IMM Quarterly Report: Winter 2012
December–February

MISO Independent Market Monitor

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Potomac Economics

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Summary of Winter 2012 Results

- Real-time prices in winter averaged $25.87 per MWh, a decline of 24 percent from last winter. Day-ahead prices also declined to $26.87 (a 4 percent day-ahead premium).
  - ✓ Prices declined as natural gas prices fell 35 percent to $2.93 per MMBtu. Western coal prices also declined 19 percent to $0.63 per MMBtu.
  - ✓ Mild temperatures this winter resulted in a 5.4 percent decline in average load.
- Wind generation set a new record at 8.6 GW on January 1, when it made up 18 percent of online generation. For the quarter, average wind output rose 34 percent to 4.0 GW.
  - ✓ Wind is being curtailed much less frequently due to the introduction of DIRs, which now account for 39 percent (4.2 GW) of all wind generation.
- Constraint relaxation was disabled on February 1, allowing unmanageable congestion to be fully priced (previously, roughly 20 percent of congestion was unpriced).
- RSG costs declined 75 percent from last winter because of high day-ahead load scheduling (decreasing the need for peaking resources) and lower voltage support costs.
  - ✓ MISO filed RSG allocation changes relating to voltage support in late December.
- Cleared virtual transaction volumes were almost 50 percent higher than last winter that were likely caused by the changes in real-time RSG allocation made in April 2011.
  - ✓ However, volumes decreased 14 percent from last quarter as a price-insensitive virtual trading strategy to arbitrage differences in marginal loss factors was discontinued.

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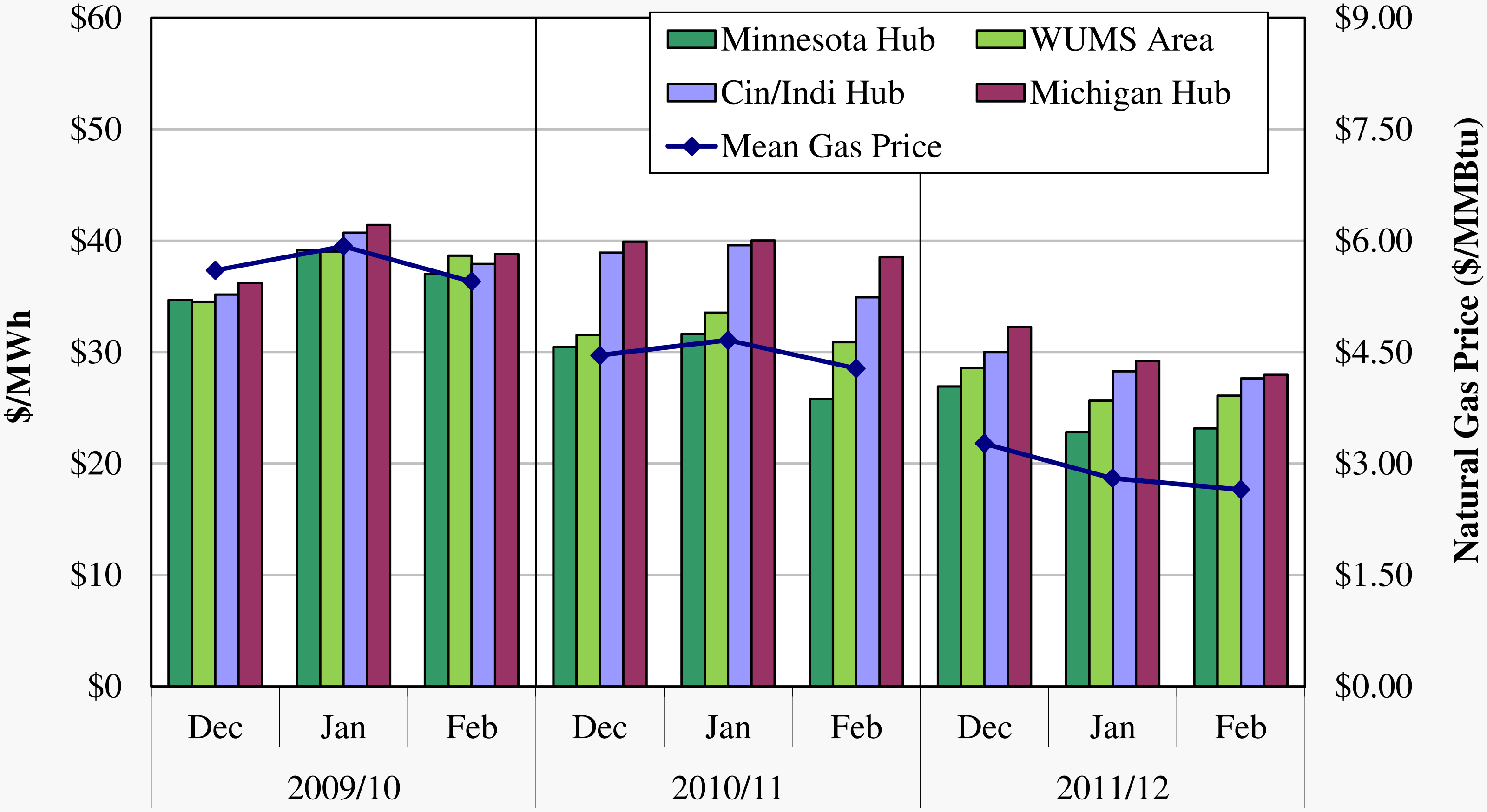
Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations hubs for each winter quarter from 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 in peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices in winter averaged just $26.87 per MWh, a decline of 23 and 29 percent from the previous two winters.
  - ✓ Natural gas prices declined 35 percent from the last winter to average $2.93 per MMBtu. Western coal prices similarly declined 19 percent.
  - ✓ Mild temperatures this winter reduced weather-sensistive load and contributed to the decline in prices.
- Price differences between western and eastern areas in MISO associated with transmission congestion and losses continued.
  - ✓ Prices in the West region remain 20 percent lower than those in the East region.
  - ✓ Some of the higher prices in the eastern areas were related to local constraints that are affected by transmission and generation outages.
  - ✓ High wind output remains a contributing factor to congestion out of the western areas, averaging 3.4 GW in the day-ahead market and up 31 percent from last winter.

Day-Ahead Average Monthly Hub Prices Winter 2010–2012

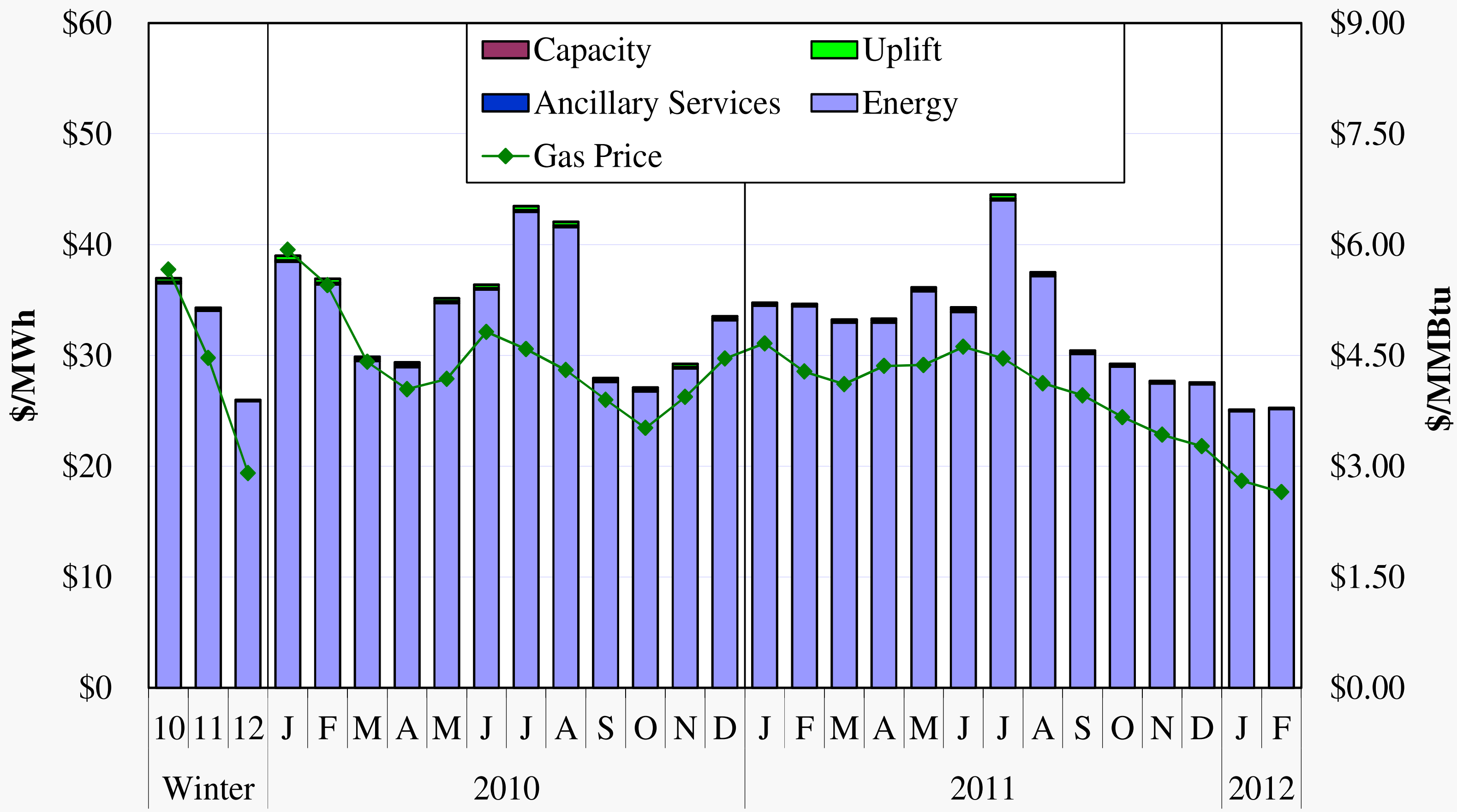


Note: Cinergy Hub was replaced by Indiana Hub as the Central Region's proxy price beginning January 2012.

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 also shows the average natural gas price in each month.
  - ✓ Energy prices generally continue to move with changes in fuel prices, as expected in a workably competitive market.
- The price declined to $25.97 per MWh, down 24 percent from the prior winter.
  - ✓ The energy component of the all-in price declined on substantial decreases in natural gas prices (35 percent) and load (5.4 percent).
  - ✓ These factors also contributed to reductions in the uplift and ancillary services components of the all-in price.
- Energy costs continue to make up nearly the entire all-in price (99.5 percent).
  - ✓ Uplift, ancillary services and capacity costs contributed a cumulative $0.12 per MWh.
  - ✓ The Voluntary Capacity Auction continues to clear at close to zero in each month, which is consistent with surplus levels of capacity in MISO (see slide 39).

