# 2012 State of the Market Report for the MISO Electricity Markets

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Independent Market Monitor
for MISO

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## Guide to Acronyms

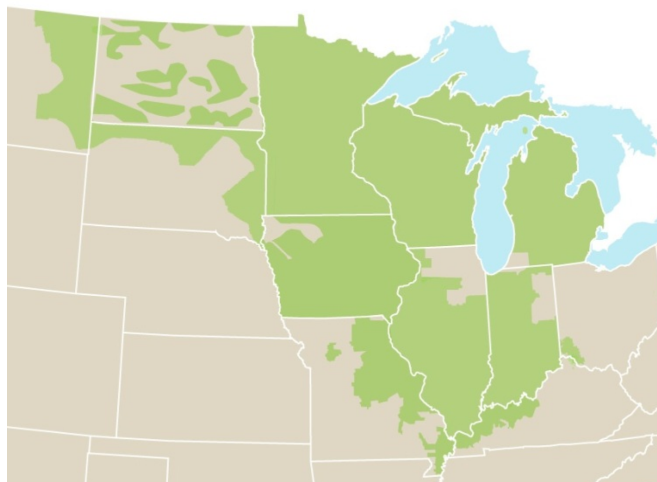
| | |
|---|---|
| ARC | Aggregators of Retail Customers |
| ARR | Auction Revenue Rights |
| ASM | Ancillary Services Markets |
| BCA | Broad Constrained Area |
| BTMG | Behind-The-Meter Generation |
| CC | Combined Cycle |
| CDD | Cooling Degree Day |
| CMC | Constraint Management Charge |
| CONE | Cost of New Entry |
| CROW | Control Room Operating Window |
| CSAPR | Cross-State Air Pollution Rule |
| CT | Combustion Turbine |
| DAMAP | Day-Ahead Margin Assurance Payment |
| DDC | Day-Ahead Deviation and Headroom Charge |
| DIR | Dispatchable Intermittent Resource |
| DR | Demand Response |
| DRR | Demand Response Resource |
| ECF | Excess Congestion Fund |
| EDR | Emergency Demand Response |
| EEA | Emergency Energy Alert |
| ELMP | Extended LMP |
| EPA | Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| FFE | Firm Flow Entitlement |
| FTR | Financial Transmission Rights |
| GSF | Generation Shift Factors |
| GW | Gigawatt (1 GW = 1,000 MW) |
| GWh | Gigawatt-hour |
| HDD | Heating Degree Day |
| HHI | Herfindahl-Hirschman Index |
| IESO | Ontario Independent Electricity System Operator |
| IMM | Independent Market Monitor |
| ISO-NE | ISO New England, Inc. |
| JCM | Joint and Common Market |
| JOA | Joint Operating Agreement |
| kWh | Kilowatt-hour |
| LAC | Look-Ahead Commitment |

| | |
|---|---|
| LAD | Look-Ahead Dispatch |
| LMP | Locational Marginal Price |
| LSE | Load-Serving Entity |
| M2M | Market-to-Market |
| MATS | Mercury and Air Toxics Standards |
| MCP | Marginal Clearing Price |
| MISO | Midwest Independent Transmission System Operator |
| MMBtu | Million British thermal units, a measure of energy content |
| MTLF | Mid-Term Load Forecast |
| MVL | Marginal Value Limit |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCA | Narrow Constrained Area |
| NDL | Notification Deadline |
| NERC | North American Electric Reliability Corporation |
| NSI | Net Scheduled Interchange |
| NYISO | New York Independent System Operator |
| PJM | PJM Interconnection, Inc. |
| PVMWP | Price Volatility Make Whole Payment |
| PY | Planning Year |
| RAC | Resource Adequacy Construct |
| RCF | Reciprocal Coordinated Flowgate |
| RDI | Residual Demand Index |
| RGD | Regional Generation Dispatcher |
| RSG | Revenue Sufficiency Guarantee |
| RTO | Regional Transmission Organization |
| RTORSGP | Real-Time Offer Revenue Sufficiency Guarantee Payment |
| SMP | System Marginal Price |
| SSR | System Support Resource |
| STLF | Short-Term Load Forecast |
| TLR | Transmission Line Loading Relief |
| VCA | Voluntary Capacity Auction |
| VLR | Voltage and Local Reliability |
| WUMS | Wisconsin-Upper Michigan System |

## Executive Summary

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. This scope includes monitoring for attempts to exercise market power, identifying market design flaws or inefficiencies, and recommending improvements to the market design and operating procedures. This Executive Summary to the *2012 State of the Market Report* provides an overview of our assessment of the performance of the markets.

MISO operates competitive wholesale markets for energy, ancillary services, capacity, and financial transmission rights (FTRs) to satisfy the electricity needs of its market participants. These markets coordinate the commitment and dispatch of generation to ensure that resources are meeting the system's demands reliably and at the lowest cost.



The MISO markets also establish prices that reflect the marginal value of energy at each location on the network . These prices facilitate efficient actions by participants in the short term (e.g., resource dispatch and import/export scheduling) and efficient decisions in the long term (e.g., investment, retirement, and maintenance).

### A. Competitive Performance of the Market

The MISO energy and ancillary service markets generally performed competitively in 2012. Conduct of suppliers was broadly consistent with expectations for a workably competitive market. Our analysis did not reveal substantial evidence of potential attempts to exercise market power or engage in market manipulation. The output gap, a measure of economic withholding, declined over the course of the year and averaged approximately 0.1 percent of actual load, which is extremely low. Consequently, market power mitigation measures were applied very infrequently.

## B. Market Outcomes and Prices in 2012

Real-time energy prices in MISO averaged $28.56 per MWh, and ranged from $26 in the West region to $30 in the East. Prices were almost 14 percent lower than in 2011, which was due primarily to lower fuel prices. Western coal prices and natural gas prices both declined by more than 30 percent. The correlation between energy and natural gas prices is expected in a workably competitive market where natural gas-fired resources are often the marginal supply. In 2012, however, energy prices fell by substantially less than the decrease in fuel prices because the energy price reductions were offset by increases in the value of shortages during summer.

Although load declined slightly from 2011, unusually warm weather in July resulted in MISO setting successive all-time peaks, including 98.5 GW on July 23. MISO maintained reliability throughout this period, but experienced a number of operating reserve shortages that produced prices between $1,000 and $2,400 per MWh. Although high load and generator forced outages contributed to the shortages on many of these days, the report identifies the lack of coordinated interchange with PJM as the single most significant cause of the shortages in a number of cases.

Our net revenue analysis in this report shows that the MISO's economic signals would not support private investment in new resources, which is partly due to the modest capacity surplus that currently exists in MISO. However, we believe the economic signals would continue to be inadequate even under little or no surplus because of the shortcomings of MISO's current capacity market described in this report. This resource adequacy concern is likely to rise as environmental regulations, increasing wind output, and low natural gas prices accelerate the retirements of coal-fired resources in the medium term.

The value of real-time congestion in 2012 rose 5 percent to $1.30 billion. Normally, sharp declines in fuel prices as occurred in 2012 would lead to significant reductions in congestion. However, the fuel price changes were more than offset by the following two factors:

- MISO began more fully pricing its constraints when it disabled constraint relaxation on internal constraints in February. This was an essential change because it allowed these constraints to be priced at their full reliability value when they are violated.
- Congestion values increased in the West region where transmission derates and upgrades were most significant. Congestion on constraints from the West also persisted partly because of growing wind output in the West, which increased 30 percent to over 3.6 GW

per hour. Expansion of the DIR capability has greatly improved MISO's ability to manage this congestion and delivered substantial production cost savings.

Finally, ancillary services prices declined by 2 to 26 percent. The impact of lower fuel prices was greatest for regulating reserves. The effects of lower fuel prices on spinning and supplemental reserve prices were mostly offset by a substantial increase in operating reserve shortages. MISO's ancillary services markets continued to operate with no significant issues, and in 2012 and early 2013 successfully integrated several important market improvements. However, this report identifies a flaw in MISO's accounting of reserves that fails to recognize the reserves being provided during the period when a quick-start unit is starting.

## C. Day-Ahead Market Performance

Convergence of energy prices between the day-ahead and real-time markets is important because day-ahead outcomes determine most resource commitments and are the basis for the payments to FTRs. Energy prices converged well in most months, exhibiting a day-ahead premium of less than two percent at the Indiana Hub after accounting for the real-time Revenue Sufficiency Guarantee (RSG) cost allocation (averaging $0.57 per MWh in 2012).

The market was less effective in arbitraging locational differences in some of MISO's more congested areas. This was most notable in the West region in spring, where several real-time events were unforeseen day-ahead. MISO has corrected an error in the allocation of congestion-related RSG to virtual transactions (which existed because of a previous FERC order) that should improve convergence in these areas. This report includes additional recommendations that should improve liquidity of the day-ahead market in these areas.

Scheduled virtual transactions rose 3 percent to 7.2 GW per hour. Approximately 40 percent of these transactions were price-insensitive (bid or offered to clear at any reasonable price), which are less valuable in providing liquidity in the day-ahead market. Two-thirds of these transactions are placed to establish an energy-neutral position (offsetting virtual supply and demand) between locations to arbitrage congestion-related price differences between the day-ahead and real-time markets. Incentives to engage in these transactions have increased since April 2011 when the RSG allocation methodology was modified to net participants' helping and harming deviations to determine who receives an allocation of the RSG costs. Harming deviations (e.g., virtual supply) can cause MISO to commit additional resources in real time to satisfy the system demands. Hence, by clearing offsetting virtual supply and demand transactions, a participant will reduce its exposure to RSG charges. While we believe these balanced positions are valuable in improving the convergence of congestion patterns between the day-ahead and real-time market, we recommend MISO develop a virtual spread product that would allow participants to engage in this activity more efficiently.

## D. Real-Time Market Performance and Uplift

Substantial volatility in real-time energy markets occurs because the demands of the system can change rapidly and because supply flexibility is restricted by the resources' physical limitations of the resources and the transmission network. In contrast, the day-ahead market is less volatile because it operates over a longer time horizon with more commitment options and liquidity provided by virtual transactions.

MISO operates a true five-minute real-time market, sending out new dispatch instructions and price signals every five minutes. As currently designed, the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs.[1] As a result, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can up or down), which produces transitory price spikes.

Because settlements are based on hourly average prices, the MISO market includes price-volatility make-whole payments (PVMWP) to ensure that suppliers have the incentive to be flexible and are not harmed when they respond to MISO's dispatch instructions. PVMWP declined 25 percent from 2011 to $63.2 million, consistent with a comparable decline in price volatility. However, the report recommends that MISO make limited changes to the eligibility rules for PVMWPs to eliminate the ability for participants to receive unjustified payments. Ultimately, we find that suppliers' incentives would be substantially improved by moving to a five-minute settlement for generators and imports/exports from the current hourly real-time settlement.

1 However,. a Look-Ahead Commitment (LAC) was implemented in the second quarter of 2012 that improves the system's ability to commit and decommit fast-starting resources economically.

RSG payments are are made in both the day-ahead and real-time markets to ensure suppliers' offer costs are covered when a unit is dispatched. These costs tend to be much larger in real-time because most resource commitments for reliability occur in real time. Nominal real-time RSG payments declined 41 percent from 2011 because: (a) fuel prices were much lower; (b) load was more fully scheduled day ahead during most months (reducing MISO's need to commit peaking resources after the day-ahead market to satisfy incremental load); and (c) commitments for voltage support where shifted to the day-ahead market. FERC also approved Tariff revisions in September that included tighter mitigation measures for units committed for voltage support and more direct allocation of these costs.

Despite several improvements made over the past two years, the allocation of RSG costs remains substantially inconsistent with the causes of real-time RSG costs. For example, roughly 90 percent of real-time RSG costs are allocated to market-wide deviations, even though they cause only about half of these costs. This report includes recommendations to address these issues.

## E. Resource Adequacy and Demand Response

Overall, our assessment indicates that the system's resources should be adequate for summer 2013 if the peak conditions are not substantially hotter than normal. Although MISO reports a planning reserve margin of 28.1 percent for the summer 2013, this margin falls to 16.9 percent if it includes only firm imports and more realistic assumptions regarding wind and demand response. This exceeds the minimum required planning margin of 14.2 percent and should be sufficient to cover MISO expected forced outages (which generally averages six to eight percent in the summer) and its operating reserve requirements of approximately 2.5 percent.

However, we also show that under "90/10" weather conditions in the summer (i.e., conditions that should occur only once every ten years), this margin will fall to less than 6 percent as load rises and temperature-related generator derates occur. At this level, MISO will have to rely relatively heavily on imports that are not contracted on a firm basis.

While the supply is likely adequate for the upcoming summer, the increased penetration of wind resources and new EPA regulations will put substantial economic pressure on baseload coal resources that should accelerate retirements and reduce planning reserve margins. MISO's analysis suggests that up to 12 GW of coal-fired capacity in MISO would be at risk of retirement due to the compliance costs of these regulations, which could be even higher if low natural gas prices continue over the long term. This underscores the importance of MISO Resource Adequacy Construct (RAC).

MISO made several improvements to its RAC in 2012 that should improve the price signals for capacity. This includes the replacement of the Voluntary Capacity Auction (VCA) with an annual Planning Resource Auction (PRA) that features a zonal requirements for capacity. However, two significant shortcomings continue to undermine the efficiency of the RAC: (a) the representation of the demand for capacity in MISO's PRA and (b) the prevailing barriers to capacity trading between PJM and MISO. These issues contributed to MISO's VCA clearing at close to zero in every month of 2012, as well as in the first annual PRA conducted in April 2013.

The minimum capacity requirements and deficiency price in Module E establish a "vertical demand curve", which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value to the system and results in inefficient capacity market outcomes. Hence, we continue to recommend MISO work with its stakeholders to develop a sloped demand curve that would recognize that incremental capacity above the minimum requirement has value (i.e., improves reliability). This change would allow prices to rise efficiently as capacity margins fall to accurately signal the value of capacity, which will be important for both new investors and for suppliers considering environmental retrofits.

Finally, we find that the capacity credit for wind resources and a large share of the demand response resources are likely overstated under MISO's current rules in Module E, which can contribute to understated capacity prices. The current capacity credit for wind is likely more than three times higher than a reasonably conservative capacity credit. Such a credit should be based on the minimum output level one could expect under peak summer conditions.

Finally, demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. However, the amount of demand response participating in MISO demand response programs, including Emergency Demand Response (EDR) increased from 400 MW in 2010 to 1,500 MW. This is a significant change because it increases MISO's ability to utilize it when needed and to set prices efficiently when these resources are deployed. MISO continues to seek to expand its DR capability, including efforts to allow for Batch Load DR and Price Responsive Demand. However, the RAC provides a key economic signal for the development of new demand response capability, so the improvements recommended for the RAC will facilitate efficient development of new DR resources.

## F. Recommendations

Although the markets performed competitively in 2012, we recommend a number of improvements. Some of these recommendations were made in prior reports, which is not unexpected as many of them require both Tariff and software changes that can require years to implement.

MISO addressed a number of prior recommendations in 2012 and early 2013, which are discussed in the final section of this report. The following table shows our current recommendations, organized by the area of the market they address.

| RECOMMENDATIONS 2012 |
|---|
| **Energy Pricing and Transmission Congestion** |
| 1. Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set energy prices in the real-time market. |
| 2. Implement a five-minute real-time settlement for generation and external schedules. |
| 3. Eliminate excess payments and excess charges to physical transactions that affect external constraints. |
| 4. Improve external congestion processes by modifying how relief obligations are calculated and how the constraints are modeled in the real-time market.<br>a. Base relief obligations on *net* Market Flows, not gross forward flows.<br>b. Cap MVL on external (non-M2M) flowgates. |
| 5. Introduce a virtual spread product. |
| **Guarantee Payment Eligibility Rules and Cost Allocation** |
| 6. Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs by making the following changes:<br>a. Net market-wide deviations to determine the share of the real-time RSG costs that should be allocated via the DDC rate.<br>b. Allocate real-time RSG only to harming deviations (pre- and post-NDL).<br>c. Eliminate the use of GSFs in determining costs that should be allocated via the CMC rate. |

7. Implement improved eligibility requirements for PVMWPs
    a. Modify eligibility requirements to address gaming issues.
    b. Correct the mitigation rule governing authority over PVMWP and RSG eligibility.
8. Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.
9. Modify the mitigation measures to allow the definition of a “dynamic NCA” that is utilized only when network conditions exist that create substantial market power.

**Improve Dispatch Efficiency and Real-Time Market Operations**

10. Develop a look-ahead real-time dispatch capability to efficiently satisfy the system’s anticipated ramp demands.
11. Implement a ramp capability product to address unanticipated ramp demands.
12. Implement changes to more effectively identify and remedy units not following dispatch.
    a. Develop enhanced tools to identify units that are effectively derated or not following dispatch so that they may be placed off-control.
    b. Tighten thresholds for uninstructed deviations.
13. Expand the JOA to optimize the interchange with PJM to improve price convergence with PJM.
14. Implement procedures to utilize provisions of the JOA that would improve day-ahead M2M coordination with PJM.
15. Eliminate the transmission constraint deadband.
16. Re-order MISO’s emergency procedures to utilize demand response efficiently.
17. Modify the market systems to recognize supplemental reserves being provided from quick-start units when they are in the process of starting.

**Resource Adequacy**

18. Remove inefficient barriers to capacity trading with adjacent areas.
19. Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.
20. Evaluate capacity credits provided to wind resources and LMR to increase their accuracy.

# I. Introduction

As the Independent Market Monitor (IMM) for MISO, Potomac Economics is responsible for evaluating the competitive performance, design, and operation of wholesale electricity markets operated by MISO. In this *2012 State of the Market Report*, we provide our annual evaluation of MISO's markets and our recommendations for future improvements.

MISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead and real-time energy markets and a market for Financial Transmission Rights (FTRs). The energy markets are designed to facilitate an efficient daily commitment of generation, to dispatch the lowest-cost resources to satisfy the system's demands without overloading the transmission network, and to provide transparent economic signals to guide short-run and long-run decisions by participants and regulators. The FTR market allows participants to hedge the risks of congestion associated with serving load or engaging in other transactions.[2]

In 2009, MISO began operating as a balancing authority and introduced markets for regulation and contingency reserves, known collectively as Ancillary Services Markets (ASM), and a spot market for capacity. ASM jointly optimize the allocation of resources between energy and ancillary services products. This joint optimization also allows energy and ancillary services prices to reflect the opportunity cost tradeoffs between products, as well as shortages of both products. The Voluntary Capacity Auction (VCA), implemented in June 2009, allows participants to buy and sell capacity to satisfy residual capacity requirements under Module E of the MISO Tariff. (It has since been replaced by a more robust Planning Reserve Auction that should identify locational capacity needs within the footprint as they arise.) The addition of each of these markets has improved the long-term economic signals in MISO.

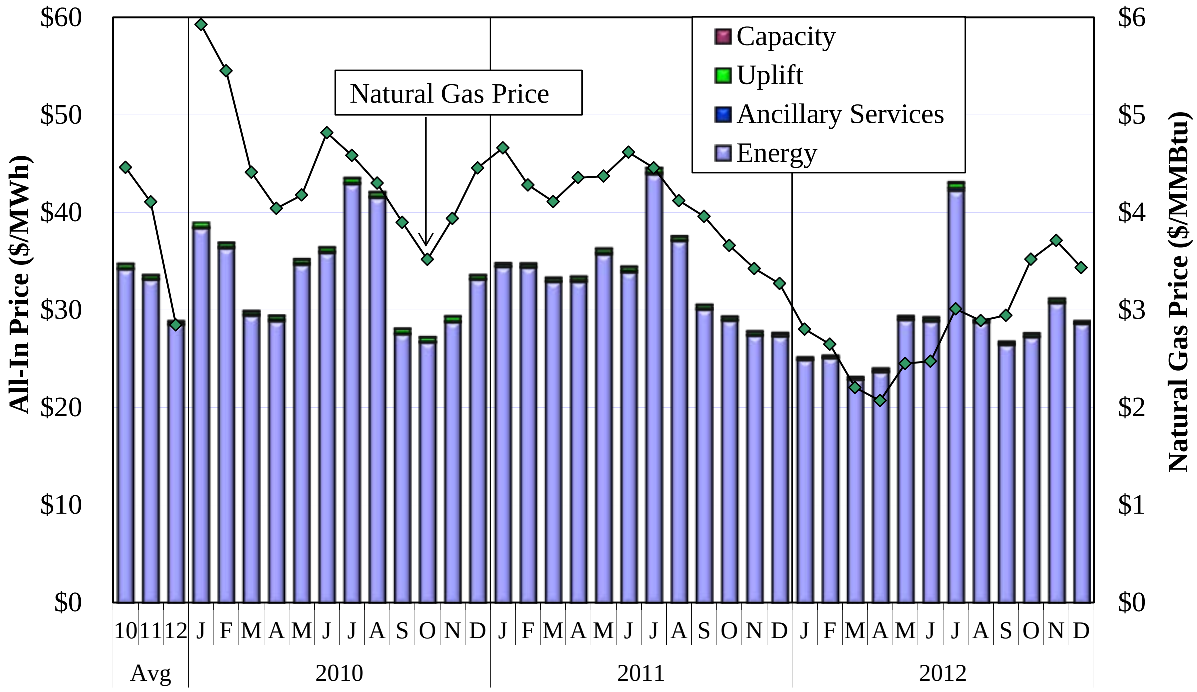
2 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

# II. Prices and Load Trends

## A. Market Prices in 2012

Figure 1 summarizes changes in energy prices and other market costs by showing the all-in price of electricity, which is a measure of the total cost of serving load in MISO. The all-in price of electricity is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[3]

**Figure 1: All-In Price of Electricity**
2010–2012




The all-in price in 2012 declined 14 percent to $28.93 per MWh. The decrease is primarily attributable to much lower average fuel prices and a slight reduction in average load in 2012. Both natural gas and western coal prices fell more than 30 percent, which would normally have led to larger reductions in electricity prices. However, unusually warm weather in July contributed to instances of substantial shortage pricing that partially offset the decrease in fuel prices. As in prior years, the energy component constituted over 99 percent of the total all-in

3 Capacity costs are estimated by multiplying the VCA clearing price times the capacity requirements in each month.

price. Uplift costs, including Revenue Sufficiency Guarantee (RSG) payments and Price Volatility Make-Whole Payments (PVMWP), decreased eight cents to $0.23 per MWh. Despite a considerable rise in operating reserve shortages that were all priced at over $1,100 per MWh, the contribution to the all-in price in 2012 of ancillary services costs declined two cents to just $0.13. Overall, these levels are nearly unchanged from prior years.

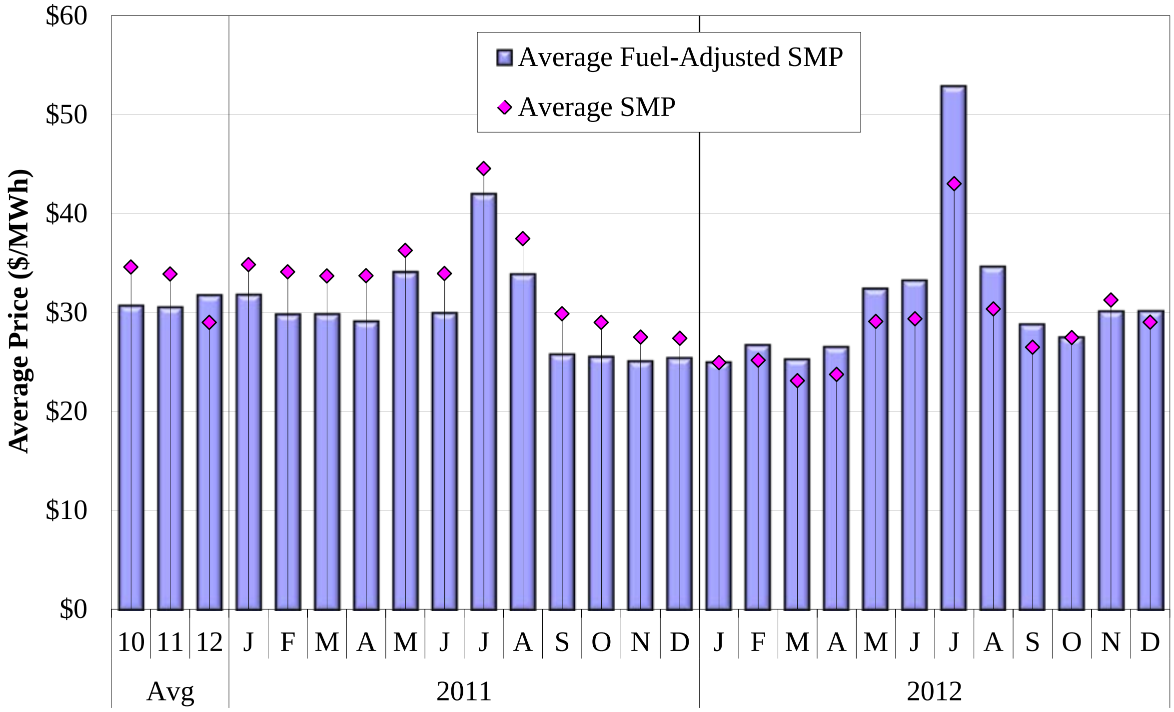
Finally, capacity costs contributed only one cent per MWh to the all-in price. The VCA in 2012 continued to clear at very low prices because of the prevailing surplus in the region and certain market design issues discussed in this report. Recent member departures (including portions of Duke in January 2012) and proposed environmental regulations did not significantly impact auction outcomes in 2012. MISO recently modified its capacity market, implementing an annual Planning Resource Auction (PRA). We do not expect substantially different prices from the PRA than the VCA.

The figure also shows that energy price fluctuations are strongly correlated with natural gas price movements. Natural gas-fired capacity set prices in 54 percent of all intervals, including almost all of the peak load periods. This correlation exists because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal cost, changes in fuel prices translate to changes in offer prices. Natural gas prices fell 31 percent in 2012 to average $2.85 per MMBtu. This led gas-fired resources to be more competitive with base-load coal, particularly in the first half of the year. Hence, natural gas-fired resources provided 78 percent more energy in 2012 than they did in 2011, while coal resources produced ten percent less.

