IMM Quarterly Report: Summer 2013
June–August

MISO Independent Market Monitor

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Potomac Economics

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Quarterly Summary

			Change[1]					Change[1]	
		Value	Prior Qtr.	Prior Year			Value	Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)	🟢	$33.16	*-2%*	*-2%*	**FTR Funding (%)**	🟢	99%	91%	98%
Fuel Prices ($/MMBtu)					**Wind Output (MW)**	🟢	2,498	*-41%*	*1%*
Natural Gas	🟢	$3.69	*-11%*	*32%*	**Guarantee Payments ($M)**				
Western Coal	🟢	$0.61	*-1%*	*27%*	Real-Time RSG	🟢	$23.3	*-7%*	*-3%*
Eastern Coal	🟢	$1.86	*3%*	*-2%*	Day-Ahead RSG	🟢	$4.5	*-6%*	*-9%*
Load (MW)[2]					Day-Ahead Marginal Assurance	🟢	$10.8	*-5%*	*-31%*
Average Load	🔵	61.3	*14%*	*-7%*	RT Operating Rev. Sufficiency	🟢	$2.6	*-15%*	*-31%*
Peak Load	🟢	95.8	*34%*	*-3%*	**Price Convergence[3]**				
% Scheduled DA (Peak Hour)	🟢	98.3%	98.6%	100.2%	Market-wide DA Premium	🔵	-2.5%	-4.5%	1.5%
Transmission Congestion ($M)					**Virtual Trading**				
Real-Time Congestion Value[4]	🟢	$371.6	*-4%*	*-1%*	Cleared Quantity (MW)	🟢	6,585	*10%*	*-9%*
Day-Ahead Congestion Revenue	🟢	$188.7	*7%*	*-35%*	% Price Insensitive	🟢	38%	38%	44%
Balancing Congestion[5]	🔵	$4.8	$19.0	$8.7	% Screened for Review	🟢	1%	2%	2%
Ancillary Service Prices ($/MWh)					Profitability ($/MW)	🟢	$1.36	$0.93	$0.47
Regulation	🟢	$9.54	*-27%*	*-6%*	**Dispatch of Peaking Units (MW/hr)**	🟢	720	437	1,786
Spinning Reserves	🟢	$3.45	*-28%*	*-22%*	**Output Gap- Low Thresh. (MW/hr)**	🟢	40	88	36
Supplemental Reserves	🟢	$2.54	*20%*	*-24%*	**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. Includes only internal constraints, no external constraints.
5. Real-time shortfalls (contributes to neg. ECF), net of real-time surpluses. No M2M offset.

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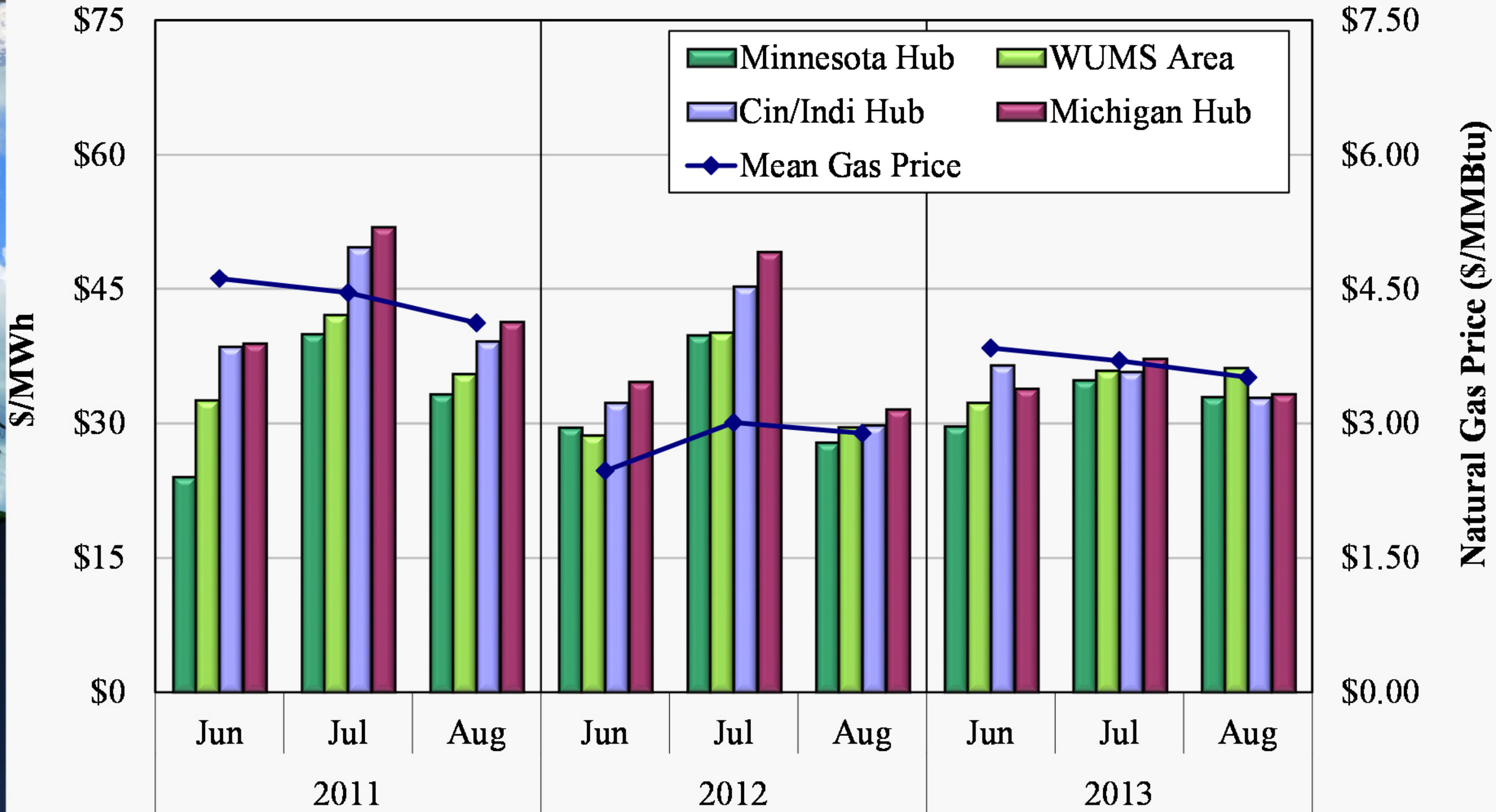
Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations in June to August for the last three years.
  - ✓ We include natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin during peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices this summer averaged $33.28 per MWh, down 5.5 percent from last summer.
  - ✓ Prices declined despite much higher natural gas prices, which rose 32 percent from last summer to $3.69 per MMBtu.
  - ✓ Weather-related reductions in load and shortages this summer were the primary cause of the lower price levels. Day-ahead scheduled load fell 8 percent.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ There was little separation among average hub prices this quarter. Minnesota deviated the most, exhibiting prices that averaged approximately $2.25 less than other hubs.
  - ✓ The most apparent patterns of day-ahead congestion were west-to-east in the first half of the summer, and into WUMS in August.

Day-Ahead Average Monthly Hub Prices
Summer 2011–2013



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

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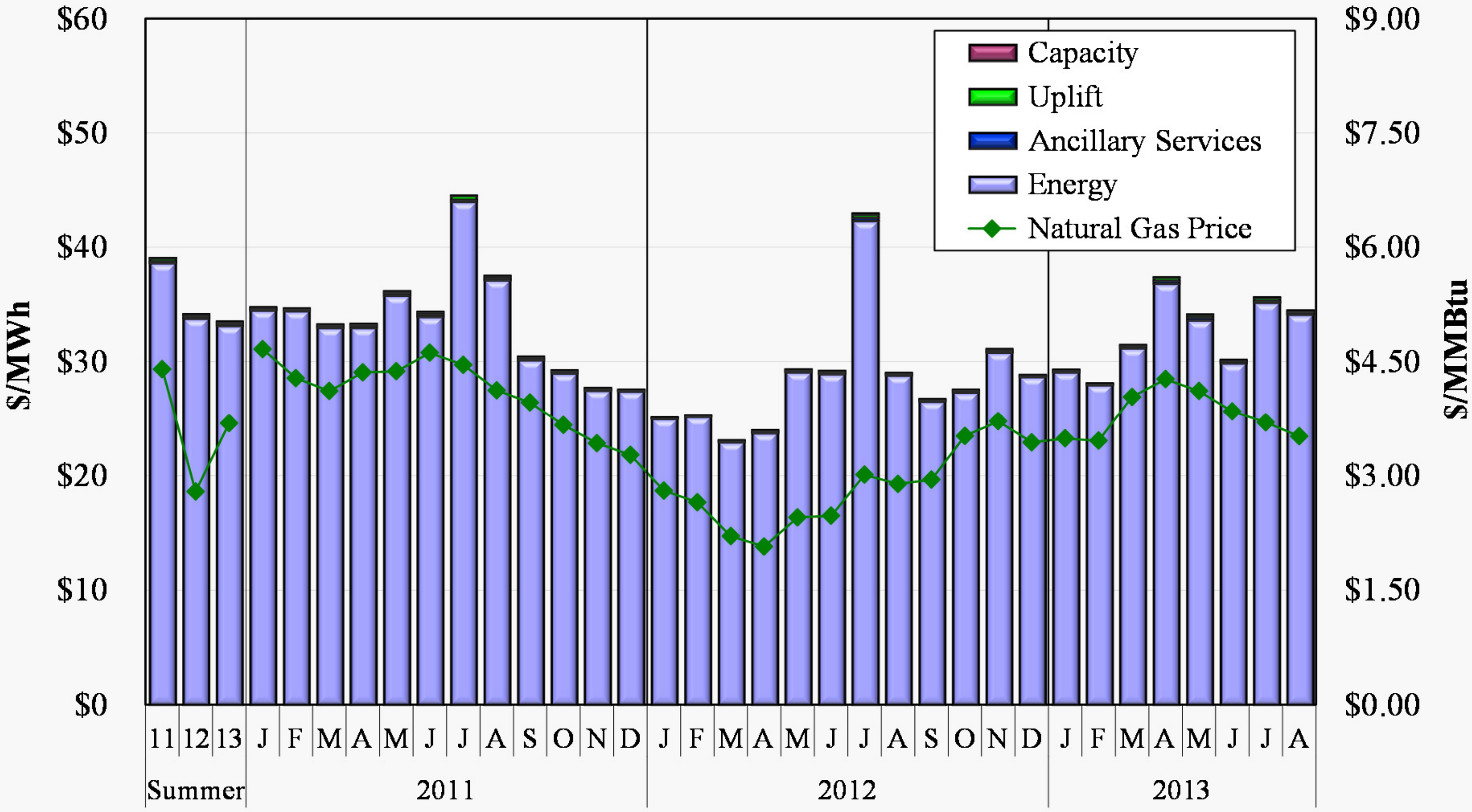
All-In Price

- The "all-in price" represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price and real-time uplift, ancillary services, and capacity costs per MWh of load.
  - ✓ The figure includes monthly average natural gas prices.
  - ✓ Day-ahead and real-time energy prices generally track changes in fuel prices.
- Despite increases in fuel prices, the all-in price declined 2 percent from last summer to $33.52 per MWh because of much lower loads in during peak periods.
  - ✓ As with day-ahead energy prices, the decline in the energy component of the all-in price was mostly driven by lower loads this summer, particularly in July.
    - – July's all-in price was 17 percent lower than in July 2012.
- Energy costs continue to make up nearly all (98.9 percent) of the all-in price.
- Non-energy costs were all nearly unchanged from last summer.
  - ✓ Uplift and ancillary services costs each added 16 cents to the all-in price.
  - ✓ The Planning Reserve Auction cleared at $1.05 per MW-day (i.e., $0.05 per MWh) for the 12 months beginning in June 2013.
    - – The importance of the PRA will increase when the capacity surplus in MISO falls and certain market issues are addressed.

All-In Price
Summer 2011–2013



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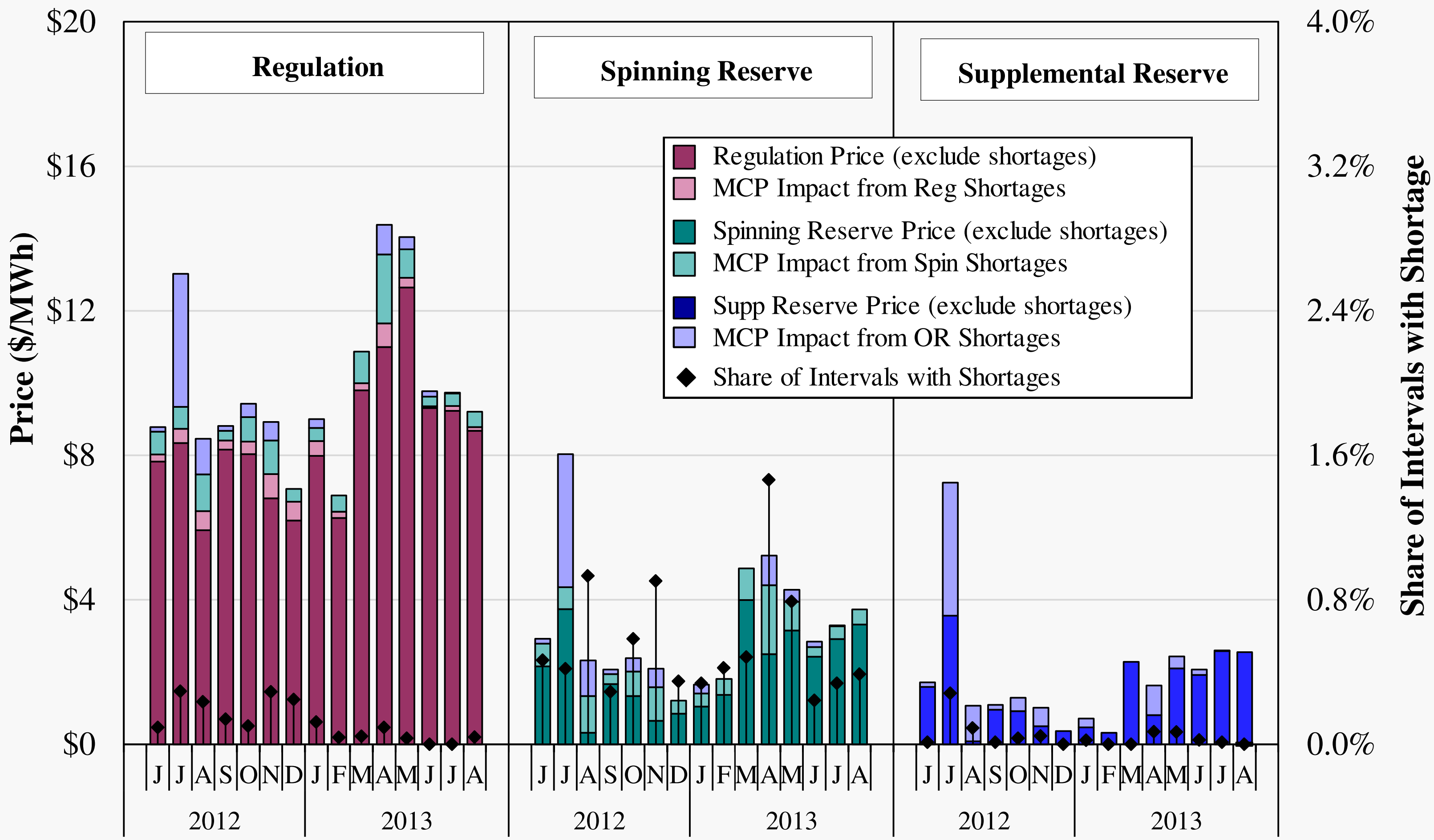
Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO's ancillary service products for the last 15 months.
  - ✓ We show separately the portion of each product's price that is due to shortages of each product (shortages for lower quality products are reflected in higher quality products because they can be substituted).
- AS prices and shortages decreased considerably from the spring and from last summer, mostly because of far fewer operating reserve shortages this period.
- Regulation prices declined 6 percent from last summer to $9.54 per MWh.
  - ✓ Shortage pricing added $2.75 to last summer's regulation price, compared to just $0.52 this summer. Higher gas prices, however, increased the non-shortage component.
  - ✓ There were 37 regulation shortages this quarter, compared to 55 last summer.
  - ✓ Prices and regulation shortages also declined notably from the spring when there were fewer units online that can provide regulation.
- Spin prices declined 22 percent to $3.45 because average load and shortages decreased.
  - ✓ There were 81 spinning reserve shortages this summer, compared to 160 last summer.
- Supplemental prices declined 24 percent to $2.54 per MWh for the same reasons.
  - ✓ In addition to the reduction in shortages, MISO implemented a step-wise demand curve for total operating reserves (OR) where the first 4 percent are priced at $200 per MWh. Each of the three shortages this quarter were priced at $200 per MWh.

