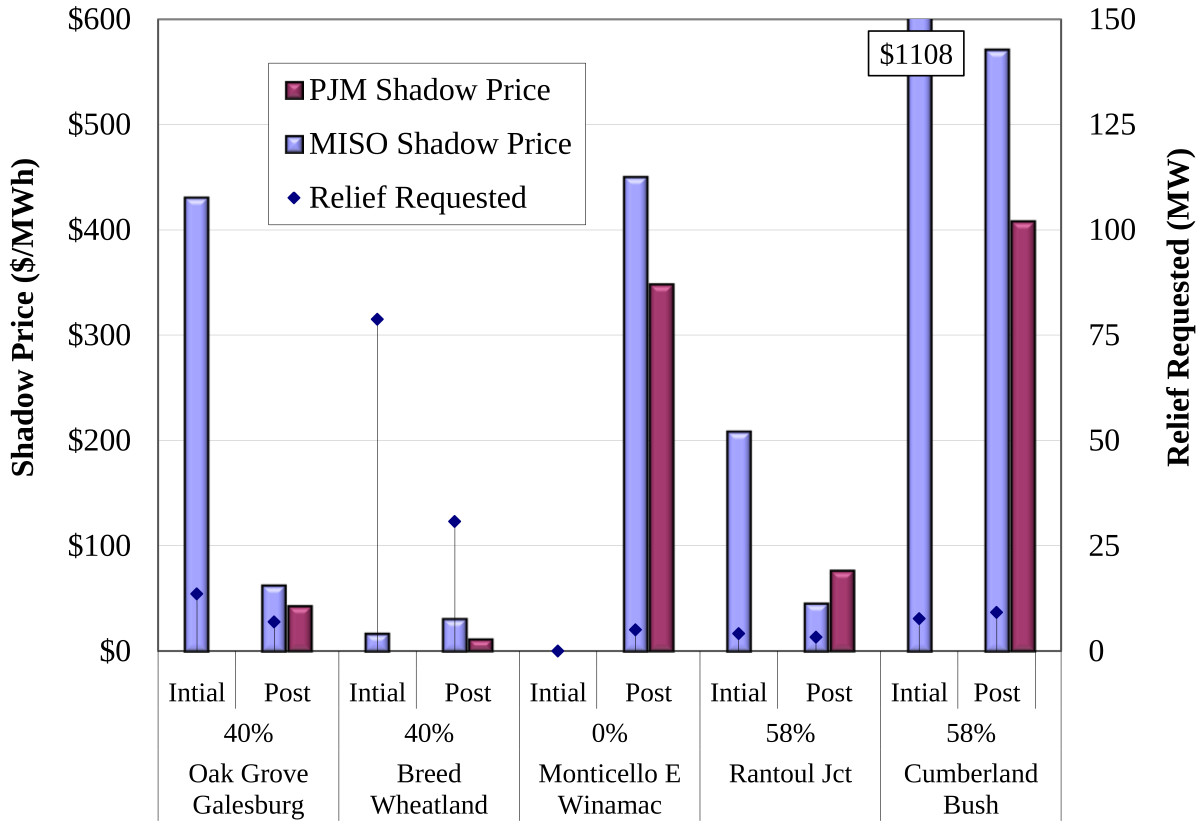


Figure A87: MISO Market-to-Market Constraints
2013



Key Observations: Market-to-Market Coordination

i. The value of congestion on MISO M2M constraints declined 10 percent from 2012 to $291.5 million.

- Congestion on PJM M2M constraints remained low, but doubled to $15.8 million.
- Net payments flowed from PJM to MISO in most months of 2013 because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.
- Net payments from PJM to MISO declined 72 percent from 2012.
  - ✓ PJM payments of $32.2 million were offset by $14.7 million in payments by MISO, mostly in May and June.
  - ✓ A substantial portion of these payments by MISO, however, were the result of an error in PJM's FFE calculation that overstated its entitlement on several constraints, reducing MISO's day-ahead limit.

- ✓ The error was corrected on February 8, 2013 and resulted in adjusted settlements on all flowgates between October 22, 2012 and February 6, 2013 valued at $4.28 million.

- – We recommended in our *2012 State of the Market Report* efforts by both RTOs to incorporate the coordinated use of FFEs into the day-ahead market, which should improve the efficiency of both RTOs' markets. We continue to support these.

- – Through the JCM process the RTOs have made considerable progress in developing a conceptual framework for coordination in the day-ahead.

- – A final design is expected in mid-2014 with possible implementation in late 2015.

ii. Shadow price convergence on MISO M2M constraints (an indicator of PJM's responsiveness to requests for relief) was good in 2013 and comparable to convergence on PJM M2M constraints.

VI. External Transactions

MISO relies on imports to supply the energy and capacity markets and is typically a net importer of power during 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 A88 to Figure A91: Average Hourly Imports

The first four figures in this section show the daily average of hourly net imports (i.e., imports net of exports) scheduled in the day-ahead and real-time markets in total and by interface.

The first figure shows the total net imports in the day-ahead market, distinguishing between weekdays (when demands are greater) and weekends. The second figure shows real-time net-imports and changes from day-ahead net import levels. When net imports decline 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 A88: Average Hourly Day-Ahead Net Imports
2013

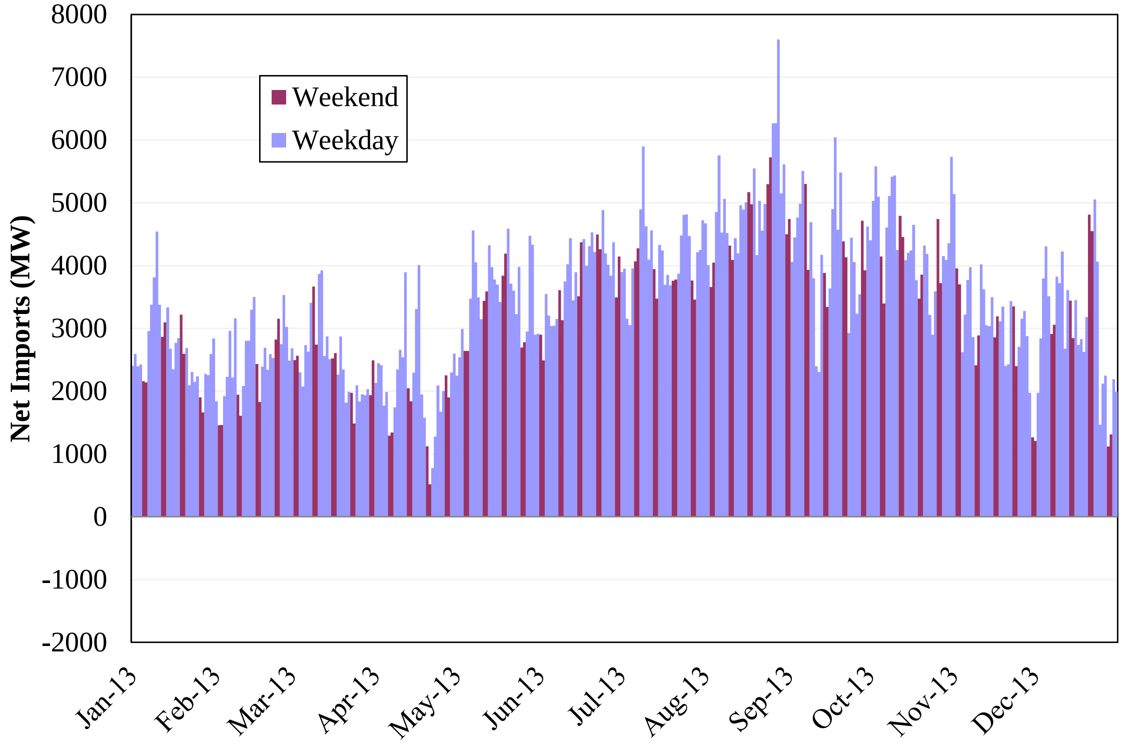


Figure A89: Average Hourly Real-Time Net Imports
2013

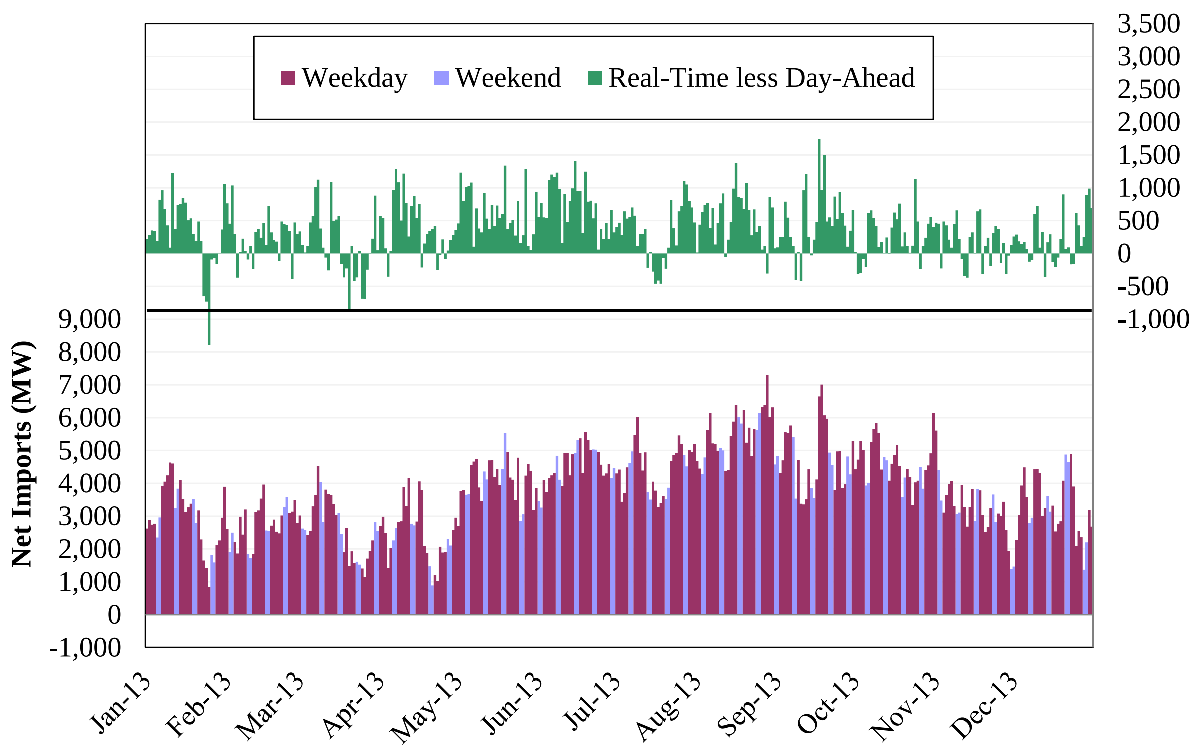


Figure A90: Average Hourly Day-Ahead Net Imports
2013, by Interface

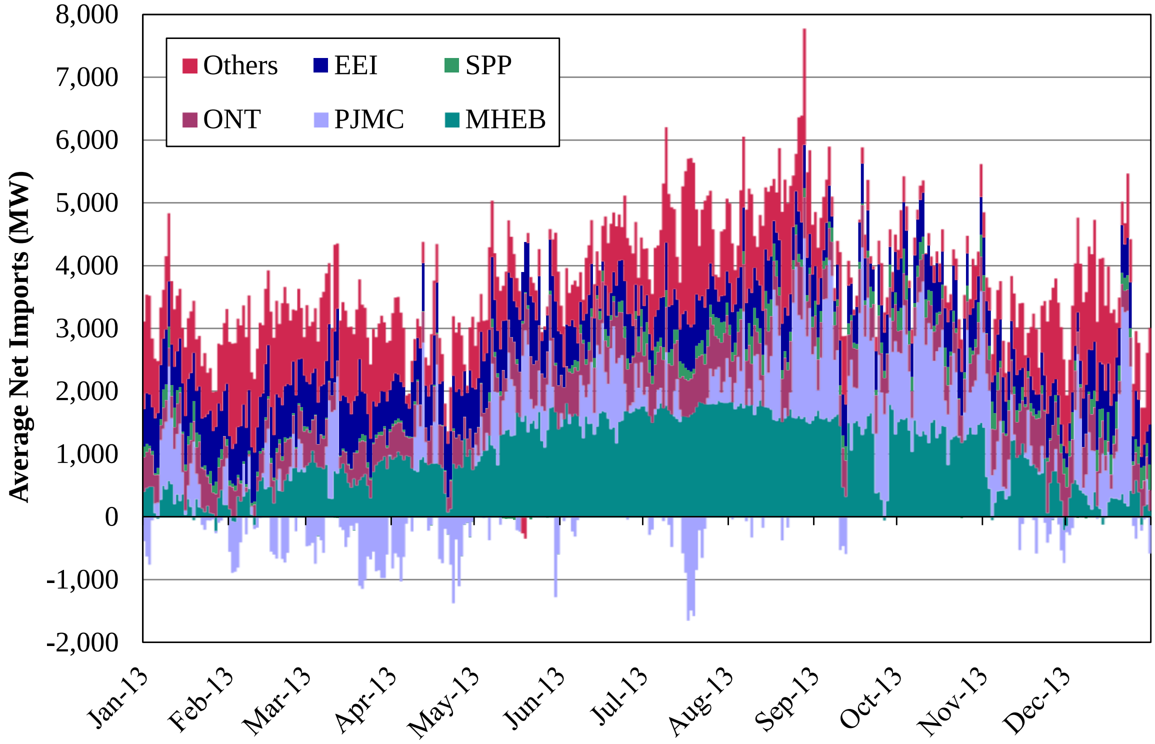


Figure A91: Average Hourly Real-Time Net Imports
2013, by Interface

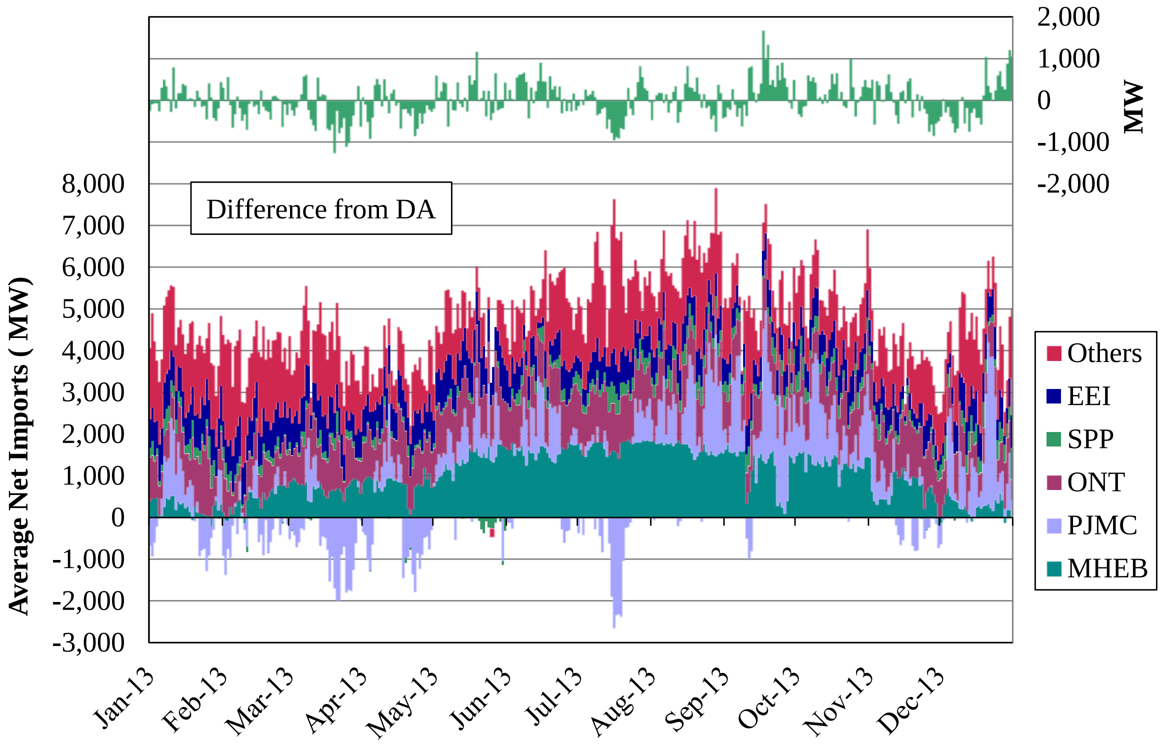
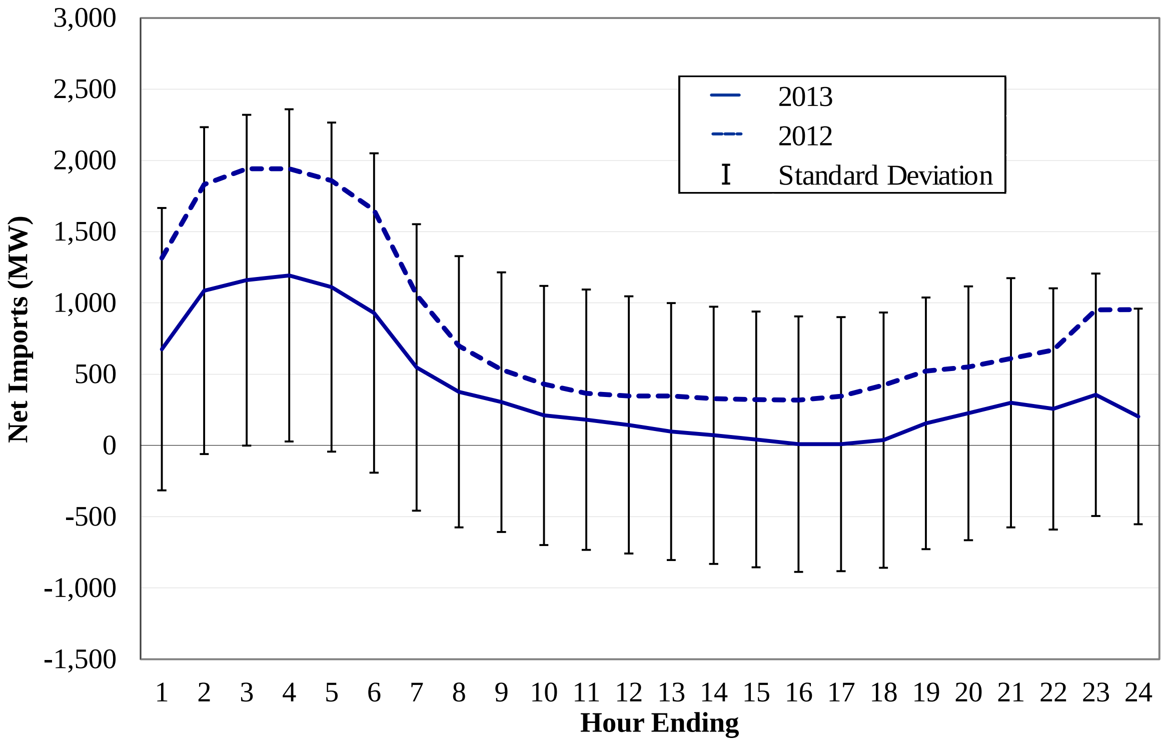