Coal-fired resources still provided over two-thirds of total generation in MISO and set price in 91 percent of intervals, including almost all off-peak intervals. (Congestion frequently caused both natural gas and coal to be on the margin in the same interval in different areas of the footprint.) Eastern coal prices declined five percent, while Western (e.g., Powder River Basin) coal prices declined 32 percent.

To estimate price effects of factors other than the change in fuel prices, we calculate a fuel price-adjusted System Marginal Price (SMP) that is based on the marginal fuel in each five-minute interval. To calculate this metric, each real-time interval's SMP is indexed to the three-year average of the price of the marginal fuel during the interval.[4]

**Figure 2: Fuel-Adjusted System Marginal Price**
2010–2012




Although average energy prices in 2012 declined 14 percent from 2011, the figure shows that average fuel-adjusted energy prices rose nearly four percent, or $1.20 per MWh. This indicates that non-fuel factors contributed to higher prices and partially offset the substantial reduction in fuel prices. The largest factor was the increase in shortage events during the high-temperature conditions in July.

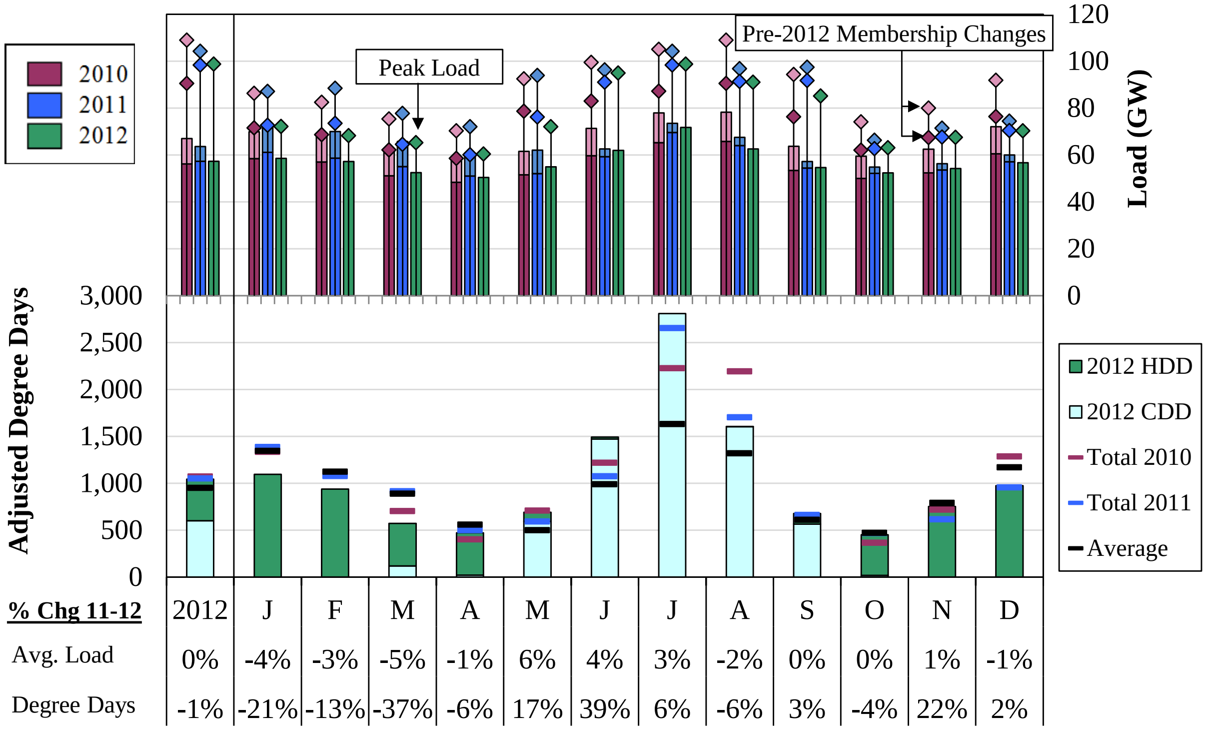
## B. Load and Weather Patterns

Figure 3 illustrates the influence of weather on load by showing the heating and cooling requirements together with the monthly average load levels for 2010 to 2012. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The

4 See Figure A4 in the Appendix for a detailed explanation of this metric.

bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across four representative locations in MISO.[5]

**Figure 3: Heating and Cooling Degree Days**
2010-2012




Total degree days declined by 0.5 percent from 2011, consistent with the modest reduction in average load of 0.2 percent.[6] Most months in 2012 recorded total degree days near or below average, with the notable exception of the May to August months, which were 22 to 72 percent above the historical average. July was exceptionally warm and MISO set several successive all-time peak loads in the month. The July 23 peak of 98.5 GW was nearly four GW higher than the "50/50" forecast in MISO's *2012 Summer Resource Assessment*, but nearly four GW below its less likely "90/10" scenario.

5 HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize their effects on load (i.e., one adjusted-HDD has the same impact on load as one CDD). The factor was estimated by regression analysis.

6 Unless otherwise stated, percentage changes in load reported in this report are adjusted for membership additions and departures, including portions of Duke Energy in January 2012.

Continued modest monthly increases in economic activity in 2012 had a small impact on load. The Chicago Purchasing Manager's Index, a leading business barometer and a broad measure of economic activity in the region, was expansionary in most months of the year, but only barely so after August. Hence, the decline in average load was only three-tenths of a percentage point less than the decline in degree days.

## C. Evaluation of Peak Summer Days in 2012

One of the most significant series of events in the MISO market in 2012 was the series of peak load events from late June through July. Successive heat waves beginning in late June contributed to record temperatures at most major load centers in MISO. On each of the days shown in the table below, MISO declared Hot Weather Alerts and Conservative Operations, and on six separate days declared Maximum Generation Alerts (shown in yellow), Warnings (orange), or an Event (red).

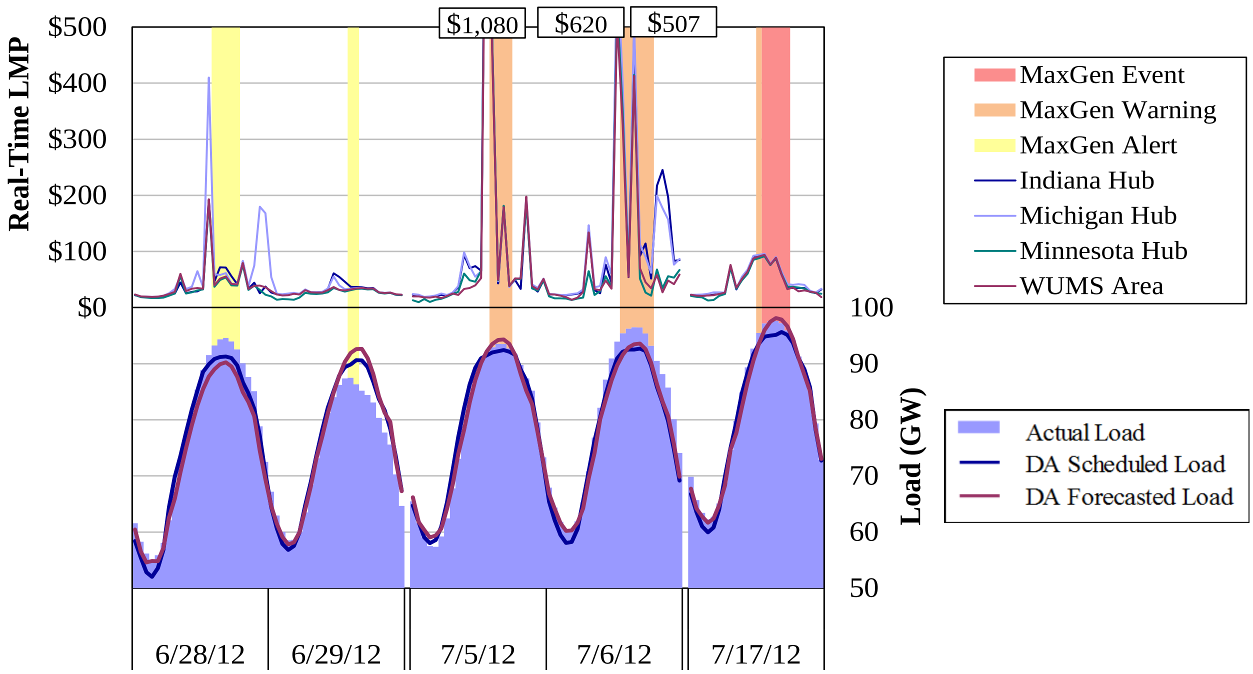
**Table 1: Temperatures in MISO during the Peak Summer Week**

| | **Hist.** | **June** | | | | **July** | | | | | | | | | | | **x** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Avg.** | **27** | **28** | **29** | **30** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **15** | **16** | **17** | **23** | **24** | **25** |
| Cincinnati | 85 | 89 | 102 | 100 | 102 | 98 | 95 | 95 | 99 | 99 | 102 | 104 | 100 | 89 | 97 | 97 | 95 | 86 | 95 |
| Detroit | 82 | 89 | 98 | 93 | 93 | 93 | 91 | 84 | 100 | 88 | 99 | 96 | 86 | 93 | 91 | 100 | 97 | 86 | 86 |
| Indianapolis | 85 | 91 | 104 | 103 | 97 | 95 | 98 | 98 | 102 | 103 | 105 | 105 | 96 | 95 | 98 | 101 | 102 | 97 | 103 |
| Milwaukee | 80 | 93 | 96 | 86 | 92 | 84 | 87 | 97 | 102 | 103 | 94 | 86 | 81 | 88 | 98 | 100 | 99 | 86 | 96 |
| St. Louis | 89 | 99 | 108 | 106 | 105 | 102 | 100 | 101 | 105 | 105 | 106 | 107 | 98 | 96 | 98 | 103 | 106 | 107 | 108 |
| Minneapolis | 79 | 91 | 87 | 89 | 89 | 93 | 98 | 93 | 98 | 91 | 99 | 84 | 87 | 90 | 98 | 94 | 96 | 82 | 92 |

x MISO set an all-time peak load of 98,556 MW.

Figure 4 shows the day-ahead and real-time load in the lower panel and real-time prices in the upper panel for six of these days, with MISO's Maximum Generation declarations in the shaded bars. The figure shows that on June 28, July 6 and July 23, load was both under-scheduled and under-forecasted. Load was significantly overscheduled on June 29, when early afternoon thunderstorms reduced load unexpectedly. Although occasional regional price separation was caused by binding constraints, most price spikes on these days were the result of reserve shortages that affected prices throughout the region.

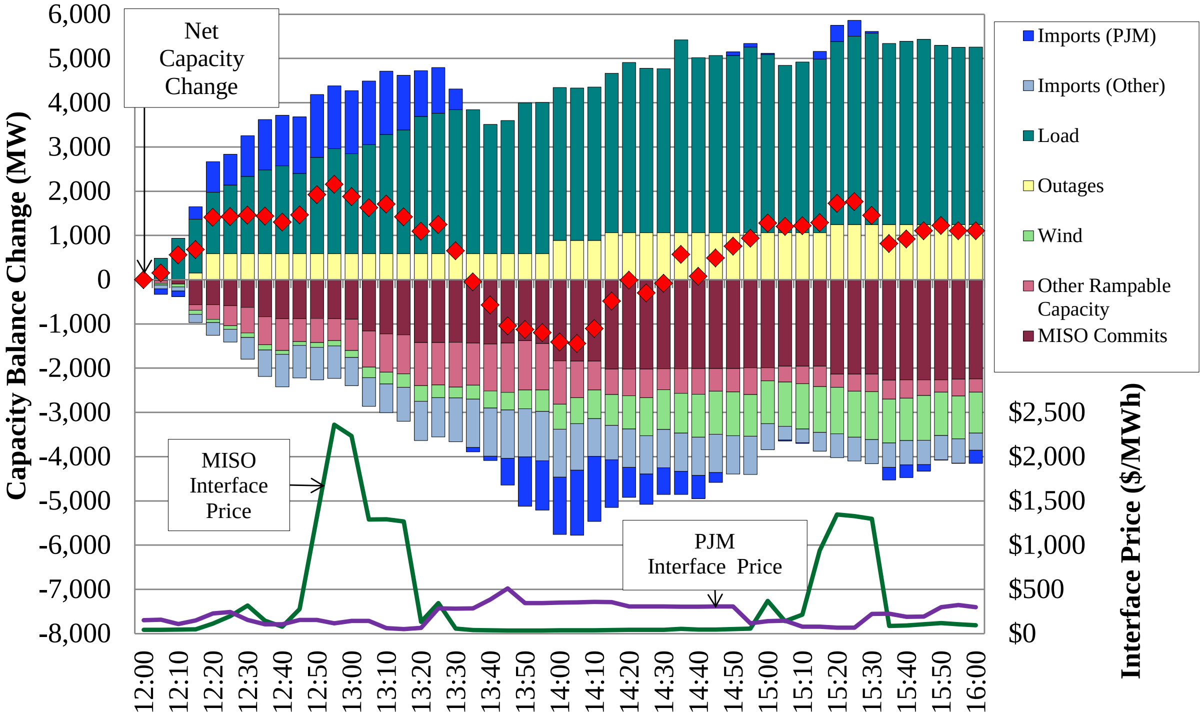
**Figure 4: Load and Real Time Prices**
Select Days, Summer 2012




In addition to extremely high demand for electricity, other factors leading to price spikes can include changes in net scheduled interchange, generator and transmission outages and derates, fluctuations in wind generation, and the timing of operator actions. To illustrate how these factors together contribute to shortages in the MISO market, Figure 5 shows the cumulative impact of real-time supply and demand factors that directly impacted capacity levels and energy prices beginning at noon on July 6, 45 minutes before MISO experienced a relatively severe capacity shortage. In this figure, "harmful" factors that contribute to higher prices are shown as positive values (reductions in supply or increases in demand), while "helpful" ones that reduce prices are shown as negative values. The "MISO Commits" are units committed by MISO to increase its available capacity. The "Other Rampable Capacity" is additional capacity that can be dispatched within five minutes that is made available on online units because they are ramping up. The net harmful capacity change is shown in the red markers. All values are measured against their respective level as of noon on July 6.

The operating reserve shortage beginning at 12:50 was caused by a 1.7 GW in load, the outage of a 586-MW unit at 12:20, and a 1.5 GW drop in net imports from PJM. Net imports declined because prices earlier in the hour were roughly $100 per MWh higher in PJM than in MISO.

**Figure 5: Contributing Factors to Capacity Levels and Energy Prices**
July 6, 2012




MISO remained in shortage for the next thirty minutes when additional output from committed capacity and online resources increased by 1.2 GW. In addition, net imports from PJM responded with a 30-minute lag so they were just beginning to respond by the time the shortage was ending.

The full response by net imports from PJM occurred by 14:00, when net imports had increased by almost three GW from their pre-shortage level. This overreaction by schedulers over the PJM interface led to low prices in MISO and caused MISO to incur substantial RSG costs to allow the peaking units it committed to recover their offered costs. By 14:10 the import surge ended and net imports began to decline. This reduction, together with the continued increases in load, contributed to another operating reserve shortage at 15:20.

This detailed examination of July 6 shows that the current scheduling rules for interchange can lead to substantial market dysfunction under tight conditions, producing both substantial economic and reliability costs. In summary, net imports from PJM:

- Contributed to the shortage initially;

- Responded too slowly to allow MISO to avoid having to commit more than two GW of high-cost units and incur $1.4 million in uplift cost on this day;
- Responded excessively to the high prices, thereby depressing prices and inflating RSG costs; and
- Fell sharply and contributed to the second operating reserve shortage.

Later in the report, we show that nearly half of transactions from PJM in 2012 were scheduled in the unprofitable direction, and that many hours still exhibited large price differences that can be attributed to scheduling uncertainties. Since the current Joint and Common Market (JCM) initiative to align the business rules will not address the underlying causes of these scheduling inefficiencies, we recommend the RTOs reduce the priority of these initiatives and make the interchange optimization initiative a high priority.

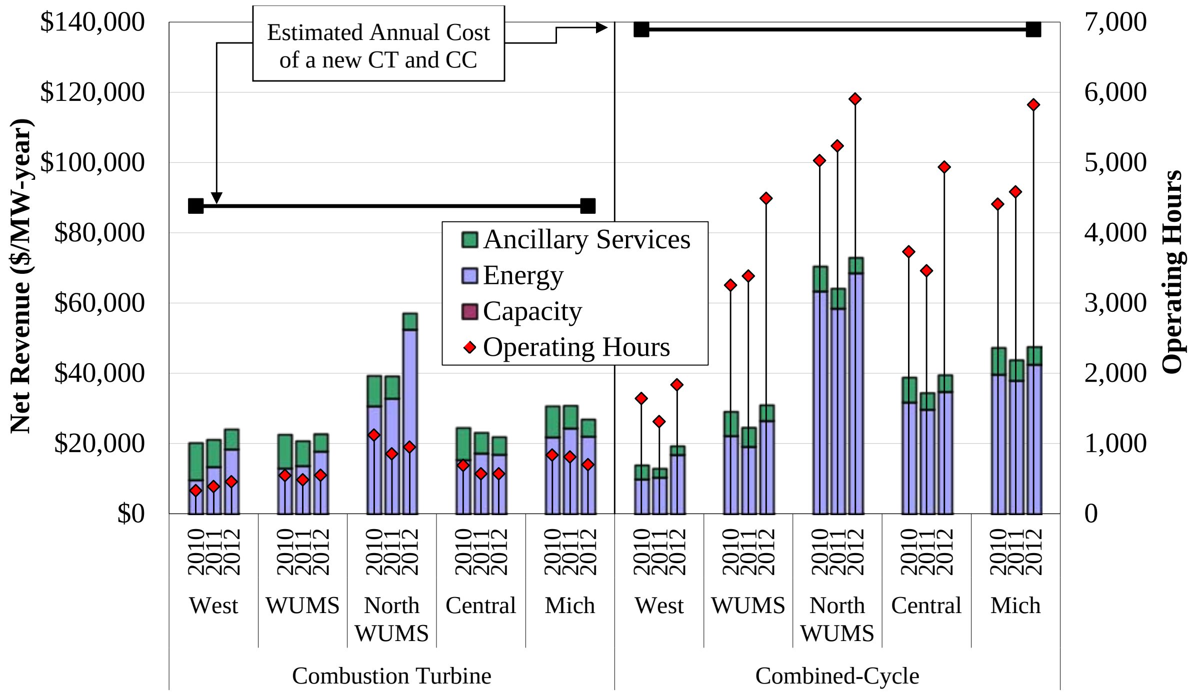
Our examination of this shortage and other shortages during the summer of 2012 also raised concerns regarding MISO's inability to efficiently utilize its demand response and BTMG. Currently, MISO can only call demand response after it has taken virtually all other emergency actions, most of which are more costly than activating demand response. We recommend MISO reconsider its emergency procedures to allow more economic utilization of this capability.

### D. Long-Term Economic Signals

While price signals play an essential role in facilitating efficient commitment and dispatch of resources in the short term, they also provide long-term economic signals that govern investment (or retirement) of resources and transmission capability. This section reviews the long-term economic signals provided by the MISO markets. These economic signals can be evaluated by measuring the "net revenue" that a new generating unit would have earned from the market under prevailing prices.

Net revenue is the revenue that a new generator would earn above its variable production costs if it ran when it was economic and did not run when it was uneconomic. A well-designed market should produce net revenue sufficient to finance new investment when available resources are insufficient to meet system needs. Figure 6 shows estimated net revenues for a hypothetical new Combustion Turbine (CT) and Combined-Cycle (CC) generator for the prior three years in five different MISO regions. For comparison, the figure also shows the minimum annual net revenue that would be needed for these investments to be profitable (i.e., Cost of New Entry or CONE).

**Figure 6: Net Revenue Analysis**
2010–2012




The net revenue in 2012 for both types of units was substantially less than CONE in all regions. This is consistent with expectations because of the capacity market design issues we describe in this report and the prevailing capacity surplus in the region.

MISO's new Resource Adequacy Construct (RAC) takes effect in June 2013. It incorporates zonal requirements designed to better identify regional capacity needs within MISO. The first Planning Resource Auction under the RAC for the 2013–2014 Planning Year cleared at $1.05 per MW-day with no zonal constraints binding, which is similar to the very low summer prices produced by the VCA in the past.

Although there is currently a capacity surplus, market design issues remain under the RAC that will likely undermine the economic signals when this surplus dissipates. To address this issue, we recommend a number of improvements to both the energy market and the capacity market. The next section discusses the supply in MISO and evaluates the design and performance of the capacity market intended to ensure the adequacy of MISO's resources.

# III. Resource Adequacy

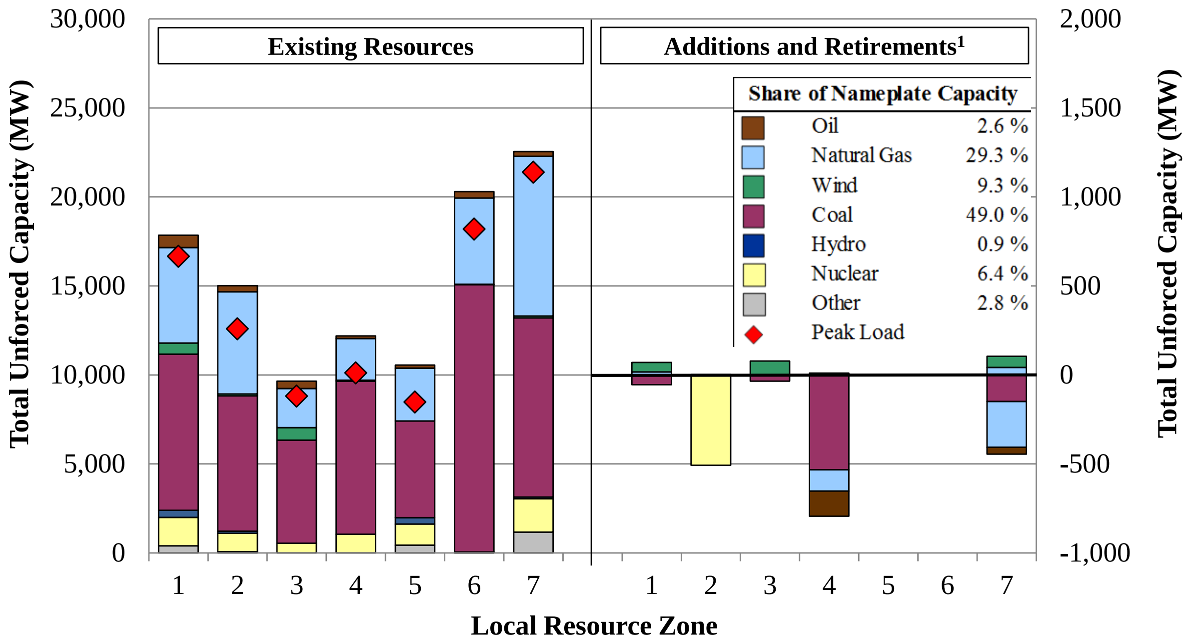
This section evaluates the supply in MISO, including:

- Summarizing the current resources and recent changes;
- Evaluating the adequacy of resources for meeting peak needs in 2013;
- Discussing future issues that may threaten supply; and
- Reviewing the outcomes and design of resource adequacy provisions.

## A. Regional Generating Capacity

Figure 7 shows the summer 2013 capacity 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 forecasted 2013 peak load in each zone. The right panel displays the change in the generating capacity from last summer. The inset table breaks down total UCAP by fuel type. UCAP values are lower than Installed Capacity (ICAP) values because they account for forced outages or intermittency. Hence, wind capacity, although it makes up 9.3 percent of nameplate capacity, does not feature prominently in this figure.

**Figure 7: Distribution of Generating Capacity**
By Fuel Type and Zone, Summer 2013



1 Includes reclassifications. If unit-specific UCAP was unavailable, the MISO fuel-type average was used.

Unforced capacity exceeds the 2013 forecasted peak load in all zones. However, because the average output from wind units in the West region is usually greater than their summer capacity levels, the 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.

Despite increased wind generating capacity and low gas prices, MISO continues to depend heavily on coal-fired generation, which accounts for nearly half of MISO's generating capacity. As discussed later in this section, MISO expects some capacity to retire in response to environmental rules, although the implementation of several of these rules has been delayed until 2015 or beyond. MISO expects fewer than 400 MW of coal retirements by summer 2013 (although several others are considered inoperable). The most significant retirement, of a nuclear unit in Wisconsin, occurred in May 2013.

Nearly all of the capacity additions expected by summer 2013 are wind units, the majority of which are in western areas where wind profiles are most attractive. Although wind resources are relatively costly, they benefit from a variety of subsidies, including production tax credits, state renewable portfolio standards, and the benefits of the transmission investments planned to improve their deliverability (i.e., Multi-Value Projects). These subsidies should cause the wind capacity levels to continue to rise over the next few years.

## B. Planning Reserve Margins

This subsection assesses capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2013. In its *2013 Summer Resource Assessment*, MISO presented baseline planning reserve margins alongside a number of valuable scenarios that show the sensitivity of the margins to changes in key assumptions. For example, MISO's *Assessment* includes a scenario that assumes hotter-than-normal peak conditions. This section includes our evaluation of MISO's planning reserve margins using the same capacity data as MISO used in its Summer Assessment so our data is consistent with MISO. However, we include some assumptions that differ from MISO's that lead to different estimated planning reserve margins, which we discuss in this subsection.

Table 2 shows both MISO's and an IMM "base case" planning reserve margin for summer 2012, assuming a normal year: (a) peak load forecasts under normal conditions;[7] (b) the assumed capacity credit for wind resources; (c) expected net imports; and (d) full response from demand response (DR) resources (interruptible load and controllable load management) and behind the meter generation (BTMG). These results are shown in the two most columns to the left.

It is highly unlikely that MISO can realize 100 percent of the estimated DR under emergency conditions or the level of wind output assumed by the capacity credit, so the third column shows the IMM base case with more realistic assumptions for these resources. Finally, abnormally hot conditions will both increase load *and* decrease supply because the ratings of many thermal units fall and some resources are subject to environmental restrictions under these conditions. The final two columns shows this effects on the planning reserve margins.

