2005 State of the Market Report
Midwest ISO

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June 2006

Introduction

- This presentation provides an overview of the State-of-the-Market Report for the Midwest ISO electricity markets for 2005.
- The Midwest ISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include:
  - ✓ Day-ahead and real-time energy markets that produce locational marginal prices (“LMP”) reflecting the value of transmission congestion throughout the system; and
  - ✓ Financial Transmission Rights (“FTRs”) that allow participants to hedge congestion between various locations.
- This report evaluates the initial results of the Midwest ISO’s energy markets and assesses the overall competitive performance of the markets in 2005.

Summary of Conclusions

- The introduction of the Midwest ISO energy markets was relatively smooth with no significant disruptions. This is significant given:
  - ✓ The expansive geographic scope of the Midwest ISO markets;
  - ✓ The transition from a decentralized wholesale market that relied on bilateral trading to a coordinated centralized set of wholesale energy markets.
- The Midwest ISO energy markets performed competitively in 2005.
  - ✓ There was very little evidence of any exercises of market power after the cost-based offer requirement was removed on June 1, 2005.
  - ✓ Individual suppliers throughout the MISO region have local market power associated with specific transmission constraints.
  - ✓ However, the mitigation measures were employed relatively infrequently to address economic withholding that would have increased energy prices or revenue sufficiency guarantee ("RSG") costs.
- The remainder of this executive summary provides our conclusions and recommendations in a number of specific areas.

Benefits of the Midwest ISO Energy Markets

- Although it is difficult to quantify, the energy markets produce substantial savings in the following areas.
- Daily commitment of generation: the coordinated commitment of generation that is achieved 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.
- Generation dispatch and congestion management: Total dispatch costs are reduced by:
  - ✓ Producing energy from the most economic resources;
  - ✓ Employing the lowest cost redispatch options to manage congestion; and
  - ✓ Much more fully utilizing the transmission capability in the region.
- Reliability: Reliability is improved because the 5-miinute 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.

Conclusions and Recommendations

Energy Prices and Net Revenue in 2005

- The average price for energy from April to December 2005 was close to $55 per MWh.
- Prices were highest during the summer, driven primarily by relatively hot weather and tight market conditions.
  - ✓ Peak demand was significantly higher in 2005 -- Load exceeded 100 GW in 165 hours in 2005, versus 16 hours and 10 hours in 2004 and 2003, respectively.
- Prices were also heavily influenced by natural gas and oil prices.
  - ✓ Natural gas prices increased by more than 66 percent in the fall and winter 2005 due to the production effects of the hurricanes in the Gulf Cost region.
  - ✓ Correlation of energy prices to natural gas and oil prices is expected since generators fired by natural gas are frequently setting the price in the Midwest (i.e., “on the margin”)
- The net revenue (revenues less production costs) produced by the energy markets was well below the levels necessary to invest in new generation. This is consistent with expectations because:
  - ✓ There is currently a surplus of generation in the Midwest;
  - ✓ There were no significant periods of shortage and associated prices spikes, which are needed to provide adequate economic signals in an energy-only market.

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Conclusions and Recommendations

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 is scheduled through the day-ahead market.
  - ✓ On average, an additional 7 percent is committed after the day-ahead market by market participants (i.e., self-scheduling) and by MISO to meet anticipated energy and reserve needs and manage congestion in real time (i.e., reliability assessment commitments).
- Net load in the day-ahead market was slightly under-scheduled (i.e., less than real-time load), particularly under the highest load conditions.
  - ✓ This is consistent with the price effects of the supplemental generator commitments that occur after the day-ahead market.
  - ✓ Such commitments reduce real-time prices and, hence, the incentive to buy in the day-ahead market.
  - ✓ It is also consistent with the fact that peaking resources, which are often relied on in real-time to serve the incremental load frequently do not set prices in the real-time market.

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Conclusions and Recommendations

Day-Ahead Market Performance

- The 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 that is bought or sold through the Midwest ISO markets is settled in the day-ahead market.
  - ✓ The entitlements of the firm transmission rights are determined by the results of the day-ahead market (the payment to an FTR holder is based on the day-ahead congestion).
- One important aspect of the markets' performance is how well the day-ahead prices converge with the real-time prices.
  - ✓ The report shows that the prices in the day-ahead market converged relatively well in most locations – convergence was comparable with other established markets.
  - ✓ The good convergence can be attributed to active virtual supply and demand participation in the day-ahead market.

Conclusions and Recommendations

Real-Time Market Performance

- Prices in the real-time market were substantially more volatile than in the day-ahead market, as expected.
- The nodal market accurately reflected the value of congestion in the Midwest – the most substantial congestion was between Minnesota and the Wisconsin-Upper Michigan ("WUMS") area – the average difference in prices exceeded $15 per MWh.
- The performance of the real-time market is compromised in some cases by reduced dispatch flexibility offered by many generators.
  - ✓ The average dispatchable range (EcoMax-EcoMin) for MISO units was only 25 percent of the generators' capacity – generators are capable of providing 50-60 percent on average.
  - ✓ The reduced flexibility to move generation over its output range can limit redispatch options for managing congestion and, thereby, affect prices.
- The next two slides provide detail on two issues that are important components of the performance of the real-time market:
  - ✓ RSG Costs- payments made to ensure the market revenue a generator receives when its offer is accepted exceeds its as-offered costs;
  - ✓ The dispatch and pricing of peaking resources.

Conclusions and Recommendations

Real-Time Market Performance – RSG Costs

- RSG costs can be incurred in both the day-ahead and real-time markets.
  - ✓ Resources committed after the day-ahead market to maintain reliability receive "real-time" RSG when their real-time revenues do not cover their as-bid costs – these costs averaged more than $50 million per month in 2005.
  - ✓ Because the day-ahead market is financial, a unit that is uneconomic will generally not be selected. Hence, day-ahead RSG average only $5 million per month.
- Peaking resources generally received approximately 75 percent of the RSG payments, despite producing only 2 percent of the energy in MISO.
  - ✓ Peakers receive the highest payments because they are generally the highest-cost resources and frequently do not set the energy price (it is set by a lower-cost unit).
- RSG costs can be caused by inefficient or excess commitment of non-peaking resources – our analysis did not show that this was a problem.
- The report shows that a number of periods that exhibited particularly high RSG costs were due to specific transmission and generation outages that required unusually high commitments of peaking resources to maintain reliability in affected local areas.
- We have consulted with the MISO regarding of number of provisions it has proposed that should improve system flexibility and reduce RSG.

Conclusions and Recommendations

Real-Time Market Performance -- Dispatch and Pricing of Peaking Resources

- The dispatch of peaking resources are an important component of the real-time market because they are a primary cause of RSG and determinant of efficient price signals.
  - ✓ On a daily average basis, the dispatch of peaking resources averaged close to 500 MW per hour in non-summer days and more than 1300 MW per hour during the summer.
  - ✓ However, on a number of peak days during the summer, the average dispatch was as high as 5000 to 7000 MW per hour.
- The commitment of peaking resources improved over the year, which we attribute to improved operating procedures by MISO.
  - ✓ These improvements involved committing peaking resources closer to when they are needed and decommitting them more quickly when no longer needed.
- 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.
  - ✓ This 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.
  - ✓ Peakers 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.

Conclusions and Recommendations

Transmission Congestion

- One of the most significant benefits of the MISO energy markets is that they provide accurate and transparent price signals that reflect the congestion on the network.
  - ✓ Congestion costs in the day-ahead and real-time markets were almost $800 million in 2005.
  - ✓ Higher gas prices in the fall increased the costs of congestion in the second half of the year because they increase the costs of re-dispatching generation to manage congestion.
  - ✓ The report shows that a large share of the increase in congestion is due to increased congestion into WUMS and on the path to TVA.
  - ✓ The LMP markets reduced the need to rely on transmission line loading relief (“TLR”) curtailments of wholesale transactions, which decreased by 75 percent from 2004 to 2005.
- The report shows that there were a number of instances when the real-time market model was unable to reduce the flow below the 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 modeling parameter (that excludes units with small impact on the constraint) are the two factors that primarily contribute to these instances.
  - ✓ The report includes recommendations to address this issue.

Conclusions and Recommendations

Transmission Congestion (cont.)

- The value of real-time congestion (based on the shadow prices and flows over each constraint) was approximately $1.2 Billion.
  - ✓ This value is larger than the congestion collected by MISO because there are a large quantity of loop flows created by the production and consumption of energy in other areas.
  - ✓ A substantial share of the loop flows were caused by PJM exports to TVA that were not well coordinated with MISO for most of the year.
    - – PJM has begun to coordinate this service based on the ATC posted by MISO.
    - – However, we recommend the joint operating agreement (“JOA”) be expanded to more efficiently coordinate this service since it has created substantial congestion.
- Most of the real-time congestion
  - ✓ 90 percent of the value of real-time congestion occurred on internal MISO constraints.
  - ✓ The remaining 10 percent occurred on external constraints for which MISO redispatches generation, including:
    - – PJM market-to-market constraints; and
    - – Constraints in other areas for which transmission line loading procedures are called to manage congestion.

Conclusions and Recommendations

Financial Transmission Rights

- Financial transmission rights provide a hedge for congestion because the day-ahead congestion over the path that defines the FTR is rebated to the holder.
  - ✓ FTRs were fully funded in 2005 – i.e., sufficient congestion costs were collected in total to pay the full obligations under the rights for the year.
  - ✓ On a monthly basis, however, the FTRs were under-funded in the last 3 months of 2005.
    - This occurs when the day-ahead transmission capability is less than implied by the FTRs.
    - In these months, the under-funding was due to a) loop flows that were not fully reflected in the FTR modeling and b) significant transmission outages.
  - ✓ Other transmission rights were created to accommodate grandfathered agreements (e.g., Option B FTRs, Carve-Outs, Expanded Congestion Hedges) – payments to 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 evaluates the performance of the FTR auctions by comparing the monthly prices for the FTRs to the actual value of congestion payable to the FTRs, which showed:
  - ✓ The FTR prices for April 2005 were generally well above the value of the congestion.
  - ✓ After April, FTR prices generally adjusted relatively quickly to changes in congestion patterns from prior months.

Conclusions and Recommendations

External Transactions

- The Midwest ISO relies heavily on imports from adjacent areas.
- On average, MISO imports almost 3500 MW in on-peak hours and close to 2000 MW in off-peak hours.
  - ✓ More than half of these imports come from Manitoba.
  - ✓ MISO is also a net importer from PJM, although the power flows across this interface frequently reverses direction.
- When the markets were first introduced, the net imports were lower than they had been pre-market.
  - ✓ In the first 45 days of market operation, the real-time net imports were often substantially less than the day-ahead net imports.
  - ✓ This raises potential reliability concerns because it can cause the generator commitments made day-ahead to be inadequate, leading to a relatively heavy reliance on peaking units.
  - ✓ After the first 45 days, the real-time net imports became much more consistent with the day-ahead net imports.

Conclusions and Recommendations

External Transactions (cont.)

- 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.
  - ✓ Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to causes 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 -- there were a number of hours exhibiting large price differences between the Midwest ISO and adjacent markets.
  - ✓ To achieve better price convergence, we recommend that the RTO's consider expanding the JOA to optimize the net interchange between the two areas.
  - ✓ The participants' transactions would, therefore, be purely 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 the generation in the two regions.
- The report also evaluates the market-to-market coordination that the MISO and PJM use to jointly manage transmission congestion that the generation in both areas affect.
  - ✓ This process has been key in allowing these constraints to be efficiently managed.
  - ✓ However, our analysis shows that the process can be improved by optimizing the relief requested by each RTO from the other and by changing how nodal prices are calculated.

Conclusions and Recommendations

Market Power Issues 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 2005.
- Although reliable inferences regarding market power cannot be drawn from market concentration statistics, the report indicates that concentration is:
  - ✓ Low for the overall MISO area;
  - ✓ Quite high in the East, West, and WUMS sub-areas within MISO. The top three suppliers control 70 to 80 percent of the supply in these areas.
- A more reliable indicator of potential market power is the indication that a supplier is "pivotal", which means a portion of the load or reserve requirements cannot be satisfied without the resources of the largest supplier. The analysis in the report shows:
  - ✓ In WUMS, there is a pivotal supplier in more than 80 percent of the hours when load exceeds 60 GW (75 percent of all hours).
  - ✓ The West and East regions exhibit a pivotal supplier in a substantial number of hours only when load exceeds 80 GW (20 percent of all hours).

Conclusions and Recommendations

Market Power Issues and Mitigation (cont.)

- We also conducted a pivotal supplier analysis by transmission constraint to identify the frequency with which a single suppliers' resources are needed to manage a constraint.
  - ✓ More than one third of the active "broad constrained area"("BCA") constraints have a pivotal supplier. BCAs are all constraints other than those into and within WUMS.
  - ✓ Almost 60 percent of the active "narrow constrained area" ("NCA") constraints have a pivotal supplier. NCAs are the constraints into or within WUMS,
  - ✓ In addition, as a percent of all intervals during 2005, there was an active BCA constraint with at least one pivotal supplier in two-thirds of the hours and an active NCA constraint with a pivotal supplier in almost 30 percent of the hours.
  - ✓ Hence, substantial local market power is associated with the BCA and NCA constraints.
- However, the report shows little evidence of substantial attempts to withhold resources physically or economically to exercise market power.
- Energy offers were mitigated for BCA constraints in 24 instances and for NCA constraints in 62 instances. This mitigation occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria.
- In addition, offers from suppliers that have market power because their units must be committed to maintain reliability can be mitigated if they economically withhold- such mitigation occurred on 42 unit-days and reduced RSG almost $6 million.

Summary of Recommendations

In its first year of operation, the Midwest ISO's market has performed relatively well. However, the lack of ancillary services markets and other issues discussed in this report indicate opportunities for improvement.

Based on the results of this report, we provide the following recommendations:

1. Develop real-time ancillary services markets as soon as practicable.
   - Ancillary service markets that are jointly optimized with the energy markets will allow the market to more efficiently allocate resources between the two services; and\
   - Set efficient prices in both markets to reflect the economic trade-offs between reserves and energy.
2. Complete and implement the full ARC procedures that allow MISO operators to activate and dispatch the reserve range on units (output above EcoMax) – it will lower costs and allow a means for the market to set efficient prices during shortages.
3. Implement a "look-ahead" capability to improve the commitment of turbines and better manage ramp capability on slow-ramping units, which should reduce the out-of-merit quantities and RSG.

Summary of Recommendations

4. In the longer-run, develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.
   - This change will improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG.
5. To increase the redispatch options and, hence, the manageability of certain transmission constraints, we recommend:
   - The real-time market model be modified to allow generating resources with lower effects on the constraints to be redispatched; and
   - Mitigation measures be applied prospectively to the physical offer parameters when generator inflexibility causes substantial congestion – such mitigation is authorized under the MISO tariff.
6. When a transmission constraint is unmanageable, we recommend the Midwest ISO use the constraint penalty factor to set the nodal prices. This is particularly important for the market-to-market constraints.
7. We recommend the Midwest ISO consider modifying the JOA with PJM to:
   - Adjust the amount of relief each RTO requests from the other;
   - Optimize the real-time net interchange between the two RTO areas; and
   - Develop a process to coordinate exports to non-MISO/PJM areas within the JOA.

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Prices and Revenues

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Average Energy and Fuel Prices

- The following two figures shows monthly day-ahead and real-time energy prices in 2005, as well as monthly average natural gas prices.
- The change in fuel prices was a primary contributor to the movements in electricity prices in 2005:
  - ✓ Natural gas prices were more than 66 percent higher in December 2005 than in January 2005.
    - – Hurricanes reduced the supply of natural gas from the Gulf Coast region in the fall of 2005, which contributed to the higher fuel prices.
  - ✓ Correlation of energy prices with gas prices is expected since fuel costs represent the majority of most generators' variable production costs and gas units are on the margin in most peak load hours.
- The figure also shows the congestion between the hubs, the most significant of which is between Minnesota and WUMS.
  - ✓ The WUMS price exceeds the price at the Minnesota hub by almost $16 per MWh and almost $17 per MWh in the day-ahead and real-time markets, respectively.
  - ✓ However, outages and other system conditions can cause transitory changes in congestion, as occurred in December when prices were higher in Minnesota.

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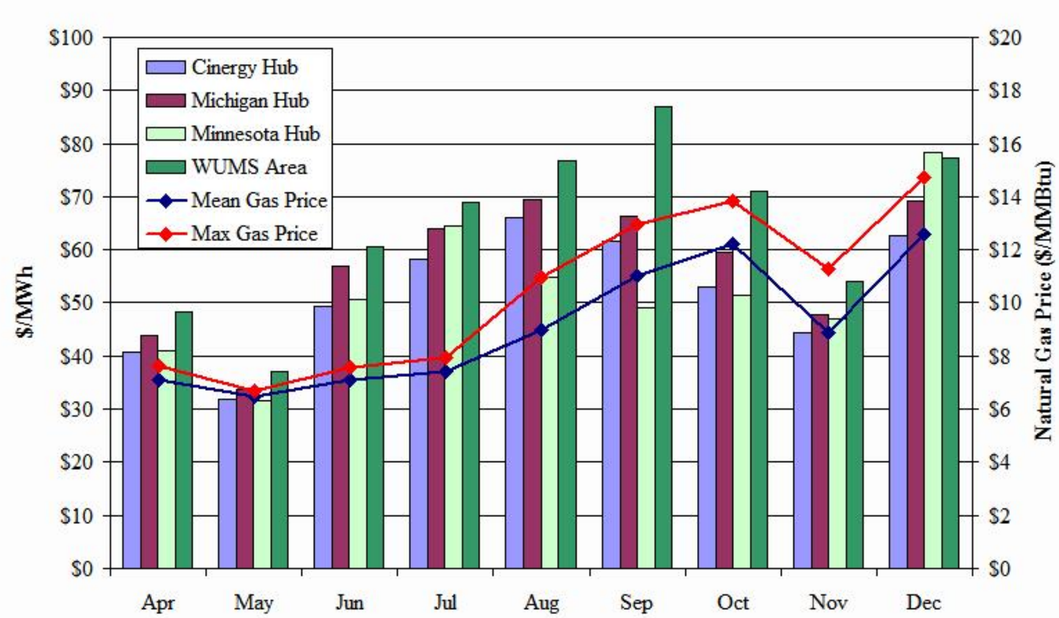
Day-Ahead Average Monthly Hub Prices 2005: All Hours



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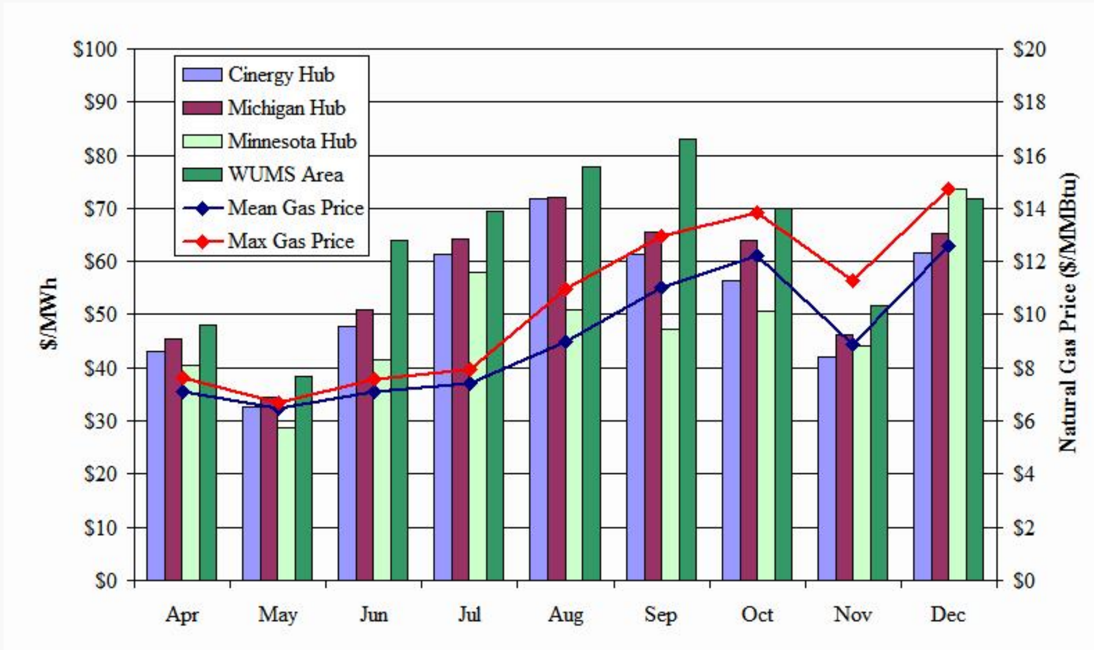
Real-Time Average Monthly Hub Prices 2005: All Hours



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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).
- These curves show that congestion and losses caused prices to vary by location:
  - ✓ The WUMS prices are the highest due to the frequent congestion into that area -- 15 percent of the hours exhibit prices above $100/MWh and 1.4 percent of the hours have prices above $200/MWh.
  - ✓ Michigan is the next highest-priced region with 11% and 0.3% hours above $100 and $200/MWh, respectively. Congestion into Michigan also often requires the supplemental commitment of gas resources there.
  - ✓ Prices were the lowest in Minnesota due to congestion into WUMS. In the hours when congestion was most severe, the prices were frequently negative, which occurred in 6% of the hours. The negative prices are caused by
    - – Limited flexibility in dispatching imports from Manitoba
    - – Limited control on DC lines
    - – Limited dispatch flexibility on baseload generation in off-peak hours.

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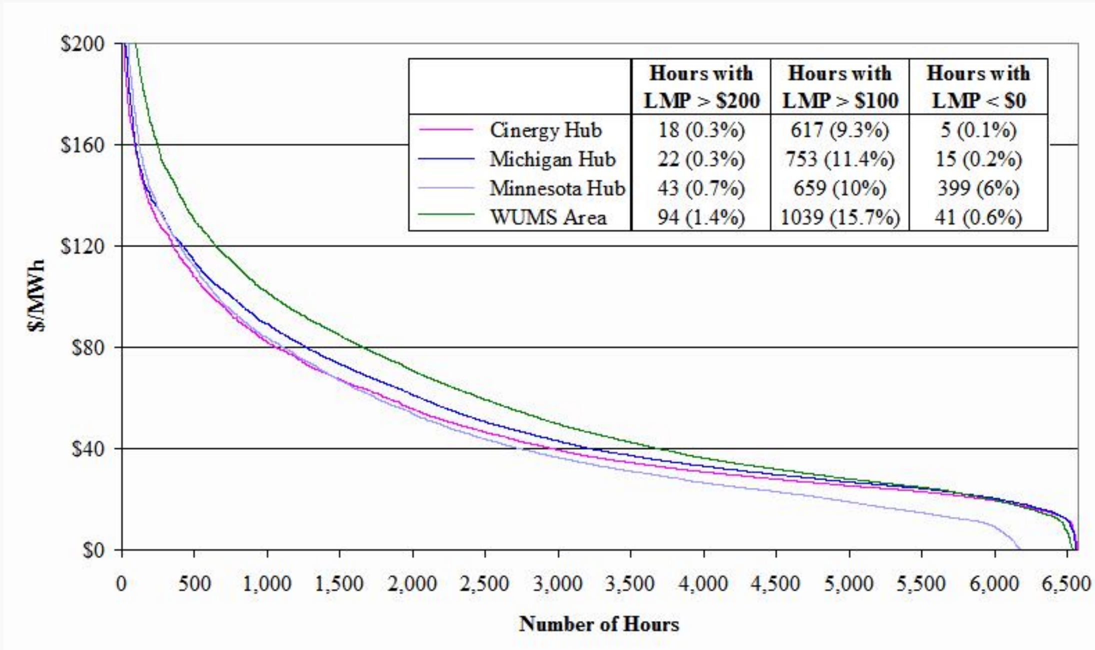
Real-Time Price Duration Curve
2005: All Hours



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Headroom and Real-Time Prices

- The next figure shows the relationship between headroom on baseload and intermediate generating resources.
  - ✓ Headroom is the dispatch range between a generator’s current output level and its maximum output level (“EcoMax”).
  - ✓ Headroom declines as demand increases and the market accepts higher-priced offers from online resources. Hence, headroom and prices should be negatively correlated.
- The figure shows that the market is functioning as expected, with headroom strongly and negatively correlated with prices.
- While the price-headroom relationship is very strong, the relationship is not more tightly defined (particularly in high-priced hours) for the following reasons:
  - ✓ Ramp limitations on a 5 minute basis can prevent headroom from being accessible in the short-term, leading to higher prices.
  - ✓ Prices can be high in constrained areas even when headroom is substantial.

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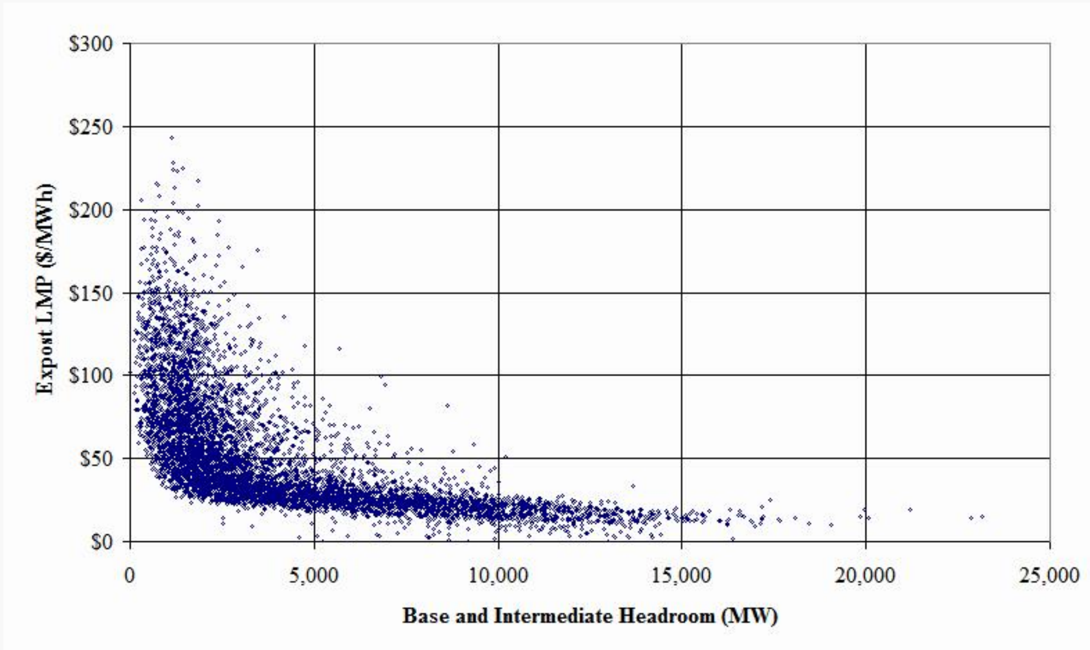
Headroom and Real-Time Prices



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All-In Price

- The following figure shows an "all-in" price that includes the costs of energy and real-time revenue sufficiency guarantee ("RSG") costs.
- This is a metric that is intended to show the total cost of serving load in the Midwest ISO from the Midwest ISO energy markets.
  - ✓ The all-in price does not include ancillary services and capacity costs since the Midwest ISO currently lacks these markets.
- The figure shows that:
  - ✓ RSG costs are very small share (less than 2 % on average) of the all-in price.
  - ✓ The all-in price was highest during the peak load months of the summer. However, it was substantial affected by the high natural gas prices that occurred after the hurricanes in the fall 2005.

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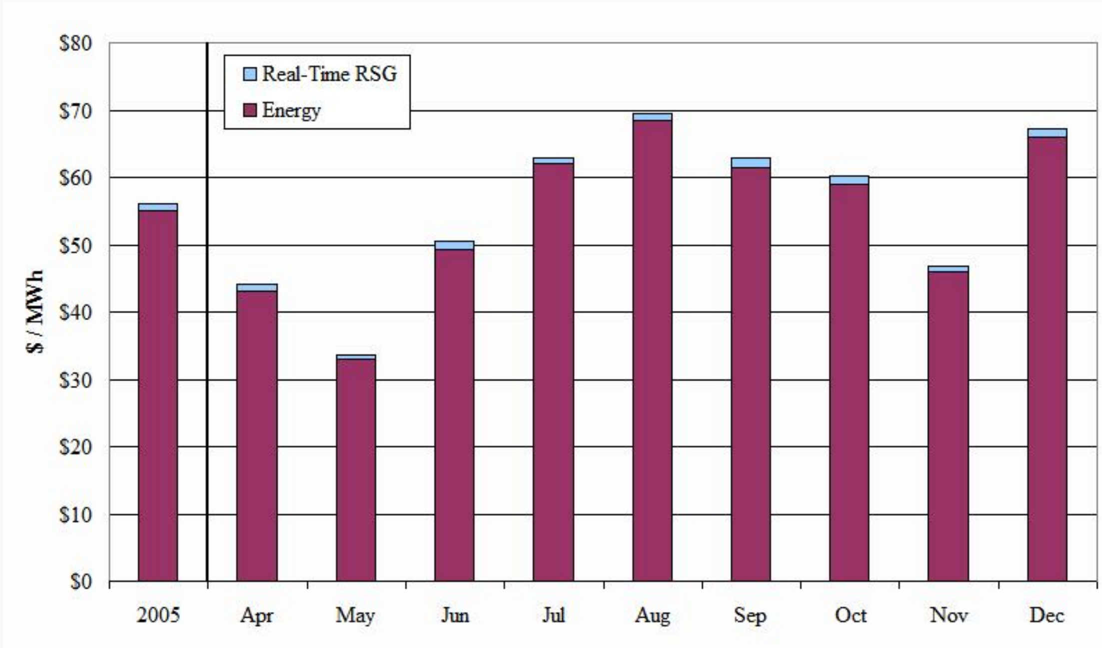
All-In-Price 2005



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Net Revenue and Operating Hours

- The following figure shows the Net Revenue provided by the MISO market over the first nine months of operation at different locations.
  - ✓ Net revenue is the revenue that a new generator would earn above its variable production costs if it runs when it is economic and does not when it is not economic.
  - ✓ This analysis utilizes FERC's standardized assumptions that account for variable O&M costs, fuel costs, and forced outages.
  - ✓ However, the analysis does not consider start-up costs, minimum run-times, or other physical limitations.
- In long-run equilibrium, the market should provide sufficient net revenues (revenue in excess of production costs) to finance new entry.
- The following figure shows the net revenue the markets would have provided for two types of units:
  - ✓ Gas combined-cycle: heat rate assumed of 7000 BTU/KWh.
  - ✓ Gas combustion turbine: heat rate assumed of 10500 BTU/KWh.

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Net Revenue and Operating Hours

- This analysis shows that even in the highest price region, neither a CT or CC unit would have earned net revenues sufficient to justify new investment.
- This outcome is expected because MISO continues to have excess generating capacity.
  - ✓ Net revenue high enough to support new entry requires either a significant number of price spikes associated with periods of shortage or capacity market revenues.
  - ✓ MISO has no capacity market. Even if it did, the excess capacity prevailing in the Midwest would limit the net revenue from either of these sources.
- The figure also shows the number of hours each type of new unit would be expected to run, which is consistent with the operating experience of gas-fired generators in the Midwest ISO region in 2005.
- Once the excess capacity in the region declines, it will be important for the Midwest ISO to have markets in place to send efficient long-term signals for investment.
  - ✓ One important market enhancement that would contribute to satisfying this requirement is the introduction of ancillary services markets.

