IMM Quarterly Report: Spring 2012
March–May

MISO Independent Market Monitor

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Potomac Economics

June 2012

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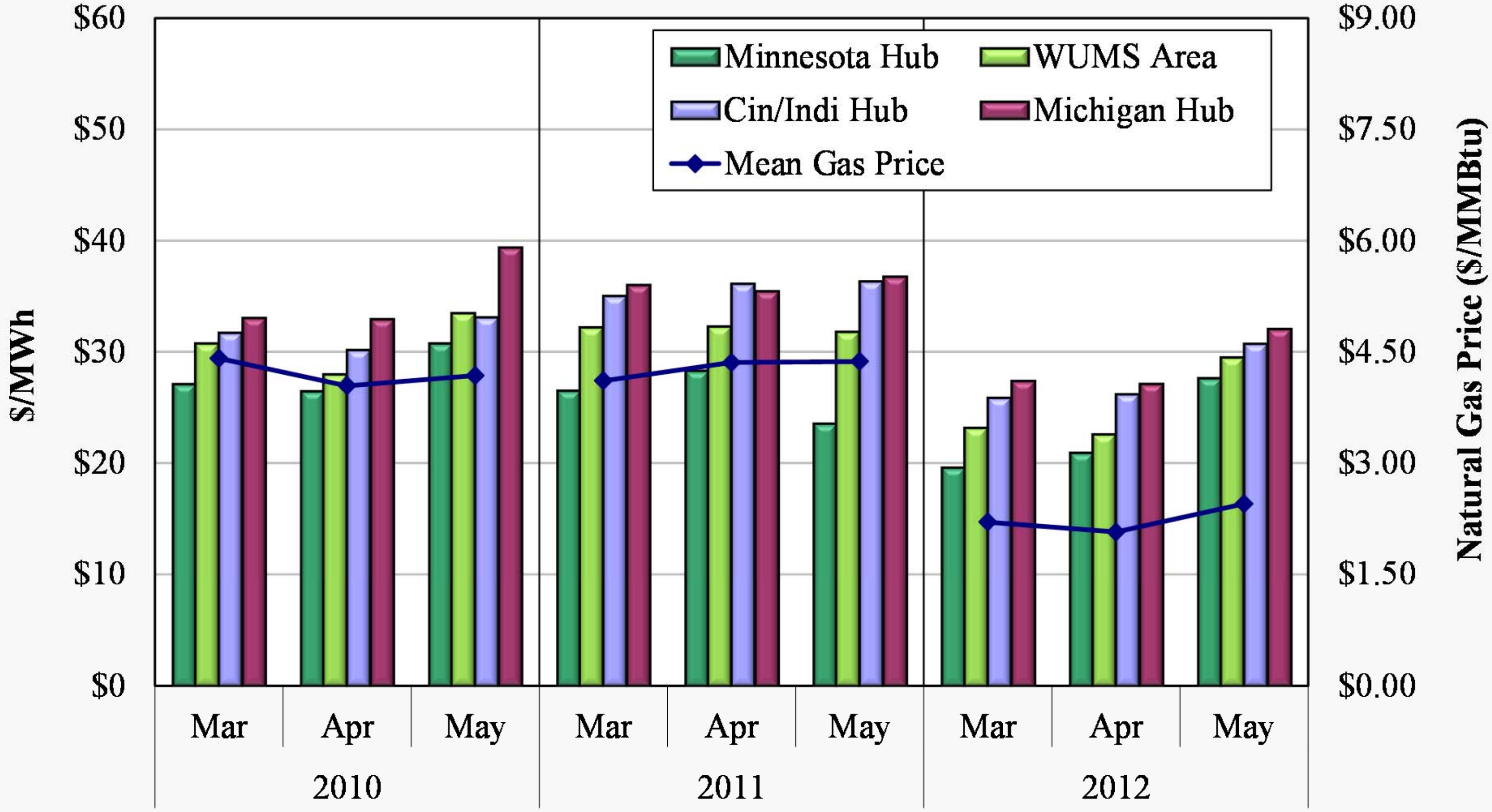
Summary of Spring 2012 Results

- Real-time energy prices in the spring quarter averaged $25.33 per MWh, down 25 percent from last spring.
  - ✓ This reduction was largely due to lower fuel prices: natural gas prices fell almost 50 percent to $2.25 per MMBtu.and western coal prices fell 35 percent to $0.48 .
  - ✓ Day-ahead prices converged well with real-time prices, exhibiting an average 2 percent day-ahead premium. This is consistent with the real-time RSG allocation.
- Load fell slightly (adjusted for membership changes) due to mild weather this spring.
- The sharp decline in gas prices has resulted in gas units being cost-competitive with some of MISO’s coal units, doubling MISO’s energy output from natural gas units (and reducing the capacity factor of many of its coal resources).
- Congestion fell by almost 10 percent from last spring (including unpriced congestoin), which was primarily due to lower fuel prices.
  - ✓ Planned generator and forced transmission outages, including parts of the Manitoba interface, contributed to congestion *into* the West region in April and May.
  - ✓ Constraint relaxation was disabled on February 1 for non market-to-market constraints, causing the unpriced congestion to fall to just 2 percent of total congestion.
- Wind generation averaged 4.0 GW, a 25 percent increase from last spring.
  - ✓ As of June 1, 37 wind resources totaling 4.8 GW are dispatchable. DIR economic curtailments are now the primary means to manage wind-related congestion.

Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations hubs for March to May of 2010 to 2012.
  - ✓ We include natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin in peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices this spring averaged \$25.75 per MWh, a decline of 22 percent from last spring and 4 percent from last quarter.
  - ✓ Natural gas prices, which averaged just \$2.25 per MMBtu in the quarter, were nearly 50 percent lower than in spring 2011. Western coal prices similarly declined 35 percent.
  - ✓ Load scheduling day-ahead decreased just 1 percent (adjusted) from last spring.
- Price differences between western and eastern areas in MISO associated with transmission congestion and losses continued this quarter.
  - ✓ Periodic congestion into the West region caused West prices to fall less than other regions (12 percent versus 20-25 percent), but they remain 26 percent lower than those in the East region.
  - ✓ Wind output continues to climb and contribute to more congestion out of western areas.
    - – Wind output averaged 3.3 GW in the day-ahead market (up 14 percent from last spring). It is still significantly under-scheduled, but virtual supply at wind locations offset 80 percent of this underscheduling.

Day-Ahead Average Monthly Hub Prices
Spring 2010–2012

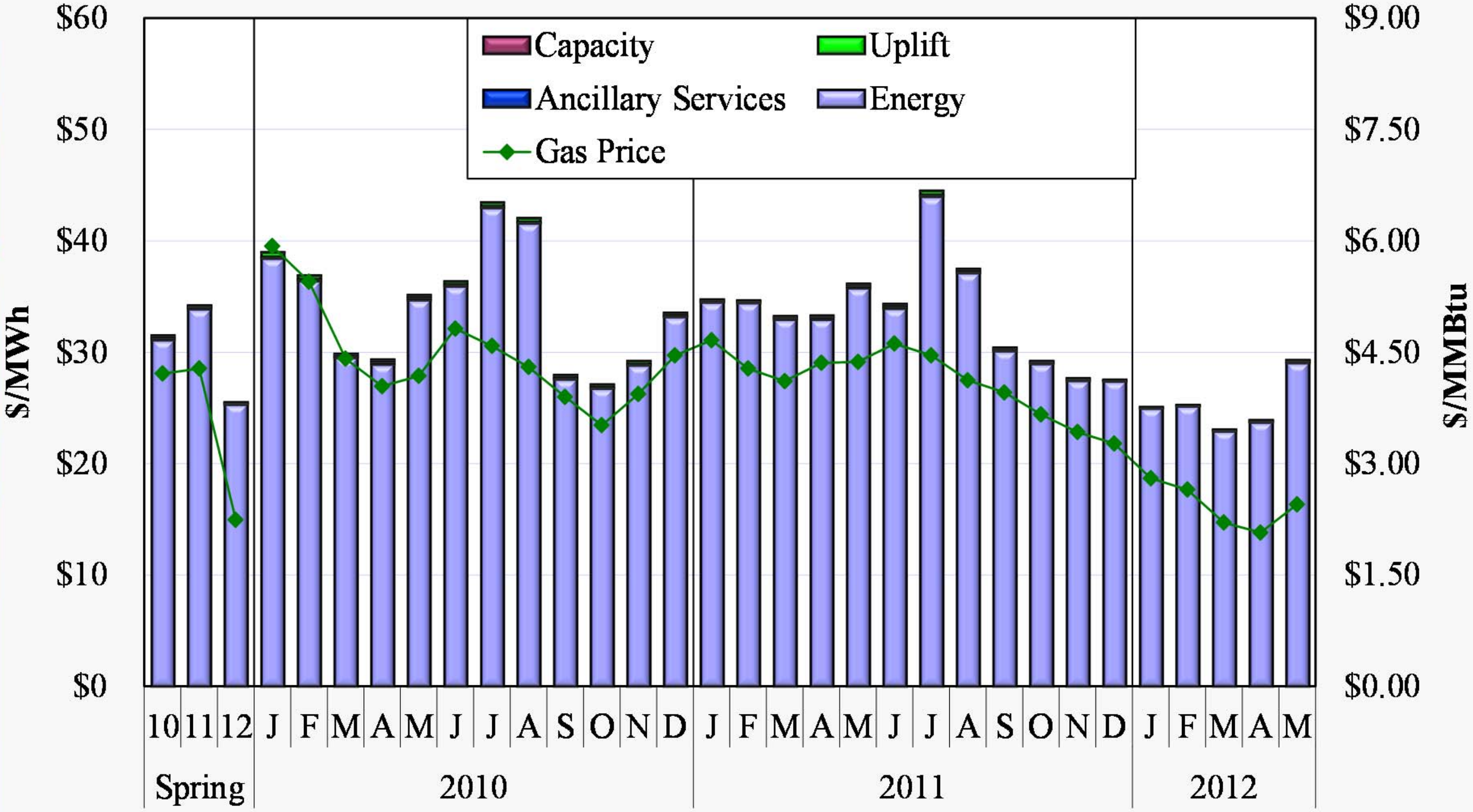


Note: Cinergy Hub was replaced by Indiana Hub as the Central Region's proxy price beginning January 2012.

All-In Price

- The "all-in price" represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price and real-time uplift, ancillary services, and capacity costs per MWh of load.
- The figure includes the monthly average natural gas price and shows that energy prices generally track changes in fuel prices.
  - ✓ This is expected in a competitive market because fuel costs are the vast majority of most units' marginal costs and gas units are often on the margin(setting prices).
- The price declined to $25.51 per MWh, down 25 percent from the prior spring.
  - ✓ The energy component of the all-in price declined, which was due to substantial decreases in natural gas prices (47 percent) and western coal prices (35 percent).
  - ✓ The decline in natural gas prices also contributed to sizable reductions in the uplift (46 percent) and ancillary services (38 percent) components of the all-in price.
- Energy costs continue to make up nearly the entire all-in price (99 percent).
  - ✓ The uplift, ancillary services and capacity costs contributions to the all-in price declined sharply in the quarter and together added only $0.20 per MWh.
  - ✓ The Voluntary Capacity Auction continued to clear at close to zero each month, which is partly due to the surplus in MISO and partly to market design issues we've previously identified.

All-In Price
2010–2012



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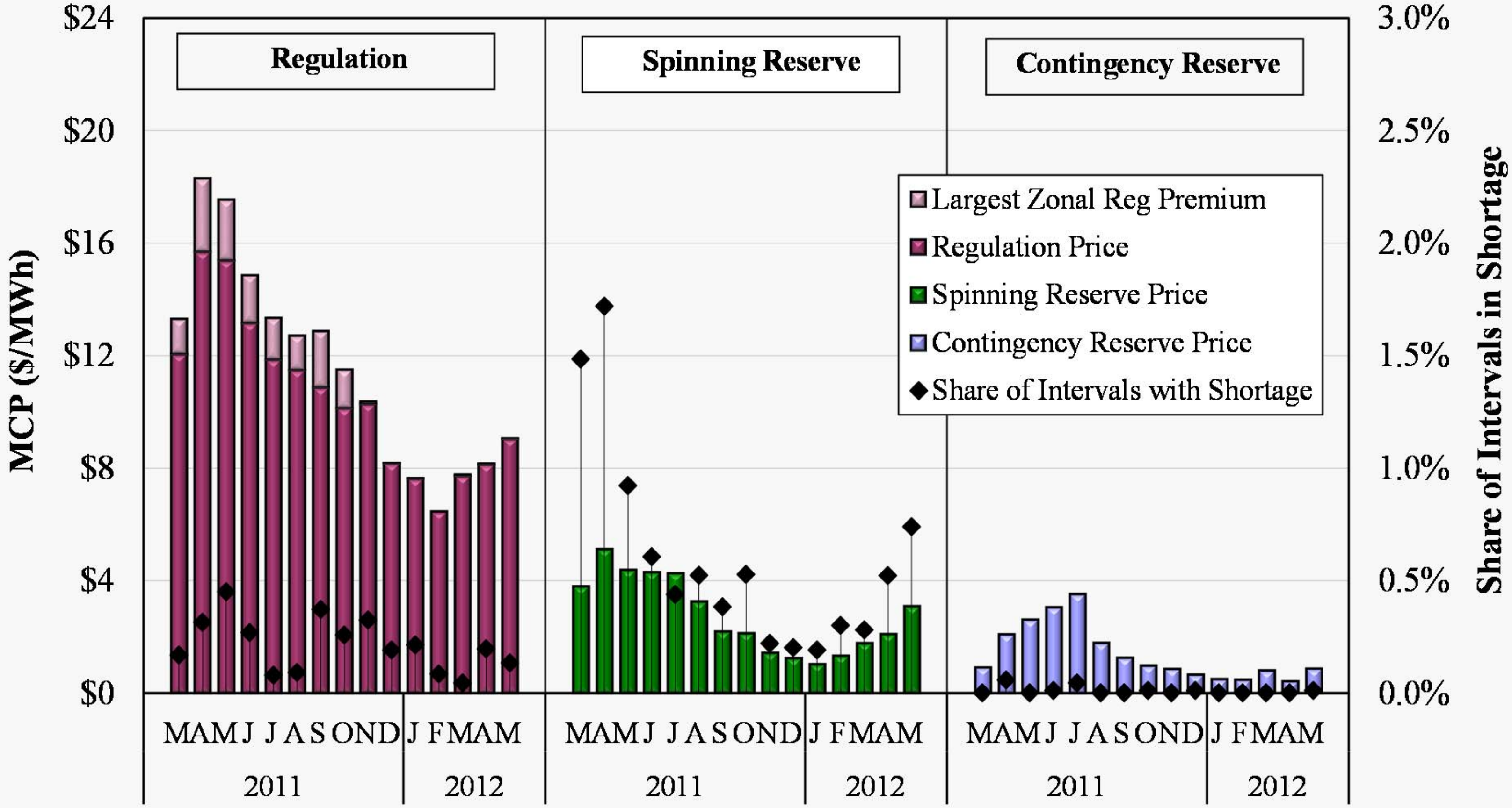
Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO’s three ancillary service products for the prior fifteen months.
  - ✓ ASM clearing prices rose from winter lows but remain 40 to 60 percent below last spring’s prices because of the low prevailing energy prices and fewer shortages.
- Regulating reserve prices averaged $8.31 per MWh in spring 2012. This is 42 percent lower than last spring, but 12 percent higher than last quarter.
  - ✓ Part of the recent increase in prices reflects the high opportunity cost of providing energy during low-load (MinGen) negative energy price periods.
  - ✓ During such periods, regulating units have to be dispatched up above their dispatch minimums to provide sufficient bidirectional regulation capability.
    - – For example, a MinGen Alert on May 27 resulted in negative LMP prices for five hours. Regulation prices during this period averaged nearly $50.
- Spinning reserve clearing prices declined 47 percent from last spring to average $2.33 per MWh. Supplemental reserve prices similarly declined 62 percent to $0.71.
  - ✓ Most of this reduction can be attributed to lower energy prices that reduce the opportunity cost trade-offs between reserves and energy.
  - ✓ However, prices rose from last quarter as ramp constraints bound more frequently.
  - ✓ MISO implemented a new two-step spinning reserve demand curve in May, which now prices the initial 100-MW block of shortage at a lower $65 penalty price. This contributes to more frequent shortages, but not to higher average prices.

