# IMM Quarterly Report: Fall 2013
# September–November


MISO Independent Market Monitor

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Potomac Economics


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## Quarterly Summary

| | Value | Change[1] Prior Qtr. | Change[1] Prior Year |
|---|---|---|---|
| **RT Energy Prices ($/MWh)** | $31.48 | *-5%* | *12%* |
| **Fuel Prices ($/MMBtu)** | | | |
| Natural Gas | $3.74 | *1%* | *11%* |
| Western Coal | $0.63 | *4%* | *14%* |
| Eastern Coal | $1.86 | *0%* | *5%* |
| **Load (MW)**[2] | | | |
| Average Load | 55.7 | *-9%* | *3%* |
| Peak Load | 89.4 | *-7%* | *5%* |
| % Scheduled DA (Peak Hour) | 99.6% | 98.3% | 100.2% |
| **Transmission Congestion ($M)** | | | |
| Real-Time Congestion Value | $445.1 | *19%* | *37%* |
| Day-Ahead Congestion Revenue | $262.2 | *39%* | *51%* |
| Balancing Congestion[4] | $11.6 | $4.8 | $11.4 |
| **Ancillary Service Prices ($/MWh)** | | | |
| Regulation | $10.83 | *14%* | *20%* |
| Spinning Reserves | $3.12 | *-10%* | *43%* |
| Supplemental Reserves | $2.53 | *0%* | *124%* |

| | Value | Change[1] Prior Qtr. | Change[1] Prior Year |
|---|---|---|---|
| **FTR Funding (%)** | 97% | 99% | 92% |
| **Wind Output (MW)** | 4,413 | *66%* | *15%* |
| **Guarantee Payments ($M)** | | | |
| Real-Time RSG | $14.0 | *-40%* | *14%* |
| Day-Ahead RSG | $7.4 | *64%* | *-15%* |
| Day-Ahead Marginal Assurance | $13.4 | *25%* | *24%* |
| RT Operating Rev. Sufficiency | $2.9 | *11%* | *-22%* |
| **Price Convergence**[3] | | | |
| Market-wide DA Premium | -2.8% | -2.5% | -3.0% |
| **Virtual Trading** | | | |
| Cleared Quantity (MW) | 6,099 | *-7%* | *-11%* |
| % Price Insensitive | 33% | 39% | 40% |
| % Screened for Review | 2% | 1% | 2% |
| Profitability ($/MW) | $1.32 | $1.36 | $0.51 |
| **Dispatch of Peaking Units (MW/hr)** | 311 | 720 | 273 |
| **Output Gap- Low Thresh. (MW/hr)** | 63 | 40 | 31 |
| **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 any 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 in September to November for the last three years.
  - ✓ 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 rose 13 percent from last fall to $31.31 per MWh.
  - ✓ This rise is broadly consistent with an 11 percent rise in natural gas prices, which averaged $3.74 per MMBtu his fall. Average load rose 3.2 percent from last fall.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ Hub prices this fall were highest at WUMS ($33.77 per MWh) and lowest at Minnesota Hub ($31.45 per MWh).
  - ✓ This reflects the significant congestion that occurred in Iowa this quarter.
    - – Three of the four most expensive constraints, totaling $60 million in day-ahead congestion value, were associated with planned generator outages in Iowa that provide relief on the constraints.
    - – These constraints had a cumulative quarterly price impact of over $35 at certain locations.



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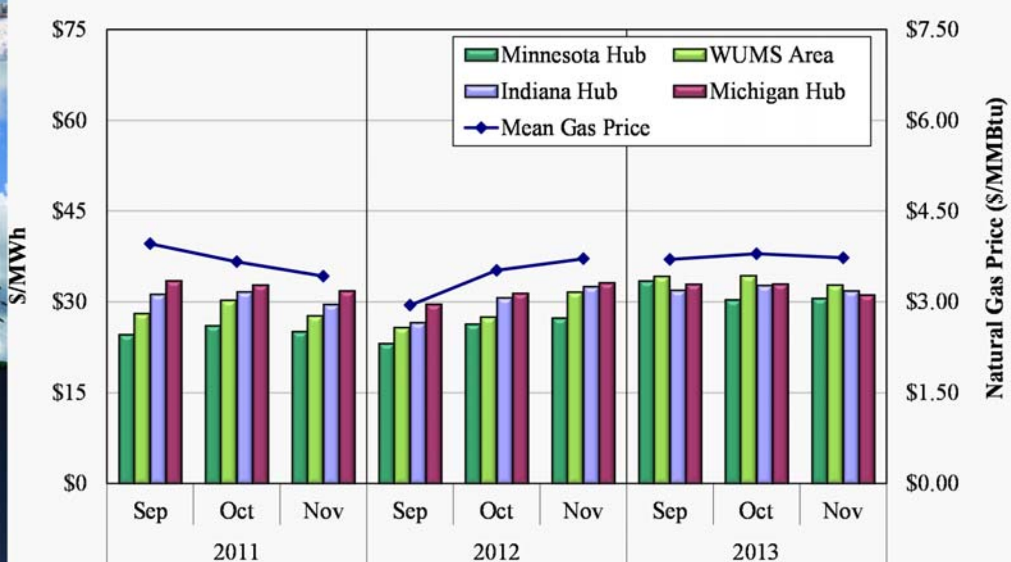
# Day-Ahead Average Monthly Hub Prices Fall 2011–2013




Note: Cinergy Hub was replaced by Indiana Hub as the Central region's proxy price after 2011.



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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 monthly average natural gas prices, since energy prices generally track changes in fuel prices.
- The all-in price rose 12 percent from last fall to $31.77 per MWh.
  - ✓ The rise was almost entirely in the energy component, which continues to account for nearly all (98.9 percent) of the all-in price.
  - ✓ Real-time energy prices rose fastest in October, when there were six operating reserve shortages.
- Non-energy costs increased slightly from last fall, but remain very small.
  - ✓ Uplift costs added 9 cents, while ancillary services added 19 cents.
  - ✓ The Planning Reserve Auction cleared at $1.05 per MW-day (i.e., 5 cents per MWh) for the 12 months beginning in June 2013.
    - – A Transitional PRA for MISO South in late November cleared at zero.
    - – The importance of the PRA will increase when the capacity surplus in MISO falls and certain market issues are addressed.



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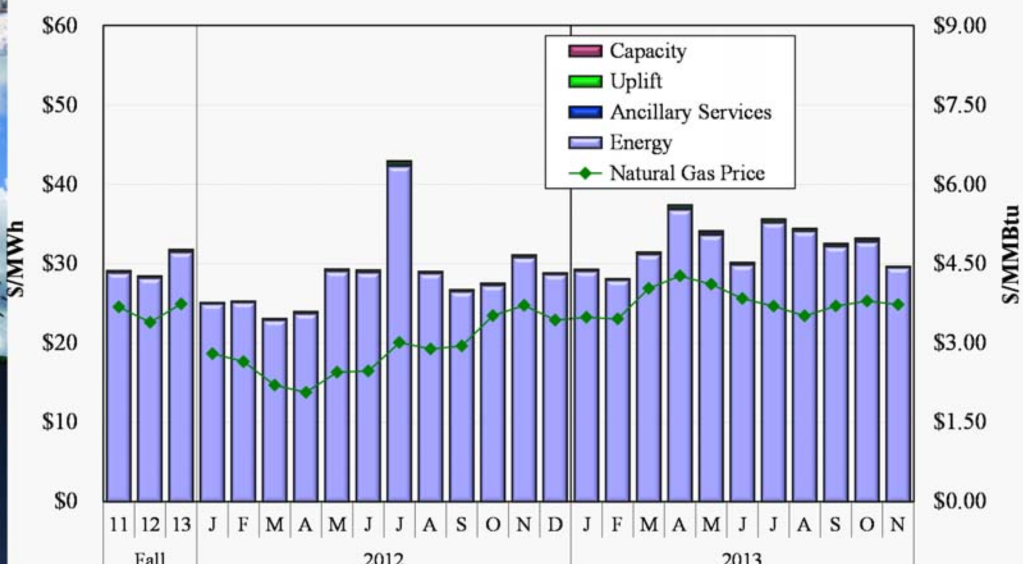
## All-In Price
## Fall 2012–2013



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# 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).
- AS prices all rose considerably from last fall due to fewer available supplemental-qualified resources and modestly higher gas and energy prices.
  - ✓ The supply of supplemental-qualified resources declined significantly from last year, partly because MISO deemed some resources to have insufficient response capability.
  - ✓ Since higher-quality reserves can substitute for lower-quality reserves, prices for all three AS products rose this fall.
- Regulation prices rose 20 percent from last fall to $10.83 per MWh.
  - ✓ Shortage pricing added just 62 cents to the price, a 49 percent decline from last fall.
  - ✓ There was just 1 regulation shortage interval all quarter, compared to 46 last fall.
  - ✓ The market continues to exhibit a modest real-time premium for regulation.
- Spin prices rose 43 percent to $3.12 per MWh, while supplemental reserve prices more than doubled to $2.53. Shortages for each product, however, declined.