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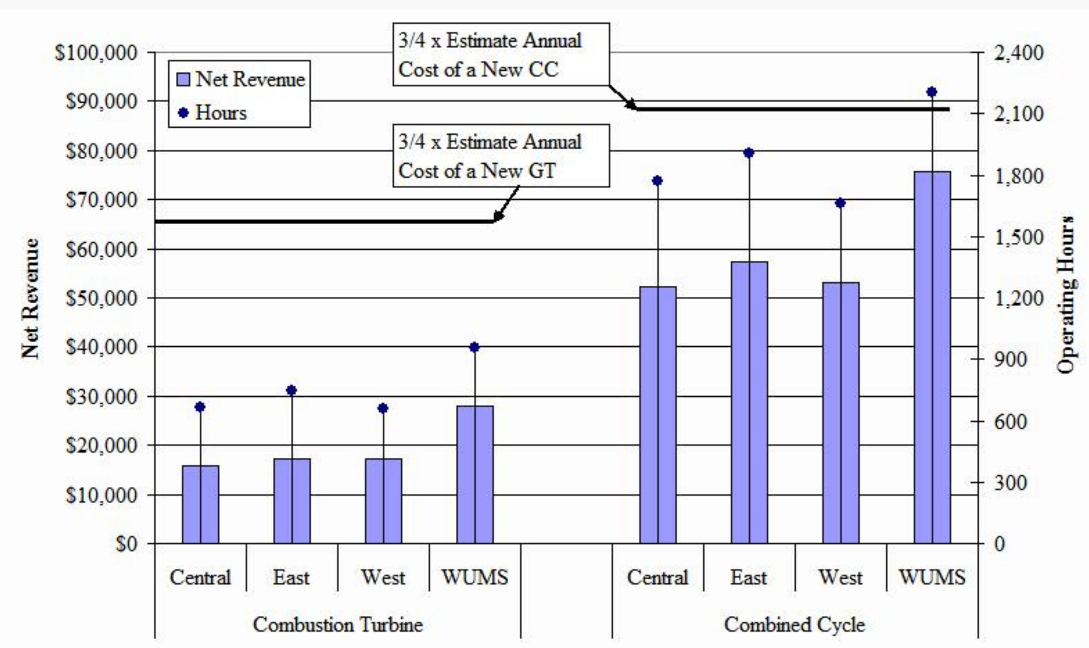
Net Revenue and Operating Hours



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Load and Resources

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Load Maximum and Average Versus Peak Prediction 2005: All Hours

- This figure shows the peak average hourly load by month for each sub-region.
- The MISO is a summer peaking region – the figure confirms that the highest loads occurred in the summer months.
- Load was significantly higher than predicted in 2005.
  - ✓ In the three Summer months, June, July and August, the peak load was 109, 112, and 112 GW, respectively.
  - ✓ Each of these monthly peaks was well above the predicted peak load for 2005 of 107 GW.
- As is characteristic of electricity markets, the peak load levels are substantially higher than average load levels.
  - ✓ During the summer months, the peak load levels were 40 percent higher than the average loads.
  - ✓ Because electricity cannot be stored, the market relies on intermediate and peaking resources to meet these demands.
- The figure also shows that most of the load in the Midwest ISO is in the Central and East sub-regions.

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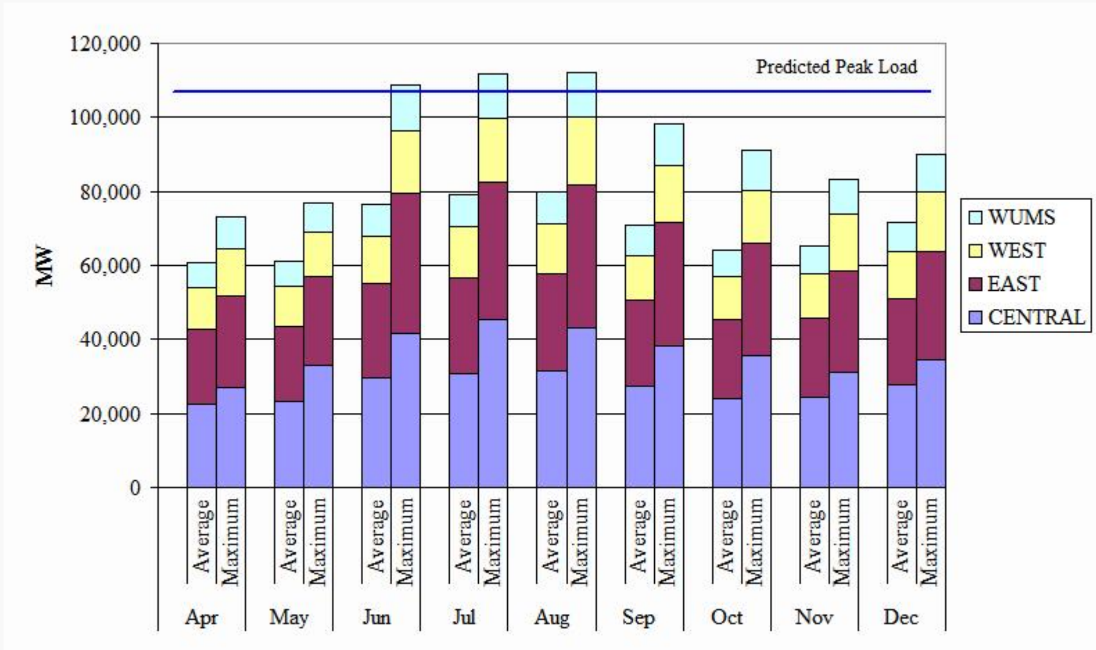
Load Maximum and Average Versus Peak Prediction 2005: All Hours



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Load Duration Curves 2003 - 2005

- The next figure shows load duration curves for 2003, 2004, and 2005.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- In 2005, there were far more hours with extreme demand levels.
  - ✓ In 2005, there were 14 hours when actual loads exceeded 110 GW, and no such hours in 2004 or 2003.
  - ✓ In 2005, there were 165 hours when actual loads exceeded 100 GW. There were 16 of these hours in 2004 and just 10 hours in 2003.
  - ✓ In 2005, there were 550 hours with load greater than 90 GW, as opposed to 123 such hours in 2004 and 121 in 2003.
- These results also indicate the importance of efficient pricing during the highest load conditions.
  - ✓ More than 25 percent of the resources are needed to serve the highest 5 percent of load and provide operating reserves for the region.

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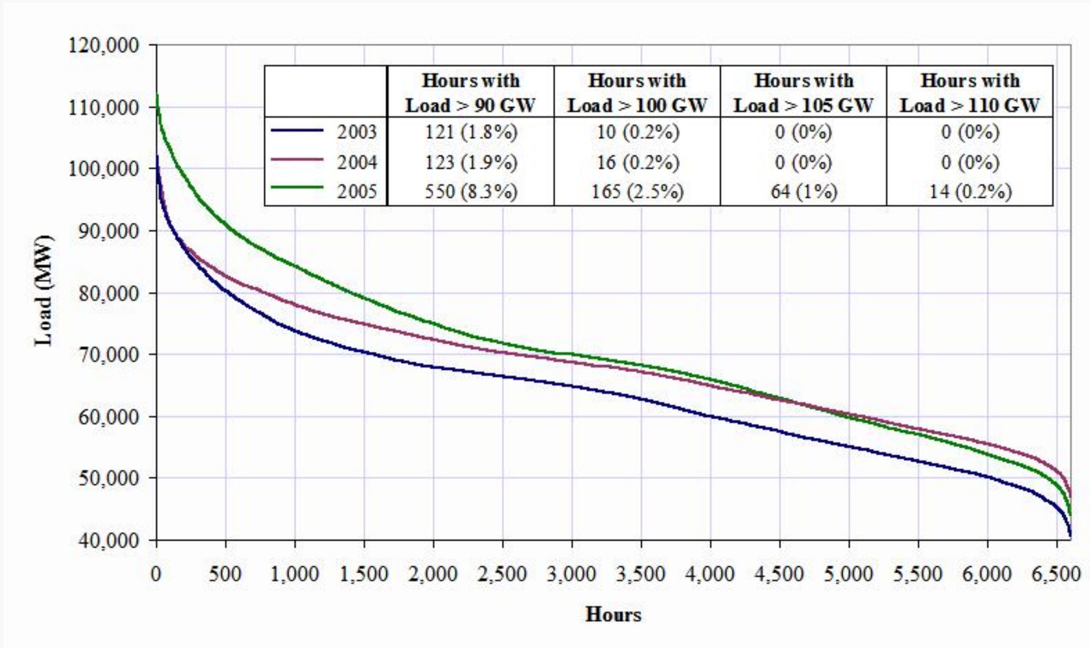
Load Duration Curves
2003 - 2005



	Hours with Load > 90 GW	Hours with Load > 100 GW	Hours with Load > 105 GW	Hours with Load > 110 GW
2003	121 (1.8%)	10 (0.2%)	0 (0%)	0 (0%)
2004	123 (1.9%)	16 (0.2%)	0 (0%)	0 (0%)
2005	550 (8.3%)	165 (2.5%)	64 (1%)	14 (0.2%)

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MISO Generating Capacity by Coordination Region

- Generating resources in the Midwest ISO market footprint totaled 137 GW in 2005;
  - ✓ The resources in this figure are those owned by Midwest ISO market participants and exclude MISO 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 four primary sub-regions in the Midwest.
  - ✓ Because it is a highly congested area, we show WUMS area separately from the rest of the eastern coordination region of MISO.
  - ✓ 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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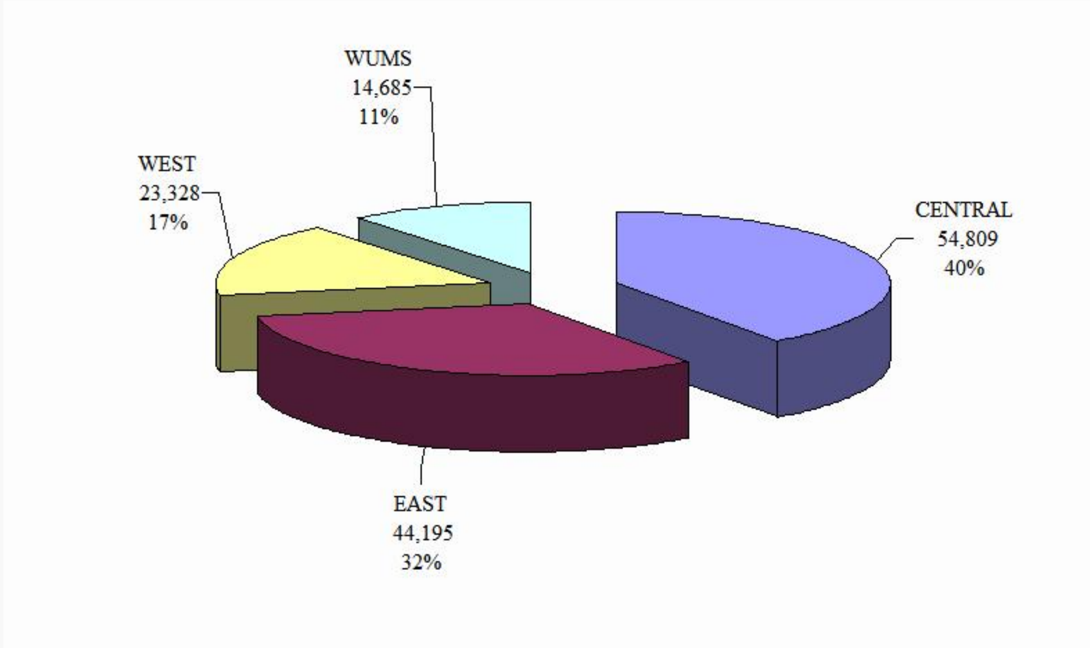
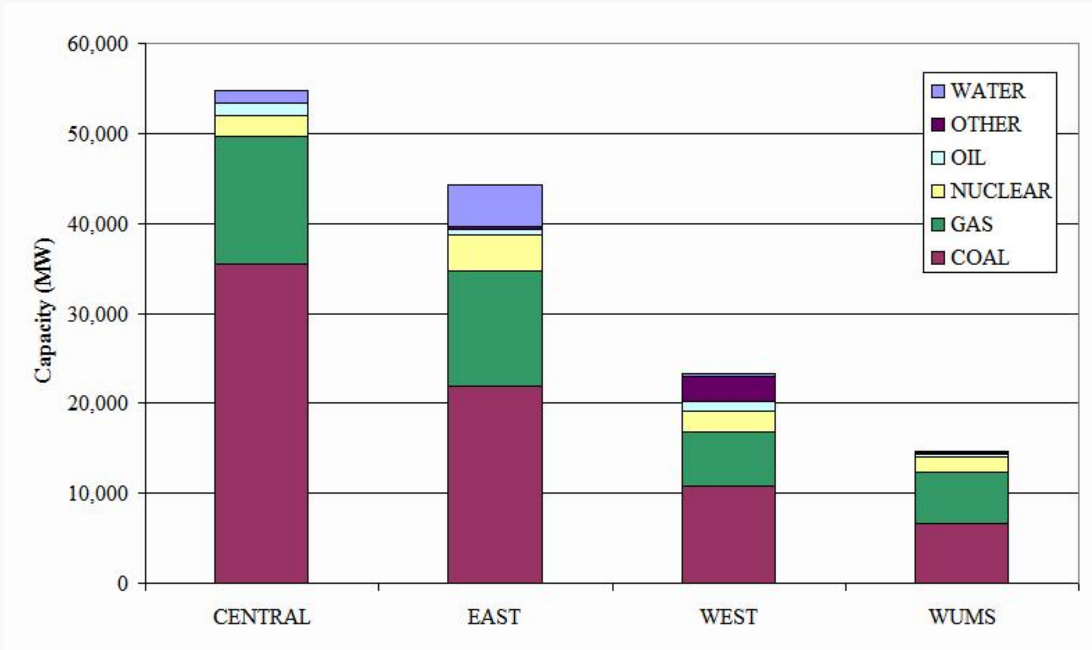
Generation Capacity by Coordination Region



Distribution of Sub-Region Generation Capacity By Fuel Type

- The MISO continues to rely heavily on coal-fired generating resources.
  - ✓ Approximately 55% of its generation capacity is coal-fired.
  - ✓ Since coal units are generally base-load, coal-fired resources generate an even larger proportion of the energy generated.
- The next source of fuel is natural gas, which fires almost 30 percent of the generating resources in the Midwest.
  - ✓ Because these resources are higher-cost than most of the other resources in MISO, they produce less than 30 percent of the energy in the region, but frequently set the price in the Midwest.
- Nuclear provides approximately 7% of capacity, while oil and hydro represent approximately 2% and 5% respectively. Other units, including wind, provide about 2% 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 quantity of nuclear resources.

Distribution of Sub-Region Generation Capacity By Fuel Type



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Equivalent Forced Outage Rate-Demand

- The following figure shows compares the Equivalent Forced Outage Rate-Demand ("EFORd") rates for 2002 through 2005.
- These data are unweighted values that are provided by NERC.
  - ✓ Because they are not capacity-weighted, outages of nuclear units and of very small units have the same effect on the region's EFORd rates.
  - ✓ The EFORd metric includes both full outages and partial outages.
- The 2002 to 2005 period has seen fairly consistent forced outage rates, from a maximum of 7.11 percent in 2002 to a minimum of 6.14 percent in 2004.

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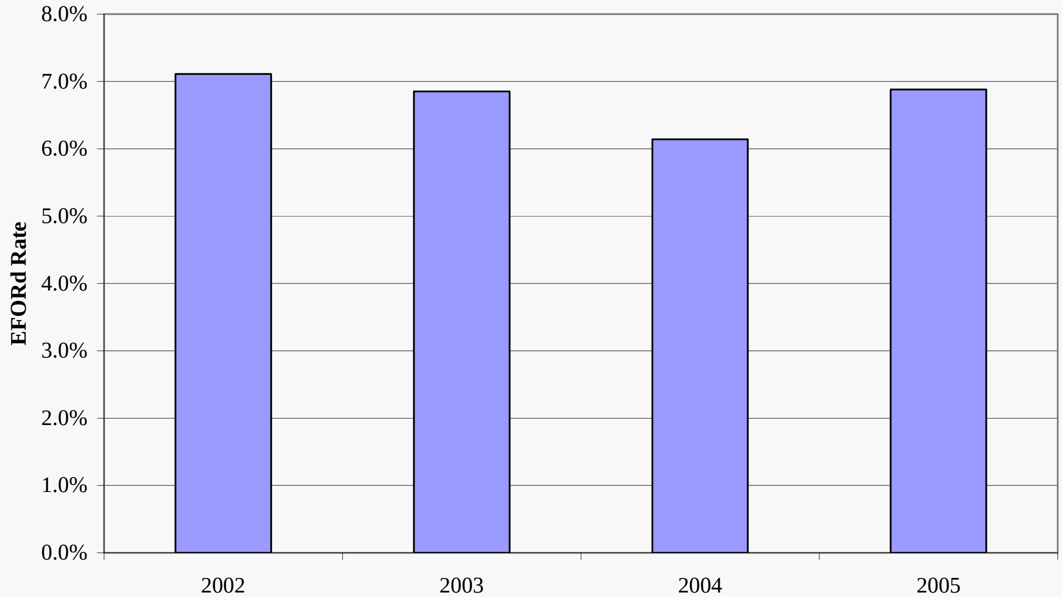
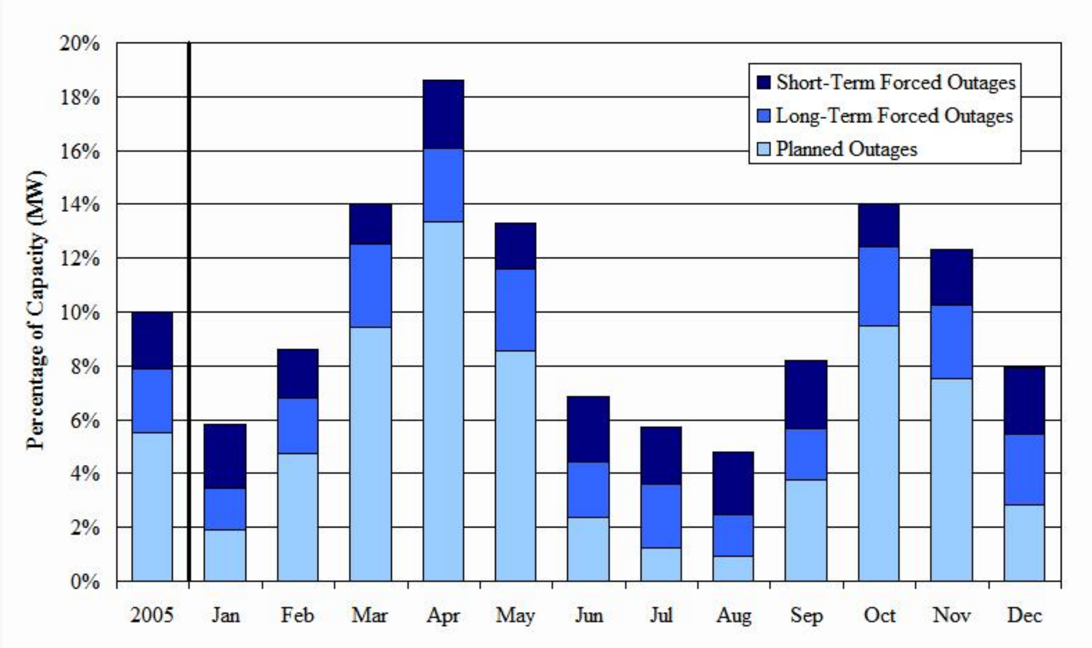
EFORd Rates
2002-2005



Generation Outages

- The following figure shows the generator outages that occurred in each month during 2005 as a percentage of total market generation capacity.
  - ✓ These values include only full outages – it does not include partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The annual combined outage rate was 10 percent for the three categories of outages.
- As expected, this figure shows that the largest total outages levels occurred in the spring and fall because planned outages are generally scheduled during these times.
  - ✓ Planned outages exceeded 10 percent during the spring and 7 percent in fall.
  - ✓ Total planned and forced outages peaked in April at more than 18 percent.
  - ✓ Planned outages were very small in the peak load months of July and August.
- The forced outage rate did not substantially increase during the summer -- it remained at the annual average of 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 day-ahead prices during peak hours and the corresponding scheduled load (including net cleared virtual demand) – the figure shows:
  - ✓ A general correlation between peak loads and peak prices;
  - ✓ The highest prices occurred in congested areas during periods of congestion.
- The higher gas prices beginning in July that remained high throughout the fall and winter are also evident in the general rise in prices over the year.
- The most significant congestion occurs between the Minnesota Hub and WUMS:
  - ✓ On average, WUMS prices exceeded prices in Minnesota during peak hours by an average of $13/MWh.
- In December, there was a notable spike in Minnesota Hub prices due to both ice storms (in the first week) and significant planned outages of transmission in Iowa and generation in Minnesota.

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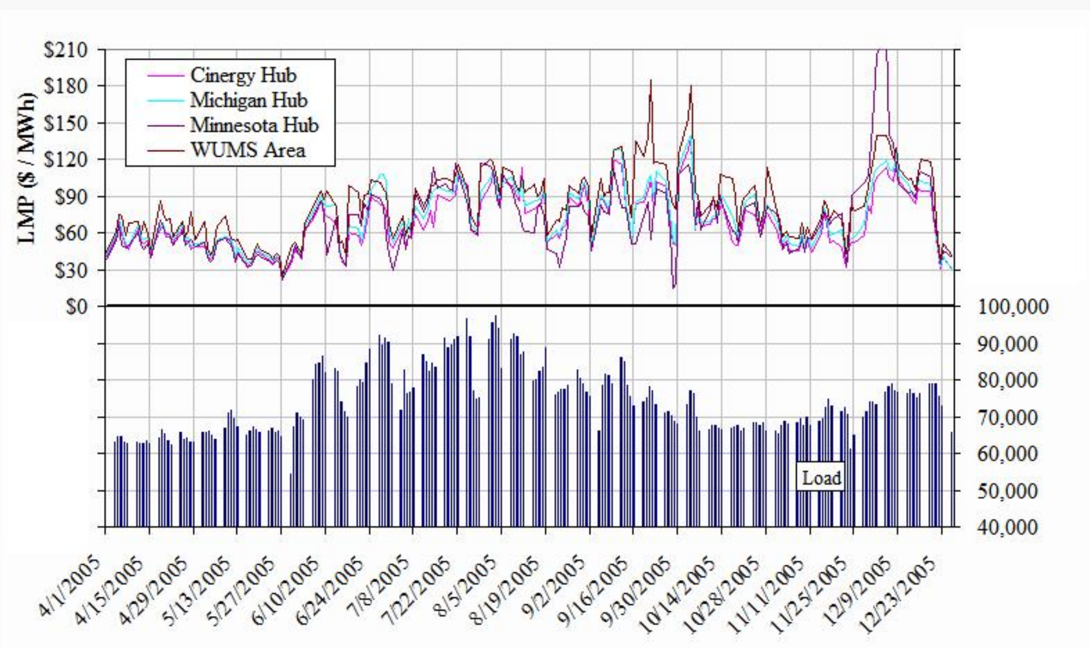
Day-Ahead Hub Prices and Load
Peak Hours



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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.
- Like the peak hours, the figure shows substantial congestion between Minnesota and WUMS.
  - ✓ During off-peak hours, congestion related price spikes occurred in the real-time market that resulted in negative prices in Minnesota.
  - ✓ To arbitrage the price levels in the day-ahead and real-time markets, the participants bid the day-ahead prices in the overnight hours down to close to zero in a substantial portion of the year.
- The substantial congestion in the off-peak hours into WUMS was due to a) limited ability to reduce baseload generation levels in Minnesota, b) power scheduled via DC lines from North Dakota, and c) imports from Canada to reduce flows on the critical lines into WUMS.
- The figure also shows that the generation and transmission outages contributed to off-peak rises in the Minnesota and WUM prices in the first weeks of December.
- Off-peak prices also show the impacts of rising fuel prices (primarily coal). The average price rose from $25 per MWh in the second quarter (April – June) to $36 per MWh in the forth quarter.

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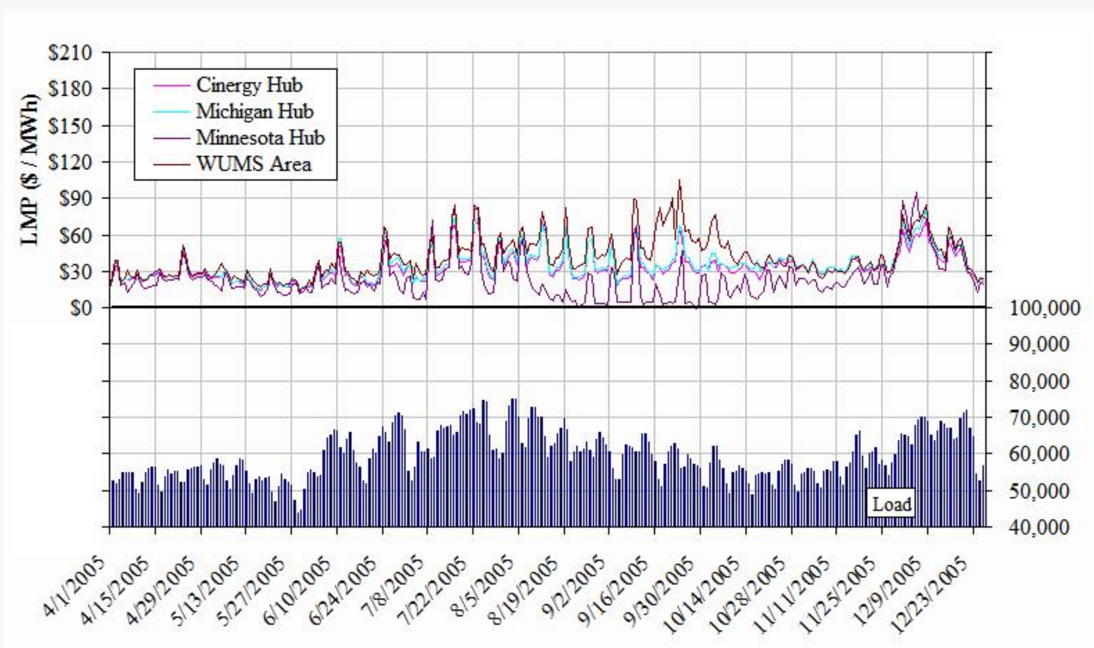
Day-Ahead Hub Prices and Load
Off-Peak Hours



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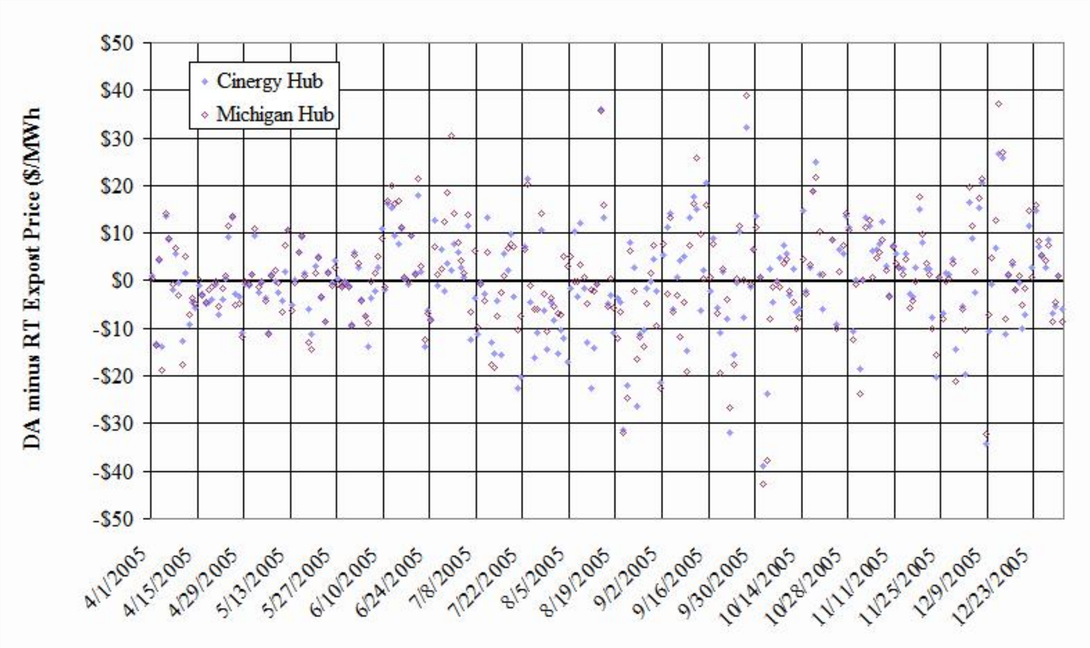
Day-Ahead and Real-Time Price Convergence

- 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 that bought or sold through the Midwest ISO markets is settled through the day-ahead market.
  - ✓ The entitlements of the 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 very small (-\$0.23, \$0.53) with standard deviations of \$10.75 and \$11.13 for the Cinergy and Michigan Hubs, respectively.
  - ✓ The Cinergy Hub prices in the Day Ahead were on average below the real-time prices by nearly \$ 4/MWh during the summer months of July and August.
  - ✓ The Michigan prices in the Day Ahead were also on average below real-time by approximately \$1.50/MWh throughout.
- The second figure shows the results for the Minnesota Hub and WUMS Area, which are frequently affected by the congestion between the two areas.
  - ✓ For the year the average price differences are larger in these areas -- \$4.25/MWh in Minnesota and \$1.57/MWh in WUMS
  - ✓ The standard deviations are also larger due to the effects of congestion -- \$16.50/MWh and \$15.26/MWh for the Minnesota Hub and WUMS area, respectively.

