2007 State of the Market Report
Midwest ISO

Prepared by:

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Independent Market Monitor

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June 2008

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Executive Summary: Introduction

- As the Independent Market Monitor ("IMM") for the Midwest ISO, one of our roles is to evaluate the competitive performance, design, and operation of the wholesale electricity markets operated by the Midwest ISO.
  - ✓ This State of the Market report provides our annual evaluation of the Midwest ISO's 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.
- These markets will soon by augmented by:
  - ✓ Operating Reserves and Regulation markets (known as Ancillary Services Markets or "ASM") will be implemented in Fall 2008 that will optimize the allocation of the Midwest ISO's resources between the ASM and Energy markets.
  - ✓ Clarified capacity requirements and enforcement mechanisms that will ensure long-run economic signals 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
  - ✓ Much fuller 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.

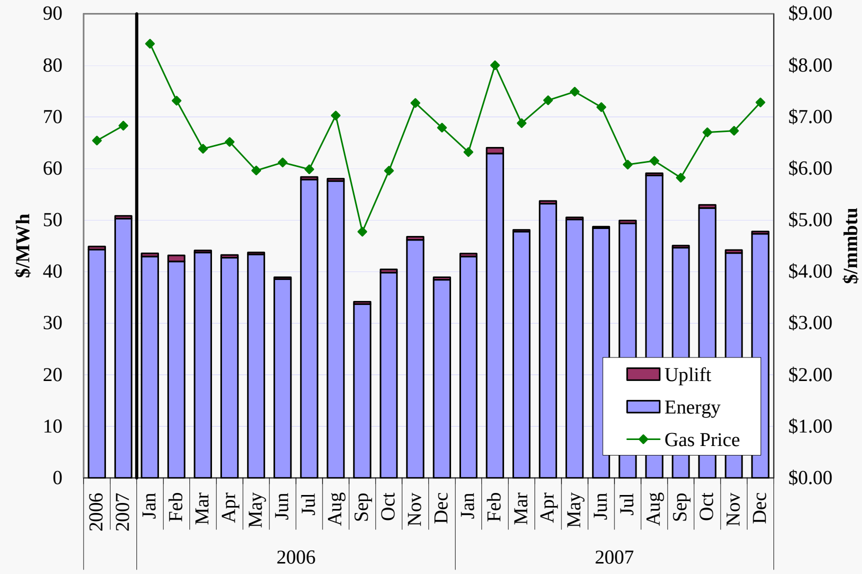
Executive Summary: Review of Results

- The Midwest ISO energy markets performed competitively in 2007.
  - ✓ Although certain suppliers in the Midwest ISO have local market power, there was very little evidence of attempts to exercise market power in 2007.
  - ✓ Hence, mitigation measures were employed infrequently to address economic withholding that would have increased energy prices or uplift costs.
    - – The most frequent mitigation occurred in Minnesota in a new Narrow Constrained Area ("NCA") defined in January 2007.
- Higher fuel prices, particularly oil and gas prices, played a primary role in the 13 percent increase in average energy prices in 2007 and other rising costs, including:
  - ✓ A 26 percent increase in uplift costs associated with revenue sufficiency guarantee payments ("RSG") that was due to higher fuel prices and increased commitment of peaking resources to manage congestion.
  - ✓ A 28 percent increase in congestion costs that was due to the increased redispatch costs caused by higher fuel prices and other factors discussed in the report.
- The remainder of this executive summary provides our assessment of the performance of the markets in 2007 and recommendations for improvements.

Executive Summary: Energy Prices

- The first figure shows an "all-in" price that represents the value load served based on prices in the real-time market.
  - ✓ The all-in price is equal to the load-weighted average real-time price and average real-time uplift per MW of load in the real-time.
  - ✓ The figure also shows the monthly average natural gas prices.
- The figure shows that the all-in price was $51 per MWh in 2007, which is 13 percent higher than the all-in price in 2006.
  - ✓ This increase was primarily due to increases in fuel costs, load and transmission congestion that occurred in 2007.
  - ✓ Uplift costs are 1 percent of the all-in price, which is similar to RSG costs in 2006 and substantially lower than uplift levels in 2005.

All-In Price
2006 & 2007



Note: The All-In Price is computed by calculating a load-weighted average real-time energy price, plus a load-weighted real-time RSG allocation rate.

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Executive Summary: Energy Prices

- The next figure shows that natural gas prices were a primary driver of energy prices. This is expected when the market is performing competitively because:
  - ✓ 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 weaker during the summer months when prices did not fall with the decreasing natural gas prices. Higher loads that prevail during the summer offset the effects of the lower fuel prices.
- Prices were generally highest during the summer, driven primarily by high load. However, the highest-priced month was February 2007, which experienced extreme winter peak load conditions that contributed to energy emergencies on three days.
  - ✓ Operational improvements made after the summer peak event of 2006 allowed the Midwest ISO to take more targeted actions, particularly when it curtails load.
  - ✓ However, our analysis indicates that prices during the winter peak event in February did not rise efficiently to reflect the near shortage conditions.
- The differences between the hub prices shown in the following figures indicate the transmission congestion on the Midwest ISO system.
  - ✓ Prices in WUMS were relatively high due to congestion occurring throughout the year.
  - ✓ The West Region experienced high prices due to substantial congestion early in the year as imports decreased over the Manitoba interface.

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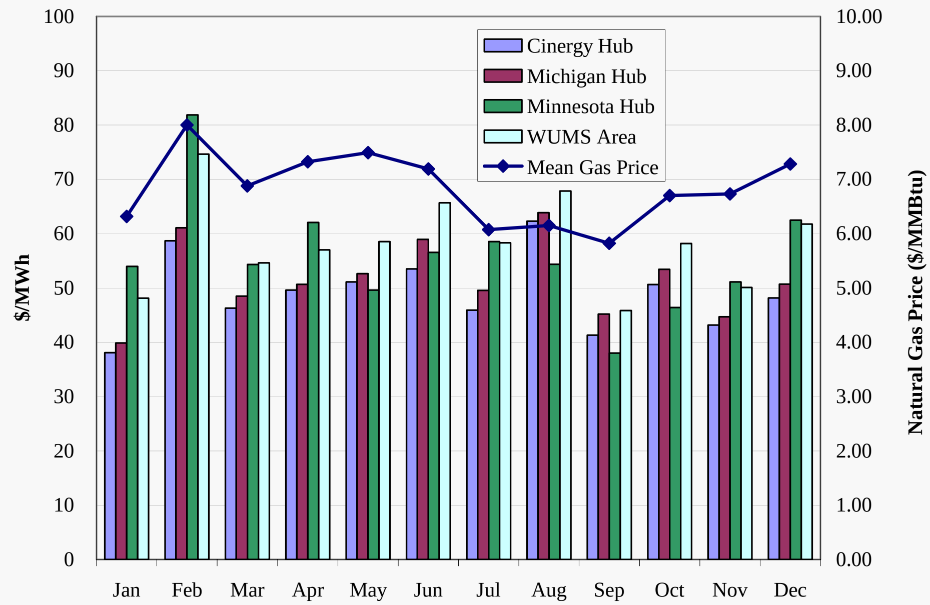
Day-Ahead Average Monthly Hub Prices 2007: All Hours



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Executive Summary: Revenue Sufficiency Guarantee Payments

- The accompanying figures show revenue sufficiency guarantee ("RSG") payments generated in the day-ahead and real-time markets 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 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 is generated in it – a unit that is uneconomic will generally not be selected.
- Of total RSG costs paid, 70 percent is real-time RSG and payable to peaking resources, 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.
- Real-Time RSG costs rose from $18.4 to $25.2 million per month from 2006 to 2007.
  - ✓ This was due to higher fuel prices and increased commitment of peaking resources to manage congestion in the West.
  - ✓ RSG peaked in February 2007 because high winter peak loads, under-scheduling by loads, and congestion into the West together resulted in heavy reliance on peaking resources.
- Day-Ahead RSG declined from more than $40 million in 2006 to $26.4 million in 2007. RSG in the Day-Ahead market continues to reflect a small share (8%) of total uplift costs.

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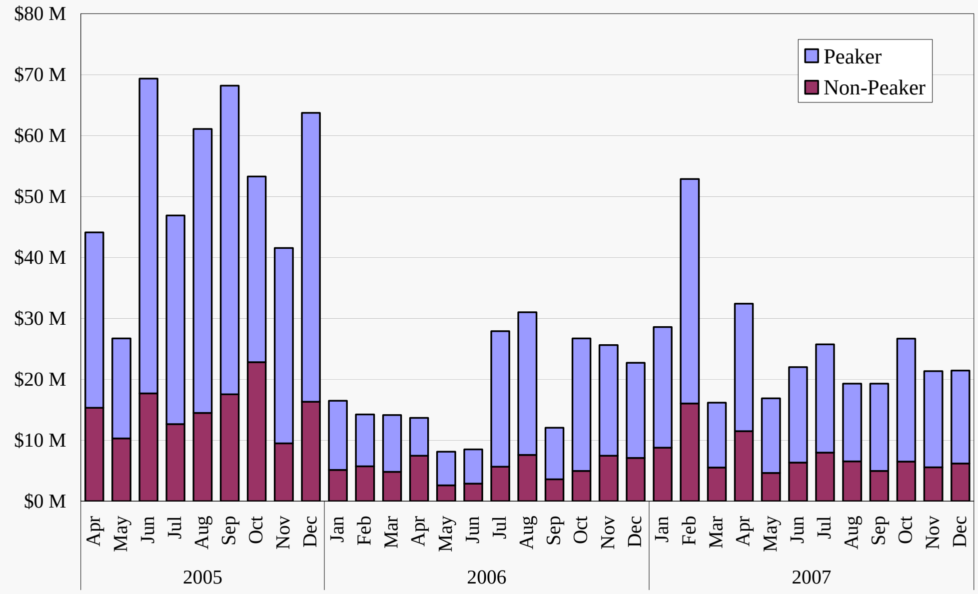
Total Real-Time RSG Distribution April 2005 through December 2007



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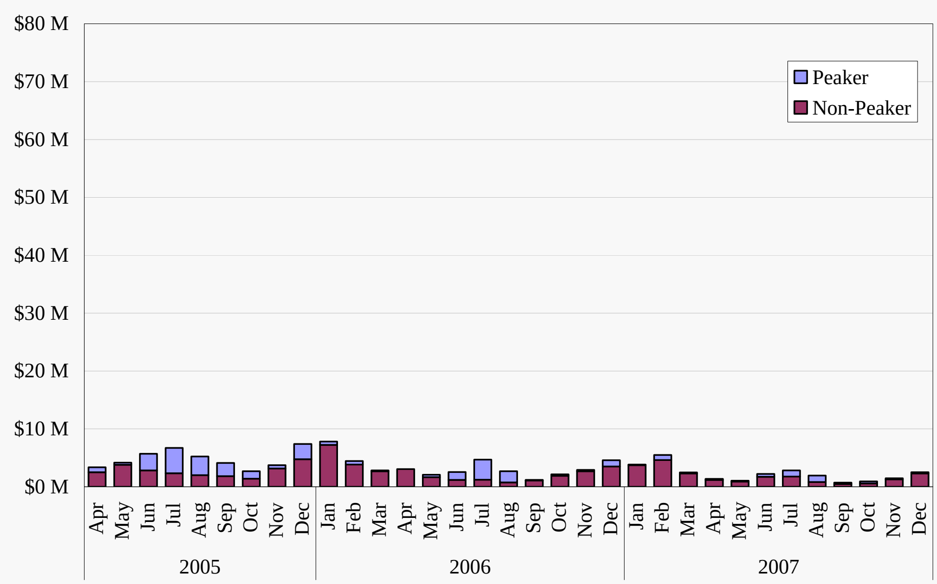
Total Day-Ahead RSG Distribution April 2005 through December 2007



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Executive Summary: Long-Term Economic Signals

- 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 over the first nine months of operation in 2005 through 2007 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, but may support investment in combined cycle generation in the congested areas.
- These results are consistent with expectations because:
  - ✓ The Midwest ISO footprint has a small capacity surplus that contributed to no significant periods of shortage occurring in 2007.
  - ✓ The current markets do not fully price shortages when they occur because operating reserve shortages and interrupted load do not contribute to setting prices.
  - ✓ The ASM markets 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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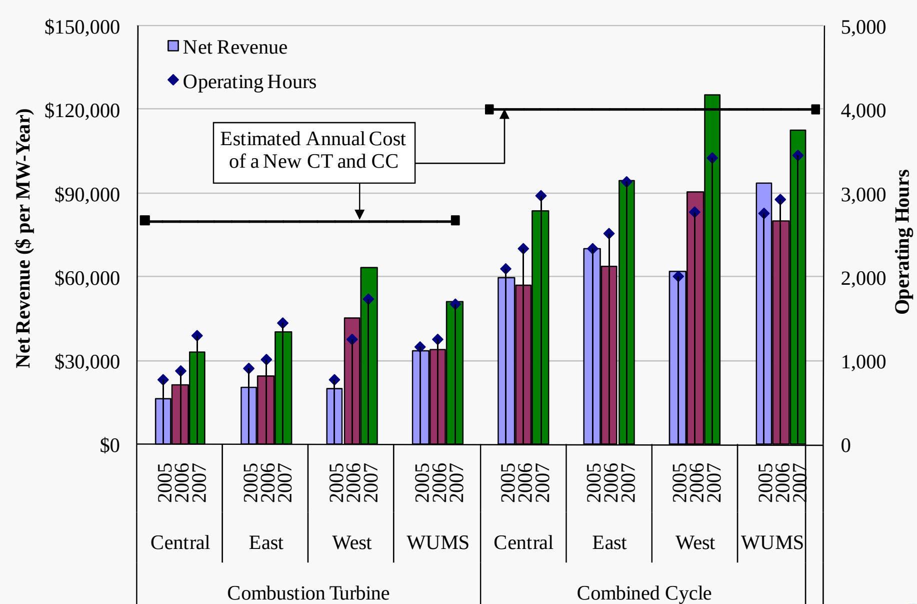
Executive Summary: Economic Signals



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Executive Summary: Day-Ahead Market Performance

- The Midwest ISO markets have substantially improved the commitment and dispatch of generating resources in the Midwest.
  - ✓ The improved commitment is largely attributable to the day-ahead market.
  - ✓ The day-ahead market provides a market-based process to commit generating resources and supply load – 97 percent of the generation dispatched to meet load in 2007 was scheduled through the day-ahead market.
- Net load scheduled in the day-ahead market decreased slightly in 2007 and remained moderately under-scheduled (i.e., less than real-time load). Under-scheduling was generally more prevalent under the highest load conditions.
  - ✓ These results are consistent with the relative prices in the day-ahead and real-time markets.
  - ✓ If load were fully scheduled in the day-ahead market, prices would be substantially higher in the day-ahead market than in the real-time market because:
    - – Supplemental generator commitments by MISO and Participants that occur after the day-ahead market tend to lower real-time prices.
    - – Peaking resources frequently do not set prices in the real-time market due to their inflexibility, which causes prices to be lower in real-time.

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).
- Good convergence between day-ahead and real-time prices helps ensure efficient commitment decisions. The following table summarizes convergence results for 2007.
  - ✓ These analyses indicate that price convergence in the Midwest ISO has been consistent with the other RTO markets, which have each been operating longer.
  - ✓ The congested areas exhibited larger average absolute differences, ranging from $18 to $22 per MWh. This is consistent with the higher volatility in these areas.
  - ✓ The day-ahead premiums in the Midwest ISO and most other markets are consistent with the higher volatility, risk, and RSG cost associated with buying in the real-time market.
  - ✓ Active virtual supply and demand participation in the day-ahead market has contributed to the price convergence exhibited in the Midwest ISO.

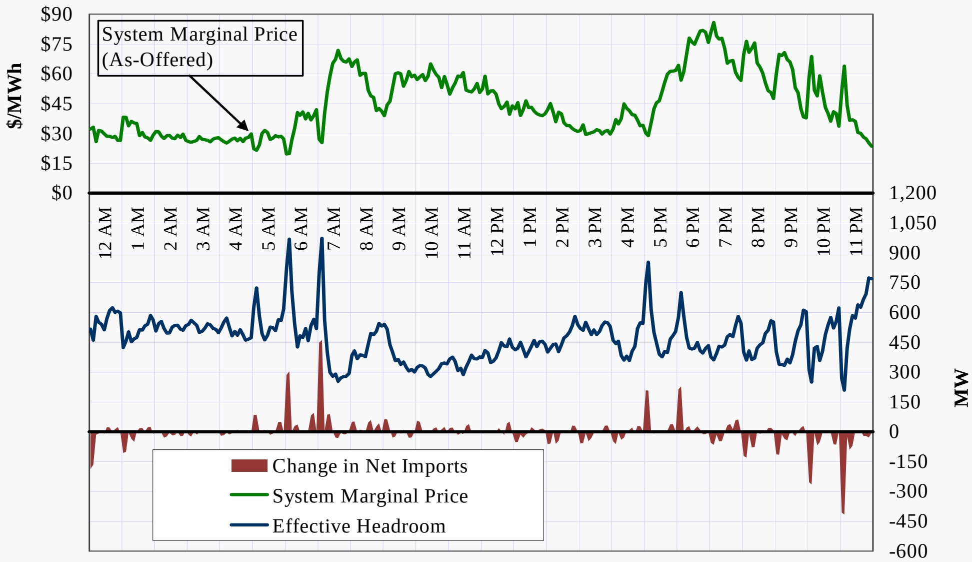
Day-Ahead to Real-Time Price Differences in 2007 MISO and Neighboring Markets

	Average Clearing Price			Average of Hourly
	Day-Ahead	Real-Time	Difference	Absolute Price Difference
Midwest RTO:				
Cinergy Hub	$46.07	$45.62	$0.38	$14.31
Michigan Hub	$48.47	$47.57	$0.84	$15.28
Minnesota Hub	$51.97	$50.24	$1.64	$20.50
WUMS Area	$54.75	$53.52	$1.17	$18.94
New England ISO:				
New England Hub	$67.97	$66.72	$1.25	$10.26
Maine	$64.35	$63.65	$0.69	$9.92
Connecticut	$71.70	$71.75	-$0.06	$12.93
New York ISO:				
Zone A (West)	$53.02	$52.35	$0.67	$15.66
Zone G (Hudson Valley)	$72.26	$72.54	-$0.27	$20.62
Zone J (New York City)	$77.21	$77.60	-$0.39	$22.58
PJM:				
AEP Gen Hub	$43.38	$44.15	-$0.76	$11.41
Chicago Hub	$45.40	$45.76	-$0.36	$11.84
New Jersey Hub	$63.45	$65.63	-$2.17	$18.45
Western Hub	$56.91	$59.77	-$2.85	$17.02

Executive Summary: Real-Time Market Performance

- Prices in the real-time market are substantially more volatile than in the day-ahead market.
- 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:
  - ✓ Unlike some of the RTOs, the Midwest ISO runs a true 5-minute real-time market. It produces a new dispatch and prices each 5 minutes.
    - – However, because the real-time market software is limited in its ability to look ahead, the system is frequently "ramp limited" (generators are moving as quickly as they can up or down), which results in transitory sharp movements in prices up or down.
  - ✓ Large changes in the Net Scheduled Interchange ("NSI") or changes that occur when a large quantity of generators are started or shut-down can cause ramp constraints to bind.
- The following figure shows average real-time prices by time of day in the winter, together with the effective headroom on the system (the amount of generation that can be utilized in the next five minutes accounting for ramp limits and dispatch limits) and the average change in NSI. It shows:
  - ✓ The changes in real time prices are directly related to changes in effective headroom.
  - ✓ A substantial portion of the change in effective headroom are related to change in NSI.
- The report contains some recommendations that should reduce the volatility of the NSI.

Real-Time System Marginal Price versus Headroom and Imports



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Executive Summary: Dispatch of Peaking Resources in Real Time

- The dispatch of peaking resources are an important component of the real-time market because they are a primary cause of RSG and a determinant of efficient price signals.
  - ✓ On a daily average basis, the dispatch of peaking resources averaged 433 MW per hour in non-summer days and almost 1000 MW per hour during the summer. However, on a number of peak load days, the average dispatch was as high as 5000 to 7000 MW per hour.
  - ✓ These dispatch levels are similar to those in 2006 and much lower than the levels in 2005. Higher net load scheduling in the day-ahead market and improved commitment of peaking resources by the Midwest ISO operators are responsible for the decrease.
- Our analysis shows a large share of the peaking resources are dispatched out-of-merit (offer > LMP), indicating that they frequently do not set the energy price.
  - ✓ OOM dispatch results in higher RSG to ensure the peaking resources recover their as-offered costs.
  - ✓ This also contributes to the under-scheduling of load in the day-ahead market.
  - ✓ Peaking resources are generally the lowest-cost means to serve the load not scheduled day-ahead – if they do not set prices (i.e., prices are set at a lower level by a non-peaker), it 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.

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Executive Summary: Generating Capacity and Reserve Margins

- Generating resources in the Midwest ISO market totaled almost 126 GW in 2007.
- The maximum capacity levels planners assume can be optimistic if all deratings are not fully reflected, particularly those that tend to occur under hot conditions.
- The following table shows the capacity levels, internal demand, and resulting reserve margins for each region, including projected additions and retirements to summer 2008.
  - ✓ Internal demand is internal load less the sum of behind the meter generation, interruptible load and other demand side response capability.
  - ✓ The reserve margin is equal to: (Capacity plus Firm Imports ÷ Demand or Load) – 1.
- The table shows that reserve margins in 2008 are highly sensitive to the assumed maximum capacity levels and whether interruptible demand is included.
  - ✓ Reserve margins based on nameplate capacity ratings indicates a substantial surplus.
  - ✓ When one removes the deratings and temperature sensitive capacity that may not be available at peak, the reserve margin ranges from 10 to 19 percent (the higher margin includes interruptible load). Margins are much tighter in the East and Central.
  - ✓ This indicates that real-time conditions may be relatively tight -- forced outages (avg. 5 percent) and operating reserves (3 percent) will utilize most of the remaining capacity surplus on generating units so that calling on interruptible load is likely.
- Although the system's resources are adequate for this summer, new resources will likely be needed soon. Hence, it is important for the market's economic signals that govern new investment and retirement decisions to be efficient.

Generation Capacity and Reserve Margins Estimates for 2008

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temperature Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	39,268	1,271	42,396	11.2%	39,484	3.8%	38,915	2.3%
Internal Demand[3]	36,221	1,271	42,396	20.6%	39,484	12.5%	38,915	10.9%
Central								
Internal Load	39,084	711	44,925	16.8%	41,144	7.1%	39,762	3.6%
Internal Demand	37,285	711	44,925	22.4%	41,144	12.3%	39,762	8.6%
West								
Internal Load	20,803	3,119	23,962	30.2%	19,304	7.8%	19,304	7.8%
Internal Demand	18,670	3,119	23,962	45.1%	19,304	20.1%	19,304	20.1%
WUMS								
Internal Load	13,554	1,189	15,921	26.2%	15,329	21.9%	14,763	17.7%
Internal Demand	12,287	1,189	15,921	39.3%	15,329	34.4%	14,763	29.8%
MISO								
Internal Load	108,255	6,290	127,204	23.3%	115,261	12.3%	112,744	10.0%
Internal Demand	100,009	6,290	127,204	33.5%	115,261	21.5%	112,744	19.0%

[1] Estimated by the Midwest ISO using Day Ahead Market offer data and observed derates in 2007. Midwest ISO Summer Relibility Assessment 2007. Includes known planned outages for 2008.

[2] The Midwest ISO estimated derates from Nameplate and for temperature are included in the Available Capacity. We have estimated additional High Temperature derate based on capacity offered on August 1, 2006 for units available in the Day-Ahead market.

[3] Net Internal Demand is internal load less behind-the-meter load and demand-side management.

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.
  - ✓ The next figure shows that total congestion costs in the day-ahead and real-time markets were just over $713 million in 2007, an increase of more than 25 percent from 2006.
  - ✓ The increase was primarily due to:
    - – Higher fuel prices in 2007, which increased redispatch costs.
    - – Reduced imports over the Manitoba interface and certain outages that increased congestion into the West (the Minnesota NCA) during the first half of the year.
  - ✓ Nearly 90 percent of total congestion was captured in the Day-Ahead market, a marked improvement from 2005 and 2006. Residual real-time congestion generally occurs when the day-ahead modeling of the network is not consistent with real-time system.
    - – Hence , the reduction in residual real-time congestion indicates that the Midwest ISO's day-ahead modeling has improved.
- There were a number of instances when the real-time market model was unable to reduce the flow below the transmission limit.
  - ✓ 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 a certain modeling methods are the two factors that primarily contribute to these instances.
  - ✓ The report includes recommendations to address this issue.

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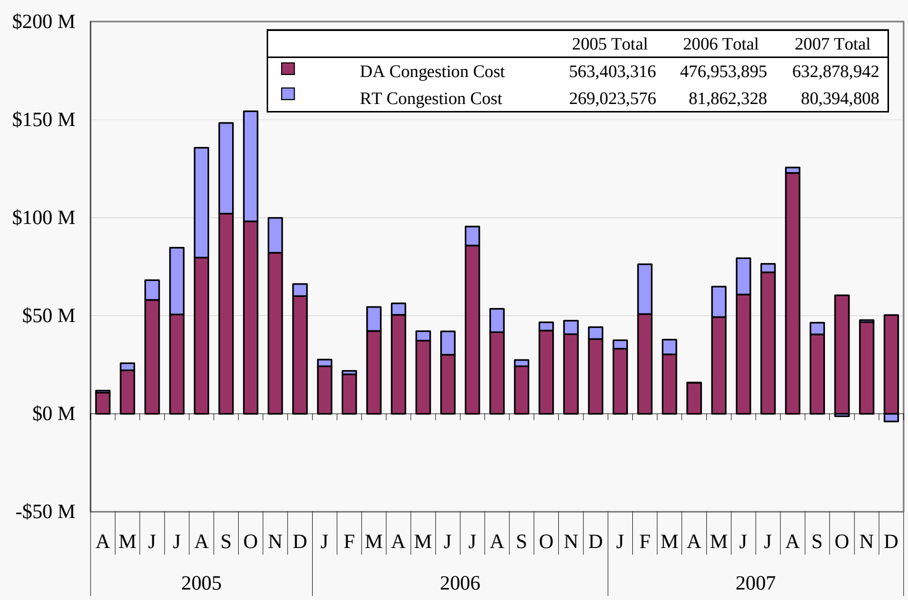
Total Congestion Costs April 2005 through December 2007



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Executive Summary: Manageability of Transmission Constraints

- More than 25 percent of the binding transmission constraints could not be managed on a five minute basis (real-time redispatch could not reduce flow below the limit).
  - ✓ 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 constraint’s limit for purposes of calculating a shadow price for the constraint and associated LMPs.
- These instances result in substantial price movements and often require operators to take other actions to maintain reliability. The primary causes of these instances are:
  - ✓ Generator inflexibility (offer parameters that provide little redispatch capability); and
  - ✓ A modeling parameter that causes the market software not to redispatch generation that has small effects on the transmission constraints.
- Both of these factors are being addressed this year through:
  - ✓ Implementation of the Price Volatility Make While Payments (with ASM) that will ensure flexible suppliers are not harmed when prices and dispatch signals are changing rapidly.
  - ✓ Reduction in the modeling parameter described above, which the Midwest ISO plans to accomplish over the next few months.
- Finally, our analysis of the constraint relaxation algorithm suggests that it often produces inefficient shadow prices and associated LMPs (more than 20 percent of the violated constraints are relaxed to a zero shadow price, indicating no congestion). Our recommendations address this problem.

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Executive Summary: Transmission Congestion

- The value of congestion in the real time (based on the shadow prices and flows over each constraint) was estimated to be $984 million in 2007, up from $960 million 2006.
  - ✓ This value is larger than the congestion collected by Midwest ISO because there are a large flows (“loop flows”) created by the production and consumption of energy in other areas.
  - ✓ The Midwest ISO does not collect congestion rent on the loop flows.
- The following figure also shows the value of real-time congestion by region.
  - ✓ More than 94 percent of the value of real-time congestion occurred on internal Midwest ISO constraints.
  - ✓ The remaining congestion occurred on external constraints for which the Midwest ISO redispatches generation, including:
    - – PJM market-to-market constraints; and
    - – Constraints in other areas for which transmission line loading procedures are called to manage congestion.
- As expected, congestion values increase under summer peak load conditions. Congestion values remained high into the fall due to the increased congestion into Minnesota.

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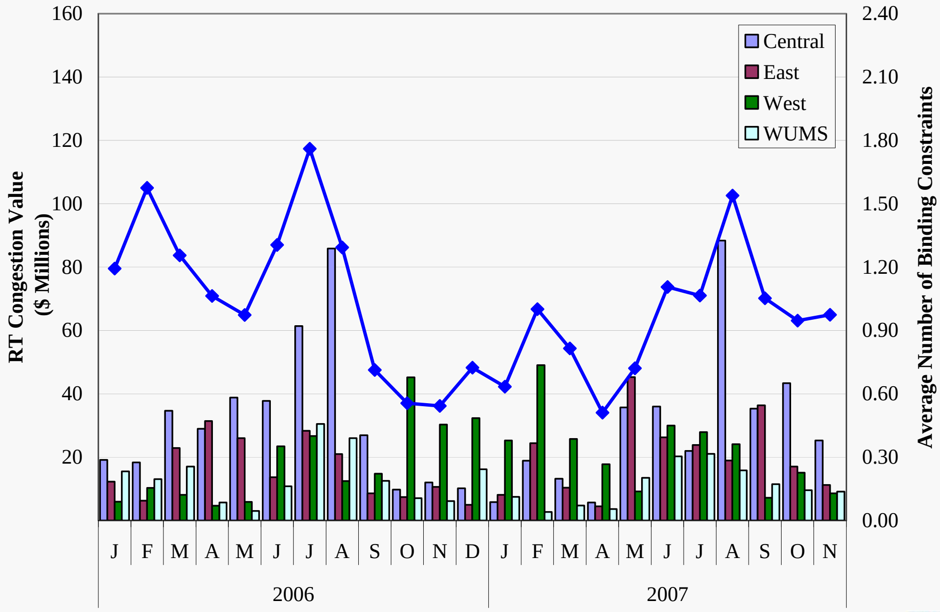
Value of Real-Time Congestion by Coordination Region 2006 and 2007



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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 2007 – i.e., day-ahead congestion 19 percent less than the obligations due to FTR holders in 2007, versus the 10 percent shortfall in 2006. A number of factors contribute to the shortfall including:
  - ✓ 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.
- To address the under-funding of FTRs, the Midwest ISO has modified the assumptions on loop flows and limits used in the annual, seasonal and monthly auctions to use more conservative assumptions to account for:
  - ✓ Expected differences in the average conditions modeled in FTR auctions versus actual hourly experience.
  - ✓ Unexpected line and unit outages and derates that affect transfer limits.
- The results of these improved assumptions will be reflected in FTR settlement results beginning in June 2008.

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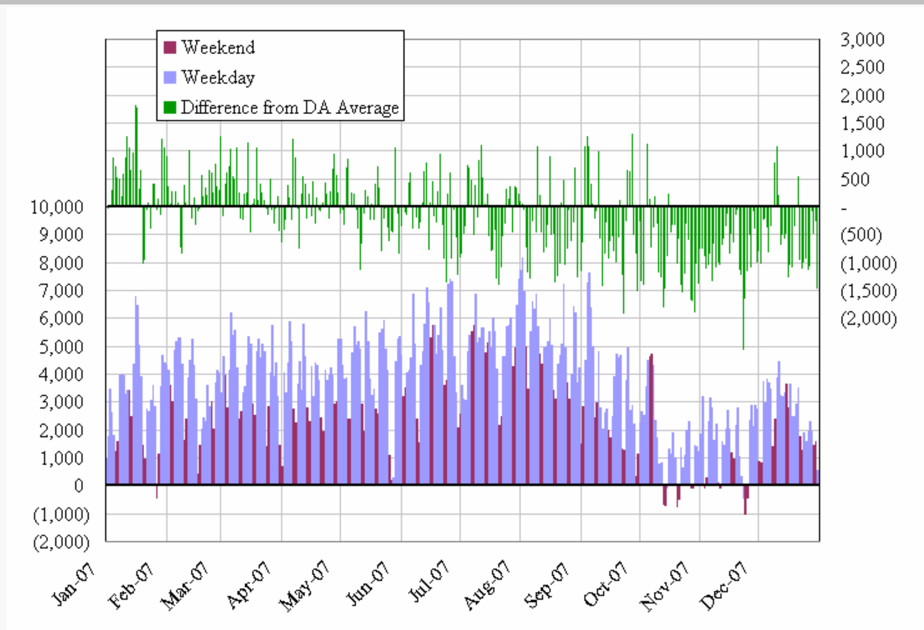
Executive Summary: Financial Transmission Rights

- Other transmission rights were created to accommodate grandfathered agreements (e.g., Option B FTRs, Carve-Outs, Expanded Congestion Hedges).
  - ✓ Payments on these rights were only 6 percent of the total payments.
  - ✓ This is good because FTRs provide more efficient incentives than these forms of transmission rights.
- 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 2007. This change:
  - ✓ Reducing the FTR profits realized by their buyers; and
  - ✓ Indicates that the performance of the FTR is improving 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.
  - ✓ The following figure shows the daily average net imports in real-time over all interfaces.
  - ✓ On average, the Midwest ISO imported almost 5 GW in on-peak hours and over 2.7 GW in off-peak hours.
- However, real-time net imports decreased more than 200 MW on average from those scheduled in the day-ahead market.
  - ✓ On many days the average net imports decreased by more than 1000 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.
  - ✓ Recommended changes in scheduling to reduce the variability in net imports.
- More than a quarter of the net imports came over the Manitoba interface, which began the year well below similar periods in 2005 and 2006 due to poor water conditions. However, imports rose to more normal levels by summer.
- The Midwest ISO is also a net importer from PJM, although power flows across this interface frequently reverse direction.

Average Hourly Real-Time Imports All Hours



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Executive Summary: External Transactions

- Our analysis of the interaction between the Midwest ISO and adjacent markets shows that the prices at the border between the markets are relatively well arbitraged in most hours.
  - ✓ 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 (transactions are scheduled in advance), we do not expect perfect convergence. Many hours exhibit large price differences between the Midwest ISO and adjacent areas.
  - ✓ 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.
    - – The participants' transactions would be financial and the RTOs would determine the optimal physical interchange based on the relative prices in the two areas.
    - – This change would achieve the vast majority of any potential savings associated with jointly dispatching generation in the two regions.
- The report also evaluates the market-to-market coordination that the Midwest ISO and PJM use to jointly manage transmission constraints that both markets affect.
  - ✓ This process has been key in allowing these constraints to be more efficiently managed.
  - ✓ Our analysis shows that the process can be improved by:
    - – Changing how constraints are modeled and not "relaxing" violated constraints; and
    - – Modifying the dispatch assumptions to allow the Midwest ISO and PJM to provide larger quantities of relief on the other's constraints.