**Table 2: Capacity, Load, and Planning Reserve Margins**
Summer 2013

| | MISO | IMM Base Case | | IMM Hi Temp Case | |
|---|---|---|---|---|---|
| | | Full DR | Realistic Wind + DR | Full DR | Realistic Wind + DR |
| **Load** | **96,193** | **96,193** | **96,193** | **101,941** | **101,941** |
| *High Load Increase* | - | - | - | *5,748* | *5,748* |
| **Capacity** | **111,149** | **111,149** | **109,776** | **106,249** | **104,876** |
| *BTM Generation* | *3,394* | *3,394* | *3,394* | *3,394* | *3,394* |
| *Realistic Wind Adj.* [1] | - | - | *(1,373)* | - | *(1,373)* |
| *Hi Temp Derates* [2] | - | - | - | *(4,900)* | *(4,900)* |
| **Demand Response** | **4,661** | **4,661** | **2,331** | **4,661** | **2,331** |
| **Imports** | **6,119** | **1,622** | **1,622** | **1,622** | **1,622** |
| *Firm* | *1,622* | *1,622* | *1,622* | *1,622* | *1,622* |
| *Non-Firm* | *4,497* | - | - | - | - |
| **Margin (MW)** | **25,736** | **21,239** | **17,536** | **10,591** | **6,888** |
| **Margin (%)** | **28.1%** | **23.2%** | **18.7%** | **10.9%** | **6.9%** |

Note: All values are MW unless noted.

1 Adjustment for using a more conservative estimate of wind output.

2 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.

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

The results show that the capacity surplus varies considerably depending on the various assumptions made. The baseline capacity margin for the MISO region is 28.1 percent, which far exceeds the Planning Reserve Margin Requirement of 14.2 percent.[8] The assumption of an expected or "typical" response from non-firm imports, wind, and DR resources makes up nearly half of this margin, however. This underscores the importance of accurately assessing the realistic capacity contributions and pricing of each of these sources of capacity.

First, non-firm expected imports are rarely included in planning reserve margins. MISO's assumption is particularly aggressive because it reflects the import levels in the highest 10 percent of hours. While we agree that it is reasonable to expect imports above the firm amount of 1,622 MW during peak conditions, it is possible that neighboring regions will also be peaking and external supplies will be scarce. It is for this reason that RTO capacity markets designed to satisfy planning reserve requirements will generally only accept supply firm imports. The second column in the table shows that if this is eliminated, the margin falls almost five percentage points to 23.2 percent.

Second, DR and wind generally do not provide the same level of reliable supply as conventional resources. We describe in Section III.C why we believe the MISO's current methodology overestimates the amount of wind output that it can rely on in its highest load hours. Under a less optimistic methodology as described in that section, the capacity value of MISO's wind resources would fall by more than 1,200 MW. Likewise, most of the DR is not under the direct control of MISO and its ability to test this capability is limited. When DR and BTMG was called in 2006, MISO received a peak response of less than 2,700 MW, which was far less than the 6,200 MW of total claimed capacity at the time. To account for this, we derate the DR quantities by one-half, which lowers the reserve margin to 18.7 percent. We believe this is a reasonable estimate of the forecasted planning reserve margin for this summer, which is much closer to the minimum requirement than most believe. Nonetheless, it indicates that supply should be adequate for 2013, particularly given MISO's large import capability in excess of its firm imports.

8 The 2013 Planning Reserve Margin Requirement is 2.5 percentage points lower than the 2012 Requirement, which is mainly due to a modeling adjustment that allows MISO to access more external resources from neighboring entities.

Finally, the final two columns show the same scenarios under peak conditions that are hotter than normal. These columns represent a "90/10" case, which should only occur one year in ten. This is an important case because particularly hot weather can have a significant impact on both load and supply. High ambient temperatures can reduce the maximum output levels of many of MISO's generators, while river water temperature restrictions certain resources to be derated. These concerns generally arise only in summer, and are most acute during very high temperatures. There is significant uncertainty regarding the size of these derates, so our number in the table is an average of what was observed on extreme peak days in 2006 and 2012.

These cases show much lower margins—as low as 6.9 percent in the most realistic supply case—than what is assumed by MISO. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no forced outages, which generally range from five to eight percent. Hence, under these conditions, MISO would only avoid firm curtailments by utilizing non-firm imports.

Overall, these results indicate that the system's resources should be adequate for summer 2013 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins are gradually decreasing and will likely continue to fall as new environmental regulations are implemented. Therefore, it is important for the resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base. These issues are discussed in detail in the following four subsections.

## C. Wind and Demand Response Capacity Credits

Wind resources receive capacity credits toward satisfying Module E requirements that are only a fraction of their installed capacity. This is because their output is variable and intermittent, and their full capability cannot be relied upon during peak load times. Credits averaged 14.9 percent for Planning Year (PY) 2012–13 and 13.3 percent for PY 2013–14. These credits reflect the average performance of wind resources during prior years' peak load hours.

We believe that these UCAP credits substantially exceed the true capacity value of the wind resources. As much as possible, wind UCAP credit should be estimated in a manner that produces a comparable level of expected availability to other types of generating resources.

However, this is not the case under MISO's methodology, which produces wind credits that will likely not be achieved in most peak load hours. Because its methodology is based on the mean wind output, one unusually windy peak day can cause this measure and the resulting capacity credits to be overstated. Using the median output level by unit in peak load hours would lower the average PY 2013–14 capacity credit to 11.5 percent. Even using the median, however, overstates the credit because one should expect the wind output to be less than this level in half of the peak load hours. Therefore, this report shows the effects of assuming the lowest quartile of output during peak hours on the unit-by-unit basis.[9] This methodology would produce an average capacity credit for the wind resources of 2.7 percent for PY 2013–14. We recommend that MISO consider this as an alternative for granting UCAP credits for wind resources in future.

Likewise, MISO should grant capacity credit to DR and BTMG resources only to the extent that their availability is likely to be comparable to conventional resources. MISO's current methodology grants these resources full credit even though they are not tested and are not fully available in all peak load hours. Therefore, we recommend MISO adopt an improved methodology for accounting for DR and BTMG under Module E that would better reflect their likely availability in peak load hours.

## D. Potential Impact of the New EPA Regulations

MISO continues to study and model the potential impacts of the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) on the MISO market. MISO's analysis suggests that up to 12 GW of capacity in MISO remains at risk of retirement because of the compliance costs of these regulations. Although CSAPR was vacated in mid-2012, MISO still estimates an energy cost impact of $1 to $5 per MWh, mostly in the form of higher variable operations and maintenance costs for control technologies. Additional coal-fired capacity could be at risk if the prevailing low natural gas prices continue for the long term. MISO surveys of market participants' compliance plans also indicate substantial amounts of potential retirements and long-term outages related to environmental retrofits.

9 See Figure A20 in the Analytic Appendix.

Together with the increased penetration of wind resources, EPA regulations will put substantial economic pressure on existing coal resources to retire, which should reduce planning reserve margins in MISO. The MISO RAC will play a pivotal role in assuring that the market supports reliable planning reserve margins over the long term.

## E. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or mothball a unit to notify MISO six months in advance of its desired retirement date. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR), which it granted for the first time in 2012. As of March 26, 2013, there were an additional 15 SSR candidates being evaluated by MISO, with a further seven already determined to qualify as SSR.[10] An SSR cannot retire until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. The SSR agreement provides for compensation to the Market Participant during this period of delayed retirement.

On July 25, 2012 MISO filed Tariff revisions that clarified both the designation and compensation provisions, which was urgently needed because of the large number of units that may retire due to the EPA regulations or unfavorable economic conditions (e.g., low gas prices, increased wind penetration). We will continue working with MISO on reviewing and, as needed, clarifying these procedures in order to ensure that SSR decisions result in efficient outcomes. As discussed further in the next section, it is also important that the capacity market sends appropriate signals to rationalize participants' decisions to retire or retrofit their resources.

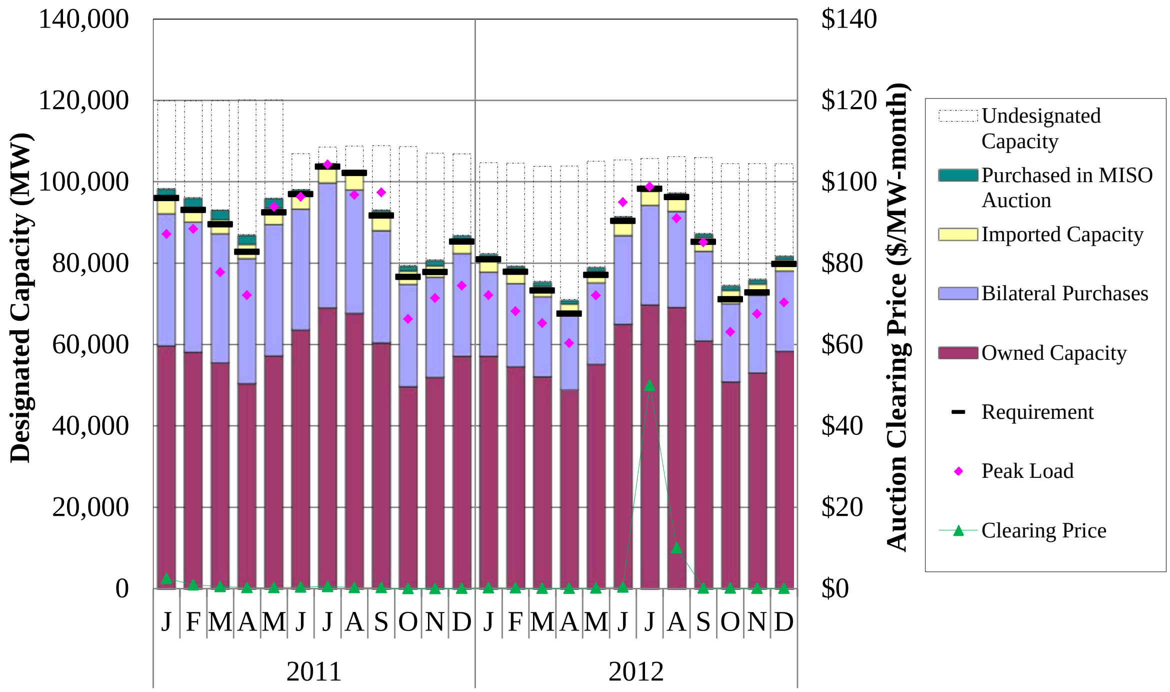
## F. Capacity Market

Since June 2009, MISO has run a monthly VCA to allow LSEs to procure capacity to meet their Module E requirements. The VCA provides a revenue stream that, in addition to energy and ancillary service market revenues, should signal when new resources are needed. However, certain design flaws with MISO's RAC substantially undermined its performance in 2012. Figure 8 shows monthly capacity obligations for 2011 and 2012 and how they were satisfied.

10 Market participants for these seven resources still need to negotiate agreements with MISO and file them with FERC.

These obligations are based on a participant's forecasted load, so they vary monthly. To indicate the accuracy of these forecasts, the figure shows the requirement based on the actual monthly peak load.

**Figure 8: Voluntary Capacity Auction**
2011–2012




Since most LSE obligations were satisfied through owned capacity or bilateral purchases, cleared capacity in the VCA averaged just 1.1 GW, or 1.3 percent of total designated capacity. Low cleared quantities are consistent with the intention of the VCA as a balancing market. Nonetheless, it is a critical component of the economic signal for investment because it provides a transparent spot price for capacity that should be the primary driver of forward capacity prices (and, therefore, a primary driver of investment).

In 2013, MISO adopted a new RAC with a number of changes, the most significant of which is the introduction of zonal capacity requirements and clearing prices. This allows the market to more accurately signal the supply and demand conditions in different areas. In addition, MISO converted its requirements into an annual requirement and implemented an annual planning resource auction ("PRA"). The PRA ran for the first time in April and produced a MISO-wide price of approximately $32 per MW-month, which is very low.

The very low price in the PRA indicates the performance of the capacity market continues to be undermined by two significant issues: 1) the current "vertical demand curve" and 2) barriers to capacity trading with PJM. The recently modified RAC effectively establishes a vertical demand curve because there is a single minimum capacity requirement for each LSE and a deficiency price for any LSE that is short. Because the marginal cost of selling capacity for most units is close to zero, a vertical demand curve will predictably establish clearing prices close to zero if supply is not withheld. In addition, the vertical demand curve is inconsistent with the underlying reliability value of excess capacity beyond the requirement. The implication of the 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. This is not true in reality—each unit of surplus capacity will improve reliability and lower energy and ancillary services costs for consumers (although these effects diminish as the surplus increases).

To address this flaw, we provided comments to FERC and recommended in prior *State of the Market Reports* that Module E of the Tariff be modified to implement a sloped demand curve.[11] A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power—a market that is highly sensitive to withholding and can clear at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless since the foregone capacity sales would otherwise be priced at close to zero. The need for a sloped demand curve may become particularly acute as planning reserve margins decline toward the minimum requirement level with the likely retirement of significant amounts of coal-fired capacity in MISO.

The second issue with MISO's current capacity market is the prevailing barriers to capacity trading between PJM and MISO. Capacity prices in both markets will only be efficient if

11 See "Motion to Intervene Out of Time and Comments of the Midwest ISO's Independent Market Monitor," filed September 16, 2011 in Docket No. ER11-4081.

participants can freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Current barriers include a variety of PJM provisions that limit access to transmission, as well as the obligations imposed on external resources that sell capacity into PJM. We described these barriers in detail in a prior filing to FERC.[12] We continue to recommend that MISO work with PJM to address these barriers. FERC has scheduled for PJM, MISO, their respective market monitors, and the States in the two regions to give presentations at an upcoming FERC meeting on these issues.

12 Motion for Request For Leave To Answer and Answer of the MISO Independent Market Monitor, Docket No. ER11-4081-000.

# IV. Day-Ahead Market Performance

MISO's spot markets for electricity operate in two time frames: real time and day ahead. The real-time market reflects actual physical supply and demand conditions. The day-ahead market operates in advance of the real-time market. The day-ahead market is largely financial, establishing financially-binding, one-day forward contracts for energy and ancillary services. Resources committed and scheduled in the day-ahead do receive start and stop instructions based on the day-ahead results.[13] Both markets continued to perform competitively in 2012.

The performance of the day-ahead market is important for at least three reasons:

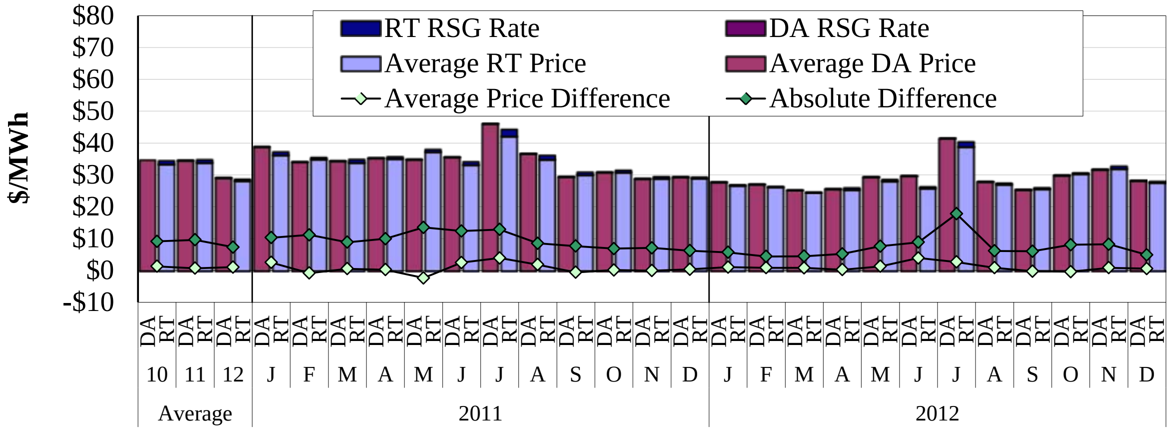
- Since most generators in MISO are committed through the day-ahead market, good performance of that market is essential to efficient commitment of MISO's generation;
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

## A. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day; however, a number of factors, such as wind output volatility, forced generation or transmission outages, and load forecasting errors, can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge well over longer timeframes (monthly or annually). Figure 9 shows monthly and annual price convergence statistics. The upper panel shows the results for only Indiana Hub (Cinergy Hub prior to April 2012), while the table below shows other hub locations. Because real-time RSG charges tend to be much larger than day-ahead RSG charges, the lower table adjusts the average price difference to account for the difference in RSG charges.

13 In between the day-ahead and real-time, MISO evaluates the day-ahead results relative to the forecasted capacity needs for the next day. Based on this Forward Reliability Assessment Commitment (FRAC) MISO may start additional capacity not-committed in the day-ahead.

**Figure 9: Day-Ahead and Real-Time Prices**
2010–2012




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

| | 10 | 11 | 12 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cin/Indi Hub | 4 | 2 | 4 | 7 | -2 | 2 | 1 | -6 | 7 | 9 | 5 | -2 | 0 | 0 | 1 | 4 | 3 | 3 | 1 | 5 | 15 | 7 | 3 | -1 | -1 | 3 | 2 |
| Michigan Hub | 4 | 2 | 4 | 6 | -5 | 3 | 7 | -5 | 2 | 8 | 4 | -3 | 2 | -4 | 3 | 5 | 2 | -1 | 5 | 5 | 7 | 7 | 3 | 4 | 1 | 3 | 1 |
| Minnesota Hub | 2 | -2 | -2 | 1 | -6 | -10 | -16 | 5 | -9 | 6 | -1 | -4 | 0 | 4 | 11 | 3 | -2 | 2 | -12 | -6 | 0 | 2 | 2 | -7 | 3 | -8 | -1 |
| WUMS Area | 7 | 3 | 1 | 3 | -6 | 0 | -4 | 5 | 6 | 8 | -1 | 1 | 9 | 8 | 8 | 3 | 0 | 4 | 0 | -1 | -1 | 2 | 3 | -4 | 0 | 0 | 3 |

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

| | 10 | 11 | 12 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cin/Indi Hub | 0 | -1 | 2 | 4 | -4 | -1 | -1 | -8 | 4 | 4 | 1 | -5 | -2 | -2 | 0 | 3 | 2 | 2 | -2 | 3 | 12 | 3 | 1 | -2 | -2 | 0 | 1 |
| Michigan Hub | 1 | -1 | 2 | 3 | -7 | 0 | 5 | -7 | 0 | 3 | 1 | -5 | 0 | -5 | 2 | 4 | 2 | -2 | 2 | 3 | 5 | 4 | 2 | 3 | 0 | 1 | -1 |
| Minnesota Hub | -1 | -5 | -4 | -2 | -8 | -13 | -18 | 1 | -13 | 0 | -5 | -8 | -3 | 1 | 10 | 2 | -2 | 1 | -14 | -8 | -3 | -2 | 1 | -8 | 2 | -10 | -2 |
| WUMS Area | 3 | 0 | -1 | 0 | -8 | -3 | -6 | 2 | 3 | 2 | -4 | -2 | 7 | 5 | 7 | 2 | -1 | 3 | -3 | -3 | -3 | -2 | 1 | -6 | -1 | -3 | 1 |

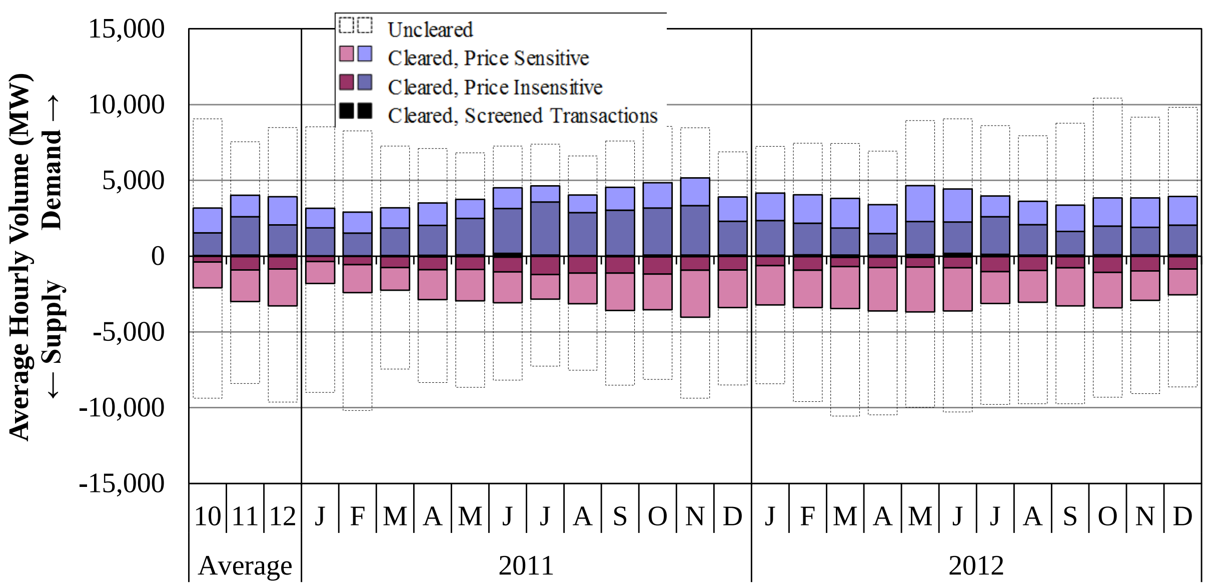
In 2012, there were modest day-ahead premiums at most hubs, including a premium of 3.6 percent at the Indiana Hub. This outcome is consistent with the high level of net load scheduling in the day-ahead market, which averaged 100.7 percent for the daily peak hour and 99.7 percent in all hours. Accounting for the $0.57 per MWh in average RSG cost allocations to real-time deviations decreases the effective day-ahead premiums by approximately two percentage points. Over the long term, we expect day-ahead load to pay a small premium (net of RSG costs) because scheduling load day-ahead limits the price risk associated with higher real-time price volatility. RSG costs were considerably lower than in prior years—$0.95 in 2011 and $2.05 in 2010. RSG costs are discussed in greater detail in Section V.D.1.

Price convergence at the Minnesota Hub in the spring was poor in several months due to several real-time congestion events. Some of these events included the loss of imports from Manitoba, which created congestion into the Minnesota area that was unforeseen day-ahead.

## B. Virtual Transactions in the Day-Ahead Market

Virtual transactions are purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources, so they are settled against the real-time price. Virtual transactions are essential facilitators of price convergence because they arbitrage price differences between the day-ahead and real-time markets. Figure 10**Error! Reference source not found.** 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 in 2011 and 2012. The virtual bids and offers that did not clear are shown as the transparent areas at the end of each bar.

**Figure 10: Virtual Load and Supply in the Day-Ahead Market**
2010–2012




**Percent Screened**

| | 10 | 11 | 12 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Demand | 1.3 | 1.6 | 2.2 | 0.7 | 0.7 | 1.1 | 1.5 | 2.4 | 4.0 | 1.4 | 1.1 | 1.1 | 1.5 | 1.5 | 1.9 | 1.5 | 2.0 | 1.7 | 1.6 | 2.1 | 4.0 | 3.1 | 1.8 | 2.1 | 2.2 | 2.1 | 2.1 |
| Supply | 0.6 | 1.2 | 1.4 | 0.4 | 1.2 | 2.0 | 2.2 | 1.5 | 2.4 | 0.8 | 0.2 | 1.0 | 1.5 | 1.0 | 0.6 | 0.9 | 1.2 | 2.4 | 1.9 | 2.2 | 1.4 | 1.2 | 1.0 | 1.2 | 1.3 | 1.1 | 1.4 |
| Total | 1.0 | 1.4 | 1.9 | 0.6 | 0.9 | 1.5 | 1.8 | 2.0 | 3.4 | 1.1 | 0.7 | 1.0 | 1.5 | 1.3 | 1.3 | 1.2 | 1.6 | 2.0 | 1.7 | 2.2 | 2.9 | 2.3 | 1.4 | 1.6 | 1.8 | 1.6 | 1.8 |

The figure distinguishes between bids and offers that are price-sensitive and those that are price insensitive (i.e., those that are very likely to clear) because price-sensitive transactions are much more valuable in providing liquidity in the day-ahead market and facilitating price convergence.

Bids and offers are considered price-insensitive when they are offered at more than $20 above and below an "expected" real-time price.[14]

Price-insensitive bids and offers that contribute to a significant difference in congestion at a location between the day-ahead and real-time markets are labeled "Screened Transactions". We routinely investigated these transactions because they are generally not rational and lead to price divergence. Therefore, they may represent an attempt to manipulate the day-ahead market.

The figure shows that offered volumes increased by 14 percent from last year to 18.1 GW per hour, while cleared volumes rose three percent to 7.2 GW per hour. Offered volumes rose more quickly than cleared volumes because one market participant in the second half of 2012 began bidding large quantities of virtual demand at very low prices that rarely cleared.

Cleared virtual transactions increased in April 2011 after a change to MISO's RSG cost allocation measures that generally reduces the allocation to virtual supply, and eliminates any allocation when virtual supply is netted against a participant's virtual load. We believe that this change has increased participants' incentives to clear equal amounts of virtual supply and demand at different locations by submitting them price-insensitively to ensure they clear.