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



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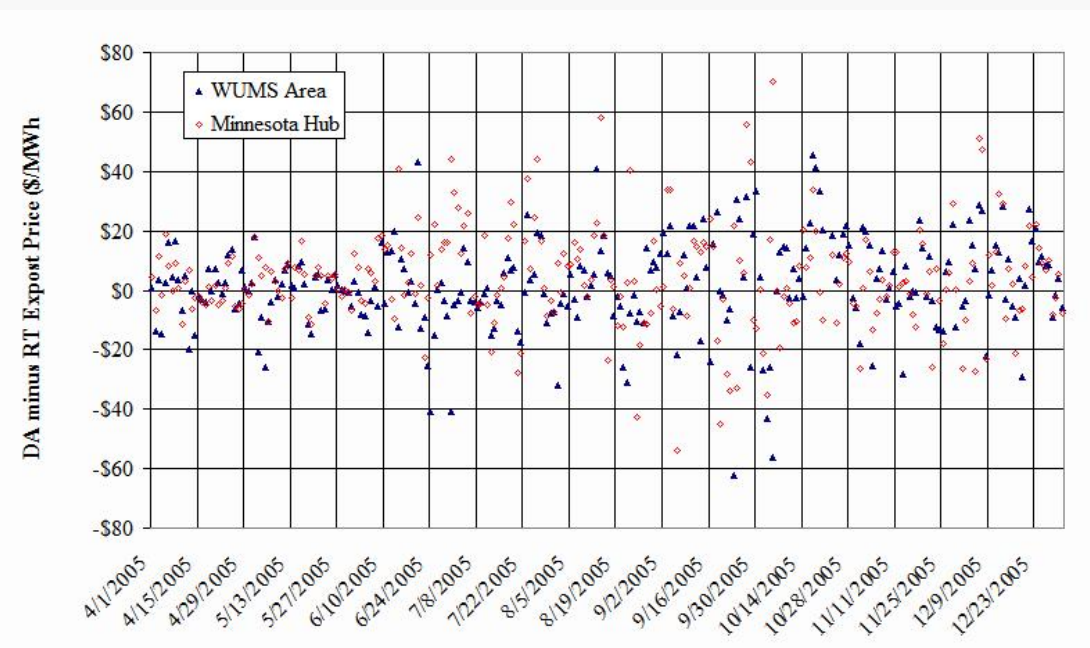
Day-Ahead and Real-Time Price Differences Minnesota Hub and WUMS Area - All Hours



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

- The following figures shows the monthly average prices in peak hours 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. Hence, this figure also includes the monthly average bilateral prices.
  - ✓ Over the whole period, the average day-ahead, real-time, and bilateral prices were nearly identical.
  - ✓ Monthly average bilateral prices were highly consistent with the day-ahead prices for Cinergy.
    - The average monthly difference was less than 5 percent difference in every month but May.
    - The average difference for the year was 0.7 percent.
  - ✓ Cinergy real-time prices were generally close to day-ahead. In the peak months of July and August they were considerably higher (an average of nearly $5 /MWh) than the day-ahead and bilateral prices.
- The real-time peak prices at Michigan hub on average were $2.14/MWh less than day-ahead -- this was due in part to a $9/MWh difference in June that was largely caused by a period of extreme high load during the end of June.

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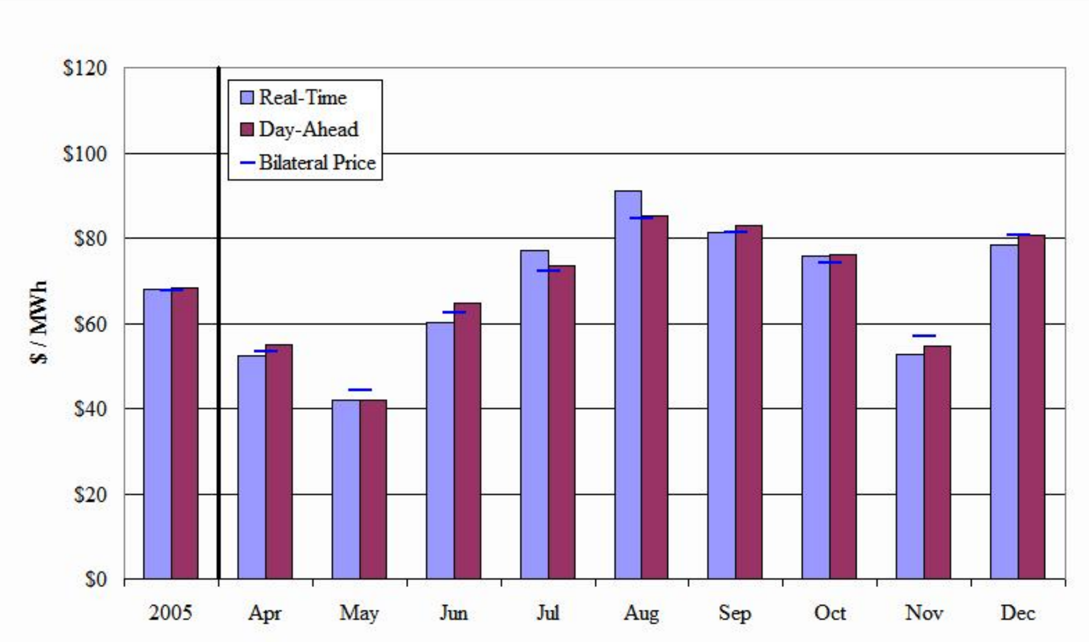
Day-Ahead and Real-Time Prices Cinergy Hub - Peak Hours



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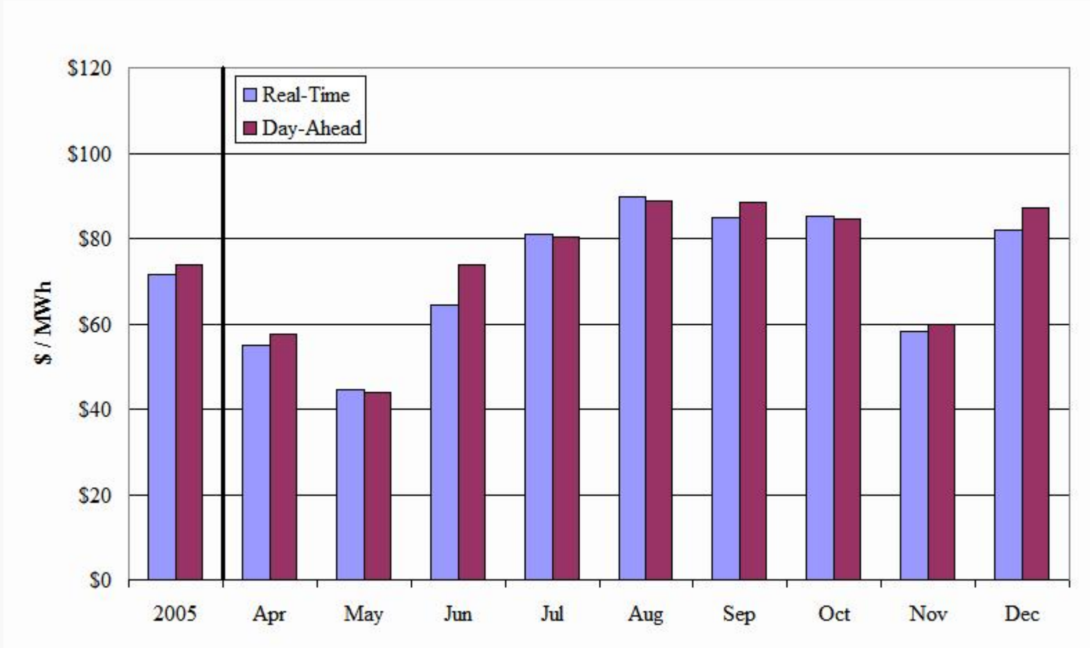
Day-Ahead and Real-Time Prices Michigan Hub - Peak Hours



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

- The following figures show peak hour Minnesota Hub and WUMS area prices for the day-ahead and real-time.
- Price convergence in these areas is more challenging because congestion causes the prices to be much more volatile.
- On the unconstrained side of the Minnesota-WUMS interface, the first figure shows:
  - ✓ The prices at the Minnesota hub in the day-ahead were on average above the real-time prices in every month.
  - ✓ The largest difference occurred in June when day-ahead prices were higher by more than $9/MWh.
  - ✓ Negative price spikes that occurred during periods of severe congestion contributed to the lower real-time prices.
- On the constrained side of the interface in WUMS, the figure shows;
  - ✓ Average prices for the year in the day-ahead and real-time markets were very close, with the day-ahead prices exceeding the real-time prices slightly.
  - ✓ However, real-time prices were higher in the highest-priced months (September and October).

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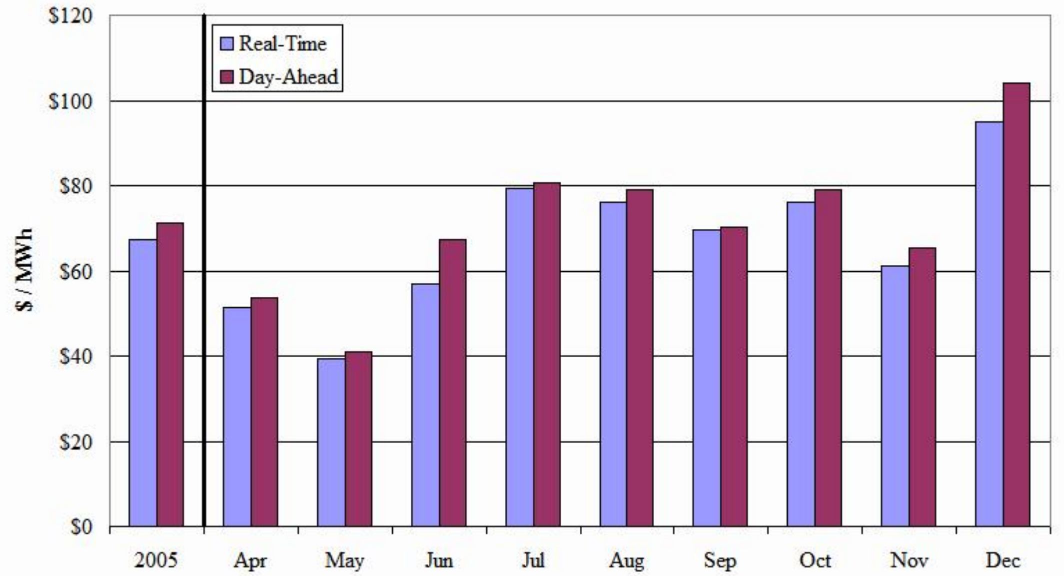
Day-Ahead and Real-Time Prices
Minnesota Hub - Peak Hours



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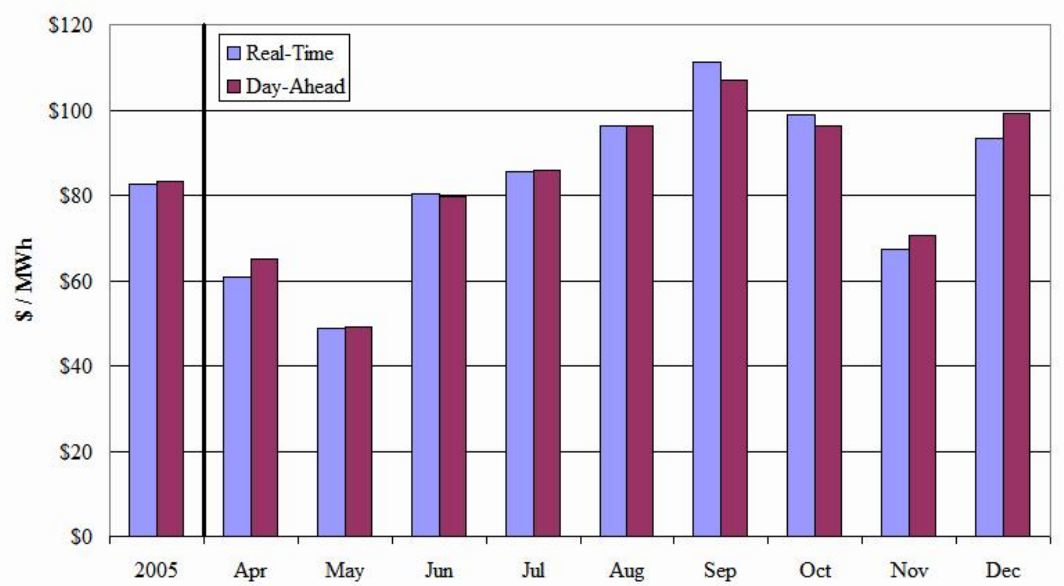
Day-Ahead and Real-Time Prices
WUMS - Peak Hours



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

- The following figure compares day-ahead and real-time price differences. The comparison includes:
  - ✓ Prices in MISO and Neighboring RTO markets (PJM, NYISO, ISO-NE)
  - ✓ Average relative price differences and absolute price differences
  - ✓ Prices in constrained and unconstrained areas in each market are shown in the figure.
- The comparison in the figure shows:
  - ✓ The price differences in areas that are not substantially affected by congestion are relatively small in all of the areas (less than $2.00/MWh).
  - ✓ With the exception of PJM, the locations affected by congestion (New York City, Connecticut, New Jersey, WUMS and Minnesota) exhibited larger average differences, ranging from $2 to $5/MWh.
  - ✓ The average absolute differences (the average size of the hourly differences, regardless of which price is higher) were generally consistent across each of the markets with higher values in the congested areas where prices are more volatile.
- Overall, these analyses indicate that price convergence has been relatively good given that this is the first 9 months of market operation – this is in part due to the rapid growth in virtual trading volumes.

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

	Average Clearing Price Day-Ahead	Real-Time	Difference	Average of Hourly Absolute Price Difference
Midwest RTO:				
Cinergy Hub	$50.88	$49.30	$1.54	$13.89
Michigan Hub	$54.18	$52.67	$1.46	$14.99
Minnesota Hub	$46.68	$43.49	$3.02	$19.93
WUMS Area	$62.48	$60.10	$2.38	$20.86
New England ISO:				
Connecticut	$83.16	$80.16	$2.99	$14.84
Maine	$70.83	$70.38	$0.45	$11.59
New England Hub	$78.55	$76.65	$1.90	$12.99
New York ISO:				
Zone A (West)	$66.87	$65.26	$1.61	$15.64
Zone G (Hudson Valley)	$82.54	$82.90	-$0.36	$20.41
Zone J (New York City)	$98.91	$103.82	-$4.90	$25.49
PJM:				
AEP Gen Hub	$46.06	$45.21	$0.85	$11.89
Chicago Hub	$46.93	$46.47	$0.46	$11.76
New Jersey Hub	$67.73	$68.20	-$0.47	$19.06
Western Hub	$60.52	$61.09	-$0.57	$16.20

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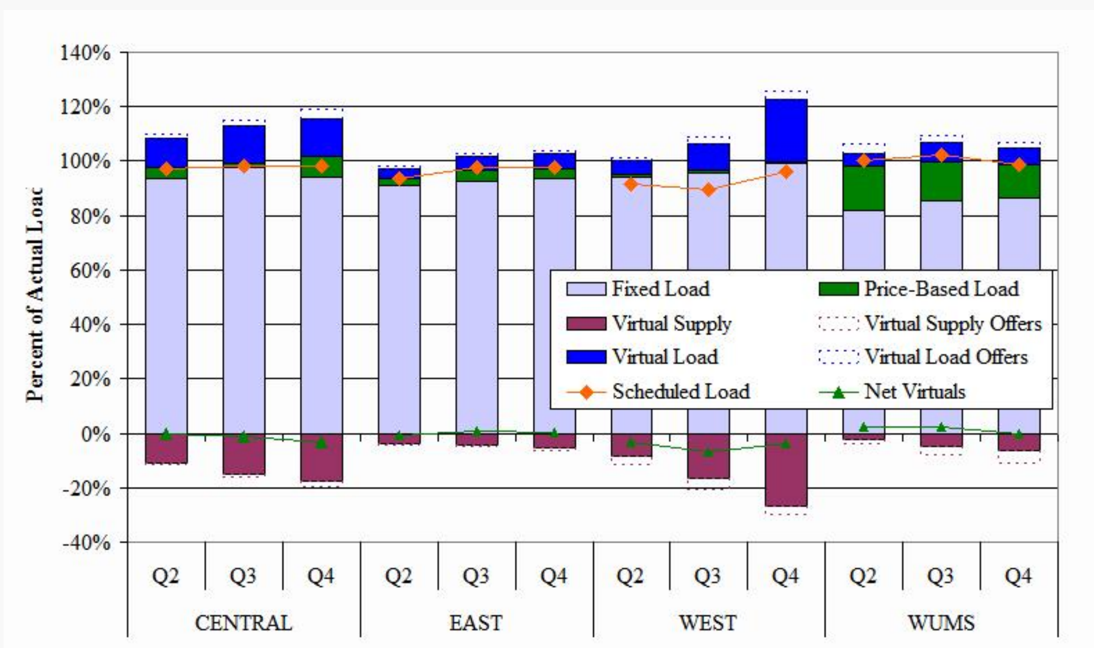
Day-Ahead Load Scheduling

- The next figure shows each of the components of the schedules that have cleared in the day-ahead market as a percentage of the actual real-time load.
- This figure shows:
  - ✓ The largest component of load scheduled in the day-ahead market is fixed, i.e., will be purchased at any price. Price-sensitive physical load is very small in all regions other than WUMS.
  - ✓ Virtual supply and demand cleared in the day-ahead market was the highest in the fourth quarter, particularly in the West where prices have been volatile due to congestion.
  - ✓ The net load (total load net of virtual supply) scheduled in the day-ahead market is slightly lower than 100 percent in all quarters in all regions except in WUMS.
  - ✓ Net load is lowest in Minnesota and highest in WUMS, which is consistent with participants' attempt to arbitrage day-ahead and real-time prices in each area.

Day-Ahead Load Scheduling versus Actual Load



Load Scheduled Day-Ahead v. Real-Time Load All Hours

- 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 2005.
- This pattern is likely cause, 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 due to their inherent operational inflexibility in the real-time market.
  - ✓ This creates economic incentive for participants to reduce their net scheduled load in the day-ahead market.

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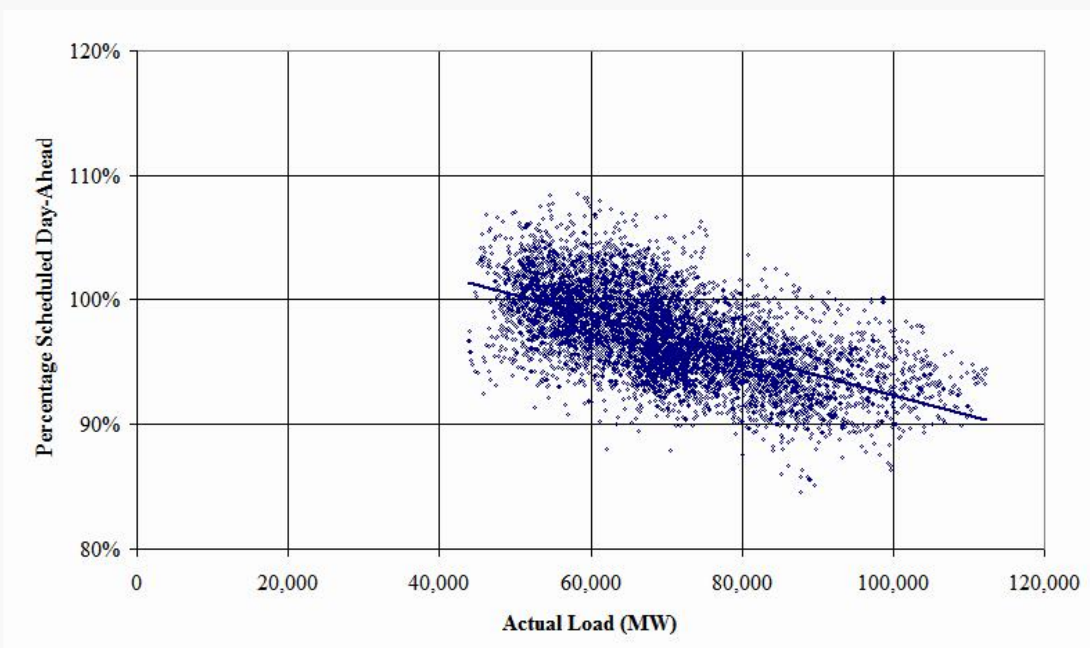
Load Scheduled Day-Ahead v. Real-Time Load All Hours



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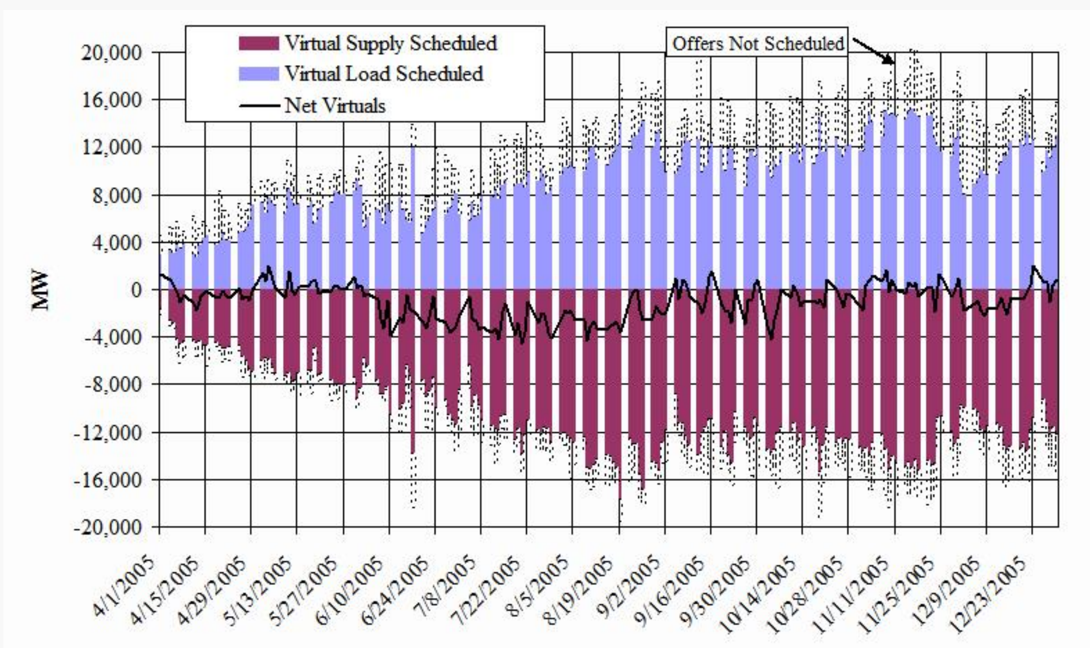
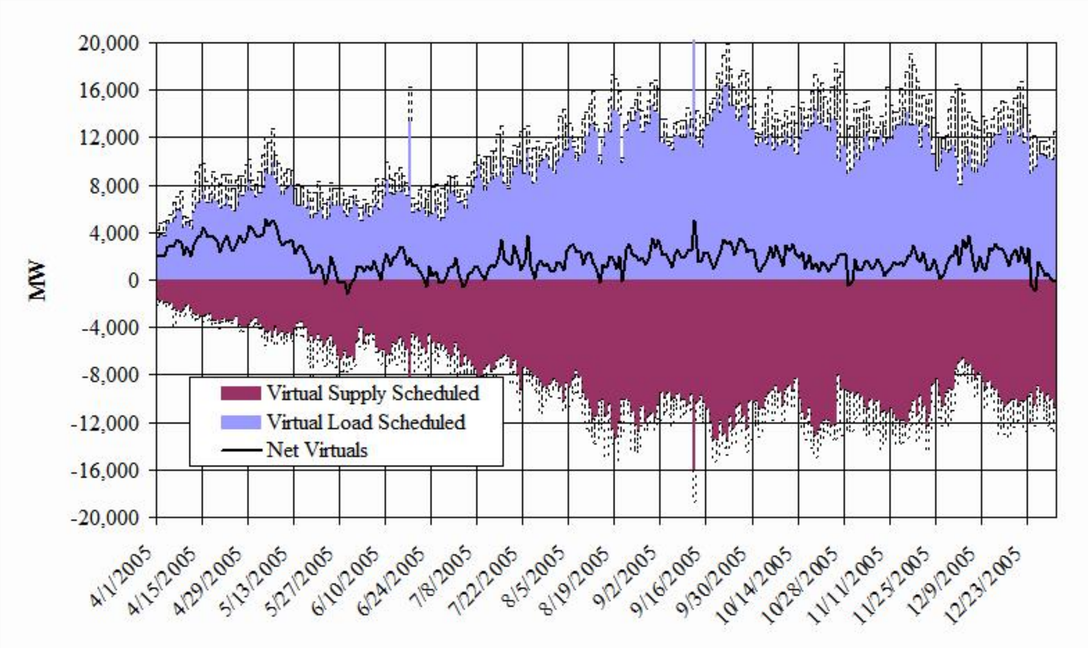
Virtual Load and Supply in the Day-Ahead Market 2005: Peak Hours

- 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 following figure shows the virtual load and supply offers for peak hours from April through December of 2005.
- Virtual trading volumes have grown rapidly.
  - ✓ Virtual load bids and supply offers have both more than tripled in volume since the market was introduced.
  - ✓ The rapid increase in the liquidity of the virtual trading contributes to efficient day-ahead market outcomes.
  - ✓ This liquidity, which already surpasses other RTO markets, is likely partially due to the low level of costs allocated to these transactions.

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



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



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Day-Ahead Forecast Error in Daily Peak Hour April to December 2005

- 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.
  - ✓ Day-ahead forecasts may also be used by some participants in the day-ahead scheduling and bidding processes.
- 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 between April and December 2005. This figure shows:
  - ✓ The average peak load forecast error was 2 percent on average (forecast error is the magnitude of the error, regardless of direction).
  - ✓ Over all of the days' hours, the average difference between the day-ahead forecast and real-time load was only 0.2 percent – indicating that the forecast is not systematically biased.
  - ✓ These results indicate that with the exception of some isolated days during 2005, the day-ahead forecasting process has been relatively good.
- However, the figure does show that the load tended to be over-forecasted in the summer and under-forecasted in the fall. The MISO should investigate whether any changes can be made to address these seasonal errors.

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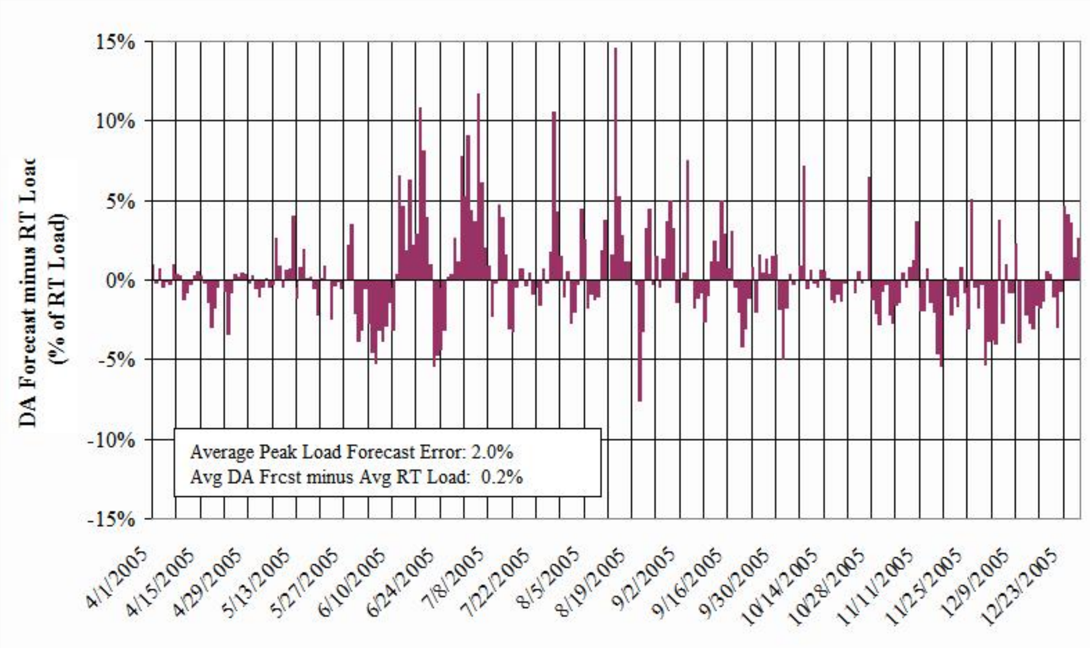
Daily Day-Ahead Forecast Error in Peak Hour April to December 2005



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Real-Time Market Performance

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Real-Time Hub Prices and Load
Peak Hours

- The next figure 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 well as impacts of higher gas prices beginning in July.
- As in the day-ahead market, the most substantial congestion occurs between Minnesota and WUMS:
  - ✓ An average annual price difference during peak load hours is well over $15/MWh with a maximum hourly price difference of over $230/MWh.
  - ✓ Price differences in real-time are greater due, in part, to reduced bid flexibility and ramp limits that tend to exacerbate congestion in the real-time market.
- In December there was a notable spike in Minnesota Hub prices due to: ice storms (in the first week) and significant planned outages of transmission in Iowa and Generation in Minnesota.

