IMM Quarterly Report: Fall 2012
September–November

MISO Independent Market Monitor

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Potomac Economics

December 12, 2012

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Quarterly Summary

		Value	*Change*[1] Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)	🟢	$28.18	*-17%*	*-2%*
Fuel Prices ($/MMBtu)				
Natural Gas	🟢	$3.38	*21%*	*-8%*
Western Coal	🟢	$0.56	*16%*	*-30%*
Eastern Coal	🟢	$1.78	*-7%*	*-12%*
Load (MW)[2]				
Average Load	🟢	54.2	*-17%*	*1%*
Peak Load	🟢	84.8	*-14%*	*-7%*
% Scheduled DA (Peak Hour)	🟢	100.2%	100.2%	101.6%
Transmission Congestion ($M)				
Real-Time Congestion Value	🟢	$324.7	*-14%*	*2%*
Day-Ahead Congestion Revenue	🟢	$176.8	*-40%*	*39%*
Balancing Congestion[4]	🟢	$11.1	$8.8	$26.0
M2M Payments *from* PJM	🟢	$9.0	$13.0	$30.5
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$9.41	*-12%*	*-10%*
Spinning Reserves	🟢	$2.44	*-51%*	*26%*
Supplemental Reserves	🟢	$1.32	*-66%*	*27%*

		Value	*Change*[1] Prior Qtr.	Prior Year
Wind Output (MW)	🔵	3,827	*54%*	*15%*
Guarantee Payments ($M)				
Real-Time RSG	🟢	$12.4	*-48%*	*-21%*
Day-Ahead RSG	🔵	$8.7	*75%*	*88%*
Day-Ahead Marginal Assurance	🟢	$12.1	*-22%*	*-31%*
RT Operating Rev. Sufficiency	🟢	$4.0	*7%*	*1%*
Price Convergence[3]				
Market-wide DA Premium	🟢	-1.3%	4.1%	1.1%
Virtual Trading				
Cleared Quantity (MW)	🟢	6,890	*-5%*	*-20%*
% Price Insensitive	🔵	40%	45%	50%
% Screened for Review	🟢	2%	2%	1%
Profitability ($/MW)	🟢	$0.50	$0.47	$0.88
Dispatch of Peaking Units (MW/hour)	🟢	273	1,788	171
Output Gap- Low Thresh. (MW/Hour)	🟢	32	36	25
Maximum VCA Price ($/MW-Mo.)	🟢	$0.15	$50.00	$0.25
Other:				

Key:
- 🟢 Expected
- 🔵 Monitor/Discuss
- 🔴 Concern

Notes:
1. Values not in italics are the value for the past period rather than the change.
2. Comparisons adjusted for change in membership.
3. Values include allocation of real-time RSG (DDC rate).
4. **Real-time shortfalls (which contributes to negative ECF), net of real-time surpluses. No offset for market-to-market settlements.**

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Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations for September to November of 2010 to 2012.
  - ✓ We include natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin during peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices this fall averaged $27.82 per MWh, a modest 5 percent decline from the prior fall. Prices were 21 percent lower than in summer.
  - ✓ The decline from last fall was due mostly to fuel price changes: natural gas prices declined 8 percent from last year, while coal prices declined 12 to 30 percent.
  - ✓ Load averaged 54.2 GW, an increase in membership-adjusted terms of less than one percent from last fall.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ Prices remained highest at the Michigan Hub, where they averaged over $30 per MWh, $4 higher than prices at Minnesota Hub.
    - – Transmission losses accounted for nearly 60 percent of this price spread.
  - ✓ Day-ahead scheduling of wind output, which affects west-to-east power flows, rose a further 11 percent from last fall to 3.1 GW.

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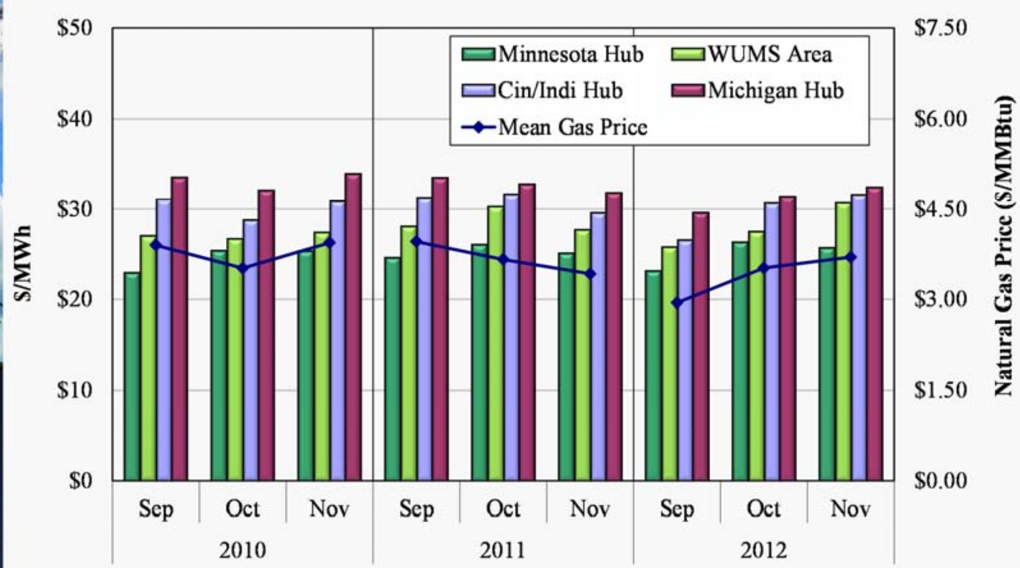
Day-Ahead Average Monthly Hub Prices Fall 2010–2012



Note: Cinergy Hub was replaced by Indiana Hub as the Central region's proxy price in 2012.

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All-In Price

- The "all-in price" represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price and real-time uplift, ancillary services, and capacity costs per MWh of load.
- The figure includes the monthly average natural gas price and shows that energy prices generally track changes in fuel prices.
  - ✓ This is expected in a competitive market because fuel costs are the vast majority of most units' marginal costs and gas units are often setting prices.
- The all-in price declined 2 percent from last fall to $28.43 per MWh.
  - ✓ As with day-ahead energy prices, the decline in the energy component of the all-in price was due to considerable declines in most fuel prices.
- Energy costs continue to make up over 99 percent of the all-in price.
  - ✓ Uplift costs declined by nearly half and contributed just 8 cents to the all-in price.
  - ✓ Ancillary services made up 14 cents of the all-in price, unchanged from last fall.
  - ✓ The Voluntary Capacity Auction cleared near zero in each month this fall, so capacity payments did not contribute materially to the all-in price.
    - – The very low capacity prices are due to MISO's capacity surplus and market design issues identified in our *2011 State of the Market* report.

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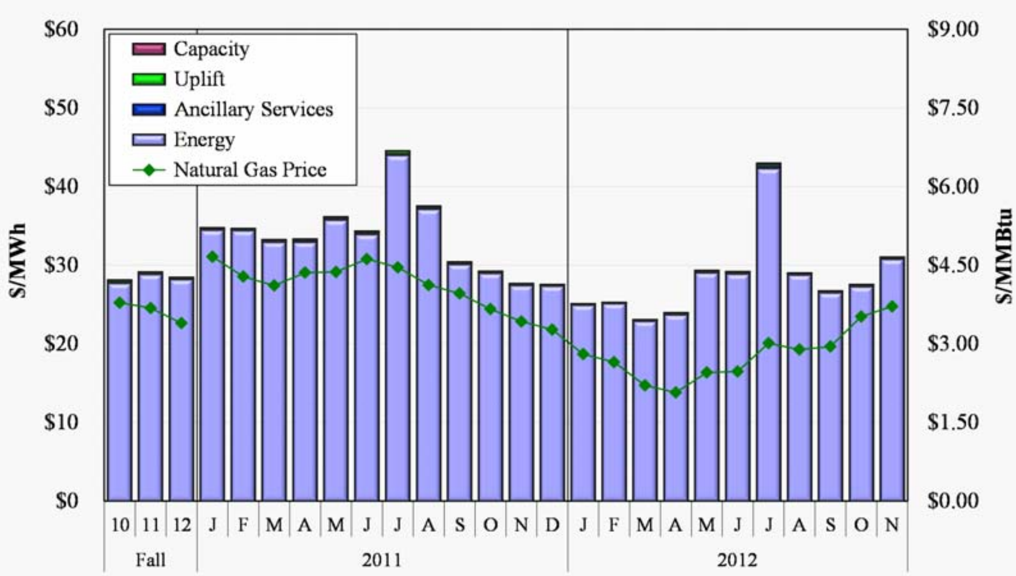
All-In Price
Fall 2010–2012