Figure A92 and Figure A93: Hourly Average Real-Time Net Imports by Interface

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 can cause incentives to import or export to change over time.

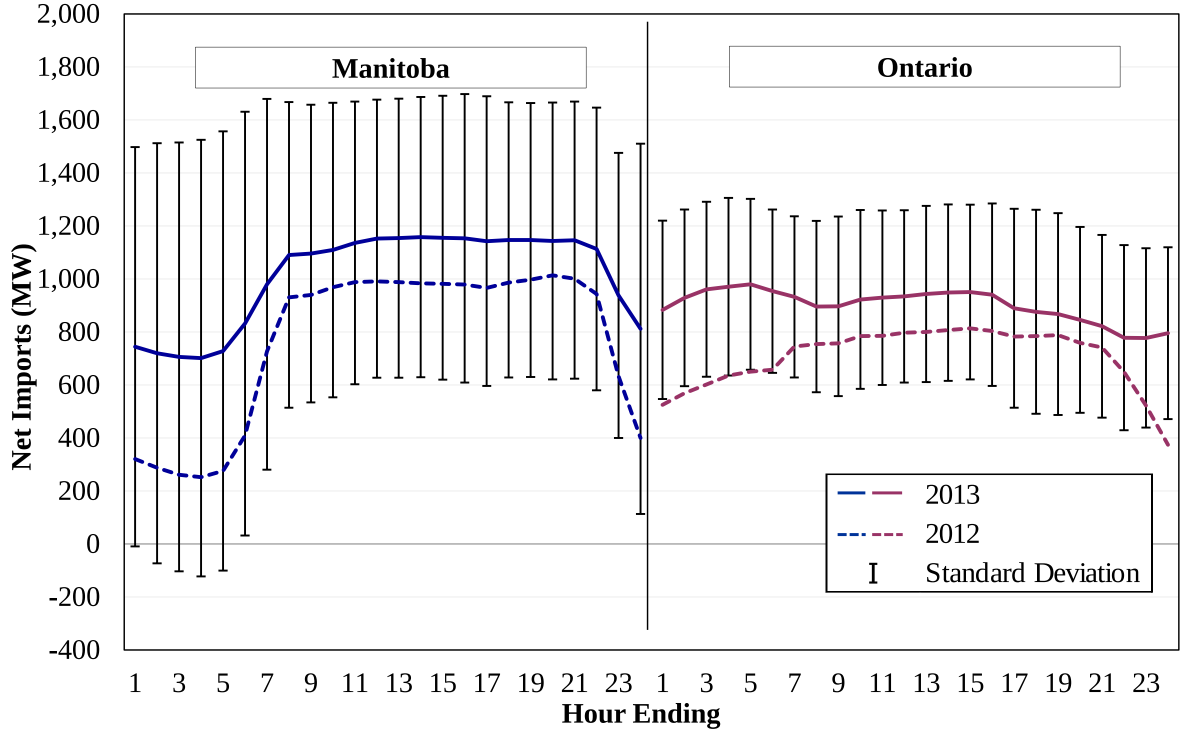
Accordingly, Figure A92 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2012 and 2013, along with the standard deviation of such imports.[33] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

Figure A92: Average Hourly Real-Time Net Imports from PJM
2012-2013



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

Figure A93: Average Hourly Real-Time Net Imports, from Canada
2012-2013



<u>Key Observations: Import and Export Quantities</u>

i. As in prior years, MISO in 2013 remained a substantial net importer of power in both the day-ahead and real-time markets.

– Average real-time net imports decreased 13.4 percent to 3.7 GW per hour. This is nearly 1 GW lower than average imports in 2012.

ii. The decrease occurred entirely on the PJM interface, MISO's largest, which declined 24 percent. Net imports rose nearly 30 percent on lower capability Ontario and Manitoba interfaces, particularly during off-peak hours.

– Imports from Manitoba were highest in summer, when water levels are at their peak and MISO energy prices are highest.

iii. About one-third of interchange was associated with wheeled transactions through MISO (see next section), including most imports from Ontario (95 percent) and 87 percent of exports to PJM.

iv. Two-thirds of exports flowed to PJM, and were significant on several occasions. During the peak period in mid-July, MISO exported on average 2.3 GW of power to PJM.

– These net exports often increased significantly from the day-ahead to real time.

v. Real-time imports averaged approximately 360 MW greater than day-ahead imports, and were greater than day-ahead imports on most days in 2013.

– Large changes in net imports in real time can contribute to price volatility. Declines in imports in particular can result in reliability issues that MISO must manage by committing additional generation, including peaking resources.

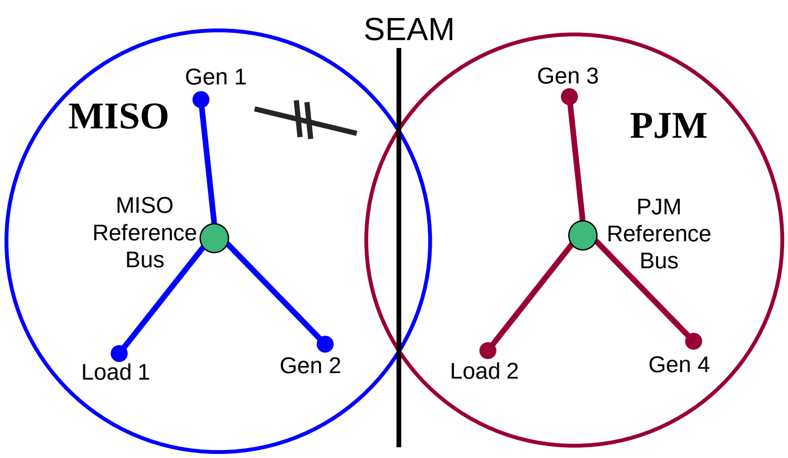
B. Interface Pricing and External Transactions

Interface prices are used to settle with participants that schedule physical schedules into, out of, or through MISO. These prices are critical because they establish the incentive that will govern participants' external transaction schedules. In this subsection, we discuss the concepts that underlie efficient interface pricing and evaluate MISO's interface pricing.

The first of a series of diagrams below illustrates the relationship between nodal locations and a central "reference bus". The congestion between any two locations can be measured relative to this central reference bus. Congestion effects are included in the LMPs at all of the generation and load locations. The LMP at each location includes the sum of: (a) the system marginal price; plus (b) the congestion component; and (c) the marginal loss component. To calculate the congestion component of the price at each location, the RTO first calculates the marginal flow impact of injecting a megawatt at the generation or load location and withdrawing the megawatt at the reference bus. The congestion component is equal to this marginal flow impact (known as a "shift factor") multiplied by the shadow price for the constraint.

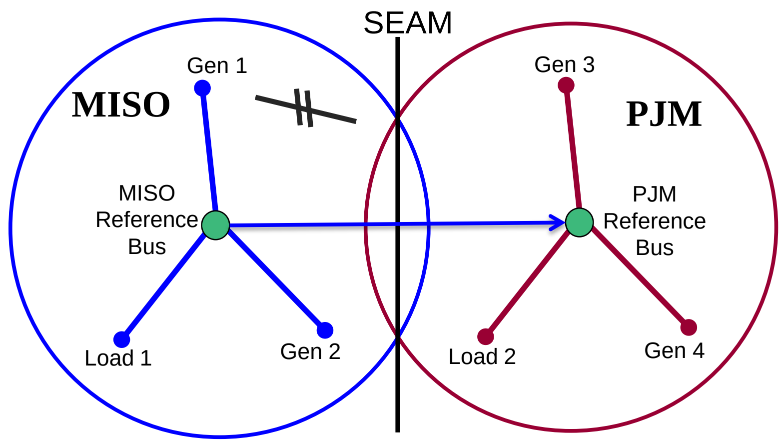
Assuming the constraint in MISO shown in Figure A94 is a market-to-market constraint, all potential opportunities to substitute output at one location for another within each market in order to reduce the flows over the constraint.

Figure A94: Diagram of the MISO-PJM Seam



Next we explain how congestion is calculated for interface prices. The congestion component of the interface price is based on the effects on the constraint of transferring power from one area to the other (which are not shown in Figure A94). The only difference in the calculation of congestion component for the interface compared to ordinary nodal locations is that instead of the power being injected at generation or load locations, it is assumed to be injected at one or more locations in the neighboring market area (known as the "interface definition"). In Figure A95, we depict a transaction from MISO to PJM. In this case, assume MISO defines the PJM interface based on the PJM reference bus. In other words, the schedule is modeled as an injection at MISO's reference bus and a withdrawal at PJM's reference bus. To calculate the congestion component of the interface price for this case of a single market-to-market constraint, MISO calculates the shift factor for this transfer times the constraint shadow price.

Figure A95: PJM Reference Bus as MISO's Interface Definition



By establishing an interface price that includes the congestion effects of the transfer from the MISO reference bus to the PJM reference bus, the congestion benefits or costs will be fully priced and settled. This is essential because this provides efficient incentives for participants to schedule transactions between the two areas.

As described below, however, the interface prices set by the RTO's do not currently provide efficient incentives to schedule external transactions when market-to-market constraints are binding or when TLR constraints are binding.

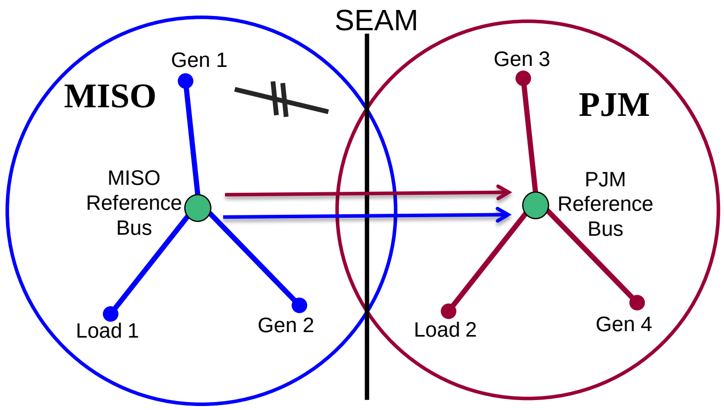
1. Excessive Pricing of Market-to-Market Congestion in Interface Pricing

In mid-2012, we first identified a flaw with the interface pricing methodology used by PJM and MISO on market-to-market constraints. In our 2012 *State of the Market Report*, we provided specific examples of the problem and quantified some of the related inefficiencies and costs to the both PJM and MISO related to this pricing flaw. We reproduce those examples below in this subsection because this issue still requires attention.

Throughout 2013 and into 2014, we have been working with MISO and PJM, and their respective stakeholders through the JCM process to explain the problem and our proposed solution. We have now largely achieved a consensus between the RTOs on the problem but continue to discuss potential solutions.

The pricing flaw is that *both* MISO and PJM were independently estimating the full marginal effects of external transactions scheduled between the areas on all binding constraints, which is depicted in the next figure. As a result, both RTO's interface prices will include congestion components that reflect the same congestion effects, resulting in duplicative settlements.

Figure A96: Duplicate Interface Pricing in MISO and PJM



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.

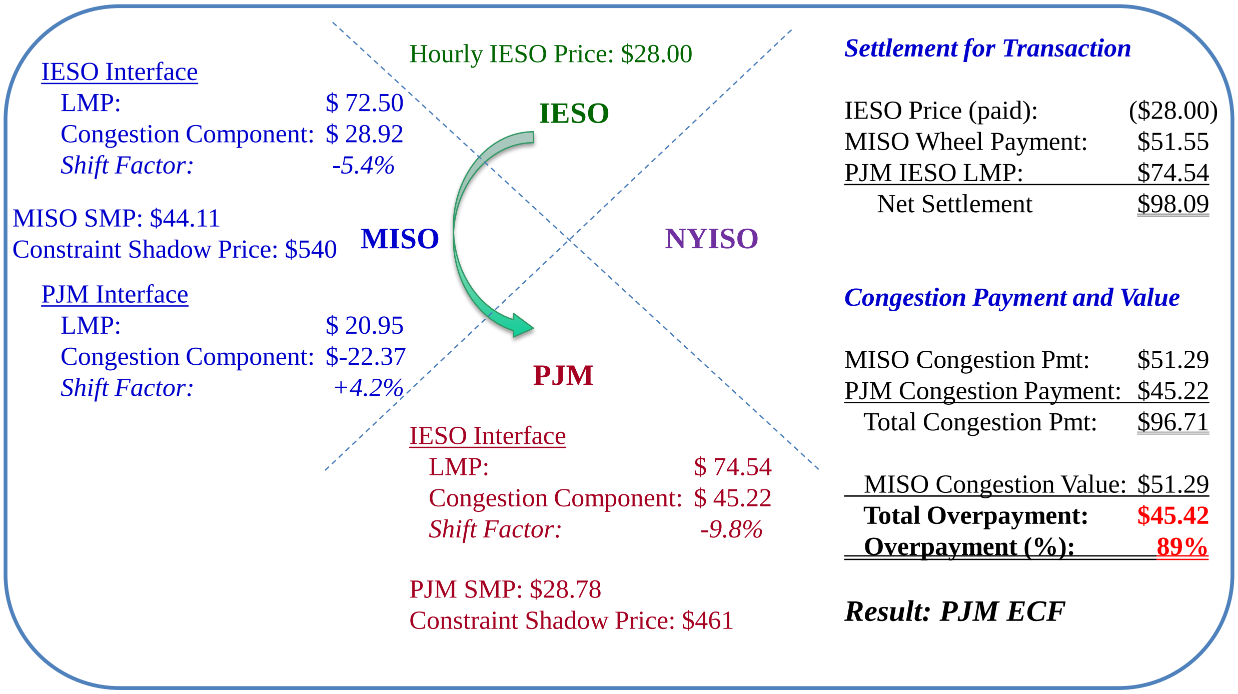
To establish empirically this double settlement, we identified hours when no constraints were binding in PJM or MISO except a single common market-to-market constraint. The following two examples are such cases. By focusing on the prices in these cases, it is relatively straightforward to evaluate this 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

