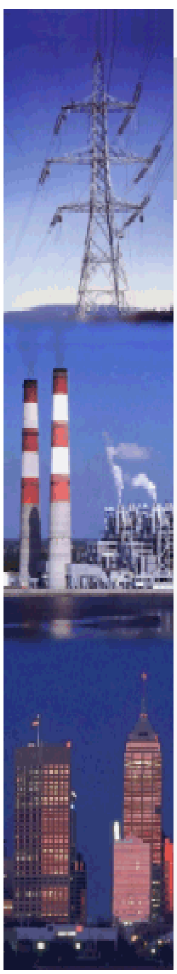
2005 State of the Market Report
New York Electricity Markets

David B. Patton, Ph.D.
Potomac Economics

Independent Market Advisor

April 2006

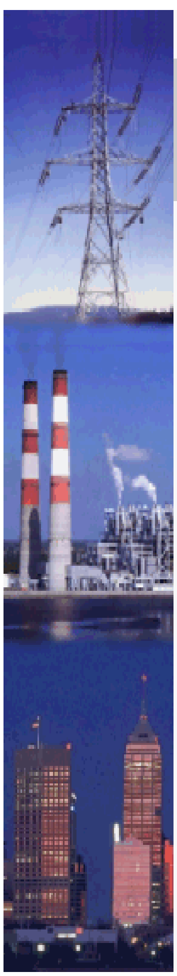


Introduction to the Annual Report

- This presentation provides highlights from the State-of-the-Market Report on the New York electricity markets for 2005.
- Standard Market Design 2 ("SMD2") was implemented on February 1, 2005.
- Several major enhancements were made to the market under SMD2 including:
  - ✓ Co-optimization of energy dispatch and ancillary services allocations every five minutes in the real-time market;
  - ✓ Use of demand curves for ancillary services under shortage conditions;
  - ✓ Real-time commitment and scheduling decisions evaluated every 15 minutes rather than hourly; and
  - ✓ Improvements to transmission loss modeling in the day-ahead market.
- This report evaluates the effects of these changes under SMD2 and assesses the overall performance of the New York electricity markets in 2005.

Summary of Conclusions

- The NYISO markets performed competitively in 2005 -- there was little evidence of significant economic or physical withholding.
- Energy prices increased in 2005 due to:
  - ✓ Higher fuel prices; and
  - ✓ Instances of shortages associated with hotter summer weather conditions that led to high peak demand levels;
- These trends caused the net revenue (market revenue – variable costs) available to a new generator in 2005 to increase.
  - ✓ Net revenue in New York City has risen to levels that would likely justify new entry; but
  - ✓ Net revenue in upstate New York continue to be less than the annual entry costs of a new gas turbine.

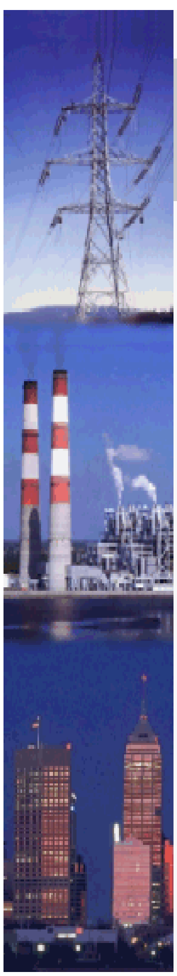


Summary of Conclusions

- Net uplift charges allocated to all load in New York state was substantially reduced under SMD2 due to:
  - ✓ Improved consistency between day-ahead and real-time loss modeling.
  - ✓ Reduced "make whole" payments to generators due to more efficient commitment of gas turbines in real-time.
  - ✓ These improvements were partly offset by tighter summer conditions and higher fuel prices that tend to increase uplift levels.
- Day-ahead congestion revenue shortfall (congestion revenue – payments to TCC holders) was virtually eliminated in 2005 due to the steps taken by the ISO in 2004.
- However, balancing congestion shortfalls continued to occur as a result of inconsistencies between the real time and day ahead markets:
  - ✓ Transmission limits;
  - ✓ Differences in modeling of the New York City Load Pockets; and
  - ✓ Transmission deratings due to thunderstorm alerts ("TSAs").

Summary of Conclusions

- Convergence between day-ahead and real-time prices for energy and ancillary services was better prior to 2005.
  - ✓ A small number of real-time peak pricing events, not anticipated by the day-ahead market, were primarily responsible for the lack of convergence.
  - ✓ Under-purchasing of load (including net virtual load) in the day-ahead market during July and August also contributed to the lack of convergence.
  - ✓ Convergence should improve as participants gain experience under the SMD2 markets.
- The capacity demand curve continues to result in stable capacity prices and facilitates price convergence between the various UCAP auctions.
  - ✓ Although new capacity became available in New York City in January 2006, prices remained near the In-City suppliers' price cap.
  - ✓ This occurred because a significant amount of existing capacity went unsold in the UCAP market.

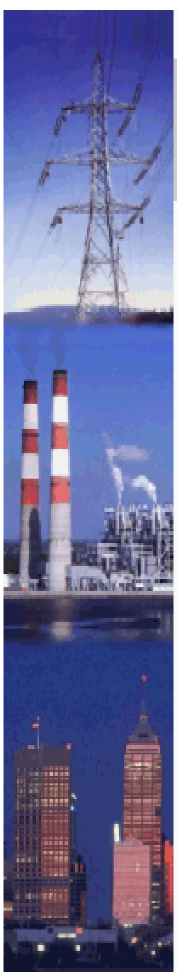


Summary of Conclusions

- The dispatch software implemented under SMD2 has significantly improved the efficiency of real-time energy and ancillary services pricing.
  - ✓ It considers how ancillary services affect the cost of energy and reduces system costs by re-allocating ancillary services every five minutes.
  - ✓ "Hybrid pricing" has been used since 2002 to allow gas turbines to set real-time energy prices when they are the marginal source of supply.
- In 2005, there were several instances of physical 10-minutes reserves shortages that were not accompanied by corresponding shortage prices.
  - ✓ These were the result of differences between how the hybrid pricing approach dispatches resources and how it treats them for pricing purposes.
  - ✓ Some differences between the pricing and physical dispatches in RTD are necessary to implement the hybrid pricing regime.
  - ✓ However, unnecessary differences will generally lead to inaccurate prices and increased uplift.

Summary of Conclusions

- Prices between New York and adjacent markets during unconstrained periods continue to not be arbitraged effectively.
  - ✓ Price convergence was worse during the study period in 2005 than in 2004, largely due to increased volatility.
  - ✓ Although the elimination of export fees likely resulted in modest improvement in the scheduling of external transactions with New England, price convergence remains poor across the New England interface.
- Efficient scheduling between New York and New England is particularly important during peak pricing events.
  - ✓ In hours where the Capital Zone price exceeded $200/MWh, prices in New England were generally much lower and substantial transmission capability was unused.
- Peak pricing events were more frequent during the study period than in previous years. Even small adjustments in flow between markets can have a large impact on prices during peak conditions.

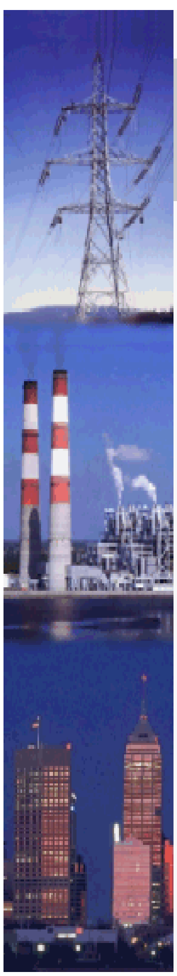


Areas of Potential Improvement and Recommendations

- Day-ahead to real-time price convergence is likely to improve as market participants gain experience with the current market.
- Good convergence in load pockets is unlikely to be achieved without modeling changes and/or virtual trading in the load pockets.
  - ✓ Changes are being implemented in May to model individual transmission lines and contingencies in NYC (rather than simplified interfaces) in the real-time market.
  - ✓ This will allow greater utilization of the transmission system within New York City, improve efficiency, and lower balancing congestion costs.
  - ✓ If the modeling changes do not improve convergence in the load pockets, we would recommend expanding virtual trading to the NYC load pockets.
- If the convergence of ancillary services prices remains poor, the NYISO should consider introducing virtual trading of ancillary services.
  - ✓ This change would promote convergence of ancillary service prices and reduce physical suppliers' incentive to raise their offers.
  - ✓ However, it would need to be carefully studied to ensure it will not have unintended consequences on the day-ahead commitment.

Areas of Potential Improvement and Recommendations

- Improving the consistency of the pricing and physical dispatch passes of RTD will improve the efficiency of New York’s energy and ancillary services pricing (particularly during shortages) and reduce uplift.
  - ✓ In the short-term, we recommend that the NYISO implement the automated derates of gas turbines in the pricing dispatch that are currently included in the physical dispatch.
  - ✓ In the longer-term, we recommend the NYISO re-calibrate the dispatch levels in the pricing pass for units that are not responding to dispatch signals.
- Transmission constraint shadow prices can reach extremely high levels for brief periods when redispatch options are unavailable or relatively ineffective.
  - ✓ Transmission demand curves could be used to prevent costly re-dispatch in situations where there is little or no reliability benefit.
  - ✓ Therefore, we recommend that the NYISO continue to evaluate the reliability impacts of implementing transmission demand curves.

