IMM Quarterly Report: Winter 2015
December – February

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)	$30.74	*-10%*	*-38%*
Fuel Prices ($/MMBtu)			
Natural Gas - Chicago	$3.49	*-14%*	*-57%*
Natural Gas - Henry Hub	$3.08	*-21%*	*-37%*
Western Coal	$0.66	*-4%*	*-6%*
Eastern Coal	$1.89	*-1%*	*1%*
Load (MW)[2]			
Average Load	79,693	*8%*	*-4%*
Peak Load	106,855	*-4%*	*-3%*
% Scheduled DA (Peak Hour)	99.5%	99.5%	100.1%
Transmission Congestion ($M)			
Real-Time Congestion Value	$340.5	*-16%*	*-67%*
Day-Ahead Congestion Revenue	$201.7	*-11%*	*-68%*
Balancing Congestion[4]	$1.8	$17.7	-$4.3
Ancillary Service Prices ($/MWh)			
Regulation	$7.72	*-28%*	*-49%*
Spinning Reserves	$1.37	*-30%*	*-69%*
Supplemental Reserves	$0.50	*-32%*	*-87%*

	Value	Change[1] Prior Qtr.	Change[1] Prior Year
FTR Funding (%)	98%	92%	100%
Wind Output (MW/hr)	5,120	*6%*	*1%*
Guarantee Payments ($M)[5]			
Real-Time RSG	$14.5	*18%*	*-68%*
Day-Ahead RSG	$24.9	*-15%*	*-21%*
Day-Ahead Margin Assurance	$10.1	*-22%*	*-75%*
Real-Time Offer Rev. Sufficiency	$3.2	*13%*	*-1%*
Price Convergence[3]			
Market-wide DA Premium	2.5%	1.3%	5.9%
Virtual Trading			
Cleared Quantity (MW/hr)	8,963	*2%*	*23%*
% Price Insensitive	43%	38%	47%
% Screened for Review	1%	2%	5%
Profitability ($/MW)	$0.56	$0.84	$1.83
Dispatch of Peaking Units (MW/hr)	318	369	588
Output Gap- Low Thresh. (MW/hr)	95	165	422
Other: Hurdle rate into MISO South rising to $42 per FERC Order.			

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 RSG.
4. Net real-time shortfalls contributing to negative ECF, unadjusted for M2M settlements.
5. Includes effects of market power mitigation.

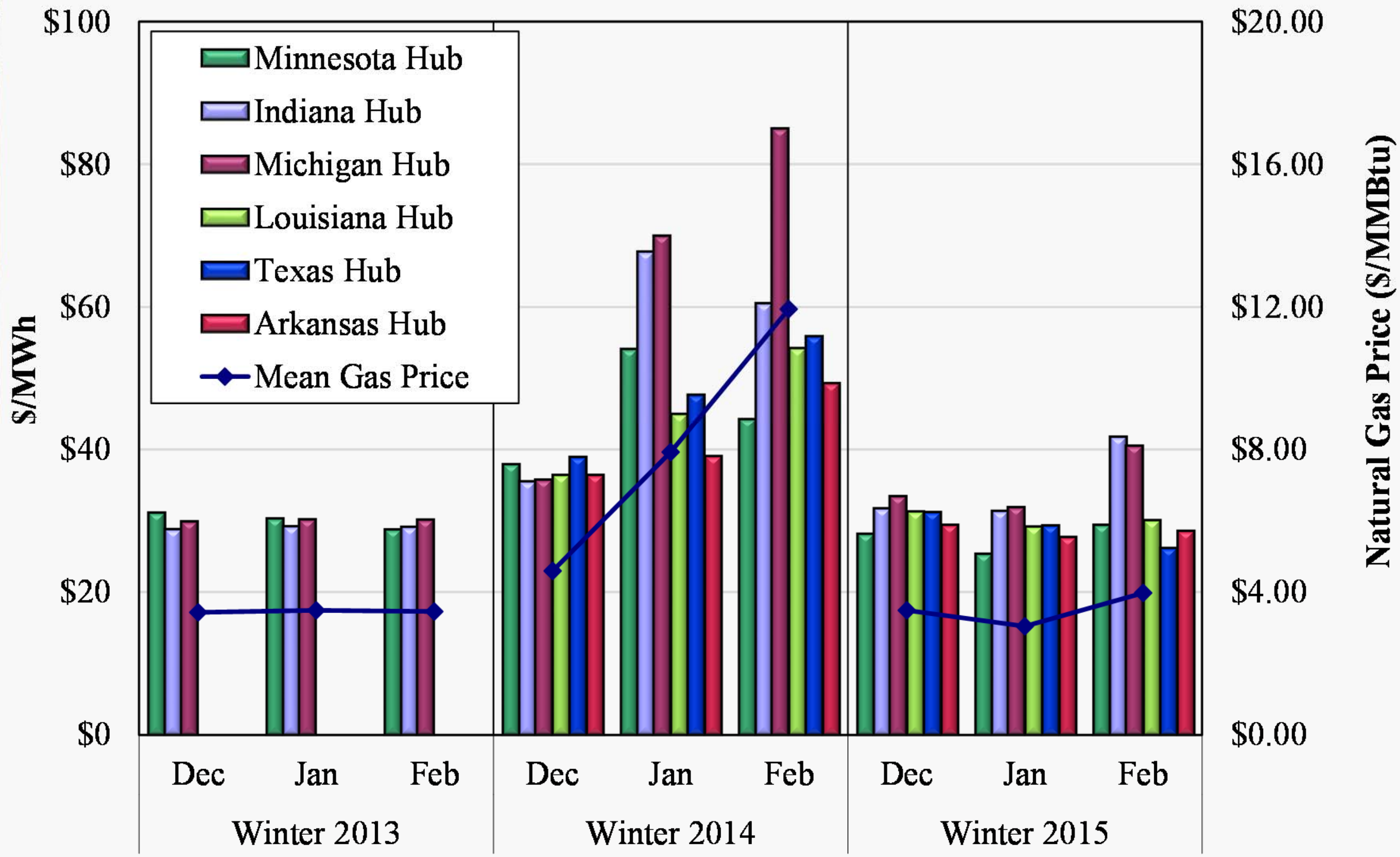
Summary of Winter 2015

- Winter 2015 was characterized by low gas prices and mild temperatures leading to moderate market prices and stable conditions. This result contrasts with last winter, when high, volatile gas prices and cold temperatures resulted in unusual market volatility, high market prices and congestion.
  - ✓ Real-time energy prices fell 38 percent from last winter to $30.74 per MWh, consistent with a natural gas price decline of 57 percent over the same period.
  - ✓ Day-ahead and real-time RSG declined 21 and 68 percent from last winter, respectively.
  - ✓ Each ancillary service price declined by 50 percent or more from last year and nearly a third from last quarter.
  - ✓ Fuel prices throughout the quarter were relatively stable; although, there were delivery concerns near the end of February that yielded significant day-to-day variability.
- A few key constraints contributed to issues with hub price convergence.
  - ✓ Specifically, TLR constraints impacted price convergence at the Minnesota and Michigan hubs.
  - ✓ MISO is working with TVA to address TLR procedures which have contributed to market volatility and inefficient congestion management.
- MISO set a wind generation record at 11.9 GW on January 8.

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 winter quarters of 2013 to 2015.
  - ✓ 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 averaged $31.31 per MWh, down considerably from last winter when the market experienced extreme conditions.
  - ✓ The moderate prices this winter are expected given low natural gas prices.
  - ✓ Day-ahead off-peak prices were 33 percent lower and peak prices were 44 percent lower than last winter.
- Hub prices were highest at the Indiana and Michigan hubs in February due to significant congestion on a TVA TLR flowgate.
- Minnesota was the lowest-priced hub in December and January due to binding on a SPP transmission constraint that is expensive to manage during high-wind periods.
  - ✓ Market-to-market coordination with SPP, which began on March 1, should alleviate much of this congestion since MISO can purchase relief at a reduced cost from SPP.
- On February 19 and 20th, MISO and the Eastern Interconnection experienced high load conditions and elevated gas prices.

Day-Ahead Average Monthly Hub Prices
Winter 2013–2015



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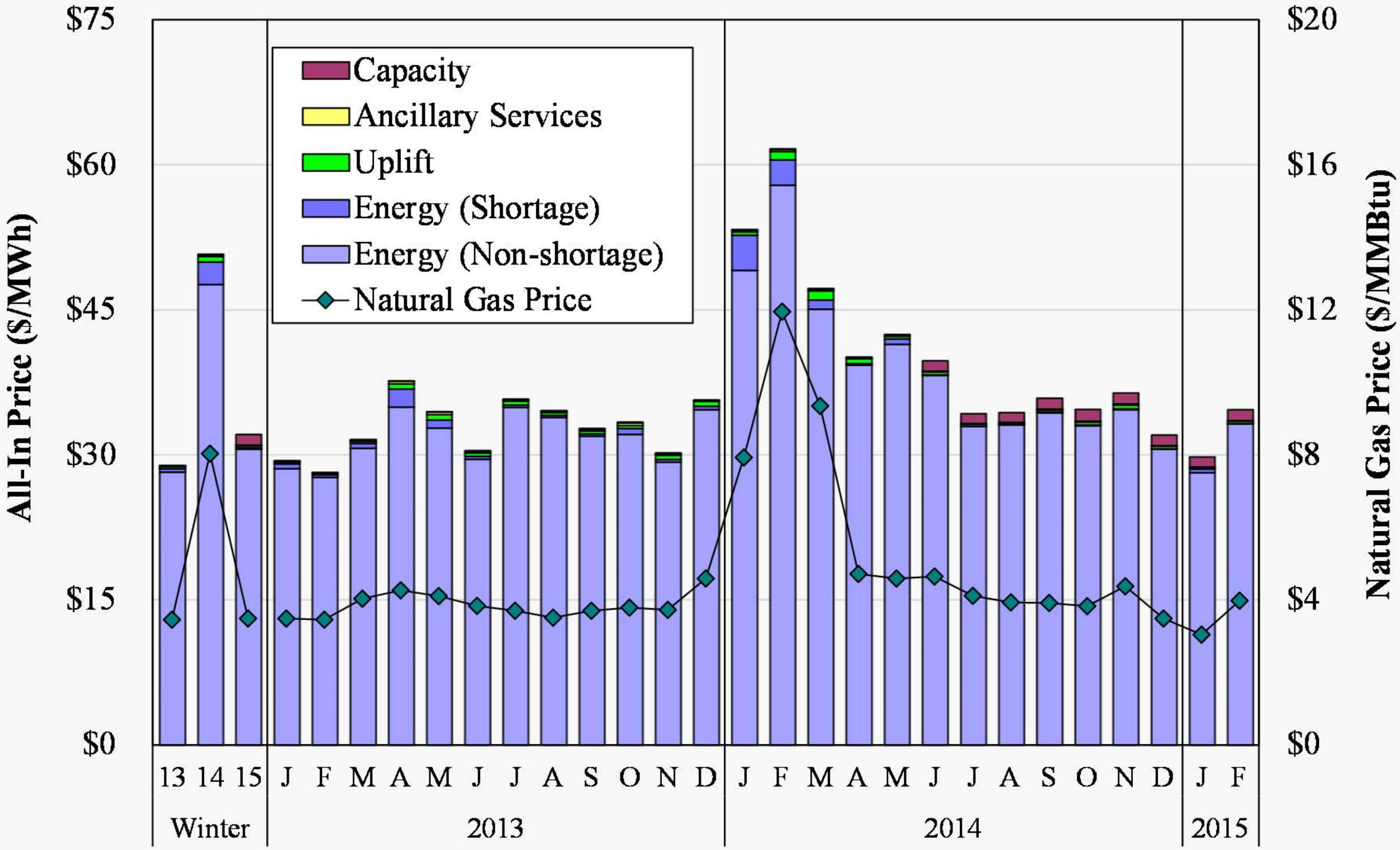
All-In Price

- 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.
    - Energy prices are divided into shortage and non-shortage components.
  - ✓ 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 dropped 37 percent from last winter to $32.13 per MWh.
  - ✓ Compared to 2013 when natural gas prices were more similar, the all-in was 8 percent higher this winter.
- The energy component still accounts for over 95 percent of the all-in price; however, capacity costs have increased to over 3 percent.
  - ✓ [DP-edit…and should continue to increase over time as the current capacity surplus dissipates/MATS coal retirements kick-in/etc].
- Ancillary service and uplift costs were modest this winter and added just 6 and 21 cents, respectively, to the all-in price.
  - ✓ [All else equal, these costs should move in lockstep with the natural gas-to-coal price ratio which declined significantly from last winter.]