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



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MISO Fuel Prices

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

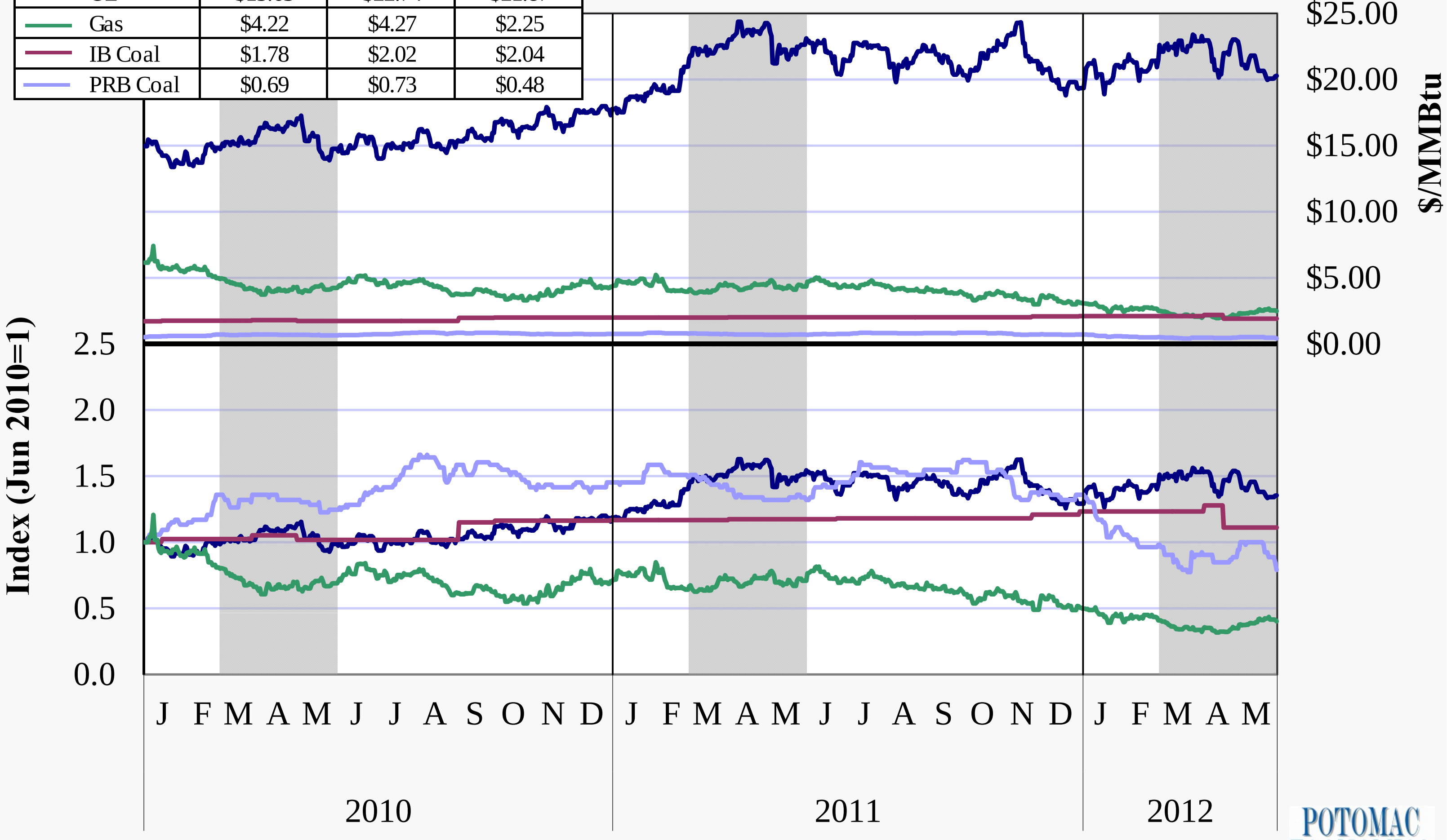
- Natural gas prices averaged just \$2.25 per MMBtu in the quarter, 47 percent lower than last spring and 23 percent lower than in the winter quarter.
- Sustained low prices for natural gas have altered dispatch patterns in MISO, as some gas resources are now competitive with some of the baseload coal resources.
  - ✓ The share of MISO's generation produced by gas resources more than doubled this spring to 12 percent (up from 5 percent in spring 2011). This increase came at the expense of coal resources (63 percent, down from 73 percent).
- Oil prices remained high, averaging \$21.87 per MMBtu this quarter.
  - ✓ Oil was rarely marginal in the spring, so this rise was not impactful on the market.

<u>Coal Prices</u>

- Average Powder River Basin (western coal) prices averaged \$0.48 per MMBtu, down 35 percent from last spring and 24 percent from last quarter.
  - ✓ This decrease allowed many of the coal resources burning PRB coal to retain a significant cost advantage over natural gas combined cycle resources.
- Illinois Basin prices were flat at just over \$2 per MMBtu, causing many resources burning IB coal to lose their cost advantage over natural gas combined cycle units.

MISO Fuel Prices 2010–2012

Spring Average	2010	2011	2012
Oil	$15.63	$22.74	$21.87
Gas	$4.22	$4.27	$2.25
IB Coal	$1.78	$2.02	$2.04
PRB Coal	$0.69	$0.73	$0.48



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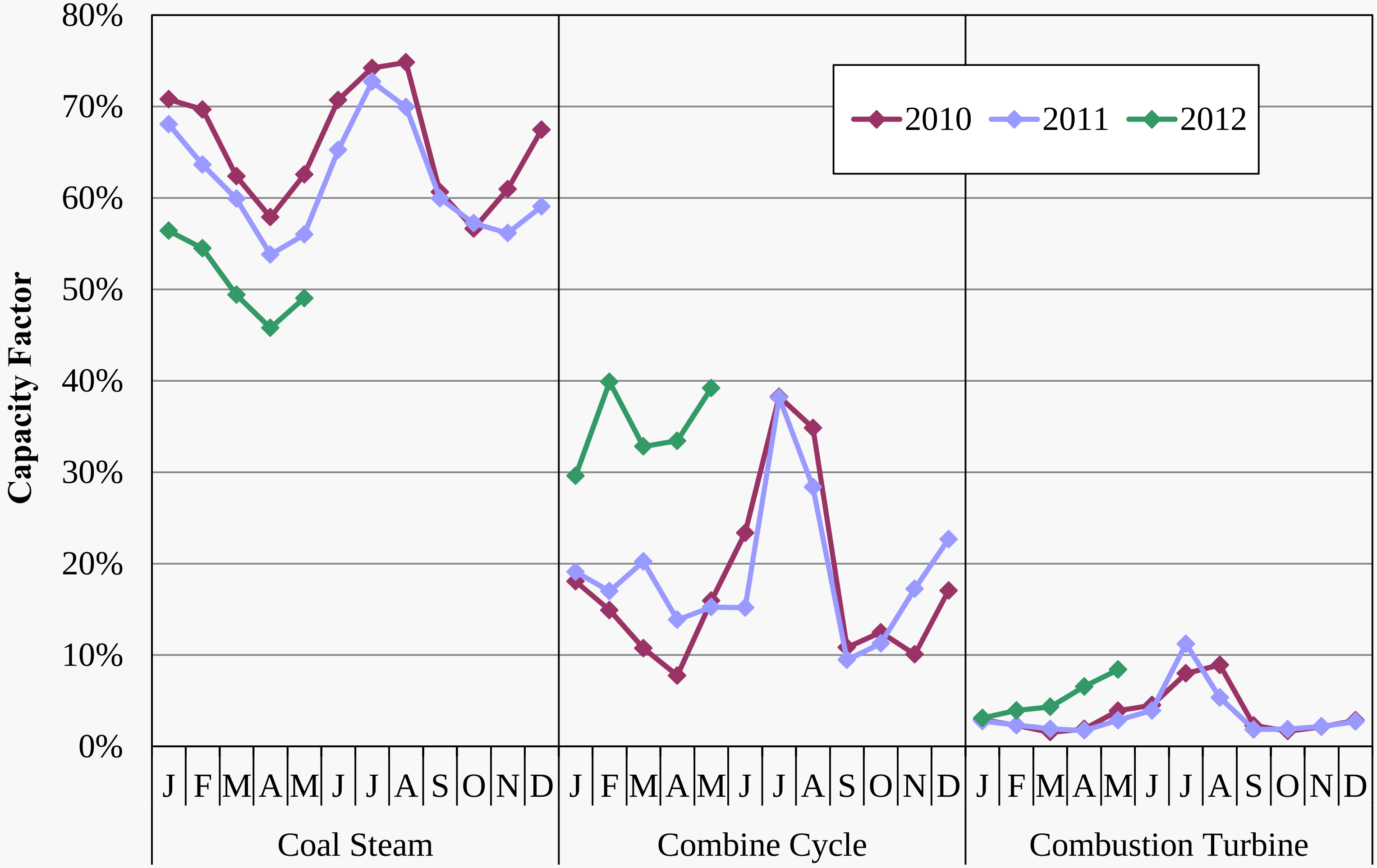
MISO Unit Type Capacity Factors

- The significant decline in natural gas prices this spring have resulted in notable changes in generation patterns.
  - ✓ At the prevailing gas prices, combined cycle resources are now competitive with a substantial share of MISO's coal resources (particularly those burning IB coal).
    - – In fact, several gas-fired peaking units were routinely scheduled day-ahead for economics during peak hours this quarter.
  - ✓ A new combined-cycle at a gas price of $2.25 per MMBtu (the spring 2012 average) would have incremental energy costs near $21 per MWh.
- The impact of the low gas prices on capacity factors of different types of resources is shown in the following chart.
  - ✓ In the first five months of 2012, the average capacity factor for combined-cycle resources averaged 35 percent, much higher than the 10-20 percent in prior years.
  - ✓ The capacity factors of combustion turbines increased by 2 to 3 times compared to prior years. Some of these units were committed economically through the day-ahead market, which is unusual.
  - ✓ The significant drop in the average capacity factor of coal-fired resources is due to both low gas prices and to higher planned outage rates as some suppliers have begun taking outages to perform environmental upgrades.

MISO Unit Type Capacity Factors 2010–2012



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Changes in Load and Weather Patterns

- The next figure shows changes in load in the spring 2010 to 2012, as well as the changes in weather patterns that contributed to the load changes.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns contributed to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days (“HDDs and CDDs”) in spring months at four locations in MISO since 2010.
  - ✓ To account for the different relative impacts of HDDs and CDDs on load, HDDs are inflated by a factor of 6.07 (based on a regression analysis).
- The figure shows that total degree days declined 13 percent from last spring.
  - ✓ A very warm spring for most of the footprint resulted in total degree days that were 11 percent below the historical average.
  - ✓ March in particular recorded degree days 36 percent below normal—average temperatures in March were warmer than in April.
- These weather factors significantly affected the monthly average and peak loads during each period shown in the top panel of the figure.
  - ✓ Excluding membership changes (e.g. the departure of FirstEnergy and portions of Duke Energy), average load was slightly lower than last spring at 52.9 GW.
  - ✓ Peak load declined by 5.4 percent, peaking at 71.5 GW on May 24.

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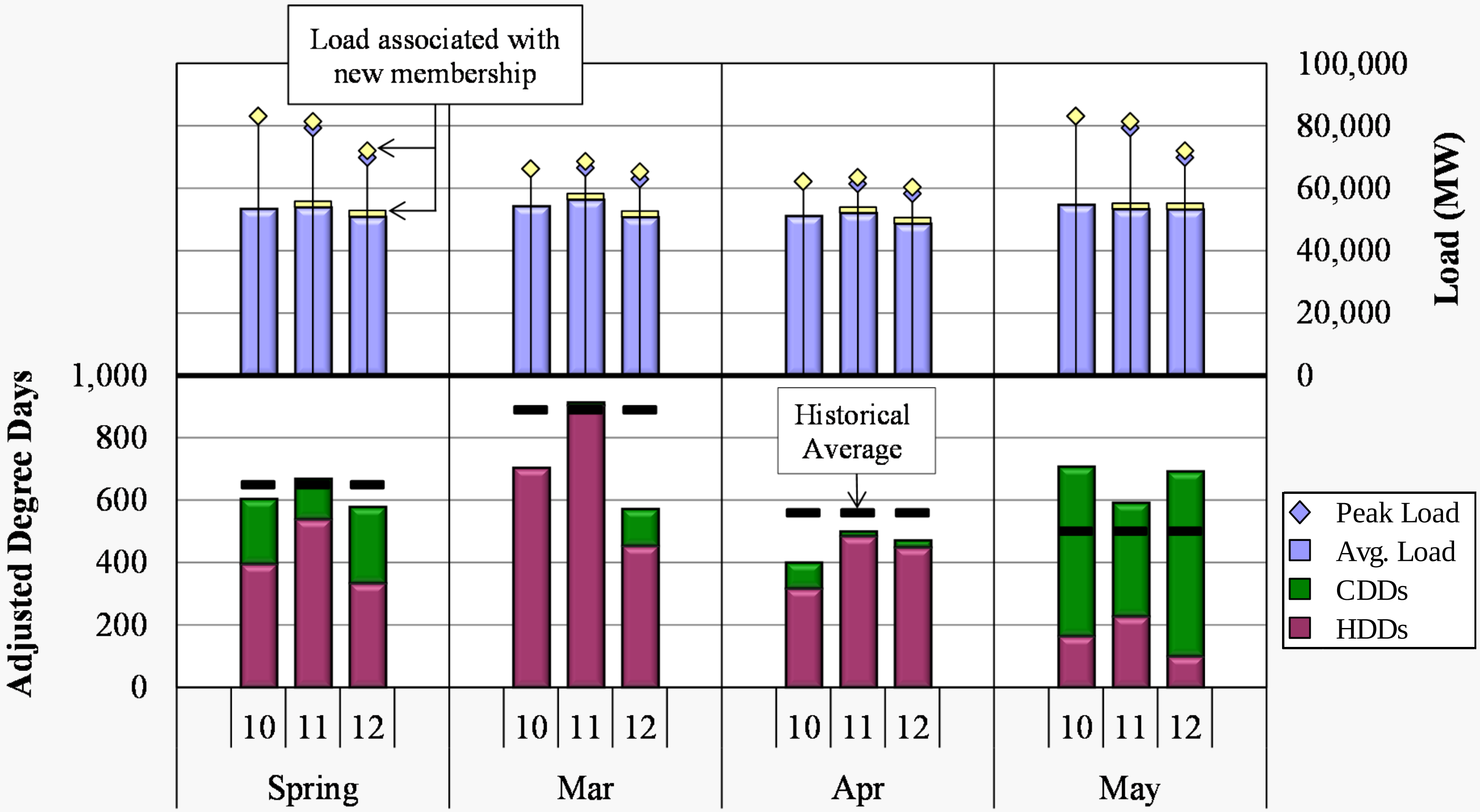
Load and Weather Patterns
Spring 2010–2012

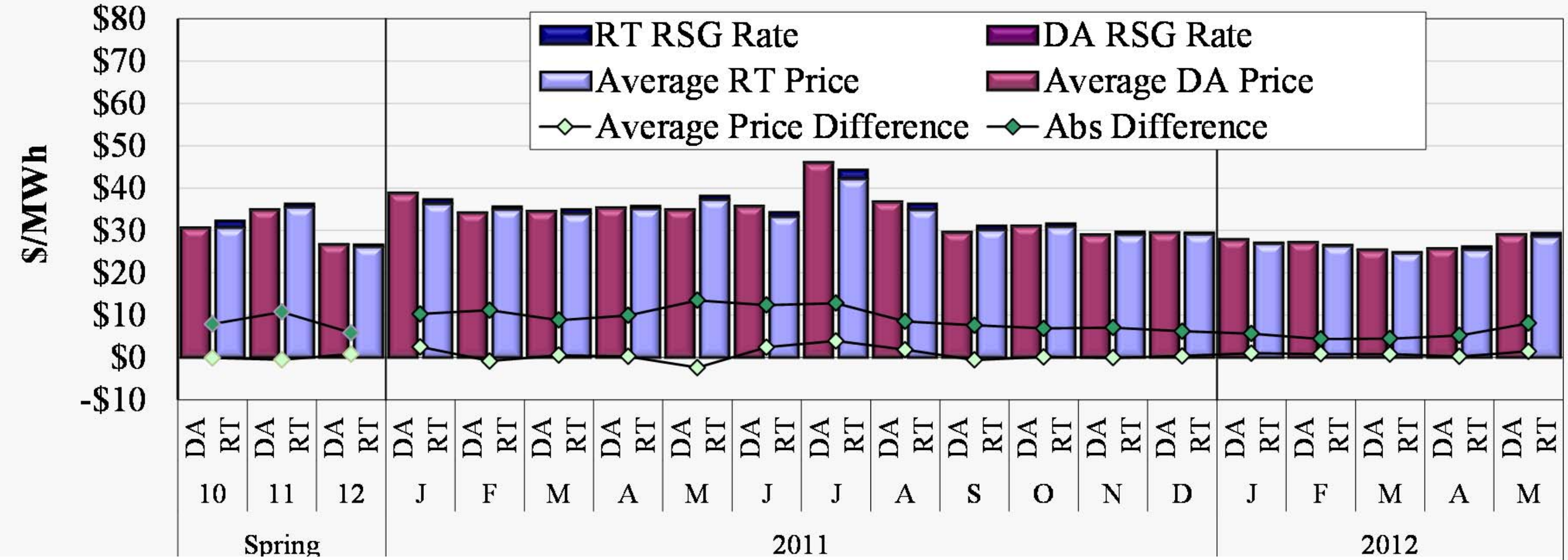


Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis. FirstEnergy and Duke Ohio is removed from the load levels.

Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub (the inset table shows other locations), along with average price differences.
- The markets converged well with day-ahead premiums of 1 to 3 percent at all hubs except at Minnesota Hub.
  - ✓ A number of congestion events in mid-April and mid-May into the West—several of which were the result of a loss of imports from Manitoba—were unforeseen day-ahead and contributed to a 6 percent real-time premium in the West.
  - ✓ In addition, load scheduling exceeded 110 percent day-ahead on May 26-27 and resulted in substantial day-ahead premiums. On May 27, the high load scheduling contributed to a Minimum Generation Alert and negative real-time prices.
- The day-ahead premiums were consistent with the DDC RSG rate applied to real-time load purchases, which averaged $0.52 per MWh this quarter.
  - ✓ The bottom table in the figure shows that prices at all of the hubs but Minnesota converged to within one percent after accounting for the DDC rate.
  - ✓ We are recommending improvements that would lower the DDC rate.

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



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

Cin/Ind Hub	0	-2	3	7	-2	2	1	-6	7	9	5	-2	0	0	1	4	3	3	1	5
Michigan Hub	3	1	3	6	-5	3	7	-5	2	8	4	-3	2	-4	3	5	2	-1	5	5
Minnesota Hub	0	-8	-6	1	-6	-10	-16	5	-9	6	-1	-4	0	4	11	3	-2	2	-12	-6
WUMS Area	2	0	1	3	-6	0	-4	5	6	8	-1	1	9	8	8	3	0	4	0	-1

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

Cin/Ind Hub	-5	-4	1	4	-4	-1	-1	-9	4	4	1	-5	-2	-2	0	3	2	2	-2	3
Michigan Hub	-2	-1	1	3	-7	0	5	-7	0	4	1	-6	0	-6	2	4	2	-2	2	3
Minnesota Hub	-6	-11	-8	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10	2	-2	1	-14	-8
WUMS Area	-4	-2	-1	0	-8	-3	-6	2	3	2	-5	-2	7	5	7	2	-1	3	-3	-3

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

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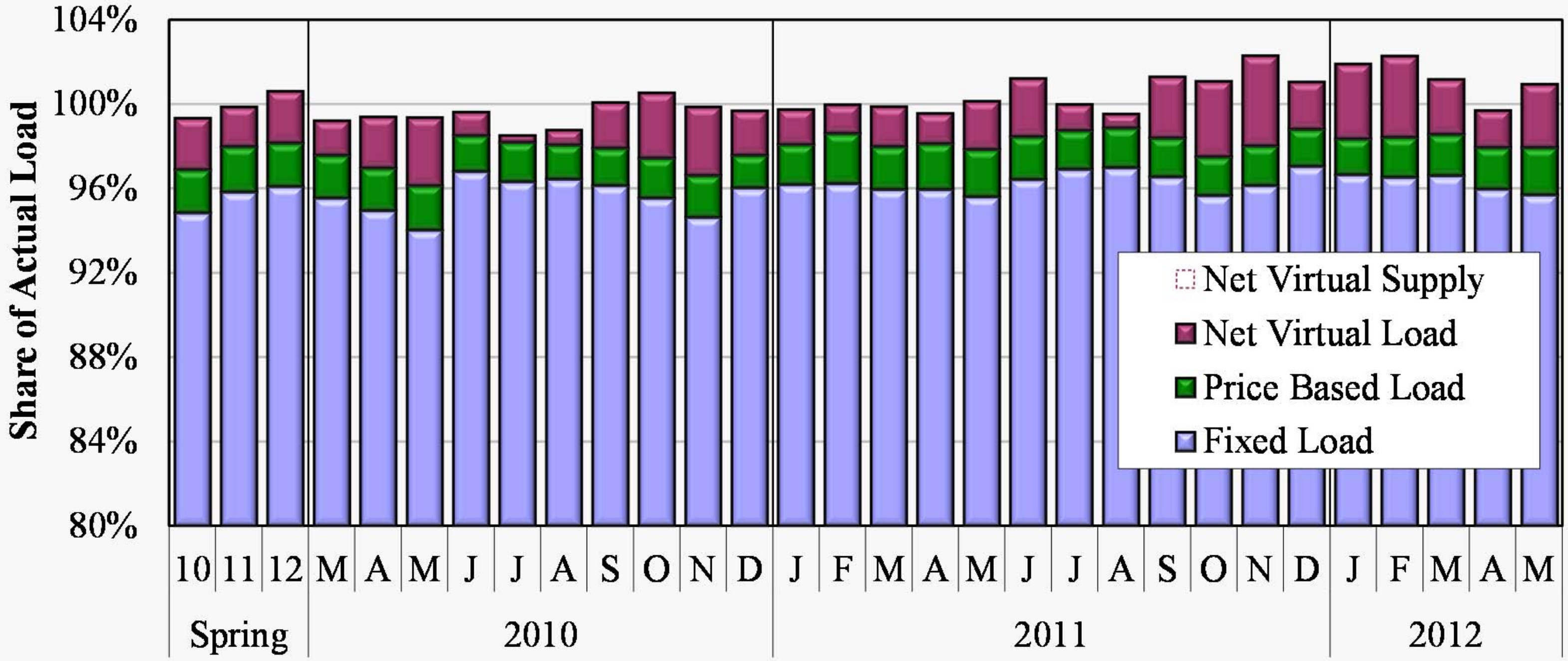
Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG costs because low levels can compel MISO to commit peaking resources to satisfy higher real-time load.
  - ✓ However, real-time commitments are still made to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- Load this spring was slightly underscheduled on average during all hours (at 99.1 percent), but slightly overscheduled during the peak daily hour (100.6 percent).
  - ✓ Net virtual load during the peak hour, much of which is offered price-insensitively by LSEs, consistently made up the scheduling shortfall of fixed and price-based physical load.
- As we show in monthly reports, this broad metric can mask considerable variation in day-to-day scheduling and the correlation with day-ahead price premiums.
  - ✓ Load was overscheduled by more than 10 percent on May 26 and 27, when holiday-weekend loads and unseasonably warm weather failed to materialize.
  - ✓ On most other days, load was accurately forecasted and scheduled by participants, and has contributed to reduced price volatility.

Day-Ahead Peak Hour Load Scheduling 2010–2012



Share of Actual Load(%)

All Hour	99.4	99.4	99.1	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2	100.4	100.4	100.5	99.6	100.1	99.7	99.7	97.7	99.9
Peak Hour	99.4	99.9	100.6	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7	99.8	100.0	99.9	99.6	100.1	101.2	100.0	99.5	101.3	101.1	102.3	101.1	101.9	102.3	101.2	99.7	100.9

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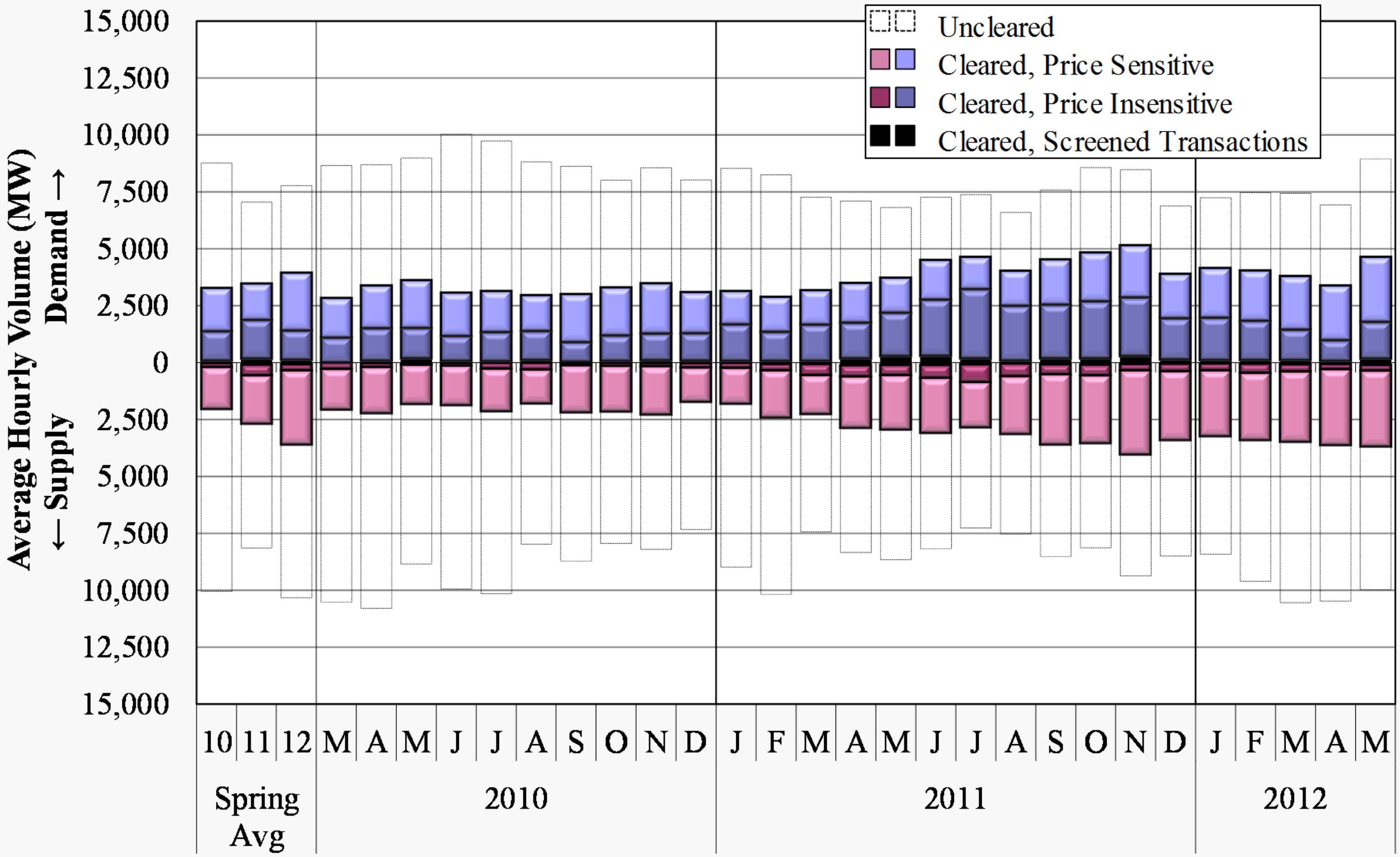
Virtual Load and Supply in the Day-Ahead Market

- 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 $30 above and below expected real-time prices, respectively.
  - ✓ Price-insensitive bids and offers that contribute to a significant difference in the congestion at a location between the day-ahead and real-time markets (labeled "Screened Transactions") raise potential manipulation concerns.
- We have been monitoring changes in virtual trading activity patterns due to MISO's changes in the RSG cost allocation in April 2011.
  - ✓ The change eliminates any 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 as discussed below.

Virtual Load and Supply in the Day-Ahead Market

- The figure indicates that offered and cleared volumes this spring rose 19 and 23 percent, respectively, from spring 2011.
  - ✓ The majority of the increase was in virtual supply: cleared supply volumes rose 34 percent to 3.6 GW, while cleared demand rose 14 percent to 4.0 GW.
- Virtual trading volumes began increasing after the change in the real-time RSG allocation in April 2011.
  - ✓ The RSG allocation change reduces the allocation for participants taking balanced positions to arbitrage basis differences (price differences between locations).
  - ✓ A balanced position can be ensured by bidding and offering price-insensitively, which explains why much of the increase was in price-insensitive volumes.
- Some of the arbitrage of basis differences in 2011 was focused on differences in marginal loss factors between the day-ahead and real-time markets.
  - ✓ MISO took steps to reduce predictable loss factor differences in early December, causing virtual volumes declined 21 percent from November.
- The share of cleared volumes that were price-insensitive has declined from 40 percent last spring to 23 percent.
  - ✓ The share of Screened Transactions similarly decreased, from 4.4 to 2.7 percent.

