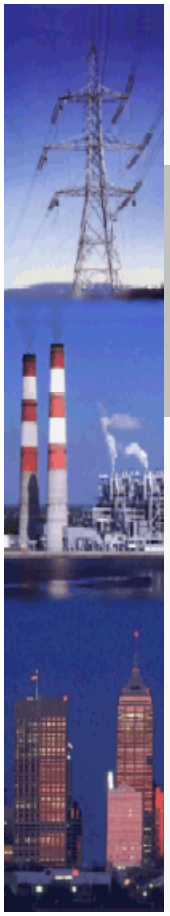

IMM Quarterly Report
First Quarter 2010

Presented by:

David B. Patton, Ph.D.
Independent Market Monitor

April 14, 2010

POTOMAC ECONOMICS

Summary of Quarterly Results

- This presentation summarizes the outcomes of the Midwest ISO energy and ancillary services markets during the first quarter of 2010.
- Overall, the markets performed competitively while producing slightly higher prices than those in the first quarter of 2009.
  - ✓ Real-time energy prices averaged $35.29 per MWh in the first quarter of 2010, 6.4 percent higher than prices during the first quarter of 2009.
    - The energy price increases were primarily due to higher fuel prices.
    - Higher load associated with the economic recovery also contributed to the increase.
    - The general pattern of west-to-east congestion continued, consistent with increased output of wind resources driving exports from the West region.
  - ✓ Ancillary service prices remained consistent with expectations.
    - Regulation prices fell gradually in 2009 due to reductions in regulation requirements and fuel prices, but rose slightly in the first quarter of 2010 as fuel prices rose.
  - ✓ Real-time transmission congestion was 21 percent lower in the first quarter of 2010 than in the first quarter of 2009 due to transmission improvements and operating changes in 2009.
  - ✓ With the exception of July, the voluntary capacity auction has cleared with a price close to zero, which is consistent with the prevailing high level of surplus capacity.

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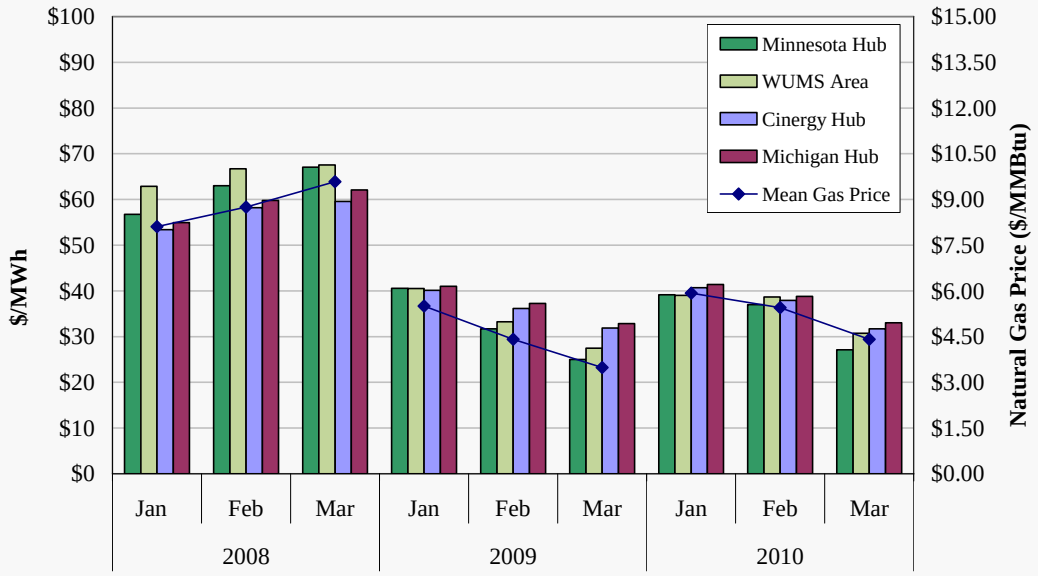
Day-Ahead Average Monthly Hub Prices
All Hours

- The first figure in this section shows average day-ahead energy prices in the first three months of 2008 through 2010 at four hubs in the Midwest ISO.
  - ✓ The figure also shows 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.
- Prices in the first quarter of 2010 were slightly higher than prices in the first quarter of 2009, but were 35 to 45 percent lower than in the first quarter of 2008.
  - ✓ The average price at Cinergy Hub was $37 per MWh in the first quarter of 2010, up 2 percent from the first quarter of 2009.
- The primary drivers of the year-over-year price increase were:
  - ✓ Higher natural gas prices, which were up 17 percent; and
  - ✓ A 2.4 percent increase in average load (excluding the effects of the addition of MidAmerican and Muscatine in September 2009).
- These drivers were partially offset by:
  - ✓ Substantially less real-time congestion, particularly during February and March; and
  - ✓ Increased output from wind resources.
- Prices at Cinergy and Michigan continue to be modestly higher than prices at WUMS and Minnesota, which is indicative of the west-to-east congestion pattern.

POTOMAC ECONOMICS

Day-Ahead Average Monthly Hub Prices
All Hours



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All-In Price
2008 – March 2010

- The "all-in price" summarizes prices in the Midwest ISO and 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, the average real-time uplift costs, and the costs of ancillary services and capacity.
  - ✓ The ancillary services are shown only after January 2009, when the Midwest ISO began operating markets for these products. Similarly, capacity costs are only included from June 2009 at the inception of the voluntary capacity auction.
- The all-in price for the first quarter of 2010 was $35.75 per MWh, a 6 percent increase from the first quarter of 2009.
  - ✓ The increase from 2009 was generally due to increases fuel prices and load, and was offset slightly by lower ancillary service and uplift costs.
- Energy costs made up nearly the entire all-in price, with uplift, ancillary services and capacity costs collectively accounting for just over 1 percent of the all-in price.
  - ✓ The voluntary capacity auction has cleared at close to zero in each month except July 2009, which is consistent with the high level of surplus capacity in the Midwest ISO.

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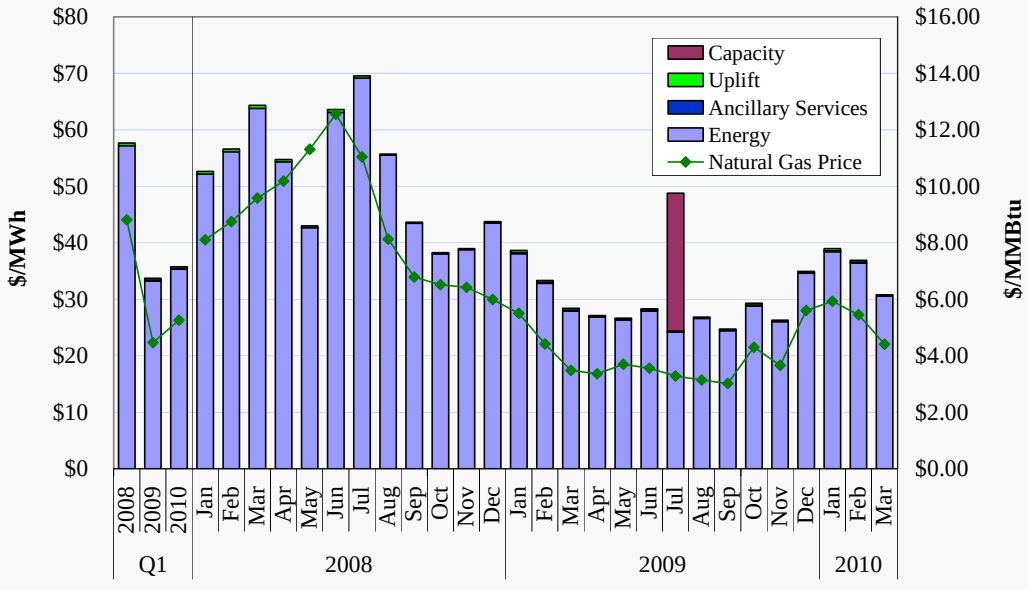
All-In Price
2008 – March 2010



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Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time clearing prices for the Midwest ISO's ancillary service products for the year-to-date.
  - ✓ ASM markets continue to operate as expected with no significant issues.
  - ✓ The prices in the Midwest ISO have been consistent with expectations, averaging $14.45 and $3.04 since inception for regulation and spinning reserves, respectively.
  - ✓ Regulation prices averaged $13.95 in the first quarter of 2010, 27 percent lower than in the first quarter of 2009.
    - The lower prices were due in part to an 80 MW reduction in the average regulation requirement made over the course of 2009 that eased demand.
    - However, the formula-based regulation penalty price, which set prices during shortage intervals, increased substantially in the first quarter of 2010.
  - ✓ Locational differences in ASM prices continue to be relatively limited.
- Spring 2009 exhibited the highest frequency of spinning reserve and regulation shortages.
  - ✓ The Midwest ISO has improved the consistency between the market requirements and operating requirements, which tends to reduce the frequency of such shortages.
  - ✓ Prices do not always accurately reflect the spinning reserve shortages due to the Midwest ISO's method of relaxing the requirement during the shortage.