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



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MISO Fuel Prices and Capacity Factors

Natural Gas and Oil Prices

- Natural gas prices averaged $3.69 per MMBtu this summer, up 32 percent from last summer (when they averaged $2.79).
  - ✓ Natural gas prices were 12 percent higher in the spring.
- Oil prices rose 2 percent from last summer to $21.50 per MMBtu.
  - ✓ Although this fuel is rarely marginal (and so has a minimal impact on energy prices), significant RSG payments can accrue to such units.

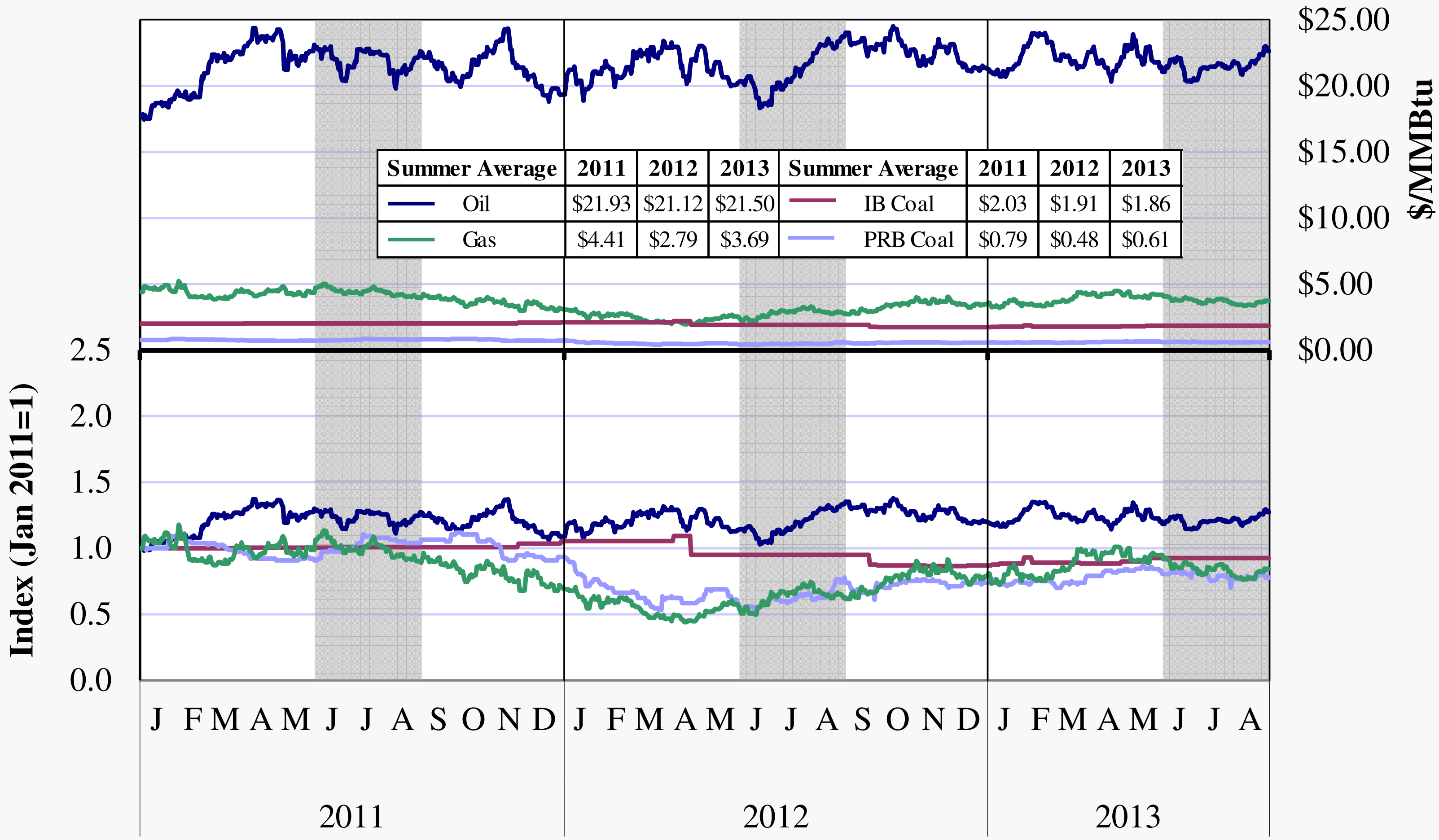
Coal Prices

- Illinois Basin prices declined 2 percent from last summer to $1.86 per MMBtu.
- Western (Powder River Basin) coal prices rose 27 percent to $0.61 per MWh.
  - ✓ Rail transportation costs can make the delivered cost of coal, and PRB coal in particular, significantly higher than mine-mouth prices.

Capacity Factors

- Higher gas prices and lower loads this summer resulted in far lower capacity factors for CC and CT units than last summer.
  - ✓ Factors for these units in July were less than half of last July's average.

MISO Fuel Prices
2011–2013



Summer Average	2011	2012	2013	Summer Average	2011	2012	2013
Oil	$21.93	$21.12	$21.50	IB Coal	$2.03	$1.91	$1.86
Gas	$4.41	$2.79	$3.69	PRB Coal	$0.79	$0.48	$0.61

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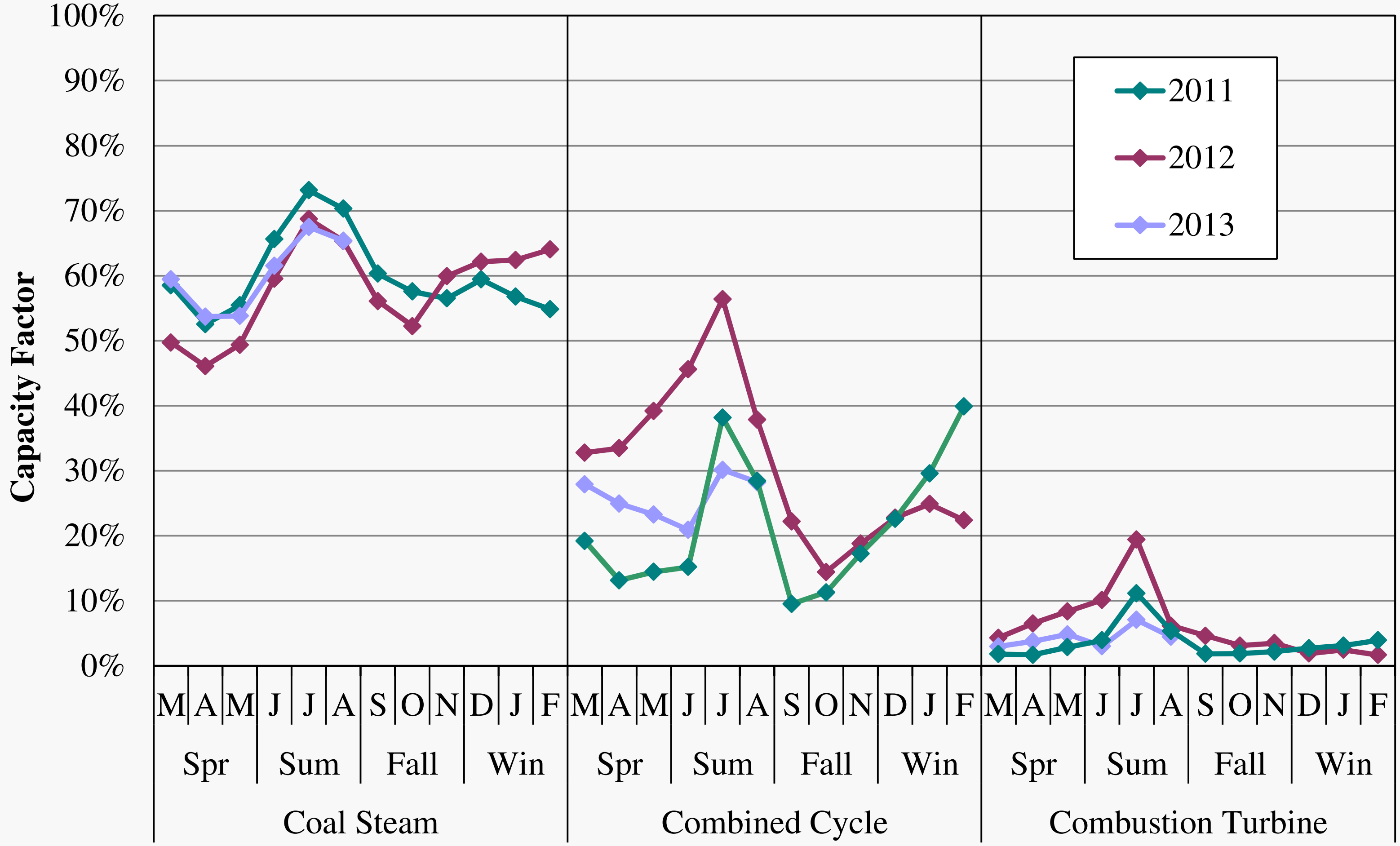
Capacity Factors by Unit Type
2011–2013



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Changes in Load and Weather Patterns

- A large share of the load is sensitive to weather, so changes in weather patterns contribute directly to changes in load. This relationship is shown in the next figure.
  - ✓ The top panel shows peak and average load in the summer months of 2011 to 2013, while the bottom panel shows the average heating and cooling degree days (a weather metric that is highly correlated with load).
  - ✓ Degree days are normalized (based on a regression analysis) so that heating and cooling days have an equal effect on load.
- The figure shows that total degree days declined 26 percent from last summer's unusually warm temperatures.
  - ✓ Total degree days remained slightly above the historical average even though the Central region experienced below-average temperatures.
  - ✓ July's degree days in particular were 37 percent lower than last year, which contributed to why MISO did not have the peak demands or shortages this July that it experienced last year.
- Demand for energy declined 6.8 percent from last summer to an average of 61.3 GW. Peak load declined 3 percent to 95.8 GW.
- We examine five days of peak load conditions (over 90 GW) from July 15 to 19 more closely on the subsequent seven slides.

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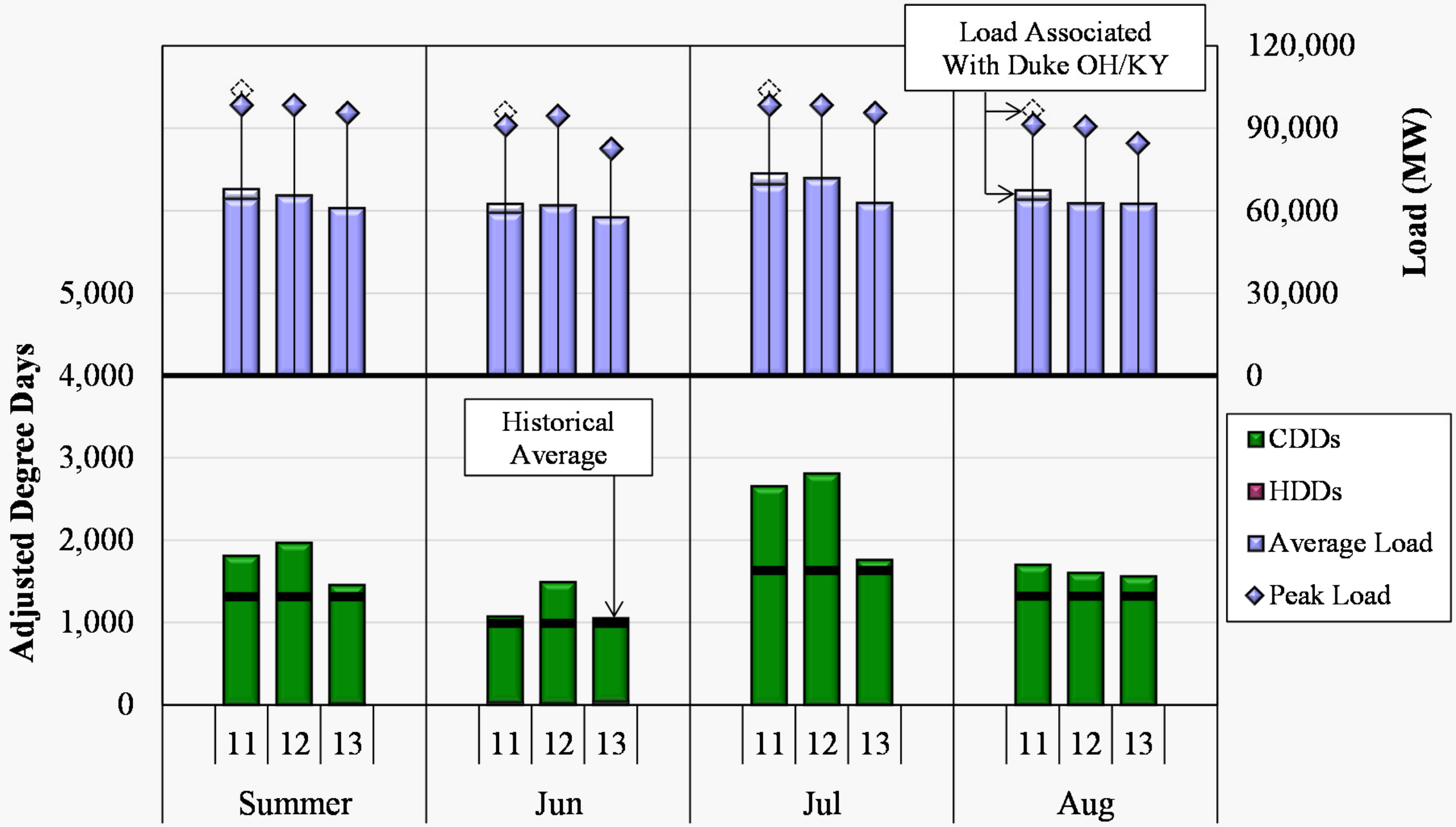
Load and Weather Patterns
Summer 2011–2013



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

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Peak Load Week, July 15-19

- Over five days in mid-July, temperatures throughout MISO were substantially higher than the historical average and the load exceeded 90 GW each day.
  - ✓ The peak load of 95.8 GW, however, was 3 percent lower than the peak in 2012.
- MISO declared its only Maximum Generation Alert on July 17.
  - ✓ Hot Weather Alerts and Conservative Operations were invoked on most days.
  - ✓ While load peaked on July 18, supply conditions were tighter on July 17 .
    Wind output in the peak hour on July 17 was 4 GW lower than on July 18.
  - ✓ Additionally, voluntary load curtailments after the MaxGen Alert was initiated appeared to truncate the peak load on July 17.