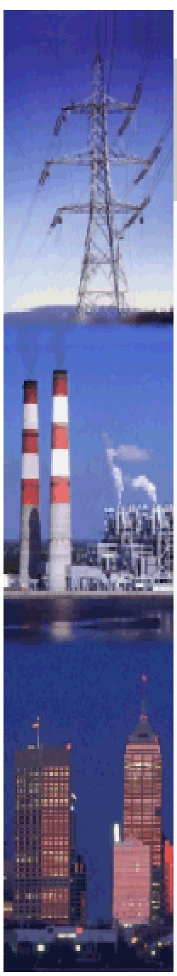


Areas of Potential Improvement and Recommendations

- Supplemental commitments through the local reliability pass of SCUC and the SRE process are often required to meet local requirements in New York City, which increases uplift on units in the City.
  - ✓ In the short-run, we continue to recommend that the ISO allow operators to pre-commit certain units that are known to be needed prior to the day-ahead market.
  - ✓ In the longer-run, the ISO should improve the modeling of local reliability rules and NOx constraints to include them in the initial SCUC commitment.
  - ✓ However, both of these changes require that the NYISO first work with participants to revise the cost-allocation methodology for uplift associated with the local reliability requirements.
- Real-time prices in adjacent regions continue to not be efficiently arbitraged, particularly during peak pricing conditions.
  - ✓ We recommend that New York and New England continue their work to develop and implement ITS (Intra-hour Transaction Scheduling) to better utilize the transfer capability between regions.

Market Prices and Outcomes

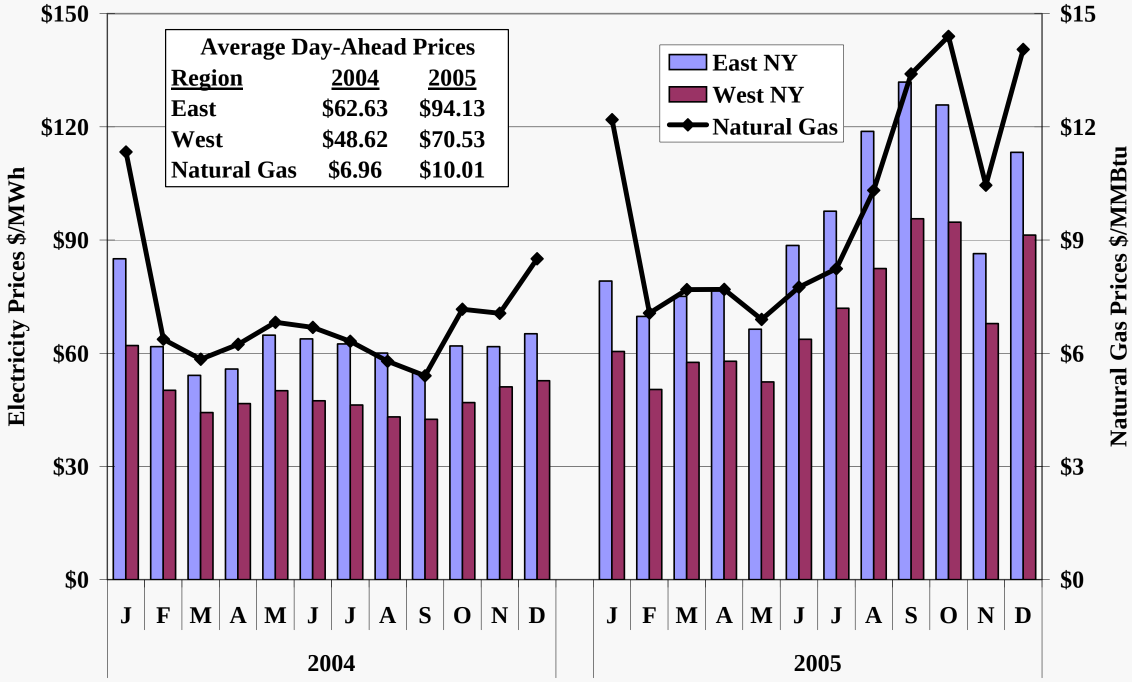
POTOMAC ECONOMICS

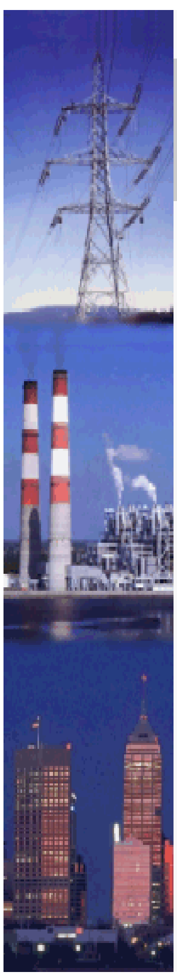


Fuel Prices and Electricity Prices

- The following figure shows monthly energy prices in 2004 and 2005.
- Movements in fuel prices led to corresponding changes in electricity prices in 2005:
  - ✓ Natural gas prices were an average of 44 percent higher in 2005 than in 2004. Likewise, oil prices increased by 45 percent.
    - – Hurricanes reduced the flow of natural gas from the Gulf Coast region from the end of August through the fall, leading to tight supply and higher prices.
  - ✓ Correlation of energy prices with oil and gas prices is expected since:
    - – a) fuel costs represent the majority of most generators' variable production costs, and
    - – b) oil and gas units are on the margin in most hours.
- Hot weather contributed a significant rise in energy prices during summer 2005. The summer of 2004 was comparatively mild.
- Substantial congestion continued to prevail from West NY to East NY (particularly into and within NYC).
  - ✓ Average prices in East NY were almost $24/MWh higher than in West NY.

Day-Ahead Electricity and Natural Gas Prices 2004 – 2005





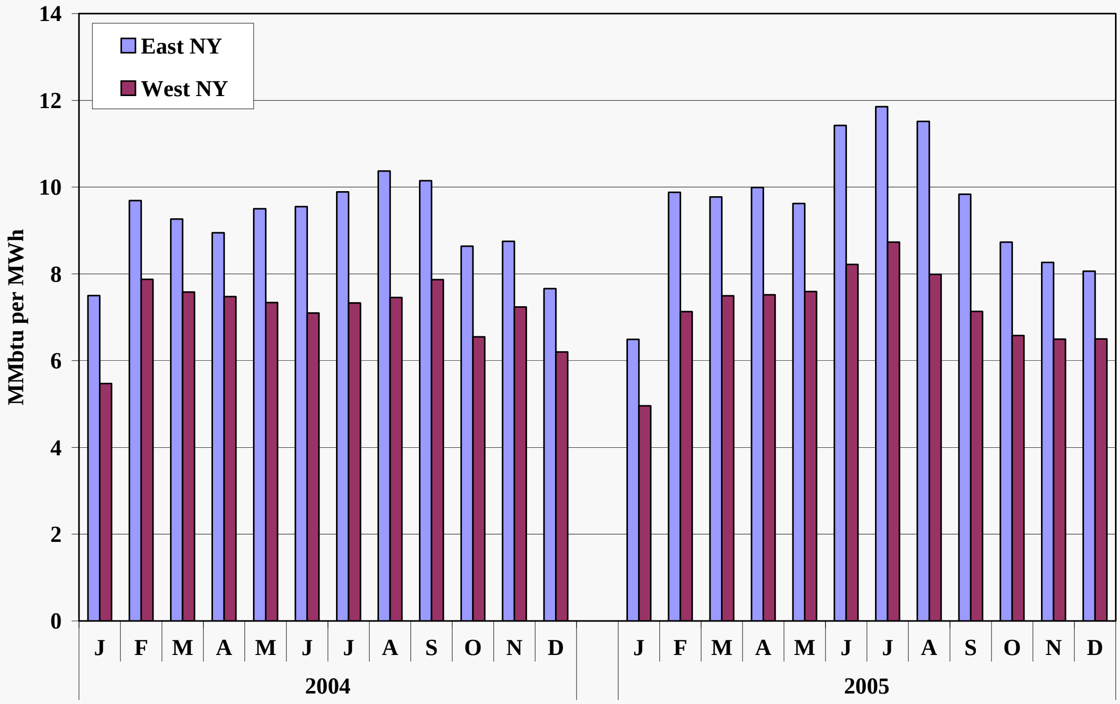
Fuel Prices and Energy Prices

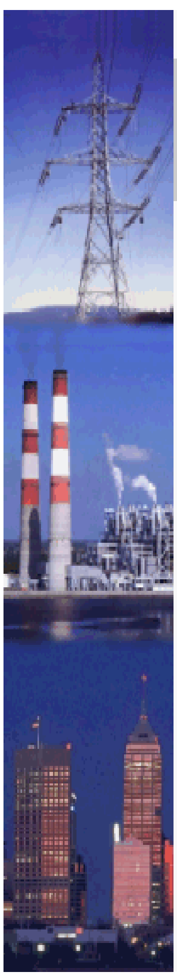
- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always on the margin.
  - ✓ Implied Heat Rate = (Day-Ahead Elec. Price) ÷ (Natural Gas Price)
- The following figure shows:
  - ✓ During the summer months, implied heat rates in East New York were 15 to 20 percent higher in 2005 than in 2004;
  - ✓ In the non-summer months, implied heat rates in East New York were approximately equal on average in 2004 and 2005; and
  - ✓ Implied heat rates dropped significantly during months with extreme natural gas prices, indicating that there were a large number of hours where natural gas was not on the margin.