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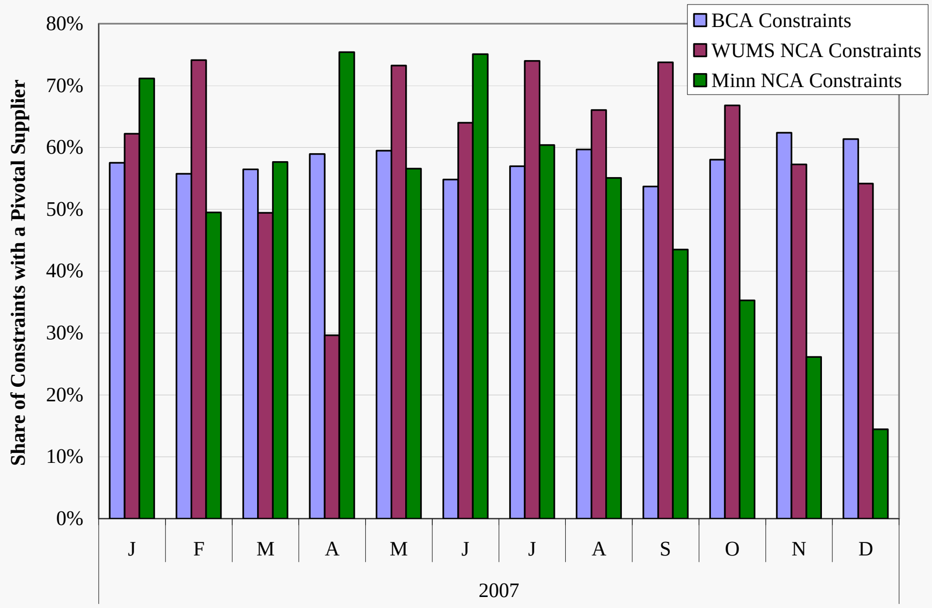
Executive Summary: Intra-Hour External Transactions

- The report also analyzes intra-hour external transactions (transactions scheduled for only part of an hour), which are desirable to the extent they contribute to price convergence.
  - ✓ However, large changes in the Midwest ISO's physical interchange caused by intra-hour schedules can lead to price volatility and operational challenges.
  - ✓ Such changes can also substantially affect prices because the Midwest ISO may have to ramp generation up or down rapidly to accommodate the schedules.
  - ✓ Our analysis shows that the majority of intra-hour transactions appear to be rational, i.e. the participant had a reasonable expectation of profit from the transaction.
  - ✓ With regard to the subset of transactions that do not appear to be profitable, there is not a sustained or consistent pattern by any participants that would indicate market manipulation.
- However, the report raises two general concerns regarding intra-hour scheduling:
  - ✓ Settling intra-hour transactions on an hourly basis, rather than on the basis of when the power is flowing can cause a mismatch of incentives (inefficient transactions that are profitable or vice versa).
  - ✓ Allowing participants to schedule transactions for the last 15 minutes of the hour after they have seen the prices in the first 15 minutes of the hour (that will be included in the hourly settlement) raises a number of concerns and has led to active intra-hour scheduling.
  - ✓ The report recommends scheduling and settlement changes to address these issues.

Executive Summary: Market Power and Mitigation

- This report provides an overview of the market concentration and other potential market power indicators, as well as a review of the conduct of participants and imposition of market power mitigation measures in 2007.
- 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.
- The next figure shows this analysis by transmission constraint. It identifies the frequency with which a single suppliers' resources are needed to manage a constraint.
  - ✓ 58 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.
  - ✓ 62 percent of the active "narrow constrained area" ("NCA") constraints into WUMS have a pivotal supplier, as do 52 percent of the active NCA constraints into Minnesota.
- In addition, two-thirds of all intervals in 2007 exhibited an active BCA constraint with at least one pivotal supplier in two-thirds of the hours.
  - ✓ Likewise, 30 percent and 20 percent of the intervals exhibited an active NCA constraints with a pivotal supplier in WUMS and Minnesota, respectively.
- Based on these results, we find substantial local market power exists associated with both the BCA and NCA constraints.

Market Power Analysis: Percent of Active Constraints with a Pivotal Supplier



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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.
- The next figure shows our "output gap" metric that is designed to detect significant 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 rose modestly at the beginning of 2007 due to the designation of the Minnesota NCA (and the tighter associated threshold) but has generally remained at relatively low and stable levels.
  - ✓ These results, and the results of other analyses 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.

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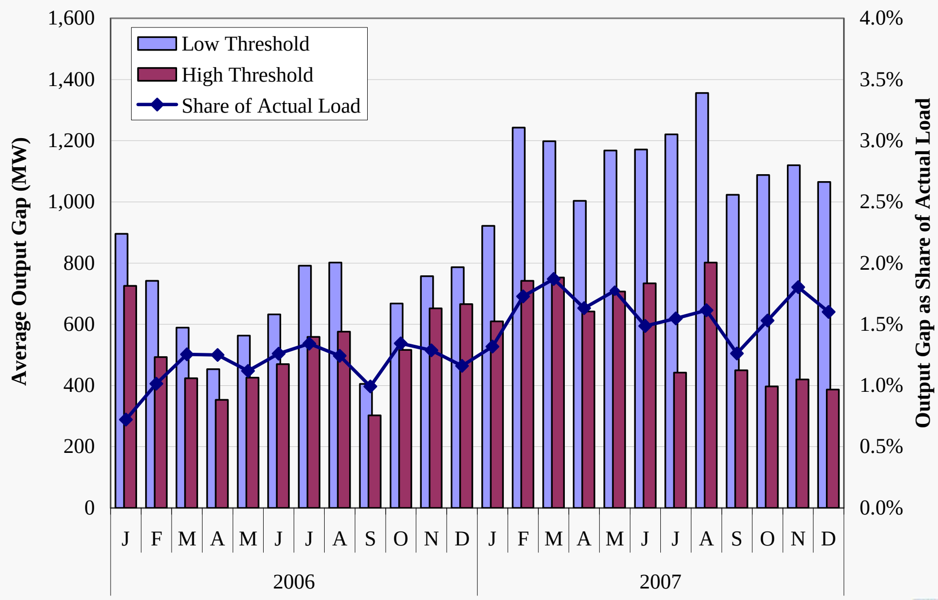
Economic Withholding: Output Gap Analysis Average of Daily Peak Hour



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Executive Summary: Development of Demand Response Resources

- 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 development of demand response in the Midwest ISO should be a high priority.
- Demand can participate in the Midwest ISO markets currently in one of two ways:
  - ✓ Price responsive demand – reducing consumption as prices rise, but not dispatched by the Midwest ISO.
  - ✓ Demand response resources ("DRRs") – dispatched like supply resources (must be dispatchable on a 5-minute basis).
- When all forms of demand response are included, the Midwest ISO has more than 8600 MW, or roughly 45 percent of the total demand response capability in all of the RTOs.
  - ✓ Most of this interruptible load was developed by utilities under regulated retail initiatives. In general, this load is curtailed for reliability and is not price-responsive.
- The Midwest ISO continues to work to facilitate growth in demand response by:
  - ✓ Allowing DR resources to sell ancillary services or energy, and satisfy the resource adequacy requirements.
  - ✓ Removing disincentives to the development of DRRs. (e.g., waiving the RSG costs to entities that stray from their economic dispatch level, setting efficient shortage prices).
  - ✓ Removing any technical barriers to the expansion of DRRs in the market.

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Executive Summary: Planned Market Improvements

The Midwest ISO is implementing a number of changes that will substantial improve the performance of the energy markets and the economic signals the markets provide.

- Midwest ISO is planning to introduce ancillary services markets in September 2008.
  - ✓ ASM will also set efficient prices in both markets to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
  - ✓ ASM will also set efficient prices in both markets to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
- Midwest ISO is completing its work to clarify the capacity requirements in Module E of the Tariff and take appropriate steps to enforce the requirements.
  - ✓ This will allow a decentralized contract market to develop for satisfying these capacity requirements.
  - ✓ These development of this market 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. *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.
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.
   - 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 2008.

Summary of Recommendations

3. *Develop a "look-ahead" capability in the real-time that would commit quick-starting gas turbines and better manage ramp capability on slow-ramping units.*
   - The Midwest ISO has made operational improvements in its commitment of peaking resources, but the commitment of these units can be further improved by reliance on an economic model to commit the units.
   - Allowing the market to commit and de-commit the turbines would reduce the out-of-merit quantities, reduce RSG payments, and improve the ability of peaking resources to set the energy price.
4. *Replace the current ex-post pricing methodology with an approach that would simply utilize ex-ante prices corrected for metering or other errors.*
   - Ex-post pricing has never been shown either theoretically or empirically to improve the efficiency of real-time prices or the incentives of suppliers.
5. *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.

Summary of Recommendations

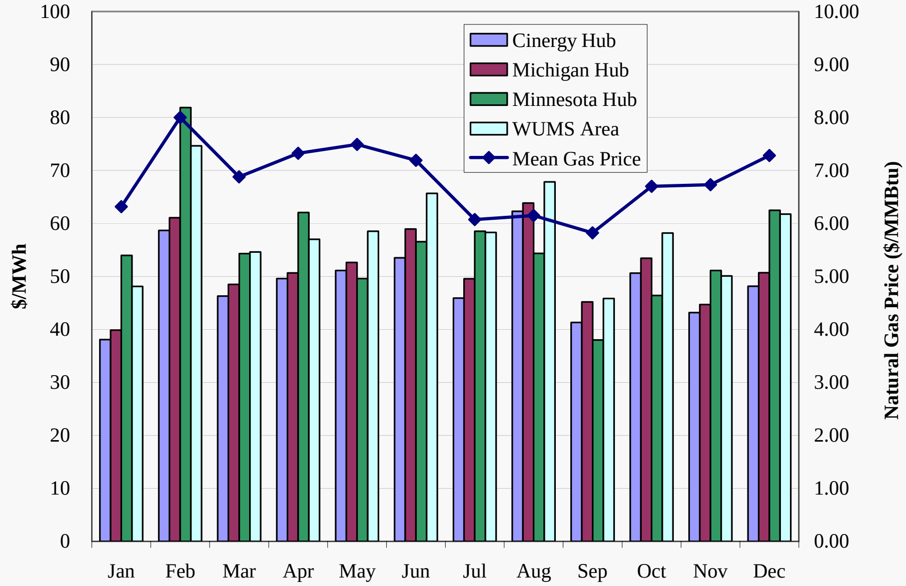
6. *Allow generating resources with lower effects on a constraint to be redispatched (i.e., GSFs less than the current 2 percent cutoff).*
   - In addition to increasing the manageability of transmission constraints, this will tend to reduce price volatility by providing the market more redispatch options.
7. *Regarding the market-to-market process, we recommend the Midwest ISO consider:*
   - Adjusting the amount of relief each RTO requests from the other;
   - 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.
8. *Regarding intra-hour imports and exports, we recommend the Midwest ISO consider:*
   - The feasibility of settling intra-hour transactions on at 15-minute basis; and
   - Limiting acceptance of such transactions based on its available capability to ramp internal generation up or down in support of the transaction.
   - Modify scheduling deadlines to ensure that no participant will observe prices that will be included in an hourly settlement prior to scheduling a transaction.

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 2007.
- 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 weaker during the summer months when prices did not fall with the decreasing natural gas prices. This is expected due to the higher loads that prevail during the summer.
- The differences between the hub prices show the congestion on the Midwest ISO system.
  - ✓ Much of the Day-Ahead market congestion occurred on market-to-market flowgates on MISO's eastern border with PJM.
    - – These constraints generally reduce the price of energy in the East and Central regions.
  - ✓ Prices in WUMS were high due to transmission congestion that occurred throughout the year.
  - ✓ The West Region experienced high prices due to high levels of congestion and winter peak loads during the winter.

Day-Ahead Average Monthly Hub Prices 2007: All Hours



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Energy Prices

- The All-In Price figure summarizes energy prices in the Midwest ISO's markets in 2006 and 2007.
- The "all-in" price represents the value load served in the real-time market.
- It is equal to the average real-time price and average uplift costs that would be allocated to a buyer in the real-time market.
  - ✓ The all-in price was approximately $51 per MWh in 2007 – a 13 percent increase over the all-in price in 2006.
  - ✓ The 2006 all-in of $44.84 per MWh was a 20% decline from 2005.
  - ✓ The major contributing factors to these annual changes are:
    - Changes in peaking commitments and resultant RSG uplift,
    - Fuel price changes, and
    - Changes in load levels.

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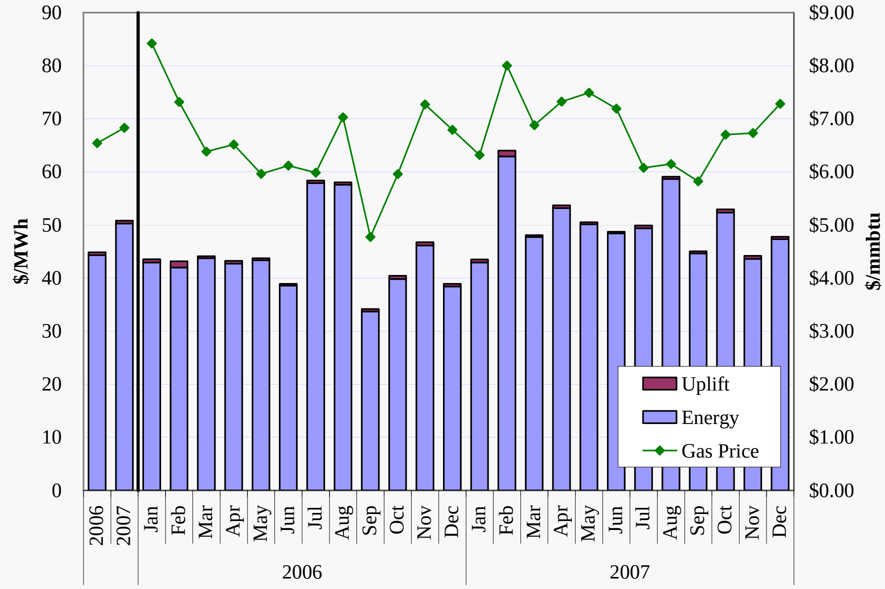
All-In Price
2006 & 2007



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.

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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 2006 and 2007. The figure shows:
  - ✓ The implied heat rates in 2007 were substantially higher than those in 2006 during January and February, and from August to December.
  - ✓ In all of these months, the average loads were higher in 2007.
  - ✓ In the one month with a significantly lower average load (July 2007), the implied heat rate was also significantly lower than in 2006.
- Substantial increases in coal prices late in 2007 also contributed to the higher implied heat rates because coal units generally set prices in more than two-thirds of the time.

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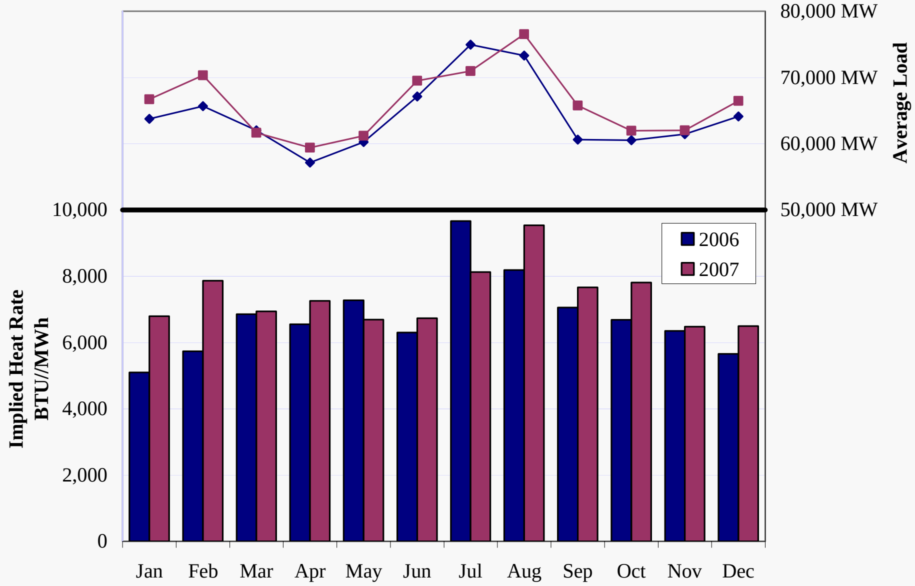
Implied Heat Rate of Energy Price



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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:
  - ✓ WUMS and Minnesota prices are the highest due to the frequent congestion into these areas – over 10 percent of the hours exhibit prices above $100/MWh at these locations versus 6 and 7 percent at the Cinergy and Michigan hubs, respectively.
  - ✓ Congestion affected Minnesota more than any other hub during 2007 – causing the highest number of hours with prices above $200/MWh (1.5 percent of hours).
    - – Number of hours exceeding $200/MWh increased from 2006 at all locations due primarily to higher oil and natural gas prices.
  - ✓ Additionally, congestion from Minnesota into WUMS caused Minnesota to have the largest number of hours with prices less than zero (1.7 percent of hours).
    - – This is an improvement over 2006 when 2.4 percent of hours at the Minnesota hub exhibited negative prices. However, the 1.7% in 2007 is ten times greater than the rate at any other hub.

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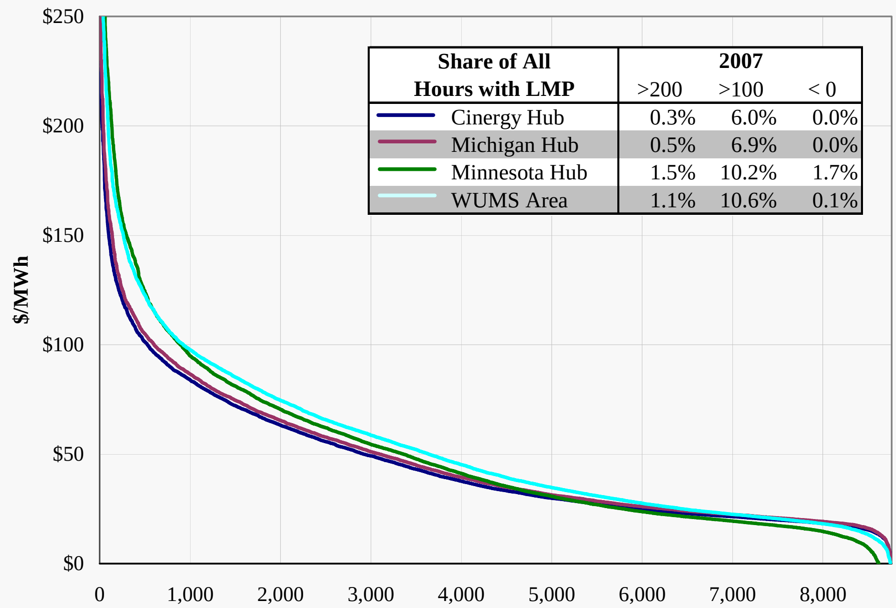
Real-Time Price Duration Curve
2007: All Hours



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Real Time Energy Prices in the Highest-Priced Hours

- 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.
  - ✓ As shown in the prior figure, prices in Minnesota and WUMS 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 four hours (0.05 percent) at Cinergy to 30 hours (0.3 percent) at the Minnesota Hub.
  - ✓ If peak pricing events continue at the frequencies that occurred in 2007, 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 that are discussed later in the report will improve the economic signals and contribute to resource adequacy.

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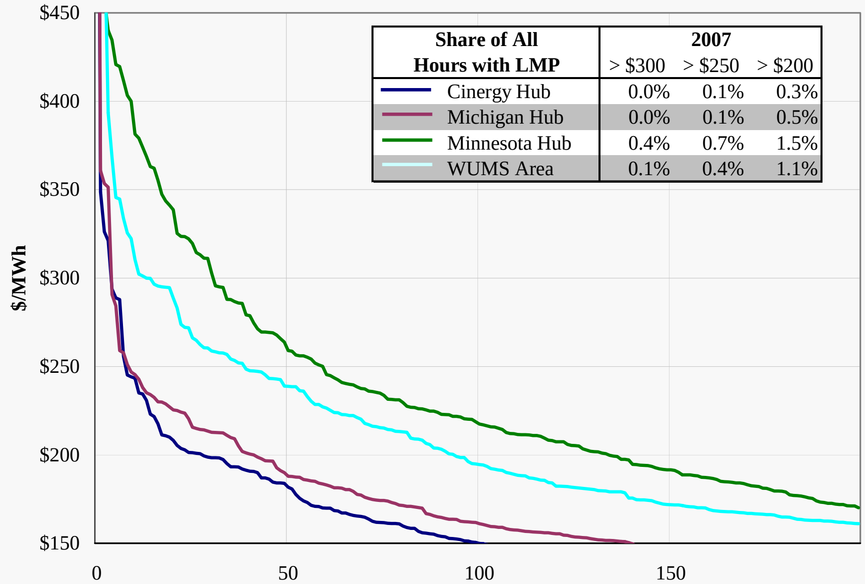
Real-Time Price Duration Curve
2007: High Price Hours



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Implied Heat Rate Duration Curve

- The implied heat rate duration curves illustrated on the next slide represent the average load-weighted hourly ex-post price during each of the 8,760 hours in 2006 and 2007.
- This figure shows that the implied heat rate, adjusted for changes in the price of natural gas, is higher during a large number of hours in 2007. As discussed previously, several contributing factors to this change are:
  - ✓ Peak load in 2007 was lower than 2006, but average load in 2007 was significantly greater;
  - ✓ Natural gas and oil-fired resources set the marginal system price in over 29 percent of real-time market intervals in 2007 compared to 20 percent of intervals in 2006.
  - ✓ Coal set the system marginal price 77 percent of the hours in 2006 and 67 percent in 2007.
  - ✓ Non-firm natural gas transportation issues compelled many dual-fueled resources, particularly in the West, to burn oil during the winter.

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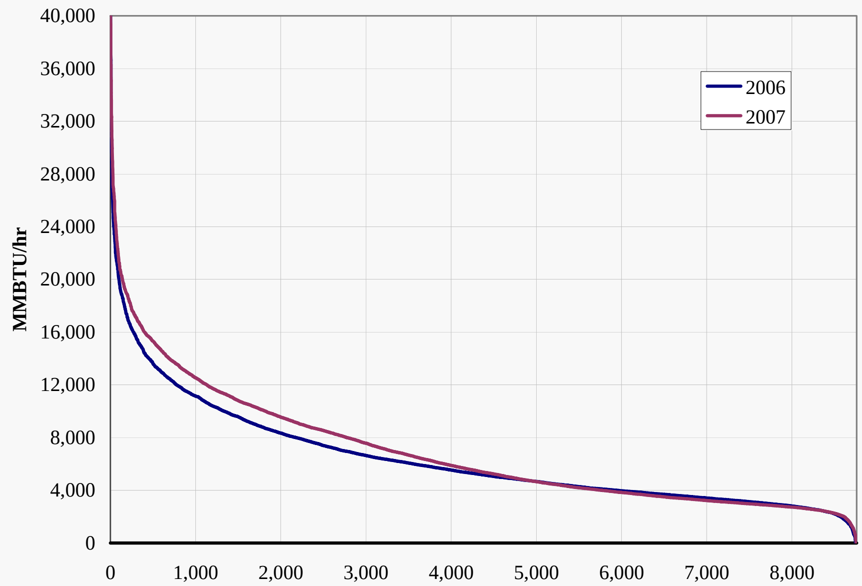
Implied Heat Rate Duration Curve
2006 and 2007



POTOMAC ECONOMICS

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 purposes of this figure, we show only the price-setter in the unconstrained areas – thus, higher cost units may set prices in constrained areas more than suggested in the figure.
- This figure shows that coal units set prices more in more than two-thirds of the hours (including virtually all of the off-peak hours).
- 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 would suggest.
- In February 2007, natural gas fired units set prices in a larger share of hours than any other month.
  - ✓ This was due to the lower day-ahead scheduling levels and high winter loads in February, which caused the Midwest ISO to really heavily on gas turbines that could be started intraday.

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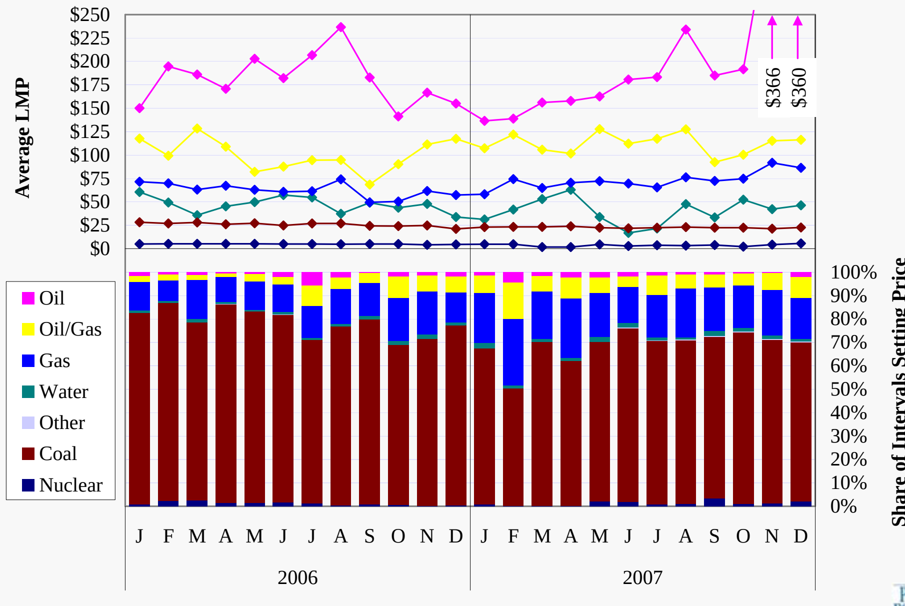
Share of Interval Price Setting By Unit Fuel Type



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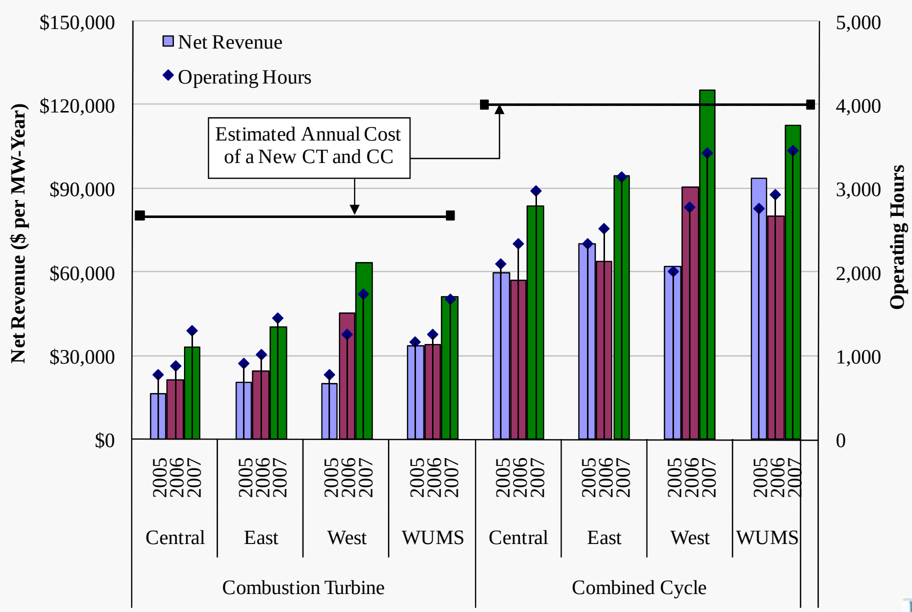
Long-Term Economic Signals to Maintain Adequate Resources

- 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 over the first nine months of operation in 2005 through 2007 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, but may support investment in combined cycle generation in the congested areas.
- These results are consistent with expectations because:
  - ✓ The Midwest ISO footprint has a small capacity surplus that contributed to no significant periods shortage occurring in 2007.
  - ✓ When shortages do occur, the current markets do not fully price them because operating reserve shortages and interrupted load do not contribute to setting prices.
  - ✓ The ASM markets 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.

POTOMAC ECONOMICS

Net Revenue and Operating Hours



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Load and Resources

POTOMAC ECONOMICS

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 2007.
- 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 heavily on imports to satisfy the demands for energy and operating reserves.
  - ✓ The headroom on the highest load days was generally low and near the expected dispatch margins. There were no conditions requiring demand side management during the summer peak periods.
  - ✓ A peak event occurred in February that resulted in demand curtailments in the West.
- The second figure provides the same results, but shows only the capacity that was unavailable. These figures show:
  - ✓ Deratings in the DA market were highest during July and August due to high temperatures, but were less than the deratings that occurred in 2006.
  - ✓ In 2006, high temperatures and environmental restrictions resulted in additional deratings of baseload capacity. Those conditions did not occur in 2007.
  - ✓ Roughly 3.6 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch across throughout the year.

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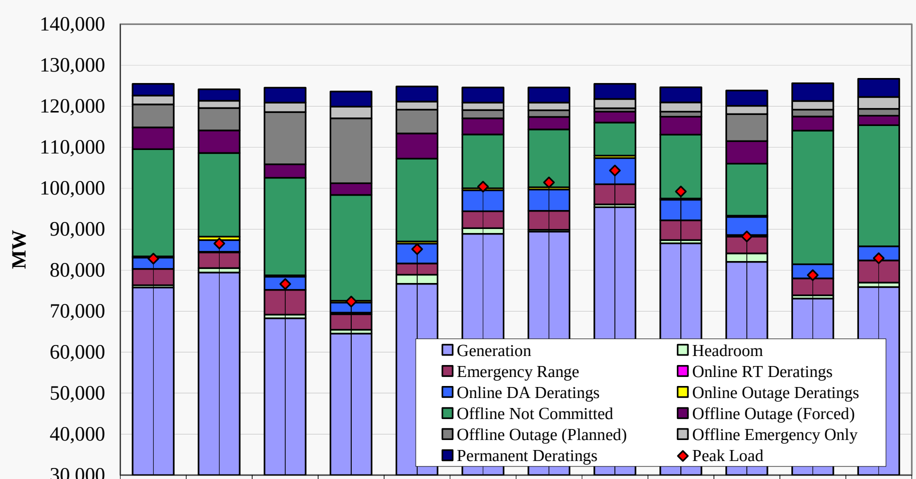
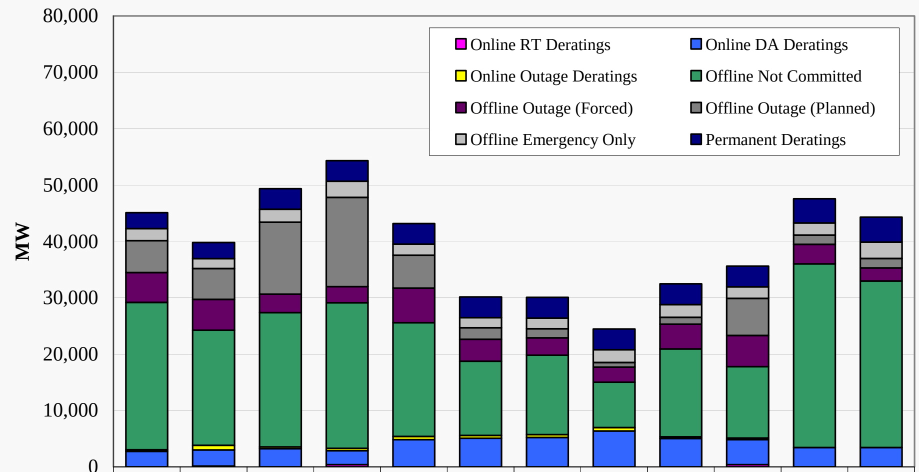
Capacity During Peak Load Hours



Peak Hour	7 PM	7 PM	7 PM	9 AM	2 PM	2 PM	4 PM	2 PM	4 PM	2 PM	7 PM	6 PM
Peak Date	Jan 30	Feb 5	Mar 6	Apr 5	May 30	Jun 26	Jul 31	Aug 8	Sep 5	Oct 8	Nov 29	Dec 17
Peak Load	82,802	86,484	76,603	72,342	85,111	100,378	101,384	104,293	99,198	88,212	78,793	82,916

POTOMAC ECONOMICS

Offline and Unavailable Capacity Monthly Peak Load Hour



Peak Hour	7 PM	7 PM	7 PM	9 AM	2 PM	2 PM	4 PM	2 PM	4 PM	2 PM	7 PM	6 PM
Peak Date	Jan 30	Feb 5	Mar 6	Apr 5	May 30	Jun 26	Jul 31	Aug 8	Sep 5	Oct 8	Nov 29	Dec 17
Peak Load	82,802	86,484	76,603	72,342	85,111	100,378	101,384	104,293	99,198	88,212	78,793	82,916

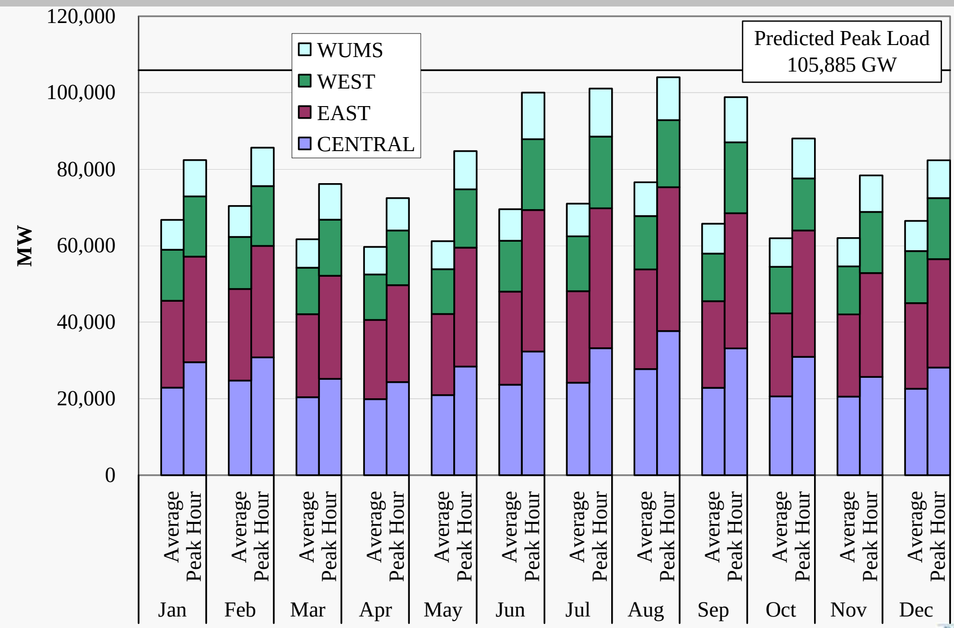
POTOMAC ECONOMICS

Load Maximum and Average Versus Peak Prediction 2007: All Hours

- This figure shows the peak average hourly load by month for each sub-region.
- The Midwest ISO is a summer peaking region – the figure confirms that the highest loads occurred in the summer months.
- Mild summer temperatures caused the realized peak load in 2007 to be less than the forecasted peak from the Midwest ISO Summer Assessment.
- Load never reached the Midwest ISO Summer Assessment's peak prediction in 2007.
  - ✓ In the months of July and August, the peak load was 101 and 104 GW, respectively.
  - ✓ Each of these monthly peaks was well below the predicted peak load for 2007 of nearly 106 GW.
- As expected, the peak load levels are substantially higher than average load levels.
  - ✓ During the summer months, peak load levels were 41 percent higher than average loads.
  - ✓ Because electricity cannot be stored, the market relies on intermediate and peaking resources to meet peak demands.
- The figure also shows that most of the load in the Midwest ISO is in the Central and East sub-regions (74 percent).