	Historical Average			July		
		15	16	17	18	19
Cincinnati	86	92	93	93	93	89
Detroit	84	93	90	94	94	95
Indianapolis	85	88	93	93	93	92
Milwaukee	80	85	93	95	95	94
St. Louis	89	91	93	94	94	98
Minneapolis	80	87	91	91	93	84

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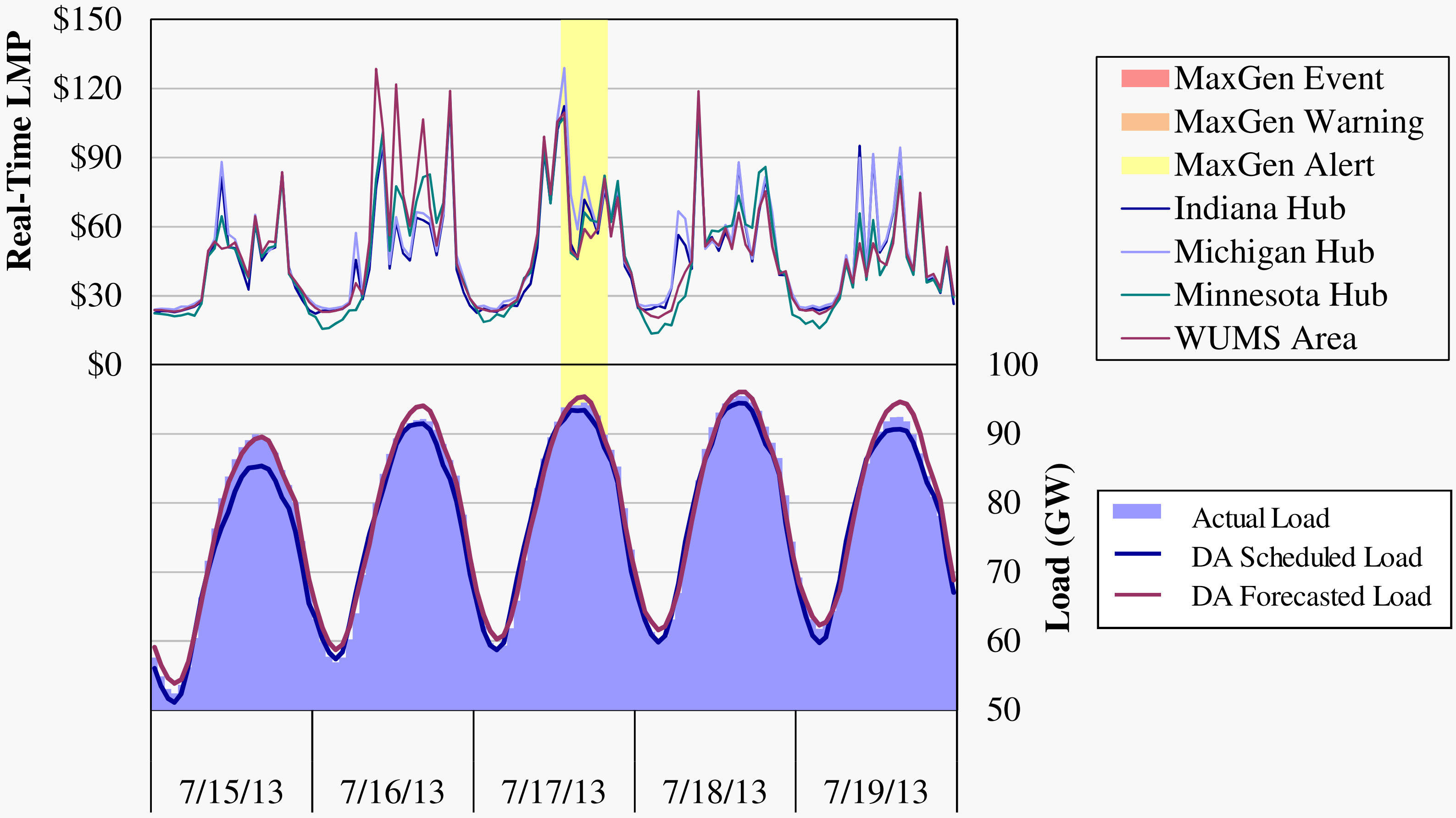
Peak Load Week, July 15-19

- The next figure shows actual load, the day-ahead forecast load by MISO and day-ahead schedules, as well as hourly energy prices.
  - ✓ The day-ahead scheduled load was generally lower than the forecast.
  - ✓ However, the day-ahead schedules were relatively consistent with the actual peak load on three of the days.
  - ✓ Day-ahead load was under-scheduled the most on July 15, which caused MISO to make large quantities of real-time reliability commitments.
- MISO maintained reliability throughout this period, and the markets did not experience any significant periods of shortage pricing.
- The high loads during the week led to a modest increase in price volatility, both MISO-wide and some volatility in local areas related to congestion.
  - ✓ However, price volatility was muted by commitments made on a number of these days.
  - ✓ In retrospect, a substantial share of the commitments were not needed and led to relatively low prices and inflated RSG costs.
  - ✓ One reason some commitments were not necessary in retrospect is that beneficial NSI changes occurred. Operators must be conservative in their forecasts of NSI changes since the external interfaces are not scheduled efficiently.

Peak Load Week, July 15-19



Real-Time Factors Impacting Energy Prices

- The next figures examines more closely the real-time factors affecting capacity levels and energy prices on July 15 and July 17.
  - ✓ The factors shown in the charts include the changes in load, NSI with PJM and other areas, wind output, MISO commitments, outages, and other supply changes.
  - ✓ "Harmful" factors that contribute to higher prices are shown as positive MW (e.g., load, outages, falling net imports) and "helpful" factors that reduce prices are shown as negative MW (e.g., increased supply, net imports, etc.).
  - ✓ The charts show the impact of supply and demand factors that affect the net capacity balance in each interval relative to start of the period shown.
- The net effect of all factors for each interval (relative to the first interval in the period) is shown by the red marker.
  - ✓ For example, the figure for July 17 shows a net effect of close to zero at 13:40 because MISO's commitments and supply changes completely offset the increase in load that occurred between 12:35 and 13:40.

Real-Time Factors Impacting Energy Prices

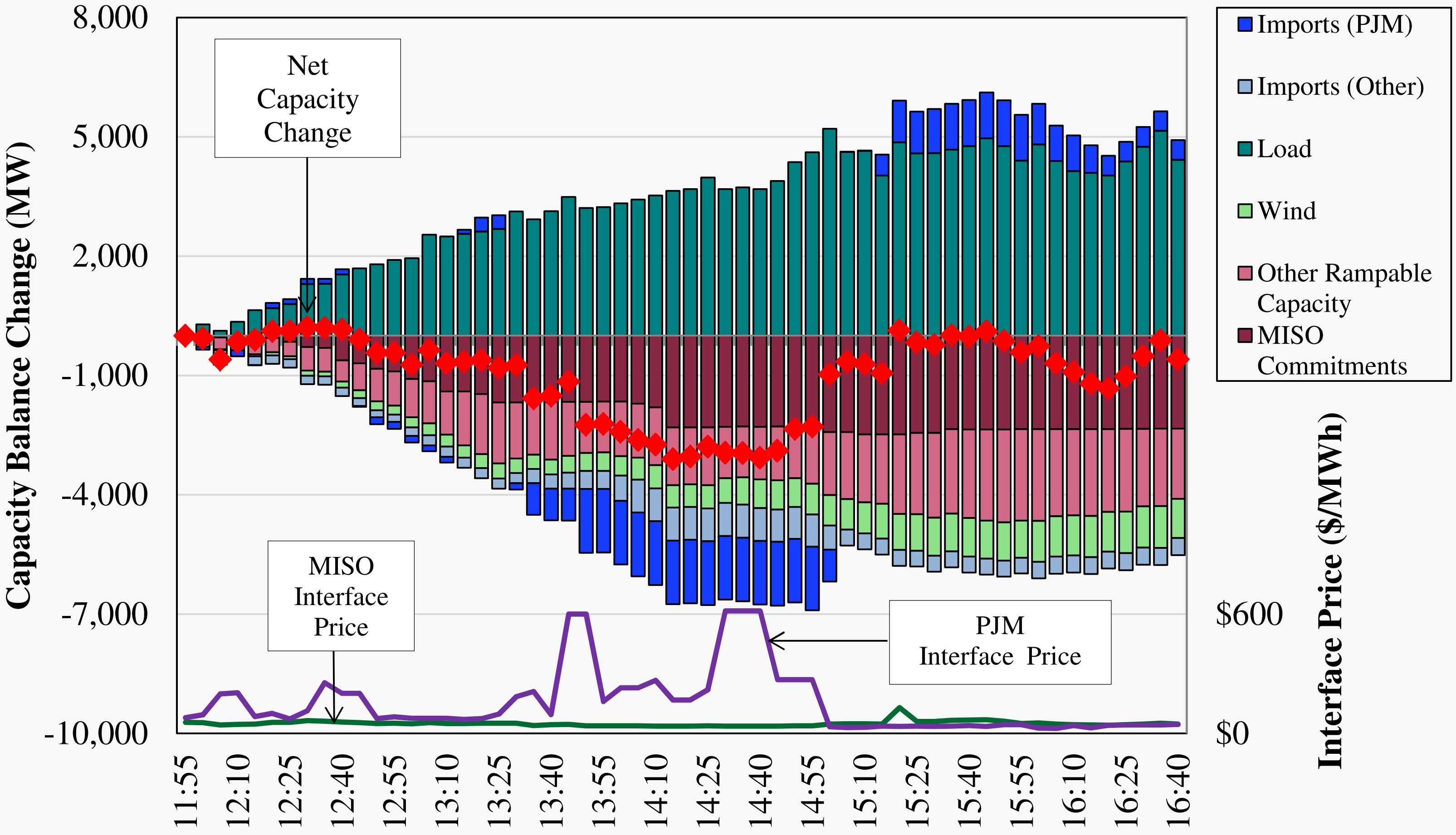
July 15

- Events on this day were the inverse of those that occurred on several days in 2012, when large swings in NSI precipitated shortages in MISO and periods of very higher energy prices.
  - ✓ On this day, shifts in NSI *into* MISO (i.e., away from PJM) led to periods of reserve shortages and high prices in PJM.
  - ✓ It also contributed to very low energy prices in MISO, which increased the RSG payments MISO had to pay to the large quantity of generators committed that day.

July 17

- Prices rose sharply between 12:30 and 13:30 as load grew rapidly and NSI shifted toward PJM by up to roughly 600 MW.
  - ✓ In response to the high MISO prices, NSI shifted toward MISO by roughly 1,400 MW from 13:15 to 14:15 and net imports on other interfaces began to grow.
- These shifts, together with a) MISO's commitments, b) the fact that load stopped growing after 13:30, and c) a modest increase in wind output caused MISO's energy prices to remain relatively low ($50-$60 per MWh).
  - ✓ PJM prices were elevated for much of the period, partly because of the large NSI shift toward MISO, and NSI did not respond.

July 15, 11:55 to 16:40



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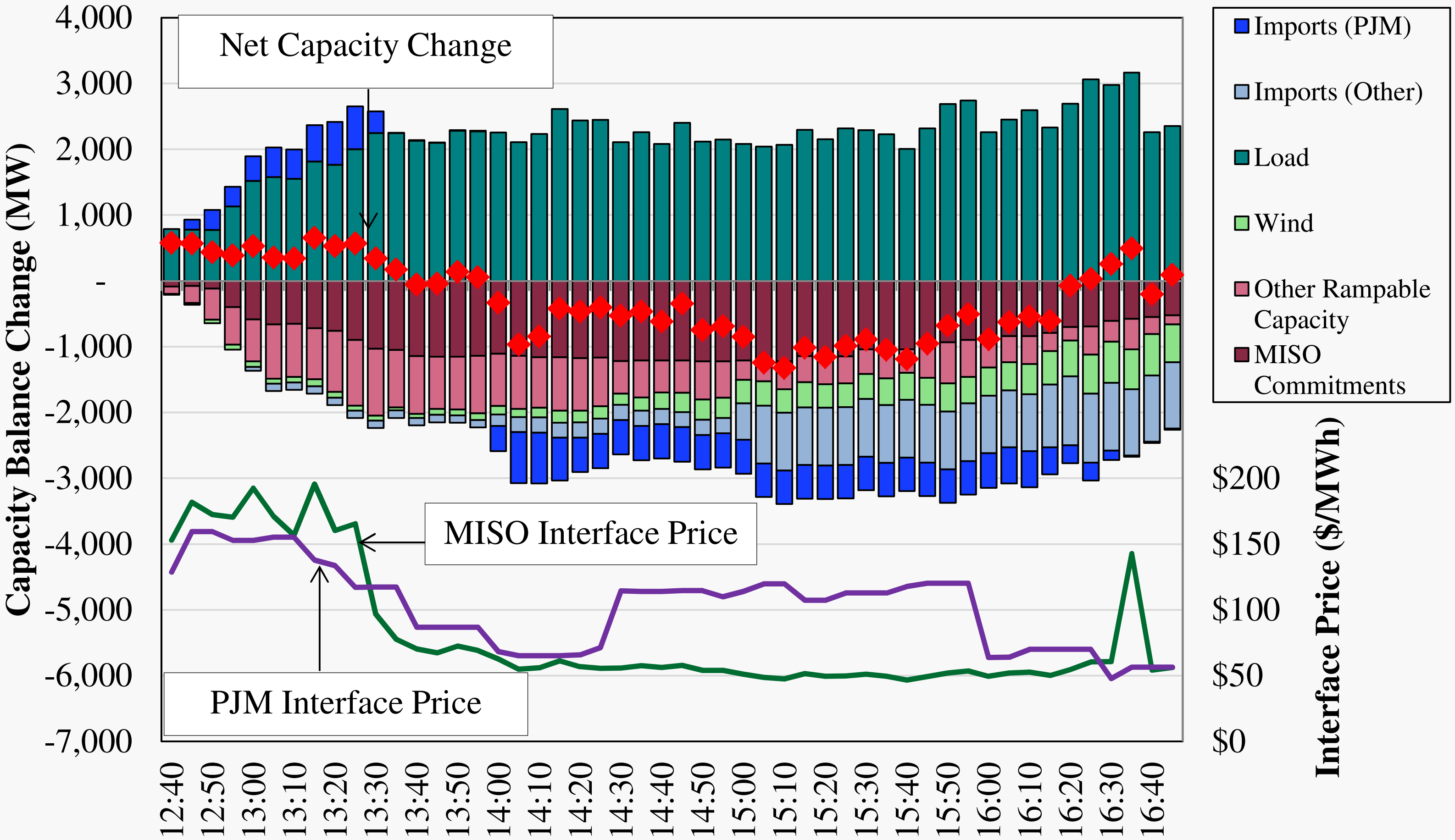
July 17, 12:40 to 16:40



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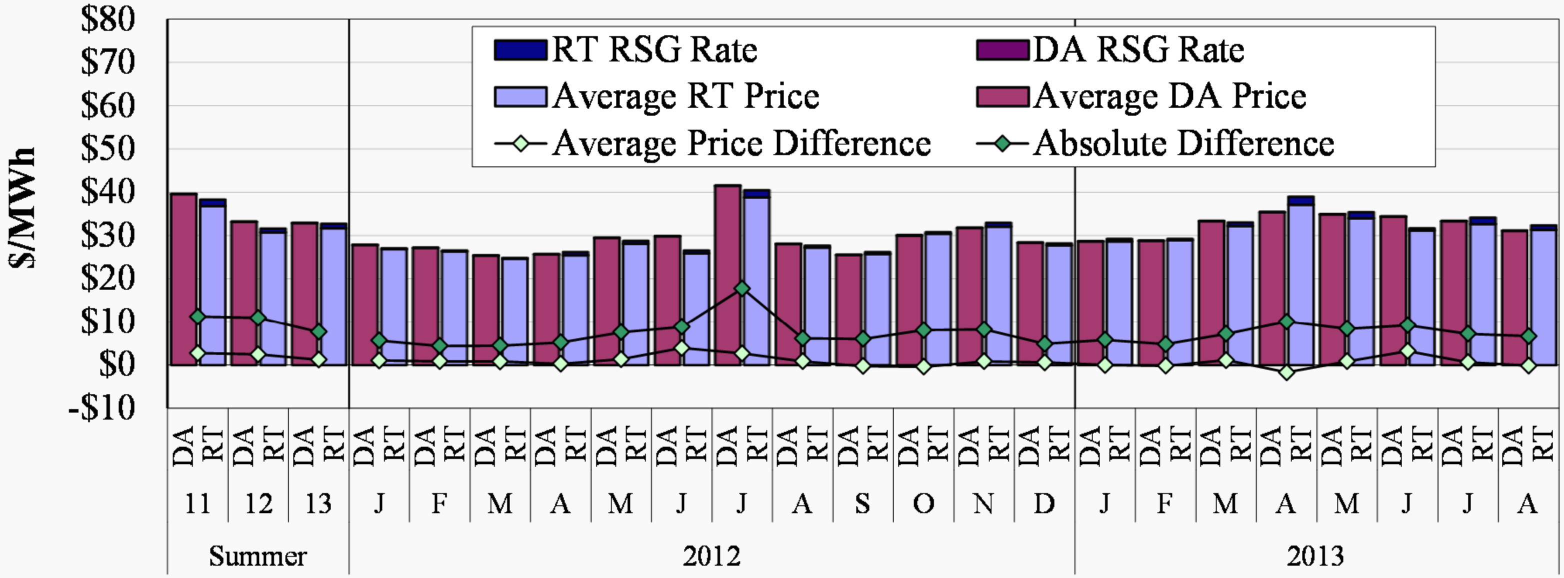
Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub (the inset table shows other locations), along with average price differences.
  - ✓ The inclusion of real-time RSG costs, which averaged $1.03 per MWh, resulted in modest real-time premiums at all hubs except Indiana.
- Premiums were greatest in June because:
  - ✓ A low day-ahead limit on a constraint impacted by a PJM FFE calculation error, causing it to bind harder than it should have.
  - ✓ Negative prices for several hours on one day in June were not anticipated.
- In August, significant outage-related congestion in the West was also unanticipated.
- Price volatility (as measured by the absolute price difference metric) declined to an average of $7.65 per interval, 30 percent lower than last summer.

