2008 State of the Market Report
Midwest ISO

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Independent Market Monitor

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Executive Summary: Introduction

- This State of the Market ("SOM") report provides our annual evaluation of the Midwest ISO's markets as the Independent Market Monitor ("IMM").
  - ✓ The report includes our assessment of the competitive performance of the markets and our recommendations for future improvements.
- The Midwest ISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include:
  - ✓ Day-ahead and real-time energy markets that produce transparent prices that vary by location to reflect the value of transmission congestion and losses; and
  - ✓ Financial Transmission Rights ("FTRs") that allow participants to hedge congestion between various locations.
- In 2009, these markets were augmented by:
  - ✓ Operating Reserves and Regulation markets (known as Ancillary Services Markets or "ASM") that optimize the allocation of the Midwest ISO's resources between the ASM and Energy markets.
  - ✓ Clarified capacity requirements and enforcement mechanisms intended to ensure that long-run economic signals will support adequate supply and demand resources.

Executive Summary: Benefits of the Midwest ISO Energy Markets

The Midwest ISO markets produce substantial savings in the following areas.

- Daily commitment of generation: Coordinated commitment of generation through the day-ahead market produces savings relative to the prior decentralized system by:
  - ✓ Reducing the quantity of generation that is committed; and
  - ✓ Ensuring that the most economic generation is committed.
- Efficient dispatch and congestion management: Total dispatch costs are reduced by:
  - ✓ Producing energy from the most economic supply and demand resources;
  - ✓ Employing the lowest cost redispatch options to manage congestion; and
  - ✓ Allowing for greater utilization of the transmission capability in the region.
- Reliability: Reliability is improved because the 5-minute dispatch provides much more responsive and accurate control of power flows on the transmission system versus Transmission Line Loading Relief procedures ("TLR") relied on previously.
- Price Signals: The prices produced by the energy market provide a transparent economic signal to guide short and long-run decisions by participants and regulators.

Executive Summary: Competitive Performance and Prices

- The Midwest ISO energy markets performed competitively in 2008.
  - ✓ Although certain suppliers in the Midwest ISO have local market power, there was very little evidence of attempts to exercise market power in 2008.
  - ✓ Hence, mitigation measures were employed infrequently to address economic withholding that would have increased energy prices or uplift costs.
- Prices in the day-ahead and real-time energy markets rose by 4 to 5 percent in 2008, which is less than expected given fuel price changes.
  - ✓ Natural gas prices increased by 14 percent on average in 2008, while oil prices rose 34 percent and coal prices rose by 30 to 110 percent (depending on type).
  - ✓ Accounting for these changes in fuel prices, "fuel-price adjusted" energy prices decreased substantially in 2008, particularly in the fourth quarter.
- Fuel price increases were offset by the following factors that lowered energy prices:
  - ✓ Average load decreased by 2.2 percent due to mild weather and deteriorating economic conditions;
  - ✓ Lower outage rates that increased generation availability; and
  - ✓ Sharp increases in intermittent generation from wind resources that led to surplus generation in real-time and relatively low energy prices.

Executive Summary: Long-Term Economic Signals

- In long-run equilibrium, the market should provide "net revenues" that create efficient incentives for investment and retirement.
  - ✓ The net revenue is the revenue the unit would have received in hours it would have run, less its variable production costs in those hours.
  - ✓ Net revenues must be sufficient to cover a new resource's fixed operating and maintenance costs and provide a return on the investment in order for the investment to be economic.
- We calculated the net revenue for a new combined-cycle unit and a gas turbine, which showed that the Midwest ISO markets would not have supported investment in either type of unit in 2008 based on their annualized costs of new investment.
- These results are consistent with expectations because:
  - ✓ The Midwest ISO footprint has a small capacity surplus that precluded any significant periods of shortage from occurring in 2008.
  - ✓ When shortages do occur, the markets in 2008 did not fully price them because operating reserve shortages and interrupted load did not contribute to setting prices.
  - ✓ The ASM markets that began in January 2009 will improve shortage pricing and the Midwest ISO is working on other pricing changes to allow interruptible load to set prices.
- Changes being introduced to Module E of the Tariff should also improve the long-term market signals needed to maintain adequate resources by allowing a decentralized market to develop to meet the Midwest ISO's capacity requirements.

Executive Summary: Day-Ahead Market Performance

- Day-ahead market outcomes are important because:
  - ✓ The day-ahead market governs most of the generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results.
  - ✓ Most wholesale energy bought or sold through the Midwest ISO markets is settled in the day-ahead market.
  - ✓ The entitlements of firm transmission rights are determined by the results of the day-ahead market (the payment to an FTR holder is based on day-ahead congestion).
- Our analyses indicate that price convergence in the Midwest ISO has been consistent with the other RTO markets, generally exhibiting day-ahead premiums.
  - ✓ The day-ahead premiums are consistent with the higher volatility, risk, and RSG cost associated with buying in the real-time market.
  - ✓ The day-ahead premiums are larger in the Midwest ISO due to higher RSG allocations.
- Active virtual supply and demand participation in the day-ahead market has contributed to the price convergence exhibited in the Midwest ISO.
  - ✓ However, virtual trading levels decreased substantial late in the year and into 2009.
  - ✓ These reductions can be attributed to RSG allocation decisions made by FERC in November 2009 and poor financial market conditions.
  - ✓ Price convergence during this period has deteriorated and we are closely monitoring these trends.

Executive Summary: Real-Time Market Performance

- This report includes a study of the real-time price volatility in the Midwest ISO, which is nearly double that of any other RTO. The causes of the price volatility are:
  - ✓ The Midwest ISO runs a true 5-minute real-time market, producing new dispatch instructions and prices every 5 minutes.
    - – The short timeframe and limited ability of the real-time market to "look ahead" causes the system to frequently become "ramp-constrained", which results in transitory sharp movements in prices up or down.
    - – Ramp constraints bind when the market's generation cannot change output quickly enough to accommodate changes in demand, net imports, etc. on a 5-minute basis.
- The analysis in this report shows that:
  - ✓ Prices fluctuate the most when load is ramping up or down near the peak (afternoon in the summer, and dual peaks in morning and evening in the winter);
  - ✓ The changes in real time prices are related to changes in Net Scheduled Interchange ("NSI") that occur at the tops of the hour, and to periods when large quantities of generators start-up or shut-down at the same time.
- Volatility has decreased under ASM markets because the real-time market now has the flexibility to jointly optimize resources for energy and ASM needs.

Executive Summary: Revenue Sufficiency Guarantee Payments

- Revenue Sufficiency Guarantee ("RSG") payments are made to ensure that the total revenue a generator receives when its offer is accepted exceeds its as-offered costs.
  - ✓ Resources started after the day-ahead market to maintain reliability receive "real-time" RSG when their costs are not covered by the real-time market.
  - ✓ Because the day-ahead market is financial, very little RSG payments are generated in it – a unit that is uneconomic will generally not be selected.
- More than 90 percent of RSG is incurred in the real-time market, which is expected because most commitments made for reliability are made in real time.
- Peaking resources received 60 percent of the real-time RSG, although they produced less than 1 percent of the energy generated in the Midwest ISO.
  - ✓ Peaking resources are generally on the margin (i.e., the highest-cost resources) when they run and prices are frequently set by a lower-cost unit.
- RSG costs decreased 35 percent in 2008 ($126 million reduction) due to:
  - ✓ Lower average load during 2008, and
  - ✓ Reduced number of commitments in the West to manage Minnesota NCA congestion, particularly during non-winter months.

Executive Summary: Dispatch of Peaking Resources in Real Time

- As discussed above, the dispatch of peaking resources is important because it is a significant determinant of RSG and efficient energy pricing.
- In 2008, the dispatch of peaking resources decreased by roughly 50 percent on average.
  - ✓ An average of over 500 MW of peaking resources were dispatched per hour in the summer and 270 MW were dispatched per hour over the whole year.
- Our analysis shows a large share of the peaking resources are dispatched out-of-merit ("OOM"), indicating that they frequently do not set the energy price.
  - ✓ Dispatching a resource OOM occurs when the its offer price is higher than the LMP, which typically requires higher RSG to ensure the resource recover its as-offered costs.
  - ✓ The fact that a peaking resource is dispatched OOM does not mean it was dispatched inappropriately. When a peaking resource is needed, if the price is set by a lower-cost resource, the peaking resource will be OOM.
  - ✓ The fact that peaking resources frequently do not set prices also contributes to under-scheduling of load in the day-ahead market:
    - – Peaking resources are generally the only resources that can be committed in real time to serve the load not scheduled day-ahead – if prices are set at a lower-cost unit, the market will not provide the loads the incentive to purchase more day-ahead.
  - ✓ The Midwest ISO is actively working on a pricing method that will allow inflexible units and demand to set prices.

Executive Summary: Generating Capacity

- Generating resources in the Midwest ISO market totaled almost 129 GW in 2008.
- We estimate the planning reserve margins for Summer 2009, which are sensitive to the assumptions made regarding deratings/outages and interruptible demand.
  - ✓ Reserve margins based on nameplate capacity ratings indicate a substantial surplus.
  - ✓ When one removes the deratings and temperature sensitive capacity that may not be available at peak, the reserve margin ranges from 15 to 23 percent (the higher margin includes interruptible load). Margins are much tighter in the East and Central.
  - ✓ These margins have increased over the past three years due to the entry of new resources and reductions in load.
- Although the system's resources are adequate for the summer of 2009, new resources will be needed over the long-run to meet the needs of the system.
  - ✓ Hence, it is still important for the market's economic signals that govern new investment and retirement decisions to be efficient.
- More than 3.5 GW of new capacity are scheduled to enter in 2009, of which almost 2 GW is wind. Only 235 MW of generation is scheduled to retire.
  - ✓ The intermittent nature of wind causes it to provide less reliability to the system than the nameplate capacity level.
  - ✓ Although wind provides substantial environmental benefits, it also creates significant operational challenges that the Midwest ISO is working to address.

Executive Summary: Transmission Congestion

- One of the most significant benefits of the Midwest ISO energy markets is that they provide accurate and transparent price signals that reflect congestion on the network.
  - ✓ Total congestion costs in the day-ahead and real-time markets decreased almost 30 percent to $508 million in 2008 due primarily to:
    - Lower load;
    - Higher net imports into the West from Manitoba; and
    - Transmission upgrades that reduced congestion into WUMS.
  - ✓ In 2008, over 98 percent of total congestion was captured in the day-ahead market, which is a significant improvement from 2006 and 2007. This suggests better convergence between day-ahead market assumptions and actual real-time conditions.
- There were many instances when the real-time market model was unable to reduce the flow below the transmission limit (i.e., congestion that was not manageable).
  - ✓ 28 percent of congestion was not manageable on a 5-minute basis.
  - ✓ These instances result in substantial nodal price movements and often require operators to take other actions to maintain reliability.
  - ✓ Generator inflexibility (offer parameters that provide little redispatch capability) and certain modeling methods are factors that contribute to these instances.
  - ✓ The report includes recommendations to address this issue.

Executive Summary: Financial Transmission Rights

- Financial transmission rights provide a hedge for congestion because day-ahead congestion over the path that defines the FTR is rebated to the holder.
- FTRs were under-funded in 2008 - day-ahead congestion was 14 percent less than the obligations to FTR holders. Some of the factors explaining the shortfalls include:
  - ✓ Continued challenges associated with accurately forecasting loop flow and non-market flows on Midwest ISO constraints in the FTR modeling.
  - ✓ Significant unplanned unit and line outages that reduce transfer capability modeled in the FTR auctions.
  - ✓ Storm-related damage to the transmission system in June 2008 led to the largest shortfalls.
- To address the under-funding of FTRs, the Midwest ISO has modified assumptions on loop flows and the transmission limits used in the FTR allocations and markets. However, these results indicate that significant improvements are still possible.
- The report also shows that the difference between prices for FTRs in the auctions and the actual value of congestion payable to FTRs has decreased significantly from the start of the market through 2008. This trend indicates:
  - ✓ Decreasing FTR profits realized by their buyers; and
  - ✓ Improving performance of the FTR market as it becomes more liquid and participants improve in the ability to value the FTRs.

Executive Summary: External Transactions

- The Midwest ISO relies heavily on imports from adjacent areas, averaging 4.4 GW in on-peak hours in 2008 and 2.1 GW in off-peak hours.
- Although power can flow in either direction depending on prevailing prices, the Midwest ISO generally imports power from PJM and Manitoba and exports power to Ontario.
- Our analysis of the NSI between the Midwest ISO and adjacent markets shows that the prices at the border between the markets are relatively well arbitraged in most hours.
- Given the uncertainty regarding price differences (transactions are scheduled in advance), many hours exhibit large price differences.
- To achieve better price convergence with PJM, we continue to recommend that the RTO's consider expanding the JOA to optimize net interchange between the two areas.
  - ✓ This change would achieve the vast majority of any potential savings associated with jointly dispatching generation in the two regions.
  - ✓ The Midwest ISO has developed a conceptual approach for implementing this change.
- Given the importance of imports in meeting the Midwest ISO's energy needs, the report includes a recommendation to ensure external resources are not unreasonably restricted in satisfying the Midwest ISO's capacity needs under Module E.

Executive Summary: External Transactions and Coordination with PJM

- In 2008, a number of issues related to "contract path" transaction scheduling around Lake Erie occurred.
  - ✓ The underlying problem in each of the cases observed in 2008 is that settlements occur based on the scheduled path (i.e., the "contract path"), but the actual power flows occur on other paths (these flows are generally referred to as "loop flows").
  - ✓ This inconsistency distorts participants' incentives and can lead to inefficient scheduling.
  - ✓ The report evaluates the two scheduling patterns that become prevalent in 2008.
  - ✓ To address these issue, we recommend that the RTOs around Lake Erie work together to modify their scheduling and settlement rules.
- The report also evaluates the market-to-market coordination between the Midwest ISO and PJM that has been key in managing constraints affected by both RTOs.
  - ✓ The Midwest ISO and PJM have made process improvements over the past two years to continually improve the performance of the process.
  - ✓ However, our analysis shows that the process can be further improved and we recommend specific improvements.
  - ✓ Additionally, the Midwest ISO identified an issue with PJM's market flow calculations that may have understated PJM's market flows and affected past settlements.

Executive Summary: Market Power and Mitigation

- This report provides an overview of the market concentration and other structural market power indicators, as well as a review of the conduct of participants and imposition of market power mitigation measures in 2008.
- The report indicates that concentration is low for the overall Midwest ISO area, but moderate in the Central and East areas and high in the West and WUMS areas.
- The fact that a supplier is "pivotal" is a more reliable indicator of potential market power, which occurs when market demands cannot be satisfied without the supplier's resources.
- Our analysis in this report identifies the frequency with which a single suppliers' resources are needed to manage a constraint.
  - ✓ 59 percent of the active "broad constrained area" ("BCA") constraints have a pivotal supplier. BCAs are all constraints other than area defined in WUMS and SE Minnesota.
  - ✓ 79 percent of the active "narrow constrained area" ("NCA") constraints into WUMS have a pivotal supplier, as do 69 percent of the active NCA constraints into Minnesota.
  - ✓ In addition, two-thirds of all intervals in 2008 exhibited an active BCA constraint with at least one pivotal supplier.
  - ✓ Likewise, 30 percent and 6.5 percent of the intervals exhibited an active NCA constraints with a pivotal supplier in WUMS and Minnesota, respectively.
- These results indicate that substantial local market power exists associated with both the BCA and NCA constraints.

Executive Summary: Market Power and Mitigation

- Our structural analyses indicate substantial local market power, but our analyses of participants' conduct provide little evidence of attempts to withhold resources (either physically or economically) to exercise market power.
- We calculate a "price-cost mark-up" that compares the system marginal price based on actual offers to a simulated system marginal price based on assuming suppliers had all submitted offers at their estimated marginal costs.
  - ✓ Based on this metric we found an average "mark-up" of the system marginal price of roughly one percent, indicating that the market outcomes in 2008 were very competitive.
- We also calculate an "output gap" metric designed to detect economic withholding.
  - ✓ The output gap is the quantity of power not produced when suppliers' competitive costs are significantly lower than the LMP.
  - ✓ This analysis shows that the output gap fell from 2007 to 2008. On a monthly average basis, the output gap ranges from 1 to 1.5 percent of actual load.
- These results and others in this report provide little indication of significant economic or physical withholding, although we monitor these levels on an hourly basis and regularly investigate instances of potential withholding.
- Market power mitigation in the Midwest ISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria. Because conduct has generally been competitive, market power mitigation has been very infrequent.

Executive Summary: Demand Response

- Demand participation in the market is beneficial in many ways. It contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.
- The Midwest ISO has more than 8,000 MW of total demand response capability, most of which is interruptible load developed by utilities under regulated retail initiatives. Modest amounts of this demand response capability participates in the MISO's markets:
  - ✓ 48 MW of dispatchable demand response resources directly participate in the Midwest ISO's energy and ancillary services.
  - ✓ 1603 MW of non-dispatchable demand response resources sell supplemental reserves and emergency energy to the Midwest ISO.
  - ✓ Other emergency demand response capability is used to satisfy an LSE's capacity requirements under Module E.
- The Midwest ISO has been active in facilitating demand response:
  - ✓ The Midwest ISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements.
  - ✓ It has filed tariff changes to allow retail aggregators to participate in the MISO markets.
  - ✓ The Midwest ISO is considering the modifications that would be necessary to allow load interruptions and other emergency actions to set prices in energy and reserve markets.
- We recommend the Midwest ISO consider changes to allow non-dispatchable demand response resources to participate in a real-time economic demand response program.

Executive Summary: Recent Market Improvements

Midwest ISO has implemented a number of changes that have substantially improved the performance of the markets and the economic signals the markets provide.

- Midwest ISO introduced ancillary services markets in January 2009.
  - ✓ The ASM markets have led to improved system flexibility and lower price volatility.
  - ✓ The ASM markets also set more efficient prices to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
  - ✓ The markets were implemented smoothly by the Midwest ISO and have operated as expected in 2009.
- Midwest ISO has clarified the capacity requirements in Module E of the Tariff and developed enforcement provisions.
  - ✓ With these changes, Module E will allows a decentralized contract market to develop to satisfy the Midwest ISO's capacity requirements.
  - ✓ These developments will improve the market signals that govern investment and retirement decisions.

Summary of Recommendations

Although the markets have performed relatively well and will perform better with the implementation of ASM, we recommend the Midwest ISO consider the following changes.

1. *Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.*
   - This change would improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs.
   - To set prices correctly, the market must distinguish between GTs that are needed versus those that would be shut-down if they were flexible and dispatched optimally.
   - The Midwest ISO has developed promising research in this area and should be in a position to test the practical feasibility of its approach later in 2009.
2. *Develop provisions that allow non-dispatchable demand response (or interruptible load) to set energy prices in the real-time market when they are called upon in a shortage.*
   - It would also improve price signals in the highest-demand hours, which is important for ensuring that the markets send efficient economic signals to:
     - ✓ Develop and maintain adequate supply resources; and
     - ✓ Develop additional demand response capability.
   - It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.

Summary of Recommendations

3. *Develop improved "look-ahead" capabilities in the real-time that would improve the commitment of quick-starting gas turbines and the management of ramp capability on slow-ramping units.*
   - In the short-run, improving the tool that determines the recommended "offset" parameter used to incrementally adjust the load modeled in the real-time market.
   - In the long-run, developing a model to assist in the economic commitment of peaking resources, which should reduce the out-of-merit quantities and RSG payments.
4. *Discontinue its constraint relaxation procedure and use the constraint penalty factor to set the LMPs when a transmission constraint is unmanageable.*
   - This will allow the prices to more efficiently reflect the overloaded constraint, particularly in cases when the relaxation procedure has caused the congestion to apparently disappear.
   - This is particularly important for low voltage and market-to-market constraints.
5. *Allow generating resources with lower effects on a constraint to be redispatched (i.e., GSFs less than the current cutoff).*
   - In addition to increasing the manageability of transmission constraints, this will tend to reduce price volatility by providing the market more redispatch options.

Summary of Recommendations

6. *Regarding the market-to-market process, we recommend the Midwest ISO consider:*
   - Instituting a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly;
   - Optimizing the real-time net interchange between the two RTO areas; and
   - Developing a process to coordinate external transactions with non-Midwest ISO/PJM areas within the JOA.
7. *Develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements.*
   - Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.
8. *If it is infeasible to settle intra-hour imports and exports on a 15-minute basis, we recommend the Midwest ISO:*
   - Evaluate its scheduling limits to determine whether they are generally consistent with the available capability to ramp internal generation up or down in support of the transactions.
   - Modify scheduling deadlines to ensure that no participant will observe prices that will be included in an hourly settlement prior to scheduling a transaction.

Summary of Recommendations

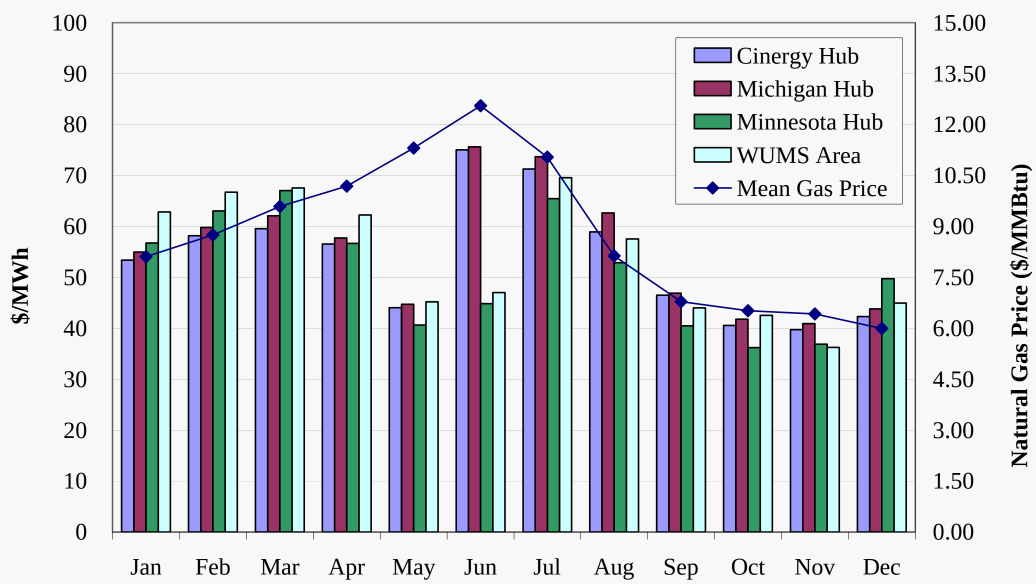
9. *Continue its work to improve the management and pricing for demand response programs, including:*
   - Developing centrally-coordinated demand response programs that allow DR resources to participate more fully in the energy and ancillary services markets; and
   - Allowing the interruptible load and demand response resources to set energy prices in the real-time market when they are called on under shortage conditions.
   - This will improve the incentive and opportunity for the development of new demand response, and allow the Midwest ISO to send more efficient long-term economic signals.
10. *Improve the integration of wind resources in the Midwest ISO system by:*
    - Allowing wind resources to be curtailable at a specified offer price, which would be eligible to set prices in the energy market.
    - Develop allocation rules for RSG and other costs (e.g., reserves and/or regulation) that assign the costs to intermittent resources to the extent that they cause them.
11. *Modify deliverability requirements for external resources to establish a maximum amount that can be utilized to satisfy LSEs' capacity requirements under Module E.*
    - Since exports and imports from adjacent markets are supported by their real-time dispatch processes, so facility-specific deliverability studies should not be needed.
    - Given the Midwest ISO's heavy reliance on net imports in real time, it is important for this source of supply to be available to the Midwest ISO capacity market.

Prices and Revenues

Average Energy and Fuel Prices

- The first figure in this section shows average day-ahead energy prices and natural gas prices in 2008.
- The figure shows that day-ahead prices are correlated with natural gas prices. There are several reasons for this relationship:
  - ✓ Fuel costs represent the majority of most suppliers' variable production costs (i.e., marginal costs) and gas units are often on the margin.
  - ✓ The correlation was strong throughout the year except in the April to June period when low load levels resulted in few hours with natural gas on the margin.
- Differences between hub prices show the congestion on the Midwest ISO system.
  - ✓ Early in the year, much of the day-ahead market congestion occurred on NCA constraints into Minnesota and WUMS.
  - ✓ Beginning in May and increasing in June due to storm damage, west-to-east constraints caused significant congestion.
    - – These constraints generally reduced the price of energy in the Minnesota and WUMS and increased the price of energy in Michigan and Cinergy.
  - ✓ Lower natural gas prices and lower load in the late fall and early winter contributed to a substantial decline in energy prices.

Day-Ahead Average Monthly Hub Prices 2008: All Hours



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Energy Prices

- The “All-In Price” figure summarizes energy prices in the Midwest ISO’s markets in 2007 and 2008.
- The all-in price represents the cost of serving load in the real-time market and is equal to the sum of the average real-time price and average uplift costs borne by real-time load.
  - ✓ The all-in price was $52.50 per MWh in 2008 – a 3.5 percent increase over the all-in price in 2007.
  - ✓ The all-in price in the 4th quarter averaged $40.32 per MWh, a 17 percent decline compared to the 4th quarter of 2007.
  - ✓ The major contributing factors to these year-on-year changes are:
    - – Changes in fuel prices; and
    - – Decreases in load levels.
  - ✓ In April and May 2008, decreasing load levels and the return of substantial amounts of generation from planned outages resulted relatively low real-time energy prices.
  - ✓ Uplift (RSG) remains a small percent (less than 1 percent) of the all-in price.

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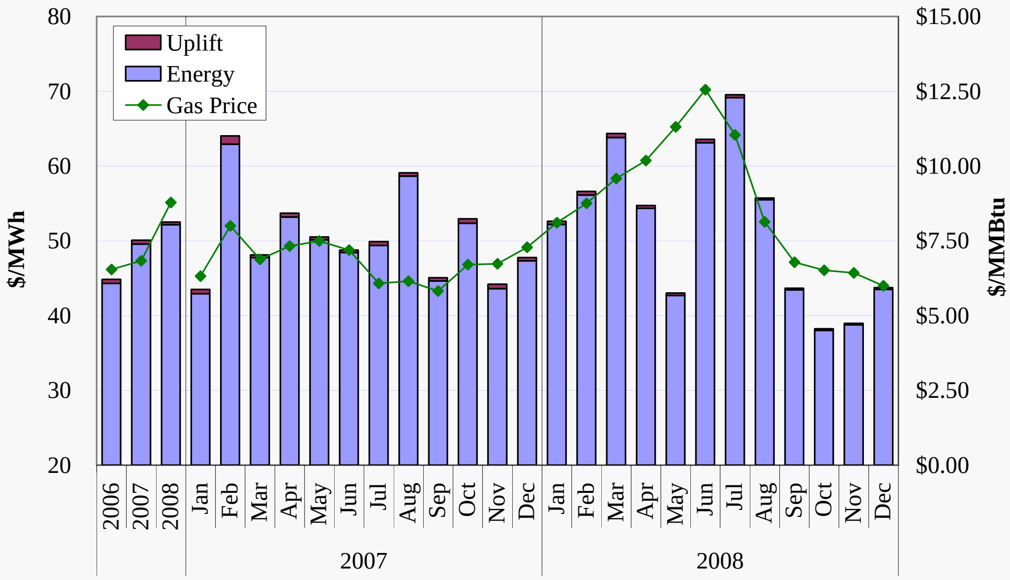
All-In Price
2007 & 2008



Note: The All-In Price is computed by calculating a load-weighted average real-time energy price, plus total revenue sufficiency guarantee costs divided by actual load.

POTOMAC ECONOMICS

Implied Heat Rates

- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Heat Rate = (real-time energy price) ÷ (natural gas price)
  - ✓ This metric highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices.
- The next figure compares the implied heat rates and average load levels for 2007 and 2008. The figure shows:
  - ✓ The metric is largely driven by gas prices relative to market clearing prices. Gas prices through most of 2008 were substantially higher than 2007.
  - ✓ Subsequent analysis shows that coal was on the margin in 73 percent of the hours; therefore, higher gas prices should result in a lower implied heat rate.
  - ✓ Average load in 2008 was substantially lower than 2007 in most months, which contributed to the lower implied heat rates in 2008.
  - ✓ In December 2008, implied heat rates were higher than in 2007 due to lower gas prices, higher load and higher coal prices.

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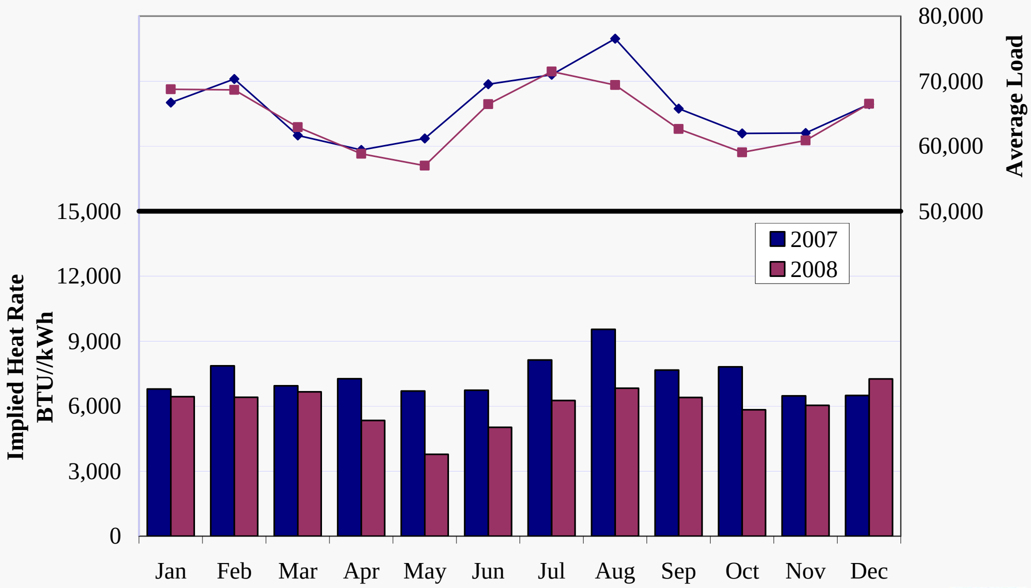
Implied Heat Rate of Energy Price



Midwest ISO Fuel Prices

The next figure shows fuel prices from January 2007 through December 2008.

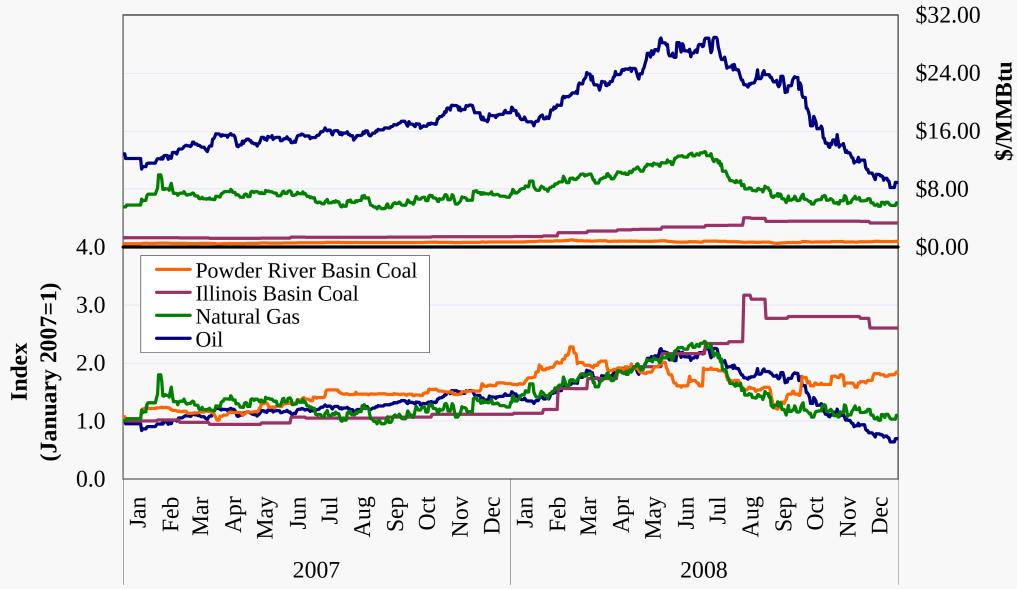
Oil and Natural Gas Prices

- Natural gas prices were volatile in 2008. After beginning the year at $7.30 per mmBtu, they rose steadily until peaking above $13 per mmBtu in early July. The price then declined sharply to end the year at $6 per mmBtu.
- Oil prices were even more volatile, beginning year at $18.50 per mmBtu, rising to nearly $29 by mid-July and finishing the year below $9 per mmBtu.

Coal Prices

- Coal prices were also quite volatile, with similar patterns throughout the year.
- Illinois Basin prices rose throughout most of the year, peaking in August and ending the year at $3.30 per mmBtu, more than double the price at the start of year.
- Power River Basin coal prices averaged $0.74 per mmBtu in 2008 and ended the year at $0.72 per mmBtu, only slightly above the January 2008 price of $0.69 per mmBtu.

Midwest ISO Fuel Prices



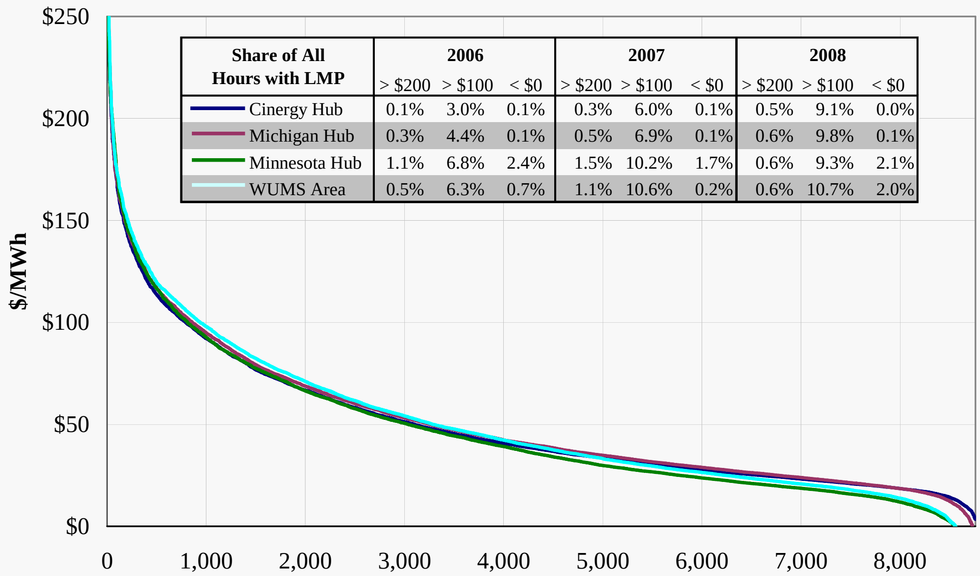
POTOMAC ECONOMICS

Real Time Energy Prices

- The next figure shows a real-time price duration curve for each hub. A price duration curve shows the number of hours (x-axis) when the LMP is greater than or equal to a particular price level (y-axis).
- Congestion and losses cause prices to vary by location:
  - ✓ In prior years WUMS and Minnesota prices were the highest due to the frequent congestion into these areas, but in 2008 congestion was less frequent and the Cinergy and Michigan Hubs also experienced congestion.
  - ✓ The number of hours exceeding $200/MWh and $100/MWh were similar for all locations, but congestion affected Minnesota and WUMS more in the winter months and Cinergy more in the summer months.
  - ✓ Compared to 2007, the number of hours exceeding $200/MWh declined significantly for Minnesota and WUMS and increased substantially for Cinergy and Michigan.
  - ✓ Much of the congestion at the Cinergy and Michigan Hubs was due to extensive storm damage to key transmission facilities in June.
  - ✓ Congestion from the west to the east of the footprint resulted in an increase in hours with prices less than zero (2 percent of hours) in Minnesota and WUMS. Much of this congestion occurred in June and was due to storm related transmission outages.

POTOMAC ECONOMICS

Real-Time Price Duration Curve
2008: All Hours



Share of All Hours with LMP	2006			2007			2008		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Cinergy Hub	0.1%	3.0%	0.1%	0.3%	6.0%	0.1%	0.5%	9.1%	0.0%
Michigan Hub	0.3%	4.4%	0.1%	0.5%	6.9%	0.1%	0.6%	9.8%	0.1%
Minnesota Hub	1.1%	6.8%	2.4%	1.5%	10.2%	1.7%	0.6%	9.3%	2.1%
WUMS Area	0.5%	6.3%	0.7%	1.1%	10.6%	0.2%	0.6%	10.7%	2.0%

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Highest-Priced Hours in the Real-Time Market

- The next figure shows a real-time price duration curve for the highest-priced hours for each hub.
- Prices in these peak hours play a critical role in sending the economic signals that govern investment and retirement of generation.
  - ✓ Minnesota and WUMS had only slightly more high prices (>$300) than Cinergy and Michigan in 2008, which represents a reduction from 2006 and 2007 that can be attributed to the restoration of imports from Manitoba and increased wind output.
  - ✓ Price duration curves for all four hubs are generally higher in these hours than the prices at other locations in the Midwest ISO.
  - ✓ Prices throughout the Midwest ISO were above $300 in a very small number of hours – ranging from 3 to 8 hours (less than 0.01 percent) at all hubs.
  - ✓ If peak pricing events continue at the frequencies that occurred in 2008, the Midwest ISO markets will not provide efficient incentives for new investment in generation or demand response resources.
    - – This is further evaluated in the Net Revenue analysis in this report.
    - – Improvements in the peak energy pricing provisions and related market rules and revenues from ancillary services that are discussed later in the report will improve the economic signals and contribute to resource adequacy.