POTOMAC ECONOMICS

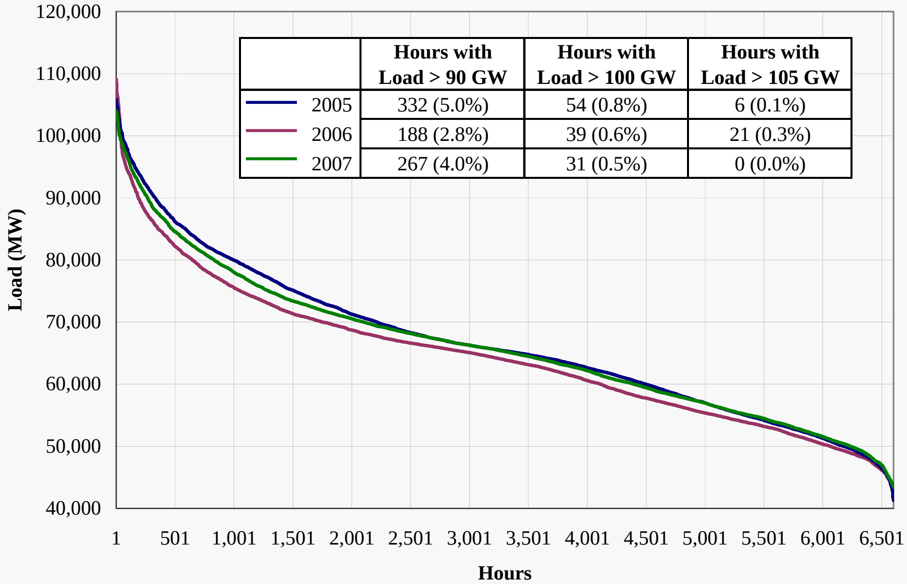
Load Maximum and Average Versus Peak Prediction 2007: All Hours



Load Duration Curves 2005 - 2007

- The next figure shows load duration curves for 2005, 2006 and 2007.
  - ✓ Because the Day 2 Markets began in April 2005, only the period from April to December are included to allow a three year comparison.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
  - ✓ LGE, who left the Midwest ISO in 2006, is excluded from the load data in this analysis and most others in this report.
- Mild summer weather resulted in fewer hours with extreme demand levels in 2007.
  - ✓ There were no hours when actual loads exceeded 105 GW in 2007, versus 21 hours in 2006 and six in 2005.
  - ✓ Although the peak was higher in 2006, average summer loads 2007 were generally higher than in 2006. There were 267 hours when actual loads exceeded 90 GW in 2006 versus 188 hours in 2006.
- Close to 30 percent of the resources are needed only to meet the energy and operating reserve requirements of the region in the highest 5 percent of load hours.
  - ✓ These results underscore the importance of efficient pricing during the highest load conditions.

Load Duration Curves
2005 – 2007: Nine Months Beginning April



	Hours with Load > 90 GW	Hours with Load > 100 GW	Hours with Load > 105 GW
2005	332 (5.0%)	54 (0.8%)	6 (0.1%)
2006	188 (2.8%)	39 (0.6%)	21 (0.3%)
2007	267 (4.0%)	31 (0.5%)	0 (0.0%)

Note: LGEE load has been removed from these data.

POTOMAC ECONOMICS

Midwest ISO Generating Capacity
by Coordination Region

- Generating resources in the Midwest ISO market footprint totaled almost 126 GW in 2007;
  - ✓ 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).
  - ✓ Including the resources of the reliability-only members, the total generating capacity would increase to 170 GW.
- The following figure shows the generating capacity located in the four primary sub-regions in the Midwest.
  - ✓ Because it is a highly congested area, we show the WUMS area separately from the rest of the eastern 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 sub-regions.

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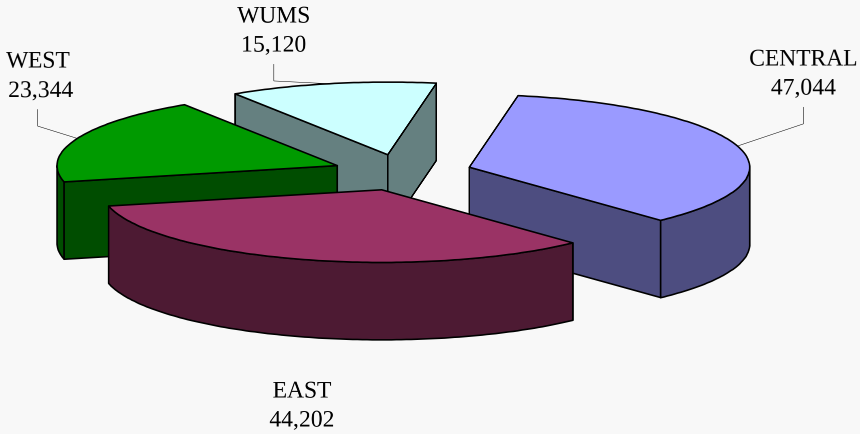
Generation Capacity by Coordination Region



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Generation Capacity and Reserve Margins

- The maximum capacity levels 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 effect of high ambient temperatures.
  - ✓ Intermittent resources cannot be counted on to provide energy in real-time.
  - ✓ Lastly units are often “permanently derated” by a small amount, indicating that they cannot physically operate at their nameplate capacity level.
- The following table shows the capacity levels, internal demand, and resulting reserve margins for each region projected for 2008 given announced capacity additions and retirements.
  - ✓ Internal demand is internal load less the sum of behind the meter generation, interruptible load and other demand side response capability.
  - ✓ The reserve margin is equal to:

    (Capacity plus Firm Imports ÷ Internal Demand or Load) – 1

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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 2008:
  - ✓ The reserve margin for the Midwest ISO region is 23 percent based on Internal Load and 34 percent based on Internal Demand (which includes demand response capability).
  - ✓ In each of the regions, the reserve margin varies from 11 percent to 30 percent based on Internal Load and from 21 percent to 45 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 2008 for the Midwest ISO region is 10.0 percent based on Internal Load and 19.0 percent based on Internal Demand.
  - ✓ In each of the regions, the reserve margin varies from 2 percent to 18 percent based on Internal Load and from 9 percent to 30 percent based on Internal Demand.
  - ✓ This indicates that real-time conditions may be relatively tight -- forced outages (avg. 5 percent) and operating reserves (3 percent) will utilize most of the remaining capacity surplus on generating units so that calling on interruptible load is likely.
- Although these results indicate that the system's resources are adequate for this summer, new resources will likely be needed soon. Hence, it is important for the market's economic signals that govern new investment and retirement decisions to be efficient.

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Generation Capacity and Reserve Margins Estimates for 2008

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temperature Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	39,268	1,271	42,396	11.2%	39,484	3.8%	38,915	2.3%
Internal Demand[3]	36,221	1,271	42,396	20.6%	39,484	12.5%	38,915	10.9%
Central								
Internal Load	39,084	711	44,925	16.8%	41,144	7.1%	39,762	3.6%
Internal Demand	37,285	711	44,925	22.4%	41,144	12.3%	39,762	8.6%
West								
Internal Load	20,803	3,119	23,962	30.2%	19,304	7.8%	19,304	7.8%
Internal Demand	18,670	3,119	23,962	45.1%	19,304	20.1%	19,304	20.1%
WUMS								
Internal Load	13,554	1,189	15,921	26.2%	15,329	21.9%	14,763	17.7%
Internal Demand	12,287	1,189	15,921	39.3%	15,329	34.4%	14,763	29.8%
MISO								
Internal Load	108,255	6,290	127,204	23.3%	115,261	12.3%	112,744	10.0%
Internal Demand	100,009	6,290	127,204	33.5%	115,261	21.5%	112,744	19.0%

[1] Estimated by the Midwest ISO using Day Ahead Market offer data and observed derates in 2007. Midwest ISO Summer Relibility Assessment 2007. Includes known planned outages for 2008.

[2] The Midwest ISO estimated derates from Nameplate and for temperature are included in the Available Capacity. We have estimated additional High Temperature derate based on capacity offered on August 1, 2006 for units available in the Day-Ahead market.

[3] Net Internal Demand is internal load less behind-the-meter load and demand-side management.

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Additions and Retirements of Generation Capacity

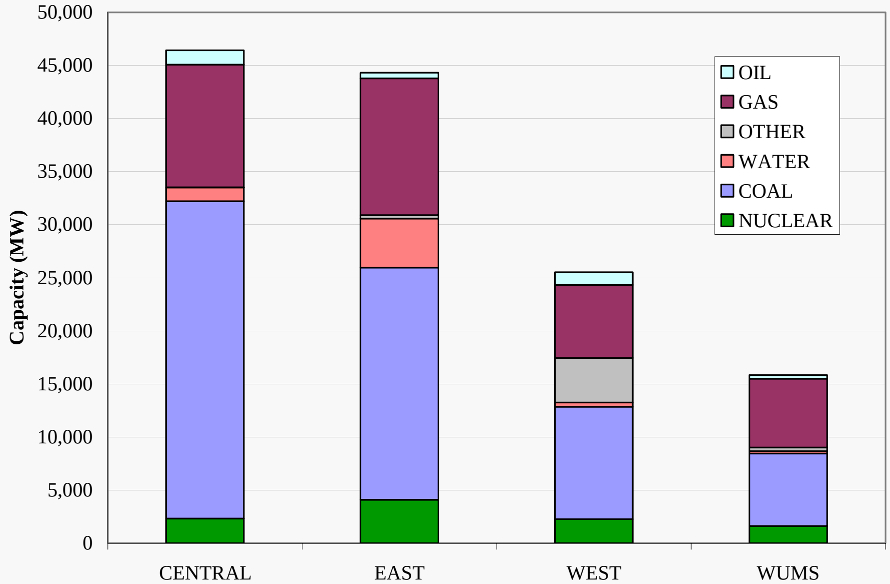
- The following table shows the new capacity additions planned for 2008. In total, 2.7 GWs of additions and 900 MWs of retirements are expected in 2008.
  - ✓ Although a total capacity addition of 2.7 GWs appears significant, much of the new capacity is wind. The intermittent nature of Wind cause it to contribute relatively less to reliability than conventional supply or demand response.
  - ✓ 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..

	Coal	Gas	Oil	Oil/Gas	Other	Waste	Water	Wind
ALTW								130
AMIL		3						
CWLD								6
DECO								53
GRE			27					117
MDU								20
MP					25			50
NIPS								131
NSP			50	1,044			24	489
OTP								179
SMP						4		
WEC								145
WPS	150							99

Distribution of Sub-Region Generation Capacity By Fuel Type

- 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 of fuel-type is natural gas-fired generation, which accounts for almost 29 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. However, they frequently set the price in the Midwest.
- Nuclear units account for approximately 8 percent of capacity, but produce 14 percent of the generation.
- Oil and hydro represent 2.6 and 5 percent of the Midwest ISO's capacity, respectively. Other units, including wind, provide about 4 percent of capacity.
- The mix of generation is relatively homogeneous across the sub-regions. However, the West sub-region hosts most of the wind resources, while the East has the largest quantity of nuclear resources.

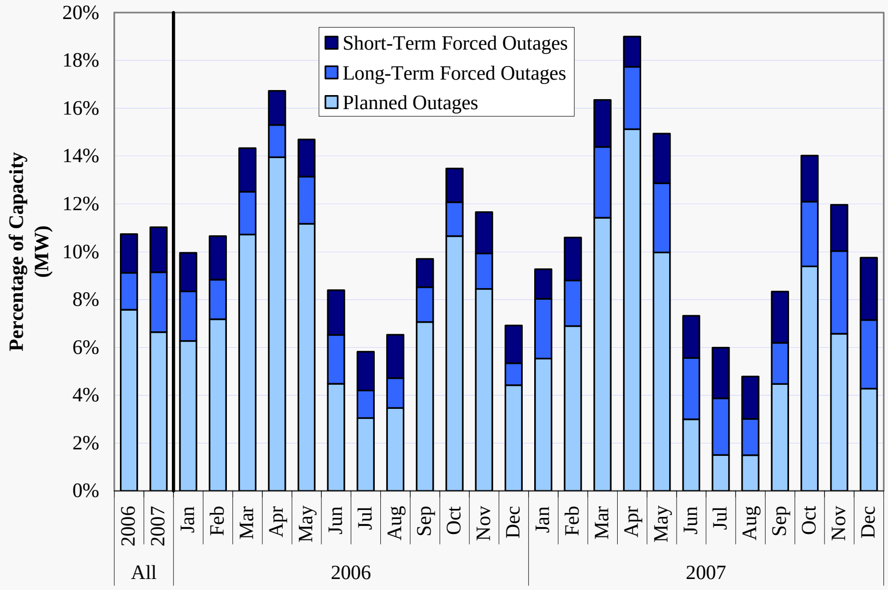
Distribution of Sub-Region Generation Capacity By Fuel Type



Generation Outages

- The following figure shows the generator outages that occurred in each month during 2007 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).
- Similar to 2006 the annual combined outage rate was almost 11 percent for the three categories of outages.
- As expected, this figure shows that the largest total outage levels occurred in the spring and fall because planned outages are generally scheduled during periods of low load.
  - ✓ Planned outages were 12 percent during the spring and 7 percent in fall.
  - ✓ Total planned and forced outages peaked in April at almost 19 percent.
  - ✓ Planned outages were lowest, at 1.5%, in the peak load months of July and August.
- The forced outage rate did not substantially increase during the summer -- it remained at typical levels ranging from 3 to 4 percent.

Generation Outage Rates



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Day-Ahead Market Performance

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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).
- For the year, peak prices were about $4.50 per MWh higher at the Minnesota and WUMS Hubs than at Michigan and Cinergy.
  - ✓ During winter months, congestion was greatest in the West due to:
    - – A relatively higher share of load in winter;
    - – Periods of non-firm gas transportation issues resulting in oil-fired turbines setting price; and
    - – Reduced imports from Manitoba during the first six months of 2007. Manitoba imports increased later in the year, contributing to the reduction of congestion during the summer and fall of 2007.
  - ✓ Prices in WUMS were high throughout the year due to frequent congestion on south-to-north constraints into the region from ComEd and periods of increased congestion from the West during the fall due to forced outages.
  - ✓ The most frequent Day-Ahead constraints (Black Oak-Bedington) bound more than 25 percent of hours and contributed to the low Day-Ahead prices at Cinergy Hub.
- As shown in the figure, high load during both the winter peak and summer peak periods led to higher prices and volatility throughout the footprint.

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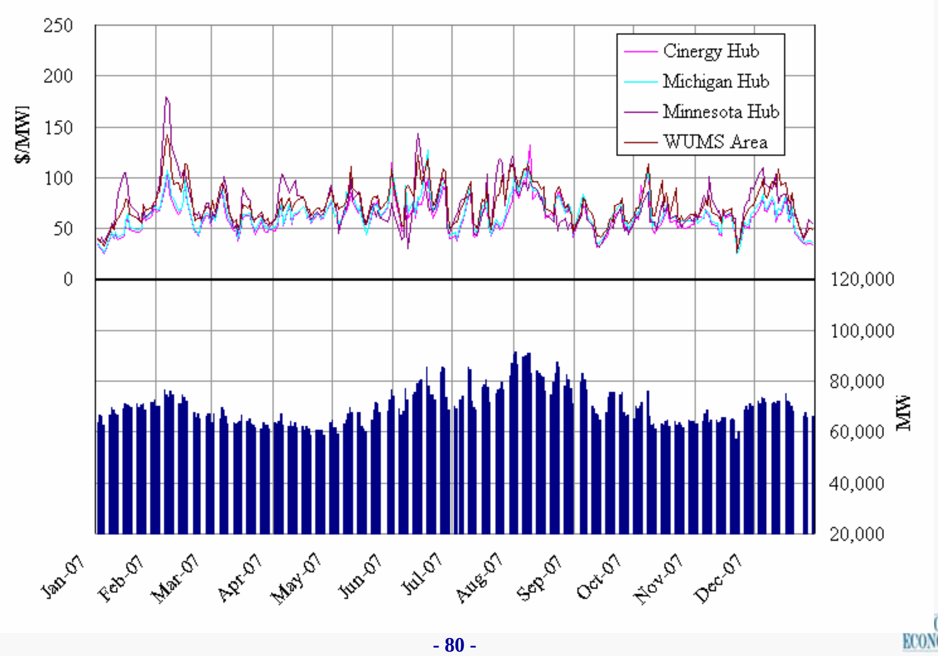
Day-Ahead Hub Prices and Load
Peak Hours



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Day-Ahead Hub Prices and Load
Off-Peak Hours

- The next figure shows day-ahead prices and load during off-peak hours.
- Although off-peak hour load achieves its maximum during August, the highest off-peak loads during the winter months are almost as high due to the cold temperatures that frequently occur overnight.
  - ✓ Day-ahead average off-peak prices were more than $50 per MWh in February and more than $40 per MWh in December.
  - ✓ In contrast, the highest average off-peak price in the summer months was $38 per MWh in August.
  - ✓ The higher winter prices were largely due to the fact that natural gas prices were higher during the winter months.
- Congestion patterns had a significant affect on off-peak prices at the Minnesota Hub:
  - ✓ Congestion *to* Minnesota lead to higher prices during winter months;
  - ✓ Congestion *from* Minnesota lead to lower low off-peak prices during summer months.
  - ✓ This changes in congestion patterns were largely related to changes in outages and imports over the Manitoba interface.
- Daily hub price variability was 77 percent higher during peak hours than off-peak hours in the Day-Ahead market.

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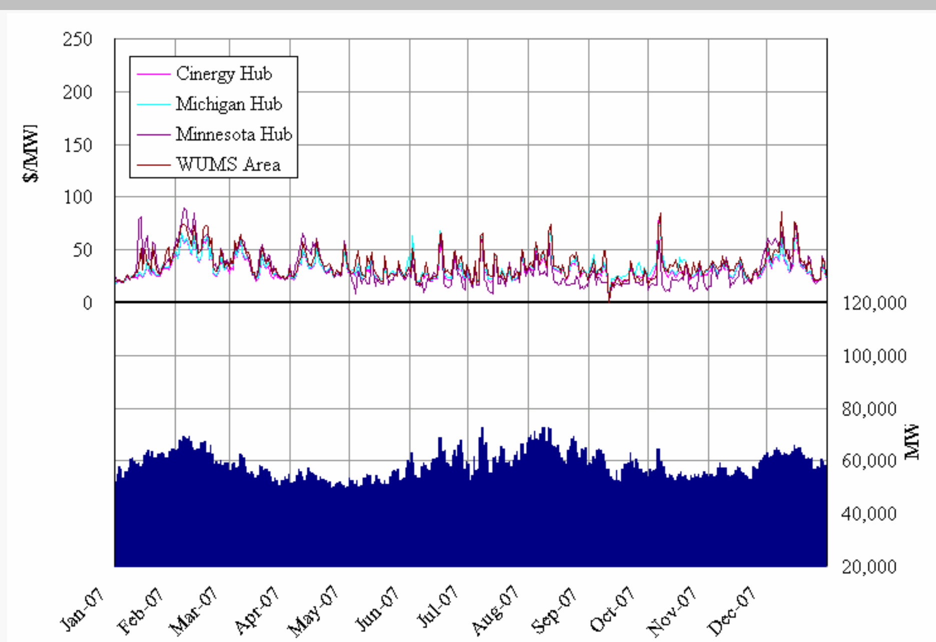
Day-Ahead Hub Prices and Load
Off-Peak Hours



AC ECONOMICS

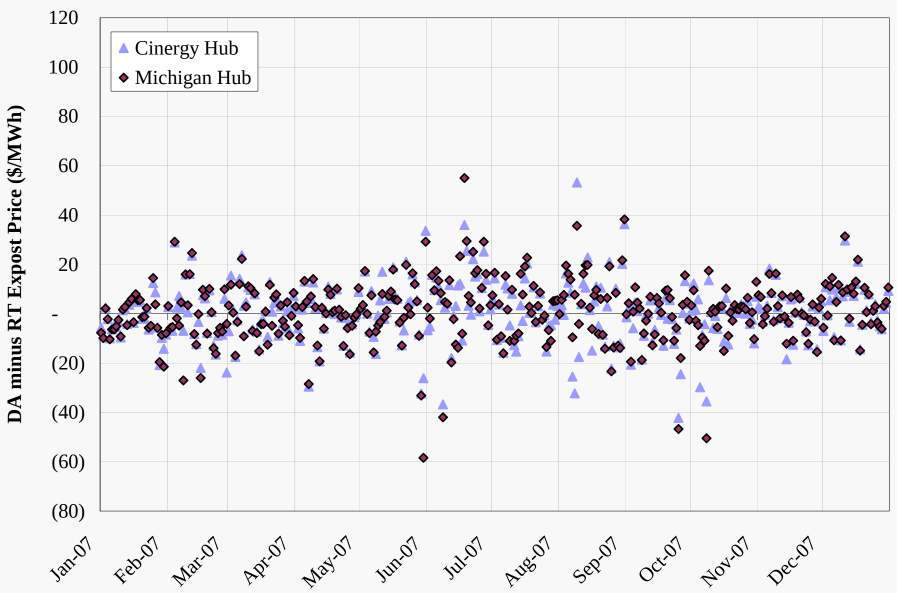
Day-Ahead and Real-Time Price Convergence

- 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 in the day-ahead market.

Hourly Day-Ahead and Real-Time Price Differences

- The next two figures show average daily day-ahead to real-time price differences (Day Ahead minus Real-Time) at four Midwest hubs.
- The results for the Cinergy and Michigan hubs in the first figure show:
  - ✓ The average price differences are small -- $0.30 and $0.79 per MWh for the Cinergy and Michigan Hubs, respectively.
  - ✓ During the summer when prices are the most volatile, these differences were larger. In July and August, the Day Ahead premiums averaged $0.90 and $2.95 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.
    - – The expectation of RSG costs increases in the summer, which should increase the day-ahead premium.
    - – RSG allocation risk is discussed later in this section.

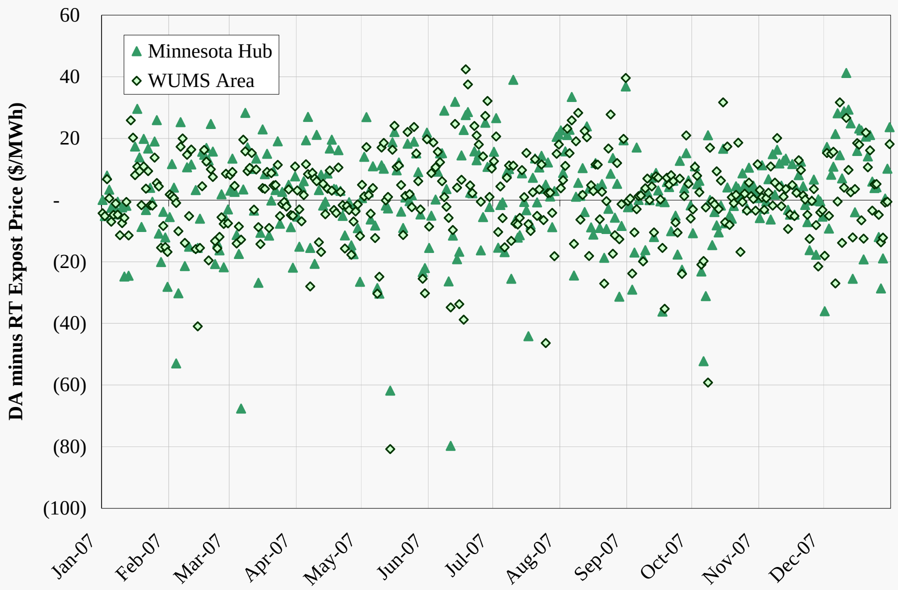
Day-Ahead and Real-Time Price Differences Cinergy Hub and Michigan Hub - All Hours



Hourly Day-Ahead and Real-Time Price Differences

- The second figure shows the results for the Minnesota Hub and WUMS Area, which are areas more frequently affected by the congestion.
- The more frequent congestion results in higher price volatility in these areas, which contributes to:
  - ✓ A wider dispersion of price differences.
    - The standard deviation of price differences was $11.55 at Cinergy.
    - The standard deviation of price differences was $16.93 and $14.35 per MWh at the Minnesota Hub and in WUMS, respectively.
  - ✓ Higher average price differences.
    - The price differences were similar in these areas -- $1.55 per MWh in Minnesota and $1.05 per MWh in WUMS.
    - These results are nearly identical to the $1.53 and $1.07 premiums calculated during 2006.

Day-Ahead and Real-Time Price Differences
Minnesota Hub and WUMS Area - All Hours



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

- The following figures shows 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.
- Purchases in the real-time market are subject to costs associated with the allocation of real-time RSG.
  - ✓ This will cause participants to increase their purchases in the day-ahead market to avoid the allocation, leading to a day-ahead premium.
  - ✓ 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 slightly higher 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 the day-ahead prices.

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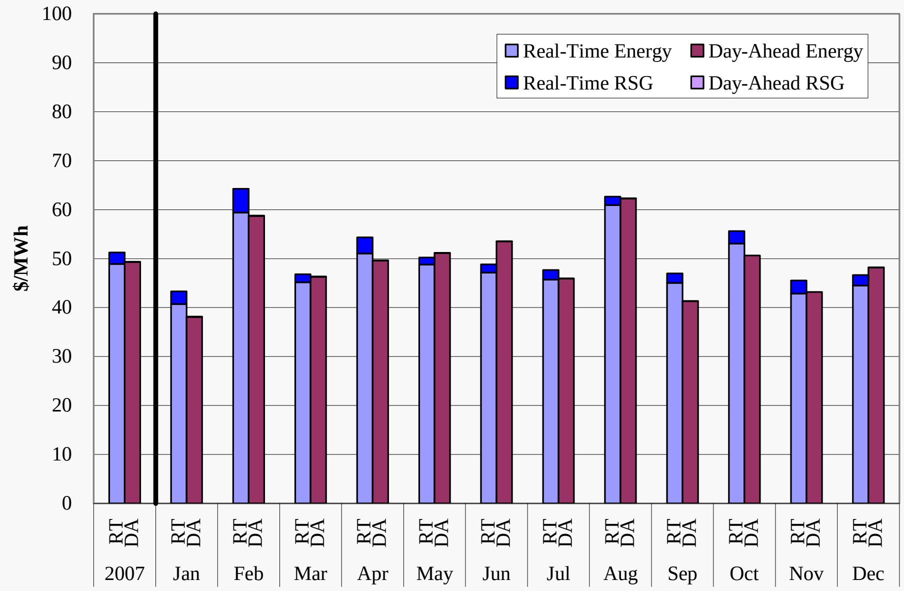
Day-Ahead and Real-Time Prices
Cinergy Hub



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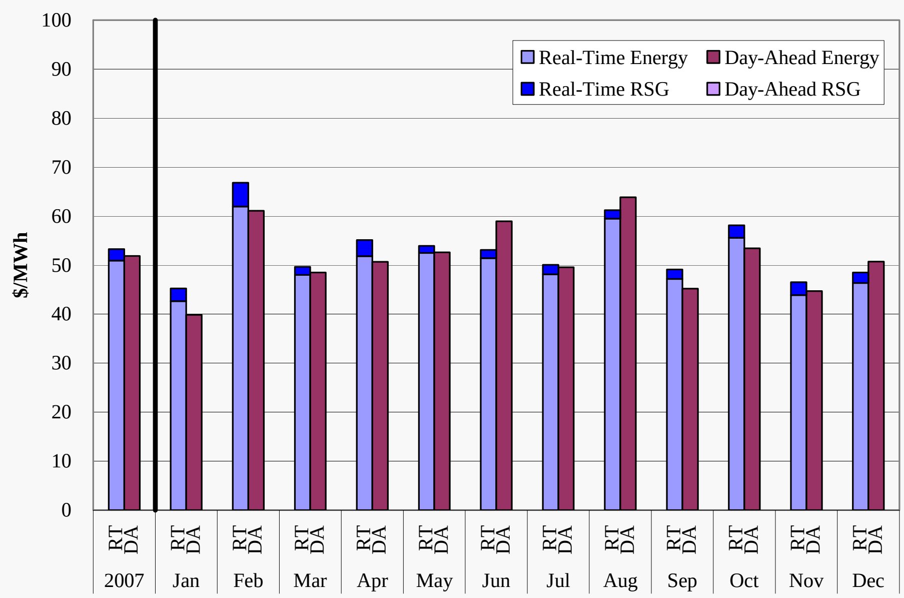
Day-Ahead and Real-Time Prices
Michigan Hub



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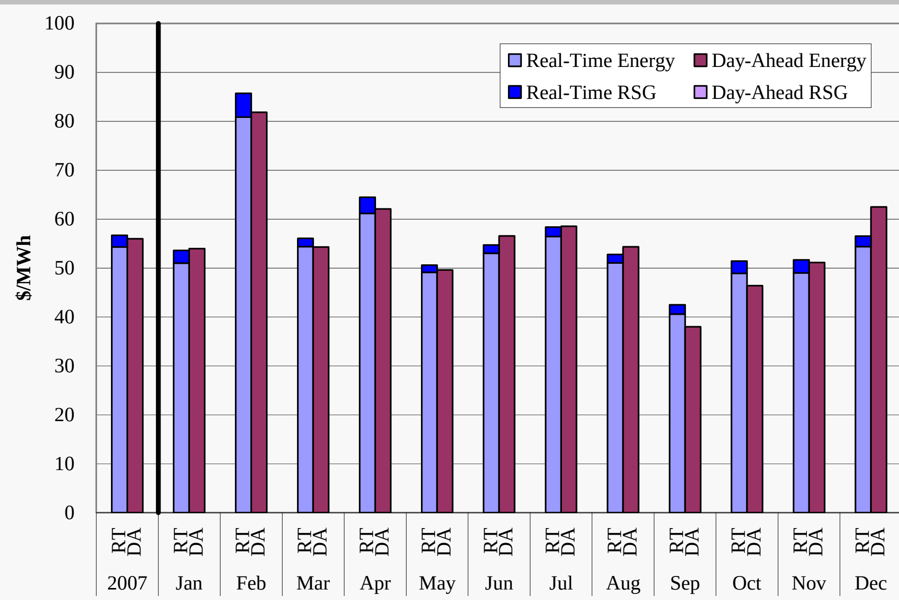
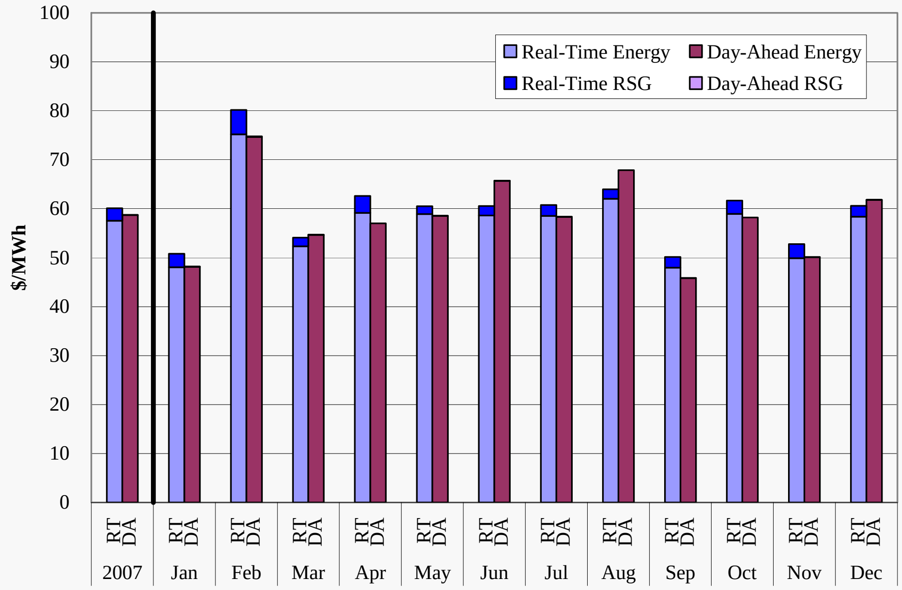
Day-Ahead and Real-Time Prices
Minnesota Hub and WUMS

- 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 more challenging because congestion amplifies price volatility.
- The increased congestion at the Minnesota Hub contributed to larger fluctuations in the monthly differences between day-ahead and real-time prices.
- However, price convergence over the entire year was comparable to that at the Cinergy Hub.
  - ✓ This indicates that arbitrage has been effective over the longer-term, despite the increased short-term volatility of the prices at these locations.

Day-Ahead and Real-Time Prices
Minnesota Hub



Day-Ahead and Real-Time Prices WUMS Area



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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 sign).
  - ✓ 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 PJM and some locations in NYISO.
  - ✓ 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:
  - ✓ With the exception of PJM, the locations affected by congestion exhibited larger average differences, ranging from $18 to $22 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 the other RTO markets, which have all been operating longer.

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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 RTO:				
Cinergy Hub	$46.07	$45.62	$0.38	$14.31
Michigan Hub	$48.47	$47.57	$0.84	$15.28
Minnesota Hub	$51.97	$50.24	$1.64	$20.50
WUMS Area	$54.75	$53.52	$1.17	$18.94
New England ISO:				
New England Hub	$67.97	$66.72	$1.25	$10.26
Maine	$64.35	$63.65	$0.69	$9.92
Connecticut	$71.70	$71.75	-$0.06	$12.93
New York ISO:				
Zone A (West)	$53.02	$52.35	$0.67	$15.66
Zone G (Hudson Valley)	$72.26	$72.54	-$0.27	$20.62
Zone J (New York City)	$77.21	$77.60	-$0.39	$22.58
PJM:				
AEP Gen Hub	$43.38	$44.15	-$0.76	$11.41
Chicago Hub	$45.40	$45.76	-$0.36	$11.84
New Jersey Hub	$63.45	$65.63	-$2.17	$18.45
Western Hub	$56.91	$59.77	-$2.85	$17.02

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Day-Ahead Load Scheduling

- The next two figures show 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% 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.

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Day-Ahead Load Scheduling

- The figures show 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 highest in WUMS at 8 percent.
- Virtual bids and offers increased throughout 2007 and plays an important role in arbitraging day-ahead and real-time prices.
- The net load (total load net of virtual supply) scheduled in the day-ahead market as a percent of the real-time load declined slightly from 2006.
  - ✓ 97.1 percent of the actual load was scheduled on net in 2007 in all hours, down slightly from 97.7 percent in 2006.
  - ✓ In the peak hour of each day (which is the hour that is most likely to require MISO to commit additional generation), 95.1 percent of the actual load was scheduled on net in the Day-Ahead market versus 96.1 percent in 2006 and 94.5 percent in 2005.
  - ✓ Much of the decrease from 2006 to 2007 was due to low scheduling levels in February (93.2 percent), which exhibited the highest RSG costs of the year.
  - ✓ With the exception of February, 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 2006 and 2007.

