IMM Quarterly Report: Fall 2014
September – November

MISO Independent Market Monitor

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Potomac Economics

December 10, 2014

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Quarterly Summary

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
RT Energy Prices ($/MWh)	🟢	$34.32	*-1%*	*9%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	🟢	$4.04	*-4%*	*8%*
Natural Gas - Henry Hub	🟢	$3.90	*-6%*	*7%*
Western Coal	🔵	$0.69	*-2%*	*8%*
Eastern Coal	🟢	$1.91	*0%*	*3%*
Load (MW)[2]				
Average Load	🟢	74.1	*-11%*	*-1%*
Peak Load	🟢	111.7	*-3%*	*-6%*
% Scheduled DA (Peak Hour)	🟢	99.4%	100.4%	99.6%
Transmission Congestion ($M)				
Real-Time Congestion Value	🟢	$403.6	*22%*	*-9%*
Day-Ahead Congestion Revenue	🟢	$227.1	*8%*	*-13%*
Balancing Congestion[4]	🔵	-$17.8	-$5.4	-$9.3
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$10.53	*17%*	*-5%*
Spinning Reserves	🟢	$1.88	*43%*	*-43%*
Supplemental Reserves	🟢	$0.76	*51%*	*-72%*

		Value	*Change*[1] Prior Qtr.	*Change*[1] Prior Year
FTR Funding (%)	🔵	91%	98%	97%
Wind Output (MW)	🟢	4,852	*77%*	*10%*
Guarantee Payments ($M)[5]				
Real-Time RSG	🟢	$12.3	*11%*	*-14%*
Day-Ahead RSG	🔵	$28.8	*-21%*	*284%*
Day-Ahead Marginal Assurance	🟢	$13.3	*-6%*	*-2%*
RT Operating Rev. Sufficiency	🟢	$2.9	*-42%*	*1%*
Price Convergence[3]				
Market-wide DA Premium	🟢	0.0%	3.4%	-2.6%
Virtual Trading				
Cleared Quantity (MW)	🟢	8,918	*27%*	*46%*
% Price Insensitive	🟢	38%	44%	33%
% Screened for Review	🟢	2%	2%	2%
Profitability ($/MW)	🟢	$0.87	$0.20	$1.32
Dispatch of Peaking Units (MW/hr)	🟢	369	548	311
Output Gap- Low Thresh. (MW/hr)	🟢	165	130	62
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. Net ECF with no offset for M2M settlements.
5. Includes effects of market power mitigation.

Summary of Fall 2014

- Fall 2014 was characterized by relatively mild loads and moderate gas prices.
- Real-time energy prices rose 9 percent from the previous fall to $34.32 per MWh, consistent with a comparable rise in natural gas prices.
  - ✓ Off-peak prices rose by 16 percent because of an increase in coal costs and coal conservation measures by participants.
  - ✓ Average coal offers were $3 per MWh higher than last fall.
- Price convergence has been very good in recent months, in part due to increased virtual transactions, which were nearly 50 percent higher than last fall.
  - ✓ A modeling issue at a zone in the Central region, combined with overselling along the same path, contributed to significant FTR underfunding during the quarter.
    - – Funding averaged 91 percent (a shortfall of nearly $36 million).
  - ✓ It also contributed to an increase in balancing congestion, which exceeded $-17 million.
- Improved generator performance and MISO modeling of the South region has resulted in considerable reductions in RSG payments and PVMWP from earlier in 2014.
  - ✓ There have also been far fewer instances of day-ahead VLR mitigation.
- MISO set an all-time wind peak of 11.1 GW in mid-November.

Note: Some numbers in this report are preliminary and subject to revision due to time constraints.

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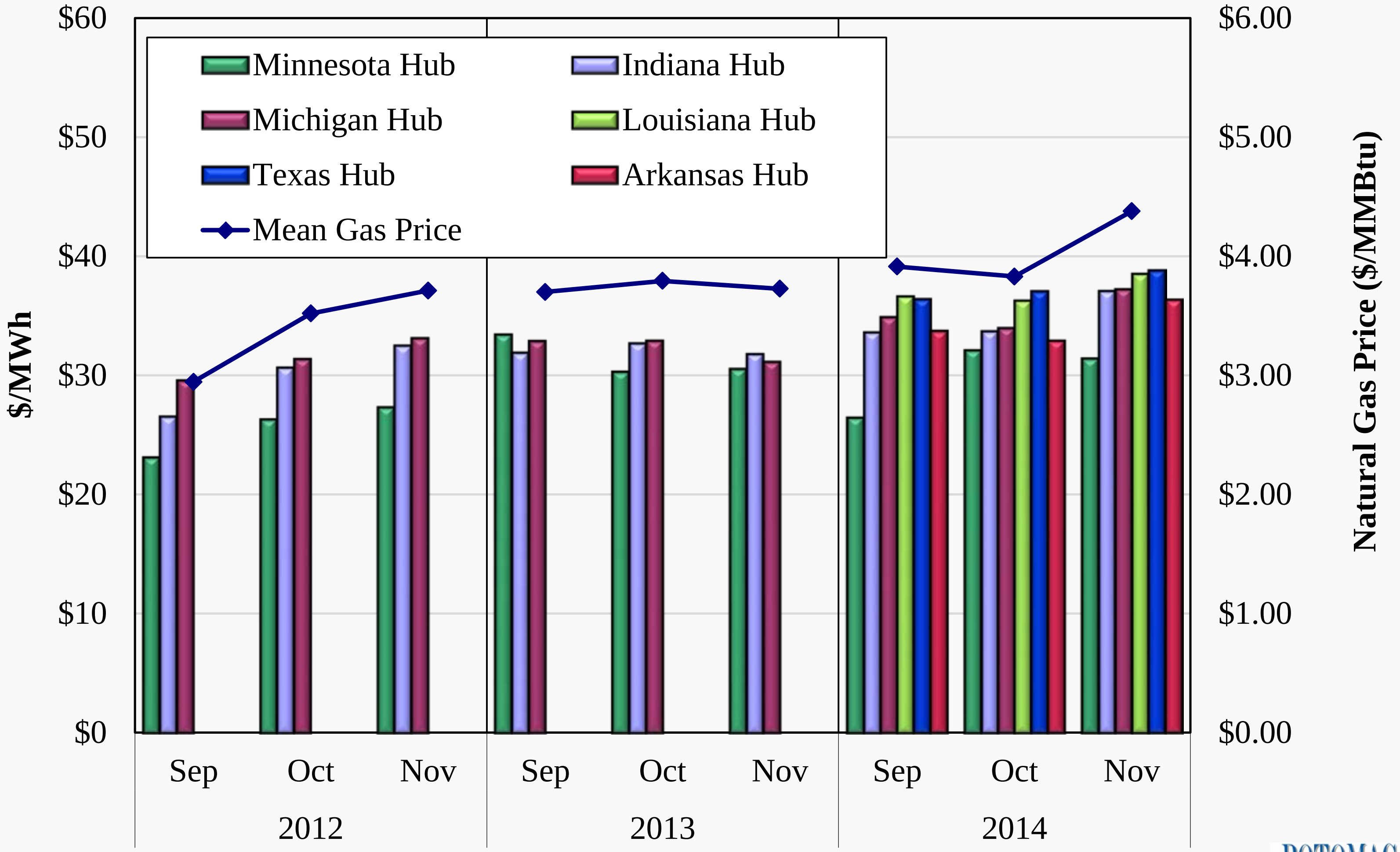
Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at six locations in the MISO footprint for each month in the fall quarters of 2012 to 2014.
  - ✓ We include a representative natural gas price 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 strongly correlated.
- Day-ahead energy prices rose 10 percent from last fall to $34.52 per MWh.
  - ✓ The rise is consistent with an 8 percent rise in natural gas prices. Scheduled load was nearly unchanged at 73.5 GW.
- Off-peak prices rose 16 percent versus 6.5 percent during peak hours.
  - ✓ This is in part due to increases in coal costs and conservation measures.
  - ✓ Coal units are frequently a marginal fuel in off-peak hours. Compared to last fall, coal capability was down 4 percent, while coal unit offer prices were up nearly 12 percent.
- Prices declined by 2 percent in the West from last fall due to congestion out of the region, particularly in September.
- South Region prices averaged more than 10 percent higher than prices in the Midwest Region because of the transfer constraints into the South.
  - ✓ Congestion into Texas that was prevalent in the summer was greatly reduced this Fall because key generators that affect the congestion returned to service.

Day-Ahead Average Monthly Hub Prices
Fall 2012–2014



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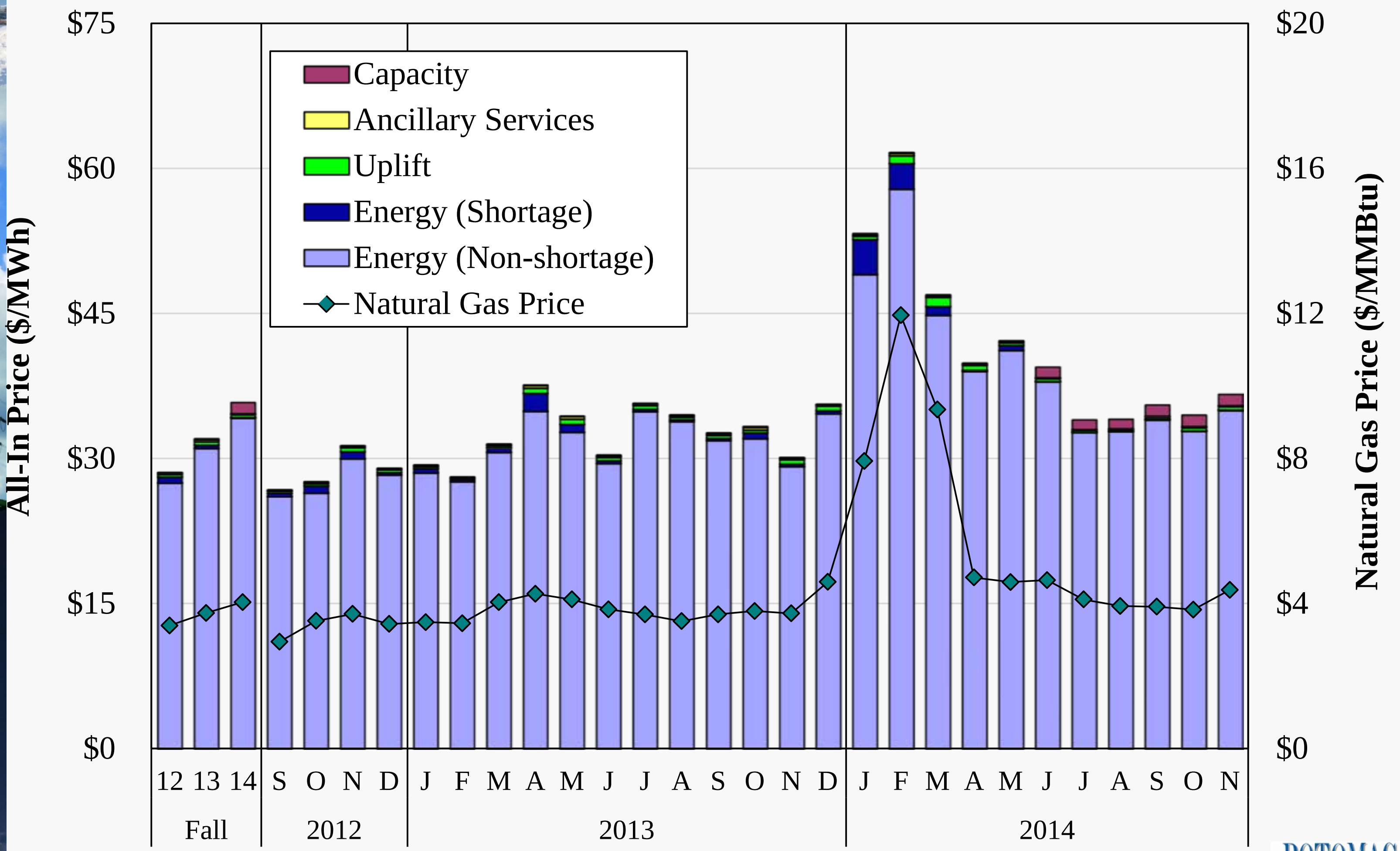
All-In Price

- 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.
    - – We separate the energy component associated with shortages.
  - ✓ The figure also shows the monthly average natural gas price at Chicago Citygate, because natural gas prices are a key driver of energy prices.
- The all-in price rose 12 percent from last fall to an average of $35.87 per MWh.
  - ✓ It rose faster than energy prices did because of the increase in capacity costs, which rose from 8 cents to $1.16 per MWh, and accounted for over 3 percent of the all-in price.
  - ✓ Although they are increased, a well-functioning capacity market would cause capacity prices to be a more significant component of the all-in price, particularly as MISO's capacity surplus declines in the future.
- The energy component continues to make up over 95 percent of the all-in price and rose 9 percent from last fall, largely due to fuel price changes.
  - ✓ The share of the energy component associated with shortage pricing declined from 38 cents to just 8 cents because of the near absence of shortage intervals this fall.
- Ancillary service prices and uplift costs both declined considerably from last fall. They added 29 and 10 cents, respectively, to the all-in price.
- The all-in price does not include SSR payments, which can exceed $6 million per month due to a recent FERC decision to allow for the inclusion of fixed costs.