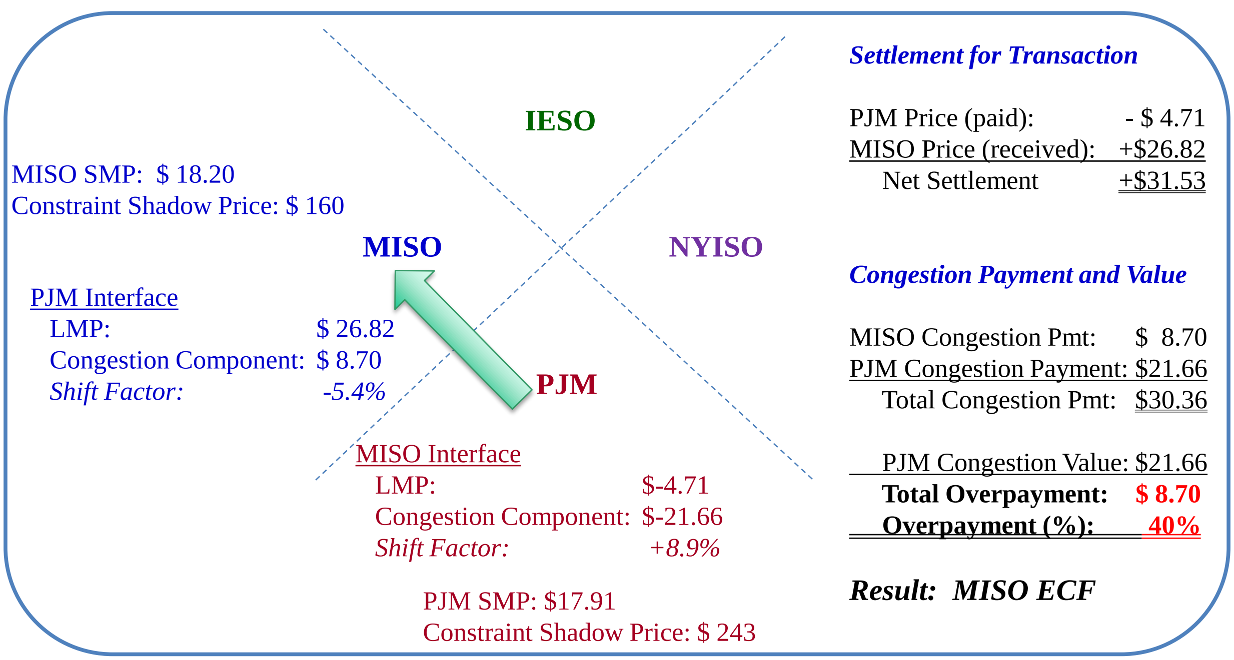
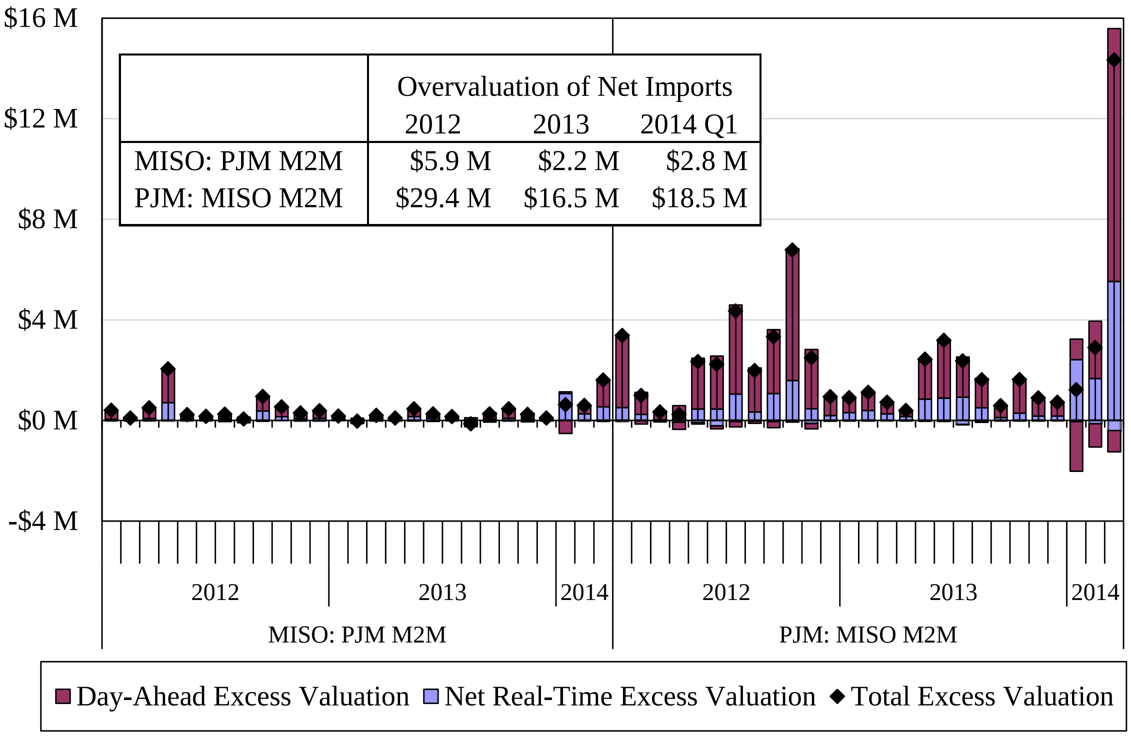


Figure A97: Excess M2M Congestion Settlements

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 A97 summarizes the overpayments and overcharges that we estimate occurred in 2013 by type of market-to-market constraint. Positive values are overpayments and negative values are transactions that were over-charged.

Figure A97: Excess M2M Congestion Settlements
By Type of Constraint, 2013 – Q1 2014



<ins>Key Observations: Excess Pricing of Market-to-Market Congestion in Interface Pricing</ins>

i. The section shows both illustratively and empirically that the current interface pricing rules are flawed and resulting in duplicative congestion settlements with external transactions when market-to-market constraints are binding.

ii. The first example shows that MISO would pay the full value of the relief provided.

- MISO would pay the transaction $51.55 per MWh to the scheduling entity for this wheeling transaction, including $51.29 per MWh for congestion relief. This congestion payment to the scheduling entity fully reflects MISO's estimated benefits of this transaction in relieving the constraint.

- However, the example shows that PJM also makes a congestion payment of $45.22 per MWh, which is why the IESO interface price is so much higher than the PJM system marginal price.
- The participant is paid $98.09 per MWh overall to schedule this transaction, of which $96.71 are congestion payments from MISO and PJM. This payment exceeds the true value of the relief by $45.42 per MWh, or 89 percent (almost double).

iii. PJM's payment in Example #1 would generate ECF or FTR underfunding.

- Because the impact of this transaction is not a component of its market flow, PJM gets no credit in the market-to-market settlement process for this real-time transaction.
- If this were a real-time transaction, the $45.22 congestion payment would be collected from its customers as an uplift charge.[34]

iv. In Example #2, ECF or FTR underfunding is generated by MISO's payment.

- If this transaction were scheduled in real time, MISO's payment would result in negative ECF.

v. We estimate that PJM made $16.5 million in overpayments on market-to-market constraints in 2013, down from $29.4 million last year.

- These overpayments have grown in the first quarter of 2014 to $18.5 million.
- These amounts do not include overpayments made by PJM for other external constraints.

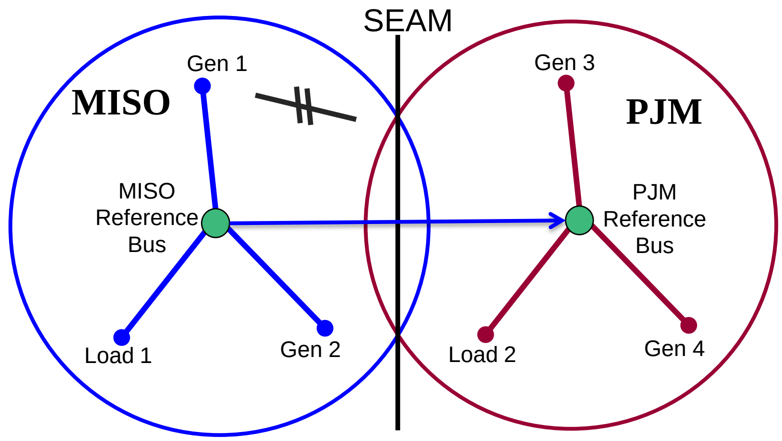
vi. Our examination of transactions that were over-charged understates the scope of this problem because there may be a large number of efficient transactions that are not scheduled because of the over-charge, which would not be shown in the figure.

vii. MISO's overpayments were much smaller because, during this timeframe, PJM experienced less congestion on its market-to-market constraints.

2. Solutions to the Excessive Market-to-Market Congestion Pricing

To eliminate the redundant market-to-market congestion pricing, the interface definitions and pricing must be modified to settle the effects of transferring power from one area to the other only once. One way to do this is to simply have the monitoring RTO alone price the congestion on its own market-to-market constraints. This is consistent with Figure A94, reproduced below.

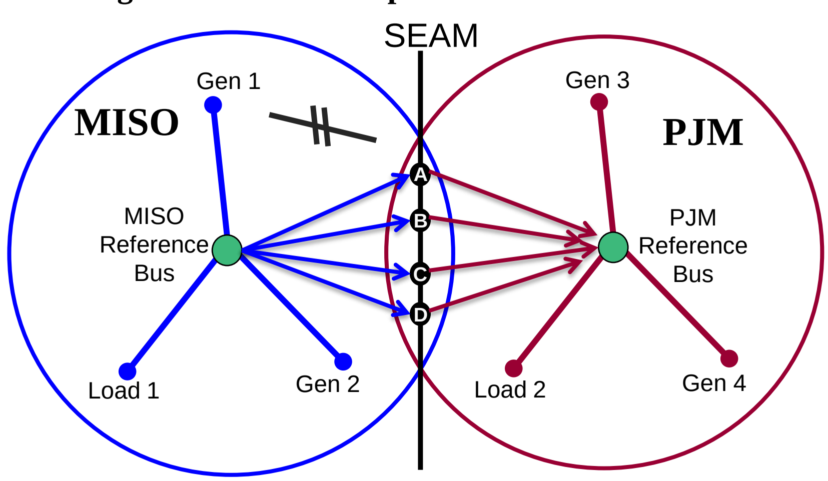
34 Since PJM's generation levels can affect its market flows on the constraint, the transaction could have a secondary effect on its market-to-market settlements (positive or negative) that we did not quantify.



In the above diagram, MISO estimates the congestion effect of the export on its market-to-market constraint and prices that effect into its interface congestion component. The congestion will be fully and efficiently priced by MISO so there is no need for PJM to independently price the congestion associated with this constraint in its interface price. It is important for PJM to price and settle the congestion for this constraint at all of its generation and load locations because MISO does not settle with PJM's generators and loads. Because this solution is simple and would ensure efficient pricing on all market-to-market and other transmission constraints, we have recommended that both RTO's adopt this approach. In the Joint and Common Market (JCM) process with the stakeholders for both RTOs, we have referred to this solution as "Alternative #1."

PJM's current preferred approach for addressing the duplicative congestion pricing for market-to-market constraints is to change the definition of the interface with MISO. Instead of assuming the power is sourcing or sinking inside the neighboring area at the reference buses as shown in the diagram above, PJM has proposed for MISO and PJM to both define their interfaces based on a common set of points at the seam. We illustrate this solution in Figure A98 below:

Figure A98: PJM-Proposed Interface Definition



Utilizing a common interface definition as proposed by PJM eliminates the redundant congestion pricing because the RTOs would each estimate only part of the flow effects of the transaction. 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 A, B, C and D ***to*** its Reference Bus.

This solution will 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 A3: 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 A4: 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 Alternative #1. Therefore, we continue to recommend that both PJM and MISO implement Alternative #1, which entails:

- The monitoring RTO defining each interface as the reference bus or "centroid" in the neighboring control area; and
- The non-monitoring RTO should not include the constraint in its interface price since it is fully priced by the monitoring RTO.

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.[35] 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.

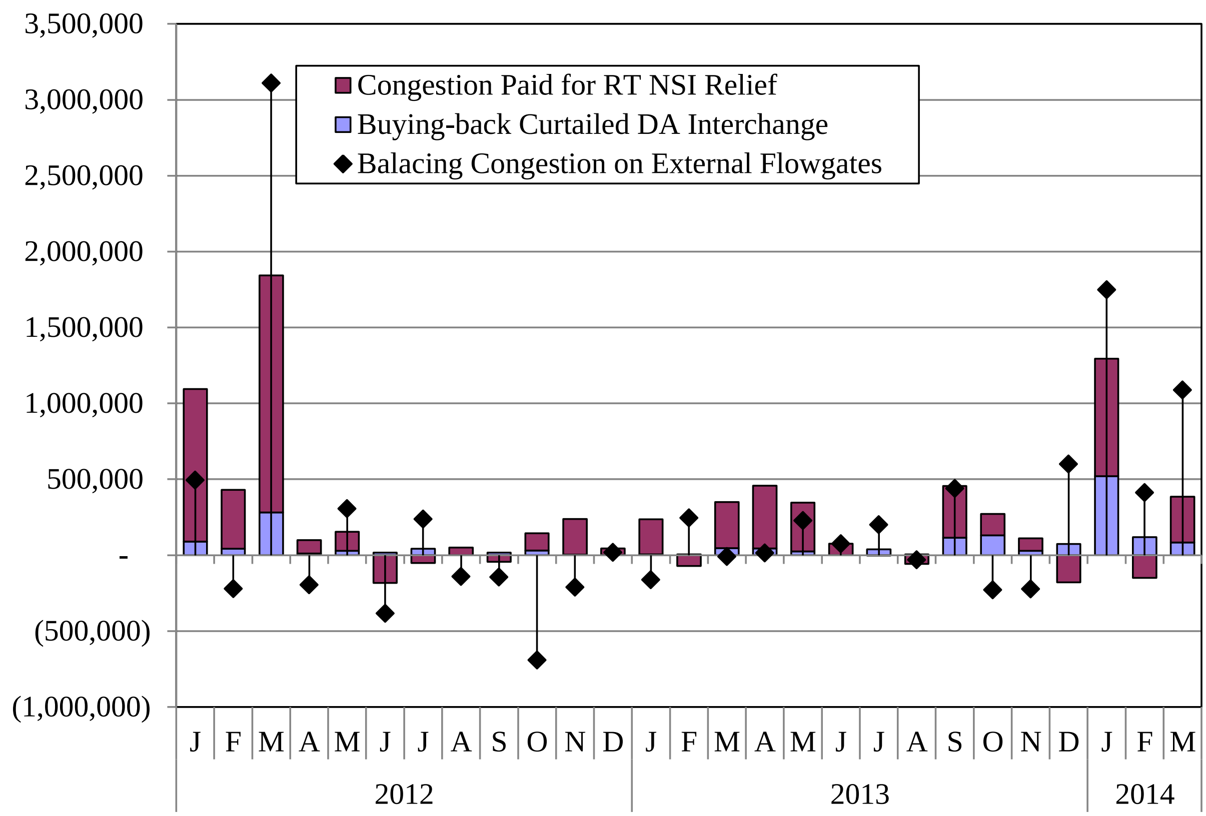
Finally, MISO's shadow cost for external TLR constraints is frequently overstated times over versus the monitoring system operator's true marginal cost of managing the congestion on the constraint. As shown in Section V.D, this causes the congestion component associated with TLR constraints that is included 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.

35 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.

Figure A99: Excess TLR Congestion Settlements for External Transactions

Figure A99 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, 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 A99: Excess TLR Congestion Settlements for External Transactions



Key Observations: External TLR Congestion in Interface Prices

i. The analyses in this report demonstrate that the congestion components in MISO's interface prices that reflect external TLR constraints are highly inefficient.

- We therefore find that MISO is providing incentives that motivate inefficient imports and exports.

- This raises costs indirectly to MISO's customers by leading to an inefficient real-time dispatch.

ii. MISO customers also incur direct costs associated with congestion payments made to imports and exports for external TLR constraints.

- These payments are generally funded through negative ECF (i.e., balancing congestion or FTR underfunding).
- These payments averaged $2.1 million in 2013, down from $3.9 million in 2012.
- In addition to being inefficient, these costs are inequitable because MISO receives no reimbursement from its neighboring systems for these payments and no credit toward its relief obligation.

iii. We continue to recommend that MISO take the necessary steps to remove external congestion from its interface prices.

