2013 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

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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	Midcontinent 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 Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity 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 *2013 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

MISO operates competitive wholesale electricity markets in the Midwest that encompasses a geographic area from Montana to Michigan. In late 2013, MISO integrated the MISO South Region covering portions of Texas, Louisiana, Mississippi, and Arkansas. This report also provides a brief summary of the initial market results in MISO South through April 2014.

MISO operates competitive 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 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., to dispatch resources and schedule imports and exports) and efficient decisions in the long term (e.g., resource investment, retirement, and maintenance).

A. Competitive Performance of the Market

The MISO energy and ancillary service markets generally performed competitively in 2013. Conduct of suppliers was broadly consistent with expectations for a workably competitive market. We calculated a "price-cost mark-up" that compares energy prices based on actual offers to a simulated energy price based on our estimate of competitive offer prices. This analysis revealed a mark-up of just 1.7 percent, which indicates that the MISO markets were highly competitive. Additionally, 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 potential economic withholding averaged approximately 0.1 percent of actual load, which is relatively low. Consequently, market power mitigation measures were applied infrequently.

The report does recommend two changes to the MISO market rules to address local market power concerns observed in 2013 and early 2014 where we concluded that the existing market power mitigation measures were not fully effective. The first change addresses market power associated with transitory conditions (usually associated with transmission or generation outages) that creates a severely-constrained area and enables a supplier in the area to raise prices sharply. Since these conditions do not persist long enough for MISO to define a narrow constrained area (NCA), and therefore be able to apply tighter market-power mitigation measures, substantial local market power can be exercised when these conditions persist.

The second recommended change addresses local market power associated with reliability commitments that can allow suppliers to extract excessive Revenue Sufficiency Guarantee (RSG) payments. Less than one-half of RSG payments in 2013 was associated with competitive offer prices. The other half was attributable to increases in one or more offer parameters above competitive levels, very little of which was subject to market power mitigation due to shortcomings to the existing mitigation framework. Based on our evaluation of the RSG results in 2013 and early 2014, we recommend a revision to the mitigation framework for RSG payments to make it comparable to the production-cost framework already employed by MISO to test and mitigate commitments for voltage and local reliability (VLR).

B. Market Outcomes and Prices in 2013

The all-in price of electricity, which is a measure of the total cost of serving load in MISO, averaged $32.51 per MWh. The energy component made up nearly the entire all-in price, and ranged from $31.81 in the West Region to $33.72 in the East Region. Prices were 12.2 percent higher than in 2012 because of higher natural gas prices and slightly higher load in 2013.

Natural gas prices rose 35 percent in 2013. 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.

Although load rose by 0.9 percent, summer 2013 was not as hot as the summers in prior years. Nevertheless, peak conditions in mid-July tested the performance of the markets. We found again that shortcomings regarding interchange scheduling and coordination resulted in substantial economic and reliability costs in MISO and neighboring markets. We continue to recommend a coordinated transaction scheduling system that would address this concern. Ancillary services prices all rose considerably in 2013 and reflected the increased cost and opportunity cost of providing reserves. Although reduced from 2012, shortage pricing was most significant in the spring, when MISO's ability to handle the ramp demands of the system is more limited than in peak load months. Shortage pricing accounted for less than 10 percent of the average regulation and supplemental reserve clearing prices but nearly 25 percent of the spinning reserve clearing price. MISO's introduction of a "regulation mileage" payment did not materially impact regulation clearing prices in 2013.

C. Long-Term Economic Signals and Resource Adequacy

This report shows that MISO's economic signals in 2013 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 many coal-fired resources in the next two years.

In the near-term, our assessment indicates that the system's resources should be adequate for summer 2014 if the peak conditions are not substantially hotter than normal. MISO estimates a planning reserve margin of 30 percent for the South Region and 19.8 percent for the Midwest Region, well in excess of the planning reserve requirement of 14.8 percent. Incorporating a realistic performance from MISO's demand response (DR) capability and hotter than normal summer conditions, however, reduces the margin in the Midwest Region to below 7 percent.

Given that this margin must account for forced outages that can average five to eight percent of the reserve margin and MISO's operating reserve requirements that are more than two percent of its peak load, MISO would need to rely on non-firm imports and emergency actions to satisfy its needs under these conditions.

While the supply is likely adequate for the upcoming summer, more stringent environmental regulations and other factors (e.g., sustained low natural gas prices and rising demand) will gradually decrease MISO's planning reserve margins. MISO's most recent surveys indicate expected coal retirements of 8 to 10 GW by April 2016, which would cause MISO to be capacity-deficient. Hence, it is important for resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base.

MISO made several improvements to its resource adequacy construct (RAC) in 2013, including replacing the monthly Voluntary Capacity Auction (VCA) with an annual Planning Resource Auction (PRA) that features zonal requirements for capacity. This zonal framework should provide a more accurate signal of the value of capacity in various locations. However, two significant shortcomings continue to undermine the efficiency of the RAC: (1) the representation of the demand for capacity in MISO's PRA; and (2) the prevailing barriers to capacity trading between PJM and MISO. These issues contributed to MISO's auction prices clearing near zero in all auctions in 2013.

The minimum capacity requirements and deficiency price set forth in Module E of the MISO Tariff establish a "vertical demand curve" for capacity, 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 capacity prices to rise efficiently as capacity margins fall to accurately signal the value of capacity to both new investors and to suppliers considering environmental retrofits.

D. Transmission Congestion

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources, establishing efficient, location-specific prices that represent the marginal costs of serving load at each location.

The value of real-time congestion in 2013 rose 22 percent to $1.59 billion. This increase was due in part to higher fuel prices because higher fuel prices increase the costs of dispatch actions taken to manage network flows. Congestion rose fastest in the West Region due to significant outages. In addition, the full adoption of the dispatchable intermittent resource (DIR) type has substantially improved MISO's ability to alter the dispatch of wind resources to manage congestion and allowed this congestion to be fully priced.

The increase in real-time congestion cost was also reflected in the day-ahead market, where collected congestion costs rose 8.3 percent in 2013. The day-ahead congestion revenue collected by MISO is paid to holders of financial transmission rights (FTRs), which represent the economic property rights of the transmission system. Because the FTRs held by MISO's customers exceeded the capability of the transmission system in some periods—the system was limited because of unmodeled transmission outages—the day-ahead congestion revenue that MISO collected was 5 percent below the amount required to fully fund the FTR obligations. This shortfall declined in the second half of 2013 as MISO improved its modeling of the FTR market.

Finally, we identify in this report significant dispatch and pricing inefficiencies to managing external constraints that are activated when Transmission Line Load Relief (TLR) procedures are invoked. For example, in almost 80 percent of the intervals in which SPP called a TLR and MISO incurred substantial congestion costs to provide relief, the SPP constraint was not binding (i.e., the relief has no value). These constraints created excess costs for MISO's customers and we recommend changes to reduce these costs and improve efficiency.

E. 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. This premium is eliminated after accounting for the real-time RSG cost allocations, which nearly doubled in 2013 to average $1.00 per MWh. There were persistent real-time premiums in the West Region, where the market was less effective at arbitraging locational differences due to congestion. In April, there were real-time premiums across MISO when operating reserve shortages were not anticipated day-ahead.

Virtual transactions were generally effective in improving the convergence of day-ahead and real-time energy prices. However, cleared transactions declined 12 percent, of which one-third were price-insensitive. Price-insensitive transactions are often 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. We believe these balanced positions are valuable in improving the convergence of congestion patterns between the day-ahead and real-time market. Accordingly, we recommend MISO develop a virtual spread product that would allow participants to engage in this activity more efficiently.

F. 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 resources' physical limitations. In contrast, the day-ahead market is less volatile because it operates over a longer time horizon with more commitment options, dispatch flexibility, and liquidity provided by virtual transactions.

MISO's real-time market produces new dispatch instructions and price signals every five minutes. 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 five-minute dispatch instructions. PVMWP declined 10 percent from 2012 to $55.5 million, consistent with a comparable decline in price volatility. Our report shows that these payments would be substantially reduced and suppliers would have better incentives to follow MISO's dispatch instructions if it settled with participants on a five-minute basis. This would also improve incentives to schedule imports and exports more efficiently. Hence, we continue to recommend that MISO implement five-minute settlements for generators and external transactions.

RSG payments are made in both the day-ahead and real-time markets in order to ensure suppliers' offered costs are recovered when a unit is dispatched. Real-time RSG payments rose 54 percent from 2012 to $81 million, nearly half of which was due to the significant rise in fuel prices. Lower day-ahead purchases, particularly in the first half of the year, resulted in MISO making more resource commitments after the day-ahead market and increasing the capacity-related RSG payments. Day-ahead RSG payments increased by nearly 25 percent because of higher fuel prices and more VLR commitments, which are most often made day-ahead.

FERC recently approved changes we recommended to the allocation of RSG costs to make it substantially more consistent with their causes. These changes provide more efficient incentives to market participants. However, FERC rejected one of the recommended changes, finding that MISO did not provide sufficient evidentiary support. MISO will be refiling to make this change with additional support.

G. External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2013, averaging 3.7 GW per hour in the real-time. Price differences between MISO and neighboring areas create incentives to schedule imports and exports that alter the net interchange between the areas. Efficient interchange is compromised by several shortcomings to the market design, including (1) flawed interface pricing on market-to-market and other external constraints, and (2) suboptimal and poorly-coordinated interchange scheduling.

Addressing the inadequate interchange coordination is important because it results in inefficient transactions that increase price volatility, reduce dispatch efficiency, and create operating reserve shortages. The most promising means to improve interchange coordination 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. MISO is working with PJM on such a proposal.

Interface pricing is currently impacted by a flaw we first identified in 2012. When external constraints—either PJM market-to-market or TLR constraints—are activated by MISO, they will be managed and priced in the real-time market like any other constraint, which means that the LMPs at every location will include the marginal effects of the constraint. These calculations are reasonable at every nodal location except at MISO's interfaces. Since the external areas are generally already reflecting the congestion in their import and export settlements, including this congestion cost in MISO's interface prices creates a redundant settlement of the congestion. MISO receives no credit from PJM or other external systems for incurring these costs and they generally increase uplift costs to MISO's load. In 2013, this pricing flaw resulted in net overpayments of $16.5 million by PJM and MISO for market-to-market constraints and overpayments by MISO of $2.2 million for other external constraints. We have been working with PJM and MISO on this issue and there is now a consensus on the problem but not yet on a solution. We continue to recommend that MISO's interface prices include only the costs associated with its own transmission constraints.

H. Demand Response

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. MISO continues to seek to expand its DR capability, including efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 10 GW of DR resources, which includes 3,400 MW of behind-the-meter generation. However, most of MISO's capability to reduce load is in the form of interruptible load developed under regulated utility programs (referred to as "load-modifying resources" or LMR). MISO does not directly control LMR and it cannot set energy prices when it is called. MISO has been working with its utilities to improve real-time information on the availability of the LMRs. We have recommended that MISO develop a means to allow LMRs to set energy prices, which will become increasingly important as generating resources retire and MISO relies more heavily on LMRs under emergency conditions. We also recommend that MISO modify its emergency procedures to utilize its DR capability more efficiently.

Finally, it is important that the capacity credits are not overstated for DR resources that MISO does not test. Accurately accounting for the true capability of LMRs would potentially increase PRA auction clearing prices significantly. We estimate that the most recent PRA would have cleared at $84 per MW-day (instead of $16.75) if the nearly 6,000 MW of LMRs received a 50 percent capacity credit.

I. Recommendations

Although the markets performed competitively in 2013, 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 2013 and early 2014, which are discussed in the final section of this report. The table of recommendations in this section shows our current recommendations, organized by the area of the market they address.

MISO has been developing a market vision, which includes guiding principles and focus areas associated with the principles. We have mapped each of our recommendations to MISO's focus areas, shown below, to allow market participants and policy-makers to understand to focus of each recommendation and how it pertains to MISO's overall market vision. This mapping is shown in the second column of the table of recommendations.

Market Vision Focus Areas	
1	Enhance Unit Commitment and Economic Dispatch Processes
2	Maximize Economic Utilization of Existing and Planned Transmission Infrastructure
3	Improve Efficiency of Prices under All Operating Conditions
4	Facilitate Efficient Transactions Across Seams with Neighboring Regions
5	Streamline Market Administrative Processes that Reduce Transaction Costs
6	Maximize Availability of Non-Confidential and Non-Competitive Market Information
7	Support Efficient Development of Resources Consistent with Long-term Reliability and/or Public Policy Objectives

The table of recommendations also includes a "SOM number," which indicates the year in which it was first introduced and the recommendation number in that year, and separately indicates whether the recommendation is of high benefit to the market and if it can be achieved in the short-term. Of the 22 recommendations shown below, four are new in 2013.

SOM Number	Focus Area(s)	Recommendation	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2008-2	3, 7	Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set real-time energy prices.		✓
2012-2	3, 4	Implement a five-minute real-time settlement for generation and external schedules.	✓	?
2012-5	1, 2	Introduce a virtual spread product.	?	
2012-9	1, 3	Allow the definition of a "dynamic NCA" utilized when network conditions exist that create substantial market power.		✓
External Transaction Scheduling and External Congestion				
2012-3	4	Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions	✓	✓
2005-2	1, 4	Expand the JOA to optimize the interchange with PJM to improve price convergence with PJM.	✓✓	
2012-4a	2	Improve external congestion processes by modifying how relief obligations are calculated by basing them on Net Market Flows, not gross forward flows		
2012-4b	4	Improve the pricing of external congestion associated with external constraints by setting the MVL on external (non-M2M) flowgates at a reasonable level.		✓
Guarantee Payment Eligibility Rules and Cost Allocation				
2013-1	1	Allocate real-time RSG only to harming deviations (pre- and post-NDL).		✓
2013-2	1	Improve allocation of VLR costs by identifying VLR commitments made by the DA market.		✓
2010-11	1	Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.		✓
2013-3	1	Improve the market power mitigation measure applicable to RSG.	✓	✓

SOM Number	Focus Area(s)	Recommendation	High Benefit	Feasible in ST
Improve Dispatch Efficiency and Real-Time Market Operations				
2011-7	1, 3	Implement a ramp capability product to address unanticipated ramp demands.	✓	
2012-12a	1	Develop enhanced tools to identify units that are derated or not following dispatch so that they may be placed off-control.		✓
2012-12b	1	Tighten thresholds for uninstructed deviations.	✓	✓
2011-10	1, 2	Implement procedures under the JOA that would improve day-ahead M2M coordination with PJM.		
2012-16	1, 3	Re-order MISO's emergency procedures to utilize demand response efficiently.		✓
2012-17	1, 3	Recognize supplemental reserves being provided from quick-start units when they are starting.		?
Resource Adequacy				
2008-11	7	Remove inefficient barriers to capacity trading with adjacent areas.		
2010-14	7	Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.	✓✓	
2011-14	7	Evaluate capacity credits provided to LMRs to increase their accuracy.		✓
2013-4	7	Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions		✓

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 *2013 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.[1]

In 2009, MISO began operating as a balancing authority and introduced markets for regulation and contingency reserves, known collectively as Ancillary Services Markets ("AS markets" or "ASM"), and a monthly spot market for capacity. AS markets 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 capacity market was modified in 2013 as MISO replaced the Voluntary Capacity Auction (VCA) with an annual Planning Reserve Auction (PRA). The PRA allows participants to buy and sell capacity to satisfy residual capacity requirements and better identifies locational capacity needs throughout MISO. Though an improvement, the PRA continues to reflect a poor representation of the demand for capacity (or planning reserves), which undermines its ability to provide efficient economic signals.

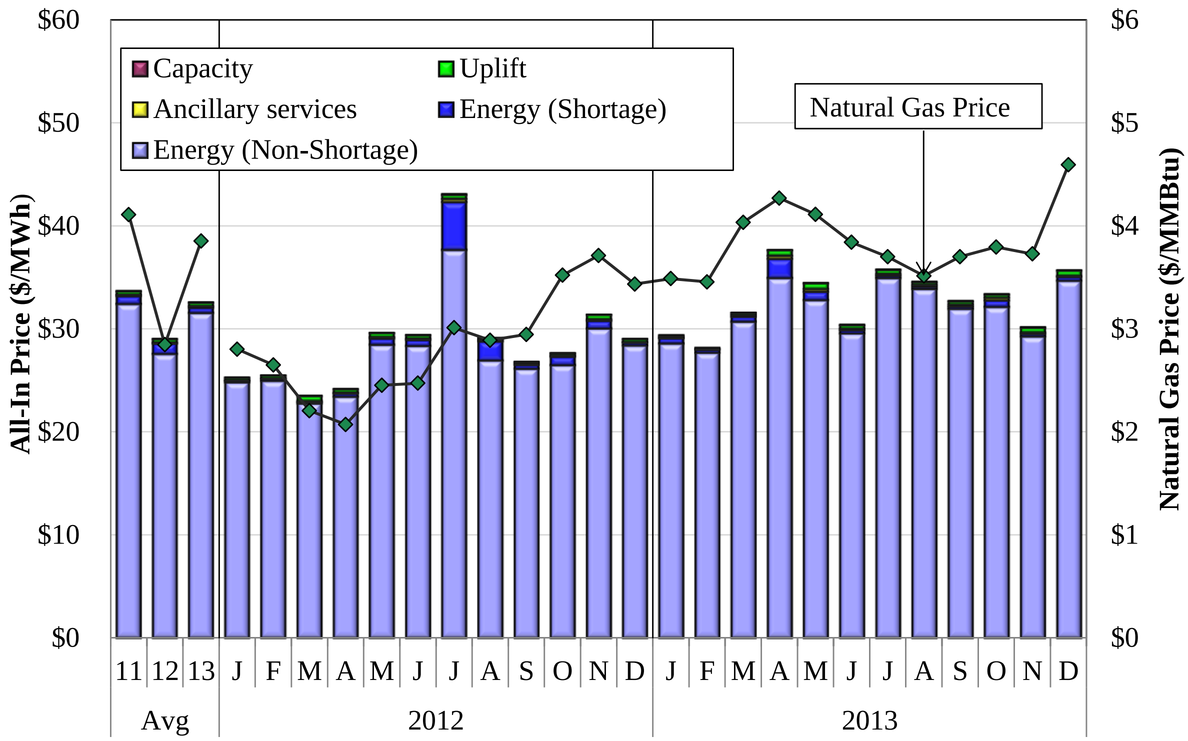
1 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

II. Prices and Load Trends

A. Market Prices in 2013

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.[2]

Figure 1: All-In Price of Electricity
2012–2013



The all-in price in 2013 averaged $32.51 per MWh, an increase of 12.2 percent from 2012. This increase was primarily a result of significant increases in fuel prices, including a 35 percent rise in natural gas prices. Although load rose slightly, MISO did not experience as hot a summer as it did in 2012. As a result, MISO experienced fewer shortages and the share of the energy component associated with shortage intervals declined by more than one-half to 1.6 percent.

2 Capacity costs are estimated by multiplying the VCA clearing price times the capacity requirements in each month. Beginning in June 2013, these costs reflect the PRA clearing price of $1.05 per MW-day.

As in prior years, the energy component constituted nearly the entire all-in price. Uplift costs, including Revenue Sufficiency Guarantee (RSG) payments and Price Volatility Make-Whole Payments (PVMWPs), rose four cents to $0.27 per MWh. Ancillary services costs added $0.17 per MWh, a 4-cent increase from 2012 despite fewer shortages. This increase reflects the higher opportunity costs of foregone energy, which tend to increase with fuel prices.

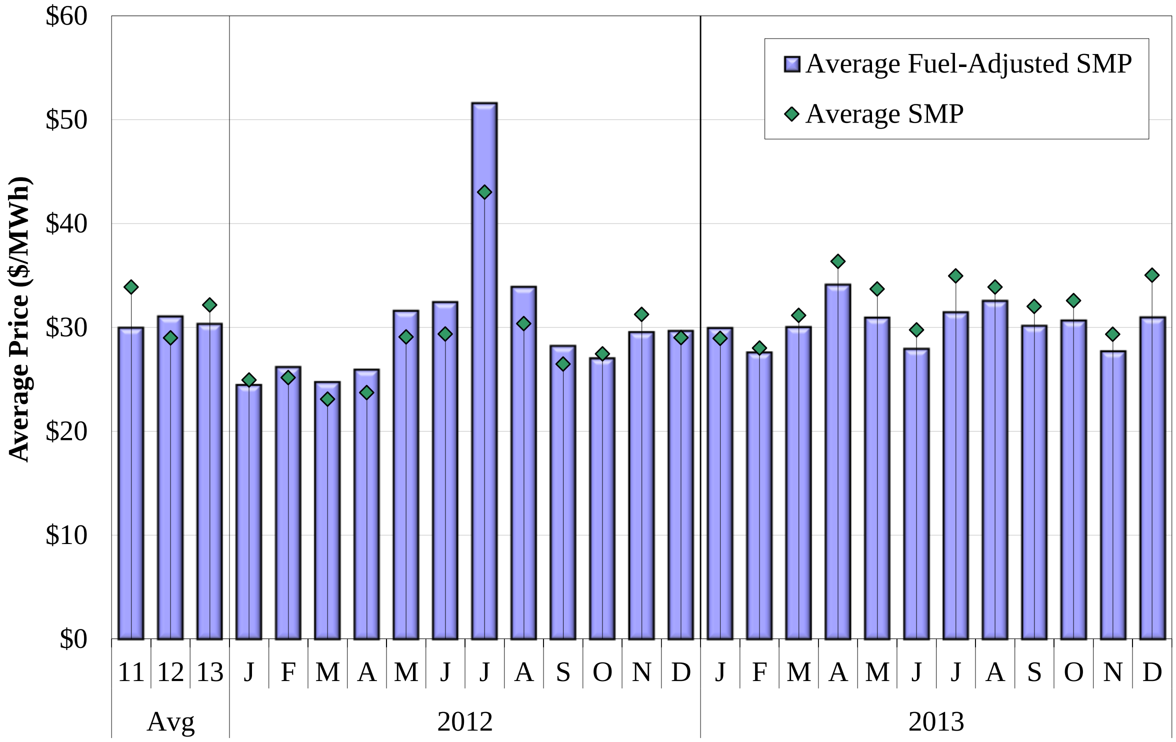
Finally, capacity costs contributed only four cents per MWh to the all-in price. All capacity auctions in 2013—five monthly VCA auctions in January to May, an annual PRA in June and a transitional PRA in November to facilitate the integration of the MISO South region—cleared at very low prices because of the prevailing surplus and the market design issues discussed in this report. It will be critical to address these issues in the near future because increased retirements and capacity exports are projected to generate a capacity deficiency as soon as 2016. Improving the performance of the capacity market may play a pivotal role in ensuring that MISO will continue to have access to sufficient capacity.