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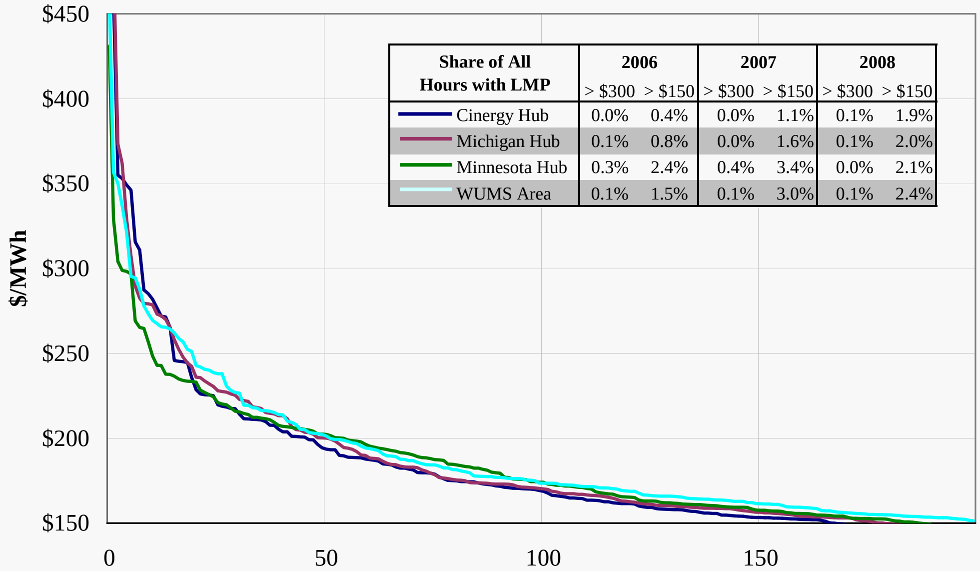
Real-Time Price Duration Curve 2008: Highest-Priced Hours

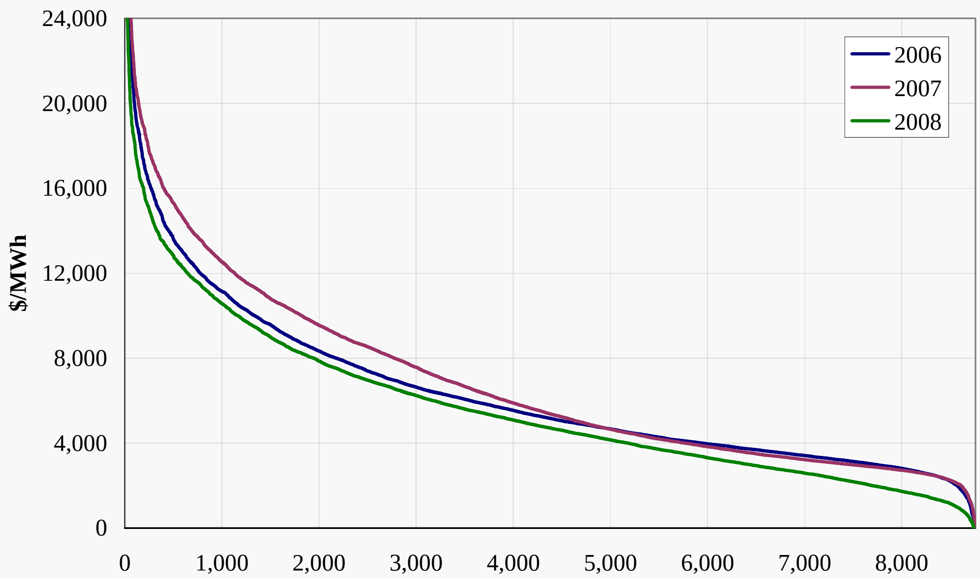


Share of All Hours with LMP	2006 > $300	2006 > $150	2007 > $300	2007 > $150	2008 > $300	2008 > $150
Cinergy Hub	0.0%	0.4%	0.0%	1.1%	0.1%	1.9%
Michigan Hub	0.1%	0.8%	0.0%	1.6%	0.1%	2.0%
Minnesota Hub	0.3%	2.4%	0.4%	3.4%	0.0%	2.1%
WUMS Area	0.1%	1.5%	0.1%	3.0%	0.1%	2.4%

Implied Heat Rate Duration Curve

- The implied heat rate duration curves illustrated on the next slide represents the average load-weighted hourly ex-post price during each of the 8,760 hours in 2006, 2007, and 2008 divided by the prevailing natural gas price.
- This figure shows that the implied heat rate is lowest for 2008 compared to other years. As discussed previously, several contributing factors to this change are:
  - ✓ Peak and average load in 2008 were lower than in 2007 and 2006.
  - ✓ Natural gas and oil-fired resources set the marginal system price in under 19 percent of real-time market intervals in 2008 compared to over 29 percent in 2007.
  - ✓ Coal set the system marginal price in 77 percent of the hours in 2006 and 67 percent in 2007 and 73 percent in 2008. A higher share of coal on the margin serves to lower the implied heat rate.
  - ✓ Non-firm natural gas transportation issues were less significant in 2008 than in 2007, when they compelled many dual-fueled resources to burn oil during the winter.

Implied Heat Rate Duration Curve
2006 through 2008



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Price Setting Summary

- The next figure shows the frequency with which different types of units set the unconstrained energy price 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).
  - ✓ For the purpose of this figure, we show only the price-setter in the unconstrained areas – higher cost units may set prices in constrained areas more than suggested in the figure.
- Coal units set prices in 73 percent of the hours (including virtually all off-peak hours), an increase from 67 percent in 2007. The increase in coal price setting is due to:
  - ✓ Decrease in average load during 2008;
  - ✓ 556 MW increase in average wind generation; and
  - ✓ Substantial increases in oil and natural gas prices in early 2008.
- Natural gas and oil set prices during the highest-load hours. Hence, these fuel prices have a larger effect on the load-weighted average prices than the percentages suggest.
  - ✓ Gas, oil-fired and dual-fueled resources only set price in 23% of hours during 2008, a significant decline from 29.5 percent in 2007.
  - ✓ Nearly half of all real-time energy costs were incurred when these resources were on the margin.

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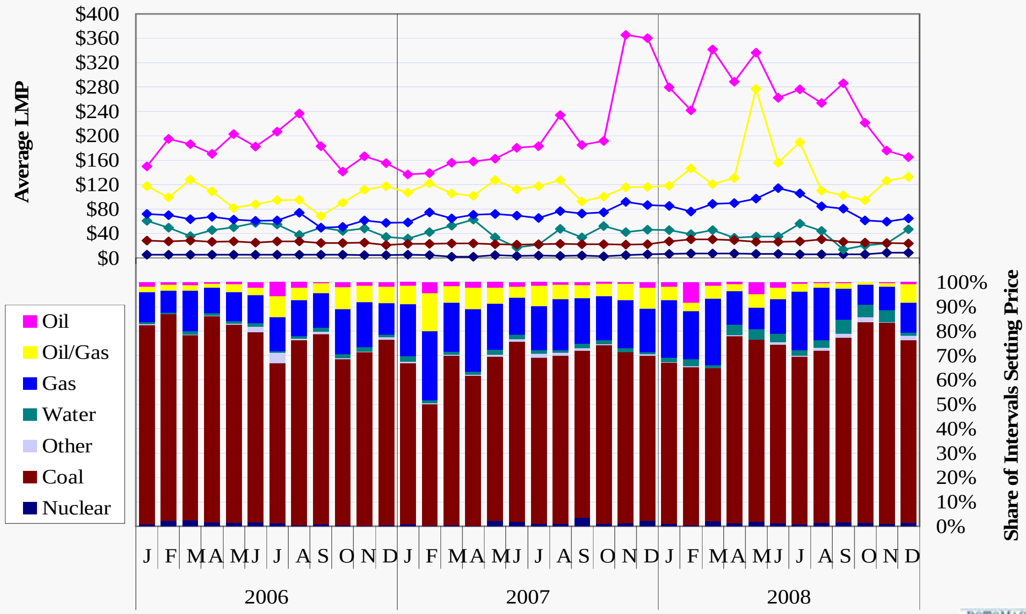
Share of Interval Price Setting By Unit Fuel Type



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Long-Term Economic Signals to Maintain Adequate Resources

- In long-run equilibrium, the market should provide net revenues (revenue in excess of production costs) that create efficient incentives for investment and retirement.
- The following figure shows net revenue provided by the Midwest ISO market from 2006 through 2008 for two types of new units:
  - ✓ Gas combined-cycle: heat rate assumed of 7,000 BTU/kWh.
  - ✓ Gas combustion turbine: heat rate assumed of 10,500 BTU/kWh.
- Based on our estimates of the annualized costs of new investment, the Midwest ISO markets would not support investment in gas turbines or combined-cycle generation.
- These results are consistent with expectations because:
  - ✓ The Midwest ISO footprint has a small capacity surplus that precluded any significant periods of shortage from occurring in 2008.
  - ✓ When shortages do occur, the markets in 2008 did not fully price them because operating reserve shortages and interrupted load did not contribute to setting prices.
  - ✓ The ASM markets that began in January 2009 will improve shortage pricing and the Midwest ISO is working on other pricing changes to allow interruptible load to set prices.
- Changes being introduced to Module E of the Tariff should also improve the long-term market signals needed to maintain adequate resources by allowing a decentralized market to develop to meet the Midwest ISO's capacity requirements.

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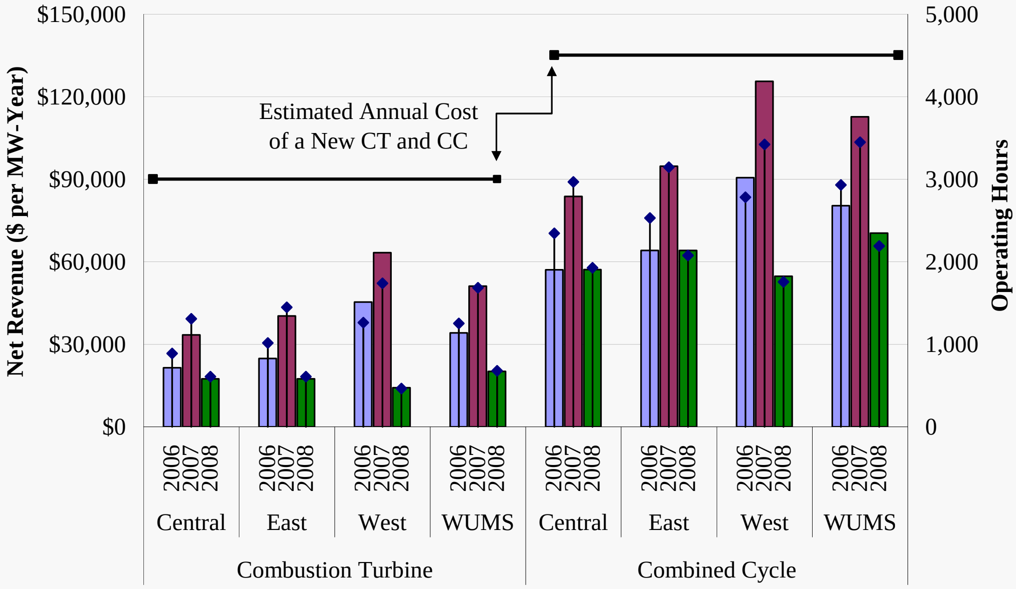
Net Revenue and Operating Hours



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Load and Resources

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Capacity During Peak Load Periods

- The following figure shows the generation capacity available and unavailable to the market during the peak-load hour of each month during 2008.
- The first figure shows that:
  - ✓ The peak load was generally higher than the emergency maximum of all online generation, which indicates that the Midwest ISO relies on net imports to satisfy demands for energy and operating reserves.
  - ✓ During all months, headroom in the peak hour was less than 2 percent of demand, indicating the market was not over-committed (which can suppress peak pricing).
- The second figure provides the same results but shows only the capacity that was unavailable. These figures show:
  - ✓ As expected, day-ahead deratings peaked during the summer due to high temperatures.
  - ✓ Roughly 4.4 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch throughout the year. This represents an increase of 0.8 GW over 2007 and is attributable to:
    - – Aging baseload capacity; and
    - – New wind resources that do not operate at nameplate levels.
- There were no conditions requiring load curtailments during the summer peak periods.

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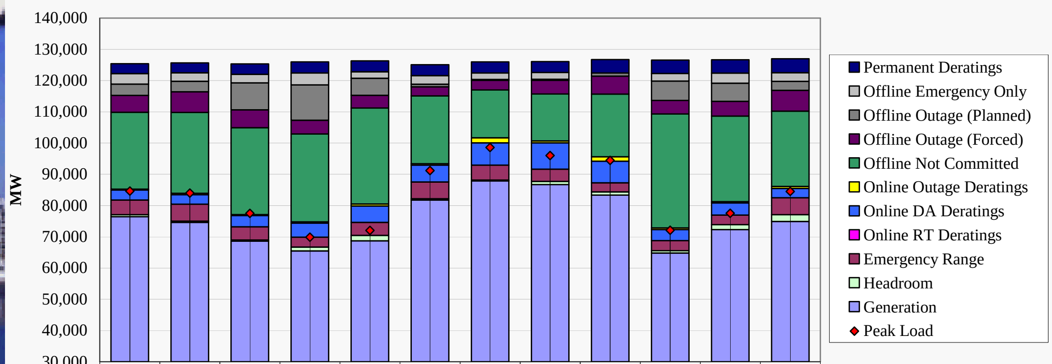
Capacity During Peak Load Hours



7 PM	6 PM	7 PM	7 AM	1 PM	1 PM	3 PM	3 PM	4 PM	6 PM	6 PM	6 PM	Peak Hour
Jan 24	Feb 11	Mar 4	Apr 2	May 30	Jun 26	Jul 29	Aug 1	Sep 2	Oct 27	Nov 20	Dec 15	Peak Date
84,633	84,011	77,491	69,879	72,037	91,188	98,611	96,013	94,471	72,099	77,528	84,536	Peak Load

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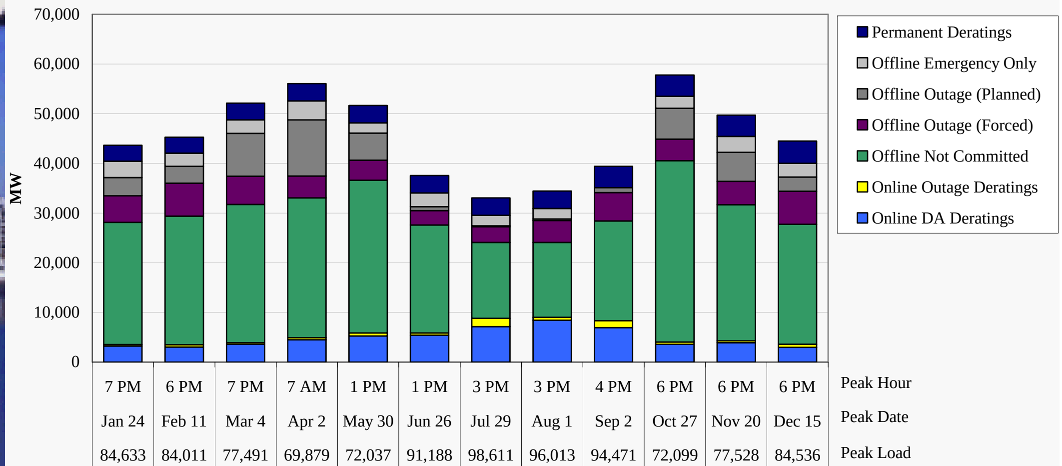
Offline and Unavailable Capacity Monthly Peak Load Hour



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Generation Outages

- The following figure shows the generator outages that occurred in each month during 2008 as a percentage of total market generation capacity.
  - ✓ These values include only full outages – they do not include 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 annual combined outage rate was 9.3 percent for the three categories of outages, a decline from 2006 (10.7 percent) and 2007 (11 percent).
- The largest total outage levels occurred in the spring and fall because planned outages are generally scheduled during low load periods.
  - ✓ Planned outages were 10 percent during the spring and 5.5 percent in fall.
  - ✓ Total planned and forced outages peaked in April at almost 15.3 percent.
  - ✓ Planned outages were lowest (1.0 percent) in peak load months of July and August.
- Forced outage rates were consistent with prior years, peaking at slightly more than 5 percent in January, February, and August.

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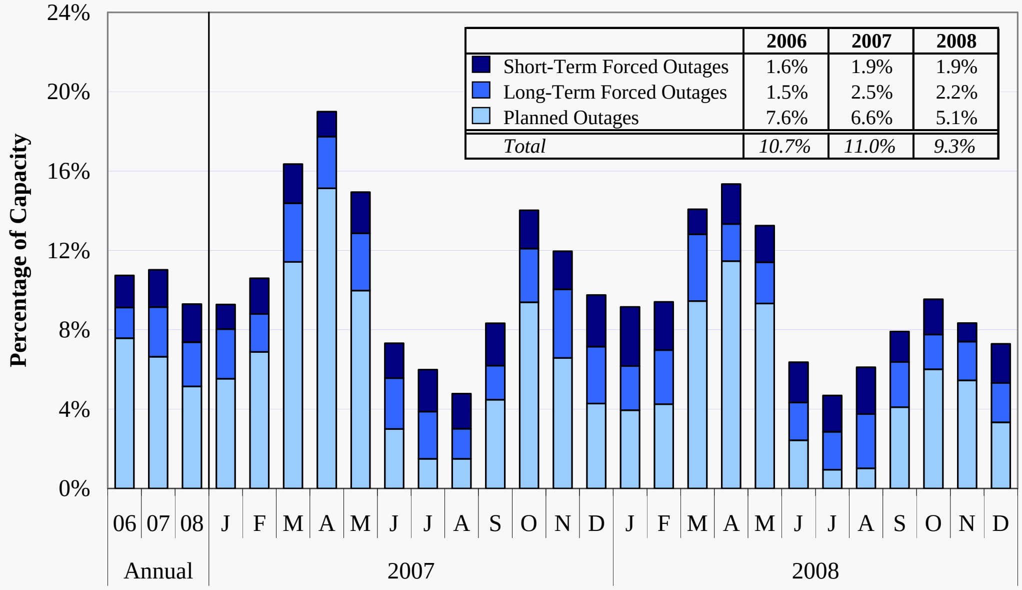
Generation Outage Rates



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Load Duration Curves 2006 - 2008

- The next figure depicts load duration curves for the past three years, which show the number of hours that the load is greater than the level indicated on the vertical axis.
  - ✓ There were no hours when actual loads exceeded 100 GW in 2008, compared to 39 and 31 hours in 2006 and 2007, respectively.
  - ✓ Average load in 2008 was less than in 2007.
  - ✓ The figure also shows that the actual peak load in 2008 was 1.6 percent below the predicted peak demand of 100 GW.
- Nearly 30 percent of generation resources are needed to meet the energy and operating reserve requirements of the ISO in the highest three percent of load hours.
  - ✓ These results underscore the importance of efficient pricing during the highest load conditions.

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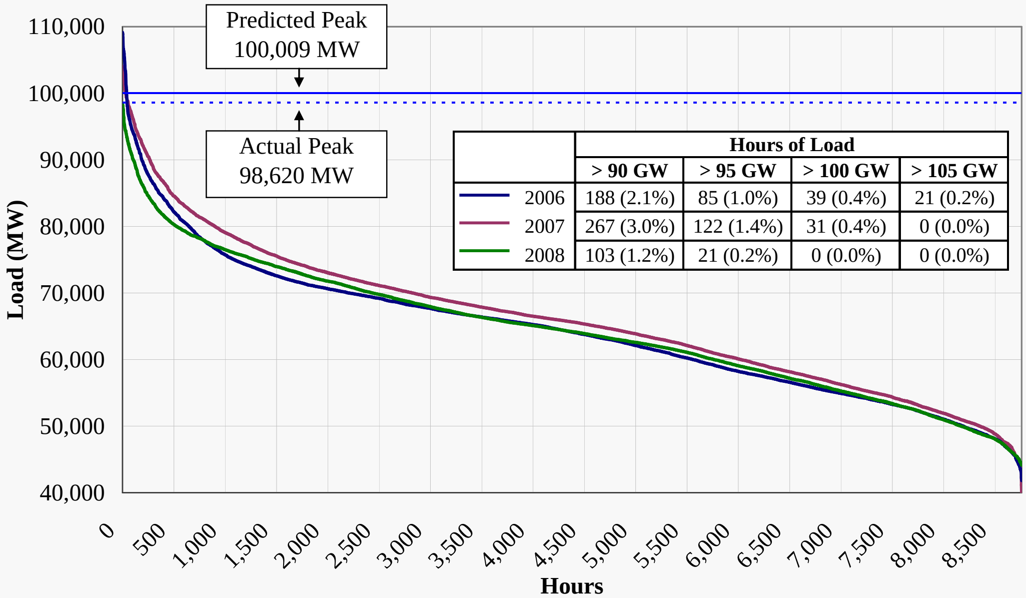
Load Duration Curves
2006 - 2008

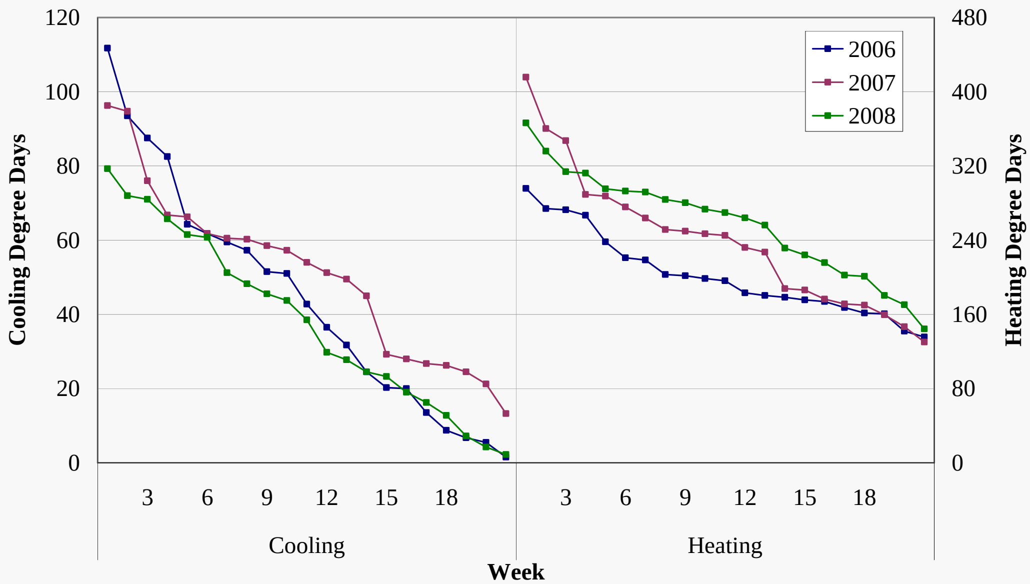


	Hours of Load			
	> 90 GW	> 95 GW	> 100 GW	> 105 GW
2006	188 (2.1%)	85 (1.0%)	39 (0.4%)	21 (0.2%)
2007	267 (3.0%)	122 (1.4%)	31 (0.4%)	0 (0.0%)
2008	103 (1.2%)	21 (0.2%)	0 (0.0%)	0 (0.0%)

Heating and Cooling Duration Curves
2006 - 2008

- The next figure shows the contribution of weather patterns to differences in load from 2006 to 2008.
- The figure depicts heating and cooling degree day duration curves, which show the number of weeks with the amount of heating or cooling degree days shown on the vertical axis.
- Mild summer weather was in part responsible for the lack of extreme demand levels in 2008.
  - ✓ Of the six hottest weeks over the past three years, four were during July and August 2006 and the other two were during 2007.
  - ✓ Winter 2007, particularly February of that year, was more severe than any single week during winter 2008, but on average 2008 was a colder winter.
  - ✓ The low average load recorded in 2006 (depicted on the load duration chart) was a result of the mild winter weather.

Heating and Cooling Duration Curves
Weekly Average of Four Cities in Midwest ISO



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Midwest ISO Generating Capacity
by Coordination Region

- Generating resources in the Midwest ISO market footprint totaled almost 129 GW in 2008.
  - ✓ The resources in this figure are those owned by Midwest ISO market participants and exclude Midwest ISO members that are only reliability members (e.g. NPPD, OPPD).
  - ✓ The reliability footprint at the end of 2008 exceeded 170 GW but declined in April 2009 when OPPD, NPPD and LES left the Midwest ISO for SPP.
- The following figure shows the generating capacity located in the four primary regions in the Midwest.
  - ✓ Because it is a frequently congested area, we show the WUMS area separately from the rest of the East coordination region of Midwest ISO.
  - ✓ Consistent with the location of the load in the Midwest, more than 70 percent of the generating resources are located in the East and Central regions.

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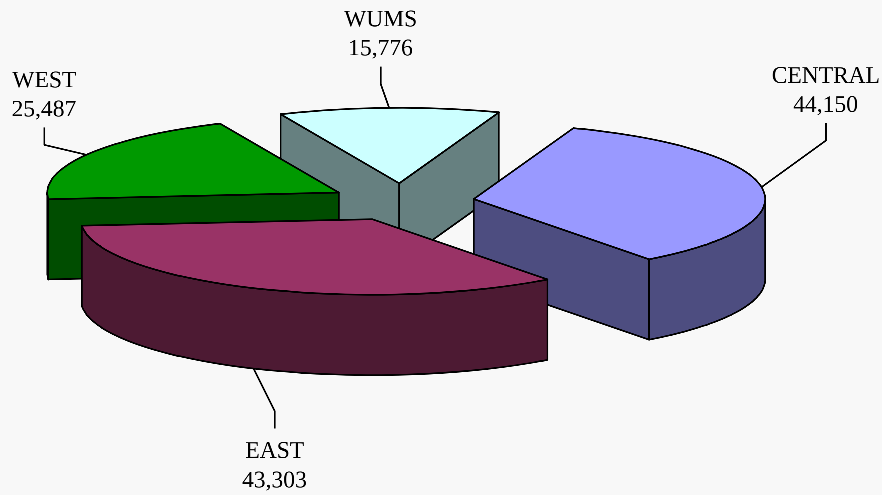
Generation Capacity by Coordination Region



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Generation Capacity and Reserve Margins

- The next analysis shows our estimates of reserve margins in the Midwest ISO footprint in 2009.
  - ✓ Our estimates differ from the Midwest ISO's estimates because the unit-ratings planners normally assume can be optimistic if all potential deratings are not fully reflected.
- In particular, capacity levels during high temperature events are significantly lower than nameplate capacity suggests, leading to lower reserve margins than planners typically estimate.
  - ✓ Many resources during peak load events must be derated in response to environmental restrictions or due to the effect of high ambient temperatures.
  - ✓ Intermittent resources cannot be relied upon to provide energy in real-time.
  - ✓ Units are often "permanently derated" by a small amount, indicating that they cannot physically operate at their nameplate capacity level.
- The next table shows capacity levels, internal demand, and resulting reserve margins for each region projected for 2009 given announced capacity additions and retirements.
  - ✓ Internal demand is internal load less the sum of interruptible load and other demand side response capability.
  - ✓ The reserve margin = ((Capacity plus Firm Imports) ÷ Internal Demand or Load) – 1

POTOMAC ECONOMICS

Generation Capacity and Reserve Margins

- The table shows that reserve margins are highly sensitive to the assumed maximum capacity levels and whether interruptible demand is included.
- Using nameplate capacity levels and the projected levels for 2009:
  - ✓ The reserve margin for the Midwest ISO region is 32 percent based on Internal Load and almost 42 percent based on Internal Demand (which includes demand response capability).
  - ✓ Among the regions, the reserve margin varies from 15 percent to 52 percent based on Internal Load and from 25 percent to 72 percent based on Internal Demand.
  - ✓ These results would lead one to conclude that the Midwest ISO has a substantial surplus.
- However, when one removes the typical deratings and the temperature sensitive capacity that was not available under peak demand conditions, we find:
  - ✓ The reserve margin projected for 2009 for the Midwest ISO region is 15 percent based on Internal Load and 23 percent based on Internal Demand.
  - ✓ Among the regions, the reserve margin varies from almost 5 percent to 18 percent based on Internal Load and from 14 percent to almost 34 percent based on Internal Demand.
- The Midwest ISO's planning margins are slightly lower than ours this year. While they do not remove high-temperature deratings as we do, the Midwest ISO does remove capacity that is not needed to satisfy LSEs' capacity obligations ,while ours includes all physical capacity.
- Although the system's resources are adequate for the summer of 2009, new resources will be needed over the long-run to meet the needs of the system. Hence, the market's economic signals that govern new investment and retirement decisions remain critical.

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Generation Capacity and Planning Reserve Margins Estimates for 2009

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temp. Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	38,111	-	43,387	13.8%	41,836	9.8%	39,438	3.5%
Internal Demand[3]	35,416	-	43,387	22.5%	41,836	18.1%	39,438	11.4%
Central								
Internal Load	37,501	2,032	45,057	25.6%	42,636	19.1%	39,550	10.9%
Internal Demand	35,636	2,032	45,057	32.1%	42,636	25.3%	39,550	16.7%
West								
Internal Load	18,399	1,744	26,363	52.8%	21,821	28.1%	19,983	18.1%
Internal Demand	17,193	1,744	26,363	63.5%	21,821	37.1%	19,983	26.4%
WUMS								
Internal Load	13,137	556	16,501	29.8%	15,488	22.1%	14,643	15.7%
Internal Demand	12,315	556	16,501	38.5%	15,488	30.3%	14,643	23.4%
MISO								
Internal Load	102,472	4,332	131,308	32.4%	121,781	23.1%	113,614	15.1%
Internal Demand	95,884	4,332	131,308	41.5%	121,781	31.5%	113,614	23.0%

[1] Midwest ISO Summer-Rated Capacity from its 2009 Summer Assessment.

[2] High Temperature capacity is based upon tempearture derates that occurred in the Day-Ahead market of August 1, 2006.

[3] Net Internal Demand estimate excludes interruptible load and behind the meter generation.

[4] Our planning reserve margins differ from the Midwest ISO's because: a) we include temperature-related deratings (reduces our margins), b) we include all physical capacity, not only those designated as capacity (increases our margins), c) we calculate our margins based on internal load and internal demand while the Midwest ISO's is generally based on internal demand.

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Additions and Retirements of Generation Capacity

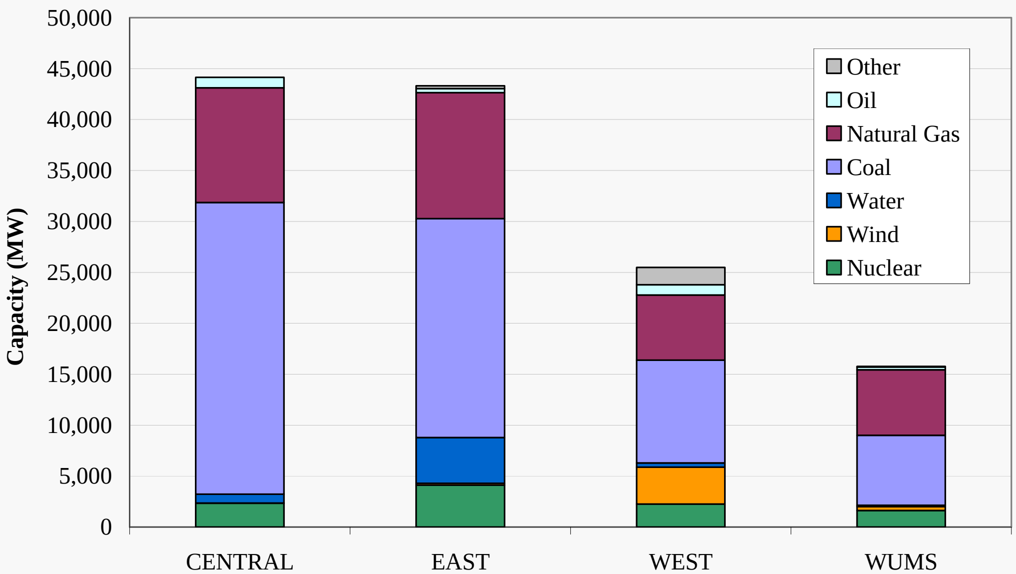
- The following table shows the new capacity additions planned for 2009.
- In total, 3.5 GWs of additions and 235 MWs of retirements/reclassifications are expected in 2009.
  - ✓ Although capacity additions of 3.5 GWs is substantial, much of the new capacity is wind. The intermittent nature of wind resources causes it to contribute less to reliability than conventional supply or demand response resources.
  - ✓ Substantial gas/oil fired capacity is also being added in the West, which should improve the Midwest ISO's ability to manage congestion into the area.

Region	Coal	Coal/ Gas	Gas	Oil/ Gas	Other	Waste	Water	Wind	Total
CENTRAL	220	0	53	0	0	0	0	101	373
EAST	0	0	578	0	8	0	0	5	591
WEST	0	15	6	688	15	6	0	1,714	2,444
WUMS	0	0	0	0	0	0	10	122	131
Total	220	15	637	688	23	6	10	1,941	3,539

Distribution of Regional Generation Capacity By Fuel Type

- The next figure shows the distribution of generating capacity by type and location.
- The Midwest ISO continues to rely heavily on coal-fired generating resources.
  - ✓ Approximately 52 percent of its generation capacity is coal-fired.
  - ✓ Since coal units are generally baseloaded, coal-fired resources generate an even larger proportion (77 percent) of total energy produced.
- The next largest fuel-type is natural gas-fired generation, which accounts for almost 28 percent of the generating resources in the Midwest.
  - ✓ Because these resources are higher-cost than most of the other resources in the Midwest ISO, they produce less than 5 percent of the energy in the region.
- Nuclear units claim 7.3 percent of capacity but produce 15 percent of the energy.
  - ✓ 40 percent of this capacity is in the East region.
- Due to an influx of over 2 GW of new capacity, wind now accounts for over three percent of capacity.
  - ✓ 86 percent of wind capacity is installed in the West region.

Distribution of Sub-Region Generation Capacity By Fuel Type and Region

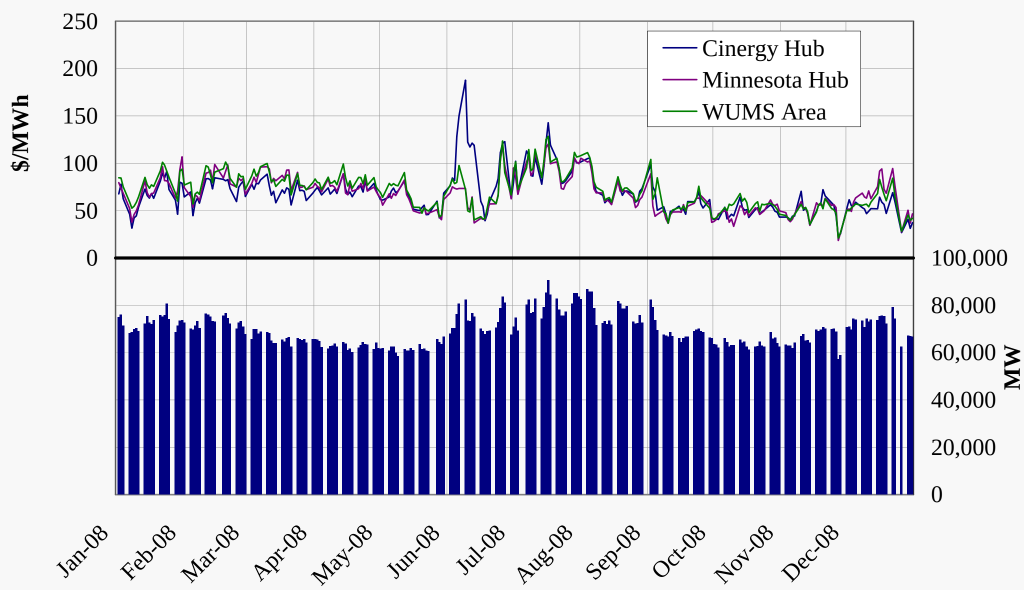


Day-Ahead Market Performance

Day-Ahead Hub Prices and Load
Peak Hours

- The next figure shows daily day-ahead prices during peak hours (6am-10pm on weekdays) and the corresponding scheduled load (including net cleared virtual demand).
- Differences in prices at the Minnesota, WUMS, and Cinergy Hubs show the prevailing congestion patterns throughout the year.
  - ✓ During the first part of the year (Jan – May) congestion was greatest into WUMS and the West due to the higher share of the winter load in the Northwest portion of the footprint and non-firm gas transportation issues.
  - ✓ In June, significant storm-related transmission outages east of Chicago caused west-to-east congestion and very high prices at the Cinergy and Michigan Hubs.
  - ✓ In the second half of the year prices at the Minnesota Hub were low due to high levels of imports from Manitoba.
  - ✓ For the year, prices continued to be the highest in WUMS, but congestion has moderated due to transmission investments into the area.
- High load during both the winter peak and summer peak periods led to higher prices and volatility throughout the footprint.