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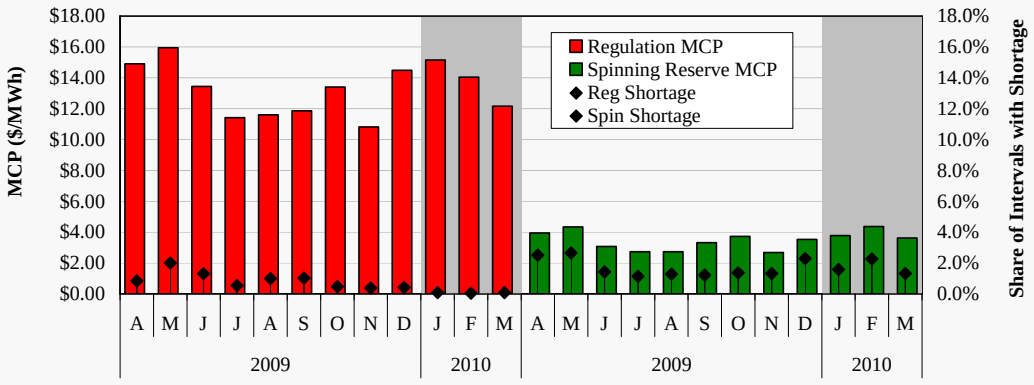
Monthly Average Ancillary Service Prices Regulation and Spinning Reserves



Zonal Price Premiums

Zone 1	0.15	0.08	0.54	0.15	0.49	0.03		0.01		0.11	0.06	0.56												
Zone 2	0.61	1.05	1.64	0.47	1.13	0.32	0.64	1.00	1.35	1.69	0.74	0.24												
Zone 3	0.10	0.13	0.18	0.04	0.10	0.05	0.02	0.09	0.07	0.44	0.30	0.02												
Zone 4																								
Zone 5	3.23	2.84	2.57	1.48	2.10	1.81	1.22	1.04	1.79	1.65	1.95	2.09												
Zone 6	0.71	1.36	1.42	0.45	0.33	0.28	0.63	0.42	0.43	0.52	0.05	0.24												
Zone 7	0.65	0.68	0.53	0.18	0.38	0.75	0.83	0.66	1.47	0.63	0.92	0.20												

POTOMAC ECONOMICS

Midwest ISO Fuel Prices

- The next figure shows daily average fuel prices from January 2008 through the first quarter of 2010.
- Economic conditions contributed to substantial reductions in fuel prices from mid-2008 through 2009. Fuel prices have recovered from their lows of summer 2009.
- <u>Oil and Natural Gas Prices</u>
  - ✓ Natural gas prices, after a sharp rise in late December, declined gradually over the first quarter of 2010. Prices averaged $5.29 per MMBtu, up 17 percent from the first quarter of 2009.
  - ✓ Oil prices in the first quarter of 2010 continued to rise gradually, a trend that began in early 2009. At an average of $14.43 per MMBtu, prices in the first quarter of 2010 were almost 60 percent higher than in the first quarter of 2009.
- <u>Coal Prices</u>
  - ✓ Quarterly average Illinois Basin prices were up 5 percent during the first quarter of 2010 at $1.76 per MMBtu, but were 30 percent lower than in the first quarter of 2009.
  - ✓ Power River Basin prices increased 36 percent during the quarter and averaged $0.64 per MMBtu. Prices were unchanged from the first quarter of 2009.

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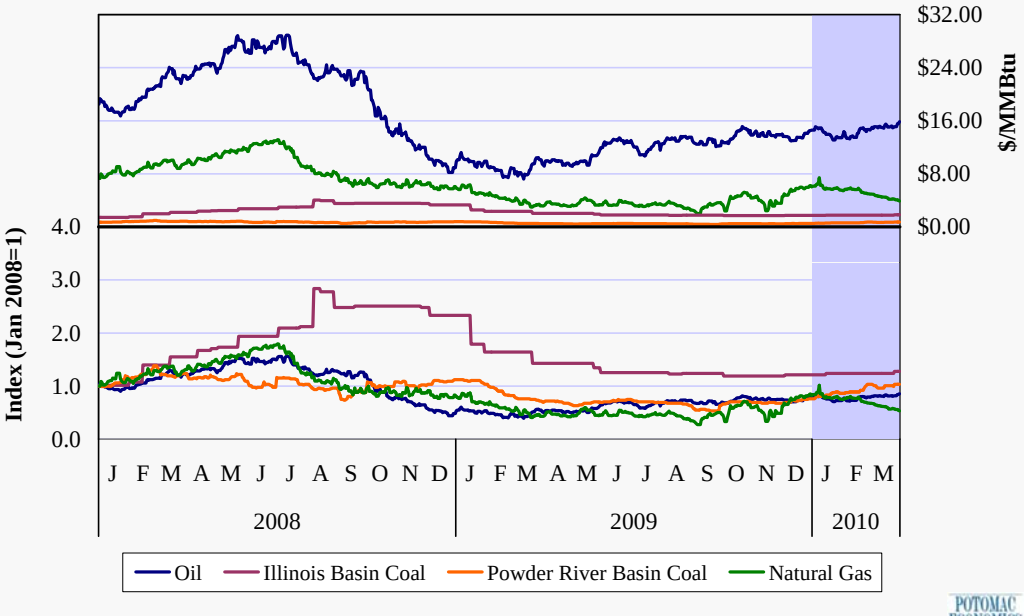
Midwest ISO Fuel Prices



POTOMAC ECONOMICS

Changes in Load and Weather Patterns

- The next figure shows changes in load over the past three years, as well as the changes in weather patterns that have contributed to the load changes.
- The top panel shows the monthly average and peak loads from 2008 to March 2010. Excluding changes due to MidAmerican joining the Midwest ISO, the average load in the first quarter of 2010 was 2.4 percent higher than in the first quarter of 2009.
- Because a large share of the load is sensitive to weather, the figure shows how weather patterns have changed over time.
  - ✓ The bottom panel in the figure shows the monthly heating degree days summed for the first quarters of 2008 to 2010 at four locations with the Midwest ISO.
  - ✓ To account for the different relative impacts of Heating Degree Days (HDDs) and Cooling Degree Days (CDDs), HDDs are inflated by a factor of 6.07 to normalize the effects on load (based on a regression analysis).
- A lack of extreme weather conditions during the first quarter of 2010 contributed to the modest load levels.
  - ✓ However, HDDs in the first quarter of 2010 were 6 percent less than during the first quarter of 2009.

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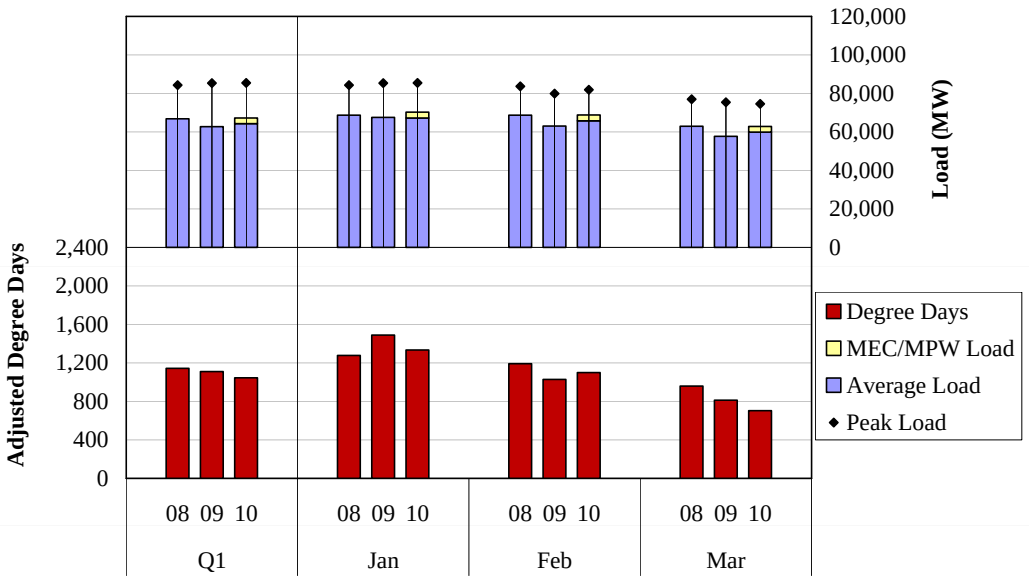
Load and Weather Patterns



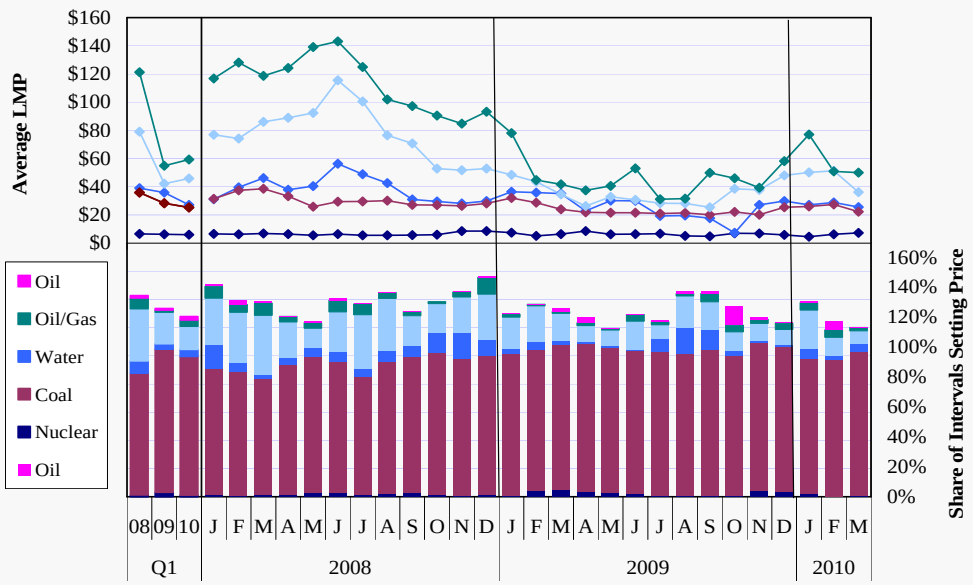
POTOMAC ECONOMICS

Share of Interval Price Setting By Unit Fuel Type

- The next figure shows the frequency with which different types of units set energy prices in the Midwest ISO.
  - ✓ When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained areas).
- Coal units set prices in 93 percent of the hours in the first quarter of 2010 (including virtually all off-peak hours), a decline from the first quarter of 2009 but a significant increase from the first quarter of 2008. These changes were due to:
  - ✓ In 2008, load was substantially higher, thereby moving coal off the margin.
  - ✓ While load decreased throughout 2009, it increased in the first quarter of 2010 due to the economic recovery.
- Natural gas and oil units often set prices during the highest-load hours. Hence, these fuels have a relatively large effect on load-weighted average prices.
  - ✓ Gas, oil-fired, and dual-fueled resources set prices in 22 percent of hours in the first quarter, a two percentage-point decrease from the same period in 2009.
  - ✓ This decrease is likely due to the reduction in congestion in 2010, which required less commitment of oil and gas-fired units.