The figure also shows that energy price fluctuations are strongly correlated with natural gas price movements. 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 in 2013 rose 35 percent from 2012 to average $3.85 per MMBtu.

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.[3] Although the average SMP in 2013 rose 3.5 percent from 2012, the figure shows that average fuel-adjusted energy prices declined 2.3 percent. This indicates that non-fuel factors, most notably a milder summer and fewer instances of shortage pricing, contributed to the decrease in the fuel-adjusted SMP.

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

Figure 2: Fuel-Adjusted System Marginal Price
2012–2013



B. Fuel Prices and Energy Production

The increase in gas prices in 2013 brought them back from the unusually low price levels that prevailed in 2012, which resulted in natural gas-fired units producing 28 percent less energy in 2013 than they did in 2012. Although natural gas-fired units were a marginal unit in less than one-third of all intervals in 2013, natural gas prices remain an important driver of energy prices because these intervals tend to be the highest-load periods.

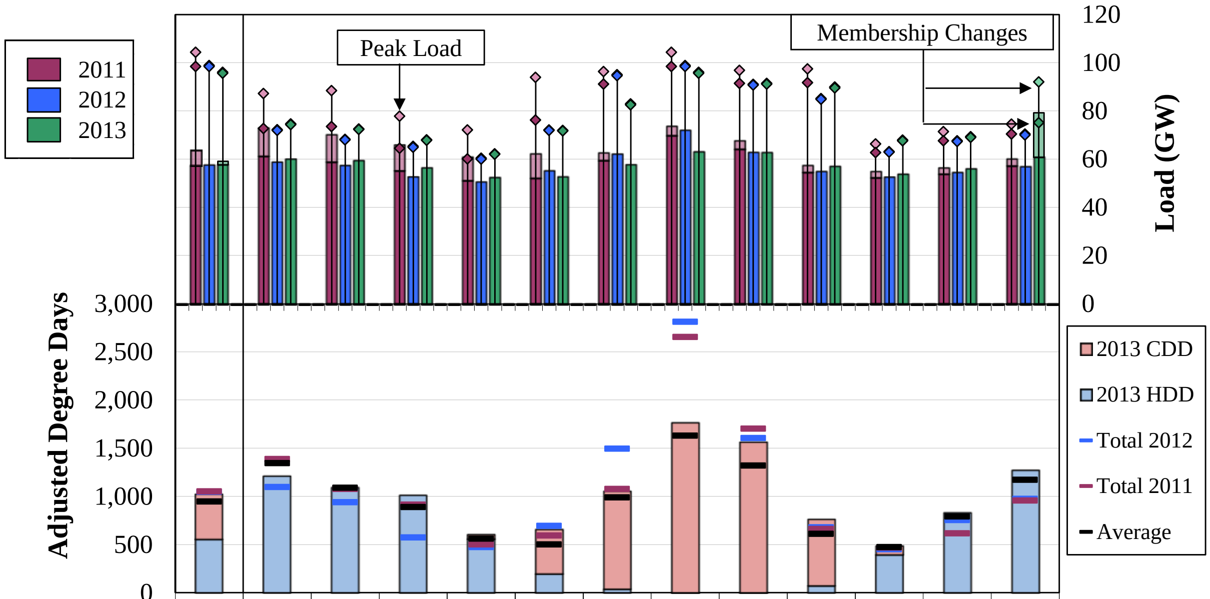
In 2013, coal-fired resources still provided over two-thirds of total generation in MISO and set price in some locations in 93 percent of intervals, including almost all off-peak intervals. Congestion frequently caused both natural gas and coal-fired resources to be on the margin in the same interval in different areas of the footprint. Western (e.g., Powder River Basin) coal prices rose 18 percent, while Eastern coal prices declined five percent.

Wind capacity and output continue to grow in MISO, increasing by 5 and 11 percent in 2013, respectively. Wind generated 7.4 percent of all energy in MISO in 2013, compared to 3.5 percent just three years ago. MISO has continued to evolve its market rules, software, and operating procedures to accommodate the rapidly expanding wind capacity. The expansion of dispatchable wind resources under the Dispatchable Intermittent Resource (DIR) capability has resulted in wind resources setting price in over one-half of all intervals (at an average price of -$11 per MWh). Wind resources typically set price in confined areas where its output is contributing to localized congestion, and it rarely sets prices system wide.

C. 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 2011 to 2013. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across four representative locations in MISO.[4]

Figure 3: Heating and Cooling Degree Days
2011-2013



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

4 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 as estimated by regression analysis. The long-term average degree-days are based on data from 1971 to 2000.

Total degree days declined by 2 percent in 2013 compared to 2012, primarily because of the milder summer weather in 2013.[5] Despite this decline, average load increased by 1 percent in 2013 as economic activity continued to grow at a modest pace in the Midwest. MISO set its annual peak load of 95,777 MW on July 18, which was slightly higher than its "50/50" forecasted peak of 93.8 GW from its *2013 Summer Resource Assessment*, but almost 4 GW below the more extreme "90/10" peak.

D. Evaluation of Peak Summer Days in 2013

MISO's highest loads in 2013 occurred in mid-July. Although conditions were not as tight as they were during the more severe heat waves in 2011 or 2012, MISO experienced a sustained period of above-average temperatures that produced peak loads in excess of the 50/50 forecast in the *Summer Assessment*. On each of the five days shown in Table 1 below, MISO declared Hot Weather Alerts and Conservative Operations. On July 17, MISO declared a Maximum Generation Alert (shown in yellow).

Table 1: Temperatures in MISO during the Peak Summer Week

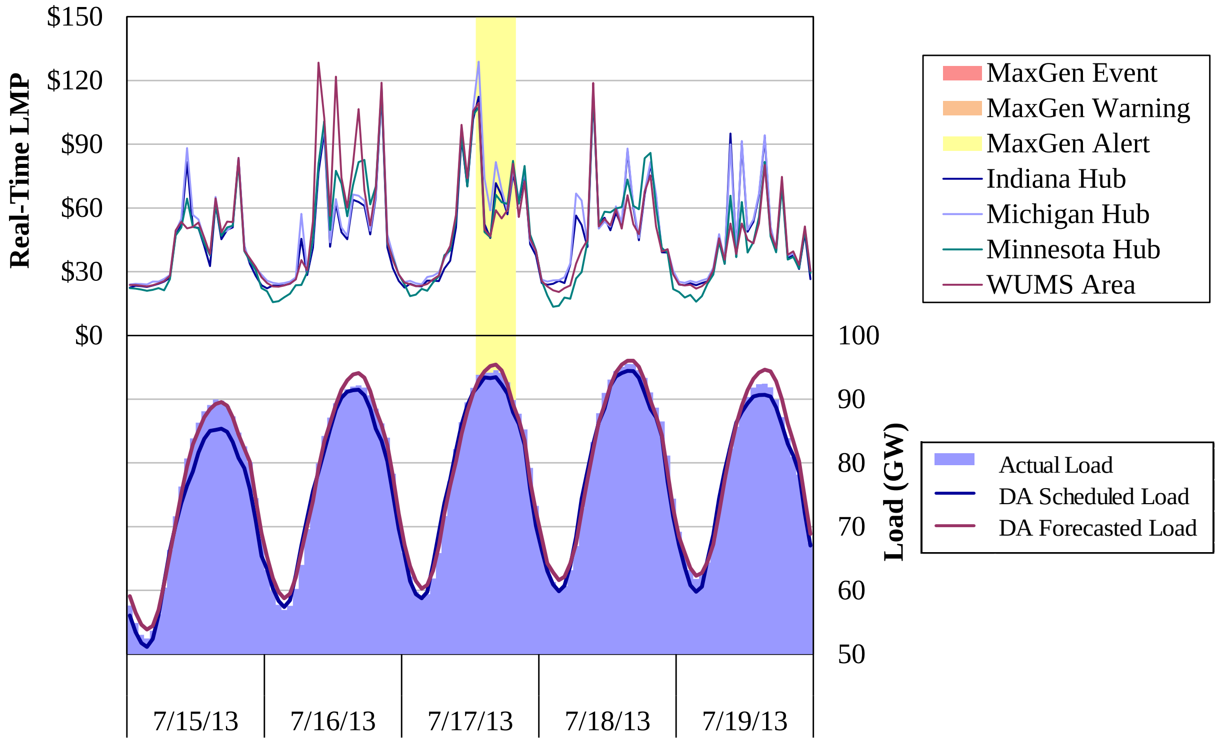
	Historical Average	15	16	July 17	18	19
Cincinnati	86	92	93	93	93	89
Detroit	84	93	90	94	94	95
Indianapolis	85	88	93	93	93	92
Milwaukee	80	85	93	95	95	94
St. Louis	89	91	93	94	94	98
Minneapolis	80	87	91	91	93	84

Figure 4 shows the day-ahead and real-time load in the lower panel and real-time prices in the upper panel. Actual loads on most days closely matched what was scheduled day-ahead, although under-scheduling on July 15 required substantial real-time capacity commitments. Load peaked on July 18, but supply conditions were tighter on July 17 (due to 4 GW less wind output). On this day, voluntary load curtailments after the Maximum Generation Alert declaration truncated the peak load, and resulted in a substantial reduction in energy prices.

5 Unless otherwise stated, changes in load in this report are adjusted for membership additions and departures.

Although MISO did not call for any demand response on this day, these results indicate the importance of allowing demand response to set energy prices when it is needed. Prices were reasonably volatile during these periods, but MISO did not exhibit significant reserve shortages.

Figure 4: Load and Real-Time Prices
July 15-19, 2013

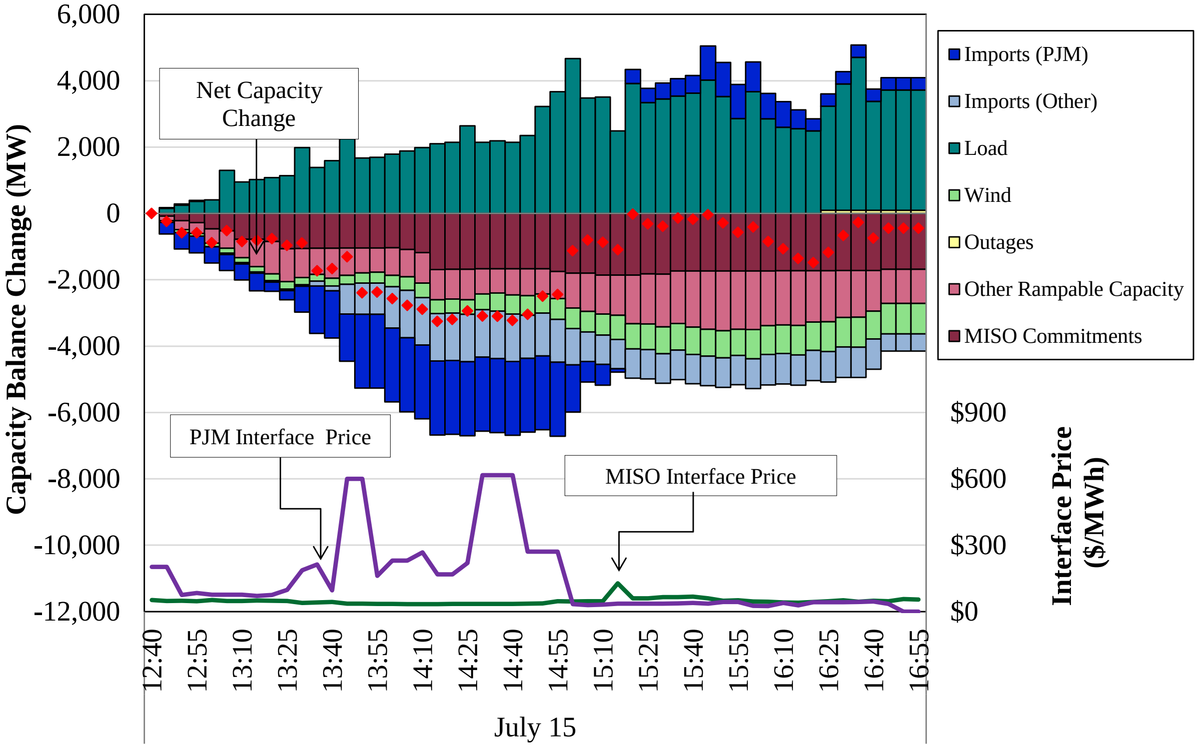


In addition to extremely high demand for electricity, other factors leading to price volatility on MISO's system and adjacent systems include changes in net scheduled interchange, generator and transmission outages and derates, fluctuations in wind generation and the timing of operator actions. To illustrate how these factors together contribute to volatility in the MISO market and adjacent markets, Figure 5 shows the cumulative impact of real-time supply and demand factors that directly impacted capacity levels in MISO and energy prices beginning at noon on July 15.

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 Commitments" is capacity committed during the period. The "Other Rampable Capacity" is additional capacity that can be dispatched within five minutes that is made available on online units as they are ramping up. Net harmful capacity changes are shown in the red markers. All values are measured against their respective levels as of noon.

On this day, changes in NSI led to reserve shortages and high prices in PJM. This is the opposite of the events that occurred on several days in 2012, when large swings in NSI toward PJM precipitated shortages and high prices in MISO. The additional 2,200 MW of net imports from PJM after noon suppressed MISO prices to below $40 per MWh. In retrospect, the 1,600 MW of real-time capacity commitments by MISO were not needed to meet MISO's capacity needs. As a result, MISO's RSG payments to 64 separate units exceeded $150,000 per hour for much of the afternoon and totaled over $1.1 million for the day.

Figure 5: Contributing Factors to Capacity Levels and Energy Prices
July 15, 2013



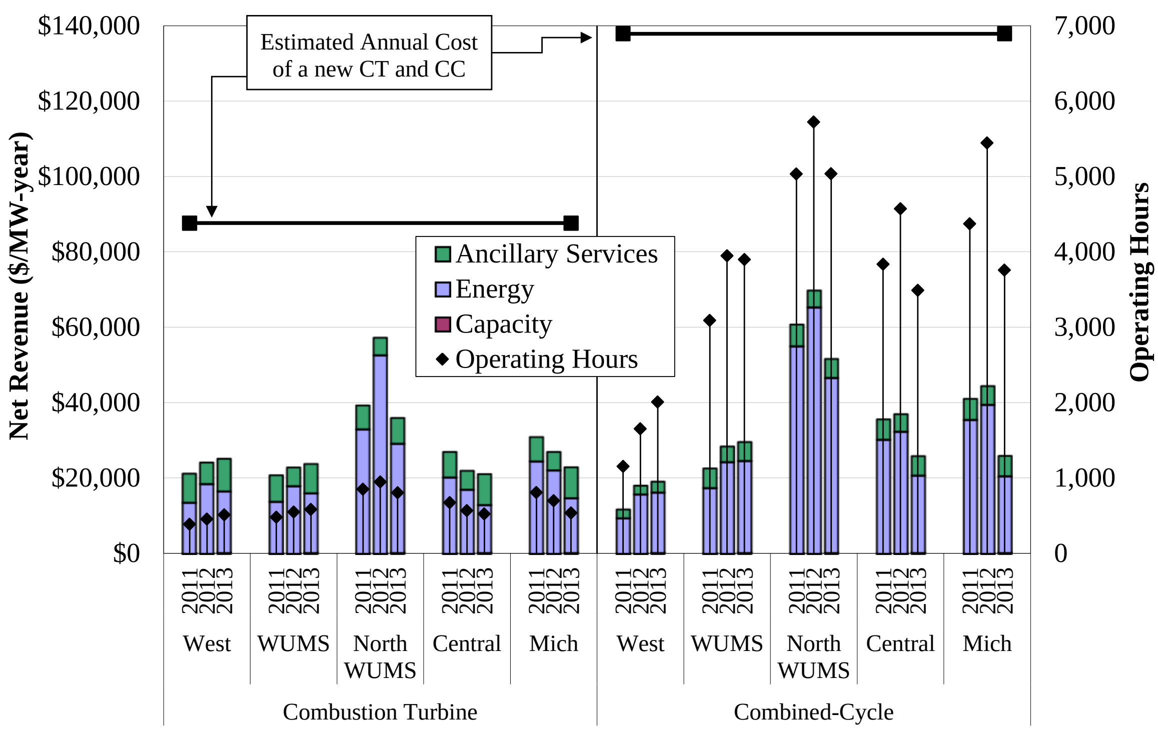
Current scheduling rules for interchange can lead to substantial market dysfunction under tight conditions, producing both substantial economic and reliability costs in MISO and neighboring markets. Later in the report, we show that nearly one-half of transactions from PJM in 2013 were scheduled in the unprofitable direction, and that many hours exhibited large price differences attributable to scheduling inefficiencies. Hence, we continue to recommend the RTOs make interchange optimization initiative a high priority. PJM supports this recommendation, but prefers to move toward implementation only after it has implemented similar processes with NYISO.

E. 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.

More precisely, 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., the "Cost of New Entry", or CONE).

Figure 6: Net Revenue Analysis
2011–2013



Estimated net revenues in 2013 for both types of units declined slightly from 2012 in most regions, and they continue to be 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 near-term capacity surplus.

Despite recent improvements made to the Resource Adequacy Construct, there remain capacity market design issues that will continue to undermine MISO's economic signals as this surplus dissipates. This may occur as soon as the 2015–2016 planning year, when increased retirements and capacity exports are projected to generate a capacity deficiency. The retirements are largely due to forthcoming environmental regulations that are surveyed to affect 57 GW of the 75 GW of coal-fired capacity in MISO. 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 as it relates to ensuring the adequacy of MISO's resources.

III. Resource Adequacy

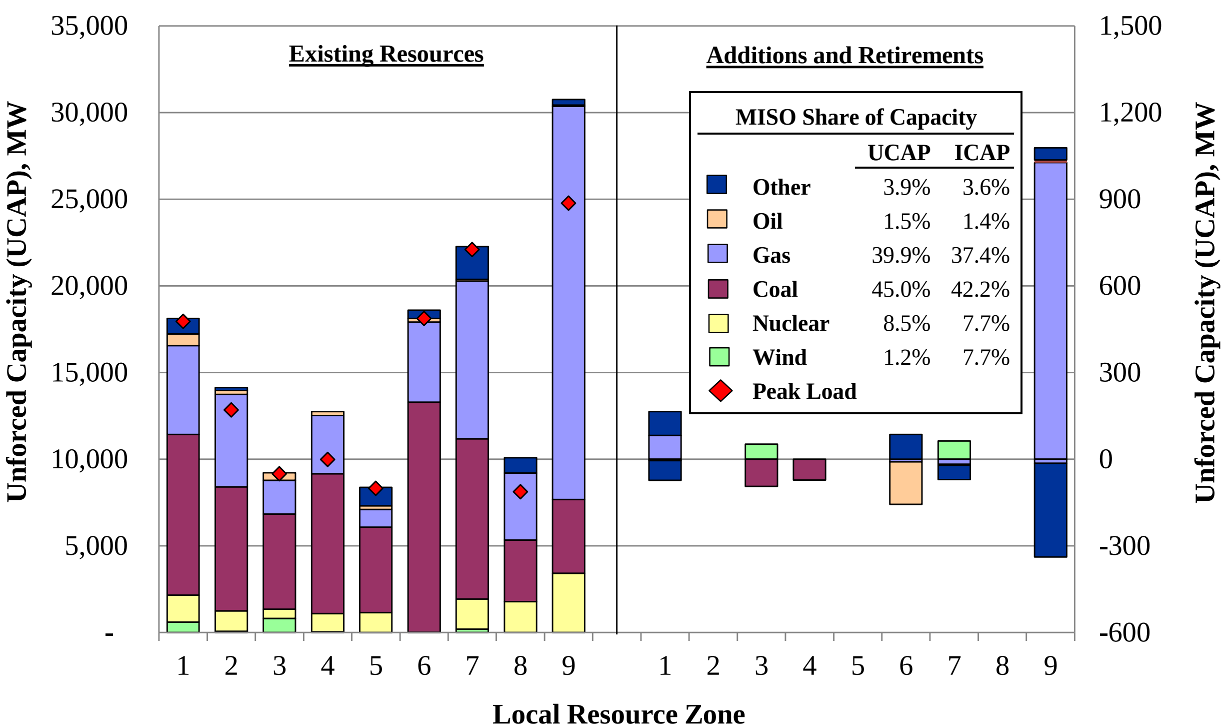
This section evaluates the supply in MISO, including:

- Summarizing the current resources and recent changes;
- Evaluating the adequacy of resources for meeting peak needs in 2014;
- Discussing future issues that may adversely affect supply; and
- Reviewing the outcomes and design of resource adequacy provisions.