Average Implied Marginal Heat Rate

Based on Day-Ahead Electricity and Natural Gas Prices

2004 – 2005

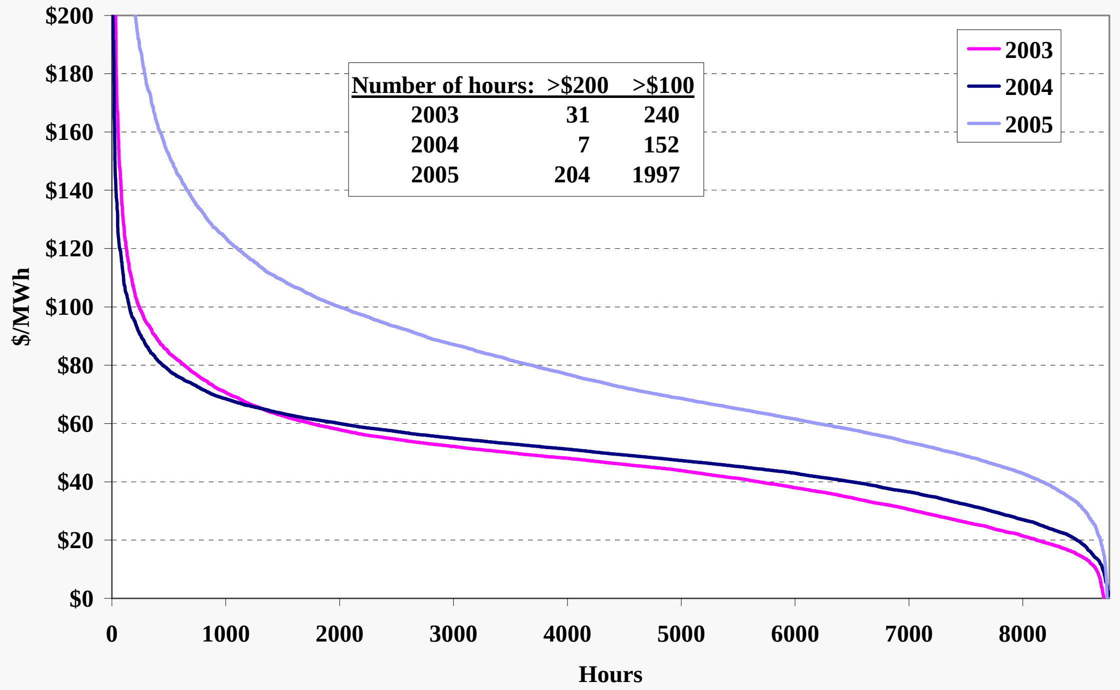




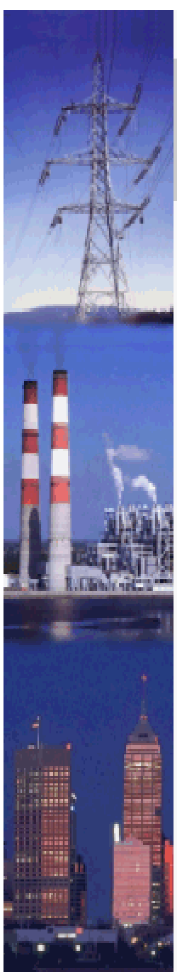
Energy Prices

- The next two figures show how prices have changed in the last three years on an hourly basis.
- The first figures show real-time price duration curves for 2003, 2004, and 2005.
  - ✓ These curves show the number of hours when the load-weighted price for New York State is greater than the level shown on the vertical axis.
- In 2005, prices were higher than in the previous year due to higher fuel prices and more frequent price spikes:
  - ✓ In 2005, there were 1997 hours with prices above $100, compared to 152 such hours in 2004.
  - ✓ In 2005, there were 204 hours with prices above $200, compared to 7 such hours in 2004.
- The widespread nature of the price increases are attributable to natural gas and oil price increases, which affect energy prices in both high and low load conditions.

Price Duration Curves
New York State Average Real-Time Price
2003 – 2005



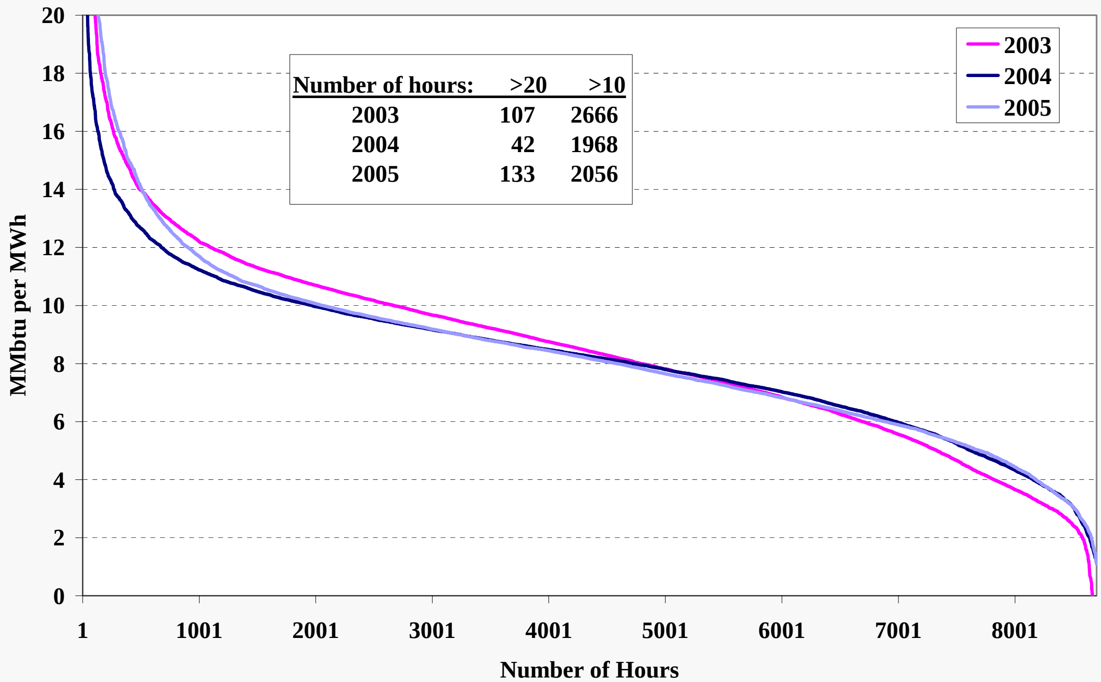
Based on calculations provided by NYISO Market Monitoring and Performance

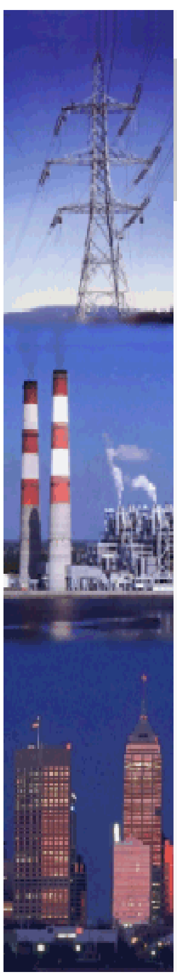


Energy Prices

- To isolate the price increases that are not caused by high gas prices, the second figure shows duration curves for implied heat rates during the same period:
  - ✓ In 2005, higher demand led to 204 hours where implied heat rates exceeded 20 MMbtu/MWh, whereas in 2004, only 42 such hours occurred.
- Outside of peak conditions, implied heat rates were comparable between 2004 and 2005.
- The substantial increase in high-priced hours (i.e. hours with implied heat rates > 20 MMbtu per MWh) is due, primarily, to the hotter weather that contributed to higher peak load in many hours:
  - ✓ Under SMD2, the shortage pricing provisions lead to approximately 20 hours of shortage prices in 2005 corresponding to reserve shortages.
  - ✓ Shortage pricing did not occur in 2004.