POTOMAC ECONOMICS

Share of Interval Price Setting By Unit Fuel Type



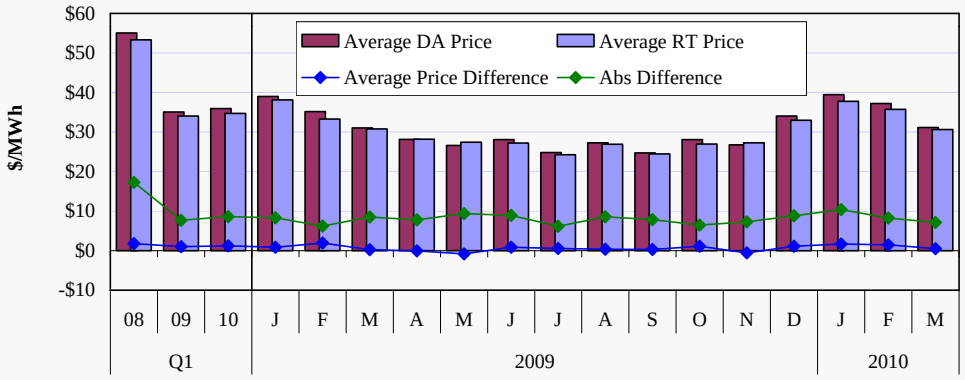
POTOMAC ECONOMICS

Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between the day-ahead and real-time prices.
  - ✓ The next figure shows the day-ahead to real-time price convergence at the Cinergy Hub (the table shows other locations).
- In the first quarter, relatively high day-ahead premiums prevailed at all the hubs.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and RSG allocation to buyers in the real-time market.
    - – The average RSG allocation rate was $2.67 per MWh during the quarter, which is about twice as large as the average day-ahead price premium.
  - ✓ Premiums continue to be higher in the western half of the footprint, where negative real-time price spikes occur due to west-to-east transmission constraints.
  - ✓ Overall, price convergence was only fair due partly to the RSG allocations and relatively low virtual trading volumes.
- The absolute value of the hourly differences measures the typical magnitude of the differences, regardless of direction. This is highest in the congested areas due to:
  - ✓ Higher volatility and negative price spikes during off-peak hours;
  - ✓ The very low average prices that increase the absolute differences ratio; and
  - ✓ Limited flexibility offered to manage congestion in the real-time market.

POTOMAC ECONOMICS

Day-Ahead and Real-Time Price Convergence



Average Price Difference

Cinergy Hub	4%	3%	3%	2%	6%	1%	0%	(3%)	3%	2%	1%	1%	4%	(2%)	3%	4%	4%	2%
Michigan Hub	5%	4%	4%	4%	5%	4%	0%	(4%)	(1%)	0%	3%	3%	7%	(1%)	2%	8%	3%	2%
Minnesota Hub	8%	9%	7%	7%	8%	12%	3%	1%	11%	(3%)	(5%)	(5%)	1%	4%	(1%)	13%	4%	4%
WUMS Area	2%	10%	10%	8%	12%	12%	6%	4%	13%	2%	5%	5%	8%	16%	5%	13%	9%	8%

Average Absolute Price Difference

Cinergy Hub	33%	23%	25%	22%	19%	28%	28%	34%	33%	25%	32%	32%	24%	27%	27%	28%	23%	23%
Michigan Hub	33%	24%	26%	22%	19%	29%	33%	34%	34%	27%	37%	47%	39%	34%	27%	30%	24%	24%
Minnesota Hub	37%	33%	31%	29%	28%	43%	46%	51%	51%	34%	42%	41%	34%	35%	36%	36%	28%	28%
WUMS Area	35%	31%	30%	25%	31%	38%	39%	55%	55%	33%	37%	39%	37%	41%	37%	35%	26%	28%

POTOMAC ECONOMICS

Day-Ahead Load Scheduling

- The following figures show the variation in the net load scheduling metric during the daily peak hour.
  - ✓ The net load scheduled day-ahead is a key driver of RSG because low load levels can force the Midwest ISO to commit peaking resources to satisfy higher real-time load.
  - ✓ High levels of day-ahead load scheduling lead to very little need to commit peaking resources to satisfy the peak load in real time, which reduces RSG costs.
  - ✓ However, real-time commitments are still made to manage congestion and resolve local reliability issues.
- Load scheduling increased substantially in 2009 under ASM, exceeding 100 percent from May through November.
- Load scheduling levels have fallen in early 2010. In the first quarter, net load scheduling averaged 98.2 percent in peak hours and 98.8 percent in all hours, a slight decrease from the first quarter of 2009.
  - ✓ The decrease in day-ahead load scheduling is consistent with the day-ahead and real-time price signals participants received in the first quarter.
  - ✓ One contributing factor was the large quantities of actual wind output that were not scheduled in the day-ahead market, which contributed to lower real-time prices.

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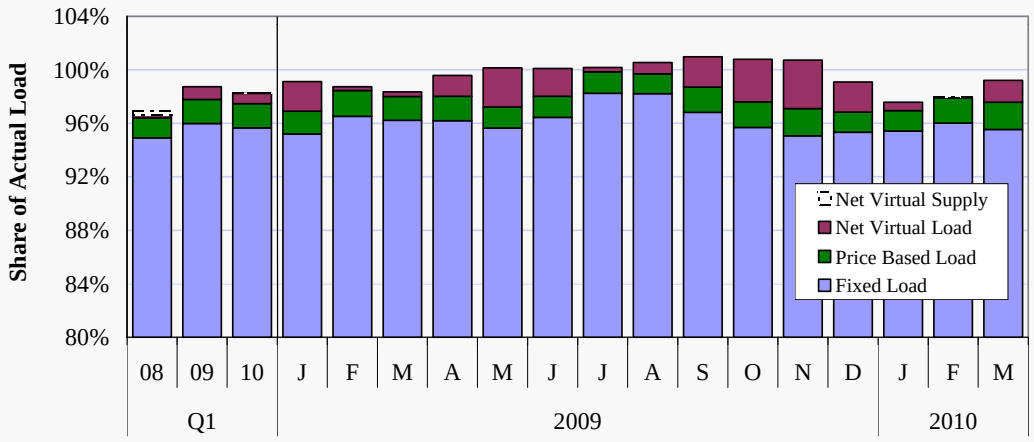
Day-Ahead Load Scheduling



Share of Actual Load

All Hours	99.1	99.4	98.8	100.1	99.4	98.7	99.2	99.4	99.9	100.3	100.7	100.4	100.1	100.2	100.6	98.2	98.9	99.3
Peak Hour	96.6	98.7	98.2	99.1	98.7	98.4	99.6	100.2	100.1	100.2	100.5	101.0	100.8	100.7	99.1	97.6	97.9	99.2

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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 the day-ahead market results and mitigate market power in the day-ahead market.
- The next figure shows the average hourly virtual bids and offers, those that were scheduled, and the net virtual load scheduled (virtual load less virtual supply).
- Virtual trading volumes fell after FERC issued an order in November 2008 requiring the allocation of RSG costs to virtual supply.
  - ✓ Although the FERC Order directly affected only virtual supply, both supply and demand offers decreased. This may be due to the fact that some traders use virtual supply and demand together to arbitrage congestion-related price differences.
  - ✓ The average levels of cleared virtuals began recovering in the second quarter of 2009.
- In the first quarter of 2010, cleared virtual demand bids were 38 percent lower than in the fourth quarter of 2009. Cleared virtual supply offers were 3 percent lower, while overall offered volumes dropped by 32 percent.
  - ✓ The day-ahead premium that prevailed in the first quarter discourages virtual demand and encourages virtual supply. However, the current RSG allocation is a disincentive for virtual supply, which may explain why both have been low.
  - ✓ We expect activity to increase when the new Indicative Rate RSG allocation rules are implemented, which will remedy the current over-allocation to virtuals.