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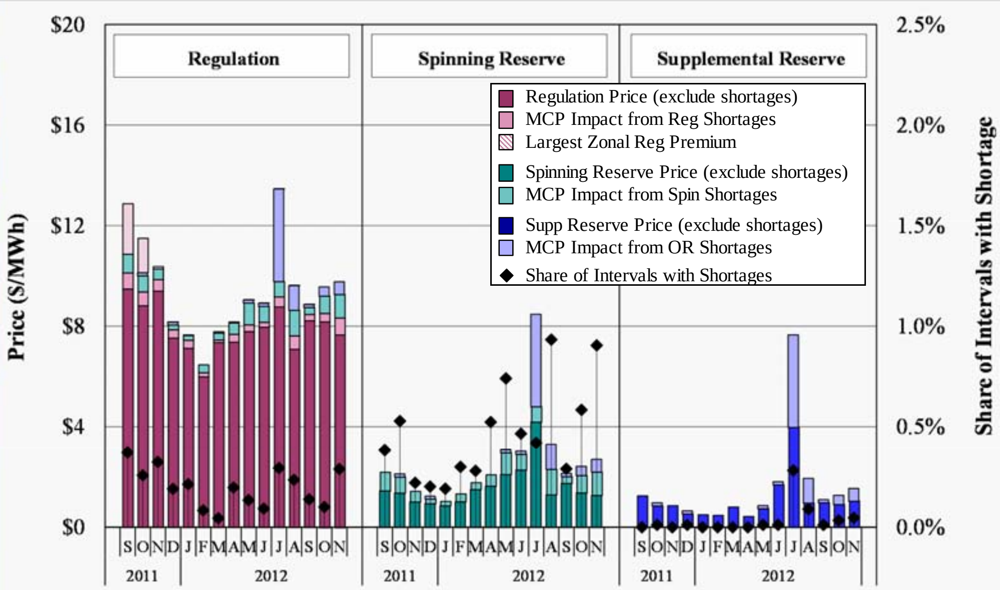
Monthly Average Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO’s ancillary service products for the last 15 months.
  - ✓ We show separately the portion of each product’s price that is due to shortages of each product (shortages for lower quality products are reflected in higher quality products because they can be substituted).
- Regulation prices declined 10 percent from last fall to an average of $9.41 per MWh. This was due predominantly to a decline in fuel prices.
  - ✓ A reduction in in regulation shortage situations—there were 46 this quarter, down from 83 last fall—reduced the average price by 19 cents per MWh.
  - ✓ The regulating reserve demand curve penalty price (which sets price during shortage intervals) fell 18 percent from last fall to $119 per MWh.
- Spinning reserve clearing prices rose 26 percent to $2.44 per MWh.
  - ✓ Spin shortage intervals rose 57 percent to 155, and accounted for the majority of the rise in the average clearing price.
- Eight supplemental reserve shortages in the quarter contributed entirely to the 27 percent rise from last fall in supplemental clearing prices, to $1.32 per MWh.
  - ✓ Excluding these shortage periods, prices were unchanged.

Monthly Average Ancillary Service Prices Regulation and Contingency Reserves, 2011–2012



MISO Fuel Prices and Capacity Factors

Natural Gas and Oil Prices

- Natural gas prices averaged $3.38 per MMBtu this fall, 8 percent lower than last fall.
  - ✓ However, gas prices continued their steady increase from earlier in the year and briefly exceeded $4 in late November, more than double the prices in mid-April.
- Oil prices averaged $22.95 per MMBtu, 5 percent greater than last fall.
  - ✓ Oil is rarely a marginal fuel, particularly in shoulder months, so high prices for the product have a negligible impact on the market.

Coal Prices

- Illinois Basin prices declined 12 percent from last fall to $1.78 per MMBtu.
- Western (Powder River Basin) coal prices rose 8 cents, or 16 percent, from the summer average to $0.56 per MMBtu, but remain 30 percent lower than last fall.

Capacity Factors

- The rise in gas prices since spring 2012 has resulted in a reversion of the generation changes, as indicated in the second figure that shows capacity factors by type of unit.
- Capacity factors for gas-fired units in the first half of 2012 were more than double those in same periods in 2010 and 2011, while those for coal units fell by roughly 20 percent.
  - ✓ Most of these year-to-year differences disappeared this quarter.

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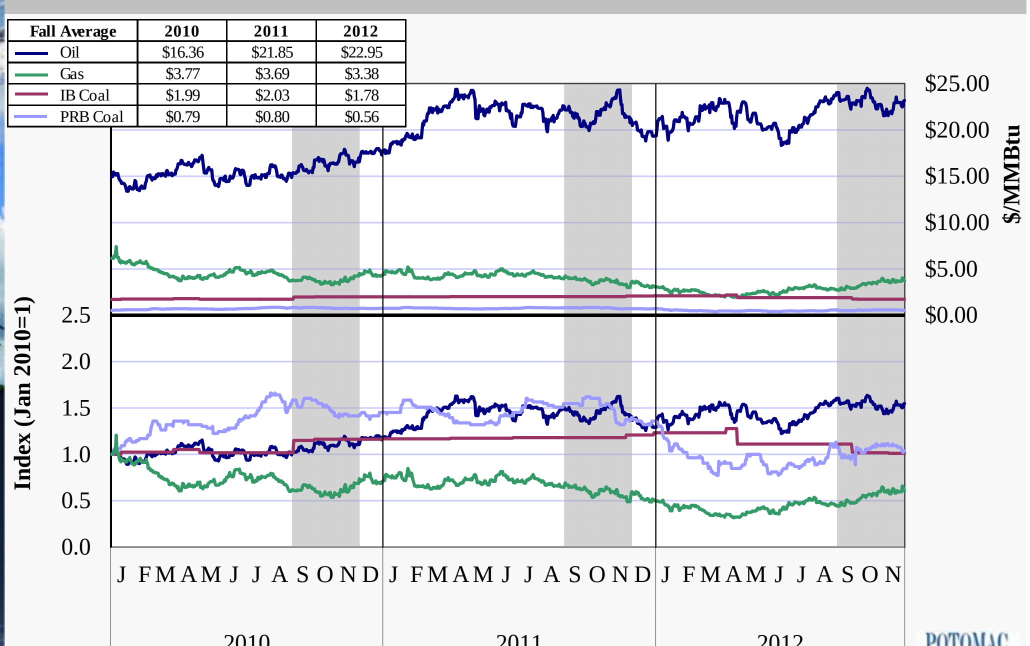
MISO Fuel Prices 2010–2012



Fall Average	2010	2011	2012
Oil	$16.36	$21.85	$22.95
Gas	$3.77	$3.69	$3.38
IB Coal	$1.99	$2.03	$1.78
PRB Coal	$0.79	$0.80	$0.56

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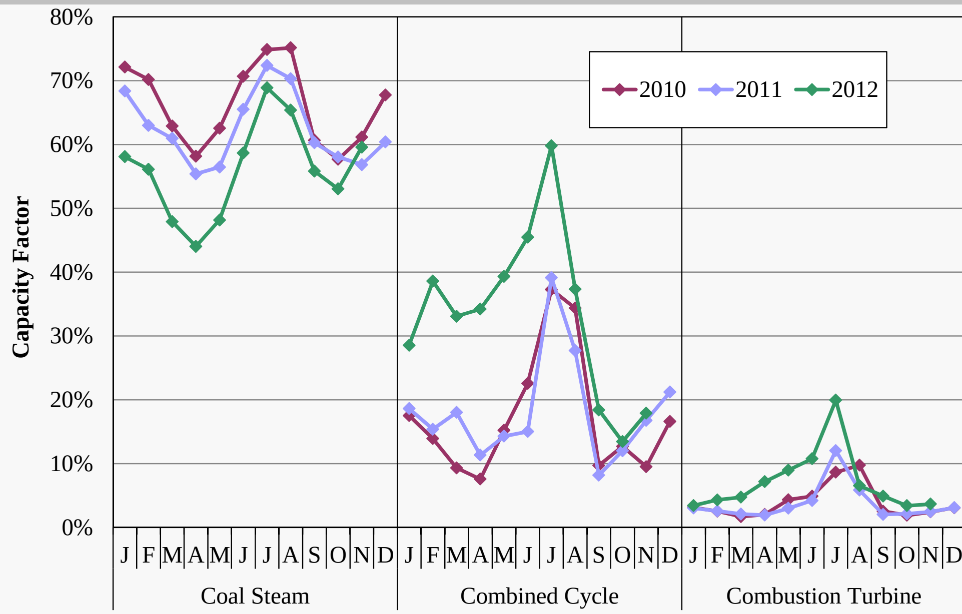
Unit Type Capacity Factors 2010–2012