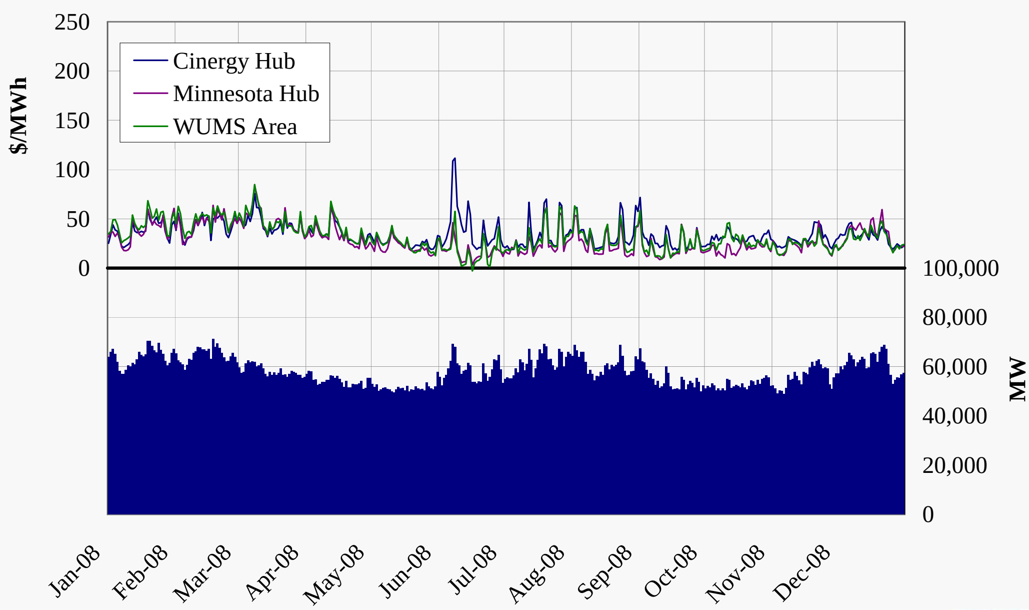
Day-Ahead Hub Prices and Load
Peak Hours



Day-Ahead Hub Prices and Load Off-Peak Hours

- The next figure shows day-ahead prices and load during off-peak hours.
- Day-ahead average off-peak prices were highest from January through March due to winter peaks and high fuel prices.
  - ✓ Prices in WUMS were the highest in these winter months, along with prices in Minnesota.
- As with peak hours, significant storm related transmission outages caused significant congestion in June at the Cinergy and Michigan Hubs.
  - ✓ Prices at Cinergy and Michigan Hubs in June averaged more than $13/MWh higher than Minnesota and WUMS.
- Though less prominent than in 2007, 2008 congestion patterns had a significant effect on off-peak prices at the Minnesota Hub:
  - ✓ Congestion *to* Minnesota led to higher prices during winter months;
  - ✓ Congestion *from* Minnesota led to lower off-peak prices during summer months.

Day-Ahead Hub Prices and Load Off-Peak Hours



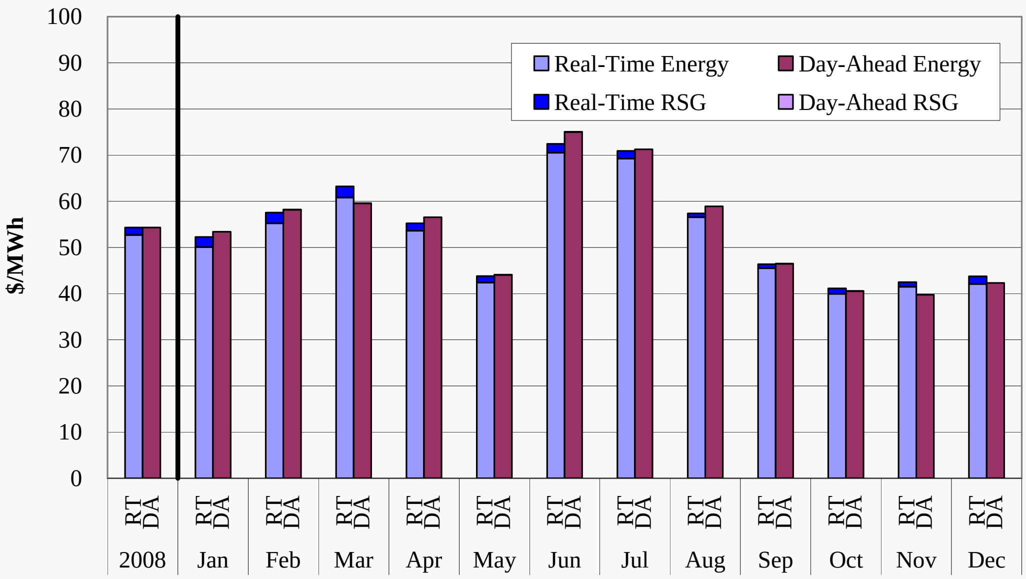
Day-Ahead and Real-Time Price Convergence

- The next series of analyses is focused on the convergence of real-time and day-ahead energy prices.
- It is important that prices in the day-ahead market converge with those in the real-time market because:
  - ✓ The day-ahead market governs most of the generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results.
  - ✓ Most wholesale energy bought or sold through the Midwest ISO markets is settled through the day-ahead market.
  - ✓ The entitlements of firm transmission rights are associated with the results of the day-ahead market.
- In general, good convergence is achieved by price-sensitive bids and offers in the day-ahead market – including active virtual supply and demand participation.

Day-Ahead and Real-Time Prices Cinergy and Michigan Hubs

- The following figures show the monthly average prices for the Cinergy and Michigan Hubs in the day-ahead and real-time markets. Cinergy Hub is the most liquid trading point for forward contracting in the Midwest ISO region.
- The results for the Cinergy and Michigan Hubs in the first two figures show:
  - ✓ Modest day-ahead premiums throughout the year.
  - ✓ During the summer when prices are most volatile, the day-ahead premimums were larger, averaging $2.84 and $3.89 per MWh for the Cinergy and Michigan Hubs, respectively.
  - ✓ Day-ahead premiums are rational because entities purchasing in the real-time market are subject to RSG uplift cost allocation.
  - ✓ To account for this factor, the following figures show the average RSG allocations (real-time RSG rate) on top of the energy price in each market.
- Although the average day-ahead prices were slightly higher than real-time prices, the total real-time price is nearly equal when RSG costs are included.
  - ✓ The largest real-time premiums (including RSG costs) occurred in months with the largest RSG cost allocations.
  - ✓ This indicates that the days with the largest RSG costs are difficult to foresee and, thus, are not fully reflected in day-ahead prices.

Day-Ahead and Real-Time Prices
Cinergy Hub



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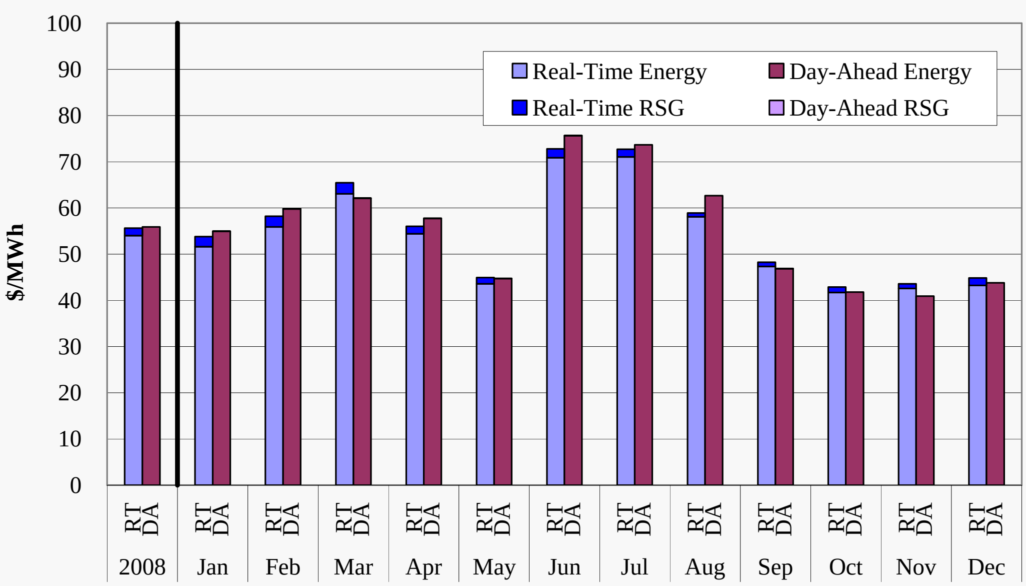
Day-Ahead and Real-Time Prices
Michigan Hub



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Day-Ahead and Real-Time Prices
Minnesota Hub and WUMS

- The following figures show average prices at the Minnesota Hub and in WUMS in the day-ahead and real-time markets.
- Price convergence in these areas is normally more variable because congestion increases price volatility.
  - ✓ The higher price volatility typically leads to a wider dispersion of price differences and higher average differences.
  - ✓ The increased congestion at the Minnesota Hub and WUMS during the early part of the year contributed to larger fluctuations in the monthly differences between day-ahead and real-time prices.
- However, average prices were roughly the same over the entire year when real-time RSG allocations are considered.
  - ✓ This indicates that arbitrage has been effective over the longer-term, despite the increased short-term volatility of the prices at these locations.

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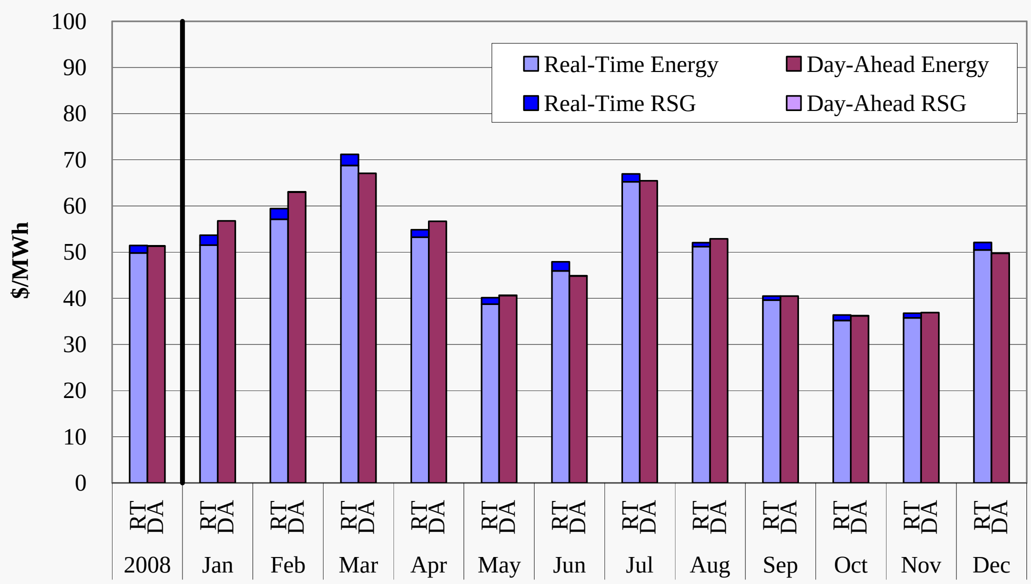
Day-Ahead and Real-Time Prices
Minnesota Hub



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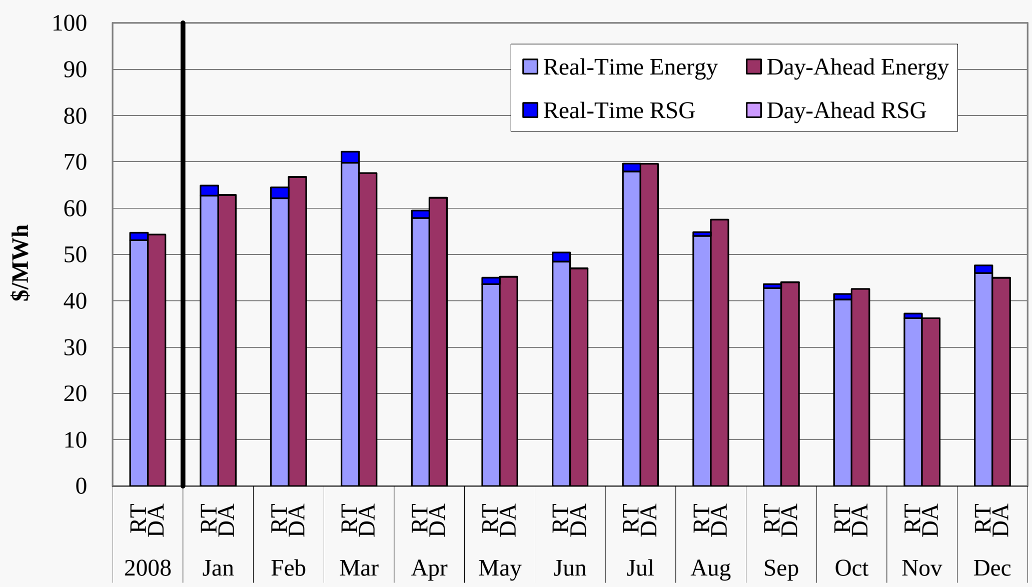
Day-Ahead and Real-Time Prices WUMS Area



POTOMAC ECONOMICS

Day-Ahead and Real-Time Price Differences Midwest ISO and Neighboring Markets

- The following figure compares day-ahead and real-time price differences in Midwest ISO and the other RTO markets in the eastern interconnect. The comparison includes:
  - ✓ Average price differences and average of the absolute value of the hourly price differences (which shows the typical difference regardless of the direction).
  - ✓ Prices in constrained and unconstrained areas in each market.
- The comparison of the average prices in the table shows:
  - ✓ The markets exhibit a day-ahead price premium at most locations, with the exception of isolated locations in PJM, NYISO and ISO-NE.
  - ✓ These premiums are consistent with the higher volatility, risk, and RSG costs associated with purchasing in the real-time market.
- The comparison of the average absolute value of the differences shows:
  - ✓ The locations affected by congestion exhibited larger average differences, ranging from \$16 to \$28 per MWh, which is consistent with the higher volatility in these areas.
  - ✓ In the real-time Market Performance section of this presentation, some reasons for differences in pricing patterns between markets are discussed.
- Overall, these analyses indicate that price convergence in the Midwest ISO has been consistent with other RTO markets.
  - ✓ The higher premiums in the Midwest ISO can be attributed to the RSG allocations.

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Day-Ahead to Real-Time Price Differences MISO and Neighboring Markets

	Average Clearing Price			Average of Hourly
	Day-Ahead	Real-Time	Difference	Absolute Price Difference
Midwest ISO:				
Cinergy Hub	$54.28	$52.70	$1.58	$16.92
Michigan Hub	$55.87	$54.02	$1.85	$17.84
Minnesota Hub	$51.33	$49.85	$1.48	$18.61
WUMS Area	$54.30	$53.09	$1.20	$19.06
New England ISO:				
New England Hub	$83.69	$84.01	-$0.32	$14.98
Maine	$78.77	$78.34	$0.42	$13.46
Connecticut	$88.52	$87.17	$1.35	$16.15
New York ISO:				
Zone A (West)	$61.83	$59.95	$1.89	$23.59
Zone G (Hudson Valley)	$91.15	$89.87	$1.28	$25.66
Zone J (New York City)	$101.80	$102.61	-$0.81	$28.44
PJM:				
AEP Gen Hub	$53.76	$53.76	$0.00	$13.62
Chicago Hub	$54.26	$53.31	$0.95	$15.09
New Jersey Hub	$84.20	$84.25	-$0.05	$21.42
Western Hub	$74.23	$73.11	$1.12	$19.02

Day-Ahead Load Scheduling

- The next figure shows the components of load cleared in the day-ahead market as a percentage of the actual real-time load.
- The net load scheduled day ahead is a key driver of RSG.
  - ✓ Net load is the physical load, plus virtual load minus virtual supply.
  - ✓ Supplies are committed and scheduled in the day ahead to satisfy the net load.
  - ✓ When net load is significantly less than 100 percent of the actual load, particularly in the peak load hour of the day, the Midwest ISO will frequently commit peaking resources to satisfy the incremental increase in load.
- Participants will have incentives to schedule net load at less than 100 percent when:
  - ✓ Significant quantities of generation are committed by participants or the ISO after the day-ahead market.
  - ✓ High-cost units (such as peaking resources) do not set prices when dispatched in the real-time market, which reduces the incentive to schedule fully day ahead.

Day-Ahead Load Scheduling

- The figure shows that the vast majority of load scheduled in the day-ahead market is fixed, i.e. will be purchased at any price.
  - ✓ Price-sensitive physical load accounts for less than 2 percent of total load scheduled market-wide and is the highest in WUMS at 9 percent.
- Virtual bids and offers fluctuated somewhat throughout 2008, but trended toward net virtual demand in the last quarter resulting in higher net load.
  - ✓ The decrease in virtual supply appears to be related to the recent increase in RSG allocations.
- Overall, the net load (total load net of virtual supply) scheduled in the day-ahead market as a percent of the real-time load increased from 2007.
  - ✓ 98.1 percent of the actual load was scheduled on net in 2008 in all hours, up slightly from 97.1 percent in 2007.
  - ✓ In the peak hour of each day (which is the hour that is most likely to require MISO to commit additional generation), 96.5 percent of the actual load was scheduled on net in the day-ahead market versus 95.1 percent in 2007 and 96.1 percent in 2006.
  - ✓ The higher scheduling levels since 2005 have reduced MISO's reliance on peaking resources in the real-time, which led to the lower RSG costs in 2007 and 2008.

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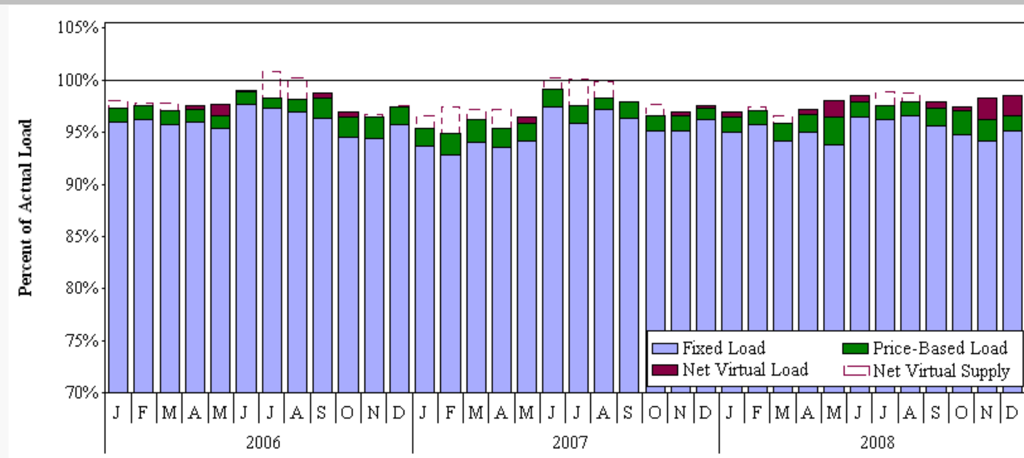
Day-Ahead Load Scheduling versus Actual Load Daily Peak Hour



2006	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.0%	99.0%	99.1%	98.8%	99.0%	100.2%	99.2%	99.0%	100.0%	98.7%	98.7%	99.6%
Peak Hours	97.3%	97.5%	97.0%	97.6%	97.6%	98.9%	98.3%	98.1%	98.8%	96.9%	96.4%	97.4%

2007	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	97.5%	97.1%	98.8%	97.2%	98.4%	100.1%	98.7%	99.7%	99.8%	99.4%	99.8%	100.3%
Peak Hours	95.3%	94.9%	96.2%	95.3%	96.5%	99.1%	97.5%	98.3%	97.9%	96.5%	97.0%	97.5%

2008	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.2%	99.8%	98.2%	99.5%	98.8%	99.7%	98.7%	99.0%	98.9%	98.9%	99.5%	99.6%
Peak Hours	96.9%	97.0%	95.8%	97.2%	98.0%	98.5%	97.6%	97.9%	97.8%	97.4%	98.3%	98.5%

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Virtual Load and Supply in the Day-Ahead Market

- Virtual trades in the day-ahead market serve to:
  - ✓ Help ensure day-ahead market results are efficient;
  - ✓ Facilitate convergence between the day-ahead and real-time prices; and
  - ✓ Mitigate market power in the day-ahead market.
- The next two figures show the daily virtual bids and offers, those that cleared the market, and the net virtual load (cleared virtual load less virtual supply).
- After virtual trading volumes grew rapidly in 2005, FERC issued an Order in April 2006 requiring the allocation of RSG costs to virtual supply.
  - ✓ Although the FERC order should have only affected virtual supply costs, both virtual supply and demand quantities decreased initially.
  - ✓ In November 2008, FERC issued an additional order resulting in additional costs being allocated to RSG.
  - ✓ The impact of RSG allocations on virtual trading and market convergence are discussed in subsequent sections.

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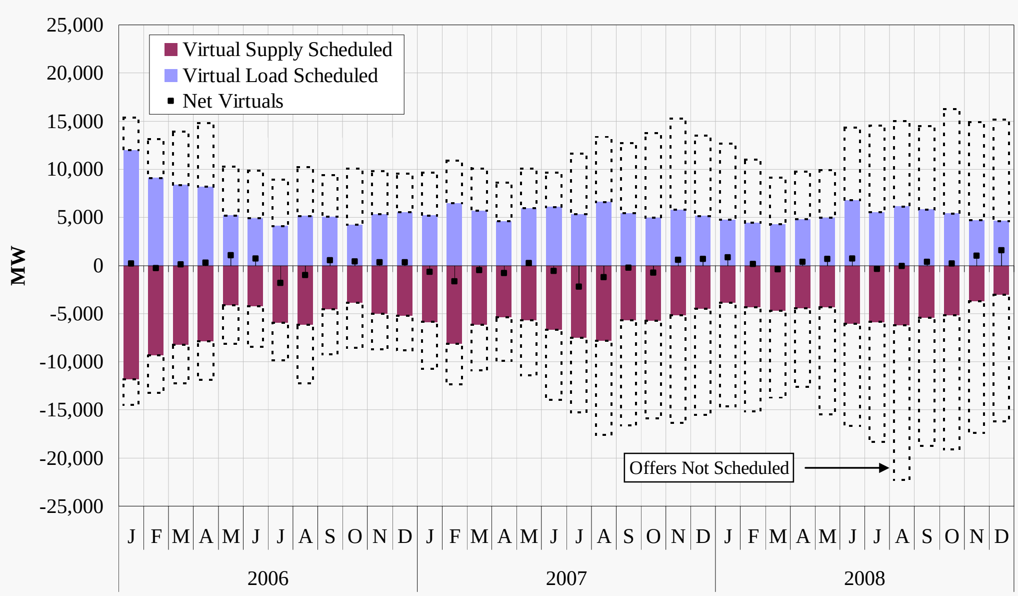
Virtual Load and Supply in the Day-Ahead Market
Average Cleared & Offered MW



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Virtual Profitability

- The next figure shows monthly average profitability of virtual purchases and sales.
- As the Day 2 markets have matured, the profitability of virtual transactions has generally declined.
  - ✓ For virtual transactions, the average gross profit per MWh cleared decreased slightly from $0.40 per MWh in 2007 to $0.32 per MWh in 2008.
  - ✓ However, after RSG allocations are deducted (not shown in figure), the average net profit was negative during 2008 as they were in 2007.
- We continually monitor for large foreseeable 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 artificial congestion in the day-ahead market.
  - ✓ The participant will buy in the day-ahead at the high, congested price and sell the energy back at a lower, uncongested price in the real-time market.
  - ✓ Although the virtual transaction would be predictably unprofitable, the participant could earn net profits if it increases its FTR payments or the value of a financial position.
  - ✓ Virtual losses that warrant further investigation have been rare, and none have warranted a referral to the Commission.

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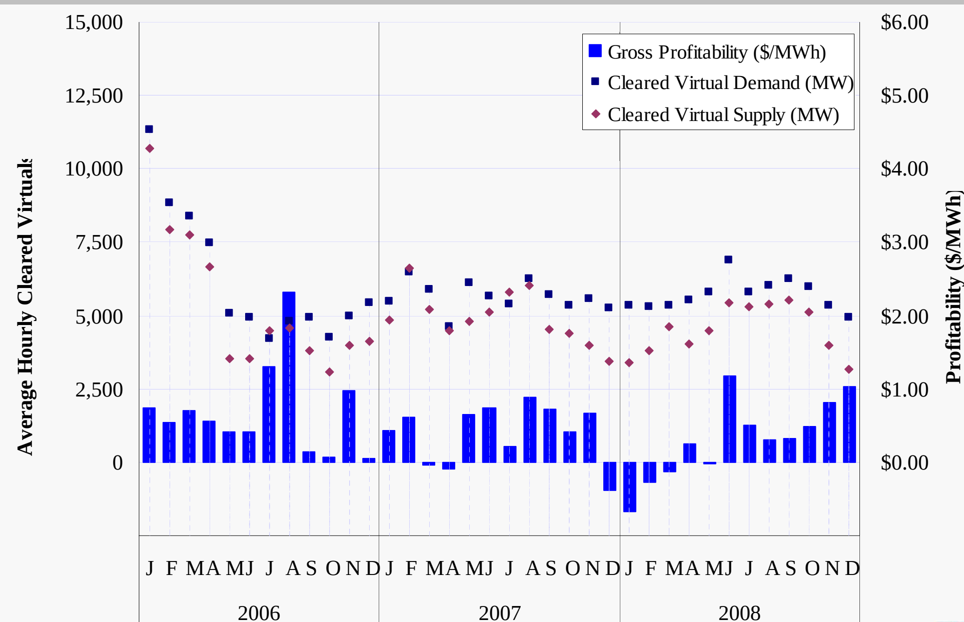
Virtual Profitability in the Day-Ahead Market



Note: Profits do not include the effects of RSG allocations.

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RSG Allocation Changes and Virtual Transaction Levels

- In November 2008, FERC ordered changes in the RSG allocation that establishes an “interim RSG allocation” to be used from August 2007 up until the new RSG allocation is implemented.
- The interim allocation causes all real-time RSG to be allocated to deviations (real-time physical load increases, virtual supply, real-time import reductions, etc.)
  - ✓ While real-time deviations are one cause of RSG, there are many other causes also (peaker price setting issues, congestion, reliability needs, outages, etc.).
  - ✓ Hence, the interim allocation over-allocates RSG costs to deviations, including virtual suppliers, as compared to any reasonable standard of “cost-causation”.
  - ✓ We estimate that virtual suppliers will bear almost 40 percent of all real-time RSG costs for the period from September 2007 to December 2008 – which is more than $120 million.
- This change in allocation is likely the prime contributor to the sharp reductions in virtual trading activity that are shown in the following figure.
  - ✓ Cleared virtual supply in January 2009 is almost 60 percent lower than the levels that prevailed in the fall prior to the FERC RSG orders.
  - ✓ Cleared virtual demand in January 2009 is more than 30 percent lower.

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Virtual Transaction Volumes

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Virtual Supply Trends

- The following table summarizes virtual trading activity in some other RTOs in the Eastern Interconnection.
  - ✓ The table shows the virtual trading levels as a percent of real-time load to account for the varying sizes of the RTO markets.
  - ✓ All of the RTO/ISOs have experienced an overall decline in virtual trading activity, which is likely due to recent financial conditions and credit problems.
  - ✓ The reduction in virtual supply levels in the Midwest have been much sharper than in other markets, and the levels in the other markets recovered by spring 2009.
  - ✓ The sustained reduction in virtual trading in the Midwest ISO indicates that it was primarily caused by the RSG allocation changes ordered by FERC.
- The following bar chart shows the cleared virtual supply levels by participant for the last six months.
  - ✓ Most participants continue to trade, but at substantially reduced levels.
  - ✓ While the total virtual supply cleared for all participants has decreased by almost 60 percent, the amount cleared by the largest three participants decreased by more than 80 percent.

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Virtual Transaction Volumes Eastern Interconnect

				Virtual Supply			Virtual Load		
			RT Load	Offered	Cleared	Share	Offered	Cleared	Share
Midwest ISO	2008	9	62,648	18,225	5,493	***8.8%***	13,813	6,273	*10.0%*
	2008	10	59,045	16,899	5,123	***8.7%***	15,753	5,995	*10.2%*
	2008	11	60,880	15,773	3,992	***6.6%***	15,219	5,382	*8.8%*
	2008	12	66,510	14,245	3,174	***4.8%***	14,336	4,953	*7.4%*
	2009	1	67,556	11,400	2,280	***3.4%***	13,364	4,180	*6.2%*
	2009	2	63,081	10,347	2,155	***3.4%***	10,808	2,454	*3.9%*
	2009	3	57,674	10,765	2,599	***4.5%***	10,355	2,604	*4.5%*
	2009	4	54,561	10,631	2,310	***4.2%***	10,497	2,836	*5.2%*
ISO-NE	2008	9	14,874	4,289	1,706	*11.5%*	2,994	1,890	*12.7%*
	2008	10	13,864	4,239	1,585	*11.4%*	2,679	1,464	*10.6%*
	2008	11	14,405	4,816	1,974	*13.7%*	3,028	1,584	*11.0%*
	2008	12	15,398	4,066	1,516	*9.8%*	2,472	1,332	*8.6%*
	2009	1	16,221	3,461	1,184	*7.3%*	2,225	1,079	*6.7%*
	2009	2	15,162	3,562	1,109	*7.3%*	1,914	763	*5.0%*
	2009	3	14,145	3,869	1,404	*9.9%*	2,188	1,185	*8.4%*
	2009	4	13,223	3,718	1,318	*10.0%*	1,994	1,149	*8.7%*
NYISO	2008	9	19,197	2,537	1,932	*10.1%*	2,110	1,613	*8.4%*
	2008	10	17,169	2,553	1,739	*10.1%*	2,163	1,592	*9.3%*
	2008	11	17,602	2,633	1,711	*9.7%*	2,154	1,426	*8.1%*
	2008	12	18,823	2,726	1,603	*8.5%*	2,231	1,426	*7.6%*
	2009	1	19,570	2,400	1,646	*8.4%*	2,467	1,536	*7.8%*
	2009	2	18,630	2,930	1,843	*9.9%*	2,238	1,460	*7.8%*
	2009	3	17,508	2,984	1,899	*10.8%*	2,149	1,325	*7.6%*
	2009	4	16,704	3,229	2,034	*12.2%*	2,323	1,368	*8.2%*

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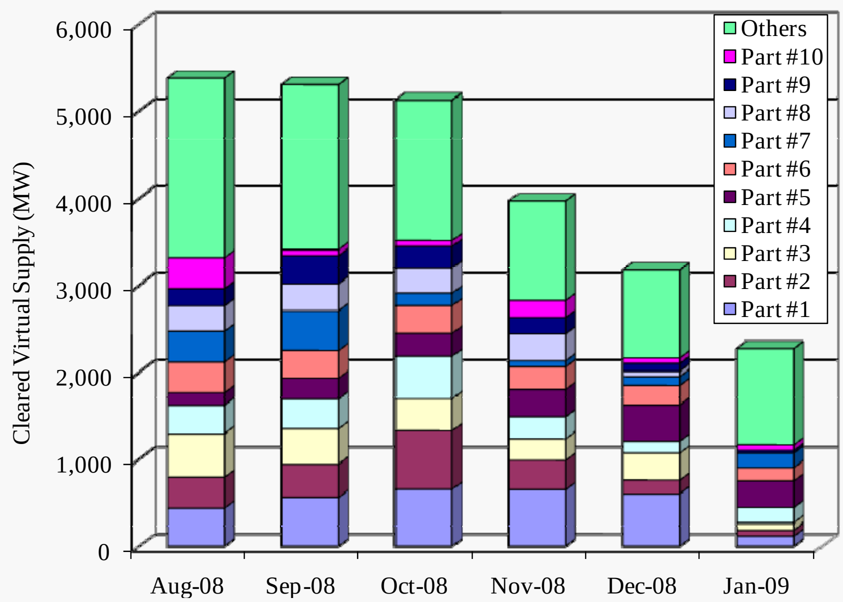
Virtual Supply Cleared
Top Participants



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Conclusions Regarding Virtual Transactions and RSG

- FERC's recent orders have established an "interim" RSG allocation that will be applied prospectively until the Midwest ISO's new RSG allocation is implemented in late 2009.
- Our analysis indicates that this interim allocation is substantially over-allocating costs to virtual suppliers and other deviations.
- These excess costs have contributed to a sharp decline in virtual trading that raises concerns regarding the performance of the day-ahead market because:
  - ✓ Active virtual trading in the day-ahead market promotes price convergence with the real-time market, which facilitates an efficient commitment of generating resources.
  - ✓ Active virtual supply protects the market against attempts to raise day-ahead prices at a location by economically withholding physical generation or making excess load (or virtual load) purchases.
- IMM has filed comments with FERC related to these findings and will continue to monitor these trends.

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Day-Ahead Forecast Error in Daily Peak Hour 2008

- Day-Ahead forecasting is a key element of an efficient day-ahead commitment process.
  - ✓ The accuracy of the day-ahead load forecast is particularly important for the Reliability Assessment Commitment (RAC) process.
  - ✓ Inaccurate forecasts can cause the MISO to commit additional resources that are unnecessary or not to commit resources that are needed, both of which can be costly.
- The following figure shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day in 2008.
  - ✓ The day-ahead forecast of peak load was 0.2 percent less than real-time peak load on average, which indicates that the forecasting was relatively accurate.
  - ✓ The average peak load forecast error was 1.5 percent (forecast error is the magnitude of the error, regardless of direction), slightly lower than 2.2 percent from the prior year. These results are comparable to the performance of other RTOs.
  - ✓ Consistent with the prior two years, the figure shows that the load tended to be over-forecasted in the summer and under-forecasted in the fall. However, the magnitude of this seasonal bias has decreased.

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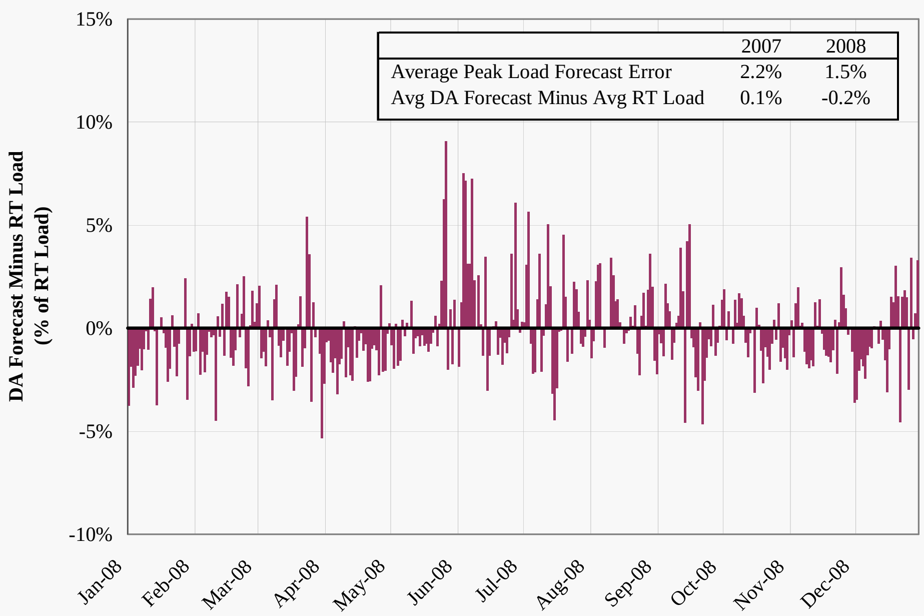
Daily Day-Ahead Forecast Error in Peak Hour 2008



	2007	2008
Average Peak Load Forecast Error	2.2%	1.5%
Avg DA Forecast Minus Avg RT Load	0.1%	-0.2%

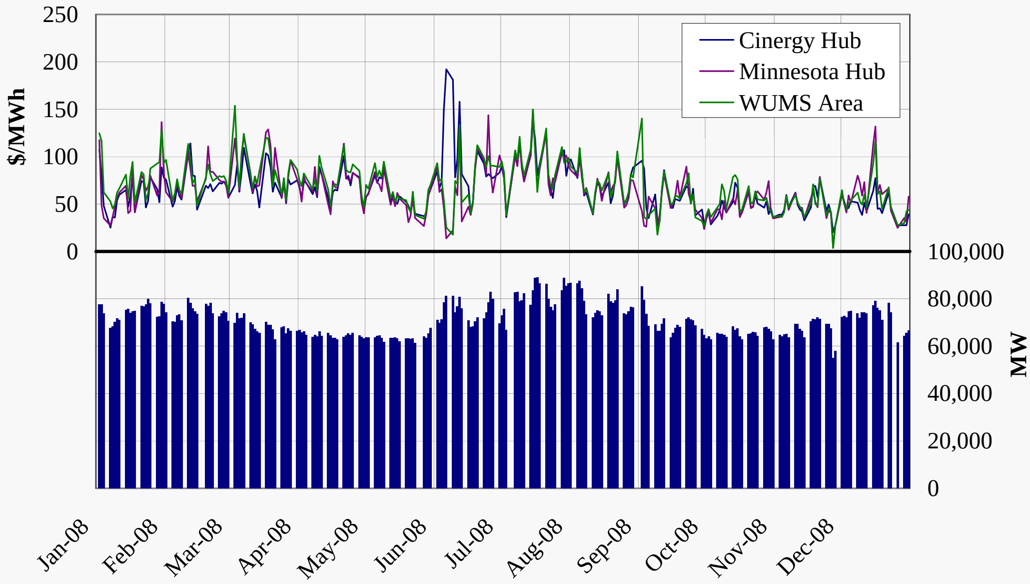
POTOMAC ECONOMICS

Real-Time Market Performance

Real-Time Hub Prices and Load
Peak Hours

- The following figure in this section shows real-time prices during peak hours and the corresponding actual load.
- The figure shows a general correlation between peak load and peak prices, with some notable price separations due to congestion events.
- As in the day-ahead market, the congestion in the early part of the year was highest into WUMS and Minnesota, but this reversed in the second half of the year.
  - ✓ Prices in WUMS and Minnesota averaged \$7 and \$2.50 higher than the Cinergy Hub, respectively.
  - ✓ In June, storm-related transmission outages contributed to congestion *out* of the Western and WUMS regions and into Cinergy and Michigan. Average peak prices at Minnesota and WUMS were \$17.7 and \$14.24 per MWh *lower* than Cinergy in June.
  - ✓ Prices and congestion declined in the last half of the year in Minnesota and WUMS.
- Fuel prices (natural gas and oil) and load declined significantly in the last quarter of the year, leading to lower prices in all regions.
  - ✓ Prices at the Cinergy Hub averaged \$32.89 in the 4th quarter of 2008.