All-In Price
2010–2012



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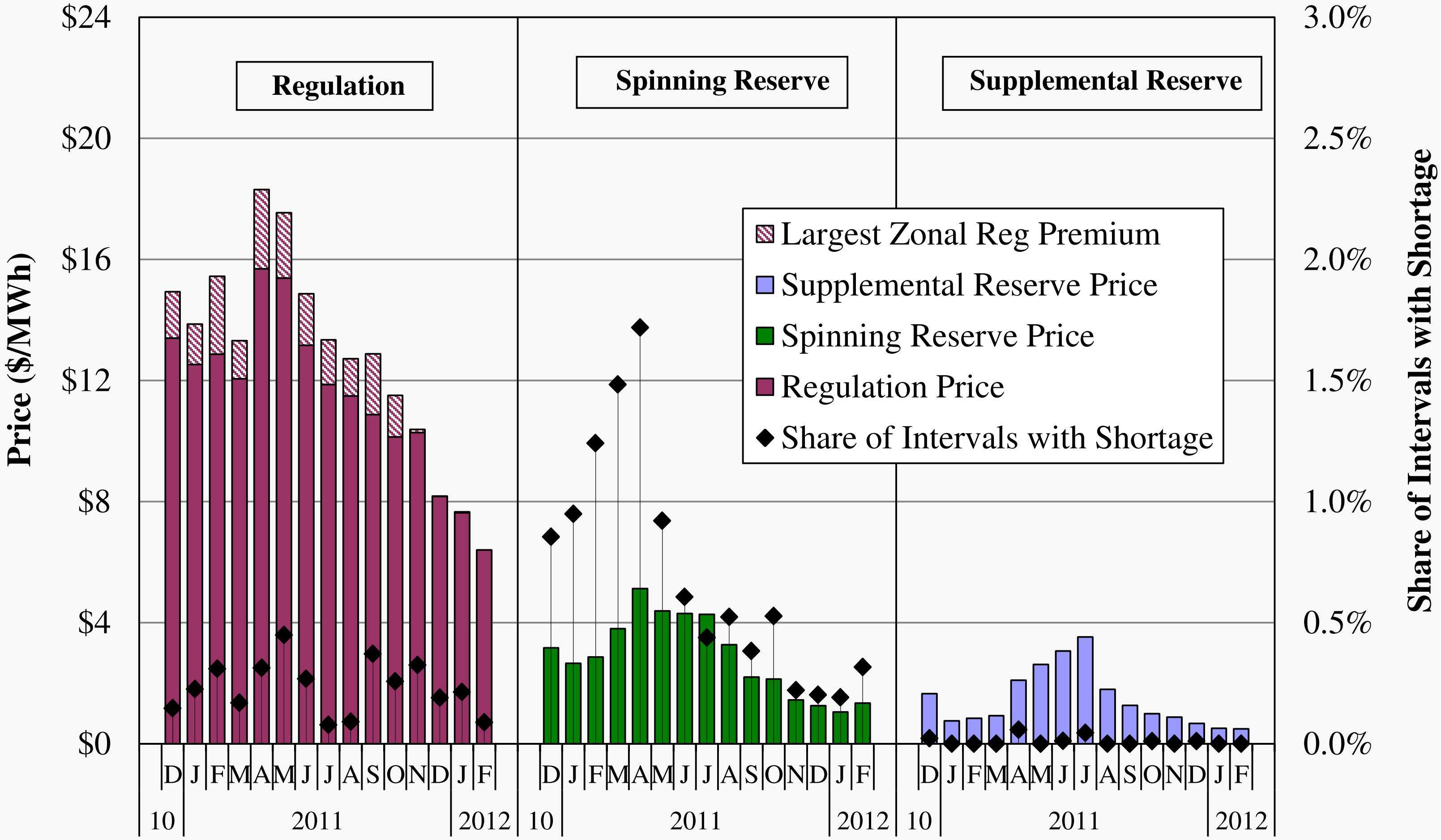
Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO's three ancillary service products since December 2010.
- Regulating reserve prices have declined for ten consecutive months. Prices averaged $7.44 per MWh in the quarter, a 41 percent decline from last winter.
  - ✓ The decline in energy prices has substantially lowered opportunity costs for providing regulation.
  - ✓ In addition, the price for regulation during shortages has fallen because the average regulating reserve demand curve penalty price fell to an average of $124 per MWh from $177 last winter. This had a small effect on prices as shortages have been infrequent.
- Spinning reserve clearing prices also fell by 56 percent from last winter to average $1.21 MWh, while contingency reserve prices declined 30 percent to $0.55.
  - ✓ Lower fuel prices, load, and associated opportunity costs caused these decreases.
  - ✓ An operating reserve shortage during the evening ramp on December 7th produced one interval priced at over $1,300 per MWh.
  - ✓ MISO will soon introduce a two-part demand curve for spinning reserve shortages to replace the current relaxation methodology.

Monthly Average Ancillary Service Prices
Regulation and Contingency Reserves, 2010–2012



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MISO Fuel Prices

<u>Natural Gas and Oil Prices</u>

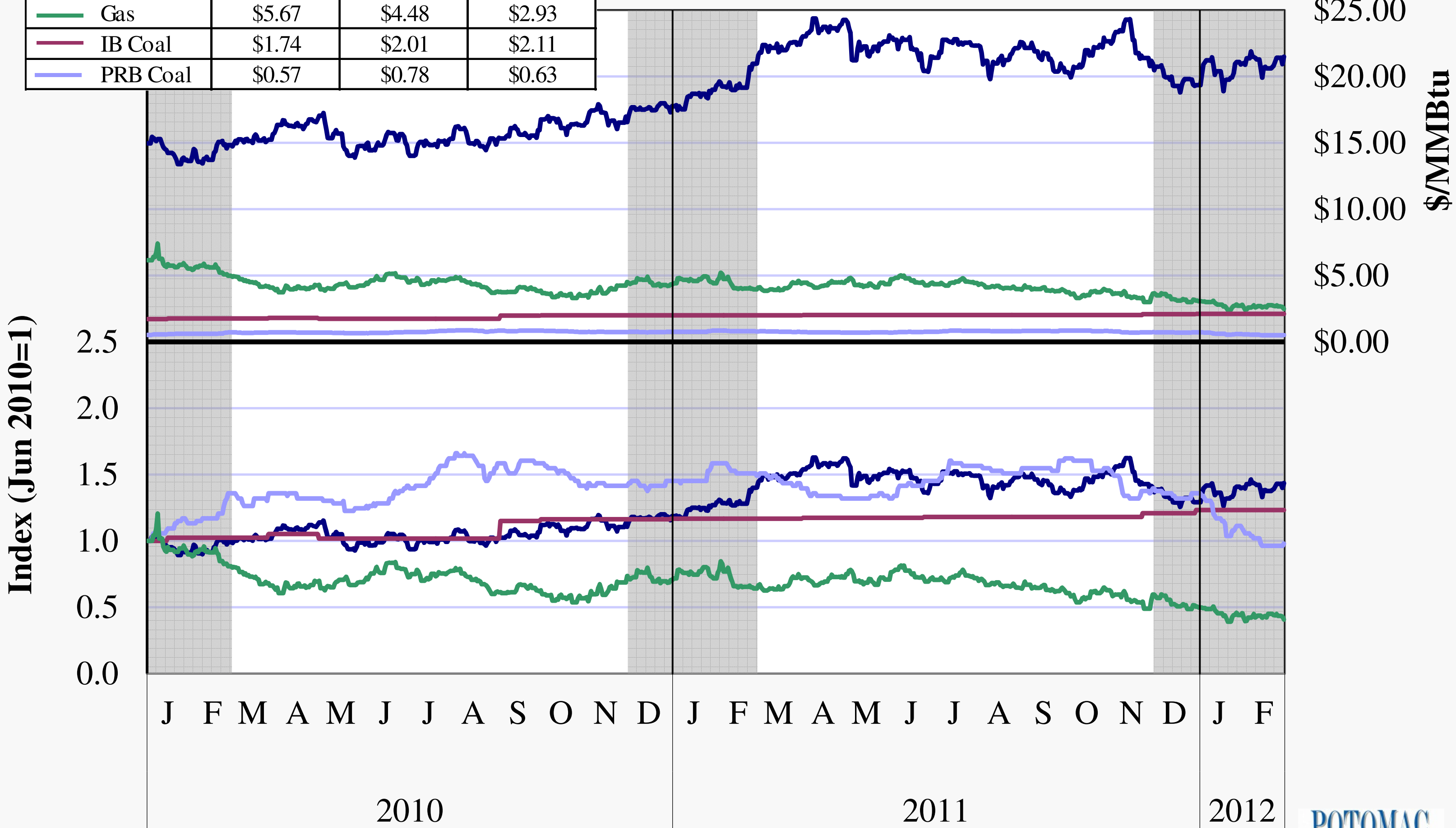
- Natural gas prices declined 35 percent from last winter to average $2.93 per MMBtu. Prices declined steadily during the winter and finished February at $2.51.
  - ✓ These sustained low prices have affected the MISO market results, and have caused some changes in dispatch patterns as some gas resources are becoming competitive with baseload coal resources.
- Oil prices averaged $20.44 per MMBtu in the quarter, down 6 percent from the fall but up 11 percent from last winter.
  - ✓ Oil prices can be a significant marginal fuel in winter when natural gas supplies are interrupted due to high demand or other issues.
  - ✓ These issues did not arise this winter so oil was rarely marginal and the rise in its price did not significantly affect the market.

<u>Coal Prices</u>

- Illinois Basin prices rose 10 cents from last winter to $2.11 per MMBtu.
- However, average Powder River Basin (western coal) prices declined 19 percent to $0.63 per MMBtu from last winter.

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

Winter Average	2010	2011	2012
Oil	$14.22	$18.50	$20.44
Gas	$5.67	$4.48	$2.93
IB Coal	$1.74	$2.01	$2.11
PRB Coal	$0.57	$0.78	$0.63



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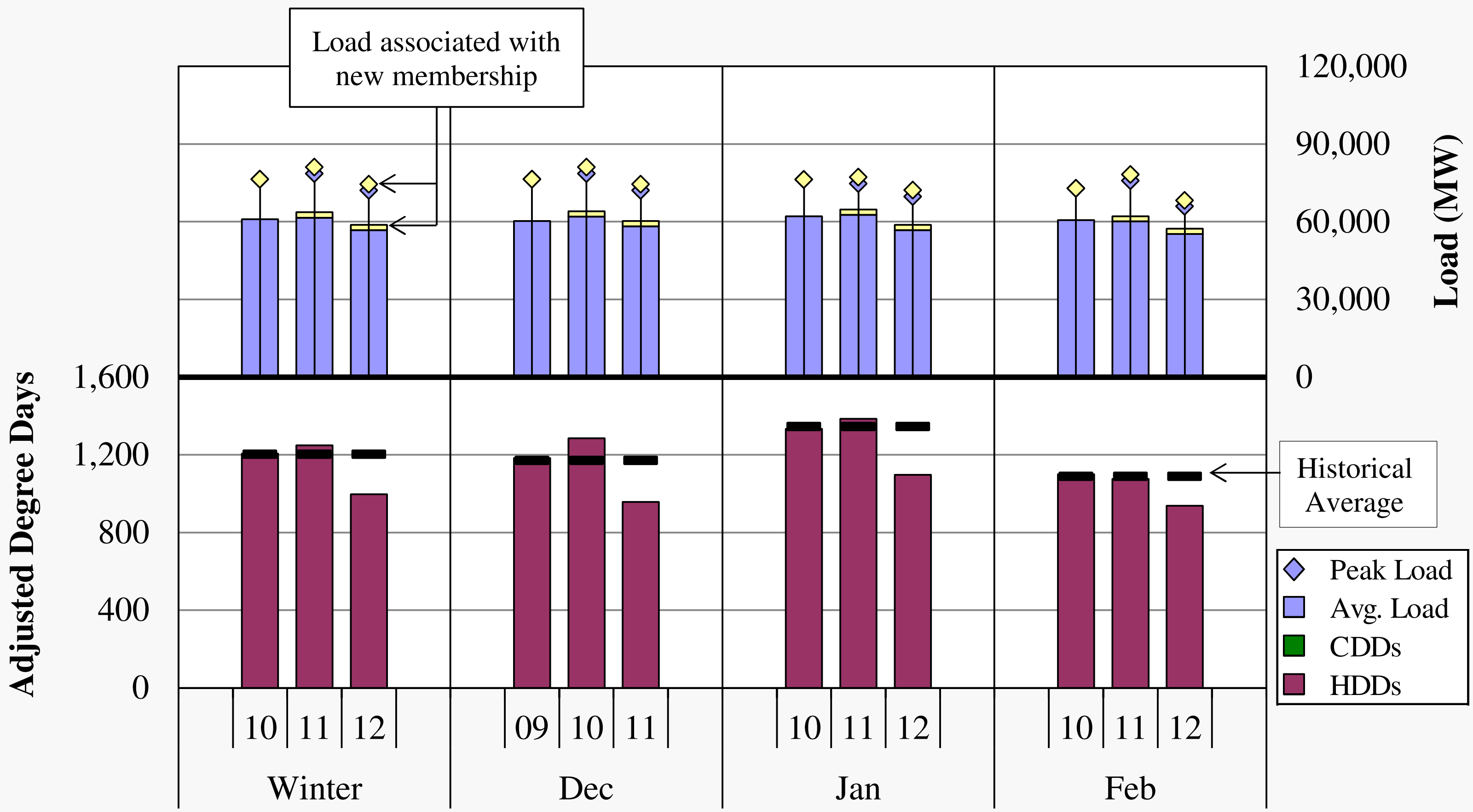
Changes in Load and Weather Patterns