A. Regional Generating Capacity

Figure 7 shows the summer 2014 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 2014 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 and ICAP quantities by fuel type. UCAP values are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. Hence, wind capacity, although it makes up nearly 8 percent of nameplate capacity, does not feature prominently in this figure.

Figure 7: Distribution of Generating Capacity
By Fuel Type and Zone, Summer 2014



Unforced capacity exceeds the 2014 forecasted peak load in all zones, although the margin was less than 3 percent in five of the nine zones. Because the average output from wind units in the West region is often greater than their UCAP credit, 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 natural gas prices, MISO continues to depend heavily on coal-fired generation, which accounts for nearly one-half of MISO's generating capacity. MISO is less reliant on coal resources than in prior years because the additional capacity in the newly-integrated South Region (zones 8 and 9) is predominantly natural gas-fired. As discussed later in this section, MISO expects large quantities of capacity to retire in response to environmental rules, and is forecasting a capacity shortfall as soon as 2016. MISO expects approximately 2 GW of coal retirements by this summer (nearly all of which have already occurred), although several hundred MW are expected to be suspended and not expected to return to service prior to retirement.

The most significant capacity additions are several natural gas-fired units in zone 9 that total over 1 GW. Several other capacity additions expected by summer 2014 are wind units, the majority of which are in western areas or in the "thumb" of Michigan, where wind profiles are 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 2014. In its *2014 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.

Over the past several years, we have commented on some of MISO's assumptions and worked with MISO to reconcile differences in these assumptions. In a limited number of areas, we continue to have concerns regarding factors that could cause MISO to be short of capacity. Therefore, we include some assumptions that differ from MISO's that lead to different estimated planning reserve margins. Table 2 shows four cases that show variations in key assumptions and illustrate the effects of these changes on MISO's planning reserve margin.

Table 2: Capacity, Load, and Planning Reserve Margins
Summer 2014

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

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

The results in Table 2 are shown separately for the MISO Midwest and South regions. The first column in the table shows the MISO base case, which we believe reasonably reflects expected planning reserves, but with one exception. MISO's base case includes an assumption that MISO will receive full response from its Demand Response (DR) resources (interruptible load and controllable load management) when they are deployed. These resources are not subject to comparable testing procedures as other generating resources, and are granted a 100 percent capacity credit. MISO has rarely deployed these resources, but its limited experience suggests response rate of little more than 50 percent. We recommend that MISO explore reasonable means to derate this capacity under Module E. The "Realistic DR" case in the table reflects the derating of the DR capacity by 50 percent but is otherwise identical to the base case.

The final two columns show the "Full DR" and "Realistic DR" 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 outlet water temperature or other environmental restrictions cause certain resources to be derated. 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 2013. In its Summer Assessment, MISO shows a high-load scenario that includes an estimate of high temperature derates based on the worst year in the past 5 years. While we believe this scenario is a realistic forecast of potential high load conditions, we continue to believe a more realistic assumption of derates that may occur under high-temperature conditions is needed.

The results in the table show that the capacity surplus varies considerably depending on the various assumptions made. The planning reserve margin in the South Region is substantially higher than the planning reserve requirement under all scenarios, but this is not true for the Midwest Region. The baseline capacity margin for the MISO Midwest region is 19.8 percent, which substantially exceeds the Planning Reserve Margin Requirement of 14.8 percent.[6] However, employing a more realistic assumption regarding the response of DR resources reduces the apparent surplus by 2.4 percentage points, but continues to indicate that MISO will be adequate this summer under normal summer conditions.

The high-temperature cases show much lower margins—as low as 6.8 percent when DR is also derated to a realistic level. 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 a combination of non-firm imports and emergency actions.

Overall, these results indicate that the system's resources should be adequate for summer 2014 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. 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 most recent surveys suggest that 8 to10 GW of capacity in MISO is at risk of retirement because of the compliance costs of these regulations. CSAPR was reinstated in April 2014, and MISO 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 of retiring if low natural gas prices continue for the long term. MISO surveys of market participants' compliance plans also indicate

6 The 2014 Planning Reserve Margin Requirement is for all of MISO. Due to the potential transfer limits from South to Midwest and Midwest to South, we have included the firm contract path limit of 1,000 MW in all scenarios. MISO has similarly included this in its Base Case.

substantial amounts of potential retirements and long-term outages related to environmental retrofits.

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. Based on its most recent survey of its participants, most of the affected coal units are planning on implementing the controls required to operate. MISO expects 8.1 GW of the 57 GW of coal-fired units affected by the regulations to retire or suspend, and there are an additional 3.1 GW whose retirement is uncertain. These retirements, together with the increase in capacity exports to PJM, are causing MISO to forecast a capacity deficiency in 2016. The shortcomings in MISO's current RAC will prevent it from performing the key role of providing efficient incentives to resolve this capacity deficiency and supporting reliable planning reserve margins over the long term. Hence, addressing these shortcomings continues to be a high-priority recommendation.

D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO 26 weeks in advance of its desired 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. An SSR cannot retire or be suspended 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.

In 2013, SSR credits net of market revenues (the portion uplifted to nearby load zones) totaled over $6 million and were paid to 6 units. There are currently 12 units classified as SSR and eligible for up to $6.1 million in gross cost recovery per month. An additional 10 units are under consideration for SSR status by MISO. We will continue to work 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.

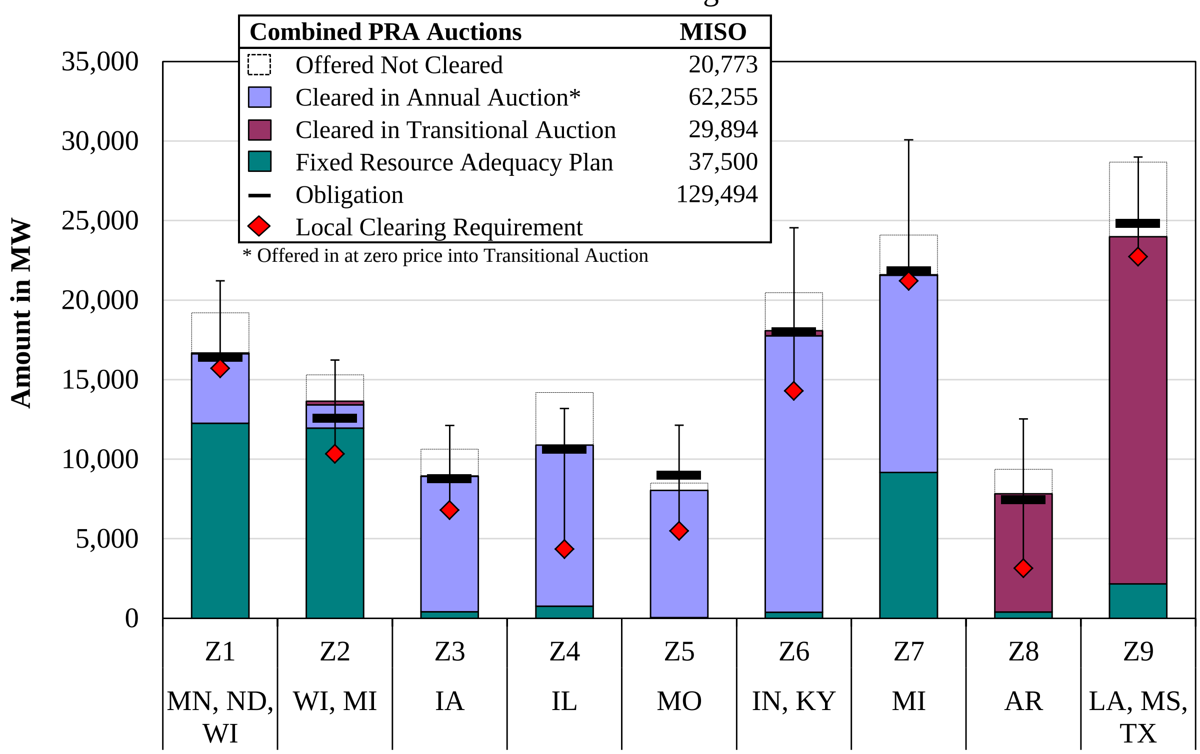
E. Capacity Market

MISO's Resource Adequacy Construct allows LSEs to procure capacity to meet their Module E requirements. Clearing prices in MISO's capacity auctions provide a revenue stream that, in addition to energy and AS market revenues, should signal when and where new resources are needed. In 2013, MISO replaced the monthly VCA with the annual PRA that better reflects regional capacity needs and can cause capacity prices in different zones to diverge when maximum import or exports levels for a zone are reached. This should provide a more accurate signal regarding the value of capacity in various locations.

1. Capacity Market Outcomes

Figure 8 shows the combined outcome of the two PRA auctions held in 2013. A transitional auction was held in November to accommodate the new MISO South Region, with quantities cleared in the April auction offered in at a zero price.

Figure 8: Planning Resource Auctions
2013 – 2014 Planning Year



The figure shows the obligation in each zone, along with the minimum and maximum amount of capacity that can be purchased in each zone. The minimum amount is equal to the obligation minus the maximum level of capacity imports. The auction for the 2013–2014 planning year cleared at $1.05 per MW-day (less than 1 percent of CONE), while the transitional November auction cleared at zero.[7]

2. Capacity Market Design

The performance of the capacity market under the new RAC is undermined by three significant issues: (1) the current "vertical demand curve"; (2) barriers to capacity trading with PJM; and (3) barriers to participation in the auction affecting units with suspension or retirement plans impacting the planning year. 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.[8] 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

7 The most recent PRA, held in March 2014 for the 2014–2015 planning year, cleared at $16.75 per MW-day in all zones except the export-constrained Zones 8 and 9, which cleared at $16.44 per MW-day, and Zone 1, which cleared at $3.29 per MW-day.

8 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.

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 as soon as the 2015–2016 planning year.

Load-serving entities and their ratepayers should benefit from a sloped demand curve. LSEs in the Midwest have generally planned and built resources to achieve a small surplus on average over the minimum requirement because:

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

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

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

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

Table 3: Costs for a Regulated LSE Under Alternative Capacity Demand Curves

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

These results illustrate three important dynamics associated with the sloped demand curve:

1.) *The sloped demand curve does not raise the expected costs for most regulated LSEs*. In this example, if an LSE fluctuates between 1 and 2 percent surplus (around the 1.5 percent market surplus), its costs will be virtually the same under the sloped and vertical demand curves.

2.) *The sloped demand curve reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE are surplus levels between 1 and 4 percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.

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

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

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 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 number of prior filings to FERC, including comments filed in a recent technical conference FERC held to address capacity market issues in the Northeast, and two sets of comments filed in response to PJM's proposal to introduce Capacity Import Limits (CILs) that would further restrict the ability of external suppliers to export capacity to PJM. We believe the CILs could be a long-term solution to this issue if they are set at reasonable levels and if they replace (rather than supplement) the other barriers to efficient capacity trading. We continue to recommend that MISO work with PJM to address these barriers.

The third issue with MISO's current capacity market relates to the Attachment Y process for suspending or retiring resources. The current market includes inefficient barriers to participation in the PRA for units in suspension or those that have filed under Attachment Y to suspend or retire a resource. These barriers include:

- Suspended units are disqualified from the PRA; and
- Resources that have submitted Attachment Y filings with effective dates during the planning year lose their interconnection rights and cannot satisfy their capacity obligations after the effective date.

In both cases, the PRA should be a process that assists suppliers in making efficient decisions regarding its resource, including whether to bring it back from suspension or to retire or suspend the unit. In order to do this, MISO would need to modify the PRA rules to allow:

- Suspended units to participate in the PRA and to defer the required testing to establish the resource's capacity value in the same manner that new resources or units with catastrophic outages can defer such testing.
- Units with Attachment Y requests to participate in the PRA and, if they clear, to either a) defer the effective date of the retirement or suspension, or to b) retire or suspend the unit during planning year if MISO determines it is not needed during the period when it would be unavailable. Without this flexibility, such units would have to arrange for

substitute capacity for the balance of the planning year and would be out of compliance with the Tariff if they are unable to do so. This risk is an inefficient barrier to participating in the PRA.

These changes to the RAC and the Attachment Y processes will allow MISO's capacity market to operate more efficiently and facilitate better decisions by market participants. The latter change to allow units to be unavailable for a portion of the planning year is consistent with the precedence for several other types of capacity resources that are only available during the summer season, including units that are not winterized, units that operate with PPAs that are considered "Diversity Contracts", and load-modifying resources.

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 cleared in the day-ahead receive commitment and scheduling instructions based on the day-ahead results.[9] Both the day-ahead and real-time markets continued to perform competitively in 2013.

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

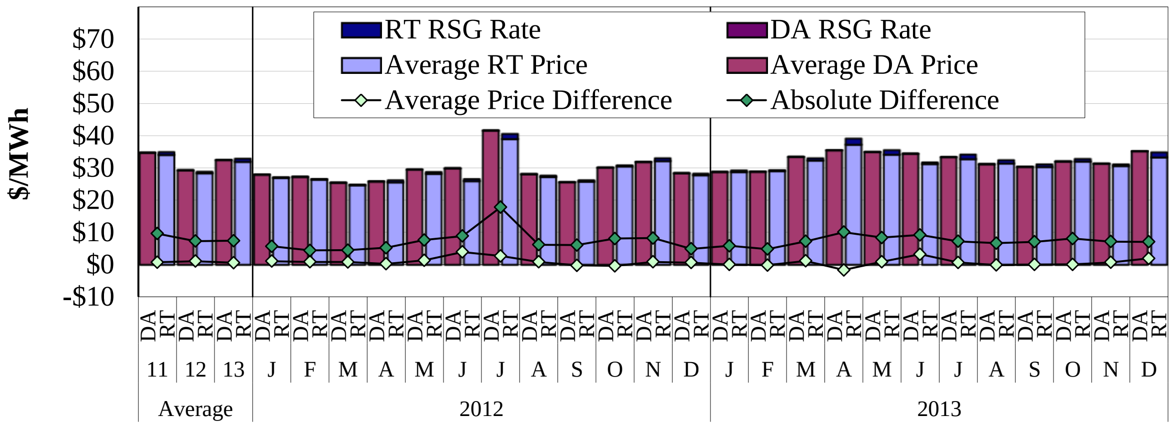
Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations 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 the Indiana Hub (or Cinergy Hub prior to April 2013), while the table below shows other

9 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.

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.

Figure 9: Day-Ahead and Real-Time Prices

2012–2013



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

Cin/Indi Hub	2	4	2	4	3	3	1	5	15	7	3	-1	-1	3	2	0	-1	3	-5	2	10	2	0	0	0	2	6
Michigan Hub	2	4	2	5	2	-1	5	5	7	7	3	4	1	3	1	1	2	5	-5	1	7	-1	0	-2	0	5	7
Minnesota Hub	-2	-2	-1	3	-2	2	-12	-6	0	2	2	-7	3	-8	-1	3	4	4	-7	7	2	-2	-5	-1	-3	-9	-2
WUMS Area	3	1	2	3	0	4	0	-1	-1	2	3	-4	0	0	3	1	4	4	-5	1	6	2	-4	3	1	7	3

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

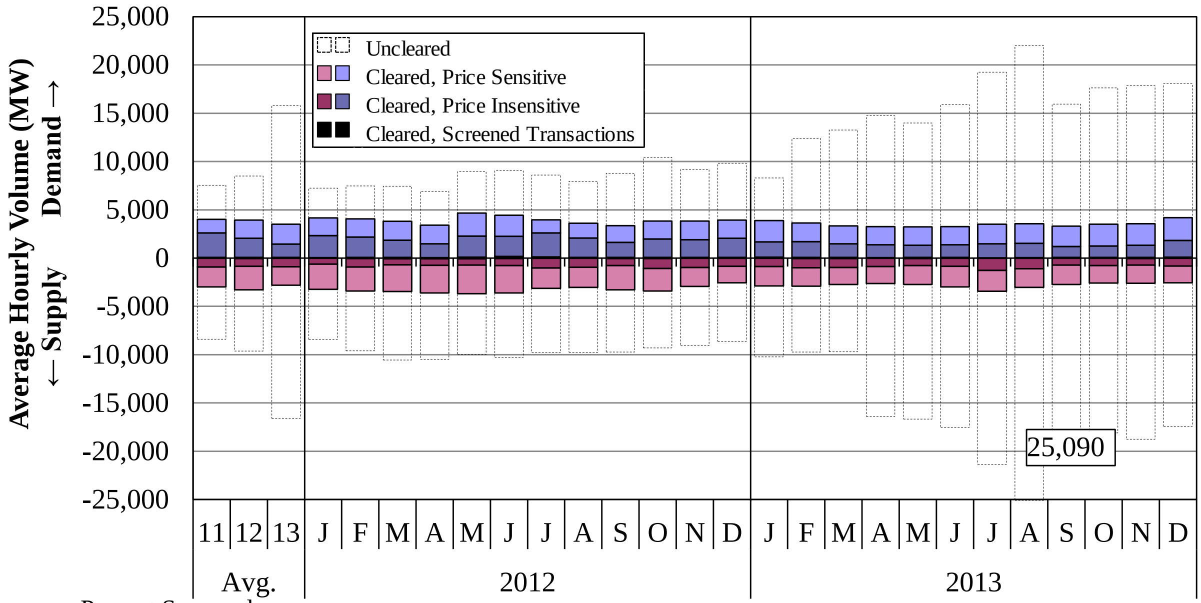
Cin/Indi Hub	-1	2	-1	3	2	2	-2	3	12	3	1	-2	-2	0	1	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1
Michigan Hub	-1	2	-1	4	2	-2	2	3	5	4	2	3	0	1	-1	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3
Minnesota Hub	-5	-4	-4	2	-2	1	-14	-8	-3	-2	1	-8	2	-10	-2	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6
WUMS Area	0	-1	-1	2	-1	3	-3	-3	-3	-2	1	-6	-1	-3	1	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1

There were modest day-ahead premiums at most hubs in 2013, including a premium of 1.7 percent at the Indiana Hub. This outcome is expected given the real-time RSG allocated to net real-time purchases and the lower volatility of prices in the day-ahead market. Accounting for the $1.00 per MWh in average RSG cost allocated to real-time deviations from day-ahead purchases (nearly double the level from 2012), the effective average day-ahead premiums disappear. In late spring, operating reserve shortages that were not anticipated in the day-ahead led to substantial real-time premiums. 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. We discuss RSG costs in greater detail in Section V.C.1.

B. Virtual Transactions in the Day-Ahead Market

Virtual transactions are financial 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 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 in the day-ahead market in 2012 and 2013. 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
2011–2013



Percent Screened

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

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 (demand willing to buy much higher than) and below (supply willing to sell much lower than) an "expected" real-time price.[10] 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 79 percent from last year to 32.3 GW. Much of this increase is in volumes by a handful of participants well above (in the case of demand) or below (supply) the expected price range, so they very rarely clear. Such "backstop" bids and offers clear less than one percent of the time, but are substantially profitable when they clear. These transactions are beneficial to the market because they mitigate particularly large day-ahead price deviations. In all, cleared transactions declined by 12 percent, the large majority of which continue to clear at generator locations.

The price-sensitivity of cleared transactions improved modestly in 2013. Nearly two-thirds of all cleared transactions were price-sensitive, up from 60 percent in 2012 and 50 percent in 2011. Price-insensitive 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.[11]

Figure 11 examines more closely these insensitive virtual transactions. "Matched" virtual transactions 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 over two-thirds of insensitive transactions and 21 percent of all virtual transactions were "matched" transactions.

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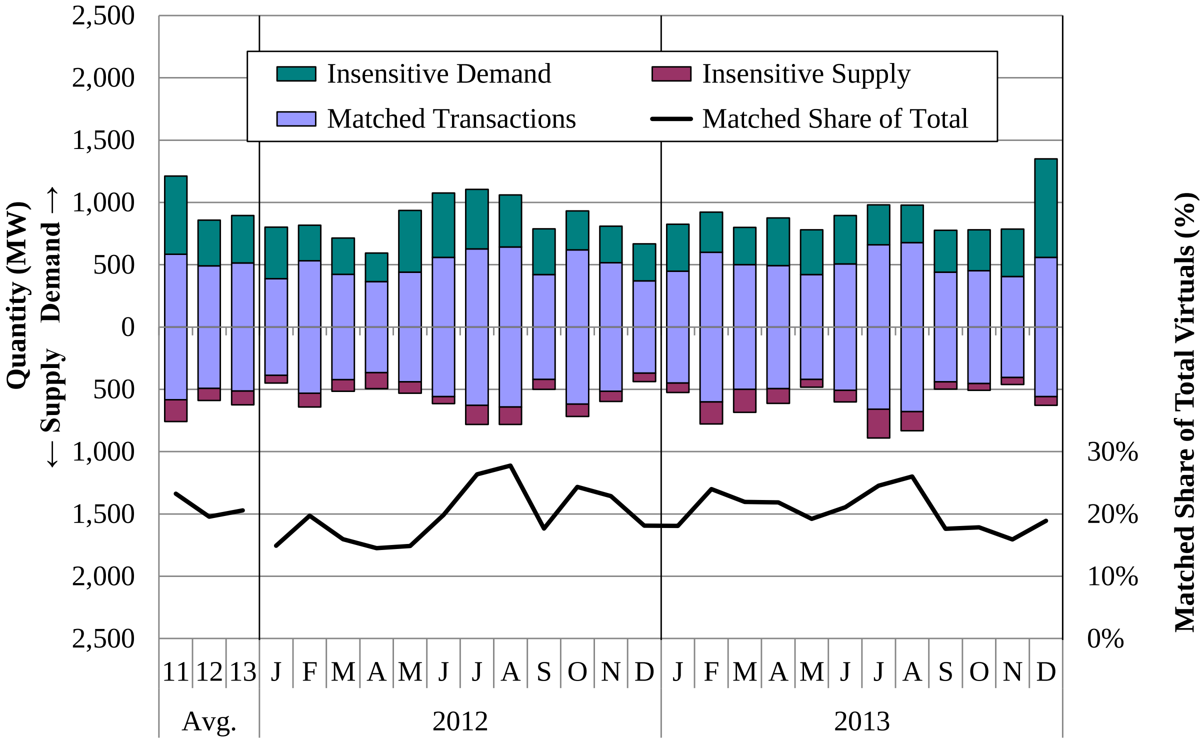
10 The "expected" real-time price is based on an average of recent real-time prices in comparable hours.