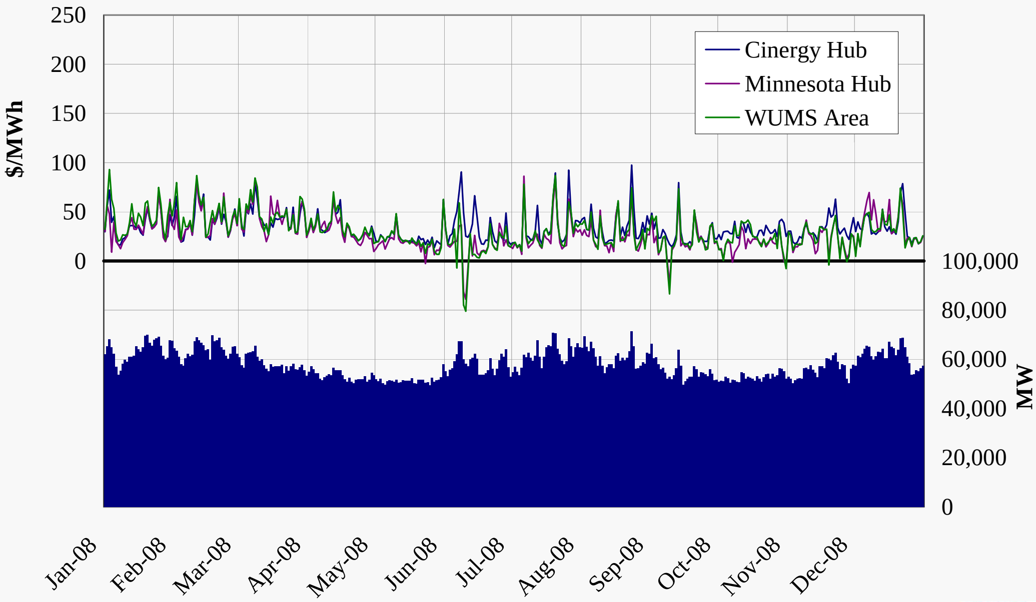
Real-Time Hub Prices and Load
Peak Hours



Real-Time Hub Prices and Load
Off-Peak Hours

- The next figure shows real-time prices during off-peak hours and actual load.
- The figure shows that load and prices are generally very low in these hours as expected.
  - ✓ Prices are generally set by coal-fired resources in off-peak hours.
  - ✓ Coal prices did rise throughout most of 2008 and had more impact in these hours.
- Storm damage in June caused significant negative price spikes at the Minnesota and WUMS Hubs. Similar congestion also led to periodic negative prices at other times during the year.
  - ✓ These negative price events were less frequent and less severe than those in early 2006 or 2007.
  - ✓ Negative price spikes continue to be exacerbated by reduced bid flexibility and ramp limits that make low load periods and related congestion difficult to manage.
- Compared to prior years, off-peak prices were relatively stable with little congestion to separate prices at the regional hubs.

Real-Time Hub Prices and Load
Off-Peak Hours



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Real-Time Prices by Time of Day

- The following figures show average interval-level real-time prices by time of day in the summer and winter months of 2008 when loads are the highest.
- To examine the drivers of the price volatility, the figures show:
  - ✓ The effective headroom on the system (the amount of generation that can be utilized in the next five minutes including ramp limitations); and
  - ✓ The average change in NSI.
- As in 2007, these figures show that in 2008:
  - ✓ Prices fluctuate the most when load is ramping up or down near the peak (afternoon in the summer, and dual peaks in morning and evening in the winter);
  - ✓ The sharp price movements are often the result of binding ramp constraints, which are limits to how quickly the system’s generation can be increased or decreased to accommodate changes in NSI, load, or other needs.
  - ✓ The changes in real time prices are directly related to changes in effective headroom, which are often related to changes in NSI that occur at the tops of the hour.
  - ✓ The other source of changes in effective headroom are when large quantities of generators start-up or shut-down at the same time. These effects are largest late in the day when generators are shutting down.
- Volatility has decreased under ASM markets because the real-time market now has the flexibility to jointly optimize the use of resources for energy and ASM needs.
- The report also contains a recommendation related to NSI scheduling rules that should reduce volatility.

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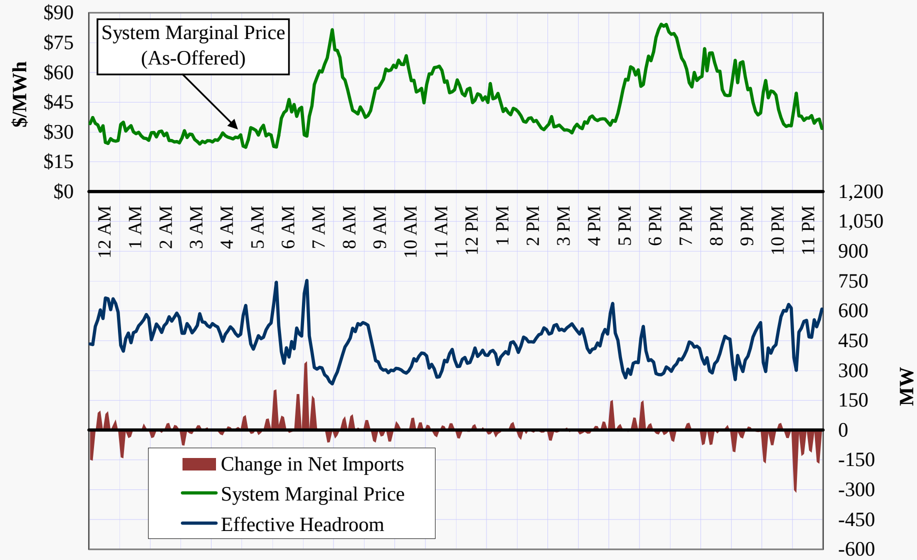
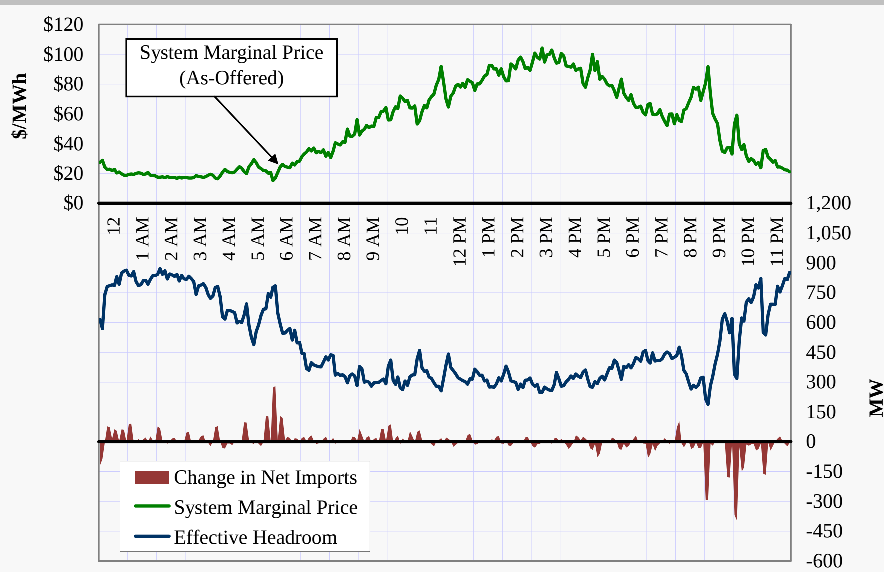
Real-Time Prices by Time of Day
Winter 2008



Real-Time Prices by Time of Day
Summer 2008



Five-Minute Real-Time Price Volatility MISO and Neighboring Markets

- The next figure shows the average percentage change in real-time price between five-minute intervals for several hubs in neighboring markets.
- The results indicate that MISO has the most price volatility and ISO-NE has the least. These differences can be explained by the differences in the software and operations of the different markets.
  - ✓ MISO and NYISO are true five-minute markets, with five-minute pricing and dispatch. Ramp constraints are more likely in these markets due to the shorter timeframes for moving the systems' generation.
  - ✓ However, the NYISO's real-time dispatch is a multi-period optimization that looks ahead over the following hour so it can anticipate ramp needs and begin moving generation to accommodate them.
- PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes, although they produce 5-minute prices using their ex-post pricing models.
  - ✓ Although this system does not alter the generation dispatch levels as frequently as MISO or NYISO, the systems are less likely to be ramp-constrained because they have 15 minutes of ramp capability to serve the systems' demands.
  - ✓ Because the system is redispatched less frequently, these markets likely rely more heavily on regulation to satisfy intra-interval changes in load and supply.

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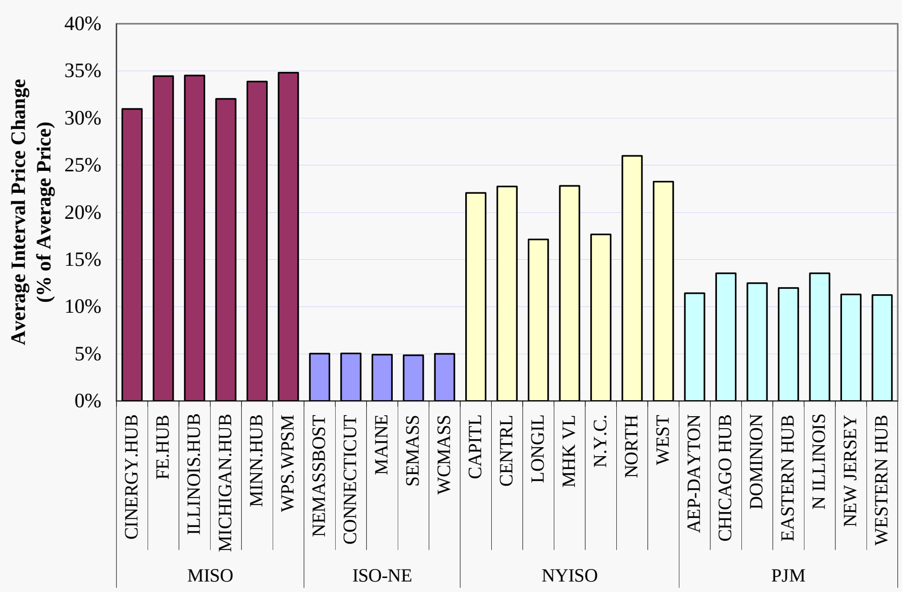
Five-Minute Real-Time Price Volatility MISO and Neighboring Markets



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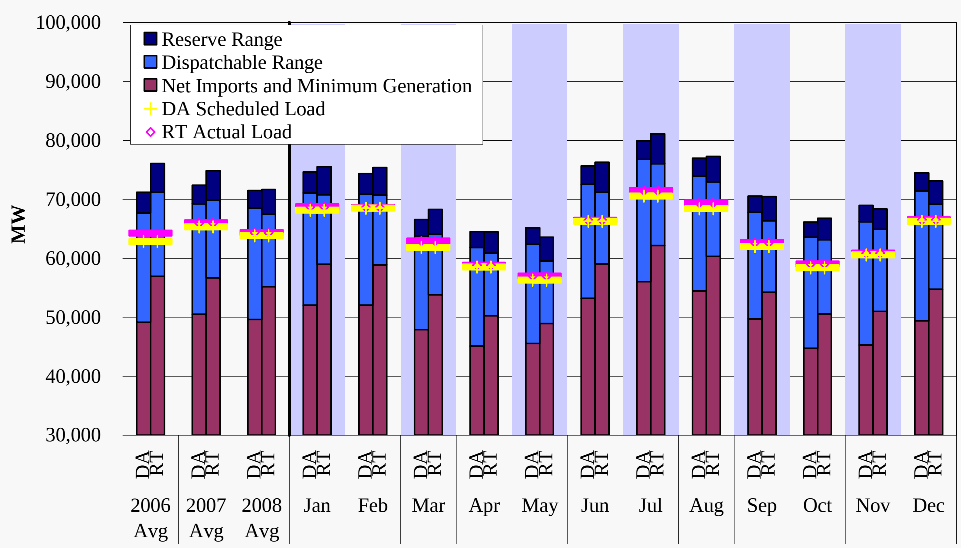
Day-Ahead and Real-Time Generation

- The following figure details the average monthly generation scheduled in the day-ahead and real-time markets.
- The figure shows that generation capability is generally greater in the real-time market because:
  - ✓ Some resources are self-scheduled by participants after the day-ahead market.
  - ✓ Generation is committed after the day-ahead market when load is higher than expected, when load is under-scheduled in the day-ahead market, when net imports decrease, or when net virtual supply is scheduled in the day-ahead that must be replaced.
  - ✓ Intermittent generation, particularly wind, often increases in the real-time market.
- The figure shows that share of real-time generation scheduled in the day-ahead market increased from 97 percent in 2007 to nearly 100 percent in 2008.
- The figure also shows that dispatch flexibility is lost in the real-time market.
  - ✓ Dispatchable range (EcoMax-EcoMin) as a percentage of total online capacity declines from 28 percent in the day-ahead market to 18 percent in the real-time. This occurs when EcoMin is increased or EcoMax is decreased.
  - ✓ These values are substantially lower than the physical flexibility of the generating resources, which could physically provide a dispatchable range of 50 to 60 percent.
  - ✓ This loss in flexibility can affect the market by limiting redispatch options for managing congestion – this is evaluated later in the report.

Day-Ahead and Real-Time Generation 2008: All Hours



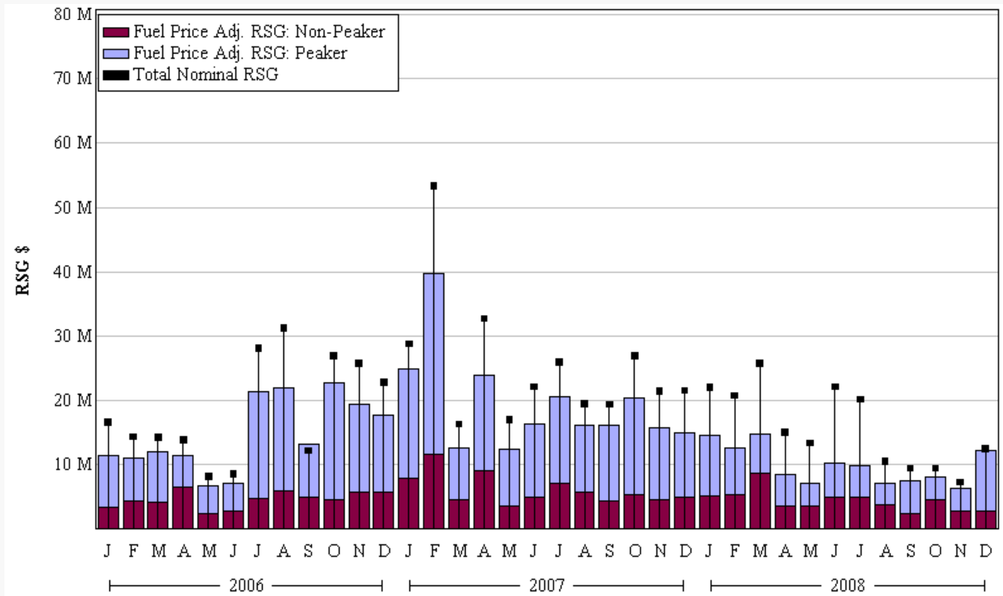
Revenue Sufficiency Guarantee Payments Day-Ahead and Real-Time

- The next two figures show monthly RSG payments in the day-ahead and real-time markets that are made to peaking units and other units.
  - ✓ RSG payments are made to ensure that the total market revenue a generator receives when its offer is accepted is at least equal to its as-offered costs.
  - ✓ Resources that are not committed in the day-ahead market, but must be started to maintain reliability are likely recipients of RSG payments – this is "real-time" RSG because such units receive their revenue from the real-time market.
  - ✓ Because the day-ahead market is financial, it generates very little RSG – a unit that is uneconomic will generally not be selected.
  - ✓ Peaking resources are typically the most likely to warrant an RSG payment because they are generally on the margin (i.e., the highest-cost resources) when they run and frequently do not set the energy price (i.e., the price is set by a lower-cost unit).

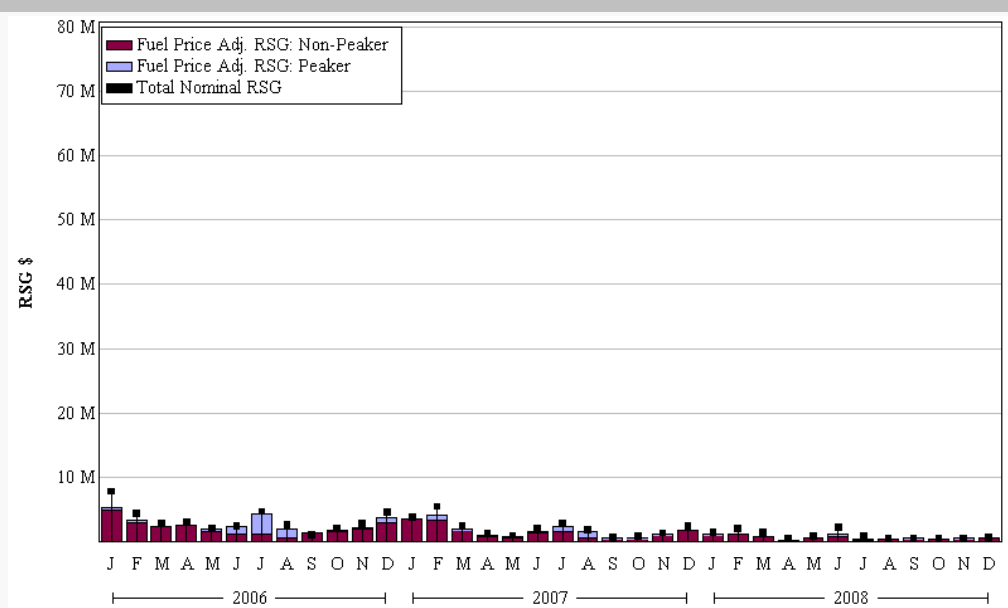
Revenue Sufficiency Guarantee Payments Day-Ahead and Real-Time

- The figures show that more than 90 percent of RSG is generated in the real-time market and most is paid to peaking resources.
  - ✓ Although they produced less than 1 percent of total energy generated in each year, peaking resources accounted for 70 percent of real-time RSG payments in 2006 and 2007 and almost 60 percent in 2008.
    - – The decline in share paid to peaking resources in 2008 is due to reduced dispatch of peaking resources resulting from lower average and peak load.
- Real-Time RSG costs decreased from roughly $330 million in 2007 to approximate $215 million in 2008. This was due to:
  - ✓ Higher day-ahead load-scheduling in 2008, and
  - ✓ Reduced number of commitments in the West to manage Minnesota NCA congestion, particularly during non-winter months.
- The second figure shows day-ahead RSG, which declined $11.6 million (or 41 percent) during 2008 to $16.6 million for the year.
  - ✓ RSG in the day-ahead market continues to be a small percentage (7.2 percent) of total uplift costs to the market.
- In total, RSG costs from both markets decreased by more than $126 million (35 percent) in 2008.

Total Real-Time RSG Distribution April 2005 through December 2008



Total Day-Ahead RSG Distribution April 2005 through December 2008



Weekly Real-Time RSG Payments

- The following figure analyzes the real-time RSG distribution data by week and region, which shows more clearly when and where RSG costs were incurred.
- As detailed elsewhere in this report, the summer peak was mild relative to prior years and the 2008 Summer Assessment. Accordingly, the RSG resulting from the summer peak load weeks was minimal.
  - ✓ As relatively high day-ahead load scheduling prevailed throughout the fall and fuel prices decreased, RSG remained low.
- Many of the highest weekly RSG costs were caused by transmission congestion.
  - ✓ During the winter weeks, the West region incurred more RSG than during the rest of 2008 due to more extreme weather conditions and forced generation outages.
  - ✓ The East region had the largest share of RSG due to transmission outages on Market-to-Market flowgates and planned outages of large nuclear resources in the region during the spring and fall.
- The Central region has a consistent level of RSG in part due to the fact that many of the cheapest (per MW of capacity) peaking resources are located there.

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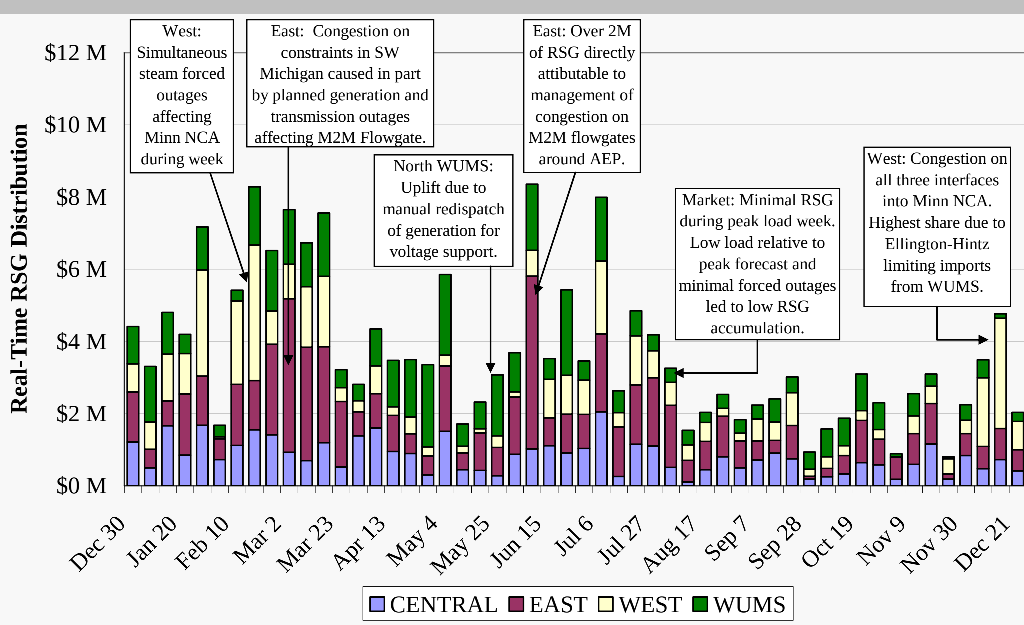
Weekly RSG Distribution by Region



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RSG Trends and Analysis

- The next figure shows a number of factors that explain the changes in the RSG costs.
- Real-time RSG is generally correlated with purchases of energy in the real-time market (i.e., real-time demand), which often requires the dispatch of peaking units.
  - ✓ The figure shows the average increase in generation and real-time demand factors in the peak hour of each day in the month.
  - ✓ This analysis indicates that the changes in net demand from the day-ahead to the real-time market are an important factor that contributes to RSG.
  - ✓ The figure also shows that the largest single contributor to the real-time demand for resources was under-scheduled load that must be served in the real-time market.
- Real-time demand and RSG declined sharply in 2008 due to:
  - ✓ Increases in day-ahead load scheduling and decreases in virtual supply.
  - ✓ Decreases in natural gas and oil prices in the second half of the year.
  - ✓ Slight declines in the amount of headroom maintained by the Midwest ISO.

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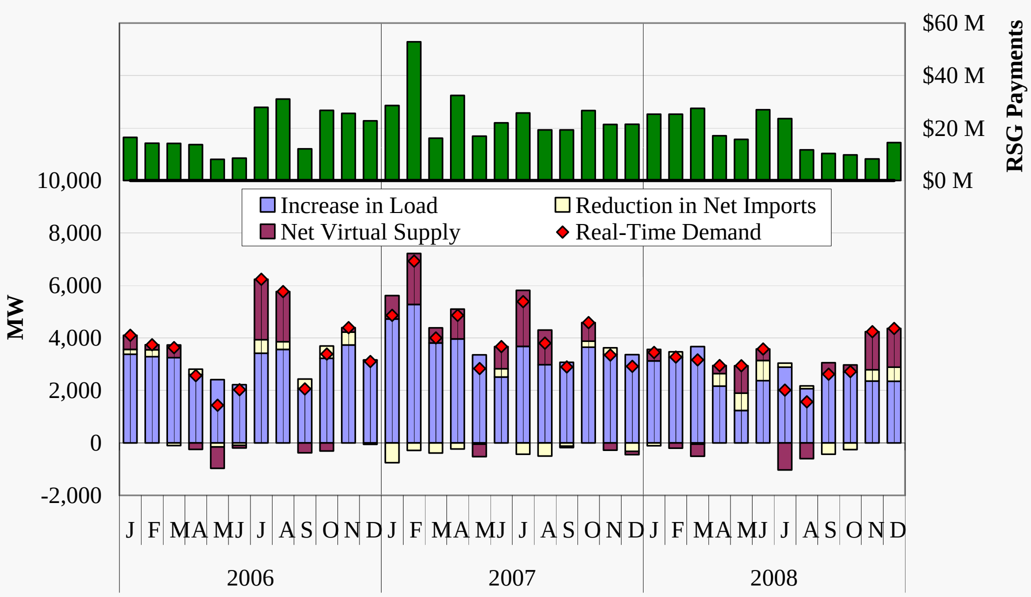
RSG Trends and Analysis



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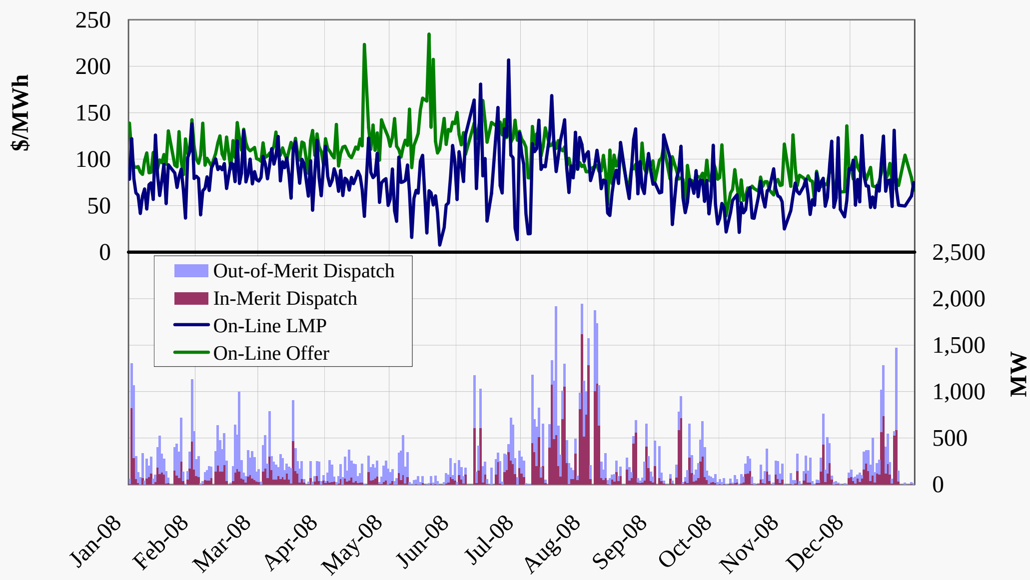
Dispatch of Peaking Resources

- As discussed above, the dispatch of peaking resources is important because it is an important determinant of RSG and efficient energy pricing.
- The following figure summarizes the dispatch of peaking resources in 2008, showing the average hourly dispatch of peaking units by day.
- In 2008, an average of over 500 MW of peaking resources were dispatched per hour in the summer and 270 MW were dispatched per hour in all months.
  - ✓ These averages are much lower than the levels in 2005, 2006, or 2007.
- The reduction in dispatch of peaking resources can be attributed to a number of factors:
  - ✓ Load has been more fully scheduled in the day-ahead market so less load must be satisfied through real-time commitments.
  - ✓ Imports over the Manitoba interface have increased while average load levels have decreased, leading to fewer peak demand conditions that require peaking resources.
  - ✓ Congestion has decreased, which had often required the commitment of peaking resources in past years.

Dispatch of Peaking Resources

- The figure also evaluates how consistent the peaking resource dispatch is with the market outcomes by showing:
  - ✓ The shares of the peaking resource output that are in-merit (LMP > offer price) and out of merit (LMP < offer price) in the bottom portion of the figure; and
  - ✓ A comparison of the average LMP at the peaking resources' locations versus the average offer price of the dispatched peaking resources in the top portion of the figure.
- This analysis shows that only 42 percent of the peaking resources were in-merit (slightly higher in the summer), indicating that they frequently do not set the energy price.
  - ✓ This is not uncommon since gas turbines often have a very narrow operating range and, therefore, operate at their minimum or maximum.
- When peaking resources (or demand response) are the most economic option for meeting the markets' demands, but do not set prices, real-time prices will be inefficiently low.
  - ✓ This affects the incentives to schedule in the day-ahead market and, ultimately, the commitment of resources that is coordinated by the day-ahead market.
  - ✓ A suboptimal commitment coming out of the day ahead will tend to raise real-time costs.
  - ✓ Inefficiently low real-time prices when peaking resources are dispatched also distorts the incentives of participants to import and export power efficiently.
- We have recommended changes to improve real-time pricing by allowing peaking resources and demand resources to set prices. The Midwest ISO has done substantial work to develop a feasible approach in this area.

Daily Peaker Dispatch and Prices
All Hours



Ex-Ante and Ex-Post Price Differences
All Hours: 2008-2009

- Like PJM and New England, the Midwest ISO settles its real-time market using “ex-post” prices (i.e., prices that are computed after the operating period is over).
  - ✓ The ex-ante prices calculated in advance of the interval are consistent with the five-minute dispatch instructions that are sent to each generator in MISO.
  - ✓ The ex-post prices are actually used for settlements and are calculated after the operating period based on the actual (rather than predicted) power flows and output.
    - Only units that are flexible and following dispatch may set prices. Hence, the units setting ex-post prices can be different than those in the ex-ante solution.
- Consistency between the ex-ante and ex-post prices is important for ensuring that suppliers have the incentive to follow ex-ante dispatch instructions.
  - ✓ Changes were made to the ex-post pricing methodology in 2005 to improve consistency between ex-ante and ex-post prices.
  - ✓ With this change, the Midwest ISO’s ex-post methodology is not consistent with the methodology used in PJM and New England.

Ex-Ante and Ex-Post Price Differences
All Hours: 2008-2009

- The next figure shows the average difference between the five-minute ex-post and ex-ante prices. The figure shows:
  - ✓ The average differences between the ex-ante and ex-post price at the Cinergy Hub were relatively small in 2008, as were the typical hourly differences (measured by the average of the absolute value of the hourly difference).
  - ✓ However, there still was a persistent bias in the ex-post calculator that caused the ex-post in nearly all cases to be equal to or exceed the ex-ante price in 2008.
- While the correction of errors in the ex-ante solution is beneficial, the other changes made by the ex-post pricing methodology are inefficient.
  - ✓ Ex-post pricing methodologies can result in real-time prices that are inconsistent with the market's dispatch instructions, which can undermine generators' incentives to follow dispatch instructions.
  - ✓ Contrary to popular belief, ex-post pricing is a very poor means to incent resource owners to follow dispatch instructions.
  - ✓ In the Midwest ISO's case, it results in an average increase in prices of roughly 3 percent.
- Beginning in 2009 with the deployment of ASM, the methodology was modified.
  - ✓ Ex-ante and ex-post pricing differences have been eliminated since the start of ASM.
  - ✓ The revised ex-post pricing approach will provide the benefits of price corrections without the inefficiencies caused by other ex-post pricing approaches.

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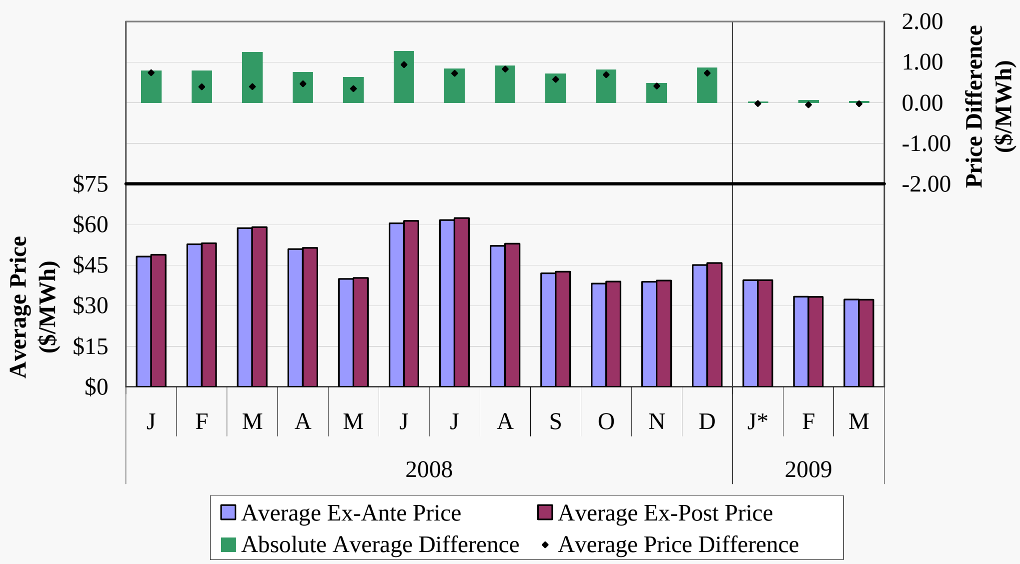
Ex-Ante and Ex-Post Price Differences
January 2008 - March 2009



* Note: The last five market days of Energy-Only market have been excluded from January 2009 data.

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Wind Generation

- Wind generation and capacity has grown rapidly in the Midwest ISO market, which is expected to continue due to the wind profiles in the West, and to Federal and State mandates and subsidies.
- Wind generation promises substantial environmental benefits. However, as an intermittent resource, it presents special operational challenges as it becomes a greater percentage of the market generation.
- The next several slides examine some of the impacts of the increased wind generation on the Midwest ISO market to date.
- The first slide shows the wind generation scheduled in the day-ahead and real-time markets.
  - ✓ The intermittent nature of wind presents forecasting and scheduling challenges.
  - ✓ The chart shows the rapid growth of wind generation since the fall of 2008.
  - ✓ The chart also shows that wind generation tends to be under-scheduled in the day-ahead market, which has grown over time.
  - ✓ The uncertainty of wind output can cause real-time RSG that wind is currently exempted from being allocated because it is an intermittent resource.

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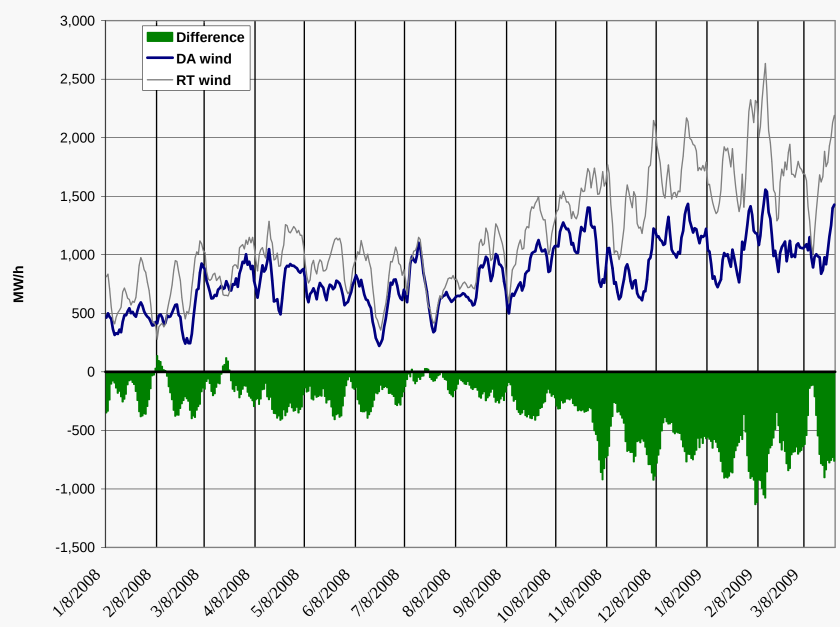
Scheduling of Wind Generation in the Real-Time and Day-Ahead Markets



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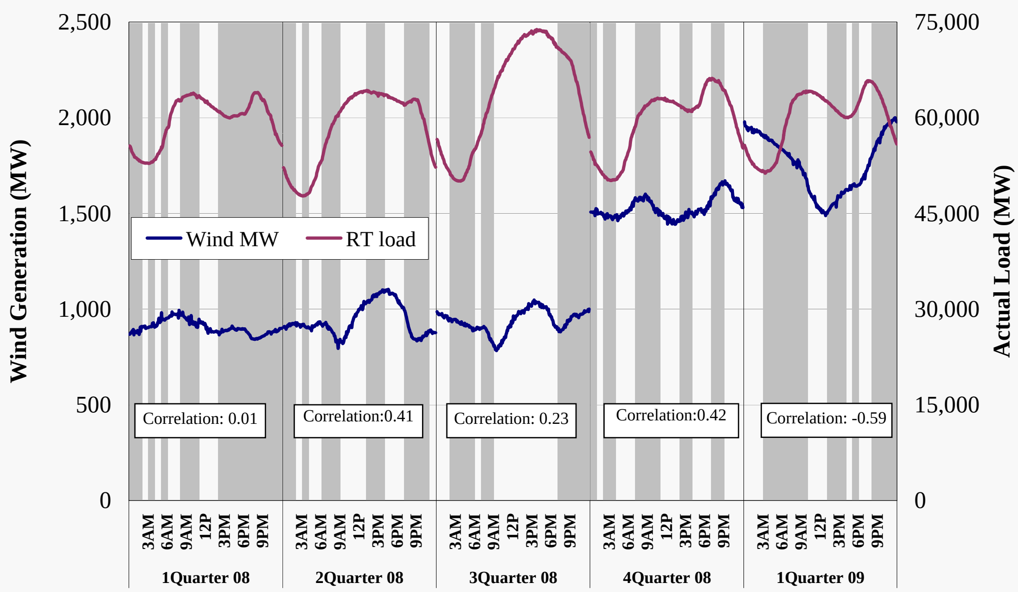
RT Impact of Wind Generation

- In addition to forecasting and scheduling challenges, wind has presented additional challenges for the Midwest ISO.
- The following figure shows average wind generation in real-time by time of day versus load.
  - ✓ The figure shows that wind generation is often highest at night, from 10:00 P.M to 3:00 A.M., when load is lowest.
  - ✓ The correlation of wind generation and load has varied significantly, but it is frequently negatively correlated.
    - Wind output in other regions, such as ERCOT, has also been negatively correlated with load.
  - ✓ The figure shows that during periods when load is ramping up or down rapidly, wind output generally is moving in the opposite direction.
    - Wind generation tends to fall during the morning load ramp-up period.
    - Wind generation tends to rise during the late evening load ramp-down period.
- Although wind provides substantial environmental benefits, it also creates significant operational challenges that the Midwest ISO is working to address.