Virtual Volumes
2010–2012



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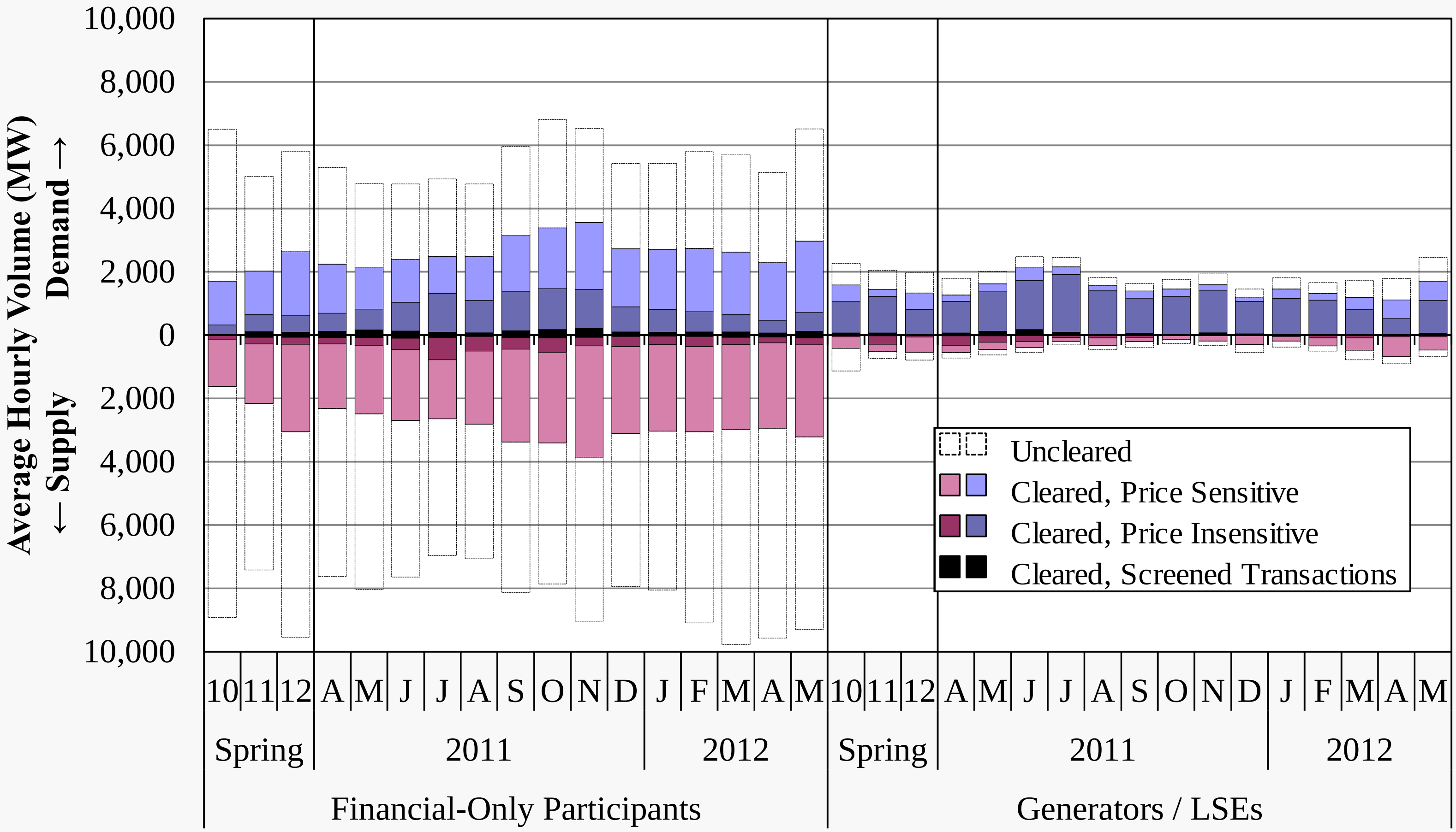
Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by type of market participant.
  - ✓ The figure distinguishes between physical participants (generation owners or LSEs) and financial-only participants.
- Most of the increase in cleared volumes was by financial-only participants: such entities comprised 75 percent of volumes in spring 2012, up from 68 percent last spring.
  - ✓ Cleared supply volumes by these participants rose 41 percent to 3.0 GW, while demand volumes rose 30 percent to 2.6 GW. Offered volumes rose comparably.
- While financial participants' volumes were roughly divided between supply and demand, over 70 percent of physical participants' volumes were demand bids.
  - ✓ Physical participants provided just 15 percent of cleared virtual supply.
- Physical participants generally offer less price-sensitively than financial participants do, which makes it more likely that such volumes clear.
  - ✓ Such transactions allow physical participants to hedge against load uncertainty or supply availability in order to manage price risk.
  - ✓ In spring 2012, only 46 percent of cleared physical participant volumes were offered insensitively, down from 76 percent last spring.
  - ✓ For financial-only participants, this share declined from 22 percent to just 16 percent.

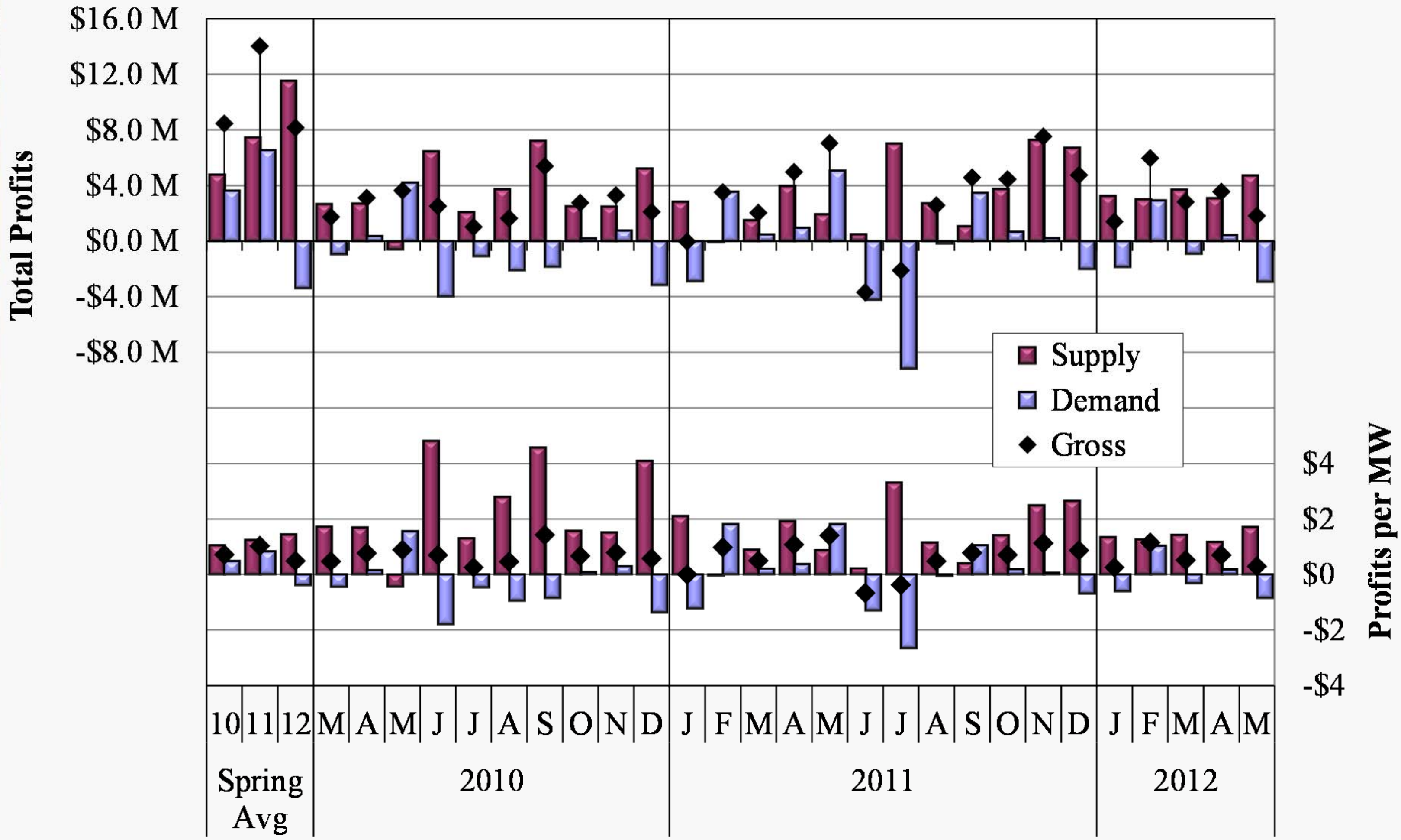
Virtual Load and Supply by Participant Type Spring 2010–2012



Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual purchases and sales.
- Gross profitability in spring 2012 declined to $8.2 million, or $0.49 per MWh, which is consistent with the modest profitability of virtual transactions in prior quarters.
  - ✓ Virtual supply continues to be considerably more profitable ($1.46 per MW) than demand ($-0.39). This is expected in markets with prevailing day-ahead premiums.
  - ✓ Supply scheduling at wind locations earned $1.8 million (22 percent of all of the gross profits).
- These margins exclude CMC and DDC charges assessed to net harming deviations, including DDC charges to net virtual supply. DDC charges averaged $0.52 per MWh in the period, which reduced the profits for virtual supply by 36 percent.
  - ✓ As previously noted, the CMC allocation to virtual transactions is incorrect, resulting in allocations to virtual transactions that contribute to convergence. We are working with MISO to identify the best procedural option for getting this fixed.
- Virtual transactions by financial participants continue to be profitable and improve convergence overall, while those by physical participants are generally unprofitable.
  - ✓ Excluding RSG allocations, financial participants' profits averaged $0.78 per MWh, while physical participants' profits averaged $-0.43 (and $-1.17 for virtual demand).
  - ✓ Physical participants consistently incur losses on virtual demand, likely to hedge risks associated with supply uncertainty and real-time price spikes.

Virtual Profitability
2010–2012



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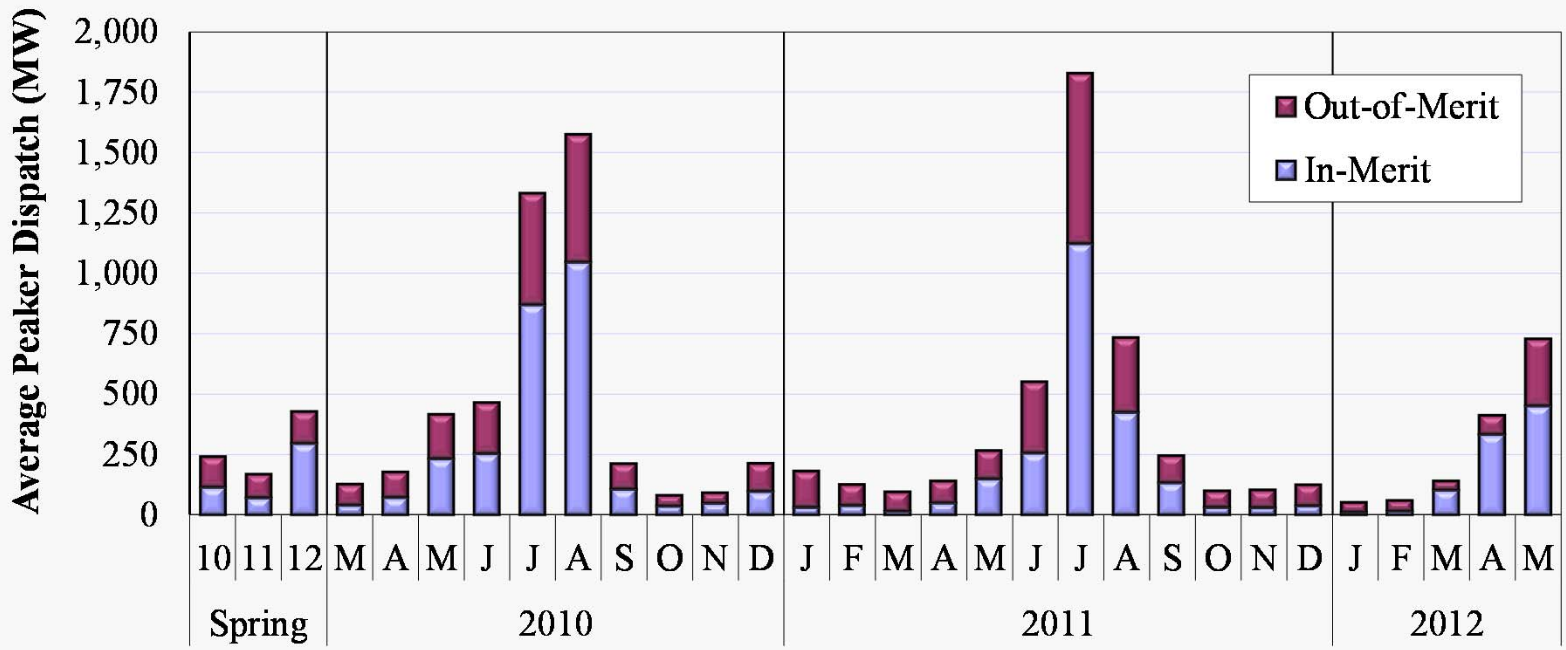
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were out-of-merit (offer price higher than the LMP).
- Peaking resource dispatch quantities rose from an average of 176 MW per hour in spring 2011 to 432 MW in spring 2012.
  - ✓ Most of the rise in dispatch was in-merit peakers, which tripled to 299 MW.
  - ✓ This is partly due to the substantial reduction in natural gas prices that have caused peaking resources to be more economic.
- Low gas prices have caused a number of peaking resources to be committed economically through the day-ahead market or LAC process.
- When peaking resources are dispatched out-of-merit, they do not contribute to setting the energy price, even though they are needed to meet system needs.
  - ✓ MISO's ELMP initiative, filed in December 2011, will allow peaking resources to set energy prices more reliably. It is set to be introduced in late 2013.
  - ✓ This will improve MISO's price signals and reduce real-time RSG costs.

Peaking Resource Dispatch and In-Merit Status 2010–2012



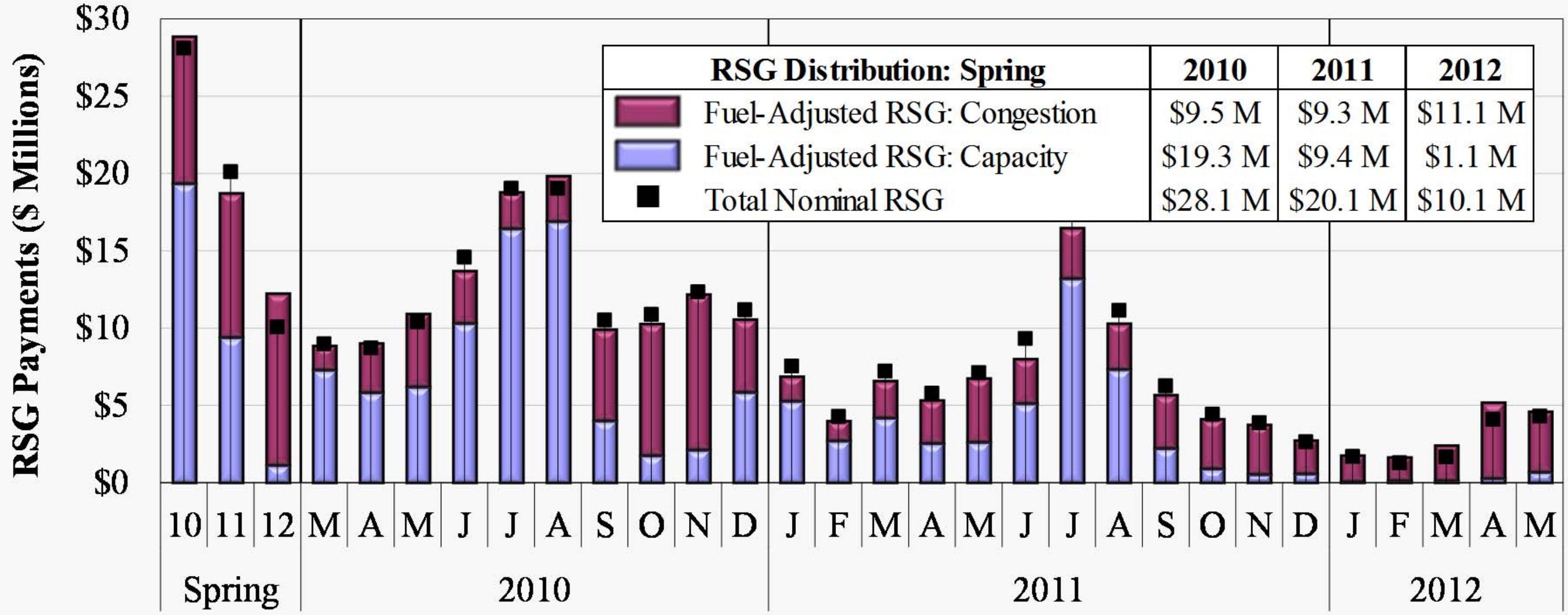
Out-of-Merit Quantity and Share

MW	126	97	133	88	106	185	212	461	530	106	46	44	116	152	87	81	91	119	295	706	310	113	69	75	88	41	45	39	80	280
%	52	57	31	1	59	44	45	35	34	49	54	47	54	82	68	82	64	44	53	39	42	46	68	70	69	75	72	27	19	38

Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices (adjusting values to correspond to the average fuel prices over the period shown).
- Nominal RSG costs fell by half this quarter from last spring to $10.1 million.
  - ✓ The decline in fuel prices accounts for 30 percent of this decrease.
- RSG for commitments made to satisfy capacity requirements declined by nearly 90 percent from last spring to just $1.1 million (fuel-adjusted).
  - ✓ Net day-ahead load-scheduling above 100 percent on most days (see slide 18) limited the need for MISO to commit additional capacity resources in real time.
- RSG for commitments for congestion rose 19 percent to $11.1 million (fuel-adjusted).
  - ✓ Nearly 60 percent ($5.7 million) of this was for congestion in the West region in the second half of the quarter. Two oil-fired units at one plant were paid over $4 million for local needs, including a week-long planned outage that required voltage support.
  - ✓ Payments to non-peaking units for voltage support in WUMS accounted for approximately 25 percent ($2.6 million) of total RSG payments.
- The second figure shows that nominal day-ahead RSG payments fell by 16 percent to $4.7 million, but increased significantly in fuel adjusted terms.
  - ✓ Such payments continue to be lower than real-time RSG payments because most reliability requirements are satisfied only in the real time.