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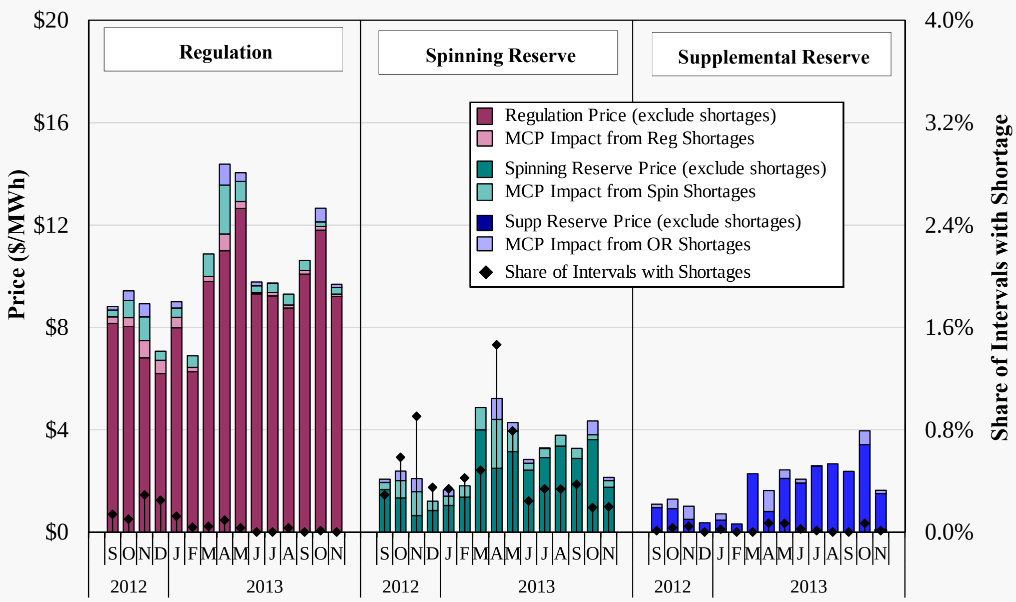
# Monthly Average Ancillary Service Prices Regulation and Contingency Reserves, 2012–2013



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# MISO Fuel Prices and Capacity Factors

Natural Gas and Oil Prices

- Natural gas prices rose 11 percent from last fall to \$3.74 per MMBtu.
  - ✓ Prices ranged from \$3.50 per MWh to \$4.07 (in late November).
- Oil prices declined gradually over the quarter and fell 7 percent from last fall to \$21.41 per MMBtu.
  - ✓ Although this fuel is rarely marginal (and so has a minimal impact on energy prices), significant RSG payments can accrue to such units.

Coal Prices

- Illinois Basin prices rose 8 cents from last fall to \$1.86 per MMBtu, while Western (Powder River Basin) coal prices rose 7 cents to \$0.63.
  - ✓ Both prices remain 20-25 percent lower than what they averaged in fall 2011.
  - ✓ Rail transportation costs can make the delivered cost of coal, and PRB coal in particular, significantly higher than mine-mouth prices.



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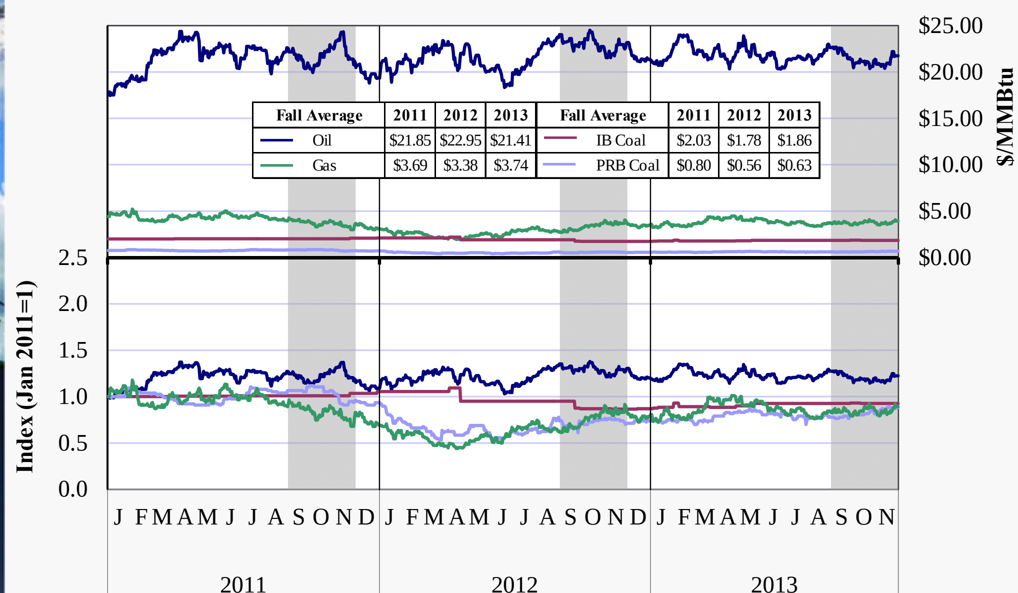
# MISO Fuel Prices 2011–2013



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## Changes in Load and Weather Patterns

- A large share of the load is sensitive to weather, so changes in weather patterns contribute directly to changes in load. This relationship is shown in the next figure.
  - ✓ The top panel shows peak and average load in the fall months of 2011 to 2013, while the bottom panel shows the average heating and cooling degree days (a weather metric that is highly correlated with load).
  - ✓ Degree days are normalized (based on a regression analysis) so that heating and cooling days have an equal effect on load.
- The figure shows that degree days rose 10 percent from last fall, and were slightly above the historical average in each month (and cumulatively 11 percent).
  - ✓ September was warmer than usual in the Midwest, which resulted in a 34 percent increase in cooling degree days.
- The higher degree days contributed to the rise in average load of 3.2 percent from last fall. It averaged 55.7 GW for the quarter.
  - ✓ From September 9 to 11, a late-summer heat wave produced daily peak loads over 85 GW. It peaked at 89.4 GW on September 10th, up from 85.1 GW last fall.
  - ✓ After this three-day period, loads never exceeded 72 GW.



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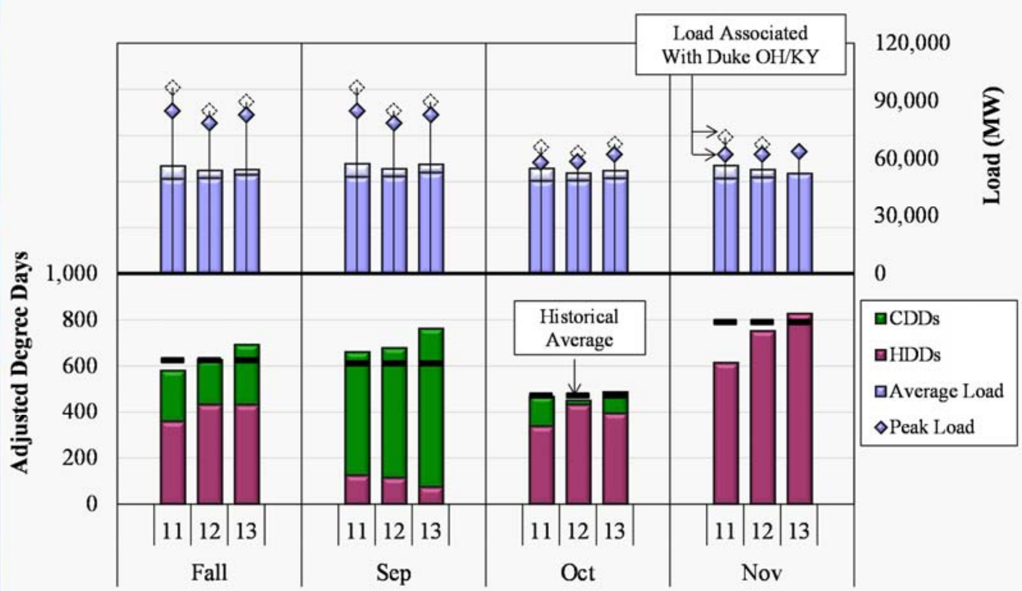
## Load and Weather Patterns
## Fall 2011–2013




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



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## 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.
- Convergence was good at all locations except Minnesota, where there was a real-time premium of 7 percent (this includes $0.78 per MWh in average RSG costs).
  - ✓ Real-time congestion in Iowa in the second half of the quarter exceeded what was anticipated by the day-ahead market.
  - ✓ Two sets of constraints contributed to approximately $3 in real-time premium (10 percent) at the Minnesota Hub.
- Congestion-related price differences at wind locations were relatively large during the fall quarter.
- Real-time price volatility (as measured by the absolute price difference metric) was nearly unchanged from last fall at $7.41 per MWh.