- The next figure shows changes in load in winter 2010 to 2012, as well as the changes in weather patterns that contributed to the load changes.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns contributed to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days ("HDDs and CDDs") in winter months at four locations in MISO since 2010.
  - ✓ To account for the different relative impacts of HDDs and CDDs on load, HDDs are inflated by a factor of 6.07 (based on a regression analysis).
- The figure shows that total degree days declined 20 percent from last winter.
  - ✓ Temperatures across the footprint were well above normal throughout the winter, resulting in total degree days that were 17 percent below the historical average.
- These weather factors significantly affected the monthly average and peak loads during each period shown in the top panel of the figure.
  - ✓ Excluding membership changes (e.g. the departure of FirstEnergy and portions of Duke Energy), average load decreased 5.4 percent from last winter to 60.3 GW.
  - ✓ Peak load declined by 7.2 percent. It peaked at 73.7 GW on Dec 6.

Load and Weather Patterns
Winter 2010–2012



Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis. FirstEnergy is removed from the load levels.

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).
- Prices converged well on average during the winter with premiums of 3 to 5 percent.
  - ✓ The improved price convergence is likely attributable to the increase in virtual trading and a reduction in price volatility across the MISO footprint in 2012.
- In dollar terms, premiums averaged $1 per MWh, slightly more than the average DDC RSG rate applied to real-time load purchases of approximately $0.28.
  - ✓ The bottom table in the figure confirms that at the four representative locations, RSG costs comprised much of the day-ahead premium.

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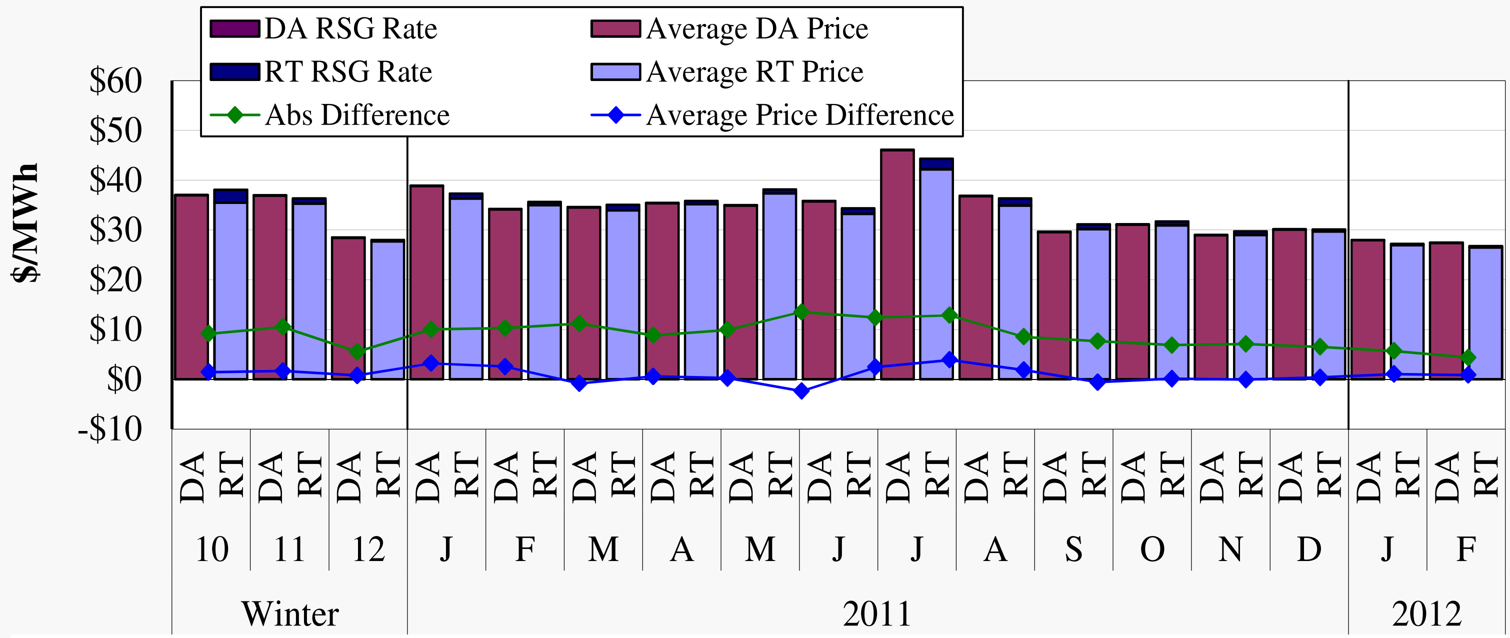
Day-Ahead and Real-Time Price Convergence 2010–2012



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

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

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

	10	11	12	J	F	M	A	M	J	J	A	S	O	N	D	J	F
Cin/Ind Hub	-2	-1	0	4	-4	-1	-1	-9	4	4	1	-5	-2	-2	0	3	3
Michigan Hub	-2	-1	3	3	-7	0	5	-7	0	4	1	-6	0	-6	2	4	2
Minnesota Hub	-5	-5	1	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10	2	-1
WUMS Area	0	0	1	0	-8	-3	-6	2	3	2	-5	-2	7	5	7	2	0

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

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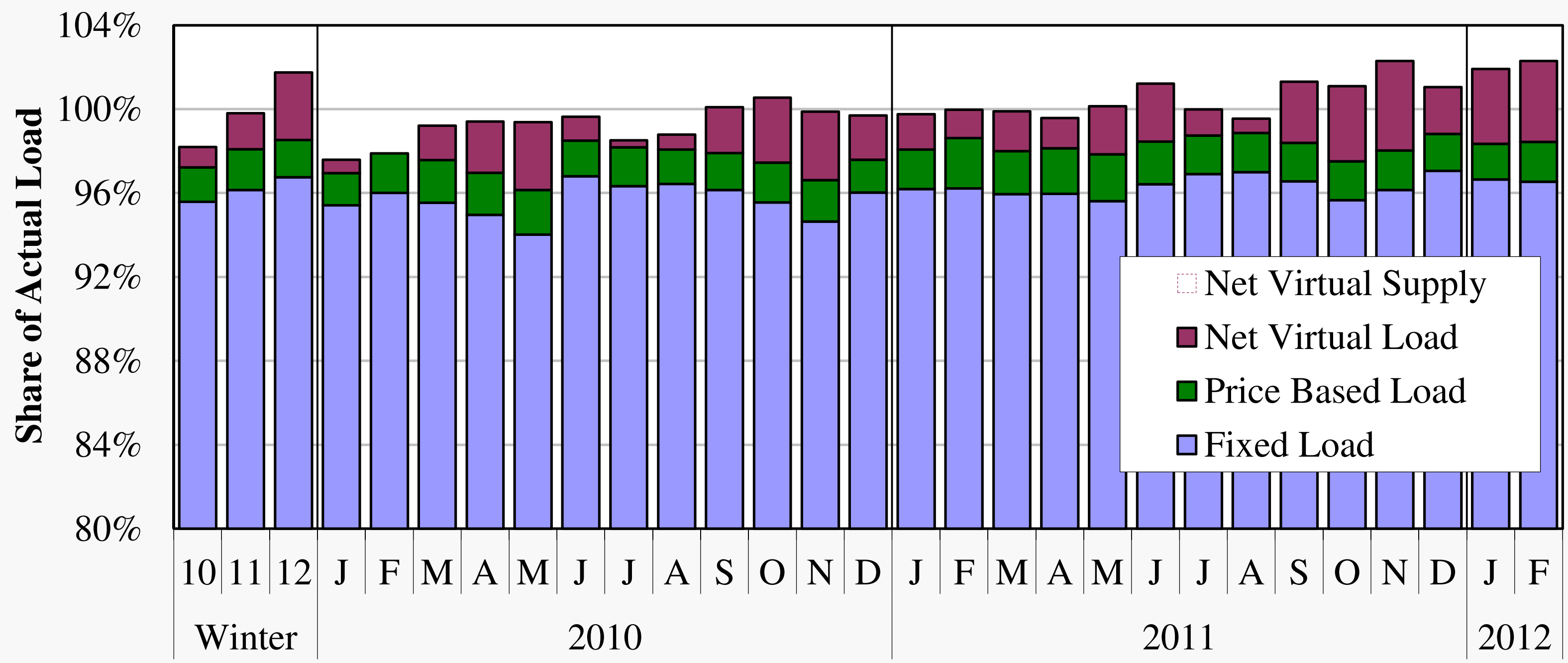
Day-Ahead Load Scheduling

- 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 winter was fully scheduled on average during all hours (99.8 percent), and during the peak daily hour (101.8 percent).
  - ✓ Net virtual load during peak hours, primarily submitted by LSEs, more than made up the scheduling shortfall of fixed and price-based physical load.
- As we show in monthly reports, this broad metric can mask considerable variation in day-to-day scheduling and the correlation with day-ahead price premiums.
  - ✓ However, load was consistently overscheduled this winter and was rarely underscheduled by a significant margin.
  - ✓ This increased consistency may be attributed to the mild weather conditions that contributed to lower and more predictable load.