All-In Price
2012 –2014



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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 prior 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.
- A near absence of shortages for all products since last winter has resulted in considerable declines in all ASM prices.
  - ✓ Regulation clearing prices averaged $10.53 per MWh this fall, down 5 percent from last fall. There were 8 periods of regulation shortage.
  - ✓ More than half of output gap (see slide 39) is associated with high regulation offers. Hence, regulation prices have not fallen as much as spin and supplemental prices.
- Spinning reserve clearing prices were 43 percent lower than last fall, and averaged $1.88 per MWh, while supplemental prices declined from $2.70 to $0.76.
  - ✓ Spin shortages declined by two-thirds, and there was only one OR shortage. These only explain a small portion (27 and 11 percent, respectively) in the decline from last fall.
  - ✓ Spin and contingency reserve requirements have not significantly changed since the integration of MISO South, which means far greater supply and lower prices.
- Prices for all three products rose modestly from the summer, when greater supply availability and mild summer conditions resulted in the lowest clearing prices.

Monthly Average Ancillary Service Prices
Regulation and Contingency Reserves, 2013–2014

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MISO Fuel Prices

Natural Gas and Oil Prices

- Natural gas prices at Chicago rose 8 percent from last fall to $4.04 per MMBtu.
  - ✓ Prices remained below $4 for the majority of the quarter before rising above $4 in November. A cold snap in mid-November briefly increased prices above $5.
    - – Price differences between Chicago and Henry Hub, where prices averaged $3.90 for the quarter, at times exceeded 60 cents.
    - – Significant price differences can contribute to inter-regional congestion.
  - ✓ Gas storage levels have not fully recovered from the effects of last winter last winter.
- Oil prices declined 8 percent to $19.62 per MMBtu. In recent weeks, however, prices have declined by over $5 (from $22.41 in early November to just $17.00).

Coal Prices

- Coal prices have risen slightly since last fall. Illinois Basin prices rose 3 percent to $1.91 per MMBtu, while Powder River Basin prices rose 8 percent to $0.69.
- Delivered coal prices, however, can be significantly higher due to rail congestion.
  - ✓ Several participants have increased their coal unit offers in response to supply or coal conservation concerns.

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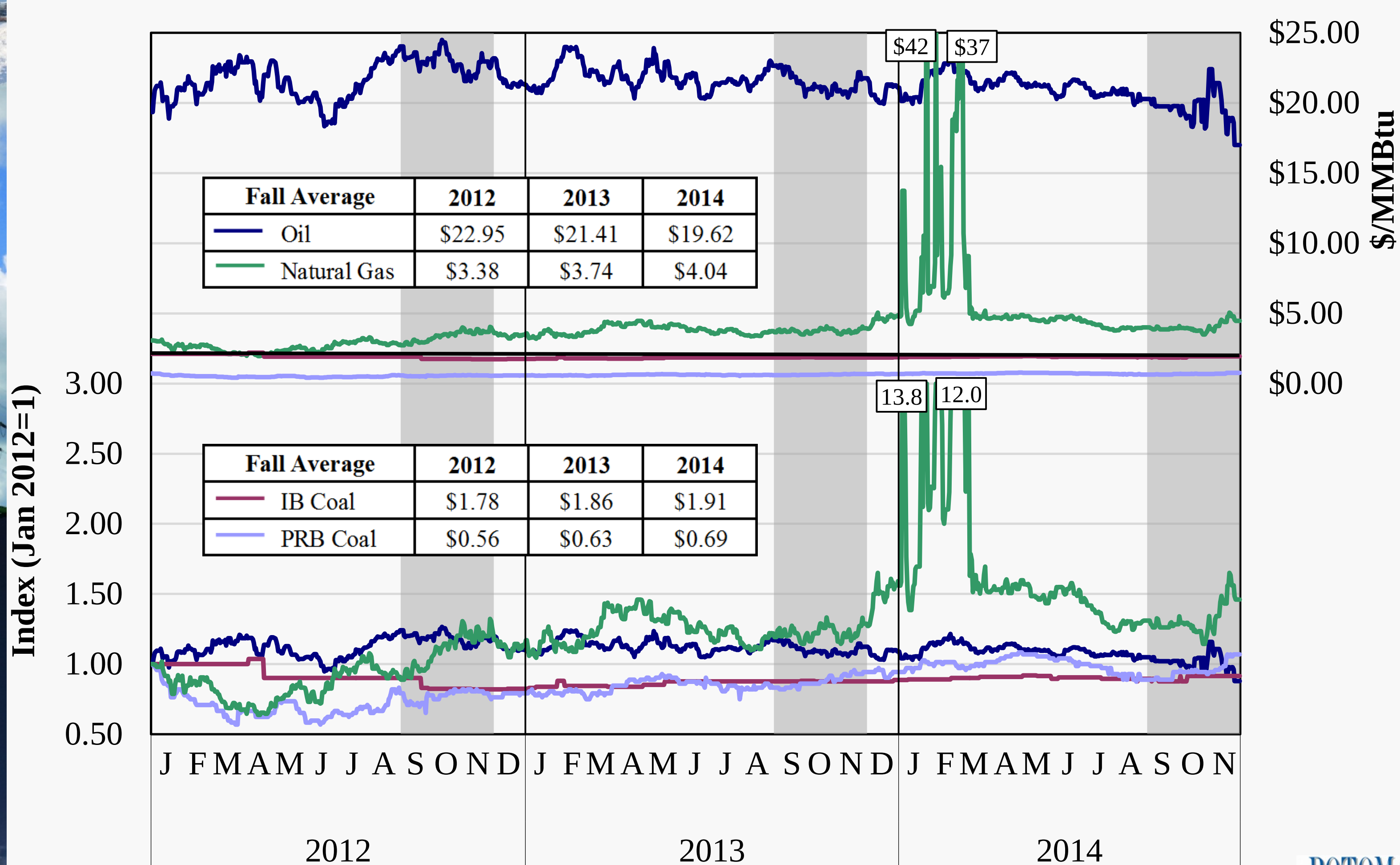
MISO Fuel Prices
2012–2014



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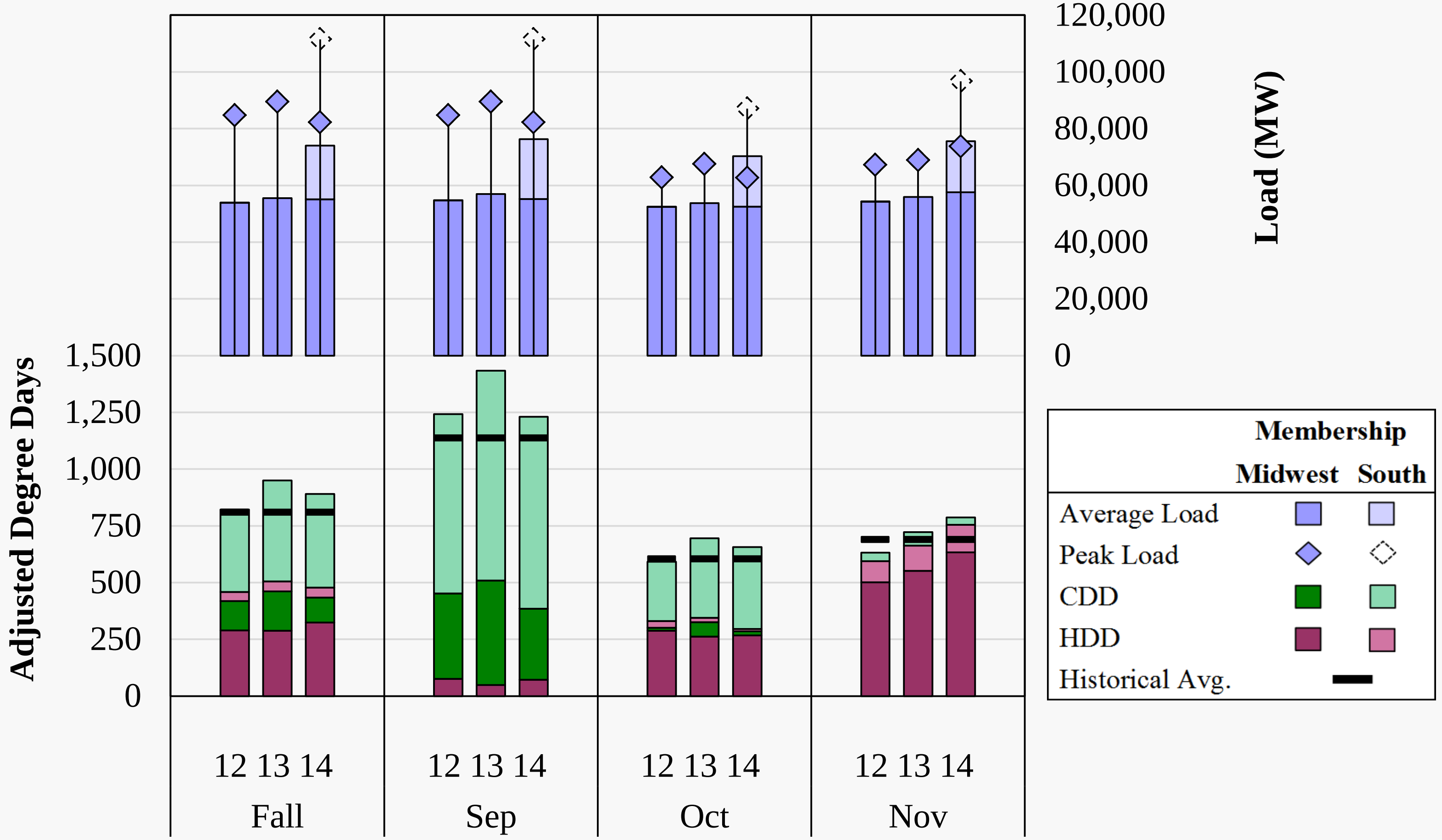
Changes in Load and Weather Patterns

- 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 2012 to 2014, while the bottom panel shows the average heating and cooling degree days (a weather metric that is highly correlated with load).
  - ✓ Cooling degree days are normalized, based on a regression analysis, by a factor of six to account for their bigger impact on demand.
  - ✓ We show the South Region's contribution to load separately and include two South cities in the degree-day metric.
- The figure shows that degree days in MISO declined 3 percent from last fall but remained 12 percent above the historical average.
  - ✓ Degree days in November were abnormally high due to an early winter cold snap.
  - ✓ Temperatures in September and October were slightly above average, although cooling degrees in the South have an outsized impact on the quarterly metric.
- As a result, average load declined 0.9 percent in the Midwest Region.
  - ✓ MISO did not experience a late-summer heat wave as in 2013.
  - ✓ The peak load this fall, adjusted for membership changes, declined 8 percent.