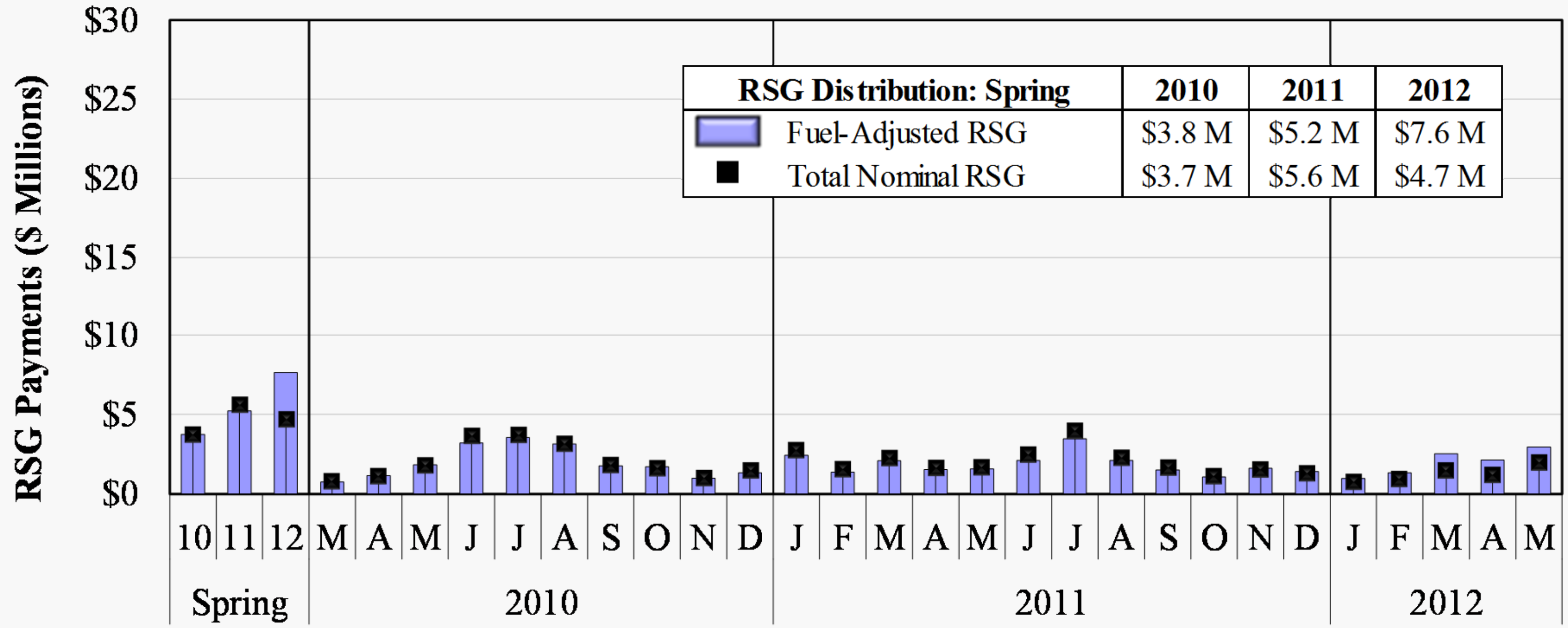
Real-Time RSG Payments 2010–2012



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

	10	11	12	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
Peaker	60	52	58	59	58	64	50	69	71	39	20	23	47	60	53	54	53	48	69	75	66	45	46	41	35	26	31	30	51	75
Constraint	16	13	53	4	16	27	5	6	10	12	13	16	13	7	13	6	17	16	15	14	15	16	32	35	29	26	31	28	48	67
Capacity	44	39	5	55	43	37	45	63	60	28	8	7	34	53	40	49	36	32	53	62	51	29	14	6	7	0	0	1	3	8
Non-Peaker	40	48	42	41	42	36	50	31	29	61	80	77	53	40	47	46	47	52	31	25	34	55	54	59	65	74	69	70	49	25
Constraint	16	36	38	13	19	16	20	7	3	52	72	67	31	15	21	31	34	43	19	6	14	47	48	52	50	69	59	64	47	18
Capacity	24	12	5	28	22	21	30	24	26	9	8	9	22	24	26	15	14	9	12	18	19	9	6	6	15	5	10	6	2	6

Day-Ahead RSG Payments 2010–2012



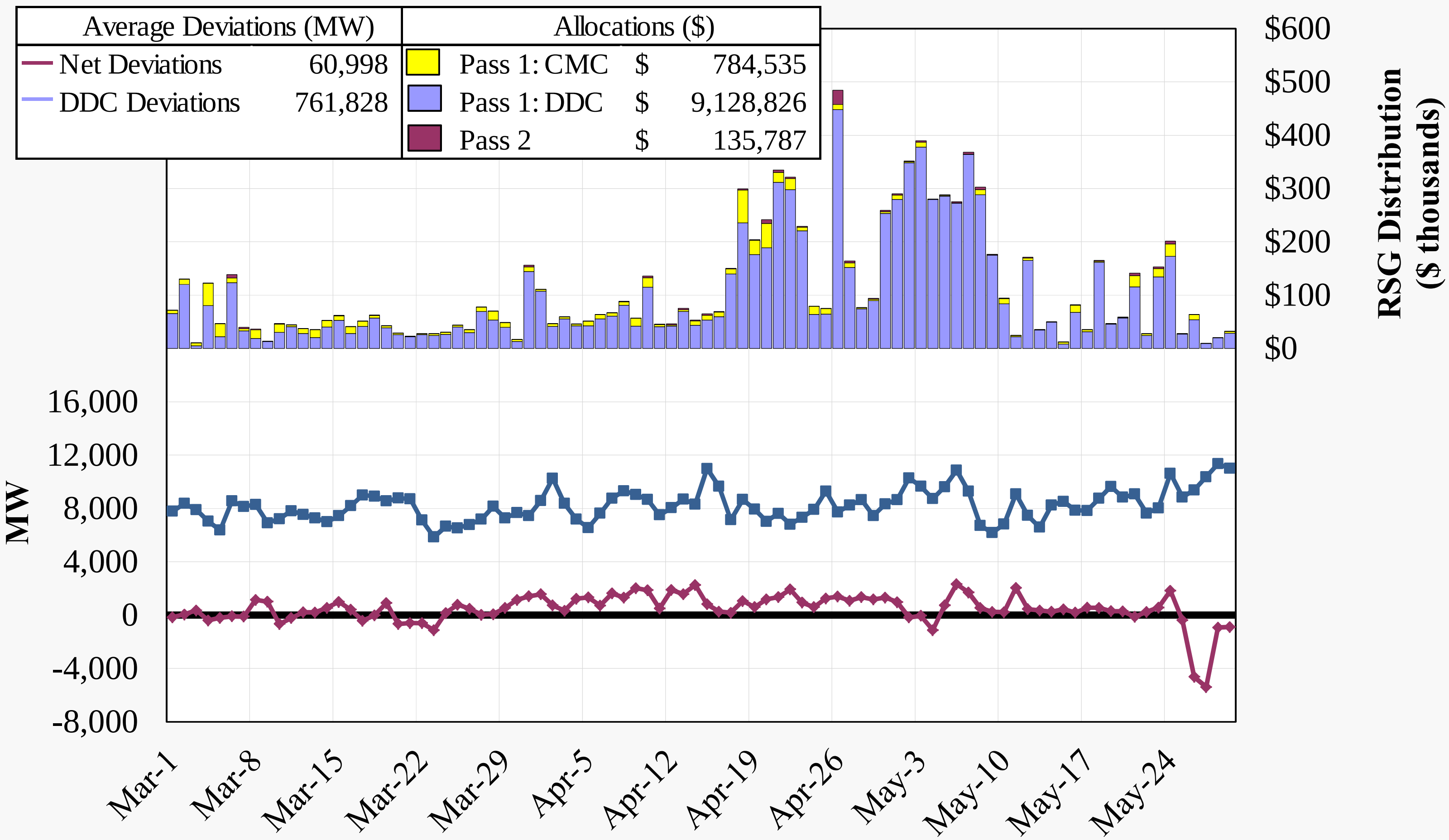
Share of Day-Ahead RSG Costs by Unit Type (%)

Peaker	8	4	12	2	3	14	11	26	35	10	3	3	9	1	0	2	2	7	21	41	15	19	11	6	4	2	1	2	8	21
Non-Peaker	92	96	88	98	97	86	89	74	65	90	97	97	91	99	100	98	98	93	79	59	85	81	89	94	96	98	99	98	92	79

Allocation of RSG Charges

- The next figure evaluates the new RSG Cost Allocation implemented in April 2011.
  - ✓ The top panel shows the real-time RSG that was allocated to market-wide deviations (“DDC”), deviations that affect constraints (“CMC”), and real-time load (“Pass 2”).
  - ✓ The bottom panel shows net deviations from physical load, virtual supply and load.
  - ✓ The high negative deviations in late May reflects substantial load over-scheduling.
- The figure shows that under the new allocation method, more than 90 percent of the real-time RSG costs are being allocated to market-wide deviations under the DDC rate.
  - ✓ This level of allocation substantially exceeds the share of the real-time RSG costs incurred to satisfy capacity needs (less than 10 percent), only a portion of which is caused by deviations.
  - ✓ The excessive share of allocations to market-wide deviations is primarily due to:
    - – Most uplift costs associated with commitments for local voltage support are ultimately being charged to DDC.
    - – Helping and harming deviations are not netted in the allocation, except at the participant level.
- Regarding voltage support costs, MISO is actively working to modify the allocation of these costs, which should be borne by the real-time load in the affected area.
- Regarding netting, the IMM previously filed a protest suggesting all deviations be netted automatically to cap the RSG costs allocated to deviations.

Allocation of RSG Charges
Spring 2012

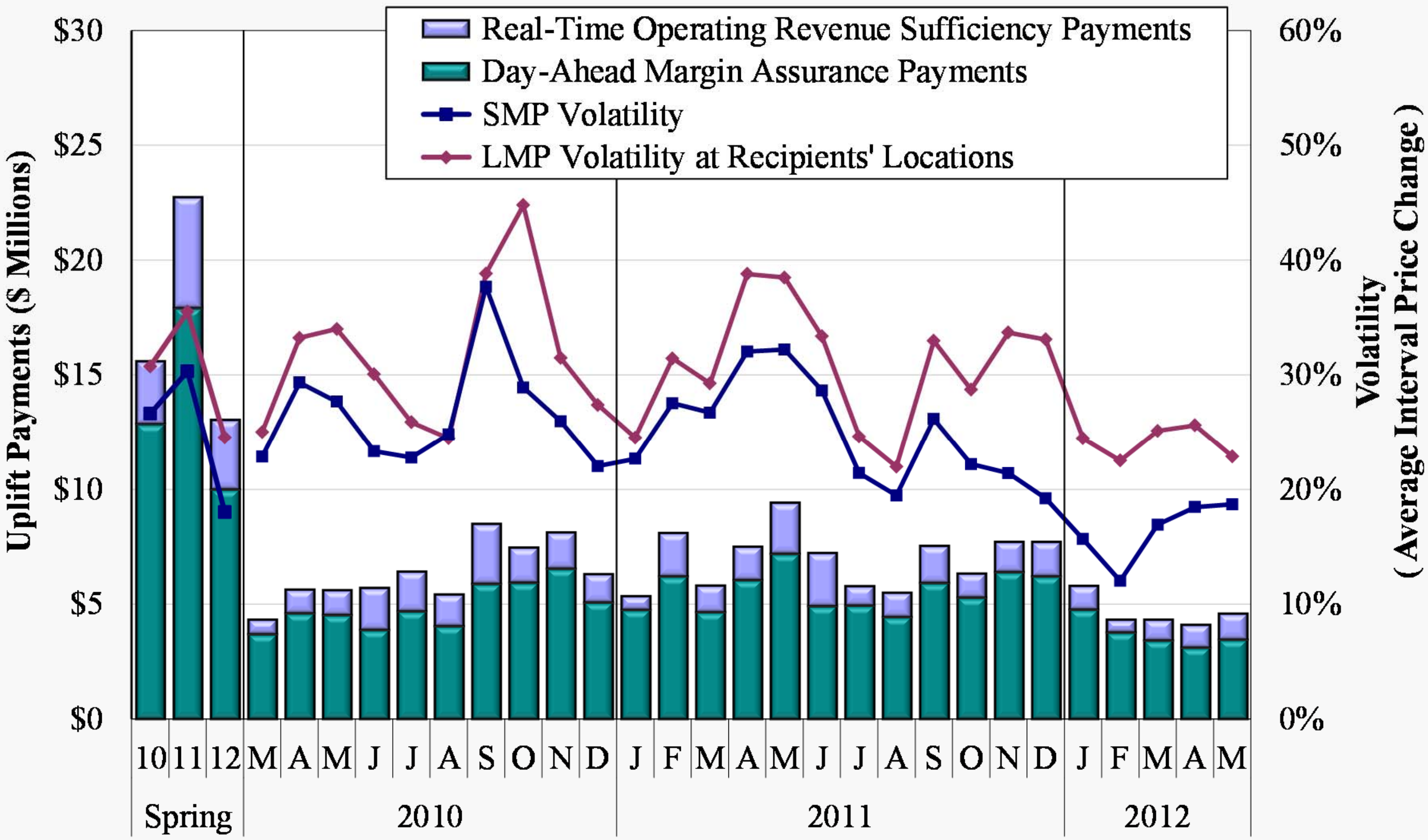


POTOMAC ECONOMICS

Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments ("PVMWP") that improve incentives for suppliers to follow dispatch instructions.
  - ✓ The payments are in two forms: Day-Ahead Margin Assurance payments ("DAMAP") and Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP").
- Total PVMWP in the quarter declined 43 percent from last spring to $13 million, which coincided with a comparable reduction in price volatility as one would expect.
  - ✓ DAMAP remains the larger of the two payments: payments totaled $10 million, down from $18 million in spring 2011.
  - ✓ RTORSGP declined by 37 percent from last spring to $3 million.
- The lines on the chart show two measures of price volatility: one based on the System Marginal Price ("SMP") and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility as expected—increased volatility leads to higher obligations to flexible suppliers.
  - ✓ It also shows that volatility is higher at recipients' locations because they are generally redispatched more than other suppliers due to the larger price changes.
- We recommended in the *2011 State of the Market Report* that MISO revise eligibility criteria for PVMWP to address certain efficiency and gaming concerns. MISO is working with stakeholders to address this recommendation.