All-In Price
2013 –2015



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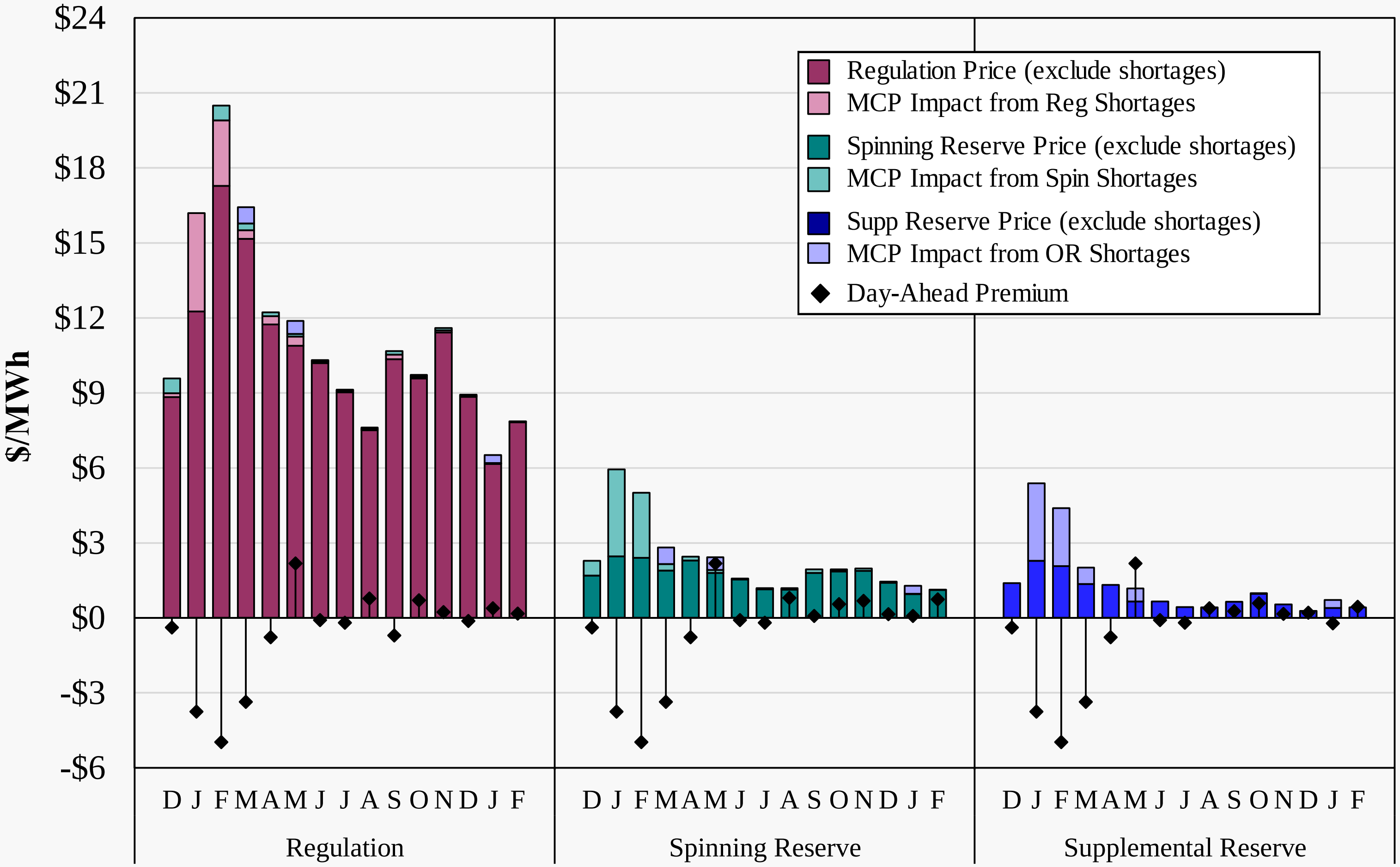
Ancillary Services Prices

- 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 $7.72 per MWh this winter, about half of the price levels last winter, and there were only 2 periods of regulation shortage.
- Spinning reserve prices averaged $1.37 per MWh, and supplemental prices were $0.50 per MWh, both less than half of the prices from last winter quarter.
  - ✓ There were only 7 spinning reserve shortages this winter, compared to 103 last winter.
  - ✓ There were 5 operating reserve shortages, compared to 46 last winter. Only 1 of the OR shortages was priced at the full $1100 penalty.
- Reserve requirements have not changed significantly since the integration of MISO South, which means far greater supply and lower prices.
- Prices for all three products have been mild since last winter.

Monthly Average Ancillary Service Prices Regulation and Contingency Reserves, 2014–2015



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MISO Fuel Prices

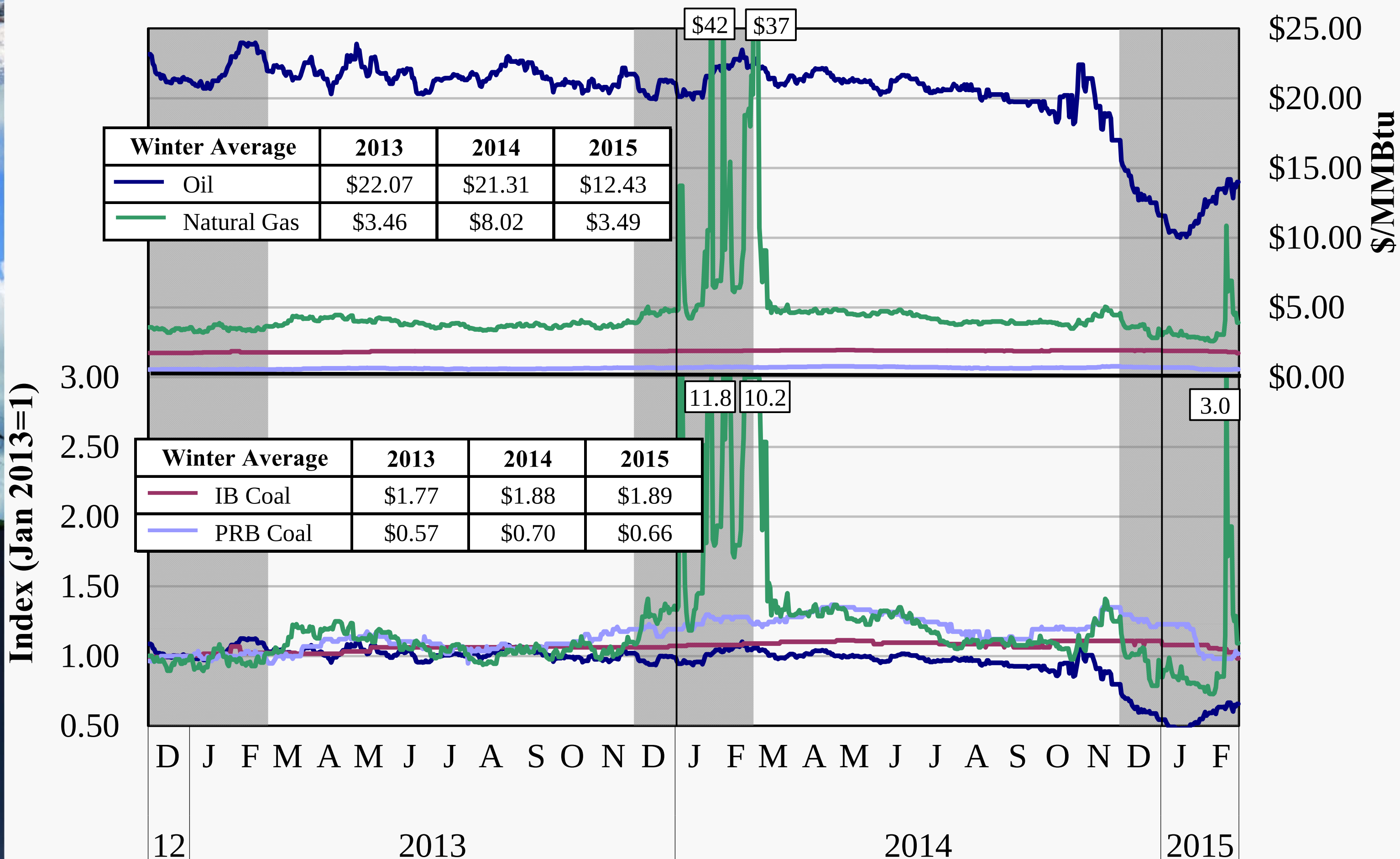
<u>Natural Gas and Oil Prices</u>

- Natural gas prices at the Chicago Hub averaged $3.49 per MMBtu during the winter, less than half the average gas price last winter.
  - ✓ Prices at the Chicago Hub declined steadily throughout the winter but spiked briefly at the end of February when they averaged $6.69 per MMBtu during a week-long period.
    - – The price premium at Chicago Hub relative to Henry Hub averaged 41 cents over the quarter but exceeded $3 per MMBtu during this week.
  - ✓ On February 19, prices were $10.86 per MMBtu because of high gas demand throughout the Eastern US during several days of extreme cold.
  - ✓ By end of February (and early March) gas prices had declined to less than $3.
- Oil prices also declined 42 percent from last winter, averaging $12.43 per MMBtu.

<u>Coal Prices</u>

- Powder River Basin coal prices fell four cents from last year to $0.66 per MMBtu. Illinois Basin prices rose just one cent and averaged $1.89 per MMBtu.
  - ✓ [DP – consider something like…The burdened cost of coal generation, which includes significant rail delivery charges, converges with combined cycle costs as natural gas approaches $2.50 per MMBtu.]

MISO Fuel Prices
2013–2015



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 winter months of 2013 to 2015, while the bottom panel shows the average heating and cooling degree days (a weather metric that is highly correlated with load).
  - ✓ The Heating 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 12 percent from last winter, but were just 3 percent below the historic average.
  - ✓ Degree days in December and January were lower than historic averages, but wintry temperatures in February pushed heating degree days 24 percent higher than historic averages.

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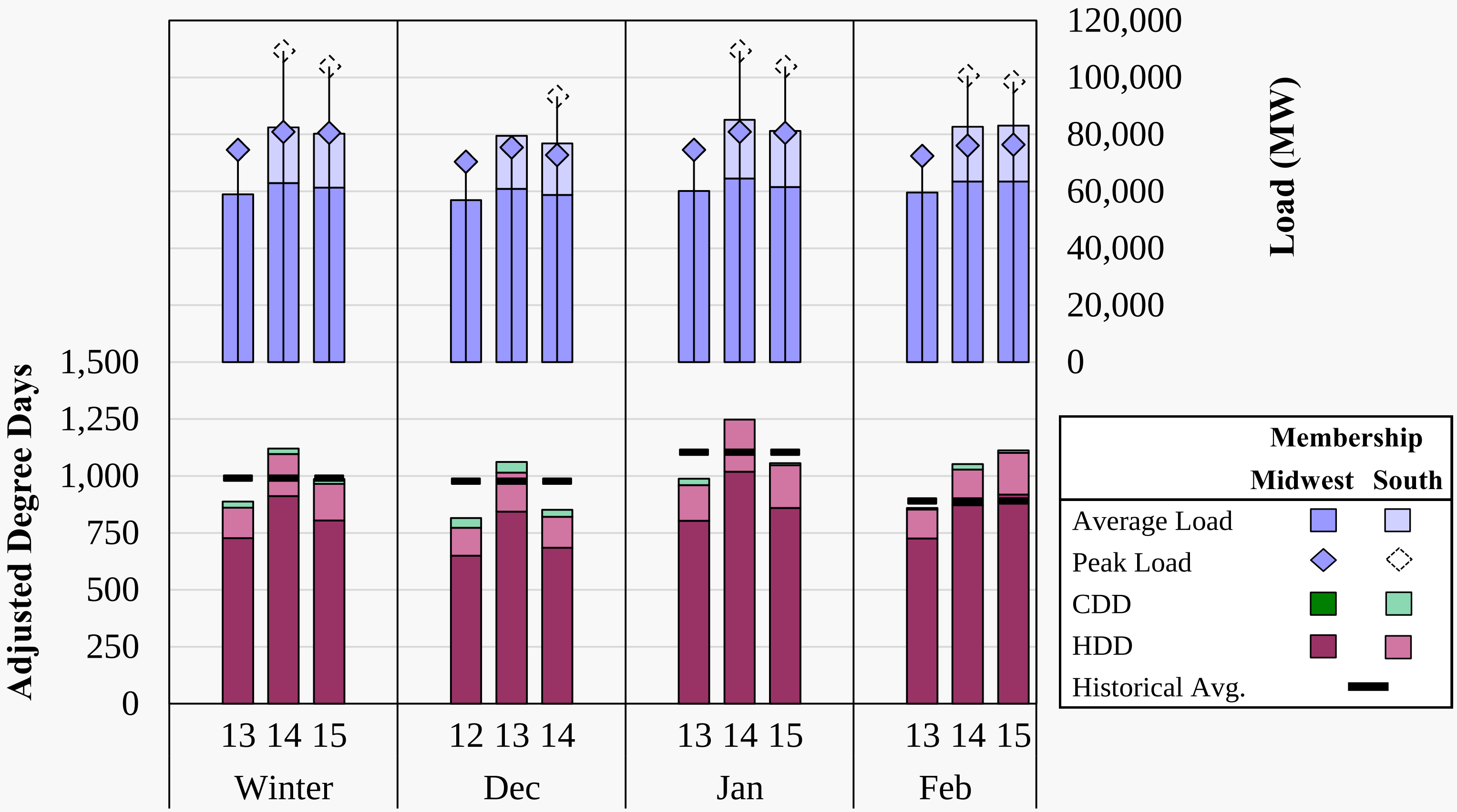
Load and Weather Patterns
Winter 2013–2015