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Changes in Load and Weather Patterns

- The next figure shows changes in load in fall 2010 to 2012, as well as the changes in weather patterns that contributed to these changes.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns correspond to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days (“HDDs and CDDs”) at four locations in MISO since 2010.
- The figure shows that total degree days increased 8 percent from fall 2011, slightly above its historical average.
  - ✓ November 2011 was unusually mild, particularly in the eastern half of MISO.
- These weather factors affected the monthly average and peak loads during each period shown in the top panel of the figure.
  - ✓ Load associated with membership changes since fall 2010, including the addition of BREC and the departures of FE and portions of Duke, is shown separately.
  - ✓ Average adjusted load rose less than 1 percent from last fall. It peaked at 84.8 GW on September 4, a 7 percent decline in adjusted terms.

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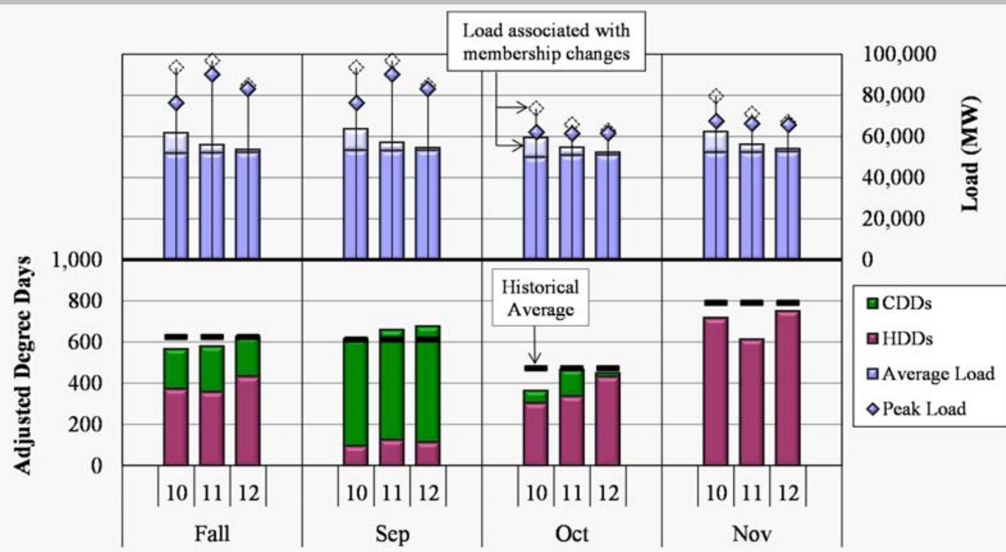
Load and Weather Patterns
Fall 2010–2012



Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis.

Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub (the inset table shows other locations), along with average price differences.
- System-wide there was a 1 percent real-time premium, which was largely due to congestion-related differences in certain regions.
  - ✓ Day-ahead premiums ranged from 3 percent at Michigan to -4 percent at Minnesota.
  - ✓ Substantial congestion events in the real-time were mostly confined to the West region, notably on September 25 and November 6, 19 and 23-24.
- Hedging real-time price volatility and avoiding real-time uplift charges typically leads to high day-ahead load-scheduling and price premiums in MISO's day-ahead market.
  - ✓ DDC charges (applied to real-time load purchases) averaged $0.58 per MWh this fall, the lowest quarterly average since its inception in 2011.
  - ✓ We have recommended improvements that would lower the share of real-time RSG that is allocated under the DDC rate.

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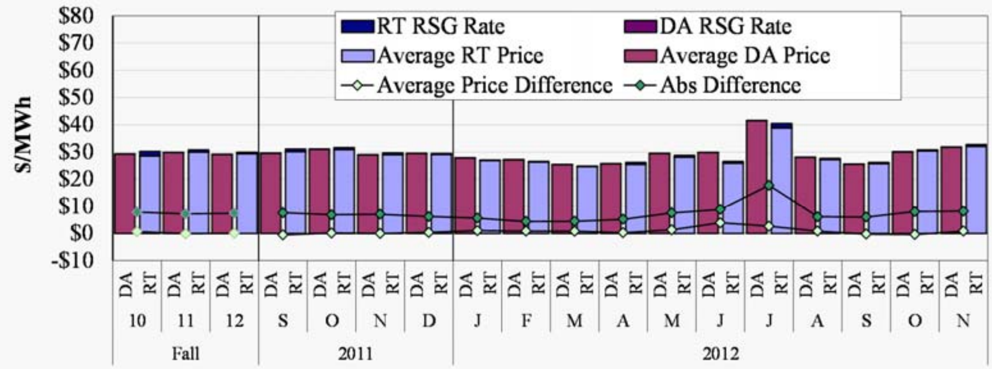
Day-Ahead and Real-Time Price Convergence 2010–2012



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

Cin/Ind Hub	2	-1	0	-2	0	0	1	4	3	3	1	5	15	7	3	-1	-1	3
Michigan Hub	0	-1	3	-3	2	-4	3	5	2	-1	5	5	7	7	3	4	1	3
Minnesota Hub	4	0	-4	-4	0	4	11	3	-2	2	-12	-6	0	2	2	-7	3	-8
WUMS Area	11	6	-1	1	9	8	8	3	0	4	0	-1	-1	2	3	-4	0	0

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

Cin/Ind Hub	-3	-3	-1	-5	-2	-2	0	3	2	2	-2	3	13	3	1	-2	-2	1
Michigan Hub	-5	-4	2	-6	0	-6	2	4	2	-2	2	3	5	4	2	3	0	2
Minnesota Hub	-4	-3	-5	-8	-3	1	10	2	-2	1	-15	-8	-3	-2	1	-9	2	-9
WUMS Area	4	3	-3	-2	7	5	7	2	-1	3	-3	-3	-3	-2	1	-6	-1	-2

Note: Beginning in April 2011, the RSG rate is specifically the DDC Rate charged to deviations, and excludes CMC rates.

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Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG costs because low levels can compel MISO to commit peaking resources to satisfy higher real-time load.
  - ✓ However, real-time commitments are still made to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- Load this fall was modestly under-scheduled on average during all hours (98.9 percent). During the peak hour it was fully scheduled at 100.2 percent.
  - ✓ Under-scheduling was most apparent during off-peak hours, which can be rational if additional supply (such as wind output or imports) is expected in real-time.
- Net virtual load consistently made up a portion of the scheduling shortfall of physical load in most hours.
  - ✓ Much of this was offered price-insensitively by load-serving entities.
- As we show in monthly reports, this broad metric can mask considerable variation in day-to-day scheduling.
  - ✓ Holiday loads are particularly difficult to accurately forecast and schedule.

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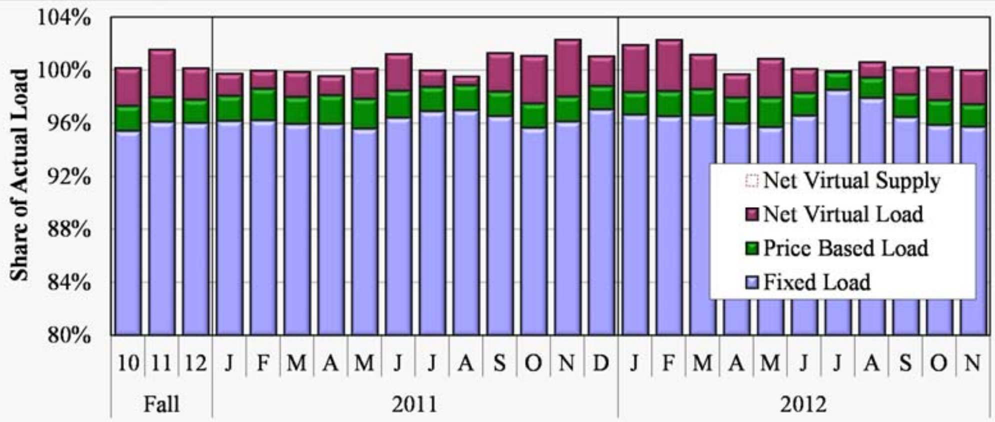
Day-Ahead Peak Hour Load Scheduling Fall 2010–2012