11 MISO in April 2011 revised its RSG cost allocation measures that generally will reduce the allocation to virtual supply, and eliminate any allocation when virtual supply is netted against a participant's virtual load. 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.

Figure 11: Matched Virtual Transactions
2012–2013



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 continue to engage in stakeholder discussions to 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 (i.e., 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. Comparable products exist in both PJM and ERCOT.

C. Virtual Profitability

The rate of gross virtual profitability in 2013 nearly doubled from 2012 to $1.01 per MWh. Demand was unusually profitable compared to prior years, consistent with the increase in periods exhibiting real-time premiums in 2013. Virtual supply profits averaged $1.30 per MWh, nearly unchanged from 2012. However, the real-time RSG costs allocated to net virtual supply under the DDC rate averaged $1.00 per MWh in 2013, which offset most of the net profitability of virtual supply transactions. Low virtual profitability is consistent with a competitive day-ahead market, which means the market efficiently schedules MISO's generating resources.

Transactions by financial-only participants in 2013 continued to be 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. Profitability of transactions cleared by physical participants in 2013 was positive for the first time since 2010 because they expressed a lower willingness to incur losses on virtual demand than in prior years.

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) do not track the changes in real-time load well.

Many participants in the real-time market attempt to match their day-ahead schedules, which can cause severe ramp demands at the top of the hour that can contribute to transitory operating reserve shortages and inflated production costs during these periods. 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 MISO 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

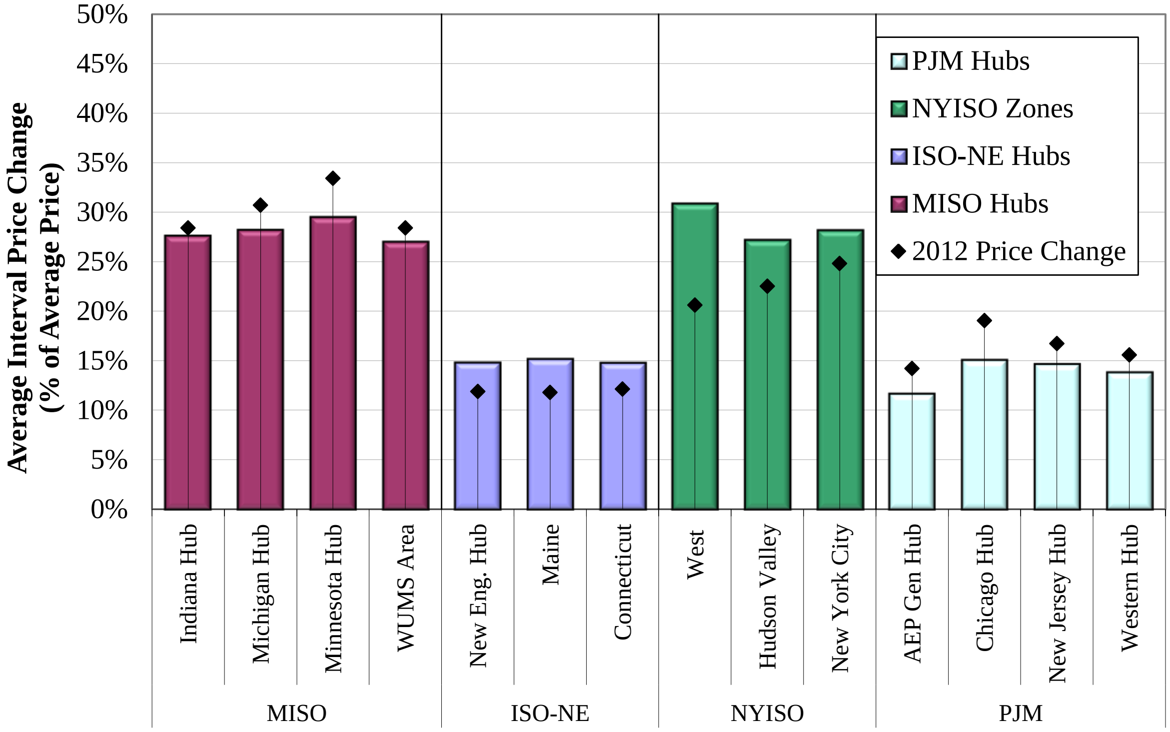
A. Real-Time Price Volatility

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. Volatility in MISO rose to $5.71 per interval, which is 10 percent higher than in 2012. This increase is largely due to the higher fuel prices in 2013; volatility after accounting for the fuel price changes was slightly lower in 2013 than 2012. However, price volatility in MISO remains considerably higher than in neighboring RTOs primarily because MISO runs a true five-minute real-time market (producing a new real-time dispatch every five minutes). PJM and New Enlgand ISO dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility (which lowers volatility). However, by producing new dispatch instructions less frequently, an RTO must rely more heavily regulation to balance supply and demand between intervals. NYISO dispatches the system every 5 minutes like MISO, but it has a look-ahead dispatch (LAD) system that optimizes multiple intervals. The multi-period optimization reduces price volatility.

Figure 12: Fifteen-Minute Real-Time Price Volatility
2013



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.

In recent years, MISO has improved the efficiency of real-time commitments with the introduction of the Look-Ahead Commitment (LAC) tool. MISO is currently developing a ramp capability product that will cause the real-time market to hold ramp capability when possible at a low cost that will improve its ability to manage the system's ramp demands. We believe this product will be beneficial and continue to recommend its adoption. It is currently scheduled for deployment in September, 2015. We also support MISO's decision to evaluate the incremental benefits of a LAD tool after deployment of the ramp product.

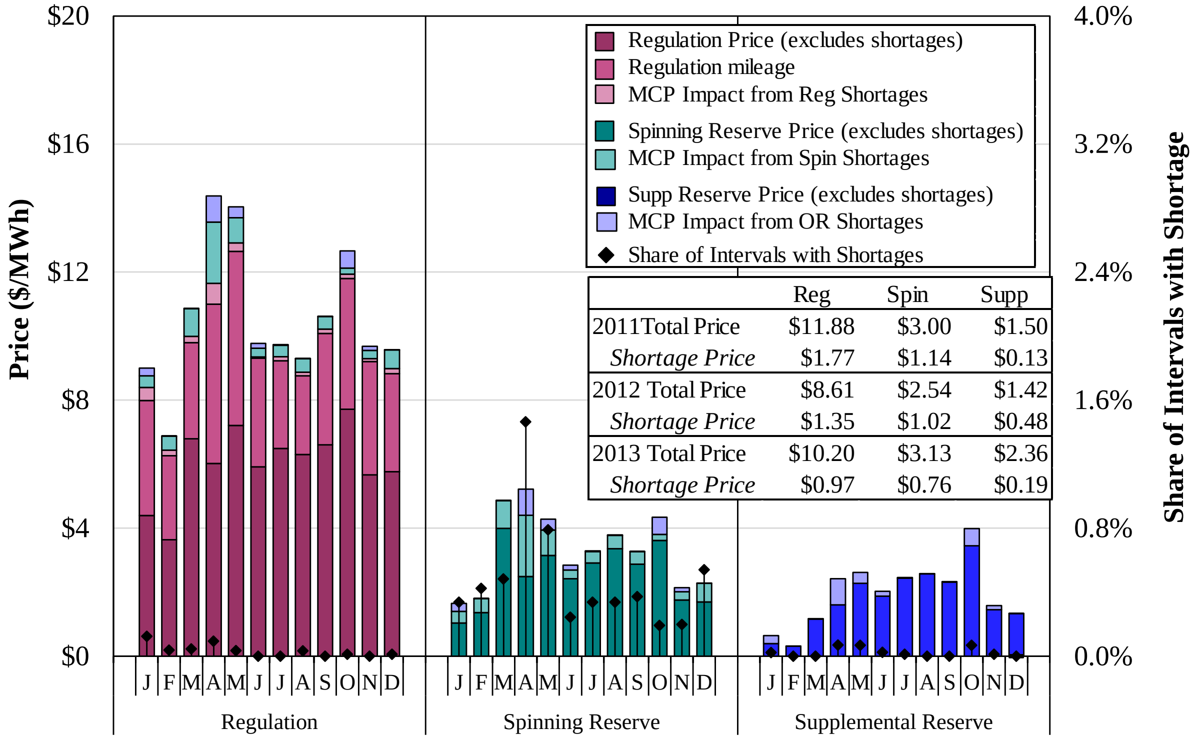
B. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2013. 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 in 2013. It also shows the share of intervals in shortage for each product. MISO uses demand curves to specify the value of all of its reserve products. When the market is short of one or more of its ancillary service products, the demand curve for that product(s) will set the price and be included in the prices of higher-valued reserves and energy. The demand curve penalty price for regulation in 2013 averaged $182 per MWh. The spinning reserve penalty price was unchanged at $65 per MWh (for shortage quantities of less than 10 percent of the reserve requirement) and $98 per MWh (for those in excess of 10 percent). MISO introduced a new Operating Reserve Demand Curve in May 2013 that prices the first four percent of an operating reserve shortage at $200 per MWh. More significant shortages are priced from $1,100 to $3,400 per MWh depending on their severity.

The supplemental reserve prices in this figure shows the price associated with satisfying MISO's market-wide operating reserve requirement. This is the only requirement that supplemental reserves can satisfy. Because a spinning reserve resource can satisfy both the operating reserve requirement and the spinning reserve requirement, the spinning reserve price will include a component associated with operating reserve shortages. In other words, shortages of operating reserves will be included in the price of supplemental reserves and all higher-value products, including energy. Likewise, the higher-value regulation product includes components associated with spinning and operating reserve shortages.

Figure 13: ASM Prices and Shortage Frequency
2013



Monthly average clearing prices for all products rose in 2013 because the opportunity costs of providing ancillary services increased with as energy prices increased:

- Regulating reserve prices rose 19 percent to $10.20 per MWh in 2013;
- Spinning reserve prices rose 23 percent in 2013 to an average of $3.13 per MWh; and
- Supplemental reserve prices rose 68 percent to $2.36 per MWh.

The impact of higher energy (and opportunity costs) was offset by the substantial reduction in shortages in 2013, particularly in the summer. Although reduced from 2012, shortage pricing was most significant in the spring. In April, 126 intervals of spinning reserve shortages and 6 intervals of operating reserve shortages were primarily due to factors that increased the ramp demands of the system. These are magnified in lower-load shoulder seasons because MISO often has fewer units online capable of providing ramp capability and may have fewer offline reserves due to increased planned outage levels. Shortage pricing in 2013 accounted for less than 10 percent of the average regulation and supplemental clearing prices, but nearly 25 percent of the average spinning reserve clearing price.

In late 2012, MISO introduced a new payment for "regulation mileage". The mileage payment pays resources for actual response during regulation deployments. The total regulating reserve clearing prices (payments for both Regulating Mileage and Regulating Capacity) in 2013 were not materially impacted by the new "regulation mileage" compensation formula. 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 after January.[12]

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 (e.g., 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 they were providing are shifted to online resources.

Unfortunately, MISO does not account for the committed resource as providing reserves or energy until the unit is fully synchronized and providing energy. Hence, all capacity from the resource will appear to be lost in the interim, 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 2013, lost reserve capability from committed quick-start resources affected a smaller number of intervals because MISO sought to avoid starting units that have been scheduled for offline reserves. The issue, however, caused four operating reserve shortages and contributed to at least five periods of operating reserve price spikes of at least $100 per MWh. This issue also increased DAMAP during the reserve shortage events by nearly $500,000. Therefore, we continue to 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.

12 The chart does not reflect the additional uplift costs associated with charging back the clearing price to resources for undeployed mileage based on actual energy withdrawals. These costs totaled $1.84 million in 2013.

C. 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).

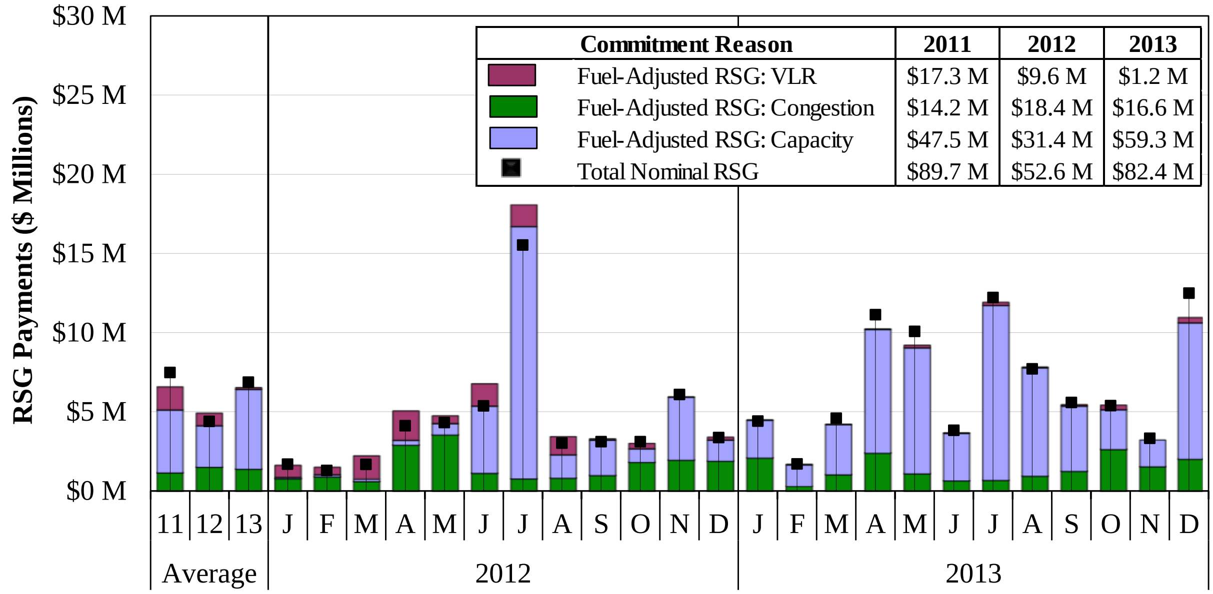
Resources committed by MISO for economic capacity or for congestion management after the day-ahead market receive a "real-time" RSG payment if their as-offered costs are not recovered through the LMP in the real-time market. The costs related to RSG payments are recovered via charges that are "uplifted" 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 monthly real-time RSG payments for the last two years. Real-time RSG payments tend to be higher than day-ahead RSG payments because the day-ahead market has greater liquidity provided by virtual transactions and greater generation flexibility. Since fuel prices have considerable influence over suppliers' production costs, the figure shows real-time RSG payments in both nominal and fuel-adjusted terms.[13] 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 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.

13 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.

Figure 14: Real-Time RSG Payments
2012–2013



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

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

Real-time nominal RSG costs rose 54 percent from 2012 to $81 million. Nearly one-half of this increase is due to the significant rise in fuel prices. After adjusting for the fuel price increase, payments rose 30 percent compared to last year. Capacity-related real-time RSG payments increased the most and accounted for three-quarters of all payments. Lower load-scheduling in the first half of 2013 (relative to the over-scheduling observed in the same period in 2012) resulted in MISO committing a larger number of units in real time, particularly in April. Payments for commitments to resolve congestion declined 10 percent to a fuel-adjusted $16.6 million. The largest payments were related to outages, notably in October when much of the $2.3 million in payments were made to expensive oil-fired units.

Payments to units committed for Voltage and Local Reliability (VLR) support, which used to be made primarily in real time, were mostly shifted to the day-ahead market in September 2012. Hence, real-time VLR payments declined to just $1.2 million.

Significant local market power can exist when MISO must commit resources to resolve transmission constraints. In late 2013 and early 2014, RSG payments associated with increases in suppliers' offer prices have increased substantially, which raise concerns regarding the effectiveness of the current RSG mitigation measures. Based on our evaluation of these results, we are proposing to modify the current RSG mitigation measures to adopt a framework comparable to the framework applied to mitigate the RSG dollars paid to resources committed for VLR requirements. This proposal is presented in Section VIII.D.

2. Real-Time RSG Cost Allocation

In April 2011, MISO implemented a revised RSG cost allocation methodology to recognize that MISO commits resources to meet either system-wide capacity needs or to manage congestion or local voltage needs. It subsequently modified the allocation in September 2012 to more directly allocate the costs of satisfying local voltage needs to local areas.

The remaining capacity and congestion-related RSG costs are allocated based on 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". In the 2012 *State of the Market Report*, we evaluated the allocation of real-time RSG and concluded that the costs were not being allocated to the actions that were causing the RSG payments. Because this allocation continued in 2013, the results were comparable to 2012.

Real-time RSG charges totaled $81.1 million in 2013, over 91 percent of which was allocated to deviations under the market-wide DDC rate even though market-wide deviations do not cause most of the real-time RSG payments. The excess level of costs allocated under the DDC rate occurred because:

- Helping deviations were not netted against harming deviations in determining the extent to which the deviations caused the RSG payments; and

- $15 million of RSG costs incurred to manage congestion were allocated under the DDC rate.

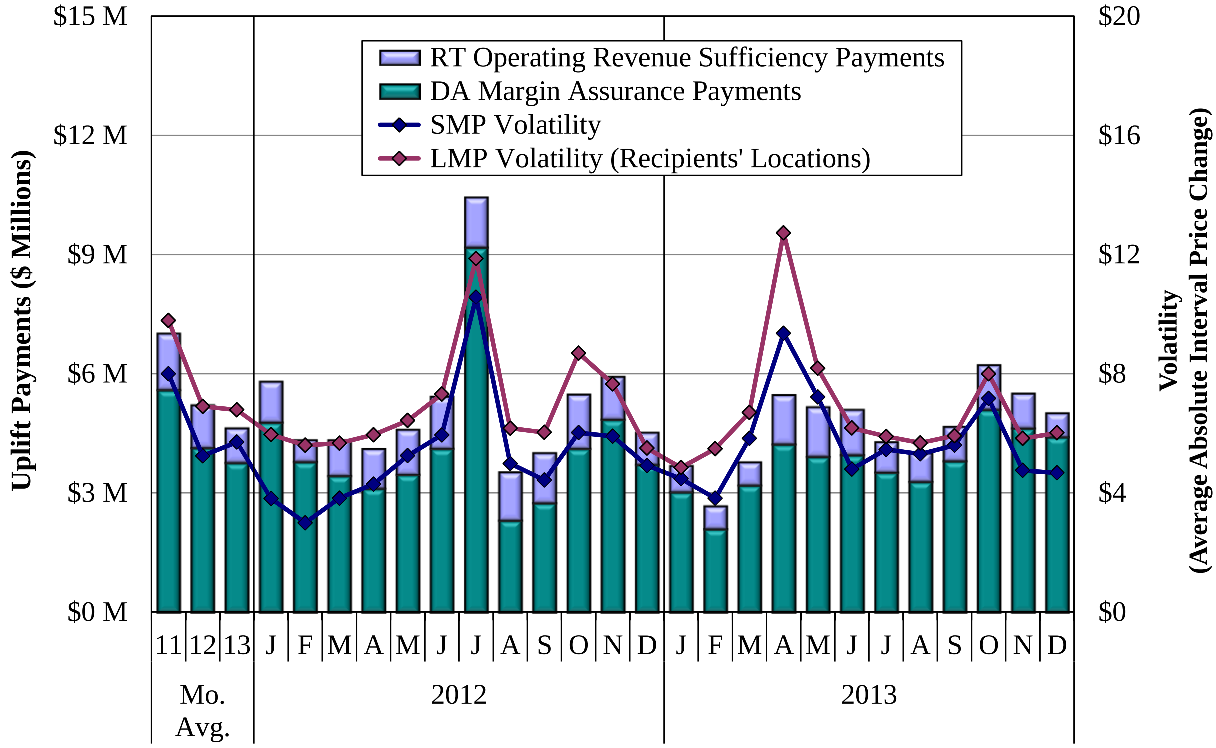
We proposed a series of changes to address these issues and MISO filed the changes in 2013. FERC approved most of these changes and they were implemented in March 2014, although FERC reject one proposed change because it found that MISO’s evidentiary support was insufficient. This proposed change involves allocating real-time RSG costs to helping deviations that occur after the notification deadline (NDL). These deviations do not directly cause real-time RSG, but in fact likely reduce real-time RSG by reducing the commitments made by LAC (which runs after the NDL) and the MISO operators. Including these deviations reduces the rate that should be allocated to the deviations that do cause RSG and, in doing so, undermines the economic incentive that should deter the conduct that causes RSG. MISO is planning on re-filing the proposed change in a future FERC filing with additional evidence and analysis for this proposal.