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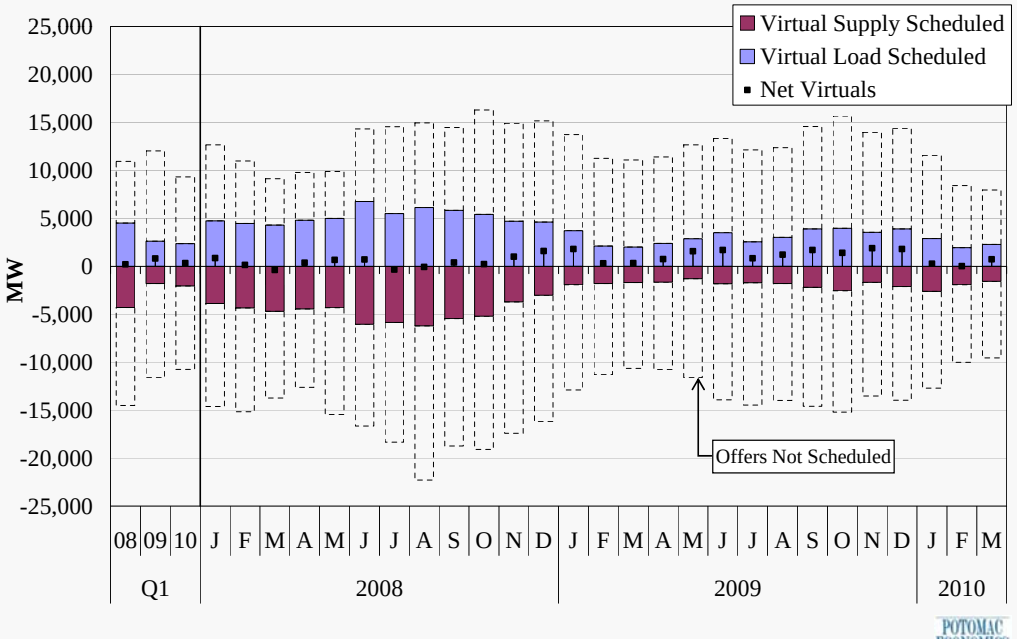
Virtual Load and Supply in the Day-Ahead Market



POTOMAC ECONOMICS

Virtual Profitability in the Day-Ahead Market

- The next figure shows monthly average profitability of virtual purchases and sales.
  - ✓ Moderate profits continued in the first quarter. Virtual supply was consistently more profitable than virtual demand, which is expected due to the prevailing day-ahead premium.
  - ✓ In January 2010, high day-ahead premiums were relatively large and contributed to high average profits for virtual supply.
    - – However, the virtual supply profit margins are reduced by RSG cost allocations.
    - – The weighted average hourly RSG Distribution Rate assessed to virtual supply averaged $2.79 per MWh in January and reduced net profitability to $1.86 per MWh.
- We continue to monitor for large losses on virtual transactions because they can indicate an attempt by a participant to manipulate the day-ahead market prices.
  - ✓ For example, a participant may submit a high-priced virtual bid at a constrained location that causes inflated congestion in the day-ahead market
    - – While this would cause foreseeable losses on the virtual, the resultant congestion could increase the participant's FTR payments or the value of a financial position.
  - ✓ The table below the figure shows that the share of transactions incurring large losses remains low and does not raise significant competitive concerns.
    - – However, we mitigated one pattern of virtual purchases that incurred a sustained low level of losses.

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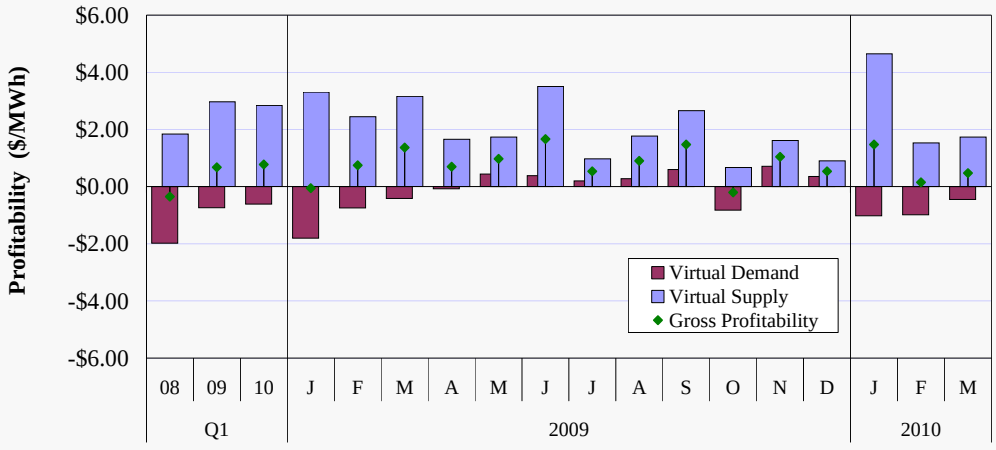
Virtual Profitability in the Day-Ahead Market



Share of Cleared Virtuals with Extreme Profitability

Profit > $50/MWh	1.7%	1.0%	1.2%	0.7%	1.2%	1.7%	0.9%	2.0%	1.6%	0.7%	1.4%	1.5%	0.8%	0.7%	1.4%	1.6%	0.5%	0.8%
Profit < -$50/MWh	3.8%	1.1%	1.7%	0.9%	1.0%	1.6%	1.7%	1.6%	1.7%	0.8%	1.6%	1.6%	1.7%	2.5%	2.2%	2.0%	1.3%	1.2%

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Peaking Unit Real-Time Merit Status

- The following figure shows the real-time dispatch of peaking resources, separately indicating the share of these peaking resources that were out-of-merit (offer price higher than the LMP).
- Dispatch of peaking resources remained at relatively low levels in the first quarter.
  - ✓ Lower load scheduling in the first quarter of 2010 led to higher amounts of capacity commitments than in the first quarter of 2008 or 2009. These commitments were highest in January when the load scheduling was the lowest.
  - ✓ However, this increase was offset by fewer commitments to manage congestion caused by the overall reduction in congestion.
  - ✓ Changes in operator procedures also contributed to fewer commitments in the first quarter of 2010.
- Commitment of relatively high-cost resources to manage congestion or meet capacity needs generally leads to a high share of the peaking resources running out-of-merit.
  - ✓ Only 25 percent of peaking resources dispatched were in-merit during the first quarter of 2010, which is lower than in prior years.
  - ✓ The Midwest ISO continues to develop pricing improvements that will allow peaking resources to set energy prices when appropriate.

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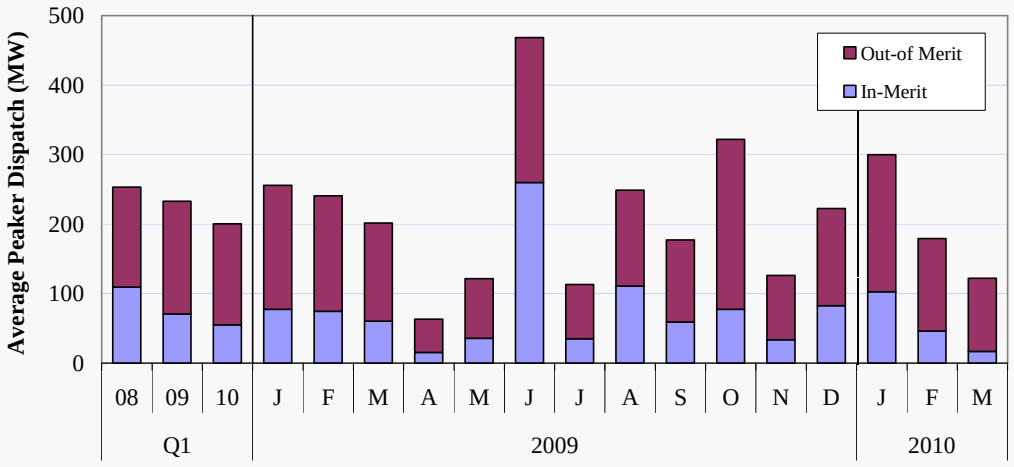
Peaking Unit Dispatch and In-Merit Status



Out-of-Merit Quantity and Share

MW	144	156	145	179	163	127	48	86	208	78	138	118	224	92	140	197	133	105
%	57%	71%	75%	70%	69%	73%	76%	71%	45%	69%	55%	67%	76%	73%	63%	66%	74%	86%

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Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets. To account for fuel prices, RSG costs are shown on a nominal basis and adjusted for changes in fuel prices.
- RSG costs in the real-time market in the first quarter were slightly higher in 2010 than in 2009 on a nominal basis, but was lower on a fuel-adjusted basis (because fuel prices were higher).
  - ✓ Fuel-adjusted RSG costs were lower by 35 percent in the first quarter of 2010 than in 2009 due primarily to lower real-time commitments to manage congestion.
  - ✓ The figure also shows that RSG costs are typically higher in the winter months due to higher fuel prices and additional commitments that are sometimes needed to satisfy the morning and evening winter peak loads.
    - – In addition, day-ahead load scheduling is frequently lower in the winter months than in the summer and fall, which contributes to the real-time commitment needs.
- As expected, the majority of the real-time RSG (57 percent) was paid to peaking units. This is expected because they are the highest-cost units and are not usually able to set real-time energy prices.
- The second figure shows day-ahead RSG levels, which continued to be much lower than in the real-time market. This is expected because the day-ahead market is largely financial (i.e., is not required to resolve physical reliability needs).