Share of Actual Load(%)

All Hour	99.4	100.4	98.9	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2	100.4	100.4	100.5	99.6	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4
Peak Hour	99.9	101.6	100.2	99.8	100.0	99.9	99.6	100.1	101.2	100.0	99.5	101.3	101.1	102.3	101.1	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6	100.2	100.2	100.0

Virtual Load and Supply in the Day-Ahead Market

- Virtual trading in the day-ahead market facilitates convergence between the day-ahead and real-time prices.
  - ✓ This serves to improve the efficiency of day-ahead market results and moderates market power in the day-ahead market.
- The next figure shows the average hourly quantities of virtual demand bids and supply offers and those that were scheduled (cleared) in the day-ahead market.
- We distinguish between "price-sensitive" and "price-insensitive" bids and offers.
  - ✓ We define bids and offers as price-insensitive when they are submitted at more than $20 above and below an "expected" real-time prices, respectively.
  - ✓ Price-insensitive bids and offers that then contribute to a significant difference in the congestion at a location between the day-ahead and real-time markets (labeled "Screened Transactions") raise potential manipulation concerns.
- We have been monitoring changes in virtual trading activity patterns due to MISO's changes in the RSG cost allocation in April 2011.
  - ✓ The change reduces the allocation of RSG to virtual supply when it is offset by the participant by virtual load or other "helping" deviations.
  - ✓ This allocation has motivated the increase in price-insensitive virtual trading strategies.

Virtual Load and Supply in the Day-Ahead Market

- The figure shows that offered volumes increased 12 percent from last fall.
  - ✓ The rise in virtual demand (up 15 percent, to 9.5 GW) slightly outpaced that of virtual supply (up 8 percent, to 9.4 GW).
- Cleared volumes, however, declined 19 percent from last fall due to the discontinuation in late 2011 of a price-insensitive virtual trading strategy motivated by marginal loss factor differences.
  - ✓ Cleared demand bids totaled 3.7 GW on average, while supply averaged 3.3 GW.
- Approximately 40 percent of cleared volumes were offered price-insensitively this fall, down from 49 percent last fall.
  - ✓ Changes to the RSG allocation in April 2011 reduced the allocation for participants taking balanced positions, which can be ensured by offering price-insensitively.
  - ✓ Much if this activity appears to be designed to arbitrage locational price differences (i.e., congestion differences). A virtual spread product has been proposed (i.e., the "real-time congestion hedge") to allow participants to take such positions.
    - – This would allow the virtual spread (an injection at one point and withdrawal at another) to clear when the difference in LMPs is less than a specified price.
    - – We believe this will be beneficial are recommend its adoption.
- The share of Screened Transactions rose from 1.3 percent last fall to 1.7 percent.
  - ✓ We investigate these closely and did not find a need to impose bid restrictions this fall.

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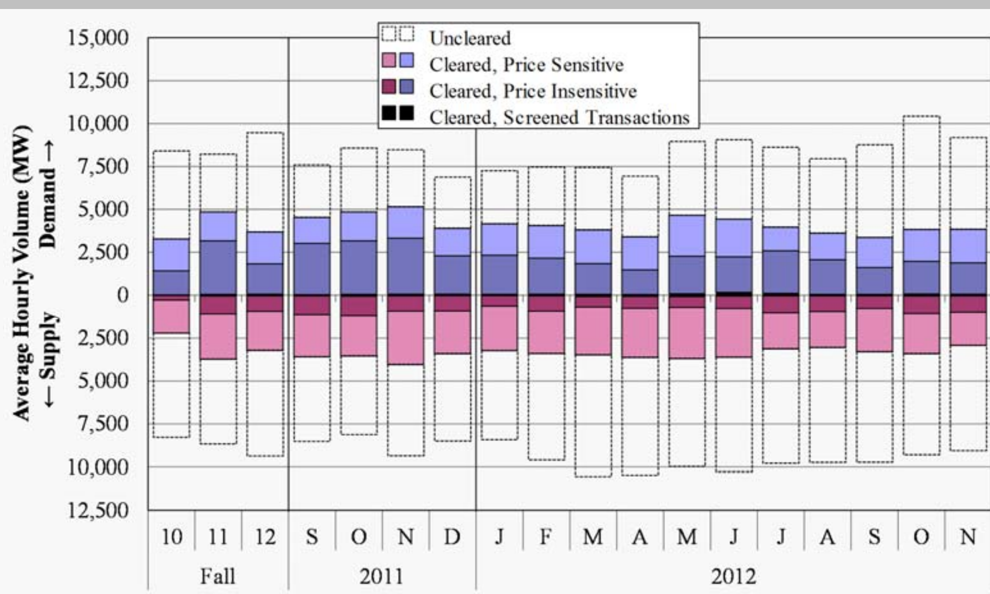
Virtual Volumes
Fall 2010–2012



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Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by two types of market participants: physical participants and financial-only participants.
  - ✓ Financial-only participants comprised 82 percent of all cleared virtual volumes this fall, slightly higher than in fall 2011.
- Virtual load bids by physical participants increased significantly from last fall, but the cleared volumes by these participants fell by 25 percent.
- Much of the decline in financial participants' cleared volumes (by 18 percent) was due to the discontinuation of a strategy targeting marginal loss factors.
- The share of volumes that are price-sensitive continues to be much higher for financial-only participants than those of physical participants (66 vs. 31 percent).
  - ✓ Both are a considerable improvement from last fall when 58 and 18 percent were offered price-sensitively, respectively.

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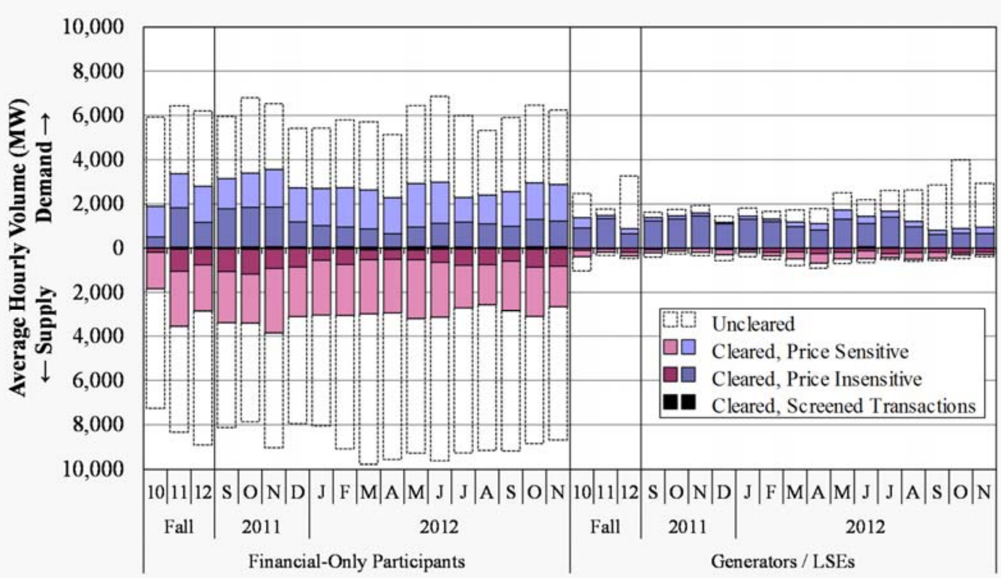
Virtual Load and Supply by Participant Type Fall 2010–2012



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Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual purchases and sales.
- Gross profits on virtual transactions totaled $7.6 million this fall ($0.50 per MW).
  - ✓ This is a modest reduction from the $0.88 per MW profit last fall.
  - ✓ For the quarter, virtual supply was more profitable (at $0.63 per MW) than demand ($0.40), which is expected when the market exhibits a day-ahead premium.
- These margins exclude CMC and DDC charges assessed to net harming deviations, including DDC charges to net virtual supply. These averaged $0.58 per MWh this fall.
  - ✓ As previously noted, the CMC allocation to virtual transactions is incorrect, resulting in allocations to virtual transactions that reduce the need for real-time commitments.
  - ✓ We are working with MISO to resolve this issue.
- Virtual transactions by financial participants continue to be profitable and improve price convergence overall.
  - ✓ Profitability of these transactions declined from $1.11 last fall to $0.55 per MW.
- Some physical participants have consistently incurred losses on virtual demand, likely to hedge risks associated with supply uncertainty and real-time price spikes.
  - ✓ This fall, however, virtual demand was uncharacteristically profitable for physical participants at $0.50 per MW. It averaged $-2.02 in summer and $-0.20 last fall.