Wind Generation versus Load



Real-Time Market: Conclusions

- The Midwest ISO's real-time market performed relatively well.
  - ✓ The nodal market accurately reflected the value of congestion in the Midwest.
  - ✓ Prices in the real-time market were substantially more volatile than the real-time prices in neighboring markets, although it has decreased under the ASM markets introduced in January 2009.
- The performance of the real-time market is compromised in some cases by:
  - ✓ Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage.
  - ✓ Not having a real-time model that optimizes the commitment and de-commitment of peaking resources.
  - ✓ Prices that do not always reflect the costs of peaking resources or demand resources when they are the marginal source of energy.
  - ✓ The fact that the real-time market optimizes only over the next 5 minutes can cause the market not to move resources optimally to satisfy the foreseeable needs of the system over the upcoming hour.
  - ✓ The current state of the integration of wind resources in the Midwest ISO markets.
- These issues are addressed by the recommendations at the end of this sections.

Real-Time Market: Recent Changes

The Midwest ISO has made a number of key improvements in its markets recently:

1. The Midwest ISO introduced ancillary services markets in January 2009.
   - Ancillary services markets that are jointly optimized with energy allow the market to more efficiently allocate resources between the two services.
   - ASM sets efficient prices in both markets to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
   - With ASM, the Midwest ISO implemented make-whole payments to ensure that generators following five-minute dispatch instructions when prices are volatile are not harmed in their hourly settlements. This provides better incentives to generators to be flexible.
2. The Midwest ISO replaced its ex-post pricing methodology with an approach that utilizes ex-ante prices corrected for metering or other errors.
   - This change improves the efficiency of real-time prices and the incentives of suppliers.

Real-Time Market: Recommendations

We recommend the Midwest ISO consider the following changes to the real-time market.

1. *Develop a "look-ahead" capability in the real-time that would facilitate better management of ramp capability and commitment of peaking resources.*
   - The Midwest ISO has made improvements in its commitment of peaking resources, but it can be further improved by reliance on an economic model to commit the units.
   - Better management of ramp needs and commitment of gas turbines would reduce out-of-merit quantities, reduce RSG payments, and improve energy pricing.
2. *Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.*
   - This change would improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs.
   - This is difficult because the market must distinguish between turbines that are economic versus those that would be shut-down if they were more flexible.
   - The Midwest ISO made substantial progress in this area in 2008 and should be in a position to test the feasibility of its approach in 2009.

Real-Time Market: Recommendations (cont.)

3. *Develop provisions that allow demand response resources to set energy prices in the real-time market when they are called upon in a shortage.*
   - It would also improve price signals in the highest-demand hours, which is important for ensuring that the markets send efficient economic signals to:
     - ✓ Develop and maintain adequate supply resources; and
     - ✓ Develop additional demand response capability.
   - It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.
4. *Improve the integration of wind resources in the Midwest ISO system by:*
   - Allowing wind resources to be curtailable at a specified offer price, which would be eligible to set prices in the energy market.
   - Develop allocation rules for RSG and other costs (e.g., reserves and/or regulation) that assign the costs to intermittent resources to the extent that they cause them.

Transmission Congestion and FTR Results

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Transmission Congestion and FTRs

- One of the primary functions of the Midwest ISO energy markets is to deliver lowest-cost supply to load while respecting limitations of the transmission network.
- The locational market structure in the Midwest ISO generally ensures that the transmission capability will be fully utilized and that the marginal value of energy will be reflected in the price at each location.
- When transmission system limits require higher-cost resources to be dispatched to serve the load (i.e., a transmission constraint is binding), the prices on either side of the transmission constraint will diverge.
  - ✓ This results in congestion costs being incurred that reflect the cost of relieving the transmission constraint.
  - ✓ The congestion costs collected by the Midwest ISO in the day-ahead market are paid to holders of Financial Transmission Rights ("FTRs"), who use the FTRs to hedge against congestion costs.
  - ✓ Congestion persists over the long-run because investment to relieve congestion should be made only when the investment cost is lower than the congestion cost.
- This section of the report evaluates the congestion costs, FTR market results, and the Midwest ISO's management of congestion.

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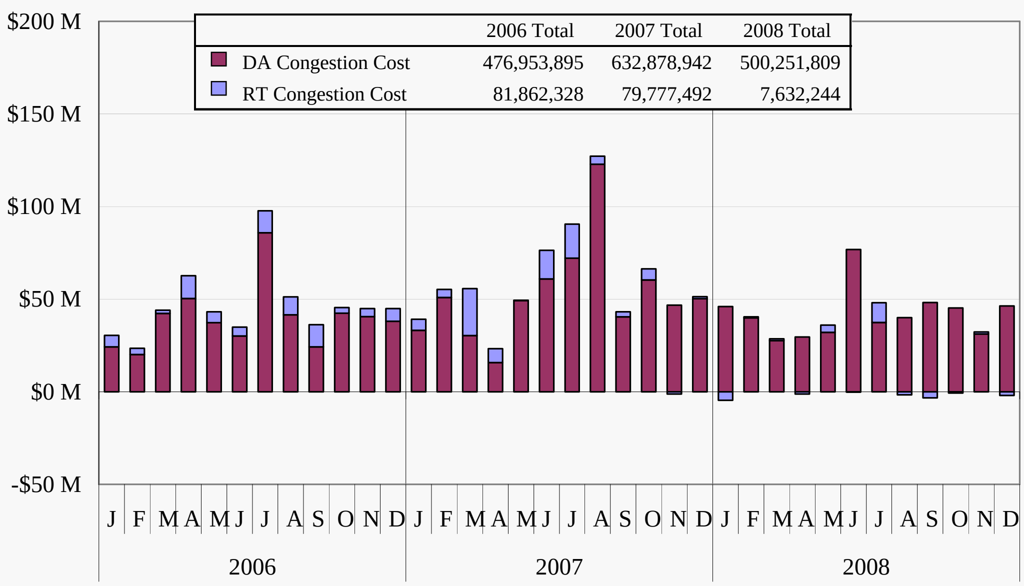
Total Congestion Costs
2006-2008

- The first figure in this section shows total congestion costs by month in the Midwest ISO market for 2006 through 2008.
- In 2007, day-ahead congestion costs increased to $633 million due primarily to higher gas prices and reduced imports over the Manitoba interface.
- In 2008, day-ahead congestion cost declined more than $132 million (more than 20 percent) as:
  - ✓ Average load decreased;
  - ✓ Imports over the Manitoba interface returned to more normal levels; and
  - ✓ Transmission upgrades into WUMS from Minnesota substantially reduced the frequency of congestion on that interface.
- Real-time residuals also declined significantly in 2008.
  - ✓ Normally, one would expect the real-time congestion to be very low if the modeling of the network is consistent between the day-ahead and real-time markets.
  - ✓ In 2008, over 98 percent of total congestion was captured in the day-ahead market, which is a significant improvement from 2006 and 2007. This suggests better convergence between day-ahead market assumptions and actual real-time conditions.
  - ✓ Congestion peaked in June as storm damage to the network led to substantial congestion into eastern areas.

Total Congestion Costs
2006 - 2008



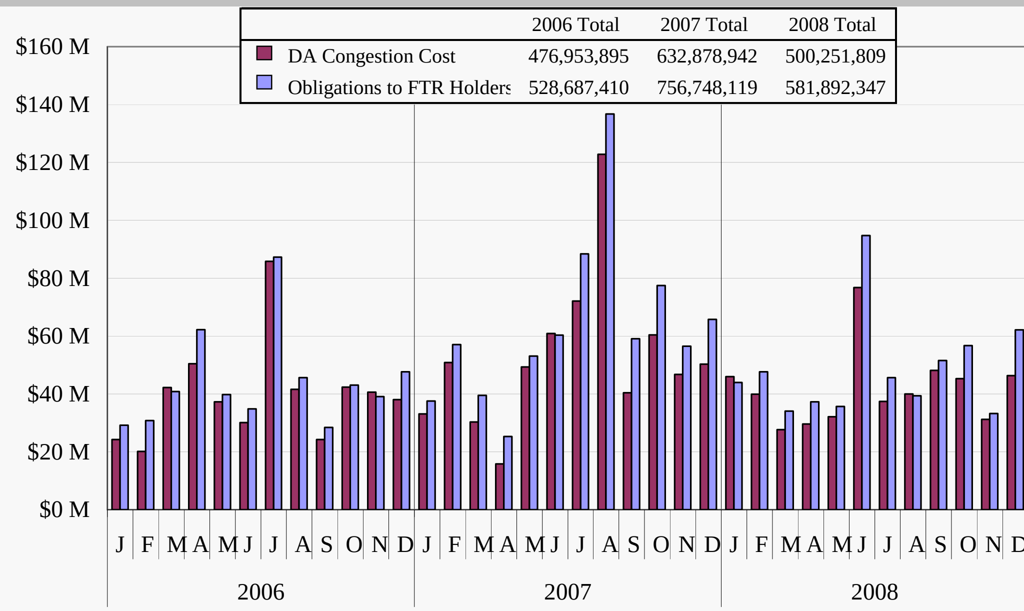
Day-Ahead Congestion and Obligations to FTR Holders

- Market participants purchase or are allocated FTR rights that entitle them to congestion costs that arise between particular locations on the network.
- Shortfalls or surpluses occur when the FTRs held by participants represent more or less transmission capacity than the physical transmission system.
  - ✓ A surplus may occur when the Midwest ISO sells fewer FTRs than the physical capability of the network;
  - ✓ A shortfall may occur when transmission outages or other factors cause the capability of the system to decrease relative to the capability in the FTR model used to allocate and sell FTRs.
  - ✓ “Loop flows” over the network caused by activity outside of the Midwest ISO can also lead to shortfalls or surpluses if they differ from the quantities assumed in the FTR model.

Day-Ahead Congestion and Obligations to FTR Holders 2006 - 2008

- The figure shows that the day-ahead congestion collections were substantially less than FTR obligations in 2008 (more than 14 percent). In 2007, the shortfall was 19 percent and in 2006 the shortfall was 10 percent.
- In 2008, the largest shortfalls occurred in June as storm-related transmission outages reduced the physical capability of the system.
- The Midwest ISO has continued to work on the FTR allocation and associated modeling to reduce the shortfalls. Major changes were made in the FTR modeling in June 2008 that sought to:
  - ✓ Improve loop flow assumptions;
  - ✓ Add additional constraints related to market-to-market and non-market constraints; and
  - ✓ Generally reduce transmission line ratings to account for expected changes to the system due to outages.
- While the improvements introduced in 2008 have contributed to lower shortfalls relative to 2007, we recommend further improvements be pursued.

Day-Ahead Congestion and Payments to FTR Holders 2006 - 2008



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Payments to FTR Holders 2006 - 2008

- The following figure shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-out FTRs (which are alternative forms of FTRs made available to participants with grandfathered agreements).
- The figure shows that the vast majority of the payments were made to FTR holders, as opposed to payments to FTR Option B and Carve-out FTRs.
  - ✓ In all three years, 2006-2008, approximately 95 percent of all payments were made to holders of conventional FTRs (i.e., only 5 percent of payments were made to holders of FTR Option B and Carve-out FTRs).
  - ✓ The low magnitude of payments for these other types of rights is good because they do not provide the same efficient incentives as FTRs.
  - ✓ As a percentage of total FTR payments, payments to the holders of the alternative rights declined slightly from 6 percent in 2007 to 4 percent in 2008.
- As discussed above, funding shortfalls declined in 2008. However, further improvement should be pursued.

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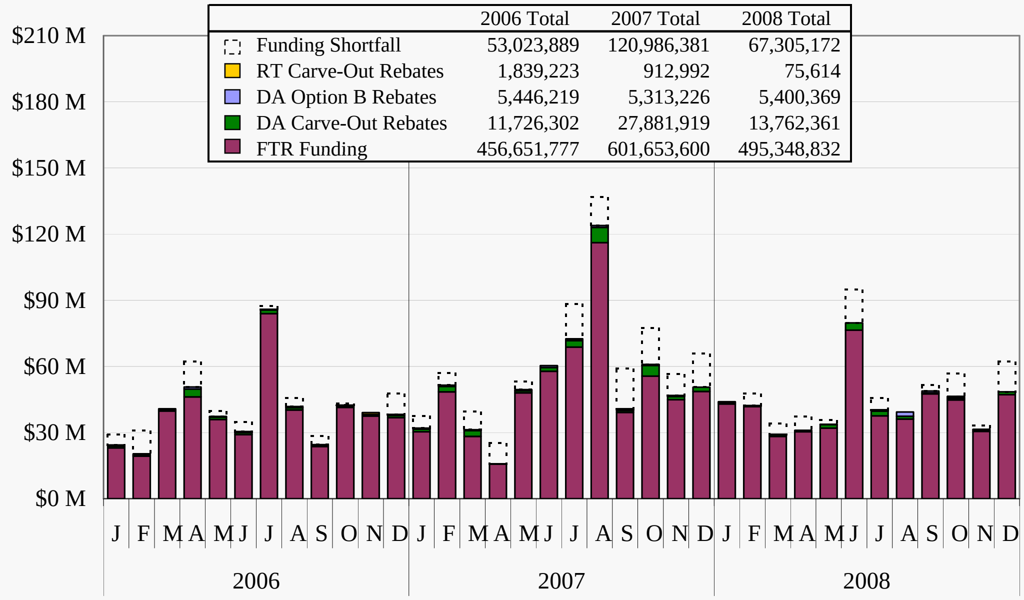
Payments to FTR Holders
2006 to 2008



	2006 Total	2007 Total	2008 Total
Funding Shortfall	53,023,889	120,986,381	67,305,172
RT Carve-Out Rebates	1,839,223	912,992	75,614
DA Option B Rebates	5,446,219	5,313,226	5,400,369
DA Carve-Out Rebates	11,726,302	27,881,919	13,762,361
FTR Funding	456,651,777	601,653,600	495,348,832

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Value of Real-Time Congestion by Coordination Region
2007 and 2008

- The prior figures showed the congestion costs incurred through the Midwest ISO markets; these costs can vary substantially from the congestion that occurs physically in real-time.
- 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 of real-time congestion decreased slightly in 2008 from 2007.
  - ✓ We estimated real-time congestion in 2008 of $938 million, which is a decrease from $1,018 million 2007.
  - ✓ These values continue to be much higher than the congestion collected by the Midwest ISO due to the loop flows that use some of the network capability without paying the Midwest ISO and to PJM’s entitlements on the Midwest ISO system.
  - ✓ The combined Central and East regions accounted for over one-half of the congestion costs in both 2007 and 2008.
  - ✓ The Central region accounted for a greater share than usual during June 2008 due to outages from severe storms.

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Value of Real-Time Congestion by Coordination Region 2007 and 2008

- The relatively large amount of congestion occurring in the West during the early part of 2007 has subsided.
  - ✓ This congestion was primarily due to reduced availability of imports over the Manitoba interface and high winter loads.
- Despite transmission improvements into WUMS from the West, WUMS continued to account for a large share of total congestion.
- The figure also shows that the average frequency of binding constraints increased slightly in 2008 (from 1.0 to 1.03 constraints binding per interval on average in 2007 and 2008, respectively).
  - ✓ However the frequency patterns were similar in both years, peaking during the summer seasons when the demands on the network are the highest.

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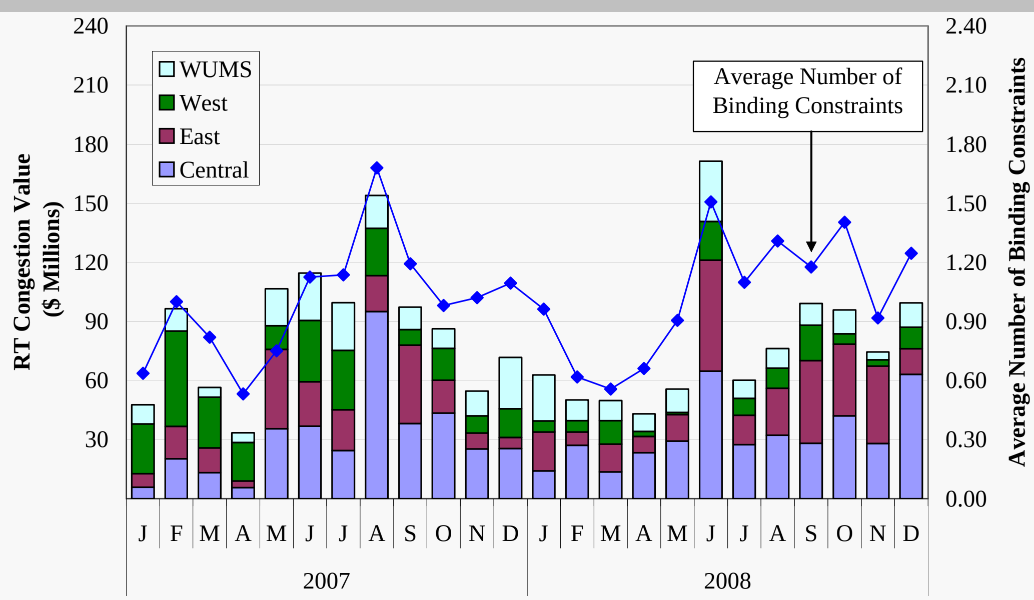
Real-Time Congestion by Coordination Region 2007 and 2008



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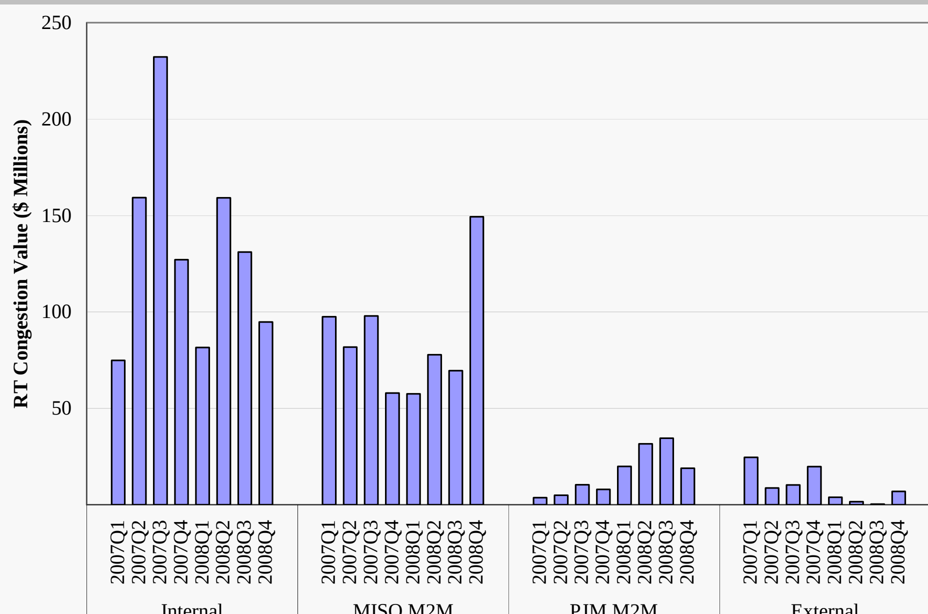
Value of Real-Time Congestion by Type of Constraint 2007 and 2008

- The next figure shows the value of real-time congestion by the type of constraint. It is computed in the same manner as in the previous analysis.
  - ✓ 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 years, most of the congestion in 2008 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) represent nearly 87 percent of the congestion value.
  - ✓ Nearly $70 million of congestion was incurred on west to east MISO market-to-market constraints in the 4th quarter 2008 due to transmission outages and the extended outage of a large baseload facility.
- On non-Midwest ISO constraints (PJM market-to-market and external);
  - ✓ The congestion on PJM constraints more than doubled;
  - ✓ External congestion (generally associated with the LG&E and TVA interfaces) decreased substantially.
- We review market-to-market results in more detail later in this report.

Value of Real-Time Congestion by Type of Constraint 2007 - 2008



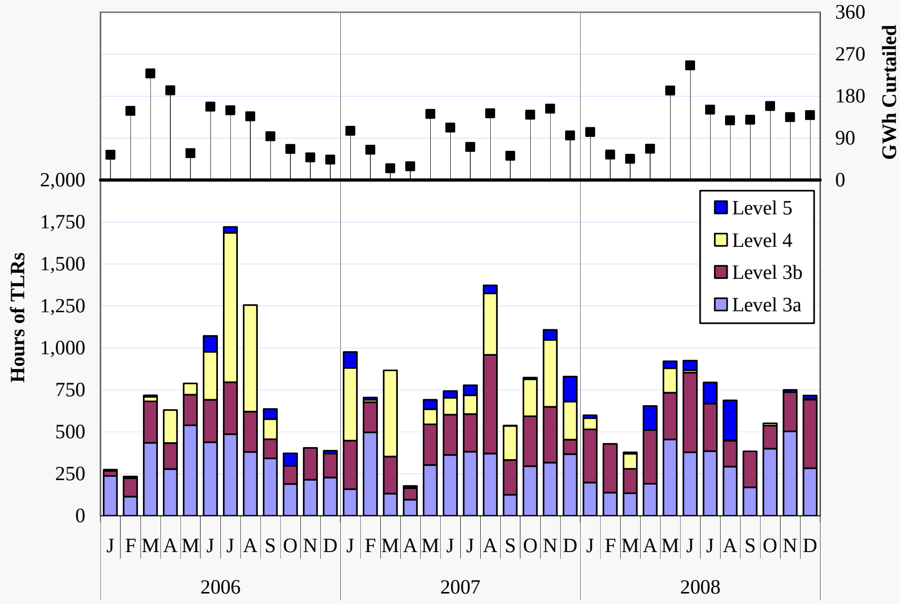
TLR Events in 2006 through 2008

- In prior reports, we showed that the transmission line-loading relief (“TLR”) process is inefficient, leading to:
  - ✓ More than three times the curtailments to manage congestion on average than the quantity of economic redispatch needed.
  - ✓ Less timely and accurate control of the system – resulting in lower reliability.
- LMP markets help to efficiently manage most internal congestion through redispatch rather than the curtailment of scheduled transactions through the TLR process.
- The TLR levels include:
  - ✓ Level 3 – non-firm curtailments.
  - ✓ Level 4 – commitment or redispatch of specific resources or other operating procedures to manage specific constraints.
  - ✓ Level 5 – curtailment of firm transactions.

Monthly TLR Activity 2006 - 2008

- The next figure details TLR activity in 2006 to 2008 by month and TLR level. In the top panel of the figure, the quantity of transactions curtailed by the TLRs are shown.
- The total GWh of TLR calls by Midwest ISO decreased after the implementation of the energy markets in 2005.
  - ✓ In 2005 there were 2,225 GWh of TLR events.
  - ✓ In 2006 there were 1,378 GWh (a 38 percent decline).
  - ✓ In 2007 the total TLRs declined again by 18 percent.
  - ✓ In 2008, TLRs increased 36 percent, due in part to the storms in the East region in June. This level is still 30 percent lower than in 2005.
- Although significant quantities of TLRs are still called to ensure that transactions external to the Midwest ISO are curtailed when they cause congestion, the Midwest ISO relies primarily on economic redispatch for managing congestion.

Monthly TLR Activity 2006 - 2008



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Congestion and Manageability 2007 – 2008

- Constraints are sometimes difficult to manage if the available redispatch capability of the generators that affect the flow on the constraint is limited.
  - ✓ When there is insufficient redispatch capability to reduce the flow below the limit in the next five-minute interval, we label the constraint “unmanageable”.
  - ✓ The presence of an unmanageable constraint does not mean the system is unreliable – reliability standards require the flow to be less than the limit within 30 minutes.
  - ✓ When a constraint is unmanageable, an algorithm is used to “relax” the limit for the constraint for purposes of calculating a shadow price for the constraint and the associated LMPs.
- The next figure shows the frequency with which constraints were unmanageable in each month in 2007-2008. This figure shows:
  - ✓ In 2008, 28 percent of the congestion was unmanageable on a five-minute basis, which is an increase of 5 percent from 2007.
  - ✓ Some of the unmanageability is caused by inflexible supply offers, which are evaluated in this report.
  - ✓ Manageability should improve in 2009 under the ASM markets with the implementation of the Price Volatility Make Whole Payment, which will provide an incentive to offer more flexibility.
  - ✓ Manageability was worst in June with the congestion caused by severe storms in the Midwest.

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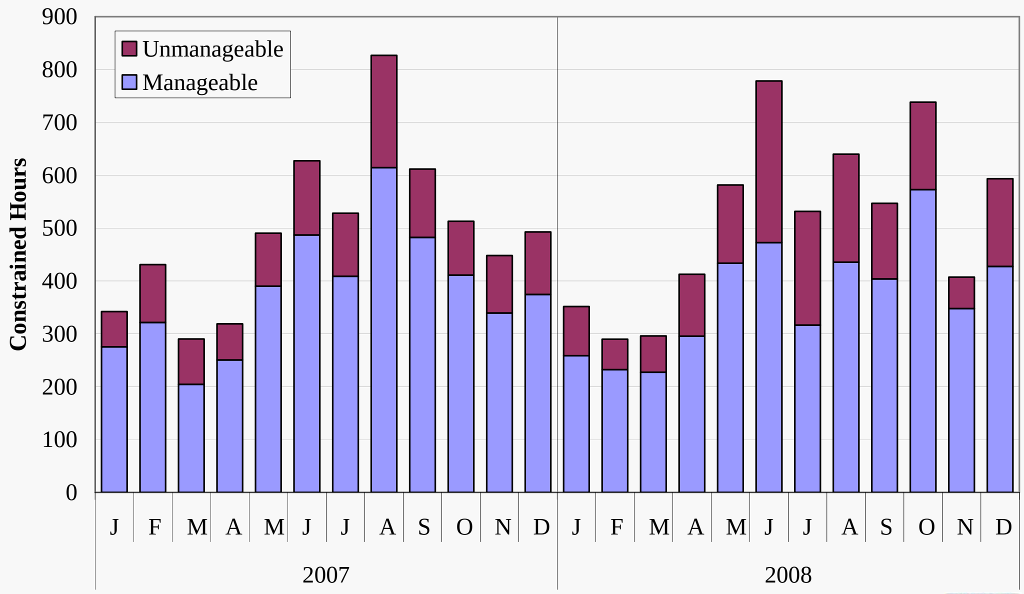
Congestion and Manageability
2007 – 2008



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Congestion and Manageability
2007 - 2008

- The next chart shows the value of real-time congestion on paths that experienced the most congestion in 2008. The chart indicates the portion of congestion that was manageable versus the portion unmanageable.
- This figure shows that congestion over the two year period was greatest on the interfaces into Minnesota.
  - ✓ Most of this congestion occurred early in 2007.
  - ✓ Total congestion Into Minnesota declined by 63 percent in 2008.
  - ✓ This path was the least manageable – only 65 percent of the congestion could be managed by real-time dispatch in 2008.
- In 2008, the West-to-East path to Indiana experienced the most congestion.
  - ✓ This was driven by a large amount of congestion in the last quarter caused by planned transmission outages.
  - ✓ 74 percent of the congestion on these paths was manageable in 2008.
- Almost 80 percent of the congestion into WUMS on the two paths shown in the figure were manageable in 2008.

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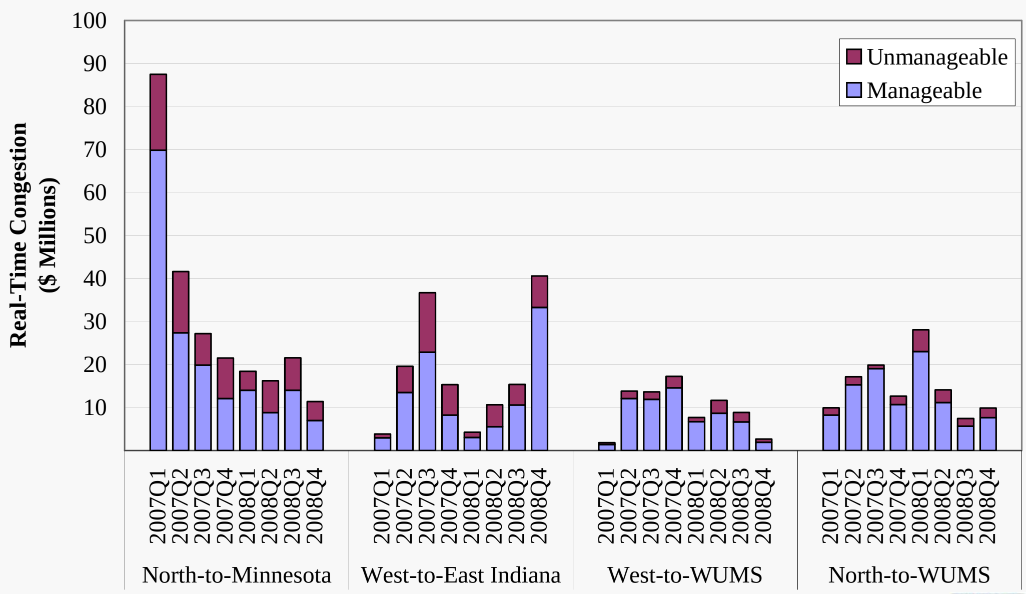
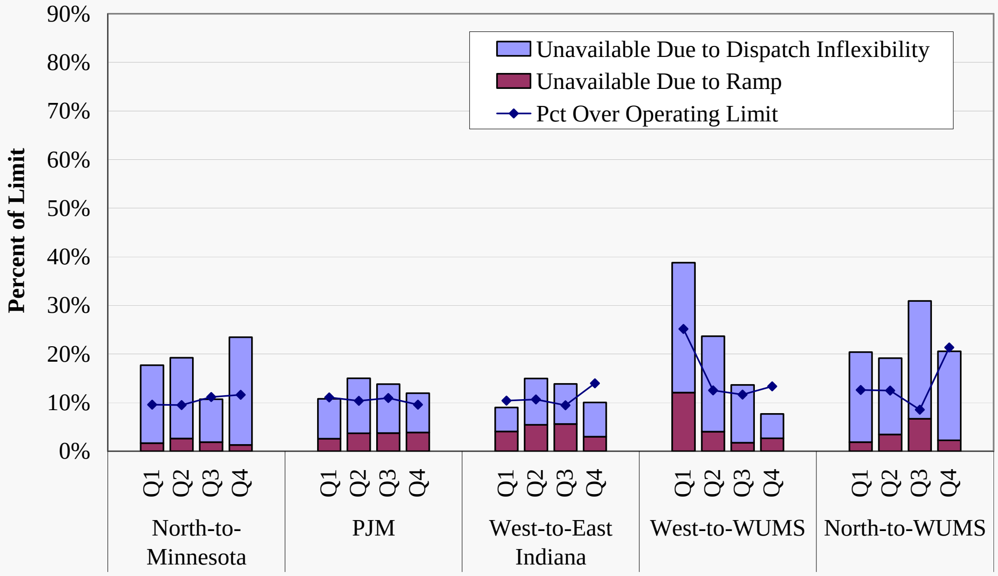
Real-Time Congestion and Manageability
Selected Paths 2007 – 2008



Unavailable Congestion Relief Capacity

- The next analysis evaluates two factors that contribute to "unmanageable" constraints:
  - ✓ Dispatch inflexibility: EcoMin levels much higher than the physical minimum output levels prevent the market from reducing the output of a resource causing flow on a line.
  - ✓ Slow ramp limits: Understated ramp rate limitations reduce the speed with which generation can be redispatched to manage congestion.
- The following figure shows the effects of these factors by showing:
  - ✓ the amount of congestion relief (as a percentage of the path limit) that was unavailable to reduce the flow on a constrained path attributable to the two factors described above; and
  - ✓ the amount of flows (as a percentage of the path limit) that was above the path limit at the time it was unmanageable (this is the "average violation").
- The results show that on most paths, the relief that could have been available physically would have been enough to manage the congestion. (i.e., the stacked bars exceed the line on the graph)
- We attribute the lack of flexibility to:
  - ✓ Justifiable technical concerns in some cases or simply a desire to operate conservatively.
  - ✓ Concerns that responding to dispatch signals when prices are volatile could reduce the supplier's profit – this is being addressed though the Price Volatility Make While Payments which was implemented with ASM in 2009.

Congestion Relief Unavailable Due to Offer Parameters Selected Paths: 2008



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Other Congestion Manageability Issues

- The final factor that contributes to unmanageable congestion is the parameter in the real-time market that prevents units with small effects on a constraint from being redispatched.
  - ✓ During 2007, the real-time market did not dispatch units to manage a constraint if their generation shift factors ("GSF") were less than 2 percent (or greater than -2 percent).
  - ✓ A generation shift factor is the amount by which the flow on a constraint will change when the output of a generator increases.
  - ✓ This effect of the parameter is particularly large for the low-voltage constraints because GSFs are generally small and less widely distributed for low voltage constraints – hence, the cutoff tends to have a larger effect.
  - ✓ The Midwest ISO lowered this threshold incrementally in 2008 and it is now set at 1.7 percent.
  - ✓ We are recommending that the Midwest ISO continue to reduce this parameter.

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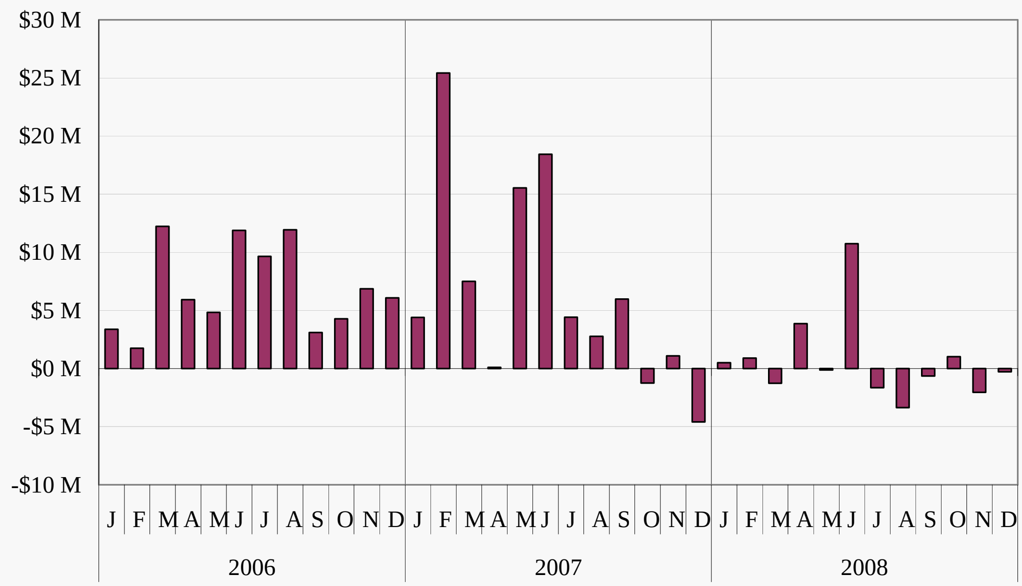
Pricing Unmanageable Transmission Constraints

- Although manageability of transmission constraints should improve, we continue to be concerned about the market outcomes when constraints are in violation.
  - ✓ We have studied the constraint relaxation algorithm used when a constraint is in violation to produce a shadow price for the constraint (the marginal economic value of the constraint that is used to calculate LMPs). The same algorithm is used by PJM and New England.
  - ✓ Based on our analysis, we have concluded that this algorithm often produces inefficient shadow prices that distort the associated LMPs.
    - For example, in more than 21 percent of the cases when a constraint is in violation, the relaxation produces a zero shadow price (indicating no congestion).
  - ✓ The more efficient approach in this case is to set the shadow price and associated LMPs at the reliability cost of violating the constraint.
    - Presumably, this value should correspond to the maximum cost the Midwest ISO is willing to incur to manage the constraint, which is reflected by the constraint penalty factors in the market software.
  - ✓ To the extent that the relaxation algorithm determines a lower shadow price, it is a poorer reflection of the true value of the constraint.
- Hence, we continue to recommend that the Midwest ISO discontinue use of the relaxation algorithm and set prices based on the constraint penalty factors. The Midwest ISO has been working with us to implement this recommendation.

Balancing Congestion Costs 2006 - 2008

- Like all other settlements in the real-time market, real-time congestion costs should be related only to deviations from the day-ahead schedules.
  - ✓ Because the real-time settlements are only for deviations from the day-ahead schedules, real-time congestion charges should be zero as long as the transmission limits and external loop flows assumed in the day-ahead market have not changed.
  - ✓ Inconsistencies in limits, loop flows, or other modeling inputs can compel the Midwest ISO to incur real-time congestion costs to reduce the flow on constrained facilities in real time, which would be recovered through uplift charges.
- The next figure shows the real-time congestion costs from 2006 to 2008.
  - ✓ Balancing congestion costs have declined since 2006, likely due to:
    - Improvements made in the day-ahead modeling of loop flows; and
    - A general decrease in congestion in 2008.
    - The largest balancing congestion costs occurred in June as storm-related outages and deratings were not fully reflected in the day-ahead market.
- Starting in late 2007, negative balancing congestion began to emerge periodically due to payments received from PJM for Market-to-Market coordination.
  - ✓ Those payments from PJM totaled $11.6 million in 2007 and nearly $45 million in 2008.
  - ✓ Settlement revenues are detailed in the Market-to-Market section of this report.