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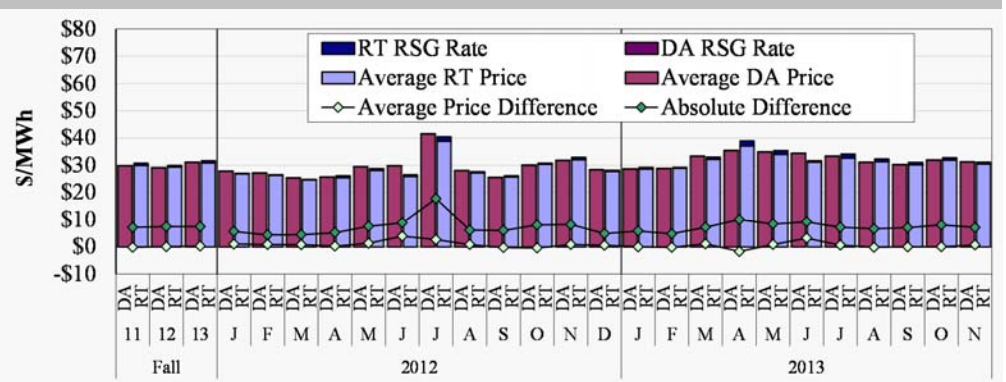
## Day-Ahead and Real-Time Price Convergence 2011–2013




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

| | Fall 11 | Fall 12 | Fall 13 | 2012 J | F | M | A | M | J | J | A | S | O | N | D | 2013 J | F | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cin/Ind Hub | -1 | 0 | 1 | 4 | 3 | 3 | 1 | 5 | 15 | 7 | 3 | -1 | -1 | 3 | 2 | 0 | -1 | 3 | -5 | 2 | 10 | 2 | 0 | 0 | 0 | 2 |
| Michigan Hub | -1 | 3 | 1 | 5 | 2 | -1 | 5 | 5 | 7 | 7 | 3 | 4 | 1 | 3 | 1 | 1 | 2 | 5 | -5 | 1 | 7 | -1 | 0 | -2 | 0 | 5 |
| Minnesota Hub | 0 | -4 | -5 | 3 | -2 | 2 | -12 | -6 | 0 | 2 | 2 | -7 | 3 | -8 | -1 | 3 | 4 | 4 | -7 | 7 | 2 | -2 | -5 | -1 | -3 | -9 |
| WUMS Area | 6 | -1 | 3 | 3 | 0 | 4 | 0 | -1 | -1 | 2 | 3 | -4 | 0 | 0 | 3 | 1 | 4 | 4 | -5 | 1 | 6 | 2 | -4 | 3 | 1 | 7 |

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

| | Fall 11 | Fall 12 | Fall 13 | 2012 J | F | M | A | M | J | J | A | S | O | N | D | 2013 J | F | M | A | M | J | J | A | S | O | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cin/Ind Hub | -3 | -2 | -1 | 3 | 2 | 2 | -2 | 3 | 12 | 3 | 1 | -2 | -2 | 0 | 1 | -2 | -2 | 1 | -9 | -1 | 9 | -2 | -4 | -3 | -2 | 1 |
| Michigan Hub | -4 | 1 | -1 | 4 | 2 | -2 | 2 | 3 | 5 | 4 | 2 | 3 | 0 | 1 | -1 | -1 | 1 | 3 | -10 | -3 | 5 | -5 | -3 | -4 | -2 | 3 |
| Minnesota Hub | -3 | -6 | -7 | 2 | -2 | 1 | -14 | -8 | -3 | -2 | 1 | -8 | 2 | -10 | -2 | 1 | 3 | 1 | -11 | 2 | 0 | -6 | -8 | -4 | -6 | -10 |
| WUMS Area | 3 | -3 | 1 | 2 | -1 | 3 | -3 | -3 | -3 | -2 | 1 | -6 | -1 | -3 | 1 | -1 | 3 | 1 | -9 | -3 | 4 | -2 | -6 | 0 | -1 | 5 |



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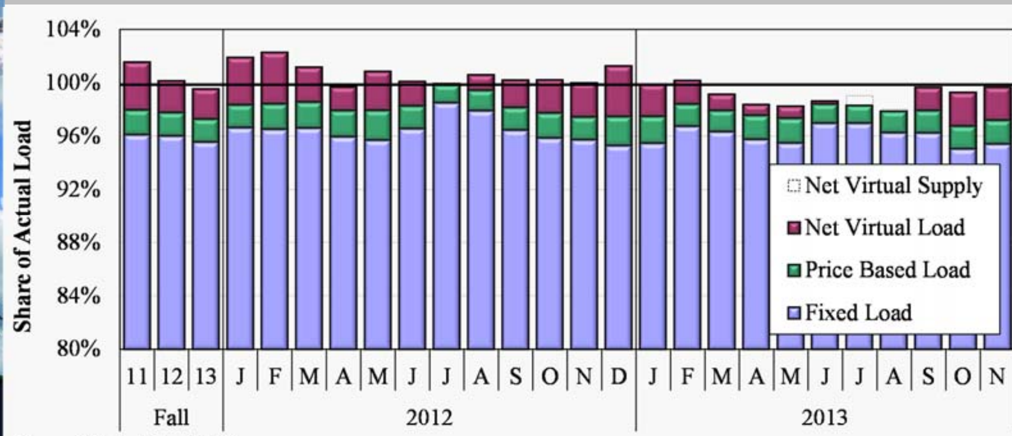
# Day-Ahead Load Scheduling

- 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 in real time to satisfy load.
  - ✓ However, some real-time commitments are made regardless of load scheduling levels. These commitments include those to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- For the quarter, load scheduling during the peak hour of each day averaged 99.6 percent compared to 100.2 percent last fall.
  - ✓ During all hours, it rose slightly to 99.0 percent.
  - ✓ Net virtual demand of 819 MW offset a 2.7 percent shortfall in physical load.





# Day-Ahead Peak Hour Load Scheduling
# Fall 2012–2013




Share of Actual Load (%)

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| All Hours | 100.4 | 98.9 | 99.0 | 100.1 | 99.7 | 99.7 | 97.7 | 99.9 | 99.3 | 100.1 | 100.0 | 98.4 | 98.8 | 99.4 | 100.1 | 99.4 | 99.7 | 99.6 | 98.9 | 98.6 | 99.0 | 98.8 | 98.9 | 99.1 | 98.8 | 99.0 |
| Peak Hour | 101.6 | 100.2 | 99.6 | 101.9 | 102.3 | 101.2 | 99.7 | 100.9 | 100.1 | 99.9 | 100.6 | 100.2 | 100.2 | 100.0 | 101.3 | 99.9 | 100.2 | 99.2 | 98.4 | 98.3 | 98.6 | 98.3 | 97.9 | 99.7 | 99.3 | 99.7 |