<u>Note</u>: 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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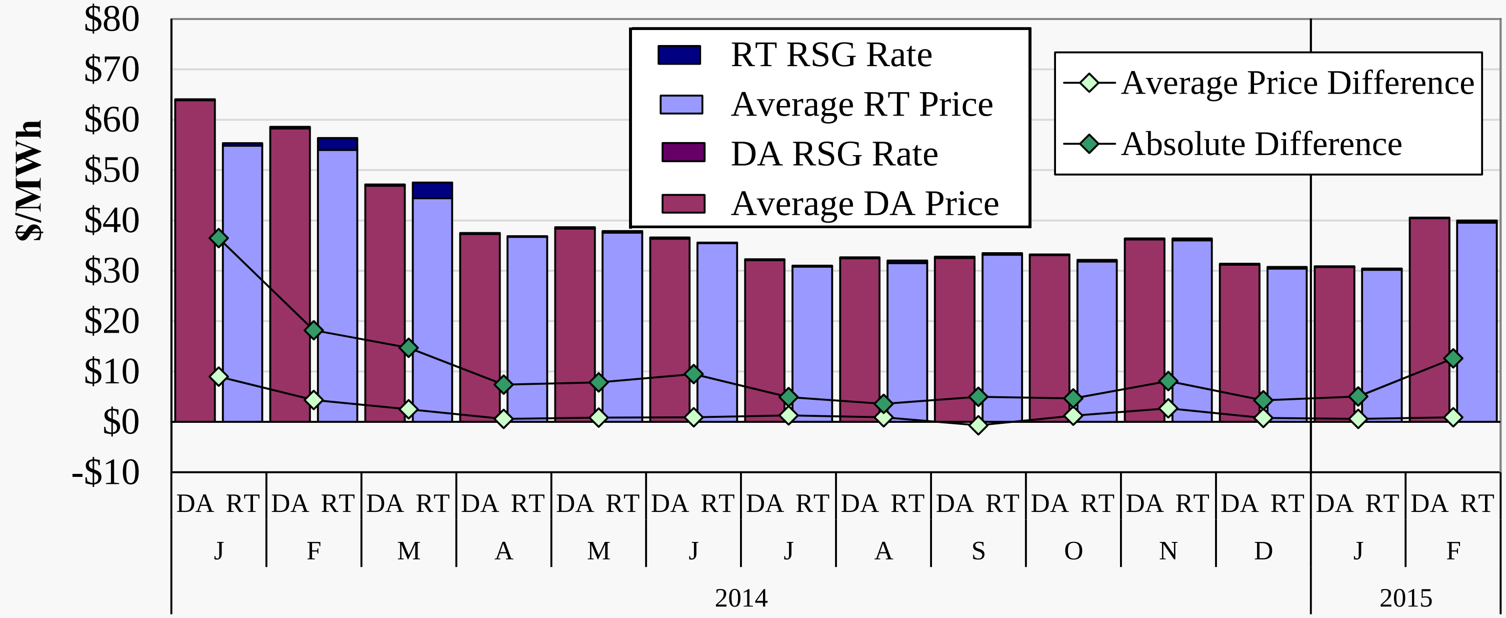
Day-Ahead and Real-Time Price Convergence

- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub in 2014 and 2015 (the table shows other locations), along with average 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.
- Except for the Michigan Hub, convergence was very good this quarter, with MISO exhibiting a slight day-ahead premium at most locations.
  - ✓ In December, the real-time premium at the Minnesota Hub was primarily caused by a SPP TLR and an internal constraint in the North region.
  - ✓ In February, the day-ahead premium at the Michigan Hub was primarily caused by the Volunteer-Phipps Bend constraint.
- Real-time RSG costs under the DDC rate averaged $0.35 per MWh this winter, down from $1.44 last winter.
  - ✓ MISO made revisions to its RSG allocation rules in March 2014 to be more consistent with cost causation. These changes allocate more costs to load and constraint-related flow deviations, and less to day-ahead schedule deviations.
  - ✓ 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 2014–2015



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

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

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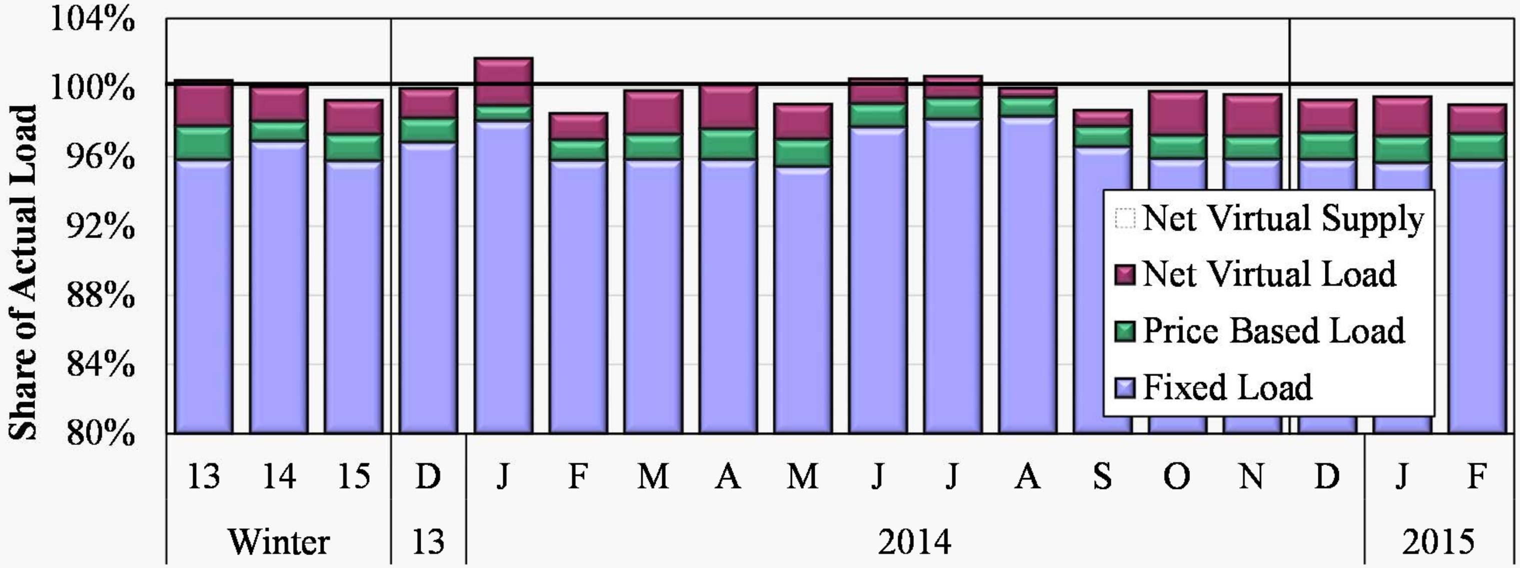
Day-Ahead Load Scheduling

- 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.
- For the quarter load scheduling averaged 99.5 percent in the daily peak hour. In all hours, it averaged 98.7 percent.
  - ✓ Scheduling for peak hours was below 98.5 percent during the last two weeks in February, a particularly low period during the quarter.
  - ✓ Net virtual demand of 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 South were under-scheduled at 97.5 percent, while the Midwest region was slightly over-scheduled at 100.2 percent this winter.
  - ✓ Scheduling in the South was the lowest for peak hours, by a significant amount, since integration with MISO.
  - ✓ Schedules in the South for peak hours have shifted from being over-scheduled early in the year, to being under-scheduled later in the year including this quarter.

Day-Ahead Peak Hour Load Scheduling 2014–2015



Share of Actual Load (%)

All	99.7	100.6	98.9	100.9	101.7	99.3	99.2	99.8	99.1	100.1	100.2	99.8	98.7	99.0	99.7	99.0	99.1	98.7
Peak Hours Midwest	100.4	99.3	100.2	99.5	100.4	98.0	99.3	99.5	98.0	99.5	99.8	99.5	98.8	100.2	100.7	101.1	99.9	99.7
Peak Hours South		103.1	97.5	104.9	104.4	99.9	100.4	101.5	101.6	102.7	102.5	100.7	99.5	99.7	99.4	97.0	97.9	97.7

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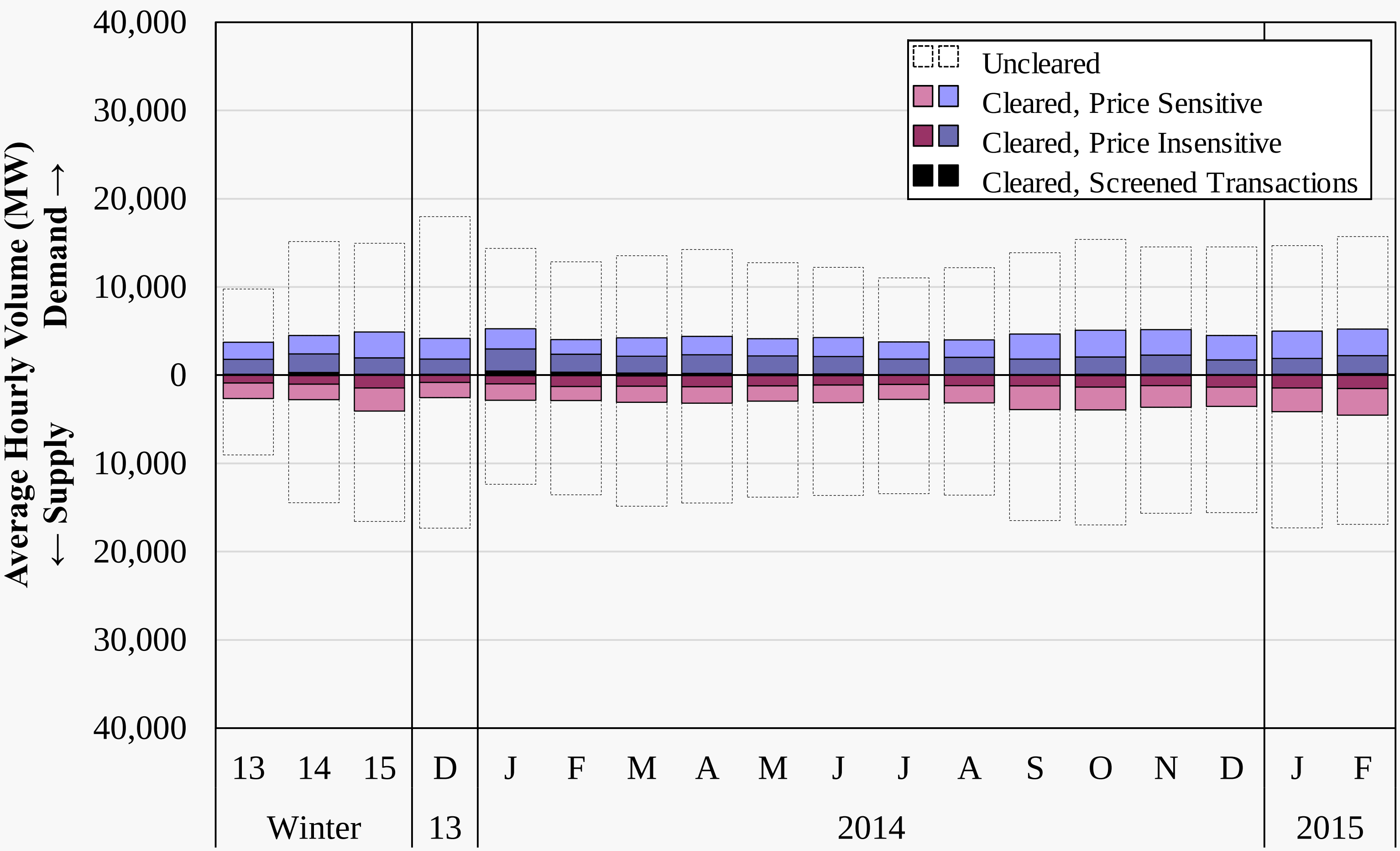
Virtual Load and Supply in the Day-Ahead Market