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 total of the two components of PVMWP declined 10 percent from 2012 to $55.5 million, of which over 80 percent was in the form of DAMAP. DAMAP payments are made when generators are dispatched below their day-ahead schedule and below the level that is economic given the hourly settlement price and their offer prices. Hence, when transitory volatility causes a unit to be dispatched downward and the supplier would be economically harmed based on the hourly average energy price, a DAMAP payment is made. Conversely, the RTORSGP is made when a unit is dispatched above the level that would be economic given the hourly energy price.

Figure 15: Price Volatility Make-Whole Payments
2012–2013



The figure shows that the PVMWPs are correlated with changes in volatility, particularly the volatility in LMP at the resources' locations. This volatility was highest in April due to significant spinning and operating reserve shortages, which resulted in the second highest level of payments in 2013. Payments continued to be paid predominantly to flexible coal units during ramping hours.

4. Unreported Derates

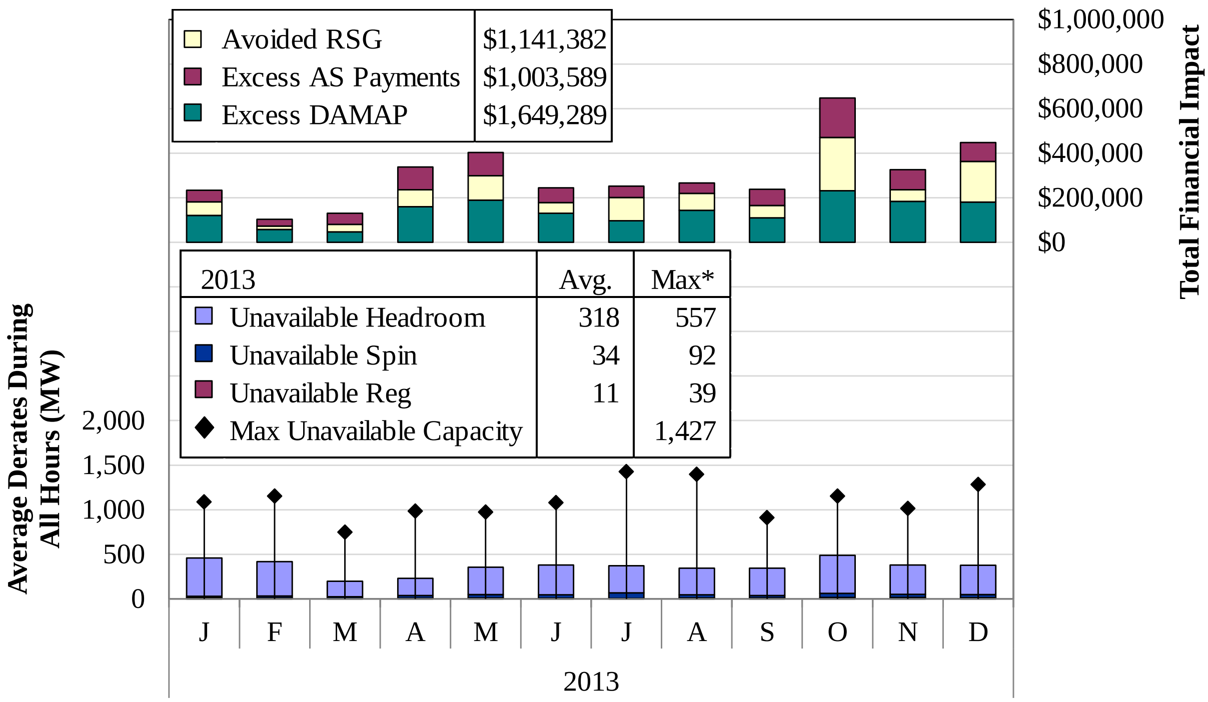
In the past two years, we have made a number of referrals to FERC regarding resources that were inappropriately paid DAMAP for energy sold day-ahead but unavailable in real time because the unit was unable to respond to setpoints. The resources remained eligible for payments in real time because they did not update their real-time offers to reflect the derated capacity. As discussed in our 2012 *State of the Market Report*, PVMWP eligiblity rules do not adequately identify when a unit is "dragging" or otherwise not following MISO's dispatch instructions. This causes:

- MISO to make PVMWPs to resources that are not providing the benefits for which the payments are intended;
- MISO to make payments for reserves that are not truly available;
- The supplier to avoid being allocated real-time RSG it would have been allocated if it derated its resource; and
- Potential reliability impacts because MISO's regional generation dispatch (RGD) procedures and tools are not designed to detect such unreported derates.

Figure 16 shows the monthly average quantity of unreported (or "inferred") derates. The bottom panel shows the average and maximum quantities of derates we identified, separated by capacity scheduled for regulation, spinning reserves, or simply providing headroom (latent reserves) in the energy market. The top panel shows 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 not updating their real-time offer parameters.

This figure shows that the quantities of inferred derates averaged 363 MW per hour in 2013, and exceeded MISO's headroom requirement (generally 750 MW) in approximately five percent of all intervals. Significant derates can substantially reduce MISO's ability to maintain reliability because these unreported derates can cause it to overestimate the amount of capacity it has available.

Figure 16: Unreported ("Inferred") Derates
Daily Peak Hours, 2013



* Daily Average Maximum

Including the effects of payments for reserves and PVMWPs, as well as avoided RSG charges, units with inferred derates in 2013 received more than $4 million in economic benefits while potentially undermining reliability. Because the failure to update a resource's real-time offers constitutes a violation of MISO's Tariff and a "market violation" as defined by FERC, we have made a number of referrals to FERC's Office of Enforcement regarding significant unreported deratings.

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. MISO staff furthermore do not have necessary tools to identify in real-time unreported derates that are the result of the failure to follow dispatch over multiple intervals.

To address these concerns, we recommended several changes in last year's *State of the Market Report*, including improving screening for such derates and tightening the tolerances for uninstructed generator deviations. MISO has begun implementing several new operating procedures, the first of which is expected to be implemented in the second quarter of 2014. While these procedures are not final, we still have concerns that the new tools may not detect signficant unreported derates.

In this report, we recommend a new standard for identifying uninstructed deviations that could be used in the settlement of excess and deficient energy, as well as in the eligibility rules for the PVMWPs.[14] MISO has also filed revised eligibility rules in October 2013 that we had previously recommended to eliminate gaming opportunities related to PVMWP. FERC accepted these proposals and they have been implemented by MISO.

5. Five-Minute Settlement

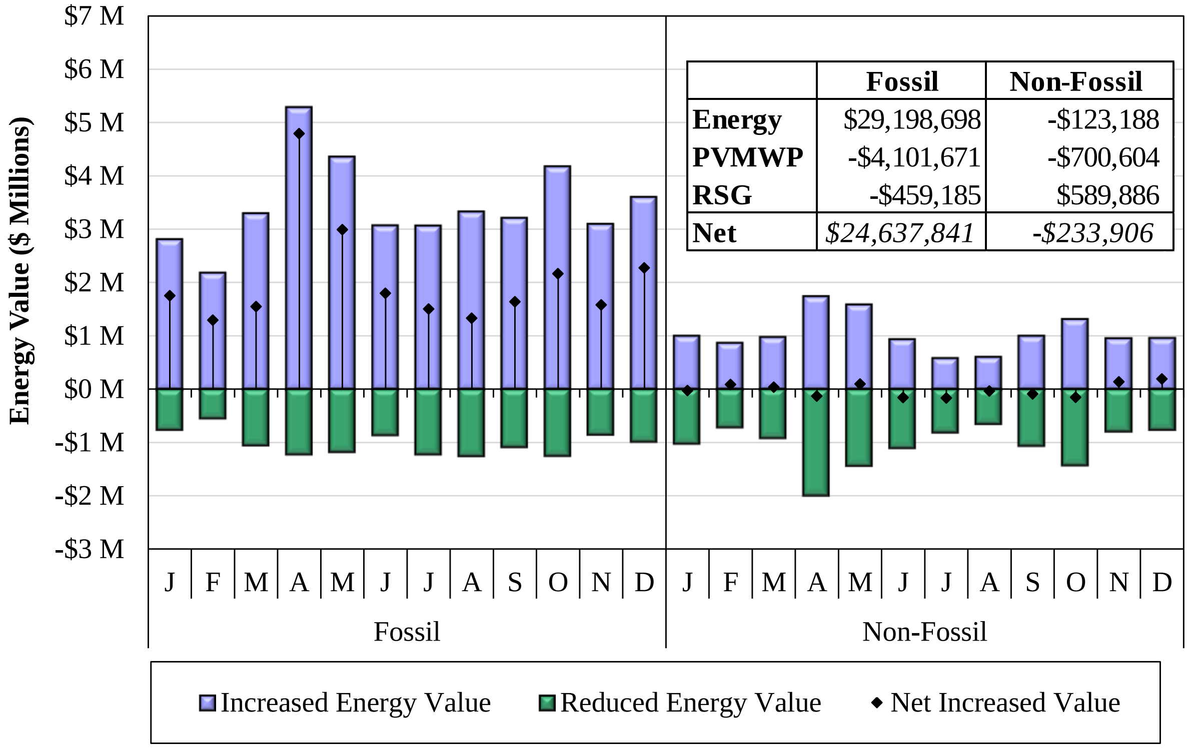
MISO produces new dispatch signals and prices every five minutes, but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signal and the hourly prices that can create incentives for generators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

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 fuel-fired and non-fossil fuel-fired resources.

14 An evaluation of generator deviations and the description of the new proposed standard can be found in Subsection 6 below.

Figure 17: Net Energy Value of Five-Minute Settlements
2013



Fossil fuel-fired resources in 2013 produced $24.6 million more in actual energy value than was reflected in their settlement revenues. The increased energy value was consistent across the year, peaking at over $5 million in April when units were responding to price spikes produced by shortages. Approximately 14 percent of this lost value was paid to resources in the form of PVMWP. Combustion turbines were particularly affected, losing $3.5 million or $0.42 per MWh. Non-fossil fuel-fired resources were paid nearly the same in hourly energy revenues as their actual five-minute energy value. This is a marked change from 2012 when such resources were paid nearly $5 million in excess of their value.

The fact that fossil fuel-fired units would receive more revenue and non-fossil ones would likely receive less is consistent with the fact that flexible, controllable resources are more valuable to the system and, therefore, would benefit from a more granular settlement. Fossil fuel-fired 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.[15]

These results show there are substantial discrepancies between the 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. Hence, our five-minute settlement recommendation will improve the incentives for generators to follow dispatch instructions, provide more flexibility, and provide incentives for participants to schedule imports and exports more efficiently. We continue to recommend MISO evaluate the feasibility of implementing a five-minute settlement. MISO is evaluating the feasibility of this change both in response to this recommendation and because it is one way to facilitate more accurate settlements with physical transactions and shorten scheduling timeframes as required by FERC's Order 764.

6. 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 when deviations remain outside an eight percent tolerance band for four or more consecutive intervals within an hour.[16] 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.

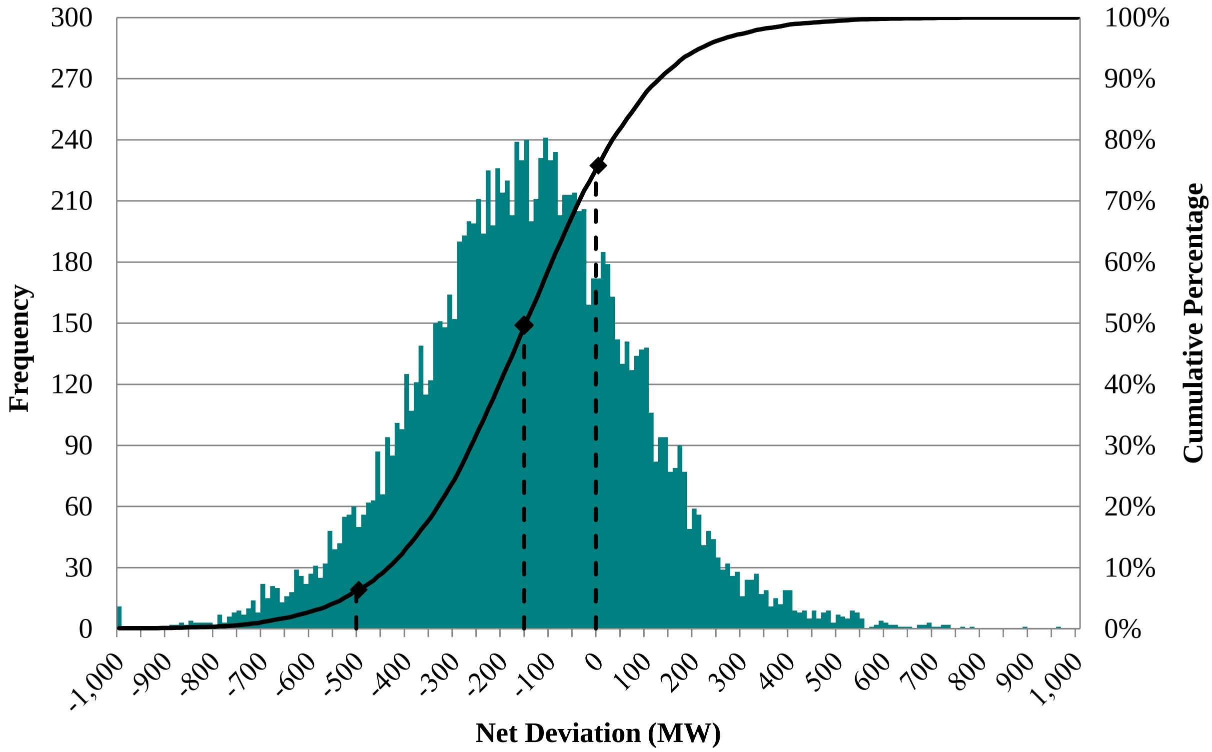
The average gross negative deviation in 2013 was 545 MW, while gross positive deviations averaged 502 MW. Two-thirds of these deviations occur when the system is ramping rapidly up

15 The contribution of RSG payments to non-fossil fuel-fired 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 payments since these units are often committed economically by MISO and thus eligible for production cost recovery.

16 See Tariff Section 40.3.4.a.i. The tolerance band can furthermore be no less than 6 MW and no greater than 30 MW. This minimum and maximum was unchanged for this analysis.

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 2013.

Figure 18: Frequency of Net Deviations
Peak Summer Hours, 2013



MISO was net deficient (generators collectively producing less than instructed) in over 75 percent of all peak summer intervals. The median deficiency was 151 MW and exceeded 500 MW in over six percent of the intervals (this share exceeded 15 percent during the top 10 load days). Significant net negative deviations can contribute to shortages because of limited availability of other resources to compensate for the negative deviations.

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 exempts the vast majority of deviation quantities from significant settlement penalties. 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. So 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.[17]

In our *2012 State of the Market Report,* we recommended that MISO tighten the tolerance bands for uninstructed deviations (Deficient and Excessive Energy). In this report, we recommend a specific approach for establishing the tolerance bands that would be more effective at identifying units that are not following dispatch. This approach is based on units' ramp rates, which has a number of advantages compared to the current output-based thresholds:

- The threshold will be the same regardless of the output level (ability to follow dispatch does not change as the output level increases);
- It will more readily identify units who are not responding to dispatch signals (resources that do not move, or move in opposition to the dispatch instruction will be identified);
- Making thresholds proportional to offered ramp rate will eliminate the current incentive to provide an understated ramp rate; and
- Output-based thresholds enable a resource to avoid being flagged for not following dispatch if it offers low ramp rates.[18]

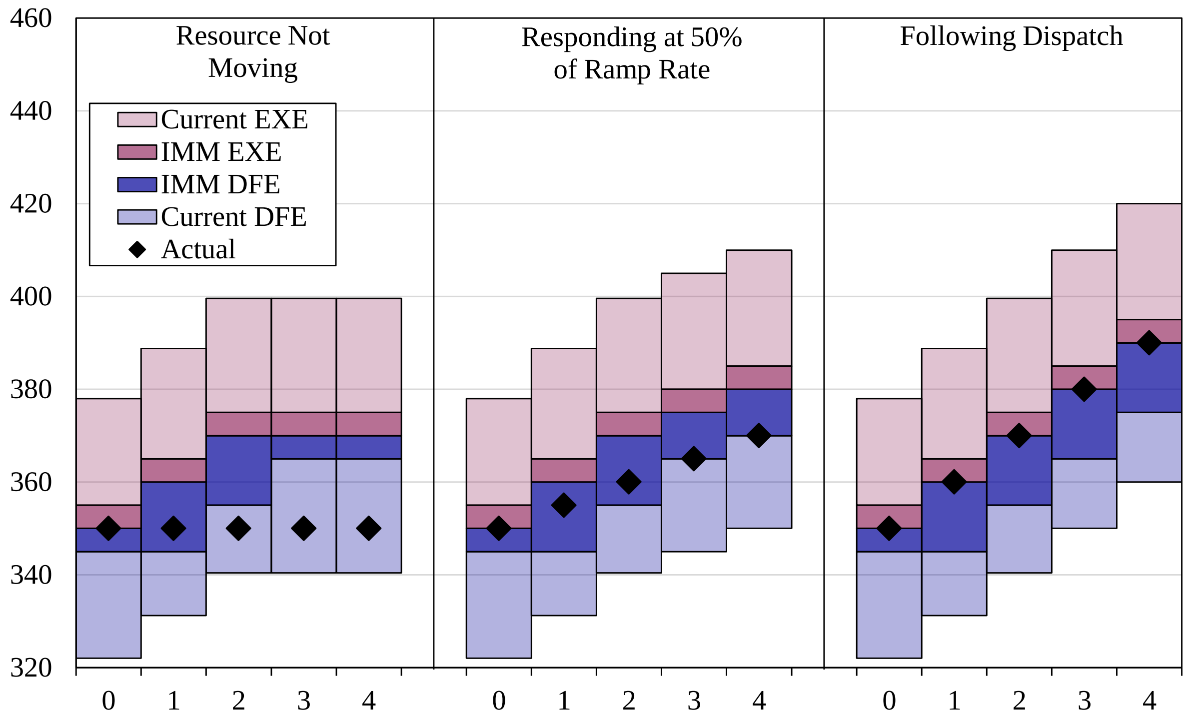
The threshold calculation we propose equals one-half of the resource's five-minute ramp capability plus a value that corresponds to the set point change for the direction in which the unit is moving (i.e., set point change included for deficient energy when the unit is moving up and for excess energy when the unit is moving down). This provides increased tolerance only in the ramping direction so units that are dragging slightly or responding with a lag will not violate the threshold. Additionally, since the current thresholds require that a unit fail in four consecutive intervals, the IMM proposed threshold would similarly require that a resource be unresponsive for four consecutive intervals before it would be considered to be deviating or not following dispatch.

17 This issue was discussed above in Section V.C.3.

18 The current minimum ramp rate for PVMWP eligibility is 0.5 MW per minute.

Figure 19 illustrates how these thresholds would be calculated and applied in three cases. Each of the cases assumes a unit that has been operating at 350 MW, has a 2 MW-per-minute ramp rate, and is receiving dispatch instructions to increase output at its ramp rate. In the first case, the unit is not moving. In the second and third cases, the unit is ramping up at 50 percent and 100 percent of the unit's ramp rate. The lighter areas are the existing thresholds while the darker areas are our proposed thresholds.

Figure 19: Proposed Generator Deviation Methodologies



This figure shows that when the resource is not moving, it will fail the IMM proposed threshold in the second interval if it is being instruction to increase its output as fast as its ramp rate allows. In contrast, this unit can be completely unresponsive in all four intervals and not exceed the current deficient energy threshold. This highlights a substantial concern with the current thresholds.

The figure also shows that if the unit moves in the direction of the dispatch instruction at 50 percent of its ramp rate, it will not fall outside our proposed tolerance band (it will be at the very bottom of the deficient energy range). Finally, when a unit is moving at its ramp rate (at the level of the dispatch instruction), it will have a wider deficient energy tolerance threshold because the unit is moving upward.

D. 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 declined 34 percent in 2013 to average 443 MW. Fewer periods of extreme heat reduced peaking resource needs by nearly 70 percent in July 2013 compared to July 2012. In addition, lower peak loads and higher natural-gas prices in 2013 made far fewer peaking resources economic in the day-ahead market. Since peaking resources frequently do not set energy prices in the real-time market, the share of peaking resources dispatched in economic merit order in 2013 was 49 percent.

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 committed peaking resources, real-time prices will be lower and will not reveal the natural incentive to schedule load fully in the day-ahead market—fully-scheduled load in the day-ahead market would allow lower-cost resources to be committed in place of the peaking resources.