## Virtual Load and Supply in the Day-Ahead Market

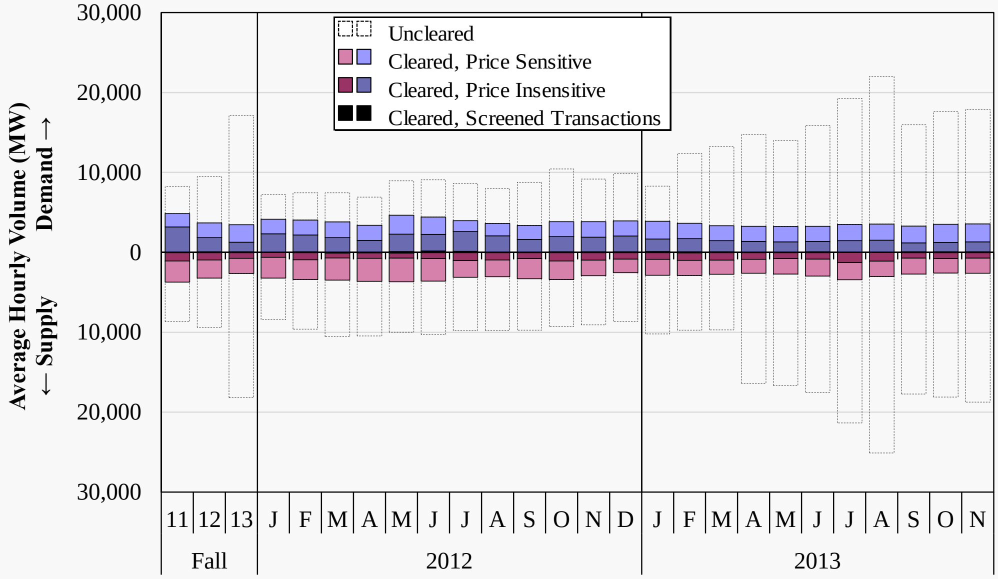
- Virtual trading in the day-ahead market facilitates convergence between the day-ahead and real-time prices.
  - ✓ This serves to improve the efficiency of day-ahead market results and moderates market power in the day-ahead market.
- The next figure shows the average hourly quantities of virtual demand 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 price, respectively.
  - ✓ Price-insensitive bids and offers that 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 closely 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 cleared transactions declined 11 percent from last fall to 6.1 GW.
  - ✓ Cleared supply declined 18 percent to 2.7 GW, compared to a 6 percent decline (to 3.5 GW) in demand.
  - ✓ A majority of virtual transactions cleared at nodal locations in the West region.
- Total bids and offers this quarter nearly doubled from last fall to 35.3 GW. Most of this rise is associated with bids and offers submitted at prices that are extremely unlikely to clear.
  - ✓ Nearly half of all demand transactions and over two-thirds of all supply transactions were not expected to clear. These bids and offers do not pose a concern.
- Price-insensitive transactions declined from 40 percent last fall to 33 percent this quarter.
  - ✓ The current RSG allocation still provides incentives for participants to take balanced positions, which can be ensured by offering price-insensitively.
- Most of these price-insensitive transactions would benefit from a virtual spread product, which would allow participants to more efficiently arbitrage locational differences.
  - ✓ Bids and offers would clear only when the congestion price difference between two selected points exceeds a specific price. MISO is considering such a product.
- The share of Screened Transactions rose slightly to two percent, which may partly be due to the rise in congestion and did not raise concerns this quarter.

# Virtual Transactions
# Fall 2012–2013








# 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.
  - ✓ Physical participants generally have different motivations to clear transactions (e.g. hedging physical obligations) than financial-only participants (e.g. price arbitrage).
- The share of virtual transactions cleared by financial-only participants rose from 69 percent last fall to 83 percent this fall.
  - ✓ Transactions by physical participants declined by more than half to average just 1 GW per hour this fall.
  - ✓ Financial participant transactions rose 6 percent to average over 5 GW per hour.
- The vast majority of uncleared transactions are offered by just a handful of participants at prices that make them very unlikely to clear.
  - ✓ Although fewer than 1 percent of these transactions clear, they are substantially profitable, and contribute to convergence, when they do.
- The share of transactions that are price-sensitive remains much higher for financial-only participants, which improved from 70 to 74 percent, than those by physical participants (30 percent).



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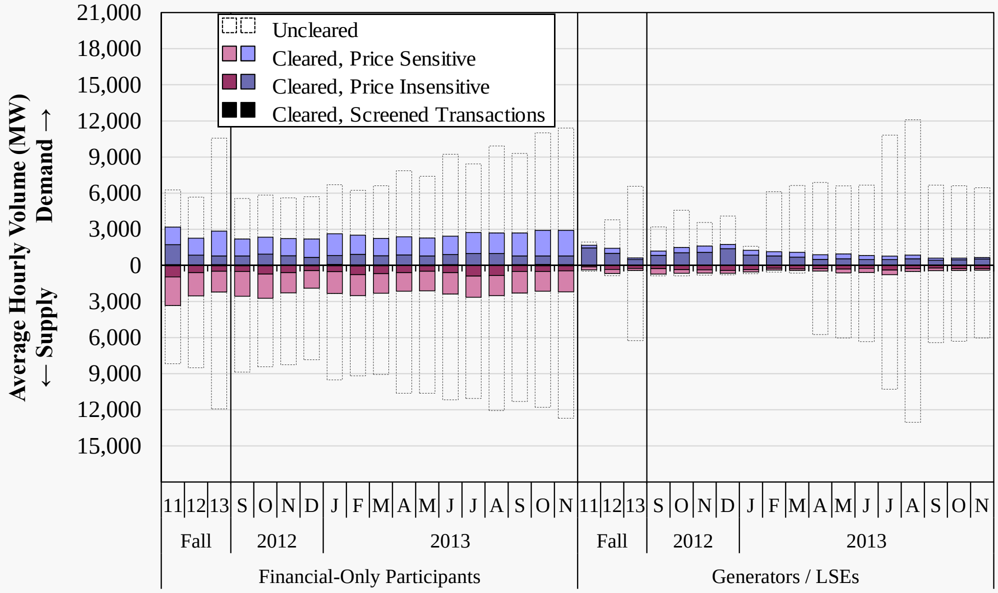
# Virtual Load and Supply by Participant Type
# Fall 2012–2013



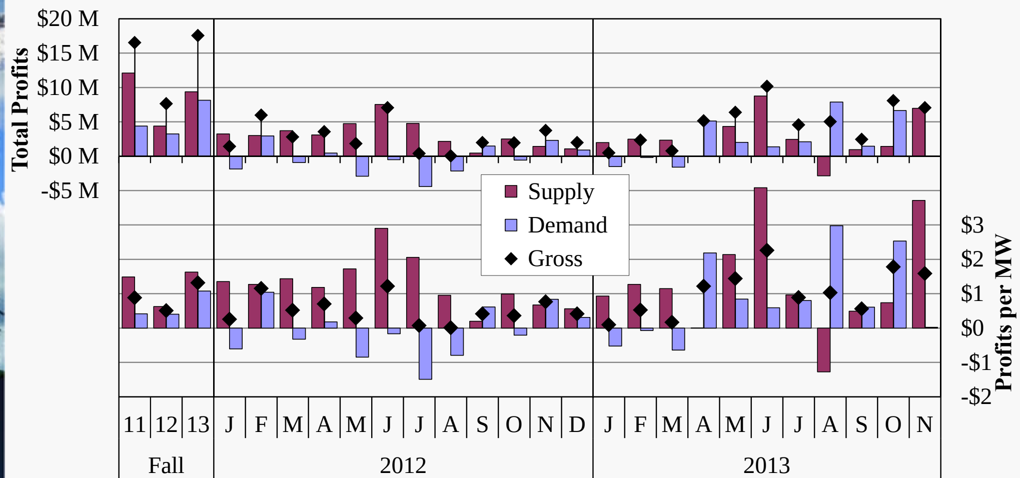





# Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross virtual profits totaled $17.5 million this fall, more than double last fall’s total, but less than gross profits during the summer quarter (nearly $20 million).
- On a per-MW basis, profitability rose from $0.51 per MWh last fall to $1.32 per MWh.
  - ✓ Supply continues to be more profitable (at $1.63 per MWh) than demand ($1.08).
  - ✓ Profitability at Indiana Hub, the most liquid trading location in MISO, averaged $0.79 per MWh.
- These margins exclude CMC and DDC charges assessed to net harming deviations.
  - ✓ Including DDC charges to net virtual supply (which averaged $0.78 per MWh) reduced its average profitability by half.
- The most profitable locations were all near the most expensive constraints in the West region where the virtual transactions contribute to price convergence.
- Virtual transactions by financial participants continue to be profitable ($1.43 per MWh this fall), indicating that they generally improve price convergence overall.
- Although profitability for physical participant transactions remained profitable ($0.77 per MWh) as well, it continues to be far lower than for financial participants.
  - ✓ This is because they offer transactions more price-insensitively and are less active in arbitraging congestion-related price differences than financial participants.

# Virtual Profitability Fall 2011–2013




**Percent Screened**

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand** | 1.4 | 2.1 | 2.3 | 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 |
| **Supply** | 1.2 | 1.2 | 1.5 | 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 |
| **Total** | 1.3 | 1.7 | 2.0 | 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 |



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# Day-Ahead Congestion and Obligations to FTR Holders

- FTR holders are entitled to the day-ahead congestion costs that arise between particular locations in MISO, which allows them to manage day-ahead price risk.
  - ✓ MISO collects day-ahead congestion from loads and pays it out via FTRs.
  - ✓ Day-ahead congestion rose by 51 percent from $174 million last fall to $262 million this fall. The most expensive constraints were in Iowa.
- The next figure shows day-ahead congestion, FTR obligations and FTR shortfalls.
  - ✓ Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- FTR obligations were fully funded in September, but underfunded by 4-5 percent in October and November.
  - ✓ All but one of the top ten most expensive constraints were fully funded.
  - ✓ One significantly underfunded constraint (shortfall of $1 million) was impacted by an unplanned outage in BREC.
- MISO continues to evaluate and improve FTR modeling assumptions.
  - ✓ It introduced a multi-period auction this fall for the November to February period, which should improve participants' ability to manage congestion risk.