Implied Heat Rate Duration Curves
Based on New York State Average Real-Time Price
2003 - 2005

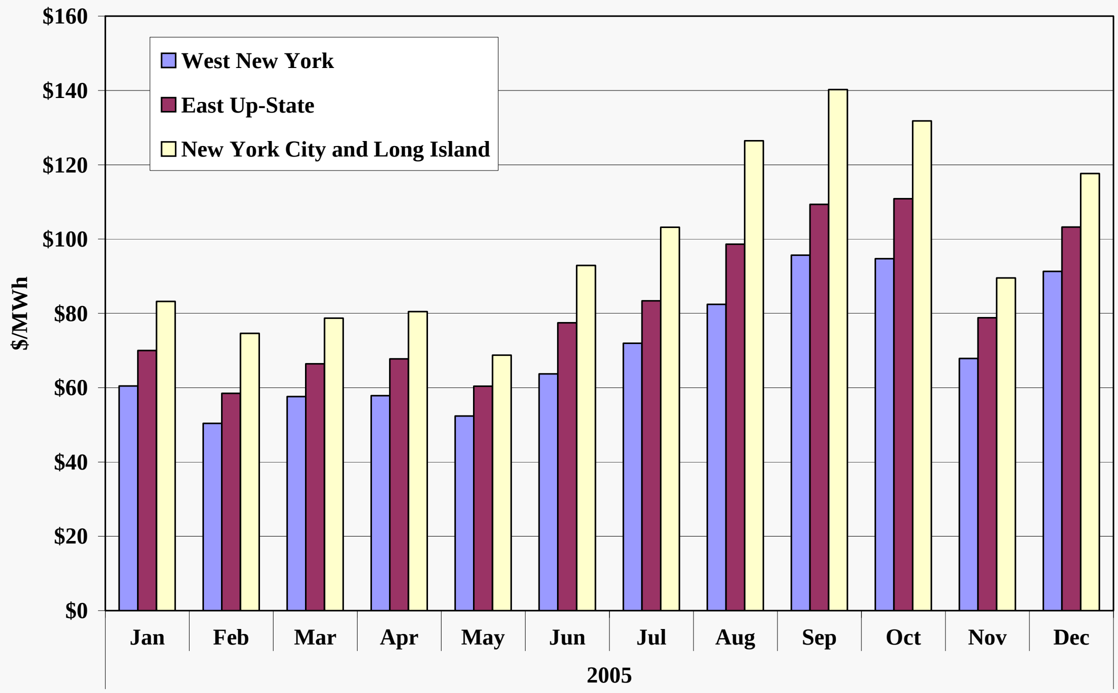


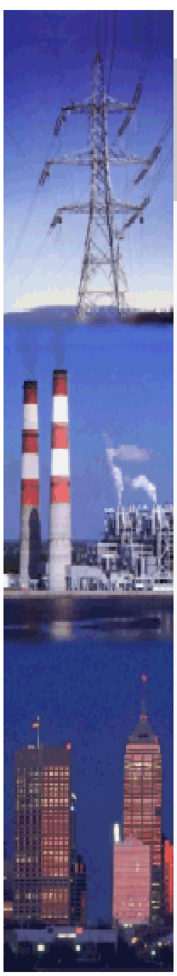


Day-Ahead Energy Prices

- The next figure presents average day-ahead energy prices by month in western NY, eastern upstate NY, and NYC/Long Island for 2005.
- Prices in east up-state exceed prices in the west by an average of $12 per MWh due to:
  - ✓ The marginal cost of transmission losses,
  - ✓ Central-East congestion, and
  - ✓ Congestion from the Capital region to areas just outside New York City.
- There are constraints into New York City and Long Island, as well as local load pockets within these areas, which raise average prices inside the constraints.
  - ✓ Price differences between New York City and Long Island and the eastern upstate region averaged $16 per MWh in 2005.

Day-Ahead Energy Prices
2005

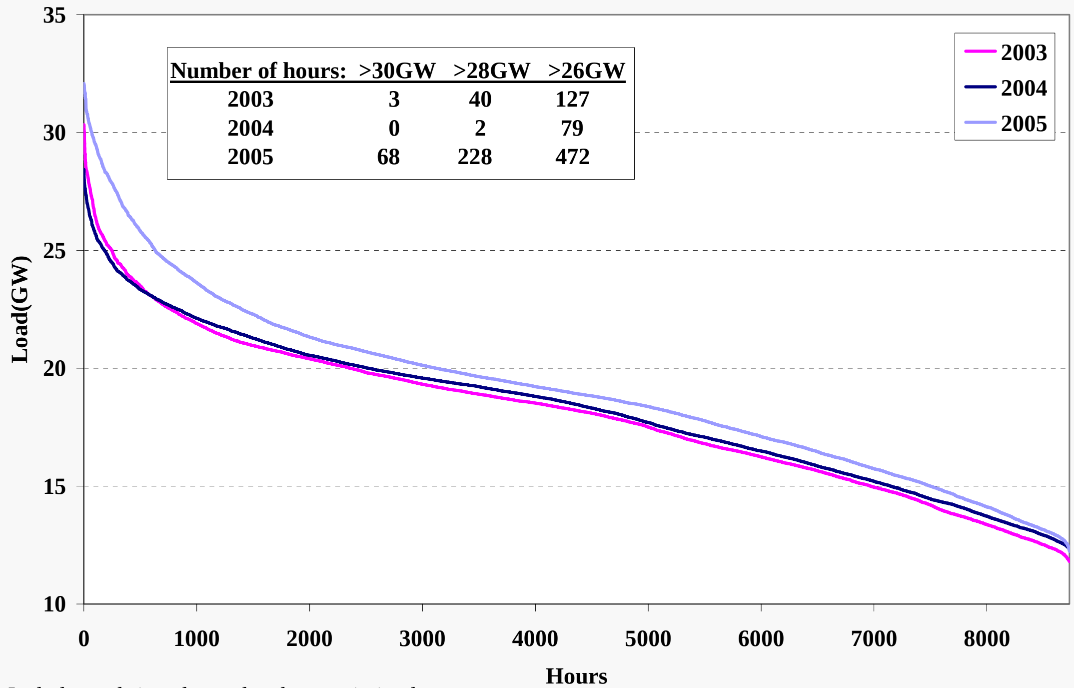




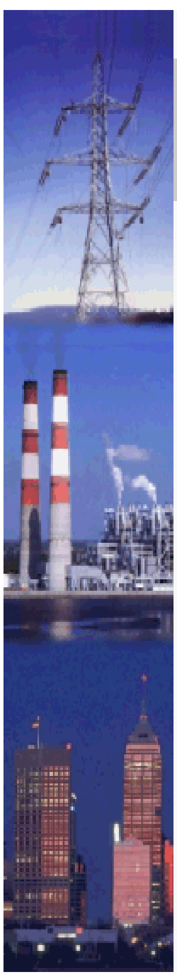
Load Profile

- The increased frequency of tight market conditions is generally caused by higher peak load levels.
- To evaluate this, 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.
- The absence of severe price spikes during 2004 was primarily due to mild summer demand.
- In 2005, there were far more hours with extreme demand levels.
  - ✓ In 2005, there were 68 hours when actual loads exceeded 30 GW, and no such hours in 2004.
  - ✓ In 2005, there were 228 hours when actual loads exceeded 28 GW, and just 2 of these hours in 2004.

Load Duration Curves*
New York State Hourly Average Load
2003 – 2005



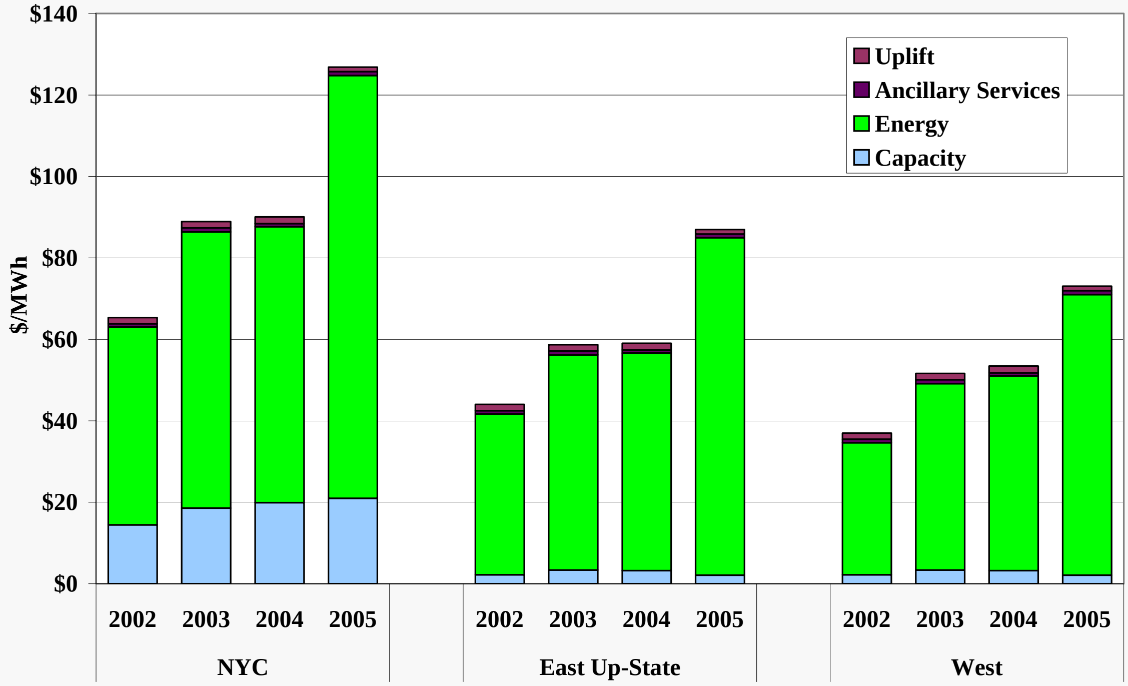
* Includes real-time demand and transmission losses.



All-In Energy Prices

- The following figure shows an “all-in” price that includes the costs of energy, ancillary services, capacity, and uplift.
  - ✓ The all-in price is calculated for various locations within New York since both capacity and energy prices vary substantially by location.
  - ✓ The capacity component is calculated by multiplying the average capacity price by the load obligations in each area, and dividing by total energy consumption.
  - ✓ Real-time energy prices are used for this metric.
- This figure shows that the all-in price rose considerably from 2004 to 2005.
  - ✓ The higher energy price component is primarily due to higher fuel prices and more frequent price spikes during peak demand periods.
  - ✓ The capacity portion of the all-in price has been relatively consistent since 2003.