Approximately 40 percent of cleared virtual volumes in 2012 were price-insensitive, down from 50 percent in 2011. Such volumes are most often placed for two reasons:

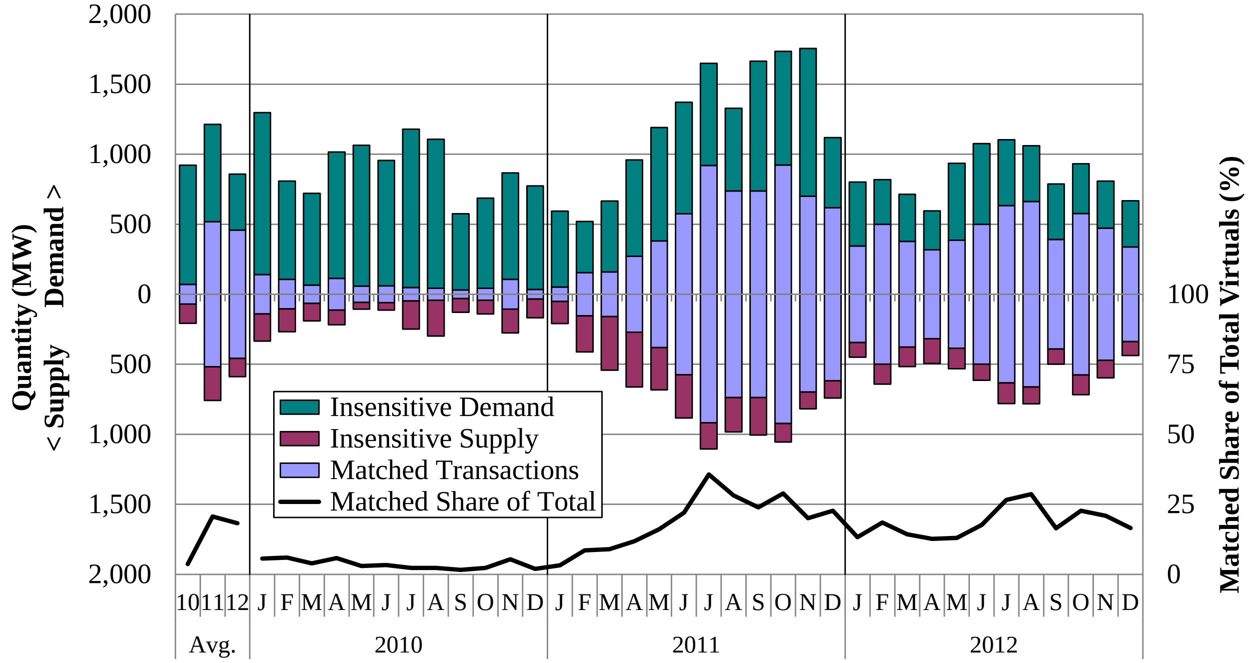
- To establish an energy-neutral position across a particular constraint to arbitrage congestion-related price differences between the day-ahead and real-time markets; and
- To balance the participant's portfolio so as to avoid RSG deviation charges assessed to net virtual supply.

Figure 11 examines more closely these insensitive virtual transactions. "Matched" virtuals in the figure are a subset of these transactions whereby the participant clears both insensitive supply and insensitive demand in a particular hour that offset one another. This figure shows that nearly two-thirds of insensitive transactions and 18 percent of all virtual transactions were "matched"

14 An average of recent real-time prices in similar hours.

transactions. The substantial rise in these transactions from 2010, when just four percent of all transactions were matched, is clearly due to RSG allocation revisions..

**Figure 11: Matched Virtual Transactions**
2010-2012




To the extent that matched transactions are attempting to arbitrage congestion-related price differences, we believe that a virtual spread product to allow participants to engage in these transactions price sensitively would be more efficient. Therefore, we are recommending that MISO pursue a virtual spread product. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (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. The transaction would lose money if the difference is less. This product would settle only on the difference in the congestion and loss components of the LMP, so the participant would bear no energy price risk and would not create a deviation that could cause MISO to be capacity-deficient.

## C. Virtual Profitability

Gross virtual profitability in 2012 averaged $0.52 per MWh and was slightly lower than in prior years. Virtual supply averaged profits of $1.31 per MWh while virtual demand lost $-0.15 per

MWh on average. However, the real-time RSG costs allocated to net virtual supply averaged $0.57 per MWh in 2012, which lowered the net profitability of virtual supply transactions to $0.74 per MWh.

Transactions by financial-only participants were considerably more profitable than those by generation owners and load-serving entities, which is consistent with the conclusion that the arbitrage by financial participants has improved the convergence between day-ahead and real-time prices. Transactions that promote convergence are profitable (e.g., selling virtual supply at high day-ahead prices), while those that lead prices to diverge are unprofitable.

## D. Fifteen-Minute Day-Ahead Scheduling

The day-ahead market currently clears on an hourly basis. As a result, all day-ahead schedule changes occur at the top of each hour. In hours when load is ramping rapidly, the hourly changes in day-ahead load (and scheduled supply to satisfy that load) does not track the changes in real-time load well.

Many participants attempt to match the day-ahead schedule in real time, which can cause severe ramp demands at the top of the hour. These ramp demands are caused by unit commitments, de-commitments, and changes to physical schedules that are all concentrated at the top of the hour. Solving the day-ahead market more frequently would result in more flexible commitments and schedules that could better align with actual ramp demands in the real-time. Computer hardware performance limitations previously prevented MISO from adopting such a granular day-ahead market. However, performance has improved significantly over time and should continue to improve in the future. Therefore, as MIISO considers its longer-term market improvements and priorities, we recommend it evaluate the costs and benefits of modifying the day-ahead market to clear on a fifteen-minute basis.

# V. Real-Time Market

## A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by the physical limitations of the resources and the transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions.

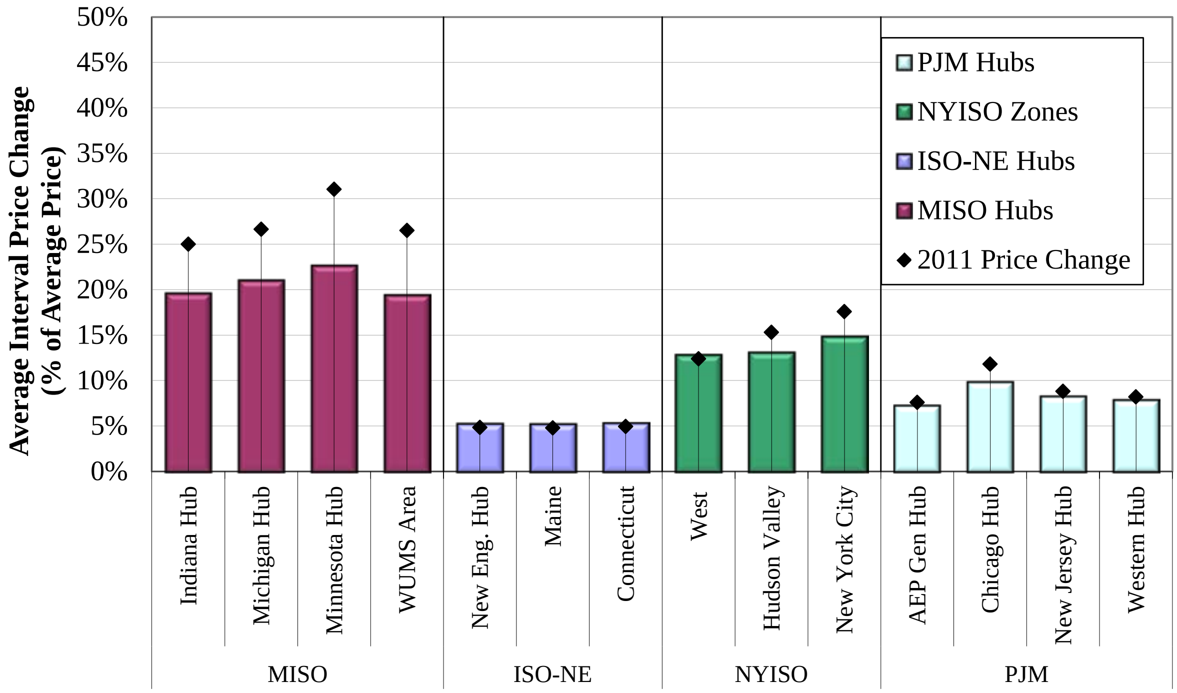
MISO's real-time market operates on a five-minute time horizon. Hence, when conditions change, the real-time market only has access to the dispatch flexibility that its units can provide in five minutes. Since the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some generators are moving as quickly as they can up or down). This limitation results in transitory price spikes, either upward or downward. This section evaluates the volatility of the real-time energy prices.

Figure 12 compares fifteen-minute price volatility at representative points in MISO and in three neighboring RTOs. Overall, price volatility in MISO remains considerably higher than in neighboring RTOs, although it declined considerably in 2012. 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 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).

The volatility in MISO occurs when ramp constraints bind and cause sharp price movements, which tends to happen when:

- Actual load is changing rapidly, including non-conforming load associated with industrial facilities that can change sharply and without advance notice;
- Net Scheduled Interchange (NSI) changes significantly;
- A large quantity of generation is either starting up or shutting down; or
- The load-offset parameter is not set optimally to manage anticipated ramp changes.

**Figure 12: Fifteen-Minute Real-Time Price Volatility**
2012




Ramp constraints tend to bind most frequently at the top of the hour, when NSI and generation changes are largest. Over the course of the day, they occur most frequently when load is ramping up or down near the peak hour of the day. In addition, transmission congestion at times results in higher price volatility in specific regions, particularly in the West region where fluctuations in wind output can contribute to substantial congestion on lines exiting the West. This report includes a number of recommendations to improve the management of system ramp capability and to reduce price volatility.

## B. Evaluation of High Real-Time Energy Prices

In most cases, the price volatility shown in the prior section is a result of relatively high energy prices that are often transitory. This subsection discusses the primary causes of high prices in MISO. Intervals priced at greater than $175 per MWh occurred 361 times in 2012, or 0.34 percent of all intervals, down from 609 intervals last year. These instances were predominantly driven by large ramp demands—including changes in load, generation outages or decommitments, and changes in NSI—that caused MISO to dispatch high-cost supply or experience transitory reserve shortages.

We believe MISO will likely continue to experience substantial fluctuations in demand and supply that will compel the system to ramp down or up very quickly, causing lower-cost units' ramp constraints to bind and leading to price volatility. In addition to the price volatility this causes, it also increases the production costs of the system by causing MISO to dispatch much more expensive units and making higher price volatility make whole payments. Therefore, changes we have recommended to improve the ability of the system to manage ramp demands will likely produce significant savings and reduce price volatility. These changes include:

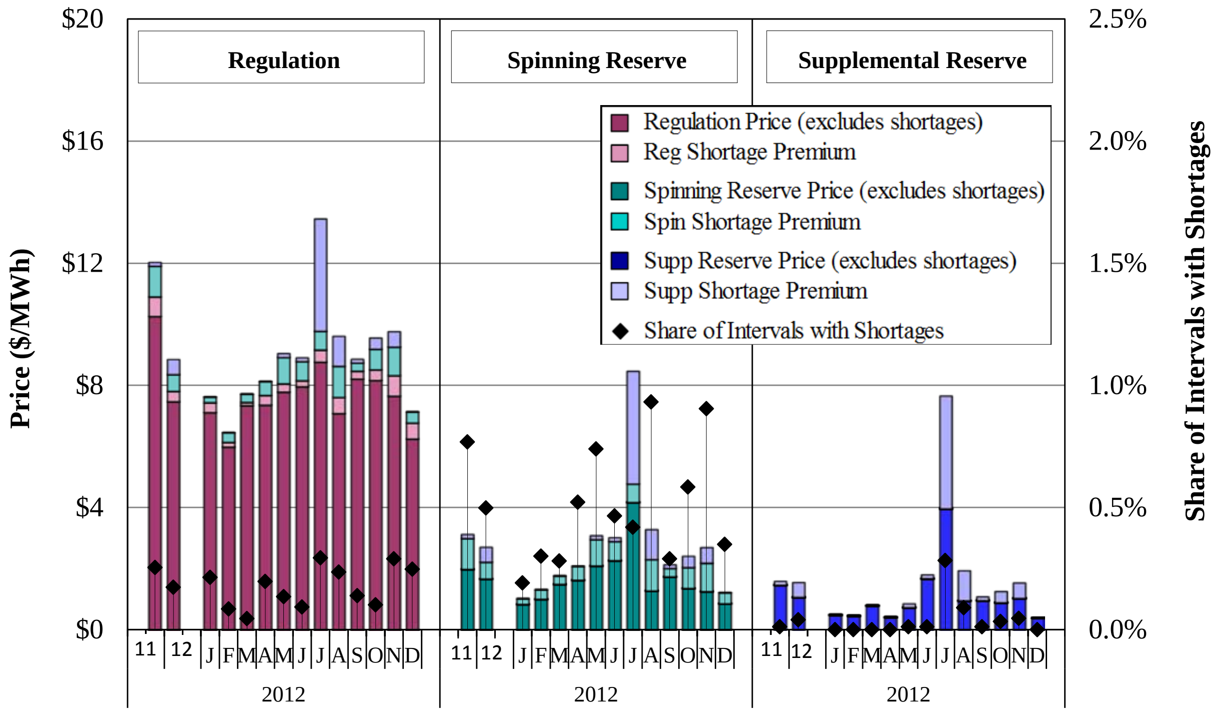
- Utilizing the load offset parameter more proactively to smooth anticipated ramp demands;
- Modifying its real-time market software to include a look-ahead dispatch capability to more efficiently manage anticipated ramp demands; and
- Introducing a "ramp" product to allow the real-time market to dispatch the system to maintain more ramp capability, which will allow it to better manage *unanticipated* ramp demands.

In April 2012, MISO introduced a Look-Ahead Commitment tool to improve its situational awareness and to improve its commitment and decommitment of peaking resources. This tool has improved MISO's use of peaking resources to address ramp demands, but does not reduce significantly the benefits of the initiatives listed above.

## C. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2012. Since their inception in 2009, jointly-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions. Figure 13 shows monthly average real-time prices for regulation, spinning reserves, and supplemental reserves, along with the contribution of shortage pricing to each product's clearing price. It also shows the share of intervals in shortage for each product. The supplemental reserve prices in this figure shows the price associated with satisfying MISO's market-wide contingency reserve requirement. This is the only requirement that supplemental reserves can satisfy. Because spinning reserve resource can satisfy either the contingency reserve requirement or the spinning reserve requirement, the spinning reserve price will include a component associated with contingency reserve shortages. In other words, shortages of contingency reserves will be included in the price of supplemental reserves and all higher value products, including energy. Likewise, the higher-value regulation product includes a component associated with spinning reserve shortages.

**Figure 13: ASM Prices and Shortage Frequency**
2011-2012




Monthly average clearing prices for regulation declined by 26 percent to $8.88 per MWh. This decline was due primarily to lower gas prices, which reduces the opportunity costs of providing regulating reserves. In addition, the regulating reserve demand curve penalty price, which sets price during regulating reserve shortage periods, declined to $113 per MWh on average and was set at its floor of $100 from April to July. Spinning reserve prices averaged $2.74 per MWh, a 13 percent decline from 2011, while supplemental reserve prices declined four cents to $1.58 per MWh. The declines for these two products were smaller than the decline in fuel prices because of a significant increase in contingency reserve shortages, which rose from 12 to 43 intervals and added $0.48 per MWh to the annual average price of all reserve products and energy. Hence, the impact in percentage terms of these shortages was greater for cheaper products. Operating reserves were deployed just three times—on May 13, May 14 and June 16—and responded very well.

MISO made two significant changes to AS markets in 2012. First, it adopted a two-step demand curve for spinning reserves on May 1. Under this demand curve, shortage quantities of less than 10 percent of the reserve requirement are priced at $65 per MWh, while those exceeding 10 percent are priced at $98 per MWh. With this change, MISO discontinued “relaxing” the spinning reserve requirement to set prices during shortage. This is efficient because pricing reserves at their penalty price is the most efficient outcome when the system is short of reserves. Such demand curves are used to price all of MISO’s reserve products during shortage conditions, but only the spinning reserve demand curves vary by the size of the shortage.

Second, per FERC Order 755, MISO introduced a two-part offer and compensation structure for regulation on December 17. Under this structure, MISO pays participants separately for regulation capacity and for “mileage” (the amount of a unit’s actual movement). Although some participants’ regulation offer prices rose considerably after this change due to a general lack of familiarity with the offer structure, it had a limited impact on clearing prices.

### 1. Lost Capacity During Supplemental Reserve Deployments

In evaluating the performance of the MISO markets during shortage conditions, we detected a flaw that occurs when quick-start units are deployed. Offline quick-start resources, usually combustion turbines and pumped storage resources, can provide supplemental reserves that satisfy MISO’s contingency reserve requirement. When resources providing supplemental reserves are committed, the reserves are shifted to online resources.

Unfortunately, MISO does not account for the committed resource as providing reserves or energy until the unit is synchronized and providing energy. Hence, all capacity from the resource will appear to be lost, generally for five to 15 minutes. During this period, the quality of reserve capability is actually enhanced because the resource can provide energy and reserves more quickly to the system once it is online.

In 2012, lost reserve capability from committed quick-start resources affected 2.3 percent of market intervals by an average of 107 MW. The issue caused two operating reserve shortages and contributed to nine operating reserve price spikes of at least $100 per MWh. Although we have not quantified it, this issue would also have increased DAMAP payments during the reserve shortage events. Therefore, we recommend MISO pursue changes in its accounting of reserves that would recognize the reserves being provided during the period when a quick-start unit is starting.

## D. Settlement and Make-Whole Payments

MISO employs two primary forms of make-whole payments in real time to ensure resources cover their as-offered costs and, therefore, have incentives to be flexible:

- RSG payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- PVMWP ensure that suppliers will not be financially harmed in the hourly settlement by following MISO's five-minute dispatch signals. The PVMWP consists of two payments: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP).

Resources committed by MISO for economic capacity or for congestion management after the day-ahead market receive a "real-time" RSG payment if their as-offered costs are not recovered through the LMP in the real-time market. The costs related to RSG payments are recovered via charges that are "uplifted" to market participants. It is most efficient to allocate RSG costs to market participants in proportion to how much they contribute to causing the costs.

### 1. Real-Time RSG Costs

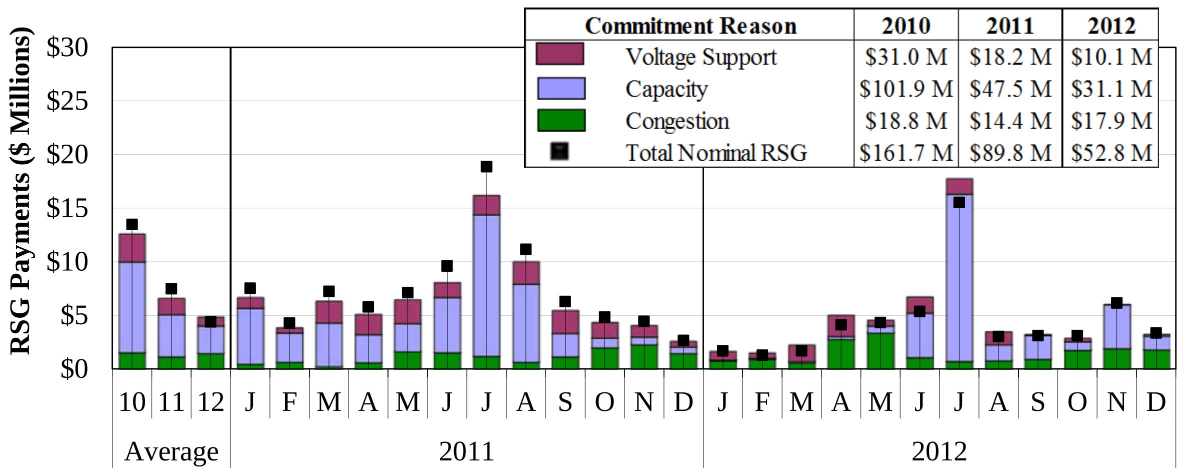
Figure 14 shows real-time RSG payments, which accounted for the majority of total RSG payments (the balance is paid day-ahead). Since fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[15] It separately shows the fuel price-adjusted RSG payments associated with commitments made for capacity purposes, local voltage support, and constraint management. The table below

15 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are therefore greatest for periods when fuel prices were highest, and vice-versa.

the figure shows the share of RSG costs paid to peaking and non-peaking resources. Peaking resources are generally high-cost, inflexible resources relied upon in real time to meet system reliability needs, particularly in summer.

**Figure 14: Real-Time RSG Payments**

2010–2012




**Share of Real-Time RSG Costs by Unit Type and Commitment Reason (%)**

| | 10 | 11 | 12 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peaker | 53 | 59 | 71 | 60 | 53 | 54 | 53 | 48 | 68 | 75 | 66 | 45 | 48 | 43 | 35 | 27 | 31 | 30 | 51 | 76 | 68 | 84 | 44 | 68 | 73 | 75 | 77 |
| Congestion | 11 | 16 | 26 | 7 | 12 | 6 | 15 | 15 | 16 | 13 | 15 | 16 | 35 | 33 | 29 | 27 | 31 | 28 | 48 | 67 | 12 | 6 | 15 | 21 | 56 | 21 | 53 |
| Capacity | 42 | 42 | 45 | 54 | 41 | 49 | 39 | 33 | 52 | 62 | 52 | 29 | 13 | 10 | 7 | 0 | 0 | 2 | 3 | 8 | 56 | 79 | 29 | 47 | 17 | 54 | 23 |
| Non-Peaker | 47 | 41 | 29 | 40 | 47 | 46 | 47 | 52 | 32 | 25 | 34 | 55 | 52 | 57 | 65 | 73 | 69 | 70 | 49 | 24 | 32 | 16 | 56 | 32 | 27 | 25 | 23 |
| Congestion | 22 | 27 | 18 | 15 | 21 | 31 | 33 | 43 | 19 | 6 | 14 | 46 | 46 | 51 | 49 | 68 | 59 | 64 | 47 | 18 | 23 | 5 | 41 | 14 | 16 | 11 | 9 |
| Capacity | 25 | 14 | 11 | 24 | 26 | 15 | 14 | 9 | 12 | 18 | 19 | 9 | 6 | 6 | 16 | 5 | 10 | 6 | 3 | 6 | 9 | 11 | 14 | 18 | 11 | 14 | 15 |

Real-time nominal RSG costs declined 41 percent from 2011 and were more than two-thirds lower than RSG in 2010. The reduction was in part due to substantially lower fuel prices: adjusting for changes in fuel prices, the RSG costs declined 26 percent. Capacity-related RSG costs declined by more than one-third to a fuel-adjusted $31.1 million, and were modest in all months except July, when record loads required significant real-time commitments on many days. RSG payments for congestion management, however, rose by 24 percent to a fuel-adjusted $17.9 million as MISO had to rely on real-time commitments more heavily to manage congestion.

Payments to units committed for voltage support declined by nearly 60 percent from 2011. In September, FERC approved MISO's proposed Tariff revisions, which adopted the recommendation of the IMM for tighter mitigation measures for units committed for voltage support. These Tariff revisions also modified the allocation of costs so that nearby LBAs pay the vast majority of them. Additionally, most such VLR commitments were shifted to the day-ahead market. Accordingly, day-ahead RSG payments declined just eight percent.

### 2. Real-Time RSG Cost Allocation

In April 2011, MISO implemented a revised RSG cost allocation methodology that recognizes that there were different reasons MISO commits resources to meet either system-wide capacity needs versus the need to manage congestion or local voltage needs. It later modified the allocation in September 2012 to more directly allocate the costs of satisfying local voltage needs.

The remaining capacity and congestion-related RSG costs are allocated based on the market participants' real-time net deviations from day-ahead schedules that cause each type of commitment. In particular, when deviations:

- Contribute to congestion on specific constraints, costs are collected via the Constraint Management Charge (CMC) rate; and/or
- Contribute to a market-wide capacity need, costs are collected via the Day-Ahead Deviation and Headroom Charge (DDC) rate.

The balance of the real-time RSG costs (not already allocated to DDC or CMC related deviations) is charged to load on a load-ratio share basis known as "Pass 2".

Real-time RSG charges totaled $52.2 million in 2012, over 90 percent of which was allocated to deviations under the DDC rate. This is substantially inconsistent with the causes of real-time RSG costs because approximately half of the costs were incurred to satisfy the market-wide capacity needs of the system. The high level of costs allocated under the DDC rate occurred because:

- The allocation is not explicitly based on the total net deviations.
- Net deviations were frequently negative (i.e., reducing the need to commit resources for capacity) and averaged 1,338 MW, while the allocation was based on harming deviations of over 8,500 MW (after netting at the participant level).
- MISO is in the process of responding to an IMM recommendation to net the helping and harming deviations to address this issue.

- Costs associated with managing congestion left over after applying the CMC allocations are then allocated under the DDC rate. The primary issue is that a share of the costs allocated under the CMC rate cannot exceed the GSF of the committed resource on the constraint. This fails to recognize that the constraint in most cases causes all of the costs, regardless of the magnitude of the GSF. We have recommended eliminating the use of the GSF in this manner and MISO is working to implement this recommendation.

- Lastly, helping deviations after the Notification Deadline (NDL) are treated as harming deviations for purposes of allocating the RSG. We believe these deviations should be excluded entirely from the RSG cost allocation (i.e., not be treated as helping or harming).

The second factor is significant because it causes the CMC rate's share of total charges to be inappropriately low (seven percent). The CMC also contained a flaw affecting the allocation to virtual transactions. In short, FERC ordered a change to the MISO Tariff provision pertaining to the CMC allocation to virtual transactions that inadvertently reversed the allocation. Under this process, helping virtual transactions were subject to the CMC allocation while harming ones were not (and may be netted against other harming deviations). This flaw was addressed by a FERC Order effective April 27, 2013.

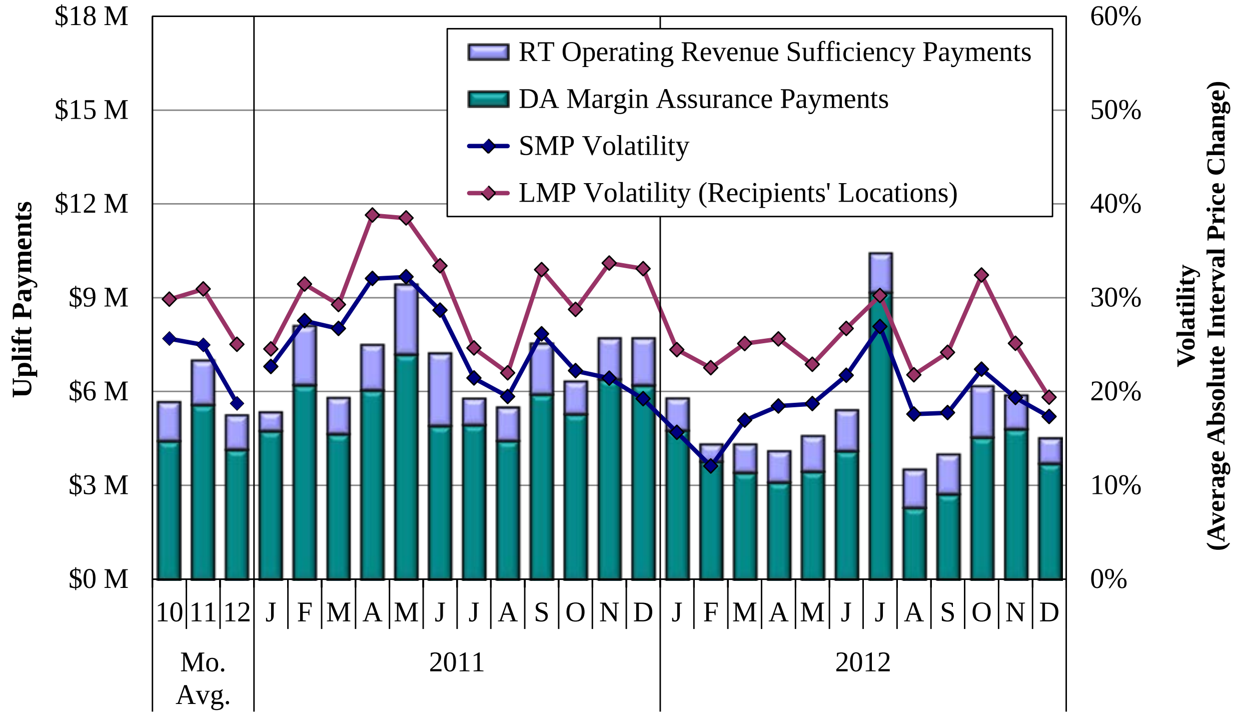
To address the other concerns, we have recommended specific changes to the RSG allocation that are detailed in the recommendation section below.