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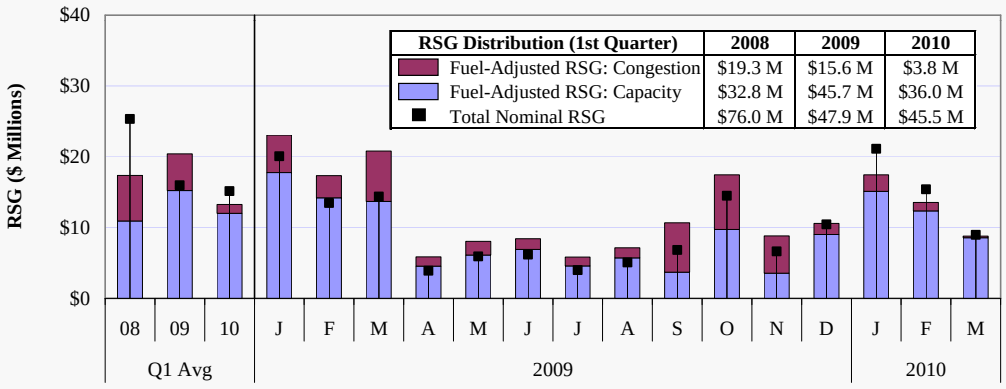
Real-Time RSG Payments



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

Peaker	56.9	57.5	57.0	57.5	65.1	50.2	46.1	66.3	68.4	48.8	61.1	73.6	80.1	70.0	70.9	58.6	53.4	59.2
Congestion	23.1	10.1	6.6	9.4	12.1	9.2	5.1	19.5	17.5	10.3	15.4	52.8	34.4	47.0	12.0	9.3	5.5	1.9
Capacity	33.8	47.4	50.4	48.1	53.1	41.0	40.9	46.8	50.9	38.5	45.8	20.8	45.7	23.1	58.9	49.3	47.9	57.3
Non-Peaker	43.1	42.5	43.0	42.5	34.9	49.8	53.9	33.7	31.6	51.2	38.9	26.4	19.9	30.0	29.1	41.4	46.6	40.8
Congestion	13.8	13.5	2.7	10.6	5.4	25.0	17.7	4.2	2.7	11.4	6.0	11.9	8.3	9.9	2.4	3.0	3.6	0.7
Capacity	29.4	29.1	40.3	31.9	29.5	24.8	36.2	29.5	28.9	39.8	32.9	14.5	11.5	20.1	26.7	38.4	43.0	40.1

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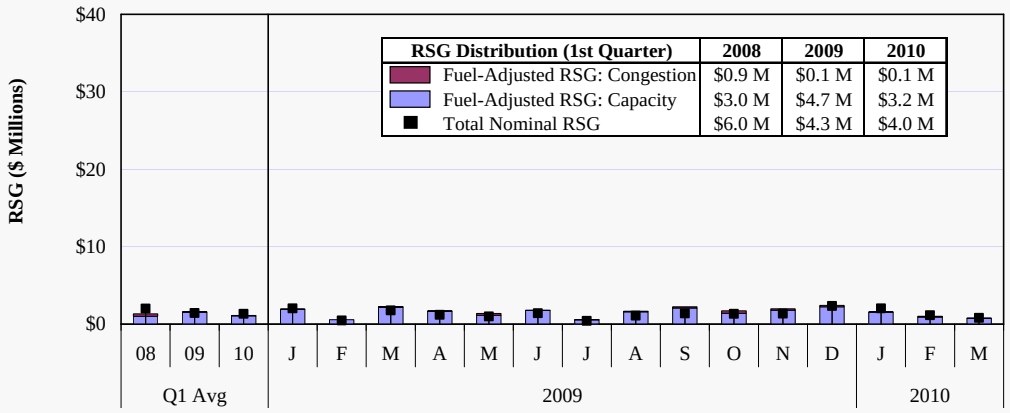
Day-Ahead RSG Payments



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

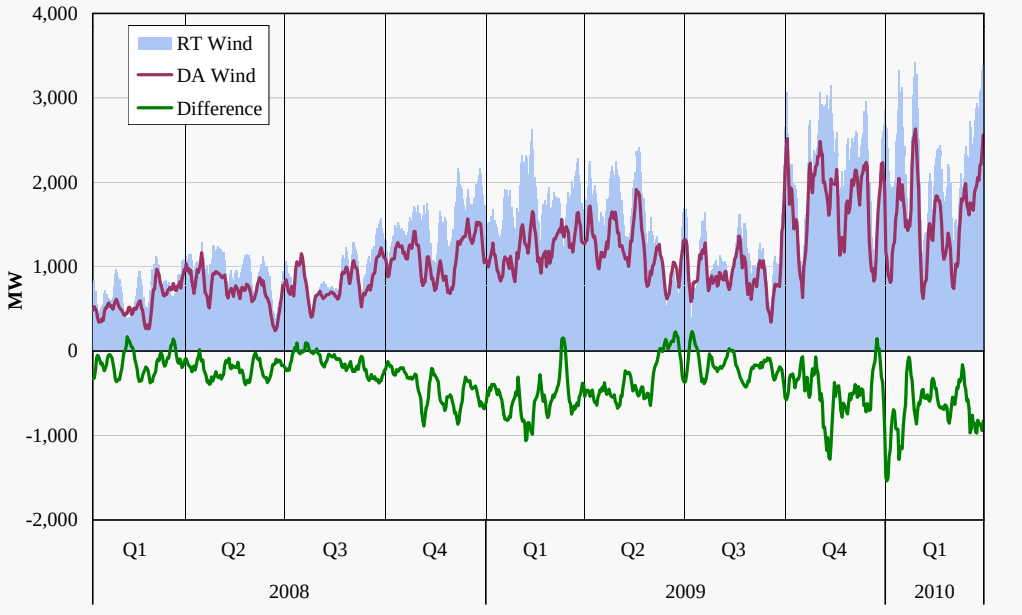
Peaker	8.3	2.4	2.5	3.8	2.6	0.9	1.4	21.5	17.2	4.2	12.6	10.0	6.0	4.3	3.6	3.8	0.2	2.3
Congestion	2.2	0.2	0.6	0.0	0.0	0.4	0.6	13.8	0.7	0.0	0.5	2.4	2.2	1.1	1.5	0.6	0.0	1.5
Capacity	6.0	2.3	1.9	3.8	2.6	0.6	0.8	7.6	16.5	4.2	12.0	7.7	3.8	3.2	2.1	3.2	0.2	0.9
Non-Peaker	91.7	97.6	97.5	96.2	97.4	99.1	98.6	78.5	82.8	95.8	87.4	90.0	94.0	95.7	96.4	96.2	99.8	97.7
Congestion	21.5	2.2	3.7	0.9	0.9	4.0	1.7	2.0	0.6	5.4	3.8	4.9	16.7	6.3	5.3	1.0	10.7	0.3
Capacity	70.2	95.4	93.9	95.4	96.5	95.0	96.9	76.5	82.3	90.4	83.6	85.0	77.3	89.4	91.1	95.2	89.1	97.4

POTOMAC ECONOMICS

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

- Wind generation and capacity have grown rapidly in the Midwest ISO market. This trend is expected to continue due to:
  - ✓ The attractive wind profiles in the West region;
  - ✓ State renewable portfolio standards; and
  - ✓ Federal mandates and subsidies.
- The following figure shows the wind generation scheduled in the day-ahead and real-time markets.
  - ✓ Wind output continues to grow in the Midwest ISO, averaging over 2.2 GW in the first quarter. This represents an increase of 25 percent and 210 percent from the first quarters in 2009 and 2008, respectively.
  - ✓ Wind generation tends to be substantially under-scheduled in the day-ahead market, which has contributed to lower day-ahead load scheduling and higher day-ahead premiums.
- Wind output volatility also increased, underscoring the forecasting, scheduling, and reliability challenges being addressed by the Midwest ISO.
  - ✓ Wind generation was negatively correlated with load in the first quarter of 2010, which tends to exacerbate the operational issues.

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



Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows the Midwest ISO's obligation to FTR holders, which entitle them to congestion costs that arise between particular locations on the network.
  - ✓ Day-ahead congestion increased almost 60 percent in the first quarter of 2010 compared to the same quarter in 2009.
- The figure also shows the actual FTR payments and the shortfall between the obligation and the payment.
  - ✓ Shortfalls and surpluses occur when the portfolio of FTRs represent more or less transmission capacity than the physical network.
  - ✓ "Loop flows" over the network caused by activity outside of the MISO can lead to shortfalls or surpluses if they differ from the amounts assumed in the FTR market.
- Day-ahead shortfalls continued in 2010 – the shortfall was 24 percent in the first quarter, compared to 16 percent and 8 percent in 2009 and 2008, respectively.
  - ✓ The shortfall was largest in January due partly to a modeling issue that we are investigating and discussing with the Midwest ISO.
- The Midwest ISO has continued to work on the FTR/ARR allocation process and associated modeling to reduce the shortfalls.

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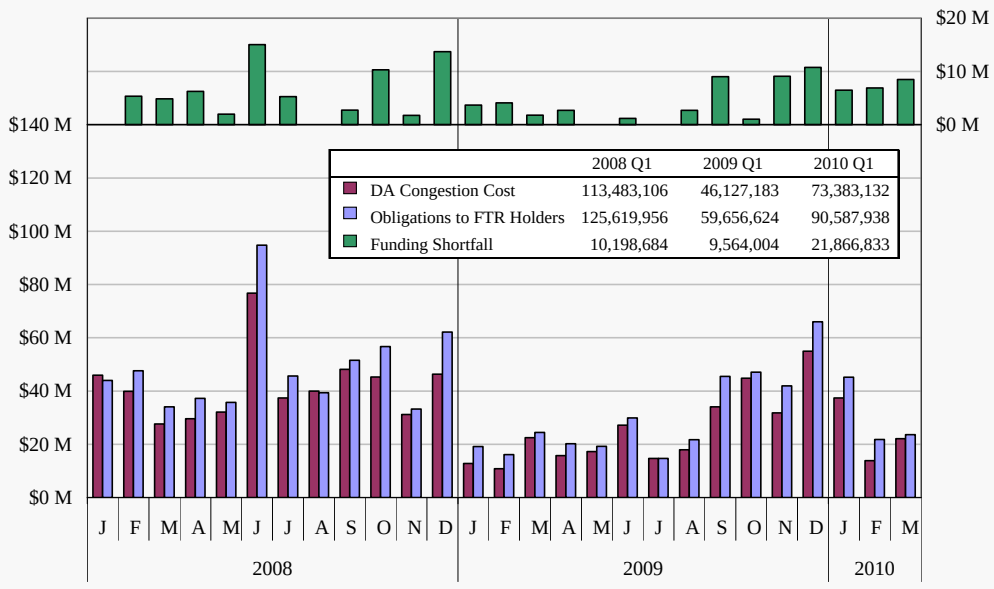
Day-Ahead Congestion and Obligations to FTR Holders



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Real-time Congestion by Coordination Region 2009 – 2010

- The next figure shows the value of real-time congestion by region.
  - ✓ The value of real-time congestion equals the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ The total value shown is higher than the congestion costs collected by the Midwest ISO because loop flows do not settle with the Midwest ISO and PJM has entitlements to transmission capability on the Midwest ISO system.
- The value of real-time congestion in the first quarter of 2010 decreased to $143 million from $182 million in the first quarter of 2009, a 21 percent decrease.
  - ✓ Congestion in the West more than doubled in the first quarter of 2010 compared to 2009, largely as a result of increased wind generation.
  - ✓ However, congestion dropped by 60 and 28 percent in Central and East due to key transmission upgrades and the implementation of an operating guide to address a high-cost constraint.
  - ✓ Despite these decreases, the average frequency of binding constraints increased slightly in 2010, averaging 0.92 constraints binding per interval in the first quarter of 2010 versus 0.74 in the first quarter of 2009.