C. Transaction Scheduling Around Lake Erie and Loop Flows

"Contract path" transaction scheduling between the four RTOs around Lake Erie has created significant issues. The underlying problem is generally that settlements occur based on the scheduled contract path, but actual power flows occur on other paths. The scheduled path of a transaction does not determine the physical power flows between generation and load. Physical flows that differ from scheduled flows are "loop flows" that must be accounted for by RTO operators.

Significant loop flows can distort participants' incentives and can lead to inefficient scheduling. MISO made several improvements to address Lake Erie loop flows in recent years. Most significantly, it participated in introducing in mid-2012 coordinated interface operations via Phase Angle Regulators (PARs) to better manage loop flows.

Figure A100: Transaction Schedules from Ontario to PJM

Figure A100 shows the average hourly quantity and profitability of these Ontario-to-PJM wheel-through transactions in each month in 2012 and 2013. Profitability is calculated based on prices in PJM and IESO minus MISO's wheeling charge.[36] This profitability is shown by the green line in the top panel of the figure and generally corresponds to the participants' actual profit. The second profitability line, shown in dark blue, is the profits the participant would earn by scheduling two transactions, one into MISO from Ontario and one from MISO to PJM. PJM would compensate the split wheel at its MISO interface which is normally less valuable than its IESO interface.

The only difference between these two is the incremental price premium that PJM provides for transactions sourcing in Ontario. One should expect this premium to be low now that the PARs are in operation and limiting loop flows through New York (so the impacts on PJM's constraints from transactions sourcing in Ontario should be similar to the impacts of transactions sourcing in

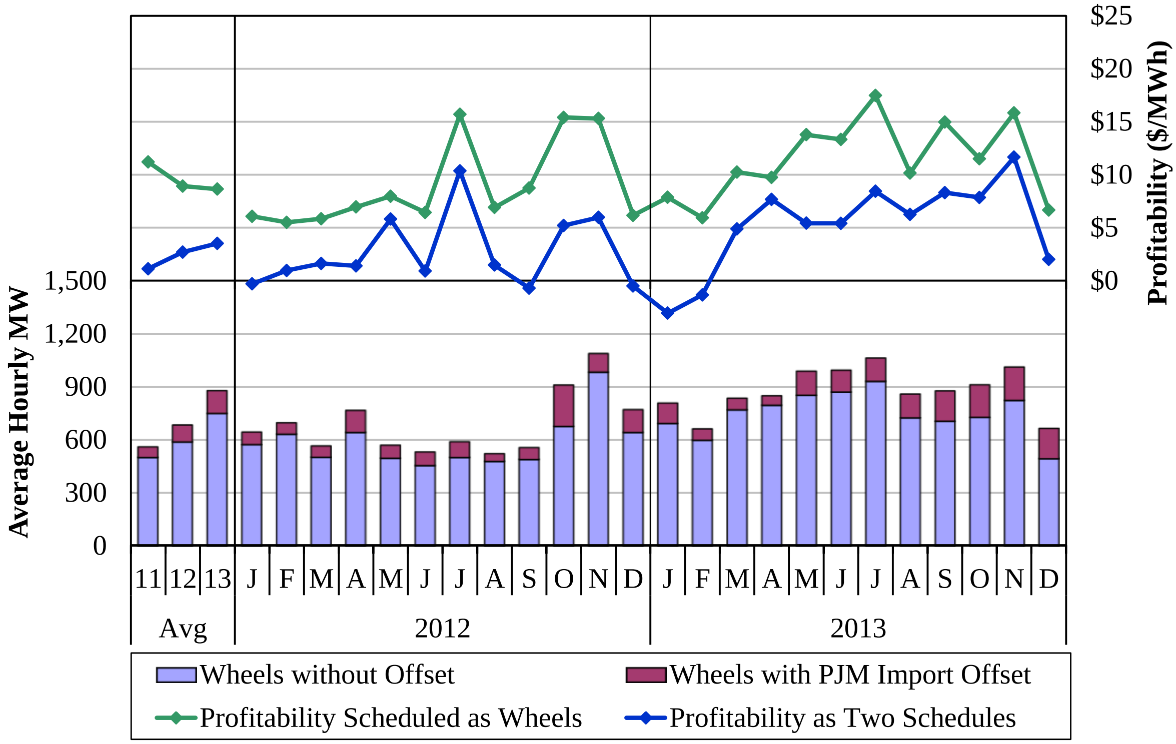
36 The profits shown are net of the IESO Export Transaction Service Rate but exclude other costs allocated by IESO which would reduce the profits.

MISO). The figure also shows the portions of the transactions that are then scheduled back into the MISO by the same participant. Effectively, these sets of transactions are scheduled from Ontario to MISO, but are first scheduled through PJM for reasons that we discuss below in the observations.

Although generally profitable, these Ontario to PJM wheels may not always be efficient because:

- They do not pay for any congestion they cause in NYISO, which raises efficiency concerns; and
- They will be over-compensated by MISO and PJM when a market-to-market constraint is binding in both markets because the interface prices in both markets will reflect the full value of the relief provided by the transaction (see the next subsection for a discussion of this flaw).

Figure A100: IESO to PJM Schedules
2012–2013



<u>Key Observations: Transaction Scheduling Around Lake Erie</u>

i. The wheeling of transactions from IESO to PJM through MISO rose in 2013 to average nearly 900 MW per hour.

   – The IESO-to-PJM transactions remained substantially profitable (averaging $8.68 per MWh), because they are compensated by both PJM and MISO when relieving market-to-market constraints and are valued incorrectly with respect to PJM's internal constraints.

ii. Fifteen percent of IESO-PJM wheel-through transactions were scheduled back from PJM into MISO and earned much higher profits than simply scheduling from IESO to MISO.

– This additional profitability is a function of PJM's external interface pricing, which pays transactions based on the perceived congestion they relieve in PJM.

– Since a substantial share of the power associated with these transactions is priced as if it flows into PJM from NYISO, it receives congestion payments for relieving constraints in eastern PJM.

✓ There has been no change to PJM's pricing of the IESO interface since the western Michigan-IESO PARs went into operation. As discussed below, these PARs align actual and scheduled flows around Lake Erie.

– If these constraints are M2M constraints that are reflected in the MISO real-time market as well, each RTO is separately paying the transaction for relief of the same constraint under their current interface pricing rules. (This market flaw is discussed in the next subsection.)

iii. The figure shows that the profitability of the wheels was roughly twice as high as it would have been if scheduled as two separate transactions.

– This would be reasonable if transactions sourced in Ontario created more beneficial network flows in PJM (or less harmful in contributing to congestion) than those sourced in MISO.

– With the PARs in operation and effectively controlling loop flows around Lake Erie, this premium is likely overstated.

iv. Full operation of the five Michigan-IESO PARs began in mid-2012, and has resulted in a controlled interface in over 95 percent of intervals, thereby substantially reducing loop flows.

– This contributed to a greater than 50 percent reduction in the instances when loop flows on the interface is greater than the 200-MW Control Band—PAR tap settings are not adjusted for flows below this amount.

– PAR operation has also reduced congestion and the frequency of TLR schedule curtailments, thereby improving overall scheduling incentives.

– MISO is proposing that the modeling of the PARs in the calculations of market flow and entitlements be made consistent with their treatment in the IDC.

D. 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 A101 and Figure A102: 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 A101: Real-Time Prices and Interface Schedules
PJM and MISO, 2013

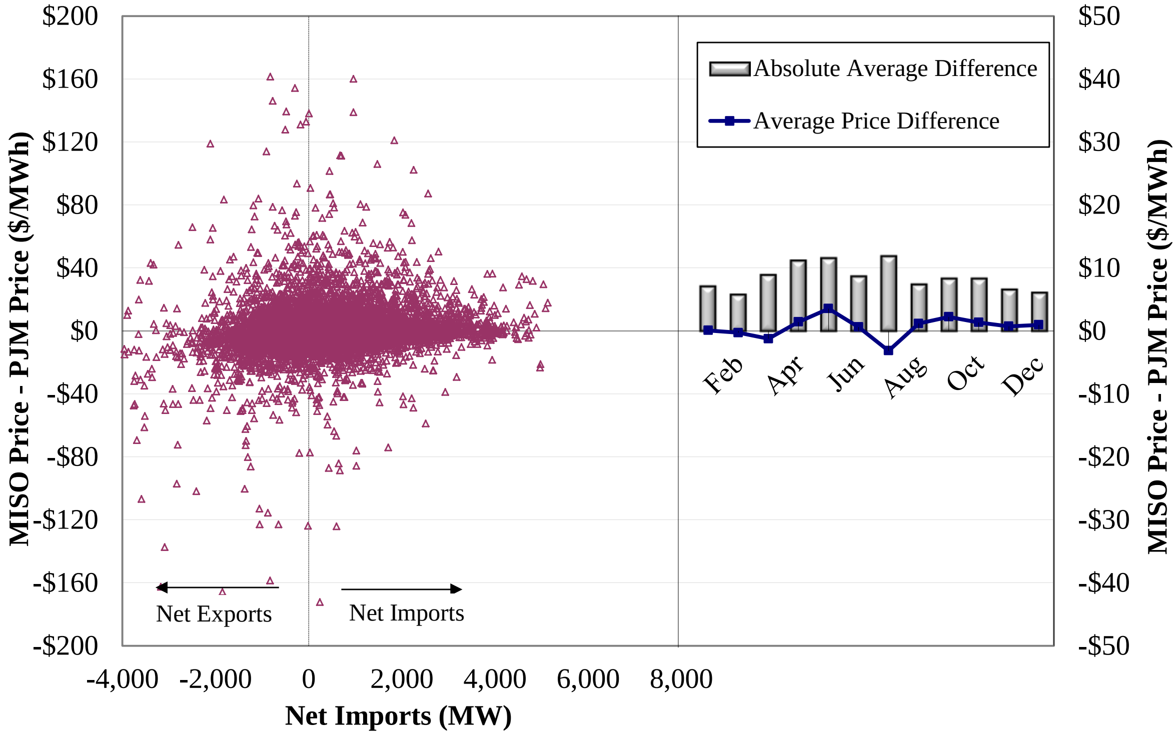
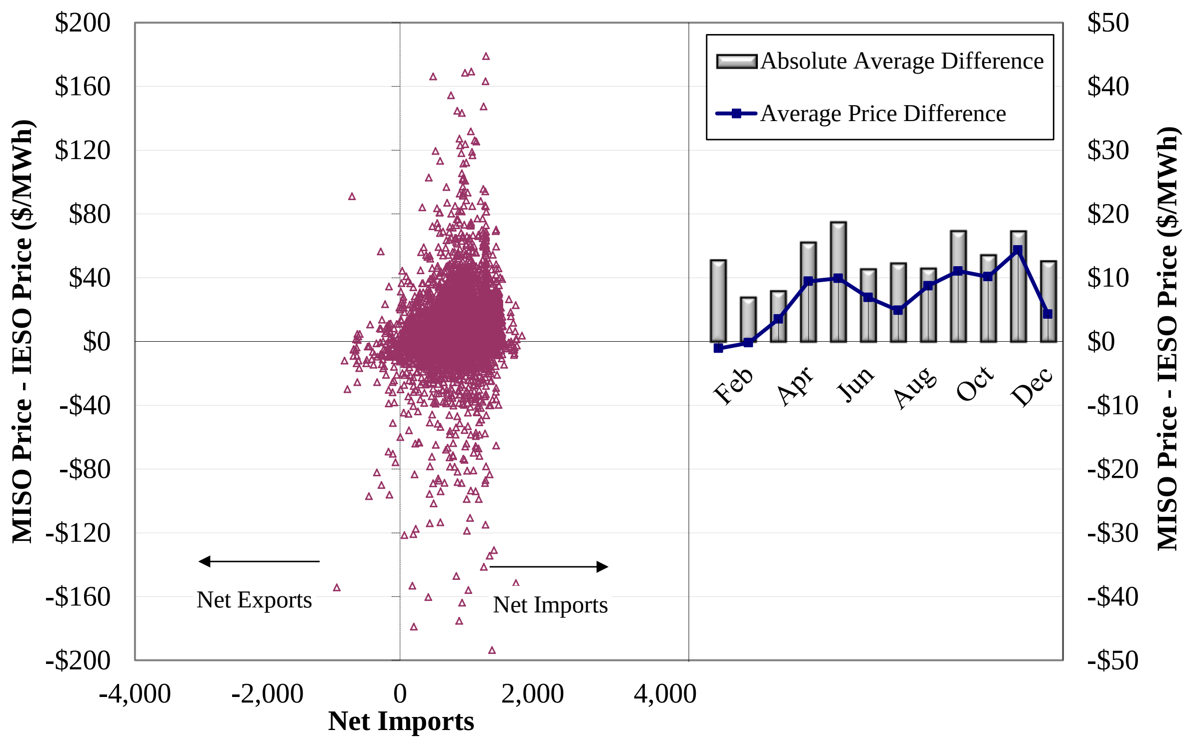


Figure A102: Real-Time Prices and Interface Schedules
IESO and MISO, 2013



<u>Key Observations: Price Convergence</u>

i. The dispersion of prices and schedules on the interfaces shows that transactions remain relatively unresponsive to price differences.

- Ideally, net exports should only occur if prices in the neighboring RTO are greater than those in MISO (values in the bottom-left panel of Figure A101 and Figure A102). The inverse holds for net imports (values in the top-right panel). This often does not occur because:
  - ✓ Real-time market schedules must be submitted no less than 30 minutes in advance of real-time market clearing.
  - ✓ Since real-time prices are relatively volatile, there is substantial uncertainty regarding the direction and magnitude for schedules between RTOs;
  - ✓ There is a lack of coordination between the market participants that arbitrage price differentials between the RTOs; and
- The lack of a nodal market in IESO also contributes to the difficulty in scheduling transactions efficiently.

ii. The share of hours in which transactions with IESO were scheduled in the profitable direction exceeded 72 percent in 2013, up from 68 percent in 2012 and just 48 percent in 2011.

iii. The PJM interface was scheduled in the profitable direction in 53 percent of all hours.

- In addition, many hours (the ones in the top left quadrant of the figures) still exhibited large price differences that can be attributed to scheduling uncertainties, which indicates that substantial savings could be achieved by improving the scheduling processes.
- In the JCM process, PJM and MISO agreed to an alignment of scheduling rules and timelines intended to improve performance.
  - ✓ However, alignment of scheduling rules will not address the observed inefficiency inherent with uncoordinated interchange.
  - ✓ Hence, we recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence.

iv. In response to this recommendation, MISO has been working to develop a proposal to adjust the physical interchange with PJM in a coordinated intra-hour scheduling process.

- One proposal is to allow for dispatchable interchange transactions that will indicate a market participant's minimum price differential needed to engage in an intra-hour interchange transaction.

- The scheduling of such transactions can be optimized and adjusted on a five- to 15-minute basis.
- We support this concept and believe it will enhance efficiency and price convergence between the RTOs. We commented in MISO stakeholder processes that:
  - ✓ Dispatchable interchange transactions should not be subject to uplift charges; and
  - ✓ RTOs should retain the congestion payments that may arise when the external interface becomes constrained.
- While PJM staff has worked with MISO on this concept, to date PJM stakeholders have not prioritized these improvements highly enough for the ISO's to move forward.

VII. 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.

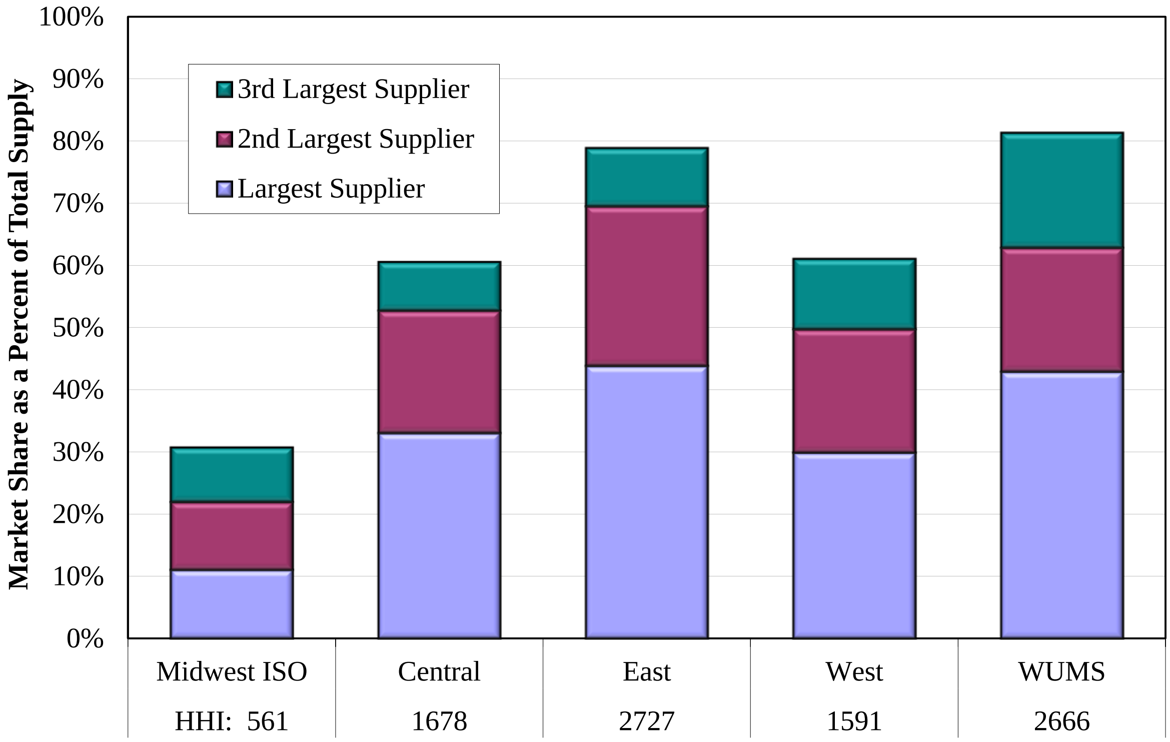
Figure A103: Market Shares and Market Concentration by Region

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 threes suppliers.