- The next two figures show the monthly average quantity of offered and cleared virtual supply and demand transactions since December 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 volumes rose 6 percent from last winter to 31.5 GW, while cleared volumes rose 23 percent to nearly 9 GW.
  - ✓ Cleared supply in particular rose 46 percent to nearly 4 GW. All of this growth occurred with price-sensitive volumes.
- Despite the persistent premium for supply, cleared demand volumes continue to exceed supply volumes by nearly 1 GW per hour, nearly 90 percent of it by financial participants.
  - ✓ The Indiana Hub remains the most liquid trading point for both supply and demand.
- Around forty percent 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 low at less than 2 percent.

Virtual Load and Supply
2014–2015



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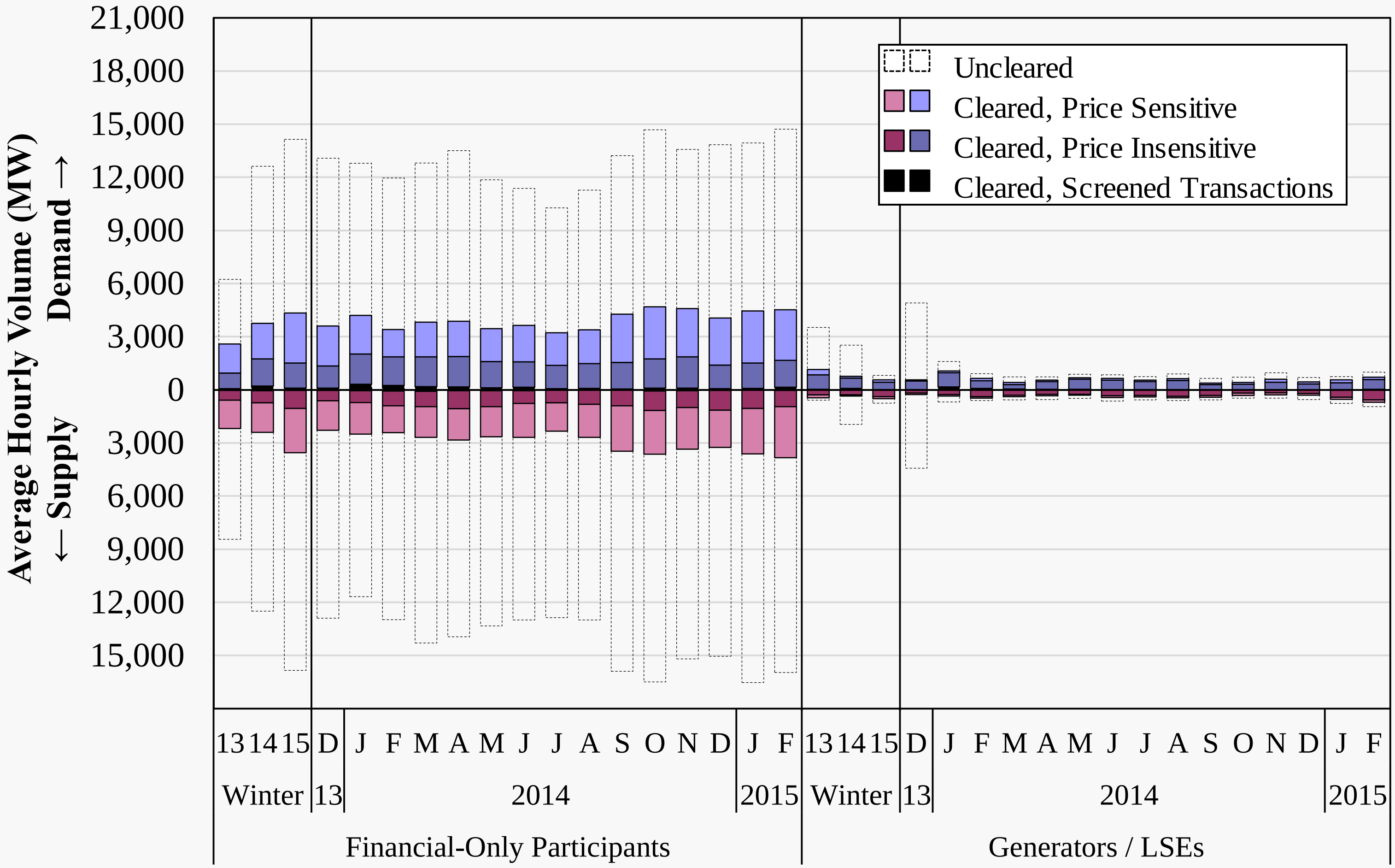
Virtual Load and Supply by Participant Type
Winter 2014–2015



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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 declined by more than half from last winter to $14 million.
  - ✓ Profitability declined from $1.83 per MWh to $0.72 per MWh. Last year's Polar Vortex and resulting congestion significantly increased opportunities for arbitrage.
- Supply continues to be more profitable ($1.36 per MWh) than demand ($0.20), 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 remains higher for financial participants ($0.78 per MWh) than for physical participants ($0.30 per MWh).
- Supply profits were greatest at a very congested location ($2.1 million) in the Central region, where they contributed to convergence, and at two locations in Michigan that at times had inconsistent day-ahead and real-time loss factor modeling.
  - ✓ [DP - Say something about investigating the behavior contributing to this outcome?]
- Net virtual supply at wind locations more than doubled from last winter to 178 MW, which helps offset the persistent under-scheduling there. Cleared virtual transactions at these locations average $1 per MWh of profit.

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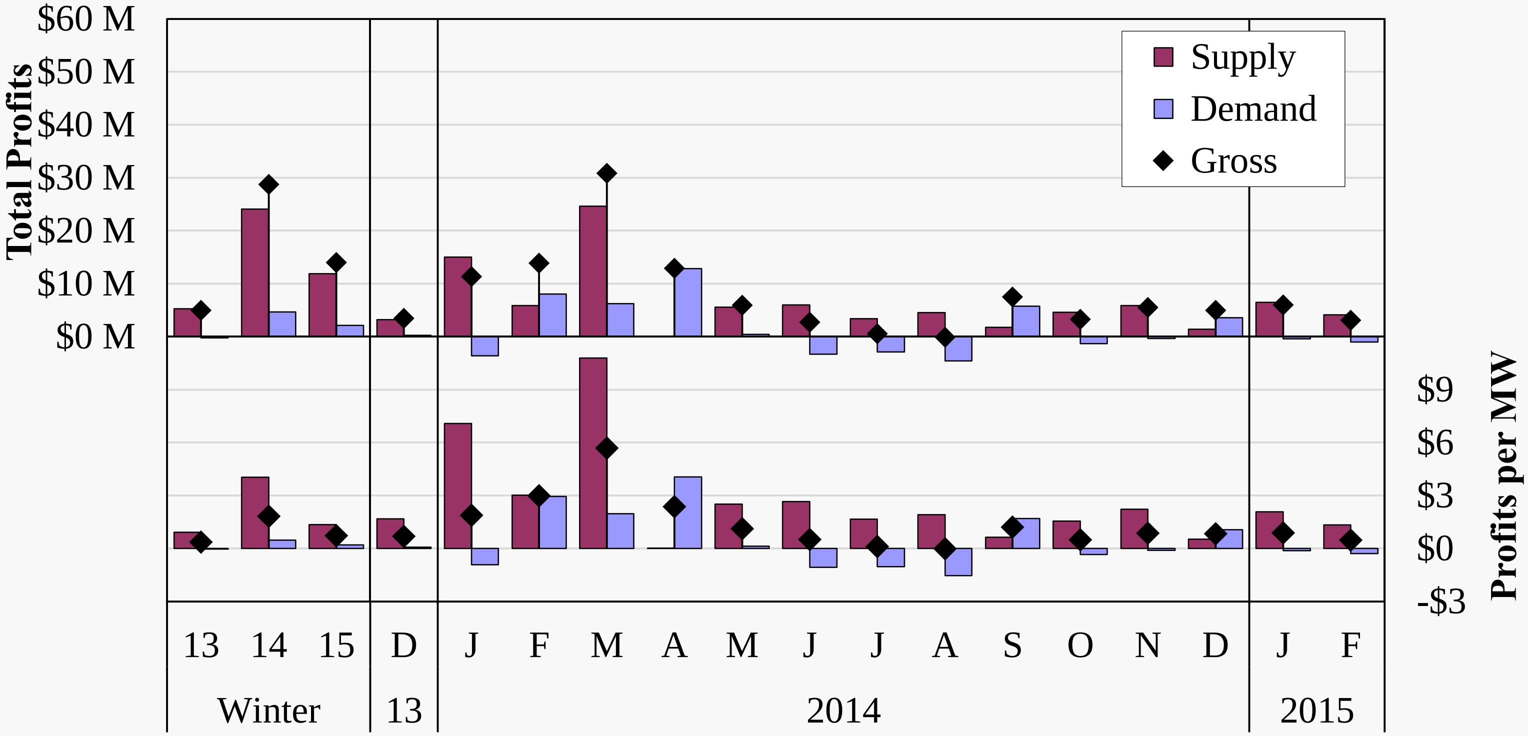
Virtual Profitability
2013–2015



Percent Screened

Demand	2.3	6.6	2.0	2.5	8.9	7.9	5.3	4.3	3.4	3.5	1.8	2.0	1.2	2.0	1.9	1.2	1.7	3.1
Supply	1.4	2.1	0.9	1.3	2.1	2.7	2.7	1.9	2.0	1.6	0.9	0.2	0.7	1.6	1.4	1.1	0.6	1.1
Total	1.9	4.9	1.5	2.1	6.5	5.7	4.2	3.3	2.8	2.7	1.4	1.2	1.0	1.9	1.7	1.2	1.2	2.2