Load and Weather Patterns
Fall 2012–2014



Note: Midwest degree day calculations include four representative cities in the Midwest: Cincinnati, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

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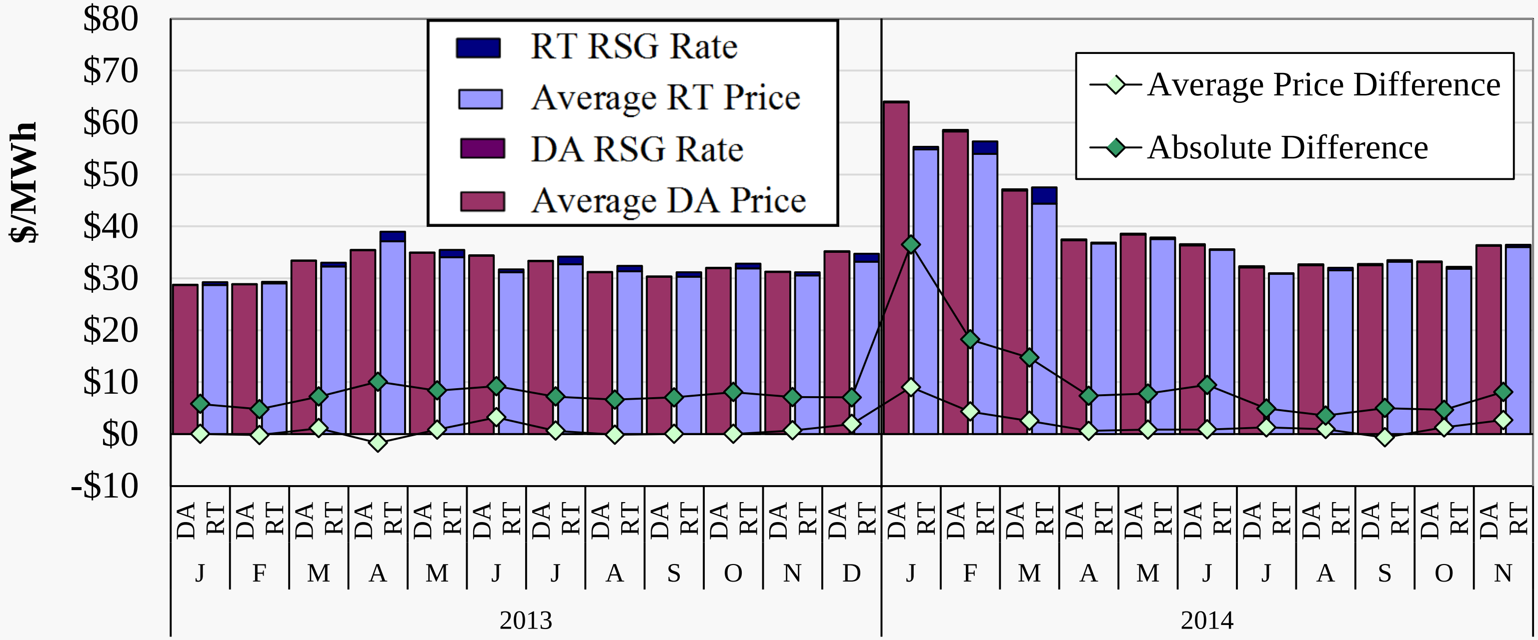
Day-Ahead and Real-Time Price Convergence

- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub in 2013 and 2014 (the table shows other locations), along with price differences.
  - ✓ Modest day-ahead premiums are generally expected in MISO due to greater real-time price volatility and uplift charges applicable to real-time load purchases.
- Convergence was very good this quarter, with MISO exhibiting a slight day-ahead premium at most locations.
  - ✓ In September, the increase in real-time congestion, including on the Minnesota-Wisconsin Export Constraint, was broadly under-estimated day-ahead.
- Real-time RSG costs under the DDC rate averaged $0.35 per MWh this fall.
  - ✓ This decline is in part due to MISO's revisions of the allocation in March to be more consistent with cost causation.
  - ✓ The share of non-VLR RSG costs borne by deviations this fall was 83 percent, down from 93 percent in summer.
  - ✓ Although this allocation is improved, we are working with MISO on an additional change that will reduce this share further by eliminating the inappropriate allocation to helping deviations (post notification deadline).

Day-Ahead and Real-Time Price Convergence 2013–2014



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

Indiana Hub	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1	16	4	-1	2	2	3	4	2	-2	3	0
Michigan Hub	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	7	26	-1	2	-5	4	3	-2	3	0
Minnesota Hub	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6	16	-9	-5	-3	3	4	1	3	0	3	3
WUMS Area	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	-2	-1	-3	3	0	2	2	-5	1	2
Arkansas Hub												1	-12	-16	-20	1	4	10	5	2	-4	-1	2
Louisiana Hub												-1	-22	-14	-19	-12	11	1	4	3	-4	2	1
Texas Hub												3	-6	-14	-13	-4	-6	31	3	5	2	1	1

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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 averaged 99.4 percent in the daily peak hour. In all hours, it averaged 99.1 percent.
  - ✓ Scheduling was unusually low on several high-load days in early September, including below 94 percent on September 5.
  - ✓ Net virtual demand of more than 1 GW, or approximately 2 percent of real-time load, continues to make up most of the shortfall in fixed and price-based load.
- Peak-hour loads in the Midwest and South regions were both slightly under-scheduled this fall.

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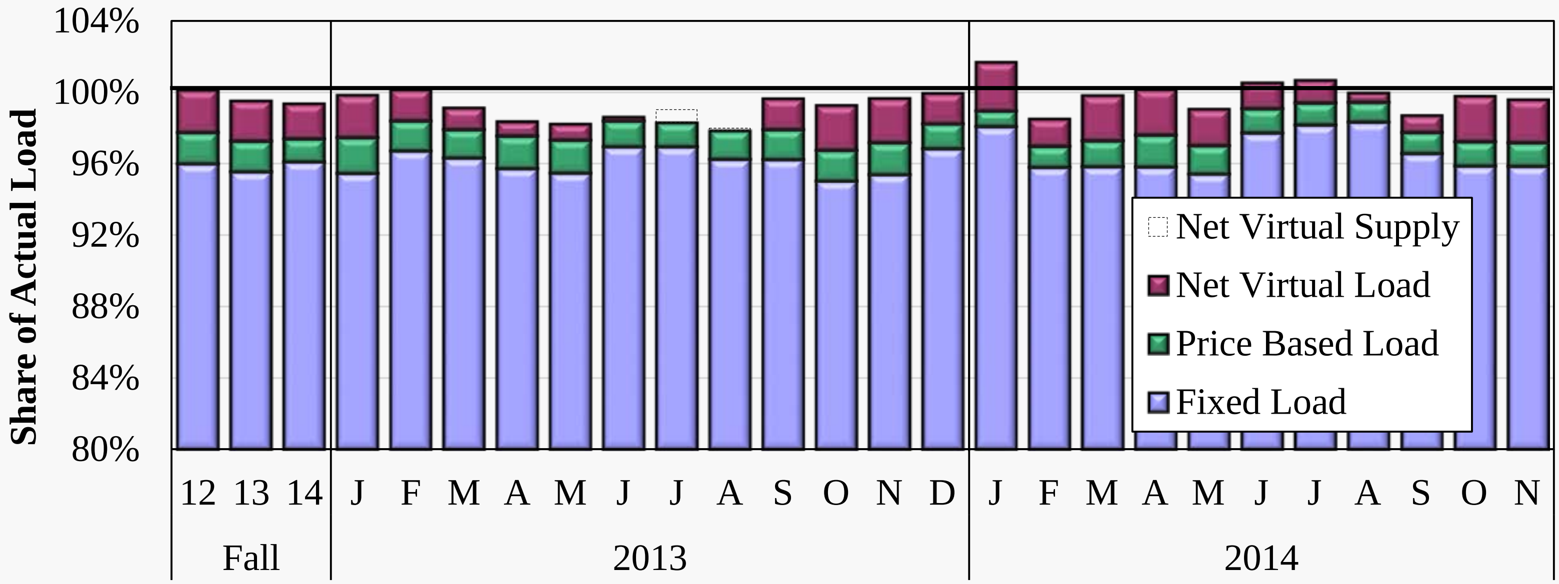
Day-Ahead Peak Hour Load Scheduling 2012–2014



Share of Actual Load (%)

	Fall			2013												2014										
	12	13	14	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N
All	98.9	99.0	99.1	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.9	101.7	99.3	99.2	99.8	99.1	100.1	100.2	99.8	98.7	99.0	99.7
Peak Hours Midwest	100.2	99.6	99.9	99.9	100.2	99.2	98.4	98.3	98.6	98.3	97.9	99.7	99.3	99.7	99.5	100.4	98.0	99.3	99.5	98.0	99.5	99.8	99.5	98.8	100.2	100.7
Peak Hours South			99.6												104.9	104.4	99.9	100.4	101.5	101.6	102.7	102.5	100.7	99.5	99.7	99.4

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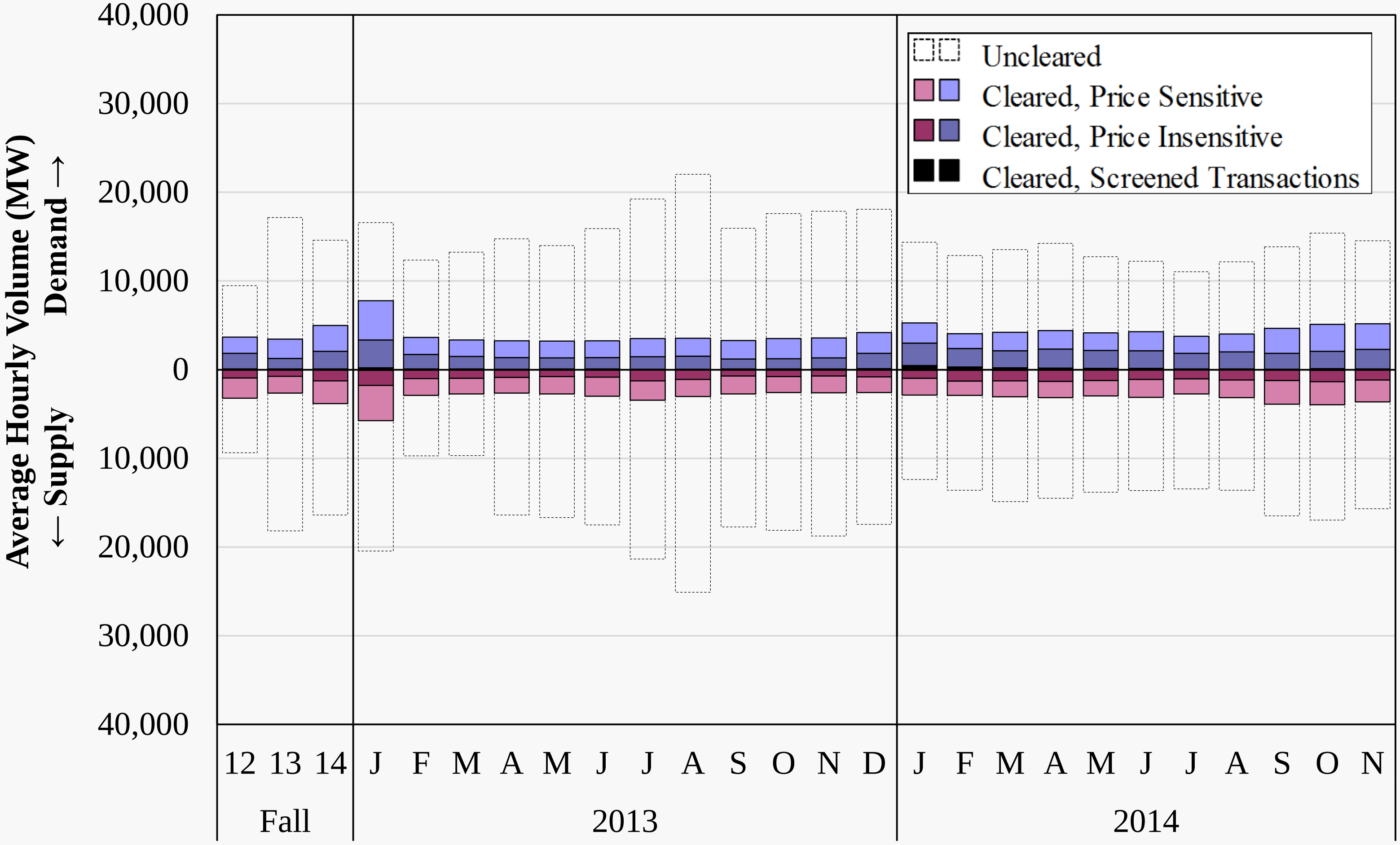
Virtual Load and Supply in the Day-Ahead Market

- The next two figures show the monthly average quantity of offered and cleared virtual supply and demand transactions since January 2013.
  - ✓ We separately identify the share that are price-insensitive, as well as those that are "screened" as also contributing to (or preventing the relief of) congestion.
  - ✓ The second figure separates these volumes by participant type.
- Offered transactions were 11 percent lower than last fall, but 24 percent higher than in summer. These fluctuations are due to changes in some participants' bidding practices of offering at prices that rarely clear.
  - ✓ Such "backstop" bids are profitable and contribute to convergence when they do clear.
- Cleared transactions rose from 6.1 GW per hour last fall to 8.9 GW, over 90 percent of which are by financial participants.
  - ✓ Despite the persistent premium for supply, demand volumes continue to exceed supply volumes by more than 1 GW.
- Around one third of the cleared transactions continued to be price-insensitive.
  - ✓ The modest increase from last year is associated with demand volumes that continue to be submitted by a participant at two locations in the South region.
- Similarly, the share of screened transactions remains around 2 percent, which is low.