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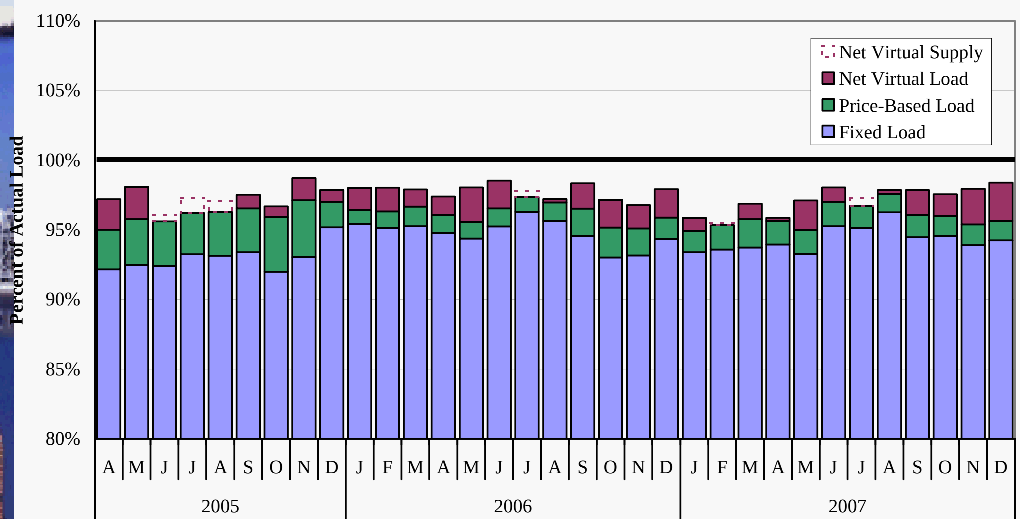
Day-Ahead Load Scheduling versus Actual Load All Hours



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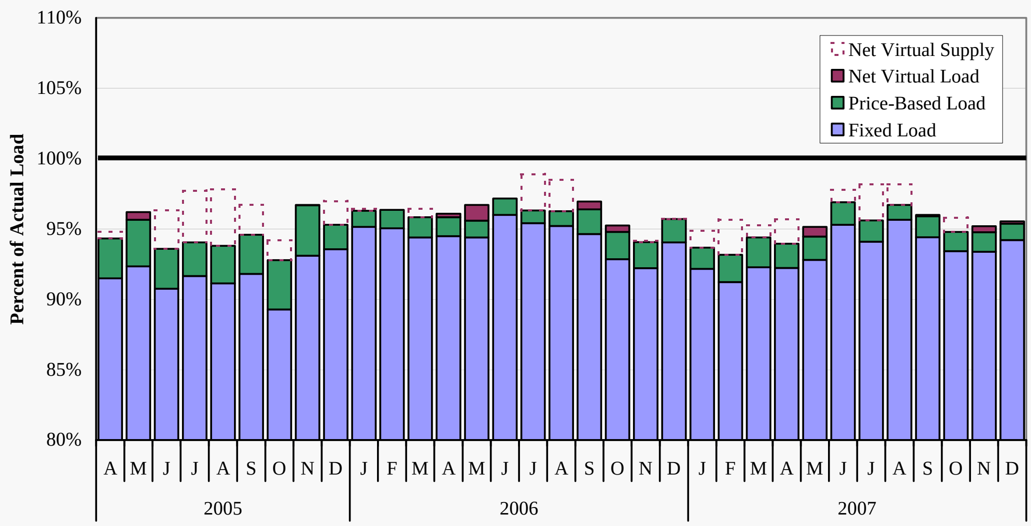
Day-Ahead Load Scheduling versus Actual Load
Daily Peak Hour



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Day-Ahead Load Scheduling

- The following figure shows the percentage of real-time load scheduled in the day-ahead market relative to the actual real-time load.
- The figure indicates that the percentage of load scheduled generally decreased as the load increased in 2007.
- This pattern is likely caused, in part, by the increased reliance on peaking resources in the highest load periods.
  - ✓ Such resources set prices when they are needed in the day-ahead market.
  - ✓ However, they frequently do not set prices in the real-time market due to their inherent operational inflexibility.
  - ✓ This creates economic incentives for participants to reduce their net scheduled load in the day-ahead market.
  - ✓ We are working with the Midwest ISO to develop pricing provisions that will correct these incentives by allowing peaking resources to set prices more frequently when they are economic in the real time.

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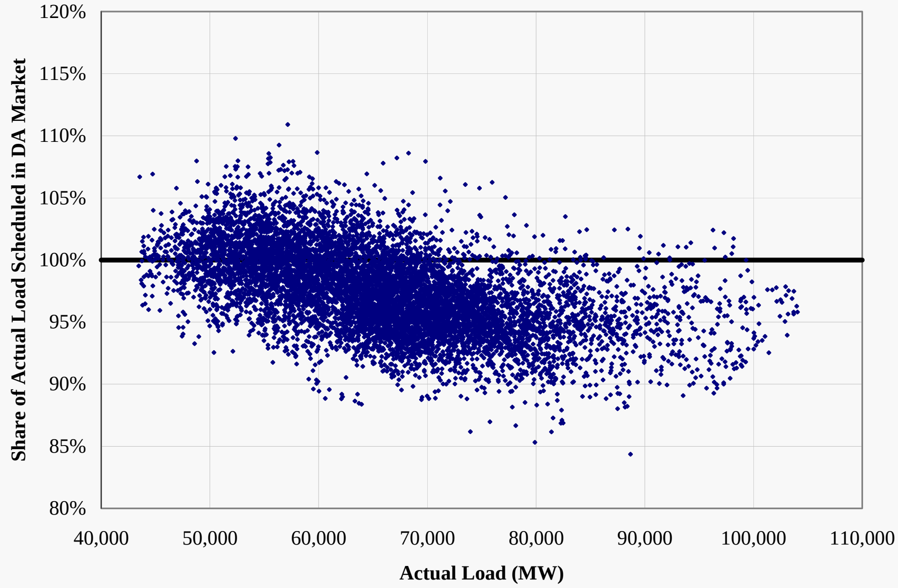
Hourly Day-Ahead Net Load Scheduling by Load Level



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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.
  - ✓ The total and cleared virtual bids and offers declined by roughly 50 percent between April and the end of 2006.
  - ✓ While cleared quantities in 2007 have not changed significantly from 2006 levels, virtual offers have increased substantially.
  - ✓ The reduced volume of cleared virtuals has not undermined the convergence of prices between the day-ahead and real-time.

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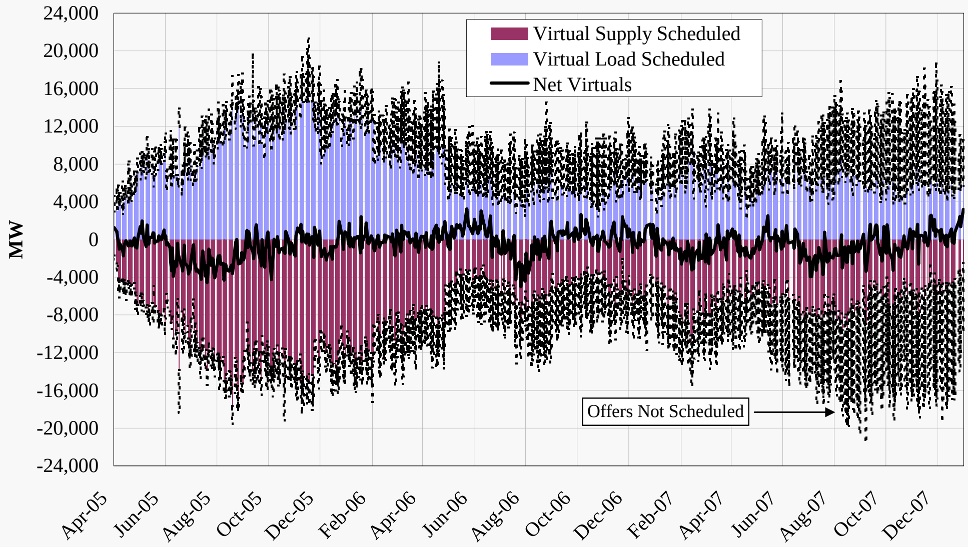
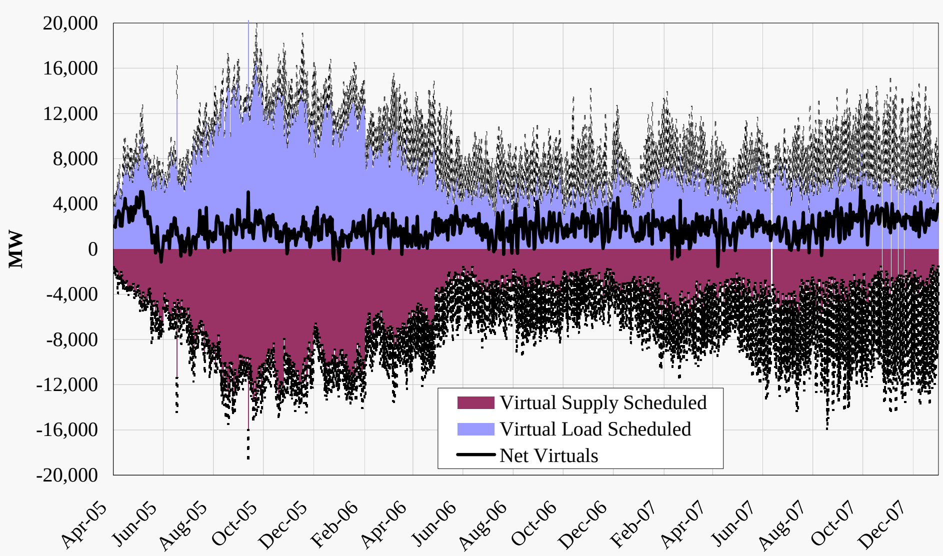
Virtual Load and Supply in the Day-Ahead Market April 2005 through 2007: Peak Hours



Virtual Load and Supply in the Day-Ahead Market April 2005 through 2007: Off-Peak Hours



Virtual Quantity and 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 declined.
  - ✓ For virtual transactions, the average gross profit per MWh cleared decreased slightly from $0.69 per MWh in 2006 to $0.43 per MWh in 2007.
  - ✓ However after RSG allocations were deducted, the average net profit was negative during 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 foresee ably 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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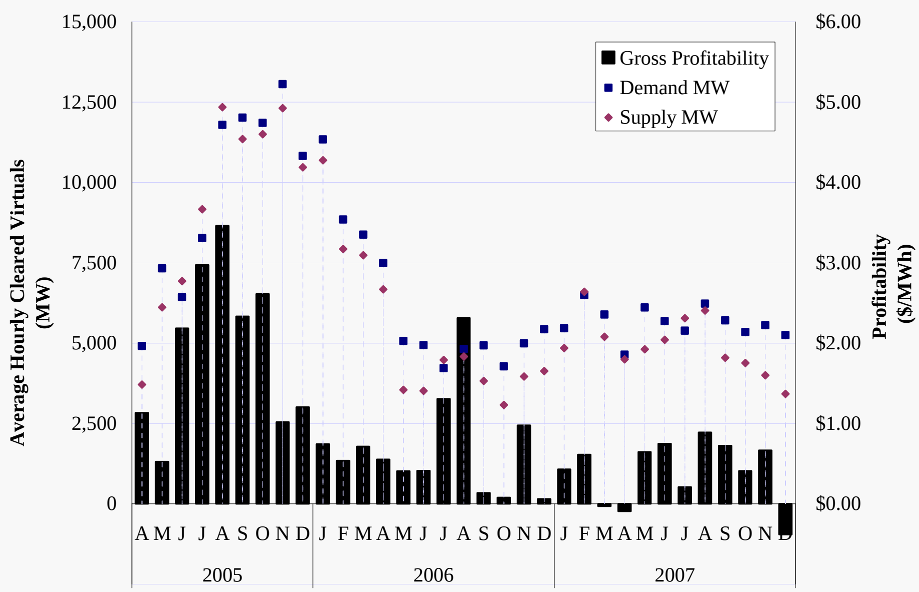
Virtual Profitability in the Day-Ahead Market



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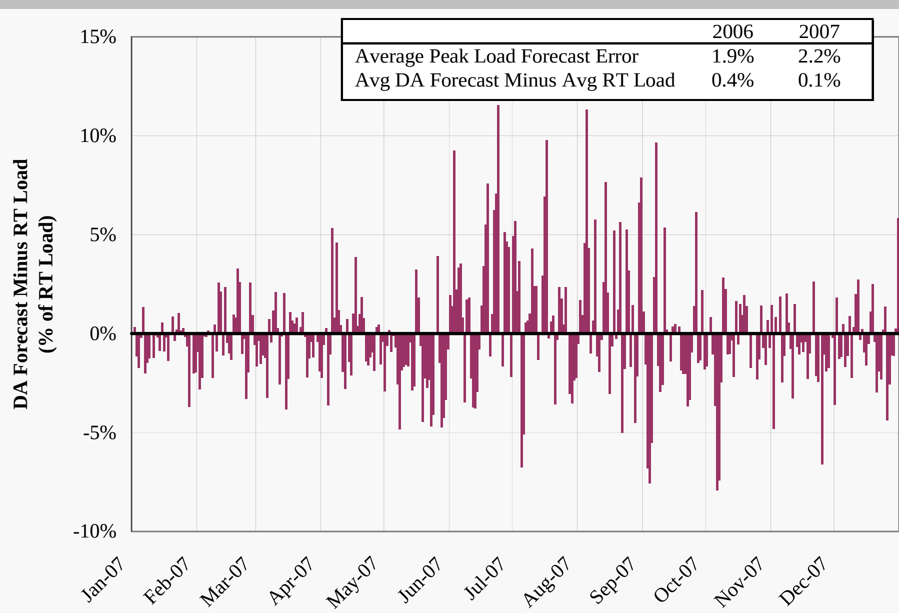
Day-Ahead Forecast Error in Daily Peak Hour 2007

- 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 2007.
  - ✓ The day-ahead forecast on average exceeded the average peak load by 0.1 percent, which indicates that the forecasting was relatively accurate on average.
  - ✓ The average peak load forecast error was 2.2% percent on average (forecast error is the magnitude of the error, regardless of direction), slightly higher than 1.9% from the prior year. These results are comparable to the performance of other RTOs.
  - ✓ Consistent with the in 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 these seasonal tendencies has declined.

Daily Day-Ahead Forecast Error in Peak Hour 2007

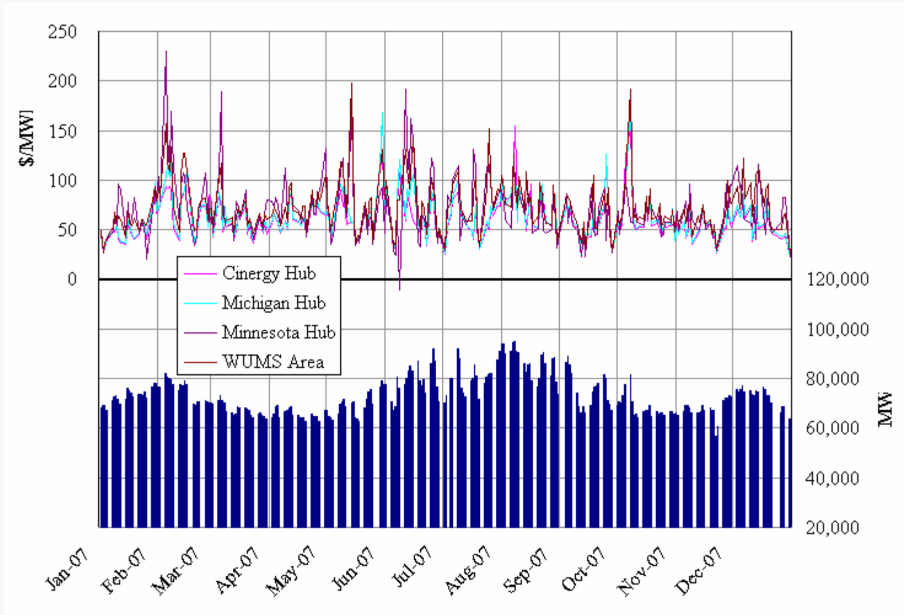


Real-Time Market Performance

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 price with some notable price separations due to congestion events.
- As in the day-ahead market, the most substantial congestion occurred into WUMS and Minnesota.
  - ✓ In the first half of the year, prices in WUMS and the West exceeded $75 per MWh, over $13 higher than at the Cinergy Hub on average .
  - ✓ Prices declined in the second half of 2007.
    - – Average peak prices at Minnesota Hub between July and December decreased over $8 per MWh from the first half of 2007. This decline can be attributed to increased imports from Manitoba during the second half of the year. See External Transactions for details.
    - – WUMS Area prices fell during the second half of 2007 by $1.40. This drop would have been larger, but for generator forced outages that increased congestion later in the year.
  - ✓ Local price volatility in real-time is due, in part, to reduced bid flexibility and ramp limits that tend to exacerbate congestion in the real-time market, particularly during ramp up and ramp down periods.

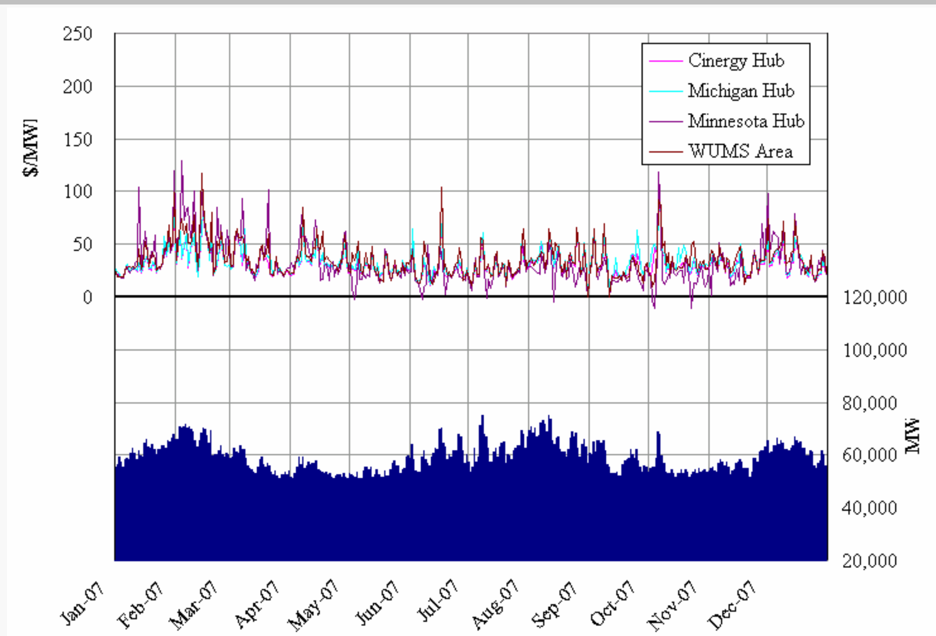
Real-Time Hub Prices and Load
Peak Hours



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.
  - ✓ Relatively higher prices in late-January, February and early-December were due to high load forcing natural gas onto the margin in many hours.
- During the middle of the year, there were several negative price spikes at the Minnesota Hub, due in large part to congestion from Minnesota into WUMS.
  - ✓ These negative events were less frequent and less severe than those in early 2006.
  - ✓ The congestion in 2006 was exacerbated by reduced bid flexibility and ramp limits that can make the congestion difficult to manage.
- Compared to summer 2006, off-peak prices during the July to August time period were relatively stable, showing few spikes in price and a general lack of congestion separating price at the regional hubs.

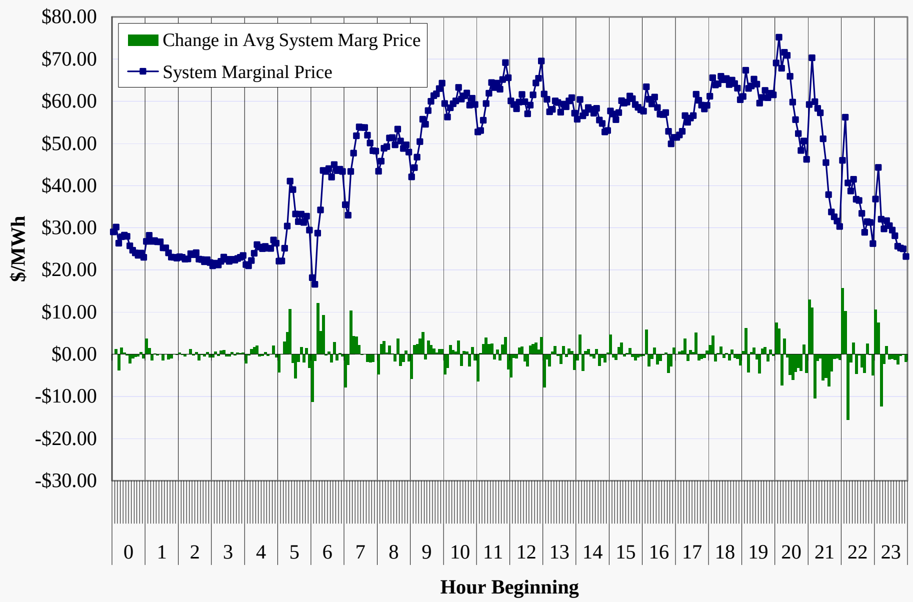
Real-Time Hub Prices and Load
Off-Peak Hours



Real-Time Price Volatility

- The following sub-section evaluates intra-hour price volatility in the real-time market.
- The next figure presents the average system marginal price during each of the 288 daily five-minute intervals, which shows that average prices:
  - ✓ Decrease substantially in the beginning of the ramp up hours in the morning; and
  - ✓ Increase sharply in the beginning of ramp down hours in the evening.
- The sharp price movements that cause these patterns are generally the result of binding ramp constraints.
- Ramp constraints are limits in how quickly the system's generation can be increased or decreased to accommodate:
  - ✓ Changes in interchange with adjacent areas;
  - ✓ Increases or decreases in market load;
  - ✓ Changes in online generation when units are committed or decommitted;
- Ramp constraints are exacerbated by generator inflexibility resulting from decreased offered ramp capability or dispatchable range;
- Changes in fuel prices can magnify price volatility (e.g., larger gas-coal price spreads increase price volatility).

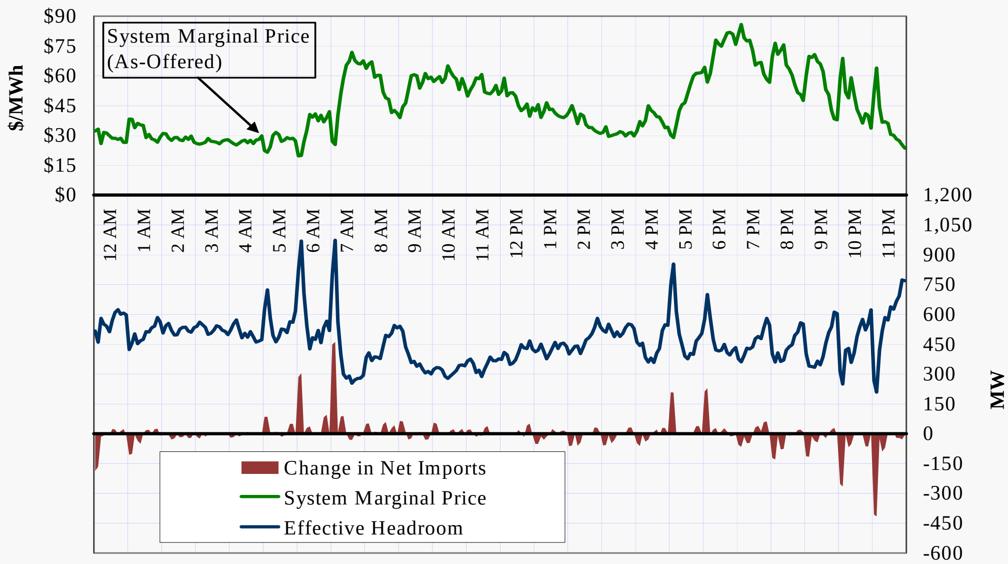
Five-Minute Interval Pricing
System Marginal Price
2007



Real-Time Prices by Time of Day

- The following figures shows average real-time prices by time of day in the summer and winter months of 2007 when loads are the highest.
- To examine the drivers of the price fluctuations, the figure shows:
  - ✓ 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.
- This figures show 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 directly related to changes in effective headroom.
  - ✓ A substantial portion of the changes in effective headroom are 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.
- The report contains some recommendations that should reduce the volatility of the NSI changes.

Real-Time Prices by Time of Day
Winter 2007



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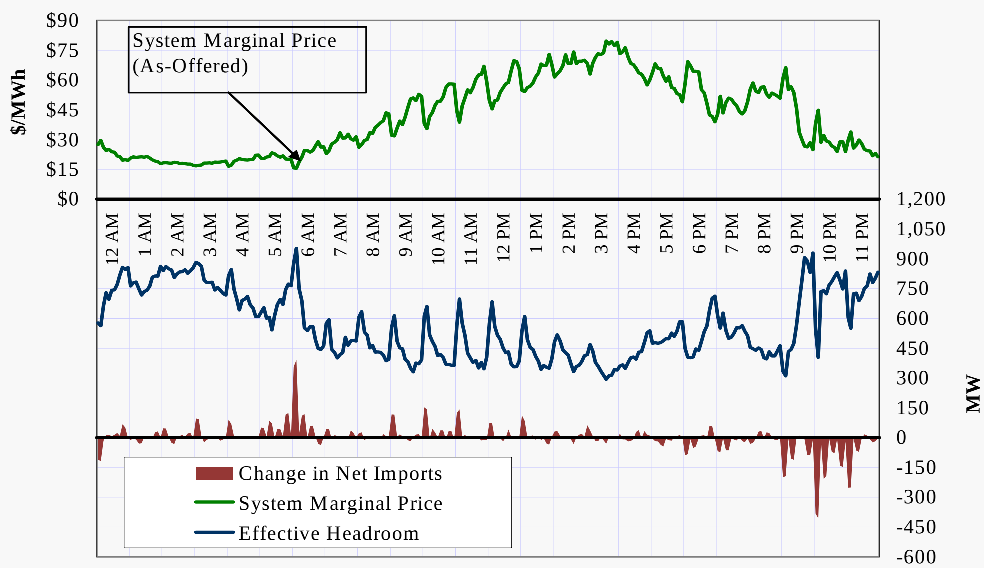
Real-Time Prices by Time of Day
Summer 2007



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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 NEISO 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 market, 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.
- We understand that PJM and NEISO generally produce a real-time dispatch every 15 minutes, although they produce 5 minute prices using their ex-post pricing model.
  - ✓ 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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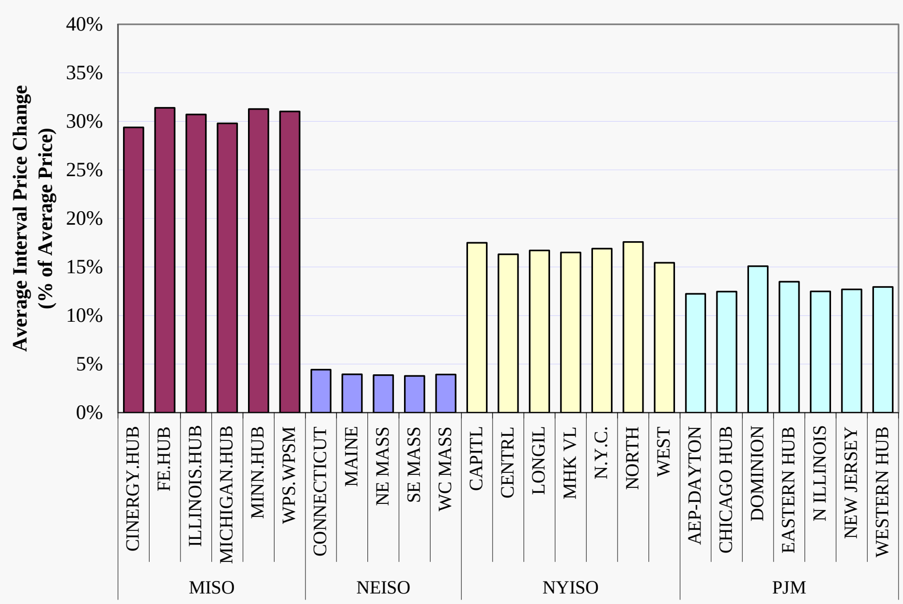
Five-Minute Real-Time Price Volatility MISO and Neighboring Markets



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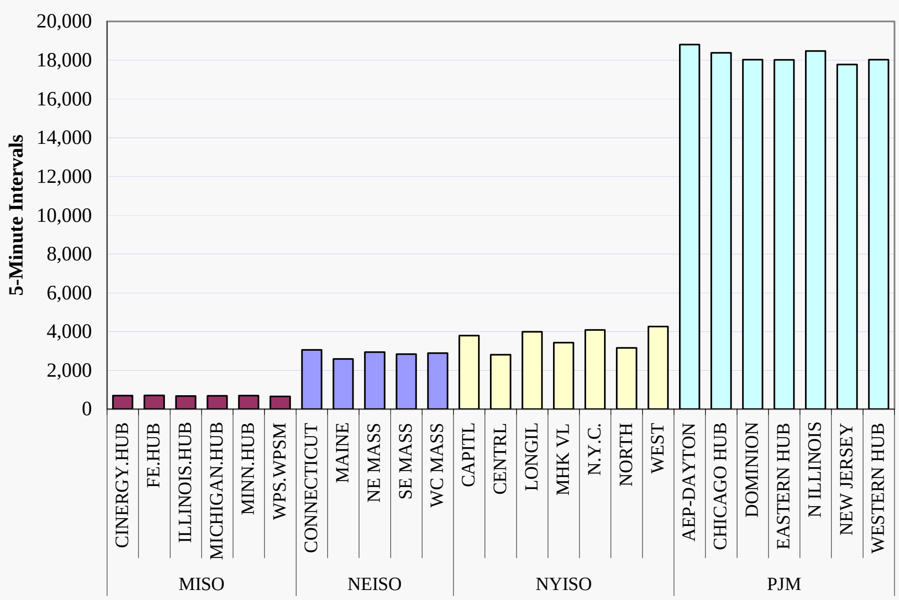
Five-Minute Real-Time Price Volatility MISO and Neighboring Markets

- One factor that may contribute to price volatility is the frequency with which 5 minute prices are approved and published.
  - ✓ One useful metric is to determine how often real-time prices are modified.
  - ✓ The Midwest ISO runs its real-time dispatch model and calculates 5-minute prices with its ex-post price calculator every 5 minutes.
  - ✓ Some of the other RTOs run their real-time dispatch model less frequently, but still calculate prices each 5 minutes.
  - ✓ In general, the more frequently the system is redispatched and prices recalculated, the more volatile the real-time prices will be.
- The second chart details how frequently five-minute prices are being modified in MISO and neighboring markets.
  - ✓ PJM did not modify their five-minute prices in 18,000 intervals during 2007. This is roughly 17% or two intervals per hour.
  - ✓ MISO solved its market in over 99% of intervals during 2007.
- Suggestions for reducing price volatility can be found at the end of this section.

Frequency of Missed Five-Minute Market Solutions MISO and Neighboring Markets



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 markets, or when net virtual supply is scheduled in the day-ahead that must be replaced.
- The figure shows that 97 percent of real-time generation is scheduled in the day-ahead market.
- 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 29 percent in the day-ahead market to 20 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.

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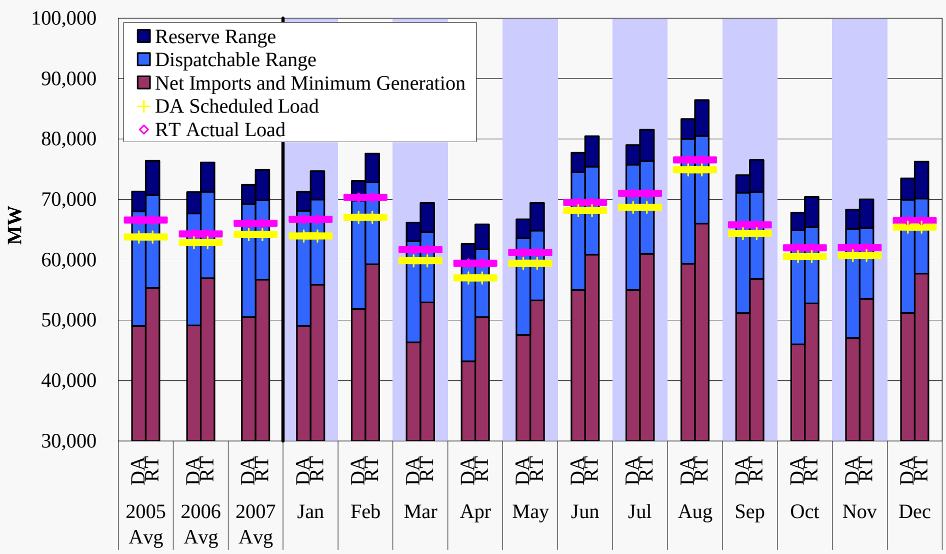
Day-Ahead and Real-Time Generation 2007: All Hours



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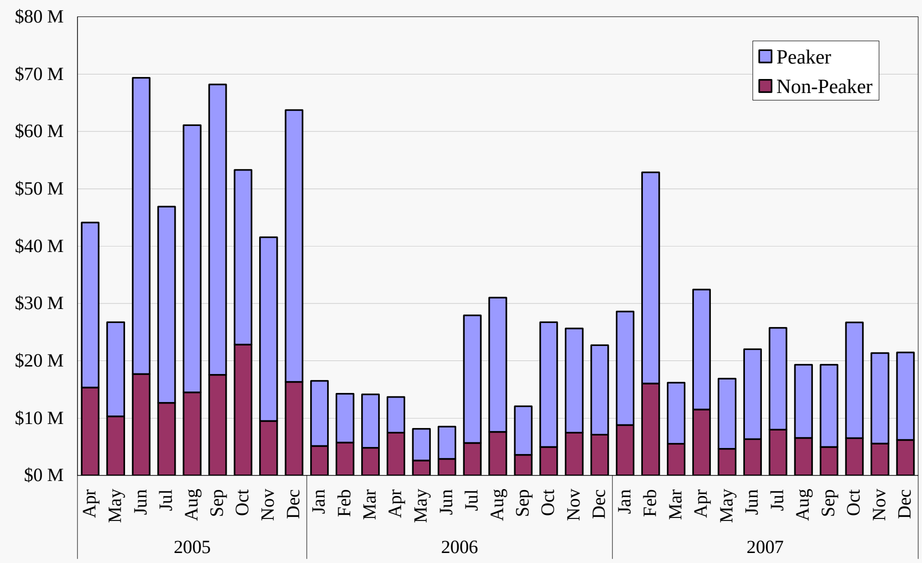
Revenue Sufficiency Guarantee Payments Day-Ahead and Real-Time

- The next two figures shows 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 are 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 the vast majority of RSG is generated in the real-time market and is paid to peaking resources.
  - ✓ RSG payments to peaking resources accounted for 70 percent of RSG payments in 2007, although they produced less than 1 percent of the energy generated in MISO.
  - ✓ This is expected because peaking resources are generally the highest cost resources and must be relied on to meet the reliability needs of the system, even when they are not economic.
- Real-Time RSG costs increased from $18.4 million per month in 2006 to $25.2 million per month in 2007. This was due to:
  - ✓ Higher load during the first six months of 2007 relative to the load during those months in 2006, and
  - ✓ Increased commitment of peaking resources in the West to manage congestion caused, in part, by lower imports over the Manitoba interface.
- The second figure shows Day-Ahead RSG, which declined $14 million (or 35%) during 2007 to $26.4 million.
  - ✓ RSG in the Day-Ahead market continues to be a small percentage (8.1%) of total uplift costs to the market.
- In total, RSG cost from both markets decreased by more than $7 million.