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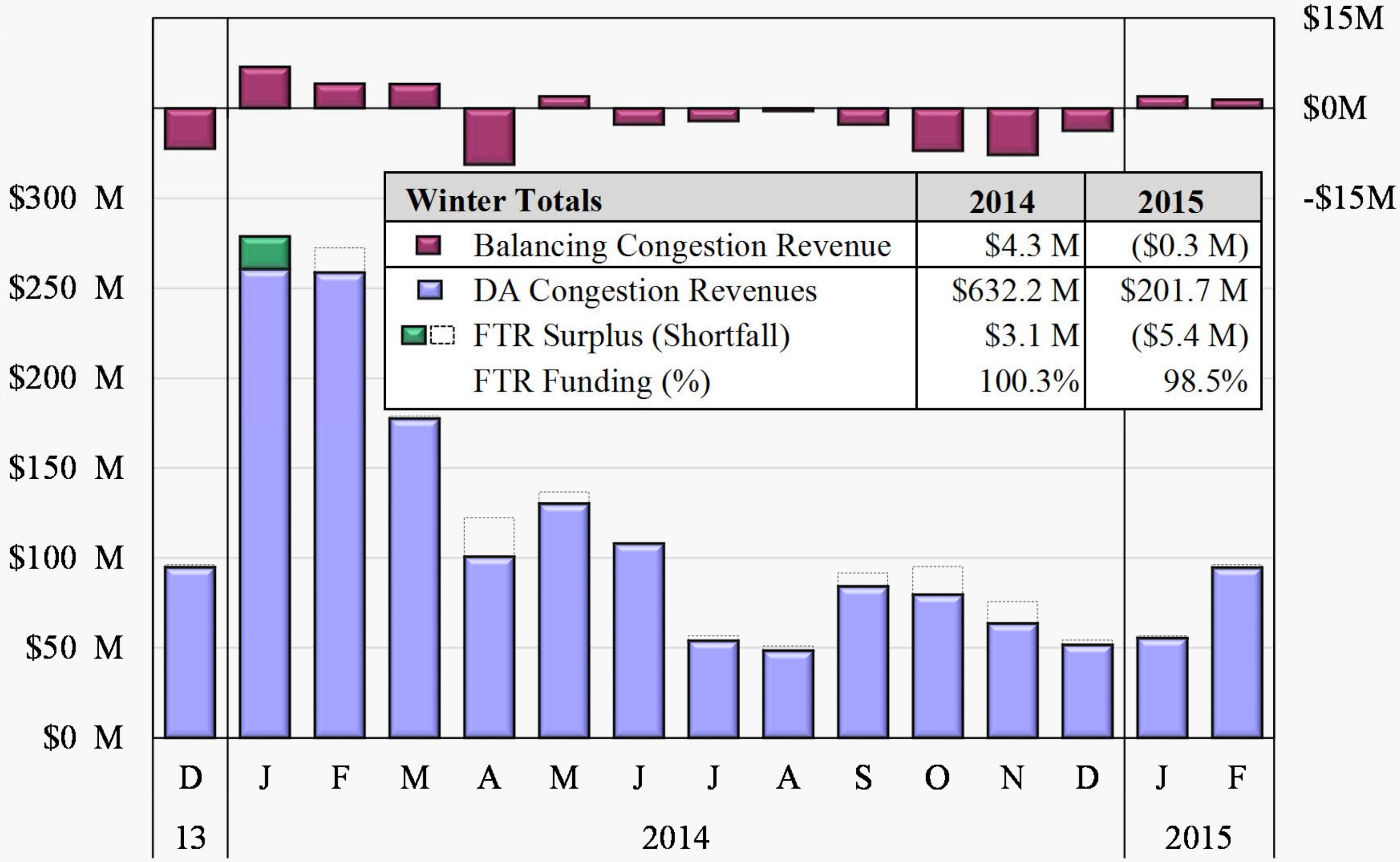
Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows monthly day-ahead congestion and FTR funding since December 2013. 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.
- Day-ahead congestion declined by almost 70 percent from last winter to $201.7 million.
  - ✓ The decline in congestion is consistent with the energy price declines noted across the footprint as well as the decrease in gas prices. Also, a reduction in the spread between gas and coal-fired generating costs lowers congestion redispatch costs.
  - ✓ The most expensive constraint was a market-to-market constraint in the Central region.
- FTRs were slightly underfunded this quarter, at 98.5 percent.
  - ✓ The most significant shortfalls occurred on a set of constraints impacted by modeling issues and outage scheduling.
    - – One particular constraint in the North region was underfunded by more than $10 million.
  - ✓ The SRPBC accrued the most surplus revenue of any constraint this winter.

Day-Ahead Congestion, Balancing Congestion and FTR Underfunding, 2014–2015



Winter Totals	2014	2015
Balancing Congestion Revenue	$4.3 M	($0.3 M)
DA Congestion Revenues	$632.2 M	$201.7 M
FTR Surplus (Shortfall)	$3.1 M	($5.4 M)
FTR Funding (%)	100.3%	98.5%

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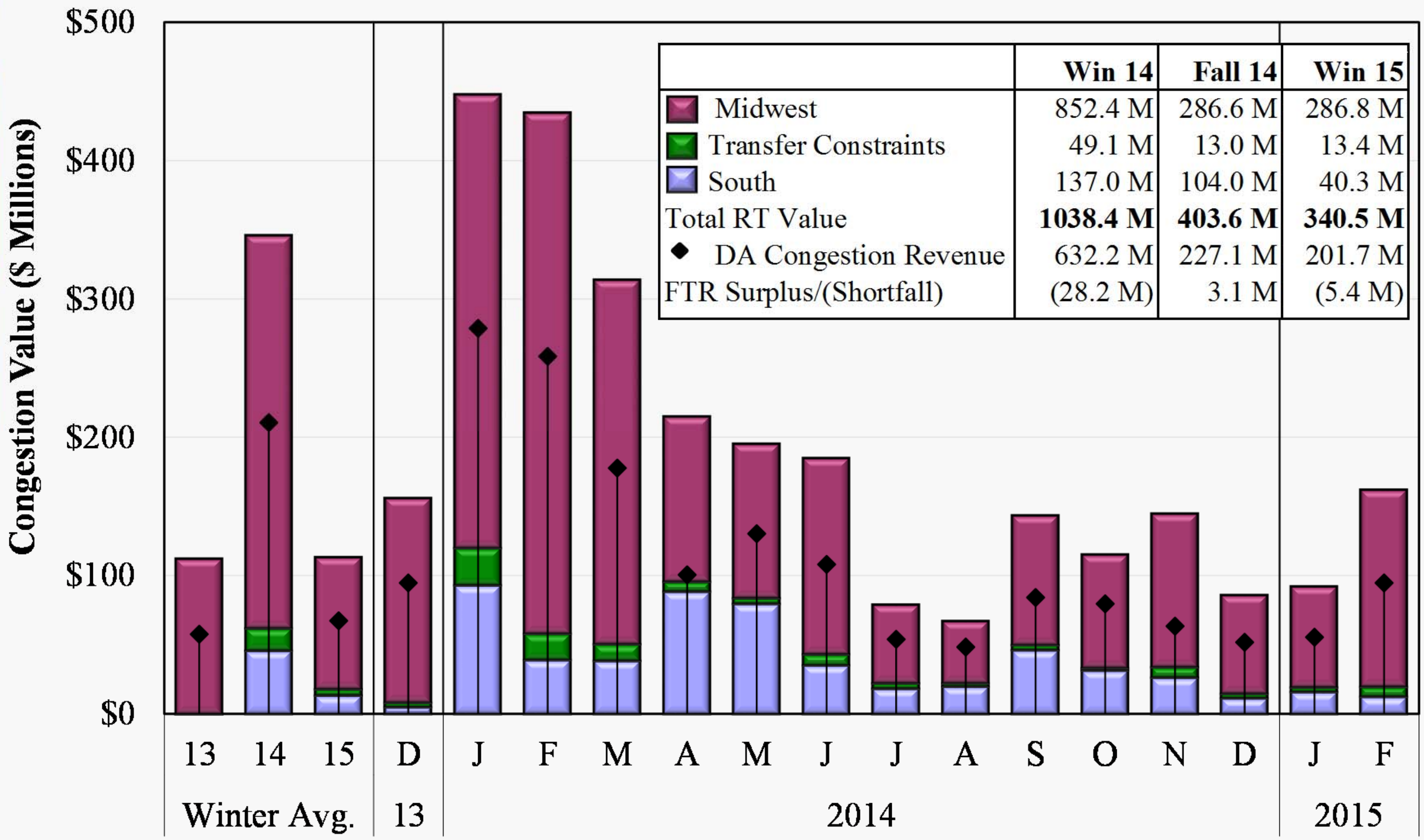
Value of Real-Time Congestion

- 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 and other JOA parties have 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 67 percent from last winter to $340.5 million and was comparable to the congestion in the fall.
  - ✓ The most expensive real-time constraints were in the Central and North regions, resulting from nearby transmission outages.
  - ✓ Real-time congestion in the South region was the lowest since integration.
- Transfer constraints were valued at just over $13 million, a large decline from last winter, and relatively unchanged compared to the fall. Although the real-time value of these constraints is relatively small, the price effects can be substantial.

Value of Real-Time Congestion 2014–2015



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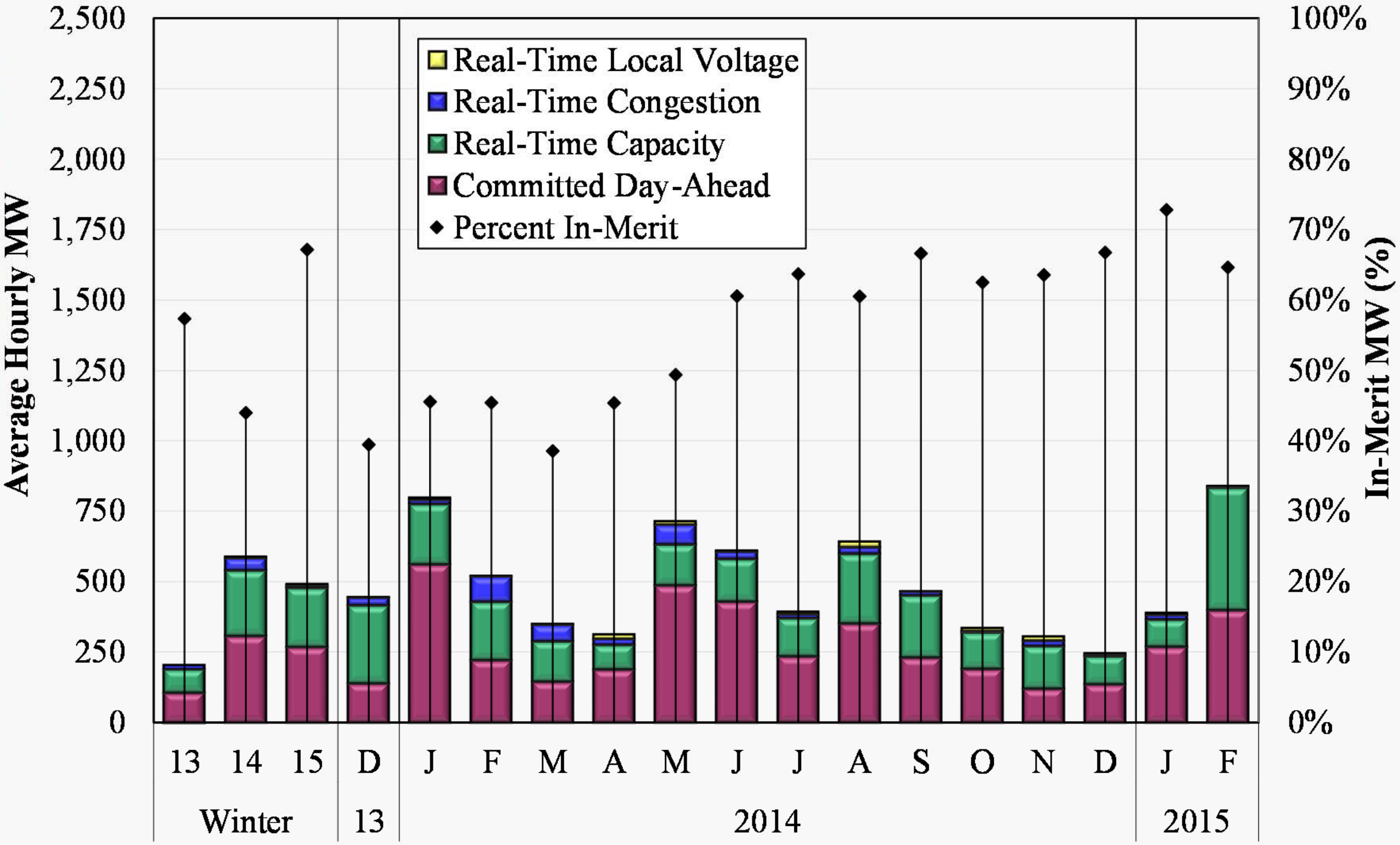
Peaking Resource Real-Time Dispatch

- 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 averaged 491 MW per hour this this winter, a 33 percent increase from last fall.
- Real-time commitments for capacity were unusually high at 434 MW during February.
  - During the last few days in February real-time commitments increased dramatically, accompanied by cold weather in the South.
- Other real-time needs, including for congestion management (8 MW) and voltage and local reliability (5 MW), remain infrequent.
  - ✓ VLR dispatches were mostly for reliability needs in the South Region.
- Dispatches of day-ahead committed units decreased from last winter from 307 MW to 267 MW.
- The share of peaking unit dispatch that was in-merit rose from 44 percent last winter to 67 percent, as the in-merit share increased throughout the year.
  - ✓ The implementation of MISO's ELMP Initiative, which will allow peaking resources to set prices more frequently, went live on March 1.