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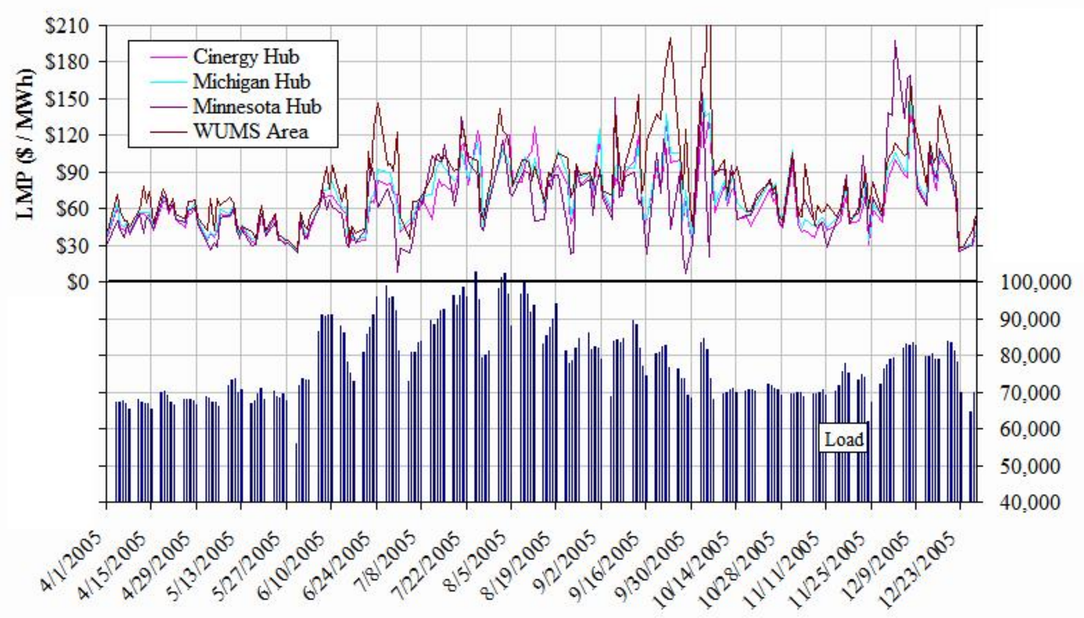
Real-Time Hub Prices and Load
Peak Hours



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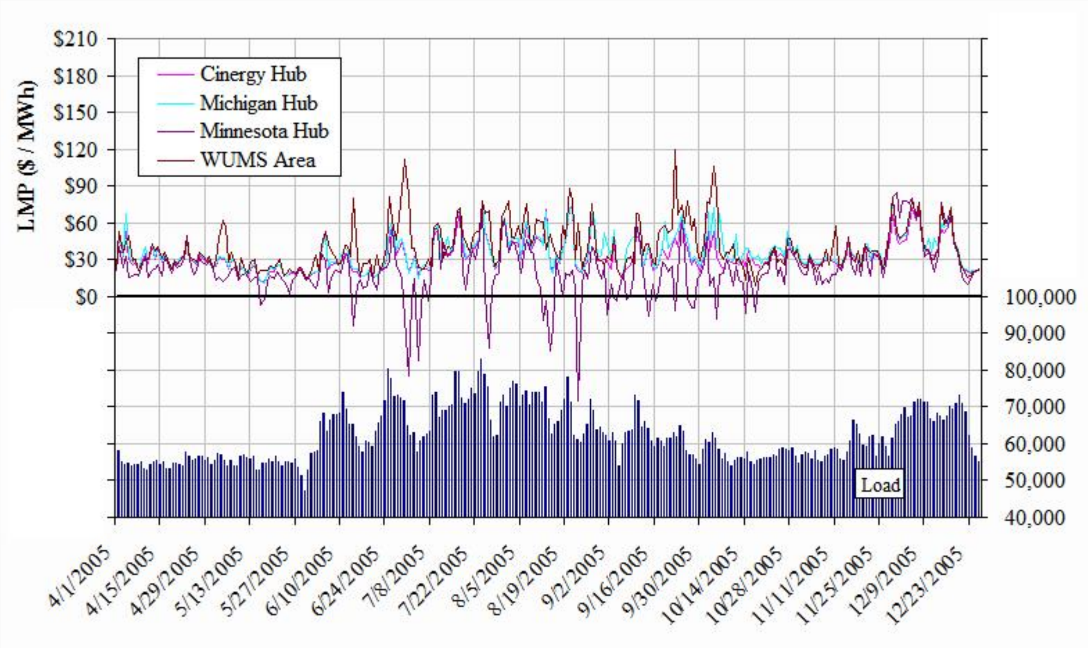
Real-Time Hub Prices and Load
Off-Peak Hours



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Day-Ahead and Real-Time Generation

- The following figure details the average monthly generation scheduled in the day-ahead and real-time markets.
- The figure shows that generation levels are generally higher 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 30 percent in the day-ahead market to 25 percent in the real-time.
  - ✓ 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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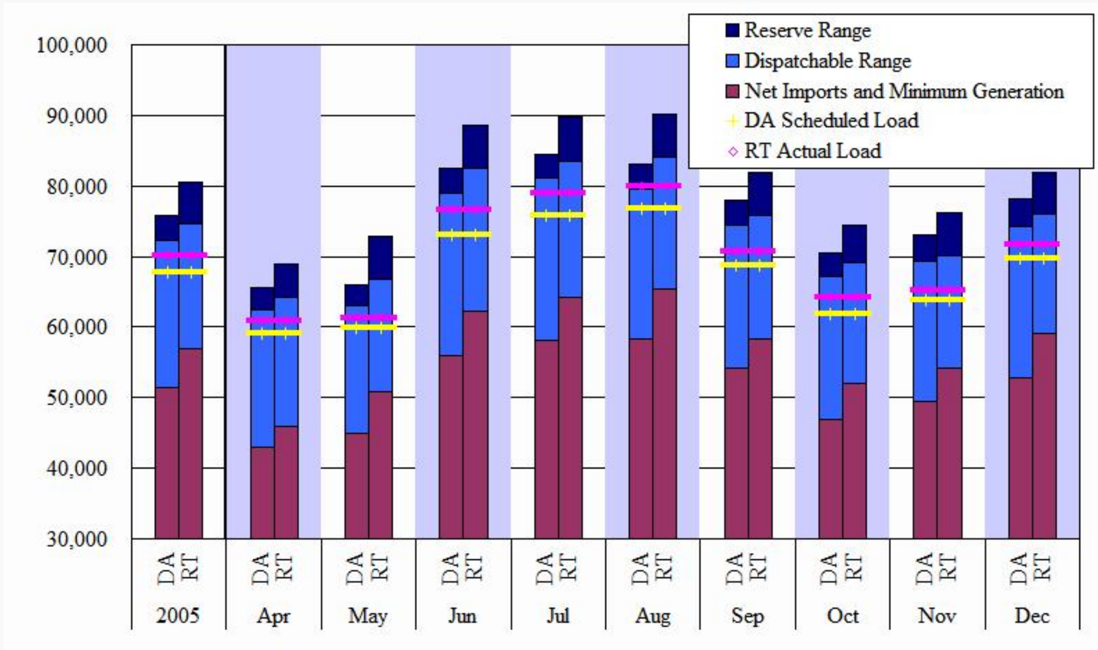
Day-Ahead and Real-Time Generation 2005: All Hours



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Revenue Sufficiency Guarantee Payments Day-Ahead and Real-Time

- The accompanying figure displays monthly revenue sufficiency ("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 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 a financial, very little RSG is generated in it – 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).
- The figure shows that the vast majority of RSG is generated in the real-time market and is payable to peaking resources, as expected.
  - ✓ RSG payments to peaking units accounted for at least 74% of RSG payments in all months except for April (64%), May (58%) and October (60%).
  - ✓ This is despite the fact that peaking resources accounted for only 2 percent of the energy generated in MISO.

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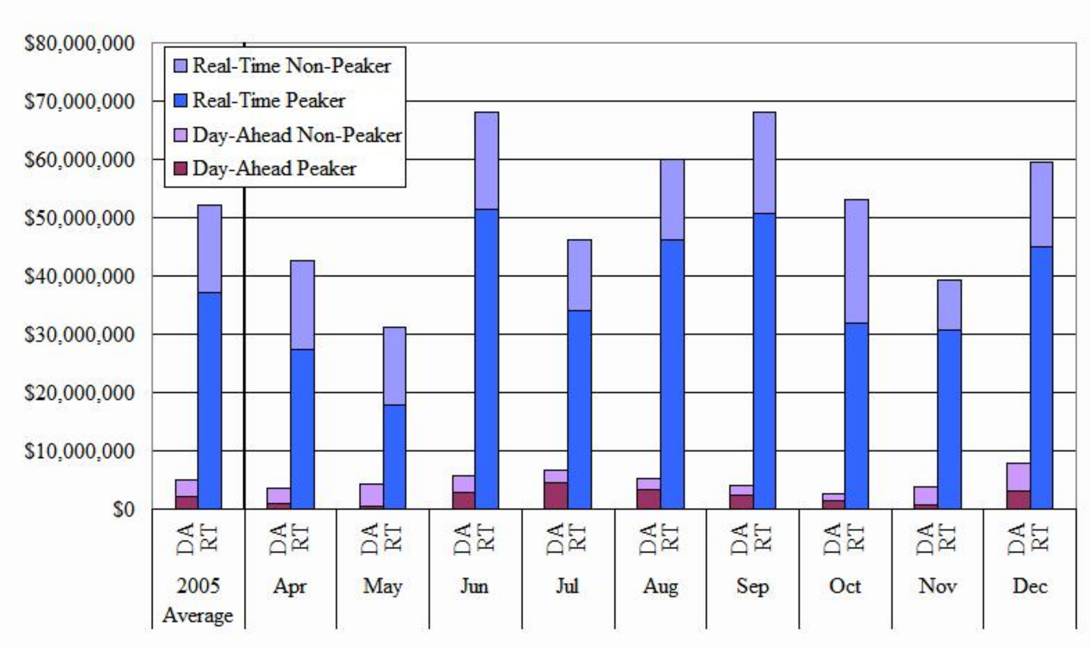
Total RSG Distribution by Market
April to December 2005



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Weekly Real-Time RSG Payments

- The following figure analyzes the data in the previous figure by week and region. From this vantage point, one can more clearly see how RSG costs were incurred.
- Summer Load Peaks –
  - ✓ The last week of June, mid to late-July, and the first two weeks of August all were time periods in which load exceeded 100 GW.
  - ✓ Peak load conditions frequently require supplemental commitments to ensure a smooth ramp and adequate reserves throughout the system.
- Transmission Congestion –
  - ✓ The first major RSG generating event was in June, caused by a steam outage in the Central region. This contributed to congestion of the Frankfort–Tyrone interface and daily commitments of peaking resources in the LGE control area.
  - ✓ In September, outages in the West region and in WUMS resulted in supplemental commitments in these areas that generated significant RSG payments.
  - ✓ The December planned generator outages in Minnesota together with a transmission outage of the Arnold-Hazelton line in Iowa resulted in substantial congestion and supplemental commitments in the West.

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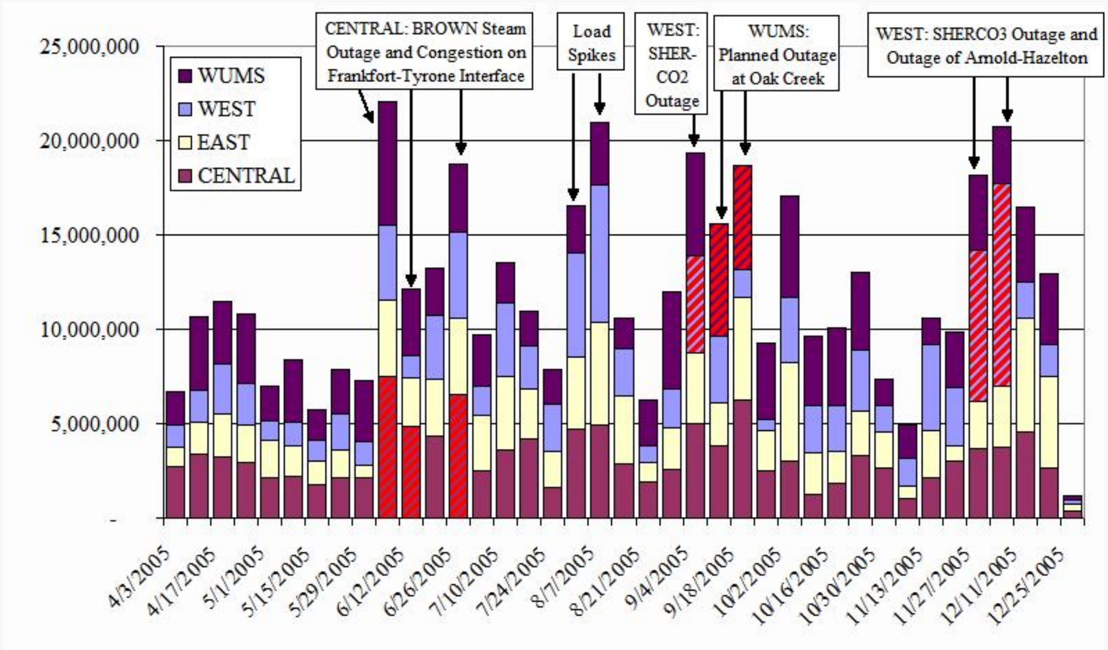
Weekly RSG Distribution by Region



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Dispatch of Peaking Resources

- As discussed above, the dispatch of peaking resources are important because it is an important determinant of RSG and efficient energy price signals.
- The following two figures summarizes the dispatch of peaking resources in 2005, showing the average and maximum hourly dispatch of peaking units by day.
- On average, 500 MW of peakers were dispatched on non-summer days and 1300 MW were dispatched on summer days.
- Average dispatch of peakers was highest on July 25, August 2-3, August 9, and June 27 -- load exceeded the forecasted annual peak of 107 GW on each of these days.
  - ✓ Average peaker dispatch levels on these days ranged from 5800 MW to 6800 MW.
  - ✓ Maximum dispatch levels ranged from close to 13000 MW to 15600 MW.
- The figures also show the average peaker offer prices compared to the LMPs at the peakers' locations, as well as the shares of the peaker output that are in-merit (LMP > peaker offer) and out of merit (LMP < peaker offer).
  - ✓ These statistics show that a large share of the peakers are out-of-merit, indicating that they frequently do not set the energy price.
  - ✓ A larger share of peakers are in-merit when they are heavily relied on in the summer.
  - ✓ The implications of peakers running out of merit are discussed later in the report.

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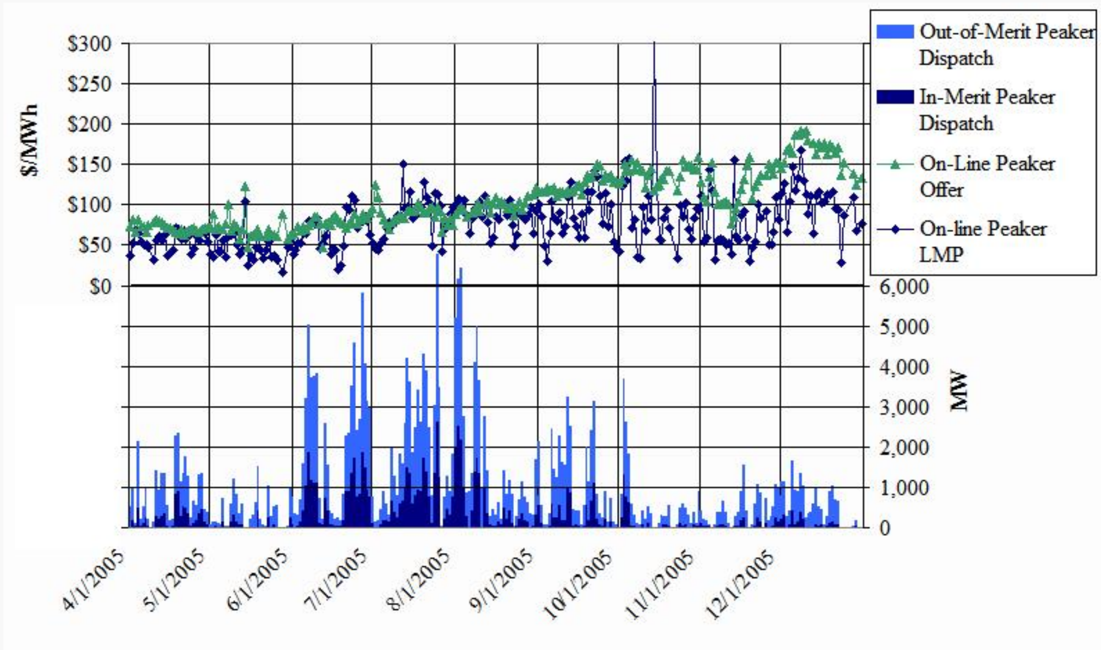
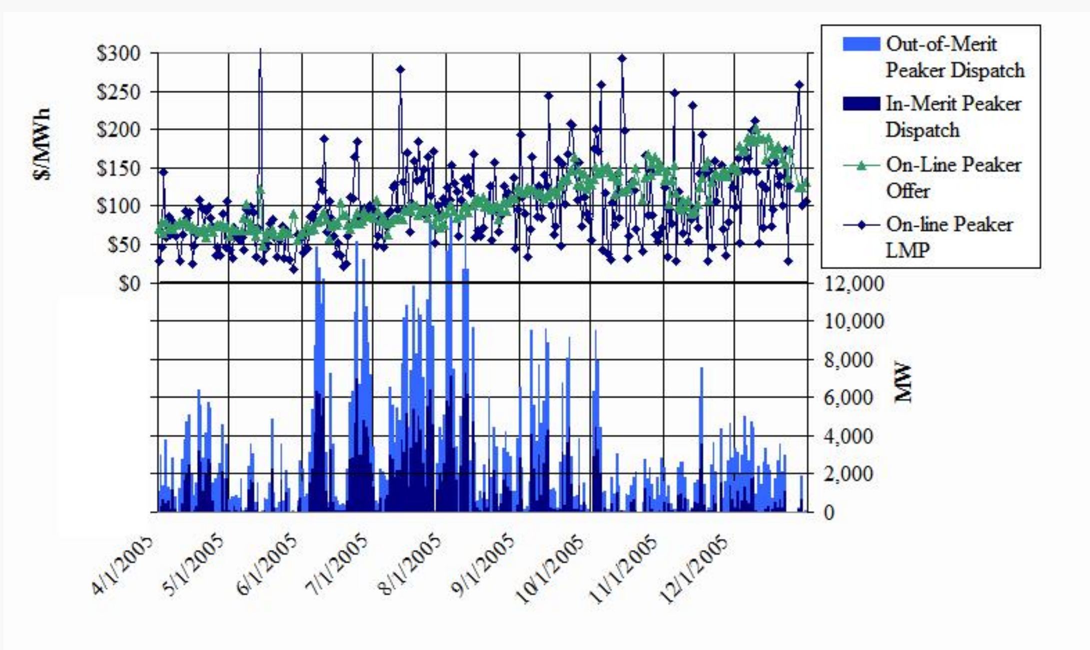
Average Daily Peaker Dispatch and Prices All Hours



Maximum Hourly Peaker Dispatch and Prices in All Hours



Out-of-Merit Peaker Dispatch

- The figure on the next slide details the monthly out-of-merit peaker dispatch.
  - ✓ A peaking resource is out-of-merit when the hourly LMP is greater than its energy offer.
  - ✓ Peakers committed out-of-merit receive real-time RSG payments for production costs not covered by LMP revenues.
- The figure shows:
  - ✓ Out-of-merit dispatch as highest during the summer when load was the highest.
  - ✓ The peak month occurred in June, which was caused by high load and voltage problems in Kentucky that required frequent dispatch of peaking resources.
  - ✓ Dispatch of peaking resources out-of-merit in April was higher than would be expected during a moderate load month.
    - – If more peakers are started than the minimum needed (or if they are started earlier than needed), they will tend to run at their minimum generation level and not set prices – resulting in higher out-of-merit quantities.
    - – The MISO made operating improvements after the start of the market to reduce the commitment of peakers, which lowered the out-of-merit quantities.

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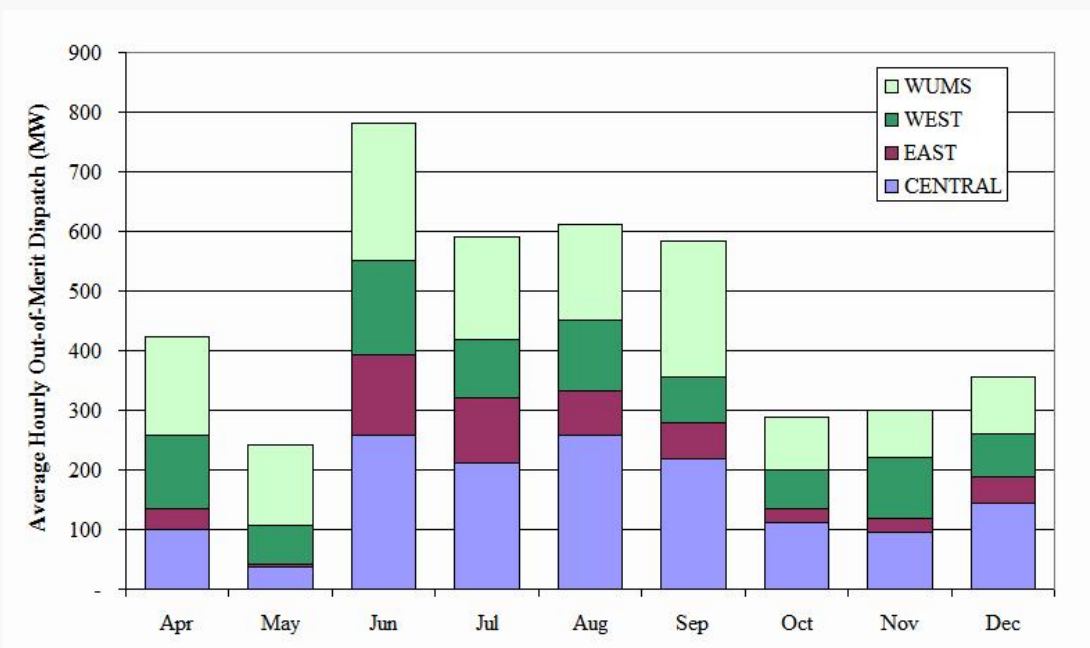
Average Hourly Out-of-Merit Peaker Dispatch 2005: All Hours



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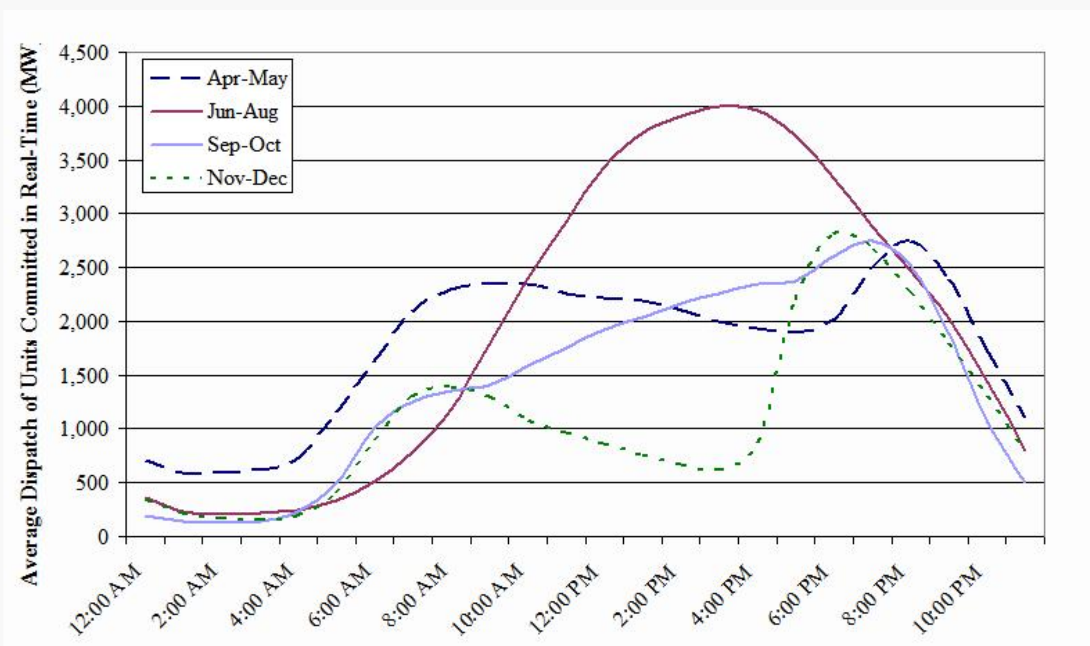
Hourly Analysis of Real-Time Commitments

- The following slides analyze commitments of units in the real-time market that are eligible for RSG payments (includes all commitments by MISO after the day-ahead market).
- This figure shows:
  - ✓ Early in the markets’ operation, units committed in the real-time often began producing energy overnight, prior to the morning ramp, and continued producing energy during the middle of the day.
  - ✓ In the fall (under similar load conditions) the MISO refined its commitment and de-commitment processes to start units later and to decommit them more frequently in the middle of the day when they are not needed to meet the ramp demand of the market – these operational improvements reduce RSG payments.
  - ✓ In the summer months, the output peaks around 3 pm because many of the real-time comments are made to meet the peak load that occurs at that time.

Energy Produced from Units Committed in Real-Time By Hour of Day



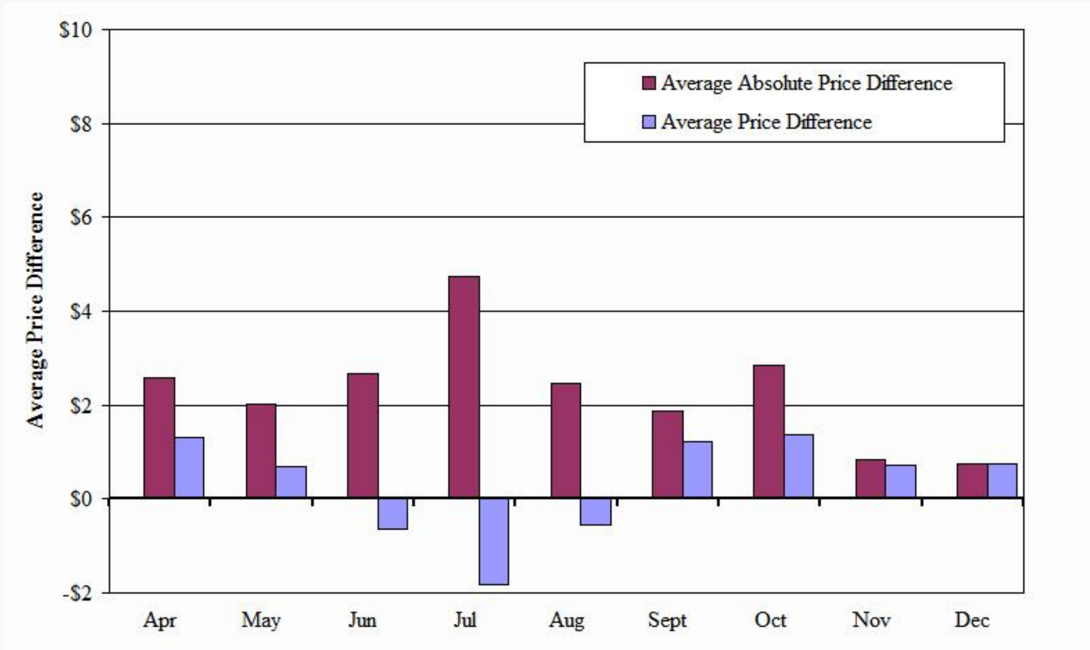
Potential Improvements in the Commitment of Peaking Resources

- The commitment and dispatch of peaking resources can be improved further by implementing a “look-ahead” capability for the current real-time market that would commit turbines as an economic dispatch decision (rather than as a reliability or capacity decision).
  - ✓ Gas turbines, which are most of the peaking resources in MISO, are unique in that they can provide capacity (operating reserves) without being turned on. Hence, the decision to turn them on should generally be an economic one.
  - ✓ Currently, operators commit and decommit turbines based on operating criteria.
  - ✓ Allowing the market to commit and decommit the turbines would reduce the out-of-merit quantities, reduce RSG payments, and improve the ability of peakers to set the energy price.

Ex-Ante and Ex-Post Price Differences April - December 2005

- 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 and market outcomes are the basis for the 5-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 eligible to set ex post prices can be different than in the ex-ante solution.
    - – Each flexible unit has a price at which a unit is assumed to offer energy in the ex-post market. This price is a function of the unit’s bid curve actual output and ex-ante price.
- Consistency between the ex-ante and ex-post prices are important for ensuring that that suppliers have the incentive to follow the ex-ante dispatch instructions.
  - ✓ The average consistency is evaluated in the next figure, which shows the average differences between the five minute ex-post and ex-ante prices.
  - ✓ This figure shows that the average differences between the ex-ante and ex-post prices were relatively small.
  - ✓ The typical hourly difference (average absolute difference) was generally also small, with the exception of July.

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



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Ex-Ante and Ex-Post Price Differences April - December 2005

- Although the average differences between ex-post and ex-ante pricing have not been large, it is important to evaluate substantial differences during peak demand conditions or periods of extreme congestion.
  - ✓ During these periods, generators may be asked to change production rapidly or dispatch very expensive output segments.
  - ✓ If ex-ante prices are inconsistent with ex-post prices during these conditions, generators can be harmed by adhering to the MISO's dispatch instructions.
  - ✓ To evaluate this issue, the next figure shows the average difference and the average absolute difference in hours and at locations with relatively extreme prices (prices above $300 per MWh or lower than -$100 per MWh).
- This figure shows:
  - ✓ The differences between the ex-ante and ex-post prices occurred when ex-ante price spikes occurred and were large during the first four months.
  - ✓ In general, these occurred when relatively extreme congestion arise that caused prices at certain nodes to rise or fall sharply.
  - ✓ Modifications were made in early August to the ex-post pricing methodology to improve the consistency between the ex-ante and ex-post prices.

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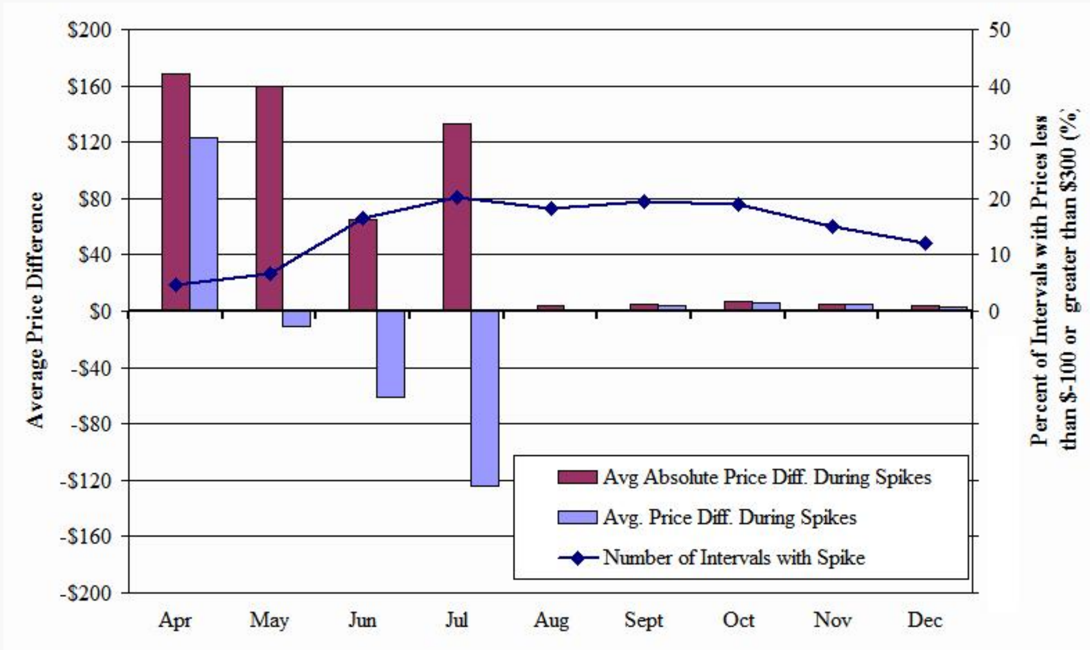
Ex-Ante and Ex-Post Price Differences During Price Spike Events: 2005



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Real-Time Market: Conclusions

- In its inaugural year in operation, the Midwest ISO's real-time market has performed relatively well.
- However, the lack of real-time ancillary services markets and certain other factors have created room for improvement in the performance of the real-time market. We provide the following recommendations:

1. Develop real-time ancillary services markets as soon as practicable.
   - Ancillary services markets that are jointly optimized with energy will allow the market to more efficiently allocate resources between the two services; and
   - Set efficient prices in both markets to reflect the economic trade-offs between reserves and energy.
2. Complete and implement the full ARC procedures that allow MISO operators to activate and dispatch the reserve range on units (output above EcoMax).
   - This process will allow the Midwest ISO to reduce system costs by relying on operating reserves for brief periods rather than committing relatively high-cost units.
   - The ARC is also a means for the market to set prices at $1000 when the system is in shortage (i.e., cannot meet its operating reserve requirements).

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Real-Time Market: Conclusions

3. Develop a "look-ahead" capability in the real time that would commit turbines and better manage ramp capability on slow-ramping units.
   - The MISO has made operational improvements in its commitment of peaking resources, but the commit of these units can be further improved by reliance on an economic model to commit the units.
   - Gas turbines, which are most of the peaking resources in MISO, are unique in that they can provide capacity (operating reserves) without being turned on. Hence, the decision to turn them on should generally be an economic one.
   - Allowing the market to commit and decommit the turbines would reduce the out-of-merit quantities, reduce RSG payments, and improve the ability of peakers to set the energy price.
4. In the longer-run, develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.
   - This is a difficult challenge because the market must distinguish between those turbines that would still be needed if they were more flexible versus those that would be ramped down to zero.
   - 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.

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Real-Time Market: Conclusions

3. The ex-post pricing changes MISO made were valuable because the ex-ante prices are, in theory, more efficient than ex-post prices.
   - Ex-post pricing has been justified as a means to provide incentives for generators to follow the dispatch signal (because a resource that doesn't cannot set the price)
   - However, it is does not efficiently provide such an incentive – it changes the price for all participants – including those following the dispatch instructions.
   - In fact, large ex-post price differences can actually create a disincentive to follow dispatch instructions when a supplier believes that ex-post prices may be inconsistent with ex-ante prices.
   - Uninstructed deviation penalties that applied only to generators that are over or under-producing is a much more efficient means to provide incentives for suppliers to follow dispatch instructions than ex-post pricing.
   - The changes made by MISO to the ex-post pricing model have resolved most of the largest inconsistencies with the ex-ante prices.