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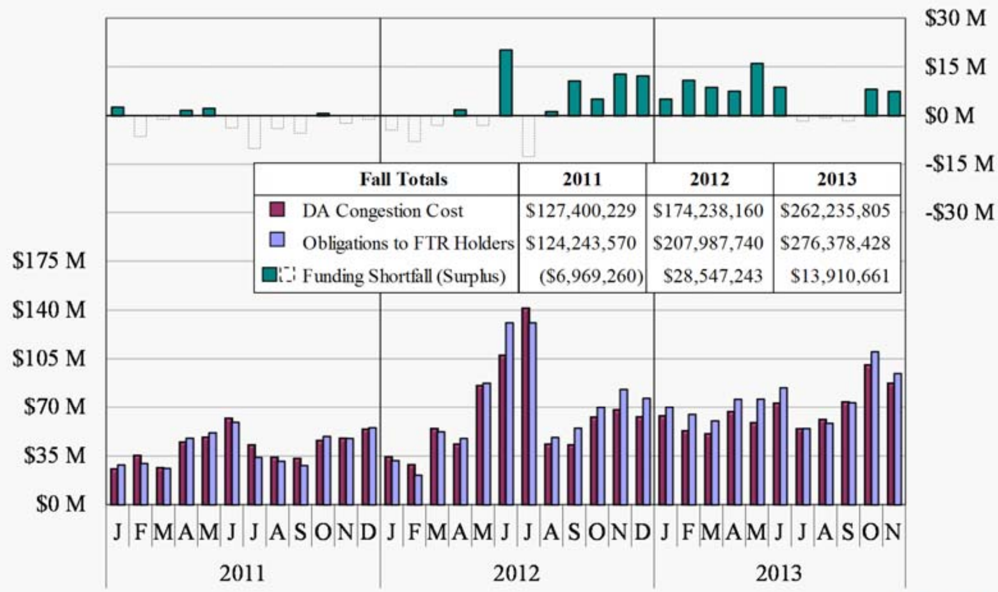
## Day-Ahead Congestion and Obligations to FTR Holders, 2011–2013



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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 rose 36 percent from last fall to $431 million.
  - ✓ It was highest in late October, when several constraints in the West were significantly impacted by planned generator and transmission outages.
  - ✓ Storms in mid-November resulted in significant transmission outages, including many 345-kV lines, although their impact on congestion value was modest.
- MISO fully deactivated its transmission "deadband" algorithm on October 1 and implemented its Transmission Constraint Demand Curve on November 16.
  - ✓ Both of these improvements should reduce shadow price volatility and improve overall price signals.
  - ✓ However, we remained very concerned about the demand curve implemented for external constraints and will be requesting rehearing from FERC.



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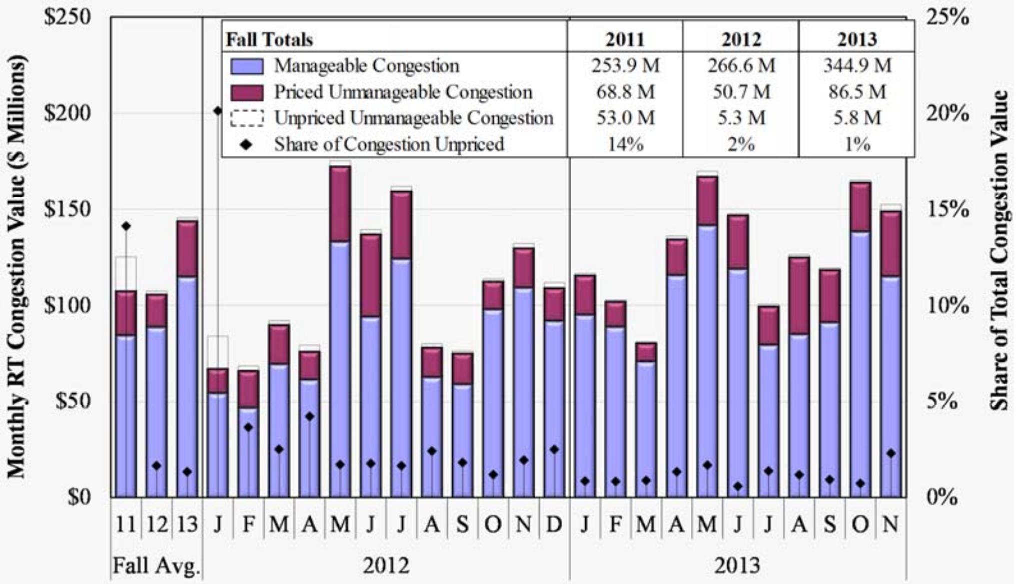
# Value of Real-Time Congestion
# Fall 2011–2013



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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 at or lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Peaking unit dispatch quantities rose 14 percent from last fall to 311 MW per hour.
  - ✓ Peaking unit dispatch was greatest in early September because of high late-summer loads, which increased MISO's peaking needs.
  - ✓ Peaking resources committed day-ahead (generally for capacity and made in-merit) in September doubled to 404 MW.
- The majority of peaking resource dispatch continues to be for commitments occurring in the day-ahead market.
- Over 90 percent of peaking unit commitments in real-time were for capacity needs.
- Congestion and VLR needs again comprised a very small portion (4 and 1 percent, respectively) of total peaking unit dispatch.
- LAC prompted a much smaller portion (51 percent) of real-time commitments this fall than in summer (82 percent) or last fall (61 percent).
- The share of peaking unit dispatch that was in-merit rose from 51 to 55 percent.
  - ✓ MISO's Extended LMP Initiative, expected to be implemented in early 2014, will allow peaking resources to set prices more frequently.



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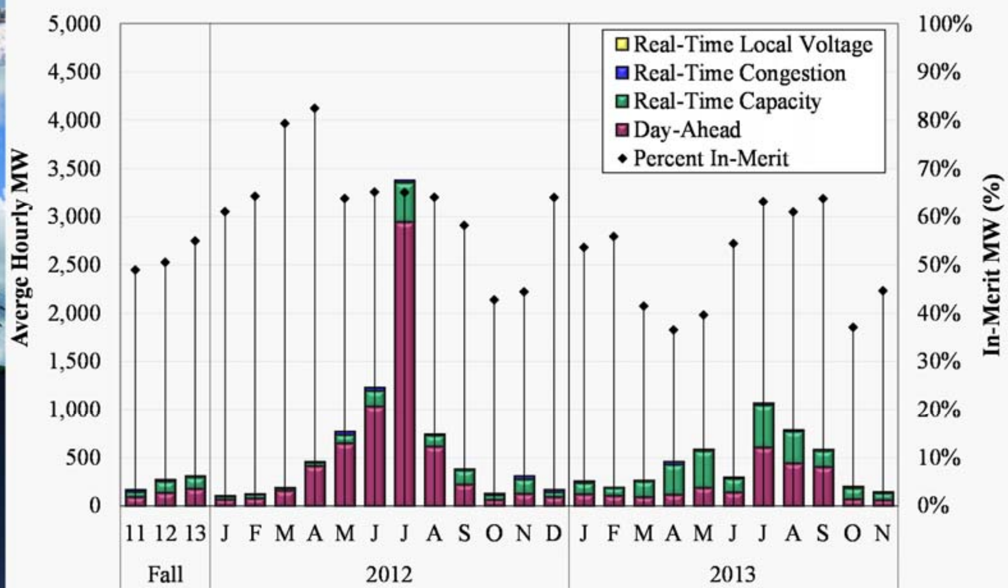
# Peaking Resource Dispatch
# Fall 2011–2013



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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 rose 14 percent from last fall to $14 million.
  - ✓ Less than one quarter of this is attributable to the rise in fuel prices. Adjusting for this, RSG costs rose 12 percent.
  - ✓ Payments for capacity and congestion rose modestly, while VLR payments declined.
- In fuel-adjusted terms, payments for capacity rose 15 percent to $7.8 million.
  - ✓ Payments were highest early in the quarter, when late-summer loads exceeded 85 GW.
  - ✓ MISO paid $1.1 million to resources committed for capacity on September 7.
- Congestion-related payments rose 8 percent to $5.1 million, much of it to units in Iowa.
  - ✓ Nearly $3.5 million was paid to three plants committed in October to manage constraints in Iowa described earlier in this report.
  - ✓ Seasonal generator and transmission outages required most of these commitments.
- The second figure shows that day-ahead RSG payments declined 15 percent (or a fuel-adjusted 28 percent) from last fall because of significantly lower VLR needs.