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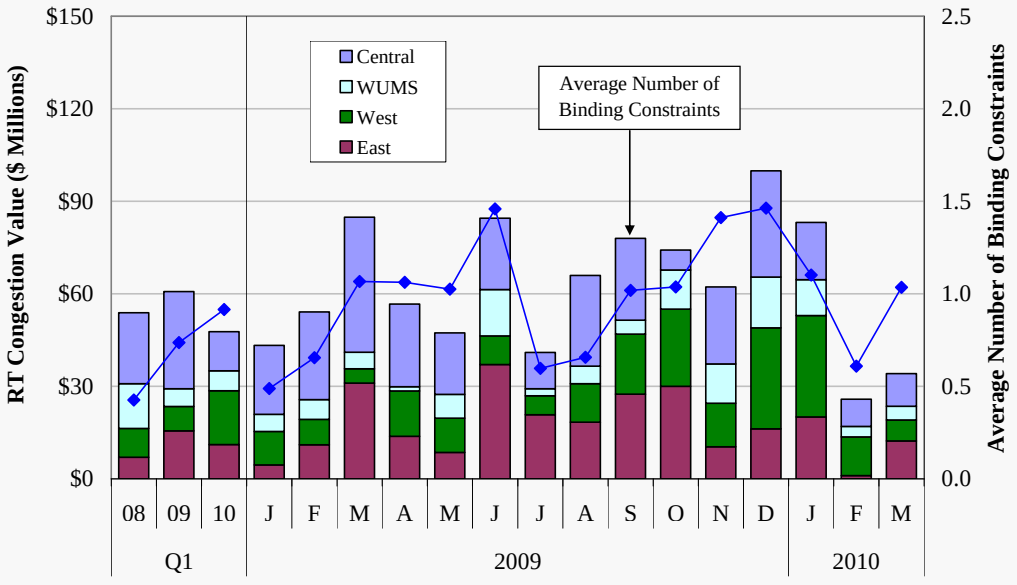
Real-time Congestion by Coordination Region



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Value of Real-Time Congestion by Type of Constraint

- The next figure shows the value of real-time congestion by the type of constraint from 2008 to the first quarter of 2010.
  - ✓ Congestion occurs on external constraints when a TLR is called on a neighboring system that causes Midwest ISO to re-dispatch its generation.
- As in prior quarters, most of the congestion during the first quarter of 2010 occurred on Midwest ISO internal constraints (including the Midwest ISO market-to-market constraints).
  - ✓ In total, the Midwest ISO constraints (internal and market-to-market) account for 94 percent of all the congestion value, essentially unchanged from 93 percent over the same period of 2009.
  - ✓ Congestion on Midwest ISO market-to-market constraints in the first quarter of 2010 decreased by 66 percent and 44 percent from the first quarters of 2009 and 2008, respectively.
    - – This reduction was due to a substantial reduction in congestion on two key constraints.
- Congestion further declined on PJM market-to-market constraints in the first quarter of 2010 (down 53 percent versus the first quarter of 2009 to $5 million).

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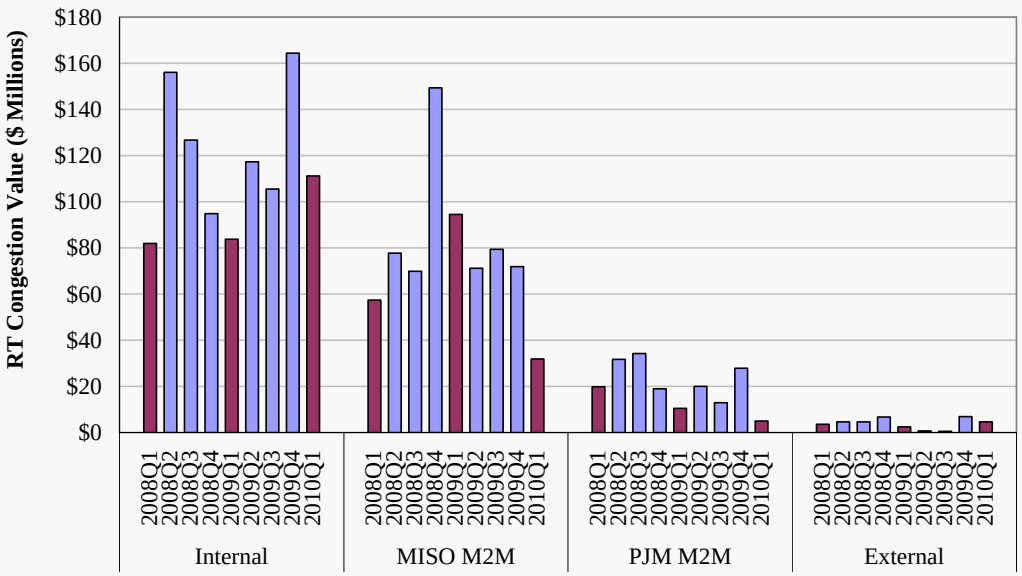
Value of Real-Time Congestion by Type of Constraint, 2008 – March 2010



POTOMAC ECONOMICS

Seasonal FTR Profitability
Spring 2008 – Winter 2009-2010

- FTR profits are the difference between the market clearing price to purchase the FTR and the payout on the FTR based on congestion realized in the day-ahead market.
  - ✓ In liquid FTR markets, profits should be low over the long-term because the clearing price for FTRs should reflect a rational expectation of their congestion value.
  - ✓ However, profits and losses may be large in the short-term when fluctuations in congestion patterns cause outcomes to deviate from expectations.
- The next figure shows the profitability of FTRs purchased in the seasonal FTR auctions. The results in this figure indicate:
  - ✓ FTRs purchased in the seasonal auctions were profitable for the second consecutive season, a marked change from the losses that characterized most of 2009.
  - ✓ Profitability averaged $0.15 per MWh, up from $0.12 during the fall of 2009 and up from negative $0.10 during the same period last year.
    - – However, average FTR profitability continues to be substantially lower than the rates that prevailed from 2005 to 2007.
  - ✓ The changes in total profitability have been much larger because the quantity settled through the seasonal auction has increased dramatically
    - – The Midwest ISO began allocating Auction Revenue Rights ("ARRs") in June 2008 that can be converted to FTRs through the seasonal auction. Before this, MISO allocated FTRs directly so they would not appear in the seasonal auction.

POTOMAC ECONOMICS

Seasonal FTR Profitability
Spring 2008 – Winter 2009-2010

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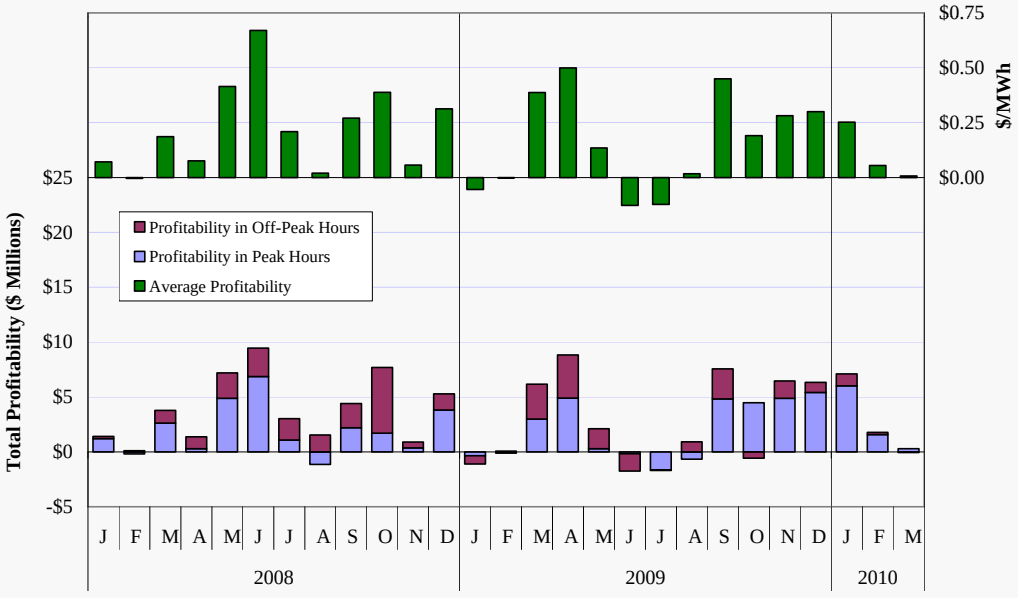
FTR Profitability
Monthly Auctions, 2008 – March 2010

- The next figures show the profitability of FTRs purchased in the monthly auctions.
- The figure shows that like the seasonal FTR market, the average profitability in the monthly FTR auction has decreased over time.
  - ✓ Annual average profitability has fallen each year since 2005, from $1.68 per MWh in 2005 (not shown) to $0.18 in 2009.
  - ✓ The average profitability in the first quarter of 2010 was $0.10 per MWh.
  - ✓ In the first quarter of 2010, 87 percent of profits occurred during peak hours, well above the historical average of 57 percent.
- Overall, these results indicate that the monthly FTR markets continues to perform well, with monthly FTR prices converging with their value based on day-ahead congestion.
  - ✓ The sharp reduction in congestion in February and March influenced the profitability of monthly FTRs during these months.
- Some of the profits in late 2009 and early 2010 for the seasonal and monthly FTRs were associated with day-ahead constraints that were not reflected in the FTR market, which caused some FTRs to be oversold.