Virtual Load and Supply 2013–2014



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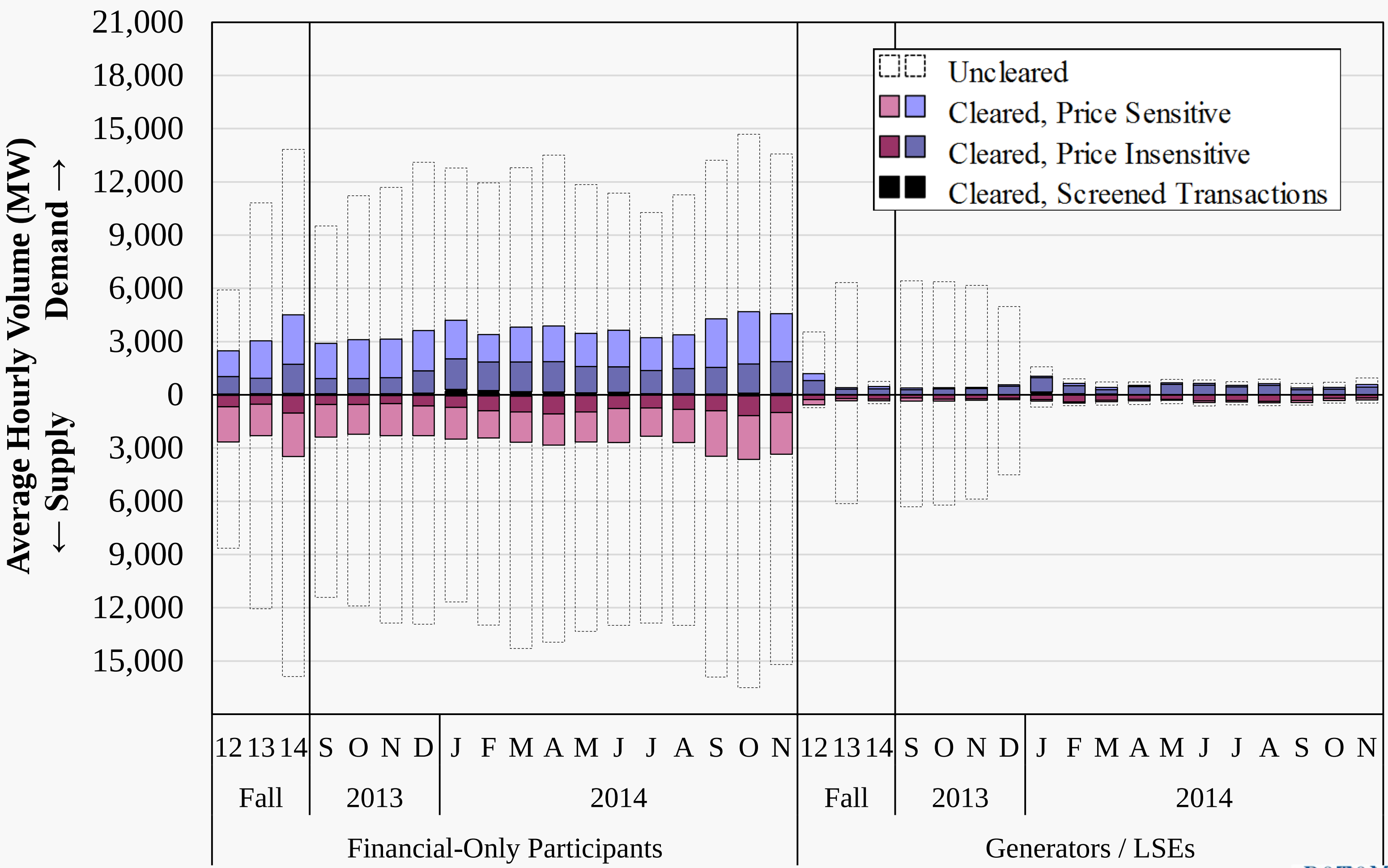
Virtual Load and Supply by Participant Type
Fall 2013–2014



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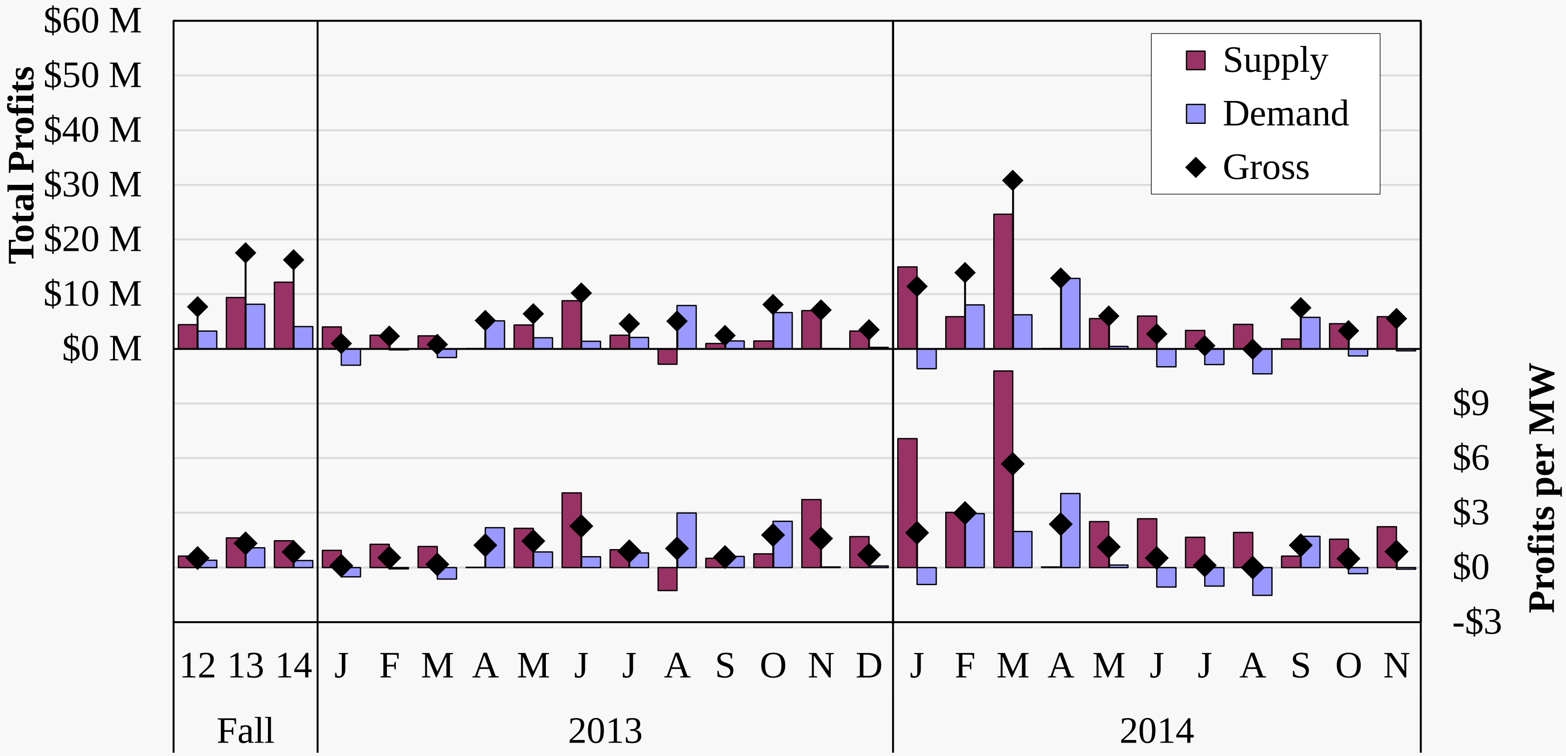
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross profits totaled nearly $16 million this quarter, or $0.87 per MWh. This is 34 percent lower than the $1.32 recorded last fall, but higher than the $0.20 in summer.
- Supply continues to be more profitable ($1.53 per MWh) than demand ($0.37), which is consistent with a modest day-ahead premium and good price convergence.
  - ✓ These margins exclude CMC and DDC charges assessed to net harming deviations, including net virtual supply, although this has not been significant in recent months.
- Profitability for financial participants averaged $0.99 per MWh, whereas it was slightly negative for physical participants ($-0.30).
  - ✓ Physical participants are more likely to put in price-insensitive demand at hub locations, which lose money when there is a day-ahead premium.
- The profitability of backstop bids, which clear less than 2 percent of the time, totaled $1.46 million, or nearly $11 per MWh.

Virtual Profitability 2013–2014



Percent Screened

Demand	2.1	2.3	1.7	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5	8.9	7.9	5.3	4.3	3.4	3.5	1.8	2.0	1.2	2.0	1.9
Supply	1.2	1.5	1.3	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3	2.1	2.7	2.7	1.9	2.0	1.6	0.9	0.2	0.7	1.6	1.4
Total	1.7	2.0	1.5	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1	6.5	5.7	4.2	3.3	2.8	2.7	1.4	1.2	1.0	1.9	1.7

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Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows monthly day-ahead congestion and FTR funding since 2012.
- Day-ahead congestion declined 14 percent from last fall to $227.1 million.
  - ✓ The most expensive constraints were near transmission outages in the North region.
- If MISO does not collect sufficient day-ahead congestion revenue to cover its obligation to the FTR holders, the shortfall results in lower payments to FTR holders.
  - ✓ 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.
- FTRs were underfunded by nearly 10 percent this quarter.
  - ✓ The most significant shortfalls (over $12 million) occurred on a set of constraints impacted by a modeling issue related to MISO's zone definitions.
  - ✓ A number of other constraints were underfunded by more than $500,000.
- This same modeling issue contributed to a nearly doubling of balancing congestion, to over $17 million.
  - ✓ Balancing congestion results from constraint modeling differences (when day-ahead scheduled flows exceed the real-time limit on a binding transmission constraint).

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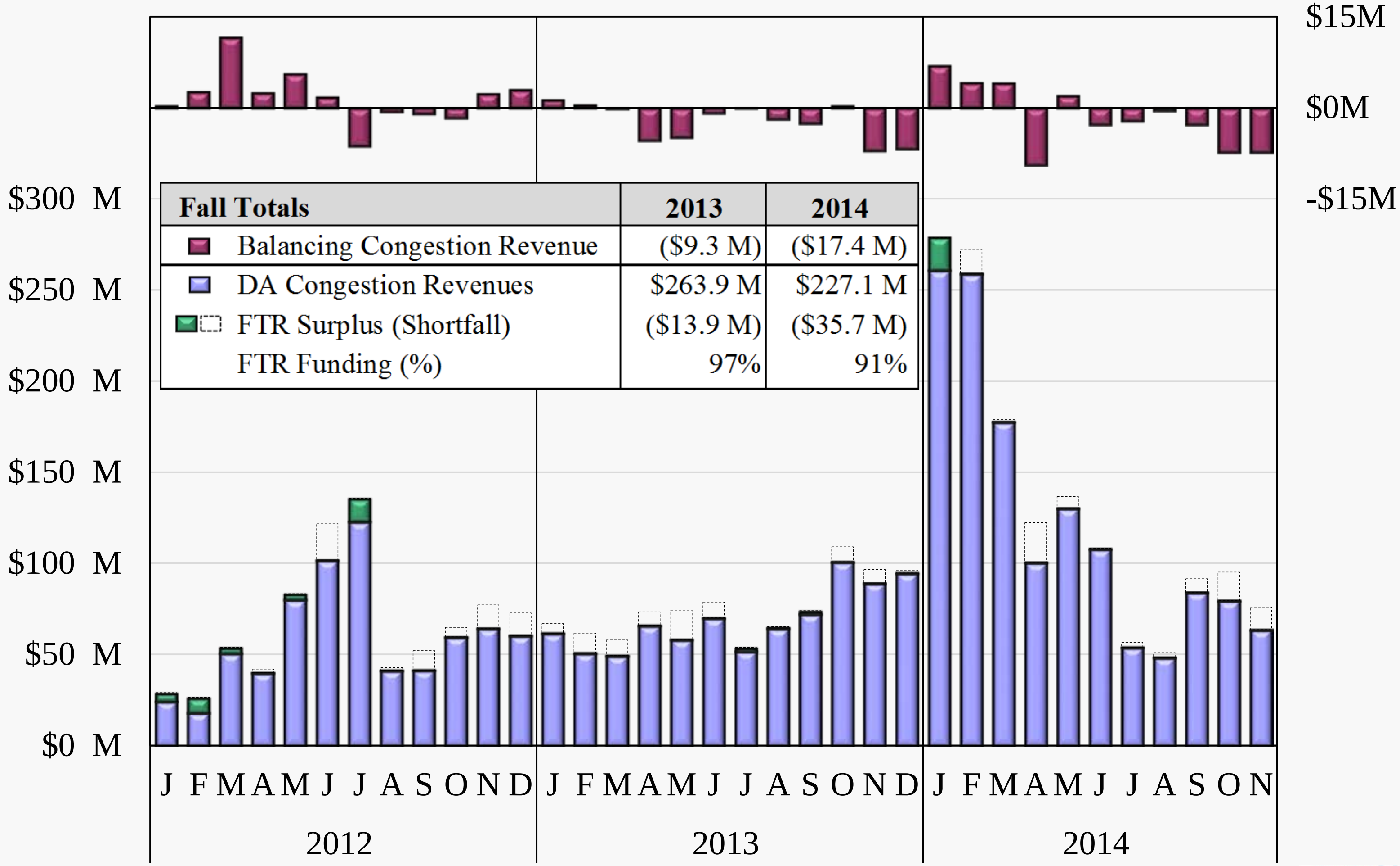
Day-Ahead Congestion, Balancing Congestion and FTR Underfunding, 2012–2014