Peaking Resource Dispatch
2013–2015



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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).
- Day-ahead nominal RSG costs for the quarter totaled nearly $25 million, a 30 percent decline from the prior winter and a 14 percent decline from the fall.
  - ✓ Adjusting for the significant decline in fuel prices from last winter, however, payments rose by 16 percent. (This is partially due to a larger footprint in December.)
  - ✓ The majority of day-ahead payments went to units needed to satisfy VLR requirements, nearly all of which continue to be in the South region. An additional $3.1 million was paid for capacity but went to units that can satisfy VLR requirements.
    - – [MISO is developing both short and long term plans to improve the modeling and classification of these commitments.]
  - ✓ Since most VLR units are offered competitively, just 5 percent of RSG was mitigated.
    - – One unit needed for VLR for an outage in the Central region was paid over $2 million but was mitigated on 24 separate days in December and early January.
- Real-time payments declined 71 percent in nominal terms and 43 percent in fuel-adjusted terms. Fuel-adjusted payments for congestion declined by two-thirds.
  - ✓ The decline in RSG costs was driven by a decrease in natural gas prices and far milder conditions compared to the extreme market conditions experienced last winter.

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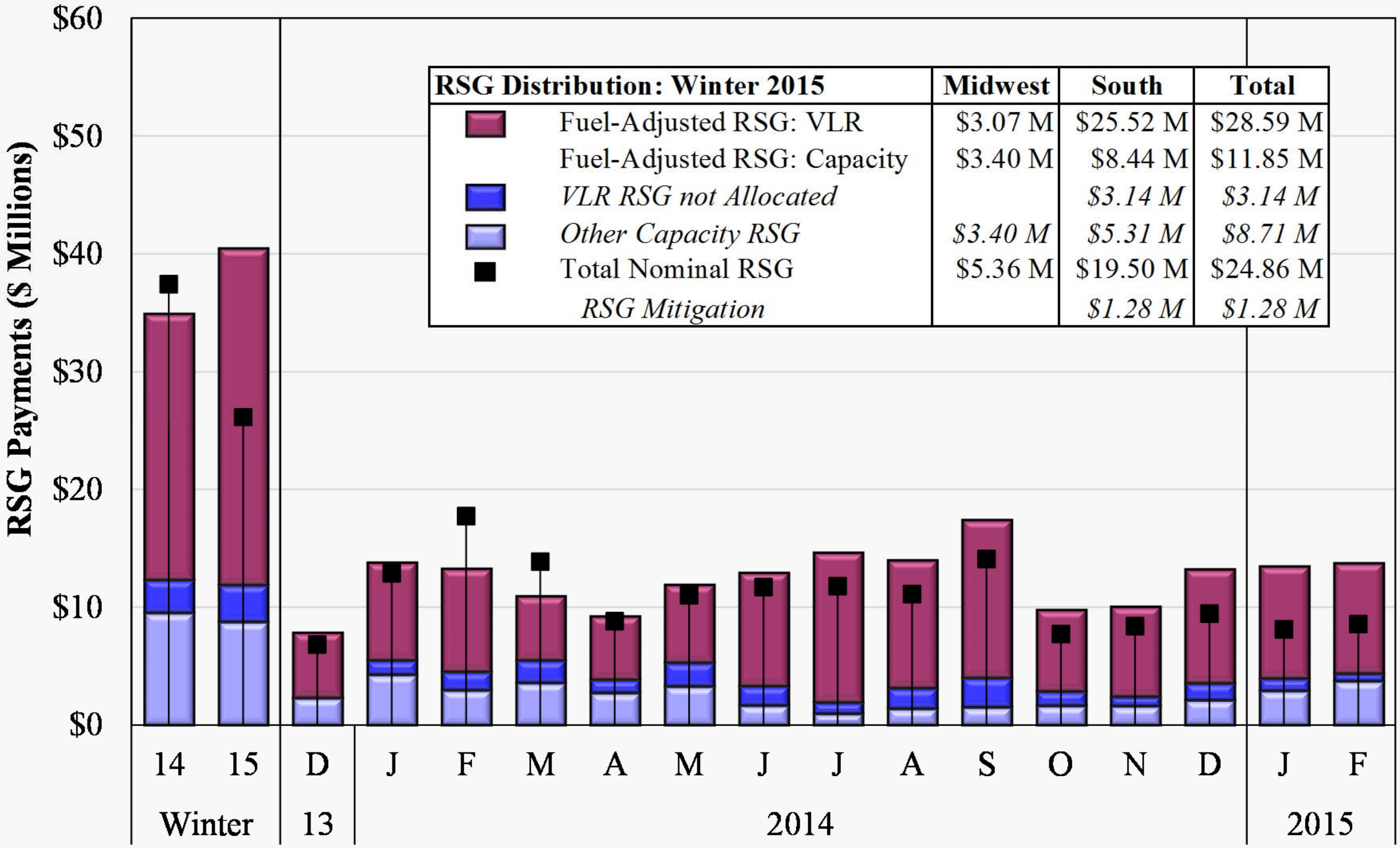
Day-Ahead RSG Payments
Winter 2014–2015



RSG Distribution: Winter 2015	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$3.07 M	$25.52 M	$28.59 M
Fuel-Adjusted RSG: Capacity	$3.40 M	$8.44 M	$11.85 M
VLR RSG not Allocated		*$3.14 M*	*$3.14 M*
Other Capacity RSG	*$3.40 M*	*$5.31 M*	*$8.71 M*
Total Nominal RSG	$5.36 M	$19.50 M	$24.86 M
RSG Mitigation		*$1.28 M*	*$1.28 M*

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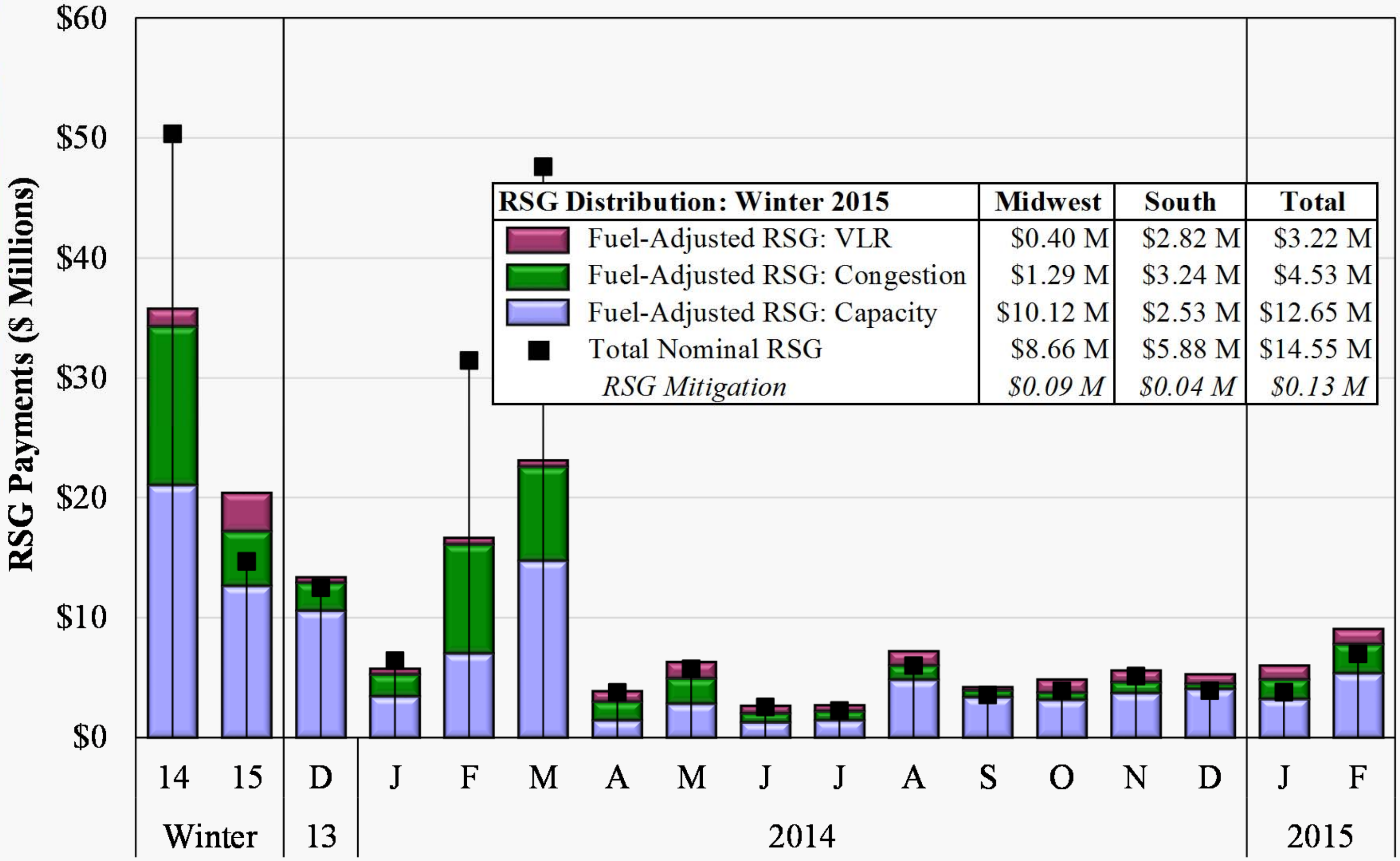
Real-Time RSG Payments
Winter 2014–2015



RSG Distribution: Winter 2015	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.40 M	$2.82 M	$3.22 M
Fuel-Adjusted RSG: Congestion	$1.29 M	$3.24 M	$4.53 M
Fuel-Adjusted RSG: Capacity	$10.12 M	$2.53 M	$12.65 M
Total Nominal RSG	$8.66 M	$5.88 M	$14.55 M
RSG Mitigation	*$0.09 M*	*$0.04 M*	*$0.13 M*

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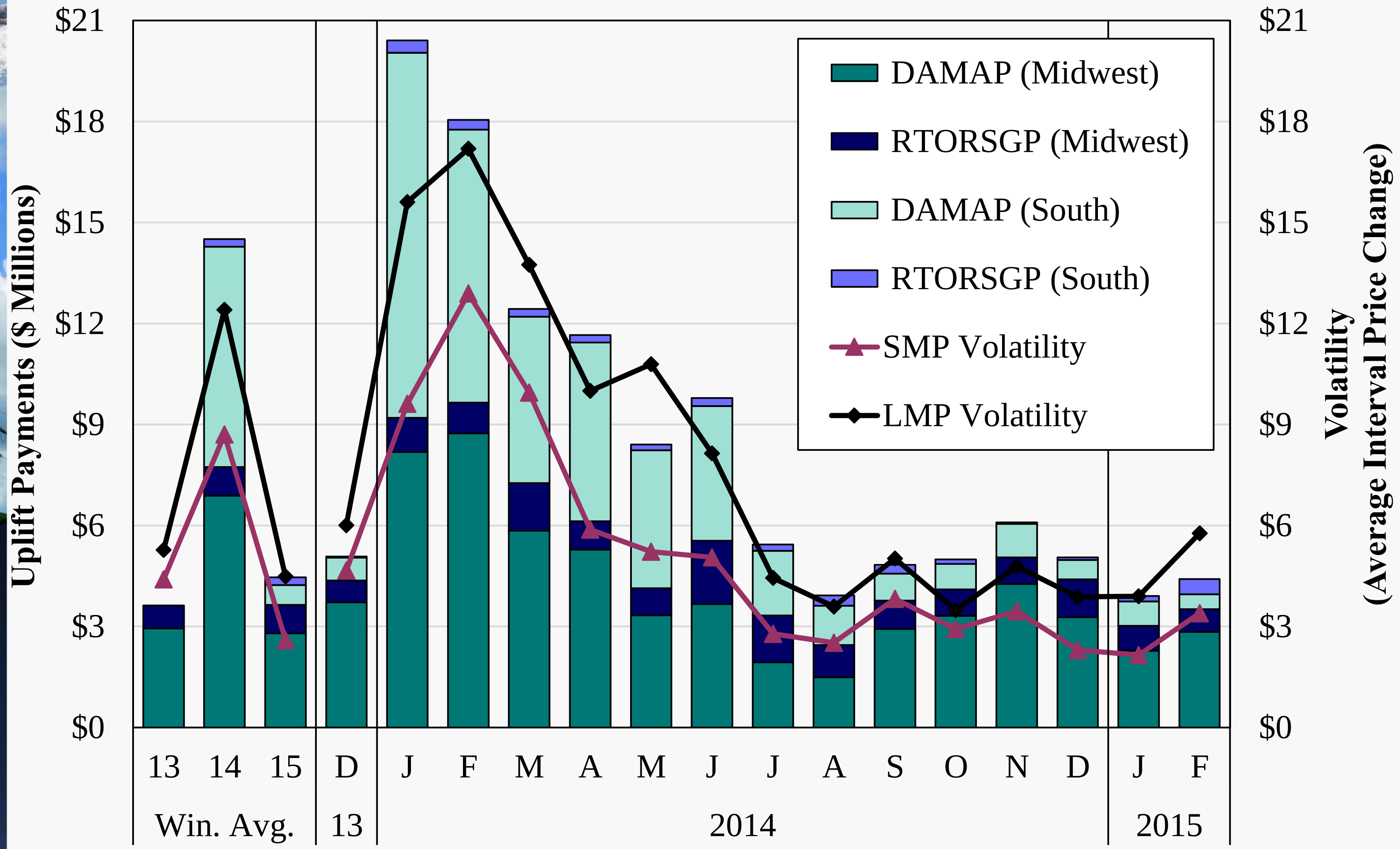
Price Volatility Make Whole Payments