FTR Profitability
Monthly Auctions, 2008 – 2010

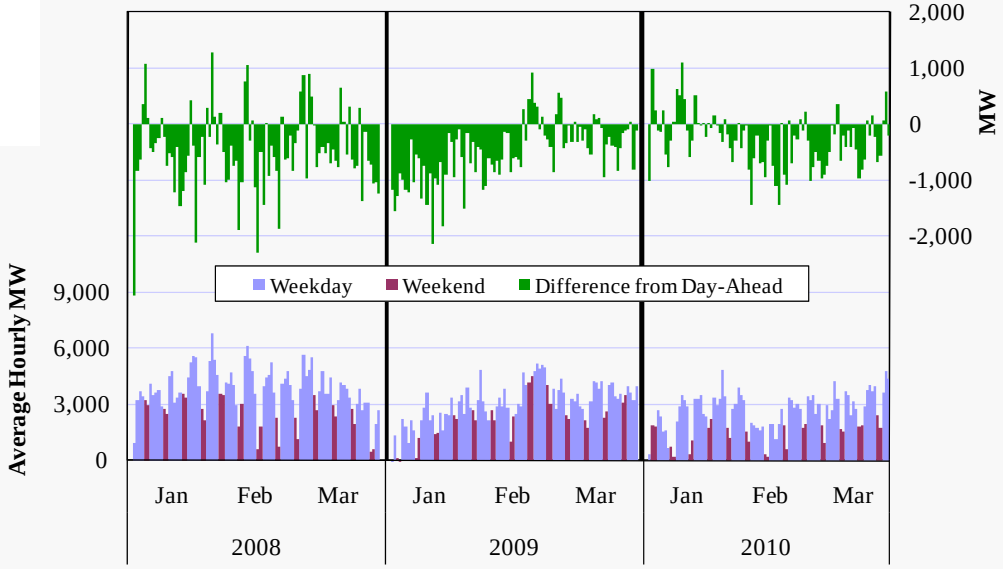


Average Hourly Real-Time Imports

- The next figure shows the net imports in the real-time market and the change in net imports from the day-ahead market during the first quarters of 2008 to 2010.
- The Midwest ISO imported 2.5 GW on average in the first quarter.
  - ✓ PJM and Manitoba Hydro were the two largest real-time exporters of power to the Midwest ISO.
- As the figure shows, real-time net imports generally decreased from those scheduled in the day-ahead market during the first quarters of all three years.
  - ✓ On 6 days during the quarter, net imports declined by more than 1,000 MW, which is less than during the first quarter in 2008 or 2009.
    - – Reduction of this magnitude can create reliability issues for the Midwest ISO.
    - – Day-ahead import over-scheduling averaged 281 MW in the first quarter of 2010, down from 495 and 466 during the first quarters of 2009 and 2008, respectively.
    - – As a percentage of day-ahead imports, over-scheduling decreased from 14.5 percent in the first quarter of 2009 to 10.2 percent in the first quarter of 2010.
  - ✓ Large changes in net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources.

POTOMAC ECONOMICS

Average Hourly Real-Time Imports
First Quarter, 2008 – 2010



POTOMAC ECONOMICS

Real-Time Ontario-PJM Wheels Quantity and Profitability

- When circuitous scheduling was disallowed by NYISO, schedules from IESO to PJM (across the Midwest ISO) increased. The next figure shows the quantity and profitability of these transactions from 2007 through the first quarter of 2010.
- The increased volume of these transactions relative to 2007 continued in the first quarter of 2010.
- The transactions are explained by their consistent profitability (85 percent of all hours).
  - ✓ Since the beginning of 2007, these transactions have netted profits between $5 and $20/MWh nearly every month, averaging $8.73 per MWh in the first quarter of 2010.
  - ✓ Profitability is calculated based on the prices in PJM and IESO minus the Midwest ISO's wheeling charge (it does not include costs assigned by IESO).
- If PJM priced the transactions at its Midwest ISO interface (instead of its current pricing method for IESO) the average profitability would drop to $3.48 per MWh.
  - ✓ The large difference between the PJM's IESO and MISO prices may create incentives to combine other transactions with these wheels to acquire the difference.
- The scheduling coordination being discussed by the ISOs around Lake Erie should address both efficiency and manipulation concerns with the current system.

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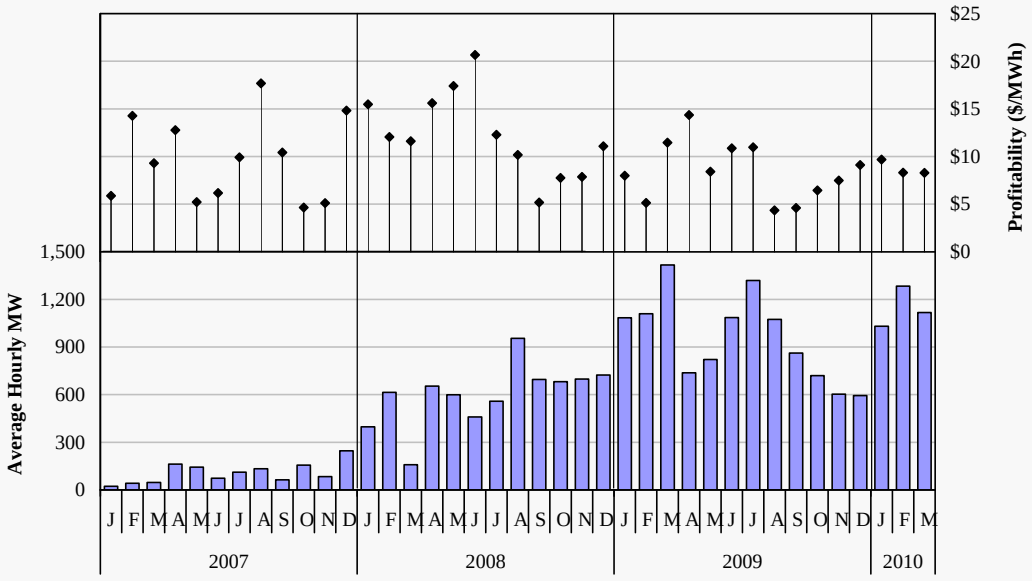
Real-Time Ontario-PJM Wheels Quantity and Profitability



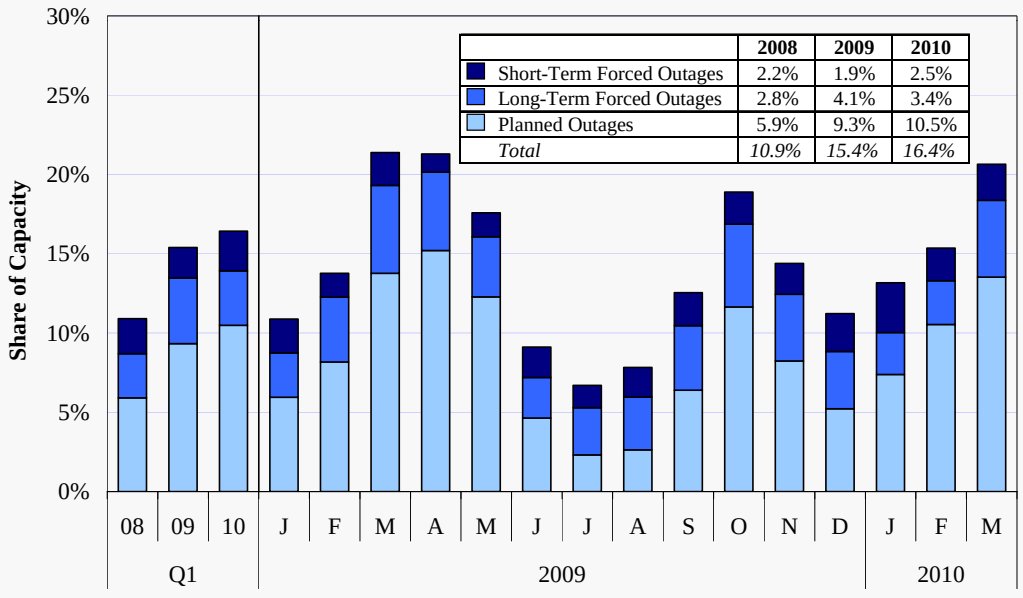
POTOMAC ECONOMICS

Generation Outage Rates

- The following figure shows the generator outages that occurred in each month from January 2009 through March 2010 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 total outage rate for the three classes of outages was 16.4 percent in the first quarter of 2010, compared to 15.4 percent in 2009 and 10.9 percent in 2008.
  - ✓ A large share of the increase in outages were planned outages, which increased to 10.5 percent during the quarter from 8.4 percent in the fourth quarter of 2009.
- Long-term forced outage rates have declined slightly year-over-year, but short-term forced outage rates have increased from 1.9 to 2.5 percent of capacity.
  - ✓ We monitor short-term outages closely because they can indicate potential exercises of market power. The increase in 2010 has not raised competitive concerns.
    - – It is in part due to enhanced incentives to report outages under Module E; and
    - – The share of capacity on forced outage is very small relative to the market's reserve margin.