Day-Ahead Peak Hour Load Scheduling 2010–2012



Share of Actual Load(%)

All Hour	98.9	100.1	99.8	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0	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
Peak Hour	97.9	99.8	101.8	97.6	97.9	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7	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

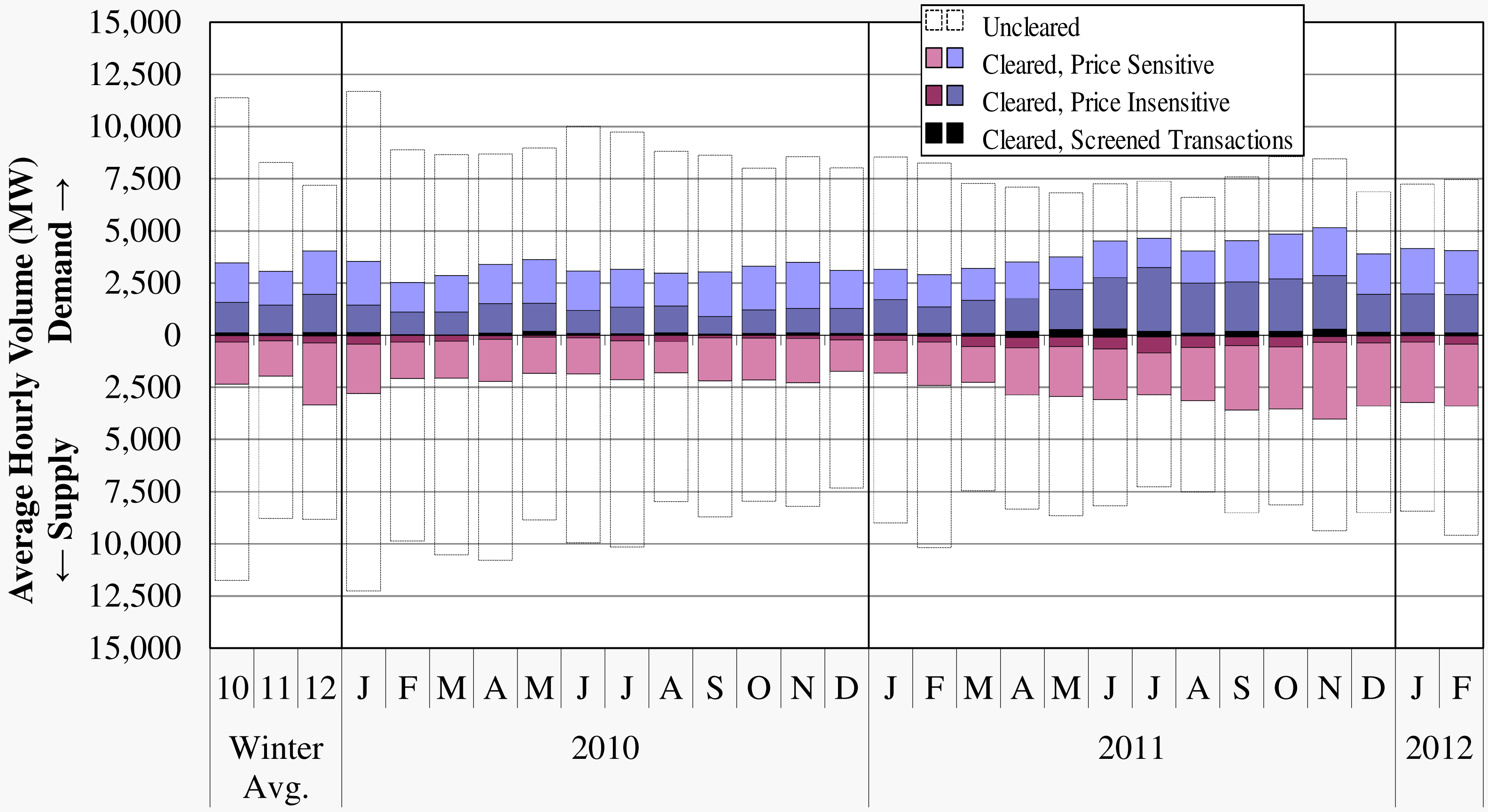
Virtual Load and Supply in the Day-Ahead Market

- 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.
  - ✓ Price-insensitive bids and offers are submitted at more than $30 above and below expected real-time prices, 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 monitoring changes in virtual trading activity since MISO changed the RSG cost allocation last April.
  - ✓ The change eliminates any allocation of RSG to virtual supply when it is netted against virtual load.
  - ✓ However, it has resulted allocations that are not consistent with cost causation and we will be proposing improvements in the SOM report.

Virtual Load and Supply in the Day-Ahead Market

- The figure shows that cleared volumes this winter rose 49 percent from the prior winter.
  - ✓ While total bid and offered quantities declined compared to prior years, cleared virtual supply and demand increased substantially .
  - ✓ Cleared supply offer volumes increased 70 percent to an average of 3.3 GW per hour, while cleared demand bid volumes rose 32 percent to 4.0 GW per hour.
- The beginning of the rise coincides with the April 2011 RSG allocation change.
  - ✓ The RSG allocation change reduces the allocation for participants taking balanced positions to arbitrage basis differences (price differences between locations).
  - ✓ A balanced position can be ensured by bidding and offering price insensitively, which explains why much of the increase was price insensitive.
  - ✓ Some of the arbitrage of basis differences was focused on differences in marginal loss factors between the day-ahead and real-time markets. MISO took steps to reduce predictable differences early December.
  - ✓ This change in the loss factors contributed to the reduction in cleared virtual transactions from the prior quarter (fall 2011) of 14 percent. Most of this reduction was price-insensitive transactions.
- Screened transactions remain a very low percentage of total cleared volumes – just over 2 percent in each of the last three winters.

Virtual Volumes
2010–2012



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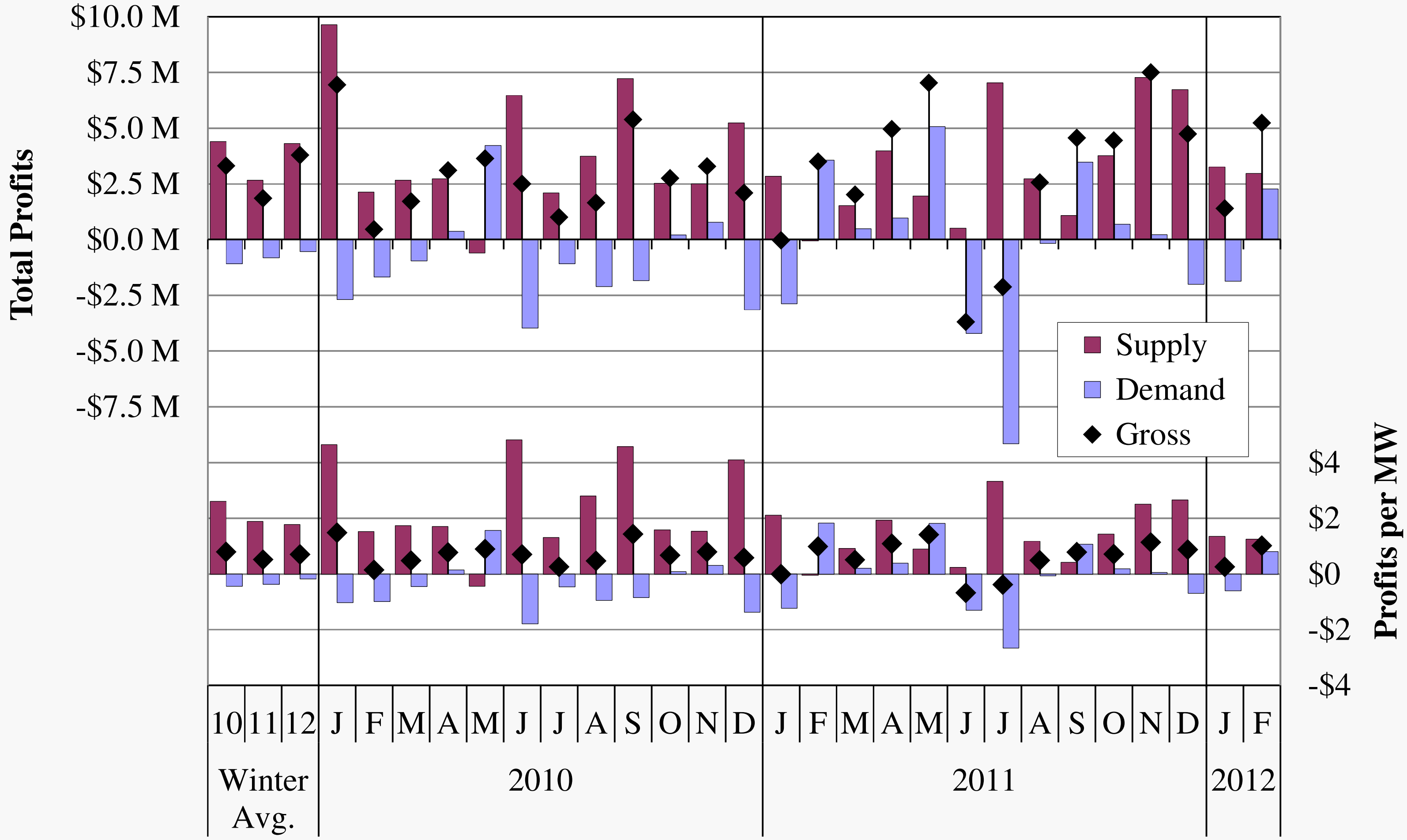
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual purchases and sales.
- Gross profitability in winter 2011 totaled $11.4 million, or $0.70 per MW.
  - ✓ This result is consistent with the modest profitability recorded in prior quarters.
- Virtual supply continues to be considerably more profitable ($1.78 per MW) than virtual demand ($-0.18).
  - ✓ Virtual supply profitability is expected in markets with prevailing day-ahead premiums.
  - ✓ These margins exclude CMC and DDC charges assessed to net harming deviations, including DDC charges to net virtual supply. DDC charges averaged just $0.28 per MWh in the period, down from $0.78 in fall and $1.53 in summer 2011.
  - ✓ As noted in prior months, the CMC allocation to virtual transactions is incorrect, resulting in allocations to virtual transactions that contribute to convergence. We are working with MISO to identify the best procedural option for getting this fixed.
- Virtual transactions by financial participants continue to be profitable and improve convergence overall, while those by physical participants are generally unprofitable.
  - ✓ Physical participants have consistently been willing to incur losses on virtual demand, likely to hedge risks associated with supply uncertainty and real-time price spikes.