Average All-In Price
2002 - 2005



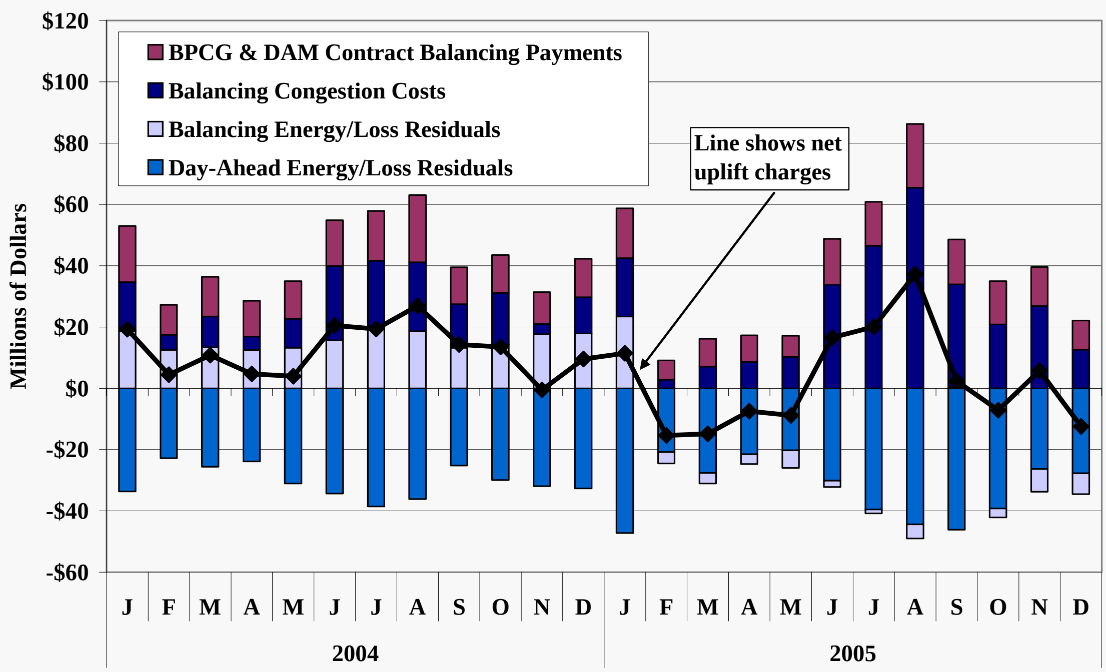
Uplift Charges to All of New York State

- The following figure summarizes monthly uplift charges and surpluses that are allocated to all load in New York state.
- The figure breaks uplift charges into the following categories:
  - ✓ BPCG and DAM Contract Balancing Payments – Includes “make whole” payments to generators for non-local reliability reasons.
  - ✓ Day-ahead Residuals – Surplus revenue collected for losses and energy from the day-ahead market and rebated to loads.
  - ✓ Balancing Residuals – Surplus (or shortfall) revenue collected for losses and energy from the real-time market and rebated (or charged) to loads.
  - ✓ Balancing Congestion Costs – When day-ahead scheduled power flows exceed real-time transmission capability, NYISO customers must buy back the excess in real-time.

Uplift Charges to All of New York State

- The figure shows a significant decline in net uplift charges after the implementation of SMD2. The declines in uplift were due to:
  - ✓ Reduced BPCG payments due to more efficient commitment of gas turbines in real-time.
  - ✓ Elimination of balancing residual charges due to improved consistency between day-ahead and real-time loss modeling.
- Tighter operating conditions in the summer led to increased uplift from balancing congestion charges:
  - ✓ The real-time congestion costs were higher in 2005, contributing to an increase in balancing congestion costs.
  - ✓ Thunder Storm Alerts led to real-time pricing events under reduced transmission capability that significantly contributed to the balancing congestion costs. A portion of these costs are assessed to the local TO.
- Other factors that contribute to fluctuations in monthly uplift include:
  - ✓ Increased reliance during the summer on GTs, which receive a large share of the BPCG payments.
  - ✓ Higher fuel prices that increase can increase a resources' out-of-merit costs and, hence, BPCG payments.

Uplift Charged to NYCA
2004 - 2005

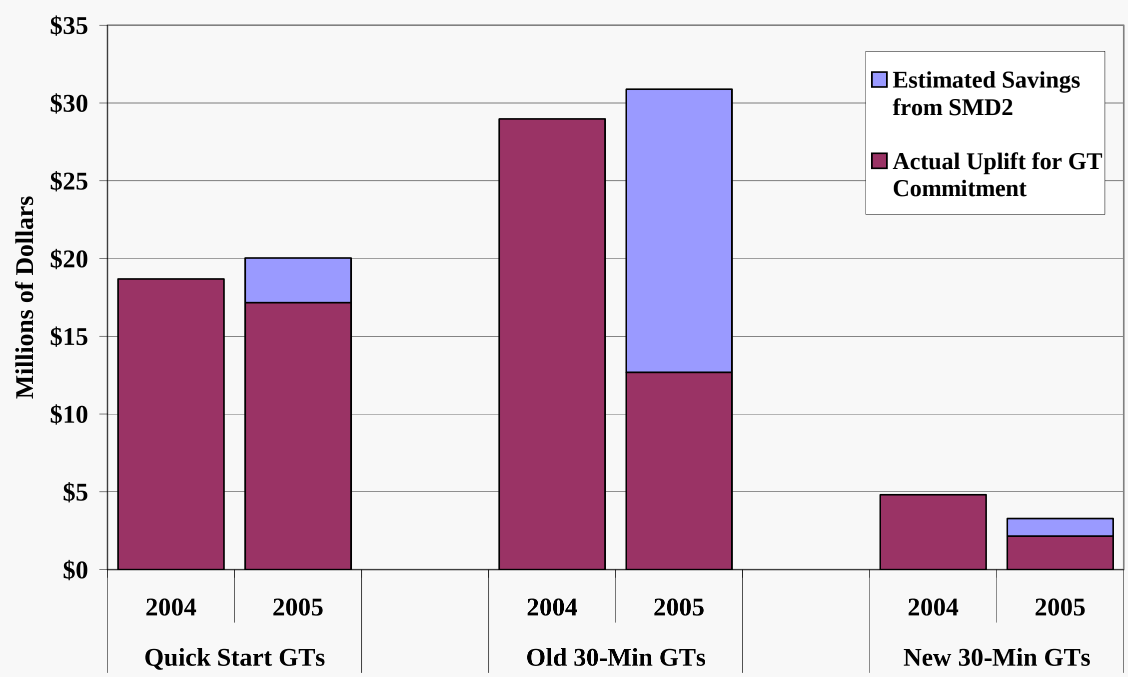


Note: The portion of Balancing Congestion Costs attributed to Thunder Storm Alerts is charged to the local TO.

Reduced Uplift Attributable to SMD2

- In the uplift area, the primary improvement of SMD2 is on the commitment and dispatch of gas turbines, particularly 30-minute turbines that are now committed via RTC under SMD2.
- As shown later in the report, commitment and scheduling of gas turbines has become considerably more efficient under SMD2. This category of uplift was:
  - ✓ $52.5 million from February to December 2004; and
  - ✓ $32.0 million from February to December 2005.
- To accurately estimate the uplift reduction attributable to SMD2, we performed an analysis controlling for the following factors.
  - ✓ Increases in fuel prices in 2005, which will generally increase uplift payments.
  - ✓ Higher LBMPs relative to gas turbine offer prices due to tighter market conditions, which generally has a downward effect on uplift payments.
- The next figure shows the actual reductions in BPCG payments for the 11 month period in 2004 and 2005 and the estimated reductions due to SMD2.
  - ✓ The estimate of uplift savings during the period was $22 million.
  - ✓ Of the estimated savings, $18 million came from more economic commitment of older 30-minute gas turbines under RTC rather than the former BME model.