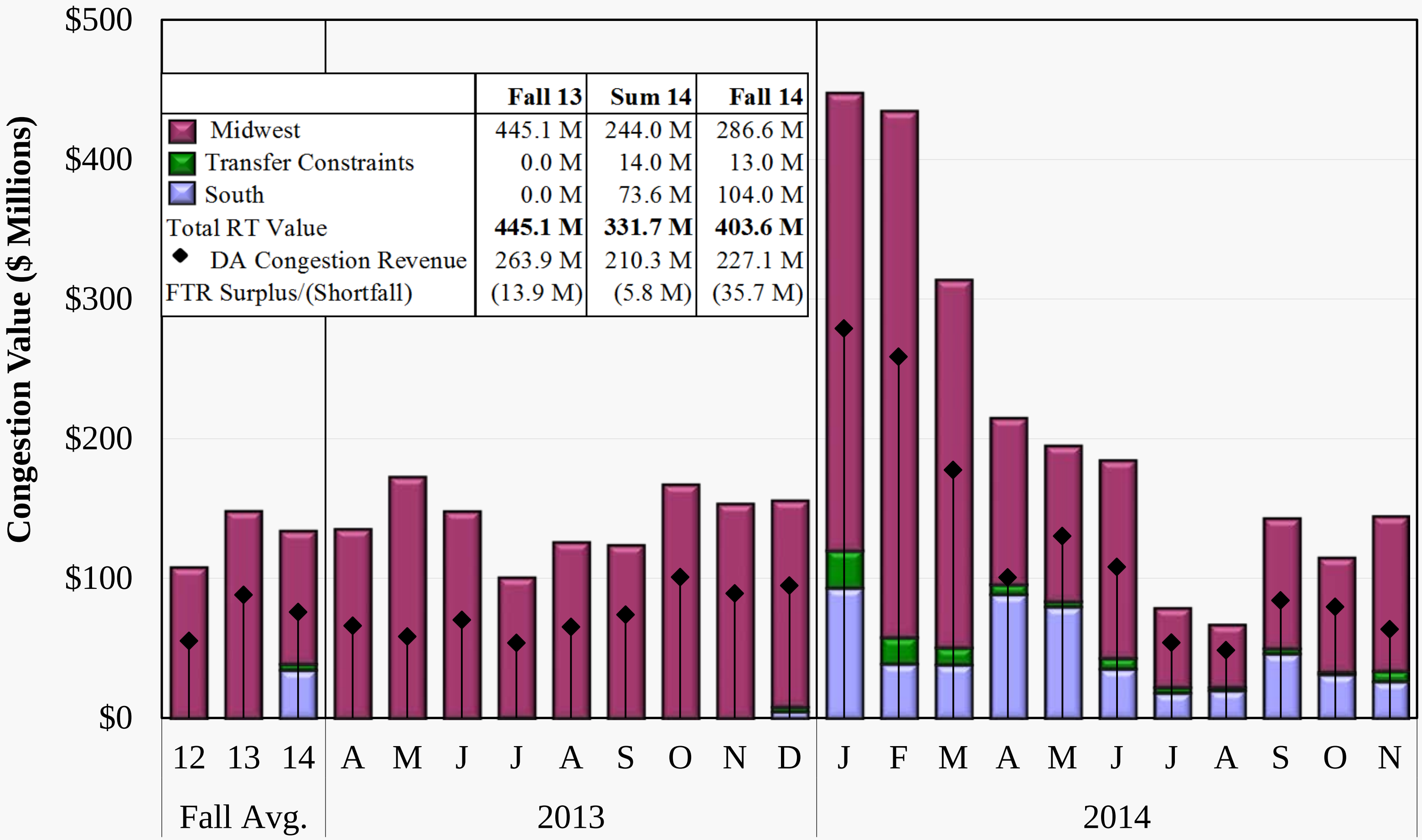


Fall Totals	2013	2014
Balancing Congestion Revenue	($9.3 M)	($17.4 M)
DA Congestion Revenues	$263.9 M	$227.1 M
FTR Surplus (Shortfall)	($13.9 M)	($35.7 M)
FTR Funding (%)	97%	91%

Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on the MISO system.
  - ✓ Real-time congestion value is the marginal cost of a constraint (the shadow price) times the flow on the constraint.   Day-ahead congestion revenues are shown in drop lines.
  - ✓ The congestion values are higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO’s capability.
  - ✓ We distinguish between congestion in the Midwest and South regions, and also separate congestion on the set of “transfer” constraints that limit flows between the two regions.
- The value of real-time congestion declined 9 percent from last fall (despite the larger footprint) to $403.6 million, although it rose 22 percent from the summer.
  - ✓ As in the day-ahead, the most expensive real-time constraints were in the North region and were the result of nearby transmission outages.
  - ✓ One of these limited flows from Minnesota (The lowest-priced hub this quarter at $29) to Wisconsin (the highest-priced hub, where real-time prices averaged over $37).
  - ✓ Compared to the summer, congestion rose more than twice as fast in the South Region (41 percent) as in the Midwest region (17 percent), partly due to key generator outages.
- Transfer constraints were valued at $13 million, a slight decline from summer. Although the real-time value of these constraints are relatively small, the price effects can be substantial.

Value of Real-Time Congestion 2013–2014

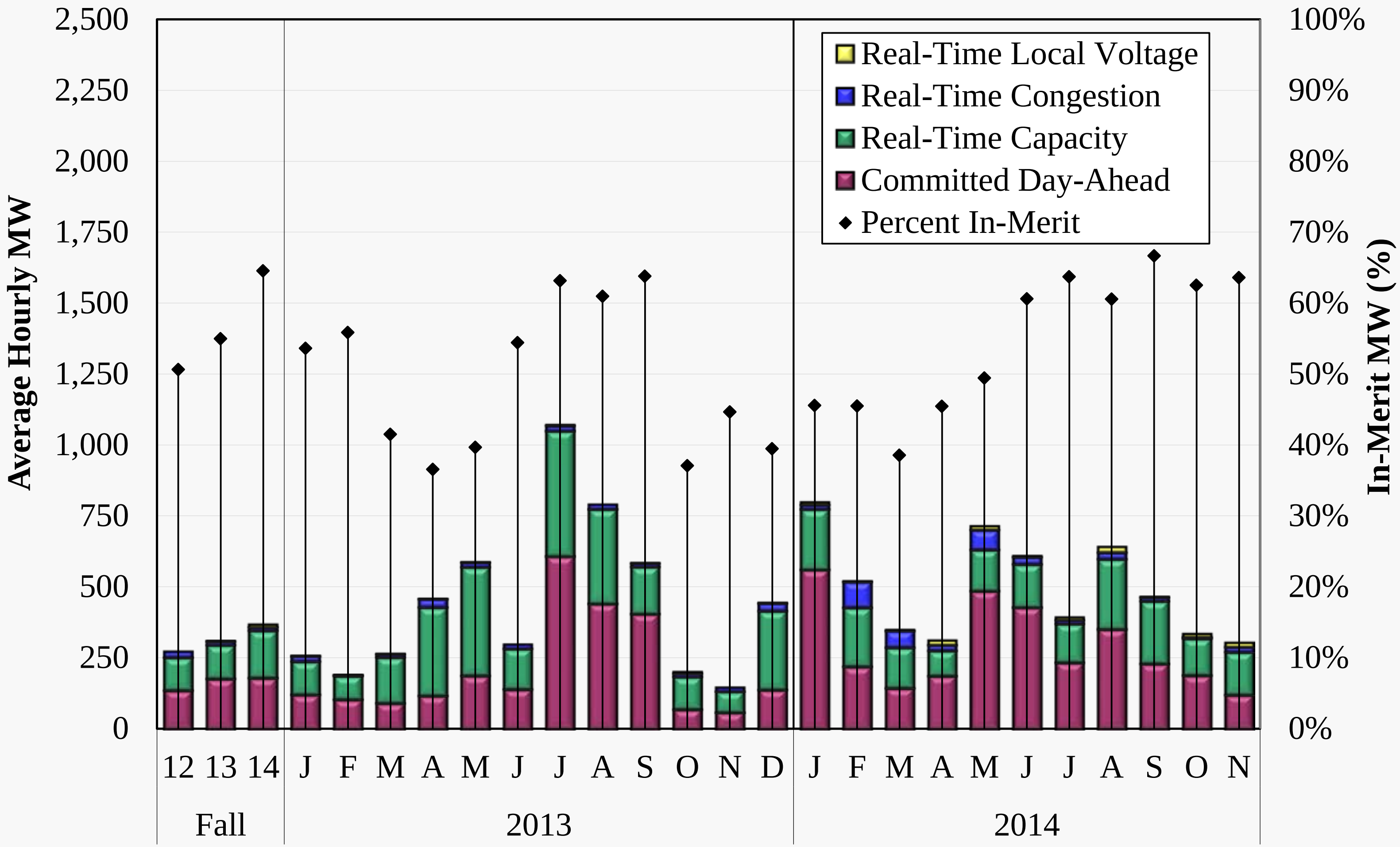


	Fall 13	Sum 14	Fall 14
Midwest	445.1 M	244.0 M	286.6 M
Transfer Constraints	0.0 M	14.0 M	13.0 M
South	0.0 M	73.6 M	104.0 M
Total RT Value	**445.1 M**	**331.7 M**	**403.6 M**
◆ DA Congestion Revenue	263.9 M	210.3 M	227.1 M
FTR Surplus/(Shortfall)	(13.9 M)	(5.8 M)	(35.7 M)

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 averaged 369 MW per hour this fall, a 19 percent rise from last fall. Quantities were one-third lower than in summer, as expected.
- Real-time commitments for capacity rose more than 40 percent, to 167 MW.
  - ✓ This need was most acute on two days in early September, when loads were significantly under-scheduled.
- Other real-time needs, including for congestion management (10 MW) and voltage and local reliability (9 MW), remain infrequent.
  - ✓ VLR dispatches were mostly for reliability needs in the South Region.
- Dispatches of day-ahead committed units were nearly unchanged at 180 MW.
- The share of peaking unit dispatch that was in-merit rose from 55 percent last fall to 65 percent.
  - ✓ The implementation of MISO's ELMP Initiative, which will allow peaking resources to set prices more frequently, is delayed until 2015.