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



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

Cin/Ind Hub	7	8	4	4	3	3	1	5	15	7	3	-1	-1	3	2	0	-1	3	-5	2	10	2	0
Michigan Hub	5	6	2	5	2	-1	5	5	7	7	3	4	1	3	1	1	2	5	-5	1	7	-1	0
Minnesota Hub	0	1	-2	3	-2	2	-12	-6	0	2	2	-7	3	-8	-1	3	4	4	-7	7	2	-2	-5
WUMS Area	4	1	1	3	0	4	0	-1	-1	2	3	-4	0	0	3	1	4	4	-5	1	6	2	-4

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

Cin/Ind Hub	3	5	1	3	2	2	-2	3	12	3	1	-2	-2	0	1	-2	-2	1	-9	-1	9	-2	-3
Michigan Hub	1	3	-1	4	2	-2	2	3	5	4	2	3	0	1	-1	-1	1	3	-10	-3	5	-5	-3
Minnesota Hub	-5	-1	-5	2	-2	1	-14	-8	-3	-2	1	-8	2	-10	-2	1	3	1	-11	2	0	-6	-7
WUMS Area	0	-1	-2	2	-1	3	-3	-3	-3	-2	1	-6	-1	-3	1	-1	3	1	-9	-3	4	-2	-6

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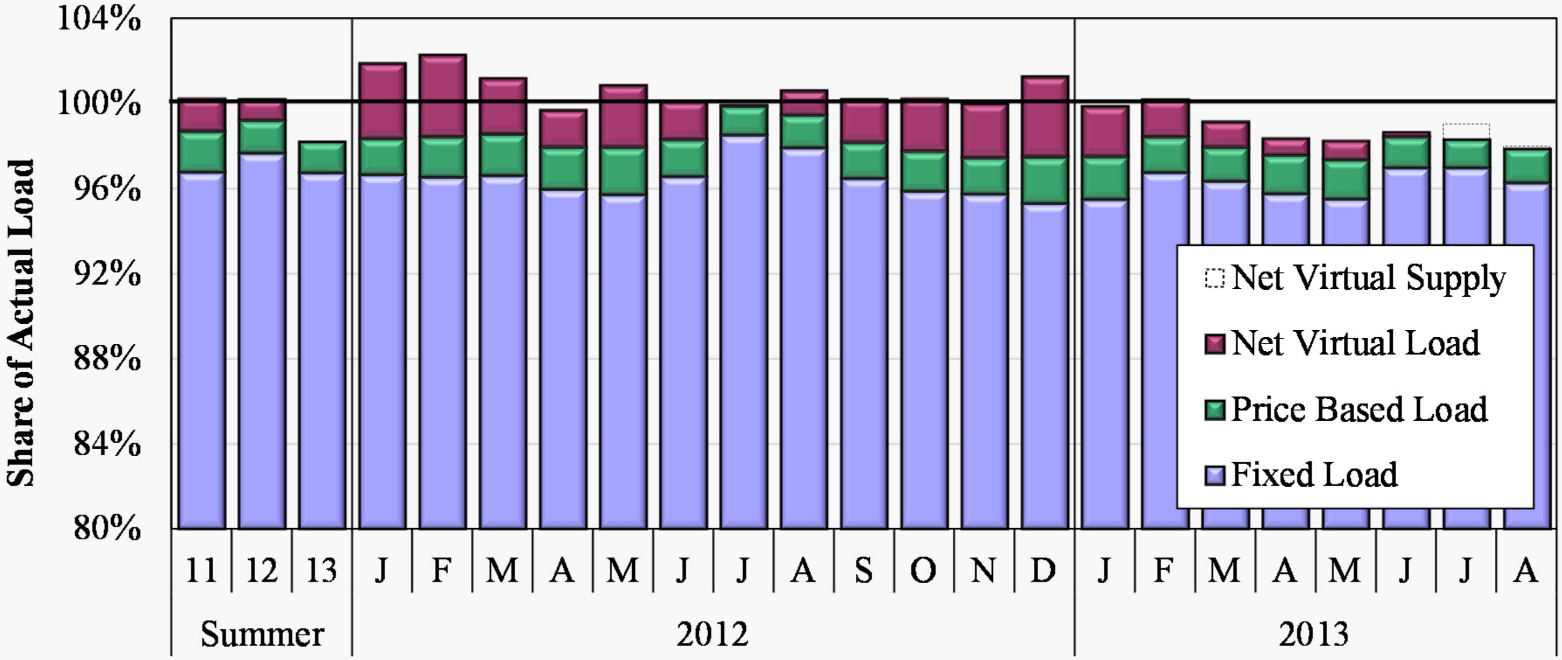
Day-Ahead Load Scheduling

- 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 to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- For the quarter, load scheduling averaged 98.9 percent, down from 99.8 percent last summer. During all hours it declined to 98.3 percent.
  - ✓ One reason for the under scheduling is that net imports continue to increase significantly from day ahead to real time, rising by an average of 520 MW during this summer.
  - ✓ Under-scheduling of wind in the day-ahead averaged less than 100 MW (3 percent) this summer, a substantial improvement from last summer when it was under-scheduled by over 350 MW (8 percent).

Day-Ahead Peak Hour Load Scheduling
Summer 2011–2013



Share of Actual Load (%)

	Summer			2012												2013							
	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A
All Hours	100.6	99.8	98.9	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4	100.1	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9
Peak Hour	100.2	100.2	98.3	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6	100.2	100.2	100.0	101.3	99.9	100.2	99.2	98.4	98.3	98.6	98.3	97.9

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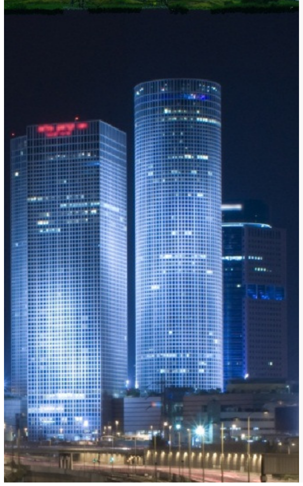


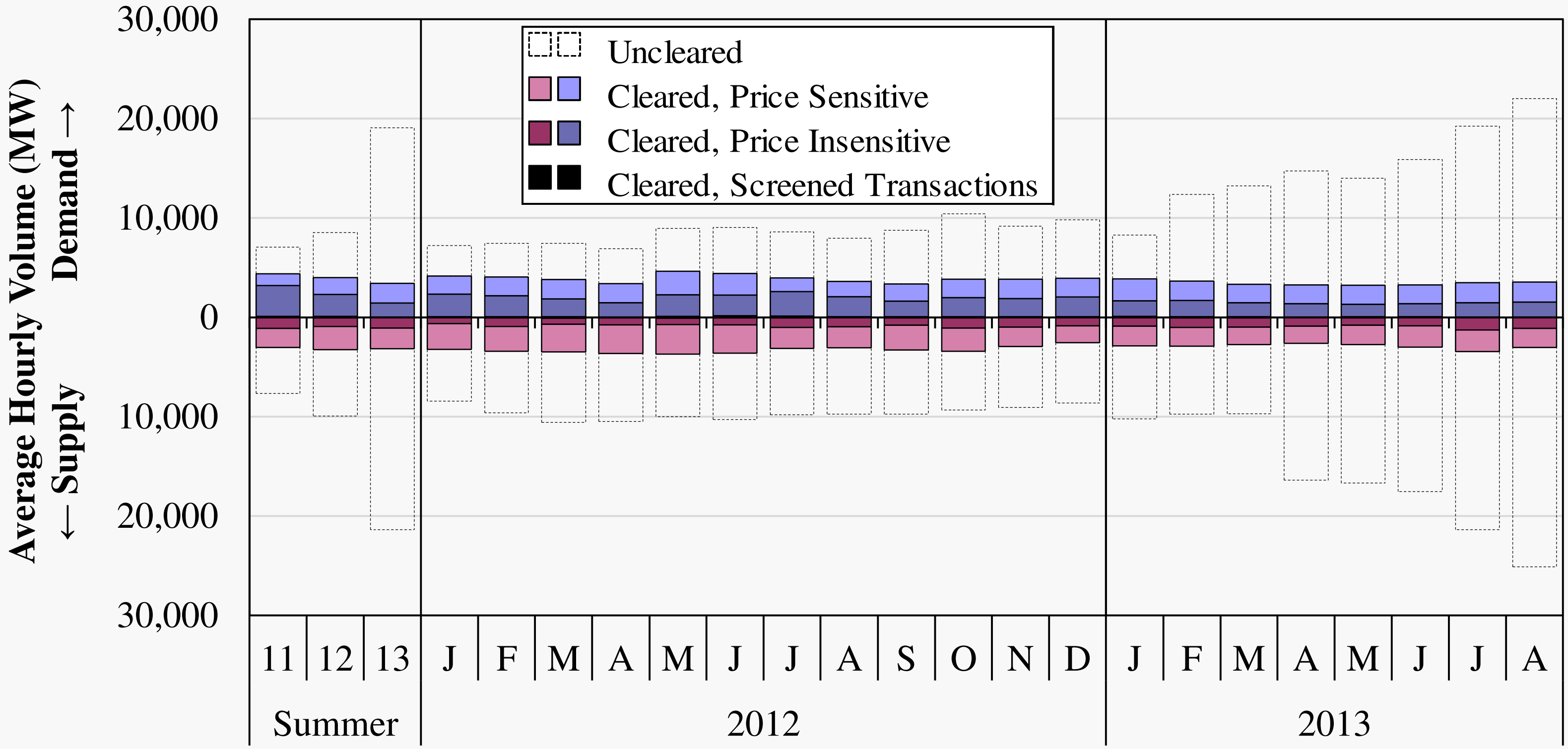
Virtual Load and Supply in the Day-Ahead Market

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

Virtual Load and Supply in the Day-Ahead Market

- The figure shows that cleared volumes declined 9 percent from last summer to 6.6 GW.
  - ✓ Cleared demand averaged 3.4 GW and declined faster (by 14 percent) than supply, which declined 3 percent to 3.1 GW.
- Offered volumes more than doubled to 40.4 GW. Nearly all of this rise, which began in February, consists of price-sensitive volumes submitted by physical participants or their subsidiaries. These volumes rarely clear and therefore do not pose a concern.
- Price-insensitive volumes declined from 44 percent last summer to 39 percent.
  - ✓ Changes to the RSG allocation in April 2011 reduced the allocation for participants taking balanced positions, which can be ensured by offering price-insensitively.
- Most of these price-insensitive volumes would benefit from a virtual spread product, which would allow participants to more efficiently arbitrage locational differences.
  - ✓ Bids and offers would clear only when the congestion price difference between two selected points exceeds a specific price.
  - ✓ We recommend such a product in *our 2012 State of the Market Report*, and MISO the benefits and feasibility of this type of product.
- The share of Screened Transactions declined to just 79 MW per hour, or 1.2 percent.
  - ✓ We investigate these closely and did not find any trading that raised concerns.

Virtual Volumes
Summer 2011–2013



Percent Screened

Demand	2.2	3.0	1.7	1.5	2.0	1.7	1.6	2.1	4.0	3.1	1.8	2.1	2.2	2.1	2.1	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5
Supply	1.1	1.2	0.7	0.9	1.2	2.4	1.9	2.2	1.4	1.2	1.0	1.2	1.3	1.0	1.4	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5
Total	1.7	2.2	1.2	1.2	1.6	2.0	1.7	2.2	2.9	2.3	1.4	1.6	1.8	1.6	1.8	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0

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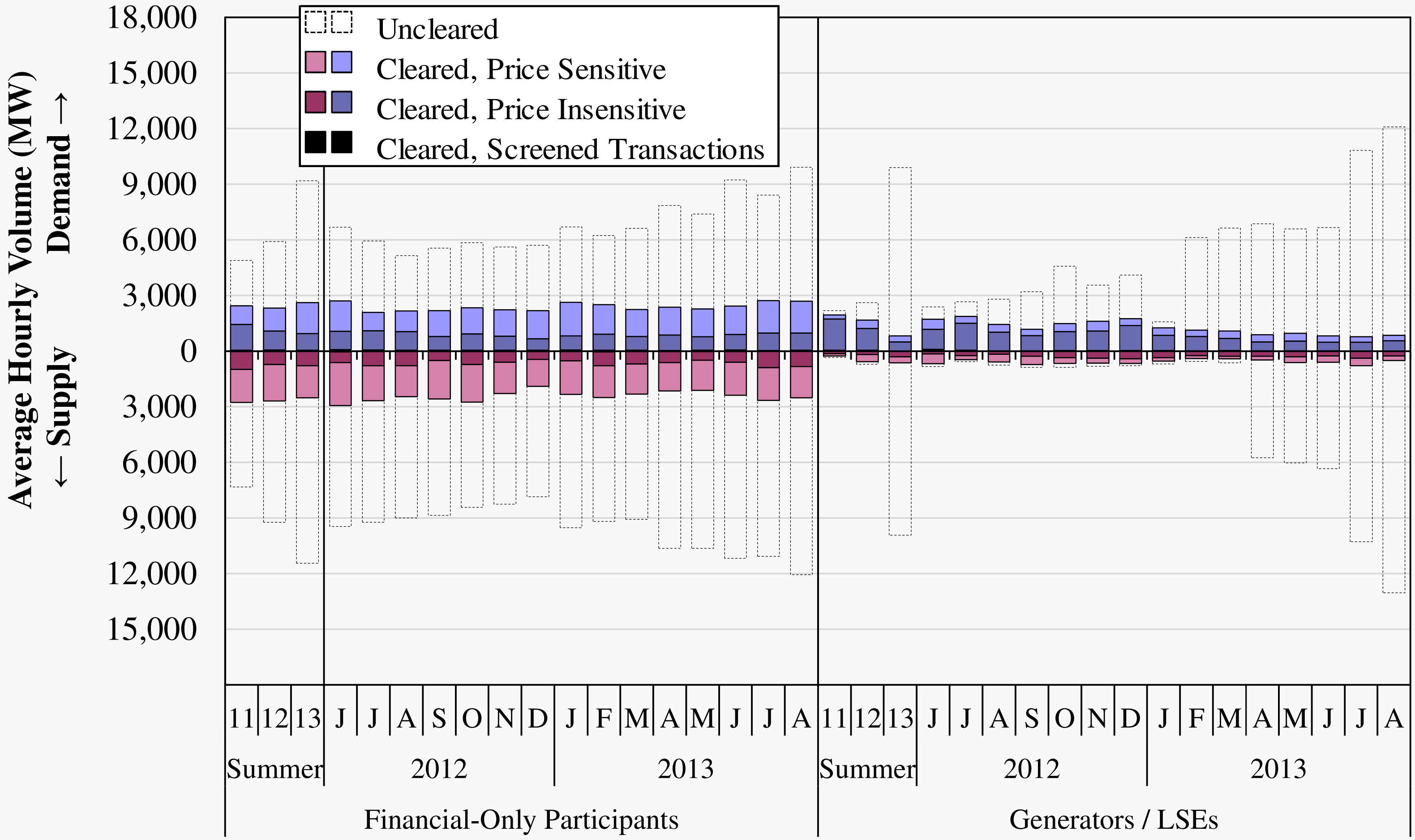
Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by two types of market participants: physical participants and financial-only participants.
  - ✓ Physical participants generally have different motivations to clear volumes (e.g. hedging physical obligations) than financial-only participants (e.g. price arbitrage).
- The share of virtual volumes cleared by financial-only participants rose from 69 percent last summer to 78 percent this summer.
  - ✓ Virtual demand in particular is now cleared predominantly by financial-only participants. Demand cleared by physical participants declined 51 percent.
- The increase in uncleared offered volumes by a small number of physical participants, which began with virtual demand in February, averaged over 10 GW this summer.
  - ✓ Very little of this quantity clears since it is offered at very high prices (in the case of supply) or very low prices (demand). This activity does not raise competitive concerns.
- The share of volumes that are price-sensitive remains much higher for financial-only participants (66 percent) than those of physical participants (44 percent).
  - ✓ Physical participant volumes, however, have become more price sensitive on average because price-insensitive volumes fell.