Virtual Profitability 2010–2012



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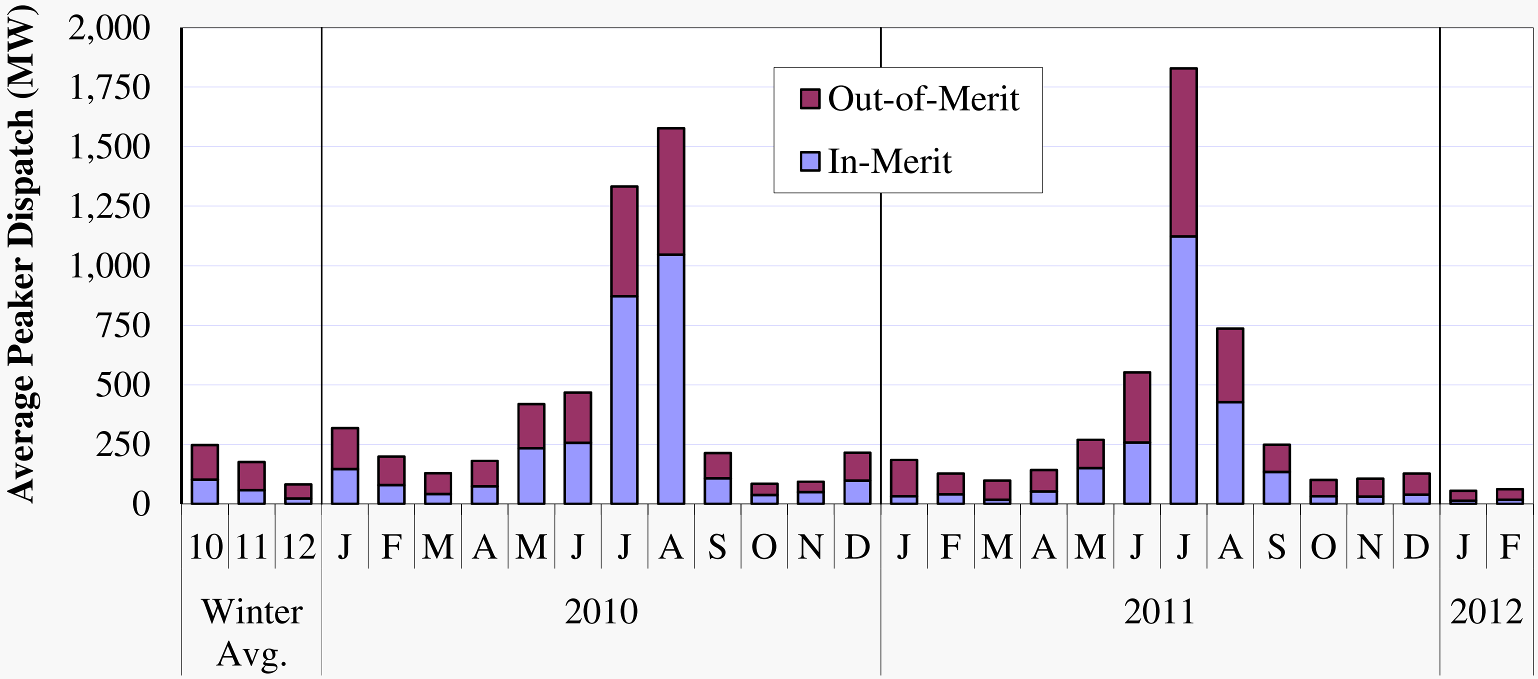
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were out-of-merit (offer price higher than the LMP).
- Peaking resource dispatch quantities declined 54 percent from last winter to an average of 81 MW per hour.
  - ✓ Although fewer commitments are typically required in winter than in summer for system capacity needs, commitments this winter were unusually low because of mild load conditions and full day-ahead load scheduling.
- Over 70 percent of units were dispatched out-of-merit, which is typical for periods that do not require large quantities of peaking resources.
  - ✓ This indicates that peaking resources frequently do not set the energy price, even when they are needed to meet the system's needs.
- When peaking resources do not set the energy price, relatively high-cost resources committed to manage congestion or to provide capacity will be out-of-merit.
  - ✓ MISO's ELMP initiative will allow peaking resources to set energy prices more reliably and was filed in December 2011.
  - ✓ This will improve MISO's price signals and reduce real-time RSG costs.

Peaking Resource Dispatch and In-Merit Status 2010–2012



Out-of-Merit Quantity and Share

MW	144	118	58	173	120	88	106	185	212	461	530	106	46	44	116	152	87	81	91	119	295	706	310	113	69	75	88	41	45
%	58	67	71	54	60	68	59	44	45	35	34	49	54	47	54	82	68	82	64	44	53	39	42	46	68	70	69	75	72

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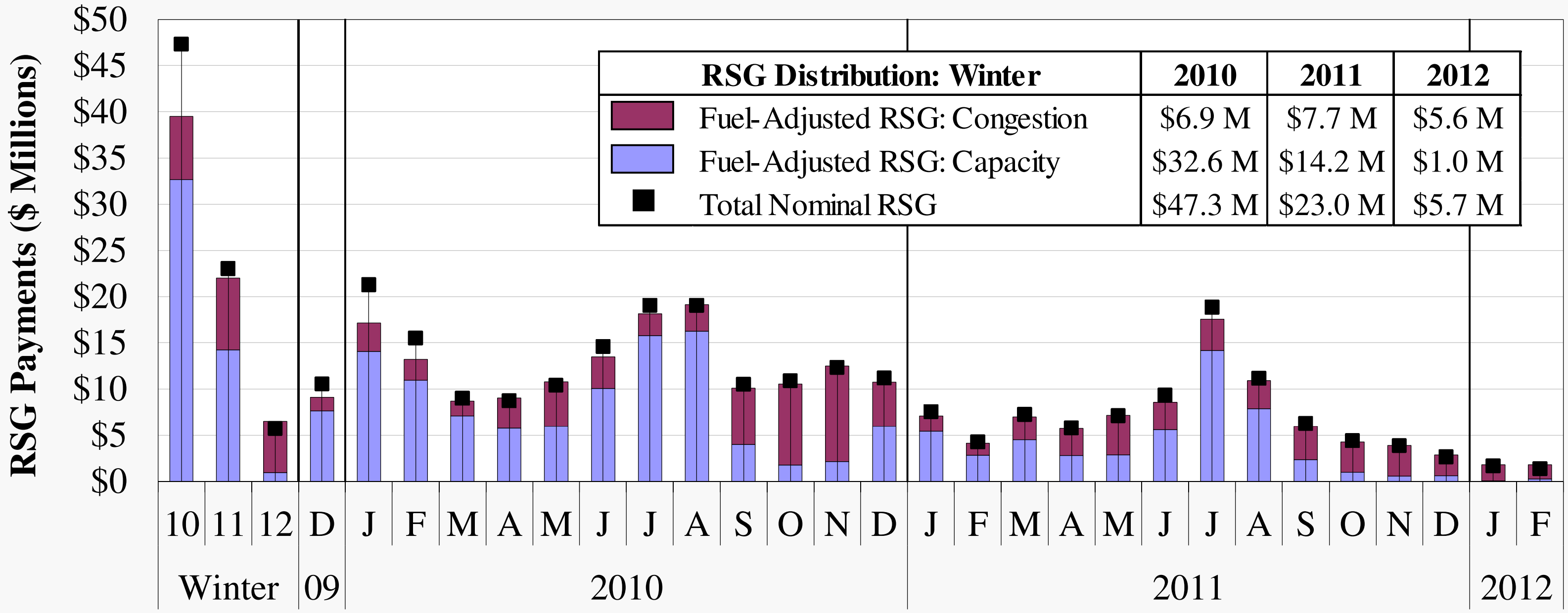
Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices.
  - ✓ Fuel prices are indexed to the average price over the period shown. Hence, the adjustment is greatest for periods when fuel prices were highest (in January 2010).
- Nominal RSG costs declined to just $5.7 million in winter 2011. This represents a decline of 75 and 88 percent from the prior two winters.
- Roughly 12 percent of the decrease is due to changes in fuel prices. The balance is attributable to:
  - ✓ Net day-ahead load scheduling of more than 100 percent in peak hours (see slide 16), which limited the need for MISO to commit additional resources in real time.
    - – Capacity commitments comprised just 15 percent of payments this winter, compared to 65 and 84 percent in the previous two winters.
  - ✓ Payments to non-peaking units for voltage support in WUMS, which totaled $4.2 million last winter, declined to $1.5 million (20 percent of the total).
- The second figure shows day-ahead RSG payments also declined by half to $3.0 million in nominal terms. Such payments continue to be lower than real-time RSG payments because most reliability requirements are satisfied only in the real time.

Real-Time RSG Payments 2010–2012



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

Peaker	59	52	31	70	58	53	59	58	64	50	69	71	39	20	23	47	60	53	54	53	48	69	75	66	45	46	41	35	26	29
Constraint	10	11	28	12	10	9	4	16	27	5	6	10	12	13	16	13	7	13	6	17	16	15	14	15	16	32	35	29	26	29
Capacity	49	41	3	59	48	44	55	43	37	45	63	60	28	8	7	34	53	40	49	36	32	53	62	51	29	14	6	7	0	0
Non-Peaker	41	48	69	30	42	47	41	42	36	50	31	29	61	80	77	53	40	47	46	47	52	31	25	34	55	54	59	65	74	71
Constraint	5	24	57	3	6	6	13	19	16	20	7	3	52	72	67	31	15	21	31	34	43	19	6	14	47	48	52	50	69	56
Capacity	35	24	12	27	36	40	28	22	21	30	24	26	9	8	9	22	24	26	15	14	9	12	18	19	9	6	6	15	5	15

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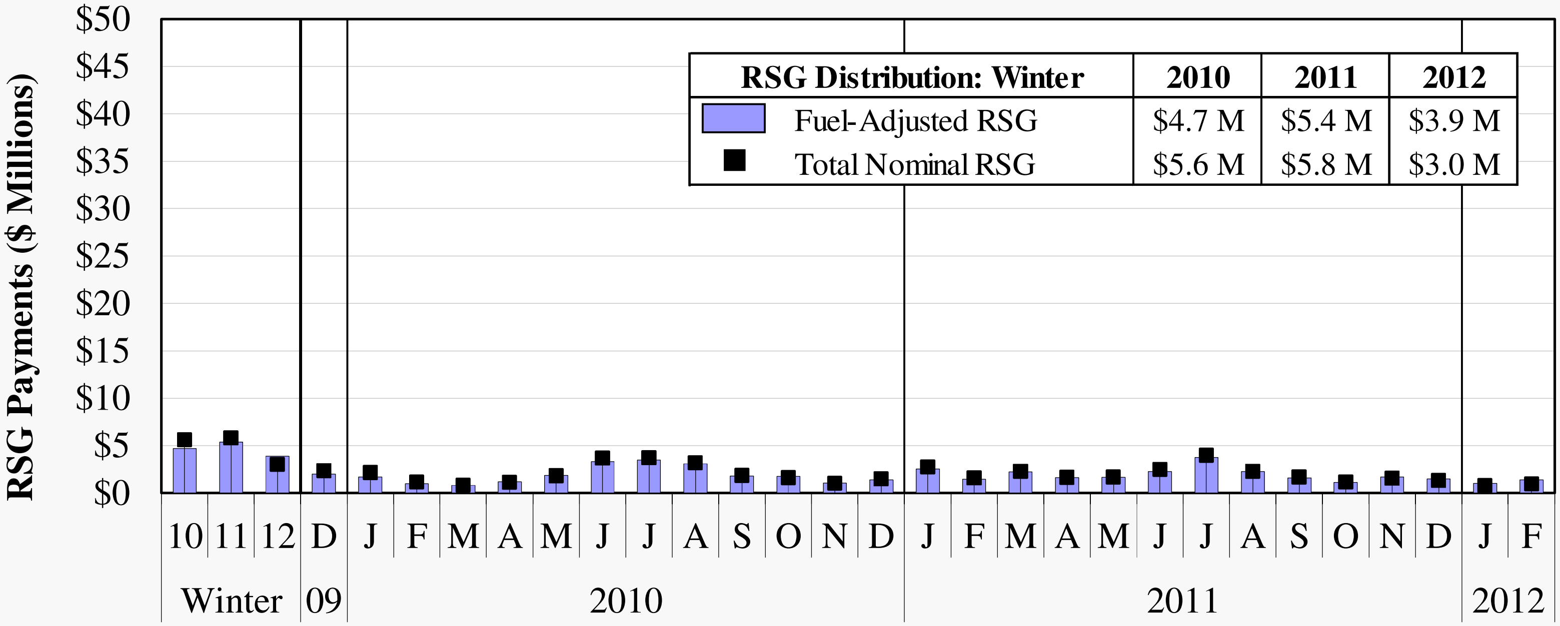
Day-Ahead RSG Payments 2010–2012