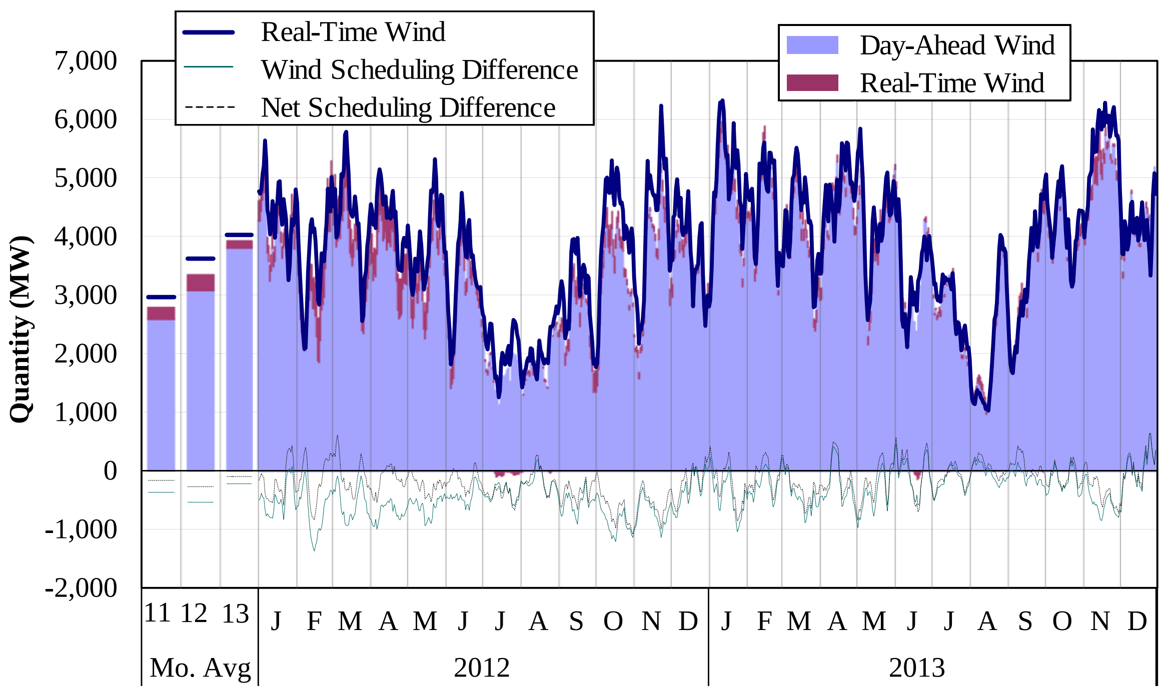
In addition, setting inefficiently-low real-time prices can encourage participants to import and export power inefficiently. MISO’s new “Extended LMP” pricing method, expected to be implemented October 2014, should allow peaking resources to set prices more often when they are needed to satisfy the system’s 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.

E. Wind Generation

Wind generation in MISO has grown steadily since the start of the markets in 2005 and exceeded 12 GW of installed capacity in 2013. 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 over 9.3 percent of installed capacity and 7.4 percent of generation in 2013.

Figure 20 shows a seven-day moving average of day-ahead scheduled wind and real-time wind output since 2012.

Figure 20: Day-Ahead and Real-Time Wind Generation
2012–2013



Real-time wind generation in MISO increased 11 percent in 2013 to an average of 4,028 MW per hour. The figure also shows that wind output is substantially lower during summer months than during shoulder months, particularly during the highest load hours. This reduces its value from a reliability perspective. Day-ahead scheduling increased in 2013. 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 shows virtual supply (net of virtual demand) at wind locations substantially offset the impact of under-scheduling by wind resources, making up more than one-half of the deficit.

Managing wind output is significantly aided by the adoption of the Dispatchable Intermittent Resource (DIR) type, which was first introduced in June 2011.[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 almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or to manage over-generation conditions. Economic curtailments in 2013 averaged 140 MW per interval and at times exceeded 1 GW, compared to just 8 MW of manual wind curtailments. Wind resources that are DIRs can set prices—they did so in nearly one-half of all intervals—at an average of -$11 per MWh. These low prices set by wind resources typical prevail in relatively small congested areas.

Finally, as total wind capacity continues to grow, the volatility of its output that must be managed by MISO also grows. Volatility of wind output, as measured by the absolute average interval change in output between intervals and excluding economic DIR curtailments, rose to 291 MW per hour and frequently exceeded 500 MW in the downward direction. Significant reductions in output, when they are not forecasted, can lead to substantial price volatility and can require MISO to make real-time commitments to replace the lost output. The DIR has been valuable in improving the control of wind resources and responding to these changes in output. 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.

19 As of the March 2014 commercial model, 118 out of 183 wind units (approximately 80 percent of capacity) are modeled as DIR. Most other wind resources are exempt from the DIR requirement.

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 in order to avoid overloading 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.

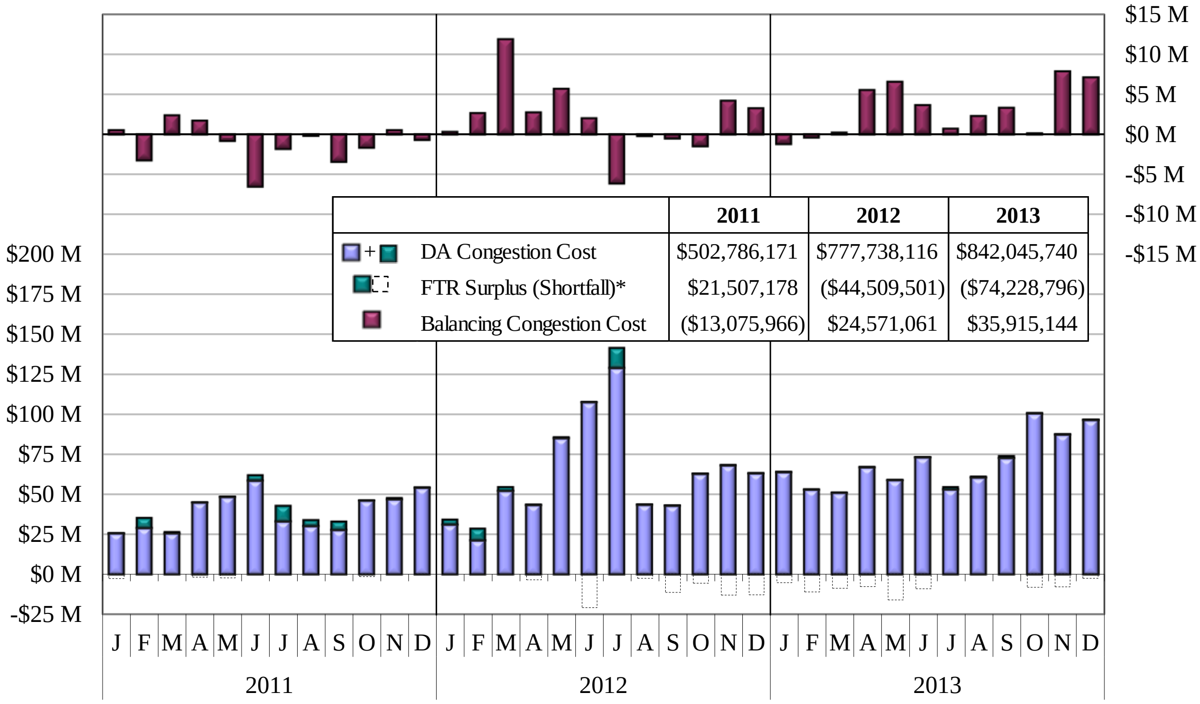
A. Day-Ahead Congestion Costs and FTRs

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 21 summarizes the day-ahead congestion, the obligations to FTR holders and surpluses/shortfalls, as well as balancing congestion on a monthly basis from 2011 to 2013.

Figure 21: Day-Ahead Congestion and Payments to FTRs
2011–2013



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

Day-ahead congestion costs rose 8.3 percent to total $842 million in 2013. The increase in day-ahead congestion coincided with increases in fuel prices that generally increase the cost of redispatching generation to manage network power flows. Much of the increase occurred on internal constraints in the West Region, many of which are affected by the increasing output from wind resources. MISO has continued to enhance its day-ahead processes to fully model potential transmission constraints in the day-ahead market.

FTR obligations exceeded congestion revenues by over 8 percent, most of which occurred in the first half of the calendar year (the prior FTR year). These FTR funding shortfalls occurred mostly on internal constraints. The largest single cause for underfunding continued to be outages that were not modeled in the 2012–2013 annual FTR auction. While the majority of the outage-related underfunding was due to forced outages, a significant amount was related to planned outages that were not provided to MISO in time for inclusion in the auction. MISO has worked to improve the convergence of the FTR modeled transmission capability and the transmission capability available in the day-ahead market. As a result, FTR funding improved at the beginning of the 2013-2014 FTR year, averaging less than 2.5 percent after May.

Other contributors to FTR underfunding included underestimated loop flow and firm-flow entitlements. Therefore, because MISO collects day-ahead congestion revenues for only the portion of transmission capability that is available to the day-ahead market, it sells or allocates FTRs for only that portion. As a result, aligning the available transmission capability in the FTR and day-ahead markets ensures that FTR shortfalls and surpluses are limited.

As a share of total dollars, FTRs in 2013 received just 84 percent of the day-ahead congestion revenue, down from 89 percent in 2012 and 91 percent in 2011. Other forms of transmission rights, such as “carve-outs” and “Option B” FTRs, accounted for over $87 million in payments. These rights 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—over $47 million went to one participant—have risen in recent years along with the increase in congestion and DIR adoption 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.

Finally, MISO implemented two significant changes to the FTR markets in 2013:

- In March, MISO eliminated the ability of participants to purchase same-bus “zero-cost” FTRs that can lead to underfunding under certain conditions.
- In the fall, MISO began operating the Multi-Period Monthly Auction or (MPMA), which permits Market Participants to purchase (or sell) FTRs for the next month and several future months in the current planning year. This should improve participants’ ability to manage congestion risk.

B. Balancing Congestion Shortfalls

Balancing congestion shortfalls in 2013, which are shown in the top panel of Figure 21, 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. Balancing congestion shortfalls can result from forced transmission outages or derates in real time, or greater than anticipated loop flows. In 2013, balancing congestion shortfalls totaled $52.6 million, indicating that the real-time binding constraint flows were slightly less than the amount cleared in the day-ahead market.

C. Real-Time Congestion Value

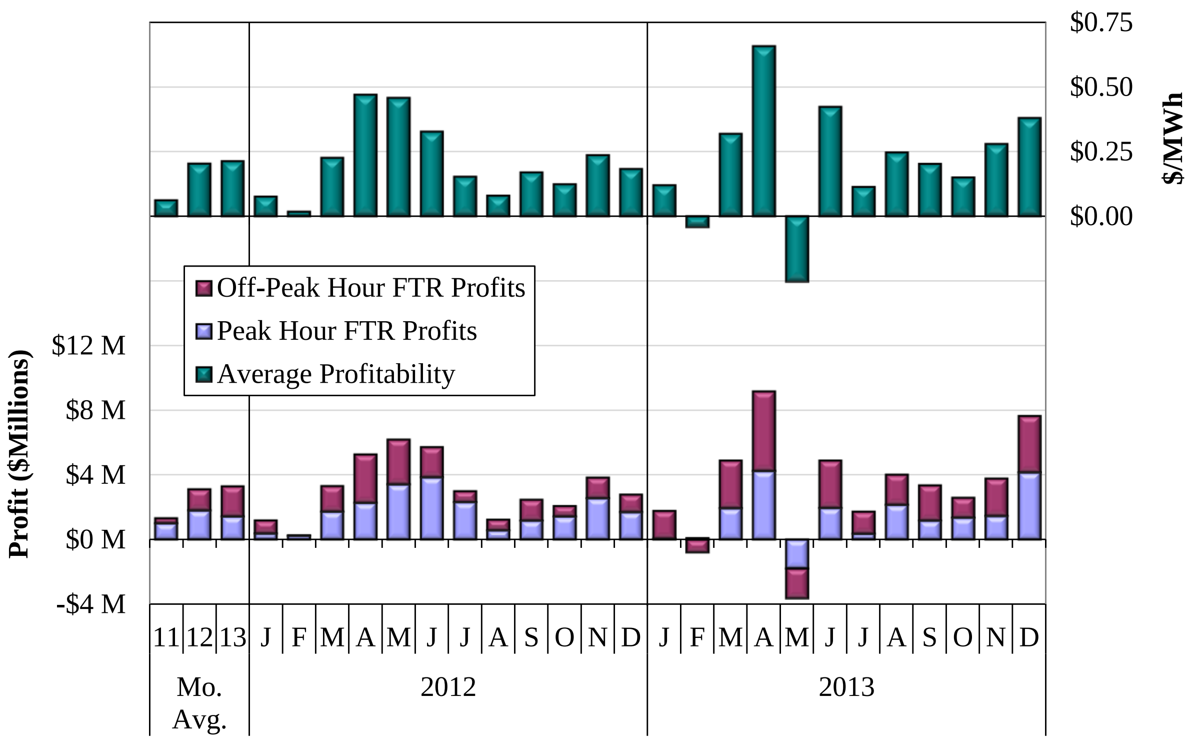
Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.59 billion in 2013. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM's entitlements on the MISO system (PJM does not pay for its use up to its entitlement).

The total real-time congestion value increased 22.1 percent from 2012, the vast majority of which occurred on internal (including MISO-managed market-to-market) constraints. It was greatest in the fourth quarter because of significant outages in the West region. Increased fuel prices also contributed to the higher congestion value in 2013.

D. FTR Market Performance

FTR price convergence with anticipated day-ahead congestion is an indicator of the performance of the FTR market. Good price convergence occurs when there are low FTR profits or losses, which are the difference between the price of the FTR and the congestion paid to it. In Figure 22, we show the profitability of FTRs sold in the monthly market.

Figure 22: Monthly FTR Profitability
2012–2013



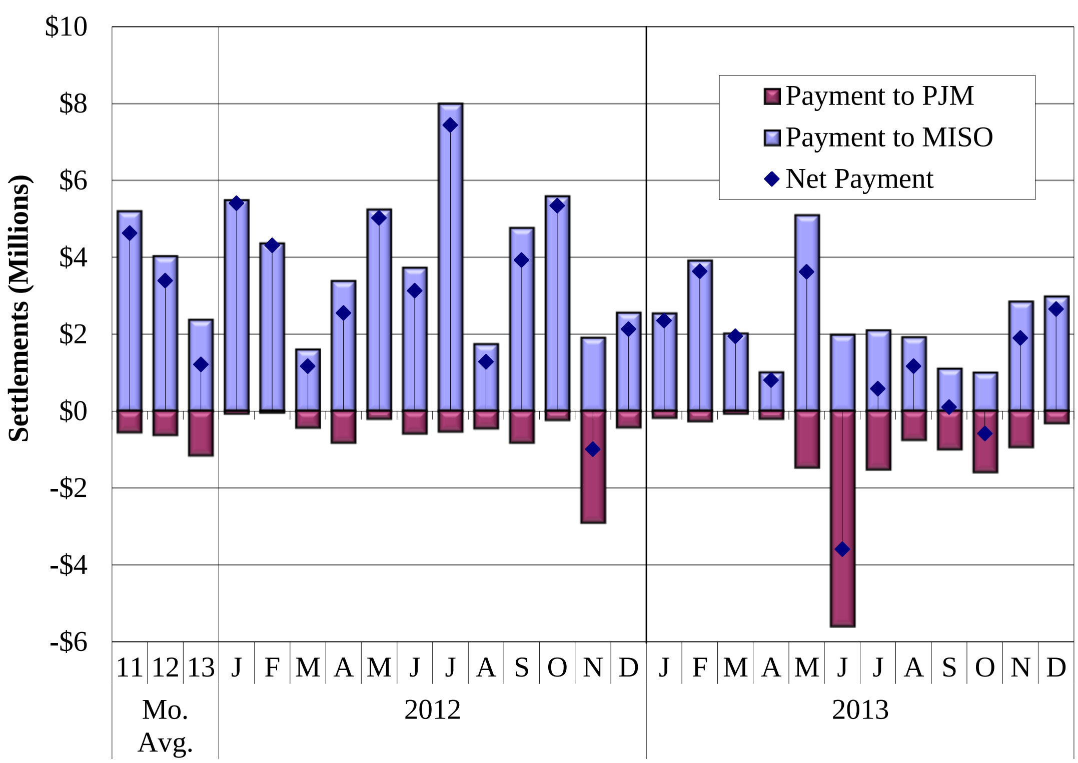
Incremental capability sold in the monthly auctions was more profitable (at $0.22 per MWh), but did not track changes in congestion as well as it has in prior years. The general prevailing pattern of west-to-east congestion was not as significant in 2013 as it was in previous years. This likely resulted in the FTR market overestimating the congestion out of the West region.

In 2013, the profitability of seasonal FTRs sold in the annual auction (not shown) averaged $0.07 per MWh, down from $0.20 last year, and was greatest in the spring and fall. In general, this indicates that the FTR markets produced prices that reasonably reflected anticipated congestion.

E. Market-to-Market Coordination with PJM

MISO's market-to-market (M2M) process under the Joint Operating Agreement (JOA) with PJM efficiently manages constraints affected by both RTOs. The process allows each RTO to utilize re-dispatch from the other RTO's resources to manage its congestion if it is less costly than its own relief. Each RTO is compensated for excess flows from the other RTO when those flows exceed their Firm Flow Entitlement (FFE). Much of the M2M process is now automated and has improved pricing in both markets. Figure 23 shows settlement results for 2012 and 2013.

Figure 23: Market-to-Market Settlements
2012–2013



Congestion on MISO M2M constraints declined 10 percent from last year to $291.5 million, while on PJM M2M constraints it remained relatively low at $15.8 million.[20] Figure 23 shows net payments flowed from PJM to MISO in most months in 2013 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 72 percent from 2012. PJM payments of $32.2 million were offset by $14.7 million in payments by MISO, mostly in June.

An error in the PJM FFE calculation that began in late October 2012 was discovered and corrected in mid-February 2013. The error overstated PJM's entitlement on several constraints in late 2012 and 2013, and resulted in a $4.28 million settlement (approximately $2 million of this occurred in 2013).

Shadow price convergence on MISO M2M constraints, an indicator of PJM's responsiveness to requests for relief, was reasonable in 2013 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.

We recommended in our *2012 State of the Market Report* that both RTOs incorporate the coordinated use of FFEs into the day-ahead market, which should improve the efficiency of both RTOs' markets. The RTOs have made considerable progress in developing a conceptual framework for coordination, and a final design is expected in late 2014 with possible implementation in late 2015.

F. Congestion on Other External Constraints

Congestion in MISO can occur when other system operators call for Transmission Line-Loading Relief (TLRs), which causes MISO to activate the external constraint in its real-time market. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers.

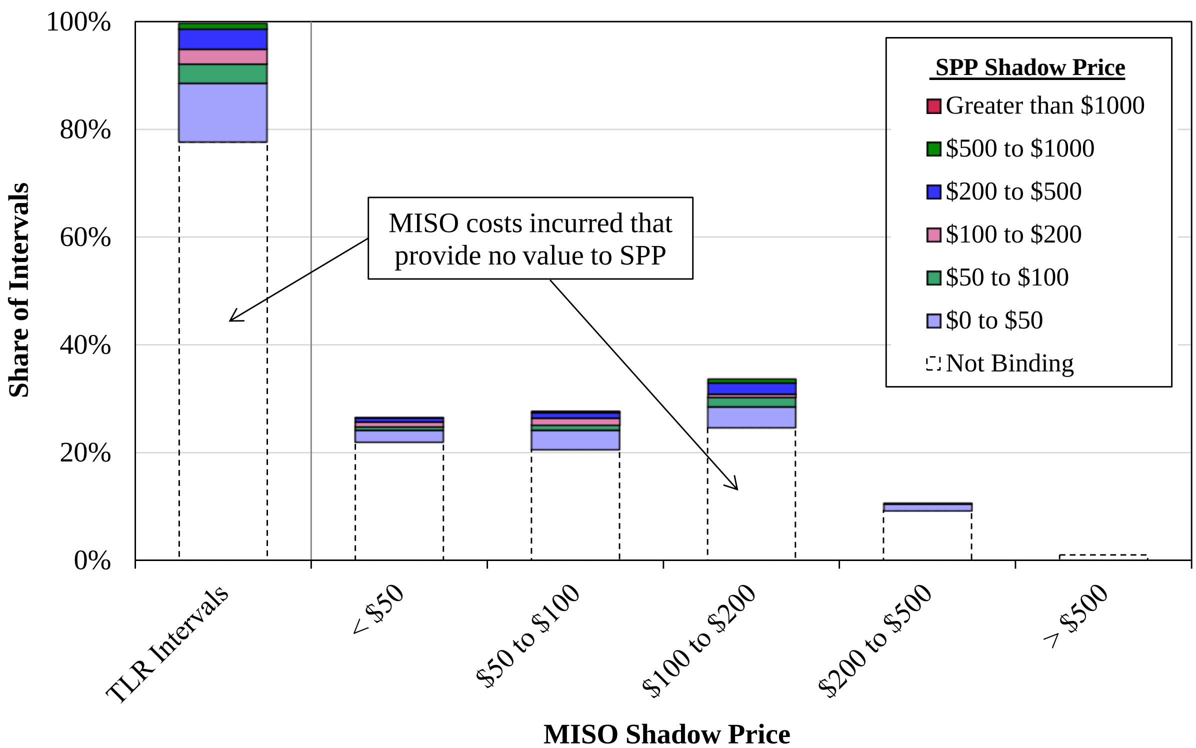
20 As mentioned in the previous subsection, even though the congestion value is relatively small on external flowgates, their price impacts can be substantial.

The congestion value on external flowgates corresponded to a small share of total congestion in 2013, but had widespread price impacts. In fact, the transmission constraint that had the largest impact on generator LMPs in 2012 was an external constraint managed by SPP (Iatan-Stranger).

One 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.

To evaluate the efficiency of this process, we compare MISO's shadow prices (the marginal cost of the relief provided by MISO) to SPP's shadow prices on the TLR constraints (the marginal value of the relief provided by MISO). This comparison is shown in Figure 24 for March of 2014, a period following the launch of SPP's new market for which we have SPP constraint data.