Virtual Load and Supply by Participant Type
Summer 2011–2013



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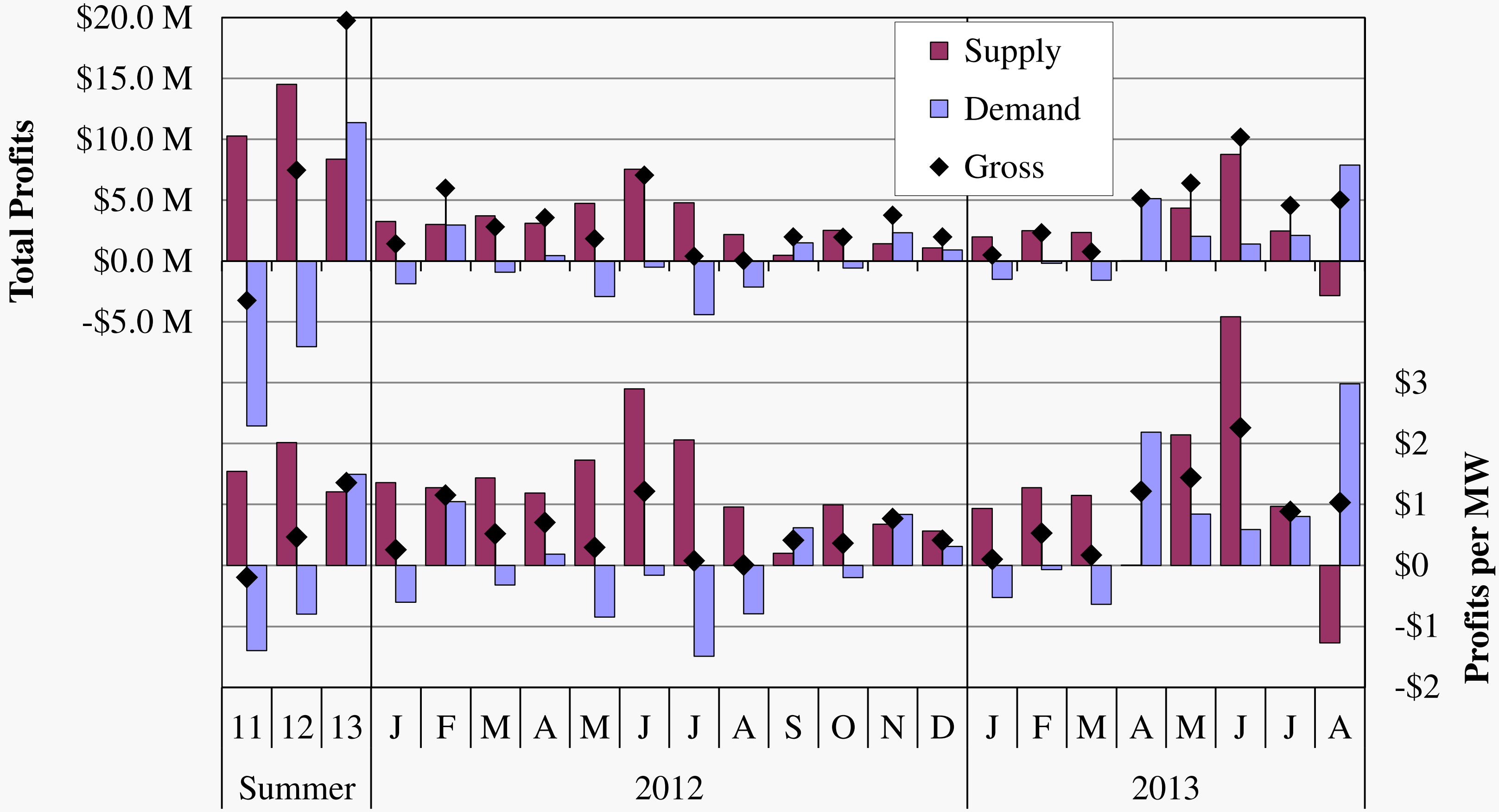
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross virtual profits in summer totaled $19.7 million, up from $7.4 million last summer.
- On a per-MW basis, profitability rose from $0.47 last summer to $1.36.
  - ✓ Supply and demand were both profitable at $1.21 per MW and $1.50, respectively.
- In August, demand was unusually profitable ($2.98 per MW) due to the real-time premium at many locations, including several that were near volatile constraints.
  - ✓ One location in the Central region saw repeated real-time price spikes. Demand there averaged $120 per MW for the quarter, while supply averaged $-140 per MW.
  - ✓ At a nearby wind location, demand earned $2.3 million ($32 per MW), mostly in June.
- These margins exclude CMC and DDC charges assessed to net harming deviations.
  - ✓ Including DDC charges, which averaged $1.03 per MW, to net virtual supply made it only slightly profitable.
- Virtual transactions by financial participants continue to be profitable and generally improve price convergence overall.
  - ✓ Profitability of these transactions rose from $1.03 per MW last summer to $1.60.
  - ✓ For physical participants, profitability improved from $-0.80 per MW to $0.51.

Virtual Profitability
Summer 2011–2013

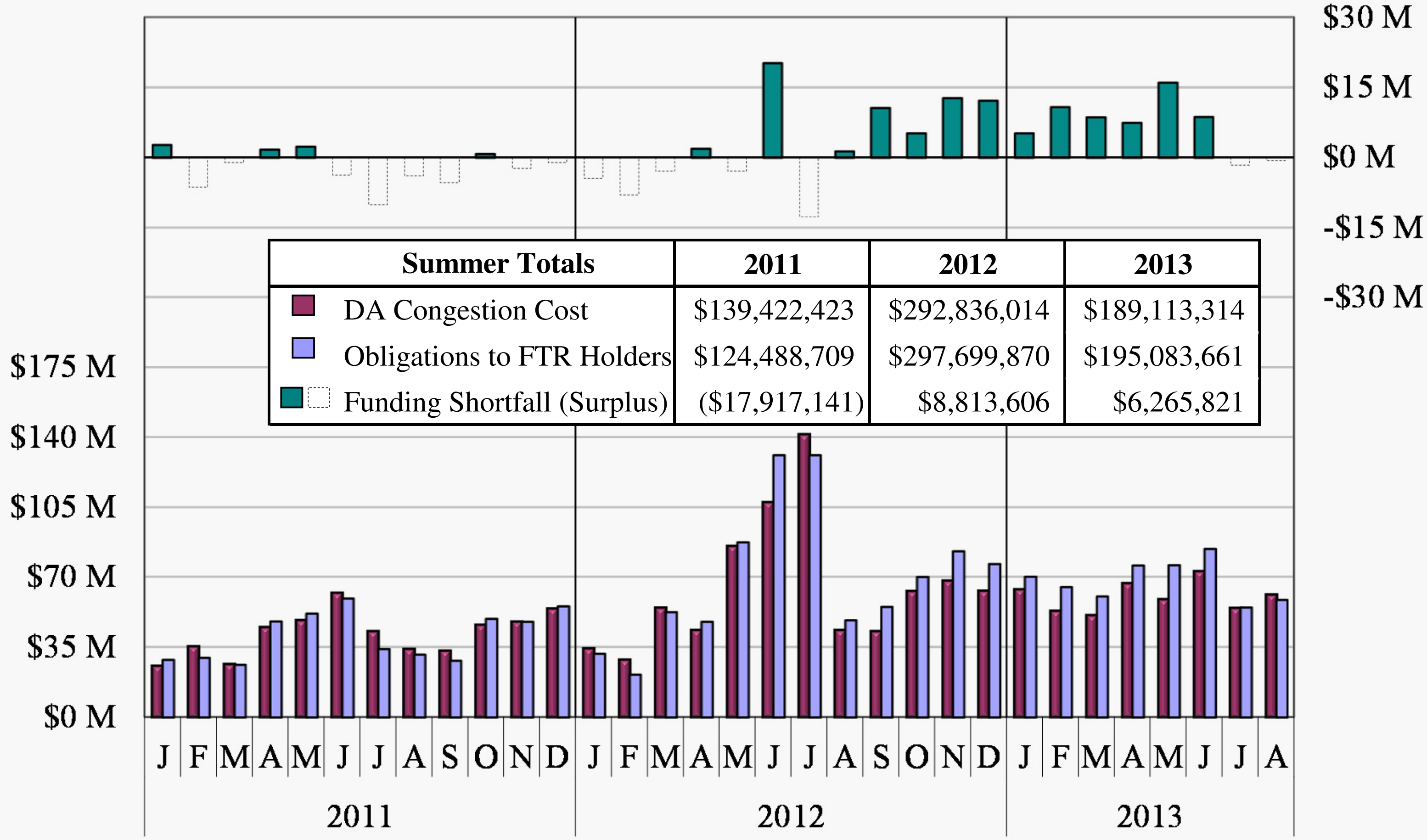


POTOMAC ECONOMICS

Day-Ahead Congestion and Obligations to FTR Holders

- FTR holders are entitled to the day-ahead congestion costs that arise between particular locations in MISO, which allows them to manage day-ahead price risk.
  - ✓ MISO collects day-ahead congestion from loads and pays it out via FTRs.
  - ✓ Day-ahead congestion declined 35 percent from last summer to $189 million.
- The next figure shows day-ahead congestion, FTR obligations and FTR shortfalls.
  - ✓ Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- FTR obligations were underfunded by 1.2 percent this summer, the bulk of which was attributable to a single constraint in the Central region in June.
  - ✓ Underfunding on this constraint, which was impacted by a PJM FFE calculation error, exceeded $6 million and also caused substantial amounts of ECF (not counted added to FTR underfunding) and erroneous JOA payments.
- Excluding this constraint, FTRs were fully funded this summer.
  - ✓ MISO continues to evaluate and improve FTR modeling assumptions in its annual and monthly auctions.

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



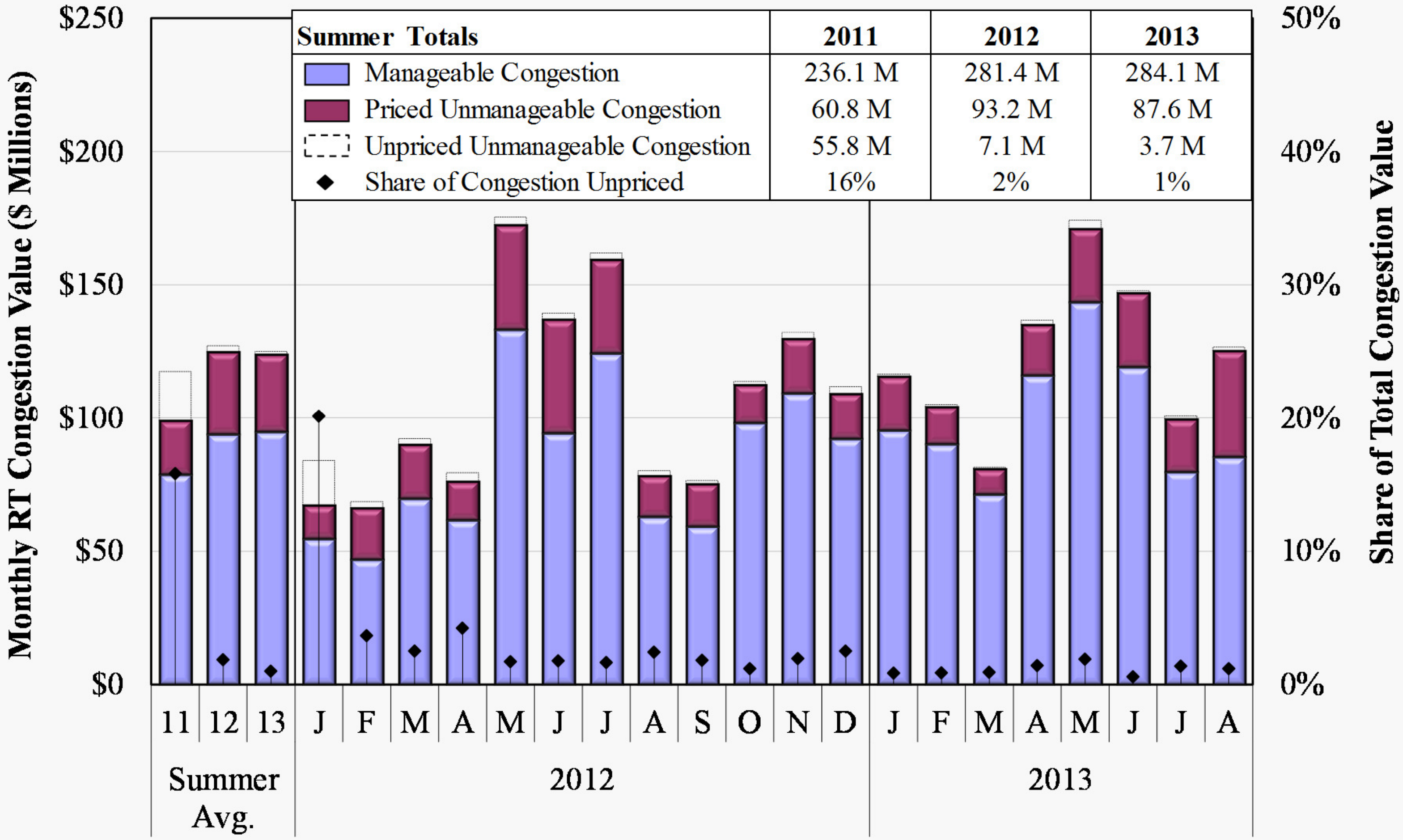
Summer Totals	2011	2012	2013
DA Congestion Cost	$139,422,423	$292,836,014	$189,113,314
Obligations to FTR Holders	$124,488,709	$297,699,870	$195,083,661
Funding Shortfall (Surplus)	($17,917,141)	$8,813,606	$6,265,821

POTOMAC ECONOMICS

Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on MISO-managed internal and market-to-market constraints (the figure excludes external constraints).
  - ✓ Real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ This is higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO's transmission capability.
  - ✓ The figure separately shows congestion on those constraints that are temporarily violated (i.e., the congestion is considered "unmanageable" in the 5-minute dispatch).
- The value of real-time congestion declined 1 percent from last summer to $371.6 million. It was 4 percent lower than in the spring.
  - ✓ It was highest in June, when scheduled transmission outages contributed to significant congestion in the Central region.
  - ✓ Constraint relaxation, which is still used on external and M2M constraints, eliminated 1 percent of congestion this quarter.
- MISO is set to extend the deactivation of the transmission "deadband" algorithm on Oct 1. This should improve congestion manageability and reduce shadow price volatility.

Value of Real-Time Congestion
Summer 2011–2013

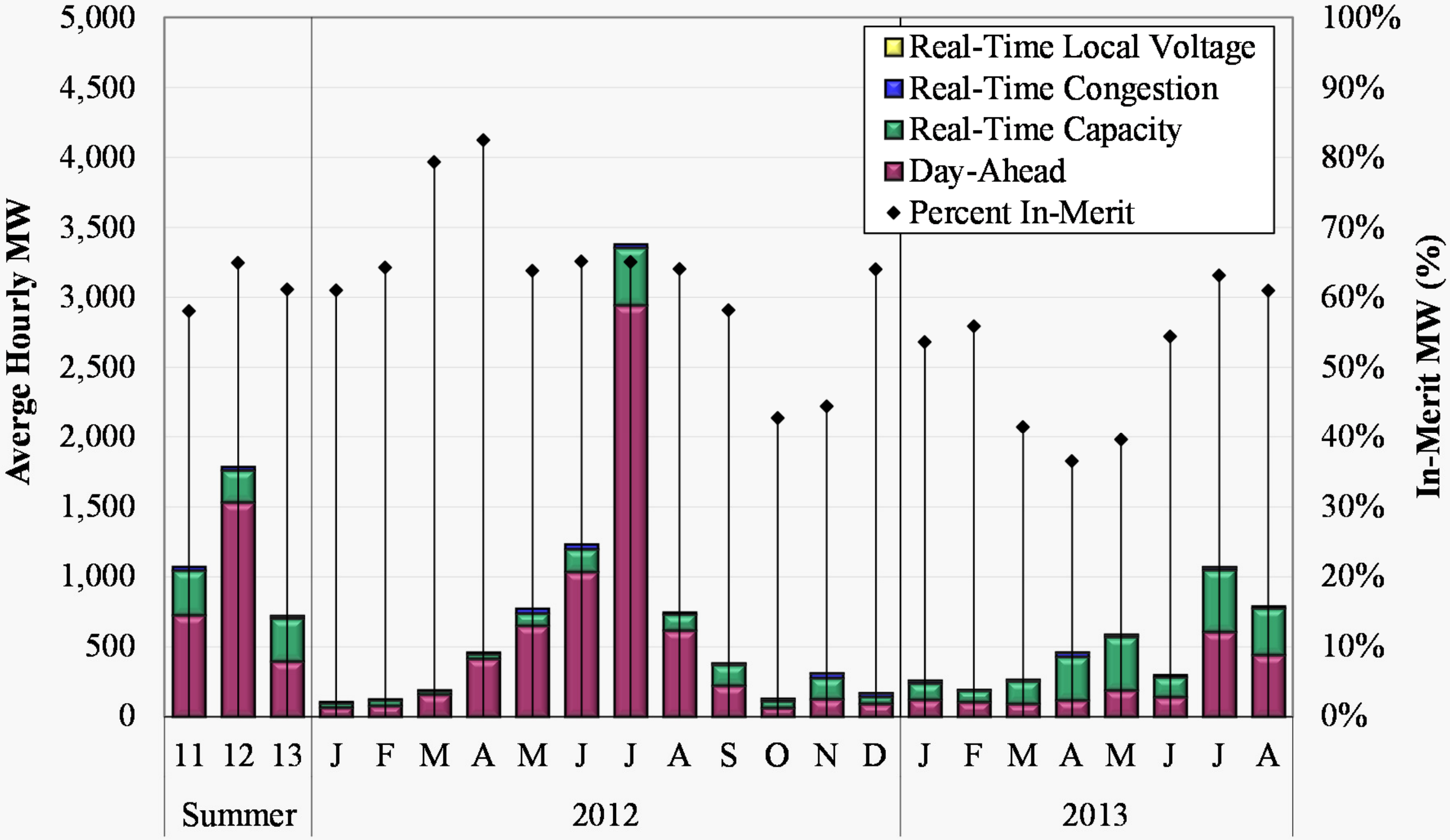


POTOMAC ECONOMICS

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.
- Total peaking unit dispatch quantities declined nearly 60 percent from last summer to an average of 720 MW per hour.
  - ✓ Day-ahead committed peaking unit output declined the (by 74 percent) because of higher gas prices and lower loads.
  - ✓ Commitments to satisfy real-time capacity needs rose 34 percent to an average of 306 MW partly because day-ahead scheduled load was slightly lower and wind output were more fully scheduled day-ahead.
  - ✓ Congestion and VLR needs again comprised a very small portion of total peaking unit dispatch.
  - ✓ Most real-time dispatch needs (82 percent) were identified via the LAC process.
- Just over 60 percent of dispatch quantities were in-merit this summer. This is comparable to prior summers.
  - ✓ MISO’s Extended LMP Initiative, expected to be implemented in early 2014, will allow peaking resources to set prices more frequently.