Total Real-Time RSG Distribution April 2005 through December 2007



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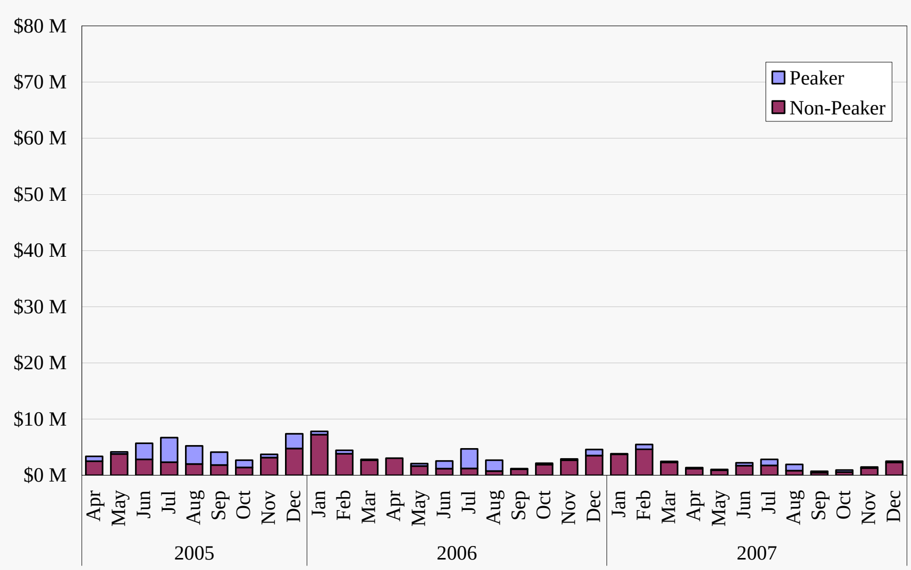
Total Day-Ahead RSG Distribution April 2005 through December 2007



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Weekly Real-Time RSG Payments

- The following figure analyzes the data in the previous figure by week and region, which shows more clearly when RSG costs were incurred.
- Much of the highest weekly RSG costs were caused, in part, by transmission congestion.
  - ✓ Early in 2007, congestion into Minnesota and WUMS required supplemental commitment of peaking resources and resulted in higher RSG costs.
  - ✓ This congestion was associated with south to north constraints in Iowa, which were binding frequently as imports decreased over the Manitoba interface. Certain transmission and generation outages also contributed to the congestion.
  - ✓ Although not all of the RSG paid to generators in Minnesota and WUMS is due to congestion, the majority of the substantial increase in such costs late in the year is due to the congestion.

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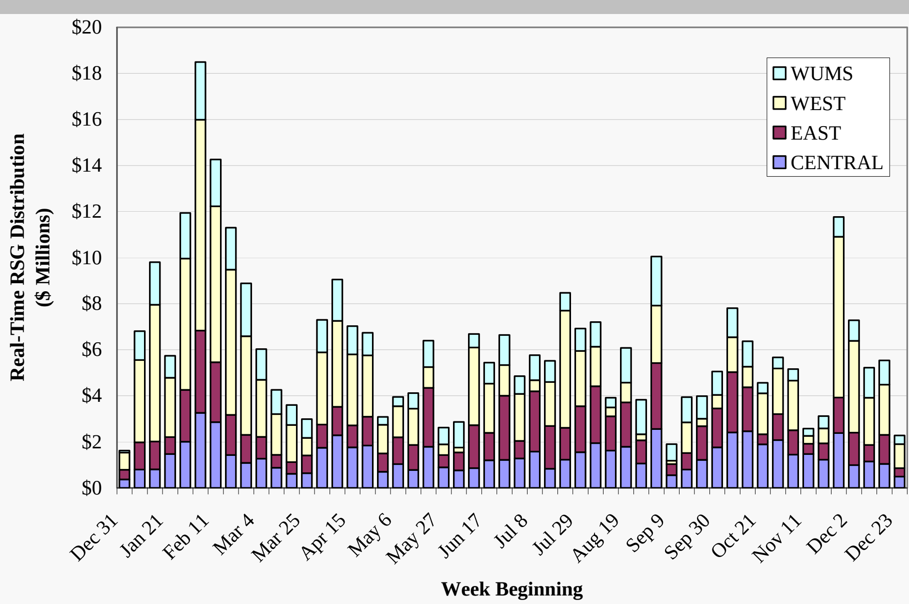
Weekly RSG Distribution by Region



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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 was highest in the summer in 2005-2006. During 2007, real-time demand and RSG both peaked in February.
  - ✓ Peak-hour net load scheduling in the Day-Ahead was close to 93 percent during February, which is the lowest level since the start of the market in 2005.
  - ✓ Actual load exceeded the capability of online units committed in the day-ahead, which caused substantial additional generation to be committed by the ISO.

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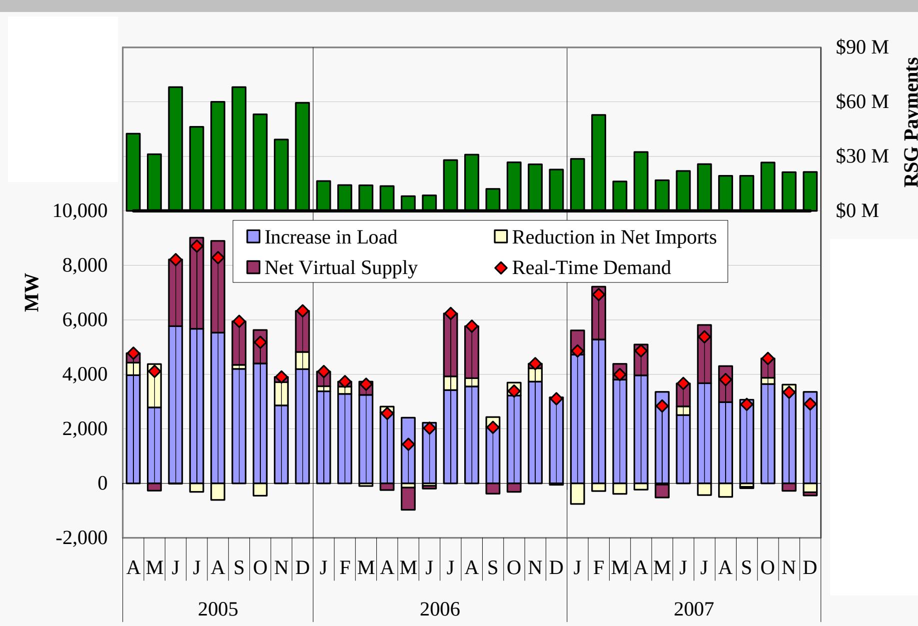
RSG Trends and Analysis



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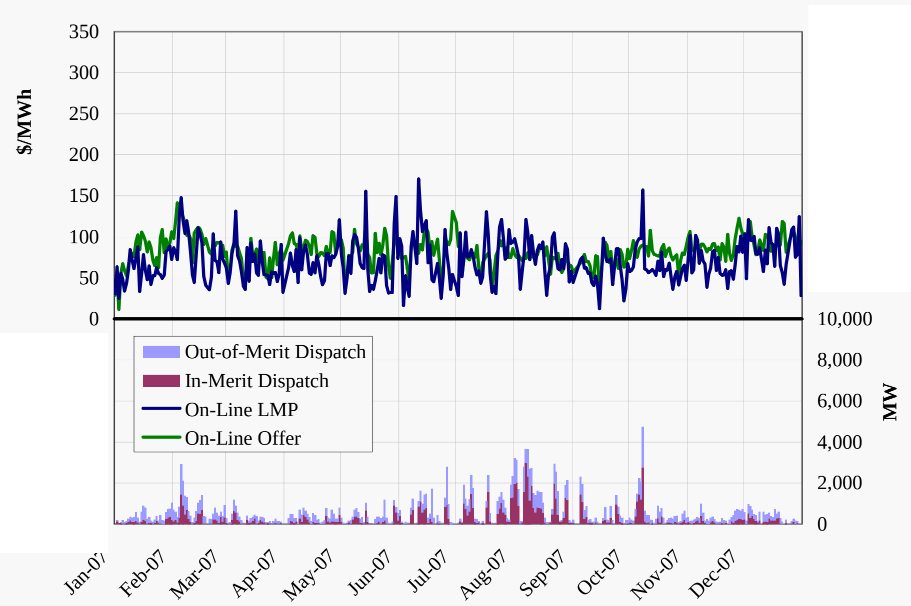
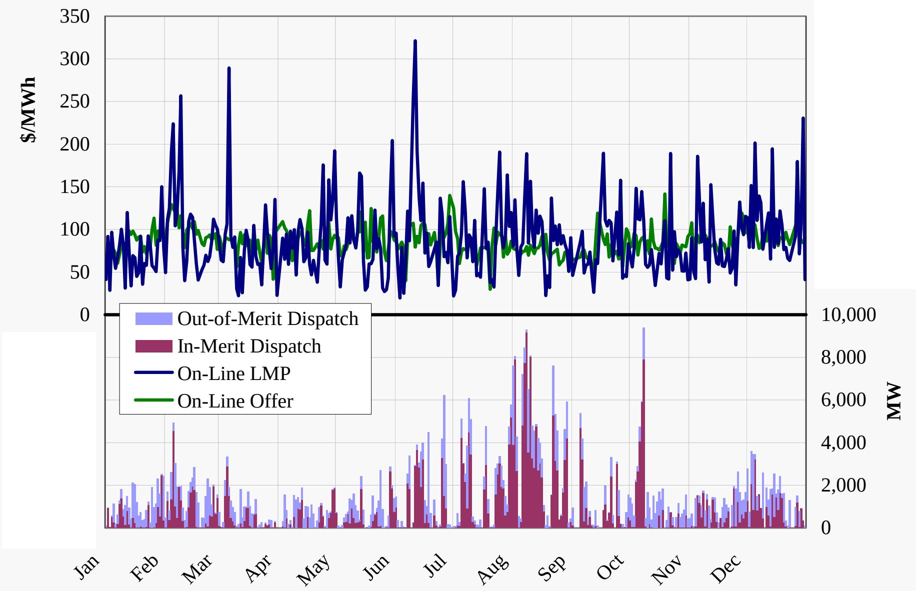
Dispatch of Peaking Resources

- As discussed above, the dispatch of peaking resources is important because it is an important determinant of RSG and efficient energy pricing.
- The following two figures summarize the dispatch of peaking resources in 2007, showing the average hourly and peak hour dispatch of peaking units by day.
- In 2007, an average of almost 1000 MW of peaking resources were dispatched per hour in the summer and 433 MW were dispatched per hour in other months -- these averages are much lower than the levels in 2005 and slightly higher than the levels in 2006.
- 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 > peaker offer) and out of merit (LMP < peaker offer) 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 economic analysis of the peaking resource dispatch shows that:
  - ✓ Only 45 percent of the peaking resources were in-merit, indicating that they frequently do not set the energy price.
  - ✓ A larger share of peaking resources (54 percent) are in-merit when they are heavily relied on in the summer.
  - ✓ The implications of out-of-merit peaking resources are discussed later in the report.

Daily Peaker Dispatch and Prices
All Hours



Peaker Dispatch and Prices in Peak Hour



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Ex-Ante and Ex-Post Price Differences All Hours: 2005-2007

- 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.

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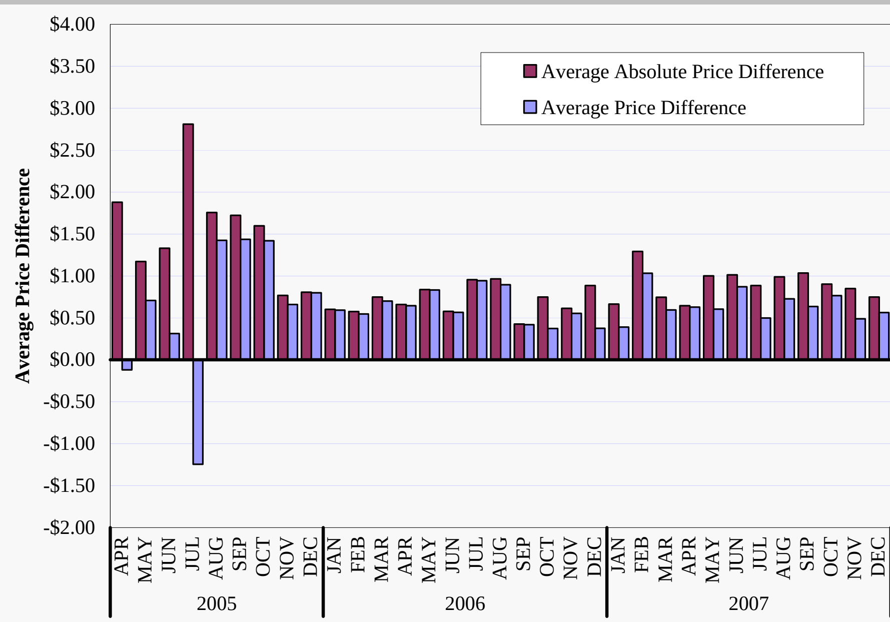
Ex-Ante and Ex-Post Price Differences
All Hours: 2005-2007

- The price consistency is evaluated in the next figure, which 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, as were the typical hourly difference (measured by the average of the absolute value of the hourly difference).
  - ✓ However, there is a persistent bias in the ex-post calculator that causes the ex-post in nearly all cases to be equal to or exceed the ex-ante.
- The ex-post pricing methodology accomplishes two purposes:
  - ✓ It allows the Midwest ISO to calculate energy prices that correct for errors that may have been included in the ex-ante dispatch and prices; and
  - ✓ It re-solves prices adjusting for generation that is not following dispatch instructions.
- 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 in general 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.

Ex-Ante and Ex-Post Price Differences
All Hours: 2005-2007



Real-Time Market: Conclusions

- In its third year, the Midwest ISO's real-time market performed well.
  - ✓ The nodal market accurately reflected the value of congestion in the Midwest – the most substantial congestion was into WUMS and into Minnesota in the first half of the year.
  - ✓ Prices in the real-time market were substantially more volatile than in the day-ahead market, as expected, but also more volatile than the prices in neighboring markets.
- 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.
  - ✓ Less than optimal commitment and de-commitment of peaking resources.
  - ✓ The fact that prices do not always reflect the marginal value of energy when the system must rely on relatively inflexible peaking resources or demand response.
  - ✓ The lack of ancillary service markets that are jointly optimized with the Midwest ISO's energy markets.
  - ✓ The ex-post pricing methodology that has served to increase prices slightly and results in inconsistencies between the real-time prices and dispatch signals.

Real-Time Market: Recommendations

The Midwest ISO is scheduled to introduce ancillary services markets in September 2008.

- Ancillary services markets that are jointly optimized with energy will allow the market to more efficiently allocate resources between the two services.
- ASM will also set efficient prices in both markets to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
- With ASM, the Midwest ISO will implement make-whole payments to ensure that generators following five-minute dispatch instructions when prices are volatile are not harmed it their hourly settlements. This should provide better incentives to be flexible.

To improve the performance of the real-time market, we recommend the Midwest ISO consider the following changes to the real-time market (this section does not address congestion management or external transactions).

1. *Develop a "look-ahead" capability in the real-time that would commit quick-starting gas turbines and better manage ramp capability on slow-ramping units.*
   - The MISO has made operational improvements in its commitment of peaking resources, but the commitment of these units can be further improved by reliance on an economic model to commit the units.
   - Allowing the market to commit and de-commit the turbines would reduce the out-of-merit quantities, reduce RSG payments, and improve the ability of peaking resources to set the energy price.

Real-Time Market: Recommendations

2. *Replace its current ex-post pricing methodology with an approach that would simply utilize ex-ante prices corrected for metering or other errors.*
   - Ex-post pricing has never been shown either theoretically or empirically to improve the efficiency of real-time prices or the incentives of suppliers.
3. *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 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 2008.
4. *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.

Transmission Congestion and FTR Results

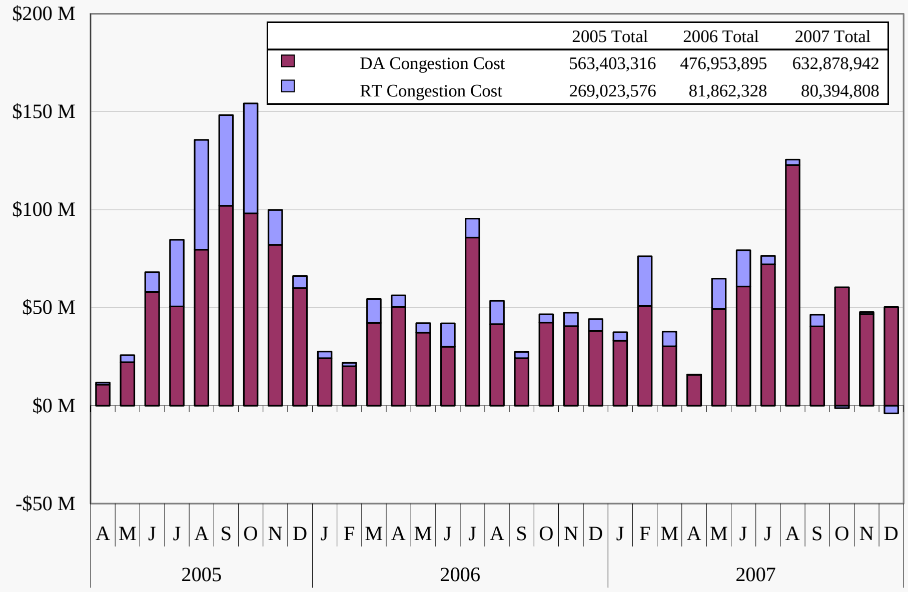
Transmission Congestion and FTRs

- One of the primary functions of the Midwest ISO energy markets is to deliver the lowest cost supply to load given the 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 capability is limiting such that higher-cost resources must be dispatched to serve the load (i.e., a transmission constraint is binding), the prices on either side of the transmission constraint will vary.
  - ✓ This results in congestion costs being incurred that reflect the value of the transmission constraint.
  - ✓ An efficient system will always have congestion because transmission investment should only be made when the cost of the investment is lower than the congestion cost.
  - ✓ The congestion costs collected by the Midwest ISO in the day-ahead market are rebated back to holders of Financial Transmission Rights (“FTRs”), which serve as a hedge against the congestion costs.
- This section of the report evaluates the congestion costs, FTR market results, and the Midwest ISO’s management of congestion.

Total Congestion Costs 2005-2007

- The first figure in this section shows total congestion costs by month in the MISO market for 2005 through 2007.
- In 2005, the congestion costs were relatively high due in part to high natural gas prices after Katrina and to PJM’s exports to TVA that were not well-coordinated with the Midwest ISO.
- In 2007, day-ahead congestion costs increased to $633 million from $477 million in 2006. This increase in 2007 was primarily due to:
  - ✓ Higher gas prices, which increases congestion by increasing redispatch costs; and
  - ✓ Reduced imports over the Manitoba interface and certain outages that increased congestion into the West (the Minnesota NCA) during the first half of the year.
- Real-time residual congestion costs in 2007 roughly equaled those in 2006.
  - ✓ One would normally expect the real-time congestion to be very low if the modeling of the transmission system is consistent between the day-ahead and real-time markets.
    - – Nearly 90 percent of total congestion was captured in the Day-Ahead market, a marked improvement from 2005.
  - ✓ This issue is evaluated and discussed later in this section.

Total Congestion Costs
April 2005 through December 2007



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Day-Ahead Congestion and Obligations to FTR Holders
April 2005 through December 2006

- The following figure compares monthly day-ahead congestion collections to monthly FTR obligations (day-ahead congestion is used to pay FTR holders).
  - ✓ Surpluses and shortfalls occur when the FTRs held by participants differ substantially from the capability of the system. Hence, surpluses or shortfalls can occur when:
    - – The Midwest ISO sells fewer or more FTRs than the capability of the network.
    - – Transmission outages or other factors cause the capability of the system to differ from the capability of the system assumed when the FTRs were allocated/sold.
    - – Loop flows over the system caused by generators and loads outside of the Midwest ISO use more or less of the transmission capability than assumed in the FTR market.
- The figure shows that the day-ahead congestion collections were substantially less than FTR obligations in 2007 (over 19 percent) after incurring a 10 percent shortfall in 2006.
- The Midwest ISO has continued to work on the FTR allocation and supporting modeling to reduce the shortfalls and major changes were made in the FTR modeling which should be fully reflected in the June 2008 funding results. The changes will generally:
  - ✓ Improve loop flow assumptions.
  - ✓ Add additional constraints related to market-to-market and non-market constraints.
  - ✓ Broadly reduce transmission line limits to account for expected differences in FTR modeled conditions and actual hourly results.

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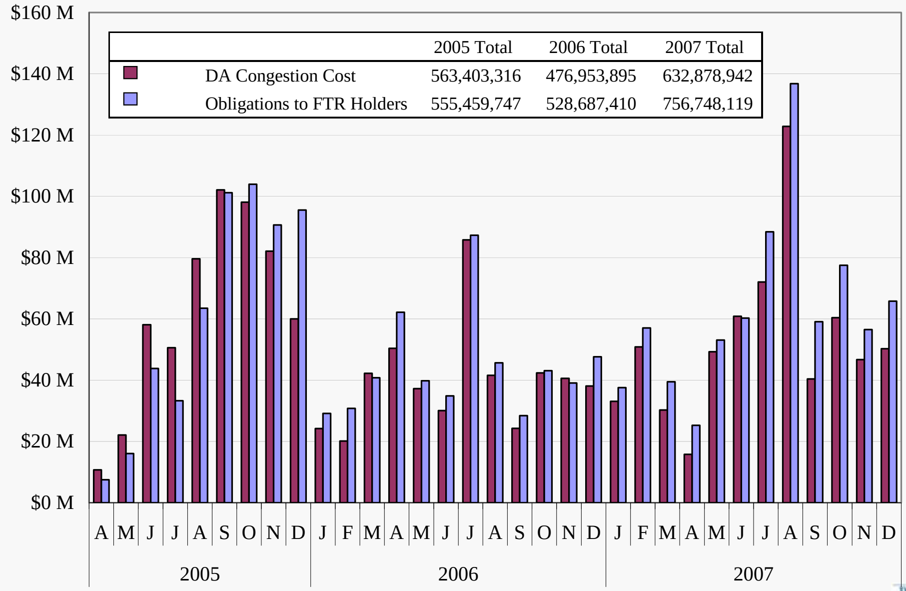
Day-Ahead Congestion and Payments to FTR Holders
April 2005 through December 2007



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Payments to FTR Holders
April 2005 through December 2006

- The following figure shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-out FTRs (i.e., 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.
  - ✓ 95 percent of all payments were made to holders of conventional FTRs (i.e., only 5 percent of payments were made to holders of other types of transmission rights).
  - ✓ Making relatively small payments on the other types of rights is good because they do not provide the same efficient incentives as FTRs.
  - ✓ Payments to the holders of the alternative rights almost doubled, but still amounted to only about 5 percent of the total FTR payments.
- As noted funding shortfalls were substantial in 2007, which indicates problems with the consistency of the assumptions employed regarding transmission capability and loop flows in the FTR and Day-Ahead markets.

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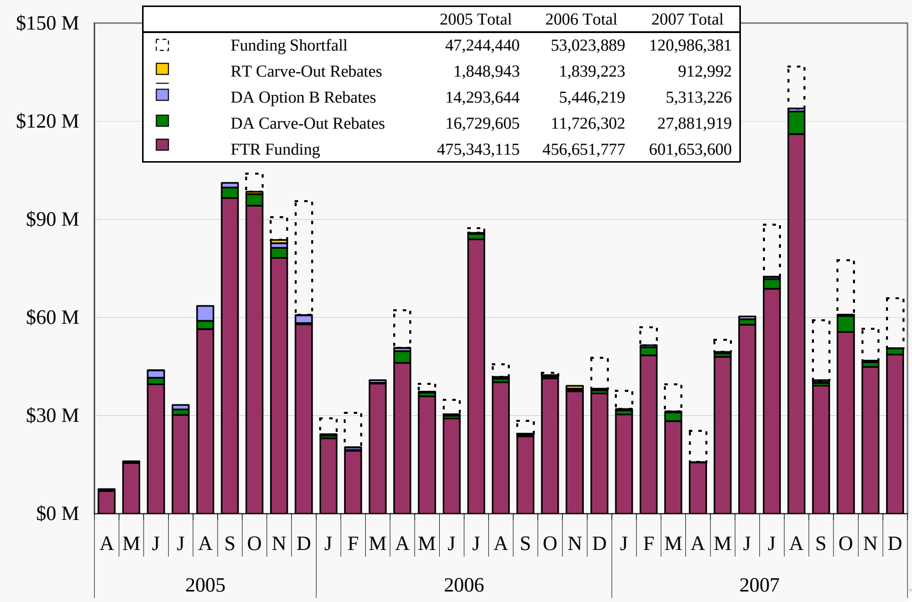
Payments to FTR Holders 2005 to 2007

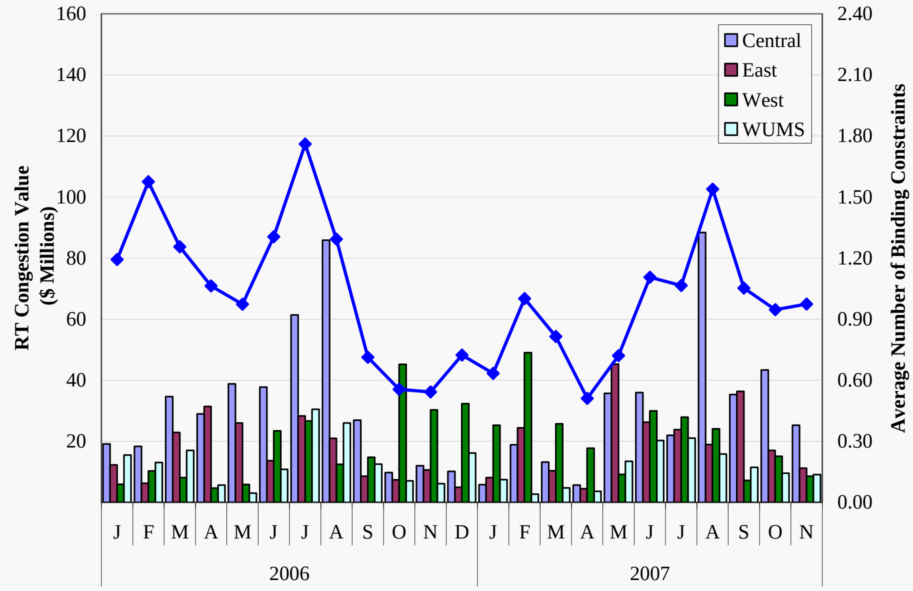


	2005 Total	2006 Total	2007 Total
Funding Shortfall	47,244,440	53,023,889	120,986,381
RT Carve-Out Rebates	1,848,943	1,839,223	912,992
DA Option B Rebates	14,293,644	5,446,219	5,313,226
DA Carve-Out Rebates	16,729,605	11,726,302	27,881,919
FTR Funding	475,343,115	456,651,777	601,653,600

Value of Real-Time Congestion by Coordination Region 2006 and 2007

- To show the value of the physical congestion in real-time, the next two figures show the value and shares of real-time congestion by region.
  - ✓ The value of real-time congestion is equal to the marginal cost of the constraint (i.e., the shadow price) times the flow over the constraint.
- The total value of real-time congestion increased slightly in 2007 from 2006.
  - ✓ We estimated $984 million of real-time congestion in 2007, up from $960 million in 2006.
  - ✓ Congestion on transmission constraints in the Central region was substantial during the summer months and in early 2006 and late 2007 – in total, it accounted for the largest share of the real-time congestion.
  - ✓ However, more than half of the congestion between October 2006 and April 2007 was related to transmission constraints into the West region.
    - – This congestion was primarily due to reduced availability of imports over the Manitoba interface and high winter loads.
  - ✓ As in prior years, WUMS accounted for a large share of total congestion relative to portion of the market load located in WUMS.
- The first figure also shows that the average frequency of binding constraints (per interval) decreased slightly in 2007 (1.08 to 0.93 constraints binding per interval).
  - ✓ However the frequency patterns were similar in both years, peaking during the summer seasons when the demands on the network are the greatest.

Value of Real-Time Congestion by Coordination Region 2006 and 2007



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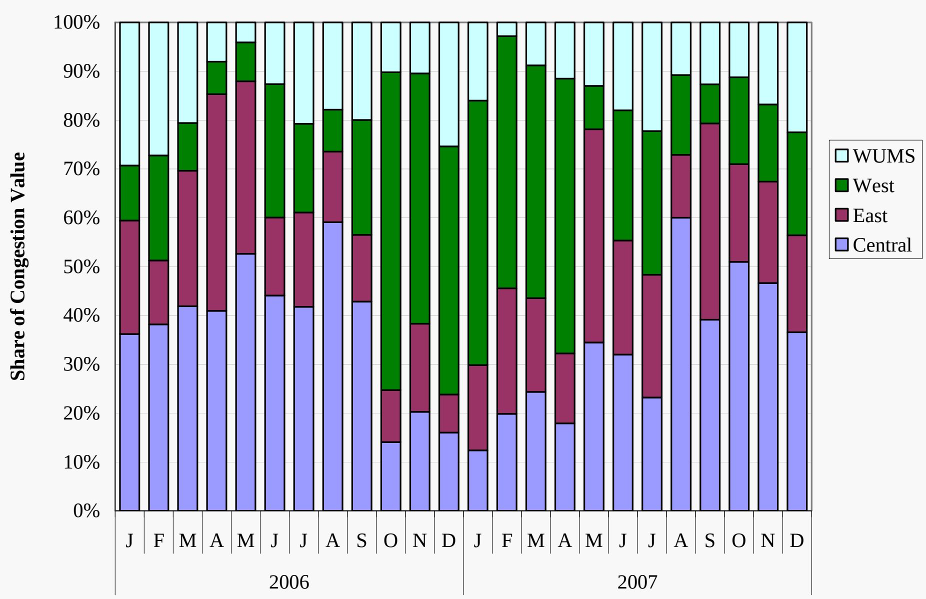
Share of Real-Time Congestion by Coordination Region 2006 and 2007



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Value of Real-Time Congestion by Type of Constraint April 2005 through December 2007

- The next figure shows the value of real-time congestion by the type of constraint – computed in the same manner as in the prior figures.
  - ✓ The types of constraints include: MISO internal constraints, MISO market-to-market constraints, PJM market-to-market constraints, and external constraints.
  - ✓ Congestion occurs on external constraints when a TLR is called on a neighboring system that causes MISO to re-dispatch its generation.
- As in prior years, most of the congestion in 2007 occurred on MISO internal constraints (including the MISO market-to-market constraints).
  - ✓ Together the MISO constraints (internal and market-to-market) represent nearly 94.3 percent of the congestion value.
- Most of the remaining congestion is associated with external interfaces -- much of the external congestion was located at LG&E and TVA interfaces.
- We review market-to-market results in more detail later in this presentation.

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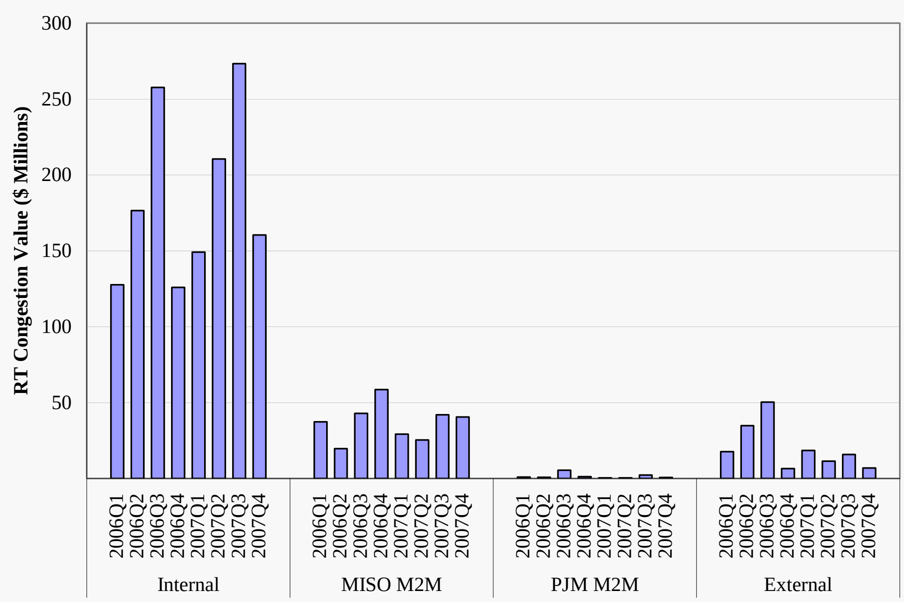
Value of Real-Time Congestion by Type of Constraint 2006 - 2007



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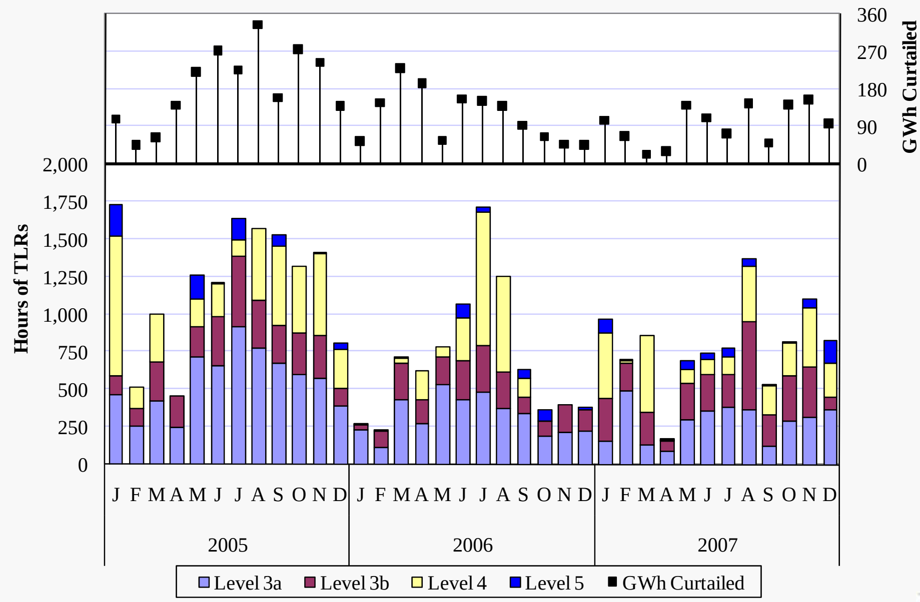
TLR Events in 2005 through 2007

- 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 2005 - 2007

- The next figure details TLR activity in 2004 to 2007 by month and TLR level. In the top panel of the figure, the quantity of transactions curtailed by the TLRs are shown.
- This figure shows that the TLR calls by MISO decreased after the implementation of the energy markets in 2005 and then declined further in 2006 and 2007.
  - ✓ The implementation of the markets was not expected to reduce the TLR calls substantially because MISO still invokes TLR procedures to ensure others outside of the MISO assist in relieving congestion on its transmission system.
  - ✓ Although the significant quantities of TLRs are still called, the reliance on economic redispatch for managing congestion has increased substantially.
  - ✓ The reduction in TLRs has translated into fewer schedule curtailments.
    - – Curtailments in 2007 were almost 50 percent lower than in 2005 and 18 percent lower than the curtailments in 2006.
- With regard to the patterns of TLR activity in 2007, the figure shows:
  - ✓ TLR activity increased early in the year as congestion into the West increased.
  - ✓ TLRs also increased in October and November 2007 due to problems with AFC calculations on flowgates in the West region.