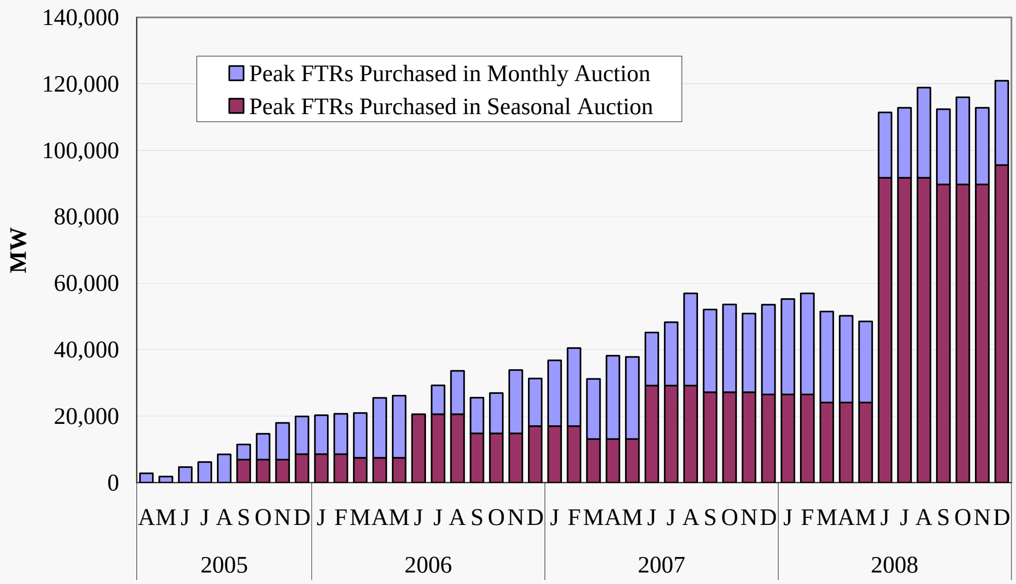
Balancing Congestion Costs
2005 – 2007



Seasonal and Monthly FTR Auction Quantities
2005 – 2008

- The next figure analyzes quantities of FTRs for peak hours that were sold in the seasonal and monthly FTR auctions.
- The figure shows:
  - ✓ Up to May 2008, the total quantity of FTR purchases had been rising steadily since the market opened in April 2005. This was due to:
    - Fewer FTRs being allocated in advance of the auctions.
    - The system being more fully subscribed.
    - In June 2008, the sharp increase in FTRs purchased in the seasonal auction was due to the transition to Auction Revenue Rights in place of allocated FTRs.
  - ✓ From 2006 until May 2008, roughly one-half of the FTRs purchased were through the monthly auctions.
    - With the transition away from allocated rights, a larger proportion is now auctioned on a seasonal basis.

FTR Purchases
Monthly and Seasonal Auctions



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FTR Profitability
2005 - 2008

- One indicator of the liquidity of the FTR markets is the profitability of the FTR purchases.
  - ✓ FTR profits are the difference between the costs to purchase the FTR and the payout on the FTR based on congestion realized in the day-ahead market.
  - ✓ In well-functioning, liquid FTR markets, the FTR profits should be relatively low because the market clearing price for the FTR should reflect a rational expectation of the congestion value of the FTR.
- The next two figures show the profitability of FTRs purchased in the seasonal FTR auctions and the monthly FTR auctions.
- The first figure shows that average FTR profitability in the seasonal auctions has declined from more than $1.50 per MWh in the fall of 2005 to less than $0.05 per MWh on average in 2008.
- The second figure shows that average profitability in the monthly auction has decreased from more than $1.30 per MWh in 2005 to less than $0.26 per MWh in most months in 2008.
- These results indicate that the liquidity and overall performance of the FTR markets has improved over time, causing FTR prices to more accurately reflect their value.

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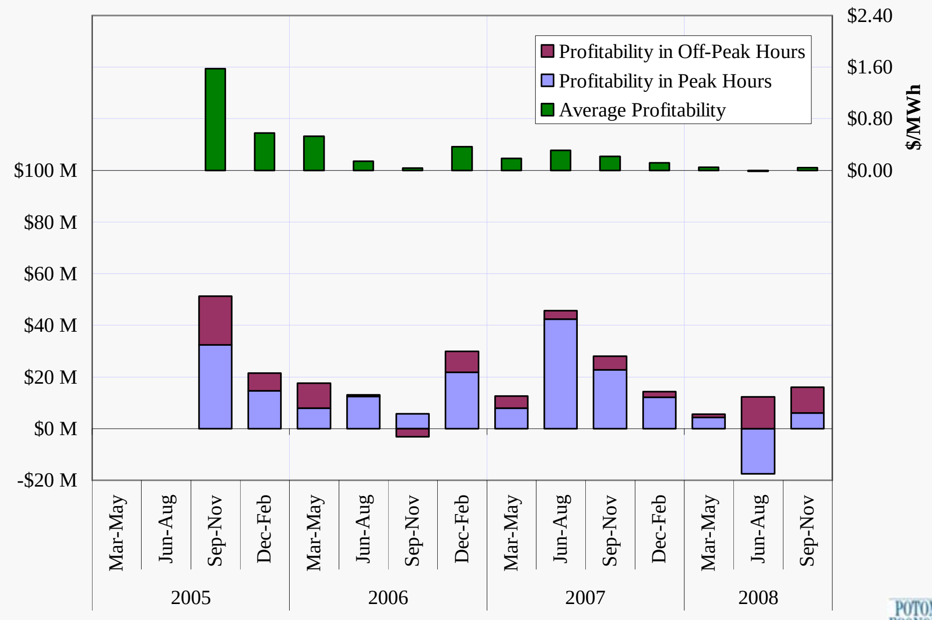
FTR Profitability
Seasonal Auctions 2005-2008



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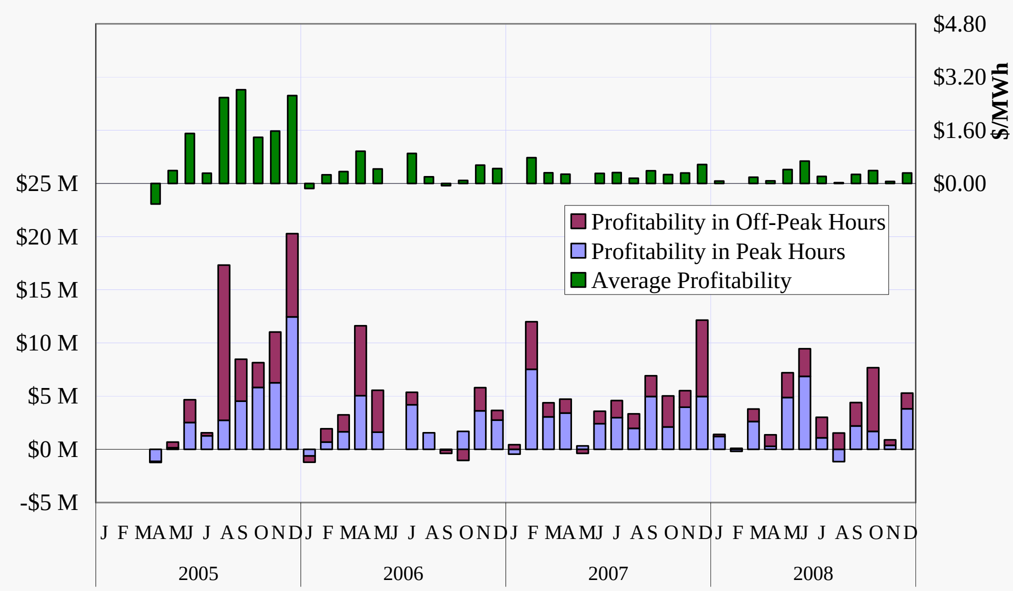
FTR Profitability
Monthly Auctions 2005-2008



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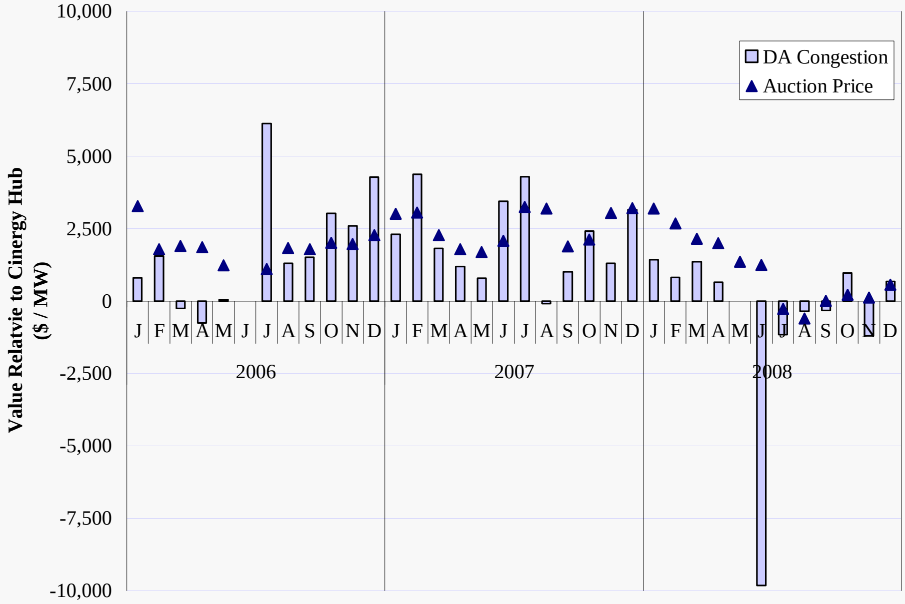
FTR Auction Summary
2006 - 2008

- To provide further detail on the performance of the FTR markets, our next analysis examines the monthly FTR prices compared to day-ahead congestion that are payable to the FTR holders.
  - ✓ We analyze values for WUMS, the Minnesota Hub, and the Michigan Hub in peak and off-peak hours.
  - ✓ All values are computed relative to Cinergy Hub, which is the most actively traded location in the Midwest ISO.
- In a well-functioning market, the FTR prices should reflect a reasonable expectation of the day-ahead congestion that will occur into the area.
  - ✓ The profit earned by an FTR holder is the difference between the FTR price paid and the congestion paid to the FTR holder.
  - ✓ The results in the following figures help explain the changes in FTR profitability shown in the analyses above.

FTR Auction Prices and Congestion
WUMS, 2006-2008

- The two figures below show the results for WUMS in peak and off-peak hours.
- The most striking feature of the results is the large shift in congestion in June 2008 into eastern areas of the Midwest ISO. This was caused by storms in that month which resulted in critical outages and congestion.
- Aside from June 2008, day-ahead congestion has declined since 2006. There was slightly more day-ahead congestion in 2007 into WUMS (relative to the Cinergy Hub) and the FTR values reflect this change.
- Since July 2006, convergence between auction prices and congestion has been strong, particularly in off-peak hours.
  - ✓ As reported last year, convergence was poor in August 2007 due to anomalously low day-ahead congestion during the month. After August, reasonably good convergence resumed.
  - ✓ The congestion patterns were less volatile during the off-peak hours, which contributed to the stronger convergence of the FTR prices and congestion during those periods.

FTR Auction Prices and Congestion
WUMS Area: Peak Hours



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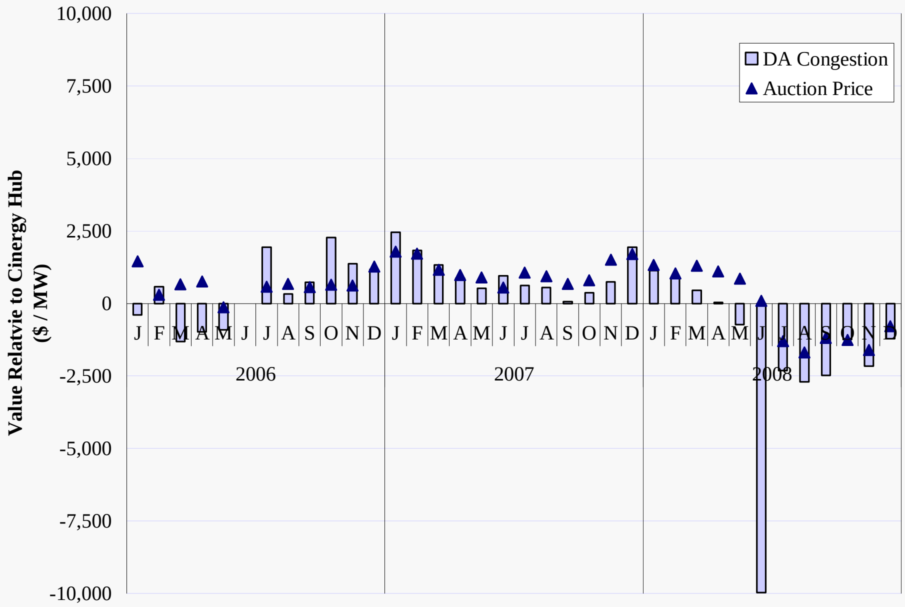
FTR Auction Prices and Congestion
WUMS Area: Off-Peak Hours



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FTR Auction Prices and Congestion
Minnesota Hub

- The convergence between congestion values and FTR prices for the Minnesota Hub was affected by the volatility of congestion during 2006 and 2007 in peak hours. However, the volatility declined in 2008 and convergence has generally improved.
  - ✓ Like WUMS, June 2008 was anomalous due to storms in the Central region affecting the Cinergy sink price.
- Convergence in off-peak hours was better than in peak hours due to lower volatility.
- One difficulty in valuing the FTRs is the fact that the congestion can change directions. As shown, some months have negative congestion while congestion is positive for other months.
- Both figures reveal a slight lag in convergence, as one would expect, because FTRs are sold prior to the month in which the congestion occurs.

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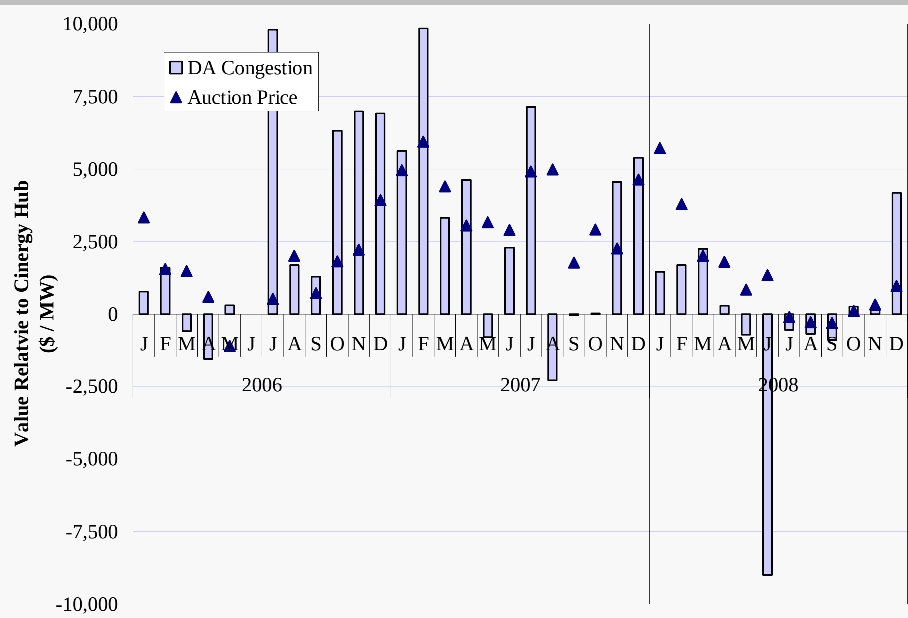
FTR Auction Prices and Congestion
Minnesota Hub: Peak Hours



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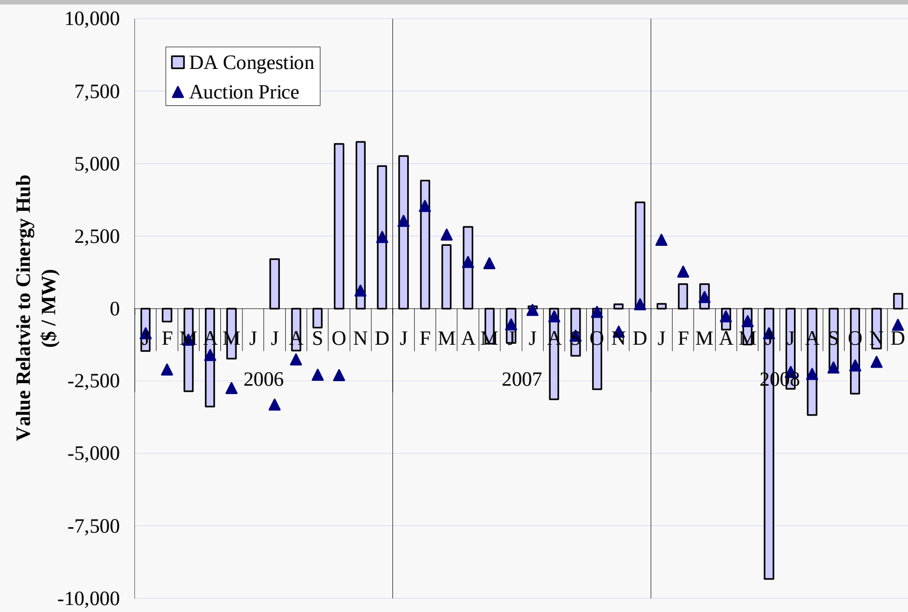
FTR Auction Prices and Congestion
Minnesota Hub: Off-Peak Hours



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FTR Auction Prices and Congestion
Michigan Hub

- The next two figures provide the same analysis of the FTR prices into Michigan from Cinergy.
- The congestion and FTR results for the Michigan Hub for both peak and off-peak hours indicate reasonably high convergence between FTR prices and the value of day-ahead congestion.
  - ✓ Convergence can be challenging on the Michigan interface because the congestion frequently switches direction.
  - ✓ Michigan congestion is often impacted by flows around Lake Erie and when the Phase Angle Regulators on the Midwest ISO – IESO interface are fully operational convergence should improve.
    - – Currently of the four PARs designed to control the interface, one is in operation, two more are available but not in operation and the fourth is being repaired.
    - – Additional agreements are still needed on the PAR operation and scheduling.

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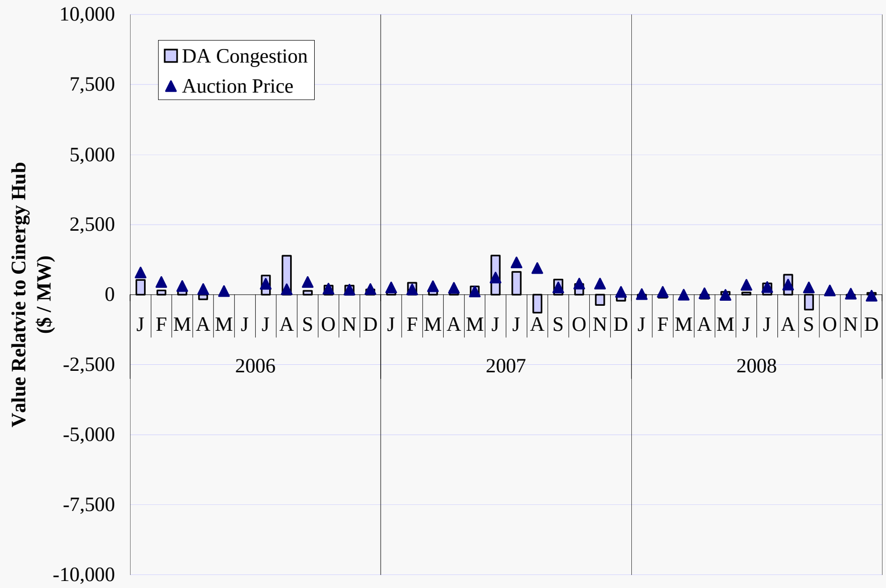
FTR Auction Prices and Congestion
Michigan Hub: Peak Hours



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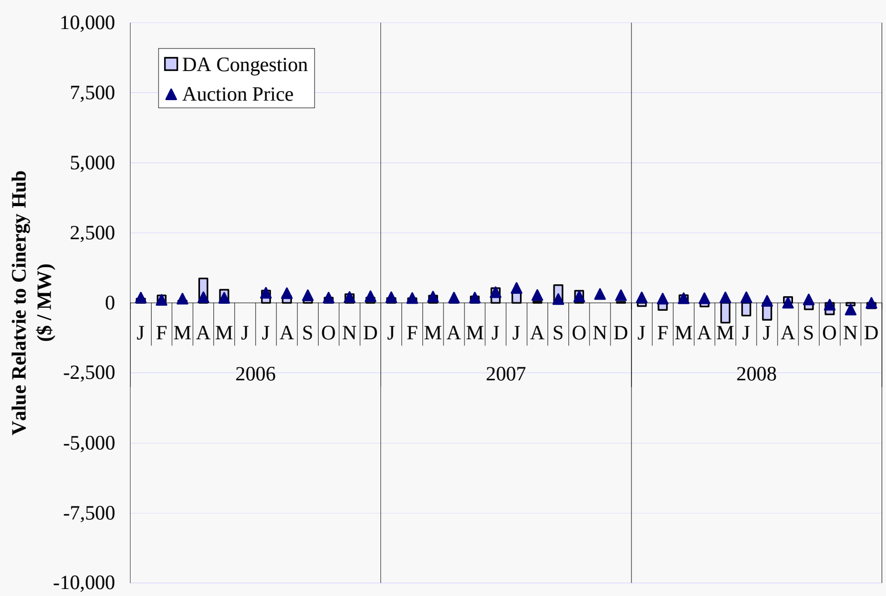
FTR Auction Prices and Congestion
Michigan Hub: Off-Peak Hours



POTOMAC ECONOMICS

Market to Market Events

- The final series of analyses evaluate the “market-to-market” process, which is the process the Midwest ISO and PJM use to coordinate the relief of transmission constraints that both systems affect.
  - ✓ A market-to-market constraint is a constraint on a Midwest ISO/PJM coordinated flowgate, which is located in one of either of the RTOs.
- When a market-to-market constraint is binding, the monitoring RTO sends a shadow price and an amount of relief requested (the desired reduction in flow) to the other RTO (i.e., the “reciprocating RTO”).
  - ✓ The shadow price measures the marginal cost of relieving the constraint.
  - ✓ When the reciprocating RTO receives the shadow price and requested relief, it incorporates these values in its real-time market to provide as much of the requested relief as possible at a cost less than the shadow price.
  - ✓ From a settlement perspective, each market is entitled to a certain flow on each of the market-to-market constraints. Settlements are made between the RTOs based on its actual flow over the constraint relative to its entitlement.
- This market-to-market process is essential for ensuring that generation is efficiently re-dispatched to manage these constraints, and that prices in the two markets are consistent.

POTOMAC ECONOMICS

Market to Market Events

- The following figure shows the total number of market-to-market constraint-hours (instances when a market-to-market constraint is binding and activated).
- The top panel represents coordinated flowgates located in the PJM system and the bottom panel represents flowgates located in the Midwest ISO.
  - ✓ The darker shade in the stacked bars are peak hours in the month when coordinated flowgates were activated, and the lighter shade represents off-peak hours.
- The figure indicates:
  - ✓ The activity on PJM market-to-market constraints in the Midwest ISO was substantially higher in 2008 than in 2007, while the activity on MISO market-to-market constraints was comparable in 2008 to 2007.
  - ✓ The number of hours with market-to-market coordination on PJM flowgates spiked in a number of months due to storms (notably June) and transmission outages on West to East constraints.
  - ✓ The PJM market-to-market constraints are generally the most frequent in the summer, when the demands on the transmission system are the greatest.
  - ✓ The Midwest ISO’s market-to-market constraints were binding most frequently during the fall due to maintenance outages on transmission lines.

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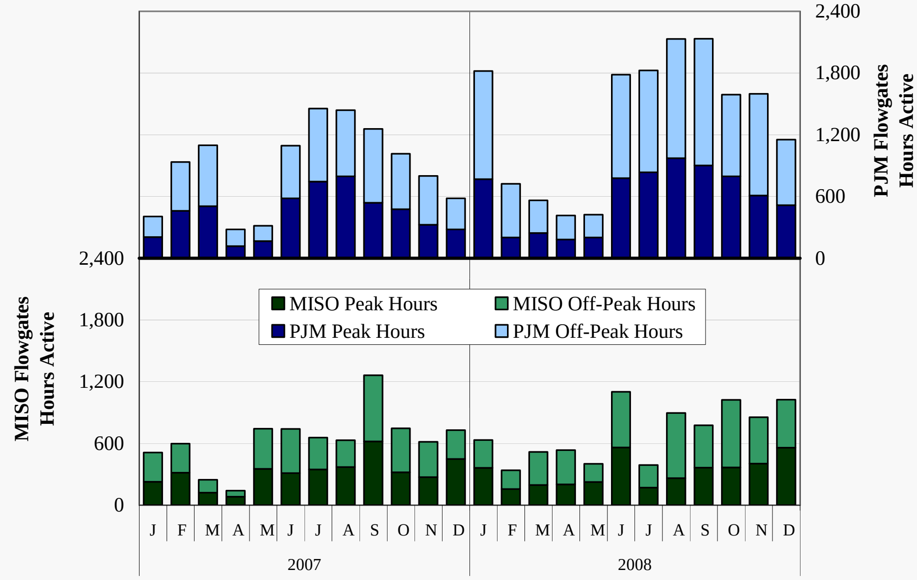
Market-to-Market Activity



POTOMAC ECONOMICS

Market to Market Settlements

- The following figure shows a summary of the market-to-market settlements.
  - ✓ The positive values represent payments made to the Midwest ISO on coordinated flowgates and the negative values represent payments made to PJM on coordinated flowgates.
  - ✓ The drop line shows net payments to the Midwest ISO or PJM in each month.
- Settlement is based on the reciprocating RTO’s actual market flows compared to its Firm Flow Entitlements (FFEs).
  - ✓ If a reciprocating RTO’s market flows are below its FFEs than it will receive a payment for providing relief at the cost of providing that relief.
  - ✓ If its flows are above its FFEs it will make a payment at the cost of the monitoring RTOs congestion.
- The figure shows:
  - ✓ Payments from PJM were substantially higher in 2008 than in 2007 totally more than $44 million.
  - ✓ In contrast to 2007, when net payments were made to PJM in the summer, net payments were made to the Midwest ISO in every month in 2008.
  - ✓ Payments in both directions were unusually large in June due to storm-related congestion on both systems.
  - ✓ The Midwest ISO identified an issue with the PJM’s market flow calculations that may have understated PJM’s market flows and affected past settlements.

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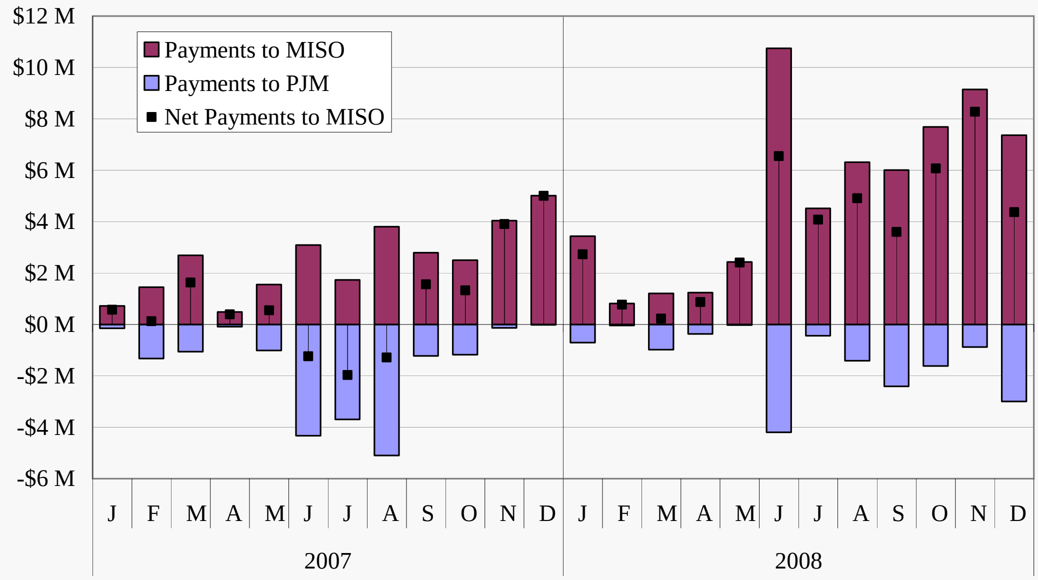
Market-to-Market Settlements



Market-to-Market Constraints Shadow Price Convergence

- The next two figures show an analysis that examines the most frequently activated market-to-market constraints on the PJM and Midwest ISO systems.
  - ✓ The analysis is intended to show the extent to which the shadow prices on coordinated constraints converge between the two RTOs.
  - ✓ The first figure shows results for the six most active PJM coordinated flowgates and the second figure shows the five most active Midwest ISO coordinated flowgates.
  - ✓ Each figure shows the initial shadow price of the monitoring RTO on each coordinated flowgate, the average shadow prices in the post-initialization period for both the monitoring and reciprocating RTOs, and the relief requested by the monitoring RTO in both periods.
  - ✓ The figure also shows (on the horizontal axis) the percent of hours the constraint was activated that it was being coordinated (i.e. relief was being provided by the Reciprocating RTO).
    - – Cases in which the Reciprocating RTO does not respond (where relief capability is not available) are excluded from the analysis.
- If the market-to-market process is operating well:
  - ✓ The shadow prices of the two RTOs should converge after a coordinated constraint is activated; and
  - ✓ In most cases, the shadow prices should decrease from the initial value as the two RTOs collaborate to manage the constraint.

PJM Market-to-Market Constraints Shadow Price Convergence

- The first figure shows the results of our analysis of the PJM coordinated flowgates.
- The shadow prices decrease and move toward convergence over the duration of the event, indicating that the market-to-market process is achieving its objective.
  - ✓ The percentage of active intervals that are coordinated (where relief is received) is relatively high on the PJM flowgates, ranging from 60 to 80 percent on these constraints.
  - ✓ The relief requested does not change significantly from the initial to the post activation period and is roughly 100 MW regardless of what constraint is involved.
- As in 2007, the results in 2008 continue to raise potential concerns, including:
  - ✓ Cases where the Midwest ISO "relaxes" a PJM market-to-market constraint because it cannot provide the relief at a marginal cost lower than PJM's shadow price.
    - – This relaxation methodology can produce shadow prices that are not representative of the value of the congestion in PJM.
    - – This issue has been addressed by software changes made recently that discontinue the use of the relaxation methodology for market-to-market constraints.

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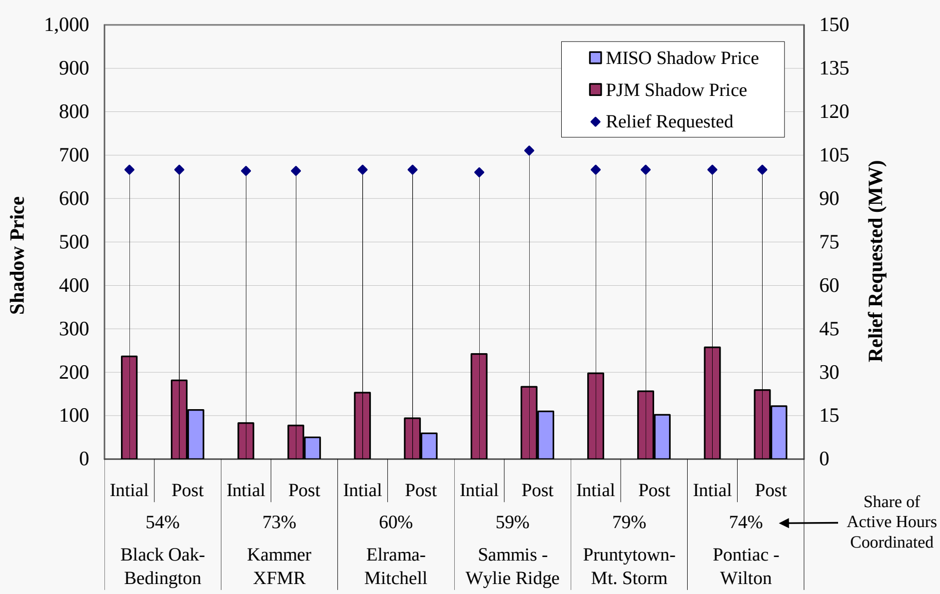
PJM Market-to-Market Constraints Relief Requested and Shadow Prices



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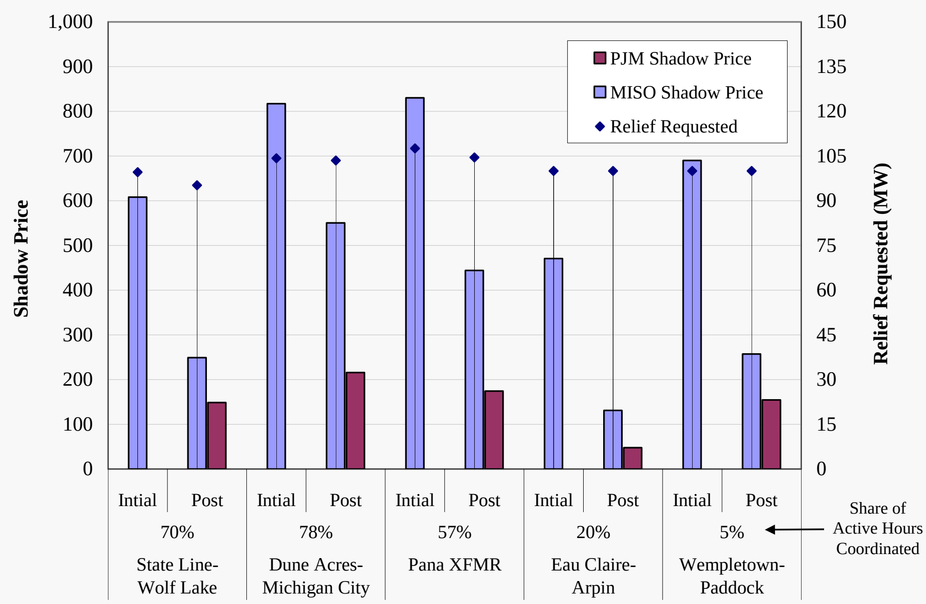
Midwest ISO Market-to-Market Constraints Relief Requested and Shadow Prices

- The next figure shows the most frequently called market-to-market constraints on the Midwest ISO system.
  - ✓ Stateline-Wolf Lake and Dune Acres-Michigan City generally limit flows from West to East. These are the most common flowgates for market-to-market coordination.
  - ✓ Eau Claire-Arpin and Wempletown-Paddock limit imports into the WUMS area.
  - ✓ The Pana XFMR generally limits generation in the Central region.
- Like the analysis of the PJM constraints, the figure shows that the shadow prices tend to decrease and move toward convergence over the duration of the event.
- The 2008 results of the Midwest ISO's market-to-market constraints raise some of the following concerns:
  - ✓ Like with the PJM flowgates, the relief quantities are rarely modified, even when the Midwest ISO shadow price is higher than PJM's and more relief may be available.
  - ✓ PJM often returned a zero or did not respond when the Midwest ISO had an active market-to-market constraint, which indicates an inability to redispatch for the constraint.
  - ✓ Though there were improvements from 2007, PJM still provided relief a low percentage of the time for some of the Midwest ISO's most critical constraints. Software changes made in 2009 should address this issue.

Midwest ISO Market-to-Market Constraints Relief Requested and Shadow Prices



Market-to-Market Recommendations

- The Midwest ISO and PJM have responded recently to a number of past recommendations which should improve the performance of the process in 2009.
  - ✓ The RTOs made software changes to optimize and modify the relief requested based on the relative shadow prices; and
  - ✓ The RTOs have discontinued use of the constraint relaxation algorithm when the reciprocating RTO cannot provide relief at a cost lower than the shadow price of the monitoring RTO.
- We continue to support recommendations we made in prior State of the Market reports:
  - ✓ The Midwest ISO should institute a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly.
  - ✓ We continue to recommend that the RTOs expand their market-to-market process to optimize interchange between markets and coordinate exports transactions.
  - ✓ PJM has made real-time modeling changes in 2009 the should improve its response on Midwest ISO constraints.
  - ✓ The Midwest ISO should discontinue the constraint relaxation algorithm, even on market-to-market constraints that cannot be resolved by the monitoring RTO.

External Transactions

Average Hourly Day-Ahead Imports
All Hours

- This section of the report evaluates the interchange between the Midwest ISO and adjacent areas. We summarize the magnitude of the external transactions and evaluate the efficiency with which imports and exports are scheduled.
- The following figure shows the daily average 2008 hourly net imports scheduled in the day-ahead market over all interfaces. It shows:
  - ✓ The Midwest ISO is a net importer of power in both peak and off-peak periods due to its reliance on large imports from the West and Canada.
  - ✓ The pattern of net imports in 2008 was seasonal with the largest imports occurring during the winter and summer peak conditions.
- Day-ahead imports averaged 3.6 GW over all hours and the daily average exceeded 5 GW during 27 summer days.
  - ✓ This indicates the degree to which the Midwest ISO relies on net imports to satisfy the demands of the market.
- Given the Midwest ISO's heavy reliance on net imports in real time, it is important for external resources to be fully the Midwest ISO capacity market.
  - Hence, we recommend the Midwest ISO modify its deliverability requirement for external resources to establish a maximum amount by interface that can be utilized to satisfy LSEs' capacity requirements under Module E.