Figure A103 shows generating capacity-based market shares and HHI calculations for MISO as a whole and within each region.

Figure A103: Market Shares and Market Concentration by Region
2013



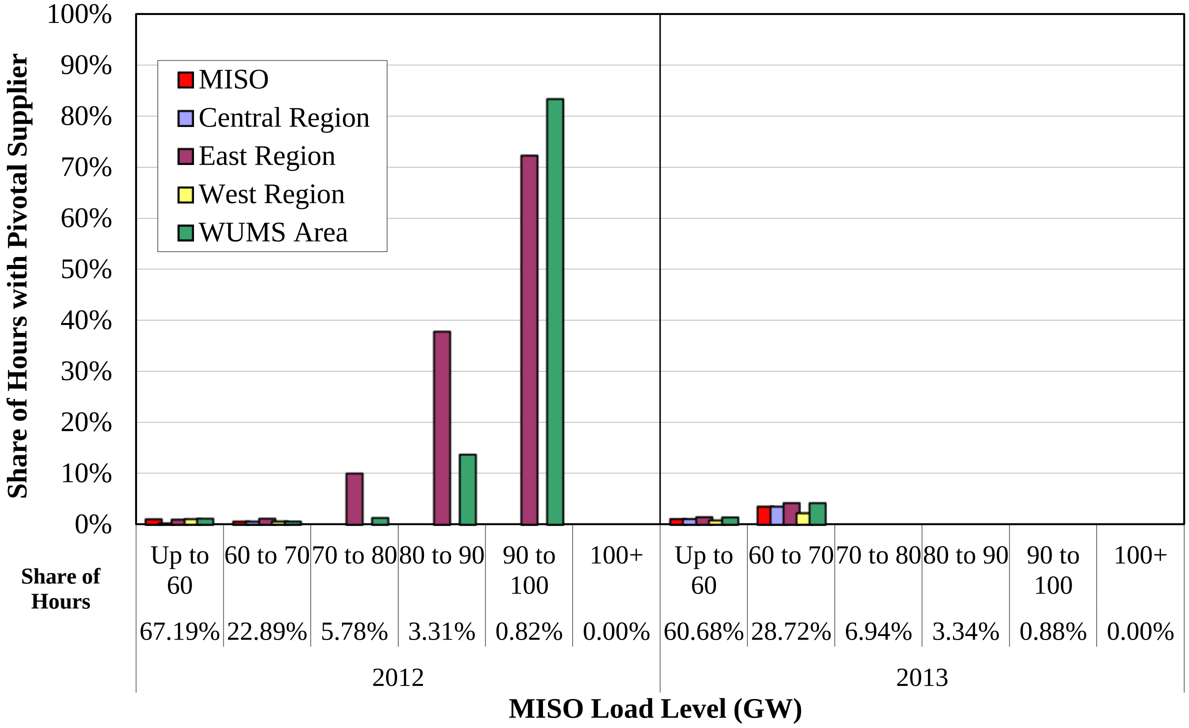
Because the subregions of MISO analyzed above do not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, the HHI alone does not allow for conclusive inferences regarding the overall competitiveness of electricity markets. The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

Figure A104: 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 A104 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 A104: Pivotal Supplier Frequency by Region and Load Level
2012–2013



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.

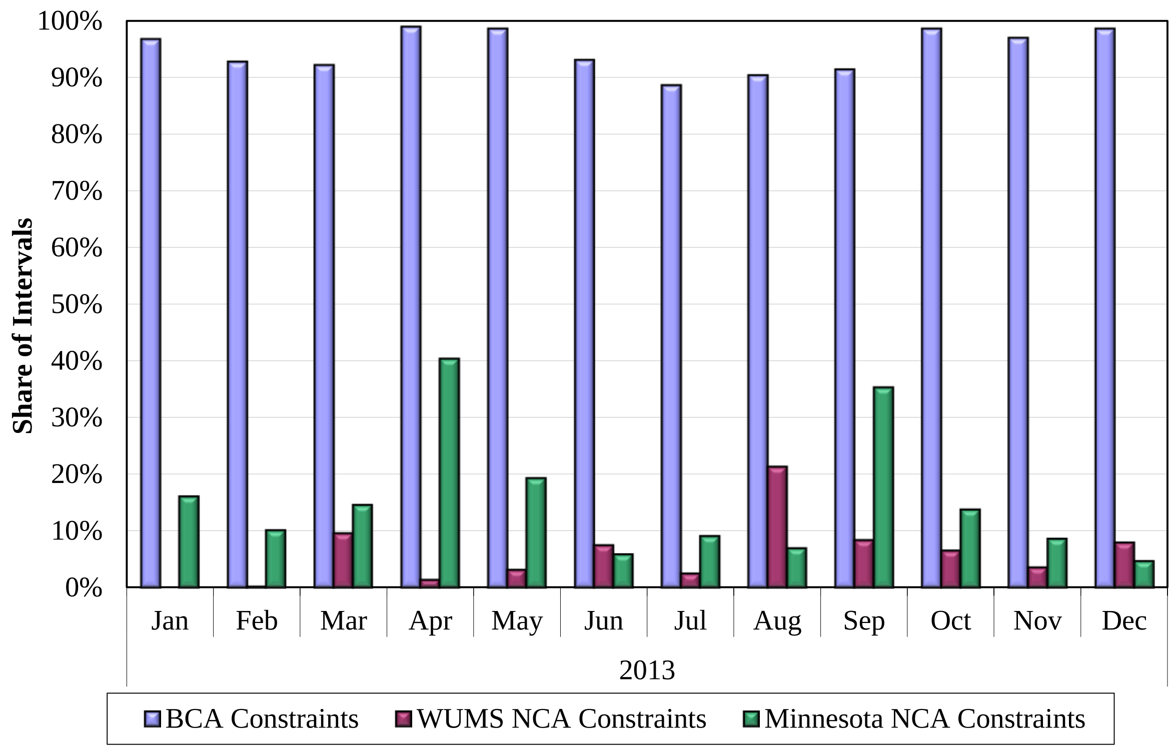
Two types of constrained areas are defined for purposes of market power mitigation: Broad Constrained Areas (BCAs) and Narrow Constrained Areas (NCAs). The definitions of BCAs and NCAs are based on the electrical properties of the transmission network that can lead to local market power. NCAs are chronically 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. The three NCAs defined in the MISO markets in 2013 were the Minnesota NCA, the WUMS NCA[37], and the North WUMS NCA. In December, 2013, FERC approved two additional NCAs in the MISO South Region, WOTAB and Amite South. Due to the short period these were active in 2013, these two NCAs are excluded from the charts.

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 A105 and Figure A106: Frequency of Pivotal Suppliers

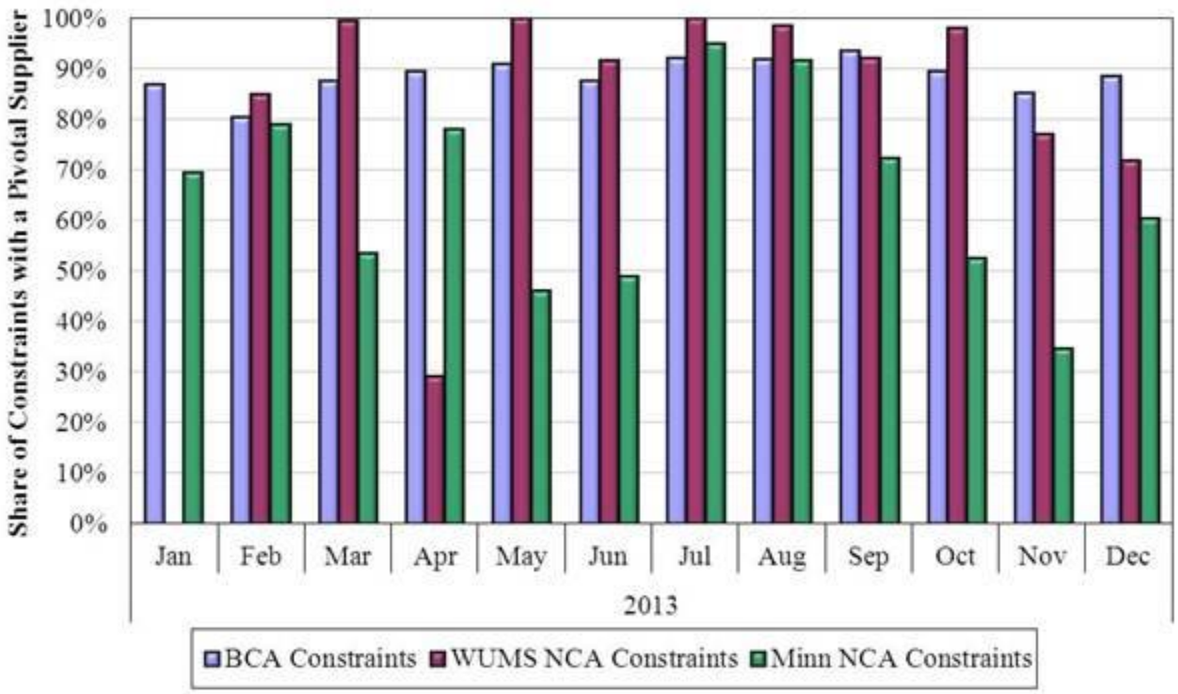
The next two figures evaluate potential local market power by showing the frequency with which suppliers are pivotal on individual NCA and BCA constraints. Figure A105 shows the percentage of all market intervals by month during which at least one supplier was pivotal for each type of constraint. For the purposes of this analysis, the WUMS and North WUMS NCAs are combined. Figure A106 shows, of the intervals with active constraints in each month, the percentage with at least one pivotal supplier.

Figure A105: Percent of Intervals with at Least One Pivotal Supplier
2013



37 Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, , the thresholds that apply to WUMS NCA were in beginning 2013 set equal to BCA thresholds.

Figure A106: Percentage of Active Constraints with a Pivotal Supplier
2013



Key Observations: Market Structure

i. The market-wide HHI in 2013 was 561, a slight decline from the 581 in 2012.

– The regional HHIs are higher than those in the comparable zones of other RTOs because vertically-integrated utilities in MISO that have not divested generation tend to have substantial market shares.[38]

– Regional HHIs and the market shares of each of the top three suppliers were also little changed from prior years.

ii. Pivotal supplier frequency in 2013 rose consistently with load. This is typical in electricity markets since electricity cannot be economically stored, so when load increases the excess capacity will fall and the resources of the largest suppliers will become increasingly critical.

– Market power mitigation measures effectively address most competitive concerns.

38 Generation divestitures in other RTOs generally reduce market concentration because the assets are typically sold to multiple entities.

- MISO introduced tighter mitigation measures in 2013 for those units committed to support the reliability of the system. These have effectively reduced market power in these areas.

iii. Nearly 90 percent of active constraints in 2013 had at least one pivotal supplier that was pivotal. This is up from less than 60 percent in 2012.

- The results were comparable for the WUMS and North WUMS NCAs. In Minnesota less than two-thirds of constraints had a pivotal supplier.
- At least one BCA constraint with a pivotal supplier was binding in nearly 95 percent of intervals, mostly unchanged from last year.
  - ✓ This share is far larger than it is for NCAs because the number of constraints in each NCA is much smaller. It was just 15.4 percent in Minnesota and 6.4 percent in WUMS.
  - ✓ Since BCA constraints are more broadly defined, there are often multiple binding BCA constraints per interval.

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

B. 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. Mark-ups of one to two percent lie within the bounds of competitive expectations.

<u>Key Observations: Price-Cost Mark-Up</u>

i. Despite indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to exercise market power by physically or economically withholding resources.

   – The average SMP mark-up was just 0.9 percent in 2013, up from 0.6 percent in 2012.

   – These results indicate that the MISO energy markets performed competitively in 2013.

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.[39]

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39 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

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

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

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

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

We employ a three-stage process to determine the economic output level for a unit in a particular hour. First, we examine whether the unit would have been economic for commitment on that day if it had offered 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:

Markets and Services administered by the Transmission Provider, while avoiding unnecessary interference with competitive price signals.

Q_i^{econon} – $\max(Q_i^{prod}, Q_i^{offer})$ 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.

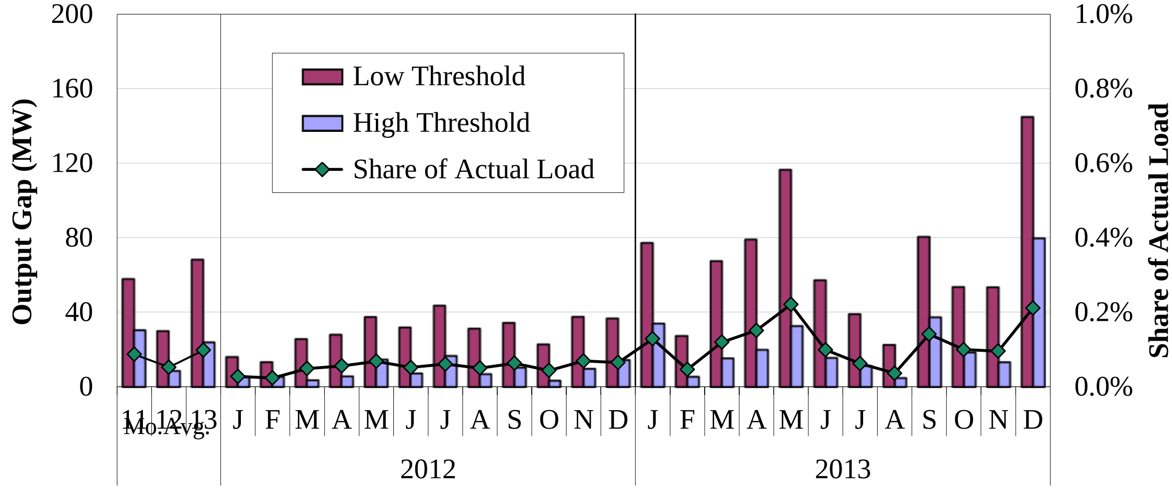
Figure A107: Real-Time Monthly Average Output Gap

Figure A107 shows monthly average output gap levels for the real-time market in 2012 and 2013. 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 2013were $100.00 per MWh for resources located in the WUMS NCA, $33.10 for those in the North WUMS NCA, and $23.17 (down from $64.10 in 2012) for those in the Minnesota NCA. 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 $11.59 per MWh (50 percent of $23.17). 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 A107: Real-Time Average Output Gap

2012–2013



Low Threshold Results by Unit Status (MW)

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	24	4	13	4	4	1	1	9	0	11	0	8	0	2	5	8	2	6	0	12	2	9	0	26	11	4	70
Online	34	26	56	12	9	24	27	29	32	33	31	26	23	36	32	69	25	62	79	104	56	30	22	55	42	50	74

High Threshold Results by Unit Status (MW)

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	22	3	10	4	4	1	1	9	0	9	0	5	0	1	4	7	1	4	0	10	1	6	0	23	7	2	59
Online	8	5	14	2	1	2	4	6	7	7	7	5	3	9	11	27	4	11	20	22	15	5	5	14	11	11	20

Figure A108 to Figure A111: 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 A108: Real-Time Average Output Gap
Central Region, 2013