### 3. Price Volatility Make-Whole Payments

PVMWP address concerns that, under the current hourly-settlement process, resources that respond flexibly to volatile five-minute price signals can lose profits or incur losses. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and follow dispatch instructions.

Figure 15 shows that the two components of PVMWP declined 25 percent from 2011 to $63.2 million. This is in line with the decline in LMP volatility at recipients' locations. Payments were greatest in July, when SMP volatility was highest due to a considerable number of operating reserve shortages. One of the factors contributing to the decrease in overall volatility was MISO's introduction of a new contingency analysis tool in late January 2012, which now provides more timely and accurate information into the real-time dispatch.

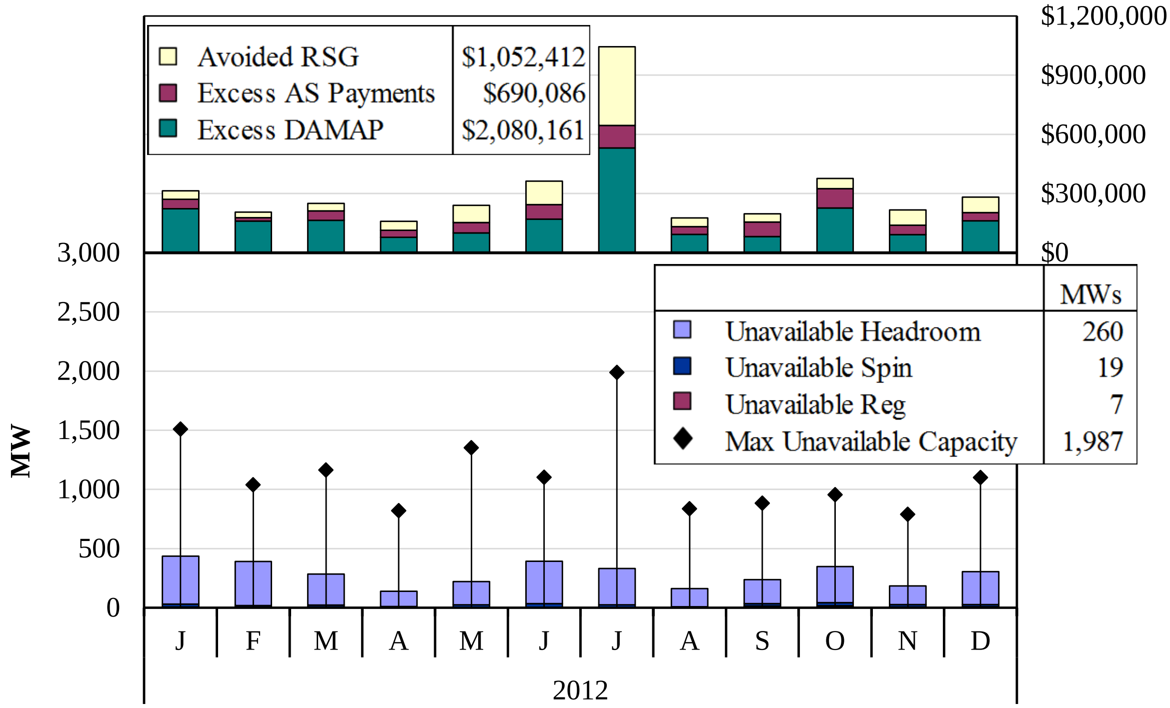
**Figure 15: Price Volatility Make-Whole Payments**
2011–2012




In 2012, we made a referral to FERC regarding a resource that was inappropriately paid DAMAP for energy sold day ahead on peak load days, but was unavailable in real-time because the unit was derated. The resource remained eligible for payments because it did not update its real-time offers to reflect the unavailable (i.e. derated) capacity.

This is not an isolated incident. Following this referral, we developed a series of screens to identify other resources that were effectively derated without updating their offer parameters (most importantly, the economic maximum). The results of this analysis are shown in Figure 16 below. The bottom panel shows the average and maximum quantities of derates we identified, broken down by capacity scheduled for regulation, spinning reserves, or simply providing headroom (latent reserves) in the energy market. The top panel show the financial impacts of this conduct in the form of unjustified DAMAP and ASM payments, as well as RSG charges that the suppliers avoided by updating their real-time offer parameters.

**Figure 16: Unreported ("Inferred") Derates**
Daily peak hour, 2012




This figure shows that the quantities of inferred derates averaged almost 300 MW in the daily peak hour in 2012. This is more than 12 percent of the operating reserves that MISO typically holds. This can potentially have serious implications for reliablity because these unreported derates can cause MISO to overestimate the amount of capacity it has available. This is particularly true under peak demand conditions when these inferred derates are significantly higher than average.

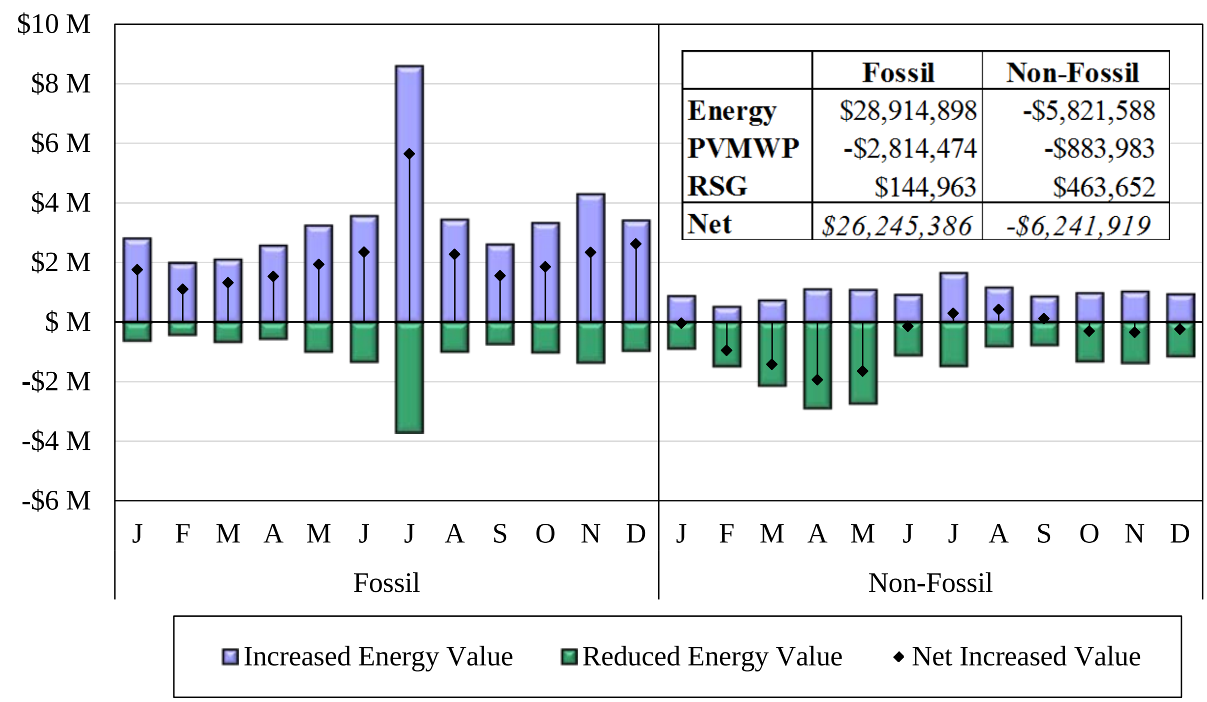
While some of the derates are reported in MISO's Control Room Operating Window (CROW) system, this system is not used to validate, benchmark, or update unit offers in the real-time market system used for dispatch. Further, the systems used by the Regional Generation Dispatchers (RGD) to identify units whose output departs significantly from base points would not detect small deviations indicated in a single interval that accumulate to large amounts of derated capacity over multiple intervals. Therefore, we recommend that MISO improve its screening and reporting of these types of derates in the control room, as well as its operating procedures for designating a resource as off-control or derated that is not responding to the dispatch signals. In the meantime, we will be developing additional referrals to FERC for the most significant deratings we detected.

### 4. Five-Minute Settlement

MISO produces new dispatch signals and prices every five minutes, but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signal and the hourly prices that can cause generators to have the incentive to not follow the dispatch signal or to simply be inflexible. To address these inconsistencies, MISO introduced the PVMWPs described earlier in the report.

The PVMWPs have been effective at eliciting additional flexibility from MISO's resources. However, it is a poor substitute for a true five-minute settlement where each generator, importer, or exporter would settle based on the actual value of energy corresponding with its production or transactions in each five-minute interval. Figure 17 shows the increases and decreases in energy settlements that would occur under a five-minute settlement (relative to the current hourly settlement) for fossil-fueled and non-fossil-fueled resources.

**Figure 17: Net Energy Value of Five-Minute Settlements**
2012




| | Fossil | Non-Fossil |
|---|---|---|
| **Energy** | $28,914,898 | -$5,821,588 |
| **PVMWP** | -$2,814,474 | -$883,983 |
| **RSG** | $144,963 | $463,652 |
| **Net** | *$26,245,386* | *-$6,241,919* |

Fossil-fueled resources in 2012 produced nearly $29 million more in actual energy value than was reflected in their settlement revenues. The increased energy value was highest in July when load and therefore commitments of dispatchable generation were highest. In other months, the increased energy value for fossil-fueled resources was fairly uniform. Approximately $3 million, or 10 percent, of the increased value not paid to these resources in the form of energy revenue was instead paid as PVMWP.

For the same period, non-fossil-fueled resources were paid more in energy revenue with hourly settlement than their actual five-minute energy value. In 2012, the total excess energy value paid to these resources was $5.8 million. Despite being overvalued in the hourly settlement, these resources were also overpaid an additional $0.9 million in PVMWP.

The fact that fossil-fueled units would receive more revenue and non-fossil would receive less is consistent with the fact that flexible, controllable resources are more valuable to the system and, therefore, benefit from a more granular settlement. Fossil-fueled resources tend to be more flexible for following load and prices 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, conversely, can only respond to price by curtailing in the downward direction. Normally they cannot ramp up in response to higher price. 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 wind generation.[16]

These results show there are substantial discrepancies between actual value of energy on a five-minute basis and settlements currently made on an hourly basis. The PVMWPs alone are not sufficient to address these discrepancies. We therefore recommend MISO explore the feasibility of implementing a five-minute settlement. This recommendation will improve the incentives for generators to follow dispatch instructions, provide more flexibility, and for participants to schedule imports and exports more efficiently.

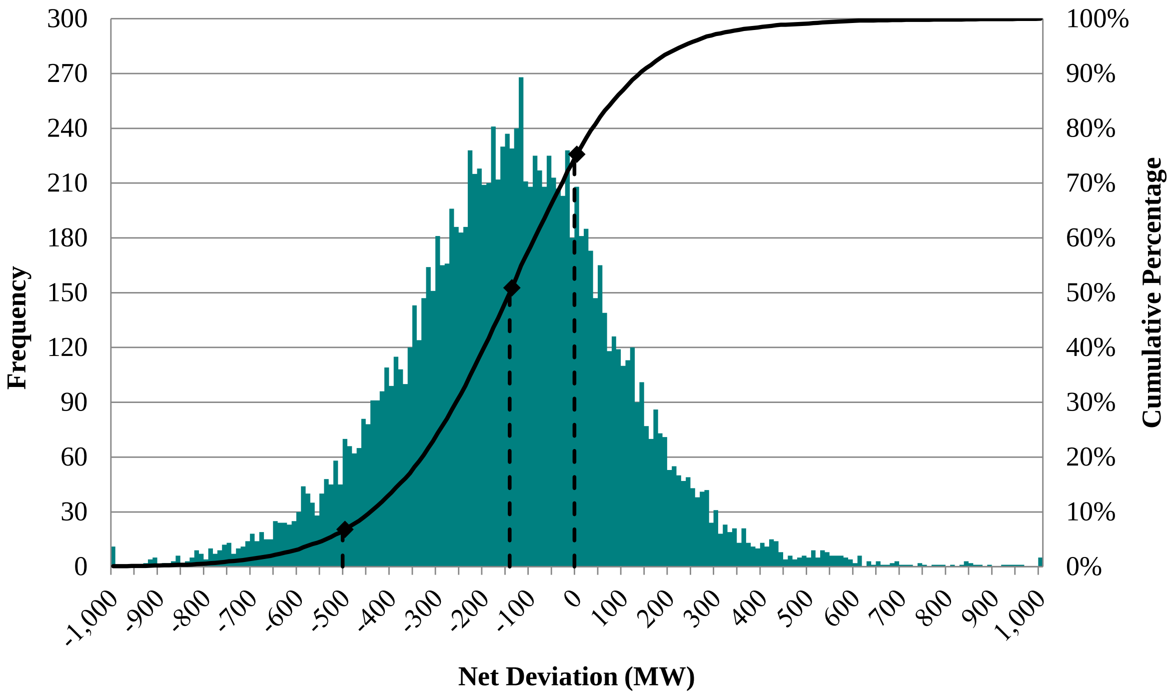
16 The contribution of RSG to non-fossil units (shown in the table) results from excess energy payments to pumped storage resources due to the hourly-integrated settlement. A reduction in energy payments would be offset by an increase in RSG since these units are often committed economically by MISO and thus eligible for production cost recovery.

### 5. Generator Deviations

MISO sends energy base-point instructions to generators every five minutes identifying the expected output at the end of the next five-minute interval. It assesses penalties for deviations from this instruction that remain outside an eight percent tolerance band for four or more consecutive intervals within an hour.[17] 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 are significantly more lenient than most other RTOs.

The average gross negative deviation in 2012 was 478 MW, while gross positive deviations averaged 453 MW. Approximately 70 percent of these deviations occur when the system is ramping rapidly up or down. Net deviations are small in many periods, but they tend to be considerably greater when loads are highest. Figure 18 shows the frequency of net deviations (absent any tolerance band) during peak hours in summer months in 2012.

**Figure 18: Frequency of Net Deviations**
Peak Summer Hours, 2012




17 See Tariff Section 40.3.4.a.i. The tolerance band can furthermore be no less than six MW and no greater than 30 MW. This minimum and maximum was unchanged for this analysis.

MISO was net deficient (generators collectively producing less than instructed) in over 75 percent of all peak summer intervals. The median deficiency was 140 MW and exceeded 500 MW in seven percent of the intervals (this share exceeded 15 percent during the top 10 load days). Significant net negative deviations can contribute to shortages because the availability of other resources to compensate for the negative deviations is limited.

MISO currently deems a generator to be incurring an uninstructed deviation only when it is more than eight percent above or below its dispatch instruction for four consecutive intervals. This results in the vast majority of deviation quantities to not be deemed uninstructed deviations (i.e., excessive and deficient energy) and, therefore, subject to no significant penalty. This is the most tolerant criteria of any RTO, most of which employ a five percent band with no consecutive interval criteria. The looseness of this band allows resources to effectively derate themselves by simply not moving over many consecutive intervals. As long as the dispatch instruction is not eight percent higher than its current output, a resource can simply ignore its dispatch instruction. Unfortunately, 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.[18]

To address these concerns, we recommend that MISO adopt tighter thresholds for excessive and deficient energy quantities to increase the incentive for MISO suppliers to adhere to MISO's dispatch instruction. For example, lowering the threshold to five percent and eliminating the four-consecutive-interval rule for excessive energy would have roughly doubled the quantity of deviations that are considered excessive or deficient energy. It may be appropriate to retain some form of the multiple interval criteria to determine when to place a unit "off control" or to make it ineligible for RSG and PVMWP.

## E. Dispatch of Peaking Resources

The dispatch of peaking resources is an important component of the real-time market because peaking units are a primary source of RSG costs and a critical determinant of efficient price signals. The average hourly dispatch of peaking resources in 2012 rose 61 percent to 667 MW. The vast majority of such commitments occurred during peak summer days, when high loads

18 This issue was discussed above in Section V.D.3.

repeatedly resulted in the need to commit over five GW per hour of peaking capacity. Commitments on such days are more often in-merit (i.e., the energy offer price is less than the prevailing LMP) than on other days because their incremental energy is needed to meet generation demand, and not needed solely to maintain headroom or provide ancillary services. In addition, very low gas prices made it economic to commit certain peaking resources in the day-ahead market. Hence, the in-merit share of peaking resources rose to nearly 60 percent in 2012, and was highest in March and April when gas prices were lowest.

However, approximately 40 percent of all peaking resource output ran “out-of-merit” order. A peaking resource dispatched out-of-merit does not indicate that the unit was committed inappropriately. Rather, it simply indicates that the LMP was set by a lower-cost resource (peaking units operating at their economic minimum or maximum are ineligible to set price). When units are dispatched out-of-merit, RSG costs generally increase. In addition, peaking resources, because they can start relatively quickly, are often the only resources that can be committed in real time to serve load not scheduled day-ahead. Hence, if real-time prices are not set by the peaking resources when committed, real-time prices will be lower and will not reveal the natural incentive to schedule load fully in the day-ahead market (which would allow lower-cost resources to be committed in place of the peaking resources).

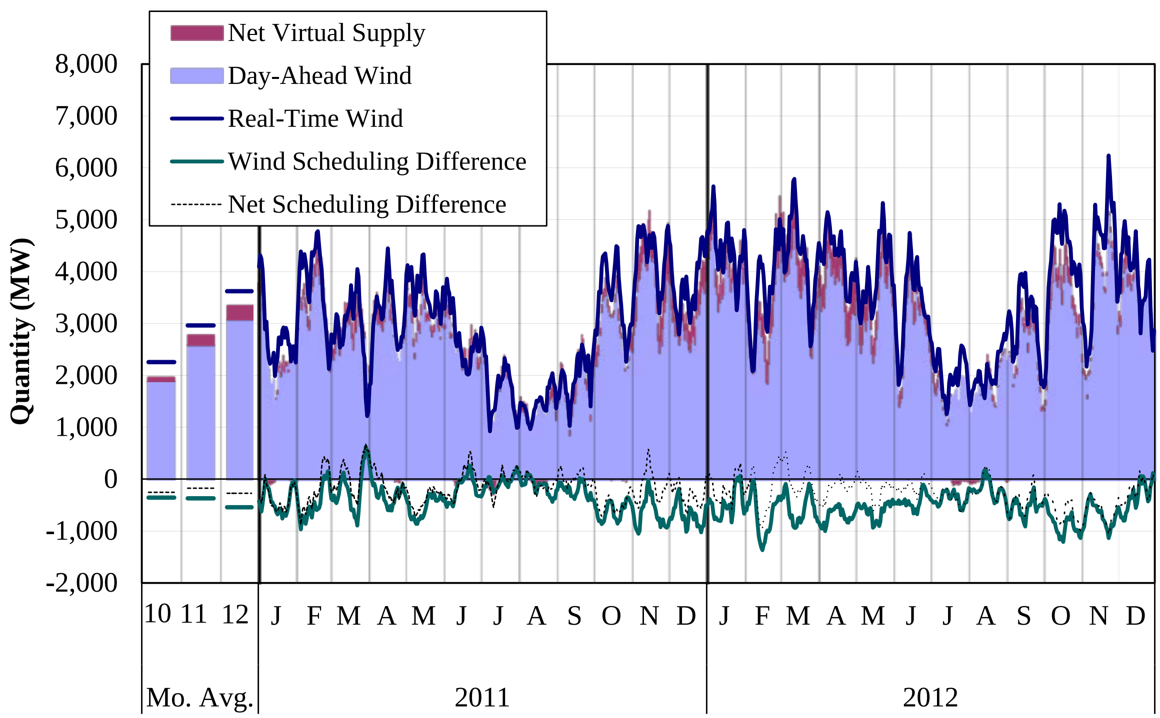
In addition, setting inefficiently-low real-time prices can encourage participants to import and export power inefficiently. MISO’s continuing efforts to implement a new “Extended LMP” pricing method should allow peaking resources to set prices more often when they are needed to satisfy the system’s energy and ASM requirements. This should improve MISO’s real-time energy pricing, reduce RSG payments, and improve the results of the day-ahead market.

## F. 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. As such, wind generation presents particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind’s portion of total generation increases. Wind resources accounted for 9.0 percent of installed capacity and 7.0 percent of generation in 2012. MISO again set new records for wind generation (over 10 GW on November 23) and volatility (2.1 GW decrease in one hour on September 24).

These challenges are aided by the continued adoption of the Dispatchable Intermittent Resource (DIR) type, which was first introduced in June 2011 and is now mostly completed.[19] DIR participation by wind resources provides MISO much more timely control over its wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). The expansion of DIR has reduced the need for manual curtailments to manage congestion or over-generation conditions by 70 percent since 2010. In addition, recommendations for managing the system's ramp capability that are included in this report should further improve MISO's ability to respond efficiently and reliably to fluctuations in wind output. Figure 19 shows a seven-day moving average of real-time wind output, as well as wind output scheduled in the day-ahead market since 2011.

**Figure 19: Day-Ahead and Real-Time Wind Generation**
2011–2012




19 As of the March 2013 commercial model, 111 out of 176 wind units (and 78 percent of capacity) are modeled as DIR, although as of this writing not all of them are capable of responding to dispatch instructions.

Under-scheduling of wind output in the day-ahead market can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. The figure also shows virtual supply (net of virtual demand) at wind locations (shown as negative value indicating that it reduces the day-ahead to real-time scheduling difference). Virtual supply in the day-ahead market has substantially offset the impact of under-scheduling by wind resources.

Real-time wind generation in MISO in 2012 increased 22 percent to 3,618 MW. It remained underscheduled by an average of 581 MW (15 percent), although net virtual supply at wind locations made up approximately half of this discrepancy. Since August 31, 2010 deviations from day-ahead (i.e., real-time reductions in wind generation compared to the day-ahead schedule) are no longer exempt from RSG charges, which may provide an incentive for participants to schedule conservatively in the day-ahead market.

The figure also shows that wind output is substantially lower during summer months than during shoulder months, which reduces its value from a reliability perspective. (We addressed the capacity credit implications of this in Section III.C.) Finally, as total wind capacity continues to grow, the volatility of its output that must be managed by MISO also grows. Sixty-minute volatility of wind output (excluding economic DIR curtailments) in 2012 increased 17 percent to an average of 279 MW per hour. Although the DIR has been extremely valuable in improving the control of wind resources and responding to these changes in output, MISO is working to develop changes in procedures and evaluate further market design changes that may be beneficial for managing the changes in wind output.

# VI. Transmission Congestion and Financial Transmission Rights

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources to establish efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because transmission capability is limited. As a result, LMPs can vary substantially across the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load while not overloading any transmission facilities. This causes LMPs to be higher in “constrained” locations.

LMPs also include a marginal loss component. Transmission losses occur whenever power flows across the transmission network. Generally, transmission losses increase as power is transferred over longer distances, at higher volumes, and over lower-voltage facilities.

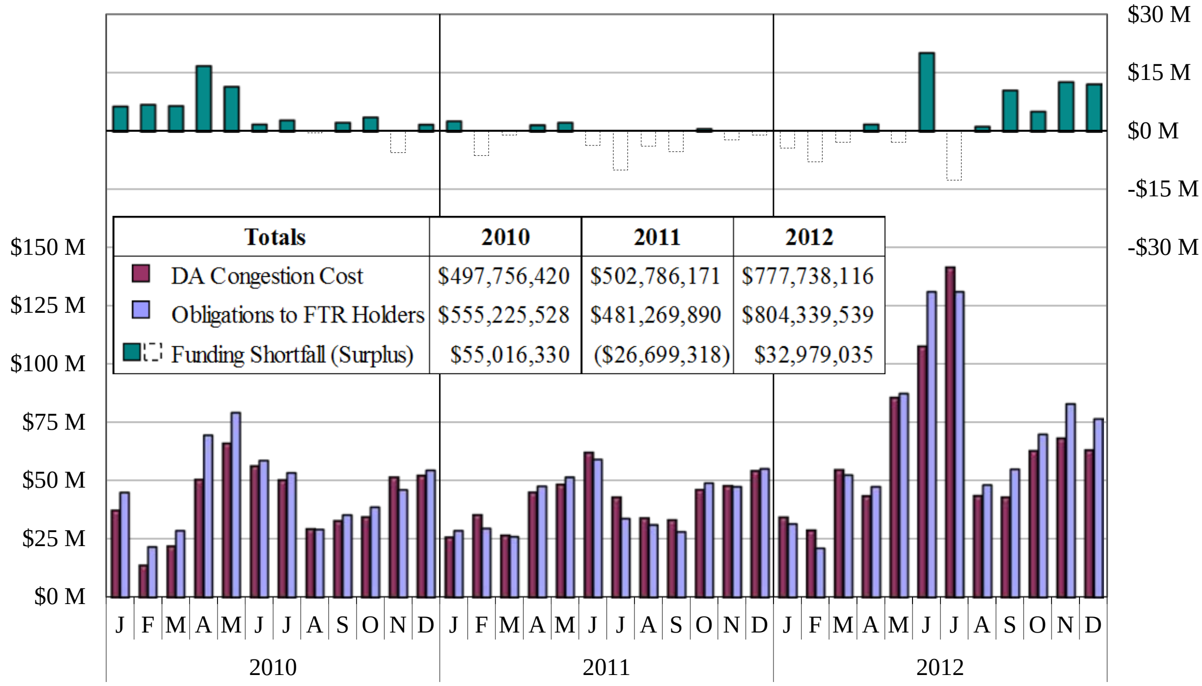
## A. Day-Ahead Congestion Costs and FTRs

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

The resulting congestion revenue is paid to holders of FTRs, which represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an opportunity for market participants to hedge against day-ahead congestion. As such, congestion costs and FTR obligations should be roughly equal unless the transmission capability reflected in participants’ FTRs is more or less than the transmission capability available to the day-ahead market.