Price Volatility Make Whole Payments 2010–2012



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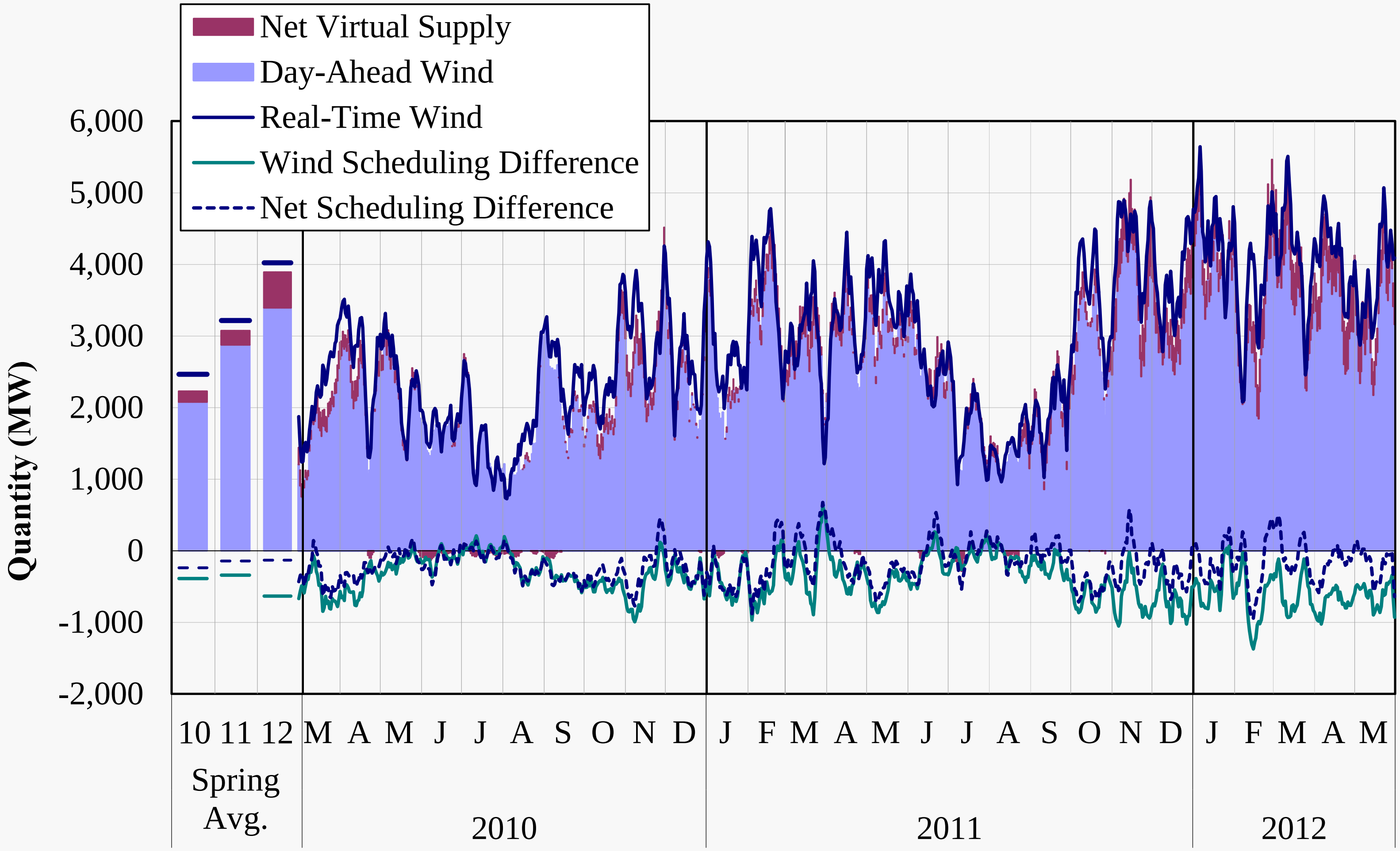
Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Attractive wind profiles in the West Region, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind generation.
- Real-time wind output averaged 4 GW this quarter, up 22 percent from last spring.
  - ✓ Nameplate capacity over the same period increased 17 percent to 10.8 GW.
  - ✓ Wind output made up 8 percent of total generation, up from 6 percent last spring.
- Variability in output—both in real-time and deviations from the day-ahead—must be managed by MISO by modifying the commitment or dispatch of other resources.
- Underscheduling of wind in the day-ahead market averaged 631 MW this quarter.
  - ✓ Nearly 80 percent of this, however, was offset by net virtual supply at wind locations in spring 2012. In this way, virtual supply plays a valuable role in improving net scheduling in the day-ahead market and the resulting market outcomes.
- Manageability of the congestion caused by wind should continue to improve as DIR resources expand in the MISO footprint.
  - ✓ As of June 1, 37 wind resources totaling 4.8 GW (41 percent of all wind capacity), are dispatchable and can set the real-time energy price.

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



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Wind Curtailments

- Manual curtailment of wind resources by MISO are at times necessary to prevent transmission overloads (most wind resources are not currently dispatchable).
  - ✓ Since the implementation of the DIR type in June 2011, increasing amounts of wind resources have become able to respond to MISO dispatch instructions.
    - DIR units provided MISO with additional flexibility to manage congestion.
  - ✓ A total of 30 resources, comprising over 4 GW of wind, were DIR in spring 2012.
    - An additional 7 resources (totaling 800 MW) became dispatchable in June.
- The following figure shows that economic DIR curtailments have replaced manual curtailments as the primary means of controlling wind output.
  - ✓ Economic curtailment of wind resources averaged 109 MW in spring 2012.
  - ✓ DIR resources are being curtailed economically at a greater rate than they were being curtailed manually prior to converting to DIR.
    - This does not suggest that the DIR is not more effective, it is a reflection of how rapidly wind output is growing. Absent DIR, manual curtailments would have been much higher.
- Manual curtailments declined by half to 51 MW per hour (1.2 percent of the wind output) in spring 2012, down from 105 (3.1 percent) and 163 MW (6.2 percent) per hour in the spring of 2011 and 2010 , respectively.

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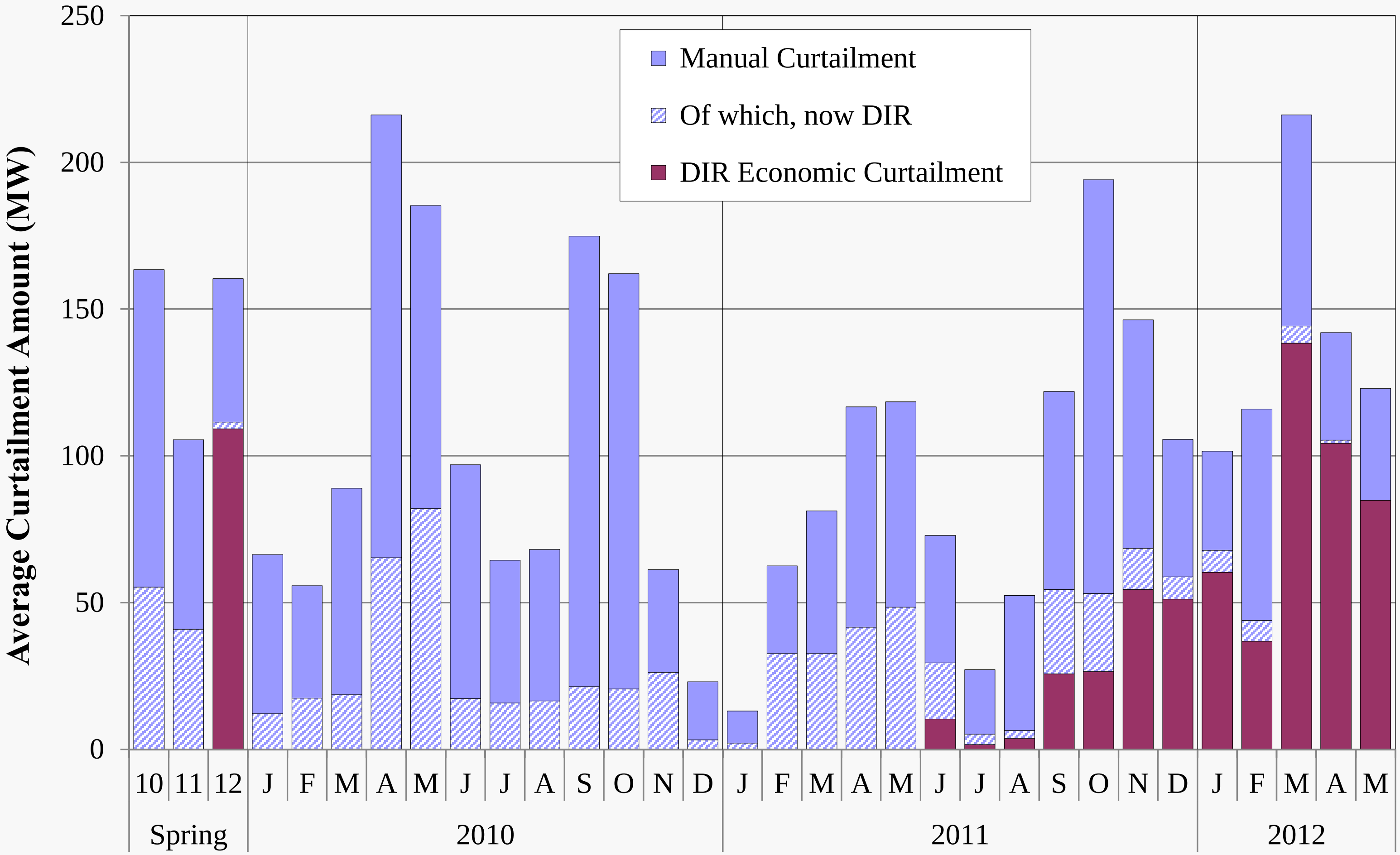
Wind Curtailments
2010–2012



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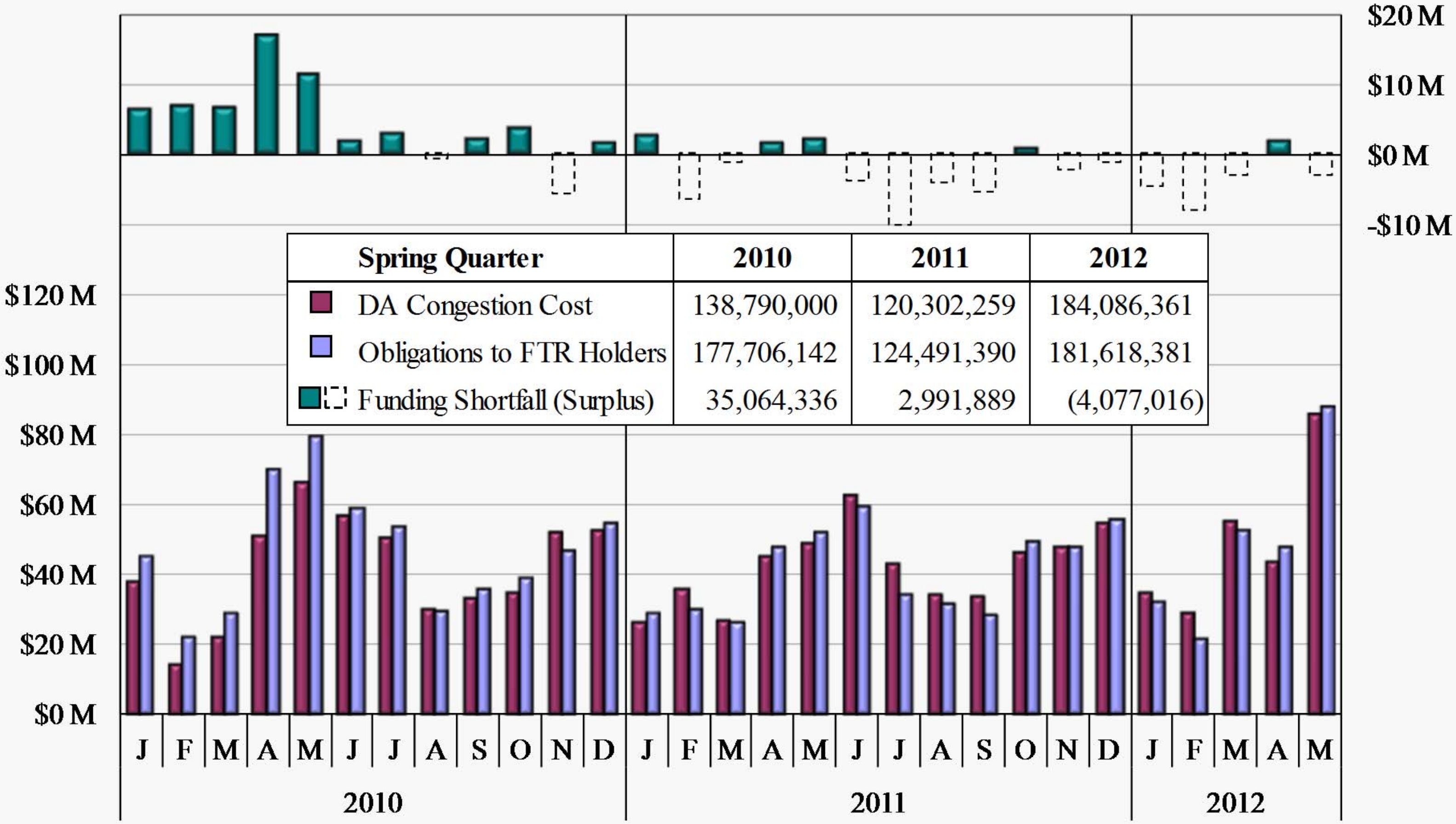
Day-Ahead Congestion and Obligations to FTR Holders

- FTR holders are entitled to the day-ahead congestion costs that arise between particular locations in MISO, which allows them to manage day-ahead price risk.
  - ✓ MISO collects day-ahead congestion from loads and pays it out via FTRs.
    - – Day-ahead congestion in spring rose 63 percent from last spring to $199 million.
  - ✓ The next figure shows day-ahead congestion, FTR obligations, and FTR shortfalls/surpluses, which occur when the portfolio of FTRs represent more or less transmission capacity than the capability of the network in the day-ahead market.
- MISO's continued work on the ARR allocation process and modeling improvements in the FTR market has increased FTR funding.
  - ✓ The day-ahead funding surplus was a modest $4 million this spring, compared to shortfalls of $3 million last spring and $35 million in spring 2010.
  - ✓ However, sustained surpluses can indicate that MISO is not making FTRs available that fully reflect the capability of the system.
    - – The largest surpluses were on market-to-market constraints that were over-funded by 25 percent. To address this, we recommend that MISO model its market-to-market entitlements in the FTR market (rather than typical flows).