Monthly TLR Activity 2005 - 2007



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TLR Events by Region

- The next figure shows the number of TLRs called in 2004 to 2007 by region.
- The figure shows that regional TLR activity has generally decreased in most of the regions.
  - ✓ In all regions except the West, TLR has decreased substantially from 2005 to 2007.
  - ✓ In the West, congestion increased markedly in 2007 due to:
    - Reduced availability of imports over the Manitoba interface and high winter loads in early 2007;
    - Errant AFC calculations caused over-scheduling of import capability in the day-ahead – this over-scheduling compelled the Midwest ISO to rely on TLRs to curtail schedules in the real-time in late 2007.
  - ✓ In the Central region, TLRs spiked in 2005 due to increased congestion caused by transmission service sold by PJM to TVA that was not coordinated with MISO. Steps have been taken to better manage this service.
  - ✓ Much of the TLR activity from 2004 has been eliminated in the East region due to the Market-to-Market coordination with PJM.
  - ✓ Level 4 TLRs have been eliminated in WUMS. Prior to the MISO markets, American Transmission Company ("ATC") redispatched generation when level 4 TLRs were called. This redispatch is now accomplished through the MISO energy market.

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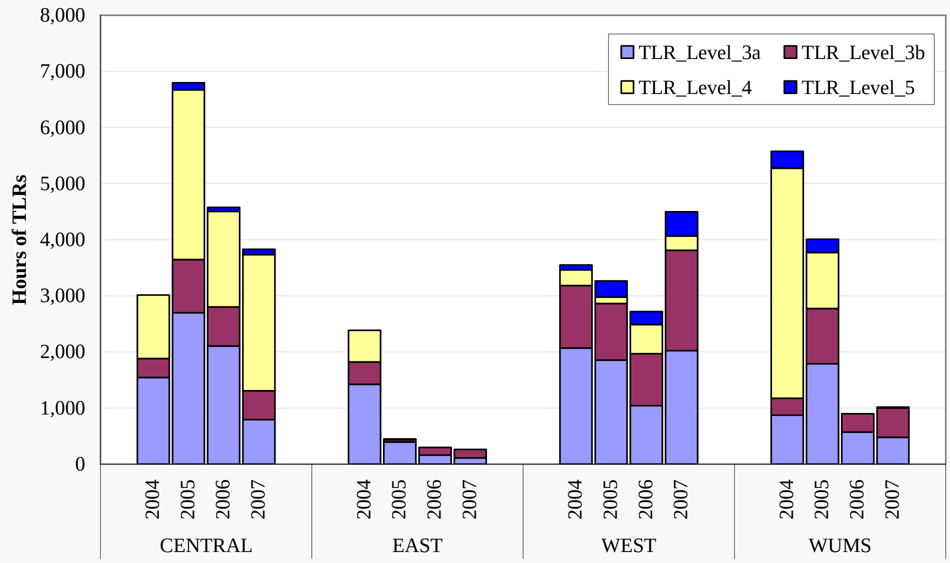
TLR Events by Severity
2004 to 2007 by Region



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Congestion and Manageability
2006 - 2007

- 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. This figure shows:
  - ✓ In 2006, 80 percent of the congestion was manageable on a five-minute basis. In 2007, this decreased to 74 percent.
  - ✓ Some of the unmanageability is caused by inflexible supply offers, which are evaluated in more detail later in this section.
  - ✓ Manageability should improve after the Price Volatility Make Whole Payment is in place as this will provide an incentive to offer more flexibility.

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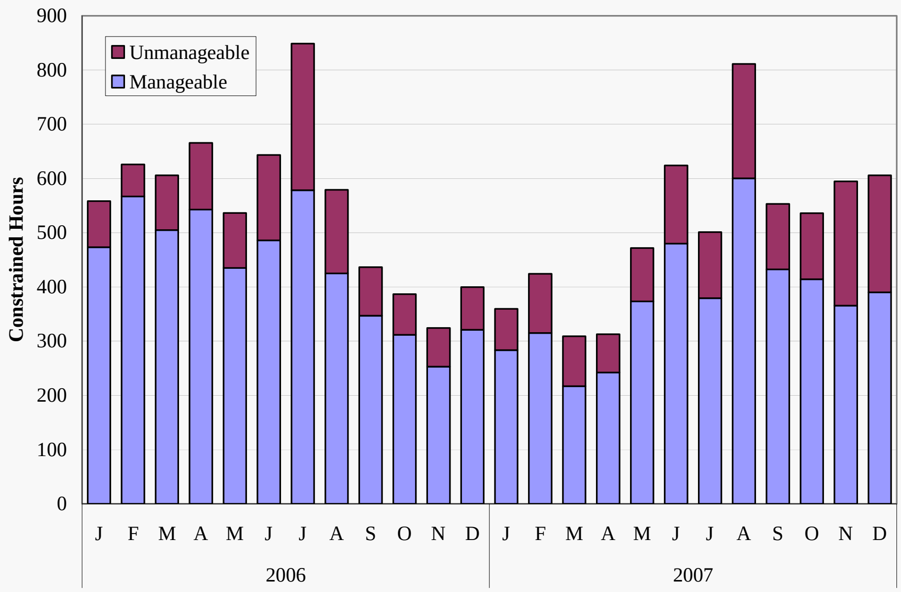
Congestion and Manageability 2006 - 2007



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Congestion and Manageability 2006 - 2007

- The next chart shows the value of real-time congestion on selected interfaces, indicating the portion of the congestion that was manageable.
- This figure shows that congestion in 2006 and 2007 was greatest on the interfaces into Minnesota and into the WUMS NCA.
  - ✓ 32 percent of congestion North-to-Minnesota during these two years was unmanageable, compared to only 15 percent and 12 percent for the southern and western interfaces into WUMS, respectively.
    - – The Minnesota NCA was designated in January 2007 as a result of the increased frequency of the congestion into the area.
  - ✓ The manageability on WUMS constraints improved substantially in 2007 due in part to the addition of transmission which reduced flows on Eau Claire-Arpin.
- The north-south congestion to TVA was a significant factor during the first two years of Day 2 operations.
  - ✓ During 2007, however, the total congestion along this path declined by more than 70 percent due to better coordination with PJM and changes in market demands.

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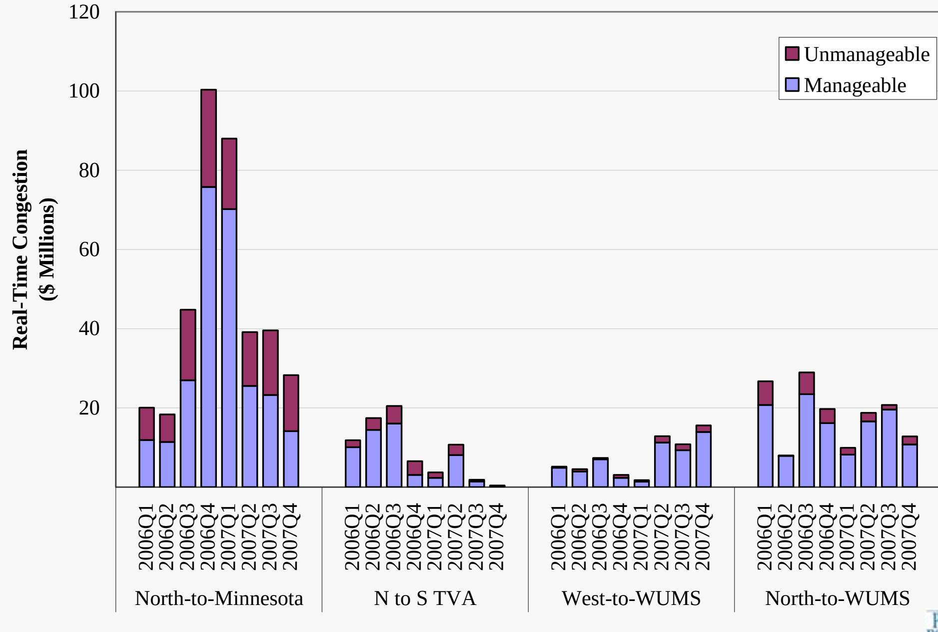
Real-Time Congestion and Manageability by Path 2006 – 2007



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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 -- prevents the market from reducing the output of a resource and can contribute to congestion when the resource's output increases the flow on a line.
  - ✓ Slow ramp limits: Ramp rate limitations that are slower than the physical ramp capability -- this reduces 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 (capability to reduce the flow on a constraint) that was unavailable due to each of these factors; and
  - ✓ the average percentage over the transmission limit of each constraint when it was unmanageable ("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. We attribute the lack of flexibility to:
  - ✓ Justifiable technical concerns in some cases or simply a desire to operate conservatively.
  - ✓ Lack of recognition by some participants of the increased profits available from the market if they are flexible.
  - ✓ 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 to be implemented with ASM.

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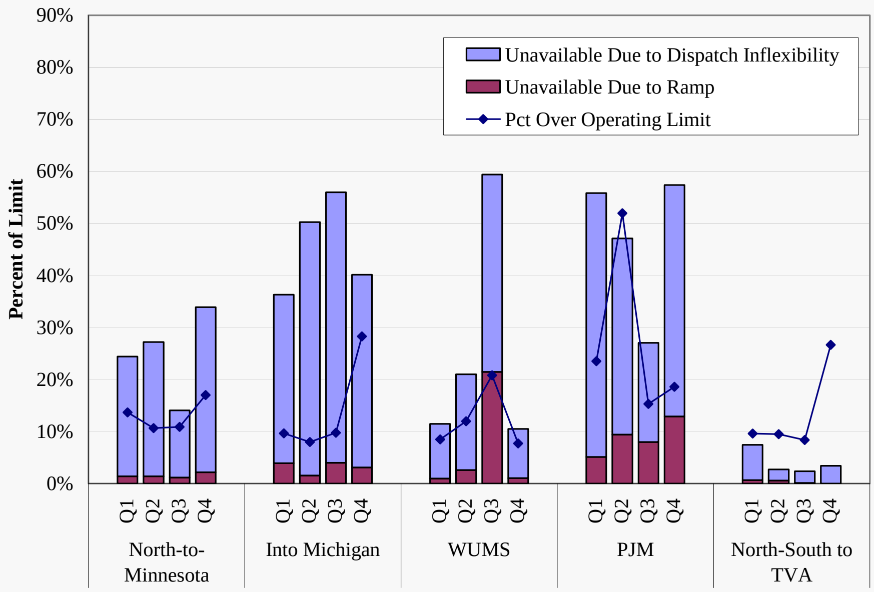
Congestion Relief Unavailable Due to Offer Parameters Selected Paths: 2007



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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.
  - ✓ Currently in the real-time market, units with generation shift factors ("GSF") less than 2 percent (or greater than -2 percent) are not redispatched to manage a constraint.
  - ✓ 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.
- In last year's report, we showed that the additional relief available by lowering the cutoff generally exceeds the average violations on the unmanageable constraints.
  - ✓ Hence, we recommended report that Midwest ISO reduce the cutoff as much as feasible.
  - ✓ The Midwest ISO has recently received a software modification that will allow it to begin to reduce this parameter in both the real-time and day-ahead markets.

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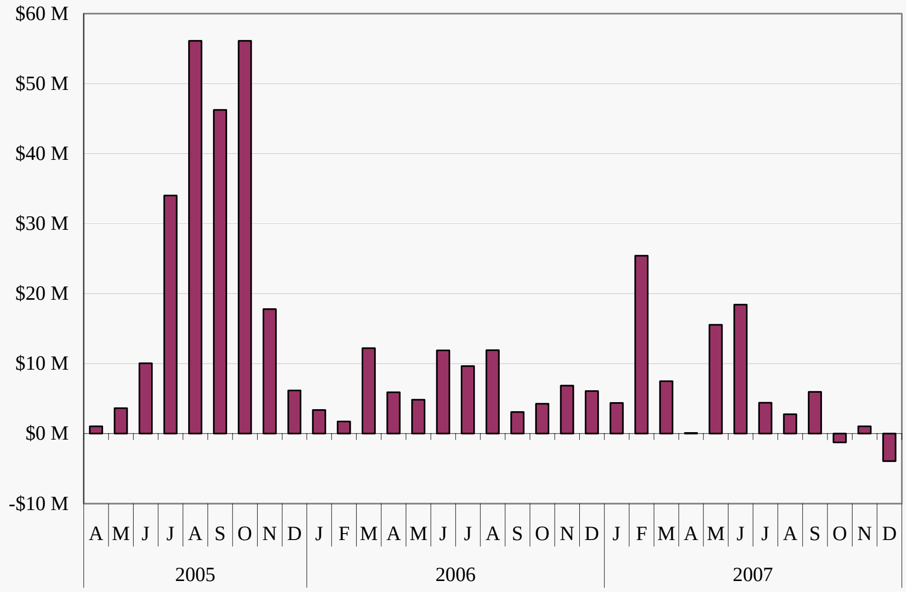
Pricing Unmanageable Transmission Constraints

- 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 20 percent of the cases when a constraint is 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 MISO 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, therefore, 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.

Balancing Congestion Costs 2005 - 2007

- 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 close to 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 MISO to incur real-time congestion costs to reduce the flow on constrained facilities in real time, which would be recovered through uplift charges.
- The figure shows the real-time congestion costs from 2005 to 2007.
  - ✓ In 2005, balancing congestion costs rose substantially in the late summer and early fall 2005, totaling $270 million for the year.
  - ✓ In 2006 and 2007, balancing congestion costs were greatly reduced to only $82 and $80 million, respectively. The factors contributing to this decline include:
    - Improvements made in the Day-Ahead modeling of loop flows;
    - A general decrease in the frequency of congestion; and
    - Lower fuel prices than in 2005, which reduces the costs of redispatching generation.
  - ✓ In October and December 2007, balancing congestion costs were negative due to payments received from PJM for Market-to-Market coordination. Those payments from PJM totaled $11.6 million in 2007. In 2006, MISO paid PJM $1.2 million under the JOA.

Balancing Congestion Costs
2005 – 2007



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Seasonal and Monthly FTR Auction Quantities
2005 - 2007

- The next analysis shows that quantities of FTRs for peak hours that were sold in the seasonal and hourly FTR auctions.
- The figure shows:
  - ✓ The total quantity of FTR purchases have been rising relatively steadily from 2005 to 2007 due to:
    - Fewer FTRs being allocated in advance of the auctions, notably in the summer of 2007.
    - The system is being more fully subscribed.
  - ✓ Like the total FTR purchased, the quantities purchased in the monthly auctions has risen substantially over time.
  - ✓ Roughly half of the FTRs purchased are through the monthly auctions in 2007.
    - Larger monthly sales allow the Midwest ISO to reflect more timely information on the state of the transmission system when it determines the quantity of FTRs that can be sold, which should reduce the surpluses and shortfalls.
  - ✓ The second half of 2007 suggests the market has approach maturity as volumes purchased have remained relatively unchanged.

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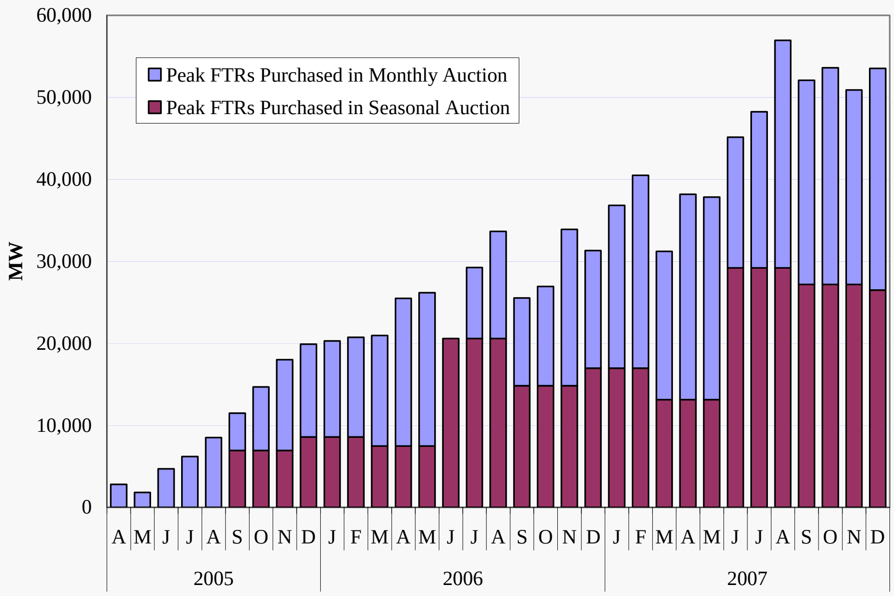
FTR Purchases
Monthly and Seasonal Auctions



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FTR Profitability
2005 - 2007

- 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 a 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 shows the profitability of FTRs purchased in the seasonal FTR auctions and the monthly FTR auctions.
- The first figure shows that average FTR profitability has declined from more than $1.50 per MW in the Fall of 2005 to less than $0.30 per MW on average in 2007.
  - ✓ Profitability is greater in peak hours than off-peak hours primarily because congestion is greater and more volatile in the peak hours.
- The second figure shows that average profitability has decreased from more than $1.30 per MW in three months late in 2005 to less than $0.20 per MW in most months in 2007.
- 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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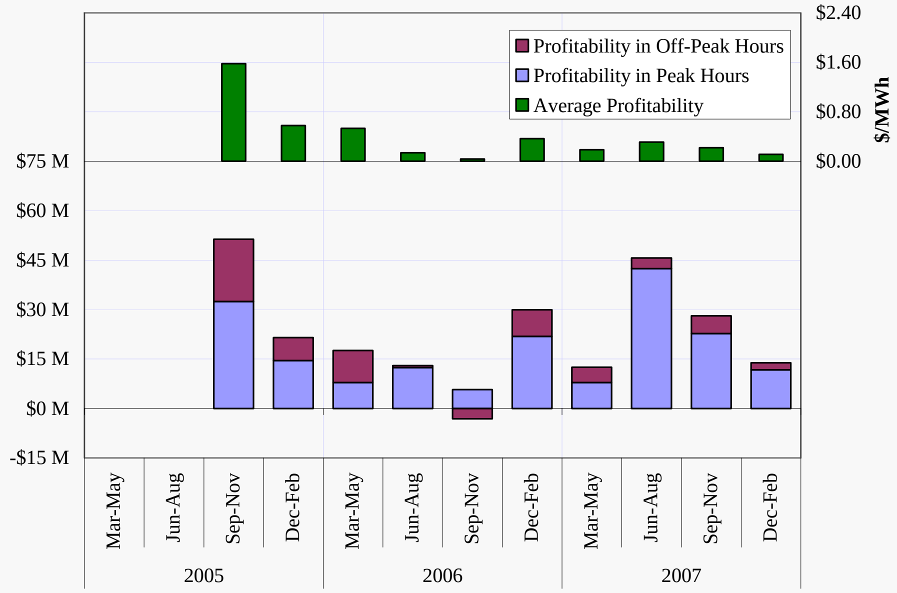
FTR Profitability
Purchases in Seasonal Auctions



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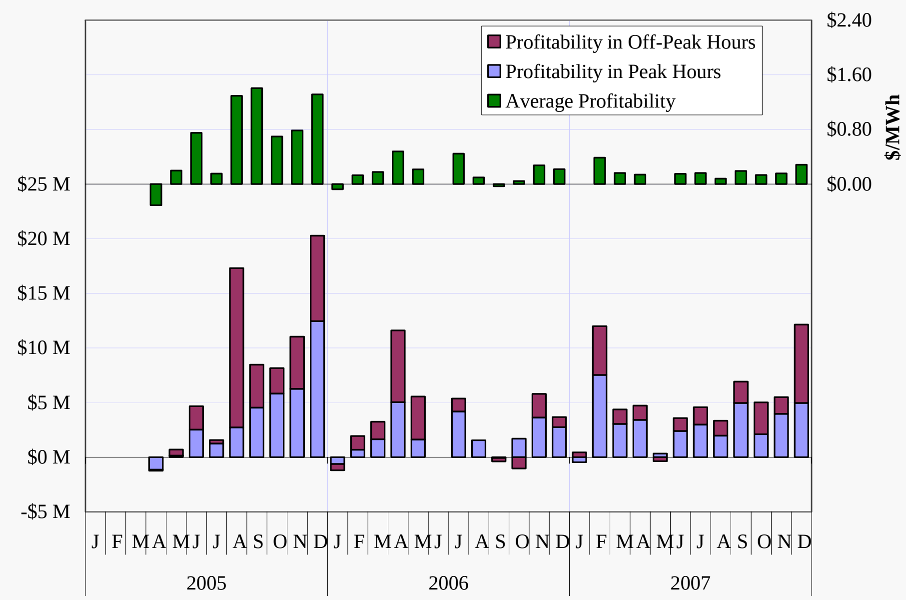
FTR Profitability
Purchases in Monthly Auctions



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FTR Auction Summary
2005 - 2007

- To provide further detail on the performance of the FTR markets, the next set of figures show the monthly FTR prices compared to day-ahead congestion that are payable to the FTR holders.
  - ✓ The figures shows the values for WUMS, the Minnesota Hub, and the Michigan Hub in peak and off-peak hours.
  - ✓ All the values shown in the figures are computed relative to Cinergy Hub, which is the most actively traded location in the MISO.
- 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 profits earned by an FTR holders is the difference between the FTR price paid and the congestion paid to the FTR holder.
  - ✓ The results in the following figure help explain the changes in FTR profitability shown in the prior figures.

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FTR Auction Prices and Congestion
WUMS

- The first two figures in this series show the results for WUMS in peak and off-peak hours.
- There was slightly more day-ahead congestion in 2007 into WUMS (relative to the Cinergy Hub) and the FTR values reflect this change.
- From July 2006 and December 2007, convergence between auction prices and congestion has been strong, particularly in off-peak hours.
  - ✓ The only peak month that did not converge well was August. However, the lack of convergence was not due to an unreasonable FTR price, but to anomalously low day-ahead congestion during the month.
  - ✓ The congestion patterns were less volatile and more predictable during the off-peak hours, which contributed to the stronger convergence of the FTR prices and congestion during those periods.

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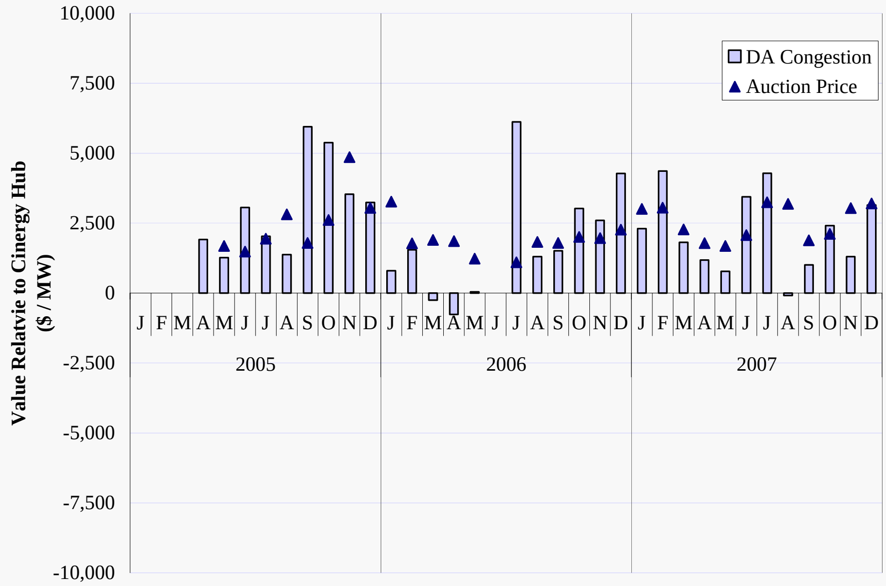
FTR Auction Prices and Congestion WUMS Area: Peak Hours



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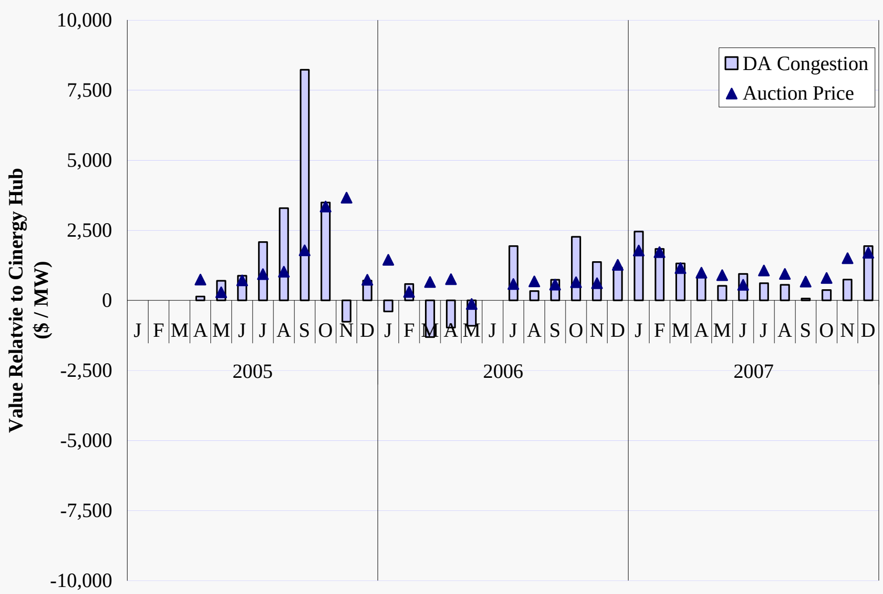
FTR Auction Prices and Congestion WUMS Area: Off-Peak Hours



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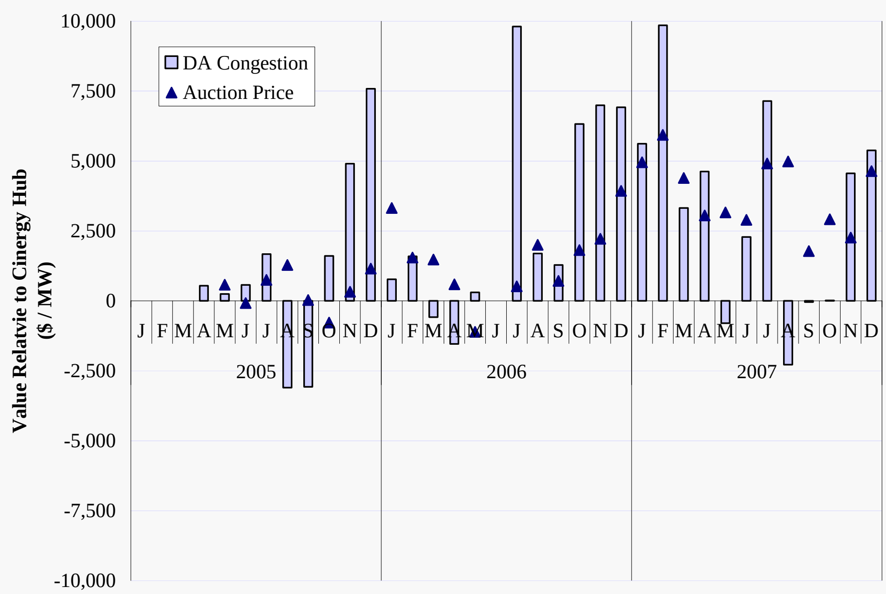
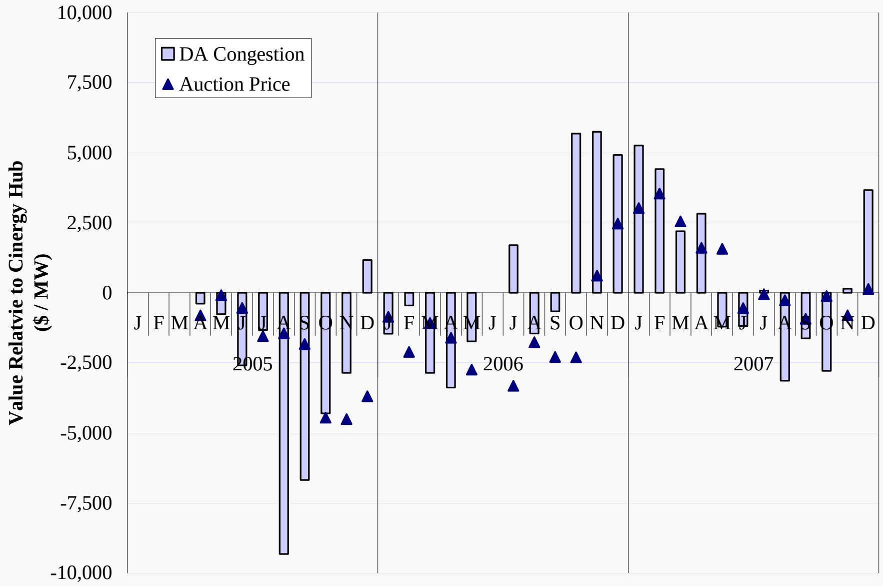
FTR Auction Prices and Congestion Minnesota Hub

- The congestion and FTR results for the Minnesota Hub have been volatile throughout the period from 2005 to 2007.
- In addition to volatility, the difficulties in valuing the FTRs are enhanced by the fact that the congestion can change directions. The Minnesota hub exhibited:
  - ✓ Negative congestion (nearly -$10,000/MW during off-peak hours in Aug. 2005); and
  - ✓ Positive congestion (nearly $10,000/MW during peak hours of February 2007).
- The negative congestion in 2005 was due to congestion into WUMS that was often difficult to manage, particularly in off-peak hours, due to dispatch inflexibility.
- Congestion reversed direction (from negative to positive) in the Fall 2006 due to increased south-to-north constraints into Minnesota that continued until Spring 2007.
  - ✓ In both peak and off-peak periods, auction prices rose during each month between September 2006 and February 2007.
  - ✓ The increased congestion into Minnesota was largely due to the reduced availability of imports over the Manitoba interface.
- Both figures shows that:
  - ✓ FTR prices responded to changes in congestion patterns with a lag as one would expect (since FTRs are sold prior to the month in which the congestion occurs).
  - ✓ Convergence is not as good for Minnesota largely because the congestion is more volatile and less predictable.

FTR Auction Prices and Congestion Minnesota Hub: Peak Hours



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



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External Transactions

POTOMAC ECONOMICS

Average Hourly Day-Ahead Imports
All Hours

- This section of the report evaluates the interchange between the Midwest ISO and adjacent areas.
- The analyses in this section summarizes the magnitude of the external transactions and evaluates the efficiency with which imports and exports are scheduled.
- The figure shows the average hourly net imports scheduled in the day-ahead market by day over all interfaces.
- The day-ahead figure 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 2007 was seasonal with the largest imports occurring during the summer under the tightest demand conditions, and to a lesser extent during winter peak conditions.
- Day-ahead imports averaged 3.7 GW over all hours and exceeded 6 GW during many peak hours in the summer.
  - ✓ This indicates the degree to which the Midwest ISO relies on net imports to satisfy the demands of the market.

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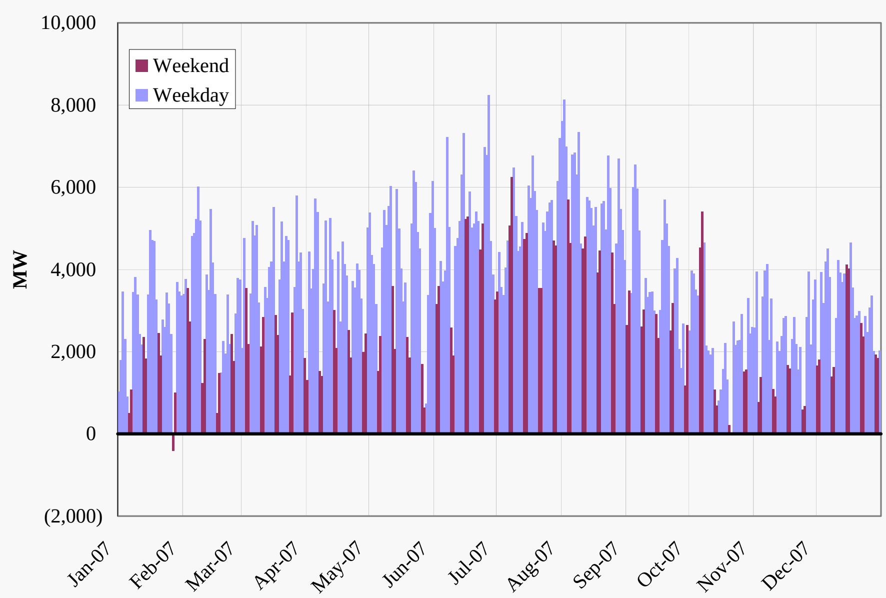
Average Hourly Day-Ahead Imports
All Hours



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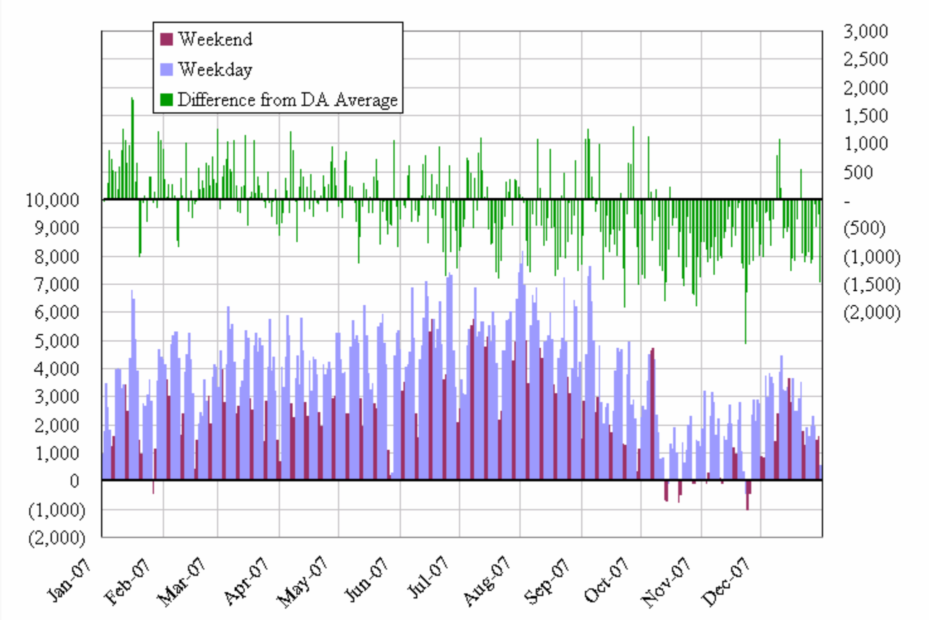
Average Hourly Real-Time Imports All Hours

- The next figure shows the net imports in the real-time market and the change in net imports from the day-ahead market.
- In 2007, the Midwest ISO imported almost 5 GW in on-peak hours and over 2.7 GW in off-peak hours -- more than a quarter of its net imports came from Manitoba.
- However, real-time net imports decreased more than 200 MW on average from those scheduled in the day-ahead market.
  - ✓ On many days the average net imports decreased by more than 1000 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 contributes to these changes and is assessed later in this section.
- The figure shows that the largest changes in net imports from day ahead to real time occurred during the 4th quarter which was largely due to:
  - ✓ Problems with AFC calculations by an adjacent transmission provider that resulted in over-scheduled day-ahead imports into the West region.
  - ✓ The excess schedules had to be curtailed in the real time.
  - ✓ The issue has been corrected and the Midwest ISO is monitoring for reoccurrences.