Figure 20 summarizes the day-ahead congestion, the obligations to FTR holders, and any differences that resulted in surpluses or shortfalls on a monthly basis from 2010 to 2012.

**Figure 20: Day-Ahead Congestion and Payments to FTRs**
2010–2012




Day-ahead congestion costs rose nearly 55 percent from $503 million in 2011 to $778 million in 2012. The sharp increase in day-ahead congestion was due in part to increased congestion on mid-to-low voltage constraints and continued enhancements to day-ahead processes to fully model potential transmission constraints in the day-ahead market.

FTR obligations exceeded collected costs by 3.4 percent, most of which occurred in the second half of the calendar year (but the beginning of the FTR year). The full funding of FTR obligations in 2011 was primarily due to surpluses on market-to-market constraints, which offset shortfalls on internal constraints. These net market-to-market surpluses disappeared in the second half of 2012, resulting in monthly funding shortfalls that continued into 2013.

Shortfalls on internal constraints continued in 2012. This was due to: (a) underestimation of loop flows; (b) significant outages and derates, including those associated with LIDAR surveys, that are difficult to fully model in the FTR auction; and (c) same-bus, “zero-cost” FTRs that can lead to underfunding when certain conditions arise. MISO filed a Tariff change, effective March 2013, which is intended to prevent MISO from awarding such same-bus FTR pairings in future.

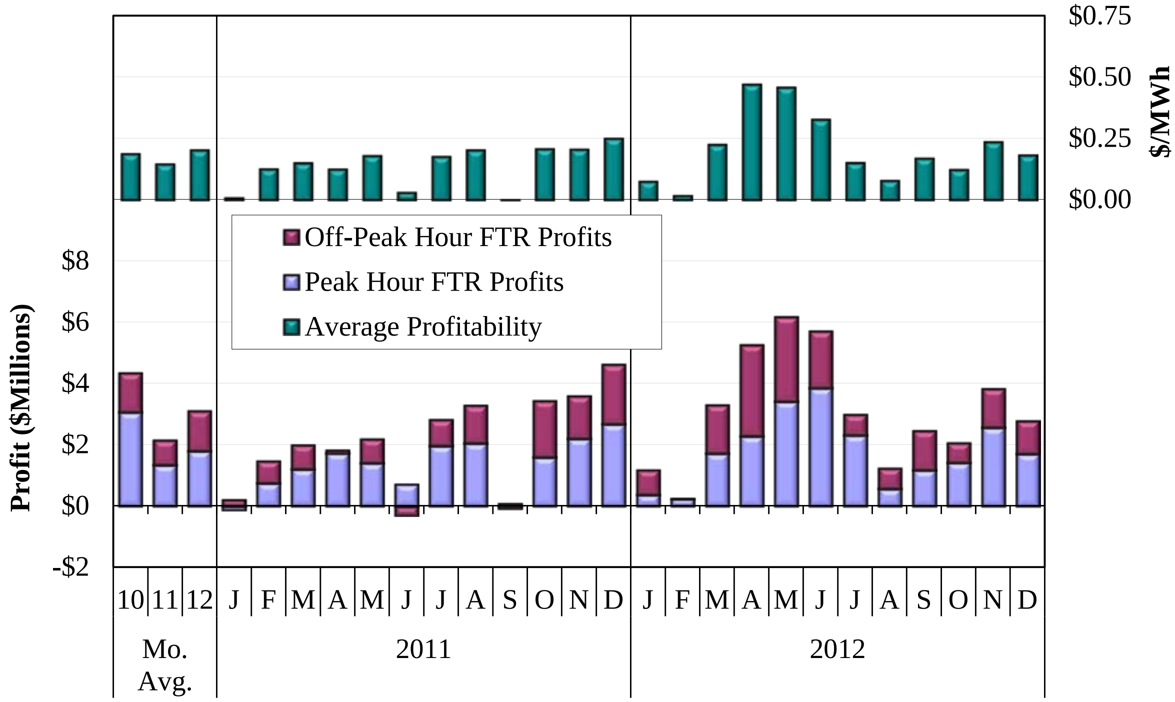
With regard to the other sources of underfunding, MISO is working diligently to improve the convergence of the FTR modeled transmission capability and the transmission capability available in the day-ahead market. Some of the current underfunding is due to capability sold in the prior annual FTR auction, which may therefore continue until these FTRs expire in May 2013.

As a share of total dollars, FTRs in 2012 received 89 percent of the day-ahead congestion revenue, down from 91 percent last year and 95 percent in 2010. The balance goes to other forms of transmission rights, such as “carve-outs” and “Option B” FTRs, which were established at the start of the markets to account for grandfathered transmission agreements. The majority of these exist in the West region, so payments to these holders have risen in recent years along with the increase in congestion in that region. It is important that a high percentage of day-ahead congestion continues to be paid to FTRs because the other transmission rights do not provide the same efficient incentives as FTRs.

Real-time congestion costs in 2012 (not shown in the figure) were a small share of total congestion costs. These costs generally occur when the transmission capability available in the real-time market is less than what was scheduled by the day-ahead market. In 2012, real-time congestion costs totaled $20.4 million, indicating that the day-ahead transmission capability scheduled by the market only slightly exceeded the real-time capability. Real-time congestion costs would be significantly greater without $50.7 million received from PJM through the M2M settlement process when PJM exceeded its Firm Flow Entitlement (FFE) in real time.

Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.30 billion in 2012. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM’s entitlements on the MISO system (PJM does not pay for its use up to its entitlement). Because MISO collects congestion revenues for only a portion of its transmission capability, it sells or allocates FTRs for only the capability it expects to be able to use in the day-ahead market. Aligning the available transmission capability in the FTR and day-ahead markets ensures that FTR shortfalls and surpluses are limited, and also contributes to FTR prices converging with anticipated day-ahead congestion. This convergence is an indicator of the performance of the FTR market (i.e., low FTR profits (losses), which are the difference between the price of the FTR and the congestion paid to it). In Figure 21, we show the profitability of FTRs sold in the monthly market. In a well-functioning and liquid FTR market, profitability should be low.

**Figure 21: Monthly FTR Profitability**
2010–2012



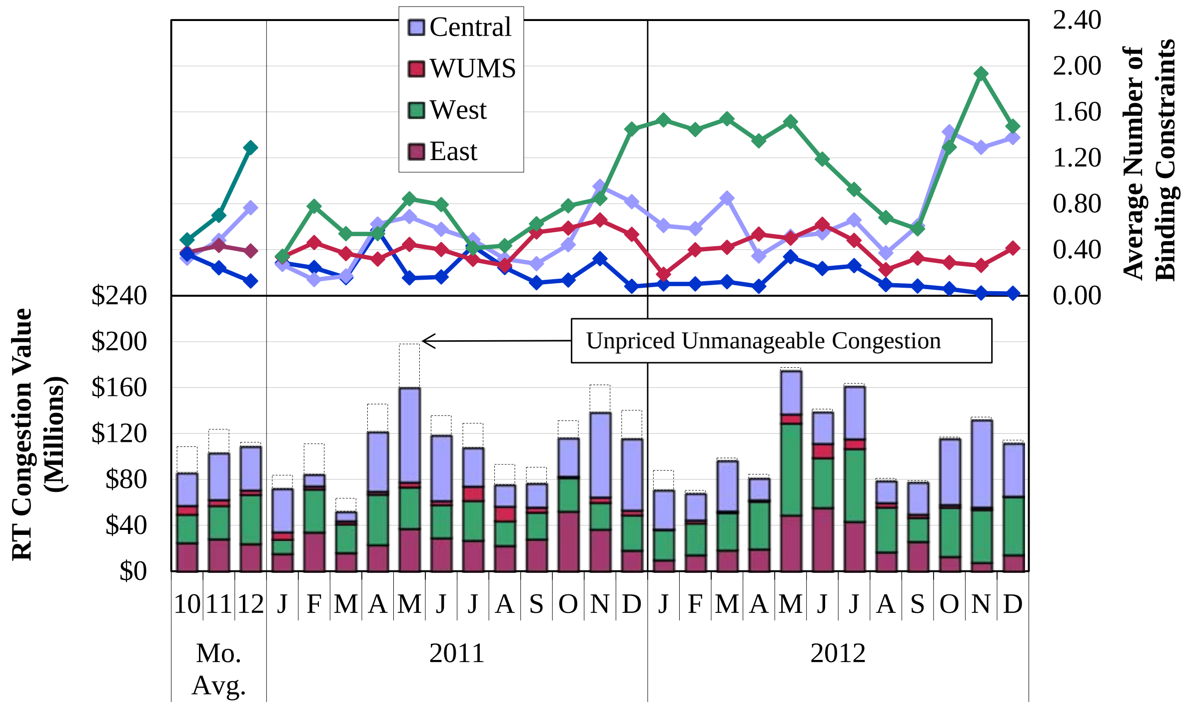

In 2012, monthly FTR profitability rose five cents from last year to an average of $0.20 per MWh. Seasonal profitability (not shown) averaged a comparable $0.18 per MWh, and peaked in summer due to tighter peak load conditions than was anticipated in the auction. FTR prices generally responded to changes in congestion patterns in the following month. However, outage-related congestion into Minnesota, notably in late spring and again in December, was poorly anticipated.

## B. Real-Time Congestion Value and Constraint Manageability

As discussed above, the congestion revenue collected through the MISO markets in 2012 was approximately two-thirds the value of real-time congestion that actually occurred on the MISO network. This subsection discusses the value of real-time congestion on the MISO network in

2012. Figure 22 shows the value of real-time congestion by coordination region, along with the average number of binding constraints.

**Figure 22: Real-Time Congestion by Coordination Region**
2010–2012




The total congestion value increased 5.5 percent from 2011 to $1.30 billion, nearly all of which occurred on internal constraints. It was highest in summer, when hot weather contributed to high load conditions across the region. Congestion value increased the most on constraints in the West (by nearly 50 percent). A number of transmission derates and outages associated with planned upgrades and remediation of deficiencies found in LIDAR surveys, affected constraints in the West. In addition, continued increases in wind output in 2012 resulted in more congestion on constraints carrying power out of the West.

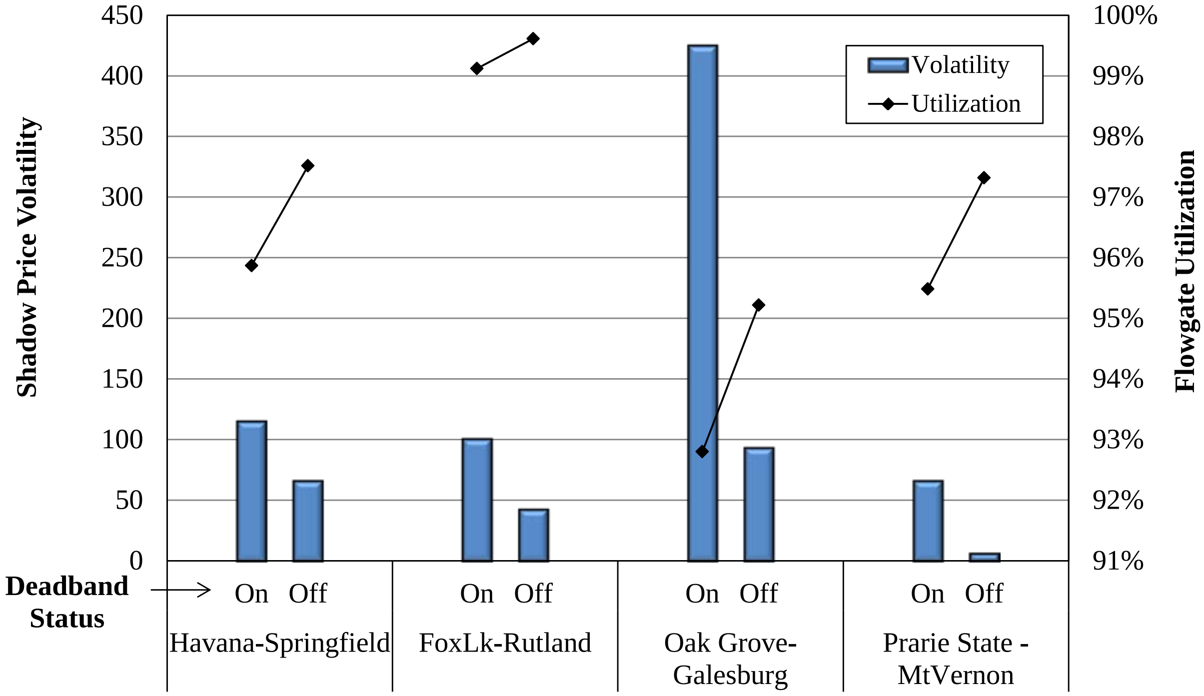
The figure also shows that congestion was more fully priced because MISO ended its practice of “constraint relaxation” on non-market-to-market constraints in February. This relaxation algorithm would reduce the pricing of congestion on constraints that are violated (where the flow exceeds the limit). In 2012, just one percent of congestion was unpriced, compared to nine percent in 2011. The remaining one percent is on market-to-markets constraints where relaxation continues because of PJM's opposition to its elimination. Constraint relaxation distorts the congestion signals provided by real-time prices, undermines the efficiency of the day-ahead prices and commitments, and adversely affects longer-term market decisions. However, we are encouraged that most the these adverse effects have been eliminated by MISO's change for the non-M2M constraints.

In addition to the pricing issues, we have also investigated the causes of the unmanageable congestion. The largest single factor that caused transitory constraint violations was unforeseen changes in network flows. However, in our 2011 report we identified an operating algorithm called the "transmission deadband" that contributed to a substantial share of the unmanageable congestion. The deadband is a constraint-specific amount (most commonly two percent) by which the limit of a constraint is automatically reduced after it initially binds. The original intent of the deadband was to limit the frequency with which constraints would bind and then immediately unbind—it was thought that this could result in LMP and generator dispatch volatility.

Starting in December 2012, MISO began conducting a field test by disabling the deadband on a subset of frequently binding constraints to determine if removing of the deadband was beneficial and whether the deactivation posed any reliability concerns. MISO had practical concerns related to dispatch volatility and theorized that some of the IMM's perceived benefits would be negated by MISO needing to control constraints at a lower percentage of their physical limit.

A summary of our findings for the four most frequently-binding test constraints is shown in Figure 23 below. These results were compiled for the three months prior to the field test when the deadband was active (the "On" period) and the first three months after deadband deactivation (the "Off" period). The shadow price volatility is measured as the average absolute change in shadow price from the first binding interval to the next binding interval,

**Figure 23: Results of Deadband Deactivation**
2010–2012

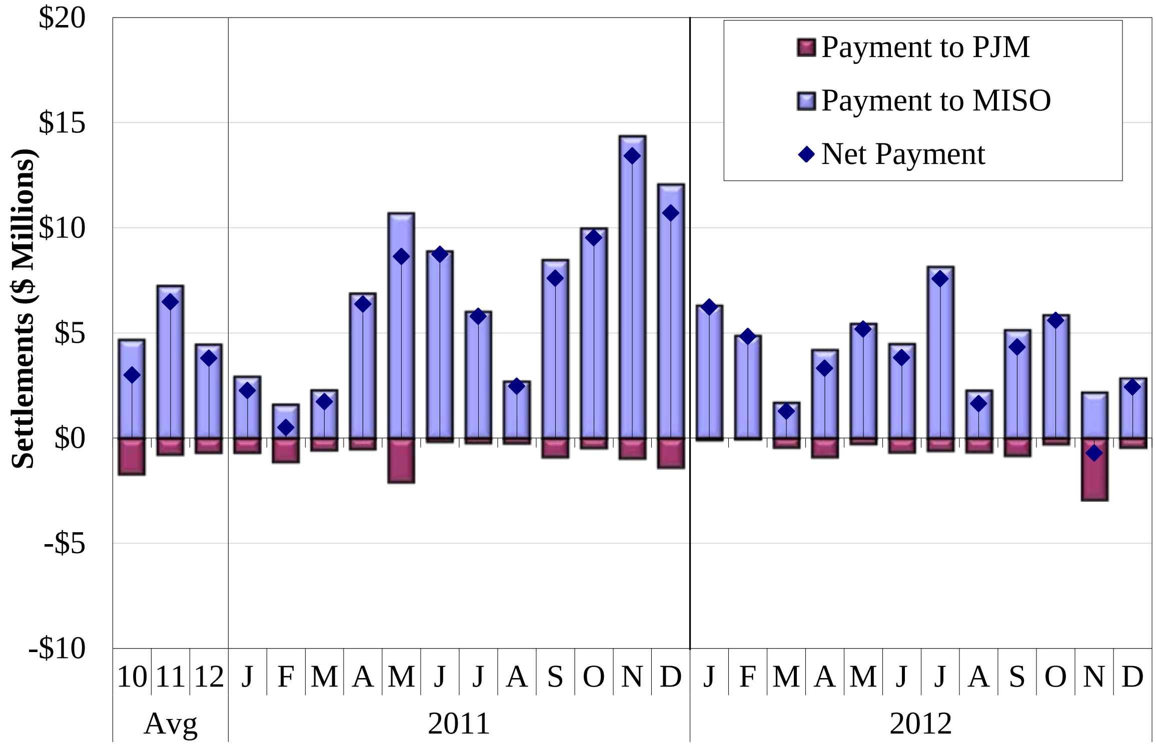



These results show that in each case the shadow price volatility declined substantially after the deadband was deactivated. Additionally, the average utilization on each flowgate increased after the deadband was deactivated. These results are consistent with the IMM's expectations and should alleviate MISO's concern regarding the effects of removing the deadband. Based on the results of the field test, we recommend MISO remove the deadband on all constraints.

## C. Market-to-Market Coordination with PJM

MISO's M2M process under the JOA with PJM efficiently manages constraints affected by both RTOs. The process allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources if it is less costly for them to do so. Each RTO is compensated for excess flows from the other RTO when that flow exceeds their FFE. Much of the M2M process is now automated and has improved pricing in both markets. Figure 24 shows M2M settlement results for 2011 and 2012.

**Figure 24: Market-to-Market Settlements**
2010–2012




Congestion on MISO M2M constraints declined 20 percent from 2011 to $367 million, while on PJM M2M constraints it declined 66 percent to just $7.5 million.[20] Figure 24 shows net payments flowed from PJM to MISO in most months in 2012 because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. Net payments by PJM to MISO declined 42 percent to a monthly average of $3.8 million. The decline occurred in part because of two JOA resettlements — one for $7 million which occurred in November, and one valued at $4 million for 2012 that will be resettled in 2013 — that reduced net payments to MISO in 2012 by $11 million.

Shadow price convergence on MISO M2M constraints, an indicator of PJM's responsiveness to requests for relief, was good in 2012 and was comparable to convergence on PJM M2M constraints. Nonetheless, the RTOs should continue to identify enhancements to the relief software, modeling parameters, or other procedures that may be limiting the provision of relief.

20 As mentioned in the previous subsection, even though the congestion value is relatively small on external flowgates, their price impacts can be substantial.

Finally, a review of JOA procedures in 2011 found that neither RTO had ever coordinated the permitted use of FFEs in their day-ahead markets. In 2012 and continuing into 2013, PJM and MISO are discussing how to implement day-ahead sharing of FFEs within the context of the JCM discussions. We support this effort and continue to recommend that MISO work with PJM to develop procedures to implement this provision to help reduce congestion management costs and improve overall efficiency.

## D. Congestion on Other External Constraints

The congestion value on external flowgates corresponded to a small share of total congestion in 2012, but had widespread price impacts. In fact, the transmission constraint that had the largest impact on generator LMPs was an external constraint managed by SPP (Iatan-Stranger). SPP invoked Tranmission Line-Loading Relief (TLRs) and MISO received market flow relief obligations for this constraint in 842 and 668 hours during 2011 and 2012, respectively.

The primary reason this flowgate and other external non-market-to-market flowgates often have a large impact on the MISO market is that MISO receives relief obligations based on forward direction flows, even if on net (when reverse-direction flows are included) its market flows are relieving the constraint. MISO reports its Market Flow to the IDC in the net, forward-only, and reverse-only directions. The forward-only flows alone are used to determine the relief obligation when an external (non-M2M) flowgate binds and a TLR is called.

MISO's average shadow price is generally higher (often three or four times higher) than SPP's shadow prices to control its flowgates. This suggests very poor flowgate coordination and supports our recommendation that MISO revisit these coordination procedures to limit response to the control costs of the monitoring RTO. MISO is working with NERC and other RTOs to address this issue.

# VII. External Transactions

## A. Overall Import and Export Patterns

As in prior years, MISO in 2012 remained a substantial net importer of power in both the day-ahead and real-time markets. Real-time net imports decreased seven percent to an average of 4.3 GW per hour. The decrease occurred entirely on the larger PJM and Manitoba interfaces, where they declined by 15 to 20 percent, and rose slightly on smaller interfaces.

Prices differences between MISO and adjacent areas create incentives to schedule imports and exports that change the net interchange between the areas. These interchange adjustments are essential from both an economic and reliability standpoint. Scheduling that is responsive to the interregional price differences captures substantial savings as lower cost resources in one area displace higher-cost resources in the other area. However, participants' ability to capture these benefits by effectively arbitraging interregional price differences is undermined by the fact that participants must forecast the prevailing price difference thirty minutes or more in advance. Additionally, the lack of coordination among participants leads to substantial errors in the aggregate quantities of interregional transaction changes.

To evaluate the efficiency of interregional scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions. The share of transactions with PJM that were scheduled in the profitable direction was 51 percent, a modest improvement from 45 percent last year. Many hours still exhibit large price differences that can be attributed to scheduling uncertainties. Additionally, the uncoordinated transaction scheduling process led to shortages that impaired reliability and to unnecessary price volatility.

To address these issues, we continue to recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence. We have previously estimated the benefits of optimizing the interchange between PJM and MISO, and between the other RTOs around Lake Erie, and found substantial available efficiency benefits. In total, we found production cost savings of $309 million per year, $59 million of which was attributable to optimizing the interchange between PJM and MISO. We believe these values to be understated because the study period of November 2008 to October 2009 was a period of low load and low fuel prices, which decreases the economic savings of optimizing the interchange.

One means to capture these benefits is to allow participants to submit offers to transact within the hour if the spread in the RTOs' real-time prices is greater than the offer price. In addition to the economic benefits, this would improve reliability by preventing operating reserve shortages that sometimes occur under the current scheduling rules. PJM and MISO have discussed this type of solution, but it has not been deemed a high priority by PJM.

## B. Loop Flows Around Lake Erie

Transactions schedules between RTOs are settled on a "contract path", while actual power flows according to the physical properties of electricity. This difference, known as loop flow, is particularly significant when transactions are scheduled around Lake Erie. Operators must account for these loop flows in the real-time, day-ahead, and FTR markets.

To better manage these flows, MISO and IESO installed Phase Angle Regulators (PARs) that began operation in the spring of 2012, although a number of operational issues prevented their full operation until late July. PAR tap settings are adjusted when the loop flow is expected to exceed 200 MW in either direction. This tolerance level has resulted in far fewer tap setting changes than their designed limit. During periods when all the PARs have been in service, they have been able to "regulate" (i.e. the PARs have had the capability to keep loop flows within the tolerance band) more than 90 percent of the time.

Both the PARs and changes in transaction patterns contributed to a substantial decrease in clockwise loop flows from 2011 to 2012. For the year, average hourly Lake Erie loop flows were 3 MW in the counter-clockwise direction in 2012, whereas it was 155 MW in the clockwise direction in 2011. Hourly clockwise loop flows exceeded 400 MW in only 3 percent of hours, down from 16 percent of hours in 2011. These reductions have reduced the need of othef RTO's around Lake Erie to call TLRs, which has benefitted MISO. For example, TLRs called by IESO lead to $7 million in balancing congestion costs (negative ECF) in the prior 18 months before the PARs began operation. These costs have virtually been eliminated.

## C. Overpayment and Overcharging of Congestion in Interface Prices

The interface prices posted for both MISO and PJM include the marginal effects of external transactions scheduled over the given interface on all binding constraints. For example, when MISO calculates its interface price for PJM (used to settle all imports from and exports to PJM), it models how the injections in one area and withdrawals in the other area are likely to affect all binding constraints in MISO. Therefore, transactions that would *aggravate* a constraint will incur a congestion charge (i.e., by being paid less for an import or charged more for an export), while those that *relieve* the constraint will receive a congestion payment (i.e., by being paid more for an import or charged less for an export).

As described above, the congestion components of the interface prices will reflect the effects of external transactions on *all* binding constraints in MISO, including internal constraints, external constraints, and market-to-market constraints. In general, this is efficient to the extent that the interface prices accurately reflect the congestion effects of the transactions because it will motivate participants to schedule transactions efficiently. However, we believe that MISO's interface prices inappropriately account for congestion on external constraints and market-to-market constraints.

It is appropriate for external constraints to be reflected in MISO's LMPs because market flows are most efficiently limited through binding in the MISO dispatch.[21] This enables MISO to respond to relief requests under the PJM JOA for market-to-market constraints and TLR obligations for other external constraints.

However, 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 they would not be credited as relief being provided by MISO.[22] In most cases, these beneficial transactions are already being fully compensated by the area where

21 Market flows are the flows that MISO generation and load cause on external constraints and are the basis for MISO's obligations to alter its dispatch under the market-to-market agreements and under TLRs.