POTOMAC ECONOMICS

Generation Outage Rates



	2008	2009	2010
Short-Term Forced Outages	2.2%	1.9%	2.5%
Long-Term Forced Outages	2.8%	4.1%	3.4%
Planned Outages	5.9%	9.3%	10.5%
Total	*10.9%*	*15.4%*	*16.4%*

POTOMAC ECONOMICS

Monthly Output Gap

- The next figure shows the output gap levels used to screen for economic withholding by month for 2008 through the first quarter of 2010.
  - ✓ Output gap measures the difference between actual output and the output level that would be expected based on competitive offers.
- The figure shows the output gap under two thresholds: a high threshold (equal to the mitigation threshold) and a "low" threshold (one-half of mitigation threshold).
  - ✓ Output gap levels in the first quarter of 2010 were 49 percent and 21 percent lower than in 2009 at the high threshold and low threshold, respectively.
    - – Despite these reductions, it was higher than the lows in 2009. These lows were associated with very low prices and loads (these conditions reduce the number of units that are potentially economic and, thus, the output gap measured).
  - ✓ We routinely investigate hourly increases in the output gap.
    - – In January and February, one unit in particular was responsible for the increase in the low-threshold output gap, although it did not raise competitive concerns.
  - ✓ As a share of overall load, the low-threshold output gap averaged only 0.7 percent and remains consistent with competitive outcomes.

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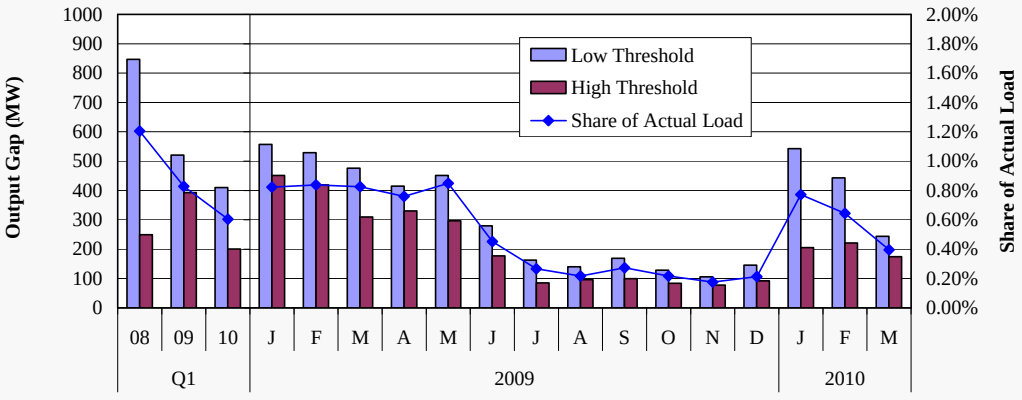
Monthly Output Gap



Low Threshold Results by Commitment Status (MW)

Off-Line	39	53	290	66	57	35	7	44	41	18	4	56	16	1	26	417	347	107
On-Line	808	468	105	491	472	441	412	407	238	144	136	113	113	105	120	126	96	94

High Threshold Results by Commitment Status (MW)

Off-Line	17	33	126	57	38	4	3	0	1	2	1	19	0	1	7	118	162	99
On-Line	232	360	69	394	381	305	331	296	176	84	96	81	84	77	85	87	59	61

POTOMAC ECONOMICS

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which mitigation has been imposed in the real-time market.
  - ✓ 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 in both the day-ahead and real-time markets has been rare due to:
  - ✓ Few resources exceeding conduct thresholds;
  - ✓ Relatively low impacts because the market has cleared in supply ranges that are highly elastic (causing withholding to have smaller impacts); and
  - ✓ Reduced market load, which increases the number of commitment options.
- Although the quarter-over-quarter comparison of mitigation shows an increase, these events are isolated and do not indicate a trend. Mitigation levels remain very low.
  - ✓ Although mitigation is not frequent, local market power continues to be a significant concern and the market power mitigation measures remain critical.
- Very little mitigation was imposed in the day-ahead market, which is expected. A competitive real-time market disciplines the day-ahead market.

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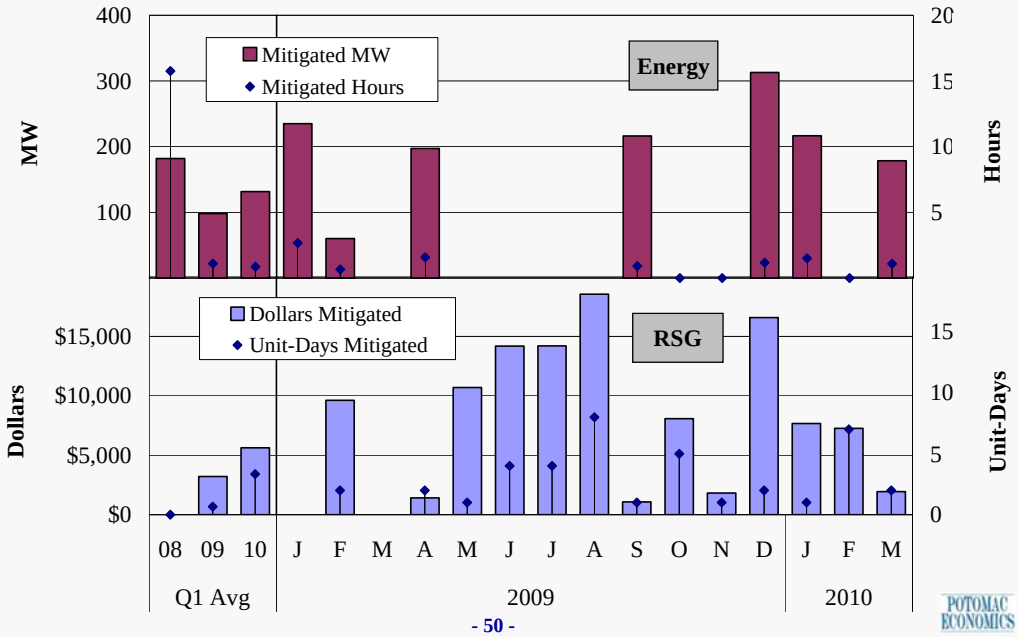
Real-Time Market Power Mitigation



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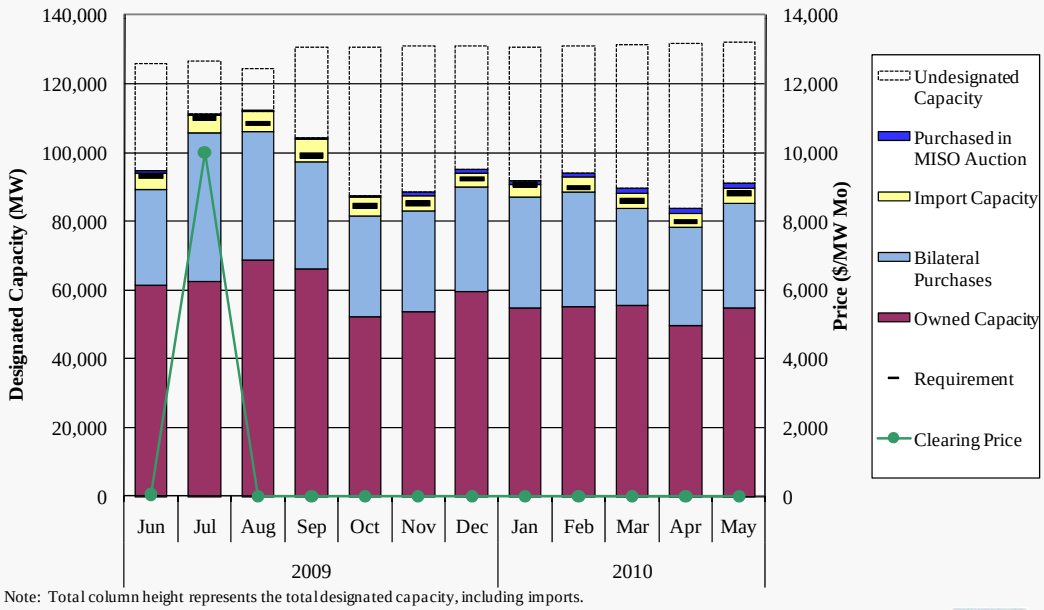
Voluntary Capacity Auction

- Beginning in June 2009, the Midwest ISO began a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The capacity cleared in the VCA remains a very small portion of the total designated capacity (nearly 1 percent) but it has been increasing.
  - ✓ This is consistent with the expectation that this market would only be a balancing market with LSEs' needs satisfied through owned capacity or bilateral purchases.
- The following figure shows the total monthly capacity requirements and how LSEs are satisfying those requirements. It shows:
  - ✓ Capacity designations always met or exceeded requirements. In the first five months of 2010, designations have exceeded the requirement by 2 to 5 percent.
  - ✓ The total capacity available exceeded the requirement by 47 percent on average in the first quarter of 2010.
    - – The low VCA clearing prices are consistent with the capacity surplus.
  - ✓ The high capacity prices in July were the result of the peak demand for capacity and large quantities of capacity that were not offered or offered at a high price.
    - – We attribute these results to inexperience with this new market and conditions occurring in this period. These issues did not recur after July.

Capacity Market Results
June 2009 – May 2010



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