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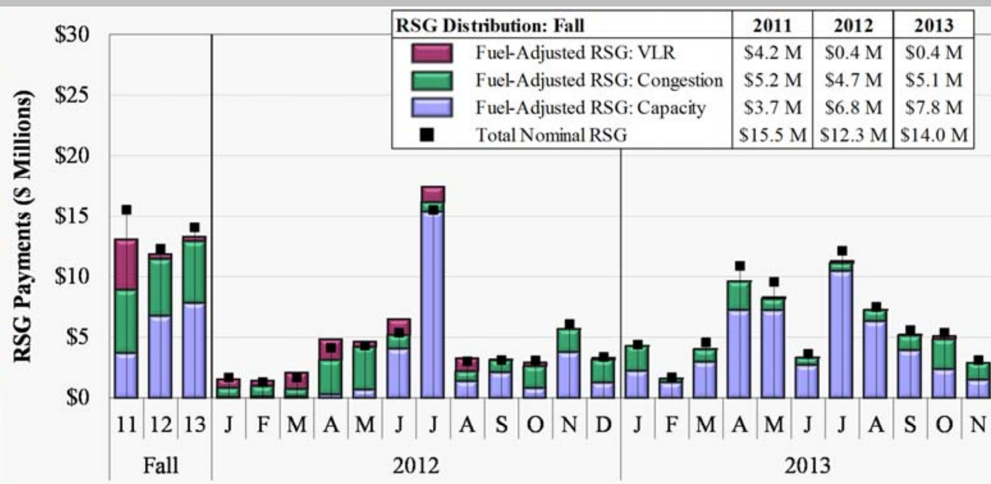
# Real-Time RSG Payments Fall 2011–2013




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

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peaker | 35 | 54 | 75 | 26 | 31 | 29 | 51 | 75 | 68 | 84 | 44 | 67 | 73 | 75 | 77 | 82 | 57 | 76 | 82 | 77 | 75 | 85 | 81 | 74 | 52 | 62 |
| Non-Peaker | 65 | 46 | 25 | 74 | 69 | 71 | 49 | 25 | 32 | 16 | 56 | 33 | 27 | 25 | 23 | 18 | 43 | 24 | 18 | 23 | 25 | 15 | 19 | 26 | 48 | 38 |



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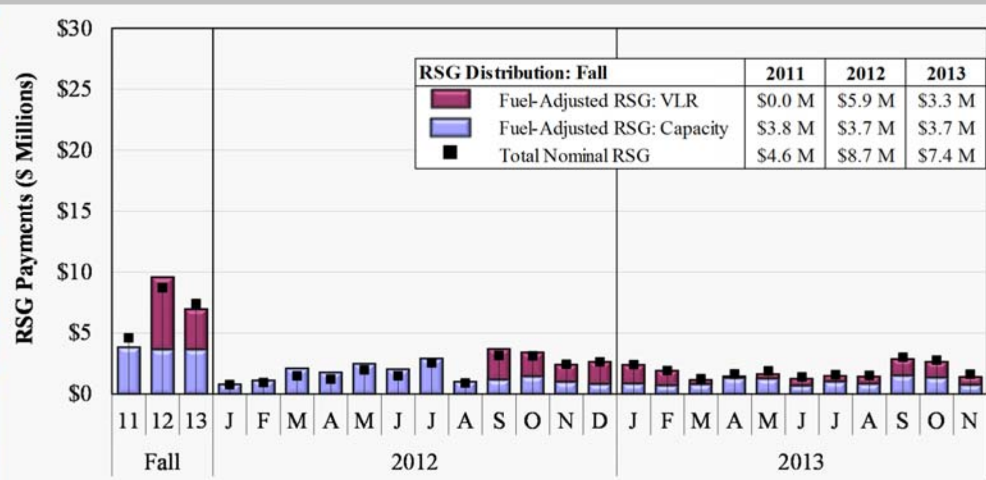
# Day-Ahead RSG Payments Fall 2011–2013




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

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peaker | 4 | 4 | 1 | 2 | 1 | 2 | 8 | 21 | 16 | 62 | 36 | 9 | 1 | 2 | 6 | 1 | 0 | 2 | 11 | 6 | 7 | 10 | 18 | 9 | 11 | 4 |
| Non-Peaker | 96 | 96 | 99 | 98 | 99 | 98 | 92 | 79 | 84 | 38 | 64 | 91 | 99 | 98 | 94 | 99 | 100 | 98 | 89 | 94 | 93 | 90 | 82 | 91 | 89 | 96 |



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## Price Volatility Make Whole Payments

- The next chart shows two types of Price Volatility Make Whole Payments (PVMWP), which improve incentives for suppliers to follow dispatch instructions.
- DAMAP rose 24 percent from last fall to $13.4 million, while RTORSGP declined 22 percent to $2.9 million.
  - ✓ Large relatively flexible coal units in the East and Central regions continue to be the largest recipients of DAMAP, predominantly during ramping hours.
  - ✓ Payments to one such station in the Central region exceeded $2 million, most of which occurred in the second half of the quarter.
- 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, and increased volatility leads to higher payments to flexible suppliers.
  - ✓ SMP volatility fell 3 percent from last fall, while LMP volatility declined nearly 20 percent. These declines were likely offset by the increase in fuel prices.
- We recommended several improvements to PVMWP settlement eligibility criteria and calculations in this year's *State of the Market Report*.
  - ✓ MISO filed Tariff changes to these criteria in October.



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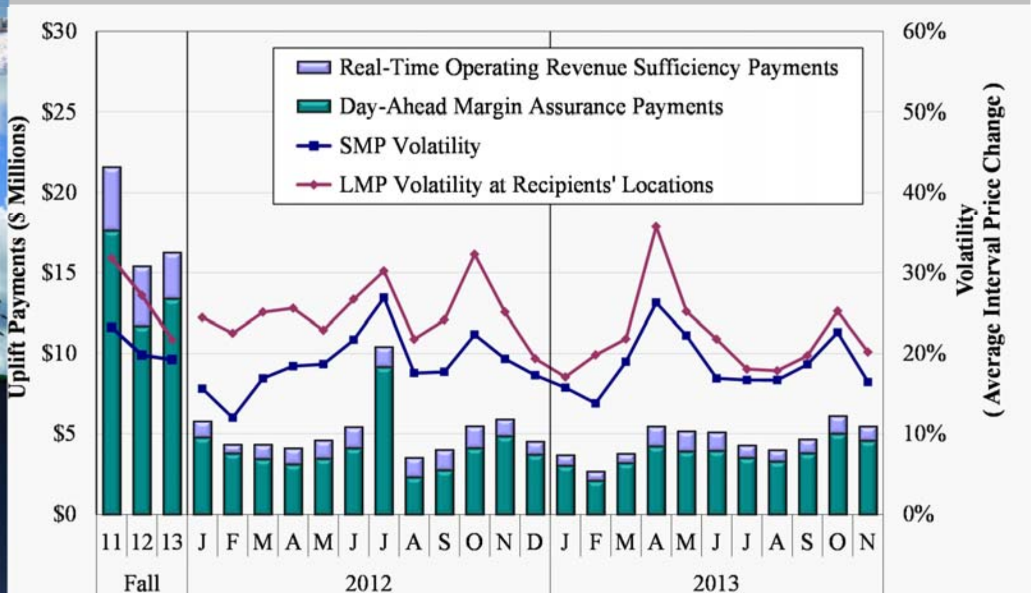
## Price Volatility Make Whole Payments Fall 2011–2013



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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 resources.
- Real-time wind output rose 15 percent from last fall to over 4.4 GW. It was 66 percent higher than in summer because of typical seasonal wind changes.
  - ✓ This quantity does not include 160 MW of average economic wind curtailments.
  - ✓ Nameplate capacity has not significantly from last fall. The number of DIR units, however, rose from 57 (representing 6.1 GW of capacity) to 115 (9.9 GW).
- Under-scheduling wind in the day-ahead improved from last fall.
  - ✓ Under-scheduling averaged 291 MW this fall, compared to 709 MW last fall.
  - ✓ Overall day-ahead wind scheduling averaged 93 percent of real-time output.
  - ✓ It was far better in the first half of the quarter, however, when output was lower and therefore less likely to be curtailed (see next slide).
  - ✓ Congestion-related price effects at wind locations contributed to lower real-time prices, which increased the incentive to schedule wind in the day-ahead market this quarter.
- Under-scheduling of wind produces incentives for participants to make up the difference with net virtual supply. It averaged 126 MW this fall.
  - ✓ It remains substantially profitable at $2.38 per MWh (up from $0.80 last fall).