Average Hourly Real-Time Imports All Hours



Hourly Average Real-Time Imports from PJM 2007

- The following figure shows the average net imports scheduled for the MISO-PJM interface for each hour of the day.
- This figure shows:
  - ✓ Overall, MISO is a net importer of power from PJM.
  - ✓ The MISO 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 range.
  - ✓ 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 that fluctuate.

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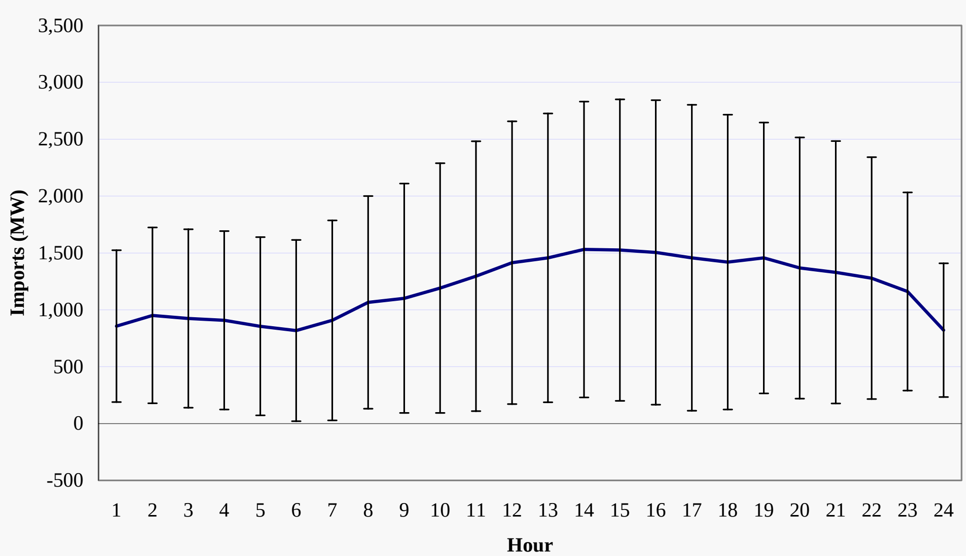
Hourly Average Real-Time Imports from PJM 2007



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Hourly Average Real-Time Imports from Canada 2007

- The following figure shows hourly real-time net imports across the Canadian interfaces:
  - ✓ The MISO exchanges power with Canada through interfaces with the Manitoba Hydro Electricity Board (MHEB) and the Independent Electricity Market Operator (IMO) of Ontario.
  - ✓ The MISO is normally a net importer from MHEB through the high voltage DC connection and a net exporter to IMO.
  - ✓ 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 IMO are generally lower in the peak and ramping hours.

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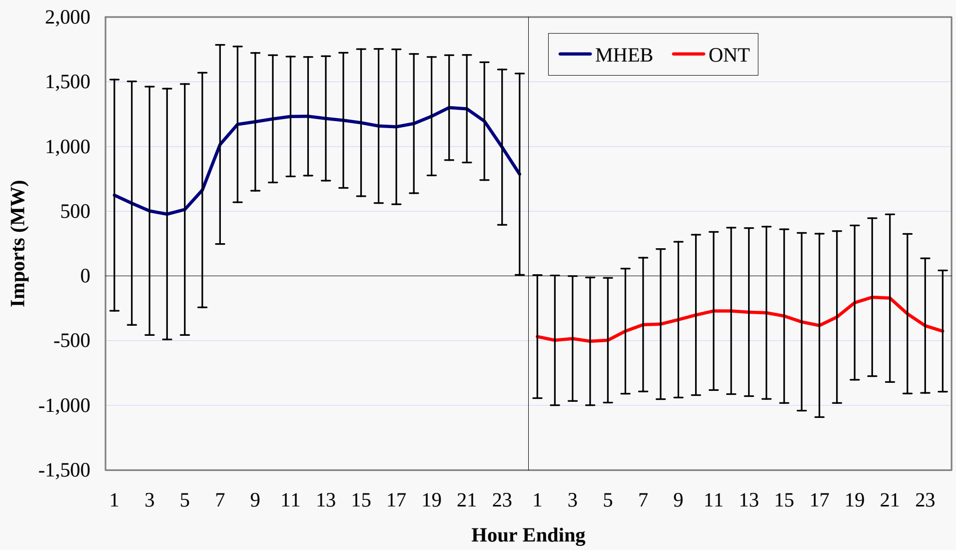
Hourly Average Real-Time Imports from Canada 2007



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Imports over the Manitoba Interface and Related Congestion

- The next figure shows the average hourly imports over the Manitoba interface between 2005 and 2007 on seven-day moving average basis. It shows that:
  - ✓ Imports were unusually low at the end of 2006 and beginning of 2007 due to poor water conditions that reduced the availability of hydroelectric resources;
  - ✓ Imports returned to more normal levels by the summer of 2007.
- 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, generally from the south.
  - ✓ Reduced imports also tend to reduce the west to east congestion into WUMS.
    - – However, the addition of new Arrowhead-Weston 345 transmission facilities should reduce the congestion into WUMS from the West.

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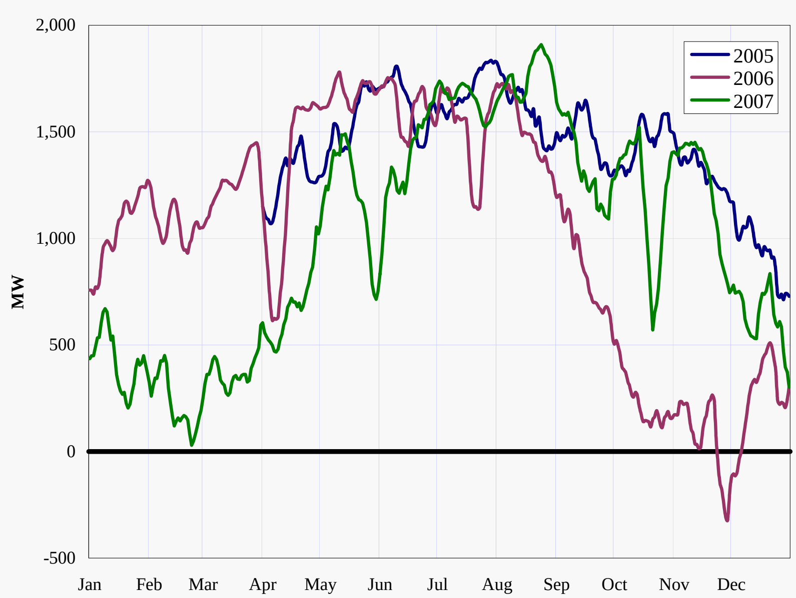
Moving Average of Net Imports from Manitoba 2005 through 2007



POTOMAC ECONOMICS

Real-Time Prices and Interface Schedules

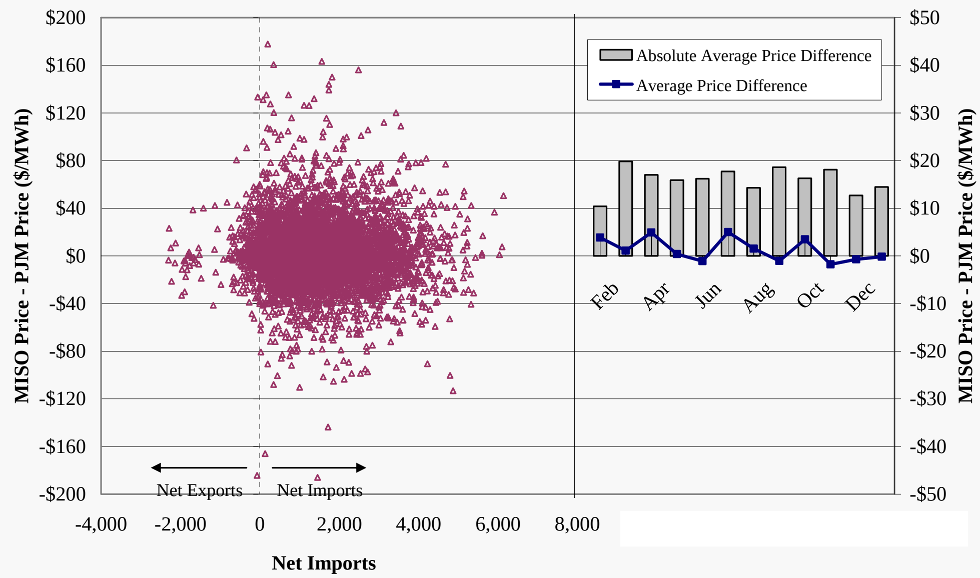
- The next three figures evaluate the price convergence and net imports between MISO and adjacent markets.
  - ✓ The left side of the figures are a scatter plot of the real-time price differences and the net imports in unconstrained hours.
  - ✓ The right side of the figures show the average hourly price differences and the average magnitude of the hourly price differences (average absolute differences) on a monthly basis.
- 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 MISO

The results for the PJM interface indicate:

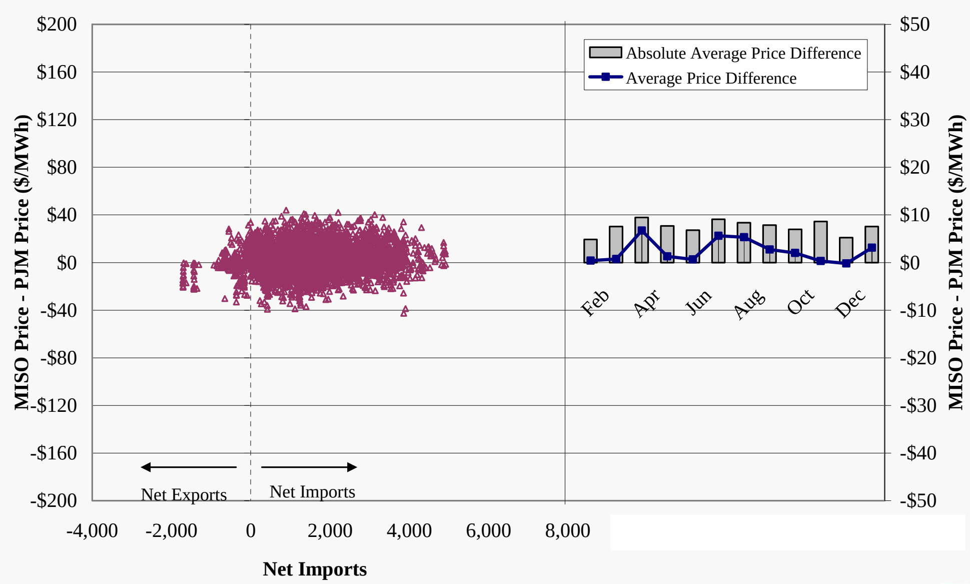
- In 2007, the prices in the two areas are relatively well arbitraged in the day-ahead, likely because day-ahead prices are less volatile and easier to forecast than in real time.
- The MISO interface prices were slightly higher than PJM's on a consistent basis for the first three quarters of 2007 but tended to be less in the last quarter.
- The first figure shows that participants have not been fully effective at arbitraging the real-time prices between the two areas, it is often the case that power is scheduled from the higher-priced market to the lower-priced market.
- To achieve better real-time price convergence, we continue to recommend that the RTOs consider expanding the 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.

Real-Time Prices and Interface Schedules PJM and MISO



POTOMAC ECONOMICS

Day-Ahead Prices and Interface Schedules PJM and MISO



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Real-Time Prices and Interface Schedules
IMO and MISO

- The following figure provides the same analysis for the MISO – IMO interface in the real-time market.
- For the year, MISO was a net exporter of power to IMO, exporting an average of 350 MW.
  - ✓ In the first 3 quarters, the Midwest ISO prices exceeded the IMO prices on average and exports averaged 170 MW.
  - ✓ During the last quarter, the IMO prices were higher than the Midwest ISO prices on average and exports averaged 860 MW. The increase in exports was a rational response to the relative prices.
- However, the dispersion of prices shows that the schedules over this interface are relatively unresponsive to the price differences in the short-term.
- Interpreting these results is complicated by the fact that IMO does not have a nodal market so the IMO price may not fully reflect the true value of power imported from the Midwest ISO.

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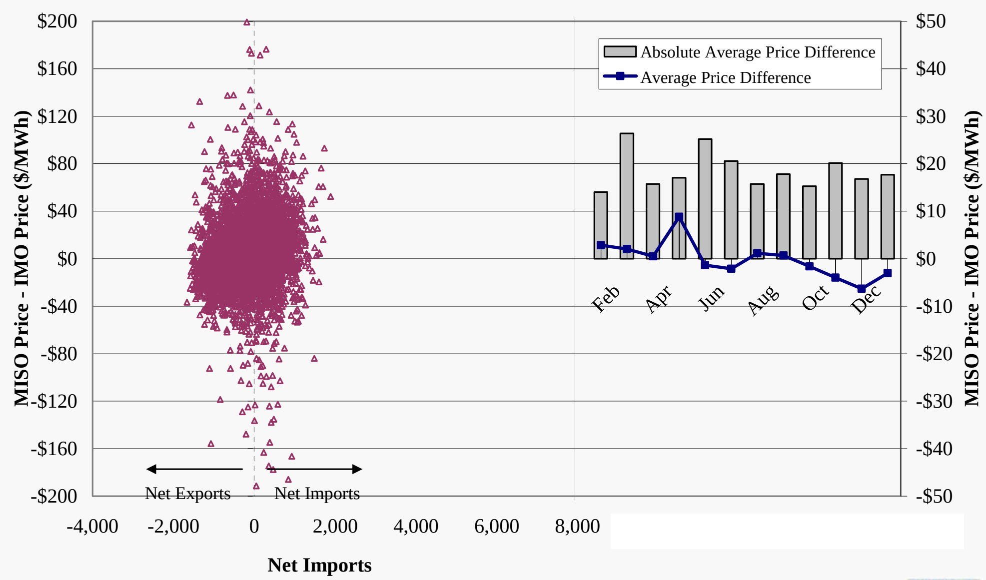
Real-Time Prices and Interface Schedules
IMO and MISO



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Market to Market Events

- The next 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.
  - ✓ When a market-to-market constraint is activated, the markets exchange shadow prices and the relief requested (the desired reduction in flow) from other market.
  - ✓ The shadow price measures the marginal cost of relieving the constraint.
  - ✓ 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 process is key for ensuring that generation is efficiently re-dispatched to manage these constraints, and that prices in the two markets are consistent.
- The following figure shows the total number of market-to-market constraint-hours (instances when a market-to-market constraint is binding and activated) in 2007.
  - ✓ The market-to-market constraints for both RTOs were equally divided between peak and off-peak hours.
  - ✓ The PJM market-to-market are 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, although value of these constraints was similar in the summer and fall as shown earlier in the report.

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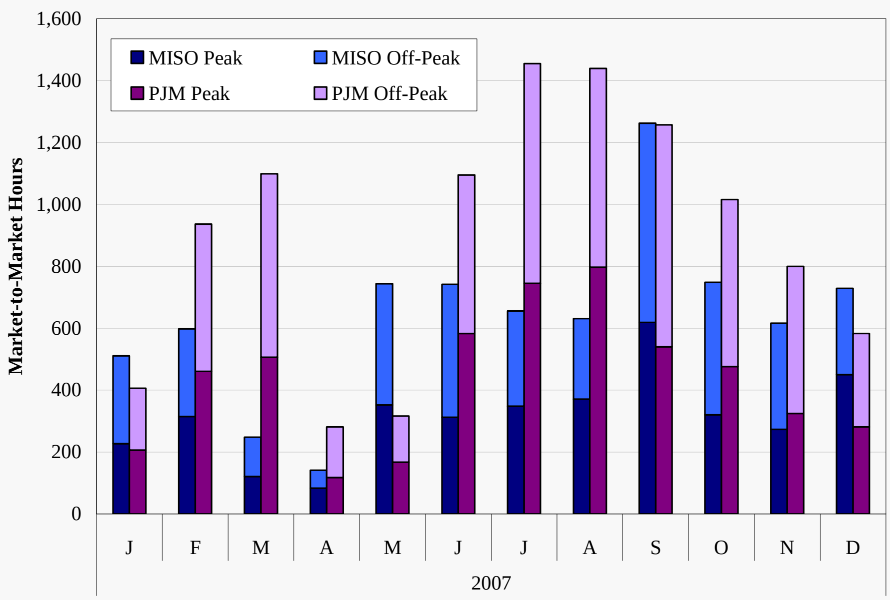
Market-to-Market Activity



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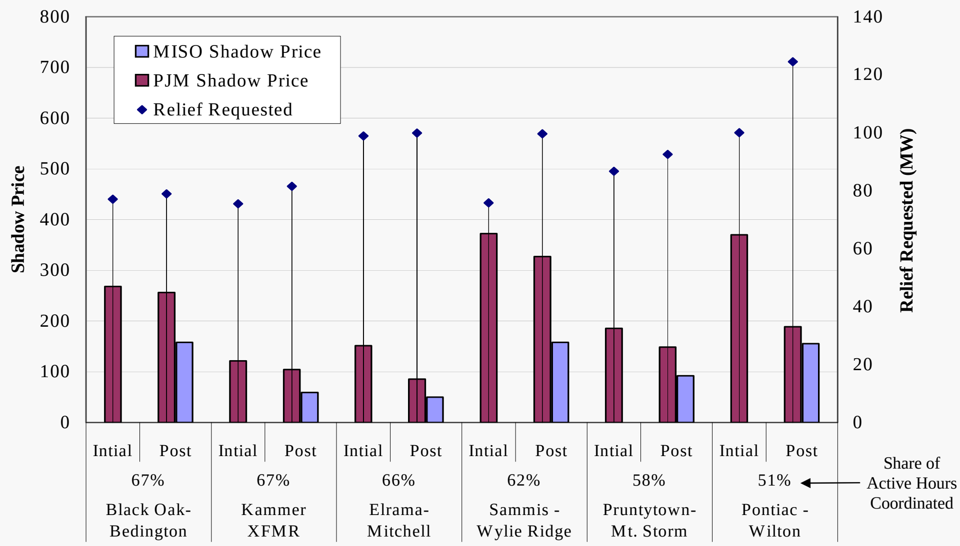
Market-to-Market Constraints
Shadow Price Convergence

- The next two figures show the most frequently called market-to-market constraints on the PJM and MISO systems.
- The analyses in these figures are intended to show the extent to which the shadow prices on coordinated constraints converge between the two RTOs.
- These figures include:
  - ✓ The initial shadow price, which is based on the shadow prices of the Monitoring RTO logged prior to the first response from the Reciprocating RTO.
  - ✓ The average shadow prices in the post-initialization period are shown for both the Monitoring and Reciprocating RTOs.
  - ✓ The figure also shows the requested relief during the initialization period and the average requested relief for the remainder of the activation period.
  - ✓ Finally the figure shows 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 of the two figures shows the results of our analysis of the PJM constraints.
- The figure shows that:
  - ✓ The shadow prices decrease and move toward convergence over the duration of the event.
  - ✓ The percentage of active intervals that are coordinated (where relief is received) is substantial on the PJM flowgates.
  - ✓ The relief requested increased from the initialization and post-initialization and this consistent with the convergence and efficient coordination.
- However, the data indicates some results that raise potential concern, 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.
  - ✓ Cases where the Midwest ISO is responding to a shadow price provided by PJM by redispatching and pricing the constraint even after the constraint is no longer binding in PJM (i.e., there is no congestion in the PJM prices).
    - – This is apparently caused by PJM sending shadow price information that is not consistent with its LMP calculations.

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



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MISO 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 Eau Claire-Arpin (combining for over 1500 hours) were the most frequently activated as market-to-market constraints.
  - ✓ Stateline-Wolf Lake also the highest percentage of coordinated hours at 74 percent while Eau Claire – Arpin was one of the lowest at 15 percent.
- 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.
- Our analysis of the Midwest ISO's market-to-market constraints raises some the following concerns:
  - ✓ The relief quantities are rarely modified, even when its shadow price is higher than PJM's and more relief may be available.
  - ✓ PJM sometimes 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.
    - – The analysis shows that PJM provides relief less than 5 percent of the time on two of the most frequently binding constraints on the Midwest ISO system
    - – With PJM's assistance, we are investigating why PJM so seldom provides relief on these flowgates.

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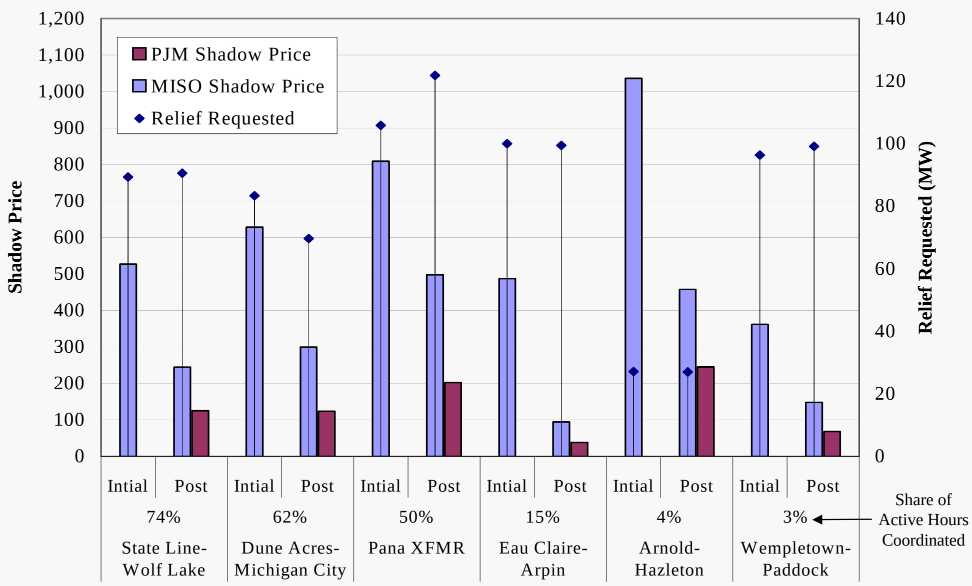
MISO Market-to-Market Constraints Relief Requested and Shadow Prices



POTOMAC ECONOMICS

Market-to-Market Recommendations

- We continue to support recommendations we made in prior State of the Market reports:
  - ✓ The market-to-market process be should enhanced to modify the relief requested based on the relative shadow prices; and
  - ✓ The constraint relaxation algorithm should be discontinued -- prices should be set based on the PJM shadow price when the requested relief cannot be provided at a lower cost.
  - ✓ 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.
- Additionally, based on our preliminary investigation, we believe that certain modeling assumptions by PJM cause its real-time dispatch model to not accurately recognize the relief that it can provide on key Midwest ISO flowgates.
  - ✓ For example, PJM utilizes a 3 percent GSF cutoff that ignores the relief that can be provided by generators with lower shift factors.
    - – As described earlier in this report, the Midwest ISO's current GSF cutoff of 2 percent raises efficiency concerns; a 3 percent GSF would raise much more significant concerns.
  - ✓ Hence, pending the findings of this investigation, we recommend that PJM make modeling changes to more fully recognize the relief that it can provide on the Midwest ISO's key flowgates.

POTOMAC ECONOMICS

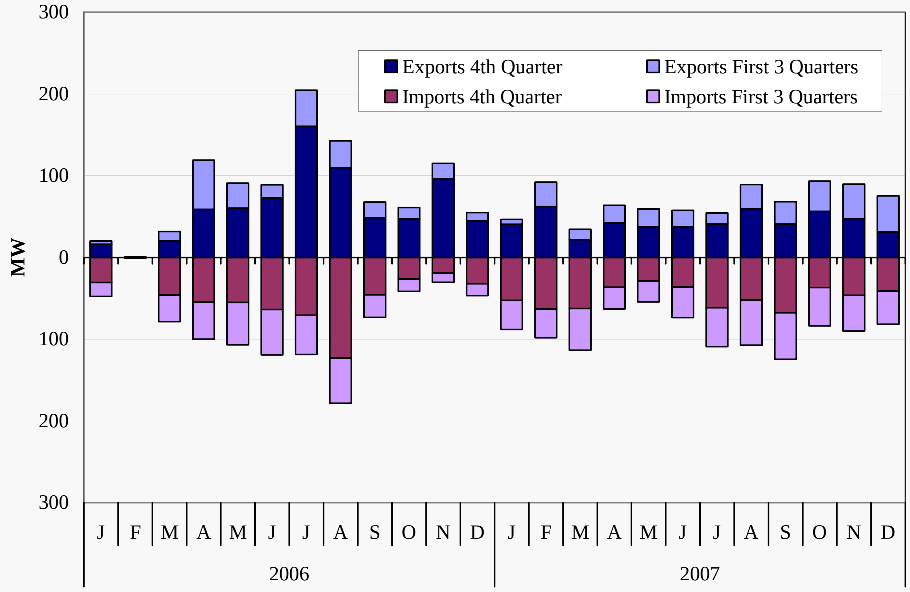
Intra-Hour Scheduling

- The last topic we address in this section of the report is intra-hour physical scheduling.
  - ✓ The MISO 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 NSI caused by intra-hour schedules can lead to price volatility and operational challenges.
- Intra-hour schedules affect prices because MISO 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 it caused because it is evaluated as on hourly average basis (400 MW export 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 are occurring with PJM.
- Hence, the following figure shows a summary of hourly intra-hour scheduling for the past 2 years between MISO and PJM.
  - ✓ The chart shows the average intra hourly scheduling occuring in the first 45 minutes of each hour and in the last 15 minutes of the hour.
  - ✓ While shown as hourly values the imports and exports are not necessarily occurring in the same interval.
- The figure shows that almost 60 percent of the intra-hour schedules were in the 4th quarter of the hour, which is less than the share in 2006.
  - ✓ The predominance of 4th quarter schedules is likely due to the fact that the scheduling deadline is 30 minutes in advance of the beginning of the schedule.
    - – Hence, the entity is able to schedule the 4th quarter transaction after it has seen the prices at the beginning of the hour that will be included in the hourly settlement for the transaction.
  - ✓ The volume of intra-hour schedules remained fairly constant throughout 2007.

Intra-Hour Scheduling Levels



POTOMAC ECONOMICS

Intra-Hour Scheduling – Price Impacts

- The next two figures show prices at the MISO proxy bus with PJM before and during intra-hour schedules on a weekly average basis.
- Exports and imports had substantial impacts on MISO prices and operations in 2007.
  - ✓ During ramp up periods, export schedules of 400 MWs or more can use all of the available ramp capability and half or more of the available headroom.
    - – Largest price effects occur when the intra-hour scheduling utilizes a substantial portion of MISO’s capability to ramp generation up or down.
  - ✓ Exports may also contribute to MISO commitment of peaking resources as operators commit to meet forecasted load, including net exports.
- The first figure shows that when the intra-hour exports are being scheduled, the prices are consistently higher by an average of almost $20/MWH. The price effects are largest during peak periods.
- Likewise, the second figure shows that when imports are being scheduled on an intra-hour basis, prices are consistently lower during the schedule than before the schedule, which is consistent with expectations.

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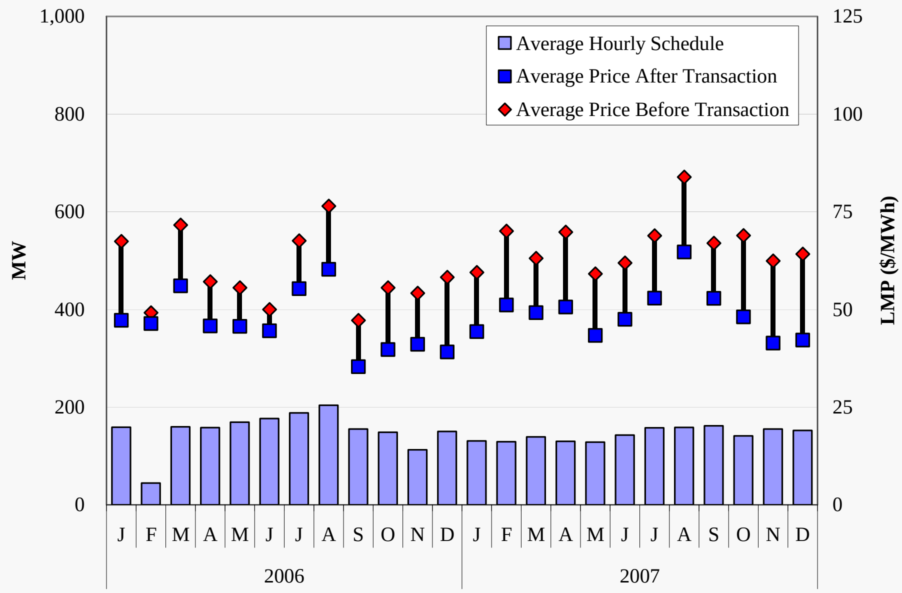
Intra-Hour Scheduling –
Price Impacts of Exports



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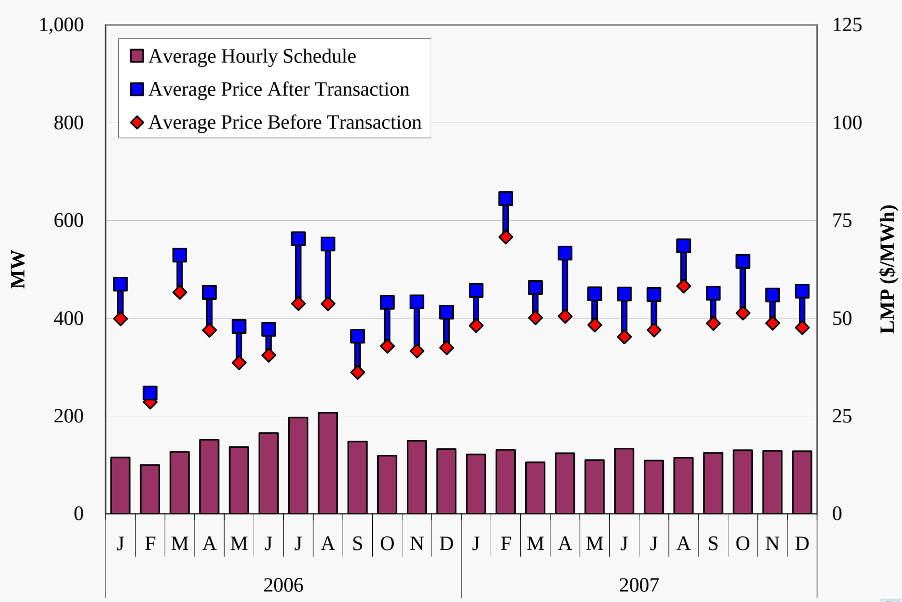
Intra-Hour Scheduling -
Price Impacts of Imports



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Intra-Hour Scheduling – Duration

- One the primary questions our analysis addresses is whether participants are engaging in economically rational (i.e., profitable) intra-hour transactions.
  - ✓ Scheduling transactions unprofitably may indicate that the participant is deriving other benefits from the transactions, raising market manipulation concerns.
- Our evaluation focuses on the apparent profitability of the transactions based on differences in the 5-minute proxy prices for MISO and PJM.
  - ✓ A participant scheduling a transaction between MISO and PJM would settle with each RTO and receive the difference in hourly average prices.
  - ✓ A transaction is indicated as seemingly profitable or unprofitable based on the prices that are observed for the hour prior to scheduling the transaction (only applies to intra-hour transactions scheduled in the 4^{th} quarter of the hour).
  - ✓ A transactions is "indeterminant" when it begins in the first 45 minutes of the hour because the entity will not have seen any prices for the hour prior to scheduling it.
- The analysis indicates:
  - ✓ As in 2006, about 80 percent of both the imports and export transactions scheduled intra-hour were scheduled when they appeared to be profitable.
  - ✓ Of those that did not appear to be profitable, 40 percent ended up being profitable based on the hourly settlement.
- These results do not raise potential manipulation concerns associated with intra-hour schedules in 2007.

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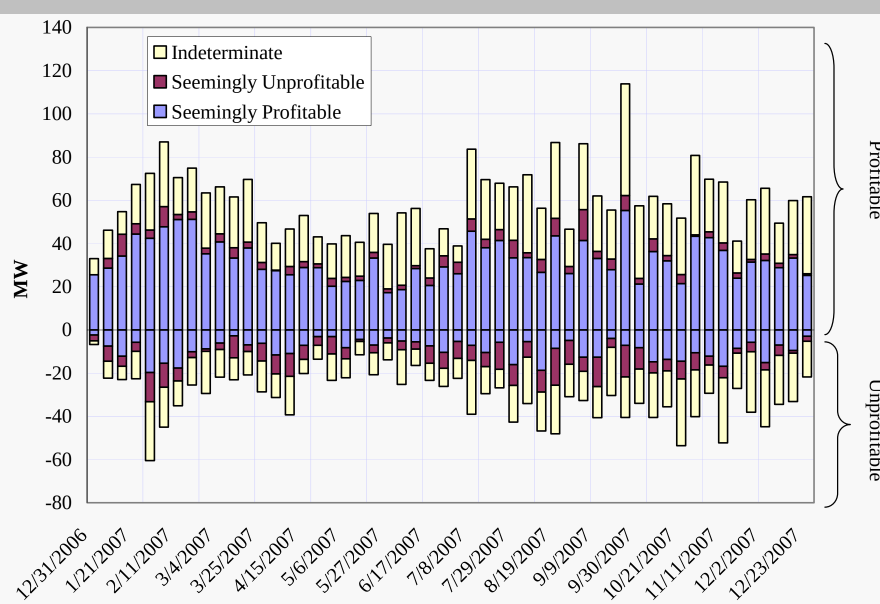
Predictable Profitability of Intra-Hour Schedules Weekly 2007



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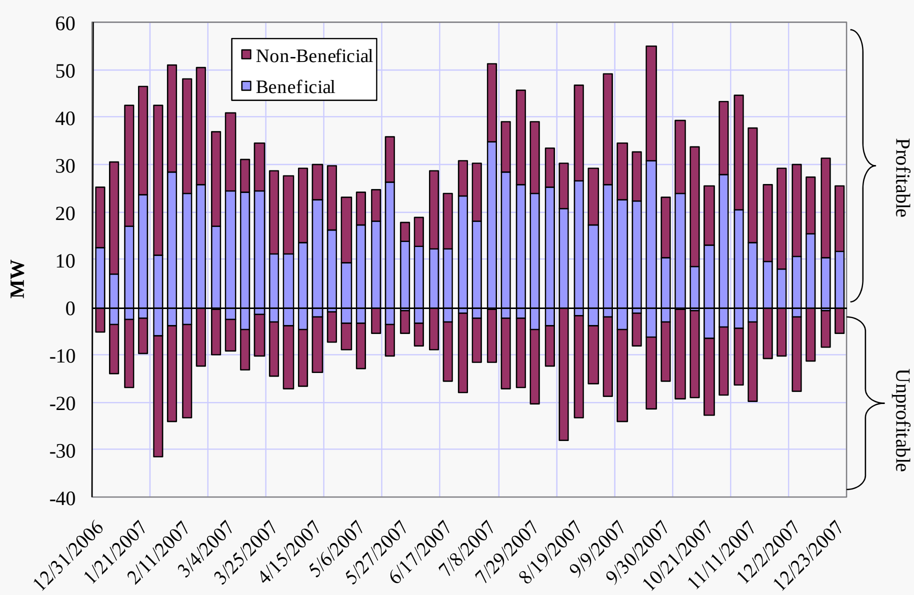
Intra-Hour Scheduling – Convergence

- Although our analysis does not indicate potential manipulation concerns, the next analysis addresses the efficiency implications of the intra-hour schedules.
- Our analysis in the next figure examines the extent to which the intra-hour transactions contributed to price convergence between PJM and MISO when the transaction is flowing.
  - ✓ The figure shows the same profitable and unprofitable transactions (based on the hourly settlement) for the fourth quarter of the hour as in the prior figure, but categorizes the transactions by whether they were beneficial.
  - ✓ Transactions are beneficial when the power flows from the lower-priced market to the higher-priced market (which will contribute to price convergence).
- The results in this figure indicate:
  - ✓ In 2007, only 43 percent of the intra-hour schedules in the fourth quarter were beneficial – contributing to price convergence.
  - ✓ Further, only slight more than half of the “profitable” transactions are beneficial.