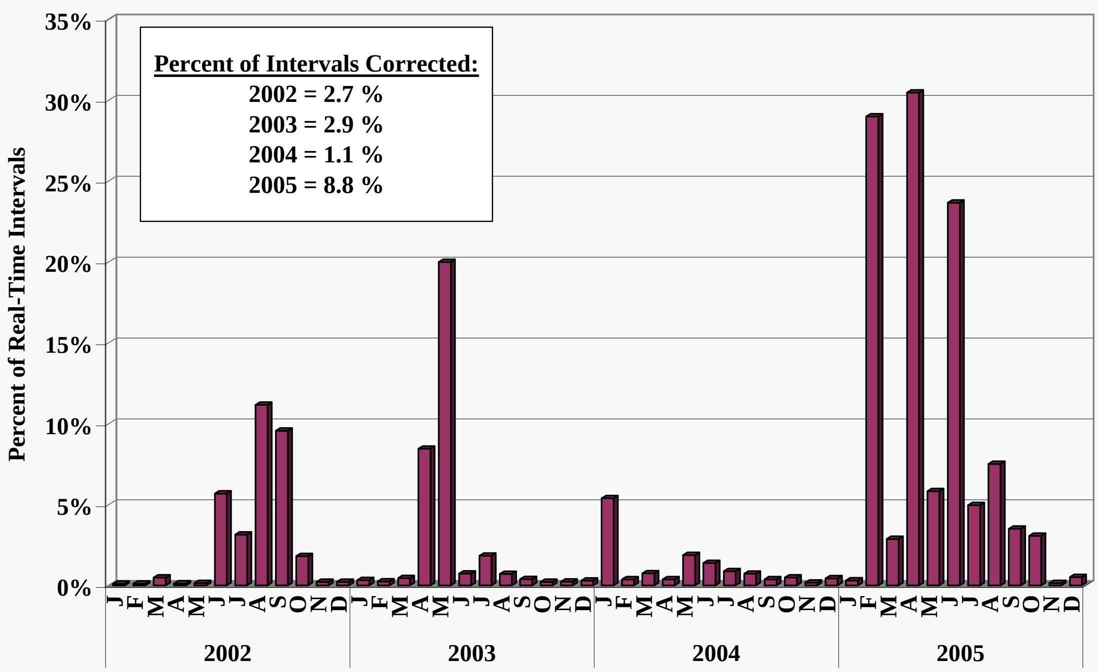
Estimated Reduction in Uplift from Uneconomic GTs February to December, 2005



Price Corrections

- All real-time energy markets are subject to some level of price corrections to account for:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- The following figure summarizes the frequency of price corrections in the real-time energy market in 2002-2005.
  - ✓ The rate of corrections spiked immediately after the implementation of SMD2 due to software issues.
- Nine major software issues arose under SMD2 that led to the majority of price corrections.
  - ✓ Several of these issues were identified and corrected in February 2005.
  - ✓ The remaining software issues began between from March 30th and June 27th and were addressed between June and October.
- Once these software issues were addressed by NYISO, the frequency of price corrections fell to typical levels by November 2005.

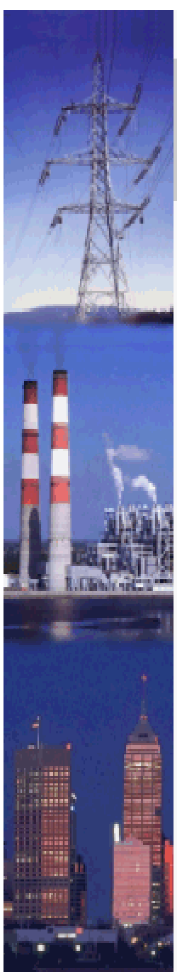
Price Corrections
2002 - 2005



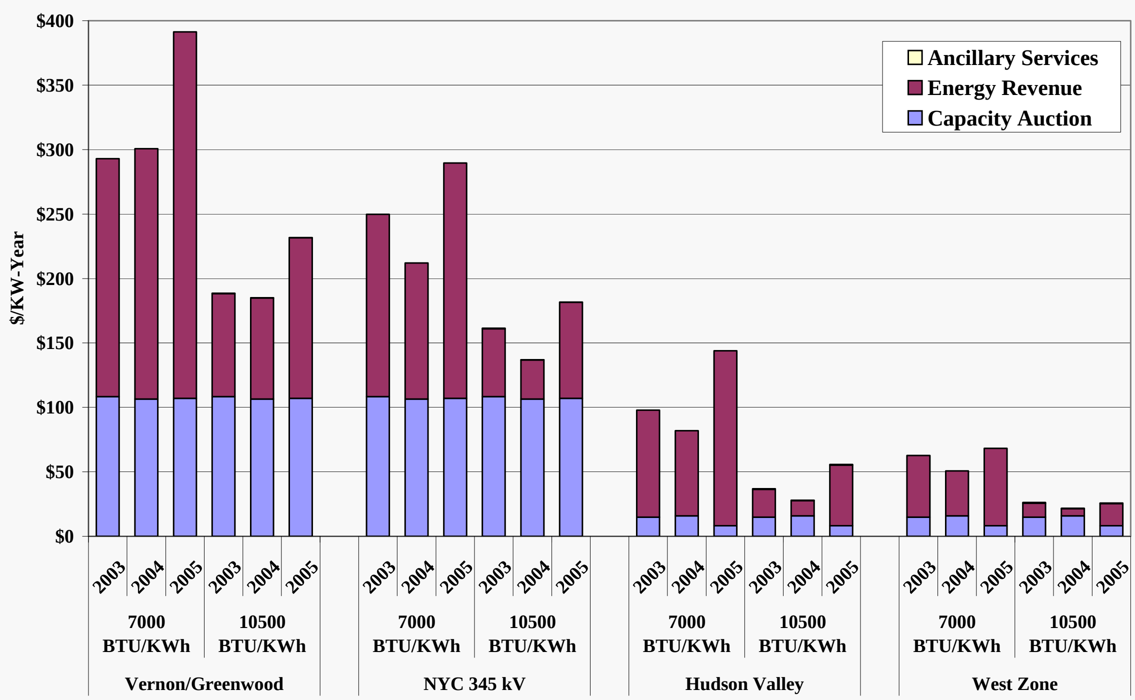
Based on calculations provided by NYISO Market Monitoring and Performance

Long-Term Market Signals

- The following figure shows the Net Revenue provided by the markets over the past three years at different locations.
  - ✓ Net revenue is the revenue that a new generator would earn above its variable production costs.
  - ✓ This analysis utilizes FERC's standardized assumptions that account for variable O&M costs, fuel costs, and forced outages in calculating Energy Revenue.
  - ✓ For the combustion turbine, the analysis includes estimated revenues from 30-minute reserves.
  - ✓ However, it does not include start-up costs, minimum run-times, and 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.

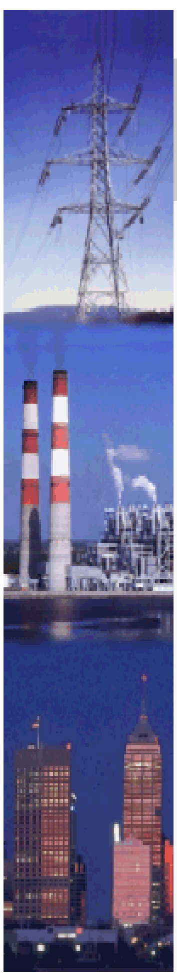


Estimated Net Revenue
Real-Time Market -- 2005



Long-Term Market Signals

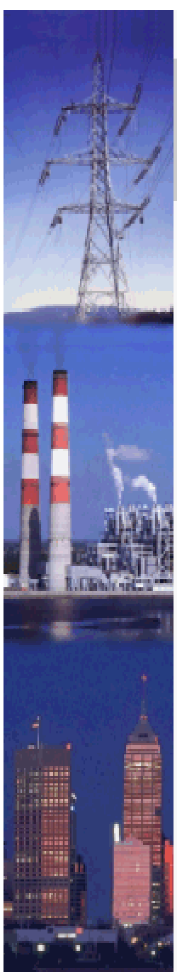
- The net revenue levels increased significantly during 2005 due to:
  - ✓ Higher load and tighter conditions in 2005;
  - ✓ Instances of shortages that resulted in very high energy prices under the shortage pricing provisions in New York's Standard Market Design ("SMD").
  - ✓ There were no shortages in 2003 or 2004, which contributed to the lower net revenue in those years.
- Despite these increases, net revenue remained below the levels necessary to justify new investment in GTs outside NYC and in combined-cycle units in western New York.
  - ✓ This is primarily due to the capacity surpluses outside of NYC that has contributed to lower net revenue particularly from the capacity market.
  - ✓ Increased shortage pricing in east New York and higher fuel prices raised combined cycle net revenue in the Hudson Valley to almost $150 per kw-year, which exceeds most estimates of the their investment costs.
    - – However, accounting for minimum run-times, start-up costs and other factors would reduce this net revenue significantly.



Long-Term Market Signals in NYC

- The net revenue analysis shows that the long-term economic signals in NYC are at levels in 2005 that are close to those that will justify new investment.
  - ✓ A new gas turbine would earn net revenue of approximately $180 per kw-year outside of the load pockets in NYC and more than $200 per kw-year inside the load pockets.
  - ✓ These levels are close to the estimated annual cost (including return on investment) of building a new gas turbine in the City.
  - ✓ Likewise, net revenue for a new combined cycle unit ranged from almost $300 to almost $400 per kw-year, which likely exceeds the net revenue needed to justify investment in NYC.
- These results are consistent with market conditions in New York City, which has been relatively close to being capacity-deficient.
  - ✓ Conditions should loosen in 2006 due to the addition of new capacity in the City.