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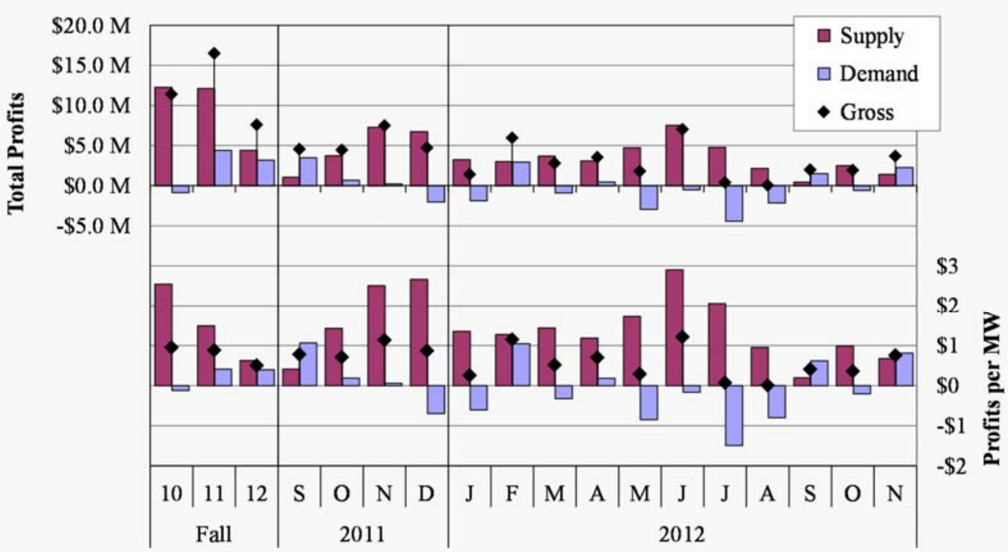
Virtual Profitability Fall 2010–2012



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Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were in-merit (offer price lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Peaking resource dispatch quantities rose 60 percent from last fall to an average of 274 MW per hour.
  - ✓ Lower natural gas prices reduces the costs of many peaking resources. Hence, the dispatch of day-ahead committed resources rose 48 percent from last fall.
  - ✓ Real-time capacity needs in November were 4 times greater than last November.
  - ✓ Units dispatched for real-time congestion needs declined 14 percent, while real-time VLR needs were minimal (most VLR commitments are now made in DA).
- Approximately half of dispatches were made in-merit, unchanged from last fall.
- When peaking resources are dispatched out-of-merit, they do not contribute to setting the energy price, even though their output may be needed to meet demand.
  - ✓ MISO's ELMP initiative, filed in December 2011, will allow peaking resources to set energy prices more reliably. It is set to be introduced in 2014.
  - ✓ This will improve MISO's price signals and lower its production costs.

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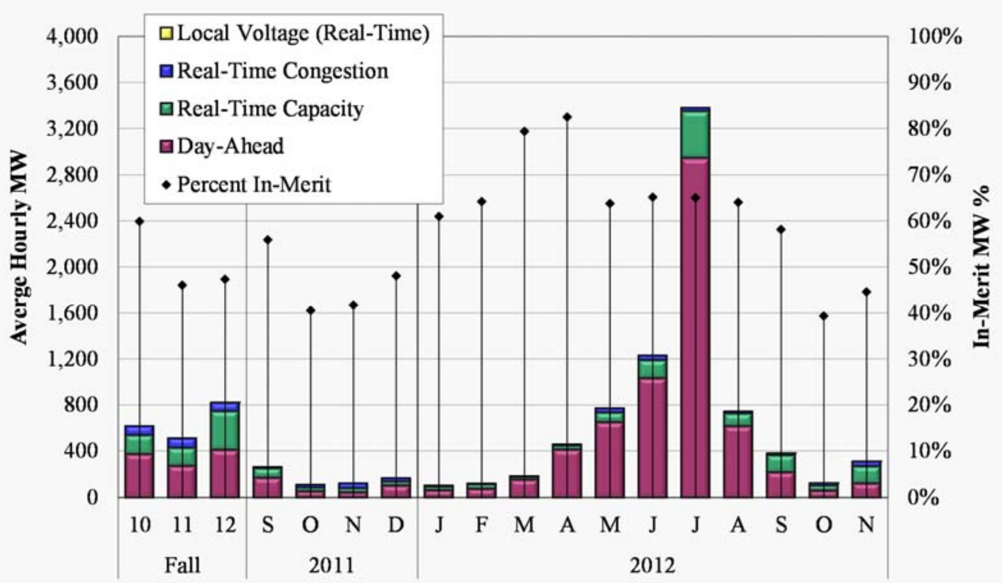
Peaking Resource Dispatch and In-Merit Status Fall 2010–2012



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Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets, respectively.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices (adjusting values to correspond to the average fuel prices over the period shown).
- Nominal real-time RSG costs declined 21 percent from last fall to $12.4 million. The decrease in fuel prices accounted for 60 percent of this decline.
- Commitments for congestion declined 12 percent to a fuel-adjusted $4.8 million.
  - ✓ One unit in the West region required $1.4 million in total payments because it was committed for 9 different constraints on 18 separate days in the quarter.
- The second figure shows that day-ahead payments more than doubled, in fuel-adjusted terms, to $10.7 million.
  - ✓ This rise was entirely attributable to VLR payments. Commitments for voltage support are now mostly made in the day-ahead market.
  - ✓ Voltage commitments in real-time declined from $4.7 million last fall to just $408,000.
- Peaking units this fall received 73 percent of total payments, up from 46 percent last fall, and were mostly committed made for capacity.

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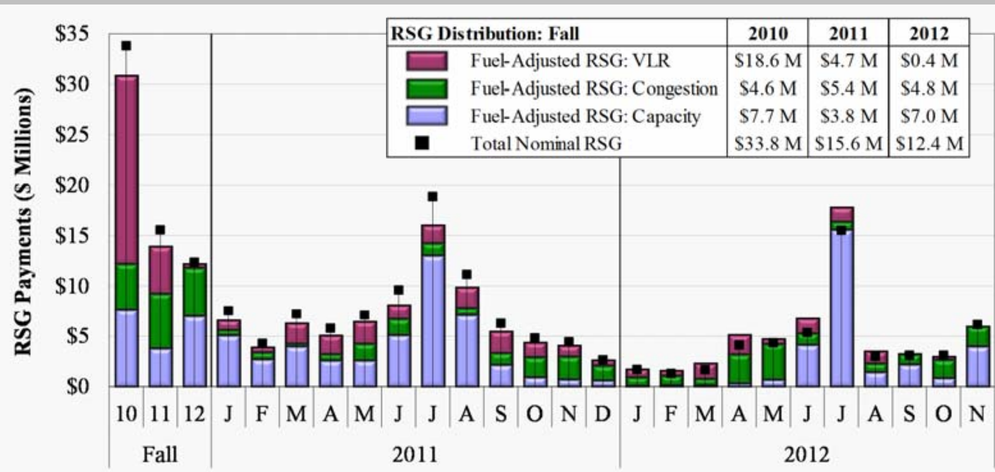
Real-Time RSG Payments
Fall 2010–2012



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

Peaker	27	46	73	60	53	54	53	48	68	75	66	45	48	43	35	27	31	30	51	76	68	84	44	68	73	75
Non-Peaker	73	54	27	40	47	46	47	52	32	25	34	55	52	57	65	73	69	70	49	24	32	16	56	32	27	25