Peaking Resource Dispatch 2013–2014



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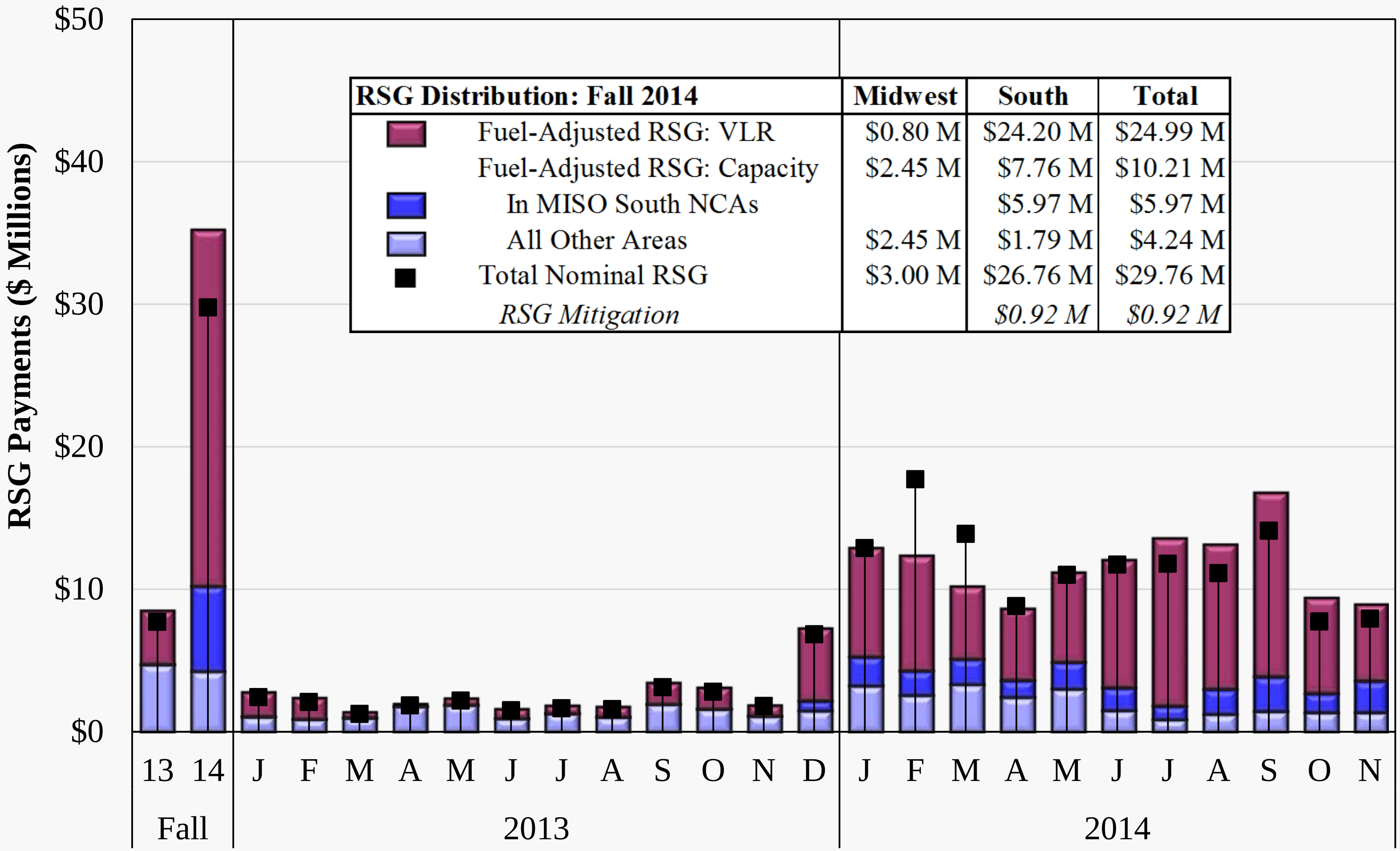
Real-Time and Day-Ahead RSG Payments

- The next figures show unmitigated RSG payments made to peaking units and other units in the day-ahead and real-time 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).
  - ✓ The last five days of November are estimated due to reporting time constraints.
- Day-ahead nominal RSG costs for the quarter totaled nearly $30 million, a 9.4 percent decline from the summer in fuel adjusted-terms.
  - ✓ Over 70 percent of this was paid to units needed for VLR requirements, nearly all of which occurred in the South region.
  - ✓ The majority of payments for capacity, which totaled over $12 million, were to units in South NCAs that are eligible for VLR.
  - ✓ Since most VLR units are offered competitively, only 3 percent of RSG was mitigated.
- Fuel-adjusted payments in the Midwest region were 38 percent lower than last fall.
  - ✓ Payments for congestion declined by more than half, most notably from last October.
  - ✓ Outage-related commitments in Wisconsin required over $600,000 in payments to a station in mid-November.
- Nominal real-time RSG costs rose 18 percent from the summer to $12.6 million due in part to fuel price increases.

Day-Ahead RSG Payments 2013–2014



RSG Distribution: Fall 2014	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.80 M	$24.20 M	$24.99 M
Fuel-Adjusted RSG: Capacity	$2.45 M	$7.76 M	$10.21 M
In MISO South NCAs		$5.97 M	$5.97 M
All Other Areas	$2.45 M	$1.79 M	$4.24 M
Total Nominal RSG	$3.00 M	$26.76 M	$29.76 M
RSG Mitigation		*$0.92 M*	*$0.92 M*

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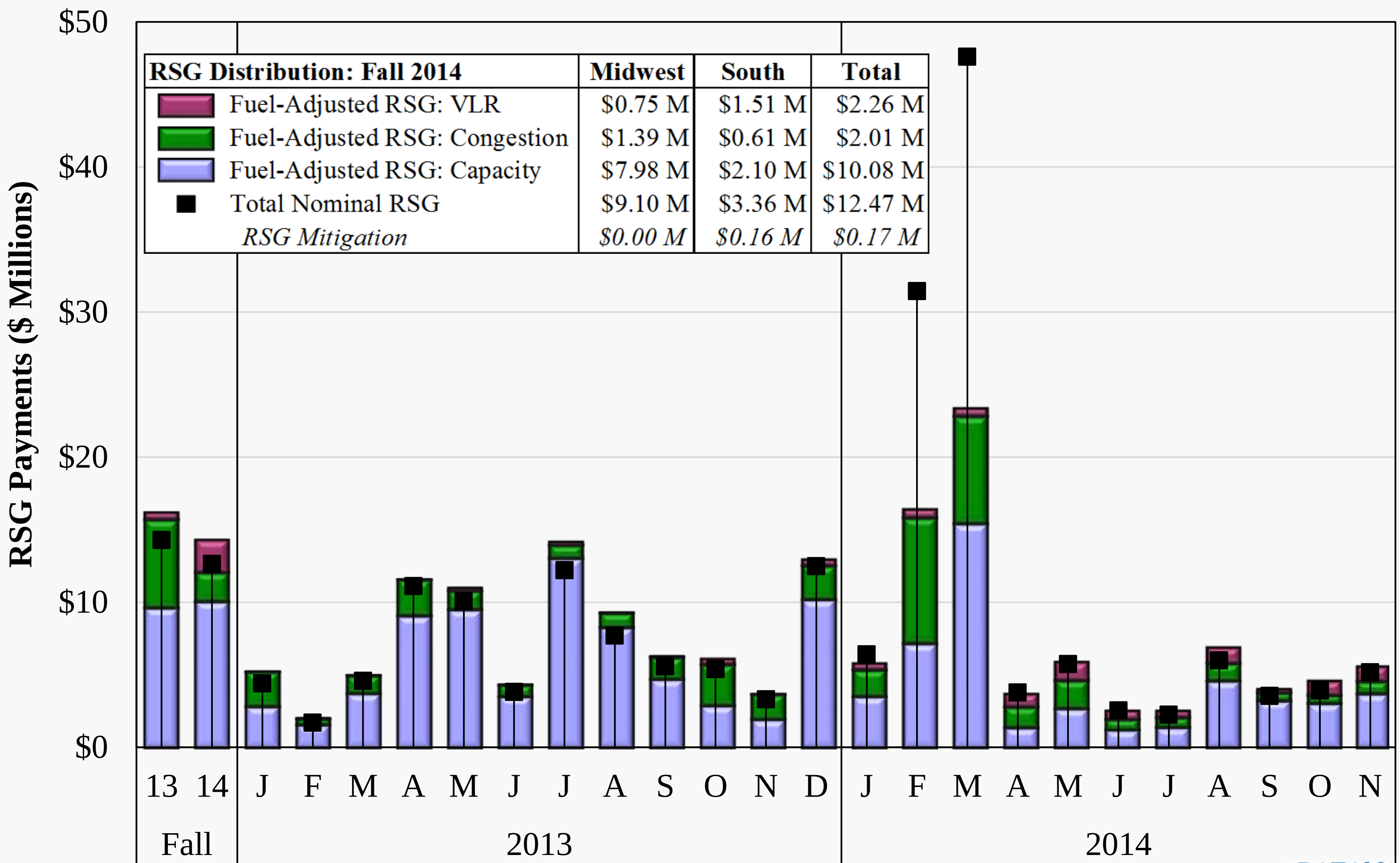
Real-Time RSG Payments 2013–2014



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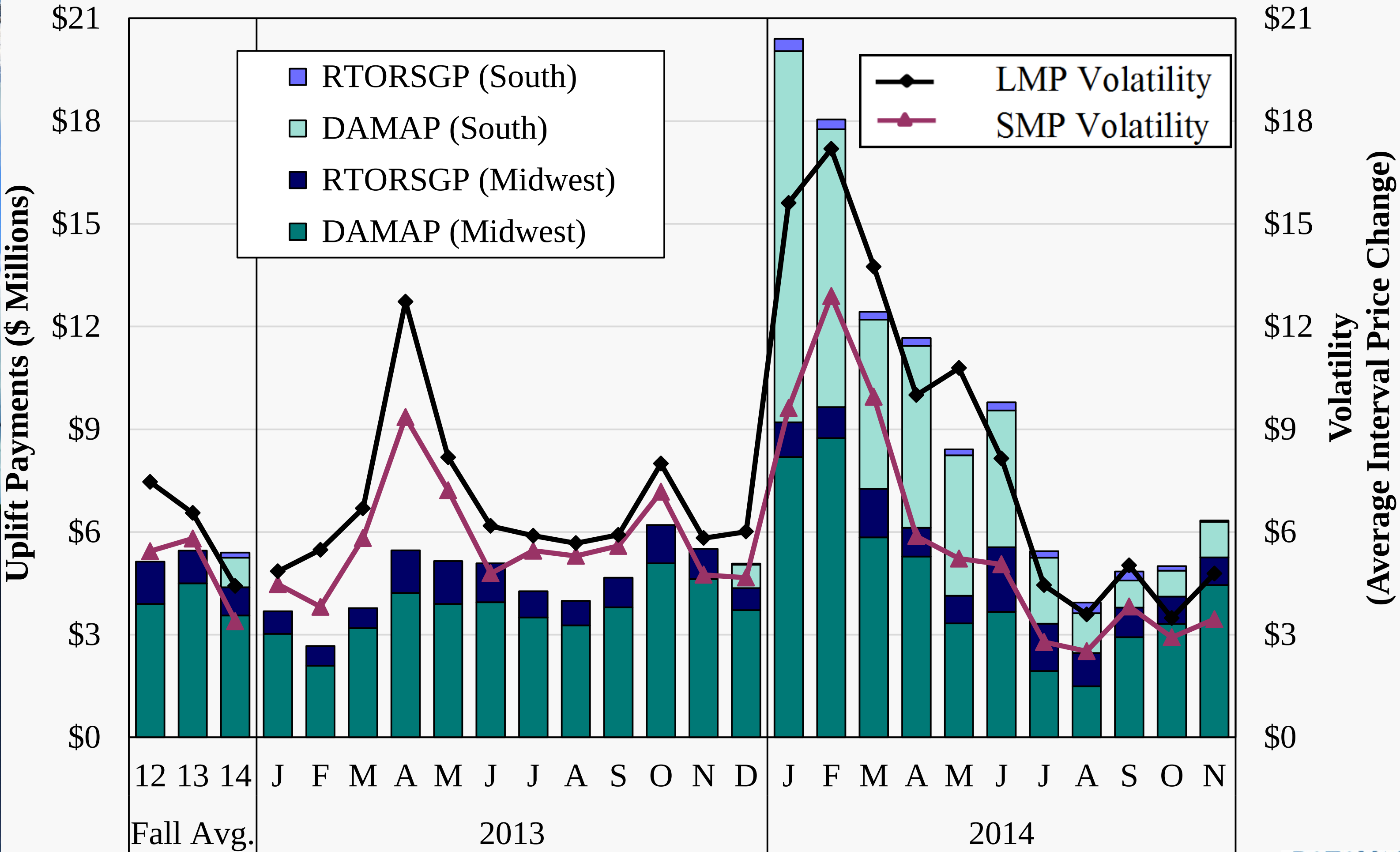
Price Volatility Make Whole Payments

- The next chart shows two types of Price Volatility Make Whole Payments (PVMWP), which improve incentives for suppliers to follow dispatch instructions.
  - ✓ 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 receiving payment.
- Total payments this fall were $16.2 million, a 19 percent decline (adjusted for membership) from last fall and 15 percent lower than in summer.
  - ✓ Payments are strongly correlated with price volatility because it leads to higher payments to flexible units. Volatility was considerably lower this fall—particularly in October—due to fewer shortage intervals.
- DAMAP totaled $13.3 million, and was highest in early November when units in the far West and in Michigan required considerable payments.
  - ✓ DAMAP to units in the South are nearly two-thirds lower than in the summer. They averaged $860,000 per month, compared to over $5 million in January to August.
  - ✓ This reduction is attributable to both modeling improvements by MISO and improved generator performance.
- RTORSGP totaled $2.9 million, 14 percent lower (membership-adjusted) than last fall.
  - ✓ Payments declined nearly 40 percent from summer, when two units near a constraint in Iowa were paid significant sums.