Figure 24: MISO vs SPP Shadow Prices on SPP TLR Constraints
March 2014



The figure reveals the gross inefficiency of this process—in 78 percent of the intervals when the TLR constraints are generating congestion costs in MISO, the constraint is not binding in SPP and the relief has no marginal value. On average, MISO's shadow prices are almost four times larger than SPP's shadow prices. These inefficient costs incurred by MISO translate to higher costs for many MISO customers in the form of higher LMPs at many locations paid by loads, lower LMPs paid to generators at many locations and inefficient payments to external transactions that are generally recovered from MISO's customers through an uplift charge. In total, we estimated that these three categories of costs totaled $192 million and $113 million in 2012 and 2013, respectively.

These results highlight the importance of our recommendations to revisit these coordination procedures to quantify MISO's relief obligations and the importance of using MISO's Transmission Constraint Demand Curve for TLR constraints to reduce these inefficiencies.

VII. External Transactions

A. Overall Import and Export Patterns

As in prior years, MISO in 2013 remained a substantial net importer of power in both the day-ahead and real-time markets. Real-time net imports decreased 7 percent to an average of 3.7 GW per hour. Imports from PJM declined 24 percent to 1.7 GW on average, while those from Manitoba and Ontario both rose nearly 30 percent (and even more during off-peak hours). Approximately one-third of interchange was associated with wheels through MISO (see next section), including 95 percent of imports from Ontario and 87 percent of exports to PJM. A substantial share of this activity is likely attributable to the interface pricing issues discussed later in this section.

Price 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 schedule in advance and, therefore, must forecast the prevailing price differences.[21] Additionally, the lack of RTO coordination of 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 52 percent, a slight improvement from recent years. 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.

21 The scheduling notification deadline was reduced to 20 minutes in October 2013 in compliance with FERC Order 764.

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, of which $59 million was attributable to optimizing the interchange between PJM and MISO. We believe these values understate the true cost savings because the study was conducted during a period of lower load and fuel prices, which decrease 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. This is generally referred to as Coordinated Transaction Scheduling (CTS). In addition to the economic benefits, this would improve reliability by preventing operating reserve shortages that sometimes occur under the current scheduling rules. PJM is implementing this type of approach with New York ISO in November 2014, and has indicated they are supportive of implementing a similar approach with MISO after this is complete.

B. Loop Flows Around Lake Erie

Transactions scheduled between RTOs are settled on a "contract path" basis, while power actually 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.

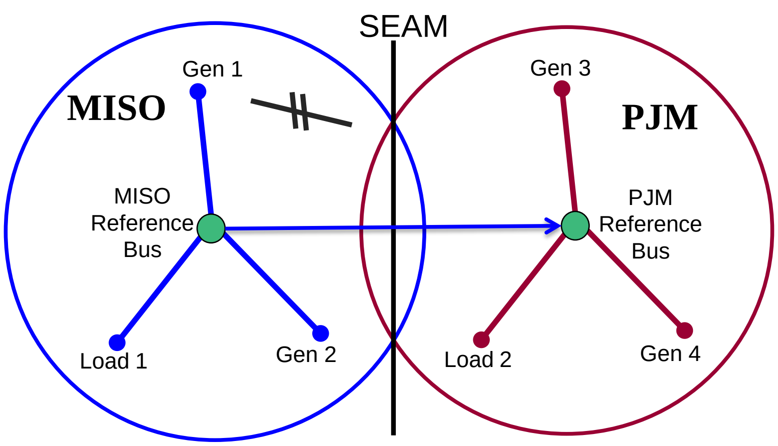
To better manage loop flows around Lake Erie, MISO and IESO installed Phase Angle Regulators (PARs) that began full operation in July 2012. Both the PARs and changes in transaction patterns contributed to a substantial decrease in clockwise loop flows from 2011 to 2013. For the year, average hourly Lake Erie loop flows were 3 MW in the counter-clockwise direction in 2013, whereas it was 155 MW in the clockwise direction in 2011. Average hourly clockwise loop flows exceeded 400 MW in only 3 percent of hours, down from 16 percent in 2011. These reductions have reduced the need of other RTOs around Lake Erie to call TLRs, which has benefitted MISO by lowering MISO's balancing congestion costs (negative ECF).

C. Interface Pricing and External Transactions

Interface prices are used to settle with participants that schedule physical schedules into, out of, or through MISO over a particular interface. These prices are critical because they establish the incentives that will govern participants' external transaction schedules.

All of the locational congestion effects in the interface prices are measured against a central "reference bus". The LMP at each location includes: (a) the system marginal price, (b) the congestion component, and (c) the marginal loss component. To calculate the congestion component of the interface price for a constraint, the RTO first calculates the marginal flow impact on the constraint (i.e., the "shift factor") of injecting a megawatt at the MISO reference bus and withdrawing it at specified locations (known as the "interface definition") in the adjacent area. This is depicted in the following illustration for MISO and PJM.

The congestion component is equal to this marginal flow impact multiplied by the shadow price for the internal constraint. In this way, the effects on the constraint of transferring power to or from an adjacent area are reflected in the congestion component of the interface price.



1. Interface Pricing with PJM

By establishing an interface price that includes the congestion effects of a transfer between MISO and PJM, the congestion benefits or costs will be fully priced and settled. This is essential because it provides efficient incentives for participants to schedule transactions between the two areas. As described below, however, the interface prices set by the RTOs do not currently provide efficient incentives to schedule external transactions when market-to-market constraints are binding or when TLR constraints are binding because of a flaw that we first identified in mid-2012.

The flaw is that *both* MISO and PJM are independently estimating the full marginal effects of external transactions scheduled between the areas on all binding constraints. As a result, both RTOs interface prices will include congestion components that reflect the congestion effects on the same constraint, resulting in duplicative settlements. For example, if MISO estimates a shift factor on a constraint for an export to be -10 percent (e.g., it provides relief) and the constraint has a shadow cost of $500 per MWh, MISO congestion component for the PJM interface will be -$50 per MW. This will encourage the export. If PJM estimates the same shift factor and has the same shadow cost for the MISO market-to-market constraint, it will also calculate a congestion component for the MISO interface of $50. This will cause the participant to receive a congestion payment of $100 per MWh to schedule this transaction even though it is only providing relief on the constraint worth $50 per MWh.

In the *2012 State of the Market Report*, we provided specific examples of the problem, which are reproduced in the Appendix of this report in Section VI.B.2. To establish empirically the double settlement, we identified hours when no constraints were binding in PJM or MISO except a single common market-to-market constraint. Hence, in these examples, the congestion component of the interface prices in both PJM and MISO will solely reflect the effects of the single binding market-to-market constraint. Indeed, we found the prices on both sides of the interfaces reflected the similar congestion.

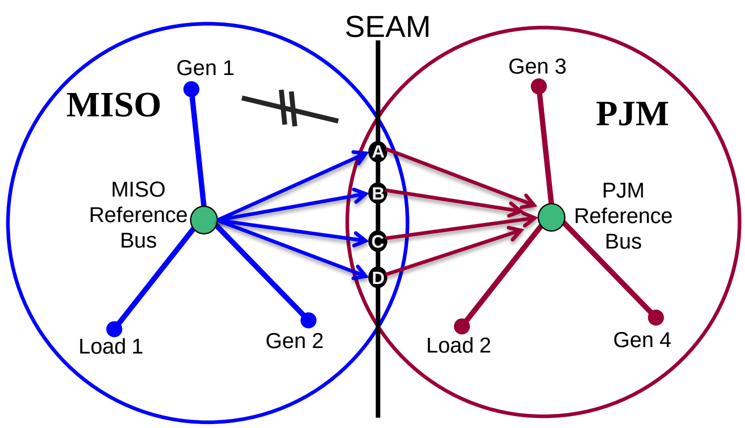
We also quantified some of the related inefficiencies and costs to both PJM and MISO related to this pricing flaw. We estimate that PJM made $16.5 million in net over-payments on market-to-market constraints in 2013, down from $29.4 million in 2012. These overpayments have grown in the first quarter of 2014 to $18.5 million. These amounts do not include overpayments made for other external constraints. In addition to the overpayments for transactions that are expected to help relieve the constraint, this issue causes transactions to be overcharged for congestion when they are expected to aggravate a constraint. Although this effect will not result in uplift, it serves as an economic barrier to efficient external transactions.

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

To eliminate the redundant market-to-market congestion pricing, the interface definitions and pricing must be modified to settle only once the effects of transferring power from one area to the other area. One way to do this is to simply have the monitoring RTO alone price the congestion on its own market-to-market constraints. This is consistent with the simple example initially discussed in this section, in which MISO estimates the effect of the export on its constraint and fully prices that effect in its interface price so there is no need for PJM to price it. Because this solution is simple and would ensure efficient pricing on all market-to-market and other transmission constraints, we have recommended that both RTO's adopt this approach.

PJM's current preferred approach for addressing the duplicative congestion pricing for market-to-market constraints is to change the definition of the interface with MISO. Instead of assuming the power is sourcing or sinking inside the neighboring area, PJM has proposed for MISO and PJM to both define their interfaces based on a common set of points at the seam as illustrated in the following diagram.

Utilizing a common interface definition eliminates the redundant congestion pricing because the RTOs would each estimate only part of the flow effects of the transaction. Under this proposal, MISO would price the congestion effects ***from*** its Reference Bus to A, B, C, and D, while PJM prices the same effects from the seam ***to*** its Reference Bus.



While this may have intuitive appeal, this solution will produce an efficient settlement only if:

- the MISO shift factor plus PJM's shift factor equal the shift factor that MISO would have calculated under our proposed approach for the entire path; and

- both RTO's real-time markets produce similar shadow prices for the constraint.

We have evaluated this solution and found that these two necessary conditions do not always hold, and that the total settlement will therefore be distorted. We find that the PJM proposal inflates the shift factors for many constraints because the seam locations are electrically closer to many of the constraints. The shift factors can still sum to the correct total because they tend to have opposite signs, so they will generally offset one another.

However, there are three problems with relying on this offsetting change:

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

We do not believe these problems can be effectively addressed under the PJM proposal and have yet to identify any potential issues or inefficiencies with our proposal. Therefore, we continue recommend that both PJM and MISO implement the approach we have developed.

2. Interface Pricing and Other External Constraints

Market-to-market constraints activated by PJM are one type of external constraint that MISO activates in its real-time market. MISO also activates constraints located in external areas when the external system operator calls a TLR and redispatches its generation to meet its flow obligation.

It is appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs because this enables MISO to respond to TLR relief requests as efficiently as possible. While redispatching internal generation is required, MISO is not obligated to pay participants to schedule transactions that relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that its external transactions may provide. Because MISO receives no credit for this relief and no reimbursements for the costs it incurs, it is inequitable for MISO's customers to bear these costs. These costs totaled $3.9 million in 2013 and $2.1 million in 2012.

In addition to the inequity of these congestion payments, they motivate participants to schedule transactions inefficiently for two reasons. In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. For example, when an SPP constraint binds and SPP calls a TLR, it will establish an interface price for MISO that includes the marginal effect of the transaction on its own constraint. Hence, MISO's additional payment is duplicative and inefficient.

Second, MISO's shadow cost for external TLR constraints is generally overstated relative to the true marginal cost of managing the congestion on the constraint. For example, we show in Section VI.F that MISO's shadow prices on SPP's constraints are on average almost four times larger than SPP's shadow prices. This causes the congestion component associated with TLR constraints that is included in the interface prices to be highly distortionary and provide inefficient scheduling incentives. One should expect that this will result in inefficient schedules and higher costs for MISO customers. Therefore, we continue to recommend that MISO take the necessary steps to remove all external congestion from its interface prices.

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 2013.

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 (NCAs) and Broad Constrained Areas (BCAs). NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). Five NCAs are currently defined: Minnesota, WUMS, and North WUMS (a subarea of WUMS) in the Midwest Region, and the Amite South and WOTAB NCAs in the South

Region.[22] BCAs include all other areas within MISO that are isolated by transient binding transmission constraints.

The vast majority (88 percent) of binding BCA constraints in 2013 had at least one supplier that was pivotal. In nearly 95 percent of intervals, at least one BCA constraint with a pivotal supplier was binding. NCA constraints into WUMS were similarly pivotal, while those into Minnesota were pivotal approximately 60 percent of the time. Fewer constraints make up an NCA, however, so the share of intervals with a pivotal supplier in these NCA regions was far lower. Overall, these results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

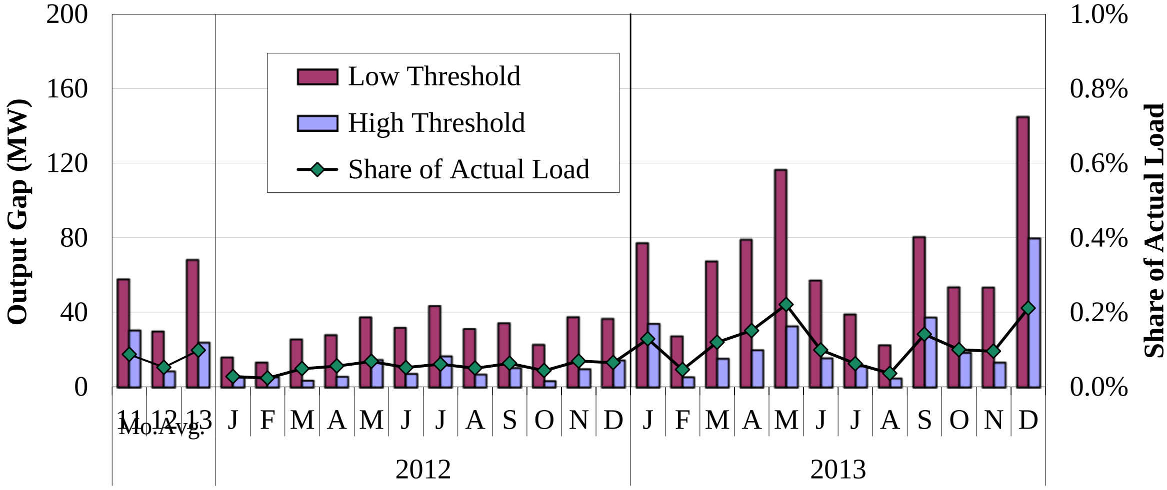
B. Evaluation of Competitive Conduct

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 1.7 percent, which reflects the competitiveness of MISO's energy markets.

The next figure shows the "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. The figure shows that output gap levels continued to be very low in 2013. At the low threshold, it averaged only 73 MW at the low threshold and 24 MW at the high (mitigation) threshold. These levels are slightly higher than in 2012, mainly because the NCA threshold for the Minnesota NCA declined from $64.10 per MWh in 2012 to $23.17 in 2013.

22 Since the South Region did not join MISO until late December, 2013, we exclude these two NCAs in our evaluations.

Figure 25: Economic Withholding – Output Gap Analysis
2012–2013



Low Threshold Results by Unit Status (MW)																											
Offline	24	4	13	4	4	1	1	9	0	11	0	8	0	2	5	8	2	6	0	12	2	9	0	26	11	4	70
Online	34	26	56	12	9	24	27	29	32	33	31	26	23	36	32	69	25	62	79	104	56	30	22	55	42	50	74
High Threshold Results by Unit Status (MW)																											
Offline	22	3	10	4	4	1	1	9	0	9	0	5	0	1	4	7	1	4	0	10	1	6	0	23	7	2	59
Online	8	5	14	2	1	2	4	6	7	7	7	5	3	9	11	27	4	11	20	22	15	5	5	14	11	11	20

These levels are extremely low, averaging approximately 0.1 percent of load, and raise no competitive concerns. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

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 (they depend on the frequency with which NCA constraints bind). The lower mitigation thresholds in the NCAs generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs.

Very little energy 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 and flexibility MISO has to commit resources. Real-time NCA and BCA energy mitigation rose from 2012, but remained infrequent. Despite infrequent mitigation in 2013, the pivotal supplier analyses discussed earlier in this section continue to indicate that local market power is a significant concern. Hence, market power mitigation measures remain essential.

D. Evaluation of RSG Conduct and Mitigation Rules

Local market power can also be associated with reliability needs that cause resources to be committed by MISO. This form of market power would be exercised by changing a resource's offer parameters to increase the RSG payment received by the supplier. To evaluate how effective the mitigation measures have been in addressing this form of market power, we determined the portion of the RSG paid that corresponds to competitive offers. This analysis indicates that only approximately one-half of the RSG cost is associated with competitive offer prices, while the other half is attributable to increases in one or more offer parameters above competitive levels. In early 2014, RSG costs rose sharply and much of the increase was associated with offers in excess of competitive levels.

The MISO market has two approaches for testing and mitigating market power exercised to increase RSG payments, one that was developed before the start of the market for congestion-related commitments and one that was developed recently to mitigate VLR commitments. We compare the two frameworks in this section. The key differences in these frameworks include:

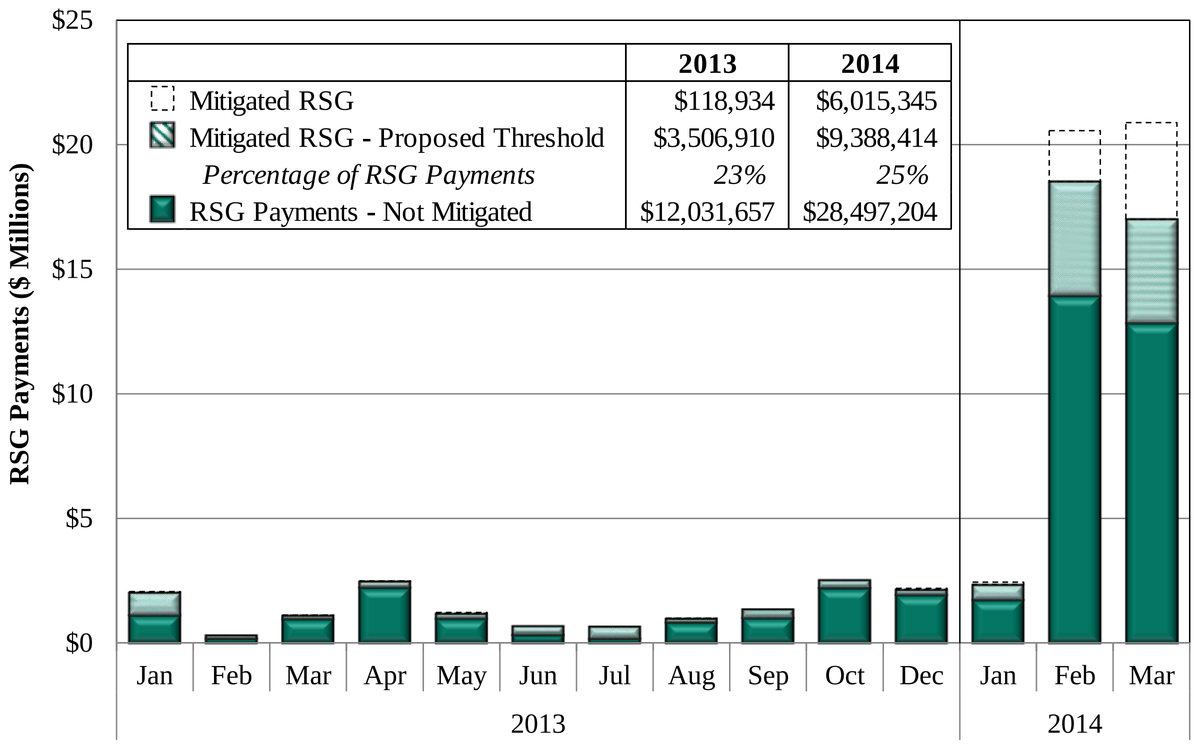
- Congestion-related mitigation measures call for conduct tests to be performed on each offer parameter individually and include an impact test with a $50-per-MW threshold to determine when conduct identified through the conduct test should be mitigated.

- VLR mitigation measures utilize a conduct test based on the aggregate as-offered production cost of a resource (recognizing the joint effect of all of the offer parameters). The VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments, in part because measuring the joint effect of all offer parameters is a superior approach for identifying anticompetitive conduct. We studied whether applying the VLR RSG mitigation framework to all RSG would be more effective than the current RSG mitigation rules. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a tighter threshold for VLR mitigation than for other RSG mitigation. Therefore, we evaluated a conduct and impact threshold equal to the greater of $25 per MWh or 25 percent (rather than the 10 percent threshold applied to VLR commitments). This threshold should balance the need for suppliers to modify their offers to reflect changes in actual costs, while more effectively mitigating market power that may allow them to inflate their RSG payments. The percentage provision allows for reasonable treatment of a wide array of units with differing costs.

Figure 26 shows total real-time RSG payments in each month in 2013 and early 2014, including the payments that were actually mitigated under current framework and the additional mitigation that would have occurred under the proposed production-cost framework.

Figure 26: Real-Time RSG Payments By Mitigation Classification
2013–2014



This figure shows that a very low share of such offers was mitigated in the period shown. Under the proposed production-cost framework for RSG mitigation, an additional $3.5 million (23 percent) of RSG payments would have been mitigated in 2013. The importance of such a revision is more clearly demonstrated in early 2014 when inflated offer prices contributed to the sharp increase in RSG payments along with increases in gas prices. In this timeframe, an additional $9.3 million would have been mitigated under the proposed framework. This analysis demonstrates both the improved effectiveness and the importance of improving the mitigation measures that are applied to congestion-related commitments.

E. Dynamic NCAs

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 affecting an area. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period. The NCA thresholds are required to be calculated based on a historical 12-month period.