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Transmission Congestion and FTR Results

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Total Congestion Costs April to December 2005

- The next figure shows total congestion costs by month in the MISO market.
  - ✓ Day-ahead congestion costs totaled $563 Million.
  - ✓ Real-time congestion costs totaled $230 Million.
- The congestion increased rapidly from the spring to the summer as higher loads and power flows throughout the Midwest resulted in higher congestion.
  - ✓ Higher gas prices in the Fall increased the costs of congestion in the second half of the year because it increased the costs of re-dispatching to manage congestion.
  - ✓ The report shows that a large share of the increase in congestion is due to increased congestion into WUMS and increased congestion on the path to TVA.
- Real-time congestion costs were higher than expected.
  - ✓ Normally, one would expect the real-time congestion to be very low if the modeling of the transmission system is consistent in the day-ahead and real-time markets.
  - ✓ The real-time congestion is evaluated later in this section.

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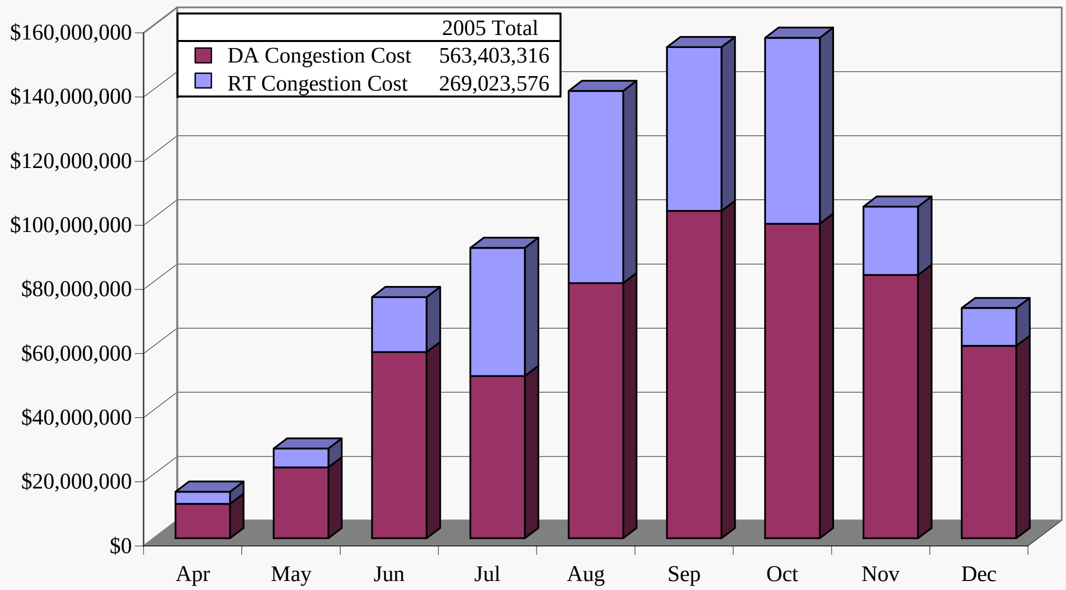
Total Congestion Costs
April to December 2005



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

- The following figure compares monthly day-ahead congestion collections to monthly FTR obligations.
  - ✓ Surpluses and shortfalls will be limited when the portfolio of FTRs held by participants matches the MISO power flows over the transmission system.
- The total day-ahead congestion collections exceeded FTR obligations for the year.
  - ✓ There was a surplus in the first six months of the markets operation.
  - ✓ However, there was a monthly shortfall in the last 3 months of the year.
- A number of factors contributed to the shortfall in the last 3 months including:
  - ✓ Significant planned and unplanned transmission outages occurring in the day-ahead markets not modeled in FTR allocations.
  - ✓ Increasing loop flows that are modeled in day-ahead, but not fully reflected in the FTR modeling.
    - – MISO collects no congestion revenue from entities causing loop flow over its key interfaces.
    - – If it has allocated FTRs for the capability on these interfaces, there will be a shortfall.

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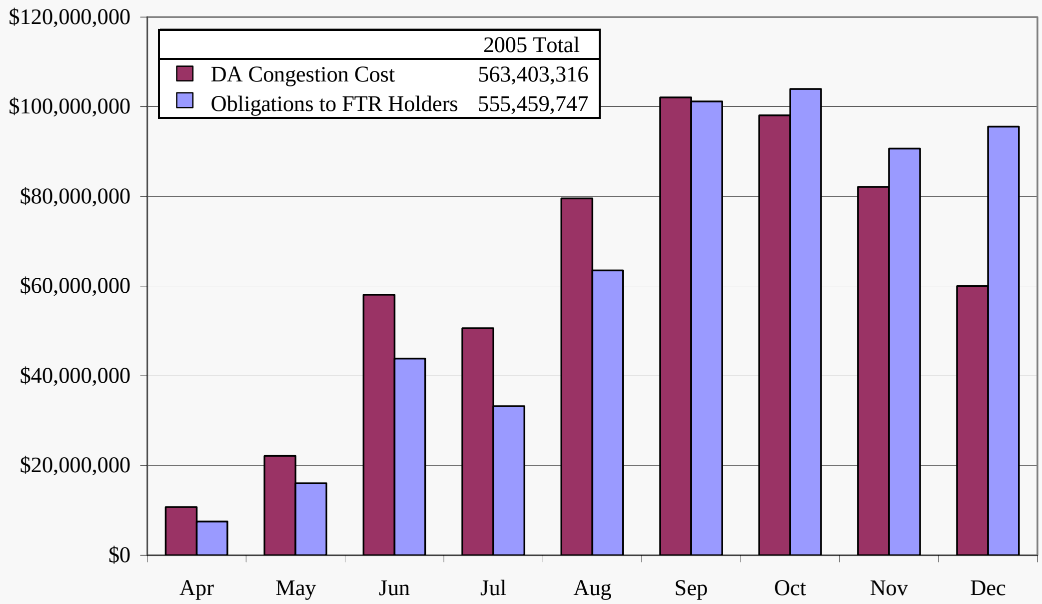
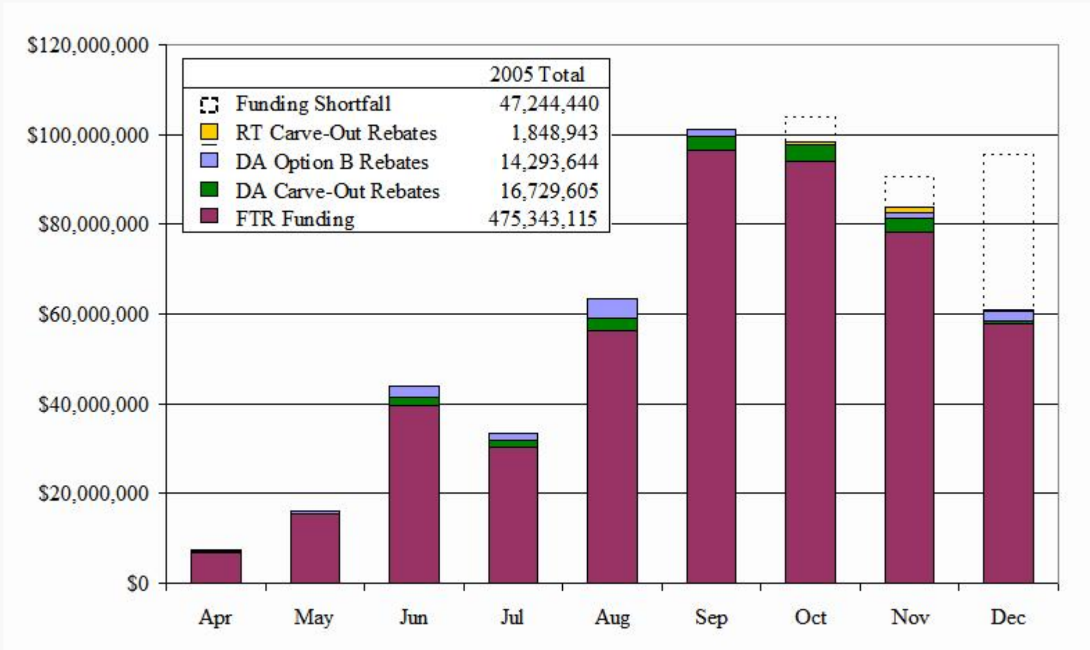
Day-Ahead Congestion and Payments to FTR Holders April to December 2005



Payments to FTR Holders 2005: All Hours

- The following figure shows the monthly payments and obligations to FTR holders including payments to FTR Option B and Carve-out FTRs.
- The shortfall in the last 3 months of $47 Million was covered by surpluses in other months so overall FTR were fully funded on an annual basis.
- The figure shows that the vast majority of the payments were made to FTR holders.
  - ✓ More than 95 percent of all payments were made to FTR-holders versus the other types of transmission rights that were made available to participants with grandfathered agreements.
- As noted, the primary causes of the shortfall include:
  - ✓ Differences in the transmission topology and loop flow assumptions in the day-ahead market and the FTR model; and
  - ✓ Significant planned and unplanned outages in December.
- The additional $52 million of surplus congestion collected was distributed to firm transmission customers.

Payments to FTR Holders
2005: All Hours



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Value of Real-Time Congestion by Coordination Region 2005

- To show how significant congestion has been in the real-time market, the next figure shows the value of real-time congestion.
  - ✓ 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 was estimated to be $1.2 billion.
  - ✓ Most of the congestion occurred in the Central and East regions (East and WUMS).
  - ✓ As expected, congestion values increase under peak load conditions in July and August though it remained high into the fall.
  - ✓ Congestion values in the fall were impacted by high natural gas prices.
- The figure also shows that the average number of constraints that are binding at any point in time (i.e., during each interval).
  - ✓ The number of constraints typically binding in each month rose to its highest level of 2.2 constraints per interval in September.
  - ✓ The constraint frequency averaged more than 1.5 constraints per interval over the nine month period.

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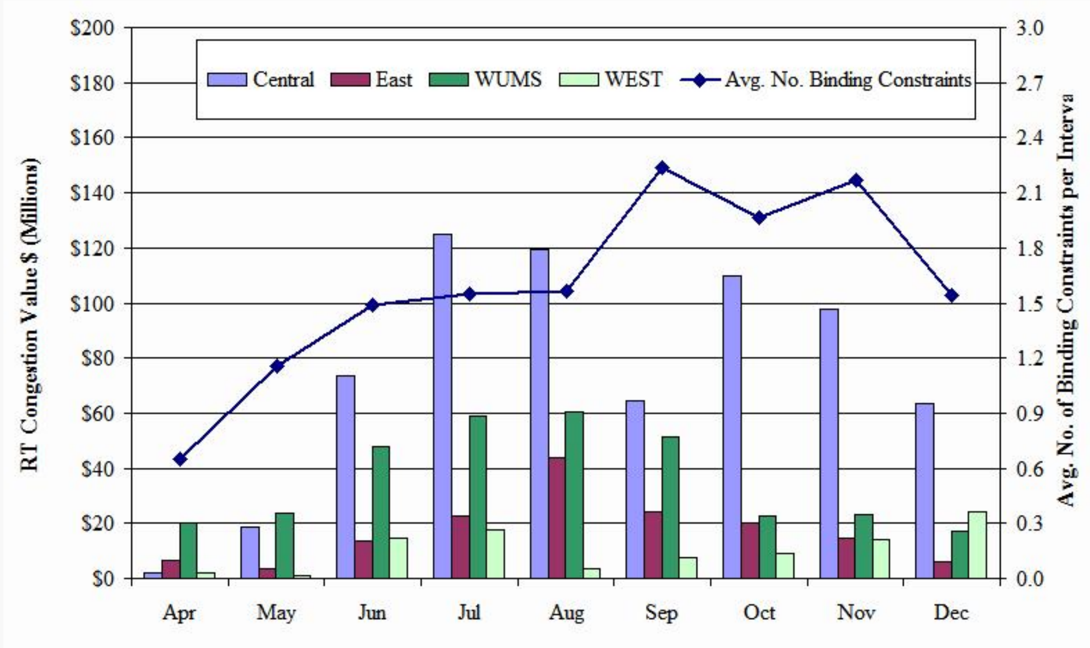
Value of Real-Time Congestion by Coordination Region April - December 2005



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Value of Real-Time Congestion by Type of Constraint 2005

- The next figure shows the value of real-time congestion by the type of constraint – it is computed in the same manner as in the prior figure.
  - ✓ 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 an a neighboring system that causes MISO to redispatch its generation.
- Most of the congestion occurred on MISO internal constraints (including the MISO market-to-market constraints).
  - ✓ Together the MISO constraints (internal and market-to-market) represent nearly 90 percent of the congestion value.
- The external congestion was caused by a small number of constraints.
  - ✓ One constraint is responsible for more than 30 percent of this congestion.
  - ✓ More than 20 percent of this congestion occurred on the next two most significant constraints.

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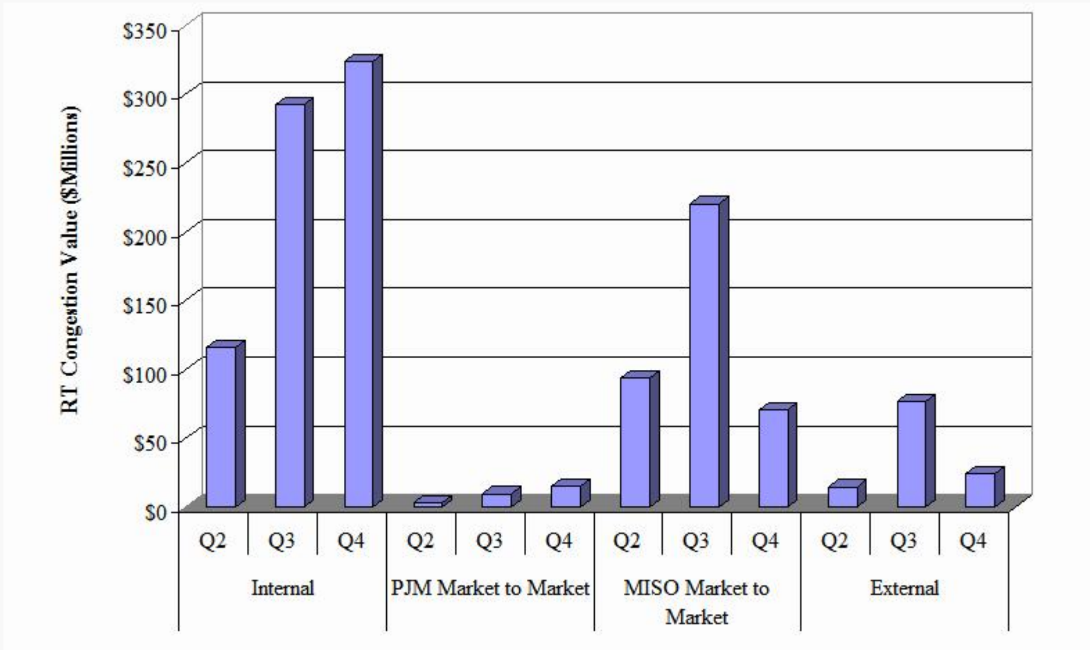
Value of Real-Time by Type of Constraint 2005



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TLR Events and Curtailments in 2005

- The next figure shows the calls by MISO for transmission line-loading relief ("TLRs") and associated transaction curtailments in 2004 and 2005.
- 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.
- The TLR calls by MISO have decreased only slightly in 2005 after the implementation of the energy markets.
  - ✓ The TLRs called on Midwest ISO flowgates (level 3 and above) still account for about 54 percent of all TLRs called in the Eastern Interconnect.
  - ✓ The implementation of the markets was not expected to reduce the TLR calls.
  - ✓ When a constraint is binding in the MISO energy market, it invokes the TLR procedures to ensure others outside of the MISO that contribute to the congestion assist in relieving it.

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TLR Events and Curtailments in 2005

- However, the curtailments were expected to decrease substantially since most of the relief for the MISO constraints is now provided efficiently by the MISO energy markets, rather than via transaction curtailments.
- The figure confirms that curtailments have decreased dramatically:
  - ✓ Curtailments were 76 percent lower overall in 2005 than in 2004.
  - ✓ Curtailments during the summer, which are generally larger in magnitude, decreased by 70 percent versus 2004.
- These reductions in curtailments indicate substantial efficiency improvements resulting from the nodal markets.
- In prior reports, we showed that the 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.

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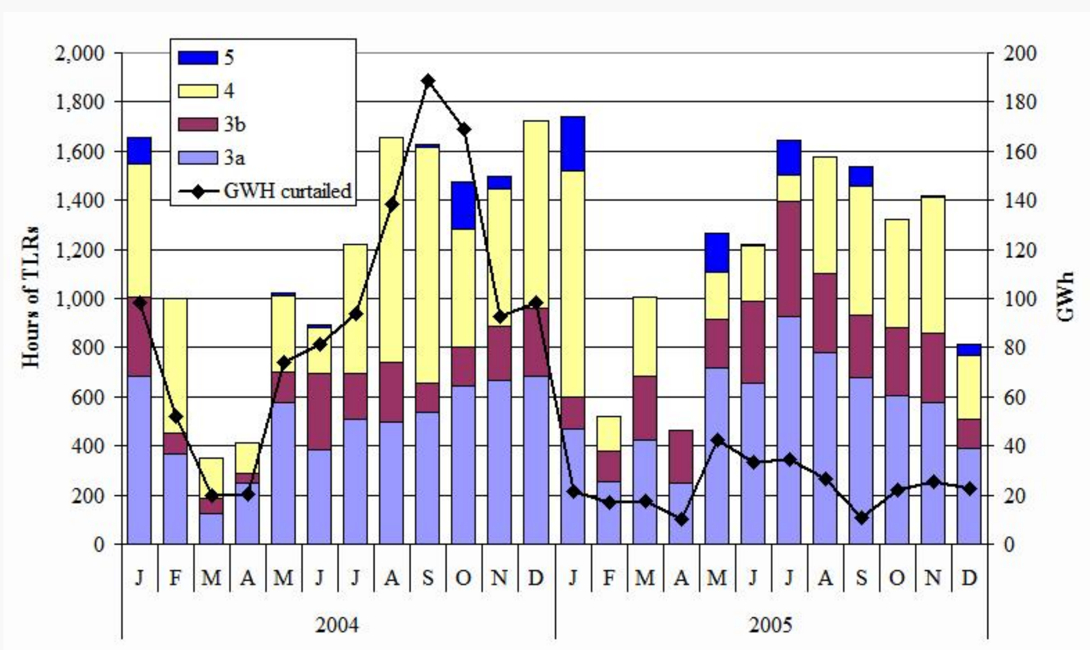
TLR Events and Transactions Curtailed 2004-2005



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TLR Events by Region
April to December: 2004-2005

- The next figure shows the monthly number of TLRs called in 2004 and 2005 by selected regions.
- Kentucky is shown separately from the Central region to show the relatively high number of TLRs in 2005 related to a) flows from north to south associated with exports to TVA, and b) local load pockets in and around Louisville.
  - ✓ The figure shows that a large share of the TLRs in these areas are TLR level 4.
  - ✓ TLR level 4 must be called before any reconfiguration of generation or transmission is done on the LGEE system.
  - ✓ A substantial contributor to the increased North to South congestion in 2005 is non-firm service sold by PJM to TVA that was not coordinated under the market-to-market provisions – steps have been taken to better manage this service.
- The figure also shows that 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 done through the MISO energy market.

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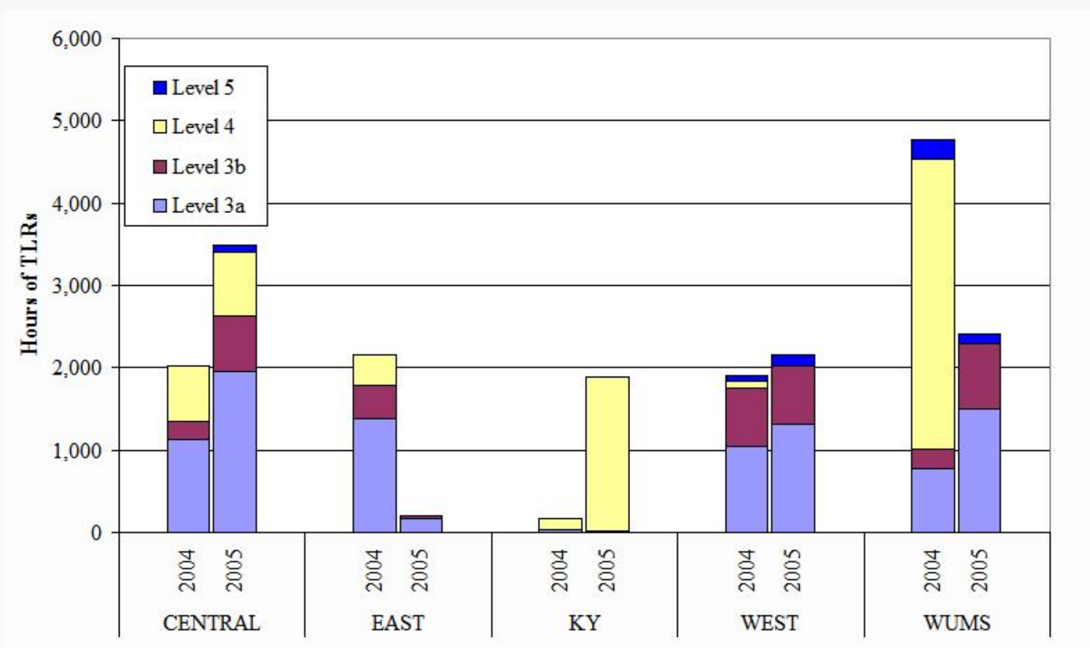
TLR Events by Duration
April - December 2004 and 2005 by Region



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Congestion and Manageability

- 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 not sufficient redispatch capability in the market to reduce the flow to less than the limit in the next 5-minute interval, we refer to the constraint as "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 a 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:
  - ✓ Overall, 75 percent of the congestion was manageable on a 5-minute basis.
  - ✓ From April to December, the percent of unmanageable congestion events trended up slightly in the first few months to a peak of 34 percent in August.
  - ✓ The unmanageable congestion decreased to an average of 24 percent over the last 3 months of the year.

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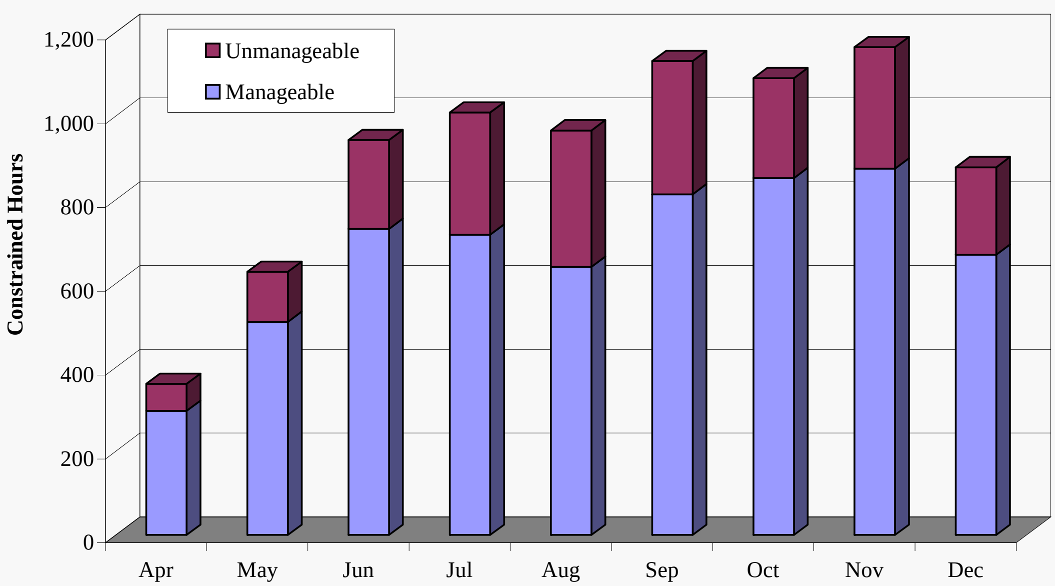
Congestion and Manageability April - December 2005



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Congestion and Manageability

- The next analysis shows the value of real-time congestion on selected interfaces, indicating the portion of the congestion that was manageable.
- This figure shows that the highest value congestion was on the interfaces into the WUMS area, as expected.
  - ✓ The unmanageable congestion into this area was caused, in large part, by generator inflexibility (inflated EcoMin levels on generators the cause power flows to increase over the constraint).
  - ✓ This inflexibility often resulted in negative prices in Minnesota, as shown earlier.
- The figure also shows that the north-south path to TVA became heavily congested in the fourth quarter of 2005.
  - ✓ Non-firm transmission service sold by PJM to TVA loaded these interfaces.
  - ✓ This service was not initially coordinated under the market-to-market provisions.
  - ✓ PJM has taken steps to limit this service when MISO has no ATC.
- The PJM market-to-market results must be interpreted differently than the others.
  - ✓ It is shown as "unmanageable" if the requested relief cannot be provided at a redispatch cost that is less than PJM's marginal redispatch costs (by design).
  - ✓ Hence, a much higher portion of the congestion is likely to show as unmanageable on these constraints.

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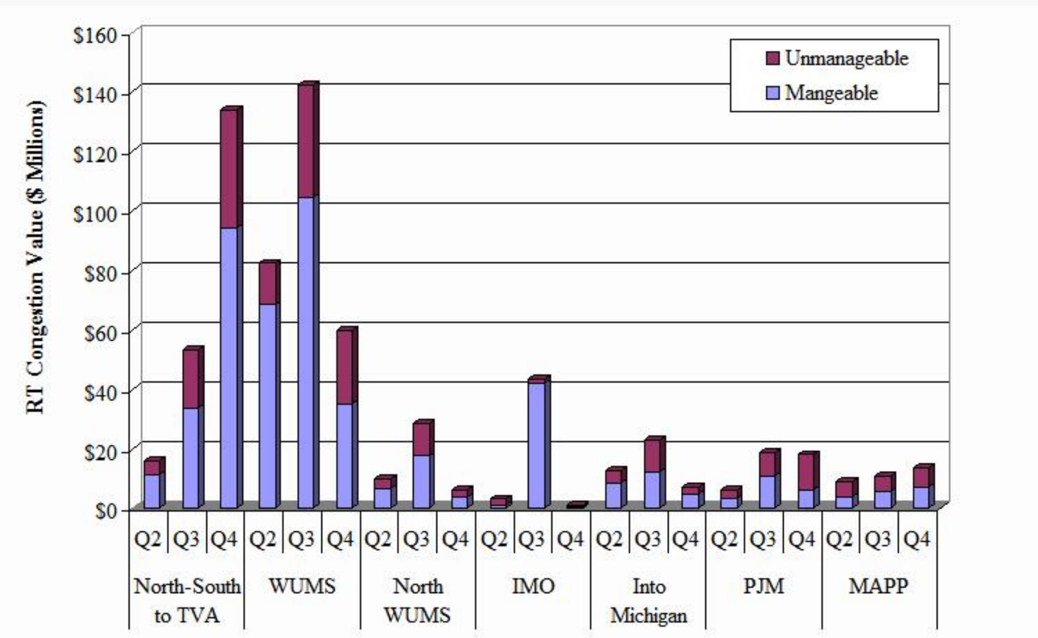
Value of Real-Time Congestion by Path 2005



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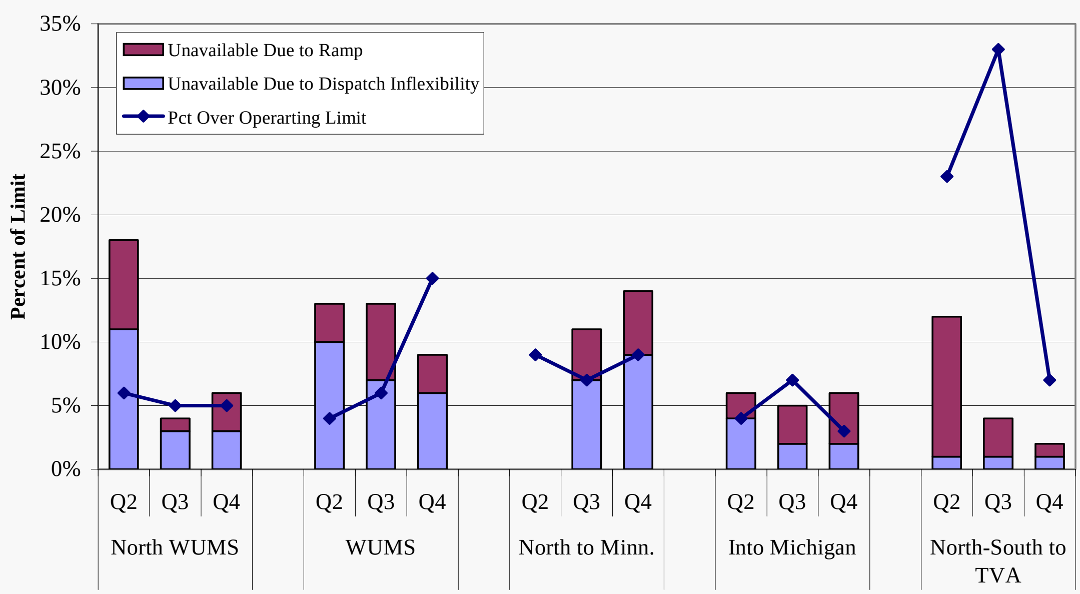
Unavailable Congestion Relief Capacity

- The next analysis evaluates two factors that contribute to instances when transmission constraints are "unmanageable":
  - ✓ 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 of a resource – 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 all of the paths, with the exception of the N-S to TVA path, the relief that could have been available physically would have been enough to manage the congestion.
- The TVA path is a different case from the others – the violations on this path were largely due to excessive non-firm schedules by PJM, which has been addressed.

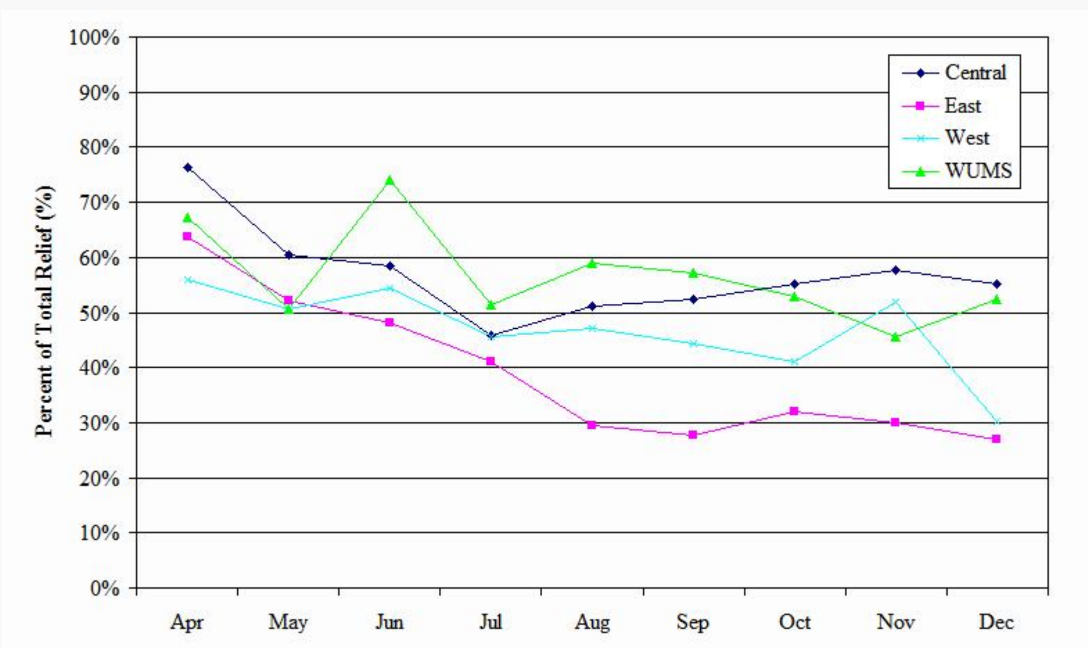
Congestion Relief Unavailable Due to Offer Parameters Selected Paths: 2005



Ratios of Offered Relief to Physical Capability

- The next figure further evaluates the effects of generator inflexibility by showing the amount of offered relief (ability to reduce network flows by reducing a unit's output) to the relief that could have been offered for binding constraints in MISO.
- This analysis shows:
  - ✓ With the exception of the Central region, offered flexibility has generally declined throughout the year.
  - ✓ The East region in particular showed significant declines in offer flexibility.
- We attribute the inflexibility to:
  - ✓ Justifiable technical or reliability concerns in some cases.
  - ✓ Inexperience with the market – some participants do not recognize that they will increase their profit by reducing their output to manage congestion
    - – Others erroneously believe that forcing their resources to run at their day-ahead schedule is a profitable or rational strategy.
  - ✓ Concerns by some participants that responding to dispatch signals during periods of high price volatility could sometimes reduce their profit – settlement rules to eliminate this concern are being developed.
  - ✓ Manipulation- we have investigated cases of apparent deliberate over-production and referred the conduct to FERC for a potential sanction.