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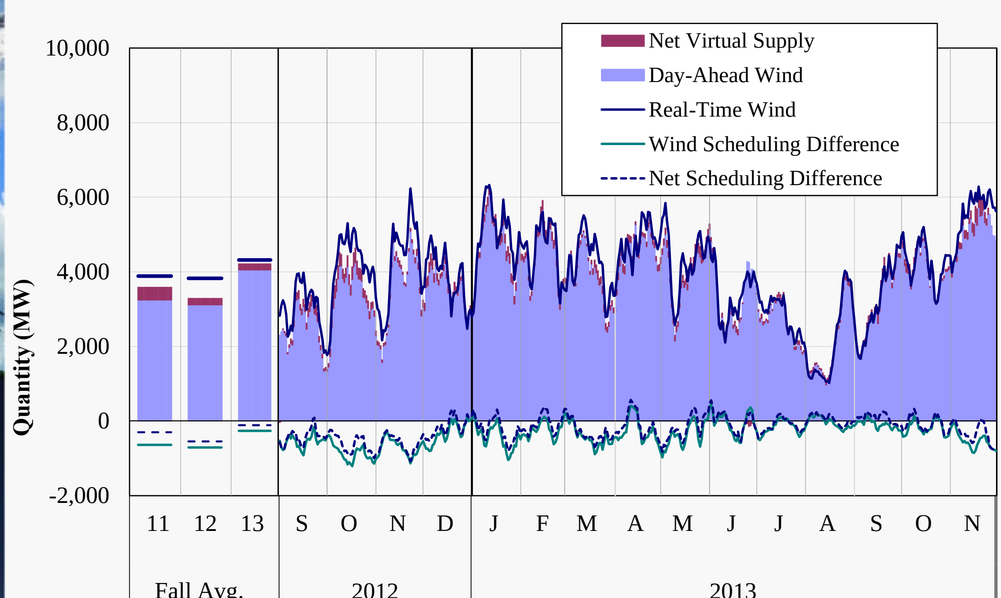
# Wind Output in Real-Time and Day-Ahead Markets 7-Day Moving Average, Fall 2011–2013



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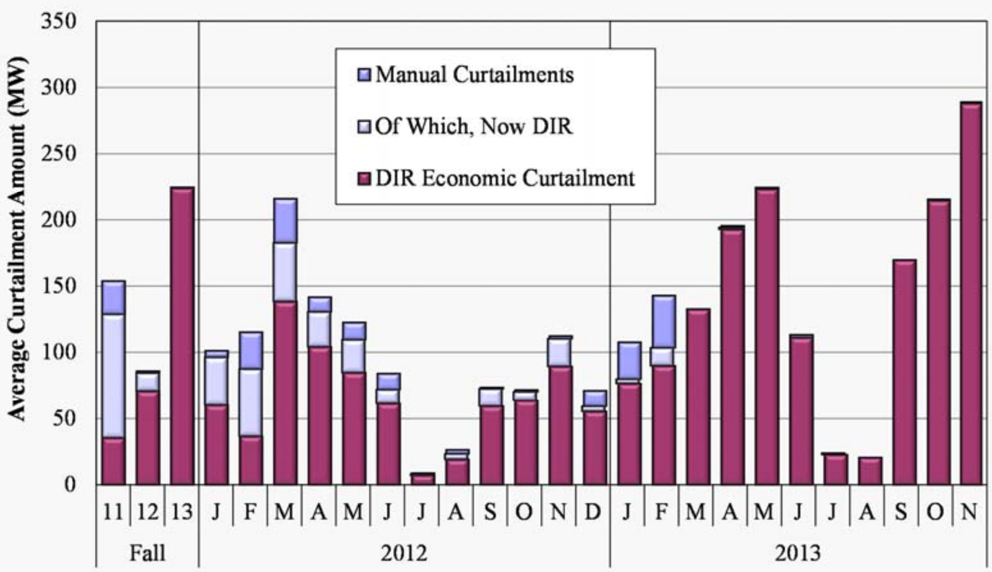
# Wind Curtailments

- Nearly 80 percent of wind capacity in the MISO footprint is registered as DIR.
  - ✓ This has significantly improved MISO's ability to manage and price the congestion that is caused by excess wind output.
- The following figure shows that economic DIR curtailments have now almost fully replaced manual curtailments as the primary means of managing congestion caused by wind.
  - ✓ There were just 23 manual curtailments all quarter (averaging less than 1 MW per interval), most of which were small curtailments of a wind unit overloading a 138-kV line in the Central region.
  - ✓ Economic curtailment of wind resources averaged 224 MW this fall, up from 71 MW last fall.
- The value of DIR is growing because as total wind output increases, MISO is experiencing increased congestion on constraints affected by the wind.
- MISO must still manage the ramp demands related to wind volatility, which averaged 49 MW per interval (based on units' forecasted maximums).
  - ✓ In addition, DIRs this fall were cumulatively deficient (below their set point instruction) by an average of 62 MW per interval.



# Wind Curtailments
# Fall 2011–2013



# Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2012 as a percentage of total generation capacity.
  - ✓ These values include only full outages, not partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The cumulative outage rate for the three types of outages was 14.4 percent.
  - ✓ This is down from fall 2012 and 2011, when it averaged 16.5 and 17.2 percent.
- Long-term forced outages declined by nearly one-half to just 3.2 percent.
  - ✓ A large coal resource that was on an extended forced outage returned to service this quarter.
- Short-term forced outages, which can indicate potential physical withholding, were unchanged at 1.7 percent.
- Planned outages rose modestly to 9.5 percent.



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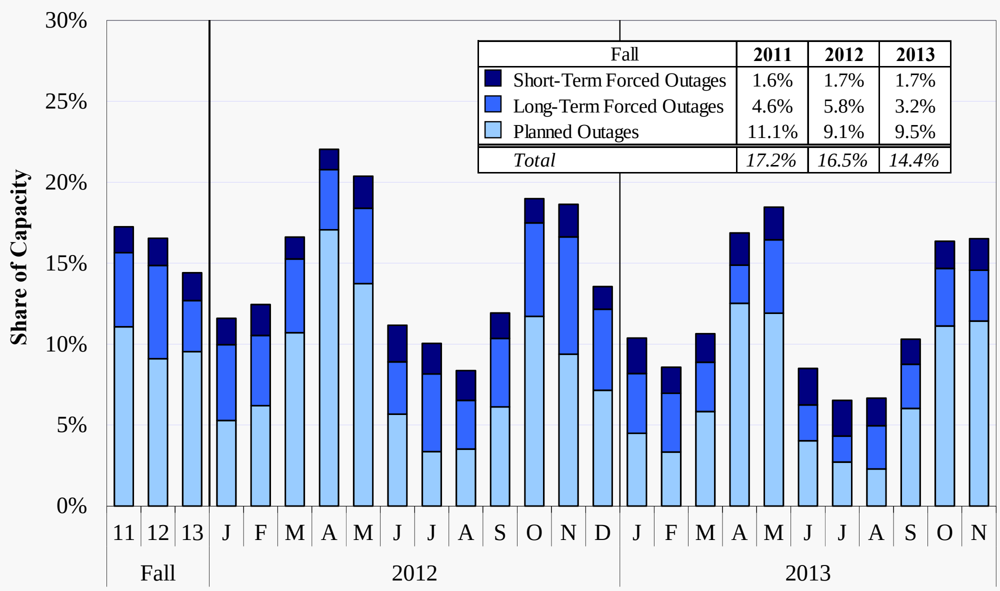
# Generation Outage Rates 2011–2012




| Fall | 2011 | 2012 | 2013 |
|---|---|---|---|
| Short-Term Forced Outages | 1.6% | 1.7% | 1.7% |
| Long-Term Forced Outages | 4.6% | 5.8% | 3.2% |
| Planned Outages | 11.1% | 9.1% | 9.5% |
| *Total* | *17.2%* | *16.5%* | *14.4%* |



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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 January 2012 under two thresholds:
  - ✓ A “high” threshold, equal to the applicable tariff mitigation threshold; and
  - ✓ A “low” threshold, equal to one-half of mitigation threshold.
- Output gap levels in MISO rose from summer and from last fall but remain near 0.1 percent of overall load.
  - ✓ At the high threshold, average output gap rose from 8 to 25 MW.
  - ✓ At the low threshold, it more than doubled from 31 to 63 MW.
  - ✓ The largest single contributor was an offline station in the Central region with modestly inflated energy offers on a handful of days early in the quarter.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances of competitive concern.