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

Although the conditions described above are transitory, they can result in substantial market power when an area is chronically constrained for a period of time. This often occurs when system changes occur related to transmission outages or generation outages. Once the congestion pattern begins, suppliers may quickly recognize that their units are needed to manage the constraints. To address this concern, we have recommended that MISO establish a dynamic NCA.

To identify when a dynamic NCA may have been beneficial, we have reviewed mitigation scenarios that we have conducted at thresholds that are 50 percent of the BCA thresholds (effectively $50 per MWh). Since this threshold is higher than what we would propose for the dynamic NCA, these results will identify fewer mitigation instances that would be mitigated by the dynamic NCA. Nonetheless, we have identified a number of instances over the past year when mitigation would have been warranted. Two examples presented in Section VI.B.2 of the Analytic Appendix illustrate why this provision would be beneficial. Both of these cases lasted less than two months, but the conduct that would have been mitigated during these periods increased prices at affected locations by roughly $150 per MWh in the hours that would have been mitigated and by $4 to $10 per MWh in the entire timeframes affected by the outages.

These examples show that current Tariff provisions are at times insufficient to effectively address episodes of local market power. Therefore, we recommend MISO expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify formulas for the threshold calculations to address transitory episodes of congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh (rather than the default BCA thresholds of $100 per MWh) and be triggered by the IMM when it detects that: (1) such mitigation would be warranted on more than one day in a one-week period; and (2) the congestion is expected to continue in at least 15 percent of hours (more than double the rate that would be required to permanently define an NCA). This provision would help ensure that transitory network conditions do not convey substantial local market power that is not effectively mitigated under the MISO Tariff.

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 4 shows overall DR participation in MISO, NYISO and ISO-NE in the prior four years.

Table 4: DR Capability in MISO and Neighboring RTOs
2009–2013

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

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

The table shows that MISO had 10.2 GW of registered demand-response capability available in 2013, which makes up a larger share of capacity than it does in MISO's neighboring RTOs. MISO's capability comes in varying degrees of responsiveness. Most of the MISO DR is in the form of interruptible load (i.e., "Load-Modifying Resources", or LMR) developed under regulated utility programs, or Behind-The-Meter Generation (BTMG). MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions. In 2013, only 13 units providing 272 MW of capacity participated directly in

MISO's energy markets as "DRR", of which 10 that offered only supplemental reserves no longer do so. MISO considers DR a priority and continues to actively expand its DR capability—it added nearly 3 GW in 2013—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 and 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. All demand response resources are treated comparable to generation resources in their ability to meet planning reserve margins in the Resource Adequacy Construct. However, LMR are not tested to verify their stated capability like generation resources are, and 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 6,000 MW of total claimed capability.

Despite the capacity market design issues we describe in this report, accurately accounting for the true capability of LMRs would potentially increase the clearing prices significantly in the PRA, making them more reflective of the actual supply and demand conditions in MISO. For example, the most recent PRA for the 2014–2015 planning year cleared at $16.75 per MW-day. This auction would have cleared at $84 per MW-day if the nearly 6,000 MW of LMR resources offered into the auction (or covered under a FRAP) received only a 50 percent capacity credit. 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 2013, 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
- External Transaction Scheduling and External 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 2013 or in early 2014; 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.

2008-2[23]: 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.

Status: MISO agrees with allowing non-dispatchable DR to set price real-time prices. MISO is currently planning to allow EDR to set prices through ELMP in the fourth quarter of 2014. However, MISO calls for the deployment of LMR and BTMG (which total nearly 8.5 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. MISO has developed a conceptual design for enabling LMR and BTMG to set price when called. MISO is planning for implementation by September 2015.

Next Steps: The progress made to allow Type I DR and EDR resources to set prices through ELMP has been substantial and we have previously suggested that this framework be expanded to address this recommendation. MISO's conceptual design is consistent with this approach and we will be providing detailed comments. We believe that MISO's target date of September 2015 is feasible.

23 To facilitate tracking, in this and future *State of the Market* reports the numbering for a particular recommendation will be held constant across annual and quarterly reports. A recommendation of 2008-3 indicates the third recommendation listed in the 2008 State of the Market Report. Beginning in the 2013 report all new recommendations will be listed sequentially as they appear in the Recommendations section as 2013-1, 2013-2, and so on.

2012-2: 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.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO has agreed this recommendation would have significant benefits, but continues to evaluate the feasibility and costs of implementation.

Next Steps: 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 continue to evaluate the costs of this proposal and seek stakeholder input and approval. Implementing five-minute settlements for physical schedules has been identified as a prerequisite for MISO fully complying with the scheduling requirements of FERC Order 764.

2012-5: Introduce a virtual spread product.

Over two-thirds of price-insensitive volumes (and 21 percent of all volumes) in 2013 were "matched" 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 (i.e., 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 recommendation was originally proposed in our *2012 State of the Market Report*. Throughout 2013, MISO has been evaluating the feasibility, costs and benefits of developing such a product. MISO has held a number of workshops with stakeholders to explore the development of such a product.

Next Steps: MISO should continue its development of the virtual spread product and work with stakeholders to prioritize and schedule its implementation.

2012-9: Modify the mitigation measures to allow the definition of a "dynamic NCA" that is utilized when network conditions create substantial market power.

The current Tariff provision (Section 63.4 of Module D) related to the designation of NCAs is focused only on chronic congestion that creates sustained local market power. However, transitory conditions (transmission or generation outages) can arise that create a severely-constrained area where the market is vulnerable to the exercise of substantial local market power. Although these areas would not satisfy the criteria to be defined as permanent NCAs, we have concluded that under these transitory conditions, the current Tariff provisions are insufficient to effectively address the resulting local market power. This recommendation would expand Module D mitigation provisions to allow temporary "dynamic" NCAs to be defined while the conditions persist and a fixed conduct and impact threshold of $25 per MWh would be utilized.

Status: The IMM has continued to evaluate instances that warrant the definition of a dynamic NCA and developed a proposed trigger for defining a dynamic NCA.

Next Steps: The IMM will work with MISO to develop proposed Tariff revisions to address this recommendation and present the proposed revisions to MISO's stakeholders.

B. External Transaction Scheduling and External Congestion

Efficient scheduling of imports, exports, and wheels is very important because it affects not only the market prices and congestion in MISO, but throughout the Eastern Interconnect. We have seen a number of cases where poor scheduling of transactions between MISO and PJM has contributed to substantial shortages and price spikes in one area or the other. We have been evaluating the scheduling processes and the interface prices the RTOs post that provide the incentives that motivate participants to schedule transactions. This evaluation has indicated the need for improvements that are addressed by the recommendations below.

2012-3: Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions.

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it generally duplicates the congestion pricing by the external system operator. For example, PJM already includes the congestion effects of external transactions in its interface pricing so when MISO includes these same effects in its interface prices, the resulting congestion settlements are redundant and inefficient. The excessive settlement 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 also occur on constraints in other areas that MISO activates when the other system operator calls a TLR. These TLR constraints raise more serious concerns than the external market-to-market constraints do because MISO typically prices TLR constraints at shadow costs that are many times higher than the value of the constraints in the neighboring area. Hence, the TLR congestion included in interface prices results in highly distorted incentives to schedule imports and exports. To fully address these concerns, we are recommending that MISO eliminate the portions of the congestion components of the interface prices associated with the external constraints.

Status: This recommendation was originally made in our 2012 SOM, although it was previously raised in our 2011 SOM. Throughout 2013 and continuing into 2014, we have been working with MISO, PJM, and stakeholders through the Joint and Common Market Stakeholder group to achieve a consensus on the nature and costs of the problem, and on a preferred solution. While a consensus has been reached on the nature and the range of costs associated with the problem, no consensus has yet been reached on the best solution.

Next Steps: MISO can address a sizable portion of this problem by modify its interface pricing and should encourage PJM to do the same. It is not essential that MISO and PJM modify their interface pricing at the same time so MISO should not wait for consensus with PJM to emerge.

2005-2: Expand the JOA to optimize the interchange with PJM to improve the price convergence with PJM.

The RTOs continue to discuss 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 2013 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. PJM and the NYISO have developed Coordinated Transaction Scheduling (CTS), which allows participants to submit intra-hour interchange transactions with a spread bid price. The RTOs could then strike these transactions on a 15 minute basis when the spread in prices is sufficient large.

In mid-April, 2014, MISO and PJM staff held their first joint workshop with stakeholders on this topic and PJM supports a coordinated transaction scheduling process with MISO. However, PJM has indicated a desire to complete its implementation of CTS with NYISO before pursuing coordinated interchange with MISO.

Next Steps: We recommend that MISO complete its development of the CTS proposal with PJM and move to schedule this project at the earliest feasible date.

2012-4a: Improve external congestion processes by modifying how relief obligations are calculated by basing them on *Net* Market Flows, not gross forward flows.

MISO reports its Market Flow to the IDC in two ways: gross forward flows and gross reverse flows. 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.

Status: MISO has deferred further evaluation of this recommendation pending the completion of the NERC Parallel Flow Visualization project.

Next Steps: MISO should explore potential changes in its procedures and agreements that could address this recommendation, even in advance of the completing the Parallel Flow Visualization project.

2012-4b: Improve the pricing of external congestion associated with external constraints by setting the MVL on external (non-M2M) flowgates at a reasonable level.

When MISO gets a relief obligation on an external (non-M2M) flowgate, MISO binds the external flowgate at its internal default TCDC ranging up to $2,000. Because the relief is often costly to provide, the high TCDC results in MISO incurring congestion costs that are often many times higher than the value of the constraint (i.e., the cost of managing the constraint by the monitoring RTO). In fact, we show in this report that in 78 percent of periods in which an SPP TLR constraint is binding in MISO, the constraint is not binding in SPP (i.e., costly relief is being provided by MISO that has no value to SPP). The dispatch and resulting congestion costs incurred in these cases is highly inefficient.

Status: When MISO filed its proposed TCDCs for external flowgates at values consistent with internal constraints rated 161kV or higher, the IMM filed comments demonstrating the inefficiency of these values. Nonetheless, FERC that approved these values, agreeing with MISO that the two classes of facilities are comparable. The IMM filed for rehearing, which was granted on January 13, 2014, and is still pending at FERC under Docket No. ER13-2295.

Next Steps: This report contains additional evaluation of the costs and inefficiencies of external congestion. We encourage MISO to review these results and conduct its own evaluation to determine appropriate TCDC levels for external constraints in the long run.

C. 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 efficient conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. Therefore, the allocation of RSG costs is very important because it affects the performance of the market.

In 2013, MISO filed a series of proposed tariff revisions consistent with our *2012 State of the Market Report* recommendations. The proposed revisions addressed problems with the allocation of real-time RSG costs that over-allocated costs to market-wide deviations and under-allocated costs to deviations that affected constraints.

Additionally, we made recommended changes in the eligibility rules for PVMWP and RSG to address gaming strategies that can result in unjustified payments. With one exception, all of these recommendations have now been adopted. The remaining recommendation in this area is discussed below.

2013-1: Allocate real-time RSG costs 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 (helping and harming) are allocated real-time RSG costs. Although these post-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. Hence, they should not be allocated real-time RSG.

Status: MISO filed to remedy this problem along with a number of other allocation issues. In March 2014, FERC accepted most of the proposed RSG allocation changes, but did not approve this proposed change because it found that MISO's evidentiary support was insufficient.

Next Steps: MISO is planning on re-filing the proposed change in a future FERC filing with additional evidence and analysis for this proposal.

2013-2: Improve allocation of VLR costs by identifying VLR commitments made by the DA market.

To satisfy a number of local reliability requirements in the MISO South region, MISO utilizes both the Multi-day Forward Reliability Assessment (MFRAC) and the Day-Ahead Commitment process. MISO's MFRAC process generally commits resources with longer startup times when necessary to meet the local reliability requirements. For all other resources, MISO relies on the day-ahead market to commit the necessary resources in these load pockets by modeling the local commitment constraint in each of these areas. Unfortunately, there is no way currently to tell why a resource committed through the day-ahead market was committed, so none of them are flagged as VLR commitments. To the extent that the local commitment constraints are binding and cause the commitment of resources that receive day-ahead RSG, these costs should be allocated locally. Therefore, we recommend that MISO develop a means to identify VLR commitments that are made through the day-ahead market so the related RSG costs can be allocated consistent with the VLR methodology.

Status: This is a new recommendation.

Next Steps: MISO is evaluating the current Operating Guides that reflect the local commitment requirements described above and may implement new Guides more compatible with market operations on July 1, 2014. To the extent that these Operating Guides continue, MISO should identify available options to determine which resources committed in the day-ahead market would not have been committed but for the Operating Guides. These options may include running a parallel SCUC process without the local commitment requirements to identify units that were only committed in the case that includes the local requirements. MISO should also determine what tariff changes are needed to classify these commitments as VLR so the associated RSG can be allocated in a manner consistent with cost-causation.

2010-11: 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.

2013-3: Improve the market power mitigation measure applicable to RSG payments.

Periods of chronic congestion occurred over the past year that required the repeated commitment of certain resources. In these cases, certain suppliers are often pivotal and can generate large increases in RSG payments without being mitigated. Based on our evaluation of these patterns, we find that the current Tariff provisions related to mitigation of RSG of commitments made to manage congestion have not been fully effective. This is due in part to the fact that the conduct test is applied to each offer parameter individually and the impact test threshold is too large.

When mitigation measures were developed to mitigate RSG associated with VLR commitments, a new framework was introduced utilizing a conduct test based on the aggregate as-bid production cost of a resource. This method recognizes the joint impact of all of the resource's bid parameters. Additionally, the VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments. Therefore, we are recommending that this framework be applied for all RSG mitigation. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a tighter threshold for VLR mitigation than for other RSG mitigation. Therefore, we evaluated a conduct and impact threshold equal to the higher of $25 per MWh or 25 percent in this report and recommend MISO adopt these thresholds.

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.

D. 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.

2011-7: Implement a ramp capability product to address unanticipated ramp demands.

The LAD 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>: MISO has continued to develop this market product in a conceptual design.

<u>Next Steps</u>: MISO expects to complete a conceptual design by the fall of 2014. Currently MISO is scheduling the ramp product to be in production by September 2015.

<u>2012-12a</u>: 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. Although there were fewer such cases in 2013, it was still a significant issue.

Unreported derates impact 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.

<u>Status</u>: MISO agrees with this recommendation and has been working to develop new procedures and tools to identify unreported derates. However, based on our review of the initial design of the new operator tool MISO is planning to develop, we conclude that it will not be fully effective in identifying unreported derates. MISO also has a related project to enable participants to update offers within the hour that is scheduled for implementation in 2015.

Next Steps: We continue to monitor for unreported derates and refer suppliers to FERC as appropriate. Additionally, MISO should modify the design of its new operator tool to ensure that it will be effective and we will continue to provide comments on the design.

2012-12b: 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.[24] Additionally, by establishing a threshold that is a fixed percent of the dispatch instruction, the deviation tolerance band effectively becomes larger as a resource is ramped from its minimum output level to its maximum output level.

To address these concerns, we recommend MISO adopt thresholds based on resources' ramp rates that are tighter than its current thresholds. This report includes a specific proposal in Section V.C.6. This will improve suppliers' incentives to follow MISO dispatch signals and, if used to determine whether a resource should remain eligible for DAMAP and RTORSGP payments, will also help address the concerns we have raised regarding unreported unit derates.

Status: MISO agrees with this recommendation, and is evaluating our proposed revisions to the uninstructed deviation threshold.

Next Steps: We will work with MISO on finalizing and testing revised rules. Once this is completed, MISO will need to present the proposal to its stakeholders and file the revised thresholds at FERC.

2011-10: 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

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

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: MISO has been working with PJM in evaluating this recommendation and has committed to stakeholders and FERC that it will meet intermediate deadlines to complete prerequisite projects including improved data exchange. MISO expects to complete cost-benefit studies for day-ahead coordination with PJM in the third quarter of 2014, and to make an implementation decision in the fourth quarter.

Next Steps: The RTOs should continue to work together to develop more detailed procedures and to complete their cost-benefit evaluations of this project to support their decisions to move forward.

2012-16: Reorder 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: Limited progress has been made to date.

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 2008-2 (to enable DR to set prices).

2012-17: 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 and contributed to nine operating reserve price spikes of at least $100 per MWh. This recommendation will prevent this inaccurate transitory capacity loss that can result in artificial operating reserve shortages.

Status: The impacts related to this issue have fallen because MISO has modified its operating practices to avoid committing resources that are providing offline supplemental reserves. Nonetheless, we have presented MISO with additional evidence of shortage pricing events in 2013 that were not appropriate.

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

E. Resource Adequacy

Reasonable resource adequacy provisions and a well-functioning capacity market are intended to provide economic signals, together with MISO's energy and ancillary services markets, to establish efficient incentives to govern investment and retirement decisions. These economic signals 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 facilitate investment in the resources over the long term that are necessary to maintain reliability.

2008-11: 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: 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. It held a technical conference on this issue and opened a docket, but FERC has not yet mandated resolution.

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

2010-14: Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.

The use of only a minimum requirement and deficiency charges to represent capacity in MISO results in an implicit vertical demand curve for capacity. 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 States requiring their regulated utilities to build new resources.

Status: MISO is developing principles governing future market developments, including changes in its resource adequacy provisions and processes. The principles include the objective of facilitating efficient investment so they are consistent with this recommendation. However, there is currently no consensus among the participants and States regarding this objective.

Next Steps: MISO should continue to work with its stakeholders and OMS to move toward a consensus regarding the economic objectives of the resource adequacy construct. The IMM will support this process by continuing to show the benefits to MISO of establishing efficient capacity price signals, which include lowering the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

2011-14: Evaluate capacity credits provided to 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. 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. These resources have been shown to only have the ability to provide a fraction of the total claimed capability in the past. For example, MISO has reported that less than one-half of these resources were available during the winter shortages in early 2014. In addition, only roughly one-half of this DR capability was responsive when they were deployed during shortage conditions in summer 2006. If this capability had been derated by 50 percent in the most recent PRA conducted in April 2014, the price would have risen from roughly $16 to $84 per MW-day. This shows that qualifying this capability at a level that accurately reflects its expected ability to reduce load can substantially affect the PRA results and economic signals provided by MISO's markets. Therefore, we continue to recommend adopting testing procedures if possible, and/or derating these resources based on their actual performance or expected performance when called.

Status: In the last couple of years some progress has been made in requiring additional documentation of capability through State programs, auditors, or MISO mock tests. In addition, MISO has continued to develop improved communication systems to enable LBAs to report curtailment of registered resources and voluntary curtailments of unregistered resources. While MISO's efforts provide more audit capability and situational awareness, these resources are still not tested in any way comparably to other resources and the limited deployment experience suggests response rates far below other resource categories.

Next Steps: Evaluate alternatives and work with stakeholders to develop reasonable changes to Module E that address this recommendation.

2013-4: Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions.

Ideally, participants should be able to utilize the PRA to make decisions whether to retire or suspend units, or to return a unit to service from suspension. This allows them to make efficient retirement or suspension decisions. For example, a supplier may submit an offer into the PRA at a price that would cover its going forward cost (or the cost that would justify returning from suspension). If such an offer clears, the unit is economic to be in service during the planning year.

Suppliers that have submitted an Attachment Y retirement request currently lose their interconnection rights as of the specified retirement date. Furthermore, units that are currently suspended cannot qualify to offer into the PRA. These rules should be modified to allow the broadest possible participation in the PRA, and to allow participants ultimate decisions to be efficiently facilitated by the PRA. Finally, capacity resources should have more flexibility to retire or shut down temporarily prior to the end of the planning year if their capacity is not needed. Flexibility will improve market efficiency by reducing inefficient barriers to participating in the PRA.

Status: This is a new recommendation.

F. Recommendations Addressed in 2013

In 2013 and early 2014, MISO addressed a number of past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions. These recommendations are discussed below.

2012-7a: Modify eligibility requirements to address gaming issues associated with PVMWPs.

We 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. MISO made two filings that address these concerns by changing the eligibility rules associated with these payments. These changes cause any supplier engaging in the gaming conduct to become ineligible for the payments. FERC approved these changes, which have eliminated the incentive to engage in these strategies.

2012-7b: 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. However, the Tariff provision did not refer specifically to PVMWP, but rather to “MRD MWP”, which is an undefined term. To correct this, MISO filed Tariff changes that provide MISO the intended authority to stop gaming strategies until it has the opportunity to modify the rules. FERC approved this change effective October 17, 2013.

2012-6: Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs.

Status: This recommendation included three sets of improvements, some of which were originally proposed in 2011 and 2012. In 2013, MISO filed proposed Tariff changes supported by the IMM to address the three areas identified in the recommendation. FERC held a technical conference and ultimately approved most of the changes in early 2014. One important change—allocating real-time RSG only to harming pre- and post-NDL deviations—was not approved because FERC asserted that sufficient evidence was not provided. We are working with MISO to develop the additional evidence needed to address the remaining item that was not approved. MISO plans to finalize Tariff revisions and file proposed modifications with FERC shortly. Recommendation 2013-1 above pertains to this change.

2011-8: Eliminate the transmission constraint deadband.

The transmission constraint deadband was an algorithm that would reduce transmission constraints’ limits by a small amount once the constraint begins binding. 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, IMM case studies showed that it actually increased volatility because it contributed to unmanageable congestion that often resulted in sharp LMP changes. We estimated that the deadband accounted for 19 percent of all congestion value in MISO during 2011. It also reduced the utilization of the transmission system by binding constraints at levels less than their physical capability. This recommendation was fully addressed when MISO deactivated the transmission constraint deadband on October 1, 2013.