- 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 winter were $13.3 million, a 69 percent decline from last winter.
  - ✓ Payments are strongly correlated with price volatility because it leads to higher payments for flexible units. Considerably less price volatility this winter, due to lower and less volatile gas prices, led to lower payments.
  - ✓ Price volatility and payments both declined modestly from the fall to the winter.
- DAMAP totaled $10.1 million for the winter, the lowest season since South integration.
  - ✓ DAMAP paid to units in the South continued to fall in the winter, as they have since integration.
    - – This reduction is attributable to both modeling improvements by MISO and improved generator performance.
- RTORSGP payments remained modest and totaled $3.0 million during the winter, 8 percent lower than the $3.3 million paid last winter.

Price Volatility Make Whole Payments 2014–2015

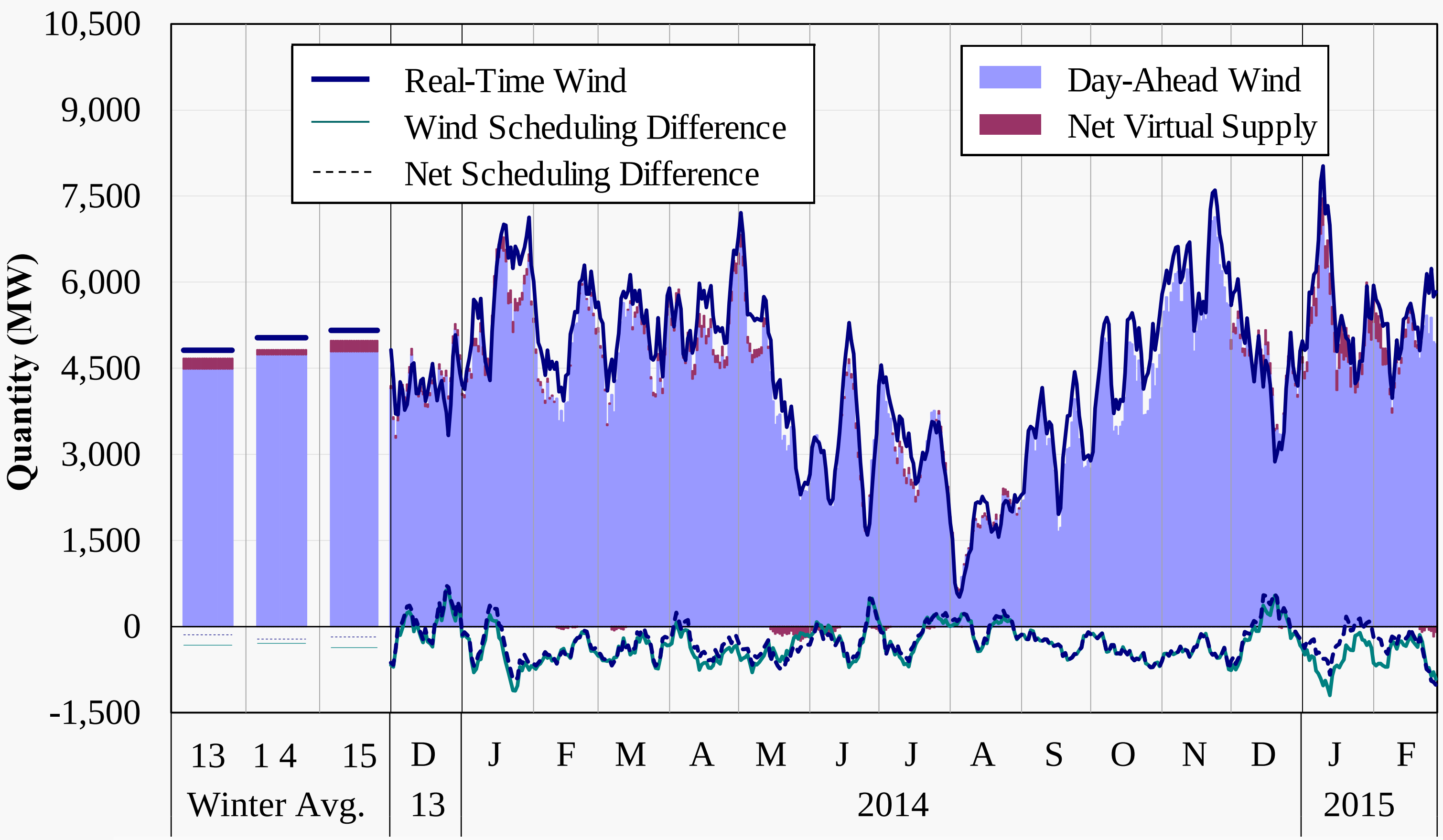


POTOMAC ECONOMICS

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; as such, economic dispatch has replaced manual curtailments as the preferred means to manage wind output.
  - ✓ The rate of growth of wind resources slowed considerably due to the expiration and uncertainty of renewal of federal subsidies.
- Real-time wind output rose 1 percent from last winter to 5.1 GW, and MISO set a new record for wind generation at 11.9 GW on January 8.
  - ✓ Although wind output is typically higher during shoulder seasons, it rose 6 percent from the fall.
  - ✓ Despite the rise, DIR curtailments declined 66 percent from last winter to an average of 91 MW per interval, or nearly less than 2 percent of wind output.
  - ✓ Since wind units typically get curtailed only when they overload constraints, the substantial reduction in congestion this winter also reduced the need for curtailments.
- Wind generation remains moderately under-scheduled (by 366 MW) day-ahead.
  - ✓ Net virtual supply at wind locations reduced the under-scheduling by nearly 200 MW, or by more than half of the total. This is a 44 percent improvement from last winter.
  - ✓ This is expected because under-scheduling provides an incentive for virtual supply to make up the difference. It averaged $1.63 per MWh.
  - ✓ Net scheduling was slightly positive in December and poor in late February.

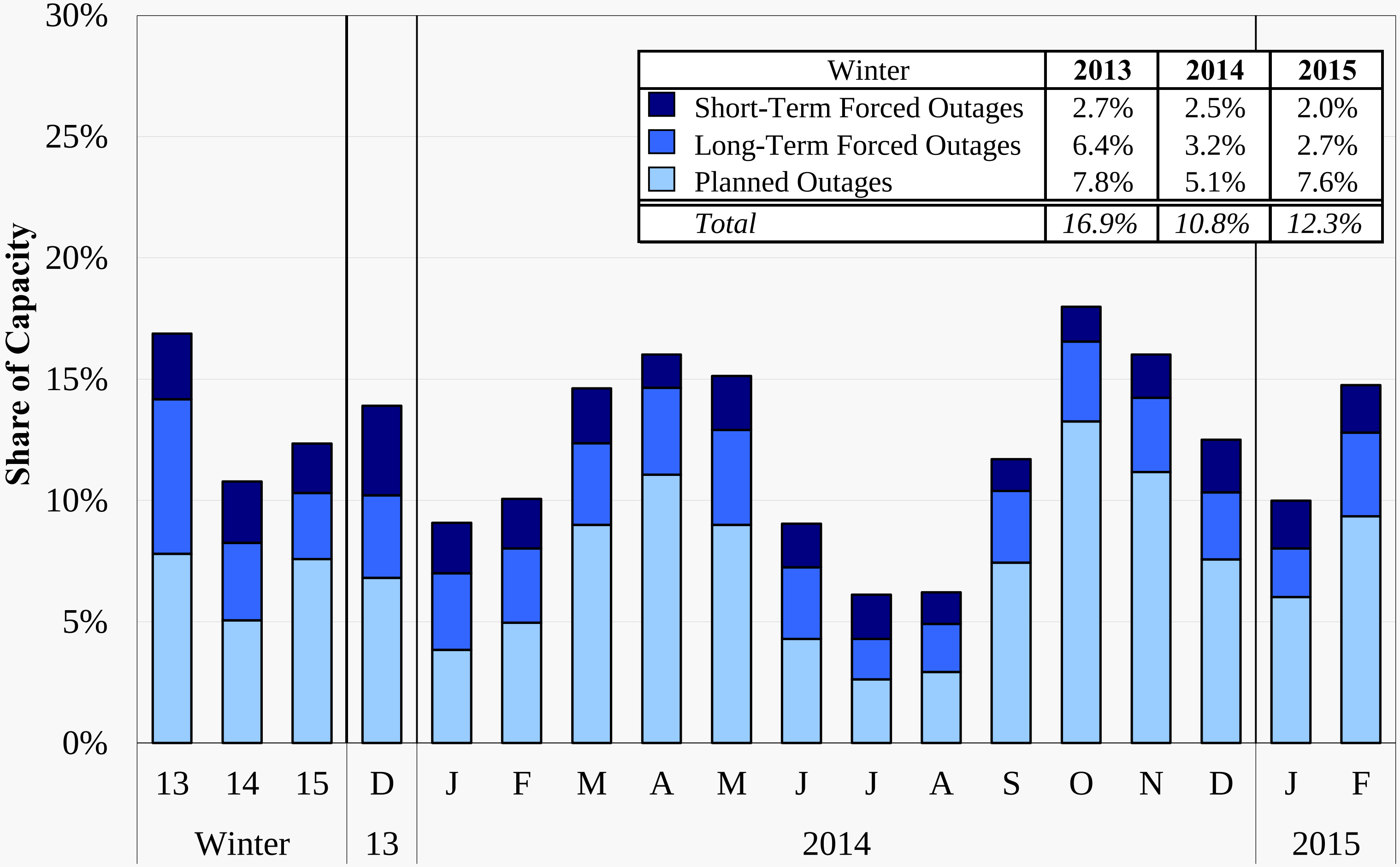
Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average, 2014–2015



Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since December 2013 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 winter rose to rose to 12.3 percent, up from 10.8 percent last winter.
  - ✓ Planned outages made up a majority of the total outages at 7.6 percent, 2.5 percentage points higher than last year during a harsh conditions.
  - ✓ Forced outages averaged 4.7 percent, lower than the prior two winters.
- Short-term forced outages declined to 2.0 percent, while long-term forced outages declined to 2.7 percent from last winter.
- We investigate outages that contribute to shortages or severe congestion, which raised no competitive concerns this quarter.