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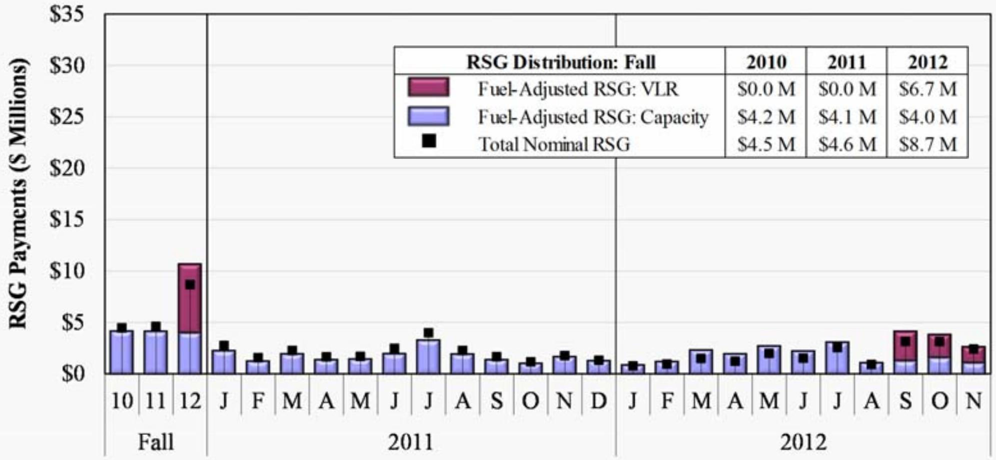
Day-Ahead RSG Payments
Fall 2010–2012



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

Peaker	7	8	2	2	0	2	2	6	20	41	16	19	12	9	4	2	1	2	9	21	13	59	34	8	1	2
Non-Peaker	93	92	98	98	100	98	98	94	80	59	84	81	88	91	96	98	99	98	91	79	87	41	66	92	99	98

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Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments ("PVMWP") that improve incentives for suppliers to follow dispatch instructions.
  - ✓ The payments are in two forms: Day-Ahead Margin Assurance payments ("DAMAP") and Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP").
- Total PVMWP declined 25 percent from last fall to $16.2 million.
  - ✓ DAMAP declined 31 percent from last fall to $12.1 million.
  - ✓ RTORSGP was nearly unchanged at $4.0 million.
- The lines on the chart show two measures of price volatility: one based on the System Marginal Price ("SMP") and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility as expected—increased volatility leads to higher obligations to flexible suppliers.
  - ✓ SMP and LMP volatility declined 12 percent from last fall.
  - ✓ It also shows that volatility is higher at recipients' locations associated with congestion, which causes more frequent dispatch changes.
- We continue to work with MISO to address potential gaming concerns raised in the 2011 State of the Market Report.

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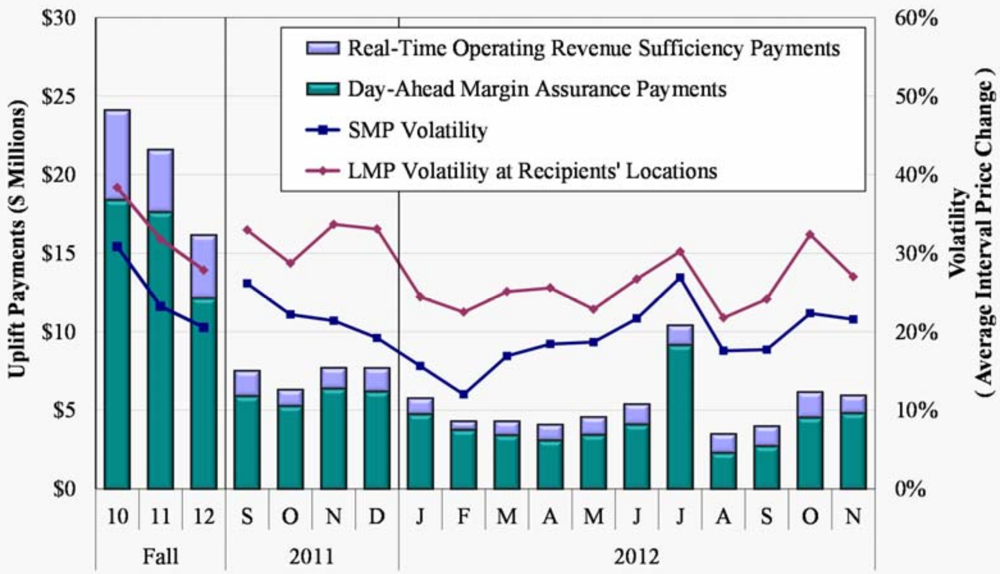
Price Volatility Make Whole Payments Fall 2010–2012



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Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Attractive wind profiles in the West Region, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind generation.
- Real-time wind output increased 15 percent from last fall to over 3.8 GW, and comprised 8.2 percent of total generation this quarter.
  - ✓ MISO set an all-time wind peak at just over 10 GW on the morning of November 23.
  - ✓ Nameplate capacity over the same period increased 17 percent to 12.4 GW. Wind resources currently comprise over 10 percent of total nameplate capacity in MISO.
- Variability in output—both in real time and deviations from the day-ahead—must be managed by MISO by modifying the commitment or dispatch of other resources.
  - ✓ Five-minute real-time wind volatility increased 13 percent from last fall to 43 MW, which is consistent with the overall increase in output.
- Under-scheduling of wind in the day-ahead rose 39 percent from last fall to 709 MW.
  - ✓ Very little of this was offset by net virtual supply at wind locations, a considerable change from last fall, when more than half was under-scheduled.
  - ✓ Profitability of virtual transactions at wind locations declined 46 percent but remained profitable at $0.78 per MW.

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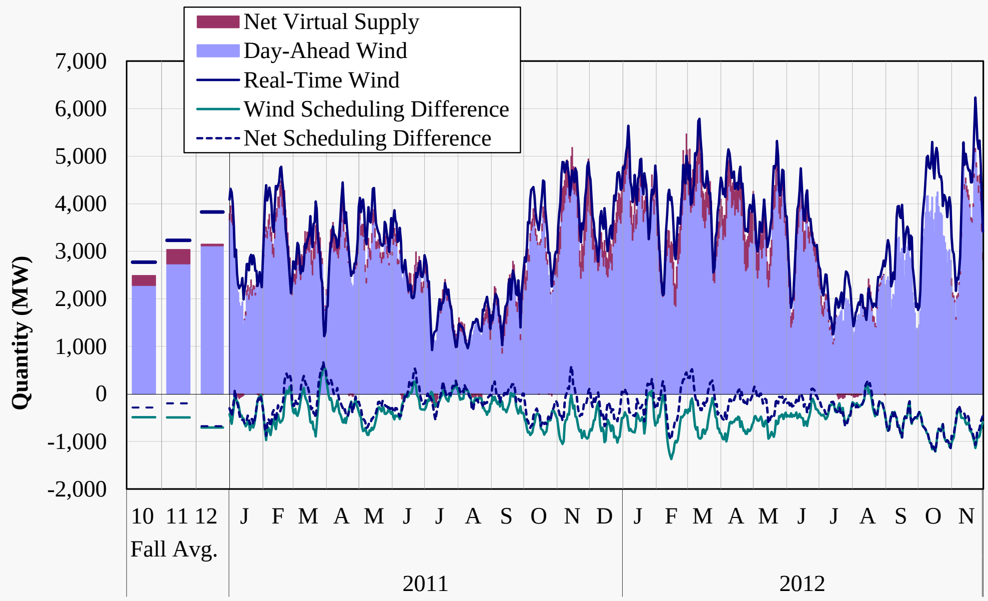
Wind Output in Real-Time and Day-Ahead Markets 7-Day Moving Average, Fall 2010–2012



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Wind Curtailment

- Since the implementation of the DIR type in June 2011, increasing amounts of wind resources have become able to respond to MISO dispatch instructions.
  - ✓ As of December 1, 59 of 182 wind units (and 52 percent of total capacity) were DIR.
  - ✓ All wind resources, unless placed into service prior to April 1, 2005 or otherwise exempt, must become DIR by March 1, 2013.
- Manageability of the congestion caused by variable wind output continued to improve as the share of DIR resources expands.
  - ✓ Manual curtailments of wind resources by MISO remained necessary at times to prevent transmission overloads.
- The following figure shows that economic DIR curtailments have replaced manual curtailments as the primary means of controlling wind output.
  - ✓ Economic curtailment of wind resources averaged 71 MW in fall 2012, nearly double the 36 MW averaged last fall.
  - ✓ Conversely, manual curtailments declined 87 percent from last fall to 15 MW per hour.
    - – As a share of wind output, manual curtailments totaled just 0.4 percent, down from 3.6 and 4.9 percent in the prior two fall quarters.