Decremental Relief Quantities Offered by Region April - December 2005



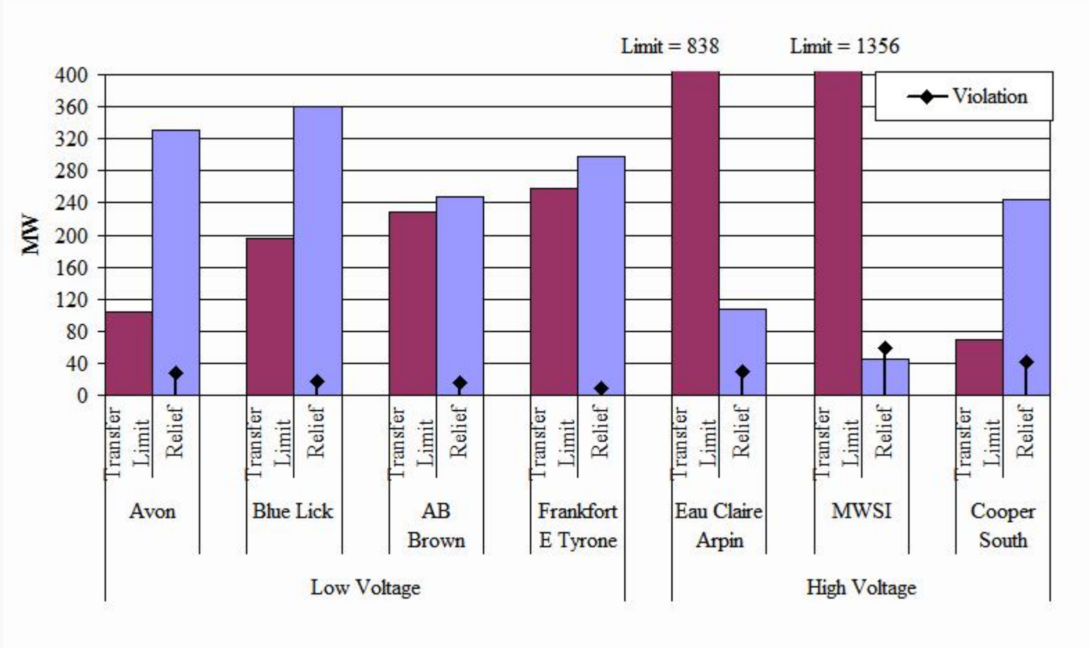
Other Real-Time Congestion Management Issues

- The final factor we evaluate that contributes to some of the instances when constraints are unmanageable is the parameter set in the real-time market that prevents units with a small effect on a constraint from being redispatched.
  - ✓ Currently in the real-time market, units with generation shift factors 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 parameter is set to reduce the size the data that must be produced and passed among the real-time systems – all units are considered in the day-ahead market.
- The following figure shows the congestion relief that is eliminated by this parameter of the real-time model relative to the limit and average violation on selected constraints –
  - ✓ We calculated the relief quantities based on a planning case for September.
  - ✓ The additional relief on each constraint was calculated based on raising the excluded units' output to its maximum or reducing the excluded units' output to its minimum.
- The results show that the additional relief available by lowering the parameter is generally larger than the average violations on the constraints that we sampled.

Other Real-Time Congestion Management Issues

- This effect of the parameter is particularly large for the low-voltage constraints. This is the case because GSFs are generally small and less widely distributed for low voltage constraints – hence, the parameter tends to have a larger effect.
- We have recommended to MISO that it reduce this parameter as much as feasible for the generator nodes in its real-time market
  - ✓ The same parameter is used for load and generator nodes.
  - ✓ There are many times more load nodes than generator nodes.
  - ✓ Given the MISO's practical concerns regarding the quantity of data that would be produced and passed among its real-time systems if the parameter is reduced, we believe it is be reasonable to initially keep the 2 percent parameter for load nodes.
- With regard to its nodal pricing when a constraint is violated (i.e., unmanageable), we recommend the MISO discontinue use of the relaxation algorithm and set prices based on the constraint penalty factor.
  - ✓ When a constraint cannot be resolved at a marginal cost less than the penalty factor, the value of the constraint must be higher than the penalty factor.
  - ✓ 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.

Potentially Available Relief by Path



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Balancing Congestion Costs

- Like all other settlements in the real-time market, real-time congestion costs should be related only to deviations from the day-ahead schedules.
  - ✓ Because the real-time settlements are only for deviations from the day-ahead schedules, real-time congestion charges should be zero as long as the transmission limits and external loop flows assumed in the day-ahead market have not changed.
  - ✓ Inconsistencies in limits, loop flows, or other modeling inputs can compel the MISO to incur real-time congestion costs to reduce the flow on constrained facilities in real time, which would be recovered through uplift charges.
  - ✓ Such costs will never be zero because transmission outages and other unforeseen network conditions can arise that will reduce real-time capability.
- The figure shows that real-time congestion costs rose substantially in the late summer and early fall 2005, due in part to the sharp increase in natural gas prices.
- MISO and the IMM investigated the sources of the real-time congestion, finding:
  - ✓ A large share of the costs are associated with real-time loop flows that were not fully reflected in the day-ahead market assumptions.
  - ✓ Real-time transmission deratings due to outages and other factors.
  - ✓ Miscellaneous data issues related to the network.
- MISO improved the day-ahead modeling of loop flows and other issues, contributing to the sharp decline in real-time congestion costs toward the end of 2005.

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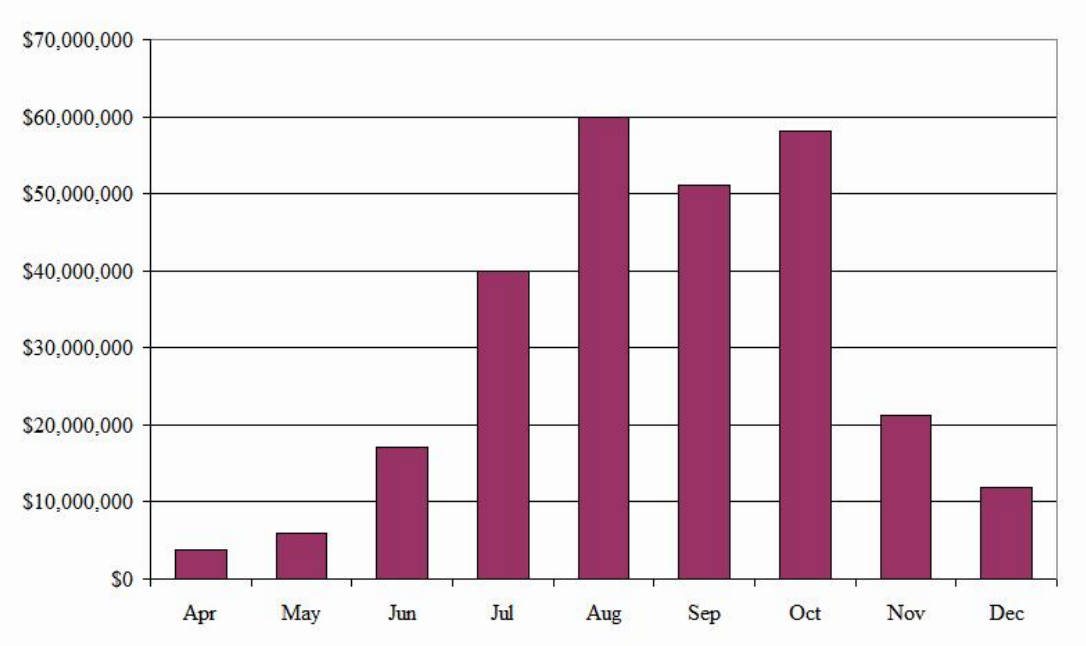
Balancing Congestion Costs 2005



FTR Auction Prices and Congestion

- The next analysis evaluates the results of the FTR auctions, which should efficiently forecast future congestion costs if they are liquid and well-functioning.
- The next four figures show the hourly FTR auction values compared to the value of day-ahead congestion.
  - ✓ All the values shown in these figures are computed relative to Cinergy Hub.
  - ✓ More FTRs per month are purchased to and from the Cinergy Hub than any other node.
- The first two figures show the values for WUMS and West regions. The prices in these regions are the most affected by the frequent congestion into the WUMS region.
- The third and fourth figures show the congestion and FTR values for the Michigan Hub and the IMO interface.

FTR Auction Prices and Congestion
WUMS and Minnesota Hub

- As the market opened in April, the FTR auction did not closely reflect the value of the day-ahead congestion -- peak FTR auction prices deviated from DA congestion by $20,000 per MW in WUMS and $12,000 at the Minnesota Hub.
- In the WUMS region, the last 8 months of 2005 showed much better convergence between the FTR and actual congestion results.
  - ✓ In September, congestion peaked due to transmission and generation outages. Off-peak congestion was negative in November due to the outage of Arnold-Hazelton and constraints that were binding *into* Minnesota.
  - ✓ For the May to December period, average congestion exceeded the FTR clearing price by less than $700 for the peak hours and less than $800 in the off-peak market.
- The congestion and FTR results for the Minnesota Hub were less consistent.
  - ✓ With the exception of the FTR prices in April, congestion values and FTR prices were low in the first four months of the market's operation.
  - ✓ From October to December, peak congestion became substantially positive in the peak hours due to transmission and generation outages that reversed the congestion.
  - ✓ The FTR prices did not converge well in peak hours, likely due in part to the erratic congestion patterns affecting prices in Minnesota.

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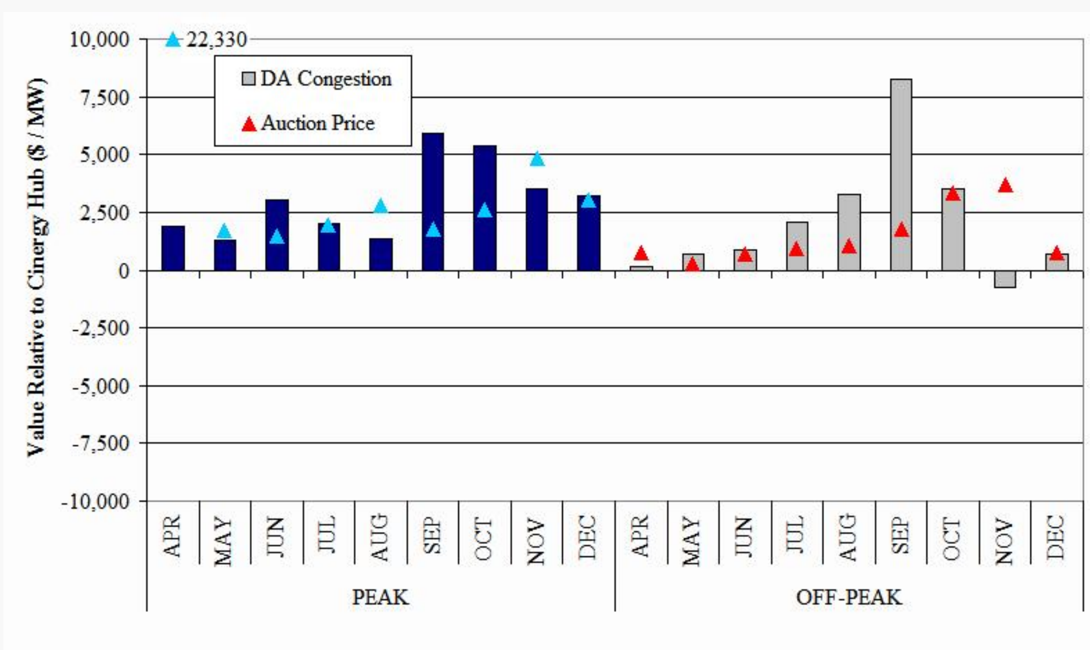
FTR Auction Prices and Congestion
WUMS Area



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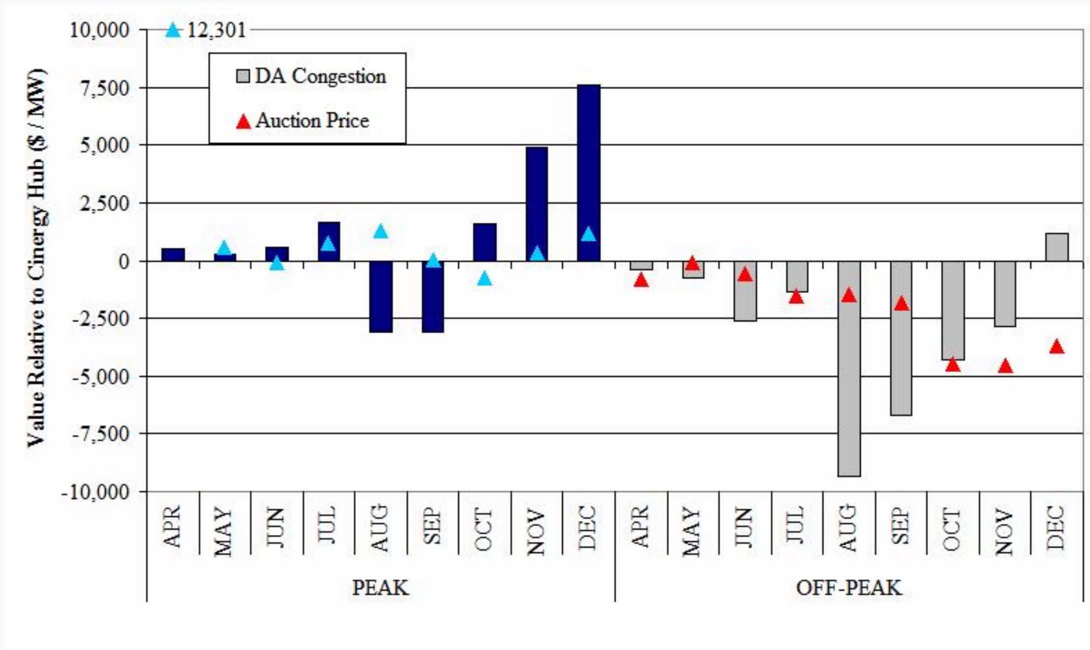
FTR Auction Prices and Congestion
Minnesota HUB



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FTR Auction Prices and Congestion
Michigan Hub and IMO Interface

- The following figure shows that the congestion and FTR values at the Michigan hub were much lower than in WUMS and Minnesota.
  - ✓ After April, the FTR auction prices at the Michigan Hub peaked in August for both peak and off-peak hours -- day-ahead congestion values were at their lowest in August.
  - ✓ Average peak difference between congestion and FTR prices is $100 per MW, while the average of the absolute peak difference is $895 per MW.
- Congestion patterns for the IMO interface are similar to those for the Michigan Hub, but FTR clearing prices were less variable and less accurate than at the Michigan Hub.
  - ✓ Between June and December, FTR prices were below congestion costs in the peak hours during 6 of the 7 months. However, FTR prices were below congestion costs during only one of those 7 months in the off-peak hours.
  - ✓ The day-ahead congestion cost from Cinergy Hub to IMO was at least $600 greater than the FTR clearing price in every one of the last four months of 2005.
    - – The average clearing price during this time was only $648 per MW while the congestion costs were $1,250 per MW.

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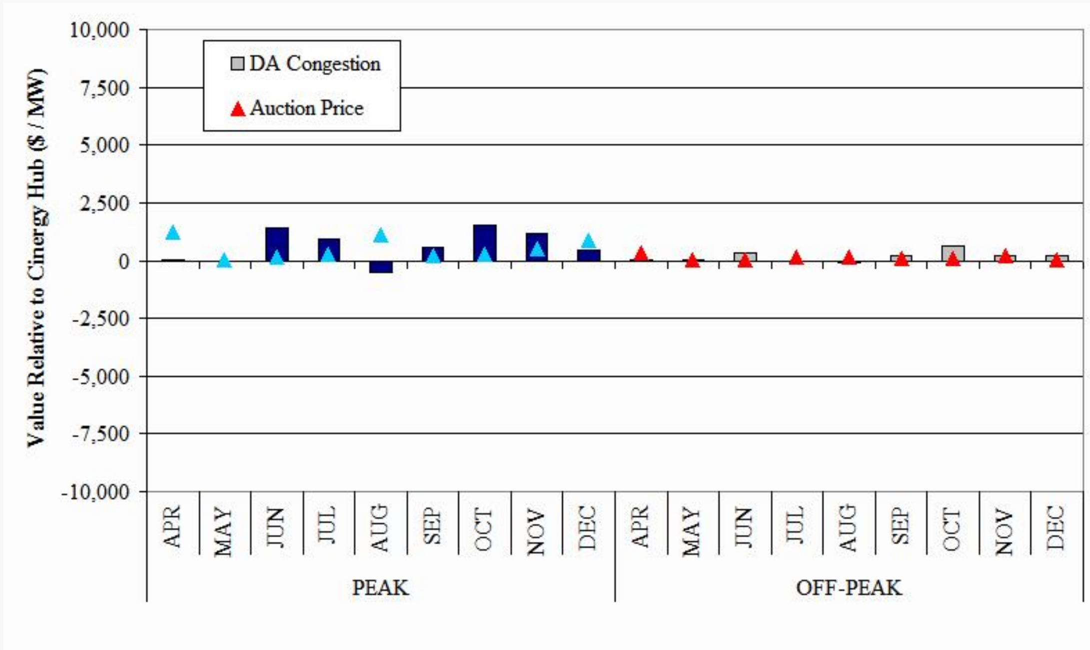
FTR Auction Prices and Congestion
Michigan Hub



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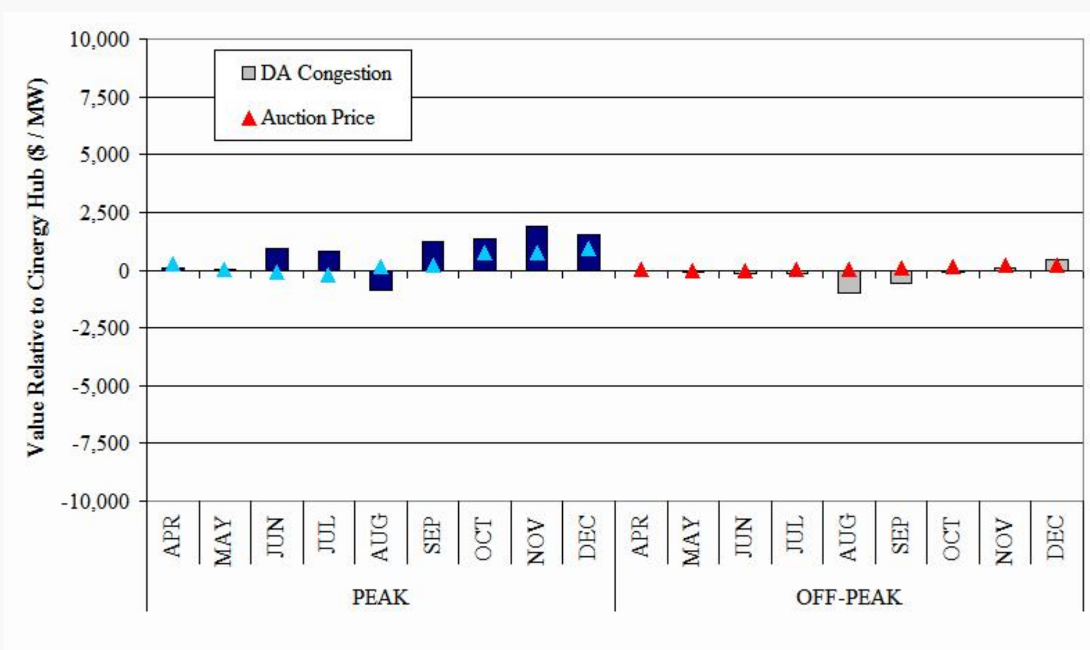
FTR Auction Prices and Congestion
IMO Interface



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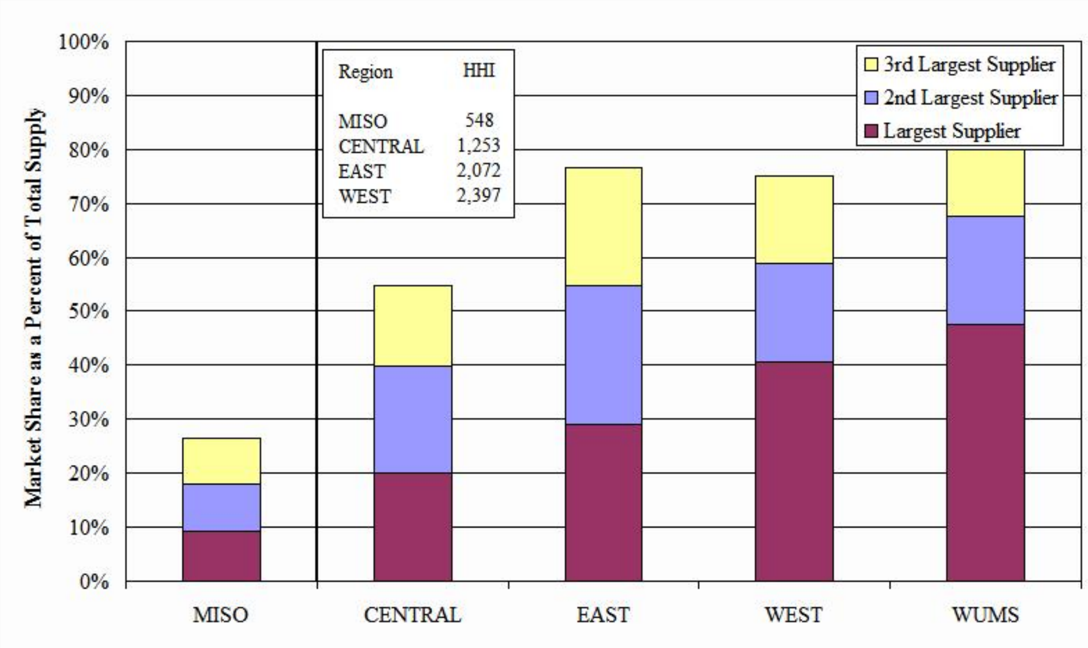
Participant Conduct and Mitigation

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 2005.
- 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 1800 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 is highly concentrated with the exception of the Central region.
  - ✓ The HHIs are higher than in other regions because the vertically-integrated utilities in the Midwest have not divested substantial amounts of generation as in other regions.

Market Concentration



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Residual Supply Index

- A better metric than the HHI for evaluating competitive issues in electricity markets is the residual supply 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.
  - ✓ This analysis shows that there is limited competition in the WUMS region at all load levels – when load is higher than 60 GW (75 percent of the time), there is a pivotal supplier in WUMS between 60 percent and 100 percent of the hours.
  - ✓ The West and East regions exhibit a pivotal supplier in a substantial number of hours only when load exceeds 80 GW (over 20 percent of the hours).

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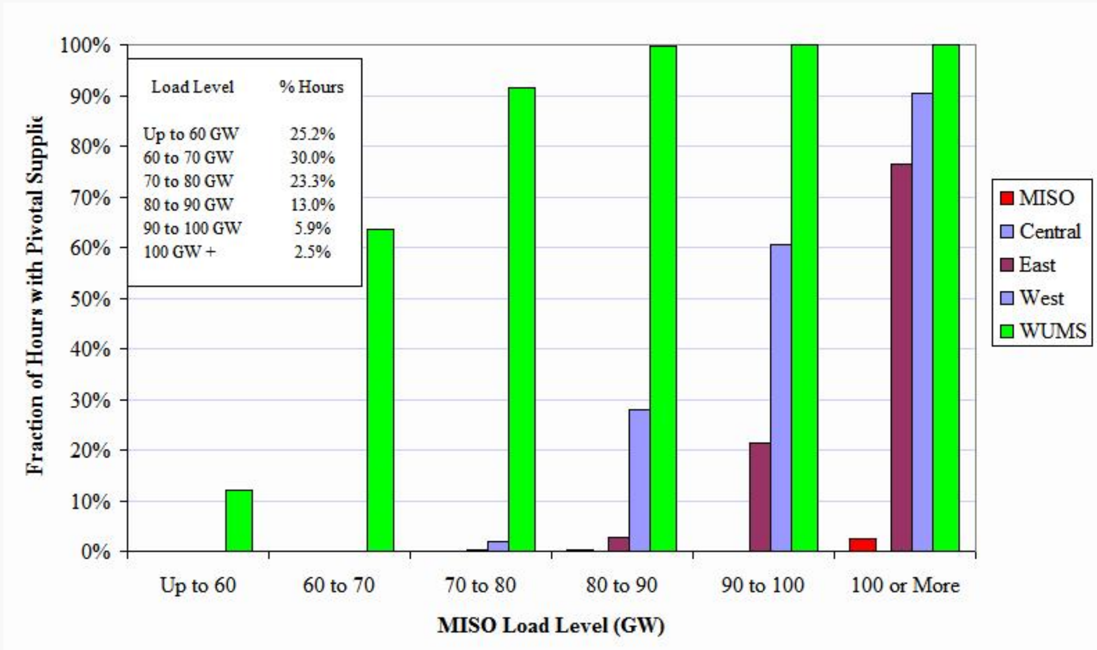
Residual Supply by Load Levels in 2005



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Residual Supply Duration Curves 2005: 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 there were no hours with a pivotal supplier in the Central region and very few hours with a pivotal supplier in the MISO region as a whole.
  - ✓ However, the WUMS region has one or more pivotal suppliers in more than two-thirds of the hours during the study period (April – December 2005), which justifies in part the special treatment of WUMS as a Narrow Constrained Area (“NCA”) under the mitigation measures in the MISO tariff.
  - ✓ The West had a pivotal supplier in about 10% of hours in 2005 and the East had a pivotal supplier in about 5% of the hours.
- Pivotal supplier analyses can also be performed on a constraint-specific basis – identifying when a supplier’s resources are needed to manage a constraint and, therefore, may have local market power.
  - ✓ Such market power exists across the entire MISO region based on our studies.
  - ✓ However, the market power mitigation to address local market power outside of the WUMS (i.e., in “Broad Constrained Areas” or BCAs) has expired, leaving the market vulnerable to substantial market power abuses.

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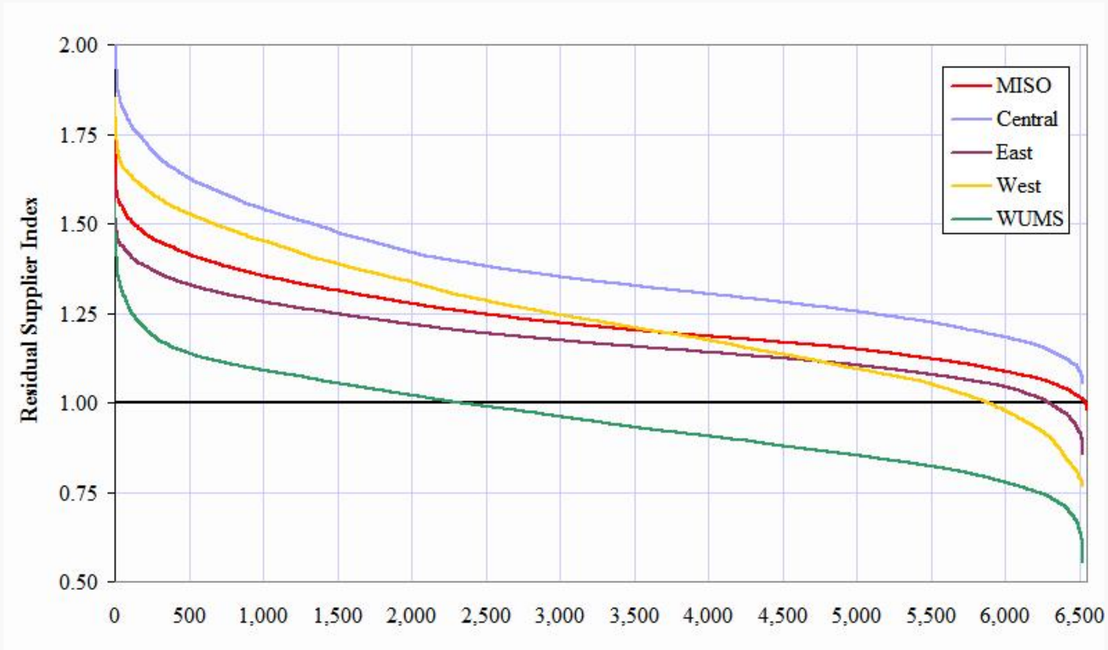
Residual Supply Duration Curves 2005: All Hours



POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis

- We also conducted an analysis to evaluate local market power associated with individual transmission constraints.
  - ✓ 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 first figure shows the portion of the active constraints that have at least one pivotal supplier.
  - ✓ 34 percent of the active BCA constraints have a pivotal supplier.
  - ✓ 41 percent of the active NCA constraints have a pivotal supplier.
- These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of the BCA constraints also create substantial local market power.