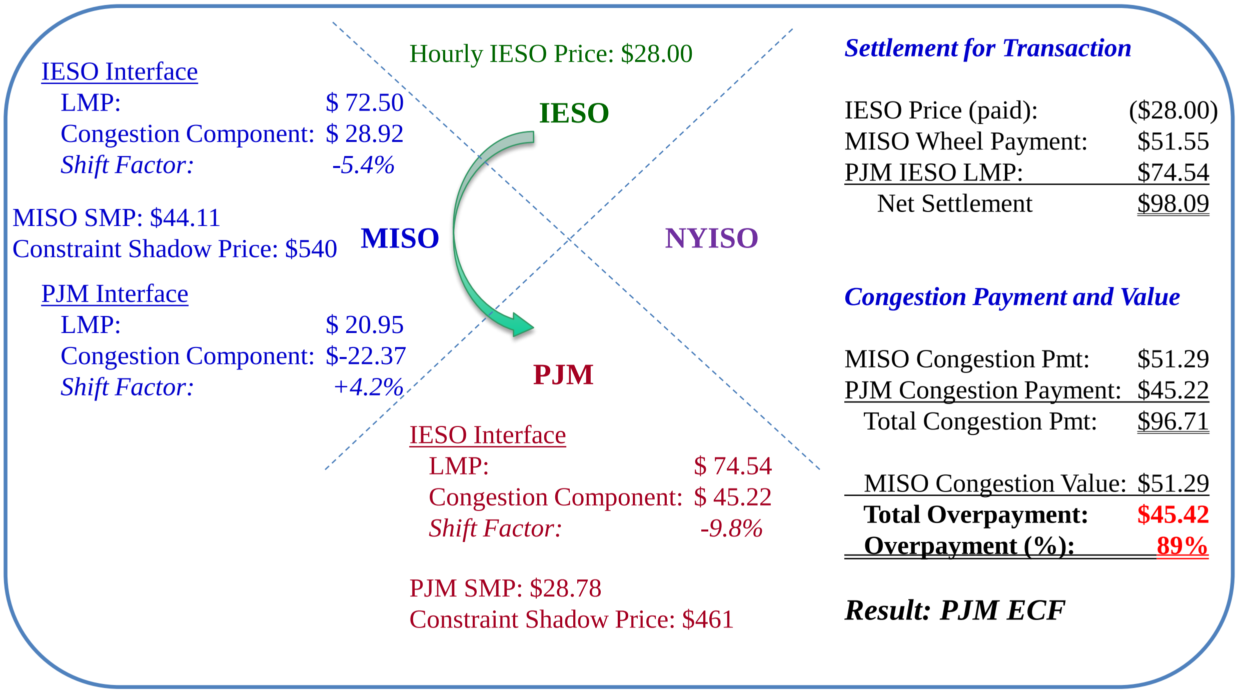
22 Likewise, transactions scheduled in MISO's day-ahead market and cut via TLR on an external flowgate are compensated by MISO as if they are relieving the constraint even though this effect is excluded from MISO's market flow calculation.

the constraint is located. For example, when PJM market-to-market constraints bind and are activated in the MISO market, both RTOs pay (or charge) the transaction for the estimated effect of the transaction on the constraint. Since the constraint is active in both markets, both RTOs follow the process described above for setting the interface prices.

To establish whether this double settlement exists, we identified hours when no constraints were binding in PJM or MISO except one market-to-market constraint. 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 example below, we show an example of 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.

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**



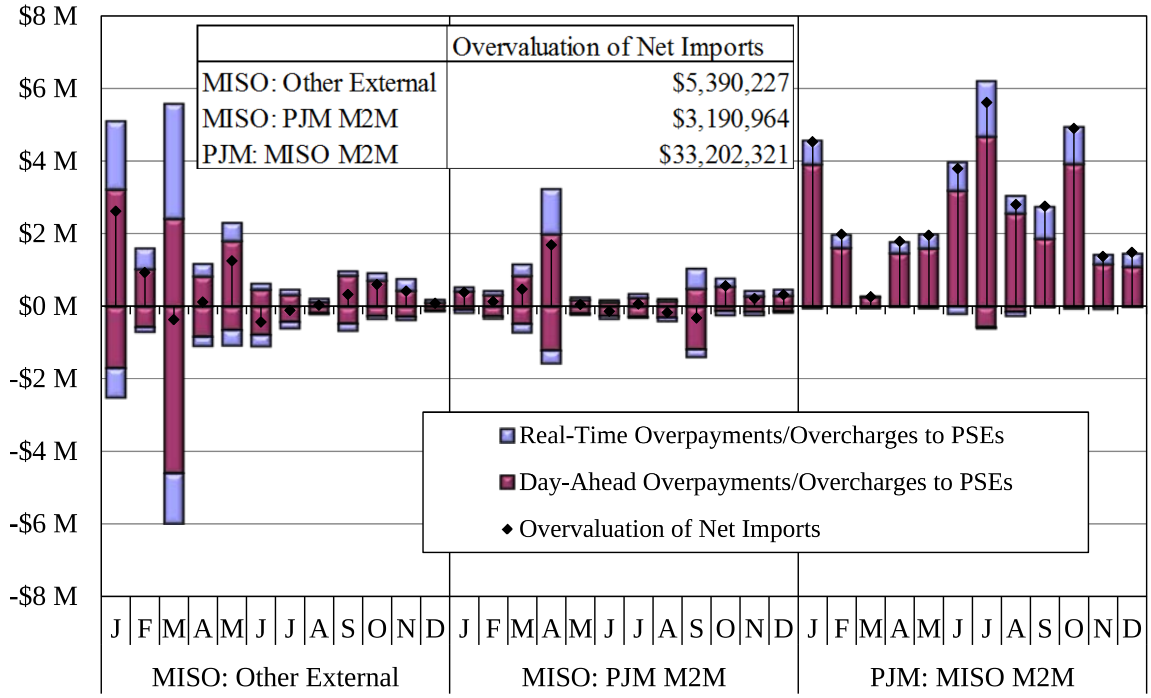

This example shows that MISO would pay $51.55 per MWh to the scheduling entity for this wheeling transaction, including $51.29 per MWh for congestion relief. This congestion payment to the scheduling entity fully reflects MISO's estimated benefits of this transaction in relieving the constraint. However,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

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. Most of the $45.22 congestion payment will be collected from its customers as an uplift charge.[23] In MISO, this charge would be categorized as negative Excess Congestion Fund ("ECF"). Likewise, MISO

23 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 are not quantified.

congestion payments made to real-time external transactions associated with PJM market-to-market constraints would be collected from MISO's load-serving entities through the real-time balancing congestion component of Revenue Neutrality Uplift. Figure 25 shows the total overpayments by both MISO and PJM over the past two years. These overpayments cause increased negative ECF costs and market-to-market settlement costs.

**Figure 25: Overvaluation of Net Imports**
MISO and PJM




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.

MISO's overpayments to external transactions for relief of external constraints also raise uplift costs to MISO's consumers. For example, when SPP invokes TLRs to solicit relief from MISO on its constraints, MISO activates the constraints and MISO's interface prices will adjust to account for the effects of the external transactions on the SPP constraint. Although the payments embedded in the interface prices will motivate participants to schedule transactions to relieve these constraints, MISO receives no reimbursement or other credit for this relief since these commercial flows do not impact its market flow-based obligation and constraint management. Instead, it generates costs that must be collected from its customers as uplift. For example, net real-time transactions affecting SPP flowgates (predominantly Iatan-Stranger) accounted for $10.5 million in negative ECF accruals during the 2011-2012 time period.

Therefore, we recommend modifying interface pricing to produce more efficient signals to facilitate physical scheduling. One approach to satisfy this objective would be to eliminate the congestion components associated with external constraints for its interfaces.

# VIII. Competitive Assessment and Market Power Mitigation

This section contains a competitive assessment of the MISO markets. Locational market power in wholesale markets can be substantial when transmission constraints or reliability requirements limit the effective competition to satisfy the system's needs in an area. This section includes a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2012.

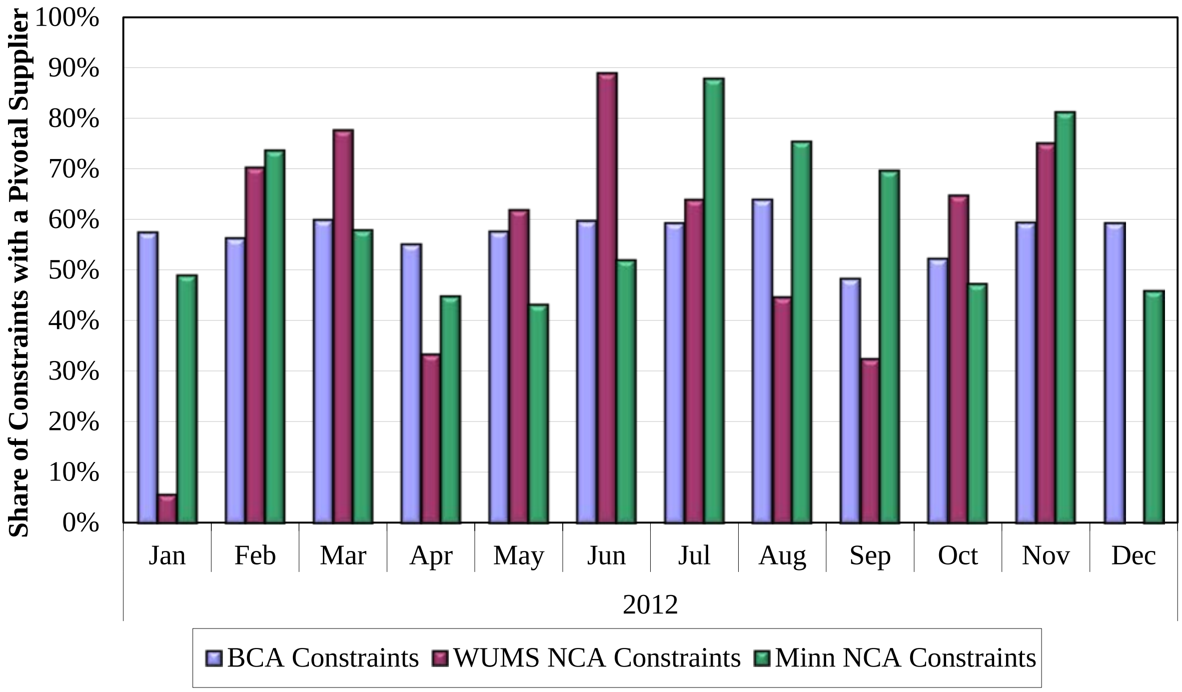
## A. Structural Market Power Analyses

We analyze market concentration as measured with the Herfindahl-Hirschman index (HHI). Market concentration is low for the overall MISO area, but the East Region and WUMS Area is highly concentrated. 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. However, since the metric does not recognize the physical characteristics of electricity or network constraints, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is pivotal, which occurs when its resources are necessary to satisfy load or to manage a constraint. Our regional pivotal supplier analysis indicates that the frequency with which a supplier is pivotal rises sharply with load. This is typical in electricity markets since electricity cannot be economically stored. Hence, when load increases, the excess capacity will fall and the resources of large suppliers will become more necessary.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints. We focus the analysis on two types of constrained areas that are currently defined for purposes of market power mitigation: Narrow Constrained Areas (NCA) and Broad Constrained Areas (BCA). NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). Three NCAs are currently defined: Minnesota, WUMS, and North WUMS (a subarea of WUMS). BCAs include all other areas within MISO that are isolated by transient binding transmission constraints.

**Figure 26: Constraint-Specific Pivotal Supplier Analysis**
2012




The majority (57 percent) of active constraints in 2012 had at least one supplier that was pivotal. The results were comparable for the subset of BCA constraints (57 percent) and NCA constraints into Minnesota (58 percent) and WUMS (63 percent). In 95 percent of intervals, however, at least one BCA constraint with a pivotal supplier was binding. 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.

The current Tariff provisions (Section 63.4 of Module D) related to the designation of NCAs, where the MISO market is subject to the exercise of significant market power, are focused only on sustained congestion. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a twelve-month period. The NCA thresholds are required to be calculated based on a historical twelve-month period.

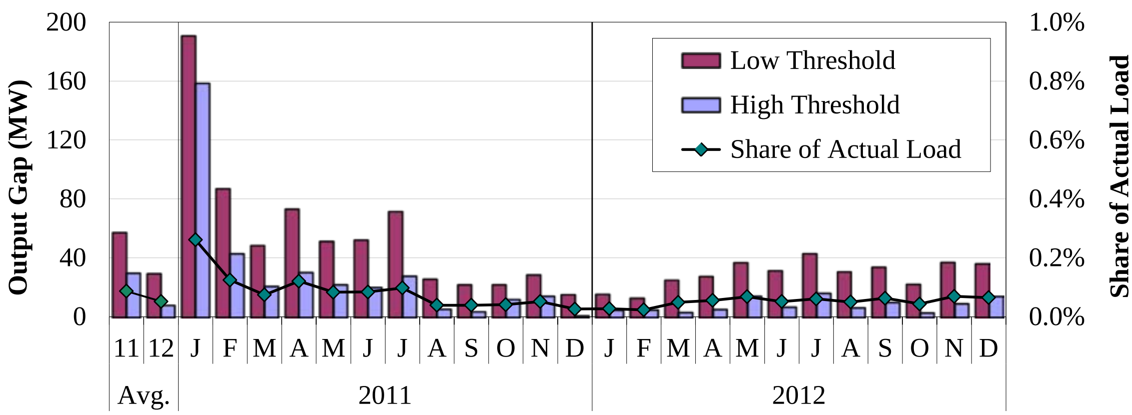
Consequently, when transitory conditions arise that create a severely constrained area with one or more pivotal suppliers, an NCA generally cannot be defined. Additional analysis presented in the Analytical Appendix shows that current Tariff provisions are insufficient to effectively address market power associated with such conditions. 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 accurately reflect severe congestion that may occur over less than a twelve-month period.

## B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate metrics of market competitiveness. We calculated a price-cost mark-up that compares the system marginal price based on actual offers to a simulated SMP that assumes all suppliers had submitted offers at their estimated marginal cost. We found an average system marginal price mark-up of just 0.9 percent, which reflects the competitiveness of MISO's energy markets.

Figure 27 shows our "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using the Tariff's conduct threshold for mitigation (the "high threshold") and a "low threshold" equal to one-half of the mitigation threshold.

**Figure 27: Economic Withholding – Output Gap Analysis**
2010–2012




**Low Threshold Results by Unit Status (MW)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 24 | 4 | 143 | 44 | 21 | 14 | 9 | 11 | 23 | 0 | 1 | 11 | 12 | 0 | 4 | 4 | 1 | 1 | 9 | 0 | 11 | 0 | 8 | 0 | 2 | 5 |
| Online | 34 | 26 | 48 | 43 | 29 | 60 | 43 | 42 | 49 | 26 | 22 | 12 | 17 | 16 | 12 | 9 | 24 | 27 | 29 | 32 | 33 | 31 | 26 | 23 | 36 | 32 |

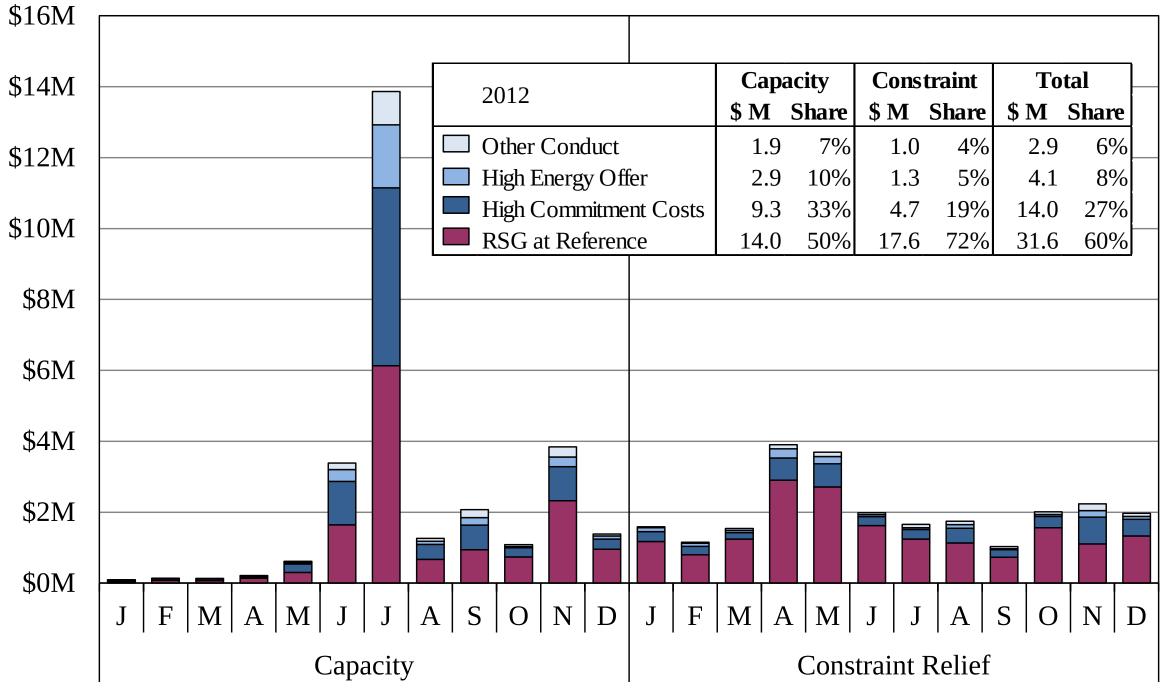
**High Threshold Results by Unit Status (MW)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 22 | 3 | 142 | 29 | 16 | 14 | 9 | 10 | 19 | 0 | 1 | 11 | 12 | 0 | 4 | 4 | 1 | 1 | 9 | 0 | 9 | 0 | 5 | 0 | 1 | 4 |
| Online | 8 | 5 | 17 | 14 | 5 | 17 | 13 | 10 | 9 | 6 | 4 | 1 | 3 | 1 | 2 | 1 | 2 | 4 | 6 | 7 | 7 | 7 | 5 | 3 | 9 | 11 |

Output gap levels declined further in 2012 and averaged just 30 MW per hour at the low threshold and eight MW per hour at the high threshold. As a share of actual load, it continued to average less than 0.1 percent. The decline occurred despite considerably tighter NCA threshold levels in Minnesota in 2012. Levels were mostly unchanged in WUMS and North WUMS. These results and others in this report show, in aggregate, very little indication of significant economic or physical withholding in 2012. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

Local market power can also be associated with repeated resource commitments for reliability needs. Hence, Figure 28 shows the subset of RSG payments that are needed to guarantee the costs associated with resources reference levels, as well as the additional RSG costs that are prompted by units raising their commitment costs, energy costs, or modifying other bid parameters. We show these results separately for units committed for capacity and for congestion management.

**Figure 28: RSG Payments by Conduct**
2011–2012




| 2012 | Capacity $ M | Capacity Share | Constraint $ M | Constraint Share | Total $ M | Total Share |
|---|---|---|---|---|---|---|
| Other Conduct | 1.9 | 7% | 1.0 | 4% | 2.9 | 6% |
| High Energy Offer | 2.9 | 10% | 1.3 | 5% | 4.1 | 8% |
| High Commitment Costs | 9.3 | 33% | 4.7 | 19% | 14.0 | 27% |
| RSG at Reference | 14.0 | 50% | 17.6 | 72% | 31.6 | 60% |

Payments associated with offering above reference declined 44 percent from 2011 to $21.0 million, of which nearly $8 million was for capacity in July. While some of these excess payments likely reflect legitimate costs that are not fully captured in resources' reference levels, some are associated with offers that exceed the resources' marginal costs. Excess payments made to units committed for capacity are not subject to mitigation, while those for congestion did not exceed the applicable conduct or impact thresholds to warrant mitigation. This was most acute for resources committed to resolve a local reliability issue. Hence, much of the decline from 2011 occurred because many commitments made for voltage support were moved to the day-ahead market in mid-2012. In addition, tighter mitigation thresholds for VLR commitments have reduced the ability of suppliers to exercise market power in such areas (see next subsection).

## C. Summary of Market Power Mitigation

Most market power mitigation in MISO's energy market continues to occur pursuant to automated conduct and impact tests that utilize clearly specified criteria. The mitigation measure for economic withholding caps a unit's offer price when it exceeds the conduct threshold and the offer raises clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

The mitigation thresholds differ depending on the two types of constrained areas that may be subject to mitigation: BCAs and NCAs. The market power concerns associated with NCAs are higher because they are chronic. As a result, conduct and impact thresholds for NCAs can be substantially lower than they are for BCAs depending on the frequency with which NCA constraints bind. The chronic nature of the NCAs and the lower mitigation thresholds generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs. Very little mitigation was imposed in the day-ahead market. This is expected because the day-ahead market is much less vulnerable to withholding because of the liquidity provided by virtual traders.

Real-time NCA and BCA energy market mitigation approximately doubled in 2012 but remained infrequent. A total of 39 BCA unit-hours and 17 NCA unit-hours were mitigated in 2012, up from respectively 22 and nine unit-hours last year. Mitigation totaled 1,958 MWh in BCAs and

546 MWh in NCAs.  Mitigation of units for RSG payments declined by 36 percent to less than $400,000, and in unit-day terms it declined by 53 percent.  Seven units were mitigated under the new VLR mitigation measures beginning in September, and an additional four units were so mitigated in the day-ahead market.

Despite infrequent mitigation in 2012, the pivotal supplier analyses discussed earlier in this section continue 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.

## IX. Demand Response

Demand Response improves reliability in the short term, contributes to resource adequacy in the long term, reduces price volatility and other market costs, and mitigates supplier market power. Therefore, it is important to provide efficient incentives for the development of DR and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes. Table 3 shows overall DR participation in MISO, NYISO and ISO-NE in the prior four years.

**Table 3: DR Capability in MISO and Neighboring RTOs**
2009–2012

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

* Registered as of December 2012. All units are MW.

The table shows that MISO had 7.2 GW of registered demand-response capability available in 2012, comparable as a share of capacity to neighboring RTOs and mostly unchanged from prior years—the decreases since 2009 are associated primarily with membership departures. MISO's capability comes in varying degrees of responsiveness. Most of the MISO DR is interruptible load (i.e., "Load-Modifying Resources", or LMR) developed under regulated utility programs or BTMG. MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions. As of December 2012, only 443 MW participated directly in MISO's energy markets as Demand Response Resources (DRR), Types I and II. Most DRR provide only supplemental reserves.

MISO considers DR a priority and continues to actively expand its DR capability, including integrating "Batch-Load" DR (a demand resource with a cyclical production process). As surplus capacity dissipates, DR resources are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. It is, therefore, important to ensure that real-time markets produce efficient prices when DR resources are deployed. One change that is particularly important is a modification to price-setting methodologies to let emergency actions and all forms of DR, including those not callable by MISO, contribute to setting efficient shortage prices in the markets. Failure to do so will undermine the efficiency of the market during peak periods and can serve as a material economic barrier to the development of new resources. 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 consider expanding this capability to LMR, including BTMG.

Finally, the integration of DR in the resource adequacy construct is very important because it can potentially have a sizable effect on the price signals provided by MISO's capacity market. LMR are treated comparable to generation resources in their ability to meet planning reserve margins in the Resource Adequacy Construct. However they are not tested to verify their capability like generation resources are, so are effectively granted a 100 percent capacity credit. When they were called in 2006, MISO received only 2,651 MW, or 42 percent, of the more than six GW of total claimed capability. Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.

# X. Recommendations

Although its markets continued to perform competitively and efficiently in 2012, we recommend MISO make a number of changes. We have organized the recommendations by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion
- RSG Cost Allocation and PVMWP Eligibility Rules
- Dispatch Efficiency and Real-Time Market Operations
- Resource Adequacy

A number of the recommendations described below were recommended in prior *State of the Market* reports. This is expected because some of the recommendations can require substantial software changes, stakeholder review and discussions, regulatory filings or litigation regarding Tariff changes. Since these processes can be time-consuming and software changes must be prioritized with other software projects, recommendations can take multiple years to complete. MISO addressed four of our past recommendations in 2012 or in early 2013; these are discussed at the end of this section. For any recurring recommendation, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendation.

## A. Energy Pricing and Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, the spot prices produced by the real-time market affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, longer-term forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest priorities from an economic efficiency standpoint must be to produce real-time prices that accurately reflect supply, demand, and network conditions. The following three recommendations address this area.

### 1. Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set energy prices in the real-time market.

As the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, BTMG or other forms of DR. If these resources cannot set prices in the real-time market, MISO will be understating the marginal value of energy during these periods. Prices in these hours play a crucial role in sending efficient long-term economic signals to maintain adequate supply resources and to develop additional demand-response capability. Therefore, allowing DR to set real-time energy prices will improve incentives to schedule imports and exports, to schedule load in the day-ahead market (and reduce RSG costs), and to invest in resources needed to maintain adequate supplies in MISO.

<u>Status</u>: The recommendation was originally proposed in 2008 and MISO agrees with it. MISO has worked to address this recommendation by allowing EDR to set prices through the ELMP initiative, which is scheduled to go into testing in early 2014. However, in an emergency MISO calls for the deployment of LMR and BTMG (which total nearly six GW) before it calls on EDR. Since LMR and BTMG will not set prices under the current ELMP proposal, real-time prices are likely not to reflect curtailment costs when MISO deploys DR.

<u>Next Steps</u>: While the progress made in allowing EDR resources to set prices as part of the ELMP initiative has been substantial, it is important to address the pricing of LMR and BTMG that will be deployed first under shortage conditions. This may be accomplished by establishing a default curtailment cost for each class, or by compelling these resources to participate in the EDR program. The latter approach has the advantage of providing MISO more direct access to these classes of DR capability, and perhaps an improved capacity to verify their ability to curtail load when needed. MISO should consider this and other possible alternatives to address this pricing issue.

### 2. Implement a five-minute real-time settlement for generation and external schedules

MISO clears the real-time market in five-minute intervals and schedules physical schedules on a fifteen-minute basis. However, it settles both physical schedules and generation on an hourly basis. This can create inconsistencies between the dispatch signal and the hourly prices that can cause generators to have the incentive to not follow the dispatch signal or to simply be inflexible.

This inconsistency is only partially addressed by the PVMWPs. Implementing this recommendation will improve the incentives for generators to follow dispatch instructions and provide more flexibility, and for participants to schedule imports and exports more efficiently.

<u>Status</u>: This is a new recommendation.

<u>Next Steps</u>: We believe MISO already has the metering and data necessary to support this recommendation, and implementing it will require only modest changes to MISO's existing settlement calculations. MISO should evaluate the costs and benefits of this proposal and seek stakeholder input and approval.