Generation Outage Rates
2014–2015



Winter	2013	2014	2015
Short-Term Forced Outages	2.7%	2.5%	2.0%
Long-Term Forced Outages	6.4%	3.2%	2.7%
Planned Outages	7.8%	5.1%	7.6%
Total	*16.9%*	*10.8%*	*12.3%*

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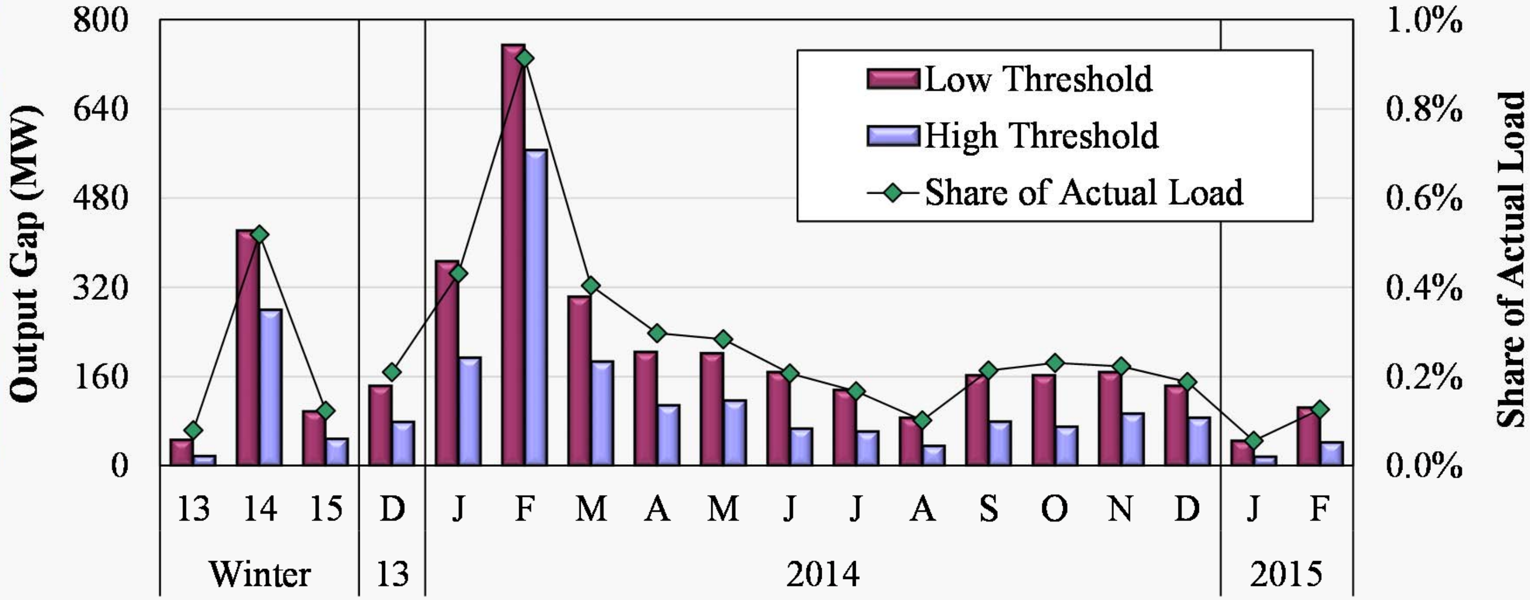
Monthly Output Gap

- 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 December 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 0.19 percent of actual load, which was the lowest quarter since integration of the South region.
  - ✓ At the low threshold, the output gap dropped from 422 MW last winter to 75 MW this winter, while at the mitigation threshold it dropped from 282 MW to 30 MW.
    - – Nearly 20 percent is associated with two units in the South with very high ancillary services 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
2014–2015



High Threshold Results by Unit Status (MW)

Offline	22	202	14	59	106	451	130	83	71	13	21	15	20	9	19	50	11	18
Online	17	80	15	20	89	116	57	26	46	54	41	21	60	62	75	36	6	24

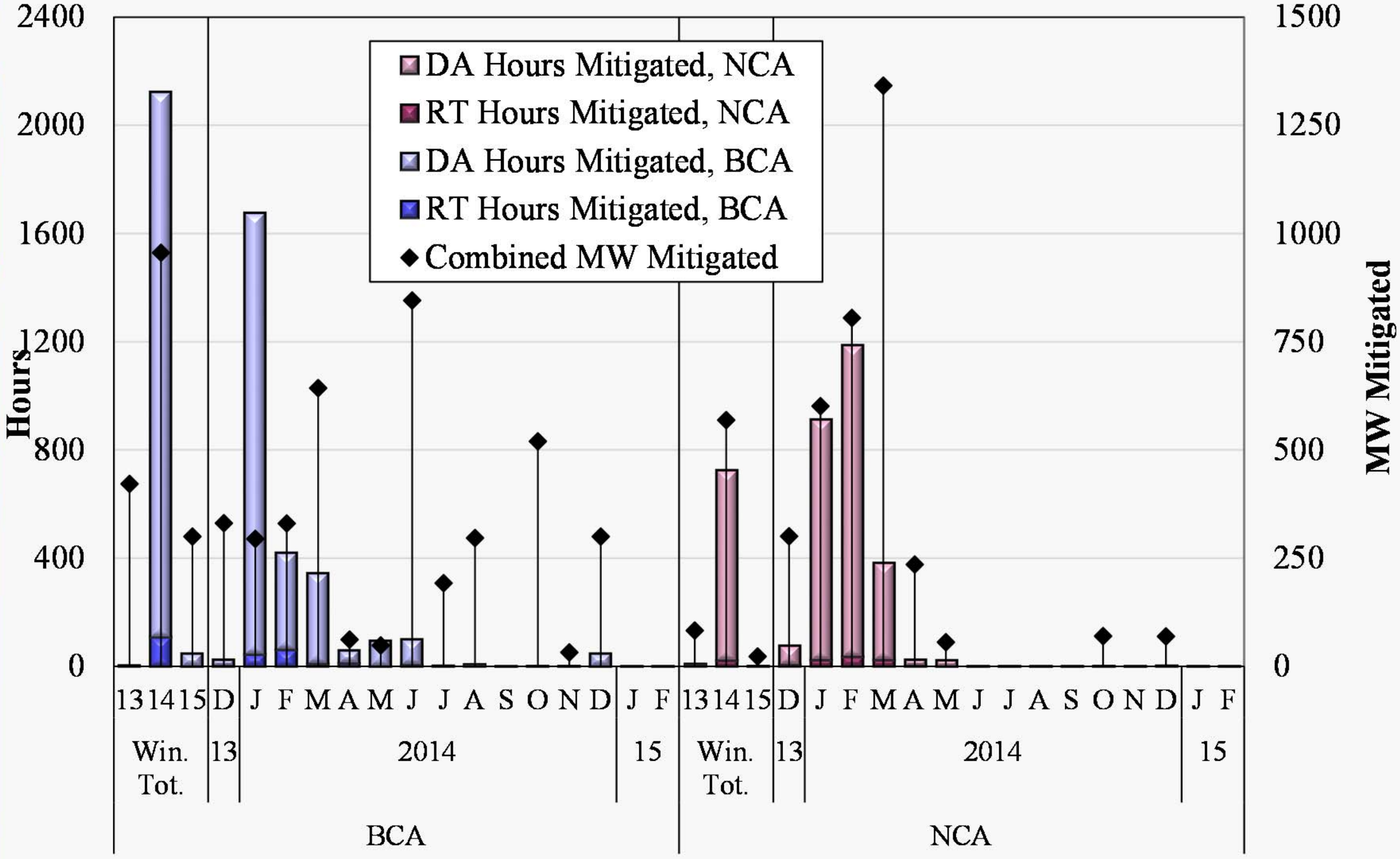
Low Threshold Results by Unit Status (MW)

Offline	27	237	22	70	140	519	154	99	82	18	29	22	32	14	21	52	12	33
Online	56	185	53	74	228	236	150	105	120	150	107	65	131	149	147	92	34	72

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 10 hours and for 611 MW this winter, down significantly from last winter.
  - ✓ Most mitigation was in December and February within BCAs.
- RSG mitigation totaled $1.4 million in the quarter, nearly all of which occurred day-ahead under the VLR framework.
  - ✓ Most units mitigated were in the South region.
- Unit-days of mitigation fell 77 percent from last winter to 107 this winter.
- 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 2013–2015



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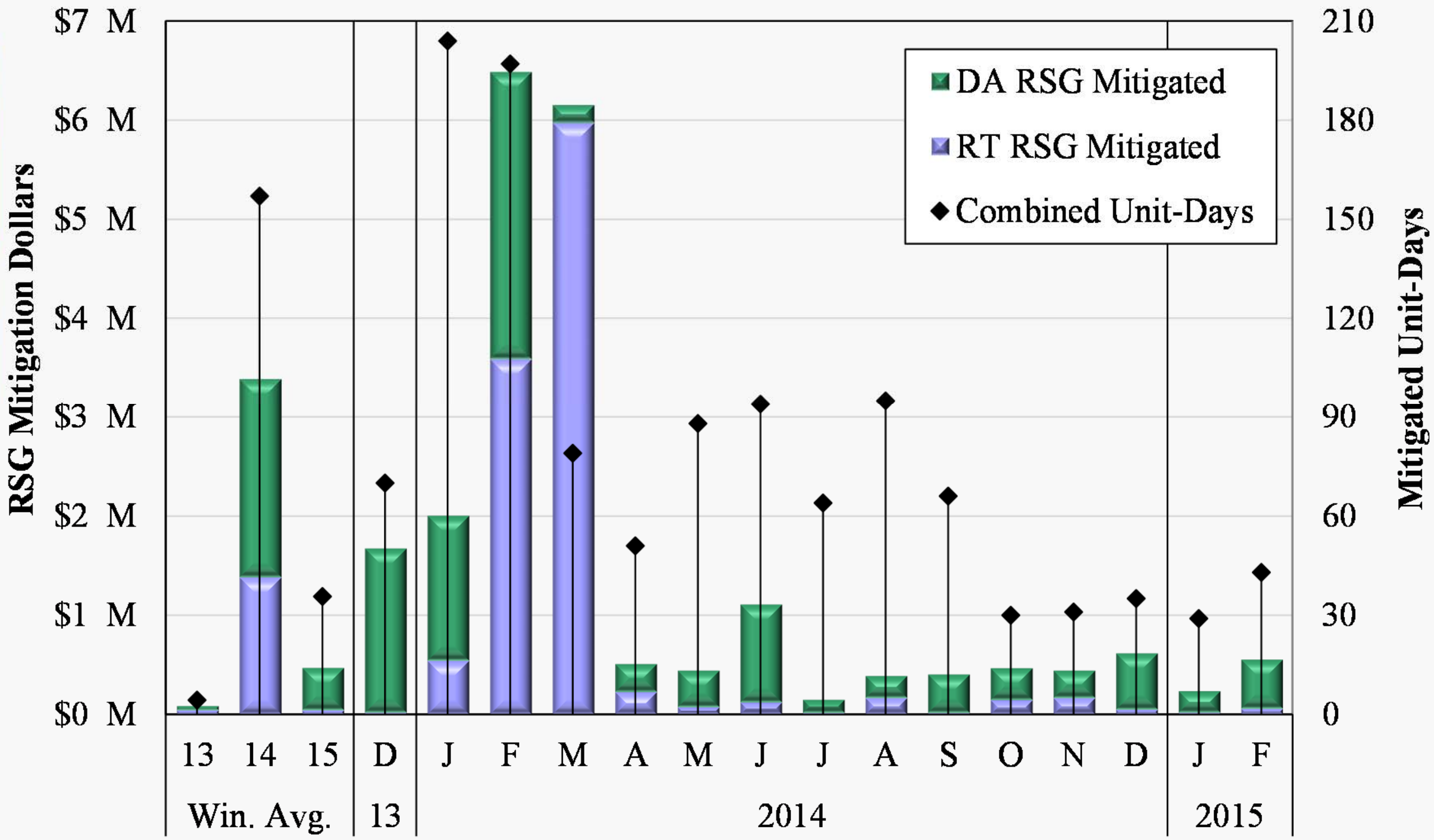
Day-Ahead and Real-Time RSG Mitigation 2014–2015



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Submittals to External Entities and Other Issues

- We provided additional data and analyses to FERC related to prior referrals regarding resources failing to update real-time offers.
- We filed comments on FERC's Price Formation Workshops on February 19. (OLD)
- We continued participation in both the JCM and Interface Pricing working groups. (OLD)
- We continued providing comments in the settlement process with SPP and other parties related to transmission charges for MISO's inter-regional transfers. (Modified)
- We participated in a joint working group with SPP and MISO on revisions to the JOA. (NEW)
- We participated in a panel at the Gulf Coast Power Association's meeting on the integration of MISO South in early February. (OLD)
- We participated in MSC discussions with MISO and PJM stakeholders on the appropriate allocation of uplift to CTS transactions. (NEW)
- We discussed market outcomes and performance with the Mississippi Public Utilities Staff and Public Service Commission. (NEW)
- We made a presentation on market outcomes to the Organization of MISO States (NEW, on MISO Calendar Feb 20?)
- We presented our approach for screening for VLR commitments made in RSC to MISO and are discussing alternative approaches with MISO. (NEW)

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