Day-Ahead Congestion and Obligations to FTR Holders, 2010–2012



Spring Quarter	2010	2011	2012
DA Congestion Cost	138,790,000	120,302,259	184,086,361
Obligations to FTR Holders	177,706,142	124,491,390	181,618,381
Funding Shortfall (Surplus)	35,064,336	2,991,889	(4,077,016)

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Congestion Management

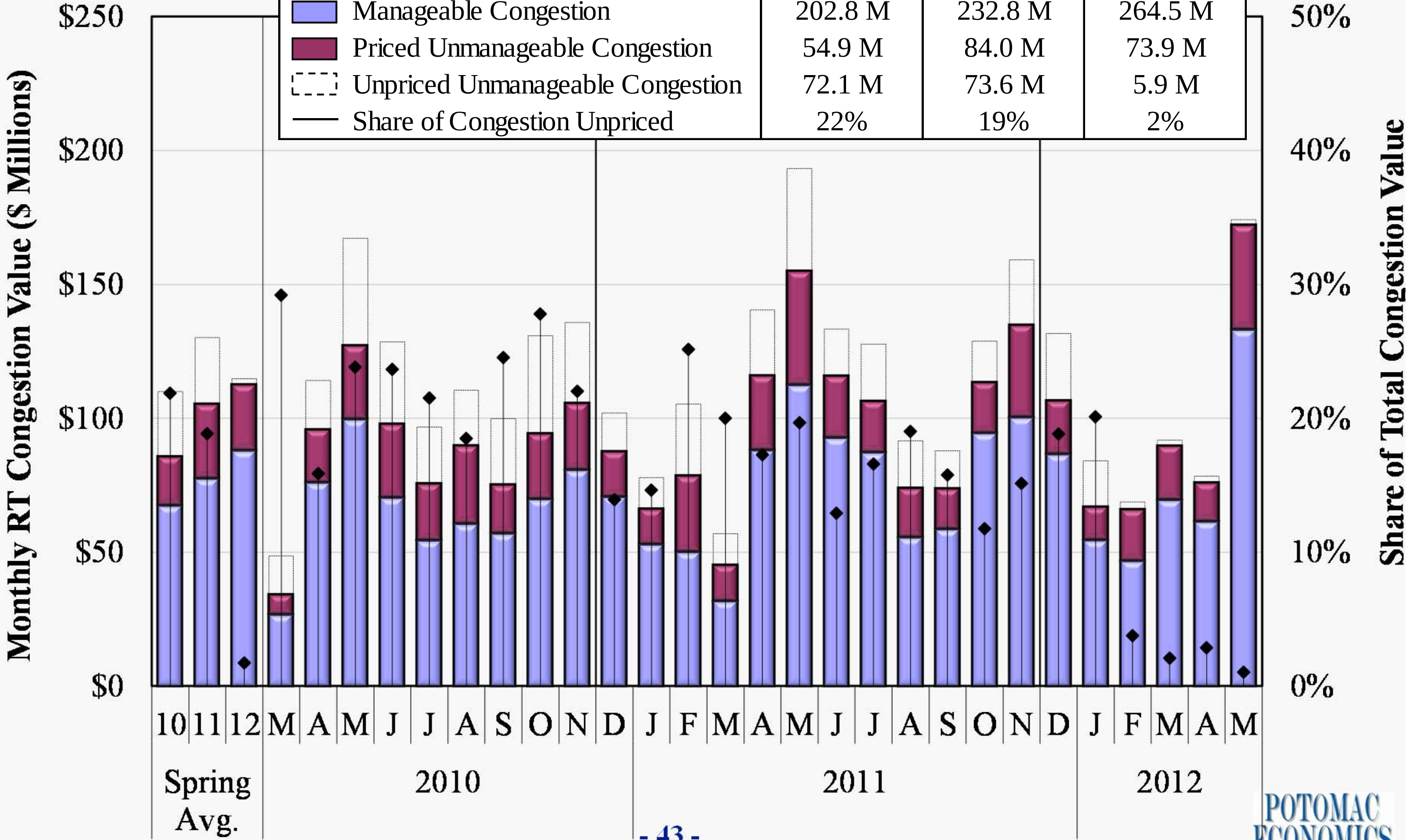
- As noted previously in prior reports MISO recently made two significant changes to congestion management
  - ✓ In late January, MISO implemented a new process to reduce the lag between observed flows on constraints and inputs into the real-time market.
  - ✓ On February 1, 2012 constraint relaxation was disabled for internal non-M2M constraints.
    - – Constraint relaxation is an algorithm that caused unmanageable constraints (whose flow exceeds its limit for at least one interval) to be underpriced.
- Based on the first full quarter of operation, these two initiatives have resulted in a substantial improvement in the manageability and pricing of constraints.
  - ✓ Violated constraints are now priced at their full Marginal Value Limit (assumed cost of violating the constraint in the real-time dispatch), leading to day-ahead market results and MP actions have improved the management of the constraints.
  - ✓ MISO has also developed new post contingency action plans with Tos, reducing the need to activate low-voltage constraints that cannot be managed.
  - ✓ We will continue to evaluate the impacts of these initiatives.

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).
- Real-time congestion rose 6 percent from last spring to $344 million. However , congestion was 10 percent lower than last spring if it congestion had been fully priced last spring.
- Congestion in May totaled $172 million, the highest monthly total in several years.
  - ✓ Most of the increase was on internal constraints (see second figure) affected by planned generator and transmission outages (much of which was in the West). One pair of constraints alone accrued $27 million of congestion.
- As noted, constraint relaxation was turned off for internal constraints in February but it continues to be used on MISO M2M and external constraints.
  - ✓ Relaxation eliminated 19 percent of congestion last spring, but just 2 percent this spring.
  - ✓ This is an improvement, but still adversely affects the day-ahead market, FTR market, and longer-term investment decisions.

Value of Real-Time Congestion
2010–2012

Spring Totals	2010	2011	2012
Manageable Congestion	202.8 M	232.8 M	264.5 M
Priced Unmanageable Congestion	54.9 M	84.0 M	73.9 M
Unpriced Unmanageable Congestion	72.1 M	73.6 M	5.9 M
Share of Congestion Unpriced	22%	19%	2%



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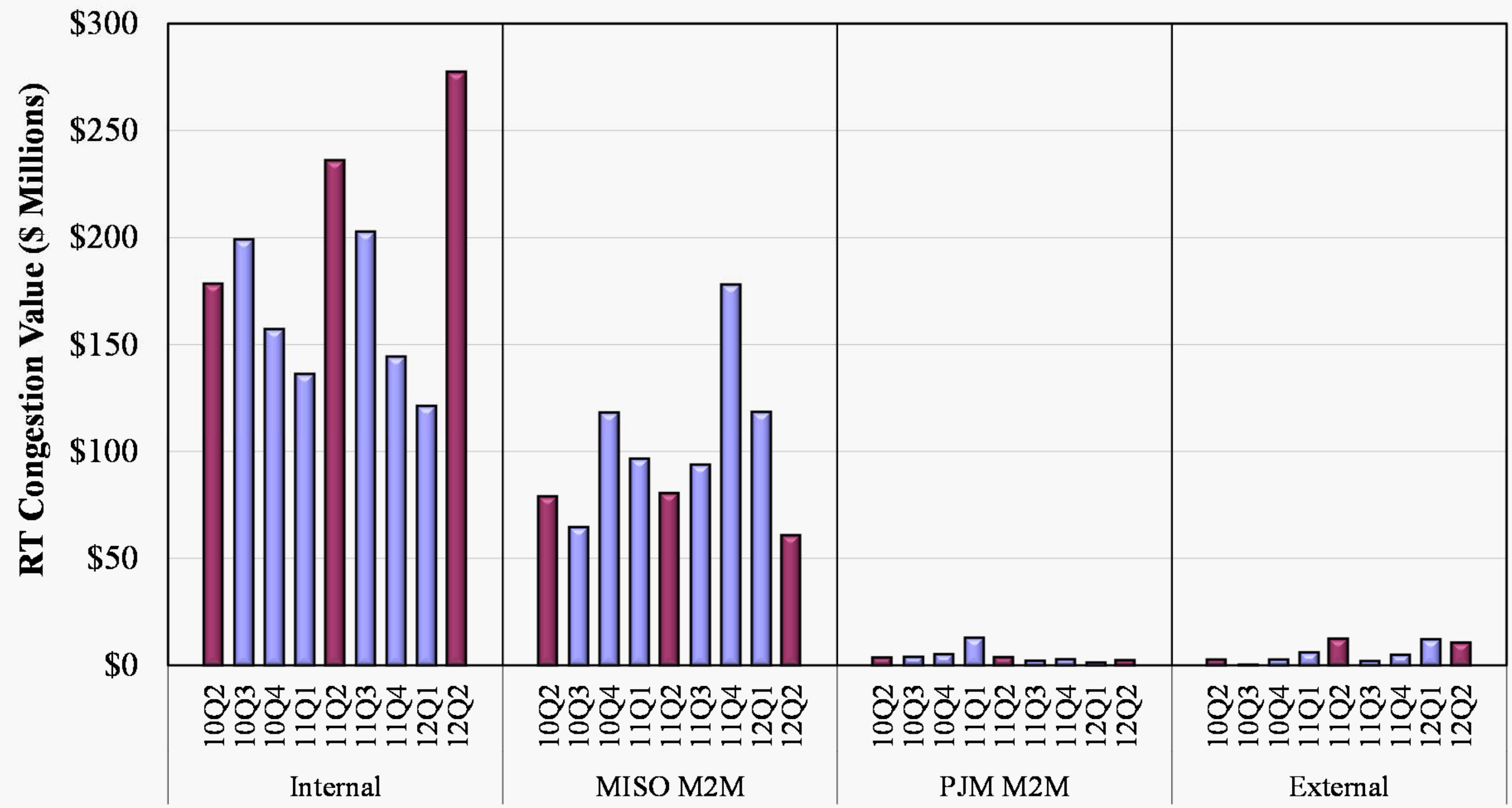
Value of Real-Time Congestion By Constraint Type 2010–2012

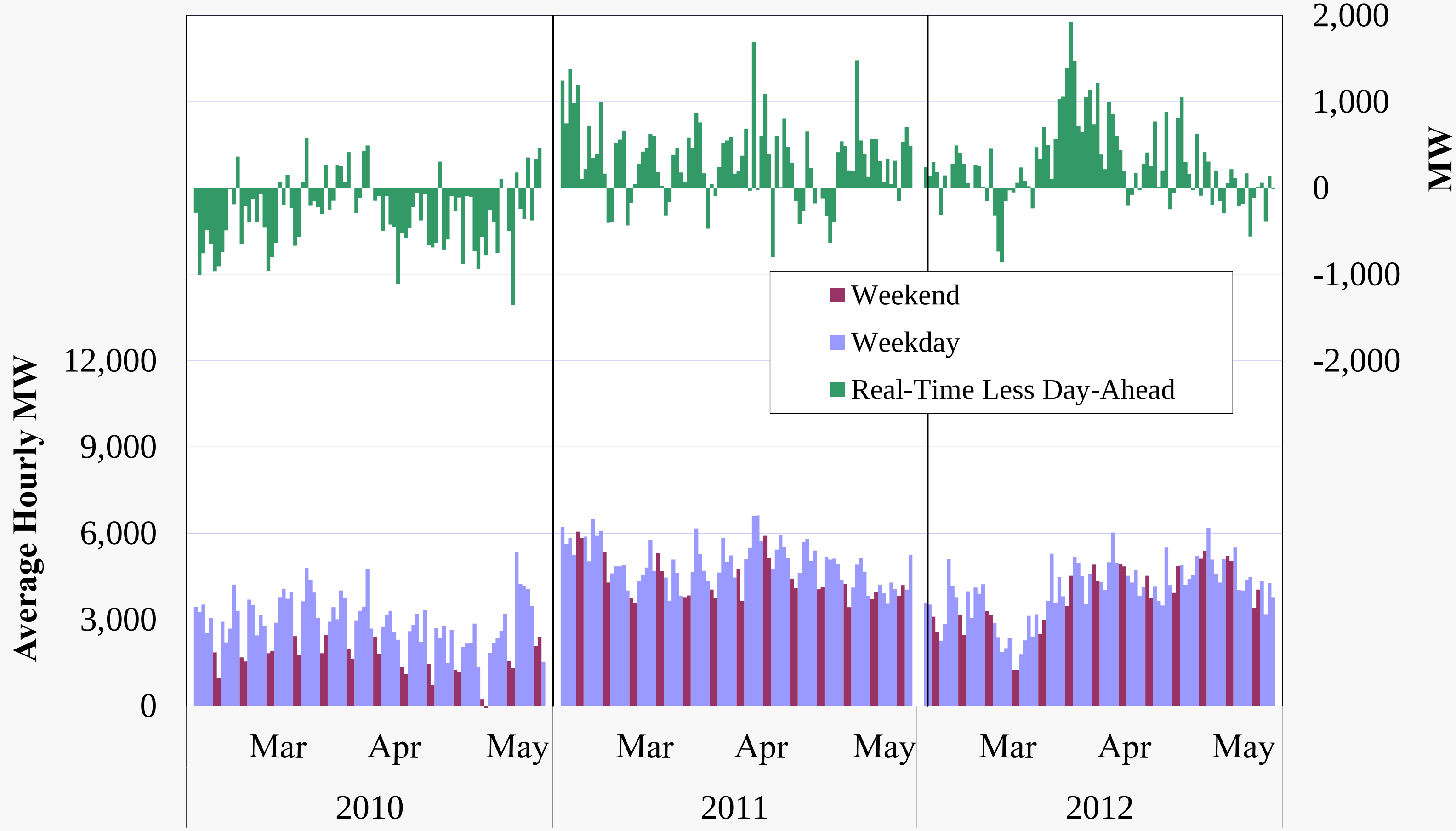


Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market during the springs of 2009 to 2011.
- MISO's net imports declined 18 percent to 4.0 GW per hour on average.
  - ✓ Imports into the East region fell by nearly 2 GW from last spring, while imports to the West region rose, particularly during peak hours (to 1.8 GW).
  - ✓ Imports from Manitoba and PJM declined by 10 and 35 percent, respectively, and together were 48 percent of MISO's imports (down from 57 percent).
- Imports were under-scheduled day-ahead by 268 MW on average (real-time net imports increased).
  - ✓ This is a modest reduction from being under-scheduled by 320 MW last spring.
  - ✓ Revisions to the RSG allocation process last April reduced charges to real-time imports. Participants are currently assessed a deviation charge only on net negative real-time volumes.
  - ✓ Imports were significantly under-scheduled in the day-ahead in early April, when average real-time imports were 1,000 MW higher on 9 days.

POTOMAC ECONOMICS

Average Hourly Real-Time Imports
Spring 2010–2012

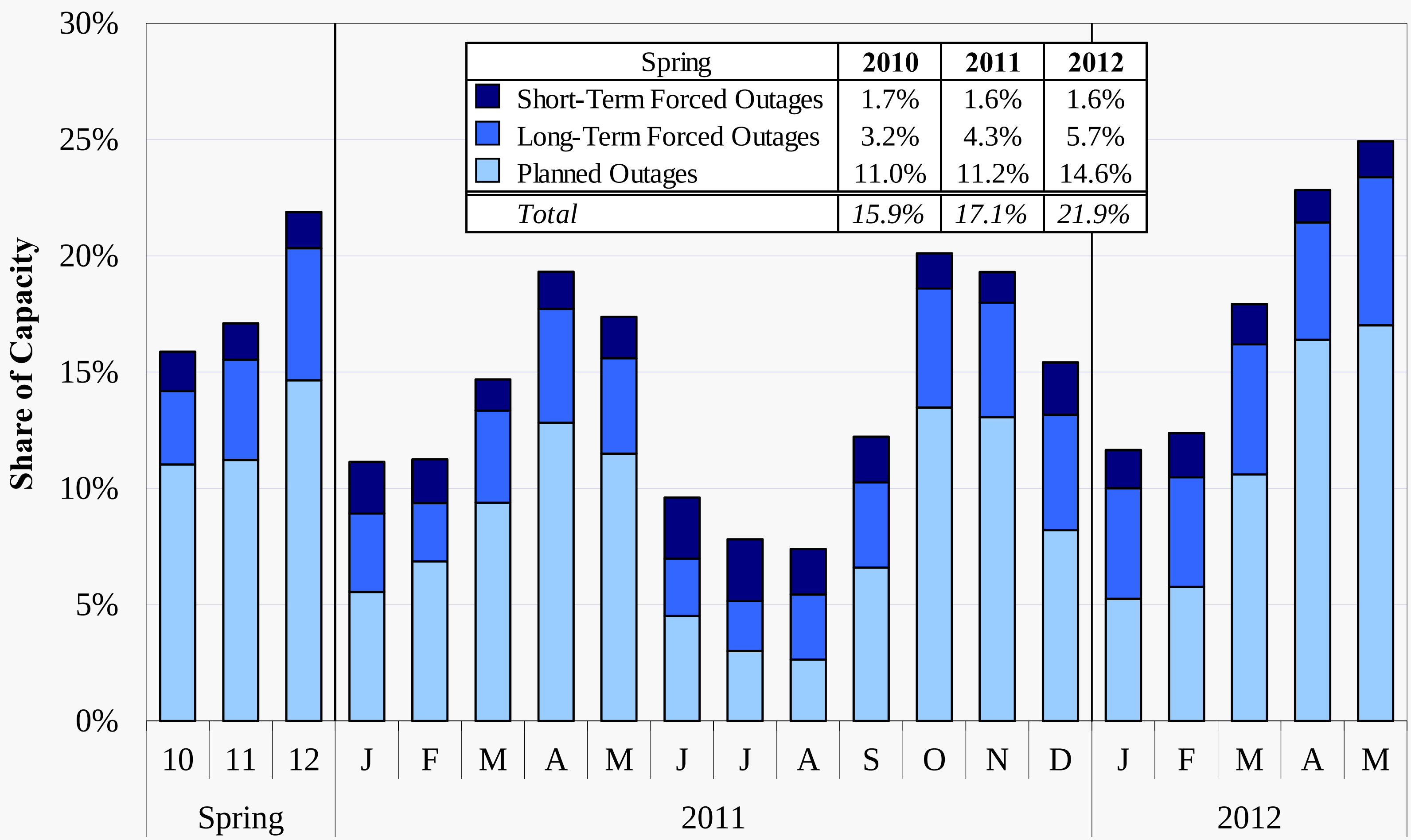


POTOMAC ECONOMICS

Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2011 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 21.9 percent in spring 2012, up from 15.9 and 17.1 percent in prior spring quarters.
  - ✓ Short-term forced outages in spring remained unchanged at 1.6 percent.
    - – Such outages can indicate potential physical withholding, although this is unlikely during low-load periods.
  - ✓ Planned outages rose from 11.2 to 14.6 percent.
    - – Low shoulder-season prices increase the incentive to schedule maintenance.
    - – Low gas prices contributed to increased planned outages of coal resources.
    - – Some of this increase was associated with environmental upgrades.
  - ✓ Long-term forced outages increased comparably to 5.7 percent.