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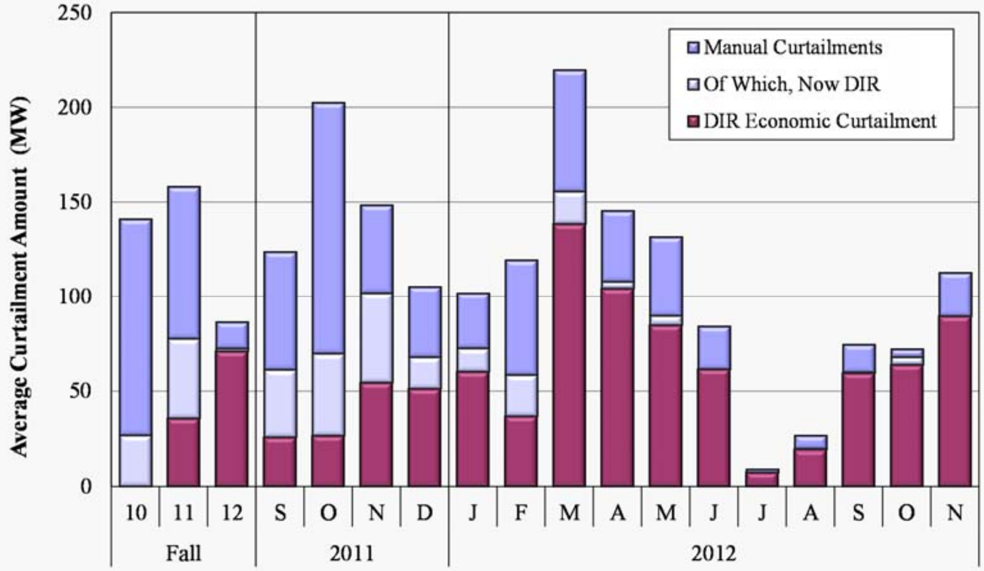
Wind Curtailment Fall 2010–2012



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Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on MISO-managed internal and market-to-market constraints (the figure excludes external constraints).
  - ✓ Real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ This is higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO’s transmission capability.
  - ✓ The figure separately shows congestion on those constraints that are temporarily violated (i.e., the congestion is considered “unmanageable” in the 5-minute dispatch).
- The value of real-time congestion declined 2 percent from last fall to $317 million.
  - ✓ The top nine most expensive constraints were all in Illinois and Indiana, many of which were as a result of several concurrent seasonal generator and transmission outages.
- Constraint relaxation continues to be used on market-to-market constraints.
  - ✓ Relaxation eliminated just 1 percent of congestion costs this quarter, compared to 14 percent last fall.
  - ✓ While much improved from last year, relaxation still adversely affects the day-ahead market, the FTR market and longer-term investment decisions.

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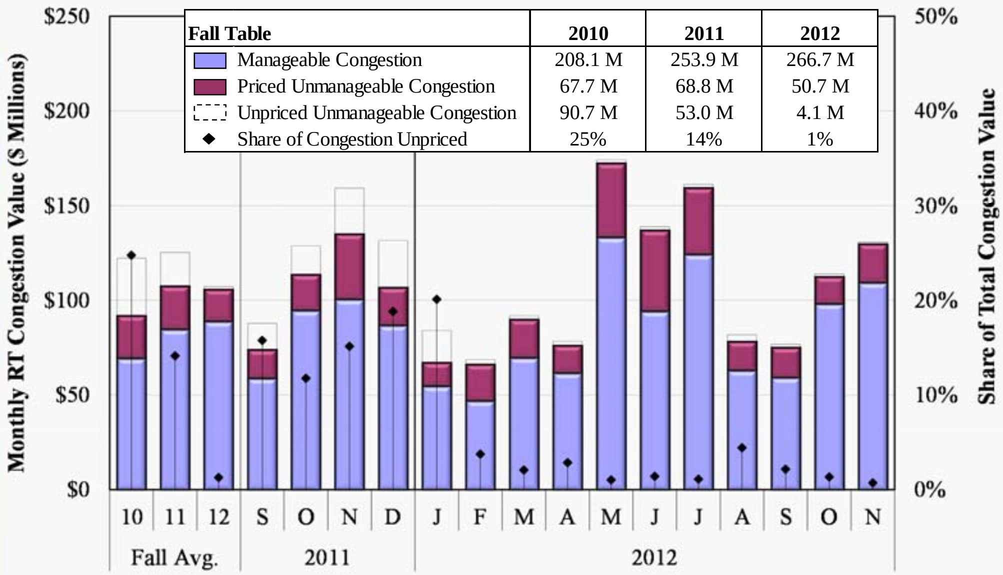
Value of Real-Time Congestion Fall 2010–2012



Fall Table	2010	2011	2012
Manageable Congestion	208.1 M	253.9 M	266.7 M
Priced Unmanageable Congestion	67.7 M	68.8 M	50.7 M
Unpriced Unmanageable Congestion	90.7 M	53.0 M	4.1 M
Share of Congestion Unpriced	25%	14%	1%

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Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market in fall 2010 to 2012.
- MISO continues to be a net importer of energy during most hours. Net imports averaged 3.7 GW per hour this fall, a 22 percent decline from last fall.
- Net imports declined from over 4.2 GW in September and October to 2.4 GW in November, driven largely by changes in relative market conditions between MISO and adjacent areas.
  - ✓ Excluding wheeled transactions, the decrease occurred across all interfaces, including 5 percent across Manitoba and 14 percent across PJM.
- Net imports were under-scheduled in day ahead by an average of 202 MW.
  - ✓ This is an improvement from the prior fall, when it averaged 378 MW.
- MISO and PJM continue to discuss proposals to improve interchange in the JCM process, including interchange optimization and alignment of scheduling rules.

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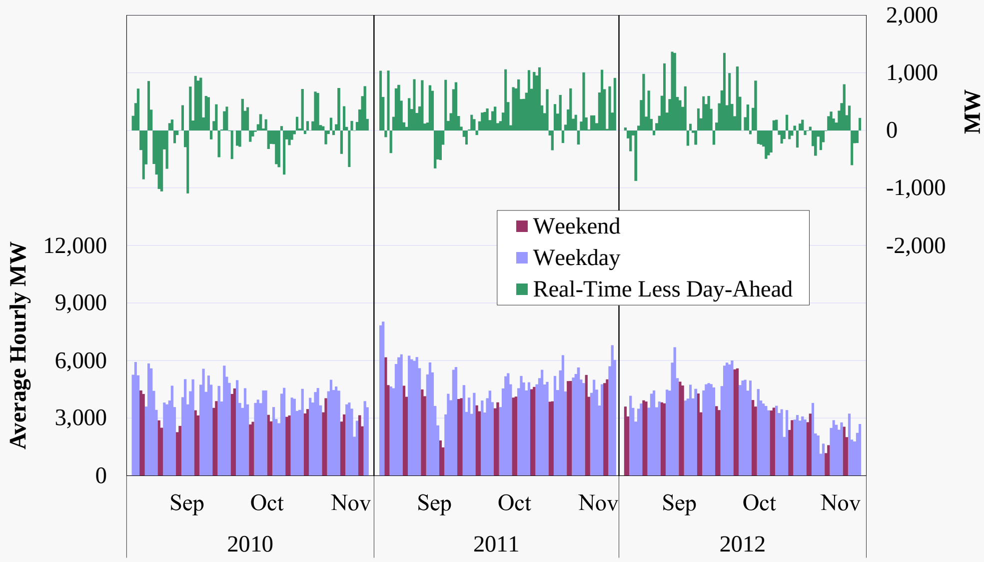
Average Hourly Real-Time Imports Fall 2010–2012



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Monthly Output Gap

- The output gap measure is used to screen for economic withholding by suppliers.
  - ✓ It measures the difference between actual output and the output level that would be expected based on competitive offers.
- The next figure shows the output gap since fall 2010 under two thresholds:
  - ✓ A “high” threshold, equal to the mitigation threshold; and
  - ✓ A “low” threshold, equal to one-half of mitigation threshold.
- Output gap levels in MISO remain extremely low under both threshold levels.
  - ✓ At the high threshold, output gap declined from 18 MW last fall to 10 MW.
  - ✓ At the low threshold, it from 50 MW last fall to 36 MW.
- As a share of overall load, the low-threshold output gap has averaged less than 0.01 percent of load since March 2011.
- Overall, these results raised no competitive concerns, although we continue to routinely investigate hourly increases in the output gap.