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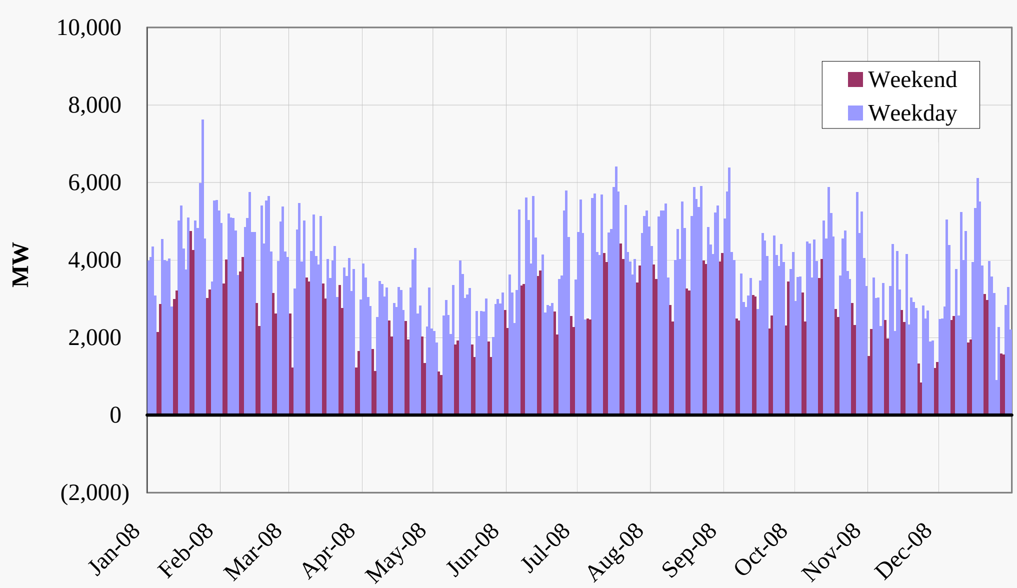
Average Hourly Day-Ahead Imports
Daily Average of All Hours



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Average Hourly Real-Time Imports All Hours

- The next figure shows the net imports in the real-time market and the change in net imports from the day-ahead market.
- In the real-time markets in 2008, the Midwest ISO imported 4.4 GW in on-peak hours and 2.1 GW in off-peak hours.
  - ✓ PJM (1.2 GW/h) and Manitoba Hydro (1.1 GW/h) were the two largest exporters of power to the Midwest ISO in the real-time market.
- As the figure shows, real-time net imports generally decreased from those scheduled in the day-ahead market.
  - ✓ On many days the average net imports decreased by more than 1,000 MW, which can create reliability issues for the Midwest ISO that must be managed.
  - ✓ Large changes in net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources.
  - ✓ Intra-hour scheduling contributed to these changes and is assessed later in this section.
- The figure shows that changes in net imports from day-ahead to real-time occurred with more frequency in the spring and in December.
- A large share of the reduced real-time imports are on the IESO interface.
  - ✓ IESO does not have a day-ahead market.
  - ✓ The IESO interface is often limited, causing import schedules to MISO to be cut in real-time.

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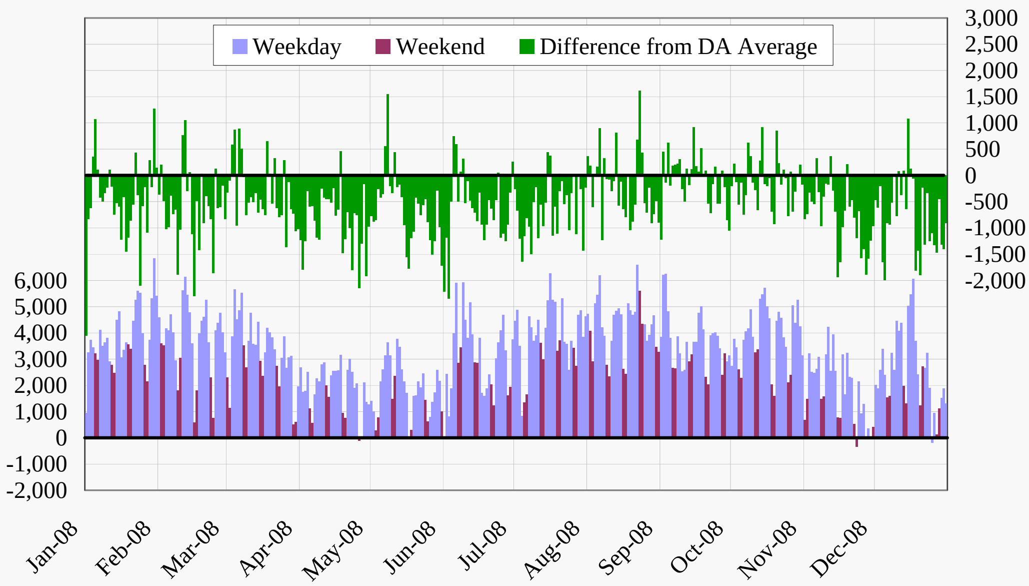
Average Hourly Real-Time Imports All Hours



POTOMAC ECONOMICS

Hourly Average Real-Time Imports from PJM 2008

- The following figure shows the average net imports scheduled for the Midwest ISO-PJM interface by hour of the day.
- This figure shows:
  - ✓ Overall, Midwest ISO is a net importer of power from PJM.
  - ✓ The Midwest ISO generally imports more power during the peak hours of the day and less power in the off-peak hours.
- However, the standard deviation of the net imports is large, indicating that the magnitude and direction of the flows between the two markets is highly variable.
  - ✓ This characteristic of the PJM transactions is due to similarity of the generating resources in the two areas. Hence, the prices in the two areas tend to move in similar ranges.
  - ✓ Because the relative prices in the two areas govern the net interchange between them, movements in the relative prices in the two areas will cause the incentives to import and export to fluctuate.

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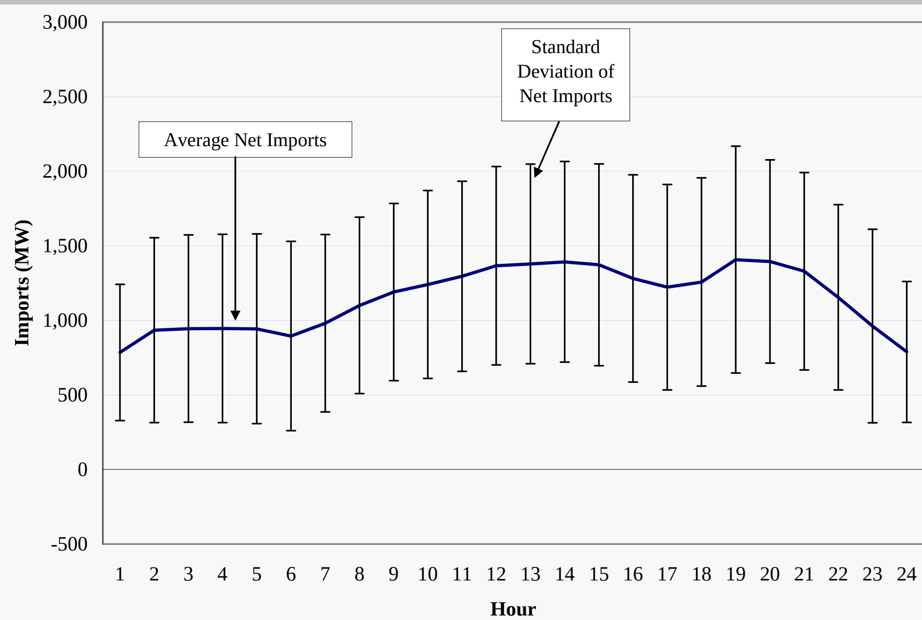
Hourly Average Real-Time Imports from PJM 2008



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Hourly Average Real-Time Imports from Canada 2008

- The following figure shows hourly real-time net imports across the Canadian interfaces:
  - ✓ The Midwest ISO exchanges power with Canada through interfaces with the Manitoba Hydro Electricity Board (MHEB) and the Independent Electricity System Operator (IESO) of Ontario.
  - ✓ The Midwest ISO is normally a net importer from MHEB through the high voltage DC connection and a net exporter to IESO, although the direction of the power flows switch periodically.
  - ✓ The net imports from MHEB are generally higher in the peak hours and lower in the off-peak hours.
  - ✓ The Midwest ISO is a net exporter to Ontario - exports to IESO are generally lower in the peak and ramping hours.

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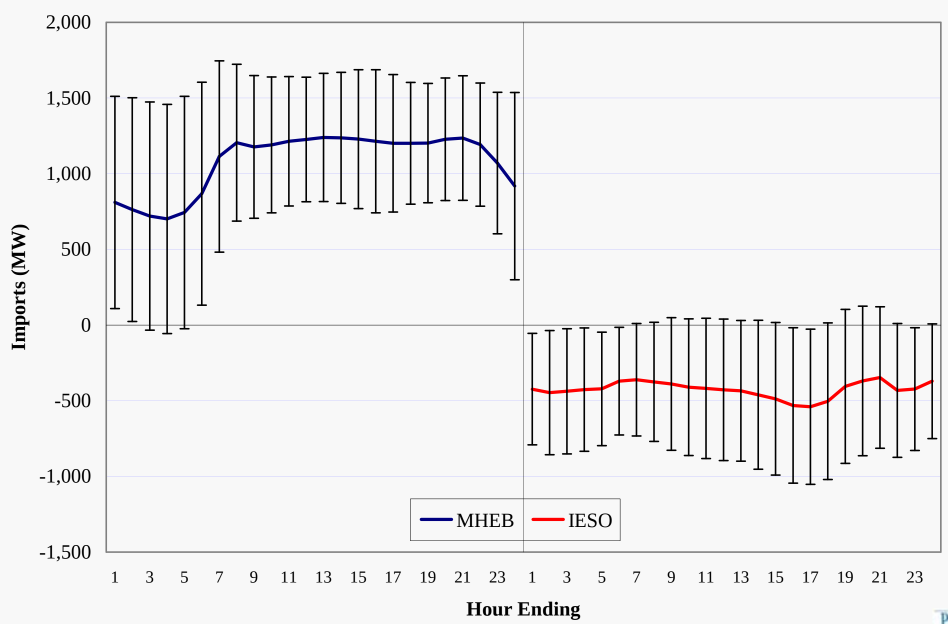
Hourly Average Real-Time Imports from Canada 2008



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Imports over the Manitoba Interface and Related Congestion

- The next figure shows the average hourly imports over the Manitoba interface from 2006 through 2008 on seven-day moving average basis. It shows that:
  - ✓ Imports peak during the summer months;
  - ✓ Import were unusually low at the end of 2006 and beginning of 2007. This was due to poor water conditions that reduced the availability of hydroelectric resources; and
  - ✓ Imports returned to normal levels by the summer of 2007 and were sustained through 2008.
- Imports over the Manitoba interface are relatively important because they serve the load in the Minnesota area and are a source of power that can be imported into the WUMS region from the west.
  - ✓ Hence, when imports over the Manitoba interface are reduced, it can contribute to congestion *into* Minnesota, from the south.
  - ✓ Reduced imports also tend to reduce the west to east congestion into WUMS.
    - – However, the addition of the new Arrowhead-Weston 345 transmission line in January 2008 has also reduced congestion into WUMS from the West.

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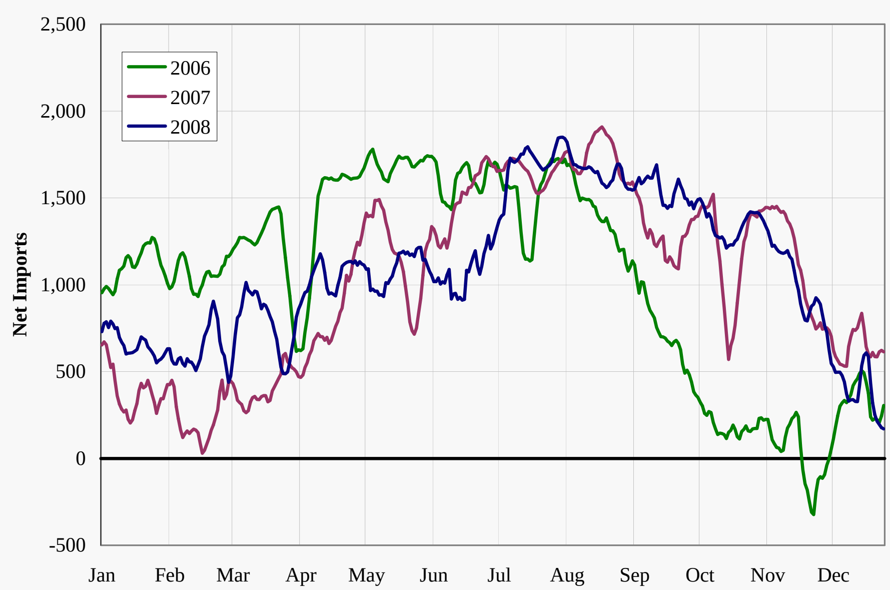
Moving Average of Net Imports from Manitoba 2006 through 2008



POTOMAC ECONOMICS

Lake Erie Loop flow

- In 2008, a number of issues related to “contract path” transaction scheduling around Lake Erie occurred.
- The following figure summarizes transaction scheduling involving the four control areas around Lake Erie.
- Some of these transactions were “circuitous”, which is defined as those that:
  - ✓ Source in New York, wheel through Ontario and the Midwest ISO, and sink in PJM; or
  - ✓ Source in the PJM, wheel through the New York and Ontario, and sink in the Midwest ISO.
- The circuitous schedules are shown in the cross-hatched portion of the bars in this figure.
- The circuitous transactions increased gradually in early 2008 before rising sharply in May. The vast majority of these were Path 1 schedules.
- On July 21, 2008, the NYISO filed under exigent circumstances to preclude scheduling of circuitous transactions.

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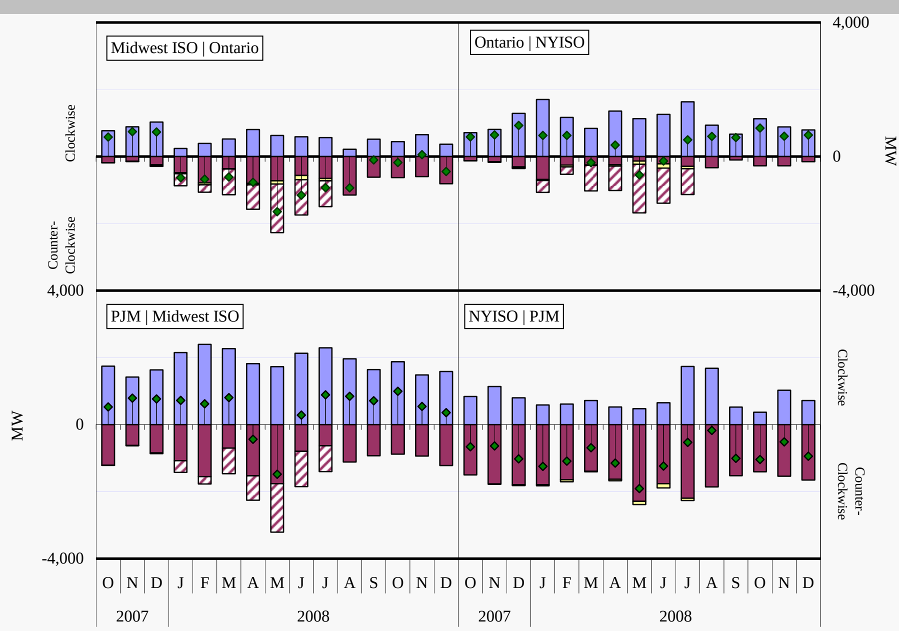
Scheduled Flows around Lake Erie



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Actual Lake Erie Flows

- Scheduling a transaction circuitously does not alter the physical flow of the power. The extent to which the physical flows differ from scheduled flows are known as “loop flows”.
  - ✓ Circuitous transactions contributed to large amounts of clockwise loop flows.
  - ✓ Clockwise loop flows can create substantial congestion, particularly in New York, without bearing the costs of the congestion.
- The next figure compares the net schedules (shown in the diamonds) to the actual flows caused by the schedules (shown in the bars).
  - ✓ This figure shows that as the circuitous scheduled transactions increased, the inconsistencies (i.e., loop flows) increased.
  - ✓ These inconsistencies were largest in May when circuitous transactions were highest - the inconsistencies (i.e., loop flows) were almost 1500 MW on average in May.
- The underlying problem in this case and in other schedules around Lake Erie (e.g., the Ontario to PJM transactions discussed next) is that settlements occur based on the scheduled path, but the actual power flows occur on other paths.
  - ✓ This distorts participants’ incentives and can lead to inefficient scheduling.
  - ✓ Our conclusions and recommendations regarding this issue are described after the next analysis.

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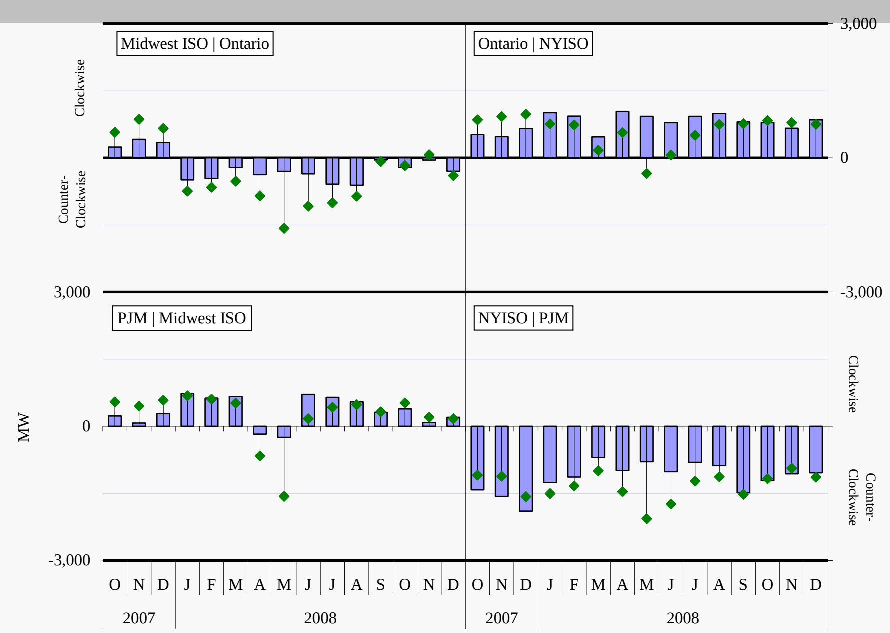
Actual Flows Around Lake Erie



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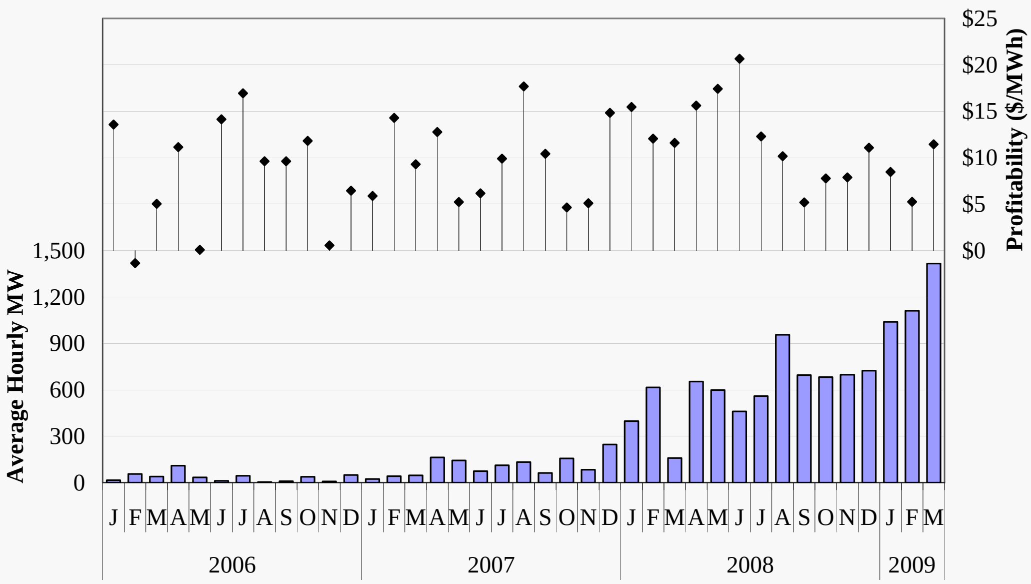
Wheels From IESO to PJM

- 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 2006 to early 2009.
  - ✓ There was a significant increasing trend in the volume of these transactions starting late in 2007 and continuing into 2009.
  - ✓ The transactions are explained by their consistent profitability.
    - Since the beginning of 2007, these transactions have netted profits between $5 and $15/MWh nearly every month, averaging almost $11 per MWh.
    - Profitability is calculated based on the prices in PJM and IESO minus the Midwest ISO's wheeling charge.
    - If PJM priced the transactions at its Midwest ISO interface (instead of its current pricing method for IESO) the average profitability would drop to -0.52 per MWh.
    - Likewise, if these transactions had to pay for the congestion they cause in New York, many of them may not be profitable, which raises efficiency concerns.
    - 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.

Real-Time Ontario-PJM Wheels
Quantity and Profitability



Transaction Scheduling Around Lake Erie Conclusions

- Both the circuitous scheduling issues and these issues are attributable to the inconsistency between the contract path schedules and actual power flows associated with the schedules.
  - ✓ These inconsistencies produce loop flows that have costs that are not borne by the participants scheduling the transactions.
  - ✓ The loop flows also create uncertainties regarding available transmission capability that must be accounted for in the real-time market, day-ahead market, and FTR markets.
  - ✓ Phase angle regulators are in the process of being placed in operation (one of four is in service) that could help improve the consistency between the schedules and flows.
    - – However, this has been significantly delayed by the lack of necessary agreements between the relevant transmission owners/operators. The Midwest ISO is limited in its ability to facilitate these agreements.
- To address the scheduling and power flow issues around Lake Erie, we recommend the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements.
  - ✓ Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.

Real-time Prices and Interface Schedules

- The following series of figures evaluate the price convergence and net imports between the Midwest ISO and adjacent markets.
  - ✓ The left side of each figure is a scatter plot of the real-time price differences and the real-time net imports in unconstrained hours.
  - ✓ The right side of each figure shows the monthly averages for hourly real-time price differences between the adjacent regions and the monthly average magnitude of the hourly price differences (average absolute differences).
- In an efficient market, prices at the interface should tend to converge when the interfaces between the regions are not congested.
- Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to cause prices to converge between markets.
  - ✓ Given the uncertainty regarding the difference in prices (because the transactions are scheduled in advance), one should not expect perfect convergence.

Real-Time Prices and Interface Schedules PJM and Midwest ISO

The following figure presents results for the PJM interface.

- The right-hand panel in the following two figures shows that the Midwest ISO interface prices tended to be slightly higher than PJM's, except in late spring.
- The left-hand-side panel in the figure shows that participants have not been fully effective at arbitraging the prices between the two areas (one would expect scatter points to be much more clustered around a $0 price difference).
- To achieve better price convergence, we continue to recommend that the RTOs consider expanding the Joint Operating Agreement (JOA) to optimize the net interchange between the two areas.
  - ✓ Under this approach, participants' transactions would be financial. The RTOs would determine the optimal physical interchange based on the relative prices in the two areas.
  - ✓ This change would likely achieve the vast majority of any potential savings associated with jointly dispatching the generation in the two regions.
  - ✓ The Midwest ISO has begun investigating the means to implement this recommendation.

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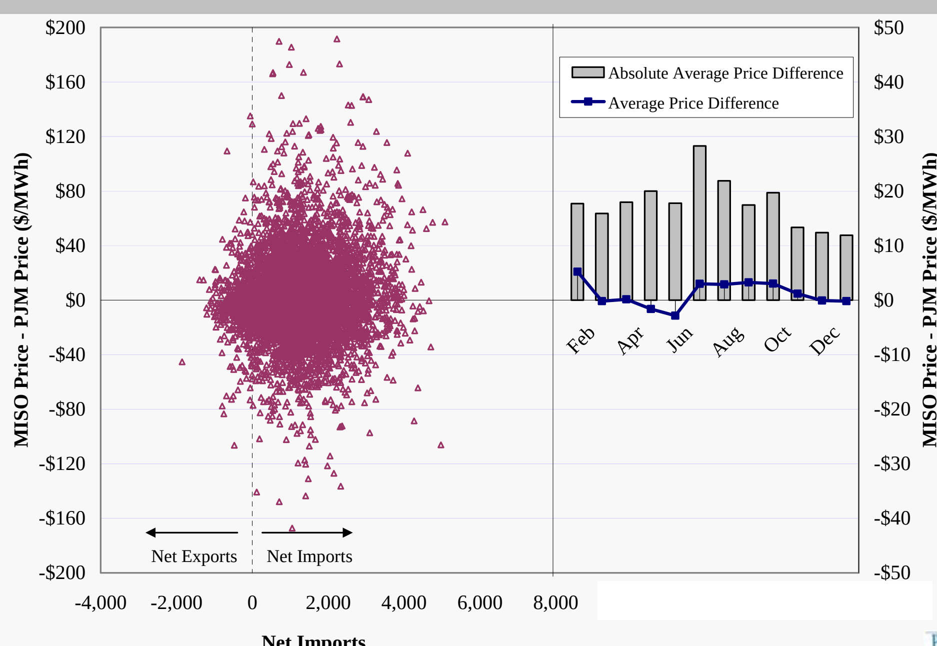
Real-Time Prices and Interface Schedules PJM and Midwest ISO



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Real-Time Prices and Interface Schedules IMO and Midwest ISO

- The next figure provides the same analysis for the Midwest ISO – IESO interface in the real-time market.
- The Midwest ISO was a net exporter of power to IESO in 2008, exporting an average of 400 MW.
  - ✓ On average, the Midwest ISO prices exceeded the IESO prices.
  - ✓ However, the difference was close to zero, in some months, and during September through November IESO prices were higher on average.
- The dispersion of prices shows that the schedules over this interface are relatively slow to respond to price differences.
- Interpreting these results is complicated by the fact that IESO does not have a nodal market so the IESO price may not fully reflect the true value of power imported from the Midwest ISO.

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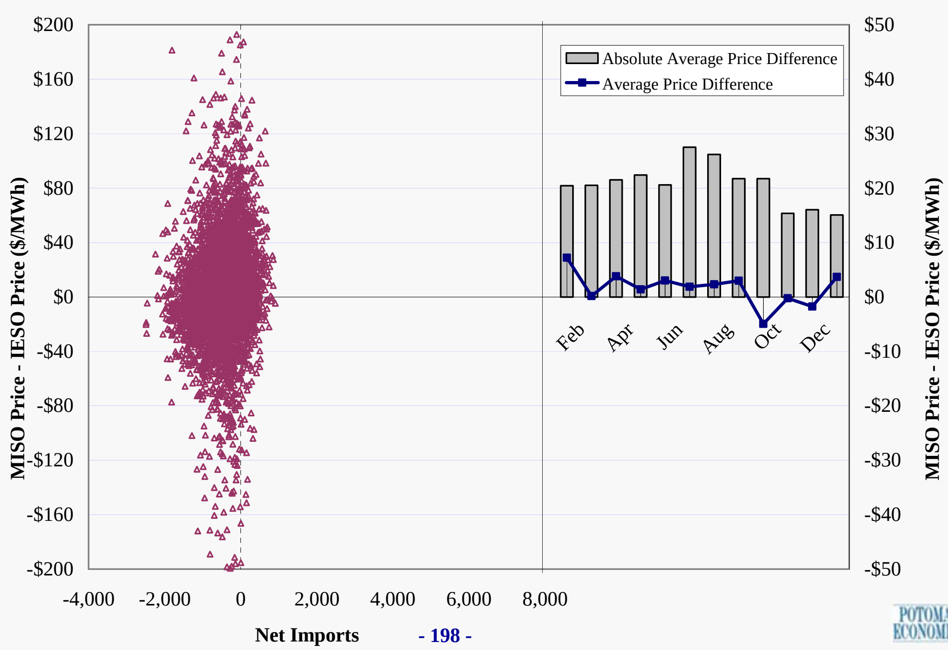
Real-Time Prices and Interface Schedules IESO and Midwest ISO



POTOMAC ECONOMICS

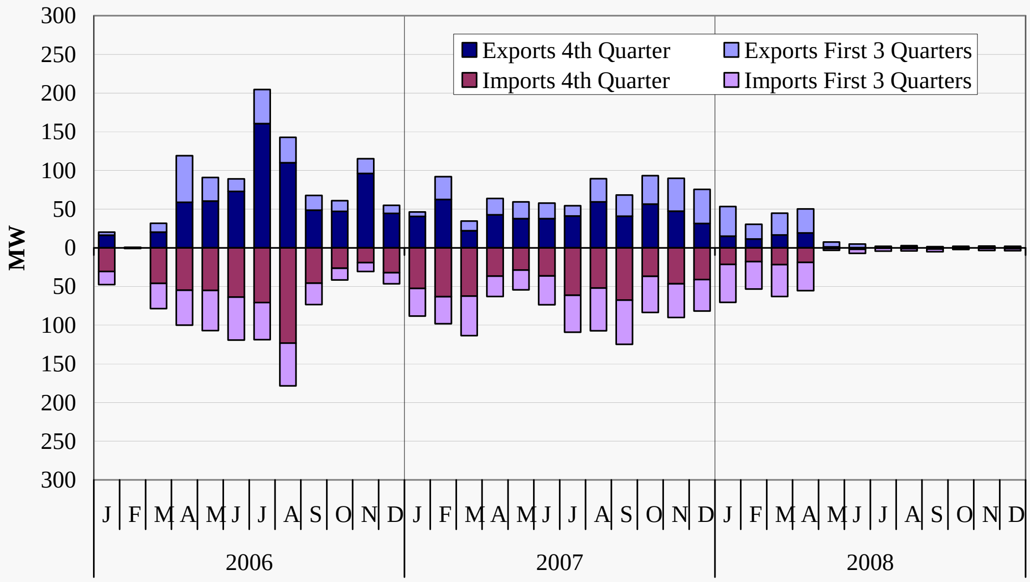
Intra-Hour Scheduling

- The last topic we address in this section of the report is intra-hour physical scheduling.
  - ✓ The Midwest ISO market rules permit physical scheduling on a time increment of as short as 15 minutes.
  - ✓ It should contribute to price convergence and efficient dispatch as market participants arbitrage the prices in adjacent areas.
- However, large changes in Net Scheduled Interchange caused by intra-hour schedules can lead to price volatility and operational challenges.
- Intra-hour schedules affect prices because Midwest ISO may have to ramp generation up or down substantially to accommodate the schedules.
- Intra-hour schedules settle at the average price in the hour in which they occur, which affects participants incentives:
  - ✓ If the schedule causes RSG, it may not bear the full costs because it is evaluated on an hourly average basis (400 MW export for 15 minutes is treated as a 100 MW hourly export).
  - ✓ A 15-minute schedule may be profitable on an hourly basis, even if it is inefficient and unprofitable during the 15-minute schedule period in which it occurs.

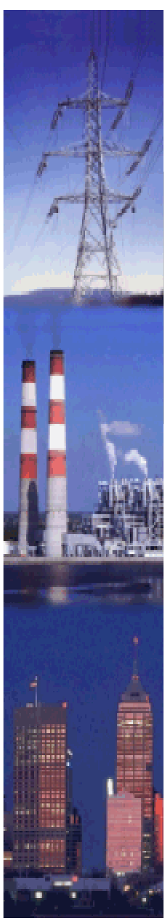
Intra-Hour Scheduling

- The majority of the intra-hour schedules occur with PJM.
- The following figure shows a summary of hourly average intra-hour scheduling for the past two years between Midwest ISO and PJM.
  - ✓ The chart shows the average intra-hourly scheduling occurring in the first 45 minutes of each hour and in the last 15 minutes of the hour.
  - ✓ While they are shown as hourly values, the imports and exports are not necessarily occurring in the same interval.
  - ✓ PJM, in coordination with the Midwest ISO implemented a prohibition against intra-hour scheduling in May 2008 by requiring that transactions be scheduled for at least one hour.
  - ✓ The figure shows a dramatic decline in 15-minute schedules corresponding with the PJM scheduling rule changes.
- Despite the decline in 15-minute schedules we still recommend that the Midwest ISO modify its scheduling deadline to not allow an entity to schedule a transaction beginning in the 4th quarter of the hour after it has seen the prices at the beginning of the hour that will be included in the hourly settlement for the transaction.

Intra-Hour Scheduling Levels



POTOMAC ECONOMICS



Participant Conduct and Mitigation

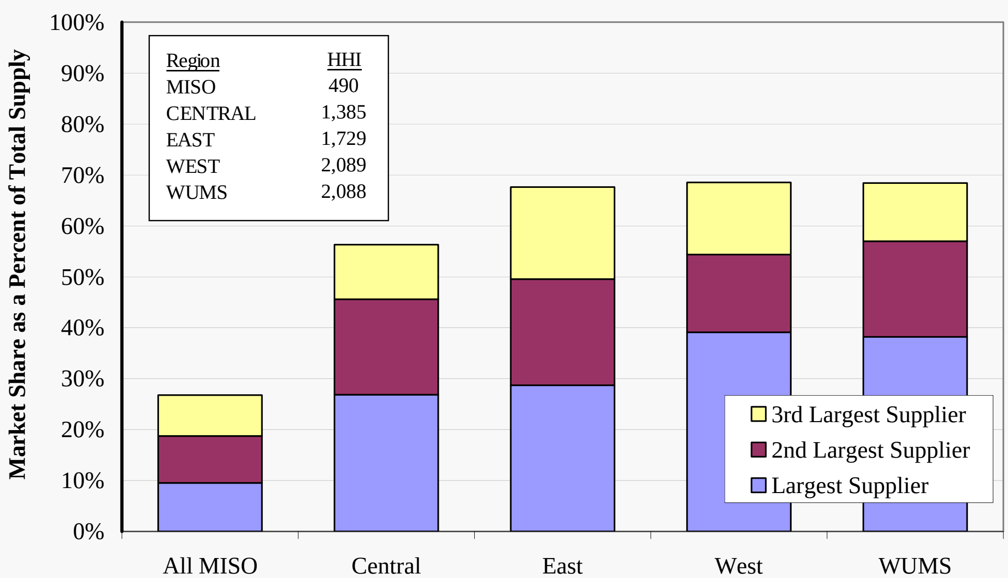
POTOMAC ECONOMICS

Market Concentration

- The analyses in this section of the report provide an overview of the competitive structure and performance of the Midwest ISO markets in 2008.
- The first analysis is of market concentration, measured using the Herfindahl-Hirschman Index ("HHI").
  - ✓ HHIs are calculated by summing the squares of each supplier's market share.
  - ✓ The antitrust agencies generally characterize markets with HHIs of greater than 1,800 as highly concentrated.
  - ✓ The HHI provides only a general indication of market conditions and is not a definitive measure of market power because it does not consider demand, network constraints, and load obligations.
- The market concentration of the entire Midwest ISO region is relatively low.
  - ✓ However, most of the Midwest sub-regions have HHI values close to or exceeding 1800 with the exception of the Central region.
  - ✓ The HHIs in Midwest ISO are higher than in some other markets because the vertically-integrated utilities in the Midwest have not divested substantial amounts of generation.

POTOMAC ECONOMICS

Market Concentration



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Residual Demand Index

- A better metric than the HHI for evaluating competitive issues in electricity markets is the residual demand index ("RDI"), which indicates the portion of the load in an area that can be satisfied without the largest supplier.
  - ✓ An RDI > 1 indicates that the load can be fully satisfied without the largest supplier's resources. An RDI < 1 indicates that a supplier is "pivotal", i.e., a monopolist over a portion of the load.
  - ✓ In general, the RDI will decrease as load increases since increasing quantities of rivals' generation will be needed to satisfy the load.
  - ✓ In calculating the RDI, we include all import capability into the area, not just the imports that were actually scheduled.
- The next figure shows the portion of hours when a supplier was pivotal.
  - ✓ The analysis shows a marked improvement in the competitive structure of WUMS.
    - – In 2007, at least one supplier was a pivotal in WUMS in a substantial share of hours any time the load in the Midwest ISO rose above 60 GW (more than 2/3rds of the time).
    - – In early 2008, transmission investments on the Minnesota to WUMS interface expanded import capability into WUMS, which improved the competitive structure substantially
  - ✓ The West and East regions exhibit a pivotal supplier in a significant share of the hours when load exceeds 80 GW (10 percent of the hours).
  - ✓ Overall, the figure shows a modest improvement in 2008 from 2007 is likely the result of lower load in 2008.