Generation Outage Rates
2011–2012



Spring	2010	2011	2012
Short-Term Forced Outages	1.7%	1.6%	1.6%
Long-Term Forced Outages	3.2%	4.3%	5.7%
Planned Outages	11.0%	11.2%	14.6%
Total	*15.9%*	*17.1%*	*21.9%*

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 2010 under two thresholds: a "high" threshold (equal to the mitigation threshold) and a "low" threshold (equal to one-half of mitigation threshold).
- Output gap levels under both thresholds continued to be extremely low, averaging just 30 and 8 MW this quarter under the low and high thresholds, respectively.
- As a share of overall load, the low-threshold output gap again averaged less than 0.01 percent of load.
  - ✓ The mitigation thresholds for Narrow Constrained Areas were updated in early February. The Minnesota threshold declined substantially while the WUMS threshold increased substantially. The North WUMS increased slightly.
  - ✓ These threshold changes can affect the output gap levels since they are used in this analysis.
- Overall, these results raise no competitive concerns, although we continue to routinely investigate hourly increases in the output gap.

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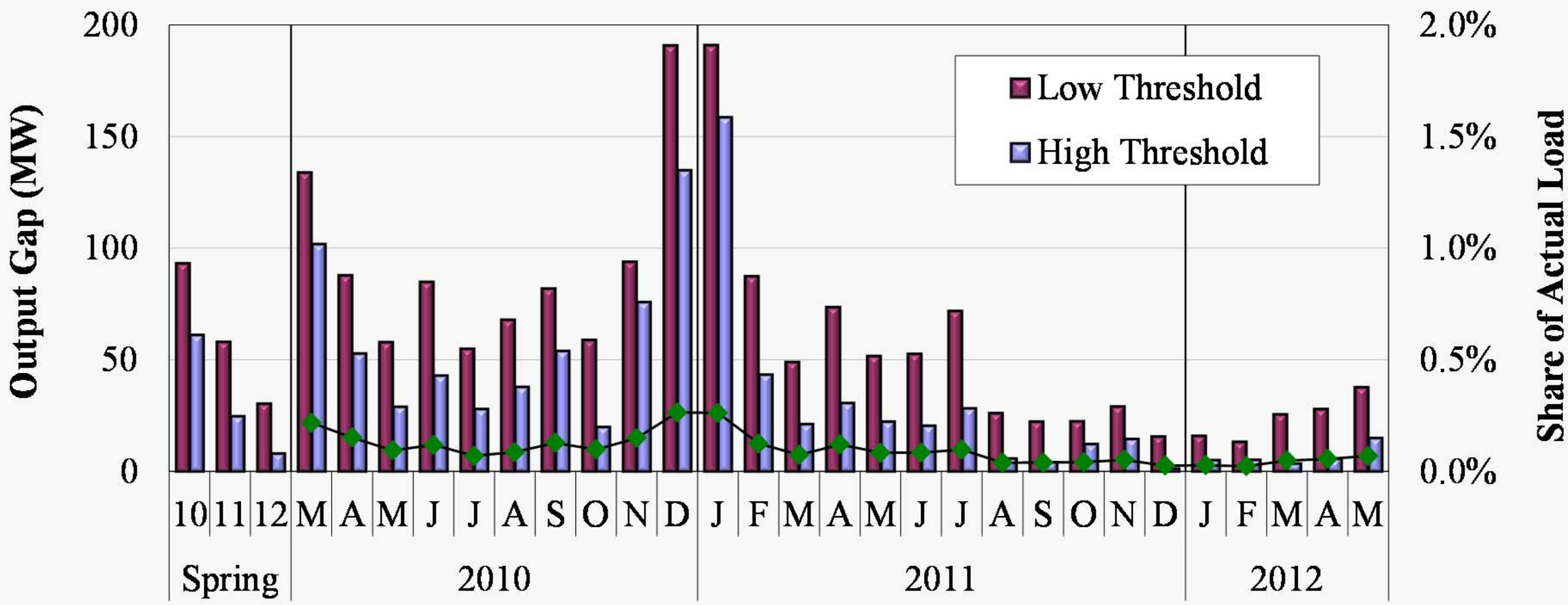
Monthly Output Gap
2010–2012



Low Threshold Results by Unit Status (MW)

Off Line	38	15	4	75	28	12	31	16	19	18	5	33	95	143	44	21	14	9	11	23	0	1	11	12	0	4	4	1	1	9
On Line	55	44	26	59	60	46	54	38	49	64	54	61	96	48	43	29	60	43	42	49	26	22	12	17	16	12	9	24	26	29

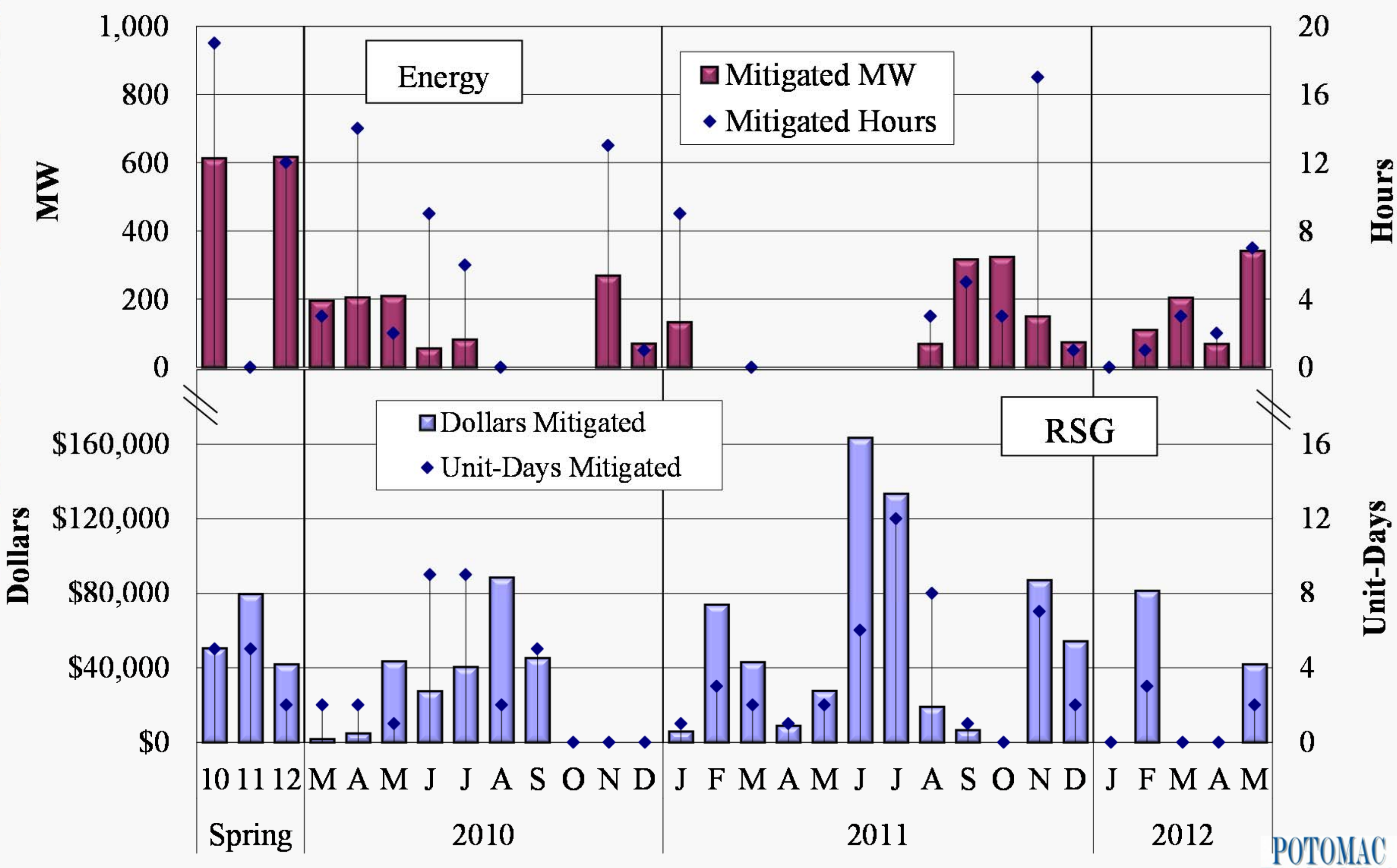
High Threshold Results by Unit Status (MW)

Off Line	37	13	4	73	27	12	31	16	19	18	5	33	89	142	29	16	14	9	10	19	0	1	11	12	0	4	4	1	1	9
On Line	24	12	4	29	26	17	12	12	19	36	15	43	46	17	14	5	17	13	10	9	6	4	1	3	1	2	1	2	4	6

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which mitigation has been imposed in the real-time market and for RSG payments.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Mitigation remains infrequent in the MISO market. Energy mitigation occurred for 12 unit-hours and a total of 617 MW in spring 2012.
  - ✓ Three-quarters of it occurred in Broad Constrained Areas; the balance occurred in the Minnesota NCA (where the mitigation threshold was recently lowered).
  - ✓ RSG mitigation in spring 2012 fell by almost half from $80,000 last spring to $42,000.
- We continue to evaluate each instance of AMP mitigation and found mitigation to be appropriately applied.
- Mitigation continues to be extremely infrequent because the vast majority of resources are offered competitively in the MISO markets. This can be attributed to:
  - ✓ The fact that most resources are owned by entities that also service load, most of which are regulated at the state level.
  - ✓ The market is less vulnerable to exercises of market power when load is low.
- Nonetheless, local market power continues to be a significant concern.
  - ✓ Market power mitigation measures therefore remain critical.

Real-Time Market Power Mitigation
2010–2012



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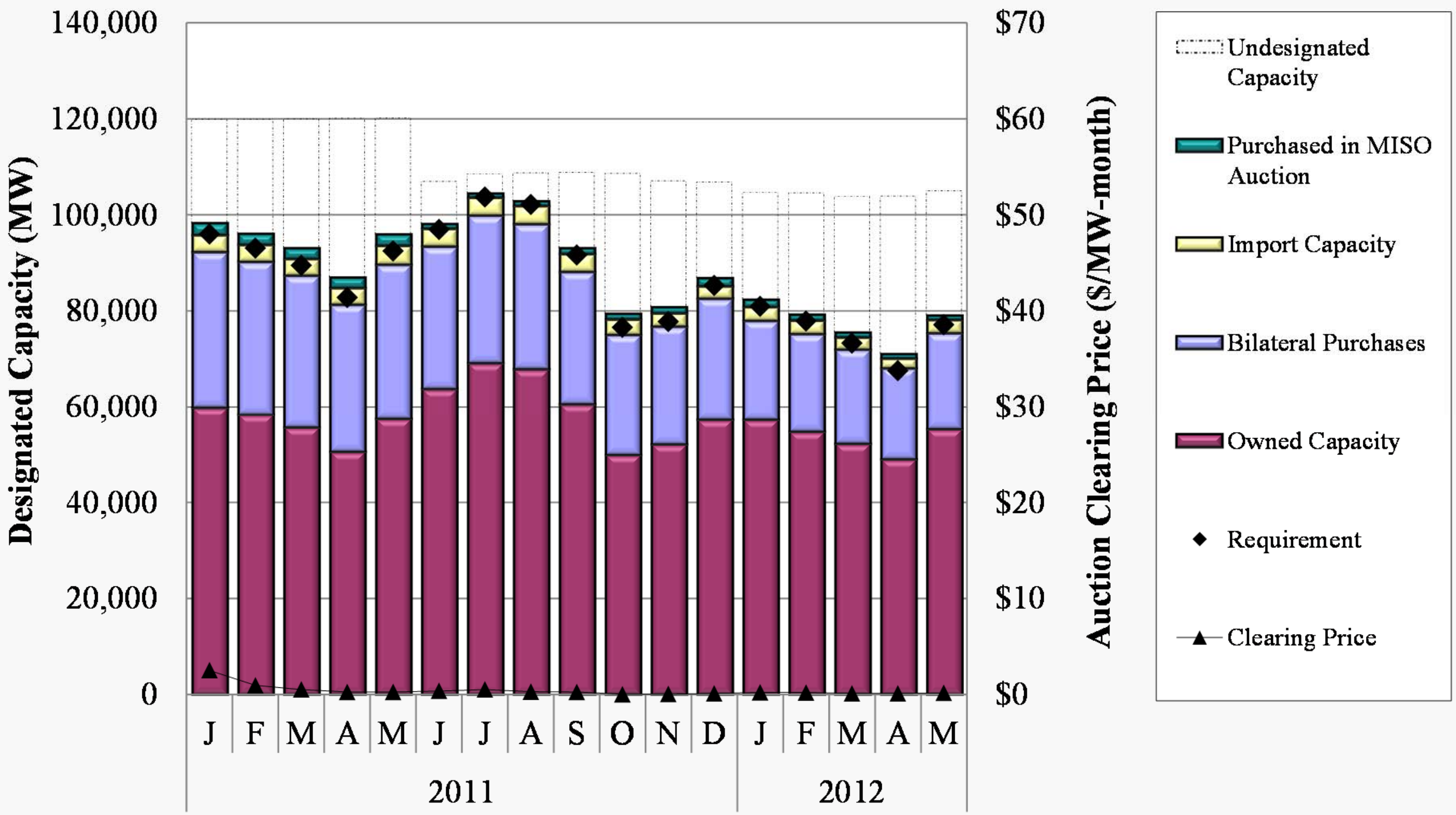
Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The auction continues to clear at close to zero (less than $1 per MW-month), which is consistent with the surplus level of capacity over the minimum requirement and the prevailing market design.
  - ✓ The departures of FirstEnergy in June 2011 and portions of Duke Energy in January has not had a material impact on resource adequacy.
- The following figure shows the monthly capacity requirements, designated capacity, and VCA clearing price since January 2011.
  - ✓ The capacity cleared in the VCA each month remains a very small portion of the total designated capacity (1-2 percent), which is consistent with fact that most LSEs satisfy their capacity needs primarily through owned capacity or bilateral purchases.
- The figure also shows the total supply and designations for resources in MISO.
  - ✓ The total capacity available exceeded the requirement by at least 25 percent (except in summer months). As a result, VCA clearing prices remain extremely low.
  - ✓ Capacity designations exceeded the requirement by 3-5 percent this spring.
- The market continues to be undermined by barriers to trading capacity with PJM and current "vertical demand curve" – we filed in January requesting a FERC mandate to address these issues, and recommended changes *2011 State of the Market Report*.

Voluntary Capacity Auction 2011–2012



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

POTOMAC ECONOMICS

Submittals to External Entities and Other Issues

Submittals to External Entities in May:

- We continue to meet regularly with FERC regarding market outcomes and responded to a number of inquiries and data requests this quarter.
  - ✓ We provided additional details to FERC related to previous referrals.
  - ✓ We submitted reports to FERC regarding participants that may have violated Module E must offer requirements.
  - ✓ We responded to FERC questions related to VLR mitigation and allocations and participated in the FERC Technical Conference and filed responses to post-conference questions.
- We presented the Annual State of the Market Report to FERC staff and the monthly report to the OMS.

Other Issues:

- We continued to coordinate with MISO staff on responses to SOM recommendations.
- We continue to work with MISO on the fall implementations of voltage/local reliability market power mitigation and Order 755 (regulation mileage product).