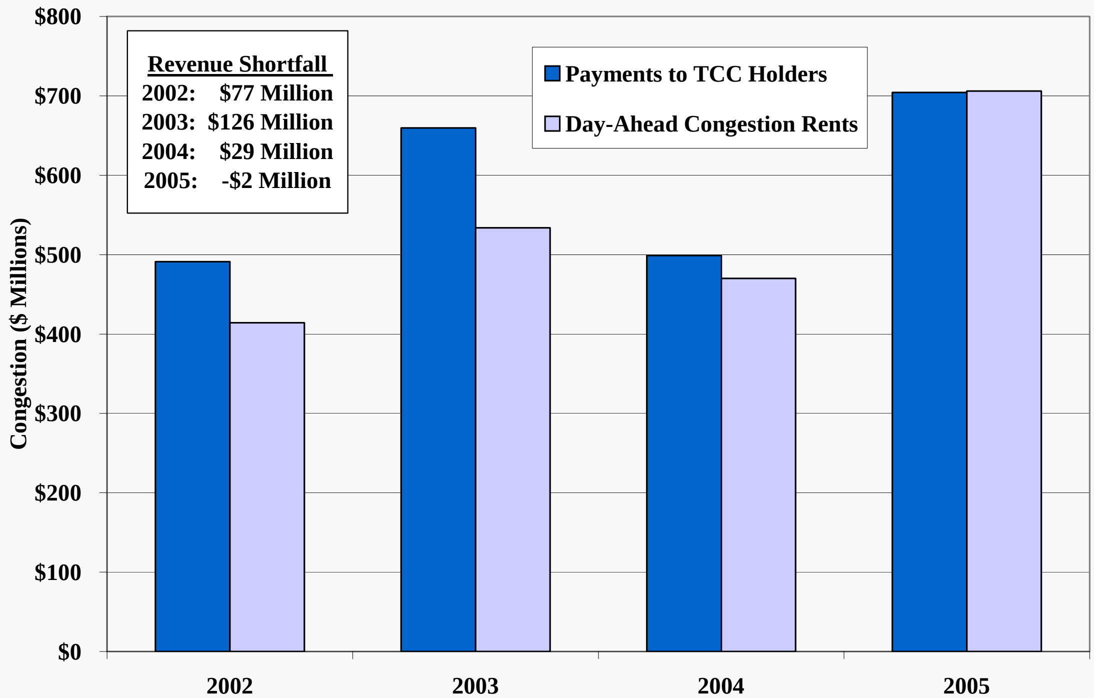
Transmission Congestion

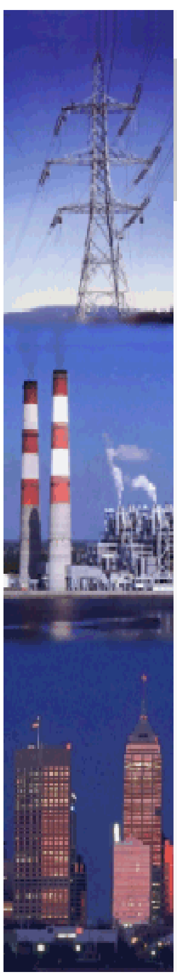


Day-Ahead Congestion Costs and TCC Revenue

- The following figure compares the day-ahead congestion rents collected by the NYISO to the payments made to TCC holders. In a well-functioning system, these values should be roughly equal over the year.
- Payments to TCC holders generally exceeded congestion rents until mid-way through 2004. This occurred because the transmission capability assumed in the TCC auction exceeded what is available in the day-ahead market.
  - ✓ A large share of the shortfall was due to excess TCCs sold into New York City. These excess TCCs were re-purchased in July 2004.
  - ✓ The NYISO also made several changes to reduce the shortfalls.
- The figure shows a considerable increase in day-ahead congestion rents relative to previous years and a corresponding increase to TCC holders.
  - ✓ Rents rose from $470 million in 2004 to $706 million in 2005.
  - ✓ One reason for this dramatic rise is that congestion generally moves in proportion with overall electricity prices which were driven up by higher fuel prices in 2005.
  - ✓ Another reason for this rise is that higher load levels in 2005 resulted in reserves shortages in eastern NY, resulting in more congestion on flows from West NY.

Day-Ahead Congestion Costs and TCC Revenue 2002 - 2005

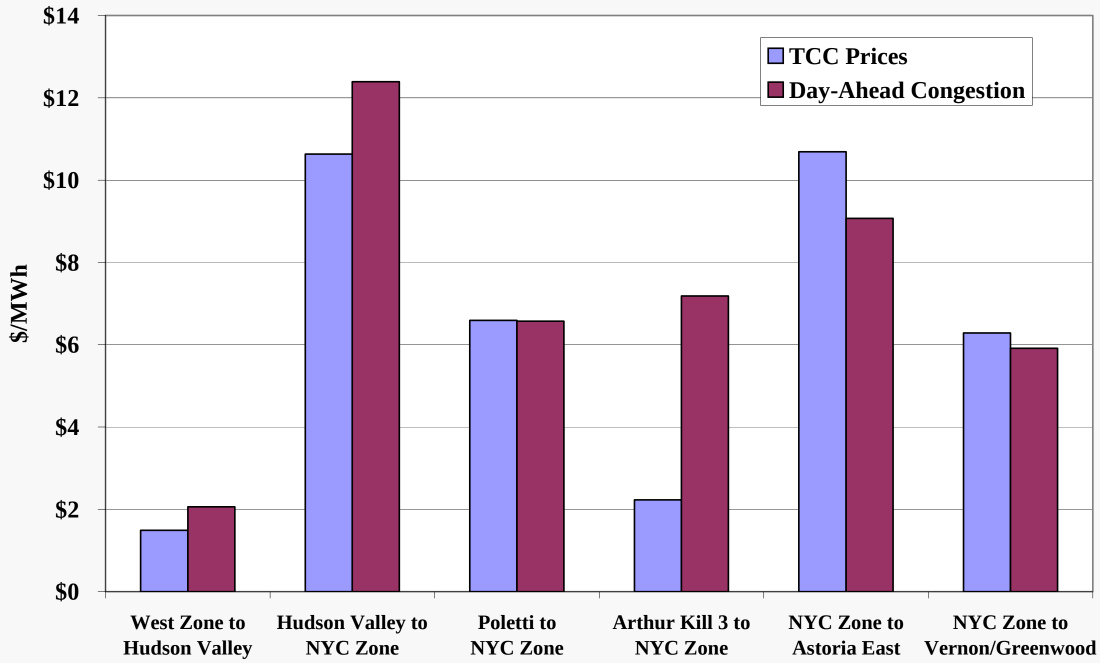


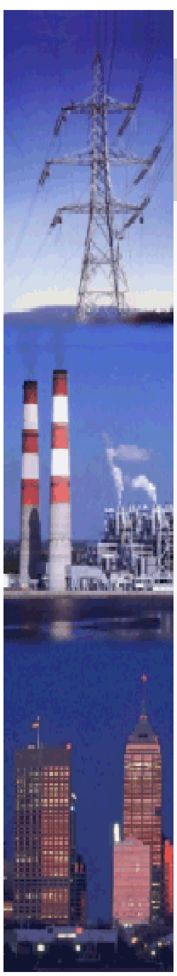


TCC Prices and Day-Ahead Congestion

- The following analysis is designed to evaluate the consistency between TCC prices and day-ahead congestion levels.
- TCCs provide an entitlement to the holder for the day-ahead congestion between two points.
  - ✓ Hence, in a well-functioning market, the price for the TCC should reflect a reasonable expectation of the day-ahead congestion.
- To evaluate this, the next figure compares the auction prices from the auction of 6-month TCCs during the summer capability period for 2005 to the day-ahead congestion that actually occurred during the period.
- The results of this analysis show:
  - ✓ TCC prices were generally consistent with day-ahead congestion for five of the six paths shown.
  - ✓ The path from Arthur Kill3 to the NYC Zone was significantly under-valued in the TCC auction.