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

Peaker	3	3	3	4	4	0	2	3	14	11	26	35	10	3	3	9	1	0	2	2	7	21	41	15	19	11	6	4	2	1
Non-Peaker	97	97	97	96	96	100	98	97	86	89	74	65	90	97	97	91	99	100	98	98	93	79	59	85	81	89	94	96	98	99

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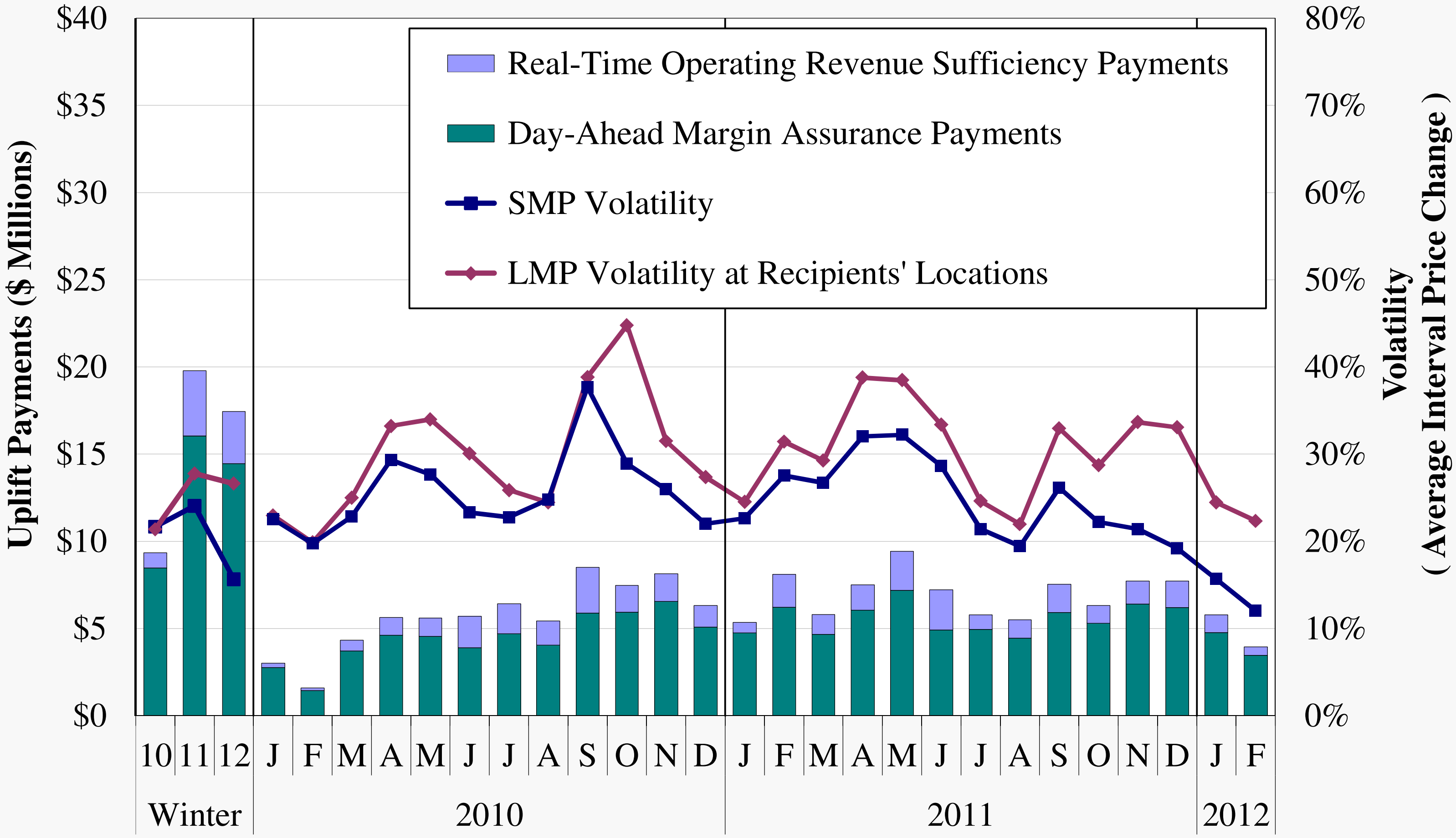
Price Volatility Make Whole Payments

- 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 12 percent from last winter to $17.5 million, which coincides with a general reduction in price volatility.
  - ✓ DAMAP continues to be the larger of the two payments at $14.4 million, which is 10 percent lower than in winter 2011. RTORSGP declined by 19 percent to $3.0 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.
  - ✓ It also shows that volatility is higher at recipients' locations because they are generally redispatched more than other suppliers due to the larger price changes.
- We recommended several changes to the calculation formulas and RTORSGP eligibility criteria in the *2010 State of the Market Report* to improve these payments and MISO is working on these changes.

Price Volatility Make Whole Payments 2010–2012



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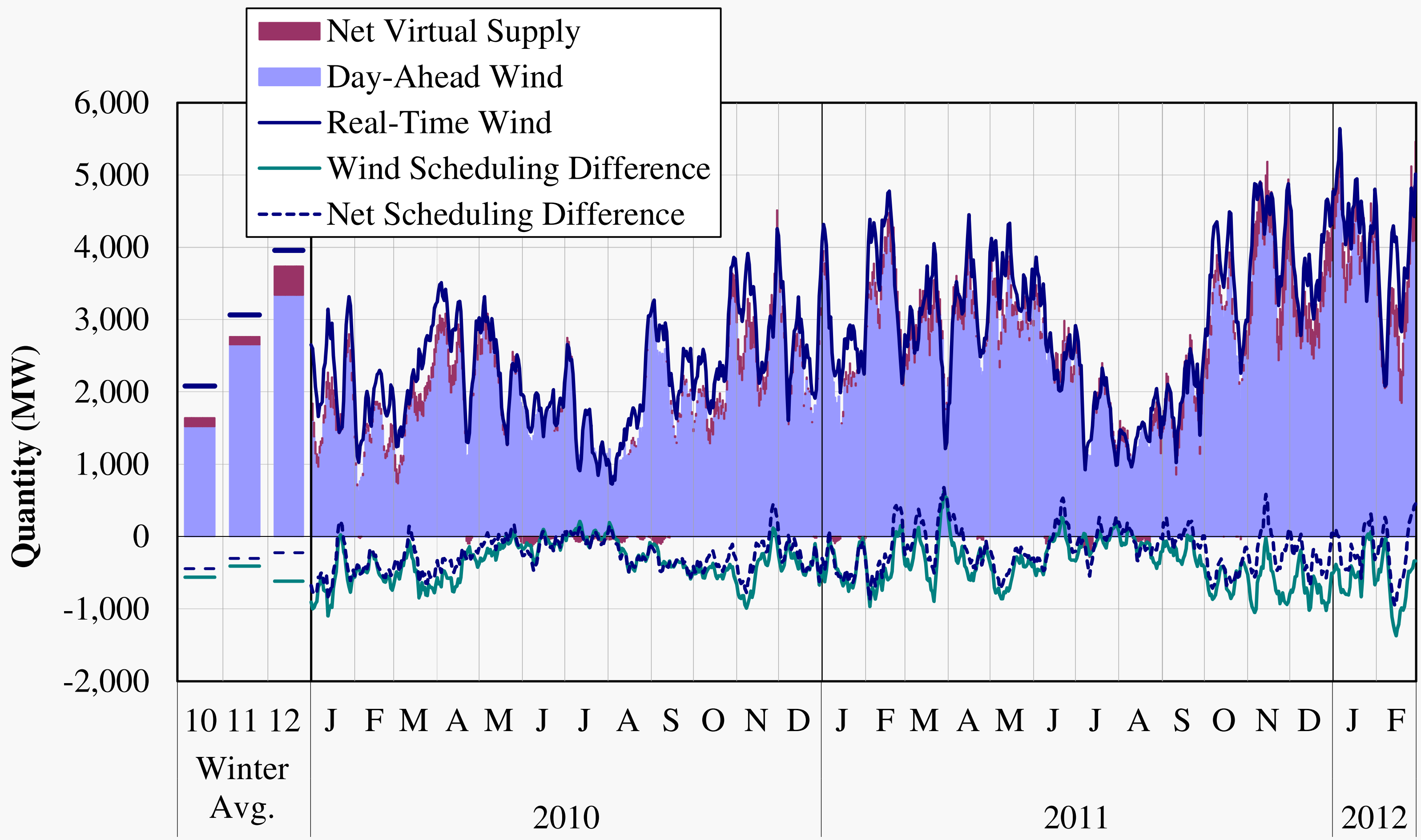
Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- 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 averaged 4 GW this quarter, up 19 percent from last winter.
  - ✓ Nameplate capacity over the same period increased 15.1 percent to 10.6 GW.
  - ✓ MISO set another wind record on January 1 when output exceeded 8.6 GW. Wind output peaked at 18 percent total output and averaged 6.5 percent.
- 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.
- Underscheduling of wind in the day-ahead market averaged 619 MW this quarter. Nearly two-thirds of this, however, was offset by net virtual supply at wind locations.
- Manageability of the congestion caused by wind should continue to improve as DIR resources expand in the MISO footprint.
  - ✓ As of March 1, 4.2 GW (39 percent) of wind resources are dispatchable and can set the real-time energy price.

Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average



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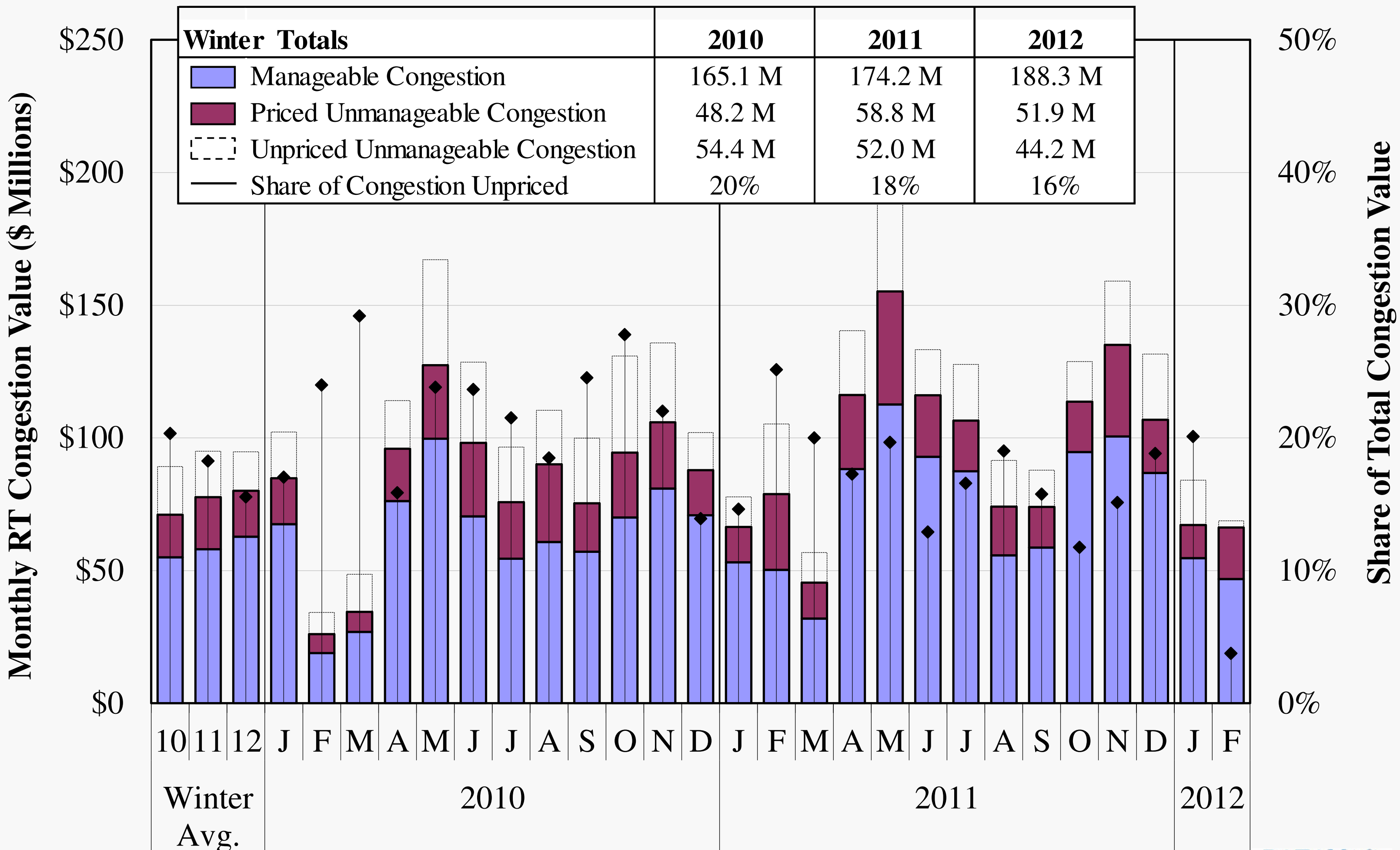
Congestion Management

- There were two significant changes to congestion management this winter.
- In late January, MISO implemented a new process to reduce the lag between state-estimated flows on constraints and inputs into the real-time market.
  - ✓ This is expected to reduce the lag from 3 to 9 minutes.
  - ✓ Initial results indicate the new process is working as intended, and should improve congestion manageability and reduce price volatility.
- Constraint relaxation was disabled for internal non-M2M constraints on February 1, 2012. There have been no operational issues as a result.
  - ✓ When constraints were unmanageable, MISO employed an algorithm that reduced the value of the congestion, often to zero.
  - ✓ Constraints in violation are now priced at their full Marginal Value Limit (the value the real-time dispatch recognizes as the cost of violating the constraint).
  - ✓ The resulting higher congestion costs have in some cases caused participants to take actions to address constraints.
  - ✓ MISO has also developed new post contingency action plans with TOs.
  - ✓ We will continue to evaluate the impacts of turning off constraint relaxation.

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, equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint, increased 3 percent from last winter to $240 million.
  - ✓ 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).
- Congestion decreased in all regions except the Central, where several large market-to-market constraints were each binding in more than a third of all intervals.
  - ✓ Nearly 40 percent of congestion occurred on M2M constraints in the Central region.
  - ✓ Much of this congestion is caused partly by PJM routinely exceeding its Firm Flow Entitlements on these constraints, for which MISO is compensated.
- Constraint relaxation continues to be used on MISO M2M and external constraints.
  - ✓ This adversely affects the day-ahead market and the revenues from the FTR market and can potentially impact reliability and investment decisions.
  - ✓ This eliminated 20 percent of congestion in December and January, but less than 4 percent in February (on market-to-market constraints) as it was turned off for internal non-market-to-market constraints.

Value of Real-Time Congestion 2010–2012



Winter Totals	2010	2011	2012
Manageable Congestion	165.1 M	174.2 M	188.3 M
Priced Unmanageable Congestion	48.2 M	58.8 M	51.9 M
Unpriced Unmanageable Congestion	54.4 M	52.0 M	44.2 M
Share of Congestion Unpriced	20%	18%	16%

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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 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 under both thresholds continued to be extremely low.
  - ✓ It averaged just 15 and 4 MW this quarter under the low and high thresholds, respectively. These levels represent declines of over 90 percent from last winter.
- As a share of overall load, the low-threshold output gap again averaged less than 0.01 percent of load.
  - ✓ The mitigation thresholds for Narrow Constrained Areas were updated in early February. The Minnesota threshold declined substantially while the WUMS threshold increased substantially, and the North WUMS increased slightly.
  - ✓ These threshold changes may cause output gap levels to change in future months.
- Overall, these results raise no competitive concerns, although we continue to routinely investigate hourly increases in the output gap.

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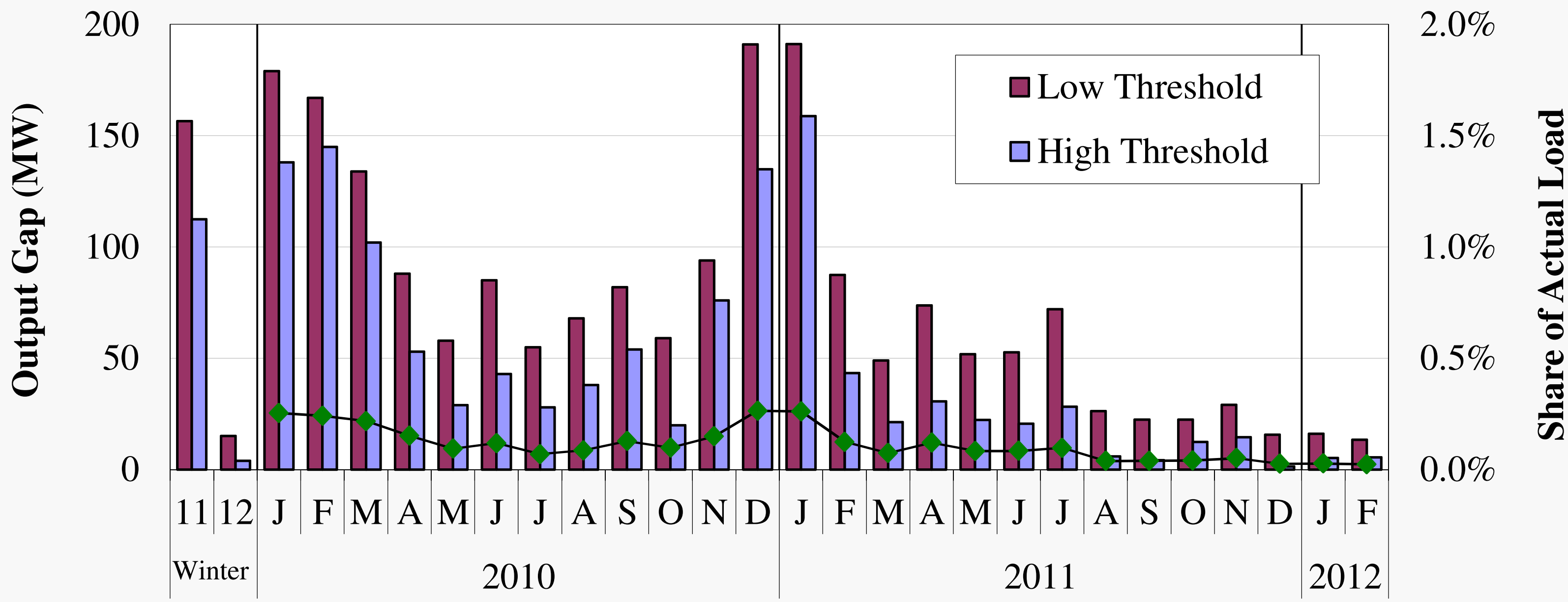
Monthly Output Gap
2010–2012



Low Threshold Results by Unit Status (MW)

Off Line	94	3	74	110	75	28	12	31	16	19	18	5	33	95	143	44	21	14	9	11	23	0	1	11	12	0	4	4
On Line	62	12	105	57	59	60	46	54	38	49	64	54	61	96	48	43	29	60	43	42	49	26	22	12	17	16	12	9

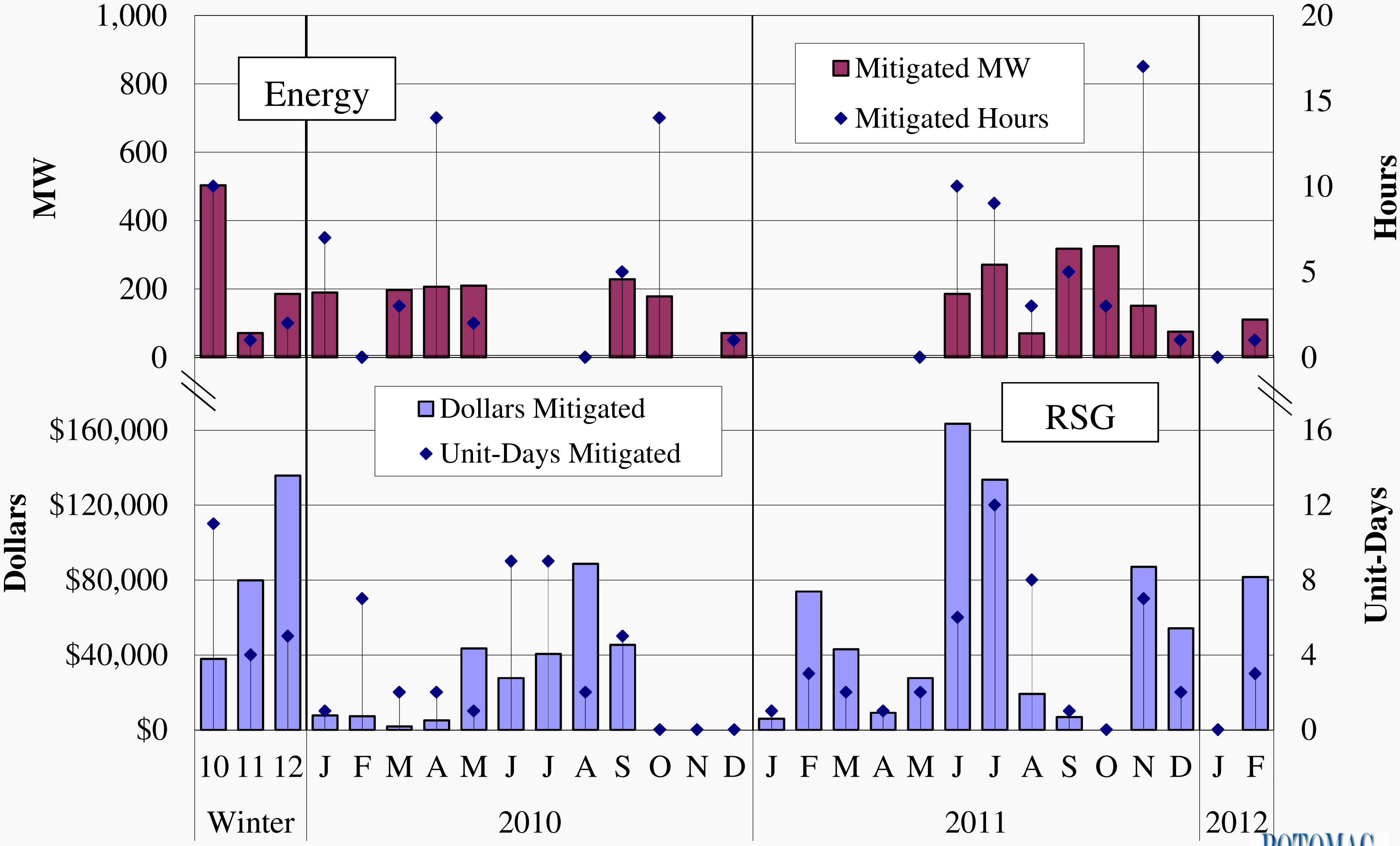
High Threshold Results by Unit Status (MW)