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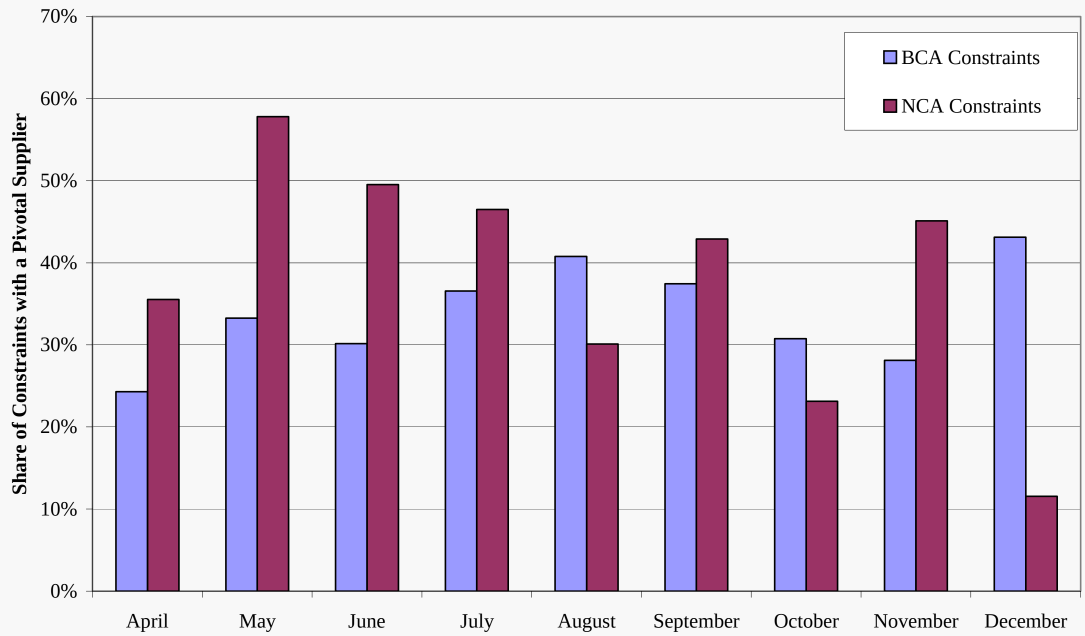
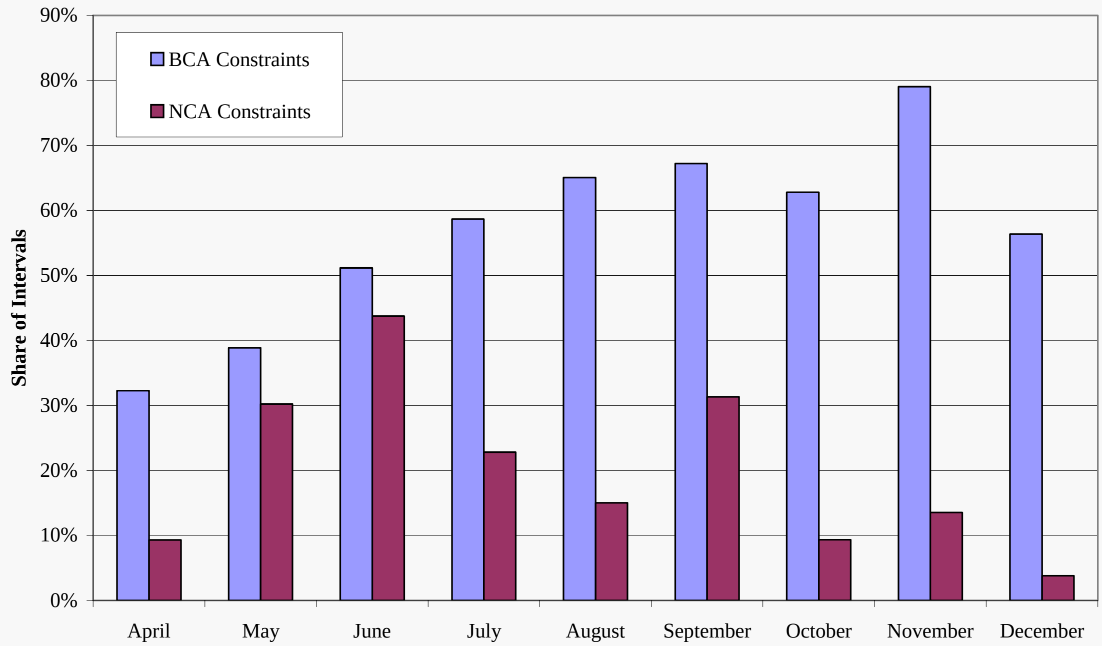
Constraint-Specific Pivotal Supplier Analysis: Percent of Active Constraints with a Pivotal Supplier



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 overall percentage of intervals during the market's operation in 2005 when at least one supplier is pivotal for the BCA and NCA constraints.
  - ✓ This analysis varies from the prior analysis because it incorporates how frequently the BCA and NCA constraints are active.
- This analysis shows that there was an active BCA constraint with at least one pivotal supplier in 57 percent of the hours during 2005.
  - ✓ These values rose over the year and peaked at nearly 80 percent of the hours in November 2005.
  - ✓ This increase is attributable to the fact that BCA constraints were active more frequently later in the year.
- The analysis also indicates that there was an active NCA constraint with a pivotal supplier in almost 20 percent of the hours.
  - ✓ The NCA ratios decreased over the year because the NCA constraints were active less frequently.
- 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

Offer Behavior in the Midwest ISO's Real-Time Energy Market

- The next analysis is the first in a series of analyses on the conduct of suppliers in the Midwest ISO.
- The first figure shows the average amount of generation offered at levels that exceed the conduct thresholds in the mitigation measures on a biweekly basis.
  - ✓ It shows both the minimum generation offers (i.e., no-load and energy offered up to a resource's EcoMin), and the energy offers that exceed the thresholds.
  - ✓ The analysis also shows the offers that exceed one half of the conduct thresholds.
- The figure shows that the average quantities exceeding the mitigation thresholds were very low.
- The quantities of energy exceeding 50 percent of the mitigation thresholds were also very low – these are the only quantities that would affect energy prices.
- The quantities of minimum generation exceeding 50 percent of the conduct thresholds peaked at almost 2000 MW.
  - ✓ These quantities are still relatively low given that more than 100 GW are typically offered in the MISO (although lower quantities are online in the real-time market).
  - ✓ This conduct does not affect energy prices, only potentially RSG costs.

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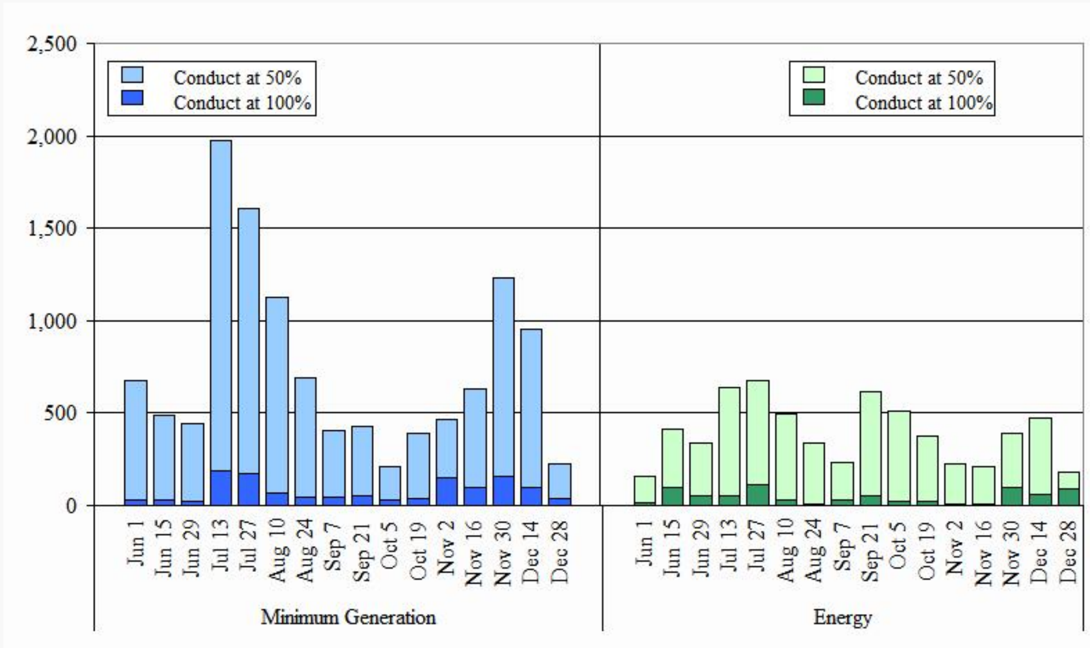
Conduct at 100% and 50% of Conduct Threshold Real-Time Market



POTOMAC ECONOMICS

Economic Withholding: Output Gap Analysis

- The next set of figures shows the results of the output gap metric.
  - ✓ The output gap shows the quantity of output that is not produced with competitive costs that are lower than the LMPs by more than a given threshold. It also includes inflated offers that set the LMPs.
  - ✓ These figures show the average output gap at the mitigation thresholds and one half of the mitigation thresholds.
  - ✓ The average output gap quantities are shown for the largest two suppliers in each region versus the other suppliers.
- These figures show:
  - ✓ The output gap at the mitigation thresholds are less than 1 percent.
  - ✓ The output gap levels at the lower threshold are also generally very low.
  - ✓ It increases with load levels because the higher prices that occur at high load levels cause a much higher share of the resources to be economic.
  - ✓ With the exception of the West region, the output gap quantities for the largest suppliers are lower than for other suppliers.
  - ✓ These results do not raise substantial competitive concerns.

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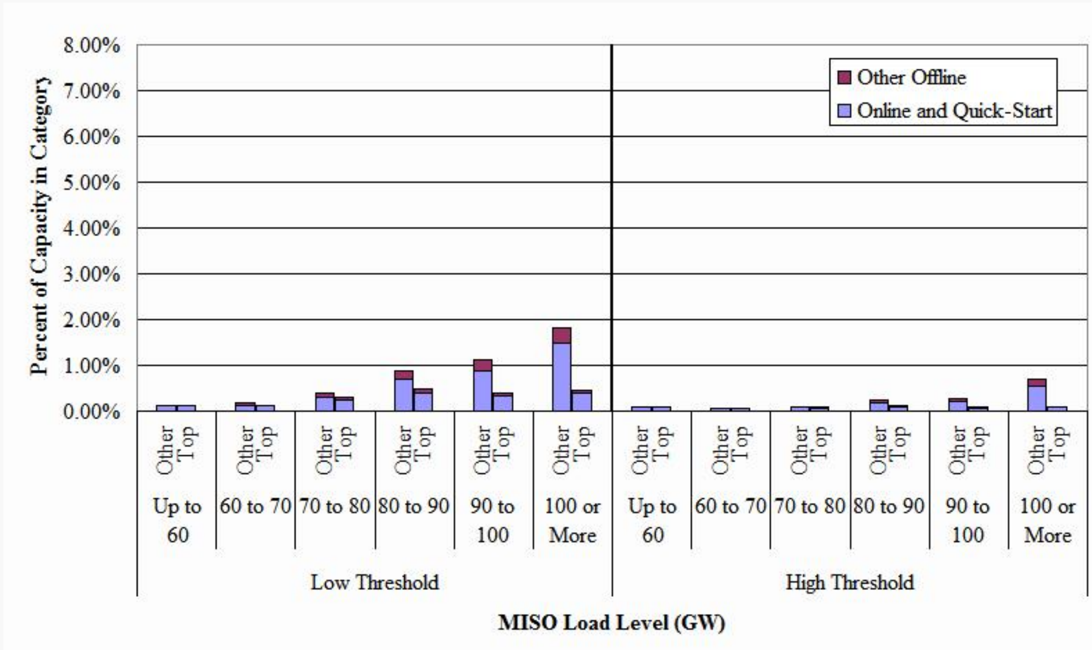
Real-Time Market Output Gap
Central: All Hours



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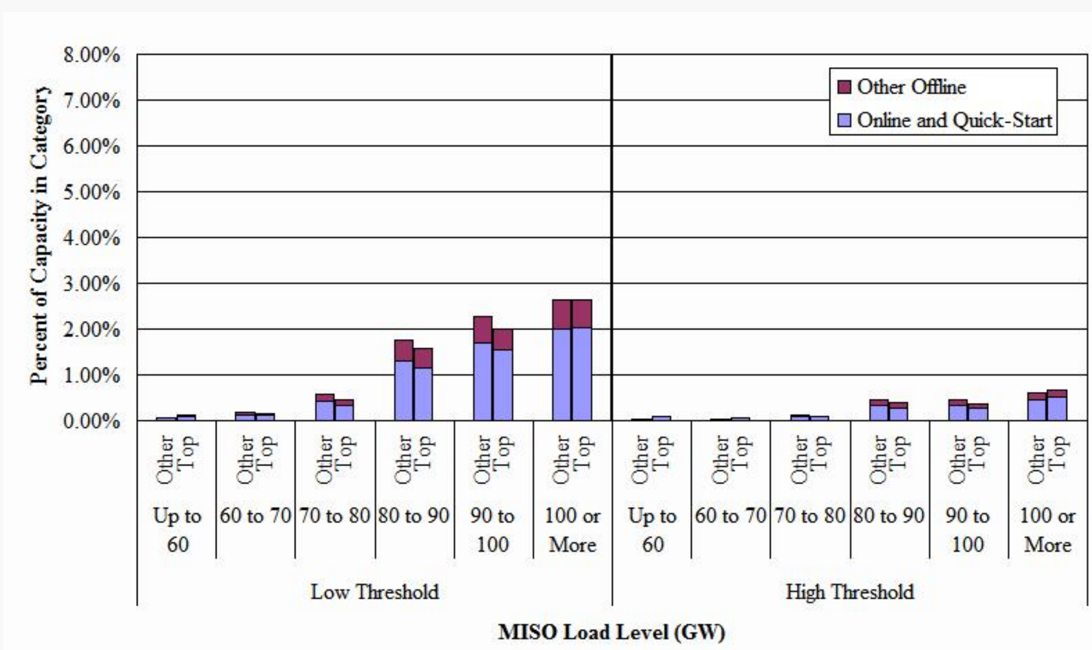
Real-Time Market Output Gap
East: All Hours



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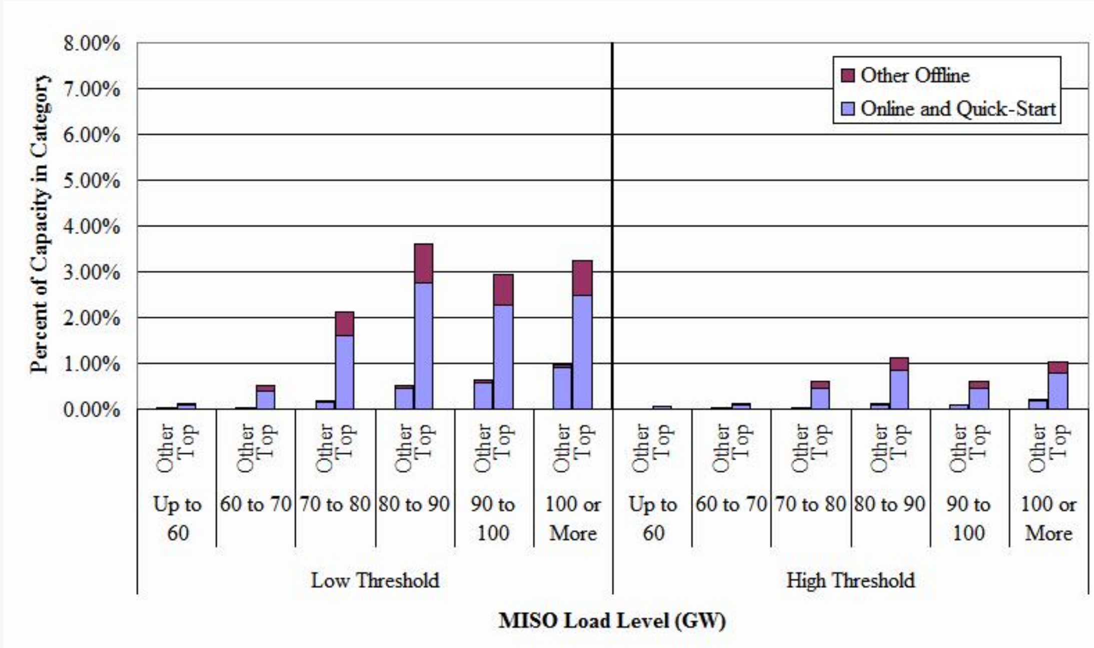
Real-Time Market Output Gap
West: All Hours



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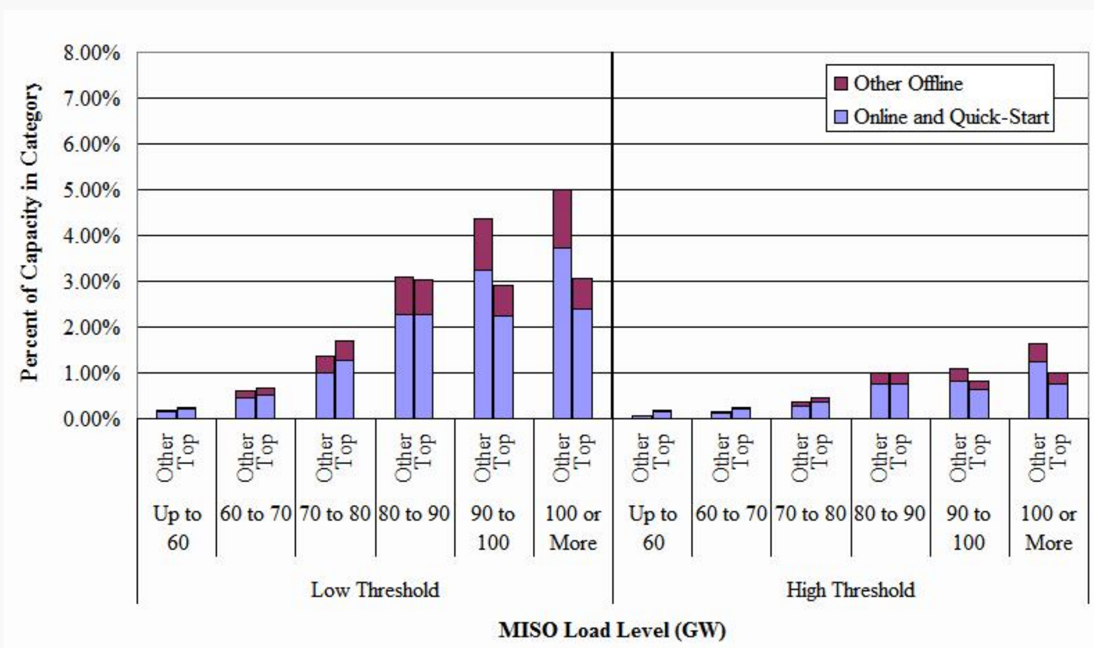
Real-Time Market Output Gap
WUMS: All Hours



POTOMAC ECONOMICS

Evaluation of Outages and Partial Deratings

- The prior analysis assess the offer patterns to identify potential economic withholding.
- The following analyses seek to identify potential physical withholding.
  - ✓ The following analyses show short-term forced outages (less than 7 days), longer-term forced outages, and deratings by load level for the largest two suppliers and the other suppliers in various regions.
  - ✓ 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 also focus particularly on short-term outages and partial deratings because long-term forced outages are least likely to be a profitable withholding strategy.
- The patterns shown in following figures do not raise substantial competitive concerns because:
  - ✓ The deratings and outages do not rise significantly under peak load conditions; and
  - ✓ The quantities for the largest suppliers are generally lower than for other suppliers (that are less likely to have market power).
  - ✓ Nonetheless, we investigate any outages or deratings that create substantial congestion or other price effects.

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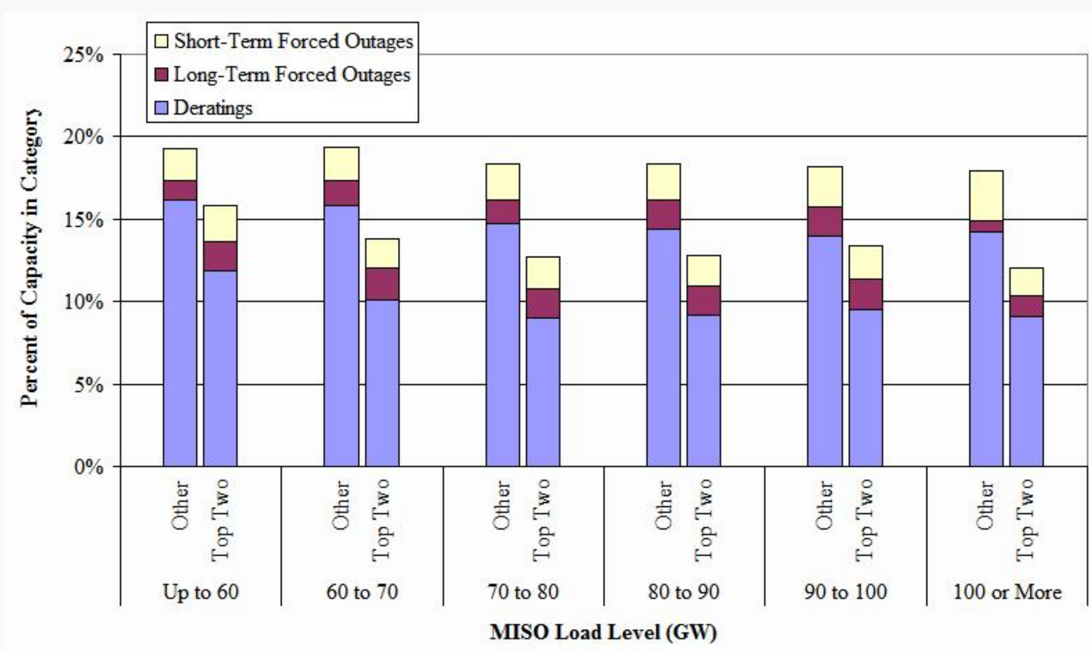
Real-Time Deratings and Forced Outages East: All Hours



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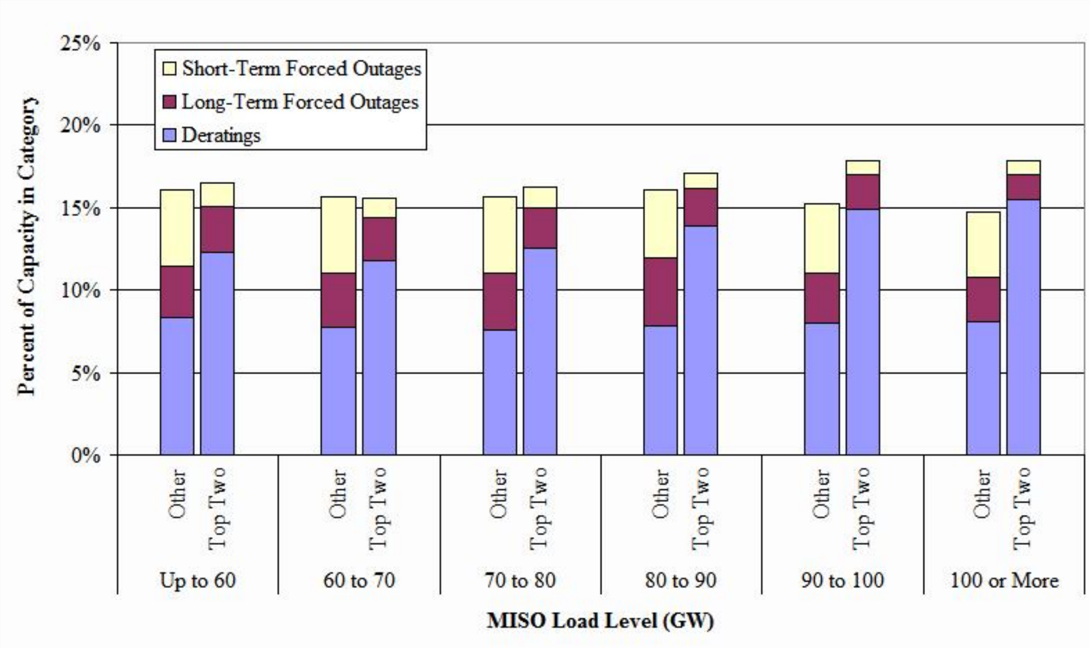
Real-Time Deratings and Forced Outages
Central: All Hours



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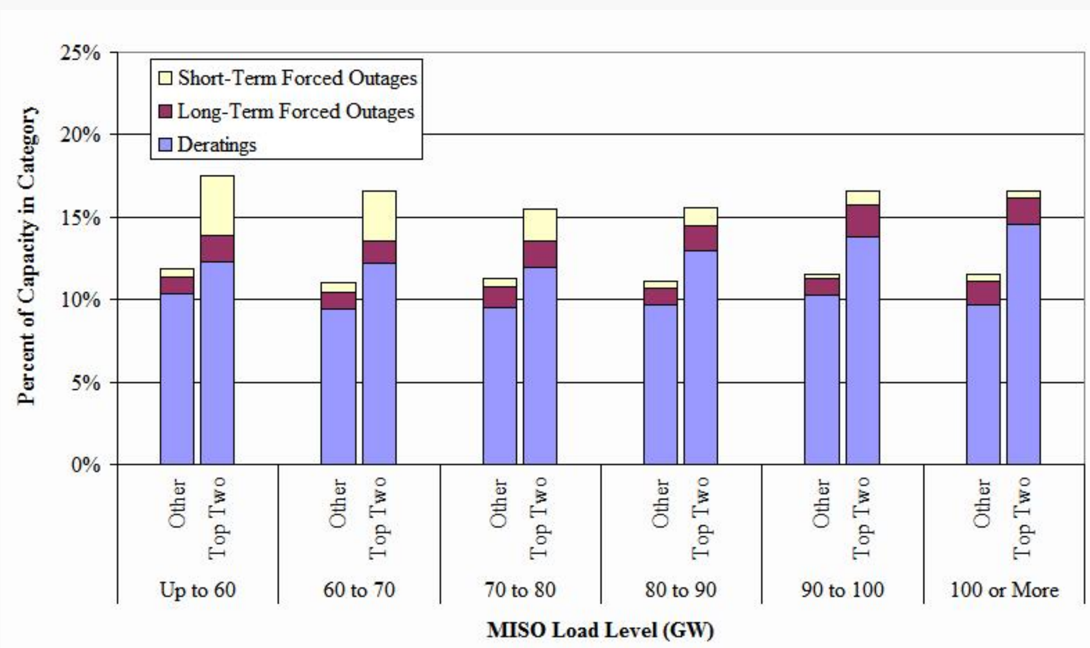
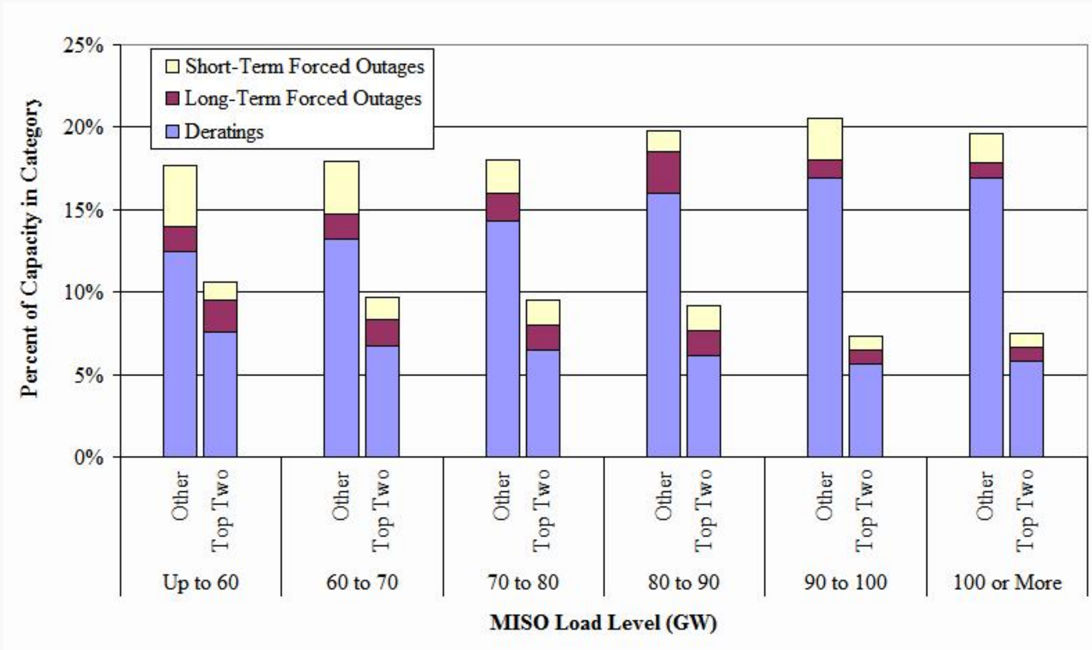
Real-Time Deratings and Forced Outages
West: All Hours



POTOMAC ECONOMICS

Real-Time Deratings and Forced Outages
WUMS: All Hours



POTOMAC ECONOMICS

Real-Time Energy Mitigation by Month

- The final two figures show the frequency with which mitigation has been imposed in the real-time market.
- The first figure shows the frequency and quantity of mitigation in the real-time market by month.
  - ✓ Mitigation occurs when a unit’s offer 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 less frequently than BCA mitigation in all but three months during the 9-month study period.
  - ✓ However, both classes of mitigation were relatively infrequent.
    - – There were 24 BCA events and 62 NCA mitigation events.
    - – The most mitigation occurred in September with 14 hours of mitigation.
- Although mitigation was relatively infrequent in 2005, local market power remains a significant issue in the MISO region.

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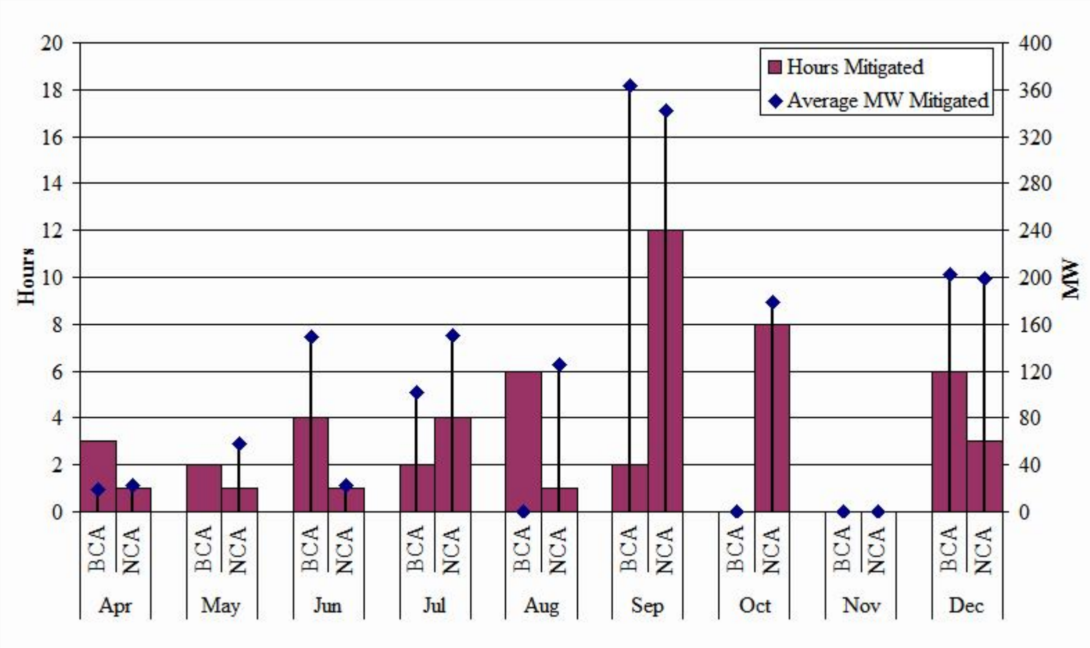
Mitigation in the Real-Time Energy Market by Month



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Real-Time RSG Mitigation by Month

- The next figure shows the frequency and amount by which RSG payments were mitigated in each month of 2005.
- This figure shows that only modest amounts of the total RSG payments were mitigated in most months due to the prerequisites for mitigation 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.
- Both the frequency and magnitude of the RSG mitigation was highest in December 2005:
  - ✓ More than $3 million of the RSG payment was mitigated in December.
  - ✓ Mitigation occurred for 46 unit-days.