Price Volatility Make Whole Payments 2013–2014



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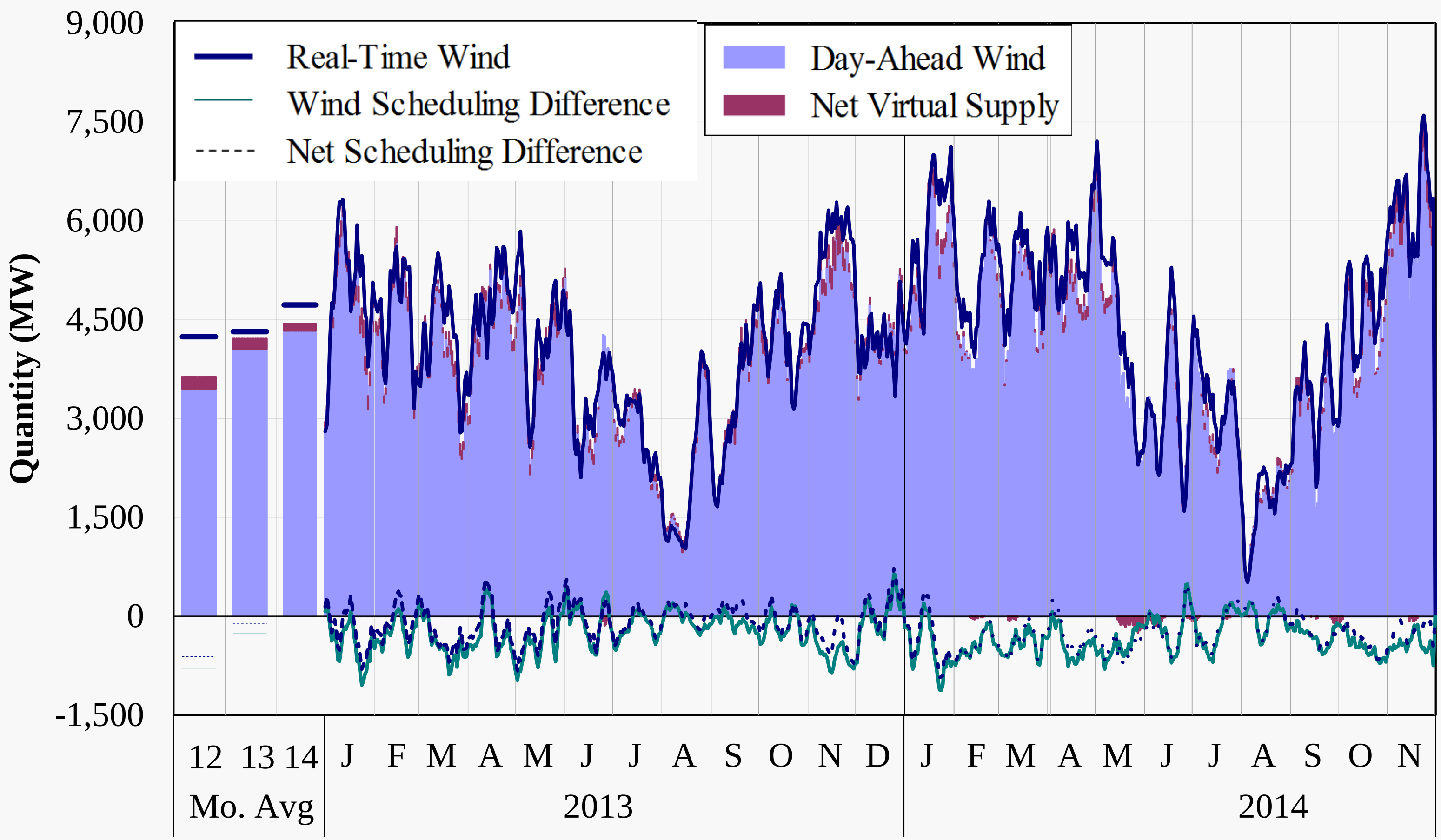
Wind Output in Real-Time and Day-Ahead Markets

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Approximately 80 percent of wind units are DIR, and have almost entirely replaced manual curtailments as the preferred means to manage wind output.
  - ✓ The rate of growth of wind resources has slowed considerably in 2014, which may be due to the uncertainty regarding federal subsidies.
- Real-time wind output rose 10 percent from last fall to 4.9 GW. MISO set an all-time peak of 11.1 GW on November 17.
  - ✓ Wind output is seasonal. Its output and aggregate volatility is far higher in the shoulder seasons than it is in summer or winter.
  - ✓ The average ramp demand of wind output was 27 percent higher than in summer.
- Despite the rise, DIR curtailments declined 14 percent to an average of 193 MW per interval or nearly 4 percent of wind output.
- Wind remains moderately under-scheduled in the day-ahead market.
  - ✓ It averaged over 400 MW in the fall, which provides an incentive for participants to make up the difference with net virtual supply (approximately 100 MW this fall).

Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average, 2013–2014



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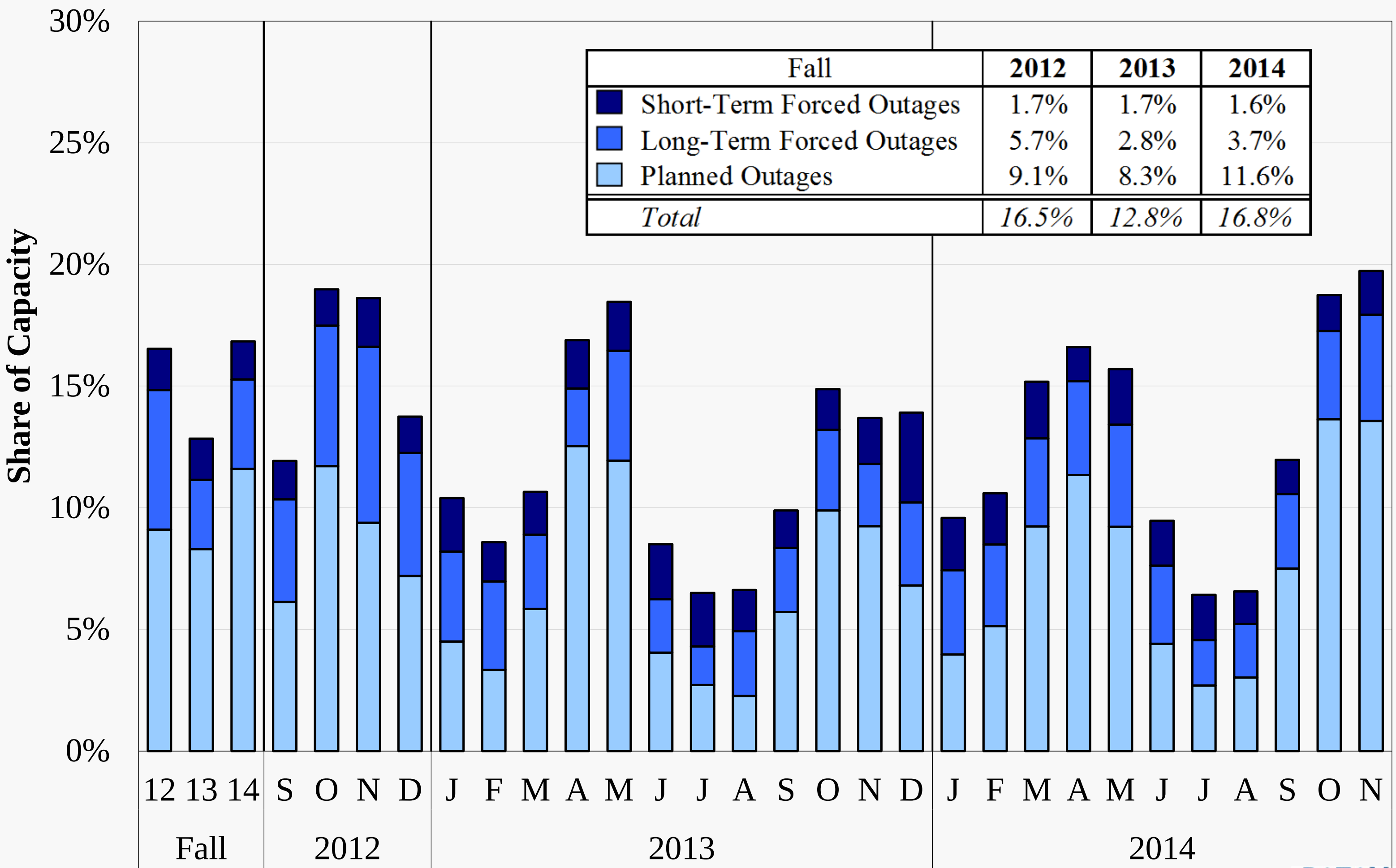
Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since September 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).
- Outages this fall rose to rose to 16.8 percent, up from 12.8 percent last fall.
  - ✓ Planned outages in particular rose to 11.6 percent, which is the highest quarterly rate in several years.
  - ✓ Coal availability declined 4 percent from last fall.
- Short-term forced outages were nearly unchanged at 1.6 percent, while long-term forced outages averaged 3.7 percent, a modest increase from last fall.
- We investigate outages that contribute to shortages or severe congestion, which raised no competitive concerns this quarter.

Generation Outage Rates
2012–2014



Fall	2012	2013	2014
Short-Term Forced Outages	1.7%	1.7%	1.6%
Long-Term Forced Outages	5.7%	2.8%	3.7%
Planned Outages	9.1%	8.3%	11.6%
Total	*16.5%*	*12.8%*	*16.8%*

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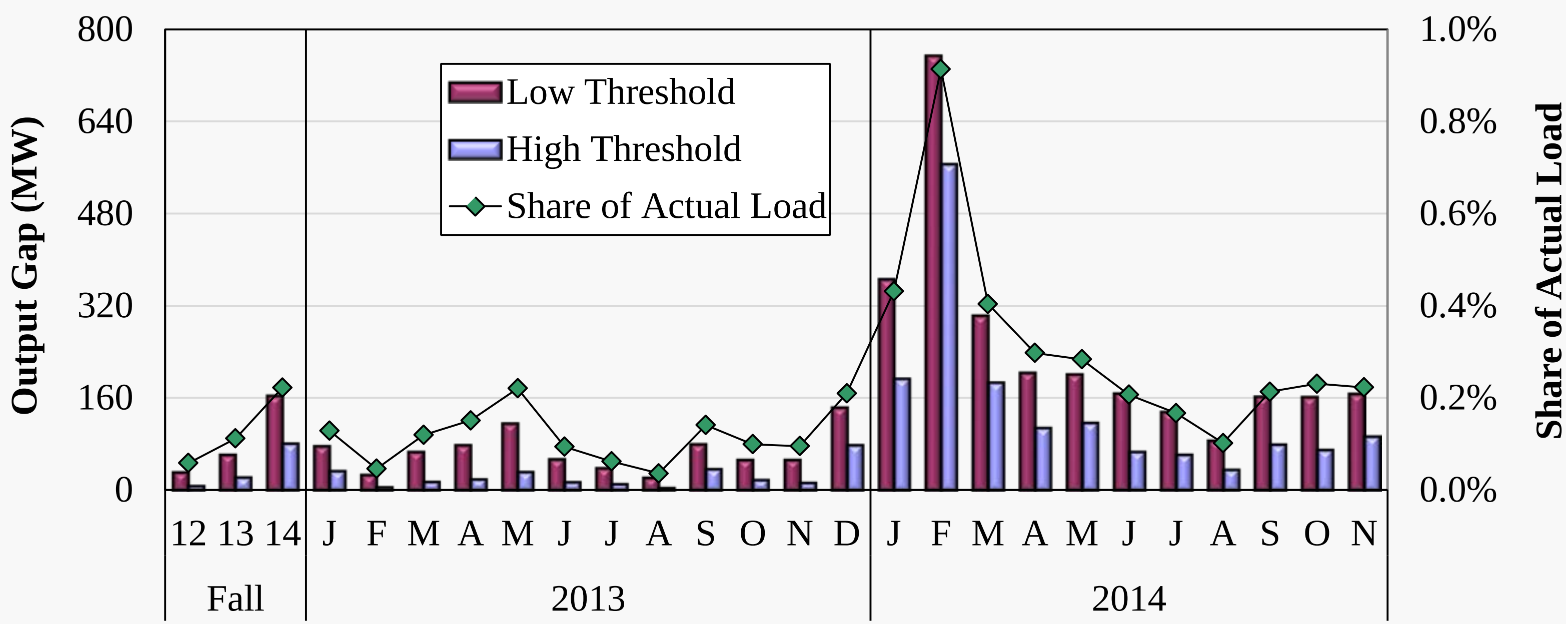
Monthly Output Gap

- 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 2013 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 averaged 0.22 percent of actual load, which remains very low.
  - ✓ At low threshold, it rose from 63 MW to 164 MW, while at the mitigation threshold it rose from 25 to 82 MW.
    - Much of this increase is due to the expanded footprint.
    - Nearly 20 percent is associated with two units in the South with very high ancillary services offers.
    - A majority of output gap is associated with high regulation offers.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances that raise potential competitive concern.