### 3. Eliminate excess payments and excess charges to physical transactions that affect external constraints

The excessive settlements of congestion in the interface prices produces the following adverse results:

- The excess payments can result in higher negative ECF, market-to-market costs, or FTR underfunding.
- The excess payments can motivate participants to schedule inefficient transactions, while the excess charges can discourage efficient transactions.

The excess payments are not limited to market-to-market constraints in PJM. They occur on all constraints that are monitored by another RTO or control area operator. A simple means to fully address these concerns would be to eliminate the portions of the congestion components of the interface prices associated with the external constraints.

<u>Status</u>: This is a new recommendation, although it was previously raised in our 2011 SOM and in our comments to the Joint and Common Market Stakeholder group in August 2012.

<u>Next Steps</u>: MISO should move as quickly as possible to modify its interface pricing and should encourage PJM to do the same.

### 4. Improve external congestion processes by modifying how relief obligations are calculated and how the constraints are modeled in the real-time market

#### a) Base relief obligations on *Net* Market Flows, not gross forward flows

MISO reports its Market Flow to the IDC in three ways: gross forward flows, gross reverse flows, and net market flows. When an external (non-M2M) flowgate binds and a TLR is called, MISO receives a relief obligation based solely on its forward-direction Market Flows, even though the *net* Market Flows represent the true impact of MISO's dispatch on the constraint. MISO has frequently received relief obligations for constraints when its dispatch is already unloading the constraint. Attempting to provide relief in these cases has caused MISO to incur inefficient costs and can result in substantial FTR underfunding.

<u>Status</u>: This is a new recommendation.

<u>Next Steps</u>: MISO should evaluate current procedures with respect to Tariff and NERC requirements propose revisions to make its congestion management processes for external constraints more efficient and equitable.

#### b) Cap MVL on External (non-M2M) Flowgates.

When MISO gets a relief obligation on an external (non-M2M) flowgate, MISO binds the external flowgate at its internal default MVL of $2,000. The internal MVL is often many times higher than the value of the constraint (i.e., the marginal cost of managing the constraint by the monitoring RTO). In fact, SPP's default MVL on binding flowgates is $500 per MW. By allowing MISO's dispatch to incur inefficient congestion management costs that are multiples of the value of the external constraint, MISO increases congestion costs its customers must bear in LMPs, as well as potentially increasing its negative ECF and causing FTR underfunding.

<u>Status</u>: This is a new recommendation.

<u>Next Steps</u>: MISO should evaluate current procedures with respect to Tariff and NERC requirements. It will soon be filing Tariff changes to specify how MVL's are determined on both internal and external constraints. These changes should establish a process whereby MISO can set efficient MVLs on the external constraints.

### 5. Introduce a virtual spread product.

Nearly 20 percent of virtual volumes in 2012 were "matched" price insensitive transactions. To the extent that the matched transactions are attempting to arbitrage congestion-related price differences, a virtual product to allow participants to do this price sensitively would be more effective and efficient. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (schedule a transaction). This would prevent the participant from engaging in transactions that are highly unprofitable for the participant and produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This is a new recommendation.

Next Steps: MISO should explore the feasibility of such a product and consider what costs should be allocated to developing such a product.

## B. Guarantee Payment Eligibility Rules and Cost Allocation

Failure to allocate RSG costs to those market participants that cause them will produce inefficient incentives by (a) discouraging conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. The current allocation rules for RSG costs, though improved in April 2011, continue to produce an allocation of real-time RSG costs that is substantially inconsistent with cost causation. In particular, MISO allocates 90 percent of the real-time RSG costs to market-wide deviations, even though such deviations are likely only causing approximately one-half of the costs. Market-wide deviations often bear a majority of real-time RSG costs in hours when the total net deviations are *negative* (thus they cannot be contributing to MISO's need to commit resources for capacity). In addition, an error in the cost allocation formula reversed the intended allocation of CMC costs to virtual load and virtual supply. This means virtuals that help reduce RSG costs are bearing the costs, while those that hurt are not. The recommendations in this area include three specific changes to address these issues.

Additionally, we have recommended changes in the eligibility rules for PVMWP and RSG to address gaming strategies that can result in unjustified payments.

**6. Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs by making the following changes:**

a) **Net market-wide deviations to determine the share of the real-time RSG costs that should be allocated via the DDC rate.**

Netting helping and harming market-wide deviations is important because it allows MISO to determine the extent to which total deviations are contributing to the need for it to commit resources after the day-ahead market. The current rules allow for netting at the market participant level and administrative netting through Financial Schedules (allowing one participant's harming deviation to be offset by another participant's helping deviation). No participants to date have used this mechanism. The current rules limit the netting to deviations that occur prior to the NDL.[24]

In response to our prior recommendation on market-wide netting, MISO has been working with its customers to develop Tariff revisions. To clarify this recommendation, we believe the market-wide netting of deviations should be calculated as follows:

$$\sum \text{Helping}_{\text{preNDL}} + \text{Harm}_{\text{preNDL}} + \text{Harm}_{\text{postNDL}} + \text{Headroom Target},$$

Helping deviations are negative and costs should be allocated to deviations only if the sum is greater than zero. Notably, helping deviations after the NDL are excluded from this netting because they do not necessarily offset the harming deviations (MISO may have already made commitments prior to this class of deviations).

Status: This recommendation was originally made in 2012 and MISO has been working with its customers to develop a proposal in response. We provided some additional detail in this year's recommendation to assist in the development of this proposal.

Next Steps: MISO's customers have voted to approve the market-wide netting proposal. MISO is still evaluating the details of the netting revisions and may need to seek additional stakeholder feedback before it makes a Tariff filing.

24 This is the cut-off time, four hours prior to the operating hour, by which schedule changes must be reported to the Transmission Provider to enable it to reflect such changes in the RAC process or the LAC process.

b) **Allocate real-time RSG only to harming deviations (pre- and post-NDL).**

MISO distinguishes between deviations that occur prior to the NDL and those that occur after it. Only harming net participant deviations prior to the NDL are allocated RSG costs, whereas all post-NDL deviations are allocated real-time RSG costs. Although these NDL helping deviations may not reduce RSG (which is why we propose not including them in the market-wide netting in the prior recommendation), we do not believe that they cause RSG. Therefore, this recommendation calls for MISO to modify its current practice of allocating real-time RSG charges to post-NDL helping deviations.

Status: This is a new recommendation. We have discussed this recommendation with MISO and suggest that it make this change in concert with the market-wide netting proposal.

Next Steps: MISO is still evaluating the details of the modified allocation recommendation and may need to seek additional stakeholder feedback before making a Tariff filing.

c) **Eliminate the use of GSFs in determining the costs that should be allocated via the CMC rate.**

The CMC formula currently under-allocates congestion-related RSG costs to the deviations that contribute to the need to incur these costs. The primary issue is that these RSG costs are multiplied by the GSF for the committed resource as one step in determining the share that will be allocated to congestion-related deviations. While it is true that this will indicate the share of the resource's output that will provide relief on the constraint, it fails to recognize that in most cases *all* of the commitment costs were incurred because of the constraint, regardless of the magnitude of the GSF. Our studies have shown the average GSF of units committed for congestion management is roughly 35 percent, but is often as low as five or ten percent. Consequently, a CMC deviation that might be entirely responsible for causing a commitment and any associated RSG payments frequently bears only a small fraction (e.g., five percent) of the costs.

Additionally, most of the costs that are not borne by deviations affecting the constraint are then borne by market-wide deviations under the current Tariff. While there are times when constraint commitments would contribute to capacity needs (such as VLR commitments), we believe the share of costs appropriately allocated to the DDC should be limited to a share that reflects

MISO’s estimate of the typical capacity benefit of these commitments. In the case of VLR commitments, this share is approximately 10 percent.

Status: This recommendation was first made in 2012. MISO has presented this recommendation to stakeholders in the Market Subcommittee, which voted to approve the proposal to remove the GSF from the allocation formula.

Next Steps: MISO plans to finalize Tariff revisions and file proposed modifications with FERC.

### 7. Implement improved eligibility requirements for PVMWPs.

#### a) Modify eligibility requirements to address gaming issues.

We have identified a number of gaming opportunities under the current PVMWP eligibility rules that could enable participants to increase PVMWP in a manner that was not intended by the rules. The specific gaming issues have been discussed with MISO and FERC. They can be fully addressed with changes to the eligibility rules associated with these payments that would cause any supplier engaging in the gaming conduct to become ineligible for the payments. This eliminates the incentive to engage in these strategies.

Status: This recommendation was made in 2012 and a more detailed memo was provided to MISO on these issues. To date, MISO has made two filings to remedy the concerns, which FERC has approved. MISO is working with the IMM to develop the remedies for the remaining issues.

Next Steps: MISO should develop the necessary Tariff revisions to address these gaming opportunities and file with FERC.

#### b) Correct the mitigation rule governing authority over PVMWP and RSG eligibility.

The Tariff provides authority for MISO to file for the removal of eligibility for make-whole payments for resources identified as being engaged in conduct to increase these payments unjustifiably. The purpose of this provision is to effectively address any unforeseen flaws in MISO's guarantee payments that provide an opportunity for market participants to engage in gaming. Unfortunately, however, the Tariff provision does not refer specifically to PVMWP, but rather to "MRD MWP", which is an undefined term. By correcting this, MISO would have the authority to stop gaming strategies until it has the opportunity to modify the rules.

Status: This is a new recommendation.

Next Steps: The requires a Tariff filing with FERC to make this relatively minor correction.

**8. Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.**

Compensating spinning reserve suppliers for out-of-market deployment costs when they are called on to produce energy leads to an inefficient selection of spinning reserve resources because these expected deployment costs are not considered when resources are scheduled. Eliminating these payments, including RTORSGP and real-time RSG payments, for spinning reserve deployments will improve reserve market efficiency by causing expected deployment costs of operating reserves to be reflected in participants' offers. This in turn will allow MISO to schedule those resources with the lowest total costs, including deployment costs. It will also allow these costs to be efficiently reflected in spinning reserve prices.

Status: This recommendation was originally made in the *2010 State of the Market Report* and MISO has presented this to its stakeholders. The stakeholders recommended that MISO evaluate potential alternatives to resolve the issue, although we continue to believe that this is the simplest and lowest-cost means to address this issue.

Next Steps: MISO should complete the requested evaluation and work with its customers to develop proposed Tariff changes.

**9. Modify the mitigation measures to allow the definition of a "dynamic NCA" that is utilized only when network conditions exist that create substantial market power.**

The current Tariff provisions (Section 63.4 of Module D) related to the designation of NCAs are focused only on sustained congestion at locations where the MISO market is subject to the exercise of significant market power. Generally, NCAs are defined and thresholds calculated based on twelve months of market results. However, transitory conditions can arise that create a severely constrained area with one or more pivotal suppliers, but the area would not qualify as an NCA because of the limited timeframe. Sometimes these transitory conditions repeat periodically, particularly if they are associated with transmission outages. We have concluded that under such cases, the current Tariff provisions are insufficient to effectively address the resulting local market power. This recommendation would expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify the formulas used to calculate the conduct and impact thresholds to appropriately address severe congestion or local reliability conditions that may occur over a period of less than twelve months.

Status: This is a new recommendation.

Next Steps: MISO should work with the IMM to develop proposed Tariff revisions to address this recommendation and present this recommendation to its stakeholders for input.

## C. Improve Dispatch Efficiency and Real-Time Market Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which include satisfying the system's needs reliably and at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system and make a variety of changes to parameters and other inputs to the real-time market as necessary. Each of these actions can substantially affect market outcomes.

One of the principal challenges to achieving efficient real-time outcomes is the five-minute time horizon of the real-time market. When the needs of the system require that resources ramp up or down rapidly, substantial costs can be incurred and real-time prices can become highly volatile to reflect these costs. It is these ramp demands that have caused MISO's real-time energy prices to be more volatile than any of the other RTOs in the Eastern Interconnect. These ramp demands can be satisfied at a much lower cost if they are anticipated and if the dispatch of resources is modified to account for them over a timeframe longer than five minutes, or if the system holds low-cost ramp capability that can be utilized when unexpected ramp demands arise. The following three recommendations seek to improve on these processes.

### 10. Develop a look-ahead real-time dispatch capability to efficiently satisfy the system's anticipated ramp demands.

This look-ahead capability would include a multi-period dispatch optimization feature to move resources in anticipation of system demands over several forward intervals. This capability would be a clear improvement over the use of the offset parameter because the look-ahead dispatch would proactively move resources in optimal locations in advance of their anticipated need, securing the necessary ramp capability at the lowest cost.

<u>Status</u>: This was originally proposed in 2005 along with a Look-Ahead Commitment (LAC) capability to better manage the economic commitment and decommitment of gas turbines. MISO has developed the LAC model and it was implemented on April 1, 2012. The Look-Ahead Dispatch (LAD) capability is relatively resource-intensive and conceptual design is scheduled for completion in 2014.

### 11. Implement a ramp capability product to address unanticipated ramp demands.

The look-ahead dispatch recommendation addresses ramp demands that can be foreseen by MISO. Some of the most significant ramp demands MISO faces, however, are unforeseen in advance. These include unforeseen ramp demands associated with unit outages, changes in wind, and changes in "non-conforming" load. To address these unforeseen ramp demands, MISO could procure ramp capability. This can be done by establishing ramp capability targets along with economic values for the ramp capability (e.g., a ramp capability demand curve). Even at a relatively low demand curve level, the real-time market can likely make low-cost tradeoffs to maintain a higher level of ramp capability. Because it would address unanticipated ramp needs, this recommendation would be valuable independent of the LAD.

<u>Status</u>: This recommendation was first made in the *2011 State of the Market Report*. MISO has continued to develop this concept.

Next Steps: MISO expects to complete a conceptual design by mid fall of 2013. Once a conceptual design is completed, MISO should be able to estimate the benefits of this product and proceed to prioritize its development.

### 12. Implement changes to more effectively identify and remedy units not following dispatch.

#### a) Develop enhanced tools to identify units that are effectively derated or not following dispatch so that they may be placed off-control.

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 unresponsive to dispatch signals over multiple intervals. Consequently, a unit that may be effectively derated by large amounts and unable to follow dispatch points may not be identified by MISO's current operating tools and procedures. In 2012, we found numerous examples where resources were well below their economic output levels because they were effectively derated, but did not update their offer parameters to show that they were derated or put off-control by MISO. This impacts reliability and can result in substantial unjustified make-whole payments and avoided RSG charges. This recommendation would allow the operators to recognize units in this condition so that they can place the units off-control, which would address the concerns described above.

Status: This is a new recommendation. We have provided MISO a list of events where resources were effectively derated. They are reviewing this information and have been discussing the means to address them .

Next Steps: MISO should identify upgrades to its systems and operating procedures that would allow it to detect resources that are effectively derated.

#### b) Tighten thresholds for uninstructed deviations.

All RTOs have a tolerance band that defines how much a resource's output can vary from the RTO's dispatch instruction before the supplier is penalized for uninstructed deviations. MISO's tolerance band of eight percent (which also requires the deviation occur in four consecutive intervals) is substantially more lenient than those of other RTOs.[25] MISO should consider tightening its thresholds for uninstructed deviations (Deficient and Excessive Energy) to be more in line with those utilized by other RTOs. Most RTOs use a five percent band with no requirement that the deviation occur in subsequent intervals. This will improve suppliers'

25 MISO's threshold also includes a minimum of six MW and a maximum of 30 MW.

incentives to follow MISO dispatch signals and will also help address the concerns we've raised regarding unreported unit derates (which occur when units do not respond to dispatch instructions, but remain within the uninstructed deviation threshold).

Status: This is a new recommendation.

Next Steps: MISO should evaluate this change and work with its customers to develop a specific proposal.

### 13. Expand the JOA to optimize the interchange with PJM to improve the price convergence with PJM.

The RTOs have discussed allowing participants to submit offers to transact within the hour if the difference between MISO's and PJM's real-time prices is greater than the offer price. This change, or others that will allow the interface between the markets to be more fully utilized, would generate substantial benefits by allowing lower-cost resources in one area to displace higher-cost resources in the other area. Additionally, it will improve reliability in both areas and avoid types of shortages MISO experienced in 2012 that were in large part caused by poor utilization of the interface with PJM.

Status: This recommendation was originally proposed by the IMM in 2005 and MISO has been discussing options with PJM. MISO staff has engaged in preliminary discussions with PJM and developed a white paper describing the options for addressing this recommendation. PJM has expressed limited interest or support for this initiative to date.

Next Steps: If PJM is willing, we recommend that MISO work with PJM to complete the development of a detailed concept. With this conceptual framework developed, the RTOs may be able to work with stakeholders in both areas to garner support for the concept.

### 14. Implement procedures to utilize provisions of the JOA that would improve day-ahead market-to-market coordination with PJM.

Under the JOA each RTO has the option to request additional FFE on M2M constraints and to compensate the responding RTO based on the responding RTO's DA shadow price. This is a valuable provision because a constraint binding in the day-ahead market at the FFE can be costly and inefficient for constraints that are not expected to bind in real time or bind at levels that would enable an RTO to exceed its FFE in real-time at a very low cost. Neither PJM nor MISO has ever requested additional FFE in the day-ahead market. Implementing this recommendation would likely improve the resource commitments in both areas.

Status: This recommendation was originally made in the *2011 State of the Market*. MISO is evaluating this recommendation and has made presentations on this recommendation to stakeholders at the Joint and Common Market meetings. Stakeholders requested additional details and evaluation of the proposed changes.

Next Steps: The RTOs should continue to work together to develop more detailed procedures. The RTOs should include data exchange related to day-ahead results in order to facilitate the ability to monitor and audit this process.

### 15. Eliminate the transmission constraint deadband.

Our evaluation of the unmanageable congestion in MISO during 2011 revealed that 30 percent of the value of constraint violations occurred when the transmission deadband alone caused a constraint to appear to be violated (i.e., when the flow was less than the original transmission limit). We estimate that the deadband accounted for $140 million in unpriced congestion and 19 percent of all congestion value in MISO during 2011. While eliminating the deadband would not cause this congestion to fall to zero, it would be significantly less.

The deadband was intended to reduce price and generator dispatch volatility by helping ensure that once constraints were binding, they continued to do so. However, the case studies performed over the past six months show that it is actually increasing volatility because it contributes to unmanageable congestion that often results in sharp LMP changes. It also inefficiently reduces the utilization of the transmission system by binding constraints at levels less than their physical capability. We are unaware of any other RTO that currently employs a transmission deadband.

Status: This was a recommendation in the *2011 State of the Market Report*. MISO started testing deactivation of the constraint deadband on select constraints in December 2012. Our analysis indicates that shadow price volatility and transmission utilization improved on these constraints after the deadband was deactivated.

Next Steps: MISO should deactivate the transmission deadband as expeditiously as possible. We will assist the MISO in monitoring for any adverse impacts on the MISO system.

### 16. Re-order MISO's emergency procedures to utilize demand response efficiently.

As noted above, as the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, BTMG or other forms of DR. However, these resources cannot be called by MISO before it has invoked a number of other emergency actions that are costly and adversely impact the market. This recommendation would allow MISO to utilize these resources in a more efficient manner.

Status: This is a new recommendation.

Next Steps: MISO should review the existing DR resources in MISO to estimate the costs of calling on them to curtail. This information would be valuable in responding not only to this recommendation, but also to Recommendation 1 (to enable DR to set prices).

### 17. Modify the market systems to recognize supplemental reserves being provided from quick-start units when they are in the process of starting.

When resources providing supplemental reserves are committed, the reserves are shifted to online resources. Unfortunately, MISO does not perceive that the committed resource is providing reserves or energy until the unit is synchronized and providing energy. Hence, all capacity from the resource will appear to be lost for five to 15 minutes. During this period, the quality of reserve capability is actually enhanced (not degraded) because the resource can provide energy and reserves more quickly to the system once it is online. This issue caused two operating reserve shortages, contributed to nine operating reserve price spikes of at least $100. This recommendation will prevent this inaccurate transitory capacity loss that can result in artificial operating reserve shortages.

Status: This is a new recommendation.

Next Steps: MISO should evaluate this recommendation and review its processes to identify the lowest-cost means to address it.

## D. Resource Adequacy

Reasonable resource adequacy provisions and a well-functioning capacity market will be increasingly important as planning reserve margins in MISO fall due to the compliance costs of new environmental regulations and due to low prevailing energy prices, both of which will increase retirements of uneconomic units. MISO filed proposed changes to its Resource Adequacy Construct in 2011 that should improve price signals and reliability. However, there remain a number of critical issues that are undermining the economic signals provided by the MISO markets. The recommendations in this subsection are intended to address these issues to help ensure that the market will provide the resources over the long term that are necessary to maintain reliability.

### 18. Remove inefficient barriers to capacity trading with adjacent areas.

A number of existing barriers limit capacity trading between MISO and PJM, which include access to transmission capability, deliverability requirements, and an unclear application of capacity obligations to external suppliers. These barriers substantially distort the capacity prices in both markets, thereby providing inaccurate economic signals to invest and retire resources. Eliminating these barriers will require the cooperation of both RTOs.

Status: This recommendation was originally proposed in 2008. MISO has been developing proposals to address this recommendation, but PJM has generally opposed changes in this area. We have sought a mandate from FERC to compel the RTOs to collaborate on a proposal to address this issue. MISO has also requested that FERC require a resolution to this issue. FERC has requested that the RTOs, their respective market monitors, and the States from each region make presentations on this issue on June 20, 2013.

Next Steps: If no mandate is provided by FERC, MISO should continue to refine its proposals and discuss them with PJM.

### 19. Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.

Establishing only a minimum requirement and deficiency charges results in an implicit vertical demand curve for capacity in MISO. This does not reasonably reflect the reliability value of capacity and understates capacity prices as capacity levels fall toward the minimum requirement. This is particularly harmful as large quantities of resources are presently facing the decision to potentially retire in response to new environmental regulations that will require substantial compliance costs.

A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also will produce more efficient and stable capacity prices, particularly as the market moves toward the minimum planning reserve requirement. If this recommendation is not addressed, the MISO markets will not facilitate efficient investment and retirement decisions by participants that will sustain an adequate resource base. Instead, the region will have to rely exclusively on the Organization of MISO States (OMS) requiring their regulated utilities to build new resources.

<u>Status</u>: This recommendation was first proposed in the *2010 State of the Market Report*. MISO has no activity underway to address this recommendation because of the lack of support by the OMS.

<u>Next Steps</u>: MISO should develop a proposal that can be discussed with MISO stakeholders and the OMS. The IMM may file a market flaw referral with FERC because the current vertical demand curve constitutes a fundamental flaw in the current RAC.

### 20. Evaluate capacity credits provided to wind resources and LMR to increase their accuracy.

In order for the capacity market to produce outcomes that are consistent with market fundamentals, it is important that the supply be accurately represented. We have identified three classes of capacity that are likely overstated in the capacity market. First, the basis for the capacity credit provided to wind resources is based on the performance of wind resources during peak load hours averaged over multiple historical years. Even one unusually windy peak day can result in an anomalously high average output level. Since the capacity credit should be based on capability that can be reasonably expected during peak conditions, the current approach may overstate the capacity credit. This will, in turn, lower capacity prices and reduce the incentive to invest in other resources that are needed for reliability. A better basis for the capacity credit would be the median output on peak days, which would exclude anomalously high output levels and more accurately account for resources that have performed poorly. However, given that using the median would provide a capacity value that the wind resource could not achieve in 50 percent of the peak days or hours, we recommend using the lowest quartile of the output on peak days or a similarly conservative assumption.

LMR (excluding BTMG) can currently be fully deducted from an LSE's capacity requirement under Module E. This effectively provides a 100 percent capacity credit to DR resources that are not tested to ensure their capability and have shown in past deployments to provide only a fraction of the total claimed capability. Therefore, we recommend adopting testing procedures if possible, and/or derating these resources based on their actual performance when called upon.

Status: This recommendation was introduced in the *2011 State of the Market Report*.

## E. Recommendations Addressed in the Past Year

MISO in 2012 and early 2013 addressed a number of past recommendations by implementing changes to its market software or operating procedures, or by completing the design and regulatory work associated with new market elements. These recommendations are discussed below.

### 1. Improve SSR designation and compensation provisions.

In the past several years MISO has received an increasing number of applications for SSR status from suppliers that intend to retire or mothball a resource. The volume of requests will continue to increase as the new environmental regulations become effective, particularly if capacity prices do not fully reflect the value of additional resources. The current Tariff language on SSR compensation was revised in 2012 to specify what costs MISO should consider when determining equitable compensation.

We recommended that MISO include only going-forward costs in the "equitable compensation" for SSR resources and that these costs include all avoidable costs of remaining in service, and exclude any sunk or unavoidable costs. It is critical that the SSR designation and compensation provisions be well-defined to avoided creating incentives for suppliers to seek SSR status for resources that would not otherwise be retired or placed out of service.

Status: This recommendation was first made in 2012. MISO proposed Attachment Y modifications that specify the SSR compensation provisions consistent with our recommendations. MISO's proposed changes have been approved by FERC and we have also been working with MISO on each SSR review process.

### 2. Consider implementing a graduated marginal value limit (i.e., transmission demand curve) for transmission constraints.

The 2012 *State of the Market* report showed that transmission constraints are frequently violated only in small quantities or for brief periods of time. This occurs because the power flows over MISO's constraints are affected by factors out of MISO's control that can cause them to change unexpectedly. Such small violations may not substantially affect reliability, and therefore pricing them at the full reliability value (e.g., MVL) may not be efficient. This can be remedied by replacing the single MVL with a graduated demand curve.

Status: This recommendation was first made in 2011. MISO has developed the software and procedures to implement this recommendation. MISO is currently preparing a filing to implement this recommendation on non-market-to-market constraints.

### 3. CMC sign error affecting the RSG cost allocation to virtual transactions.

Since 2011, CMC charges to virtual transactions have been inadvertently *charged* to virtual transactions that relieve the constraint and *credited* (against other deviations) to virtual transactions that load the constraint. While the sign error was identified by MISO in numerous filings and questioned by certain participants in a complaint, FERC denied rehearing on the issue and dismissed the complaint. Nonetheless, MISO filed to correct this flaw and FERC approved this change in an Order effective April 27, 2013.