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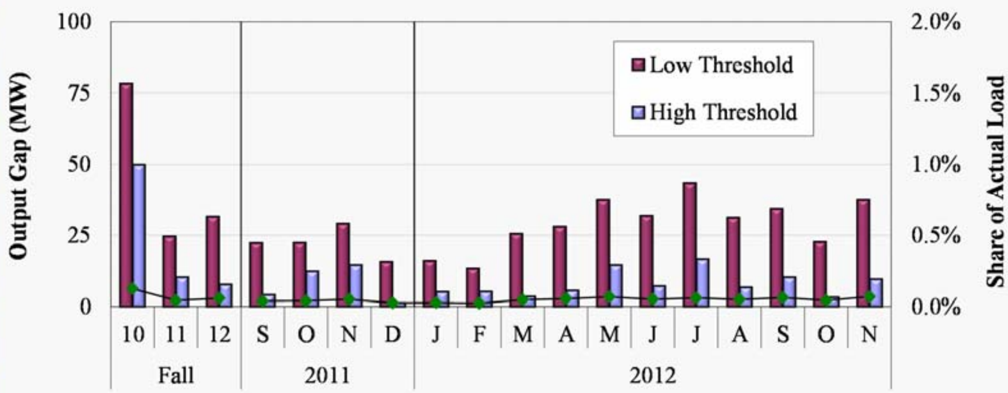
Monthly Output Gap
Fall 2010–2012



Low Threshold Results by Unit Status (MW)

Off Line	19	8	3	1	11	12	0	4	4	1	1	9	0	11	0	8	0	2
On Line	60	17	28	22	12	17	16	12	9	24	27	29	32	33	31	26	23	36

High Threshold Results by Unit Status (MW)

Off Line	19	8	2	1	11	12	0	4	4	1	1	9	0	9	0	5	0	1
On Line	31	3	6	4	1	3	1	2	1	2	4	6	7	7	7	5	3	9

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Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which energy and RSG mitigation was imposed in the real-time market.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Since most resources are offered competitively, mitigation in MISO remains infrequent.
  - ✓ We continue to evaluate each instance of AMP mitigation and found mitigation to be appropriately applied in each instance.
- Energy mitigation occurred for 10 hours and 600 MW, up from 300 MW last fall.
  - ✓ Three resources this fall were mitigated under the new VLR mitigation authority, enacted earlier in 2012. It has tighter conduct and impact thresholds.
  - ✓ Nearly 90 percent of mitigation quantities occurred in Broad Constrained Areas.
  - ✓ The rest occurred in the Minnesota NCA, where the mitigation threshold was lowered in early 2012.
- RSG mitigation quantities rose from last fall to $130,000.
  - ✓ Two unit-days were mitigated under VLR in the day-ahead market.
- Although mitigation is infrequent, local market power continues to be a significant concern and market power mitigation measures remain critical.

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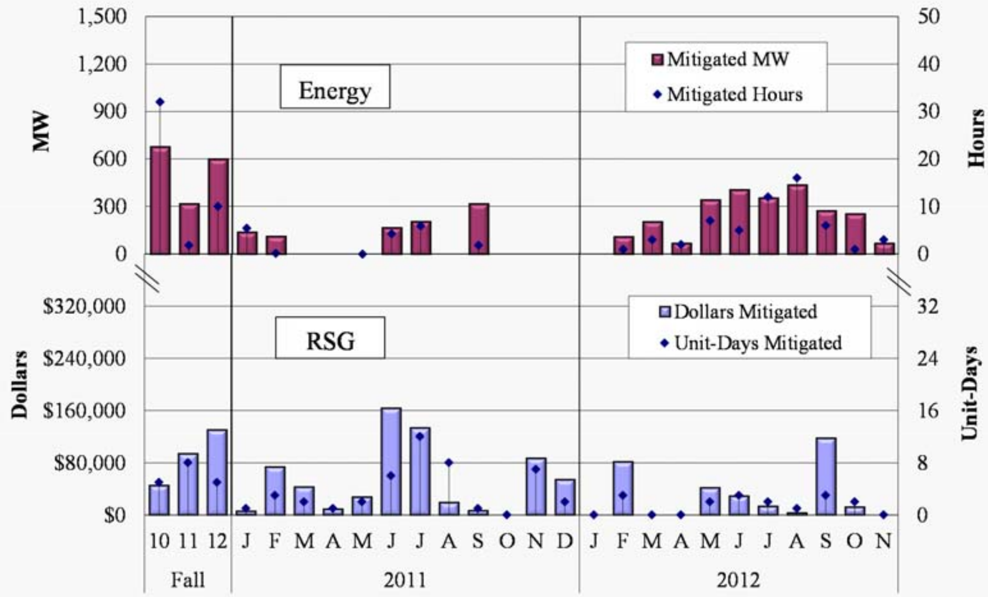
Real-Time Market Power Mitigation
Fall 2010–2012



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Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities (LSEs) to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The following figure shows the monthly capacity requirements, designated capacity, and VCA clearing price since January 2011.
- The auction cleared at $0.10 to $0.15 per MW-month in each month this fall, which is very low and reflects the shoulder-month capacity surplus in MISO.
  - ✓ The surplus exceeded the VCA requirement (based on forecasted load) by 24 percent in September to 47 percent in November.
- Barriers to trading capacity with PJM and the current vertical demand curve continue to contribute to inefficiently low capacity prices, particularly in summer months.
  - ✓ Changes to improve MISO's Resource Adequacy Construct have been approved by FERC, but it remains important to separately address these two market design flaws.
- The figure also shows how LSEs met their capacity obligations.
  - ✓ The capacity cleared in the VCA each month remains a very small portion of the total designated capacity (approximately 1 percent). This reflects the fact that most LSEs satisfy their needs primarily through owned capacity or bilateral purchases.
  - ✓ Capacity designations by LSEs this fall exceeded the requirement by 3 to 5 percent.

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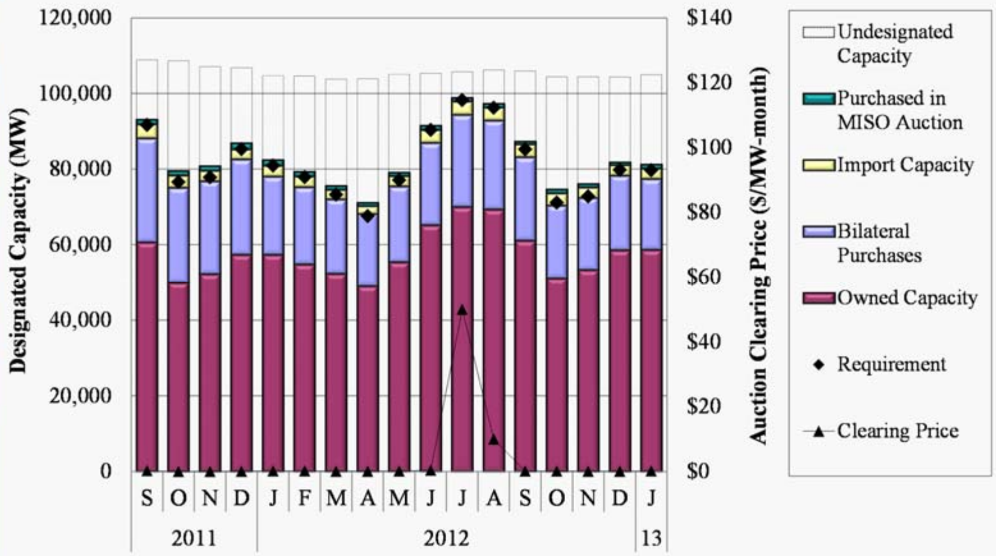
Voluntary Capacity Auction
Sept 2011–Jan 2013



Note: Total column height represents the total designated capacity, including imports.

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Submittals to External Entities and Other Issues

Submittals to External Entities:

- We continue to meet with FERC regarding market outcomes and prior referrals.
- We continue to respond to inquiries and data requests, and to submit reports to FERC on virtual trading activity and compliance with Module E must-offer requirements.
- We continued to participate in a MISO-PJM working group on JCM priorities.
- We have been working with MPs to develop necessary data for new Regulation references required for upcoming Order 755 implementation.

Other Issues:

- MISO recently refunded almost $7 million in market-to-market charges.
  - ✓ Based on a review of the applicable tariff provisions and FERC orders, our FERC counsel concluded that the tariff provides no authority for this refund.
  - ✓ MISO customers should not incur these costs because PJM accounted for the majority of the flow on the constraints and was well over its entitlement.
  - ✓ This was reviewed with stakeholders at the MSC and numerous billing disputes have been filed.
- We have been investigating concerns regarding resources failing to update real-time offers parameters to reflect generator deratings.

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