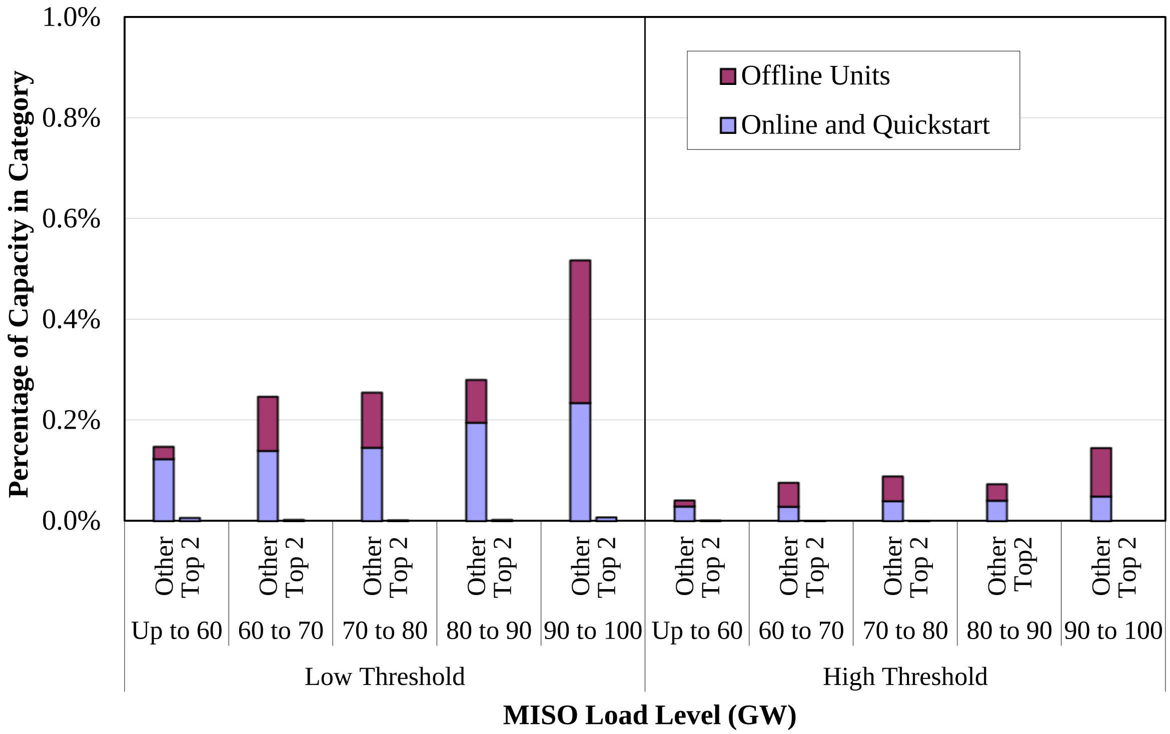


Figure A109: Real-Time Average Output Gap
East Region, 2013

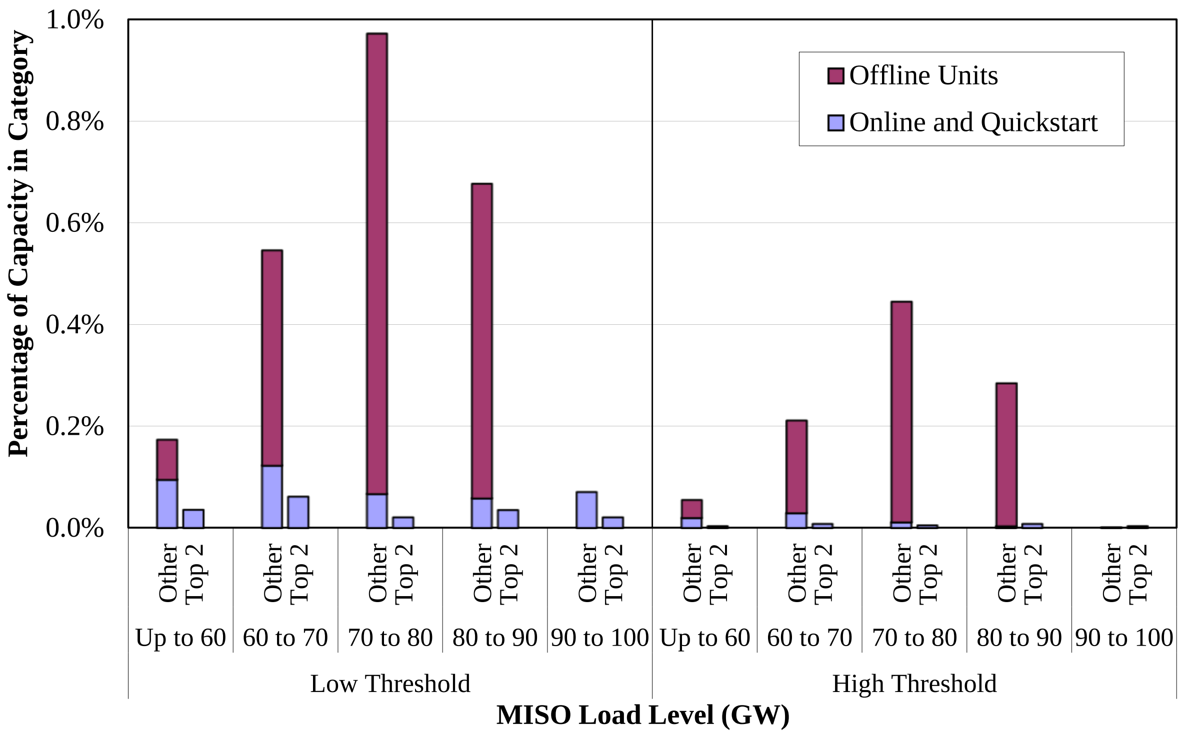


Figure A110: Real-Time Average Output Gap
West Region, 2013

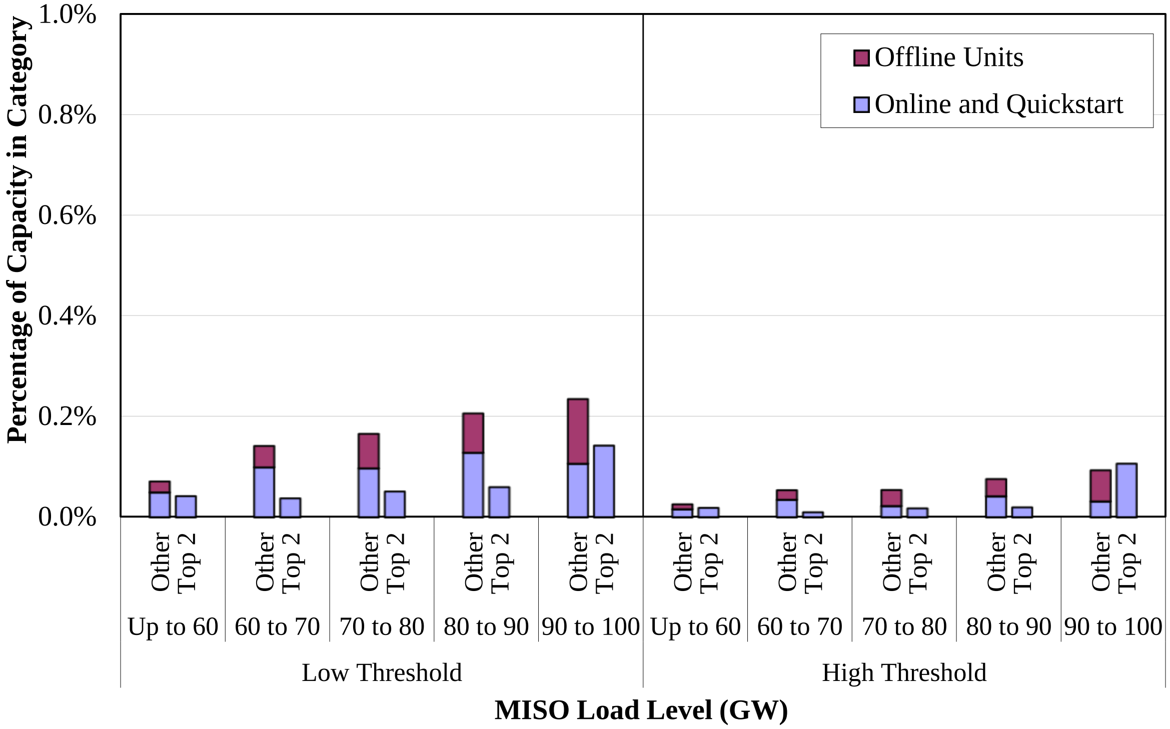
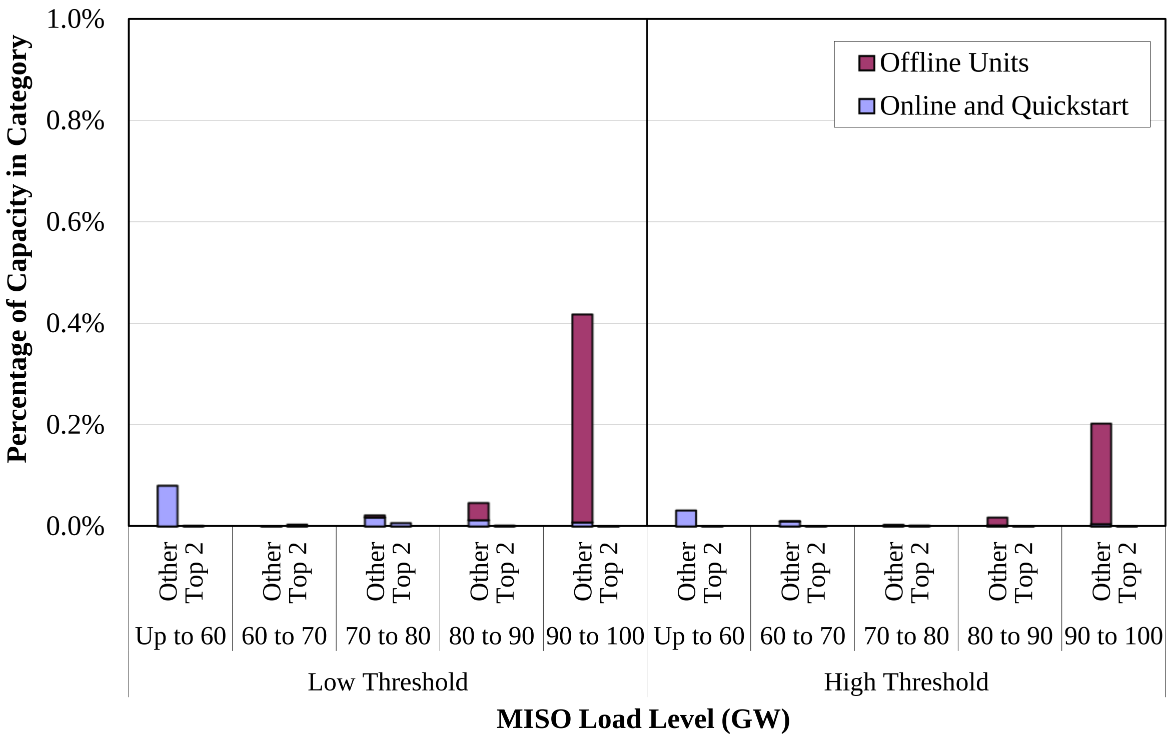


Figure A111: Real-Time Average Output Gap
WUMS Area, 2013



<u>Key Observations: Economic Withholding</u>

i. Output gap in 2013 was higher than 2012 levels but continued to be very low. As a share of actual load it averaged just over 0.1 percent.

  – At low threshold, output gap averaged 73 MW, while at high (mitigation) threshold it averaged 24 MW.

  – A significant contributor to the rise was a significantly tighter NCA threshold in the Minnesota NCA.

  – It was highest in December in part due to the increase in capacity in MISO South.

ii. Output gap rarely exceeded 0.5 percent of capacity in any region. The exception was in the East region, where several units in Michigan with high energy offers contributed to a material increase.

  – Output gap generally increases slightly with load because the high prices that occur at high-load levels result in a much greater share of a resources being economic.

iii. In every region, the conduct of the largest two suppliers was lower than for smaller suppliers. This is a positive indicator regarding the competitive performance since smaller suppliers are less likely to have market power.

D. Market Power Mitigation

In this next subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2013. 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 lower than for BCAs.

Figure A112: Day-Ahead and Real-Time Energy Mitigation by Month

Figure A112 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month. Mitigation is more frequent in the real-time market because the day-ahead is more flexible and liquid. Day-ahead liquidity is provided by virtual participants and the multitude of commitment options makes the day-ahead market much less vulnerable to withholding.[40]

Figure A112: Day-Ahead and Real-Time Energy Mitigation by Month
2013

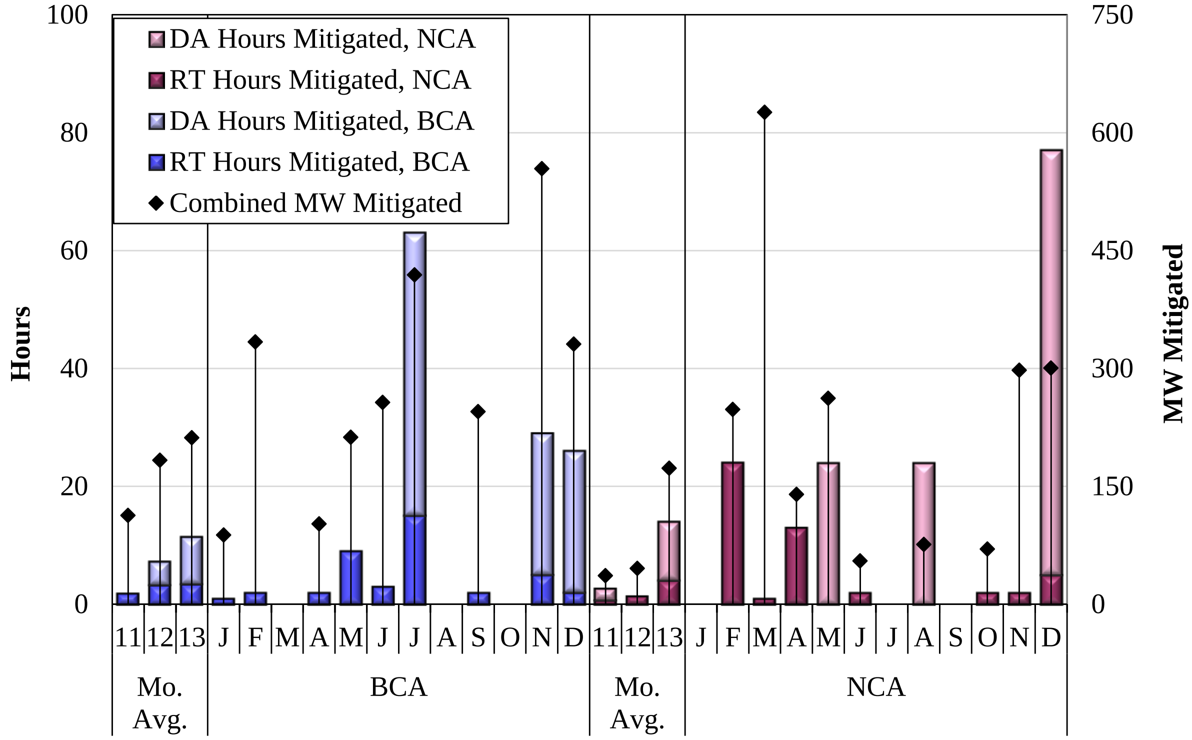


Figure A113: Day-Ahead and Real-Time RSG Mitigation by Month

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).

Figure A113 shows the frequency and amount by which RSG payments were mitigated in 2012 and 2013.