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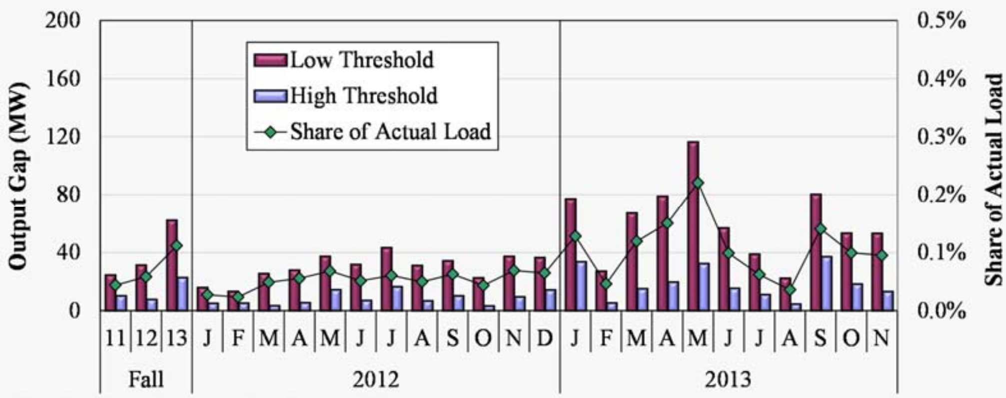
# Monthly Output Gap
# Fall 2011–2013




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

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Off-Line | 8 | 2 | 11 | 4 | 4 | 1 | 1 | 9 | 0 | 9 | 0 | 5 | 0 | 1 | 4 | 7 | 1 | 4 | 0 | 10 | 1 | 6 | 0 | 23 | 7 | 2 |
| On-Line | 3 | 6 | 12 | 2 | 1 | 2 | 4 | 6 | 7 | 7 | 7 | 5 | 3 | 9 | 11 | 27 | 4 | 11 | 20 | 22 | 15 | 5 | 5 | 14 | 11 | 11 |

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

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Off-Line | 8 | 3 | 14 | 4 | 4 | 1 | 1 | 9 | 0 | 11 | 0 | 8 | 0 | 2 | 5 | 8 | 2 | 6 | 0 | 12 | 2 | 9 | 0 | 26 | 11 | 4 |
| On-Line | 17 | 28 | 49 | 12 | 9 | 24 | 27 | 29 | 32 | 33 | 31 | 26 | 23 | 36 | 32 | 69 | 25 | 62 | 79 | 104 | 56 | 30 | 22 | 55 | 42 | 50 |



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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 in each month since January 2012.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the mitigated quantity.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigation.
- Since most resources are offered competitively, mitigation in MISO remains infrequent.
  - ✓ Considerable local market power continues to exist, however, and market power mitigation measures remain critical.
- We continue to evaluate each imposition of mitigation and found mitigation this quarter to be appropriately applied in each instance.
  - ✓ Energy mitigation occurred for 11 hours and 778 MW. This is a modest increase from the 10 hours and 600 MW recorded last fall.
    - – Nearly half of this occurred in the Minnesota NCA, where thresholds are tighter than other areas. The balance occurred in Broad Constrained Areas.
  - ✓ RSG mitigation was nearly nonexistent, declining to just 3 unit-days and $9,000.
    - – Two of these were for VLR. There were also 9 day-ahead mitigations, mostly of a unit that required over $1 million in RSG payments.
    - – Absent these mitigation rules, RSG payments to this unit would have been considerably higher.



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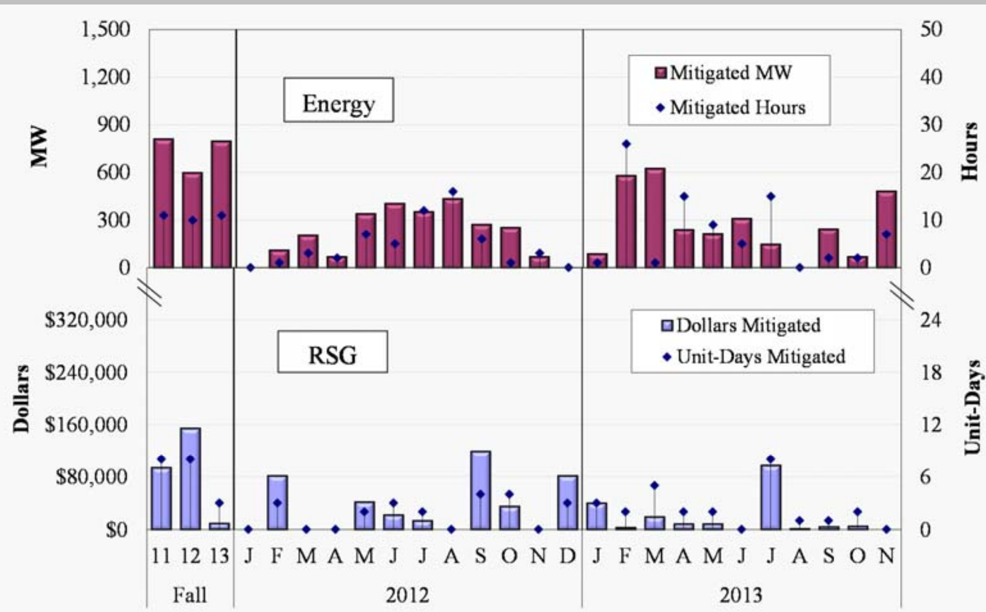
# Real-Time Market Power Mitigation
# Fall 2011–2013



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## Submittals to External Entities and Other Issues

Submittals to External Entities:

- We referred a resource to FERC for failing to accurately update real-time offers, and will likely be making additional referrals to FERC and we continue to discuss past referrals with FERC.
- In October, we provided testimony in support of MISO's filing to address gaming concerns associated with RSG and PVMWP payments and in November we jointly filed comments with MISO in answer to limited protests.
- We participated in a FERC Technical Conference on MISO's prior filing revising RSG allocations.
- We have continued to present our market power study and NCA evaluations to stakeholders and state commissions in the MISO South region.

Other Issues:

- MISO received approval for its proposed Transmission Constraint Demand Curves in November.
  - ✓ The TCDCs will improve efficiency and pricing for internal constraints.
  - ✓ However, we continue to oppose the TCDC values for TLR flowgates are inefficient and costly for MISO's customers. We will be filing for rehearing with FERC.
- We continued to work with MISO and PJM staff in their reviews of the interface pricing error detailed in our SOM and have presented recommended solutions.



## Selected Conduct Investigations

- Updating Real-Time Offers
  - ✓ We continued to investigate "inferred derates" where units are operating well below their economic output level because they are not following dispatch signals.
  - ✓ Previous instances have shown that some units that are physically unable to follow MISO's dispatch instructions (i.e., are effectively derated) did not update their real-time offers.
  - ✓ Failure to update real-time offers results in unjustified DAMAP payments and allows resources to avoid RSG allocations.
  - ✓ We have also identified cases where suppliers have chosen not to follow dispatch even though they are physically able to do so.
    - – This decision also obligates the supplier to update its real-time offers, even if it will remain within the uninstructed deviation tolerance band.
  - ✓ We have recommended changes to address these issues and will continue to refer the most significant events to FERC enforcement.
- Uneconomic Production
  - ✓ Additional cases of potential uneconomic production have occurred this quarter.
  - ✓ These cases occur when a generator that loads a constraint produces uneconomically by refusing to ramp down (usually by submitting an inflated EcoMin) or shut down.
  - ✓ We have been increasing the automation of our testing to incorporate cycling costs, which is allowing us to evaluate these cases more quickly.

# List of Acronyms

| | |
|---|---|
| AMP | Automated Mitigation Procedures |
| BCA | Broad Constrained Area |
| CDD | Cooling Degree Days |
| CMC | Constraint Management Charge |
| DAMAP | Day-Ahead Margin Assurance Payment |
| DDC | Day-Ahead Deviation & Headroom Charge |
| DIR | Dispatchable Intermittent Resource |
| HDD | Heating Degree Days |
| JCM | Joint and Common Market Initiative |
| LAC | Look-Ahead Commitment |
| LSE | Load-Serving Entities |
| M2M | Market-to-Market |
| NCA | Narrow Constrained Area |
| ORDC | Operating Reserve Demand Curve |
| PRA | Planning Resource Auction |
| PVMWP | Price Volatility Make Whole Payment |
| RAC | Resource Adequacy Construct |
| RSG | Revenue Sufficiency Guarantee |
| RTORSGP | Real-Time Offer Revenue Sufficiency Guarantee Payment |
| SOM | State of the Market |
| TLR | Transmission Line Loading Relief |
| TCDC | Transmission Constraint Demand Curve |
| VCA | Voluntary Capacity Auction |
| VLR | Voltage and Local Reliability |
| WPP | Weekly Procurement Process |
| WUMS | Wisconsin Upper Michigan System |



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