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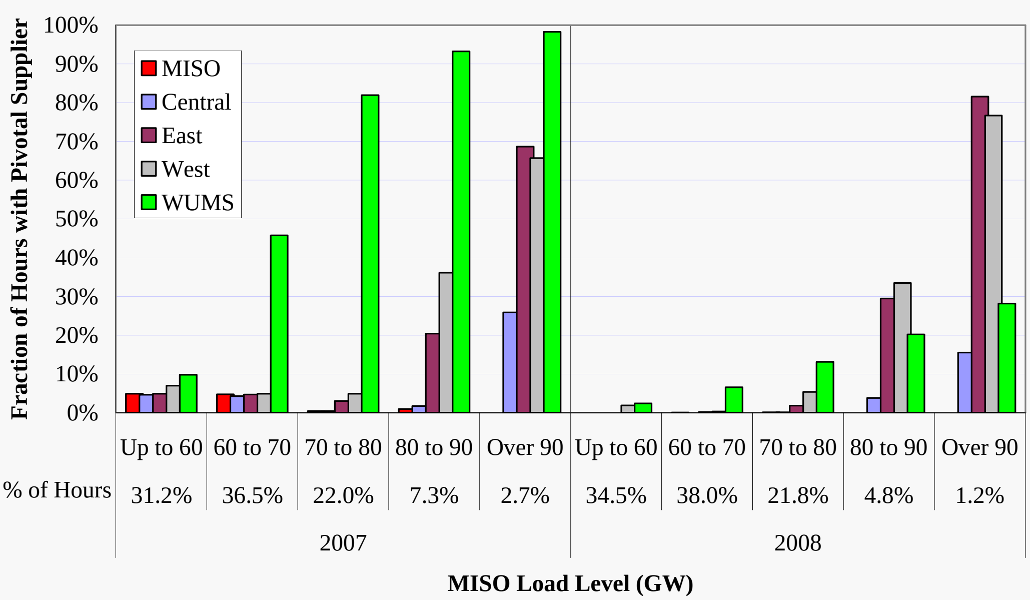
Residual Supply by Load Levels 2007-2008



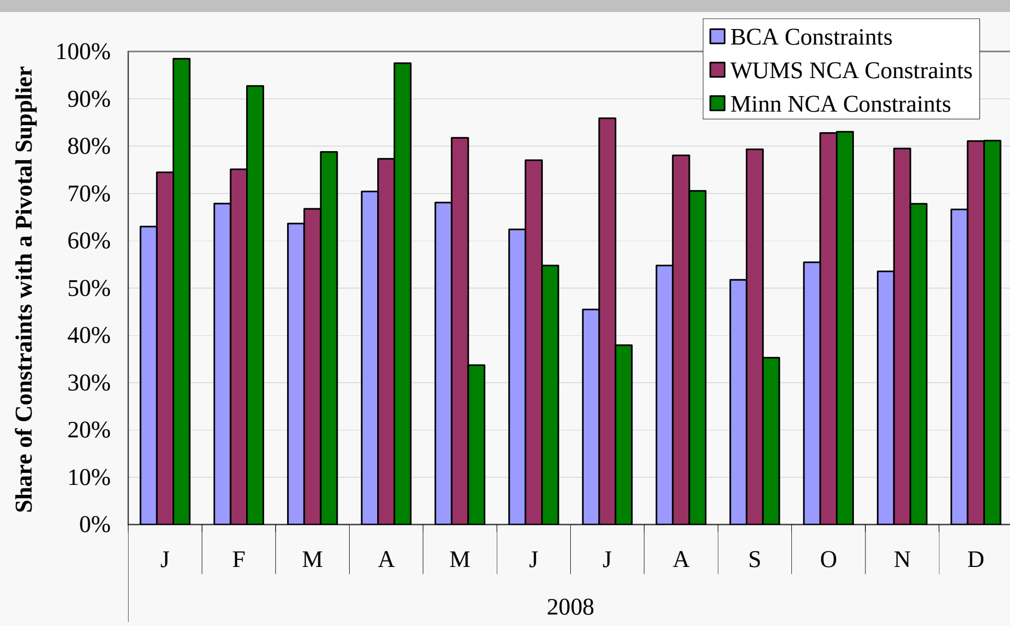
POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis

- We conducted a pivotal supplier analysis for individual transmission constraints in periods during which the constraints were active.
  - ✓ A supplier is pivotal for a constraint when its resources are needed to manage the transmission constraint (i.e., it has the ability to overload the constraint such that other suppliers cannot unload it).
  - ✓ This is frequently the case for lower voltage constraints because the resources that significantly affect the flows over the constraint are those that are near the constraint – if they are all owned by the same supplier, it is likely to be pivotal.
- The next figure shows the portion of active NCA constraints (WUMS and Minnesota) and BCA constraints (ISO-wide) that have at least one pivotal supplier.
- This figure shows that in 2008:
  - ✓ 79 percent of the active constraints into WUMS had a pivotal supplier.
  - ✓ 69 Percent of the active constraints into Minnesota had a pivotal supplier.
  - ✓ 59 percent of the active Midwest ISO BCA constraints had a pivotal supplier.
- These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2008 created significant potential for local market power.

POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis: Percent of Active Constraints with a Pivotal Supplier



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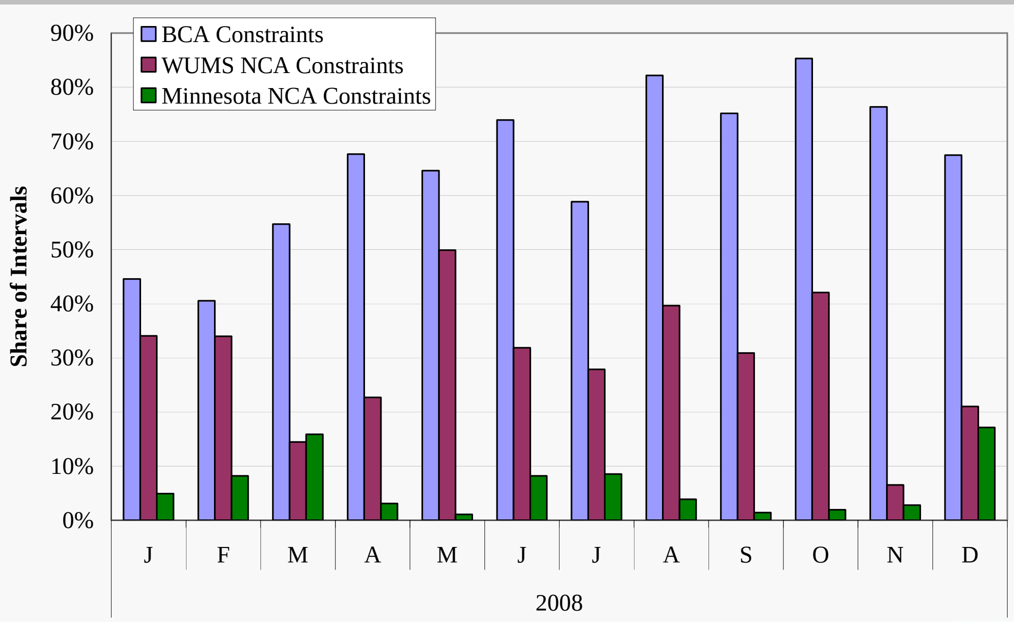
Constraint-Specific Pivotal Supplier Analysis

- The figure above showed that a supplier was frequently pivotal when a BCA constraint or NCA constraint was active.
- The next figure shows the percentage of intervals during the market's operation in 2008 when at least one supplier was pivotal for a BCA or NCA constraint.
  - ✓ This analysis varies from the prior analysis because it incorporates how frequently BCA and NCA constraints are active.
- This analysis shows that:
  - ✓ There was an active BCA constraint with at least one pivotal supplier in 66 percent of the hours during 2008.
    - – The regional distribution of BCA constraints varied throughout the year;
    - – The monthly frequency ranged from 40 percent to more than 85 percent.
  - ✓ The underlying data indicates that there was an active NCA constraint with a pivotal supplier in 30 percent of hours in WUMS and 6.5 percent in Minnesota in 2008.
- These results indicate that the BCA and NCA mitigation continues to be essential.

POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis: Percent of All Intervals with a Pivotal Supplier



POTOMAC ECONOMICS

Price-Cost Mark-Up

- The prior analyses (pivotal supplier and market concentration) are structural analyses intended to identify potential market power concerns.
- The remainder of this section evaluates the competitive performance of the market based on the conduct of the participants.
- The first analysis estimates a “mark-up” of real-time market prices over suppliers’ competitive costs.
- To produce a valid comparison, we estimate the system marginal price assuming that suppliers offer at prices equal to a) their reference levels, and b) their actual offers.
  - ✓ This analysis is a broad metric that does not account for physical restrictions on the units and transmission constraints, which would require re-running the market software.
- We performed this analysis for the past two years and found average annual mark-ups of:
  - ✓ Less than half of 1 percent in 2007; and
  - ✓ Approximately 1.1 percent in 2008.
- Given the many factors that can cause reference levels to vary slightly from suppliers’ true marginal costs, mark-ups this small indicate that the markets have performed very competitively over the timeframe studied.

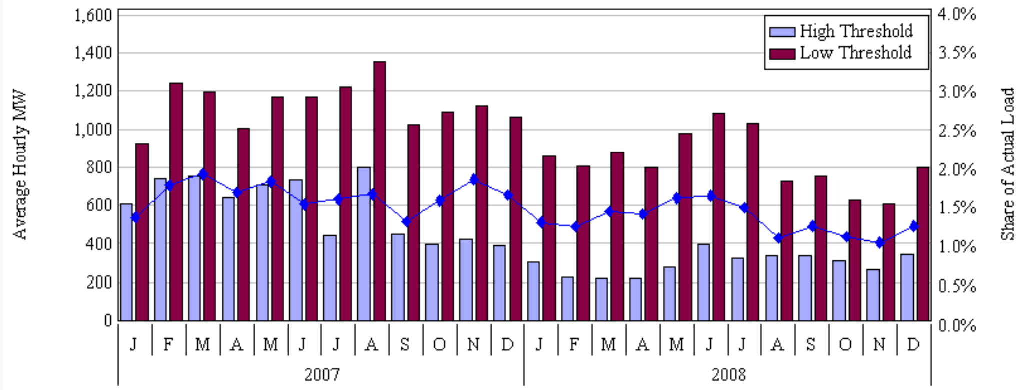
POTOMAC ECONOMICS

Economic Withholding: Output Gap Analysis

- Next we present a series of analyses on the conduct of suppliers in the Midwest ISO. These analyses seek to detect significant economic or physical withholding.
- We first analyze economic withholding, which occurs when a participant offers resources above competitive levels to raise energy prices or RSG payments.
- Economic withholding is measured using the “output gap” metric.
  - ✓ The output gap shows the quantity of output that is not produced when suppliers’ marginal costs are lower than the LMPs by more than a given threshold.
- This figure shows that:
  - ✓ The output gap declined between 2007 and 2008.
  - ✓ The 2008 output gap levels were slightly higher in the summer, but we judge the overall pattern to be relatively stable, which does not indicate significant evidence of economic withholding.
  - ✓ However, we monitor these levels continually and have investigated many specific output gap issues. In most cases, values can be explained by competitive factors.

POTOMAC ECONOMICS

Economic Withholding: Output Gap Analysis
Average of Daily Peak Hour



		J	F	M	A	M	J	J	A	S	O	N	D
2007													
Low Thresh	Commit	36	150	44	112	217	61	127	102	79	141	36	5
Low Thresh	On-Line	886	1,092	1,154	892	951	1,111	1,094	1,254	944	947	1,084	1,060
High Thresh	Commit	13	60	20	56	127	36	42	35	34	56	9	21
High Thresh	On-Line	597	682	733	586	580	697	401	767	416	341	411	356

		J	F	M	A	M	J	J	A	S	O	N	D
2008													
Low Thresh	Commit	35	35	47	91	89	112	130	102	84	146	126	222
Low Thresh	On-Line	825	771	828	708	888	971	897	625	671	484	479	579
High Thresh	Commit	17	10	25	16	31	26	73	79	65	124	83	110
High Thresh	On-Line	289	213	194	203	244	373	250	257	273	189	181	235

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Economic Withholding: Output Gap Analysis

- Despite the relatively low output gap levels shown in the prior chart, it is useful to also examine this metric by load level and size of participant.
  - ✓ The incentive to economically withhold supply generally increases under high load conditions when prices are most sensitive to such withholding. Additionally, large suppliers generally have a greater ability to increase prices.
  - ✓ Therefore, the following four figures show the output gap in each region by load level, separately showing the two largest suppliers in the region versus others.
- These figures show:
  - ✓ The output gap at both threshold levels are less than 1 percent at nearly all load levels and locations, with the exception of the West where lower thresholds are used.
  - ✓ The output gap tends to rise at higher load levels because the higher prices that occur at high load levels cause a much higher share of the resources to be economic.
    - – However, these levels are not high enough to raise economic withholding concerns.
  - ✓ With the exception of the West, the output gap quantities for the largest suppliers are not significantly higher than for other suppliers.
  - ✓ Overall, these results and our ongoing Monitoring and investigations of hourly results indicate that economic withholding has not been a concern in 2008.

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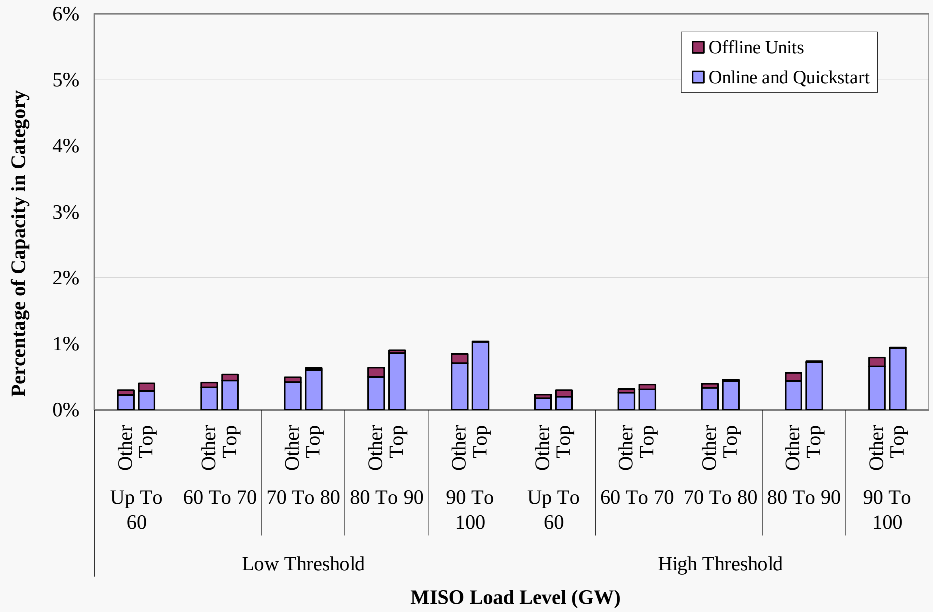
Real-Time Market Output Gap
Central: All Hours



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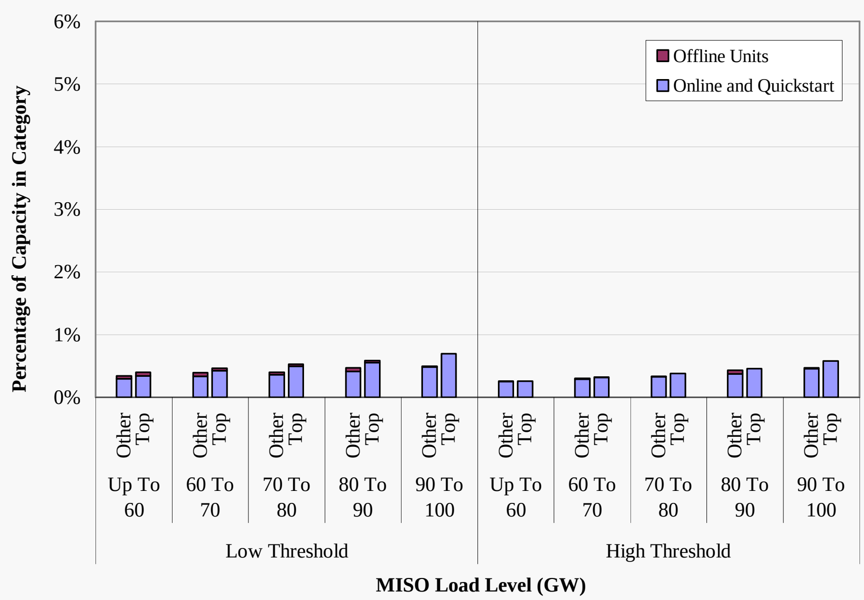
Real-Time Market Output Gap
East: All Hours



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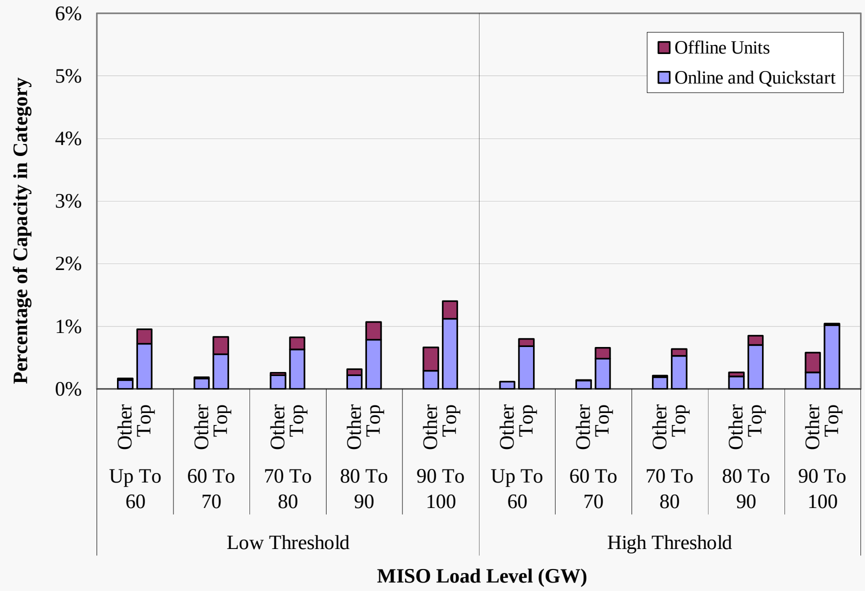
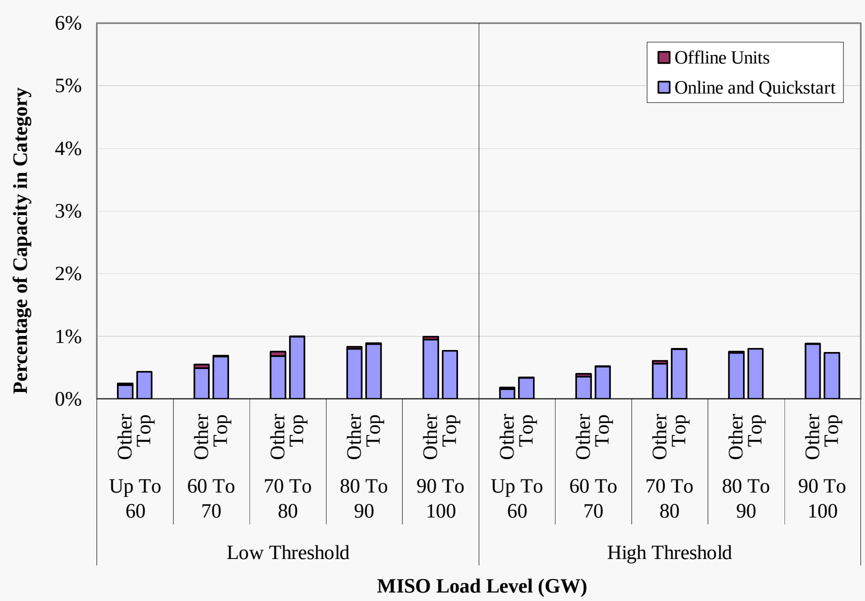
Real-Time Market Output Gap
West: All Hours



Real-Time Market Output Gap
WUMS: All Hours



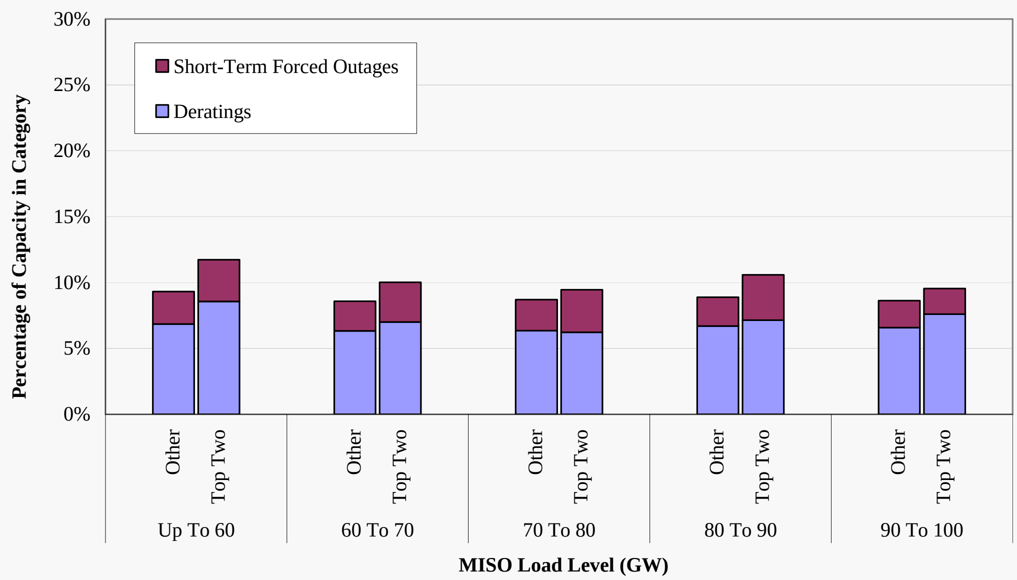
Evaluation of Outages and Partial Deratings

- While the prior analyses assessed offer patterns to identify potential economic withholding, the following analyses seek to identify potential physical withholding.
- Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output. This is accomplished by the supplier unjustifiably claiming an outage or derating the resource.
- Our physical withholding analysis is shown in the following figures for each region:
  - ✓ The figures show short-term forced outages (less than 7 days), and other deratings (excluding permanent deratings).
  - ✓ The data is shown by load level and for the largest two suppliers compared the other suppliers.
    - – The results are shown by load level because attempts to withhold would likely occur at high load levels when prices are most sensitive to withholding.
  - ✓ We focus primarily on short-term outages and partial deratings because withholding through long-term forced outages is less likely to be a profitable strategy.

Evaluation of Outages and Partial Deratings

- The results in the following figures do not raise substantial competitive concerns because:
  - ✓ The deratings and outages do not rise under peak load conditions in any region, generally remaining less than 15 percent; and
  - ✓ In the Central and East, the largest suppliers generally have the same or lower deratings and outages than other suppliers (that are less likely to have market power).
  - ✓ In the West and in WUMS, the largest suppliers generally have higher deratings and outages than other suppliers; but our review of these outages and deratings did not raise competitive concerns.
- We continue to investigate any outages or deratings that create substantial congestion or other price effects. Audits and investigations have not uncovered any significant attempts to physically withhold generation in 2008.

Real-Time Deratings and Forced Outages
Central: All Hours



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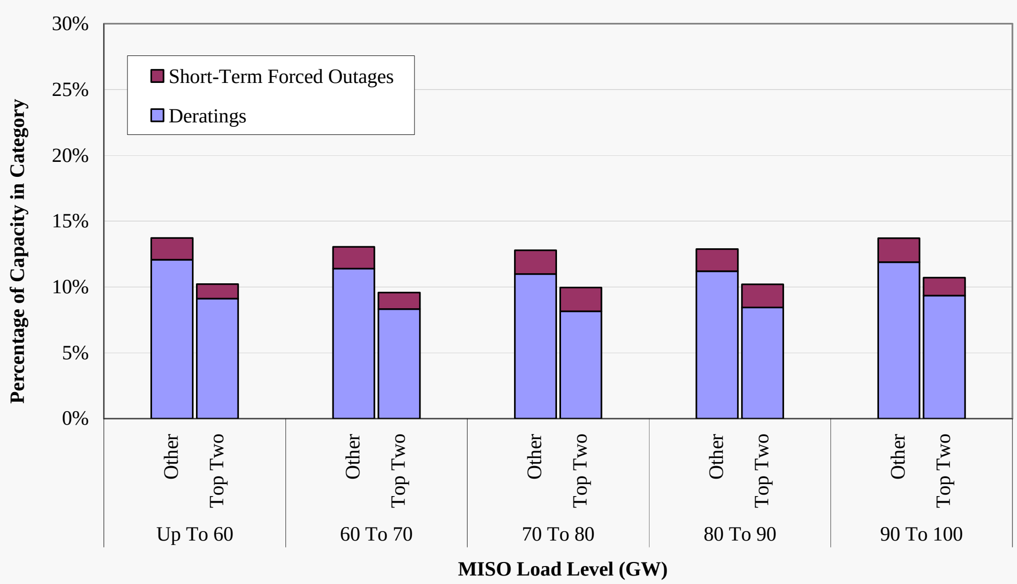
Real-Time Deratings and Forced Outages
East: All Hours



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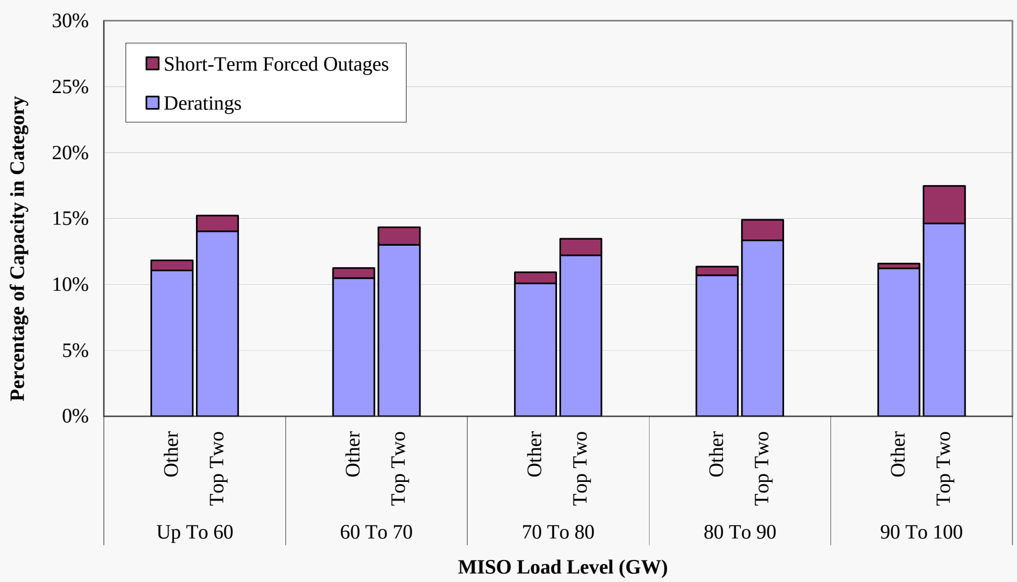
Real-Time Deratings and Forced Outages West: All Hours



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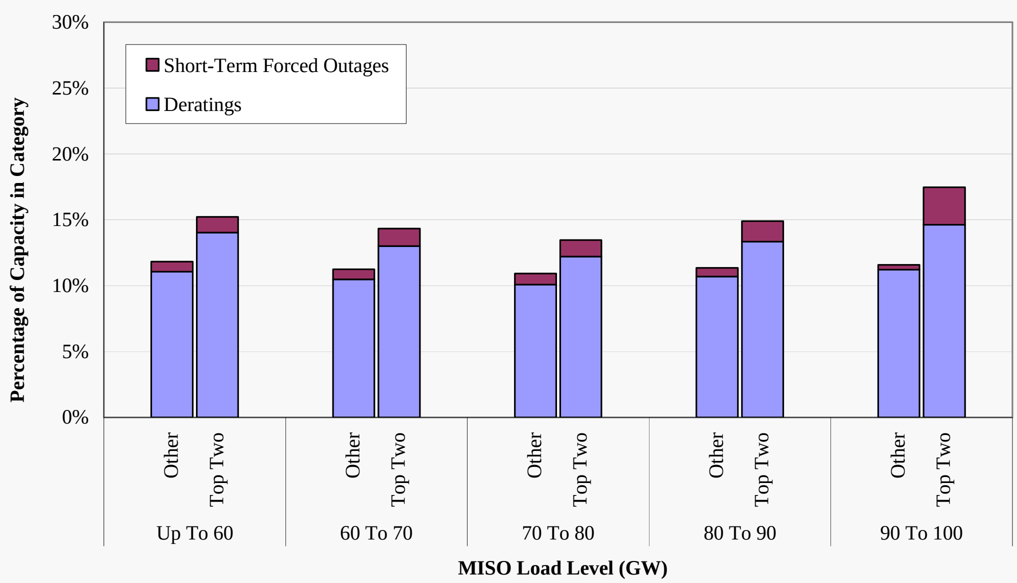
Real-Time Deratings and Forced Outages WUMS: All Hours



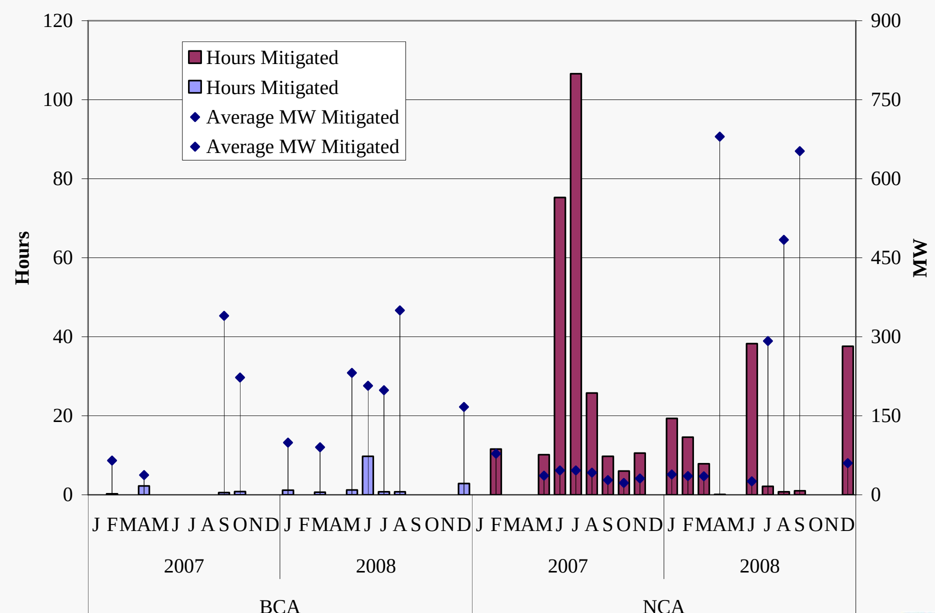
POTOMAC ECONOMICS

Real-Time Energy Mitigation by Month

- The final two figures in this section show the frequency with which mitigation has been imposed in the real-time market (no mitigation was imposed in the day-ahead market).
- The first figure shows the frequency and quantity of mitigation by month.
  - ✓ Mitigation caps a unit's offer price when it exceeds the conduct threshold and the offer raises clearing prices substantially – this process is nearly completely automated.
  - ✓ The first figure shows that NCA mitigation generally occurred more frequently than BCA mitigation in 2008. It also shows more NCA mitigation in 2007 than 2008.
  - ✓ Both classes of mitigation were relatively infrequent.
    - – 17 BCA unit-hours and 122 NCA unit-hours of mitigation occurred in 2008.
    - – Most of the mitigation occurred in June and December 2008 when 70 unit-hours of mitigation occurred.
    - – There was a decrease in the NCA mitigation in 2008, due in part to reduced congestion as a result of expanded transmission into WUMS.
- Although mitigation was relatively infrequent during 2008, the analyses above continue to show that local market power is a significant concern.
  - ✓ If exercised, local market power could have substantial economic and reliability consequences within the Midwest ISO market.
  - ✓ Hence, market power mitigation measures remain essential.

POTOMAC ECONOMICS

Mitigation in the Real-Time Energy Market by Month



POTOMAC ECONOMICS

Real-Time RSG Mitigation by Month

- In addition to the mitigation of energy offers shown in the prior figure, mitigation is also applied to offers that result in RSG payments.
- The next figure shows the frequency and amount by which RSG payments were mitigated in each month of 2007 and 2008.
- The figure shows that mitigation of RSG payments declined from 2007 to 2008. This is likely due to the mitigation criteria that must be satisfied:
  - ✓ The unit must be committed for a constraint or a local reliability issue.
  - ✓ The unit's offer must exceed the conduct threshold.
  - ✓ The effect of the inflated offer must exceed the impact threshold (i.e. to raise the unit's RSG payment by 200 percent on a BCA constraint).
- Mitigation occurred for seven unit-days and slightly more than $280,000 in 2008.
  - ✓ While mitigation of RSG was minimal, this does not indicate a lack of locational market power.

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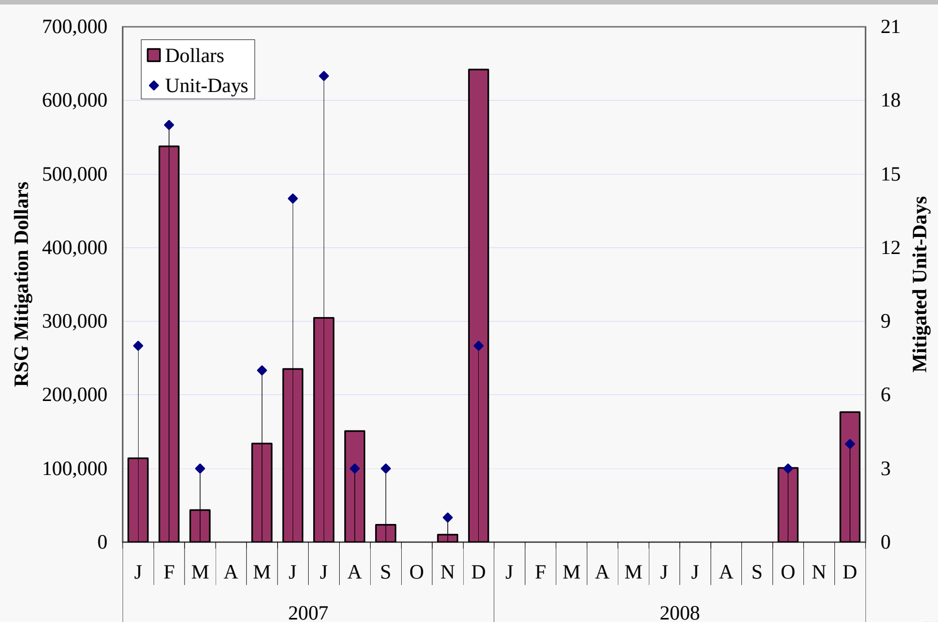
Real-Time RSG Mitigation by Month



POTOMAC ECONOMICS

Competitive Performance: Conclusions

- Our structural analyses indicate that there is substantial local market power within the Midwest ISO region.
- However, our analyses of participants' conduct and the market outcomes indicated that the market performed very competitively in 2008.
  - ✓ We estimated a price-cost mark-up of roughly one percent, confirming that the market outcomes in 2008 were very competitive.
  - ✓ We found little evidence of attempts by suppliers to withhold resources (either physically or economically) to exercise market power.
  - ✓ Hence, mitigation measures were employed infrequently to address economic withholding that would have increased energy prices or uplift costs.

Demand Response Programs

Demand Response Programs – Existing Programs

- The Midwest ISO has more than 8,600 MW of total demand response capability, most of which is interruptible load developed by utilities under regulated retail initiatives.
- Midwest ISO demand response resources consist of “Type I” and “Type II” resources.
  - ✓ Type I resources are resources capable of supplying a specific quantity of energy or reserves through load interruption.
    - – These resources must be notified well in advance and, therefore, are not generally responsive to prices (i.e., are “emergency” demand response interrupted for reliability).
  - ✓ Type II resources are capable of supplying energy and/or operating reserves over a dispatchable range, such as through controllable load or behind-the-meter generation.
    - – These resources can be dispatched on a five to fifteen minute basis that is comparable to generation so it can fully participate in the markets on a price-sensitive basis (i.e., “economic” demand response).
- Although the Midwest ISO allows Type II resources to directly participate in the energy and ancillary services, only 48 MW currently participate.
- Type 1 resources can sell supplemental reserves and emergency energy, which 1603 MW do currently. Module E of the Midwest ISO’s Tariff allows these resources and other emergency demand response to be used to satisfy an LSE’s capacity requirements.

Demand Response Programs

- The following table compares the Midwest ISO’s demand response programs to the demand response programs of ISO-New England and New York ISO.
  - ✓ The figure shows that the Midwest ISO utilizes emergency demand response and allows for direct participation of Type II resources.
- The second table shows the quantity of existing demand response resources in the Midwest ISO, ISO-New England and New York ISO.
  - ✓ The table shows that while the Midwest ISO has the greatest quantity of total demand response, it has the smallest amount enrolled in its ISO administered programs (48 MW of economic demand response and 1603 MW of emergency demand response).
  - ✓ The peak hour reduction in load achieved in 2006 (the last year that widespread emergency demand response was needed) ranged from 2 to 3 percent, with the Midwest ISO achieving 2.3 percent of the ISO’s peak load.
- The Midwest ISO has been active in facilitating demand response:
  - ✓ The Midwest ISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements.
  - ✓ It has filed tariff changes to allow retail aggregators to participate in the MISO markets.
  - ✓ The Midwest ISO is considering the modifications that would be necessary to allow load interruptions **and** other emergency actions to set prices in energy and reserve markets.

Comparison of ISO Demand Response Programs

	ISO-NE					NYISO				MISO	
	RT DRP	RT PRP	RT PrRP	DA LRP	DP	EDRP	SCR	DA DRP	DS ASP	EDR	DP
RT Energy Market			✓								✓
DA Energy Market				✓				✓			✓
Emergency	✓	✓				✓	✓			✓	
Capacity Market	✓	✓					✓				✓
Ancillary Services					✓				✓		✓

Table Key:

RT DRP = Real-Time Demand Response Program
RT PRP = Real-Time Profiled Price Response Program
RT PrRP = Real-Time Price Response Program
DA LRP = Day-Ahead Load Response Program
EDRP = Emergency Demand Response Program
ICAP/SCR = Installed Capacity/Special Case Resource Program
DA DRP = Day-Ahead Demand Response Program
DS ASP = Demand Side Ancillary Services Program
EDR = Emergency Demand Response
DP = Direct Participation
✓ = Existing Participation

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Comparison of Participation in ISO Demand Response Programs

	Program	ISO-NE	NYISO	MISO
Enrollment in ISO-Administered Programs	RTO Emergency (2008 MW)	1,634	2,108	300
	RTO/ISO Economic (2008 MW)	445	331	45
Enrollment in LSE-Administered Programs	Non-ISO Emergency (2008 MW)	270	200	8,600+
	Non-ISO Economic (2008 MW)			
Realized DR ISO	Annual Demand Response (2007 GWh)	235	Unknown	Unknown
	Peak Hour Reduction (2006 MW)	597	948	2,651
	Reduction as a percentage of Peak Load (2006)	2.1%	2.8%	2.3%

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