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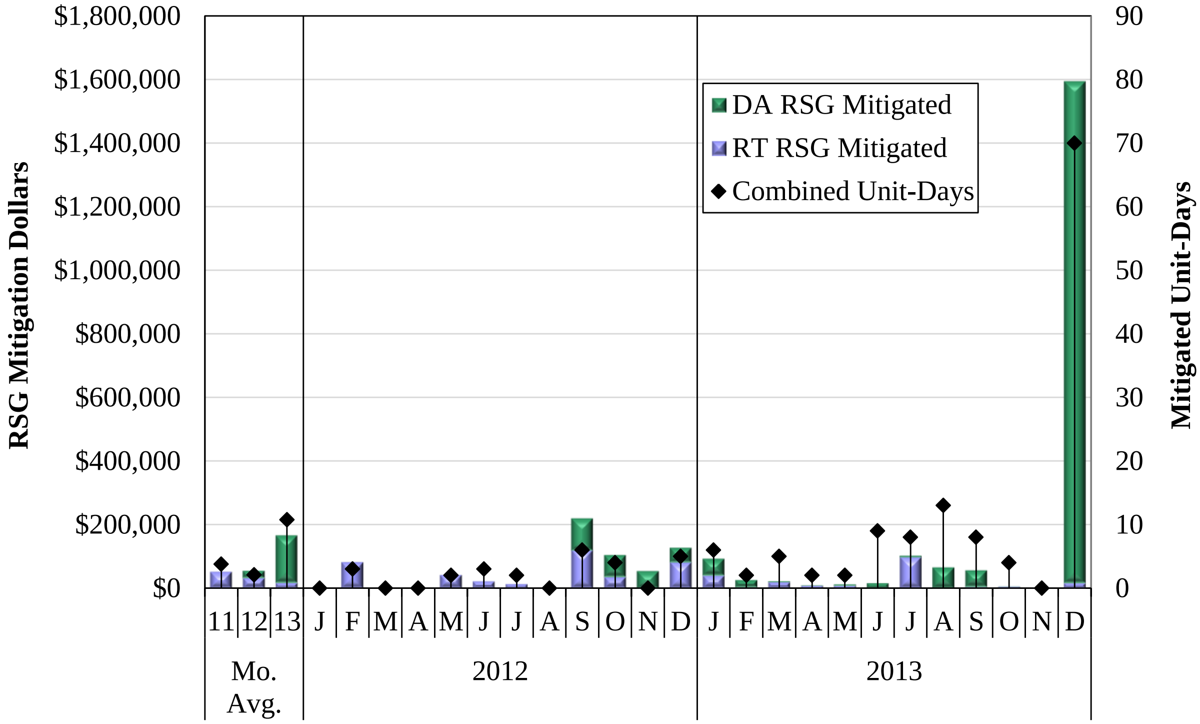
40 Mitigation in the day-ahead market has increased since the MISO South integration, mostly because of the significant number of daily VLR-related commitments in load pockets there.

Figure A113: Day-Ahead and Real-Time RSG Mitigation by Month
2012–2013



Key Observations: Market Power Mitigation

i. Real-time NCA and BCA energy mitigation remained relatively infrequent.

– A total of 41 BCA unit-hours and 40 NCA unit-hours were mitigated in 2013, up from 31 and 17 unit-hours in 2012.

– Mitigation totaled 1,825 MWh in BCAs and 1,504 MWh in NCAs.

– Mitigated quantities in NCAs nearly tripled because the Minnesota threshold was significantly reduced in early 2013. The 24 mitigated hours in February were entirely associated with two units at one station in the middle of the month.

ii. Mitigation of units for RSG payments declined by nearly one-half to just $204,000, and for 28 unit-days.

iii. Mitigation under the VLR mitigation measures was more significant.

– Eighteen unit-days were mitigated under VLR mitigation measures in the real-time market. An additional 101 unit-days were mitigated in the day-ahead market, mostly of units in MISO South in late December.

iv. Despite infrequent mitigation this year, the pivotal supplier analyses discussed earlier in this section continues to indicate that local market power is a significant concern.

– If exercised, local market power could have substantial economic and reliability consequences within MISO. Hence, market power mitigation measures remain essential.

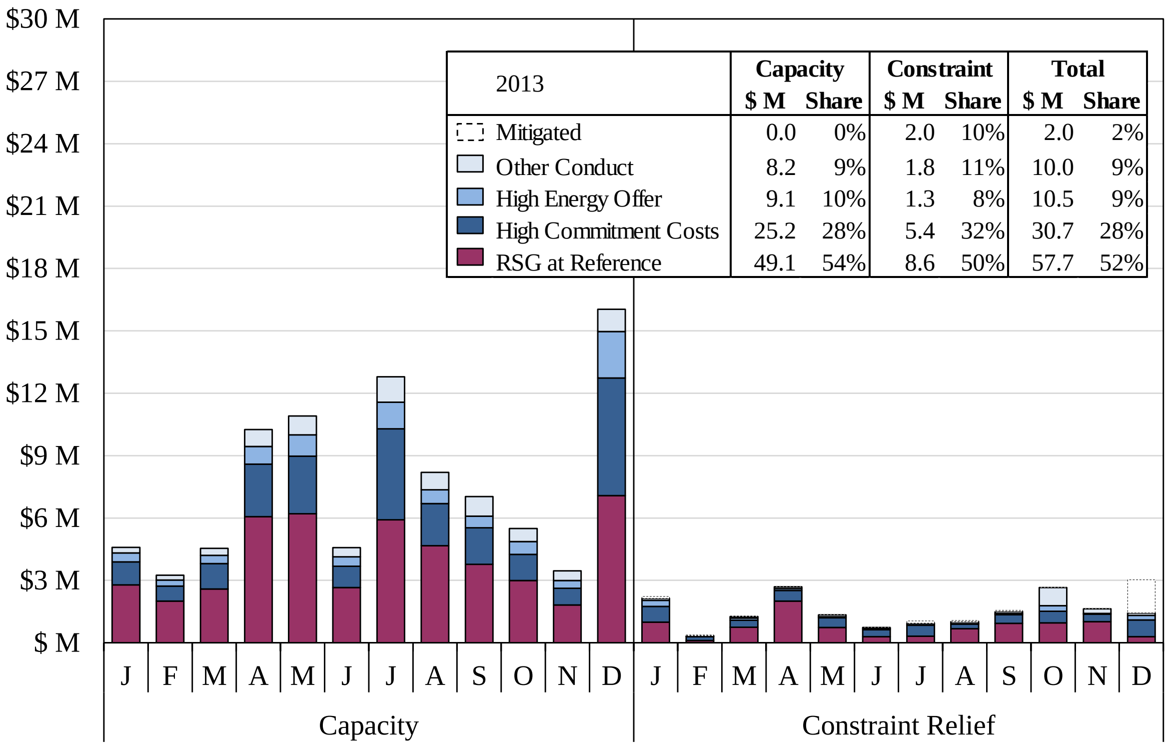
E. Evaluation of RSG Conduct and Mitigation Rules

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 A114: Real-Time RSG Payments by Conduct

We evaluate conduct associated with RSG payments in the following figure, separating the payments associated with resources' reference levels, and the payments associated with the portions of resources' bid parameters (e.g., 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.

Figure A114: Real-Time RSG Payments by Conduct
By Commitment Reason, 2013



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-bid production cost of a resource. This method recognizes the joint impact of all of the resources' bid parameters.

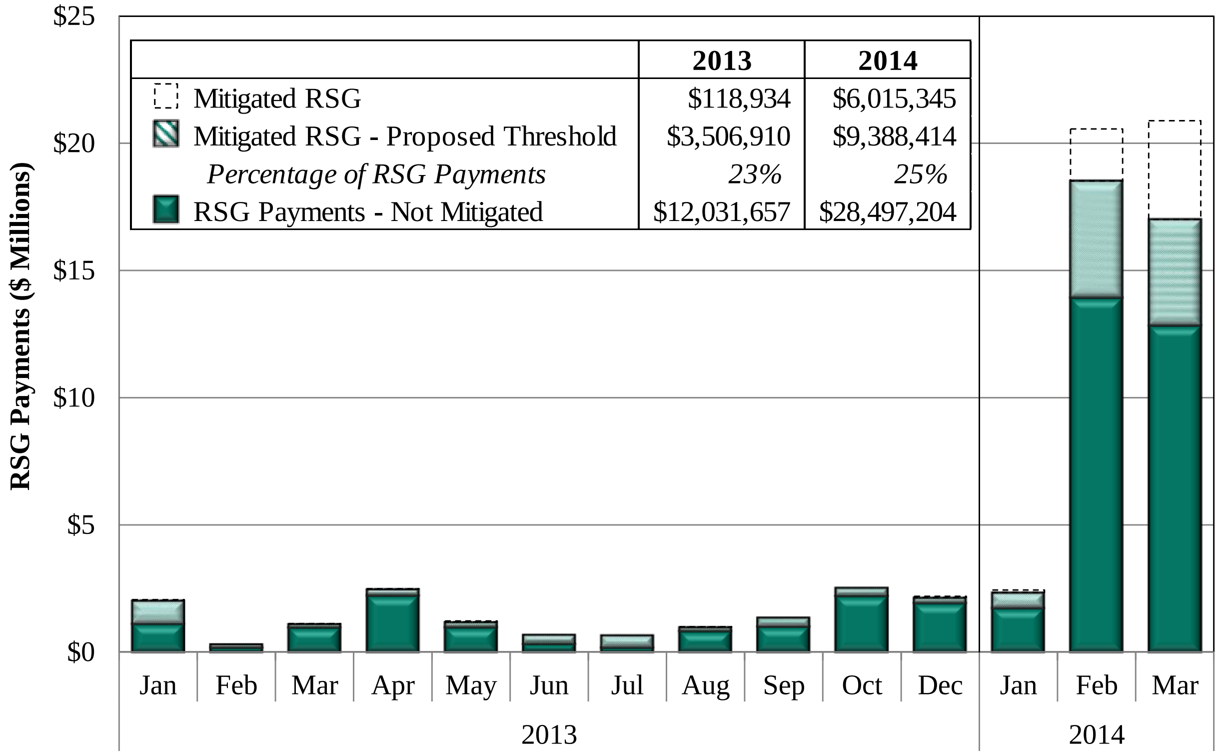
Additionally, the current RSG mitigation measures include an impact test with a $50-per-MW impact threshold to determine when conduct identified through the conduct test should be mitigated. The VLR production cost-based conduct test effectively serves as an impact test as well. When units committed 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. 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 A115: Real-Time RSG Payments

Figure A115 shows total real-time RSG payments in each month in 2013 and early 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 A115: Real-Time RSG Payments By Mitigation Classification
2013–2014



Key Observations: Evaluation of RSG Conduct and Mitigation Rules

i. Roughly sixty percent of RSG payments were made to units for costs associated with the units' reference levels.

- The share was slightly higher for those units committed for capacity since these units are more often committed in-merit.
- Most of the costs above reference, and nearly 30 percent of the total RSG cost, were associated with high commitment costs.
- These results are similar to 2012, although the payments rose substantially from $21.0 million to $33.5 million.

ii. Our analysis shows that the current RSG mitigation rules have not been fully effective in addressing inflated RSG costs associated with offers above the reference levels in 2013.

- As shown in the previous section, a very low share of such offers was mitigated in 2013.

iii. We are proposing that MISO adopt a production cost-based conduct and impact test for mitigating RSG payments.

- Under the proposed production-cost framework, an additional $3.5 million (23 percent) of RSG dollars would have been mitigated in 2013.
- The importance of such a revision is clearly demonstrated in early 2014, when high and volatile natural gas prices resulted in extremely high levels of RSG payments.
- Most of the existing mitigation in early 2014 was of units in MISO South Region under the VLR criteria.
- An additional $9.3 million would have been mitigated under the proposed framework in early 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.

<u>Key Observations: Dynamic NCAs</u>

i. Our examples show that persistent congestion can arise due to transitory changes in system conditions that can create substantial market power.

ii. The current Tariff provisions are at times insufficient to effectively address these episodes of local market power.

   – Therefore, we recommend MISO expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify formulas for the threshold calculations to address transitory episodes of congestion.

iii. We recommend that the threshold for the dynamic NCA be set at $25 per MWh and be triggered by the IMM when it detects that:

   – Such mitigation would be warranted on more than one day in a one week period; and

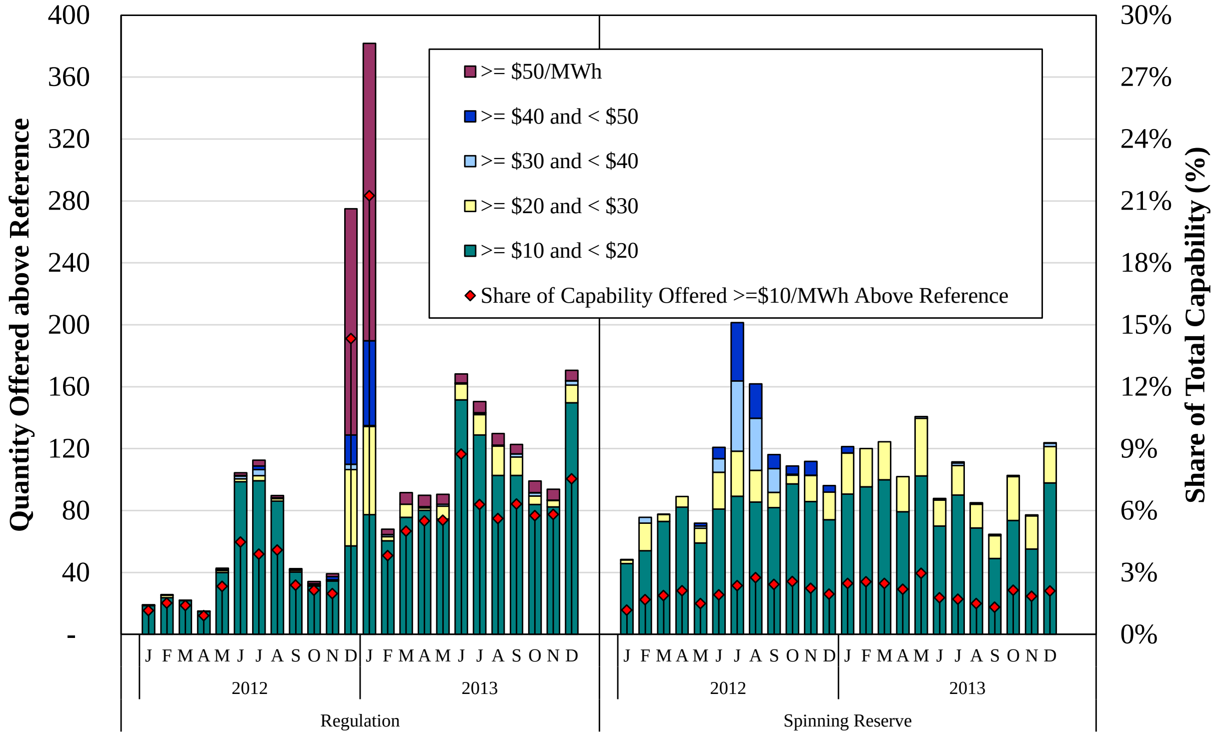
   – The congestion is expected to continue in at least 15 percent of hours (more than double the rate that would be required to permanently define an NCA).

G. Participant Conduct – Ancillary Services Offers

Figure A116: Ancillary Services Market Offers

Figure A116 evaluates 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 never offered at more than $10 per MWh above reference levels.

Figure A116: Ancillary Services Market Offers
2013



Key Observations: ASM Offers

i. The share of regulating reserves offered at more than $10 per MWh above reference more than doubled from 2.5 percent in 2012 to 5.8 percent this year.

- The majority of this quantity was offered by a small number of resources.
- As a share of capacity, it remained relatively low at 5.7 percent.

ii. The introduction of the regulation mileage offer and compensation scheme late in December resulted in some participants mistakenly offering regulation at prices up to $100 above reference for a short time.

- Although this continued into January 2013, it did not materially impact clearing prices.

iii. Almost no spinning reserve quantities were offered at more than $30 per MWh above reference, a significant reduction from last year.

- In 2012, a very warm summer resulted in more resources online and available for scheduling of spinning reserves and regulation, including those that otherwise would not offer.

- In all, quantities offered above $10 per MWh were unchanged at just over 2 percent.

iv. No supplemental reserves were offered at more than $10 per MWh above reference.

- Infrequent offline deployments (only five events in 2013) limit the risk associated with offering offline reserve, which likely led to the low offer prices.