Peaking Resource Dispatch
Summer 2011–2013

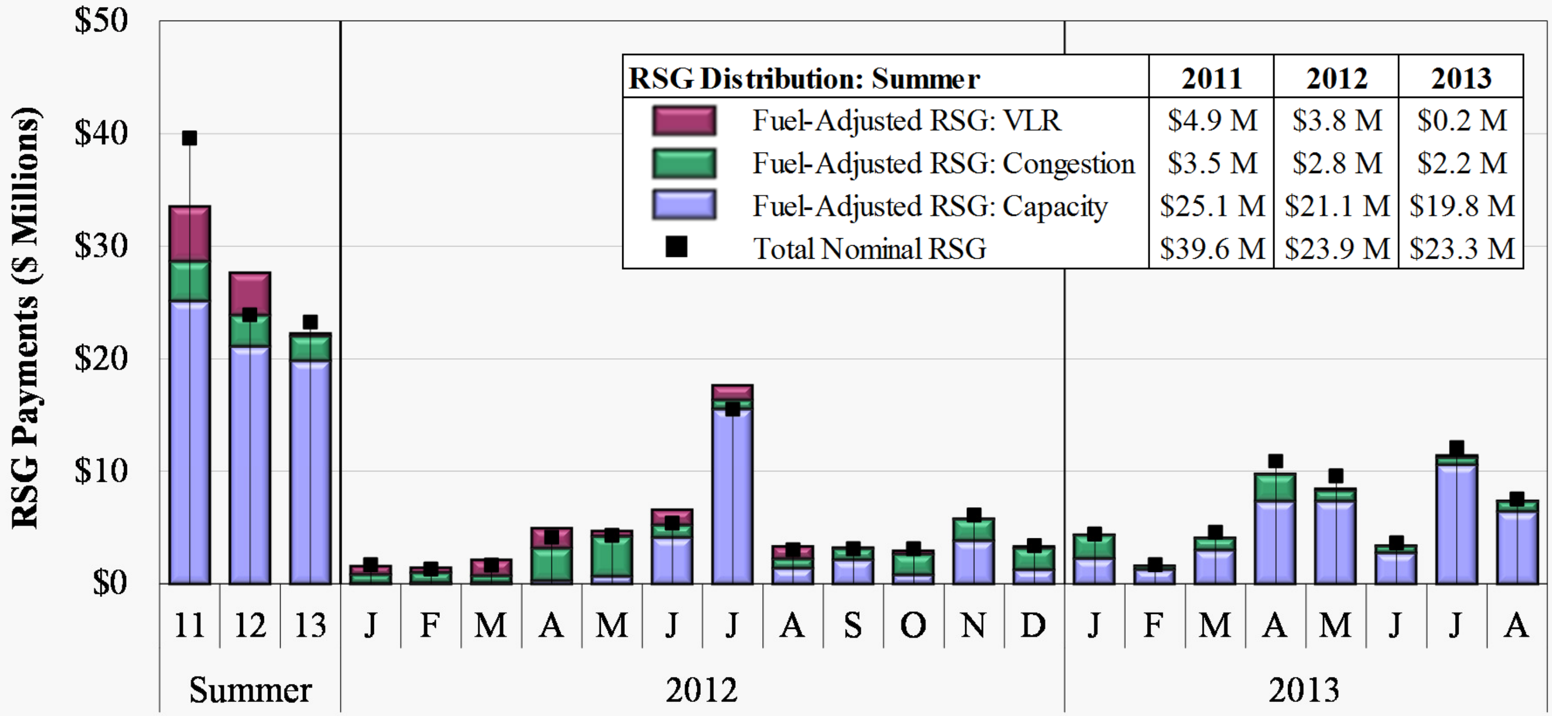


POTOMAC ECONOMICS

Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets, respectively.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices (adjusting values to correspond to the average fuel prices over the period shown).
- Nominal real-time RSG costs declined 2.5 percent from last summer to $23.3 million.
  - ✓ Adjusting for the rise in fuel prices, RSG costs declined 19 percent.
  - ✓ VLR needs generated nearly $4 million of real-time RSG last summer, compared to just $248,000 this summer. Such commitments are now made mostly day-ahead.
- In fuel-adjusted terms, payments for capacity declined 6 percent to $19.8 million.
  - ✓ Over $7 million of this accrued on July 14 to 20, when loads were very high. Higher loads in 2012 contributed to a much larger number of these types of events.
  - ✓ Nearly all of these were paid to units committed through the LAC process.
- Congestion-related payments declined by 20 percent to $2.2 million.
  - ✓ One-third of payments went to a set of oil-fired units in Iowa that were committed for constraints impacted by nearby outages, particularly on August 19, 30 and 31.
- The second figure shows that day-ahead RSG payments declined 8 percent from last summer, despite higher gas prices and increased VLR commitment.
  - ✓ In fuel-adjusted terms they declined 30 percent.

Real-Time RSG Payments
Summer 2011–2013

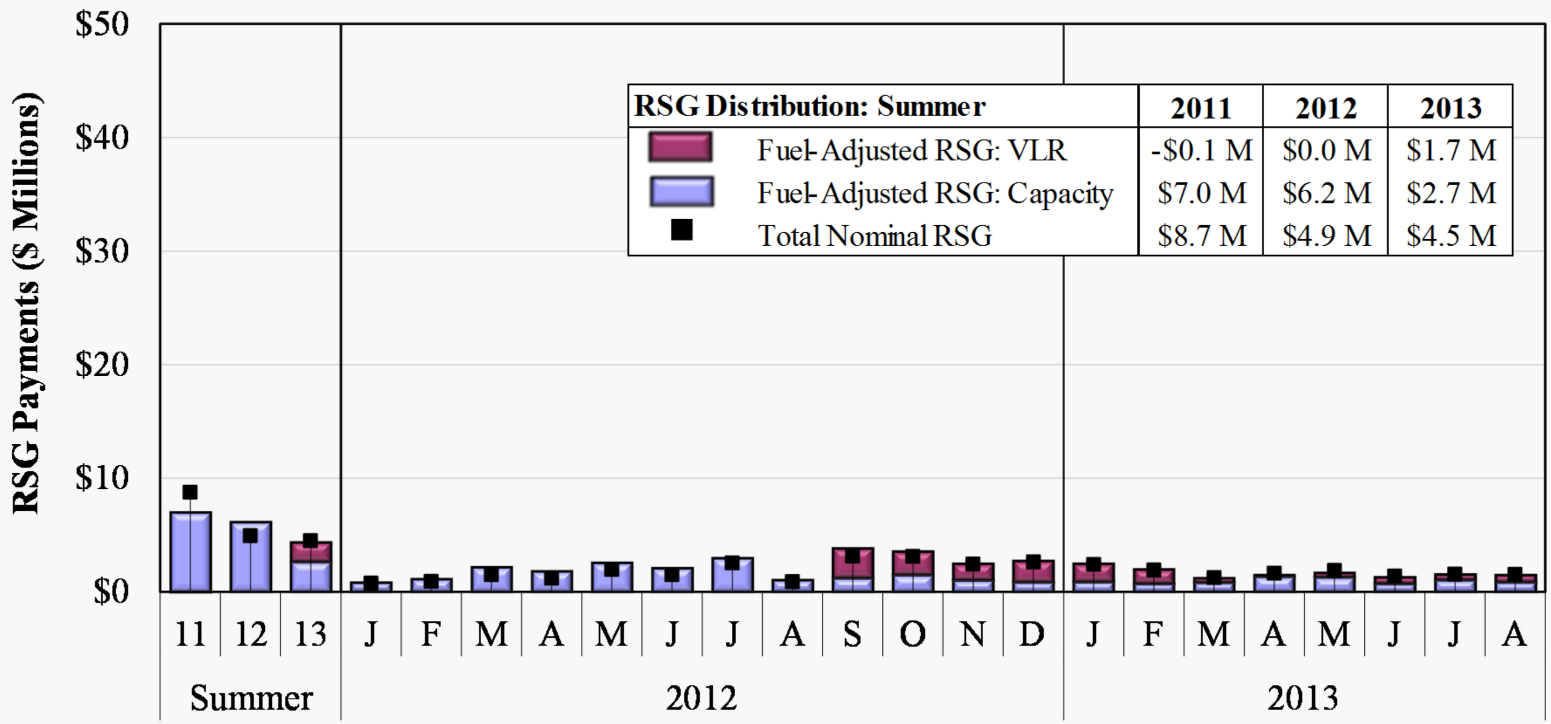


Share of Real-Time RSG Costs by Unit Type (%)

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

POTOMAC ECONOMICS

Day-Ahead RSG Payments
Summer 2011–2013



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

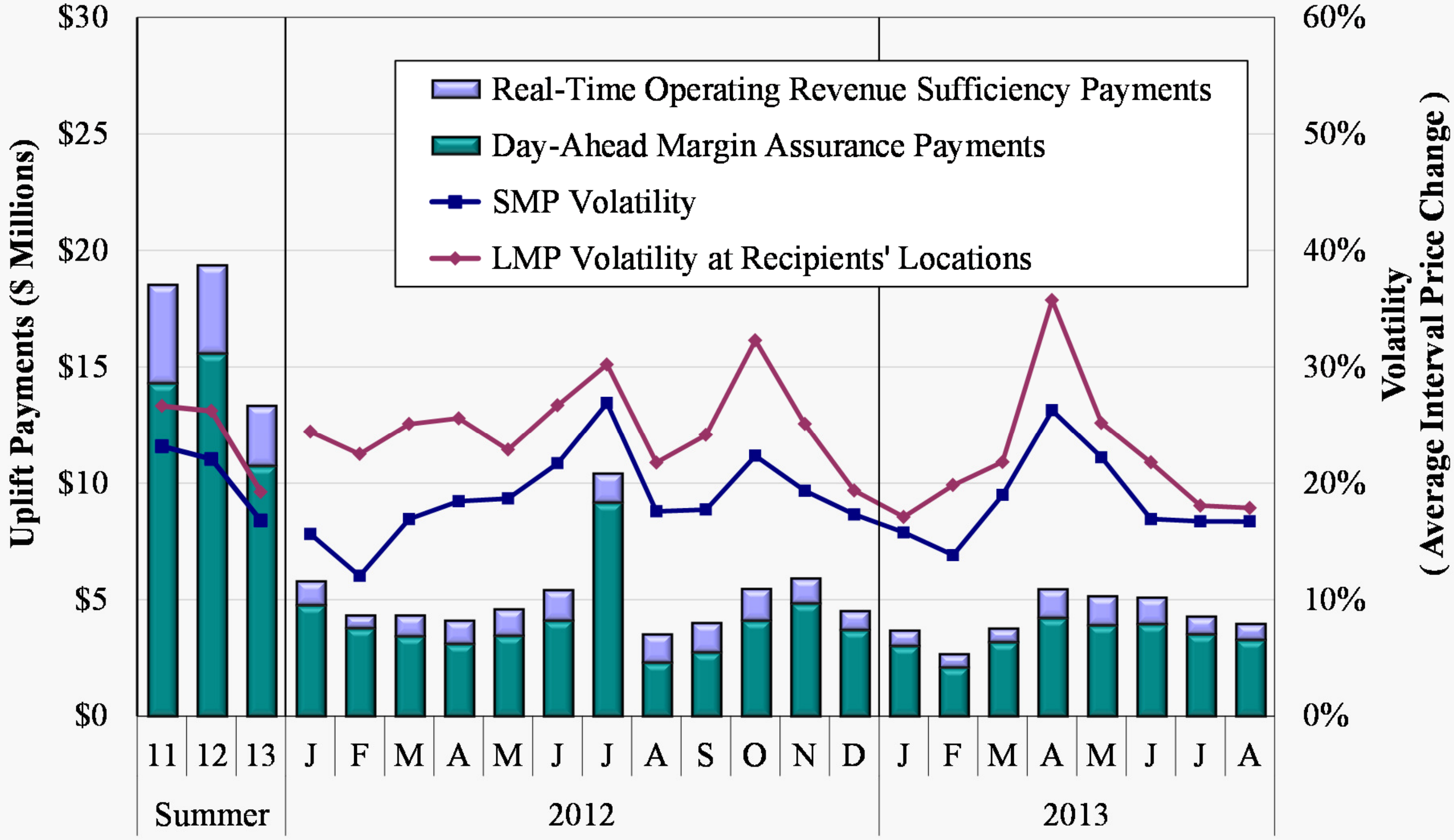
Peaker	4	4	1	2	1	2	8	21	16	62	36	9	1	2	6	1	0	2	11	6	7	10	18
Non-Peaker	96	96	99	98	99	98	92	79	84	38	64	91	99	98	94	99	100	98	89	94	93	90	82

POTOMAC ECONOMICS

Price Volatility Make Whole Payments

- The next chart shows two types of Price Volatility Make Whole Payments (PVMWP), which improve incentives for suppliers to follow dispatch instructions.
- DAMAP and RTORSGP both declined 31 percent from last summer to $10.8 and $2.6 million, respectively.
  - ✓ DAMAP this July were 62 percent lower than last July because of far fewer price spikes (mainly associated with shortages).
  - ✓ Large relatively flexible coal units in the East and Central regions continue to be the largest recipients of DAMAP, predominantly during ramping hours.
- The lines on the chart show two measures of price volatility: one based on the System Marginal Price (SMP) and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility, as expected, and increased volatility leads to higher payments to flexible suppliers.
  - ✓ SMP and LMP volatility both declined by approximately 25 percent from last summer.
- We recommended several improvements to PVMWP settlement eligibility criteria and calculations in this year's *State of the Market Report*.
  - ✓ MISO is scheduled to file Tariff changes to these criteria in the near future.

Price Volatility Make Whole Payments Summer 2011–2013

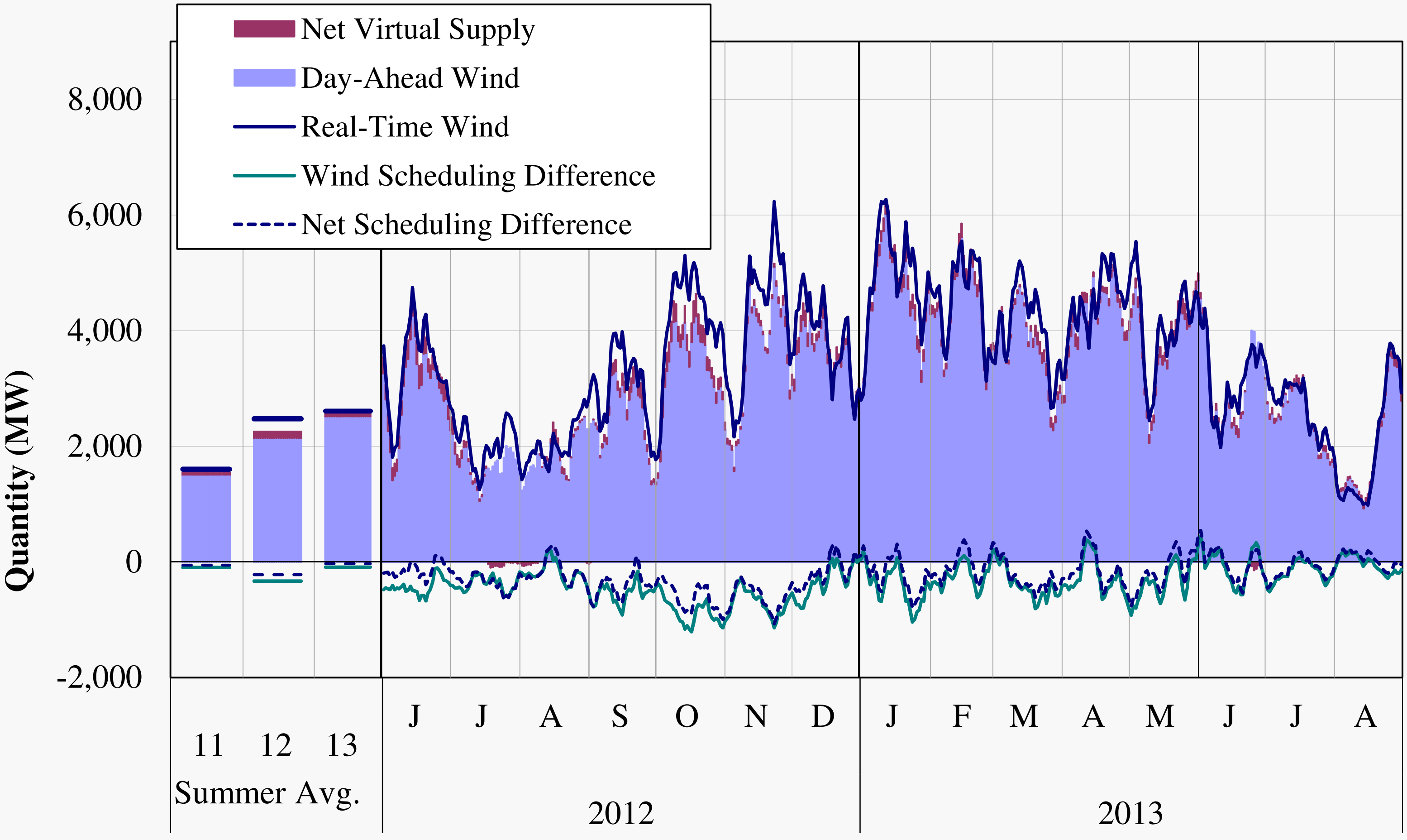


POTOMAC ECONOMICS

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

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Attractive wind profiles in the West Region, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind resources.
- Real-time wind output rose 1 percent from last summer to 2.5 GW, and comprised 4.6 percent of total generation (up from 4.1 percent last summer).
  - ✓ Nameplate capacity over the same period increased 3 percent to 12.2 GW -- 8.8 percent of total capacity.
  - ✓ Wind output is far lower in summer than it is in shoulder months.
- Under-scheduling of this wind output in the day-ahead improved this summer, averaging 85 MW compared to 331 MW last summer.
  - ✓ This increase in scheduling may be attributable to the full implementation of the dispatchable intermittant resource (DIR) provisions.
- Because underscheduling quantities fell, incentives fell to schedule virtual supply at wind locations.
  - ✓ Only 60 MW of net virtual supply cleared at wind locations this summer.
  - ✓ Its profitability declined from $2.83 per MWh last summer to just $0.41.