Off Line	87	3	67	110	73	27	12	31	16	19	18	5	33	89	142	29	16	14	9	10	19	0	1	11	12	0	4	4
On Line	26	1	71	35	29	26	17	12	12	19	36	15	43	46	17	14	5	17	13	10	9	6	4	1	3	1	2	1

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which mitigation has been imposed in the real-time market and for RSG payments.
  - ✓ 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.
- Mitigation hours rose modestly in December to February from last winter.
  - ✓ Energy mitigation occurred for 2 unit-hours and186 MW, up from 1 unit-hour and 71 MW last winter. All of it occurred in Broad Constrained Areas.
  - ✓ RSG mitigation in dollar terms rose from $80,000 last winter to $136,000.
- Despite this increase, mitigation continues to be extremely infrequent because the vast majority of resources are offered competitively in the MISO markets.
  - ✓ Resources typically have fewer opportunities to exert market power when load is low.
- Although mitigation levels indicate that these events continue to be infrequent, local market power continues to be a significant concern.
  - ✓ Market power mitigation measures therefore remain critical.
  - ✓ We continue to evaluate AMP mitigation and found mitigation to be appropriately applied in all instances.

Real-Time Market Power Mitigation 2010–2011



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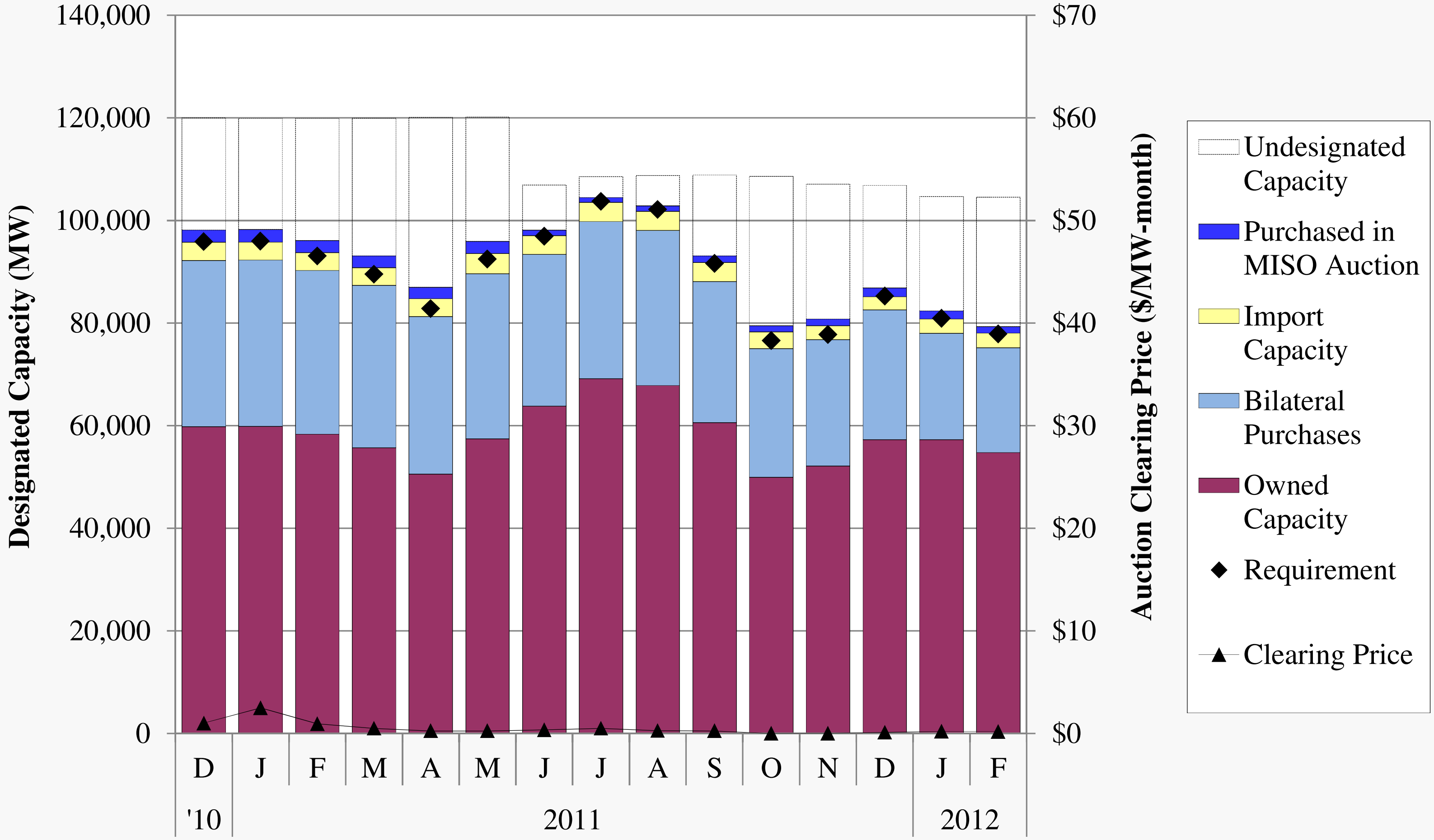
Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The auction continues to clear at close to zero (less than $1 per MW-month), consistent with the surplus level of capacity that exists in the MISO footprint.
  - ✓ The departures of FirstEnergy in June and portions of Duke Energy in January has not had a material impact on resource adequacy.
- The following figure shows the monthly capacity requirements, designated capacity, and VCA clearing price for the preceding fifteen months.
  - ✓ The capacity cleared in the VCA each month remains a very small portion of the total designated capacity. It has not exceeded 2 percent since May 2011.
  - ✓ This outcome is consistent with the expectation that most LSEs satisfy their capacity needs primarily through owned capacity or bilateral purchases.
- The figure also shows the total supply and designations for resources in MISO.
  - ✓ The total capacity available exceeded the requirement by at least 25 percent (except in summer months). As a result, VCA clearing prices remain extremely low.
  - ✓ Capacity designations continue to meet or exceed requirements—designations exceeded the requirement by approximately 2 percent in each month this winter.
- The capacity market continues to be undermined by barriers to trading capacity with PJM – we filed in January requesting a FERC mandate to address this issue.

Voluntary Capacity Auction December 2011–February 2012



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

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Submittals to External Entities and Other Issues

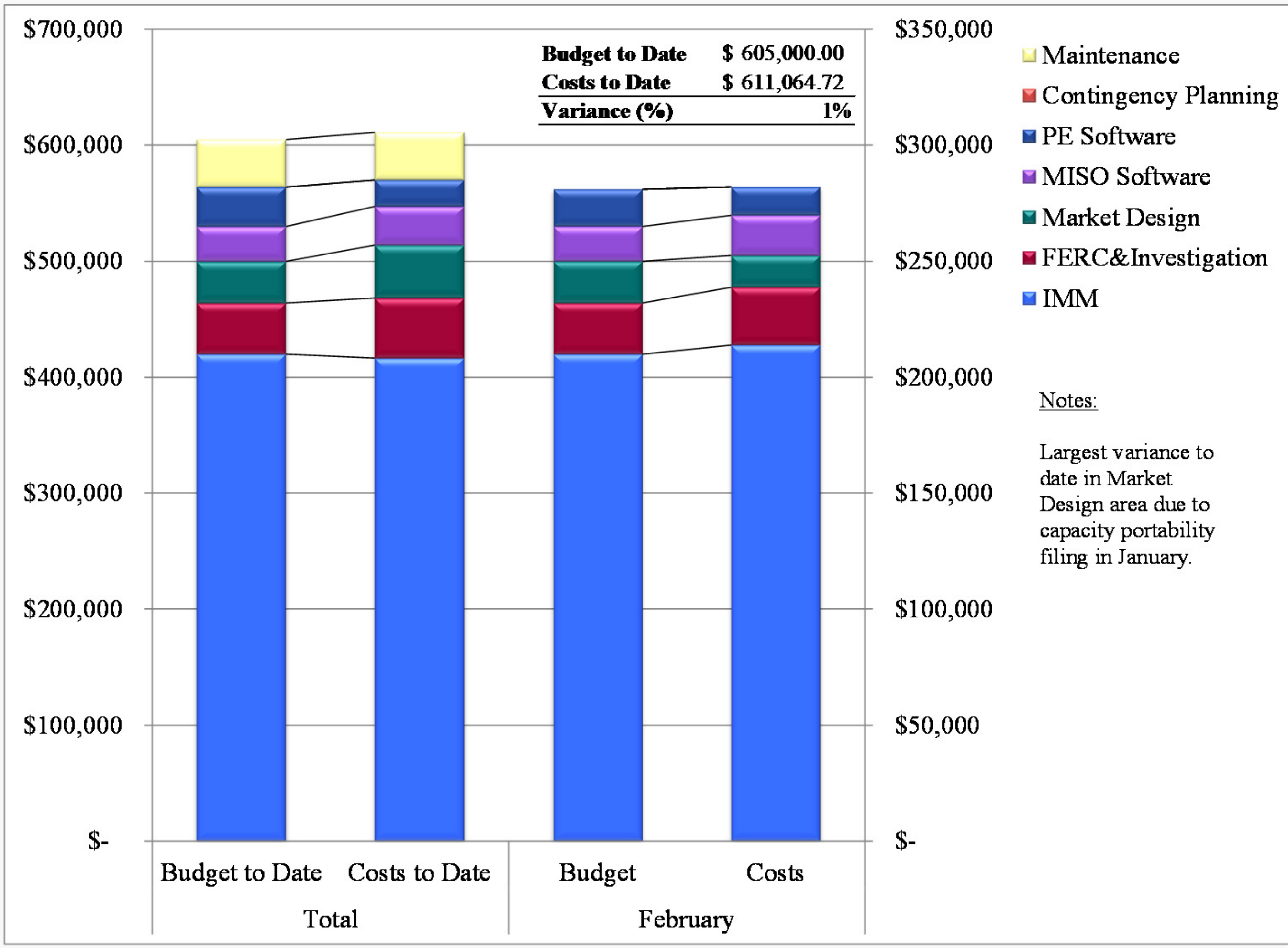
Submittals to External Entities:

- We continue to meet regularly with FERC regarding market outcomes and responded to a number of inquiries and data requests in February.
  - ✓ We provided additional details to FERC related to previous referrals.
  - ✓ We submitted reports to FERC regarding participants that may have violated Module E must offer requirements.
  - ✓ We responded to data requests related to price spike events.
- We presented the January monthly report to the OMS.

Other Issues:

- We continued to coordinate with MISO staff on responses to SOM recommendations.
- We are working with MISO on the April 1 implementation of voltage/local reliability market power mitigation, which we supported with an affidavit.
- We are reviewing MISO's first SSR status determinations for 5 units and will be evaluating the data and assumptions in MISO's equitable compensation under Attachment Y.

IMM Cost Summary



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