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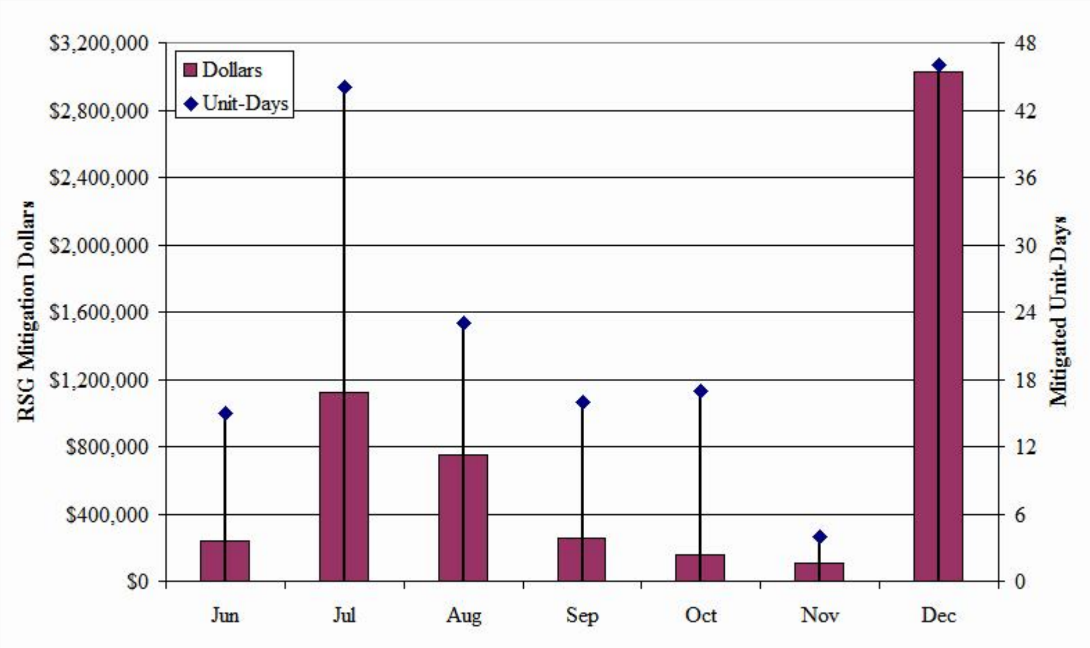
Real-Time RSG Mitigation by Month



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External Transactions

POTOMAC ECONOMICS

Average Hourly Day-Ahead Imports All Hours

- This last 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 first two figures show the average hourly net imports scheduled in the day-ahead and real-time markets 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 level of net imports was initially below pre-market levels.
  - ✓ However, the net imports increased rapidly to a maximum of more than 6100 MW on August 3.
  - ✓ The pattern of net imports was seasonal with the largest imports occurring during the summer under the tightest demand conditions.
  - ✓ Net imports also rose sharply in late November due largely to planned transmission and generation outages that led to very high prices in Minnesota.

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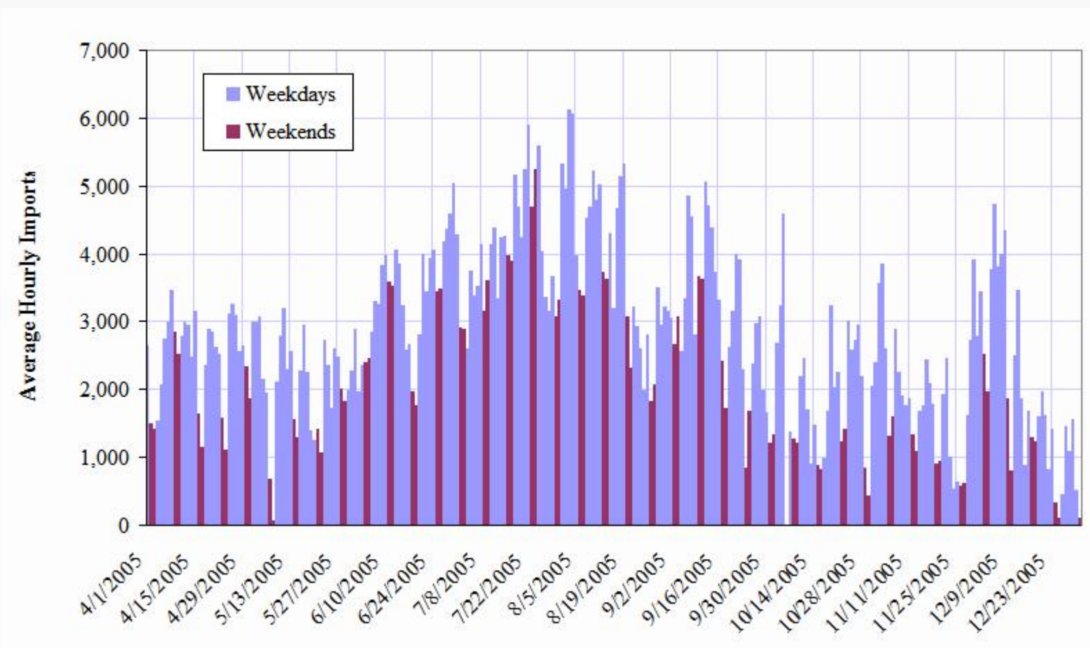
Average Hourly Day-Ahead Imports All Hours



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Average Hourly Real-Time Imports
All Hours

- The real-time figure shows that the net imports in the real-time market were comparable to the net imports scheduled in the day-ahead market.
- On average, the MISO imports almost 3500 MW in on-peak hours and close to 2000 MW in off-peak hours. More than half if this net imports come from Manitoba.
- However, sizable differences in the net imports sometimes occurred, particularly early in the market's operation.
  - ✓ There were a number of days early in the market when the Midwest ISO became a net exporter of power in the real-time market.
  - ✓ Large changes in net imports from the day-ahead to the real-time market cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources.

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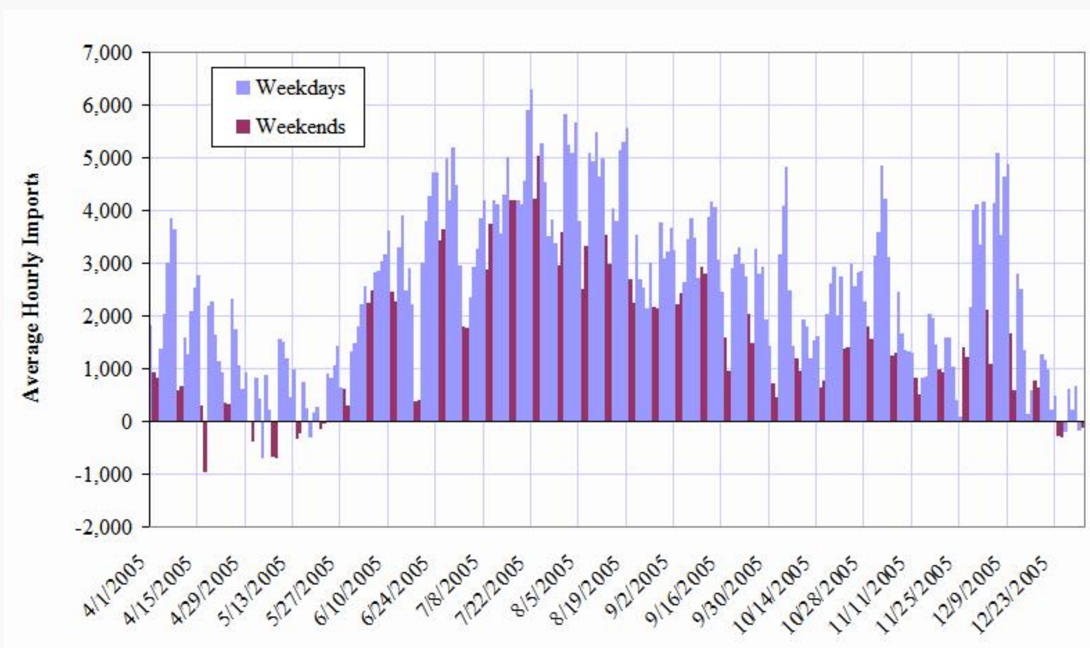
Average Hourly Real-Time Imports
All Hours



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Hourly Average Real-Time Imports from Canada April through December 2005

- The next two figures show the average real-time net imports into MISO over selected interfaces by hour of the day.
- The first figure shows the 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 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 hours and higher in the off-peak hours.
- The figure also shows the standard deviation of the net imports, indicating that:
  - ✓ Net imports from MHEB are much more variable in the off-peak hours overnight, likely caused by the relatively volatile prices in Minnesota in these hours; and
  - ✓ The net imports from MHEB in the other hours and the net exports to IMO are relatively stable.

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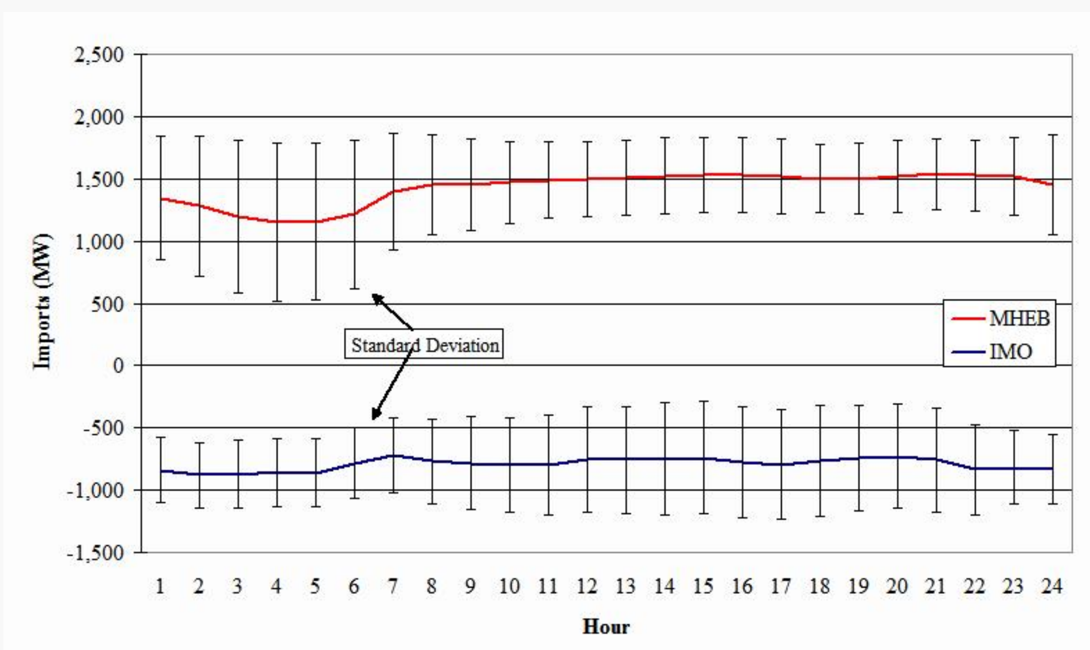
Hourly Average Real-Time Imports from Canada April through December 2005



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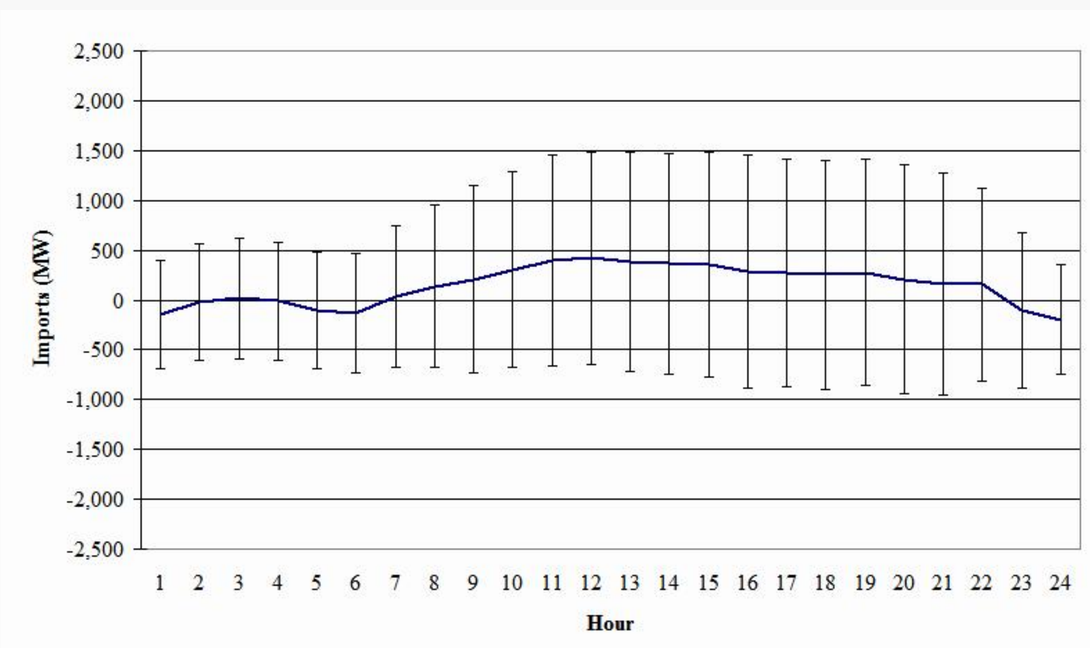
Hourly Average Real-Time Imports from Canada April through December 2005

- 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 power during the peak hours of the day and exports 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 external transactions with PJM is due to the fact that the supply resources in the two areas have similar cost characteristics.
- The relative prices in PJM and MISO should govern the real-time net interchange of power between the two areas.

POTOMAC ECONOMICS

Hourly Average Real-Time Imports from PJM April through December 2005



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 is not congested.
- Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to causes 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.

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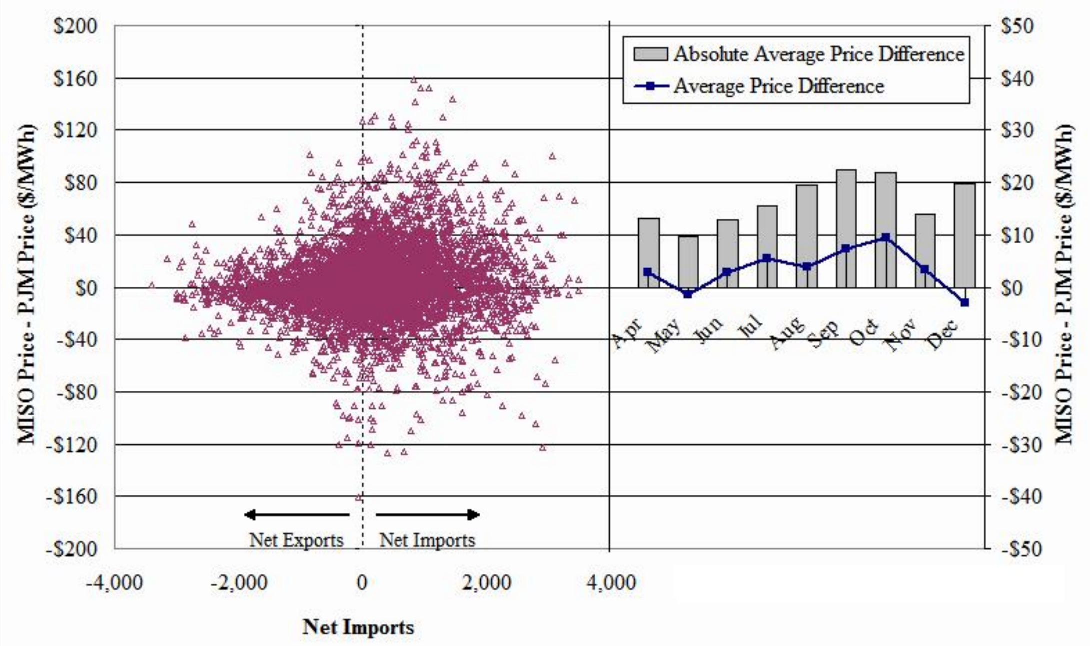
Real-Time Prices and Interface Schedules PJM and MISO

The results for the PJM interface indicate:

- The prices in the two areas are relatively well arbitraged in most hours.
- The convergence is better in the day-ahead market because the prices are much less volatile than in real time.
- MISO interface prices are slightly higher than PJM's on a consistent basis.
  - ✓ This may be due in part to differences in how the interface price is calculated – MISO uses an average of all PJM nodes, which can overstate the price under some conditions.
- Participants have not been fully effective at arbitraging the prices between the two areas.
- To achieve better price convergence, we recommend that the RTOs consider expanding the JOA to optimize the net interchange between the two areas.
  - ✓ Under this approach, the participants' transactions would be purely 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.

POTOMAC ECONOMICS

Real-Time Prices and Interface Schedules PJM and MISO



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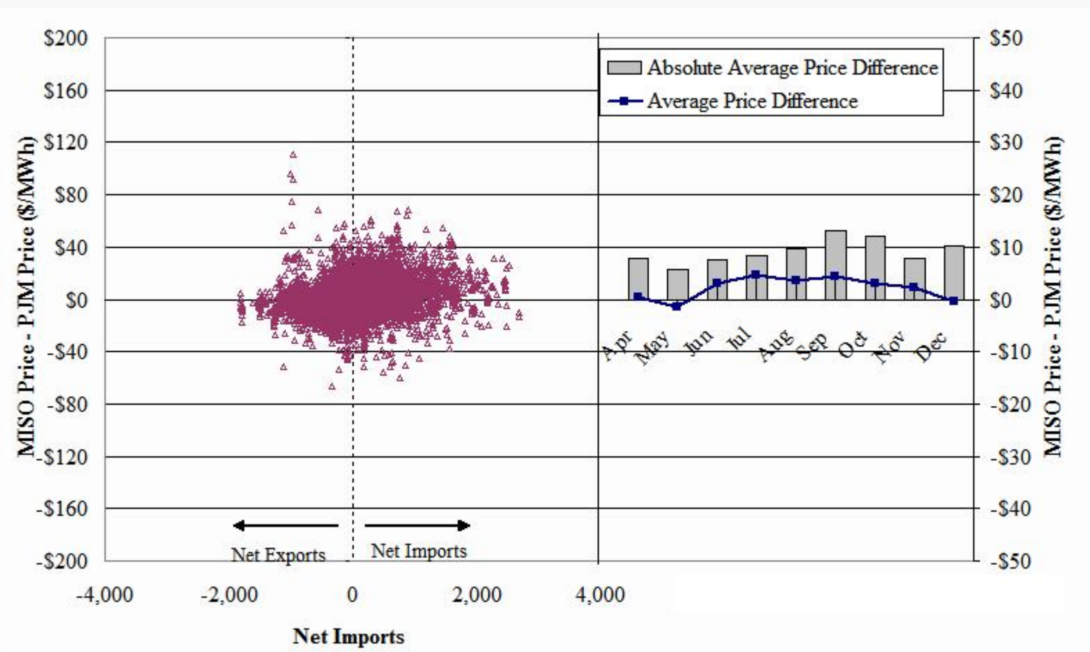
Day-Ahead Prices and Interface Schedules PJM and MISO



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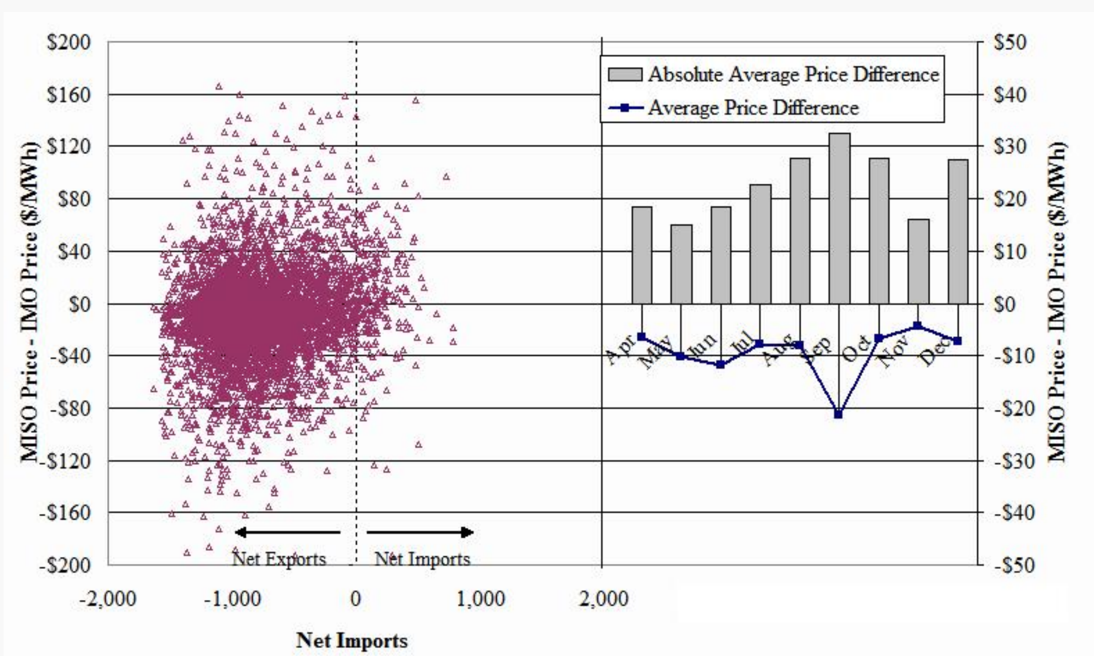
Real-Time Prices and Interface Schedules IMO and MISO

- The following figure provides the same analysis as the prior two, but for the MISO – IMO interface.
  - ✓ The MISO is a net exporter of power to IMO in virtually all hours, which is clear from the scatter plot.
  - ✓ On average, the prices in MISO are lower than the prices in IMO, which makes the net exports rational.
  - ✓ However, there are many instances when the exports occur when the IMO price is lower than the price in MISO.
- The schedules over this interface do not appear to be highly responsive to the price difference between the two markets.
- 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 being imported from MISO – internal constraints could cause such imports to be undesirable.

Real-Time Prices and Interface Schedules IMO and MISO



Market to Market Events

- The MISO and PJM currently coordinate the relief of transmission constraints that both systems impact (referred to as the "market-to-market" process)
  - ✓ 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 cost of relieving the constraint as determined by each respective market.
  - ✓ Each market is entitled to a certain flow on each of the market-to-market constraints. Settlements are made between the ISOs depending on its 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 events (instances when a market-to-market constraint is binding) by month. The figure shows:
  - ✓ The MISO market-to-market constraints occur seasonally (peaking in the summer) and are evenly divided between the peak and off-peak hours.
  - ✓ PJM has activated market-to-market constraints slightly less frequently and they occur more frequently in off-peak hours.

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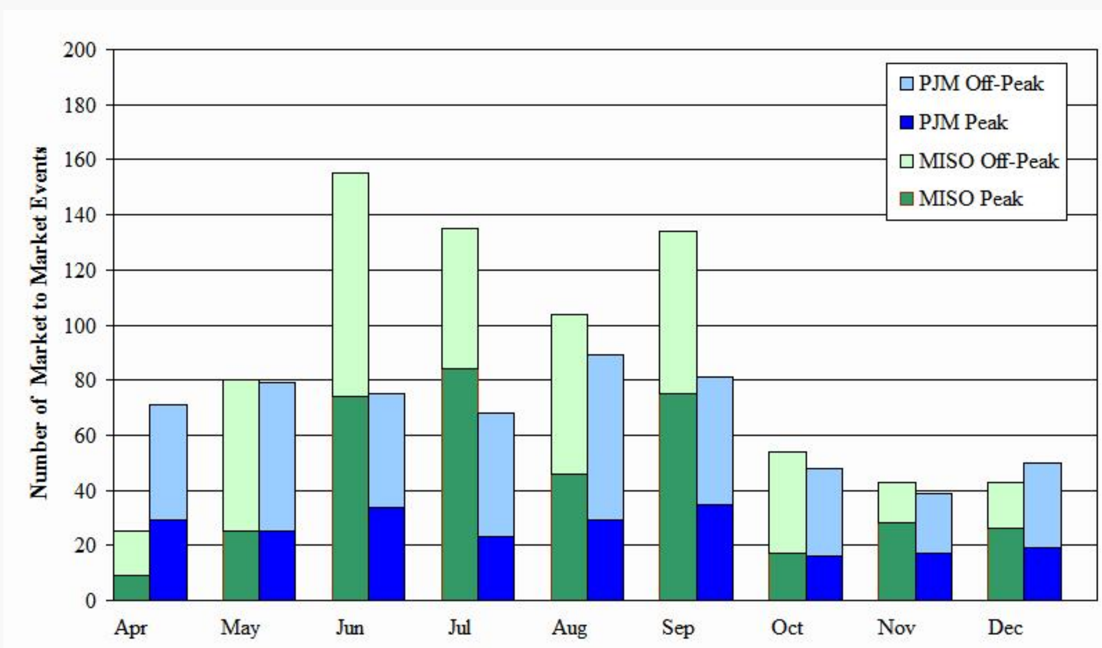
Market to Market Events



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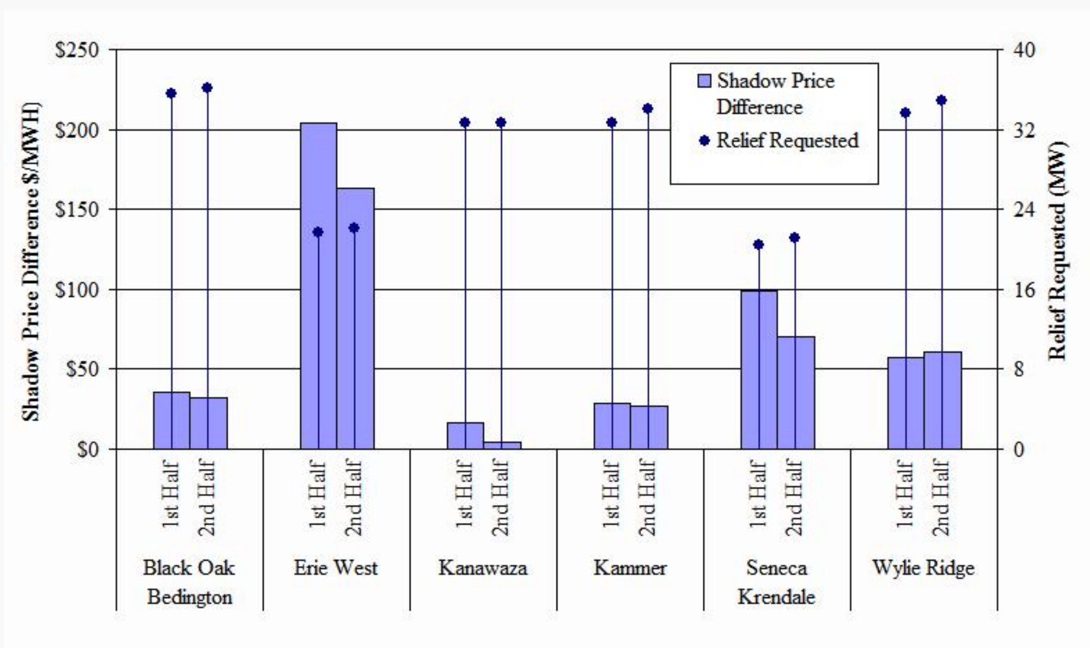
PJM Market-to-Market Constraints
Shadow Price Convergence

- The next figure shows the most frequently called market-to-market constraints on the PJM system.
  - ✓ Events are determined when a market-to-market constraint is active and binding for at least 6 intervals (30 minutes).
  - ✓ The events are divided in half -- the average shadow price difference between the two systems and requested relief is shown for each half.
- The figure shows that the shadow prices move toward convergence over the duration of the event, but good convergence is frequently not achieved, likely due to:
  - ✓ The fact that the requested relief is typically not modified over the term of the event;
  - ✓ A “relaxation” by MISO on the limit for the constraint when the requested relief cannot be provided at a cost that is lower than the PJM shadow price.
- To address these issues, we recommend:
  - ✓ The market-to-market process be enhanced to optimize the relief requested based on the relative shadow prices.
  - ✓ The constraint relaxation algorithm be discontinued and the prices be set based on the PJM shadow price when the requested relief cannot be provided at a lower marginal cost – this will substantially improve the convergence of the prices affected by the market-to-market constraints.

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



Active MISO Market-to-Market Constraints
April - December 2005

- The next figure shows the most frequently called market-to-market constraints on the MISO system.
  - ✓ Eau Claire Arpin is the most frequently called market-to-market constraint by MISO.
  - ✓ It is called more frequently than all other MISO market-to-market constraints combined.
  - ✓ We did not have access to the PJM shadow price for these constraints so the figure only shows the magnitude of the MISO shadow price on these constraints and the average relief requested.
- This figure shows that
  - ✓ The shadow prices do not decline substantially after the market-to-market constraint is activated; and
  - ✓ Like the PJM constraints, the requested relief is relatively stable over the term of the events and the relief requested is frequently fairly low.
- Like our recommendation for the PJM constraints, optimizing the quantity of relief that is requested would improve the operation of the market-to-market process.

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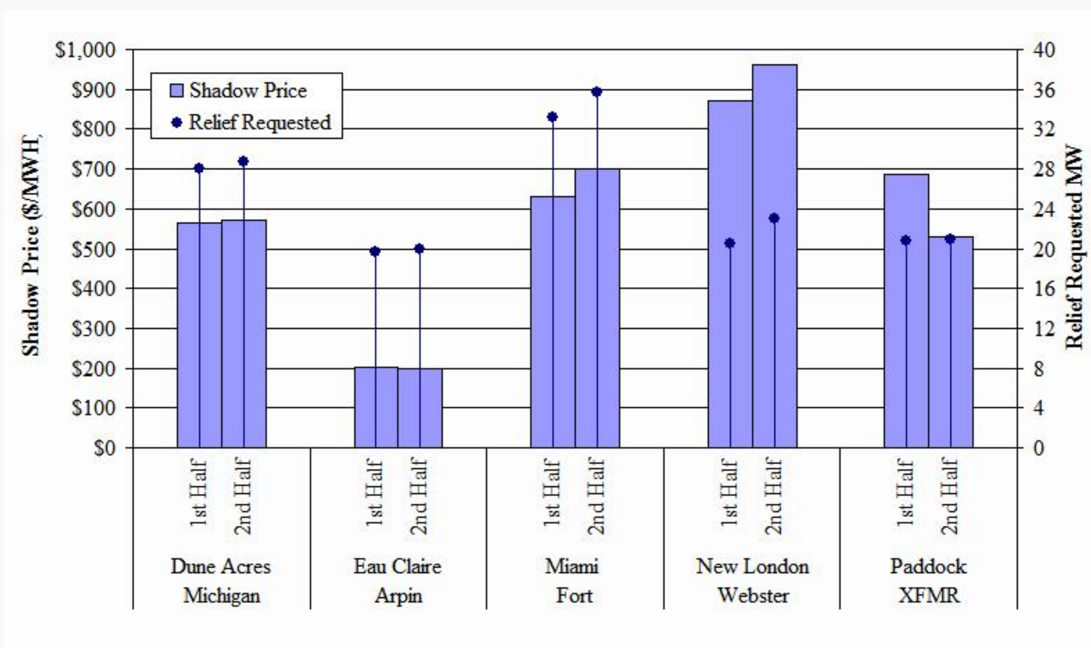
MISO Market-to-Market Constraints
Relief Requested and Shadow Prices



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