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 A117 to Figure A120: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2013 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 partial 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 A117: Real-Time Deratings and Forced Outages
Central Region, 2013

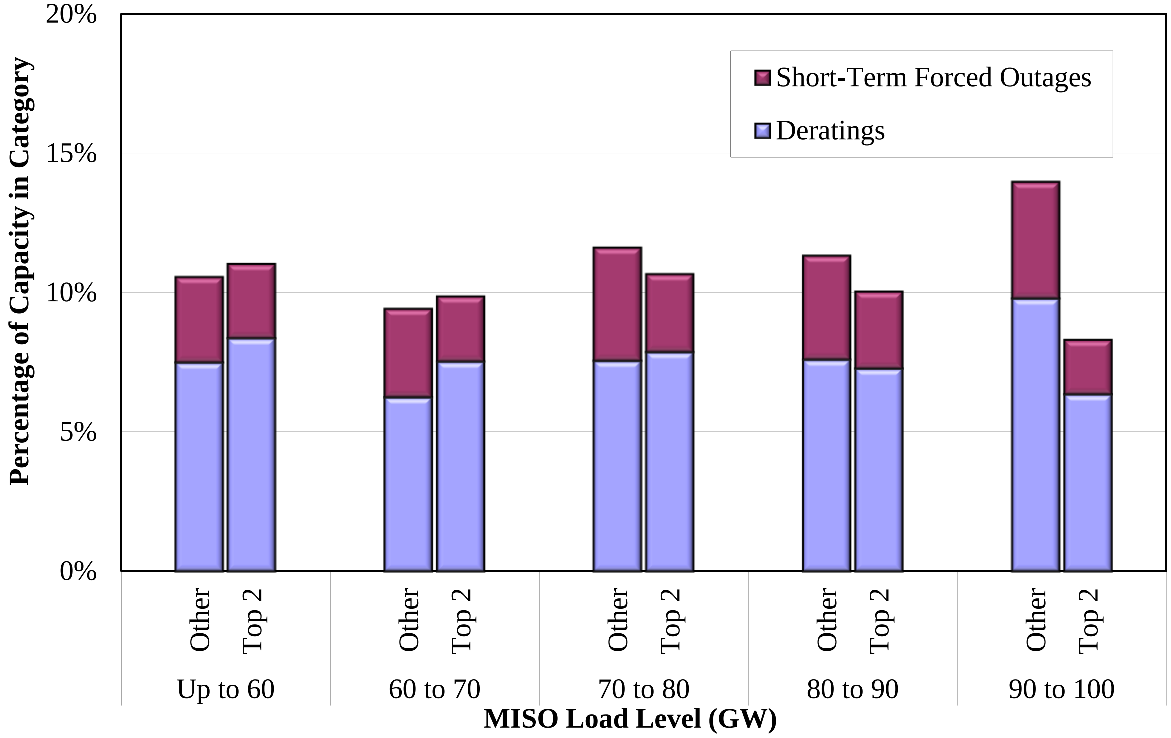


Figure A118: Real-Time Deratings and Forced Outages
East Region, 2013

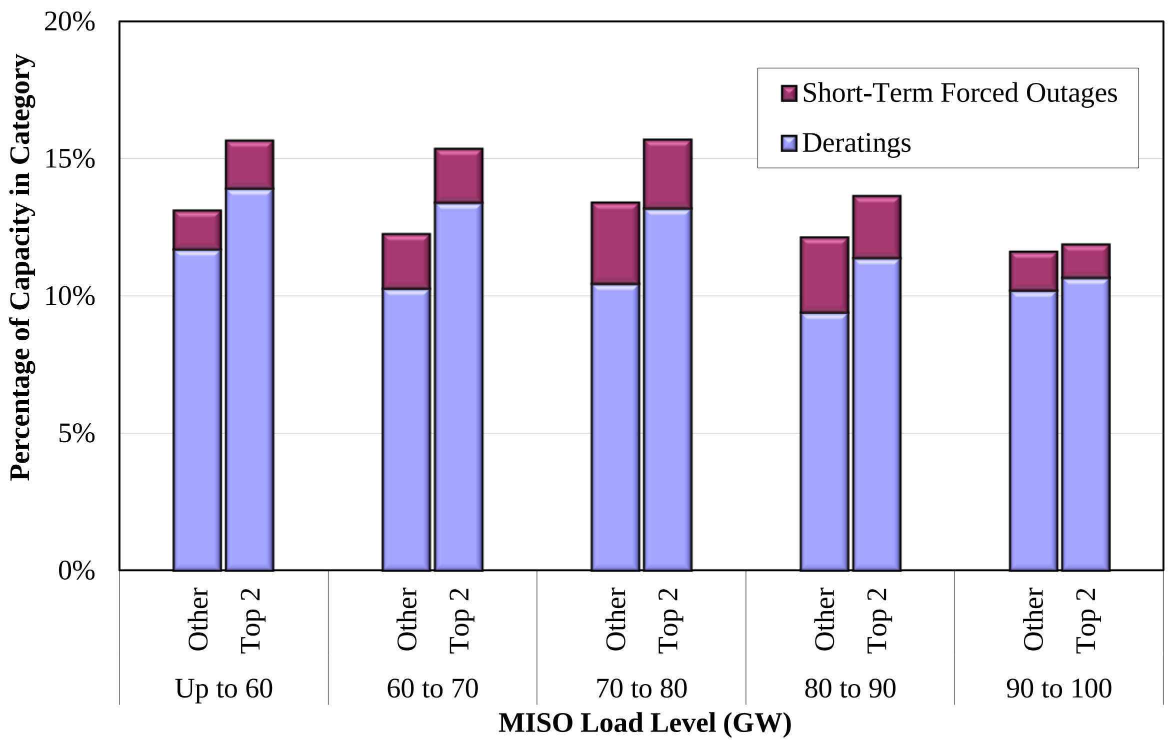


Figure A119: Real-Time Deratings and Forced Outages
West Region, 2013

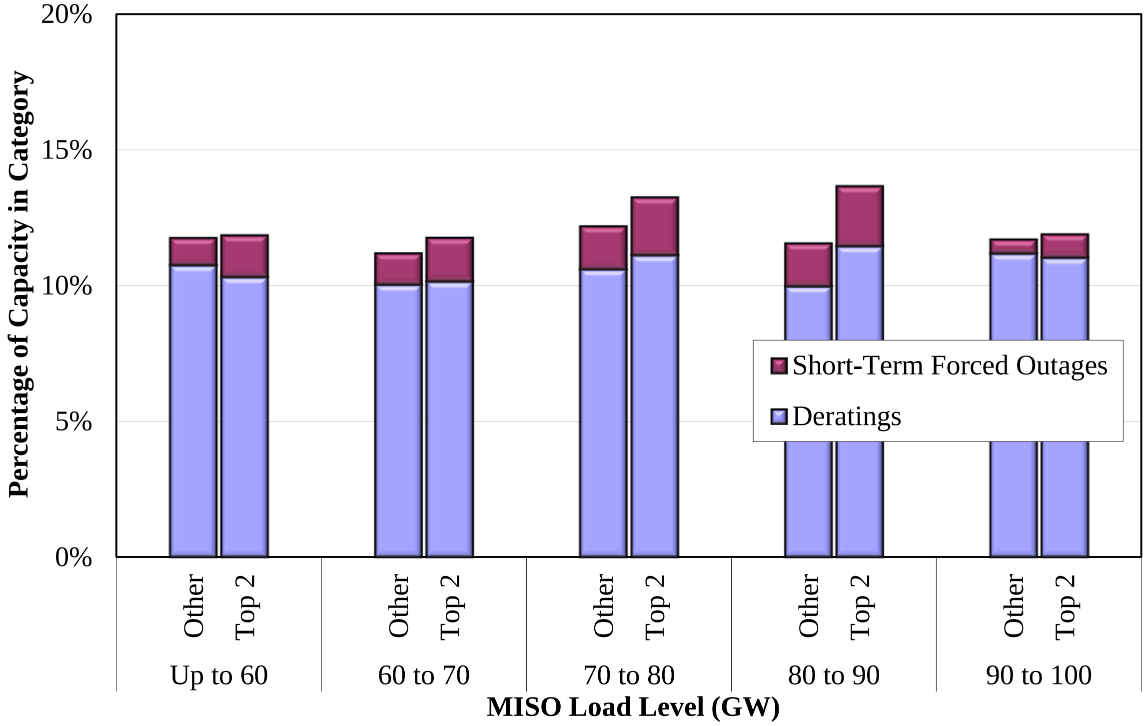
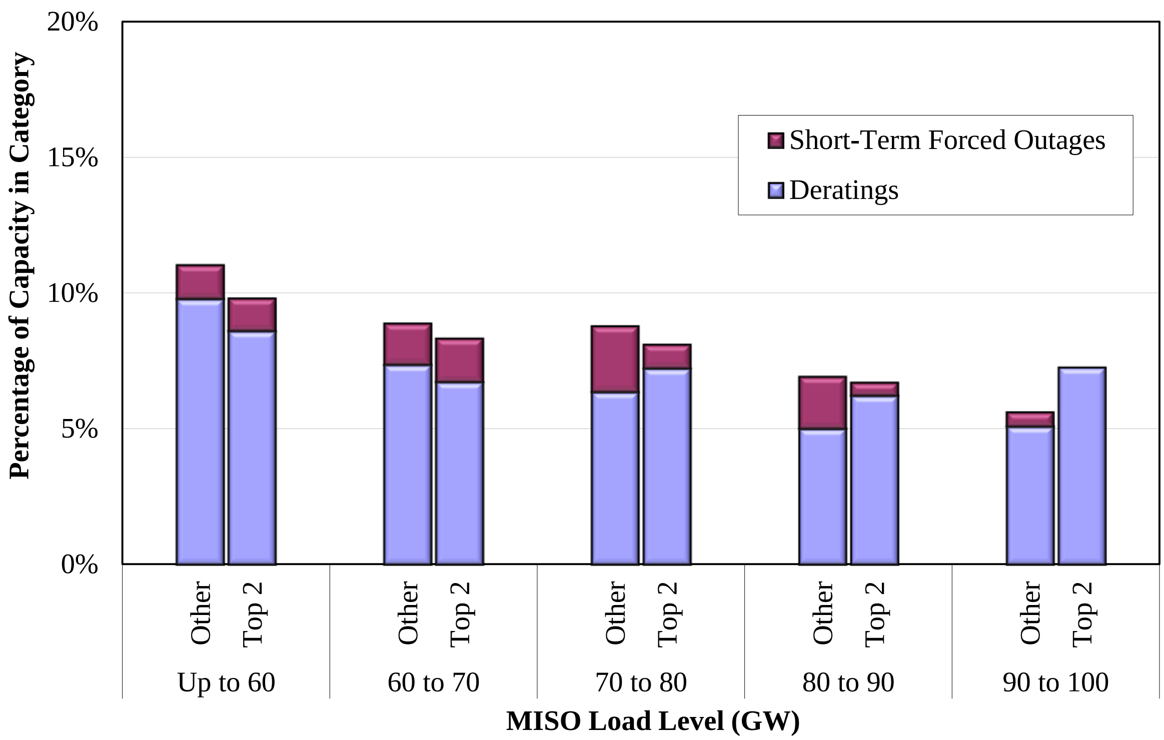


Figure A120: Real-Time Deratings and Forced Outages
WUMS Area, 2013



Key Observations: Potential Physical Withholding

i. Deratings of approximately 10 percent of capacity in most regions and at most load levels were generally in line with previous years and in aggregate do not raise substantial competitive concerns.

- Generally, very high ambient temperatures can cause the ratings of thermal units to decrease and instances of forced outages to increase.

- The usual pattern of increased deratings at higher load levels did not hold in 2013 because of a milder summer.

ii. The deratings and outage rates of the largest suppliers were comparable to the rates for other suppliers, and none were unusually high during peak conditions.

iii. We review these deratings and outages for those that could have potentially contributed to substantial congestion and associated price increases.

- We did not find substantial attempts to raise price by physically withholding resources in 2013.

VIII. 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.[41] 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.

41 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 19 Type I resources and one Type II resource available to the markets in 2013.

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 2013.

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 2013, DRR units provided an average of 13 MW of regulating reserves (one unit), 127 MW of spinning reserve (three units) and 15 MW of supplemental reserves (13 units). Supplemental reserves were not offered at all after early May, when all resources that offered this product were moved behind the meter.

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. 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. There were 30 resources providing 894 MW of capacity registered as EDR for the current 2013–2014 Planning Year.

EDR offers (curtailment prices and quantities, along with other parameters such as shutdown costs) are now 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 are not yet eligible to set price because of their inflexibility, but MISO has proposed changes as part of its ELMP initiative that would allow them to do so when they are needed.

Table A5: DR Capability in MISO and Neighboring RTOs

Table A5 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 A5: DR Capability in MISO and Neighboring RTOs
2009–2013

		2013	2012	2011	2010	2009
Midwest ISO	**Total***	**10,163**	**7,197**	**7,376**	**8,663**	**12,550**
	Behind-The-Meter Generation	3,411	2,969	3,001	5,077	4,984
	Load Modifying Resource	5,045	2,882	2,898	3,184	4,860
	DRR Type I	372	372	472	46	2,353
	DRR Type II	75	71	75	0	111
	Emergency DR	894	902	930	357	242
	Of which: LMR	366	380	404	N/A	N/A
NYISO	**Total**	**1,306**	**1,925**	**2,161**	**2,691**	**2,715**
	ICAP - Special Case Resources	1,175	1,744	1,976	2,103	2,061
	Of which: Targeted DR	379	421	407	489	531
	Emergency DR	94	144	148	257	323
	Of which: Targeted DR	40	59	86	77	117
	DADRP	37	37	37	331	331
ISO-NE	**Total**	**2,101**	**2,769**	**2,755**	**2,719**	**2,292**
	Real-Time DR Resources	793	1,193	1,227	1,255	873
	Real-Time Emerg. Generation Resources	279	588	650	672	875
	On-Peak Demand Resources	629	629	562	533	N/A
	Seasonal Peak Demand Resources	400	359	316	259	N/A

* Registered as of December 2013. All units are MW.

C. Aggregators of Retail Customers

In August 2008, FERC issued Orders 719 and 719-A directing RTOs to improve DR participation in wholesale electricity markets. More specifically, these orders require comparable treatment for DR and existing generation resources. In response, MISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements. The largest such barrier is the limitation of direct market participation to resources with loads of more than one MW. By pooling small resources, Aggregators of Retail Customers (ARCs) can serve as an intermediary between MISO and retail customers who can reduce consumption.[42] This measure has been successfully implemented in neighboring RTOs. MISO filed Tariff revisions on October 2, 2009 to allow ARCs to participate in all the MISO markets, which FERC approved in late 2011.

42 An ARC is defined as a market participant sponsoring a DRR resource provided by a customer whom it does not serve at retail. An ARC can also be an LSE sponsoring a DRR that is the retail customer of another LSE.

<u>Key Observations: Demand Response</u>

i. MISO had over 10 GW of registered DR capability in 2013, comparable as a share of capacity to neighboring RTOs. This is up from 7.2 GW in 2012.

- Nearly all of the growth was in interruptible load such as LMR, most of which is developed under regulated utility programs, or behind-the-meter generation (BTMG).
- MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions.
- Only 13 units with 272 MW of capacity participated directly in MISO's energy markets as DRR Types I or II in 2013. All but three units provided only supplemental reserves.

ii. MISO considers DR to be a priority and continues to actively expand its DR capability. One means to do so is for ARCs to actively participate in the MISO markets.

- MISO continues to explore integrating Batch-Load Demand Response (BLDR) resources and Price-Responsive Demand (PRD) into the energy and ancillary services markets.
- One additional change that is particularly important is a modification to price-setting methodologies to allow DR resources to set real-time energy prices when they are needed.
  - ✓ When DR resources are deployed and do not set prices, it undermines the efficiency of the market during peak periods and can serve as a material economic barrier to net imports in the short-run and the development of new resources in the long-run.
  - ✓ MISO's proposed ELMP pricing methodology will improve the extent to which DR resources are integrated by allowing EDR to set energy prices. We recommend that MISO expand this capability to LMR, including BTMG.

iii. Since mid-2012, and as required by FERC Order 745, ARC resources are compensated for their energy at the full LMP.

- Paying the full LMP when DR resources curtail load raises efficiency concerns because:
  - ✓ It will increase their incentive to curtail at prices less than the value of the electricity to the customer, which should inefficiently increase the frequency of curtailments; and
  - ✓ It will create incentives to develop small-scale BTMG that is generally much more expensive, less flexible (not dispatchable by MISO), and more environmentally harmful than new conventional generation.

iv. Finally, the integration of DR in the RAC is very important because it can have a sizable effect on the price signals provided by MISO's capacity market.

- Over 400 resources offered nearly 6,000 MW directly into the auction, with an additional 3,600 MW covered under Fixed Resource Adequacy Plans (modeled as a zero dollar offer).
- Nearly 40 percent of this was in the form of LMR, such as interruptible loads. The rest was BTMG.
- Unlike some other neighboring RTOs, MISO does not test these resources to verify their stated capability, so they are granted a 100 percent capacity credit.
  - ✓ When they have been called in the past, MISO has received only a fraction of their total claimed capability.
  - ✓ In 2006, MISO received a peak response of 2,651 MW, far less than the more than 6,000 MW of total claimed capability at that time.
- The PRA, which cleared at $16.75 per MW-day, would have cleared at $84 if LMR resources received a 50 percent capacity credit.
  - ✓ Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.