Monthly Output Gap
2013–2014



High Threshold Results by Unit Status (MW)

Offline	2	11	16	7	1	4	0	10	1	6	0	23	7	2	59	106	451	130	83	71	13	21	15	20	9	19
Online	6	12	66	27	4	11	20	22	14	5	5	14	11	11	20	89	116	57	26	46	54	41	21	60	62	75

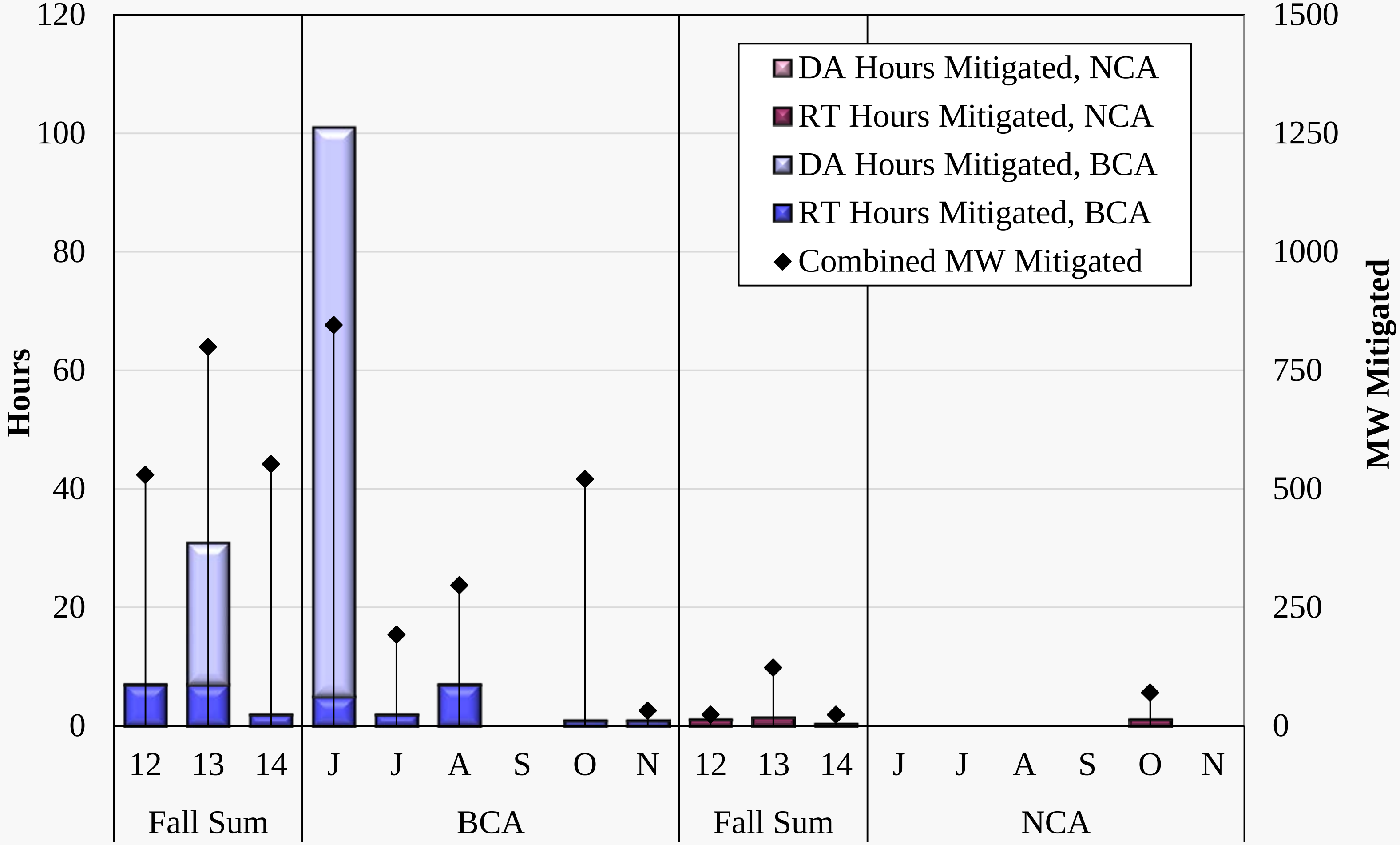
Low Threshold Results by Unit Status (MW)

Offline	3	14	22	8	2	6	0	12	1	9	0	26	11	4	70	140	519	154	99	82	18	29	22	32	14	21
Online	28	49	142	69	25	62	79	104	53	30	22	55	42	50	74	228	236	150	105	120	150	107	65	131	149	147

Mitigation in the Real-Time Energy Market

- The next two figures show the frequency with which energy and RSG mitigation was imposed in the day-ahead and real-time markets in recent months.
  - ✓ The first figure separates energy mitigation by broad and narrow constrained area.
- Energy mitigation was imposed for a total of 3 hours and for 622 MW this fall.
  - ✓ The BCA quantity in October was attributable to a very inflexible gas unit that offers above its reference costs in real time.
- RSG mitigation totaled $1.1 million in the quarter, nearly all of which occurred day-ahead under the VLR framework. Most units mitigated were in the South region.
  - ✓ Unit-hours of mitigation rose from just 12 last fall to 117 this fall, although this is far lower than mitigated hours earlier in 2014.
  - ✓ Since VLR units are generally offered fairly competitively, however, the day-ahead mitigation amounts were usually small (less than $9,000 on average).
- We are continuing to work with MISO on a small number of disputes regarding certain instances of RSG mitigation.

Day-Ahead And Real-Time Energy Mitigation 2013–2014



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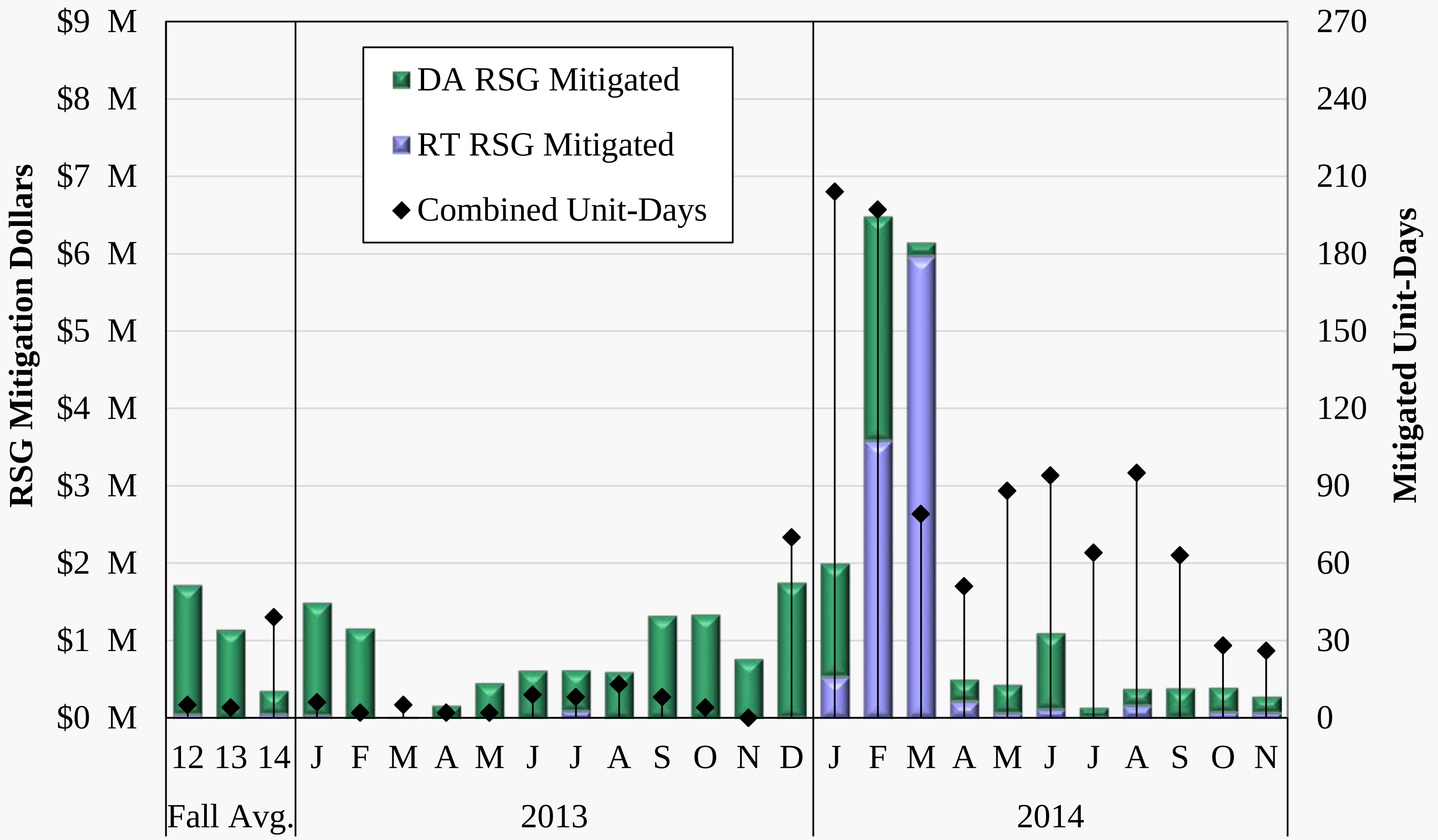
Day-Ahead and Real-Time RSG Mitigation 2013–2014



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Submittals to External Entities

- We provided additional data and analyses to FERC related to prior referrals regarding resources failing to update real-time offers.
- We responded to additional FERC requests for information on prior Sanction recommendations we have submitted to MISO.
- We presented additional comments and analysis supporting our recommendations to improve the performance of the ELMP model to the MSC.
  - ✓ We provided support for MISO's filing to postpone implementation of ELMP.
- We hosted a conference of international market monitors (EISG).
- We participated in a FERC Technical Conference on Price Formation (focused on shortage pricing and market power mitigation).
- We continued participation in both the JCM and Interface Pricing working groups.
- We are providing comments on settlement issues related to the SPP transmission charges and the PJM market-to-market dispute.
- In September, we presented updates on the Initial Reference Level for Zonal Reserve Offers for the 2015/2016 Planning Year to the SAWG.
- We also provided comments to MISO and stakeholders on proposed emergency pricing provisions.

Other Issues

- In September, we participated in a FERC technical conference on the SPP JOA and filed comments on the identified issues including comments on interface pricing.
  - ✓ We filed post-Technical Conference comments on the SPP market-to-market issues..
  - ✓ We are continuing to participate in joint MISO-SPP stakeholder discussions on seams issues including the interface pricing design issue.
- We are developing enhanced procedures for adjusting reference prices during volatile gas pricing periods and to identify the need for reference price consultations.
  - ✓ We presented a summary of these procedures to the MSC in early December.
  - ✓ We will also be supporting MISO’s interim proposal addressing the bid-cap through the use of IMM cost-based references to validate bid-costs above $1000 per MWh.
- We also supported MISO’s presentation at the MSC on the implementation of the IMM recommendation to improve the framework for RSG Mitigation in NCA and BCAs.

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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
ORCA	Operations Reliability Coordination Agreement
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
SRPBC	Sub-Regional Power Balance Constraint
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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