Efficiency of Intra-Hour Schedules Weekly 2007



Intra-Hour Scheduling – Conclusions

- Our findings regarding intra-hour transactions are the following:
  - ✓ The majority of intra-hour transactions are rationale based on profitability.
  - ✓ There is not a consistent pattern of unprofitable transactions by any participants.
  - ✓ Together, these results limit potential market manipulation concerns.
- However, scheduling and settlement rules governing intra-hour transactions result in a substantial quantity of intra-hour transactions that are not beneficial.
  - ✓ Because transactions are settled at hourly average quantities and prices (rather than the quantity and price prevailing when the transaction is flowing), transactions can be profitable even when they are not beneficial.
  - ✓ This issue is exacerbated by the fact that transactions in the last 15 minutes of the hour are scheduled after the prices in the first 15 minutes of the hour are known.
    - – PJM tried to reduce 4th quarter transactions by requiring that intra-hour transactions be scheduled for at least 45 minutes – however, this will likely not be effective because participants can schedule overlapping transactions in opposite directions.
  - ✓ Finally, the large changes in NSI that are sometimes caused by these transactions contributed to increased price volatility.

POTOMAC ECONOMICS

Intra-Hour Scheduling – Recommendations

- To address the inefficiency of the non-beneficial transactions and the price volatility caused by large changes in NSI, we recommend the following:
  - ✓ In the long-term, the Midwest ISO should consider the feasibility of settling intra-hour transactions on a 15-minute basis to align the incentives of participants with the system.
  - ✓ In the short-run, the Midwest ISO should require that intra-hour transactions be scheduled by the beginning of the hour (45 minutes in advance) to prevent participants from seeing prices before scheduling the transactions.
  - ✓ To limit large NSI changes, the Midwest ISO should reconsider their scheduling criteria (which allow up to 1000 MW of NSI changes in each 15 minutes) to limit accepted transactions to:
    - – the actual available ramp capability; or
    - – a small quantity that reflects an amount ramp capability that can typically be accommodated.

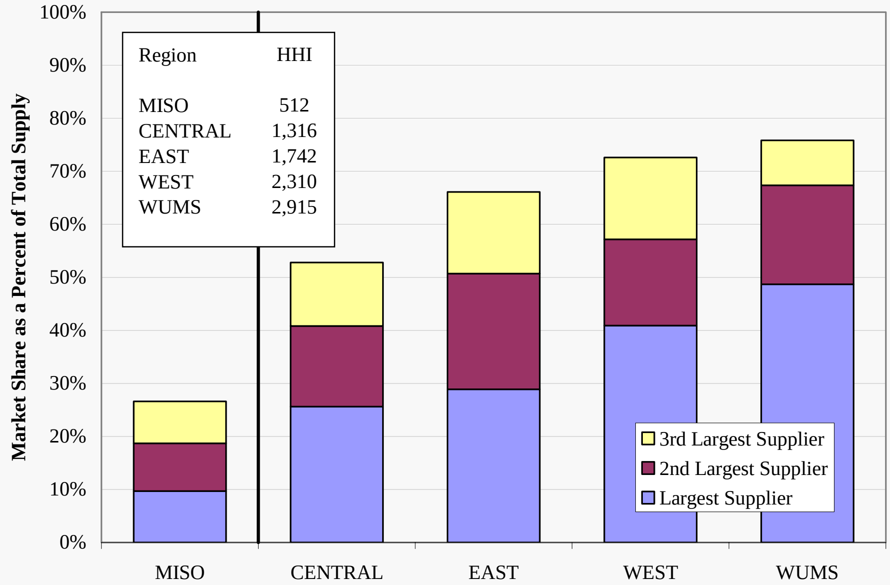
POTOMAC ECONOMICS

Participant Conduct and Mitigation

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 2007.
- 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, each of the Midwest sub-regions have HHI values close to or exceeding 1800 with the exception of the Central region.
  - ✓ The HHIs in MISO are higher than in some other markets because the vertically-integrated utilities in the Midwest have not divested substantial amounts of generation.

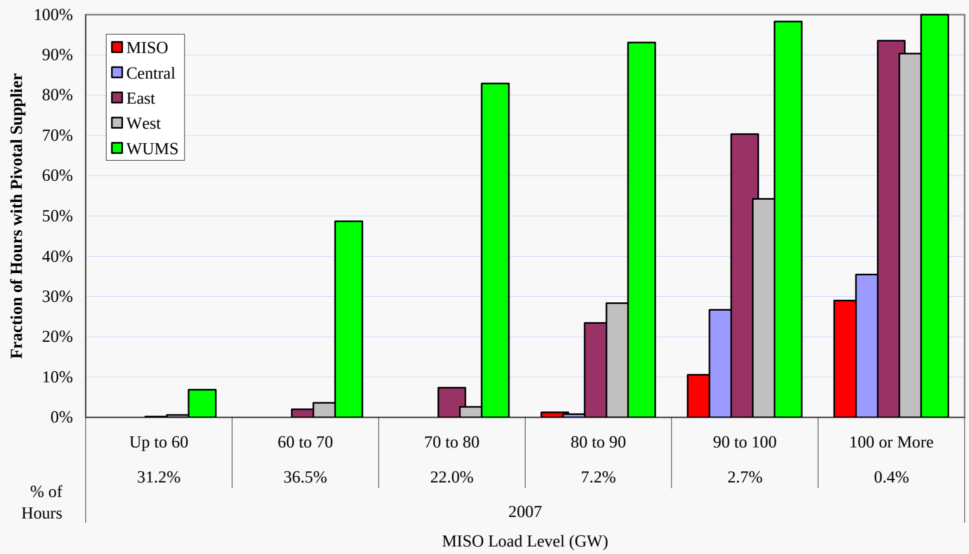
Market Concentration



Residual Demand Index

- A better metric than the HHI for evaluating competitive issues in electricity markets is the residual demand index ("RDI").
- The RDI metric indicates the portion of the load in an area that can be satisfied without the resources of the largest supplier.
  - ✓ Hence, 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 calculating the RDI, we include all import capability into the area, not just the imports that were actually scheduled.
  - ✓ In general, the RDI will decrease as load increases since increasing quantities of rivals' generation will be needed to satisfy the load.
- The following figure shows the RDI by load level in different areas within MISO.
  - ✓ The analysis shows that in 2007 there is limited competition in the WUMS region at all load levels – when load is higher than 80 GW (about 1/3 of the time), there is a pivotal supplier in WUMS approximately 90 percent of the hours.
  - ✓ The West and East regions do not exhibit a pivotal supplier in a substantial share of hours, except when load exceeds 80 GW (7.3 percent of the hours).

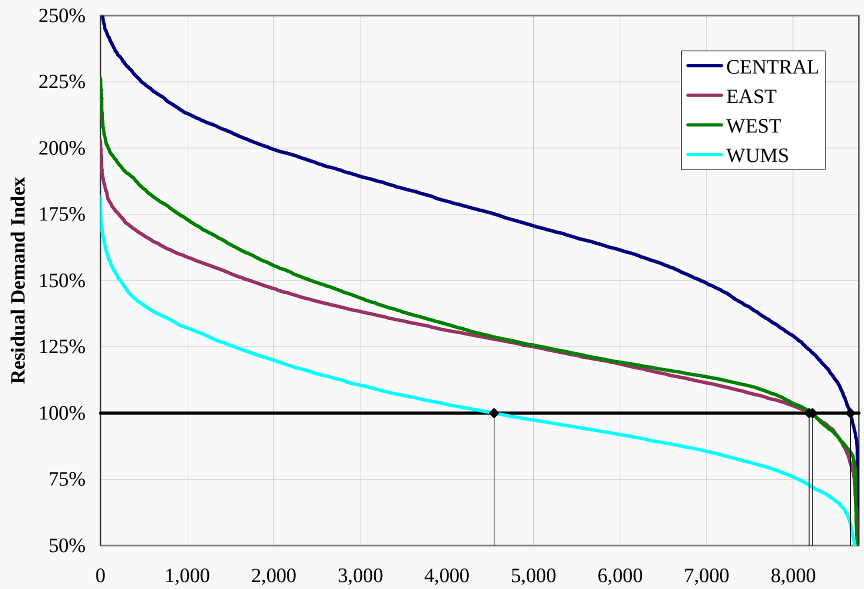
Residual Supply by Load Levels 2007



Residual Supply Duration Curves 2007: All Hours

- The next figure shows the residual supplier index in the form of a duration curve from highest index (most competitive) to lowest index (least competitive).
- These curves show that:
  - ✓ The WUMS region had one or more pivotal suppliers in almost 50 percent of hours during 2007, which is one reason WUMS is a Narrow Constrained Area ("NCA") under the mitigation measures in the MISO tariff.
  - ✓ The East had a pivotal supplier nearly 7 percent of the hours.
  - ✓ The West had a pivotal supplier in 6 percent of hours (the Western region includes the Minnesota NCA that was defined in early 2007 as well as other areas).
  - ✓ There were very few hours with a pivotal supplier in the Central region, slightly over 1 percent of the hours.

Residual Supply Duration Curves
2007: All Hours



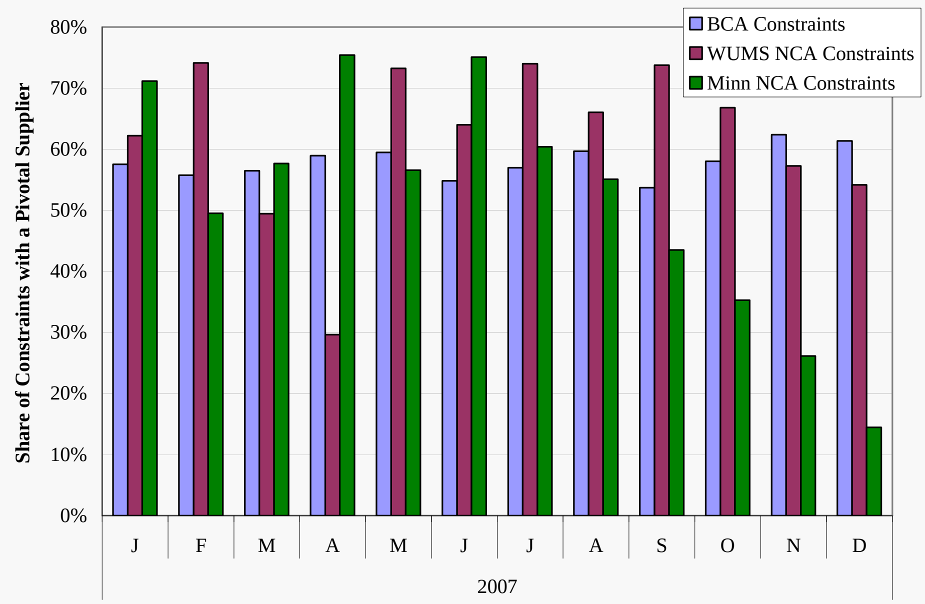
POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis

- We also conducted a pivotal supplier analysis for individual transmission constraints during periods that they were active in the MISO market.
  - ✓ 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 results of this analysis are shown in the following two figures. The first figure shows the portion of the active NCA constraints (in the WUMS and Minnesota areas) and BCA constraints that have at least one pivotal supplier.
- This figure shows that in 2007:
  - ✓ 62 percent of the active constraints into WUMS had a pivotal supplier.
  - ✓ 52 percent of the active constraints into Minnesota had a pivotal supplier.
  - ✓ 58 percent of the active 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 2007 created substantial potential local market power.

POTOMAC ECONOMICS

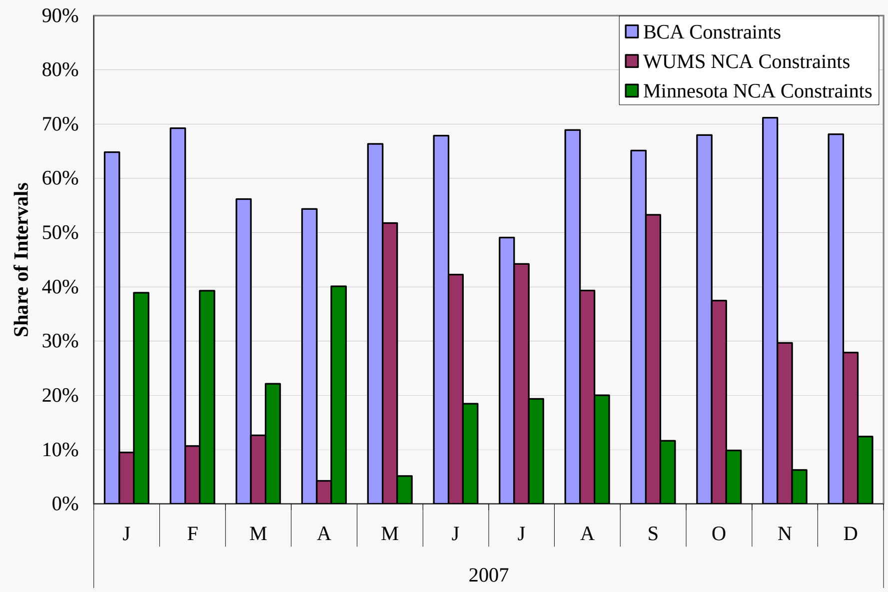
Constraint-Specific Pivotal Supplier Analysis: Percent of Active Constraints with a Pivotal Supplier



Constraint-Specific Pivotal Supplier Analysis

- The prior analysis 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 2007 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 2007.
    - – The regional distribution of BCA constraints varied throughout the year, yet the total frequency was relatively constant.
  - ✓ The analysis also indicates that there was an active NCA constraint with a pivotal supplier in 30 percent of hours in WUMS and 20 percent in Minnesota in 2007.
- These results indicate that the BCA and NCA mitigation continues to be essential.

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



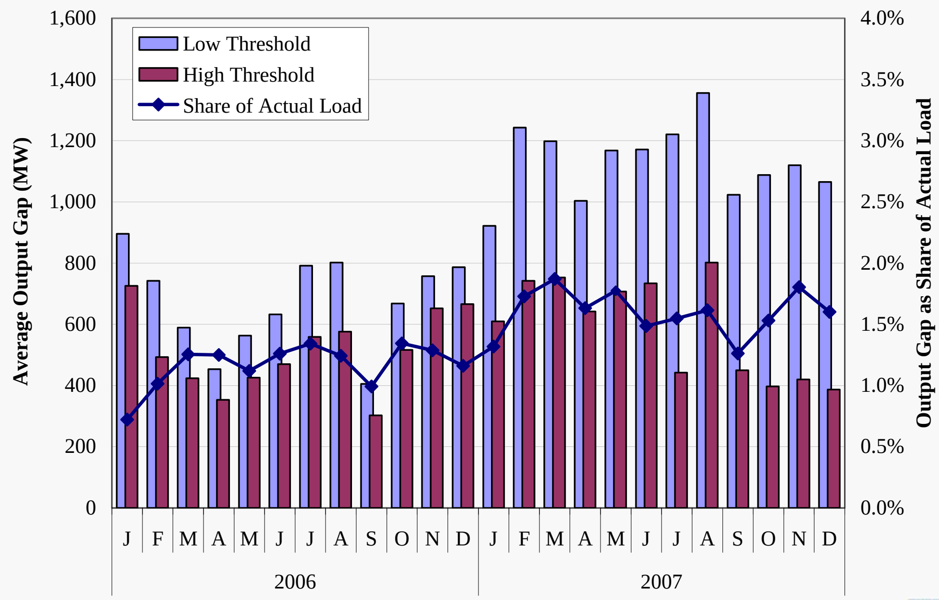
POTOMAC ECONOMICS

Economic Withholding: Output Gap Analysis

- The next analysis is the first in a series of analyses on the conduct of suppliers in the Midwest ISO, which is designed to detect significant economic withholding.
- These analyses use the "output gap" as a measure of potential economic withholding.
  - ✓ The output gap shows the quantity of output that is not produced when suppliers' competitive costs are lower than the LMPs by more than a given threshold.
  - ✓ The output gap also includes inflated offers that set the LMPs.
- The next figure shows the monthly average output gap levels in 2006 and 2007.
  - ✓ Output gap is shown for two types of units. 1) online and quick-start units available in real time, and 2) offline units that would have been economic to commit.
  - ✓ It also shows the output gap using the mitigation threshold in each area ("high threshold"), and one half of the mitigation threshold ("low threshold"). The lower threshold would indicate potential economic withholding via offers slightly below the mitigation threshold.
- This figure shows that:
  - ✓ The output gap rose modestly at the beginning of 2007. This was primarily due to the designation of the Minnesota NCA, which resulted in lower thresholds to be used to calculate the output gap for 2007 in this area.
  - ✓ Output gap levels were stable and generally declined slightly over the course of 2007. These levels provide little indication of significant 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



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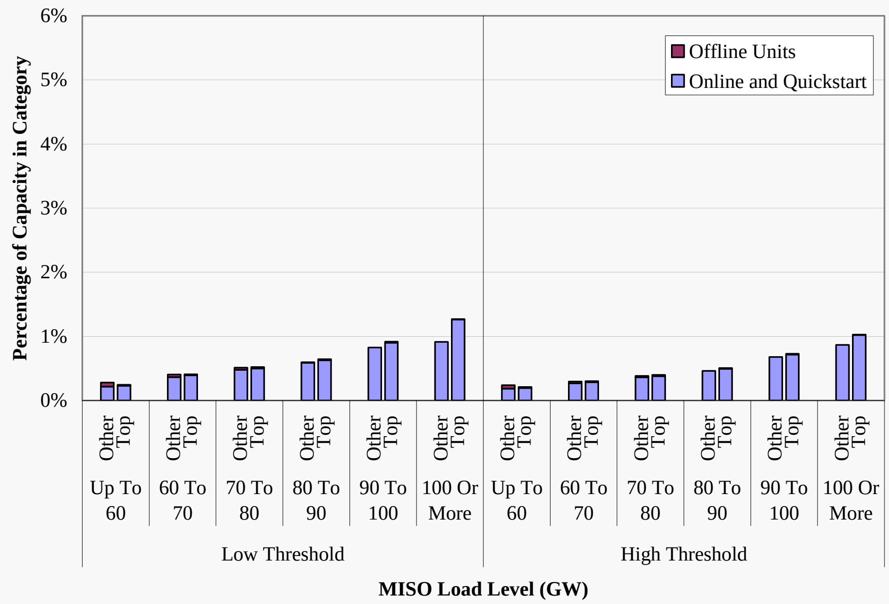
Economic Withholding: Output Gap Analysis

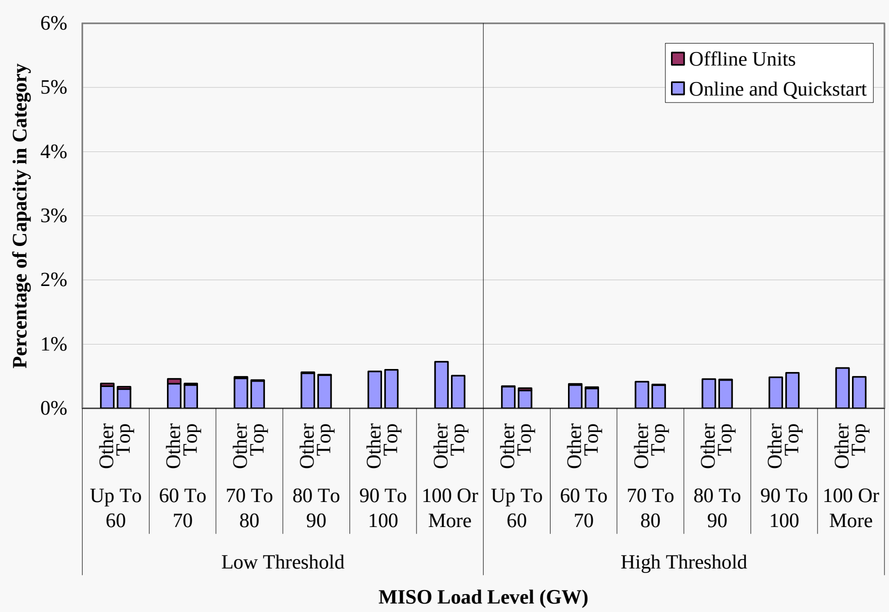
- Despite the relatively low output gap levels shown in the prior chart, it is useful to also examine this metric by load level and size of participant.
  - ✓ The incentive to economically withhold supply generally increases under high load conditions when prices are most sensitive to such withholding. Additionally, large suppliers generally have a greater ability to increase prices.
  - ✓ Therefore, the next 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 WUMS and the West where lower thresholds are used.
    - – Given the lower thresholds applied to NCAs, the higher output gap results (exceeding 2 percent at higher load levels) do not raise substantial concerns.
  - ✓ 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 indicate that economic withholding has not been a concern in 2007.

POTOMAC ECONOMICS

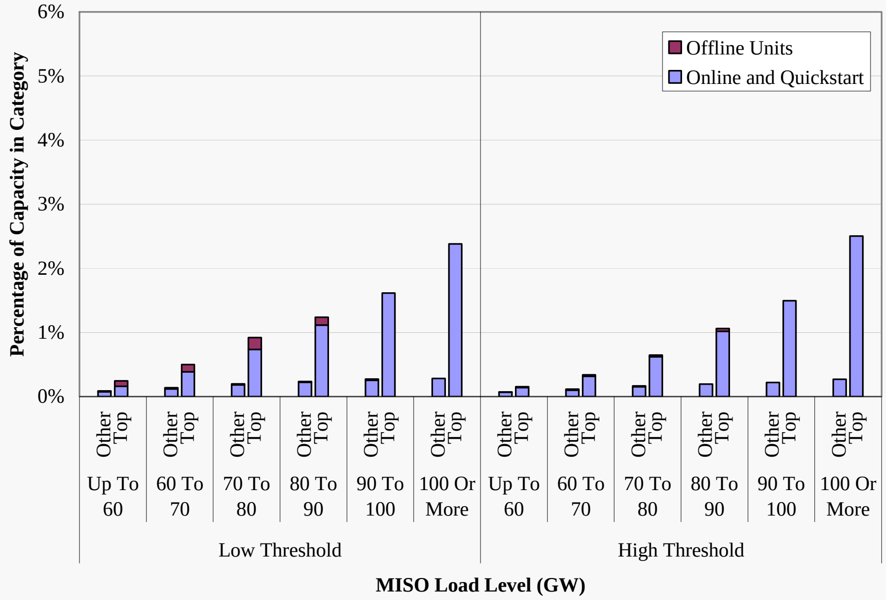
Real-Time Market Output Gap
Central: All Hours



Real-Time Market Output Gap
East: All Hours

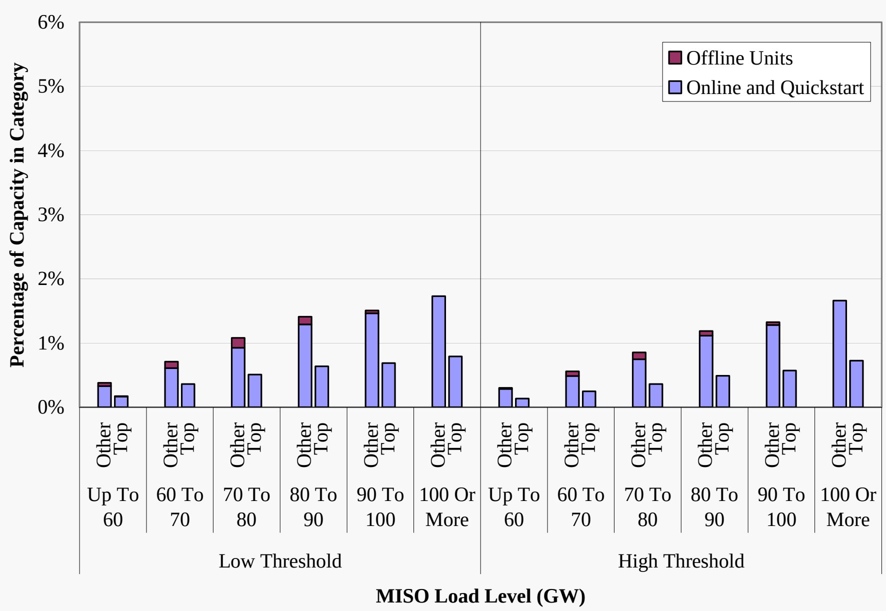


Real-Time Market Output Gap
West: All Hours



POTOMAC ECONOMICS

Real-Time Market Output Gap
WUMS: All Hours



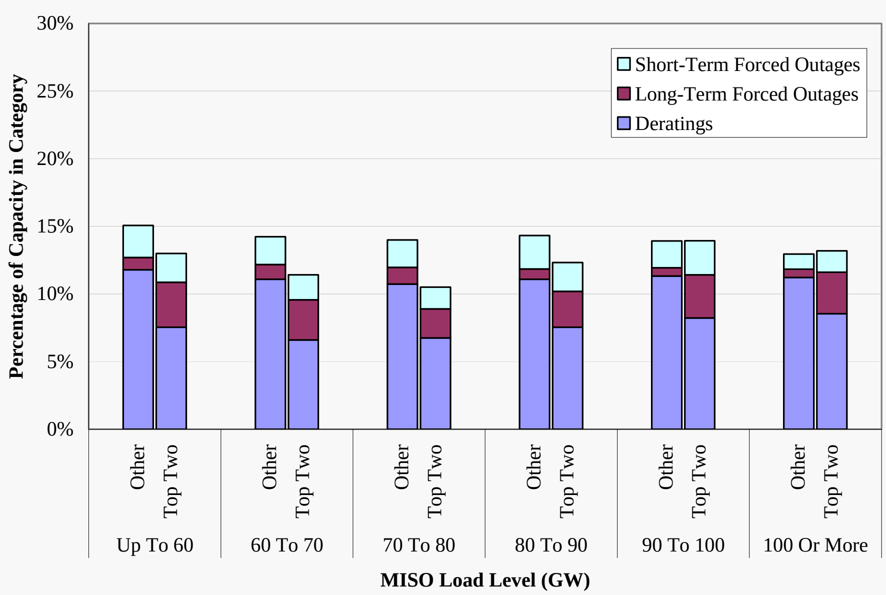
POTOMAC ECONOMICS

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.
  - ✓ The following figures show short-term forced outages (less than 7 days), longer-term forced outages, and other deratings by load level for the largest two suppliers and the other suppliers by region.
  - ✓ 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.
- 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
  - ✓ Except in the West, the largest suppliers generally have the same or lower physical withholding than other suppliers (that are less likely to have market power).
- Nonetheless, 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 2007.

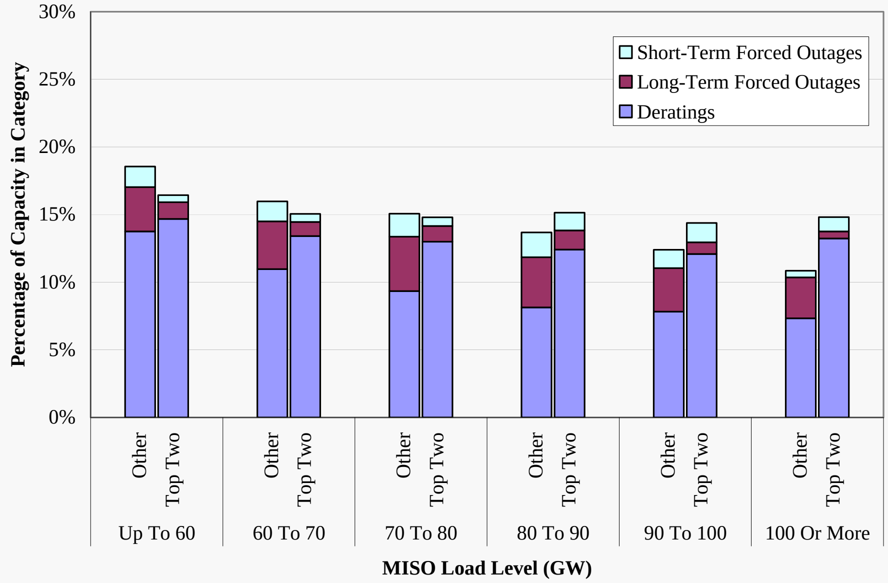
POTOMAC ECONOMICS

Real-Time Deratings and Forced Outages Central: All Hours



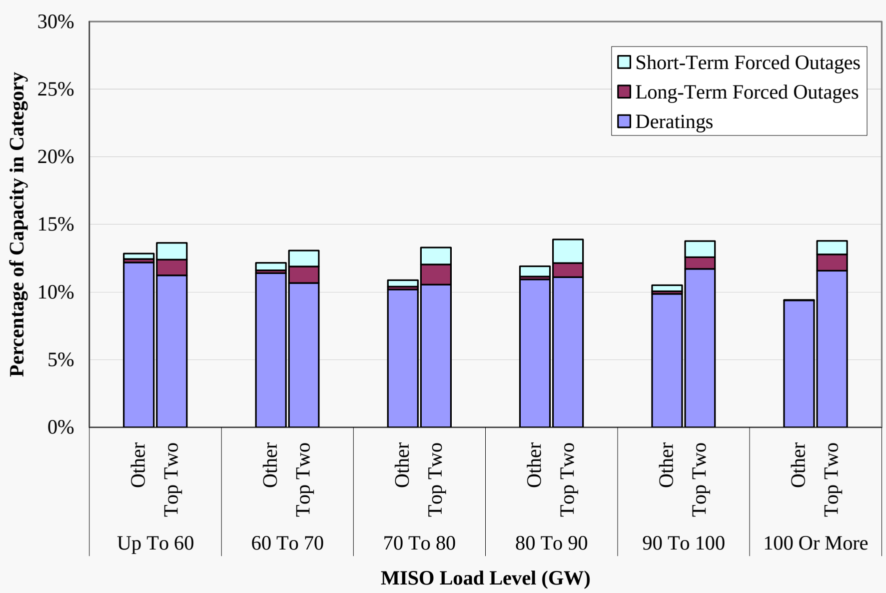
POTOMAC ECONOMICS

Real-Time Deratings and Forced Outages East: All Hours



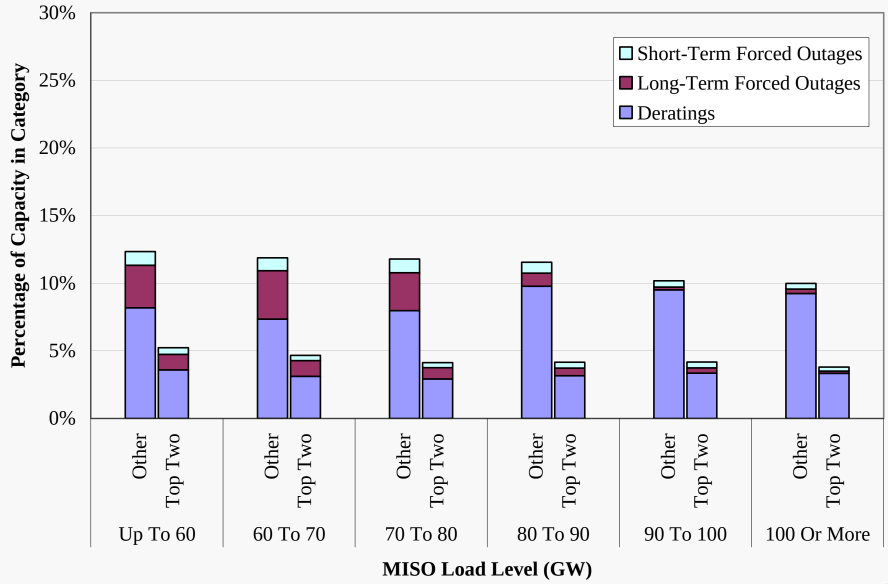
POTOMAC ECONOMICS

Real-Time Deratings and Forced Outages West: All Hours



POTOMAC ECONOMICS

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 replaces a unit's offer when it exceeds the conduct threshold and the offer raises prices substantially – this process is nearly completely automated.
  - ✓ The first figure shows that NCA mitigation generally occurred more frequently than BCA mitigation in 2007. The Minnesota NCA was added in January 2007.
  - ✓ Both classes of mitigation were relatively infrequent.
    - 27 BCA unit-hours and 256 NCA unit-hours of mitigation occurred in 2007.
    - Most of the mitigation occurred in June and July 2007 when 182 unit-hours of mitigation occurred.
    - There was a substantial increase in the NCA mitigation in 2007 – this was largely due to the definition of the Minnesota NCA in January 2007, which resulted in a large share of the NCA mitigation that occurred in 2007.
- Although mitigation was relatively infrequent during 2007, the analyses earlier in this section 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.

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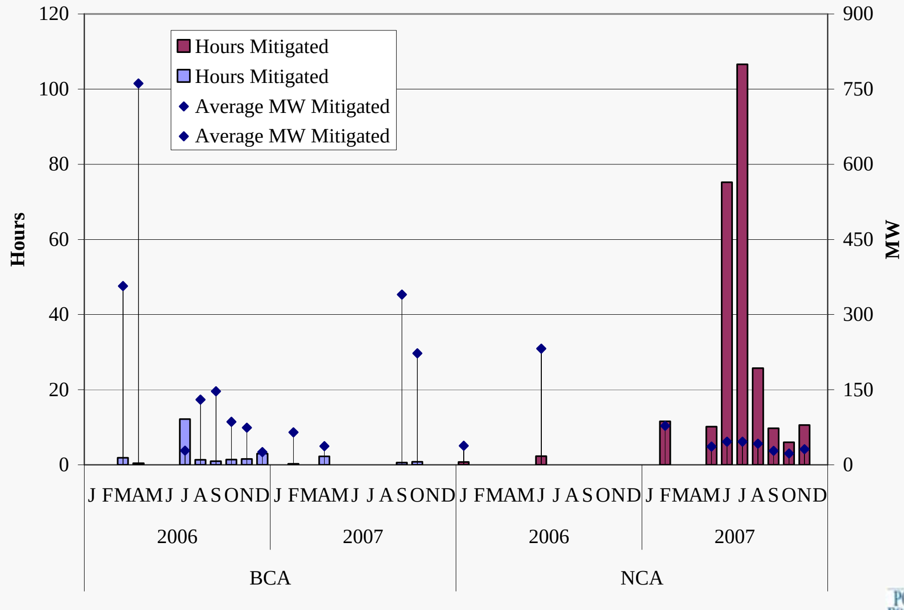
Mitigation in the Real-Time Energy Market by Month



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.
- This figure shows that only modest amounts of the total RSG payments were mitigated in most months due to the prerequisites 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).
- RSG mitigation in the Minnesota NCA began to be tested at the 50 percent impact threshold in January 2007.
- Mitigation occurred for 98 unit-days and slightly more than $3 million in 2007.
  - ✓ While mitigation of RSG was modest, this does not indicate a lack of locational market power.

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Real-Time RSG Mitigation by Month