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

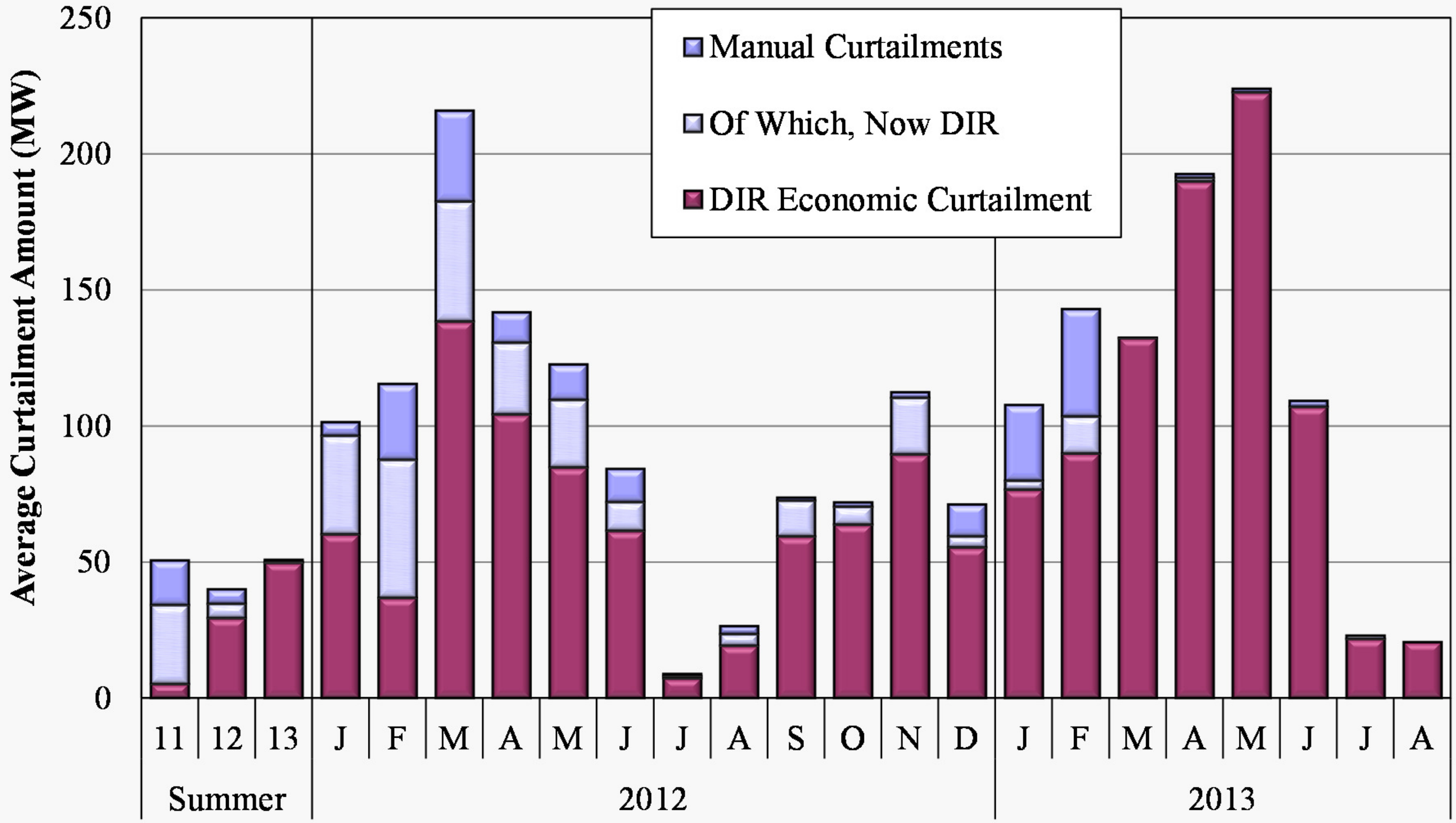


POTOMAC ECONOMICS

Wind Curtailments

- Nearly 80 percent of wind capacity in the MISO footprint is registered as DIR.
  - ✓ Although not all of these are yet able to respond to MISO dispatch instructions, they have substantially improved congestion management and pricing.
- MISO must still manage the ramp demands related to wind volatility, which rose to 70 MW per interval (based on units' forecasted maximums).
  - ✓ In addition, DIRs this summer were cumulatively deficient (below their set point instruction) by an average of 77 MW per interval.
- The following figure shows that economic DIR curtailments have now almost fully replaced manual curtailments as the primary means of controlling wind output.
  - ✓ Manual curtailments averaged less than 1 MW, nearly all of which were of one wind farm in the Central region in June.
  - ✓ Economic curtailment of wind resources averaged 50 MW this summer, up from 29 MW last summer.
- The value of DIR is growing because as total wind output increases, MISO is experiencing increased congestion on constraints directly affected by the wind.

Wind Curtailments
Summer 2011–2013

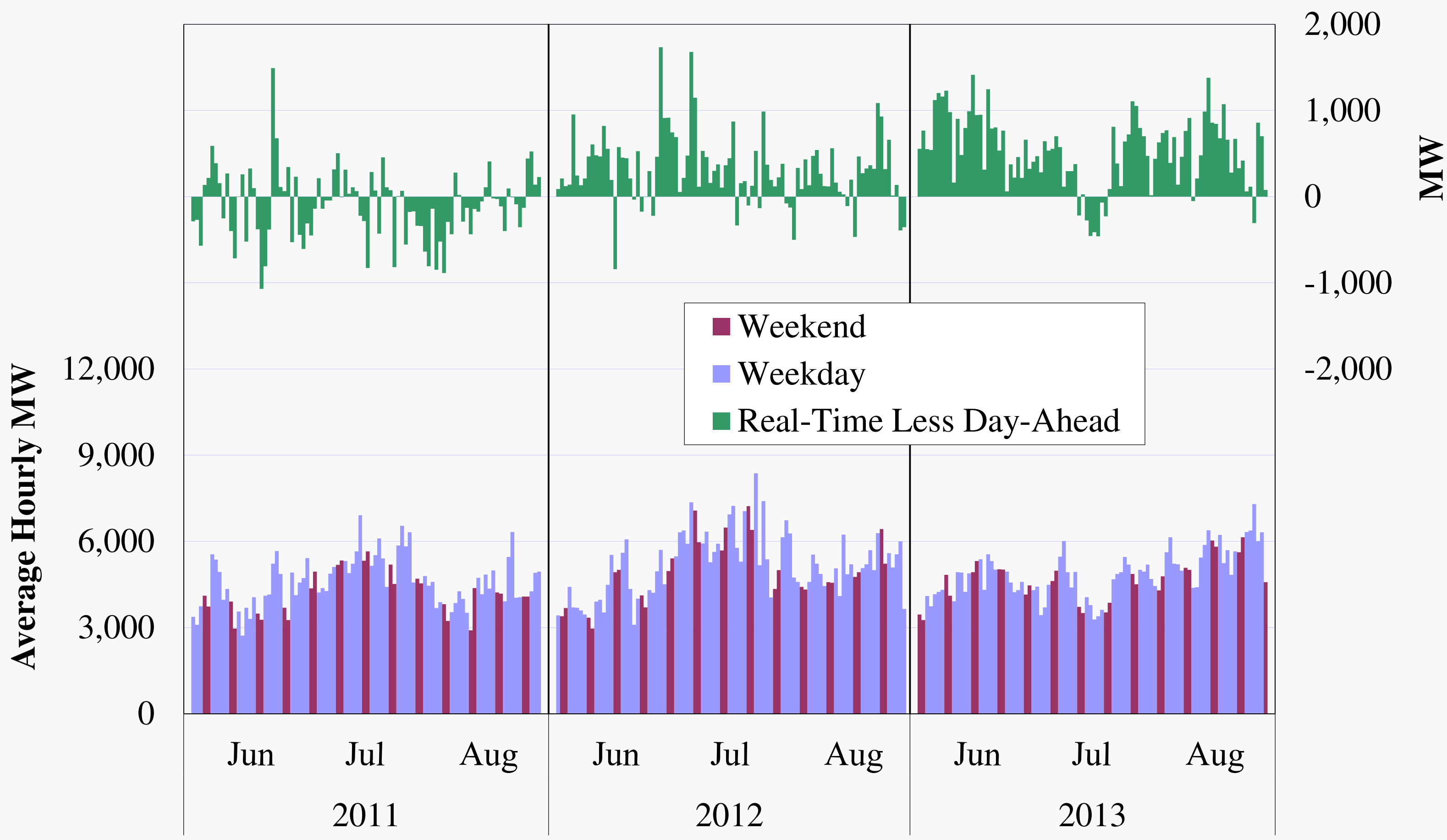


POTOMAC ECONOMICS

Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market in summer of 2011 to 2013.
- Net imports declined by 6 percent from last summer to 4.8 GW.
  - ✓ MISO remains a considerable net importer (at least 3 GW) in all hours.
  - ✓ Imports were underscheduled on almost all days except during the peak week.
  - ✓ Imports declined by 16 percent from PJM to 2.1 GW, but rose on the smaller Ontario and Manitoba interfaces by 67 and 24 percent, respectively.
- Transactions wheeled through MISO still originate predominantly in Ontario, and are almost exclusively scheduled to PJM.
  - ✓ These averaged over 1.5 GW, up from 1.1 GW last summer.
  - ✓ These transactions are partly motivated by substantial excess payments being made by PJM and MISO, which is discussed in detail in our *2012 SOM Report*.
- MISO and PJM continue to discuss proposals to improve interchange in the JCM process, including interchange optimization and alignment of scheduling rules.
  - ✓ Our analysis of interchange continues to show that the interface with PJM is not efficiently utilized, which should be addressed by interchange optimization.
  - ✓ The JCM has made progress on alignment, but this will not alleviate the inefficiencies demonstrated in our *SOM*.

Average Hourly Real-Time Imports Summer 2011–2013



POTOMAC ECONOMICS

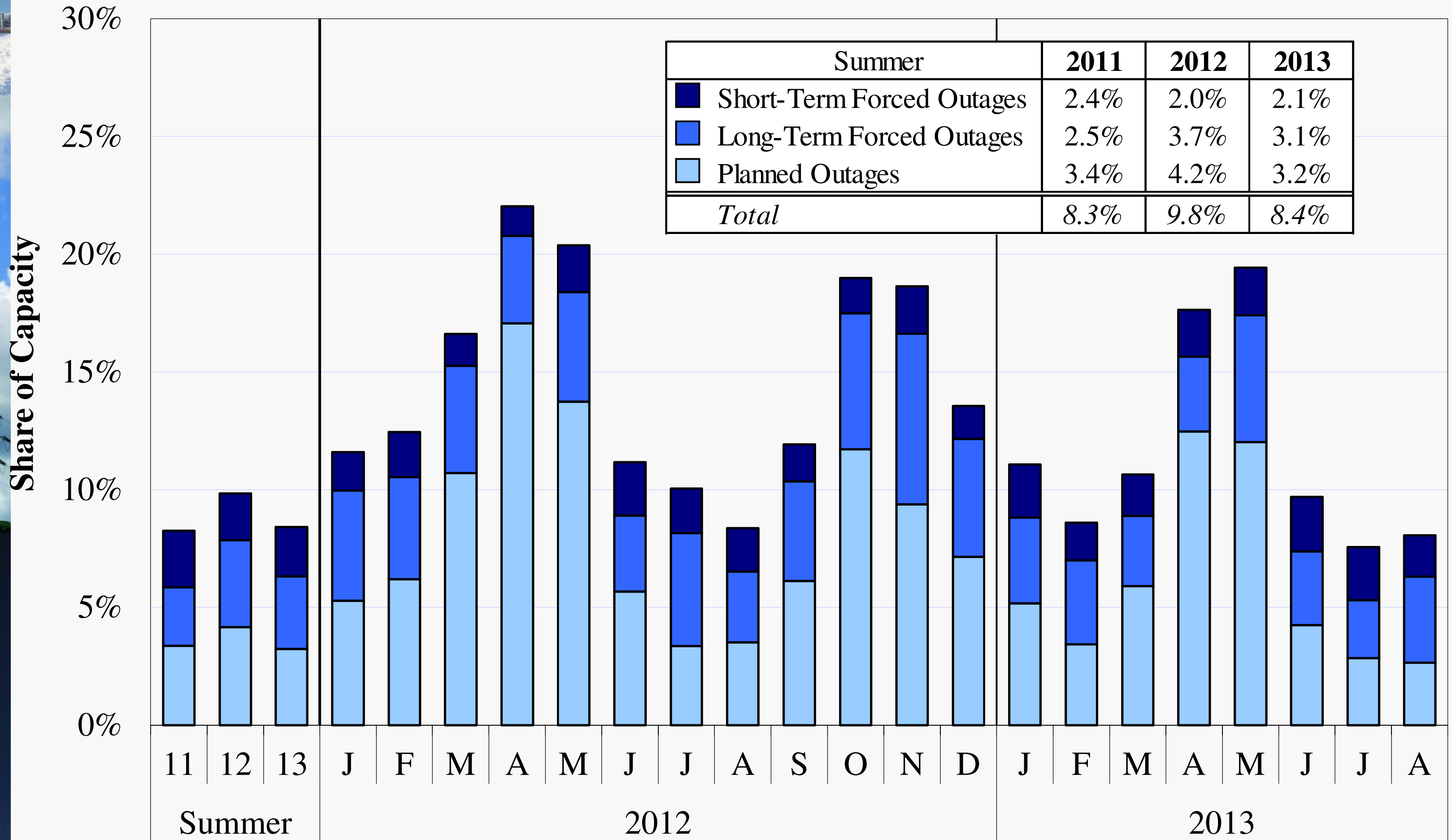
Interface Pricing Error

- We continue to be very concerned that MISO and PJM's interface prices contain a substantial error when a market-to-market constraint is binding.
- The error arises when a M2M constraint is binding in both the MISO and PJM markets. In this case, when a transaction is scheduled that involves both RTOs, the transaction will be over-paid or over-charged because it settles with both RTOs.
  - ✓ The problem is that the payment by the *monitoring* RTO fully and efficiently compensates the transaction for the flow relief it provides.
  - ✓ Therefore, *every dollar paid by the non-monitoring RTO for the same relief is redundant with the payment made by the monitoring RTO.*
  - ✓ There is no justification for the non-monitoring RTO to make an additional payment or impose an additional charge on the transaction.
- The non-monitoring RTO has no funding source for these payments, so these costs will ultimately be uplifted to the non-monitoring RTO's customers as:
  - ✓ Negative excess congestion fund (ECF) in MISO, balancing congestion in PJM, or
  - ✓ FTR underfunding (MISO and PJM).
- The larger costs of this error are likely the higher dispatch costs that are incurred because external transactions are being scheduled inefficiently.
- We recommend MISO seek an expedited remedy to this error.

Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2012 as a percentage of total generation capacity.
  - ✓ These values include only full outages, not partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The cumulative outage rate for the three types of outages was 8.4 percent, a decline from the 9.8 percent observed last summer.
  - ✓ The decline was most apparent in planned outages, which fell from 4.2 to 3.2 percent.
- Long-term forced outages also decreased from 3.7 to 3.1 percent.
  - ✓ Fewer high load days this summer likely contributed to this decrease, since forced outages are most likely when units are starting, stopping, or operating at their maximum capacity.
- Short-term forced outages, which can indicate potential physical withholding, remained very low near 2 percent.

Generation Outage Rates
2011–2012



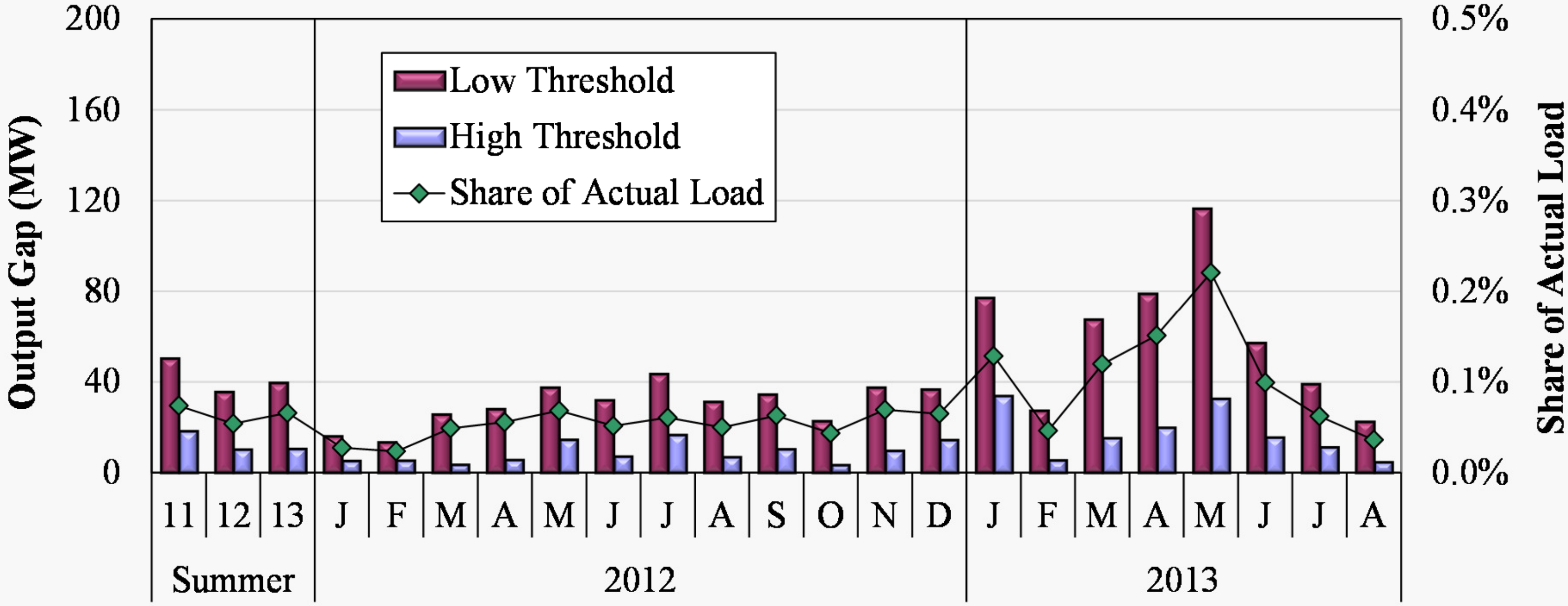
Summer	2011	2012	2013
Short-Term Forced Outages	2.4%	2.0%	2.1%
Long-Term Forced Outages	2.5%	3.7%	3.1%
Planned Outages	3.4%	4.2%	3.2%
Total	*8.3%*	*9.8%*	*8.4%*

POTOMAC ECONOMICS

Monthly Output Gap

- The output gap measure is used to screen for economic withholding by suppliers.
  - ✓ It measures the difference between actual output and the output level that would be expected based on competitive offers.
- The next figure shows the output gap since January 2012 under two thresholds:
  - ✓ A "high" threshold, equal to the applicable tariff mitigation threshold; and
  - ✓ A "low" threshold, equal to one-half of mitigation threshold.
- After rising modestly in the spring, output gap levels in MISO this summer again averaged less than 0.01 percent of load at both thresholds.
  - ✓ At the high threshold, average output gap was unchanged at 10 MW per hour.
  - ✓ At the low threshold, it rose slightly from 36 to 40 MW per hour.
    - – Nearly two-thirds of this was due to high regulation offers.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances of competitive concern.

Monthly Output Gap
Summer 2011–2013



High Threshold Results by Unit Status (MW)

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

Low Threshold Results by Unit Status (MW)

Off-Line	11	4	4	4	4	1	1	9	0	11	0	8	0	2	5	8	2	6	0	12	2	9	0
On-Line	39	32	36	12	9	24	27	29	32	33	31	26	23	36	32	69	25	62	79	104	56	30	22

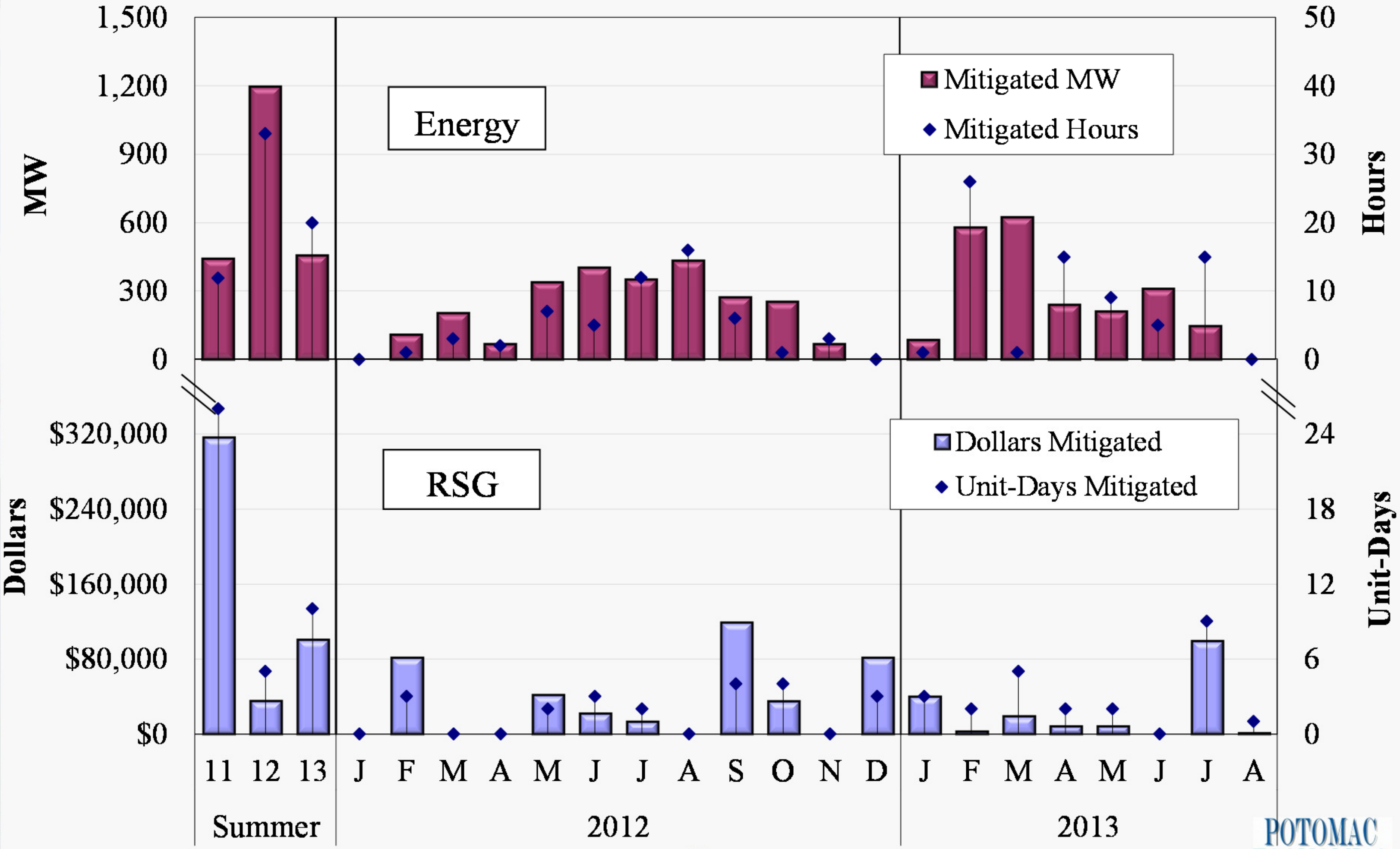
POTOMAC ECONOMICS

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which energy and RSG mitigation was imposed in the real-time market in each month since January 2012.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Since most resources continue to be offered competitively, mitigation in MISO remains infrequent.
  - ✓ Considerable market power continues to persist, however, and market power mitigation measures remain critical.
- We continue to evaluate each imposition of AMP mitigation and found mitigation this quarter to be appropriately applied in each instance.
  - ✓ Energy mitigation occurred for 20 hours and 459 MW, compared to 33 hours and 1,197 MW last summer. Nearly all of this occurred in Broad Constrained Areas.
  - ✓ RSG mitigation quantities rose to 10 hours and $101,000, but remains infrequent.
  - ✓ There were an additional five day-ahead mitigations for VLR this quarter.

POTOMAC ECONOMICS

Real-Time Market Power Mitigation
Summer 2011–2013



POTOMAC ECONOMICS

Submittals to External Entities and Other Issues

<u>Submittals to External Entities since July 2013</u>:

- We continue to meet with FERC regarding market outcomes and prior referrals.
  - ✓ We continue to discuss with MISO and FERC our concerns about resources that fail to accurately update real-time offers.
- We met with OMS to discuss recent market results and potential market improvements.
- We continue to meet with FERC regarding market outcomes and prior referrals and notifications to respond to data requests.
- We provided extensive comments at the MISO/PJM JCM meeting on the interface pricing error detailed in our SOM.
  - ✓ We are working with both RTOs to try to expedite the review and resolution to the problem.
  - ✓ We also commented on the inefficiency of PJM's proposals to discontinue M2M coordination or settlements on MISO flowgates that negatively impact PJM FTR funding (either due to outages or other undefined causes).

Submittals to External Entities and Other Issues

Other Issues:

- We continue to work with MISO on a number of upcoming filings related to PVMWP settlement rules including eligibility and allocations which should be filed very soon.
- We filed comments protesting one aspect of MISO's proposed transmission constraint demand curves we believe will be inefficient, which is related to the proposed TCDCs for external constraints.
- We continue to work on a market power study of the MISO South region to determine whether new NCAs should be defined in MISO South.
  - ✓ The study and other integration tasks by the IMM are on schedule.
- Based on our investigation of sub-optimal WPP market results in Entergy, we have implemented a procedure for the IMM to make discrete changes to improve the solution.
  - ✓ This procedure has increased the WPP's savings significantly over the last month.
- FERC required us to file a brief in early October related to aspects of MISO's resource adequacy contract that had prompted us to file a rehearing request.

IMM SOM Recommendation Summary

Recommendations 2012	High Benefit	Feasible in Short-Term	IMM Comment
Energy Pricing and Transmission Congestion			
1. Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set energy prices in the real-time market.		✓	Feasible in ST if ELMP can be adapted to address this recommendation. Benefits will grow over longer-term when DR is relied on more heavily.
2. Implement a five-minute real-time settlement for generation and external schedules.	✓	?	Will improve incentives of suppliers to be flexible and reaponsive.
3. Eliminate excess payments and excess charges to physical transactions that affect external constraints.	✓	✓	This flaw significantly distorts external scheduling incentives and flow patterns in the Eastern Interconnect. It also raises costs to PJM and MISO customers.
4. Improve external congestion processes by modifying how relief obligations are calculated and how the constraints are modeled in the real-time market.			Congestion on external constraints inefficiently reflected in MISO's prices and dispatch produce moderate cost increases.
a. Base relief obligations on *net* Market Flows, not gross forward flows.			Likely requires changes to agreements and software.
b. Cap MVL on external (non-M2M) flowgates.		✓	Easy to implement, likely requires FERC approval.
5. Introduce a virtual spread product.	?	?	Difficult to estimate magnitude of benefits, but this product would increase the performance of the day-ahead market.
Guarantee Payment Eligibility Rules and Cost Allocation			
6. Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs by making the following changes: a. Net market-wide deviations to determine the share of the real-time RSG costs that should be allocated via the DDC rate. b. Allocate real-time RSG only to harming deviations (pre- and post-NDL). c. Eliminate the use of GSFs in determining costs that should be allocated via the CMC rate.	?	✓	Changes will improve incentives of participants in the day-ahead market, the effects of which are difficult to estimate.
7. Implement improved eligibility requirements for PVMWPs a. Modify eligibility requirements to address gaming issues. b. Correct the mitigation rule regarding PVMWP and RSG eligibility.		✓	Short-term benefit is modest because the gaming conduct identified is not occurring, but the exposure of the market is large.
8. Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.		✓	Would reduce costs of satisfying MISO's spinning reserve requirements modestly.
9. Modify the mitigation measures to allow the definition of a "dynamic NCA" utilized when network conditions exist that create substantial market power.		✓	The market benefit depends on the frequency and duration of the conditions that arise.

POTOMAC ECONOMICS

IMM SOM Recommendation Summary

Recommendations 2012	High Benefit	Feasible in Short-Term	IMM Comment
Improve Dispatch Efficiency and Real-Time Market Operations			
10. Develop a look-ahead real-time dispatch capability to efficiently satisfy the system's anticipated ramp demands.	✓		This will substantially lower the costs and price volatility incurred to satisfy the system's expected ramp demands over the upcoming 30 minutes to an hour.
11. Implement a ramp capability product to address unanticipated ramp demands.	✓		Will substantially lower the costs and price volatility incurred to satisfy the system's *expected and unexpected* ramp demands over the upcoming 5-10 minutes.
12. Implement changes to more effectively identify and remedy units not following dispatch. a. Develop enhanced tools to identify units that are effectively derated or not following dispatch so that they may be placed off-control. b. Tighten thresholds for uninstructed deviations.	?	✓	Benefits are difficult to estimate, but this change will lower DAMAP payments and improve real-time operator visibility regarding what resources are available.
13. Expand the JOA to optimize the interchange with PJM to improve price convergence with PJM.	✓✓		Among the most beneficial enhancements that could be implemented.
14. Implement procedures to utilize provisions of the JOA that would improve day-ahead M2M coordination with PJM.			Difficult to estimate the benefits, in part because virtual traders can mitigate this issue by responding to day-ahead/real-time congestion differences on M2M constraints.
15. Eliminate the transmission constraint deadband.	✓	✓	Contributes to significant and inefficient congestion-related price volatility and can be turned off at any time.
16. Re-order MISO's emergency procedures to utilize demand response efficiently.		✓	Benefits are limited in the short-run because emergency conditions are rare, but they will increase over the long-run as surplus dissipates.
17. Modify the market systems to recognize supplemental reserves being provided from quick-start units when they are in the process of starting.		?	Will avoid inaccurate transitory shortages that can be caused with units are starting.
Resource Adequacy			
18. Remove inefficient barriers to capacity trading with adjacent areas.	✓		Over the long run, this will allow capacity to be built and utilized where it is most valuable, and satisfy the planning reserve requirements throughout the Eastern Interconnect at a lower cost.
19. Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.	✓✓	?	This is a fundamental change in the capacity market needed for the capacity market to facilitate private investment. Only regulated investment is feasible without this change.
20. Evaluate capacity credits provided to wind resources and LMR to increase their accuracy.		✓	This could be more significant over the long run, but will have limited effects under the current RAC.

List of Acronyms

✓	AMP	Automated Mitigation Procedures
✓	BCA	Broad Constrained Area
✓	CDD	Cooling Degree Days
✓	CMC	Constraint Management Charge
✓	DAMAP	Day-Ahead Margin Assurance Payment
✓	DDC	Day-Ahead Deviation & Headroom Charge
✓	DIR	Dispatchable Intermittent Resource
✓	HDD	Heating Degree Days
✓	JCM	Joint and Common Market Initiative
✓	LAC	Look-Ahead Commitment
✓	LSE	Load-Serving Entities
✓	M2M	Market-to-Market
✓	NCA	Narrow Constrained Area
✓	ORDC	Operating Reserve Demand Curve
✓	PRA	Planning Resource Auction

✓	PVMWP	Price Volatility Make Whole Payment
✓	RAC	Resource Adequacy Construct
✓	RSG	Revenue Sufficiency Guarantee
✓	RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
✓	TLR	Transmission Line Loading Relief
✓	TCDC	Transmission Constraint Demand Curve
✓	VCA	Voluntary Capacity Auction
✓	VLR	Voltage and Local Reliability
✓	WUMS	Wisconsin Upper Michigan System