TCC Prices and Day-Ahead Congestion
May to October 2005

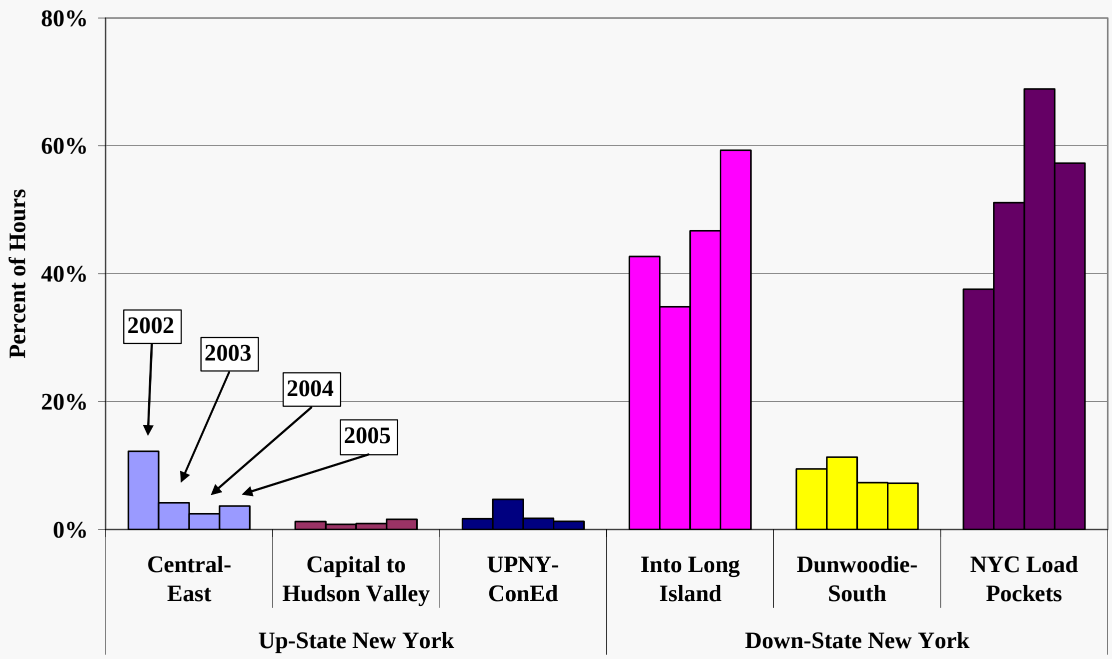




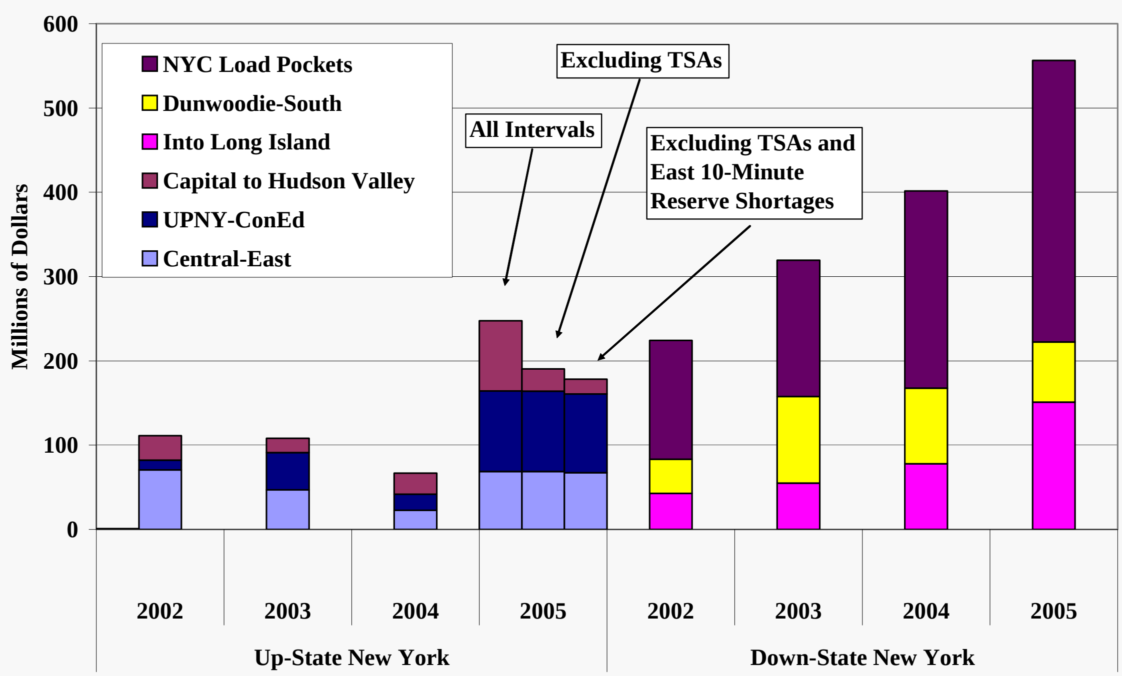
Real-Time Congestion on Major Interfaces

- The following two figures summarize the extent of transmission congestion on select interfaces in up-state and down-state New York. The first figure shows the frequency of congestion.
  - ✓ In 2005, the frequency of congestion increased slightly for the Central-East interface and from Capital to Hudson Valley.
  - ✓ Congestion continues to be very frequent into Long Island and various New York City sub-load pockets.
- The second figure measures the approximate value of congestion in real-time annually for each of the interfaces.
  - ✓ The value of constrained interfaces in up-state New York increased dramatically in 2005 from approximately $70 million to $250 million.
  - ✓ The value of down-state interfaces increased substantially from approximately $400 million to $550 million.
  - ✓ Intervals with Thunder Storm Alerts accounted for $60 million of the value of up-state congestion.

Frequency of Real-Time Congestion on Major Interfaces 2002 – 2005



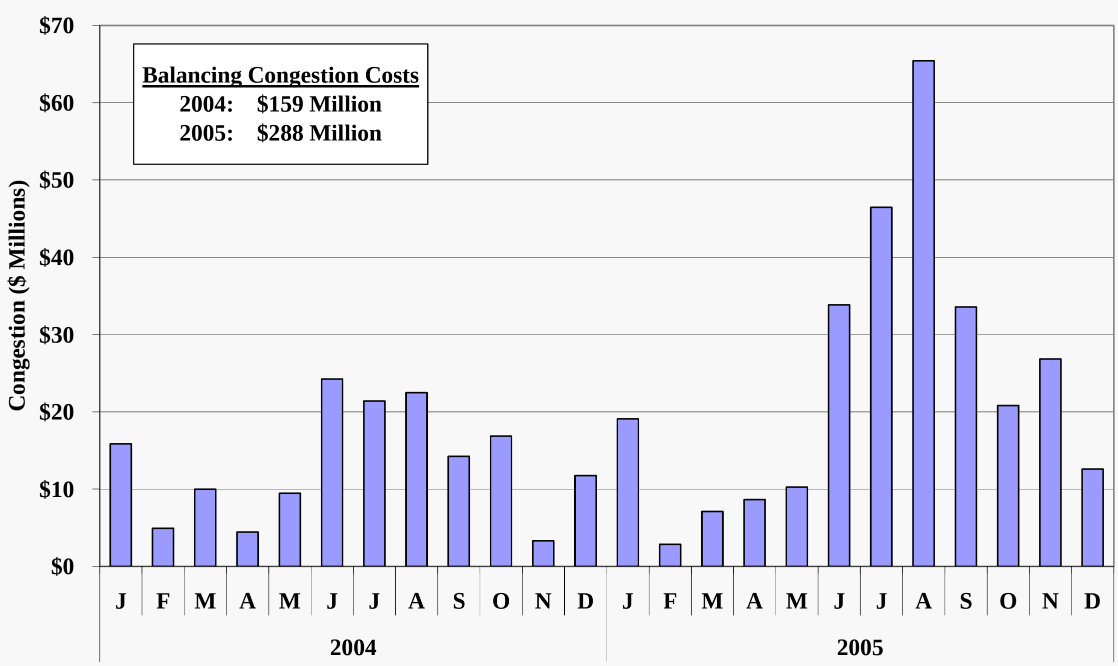
Value of Real-Time Congestion on Major Interfaces 2002 – 2005



Balancing Congestion Shortfall

- We examined the congestion revenue shortfall incurred in the balancing market in the following figure.
- The primary cause of balancing congestion costs are changes between the day-ahead and real-time markets in the amount of transfer capability associated with the transmission system.
  - ✓ When day-ahead schedules exceed real-time transmission capability, the NYISO must buy back the excess in real-time.
- Prior to SMD2, the day-ahead market model did not fully incorporate the impact of losses on transmission utilization. Although this was fixed under SMD2 and tends to reduce balancing congestion costs, several factors have led to the rise in balancing congestion:
  - ✓ Total congestion increased in 2005, contributing to an increase in balancing congestion costs.
  - ✓ TSAs led to real-time pricing events under derated transmission limits that significantly contributed to the balancing congestion costs.
  - ✓ Higher fuel costs have contributed to higher balancing congestion costs.
  - ✓ Differences between day-ahead and real-time transmission modeling resulting in higher effective interface capability in the day-ahead market.

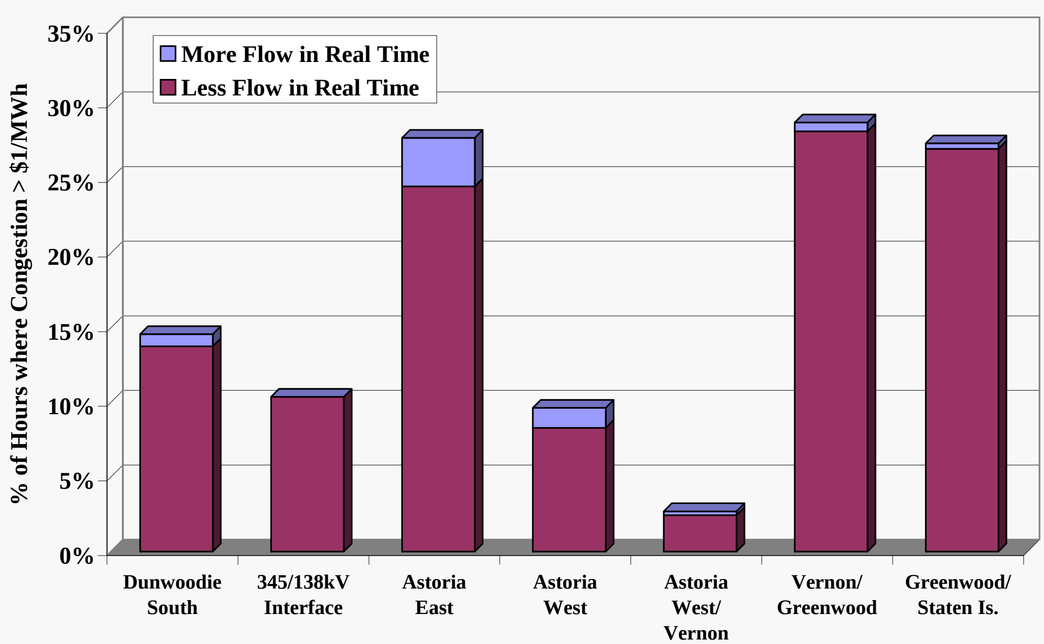
Balancing Congestion Costs
2005



Interface Flow Changes During Periods of Real-Time Congestion

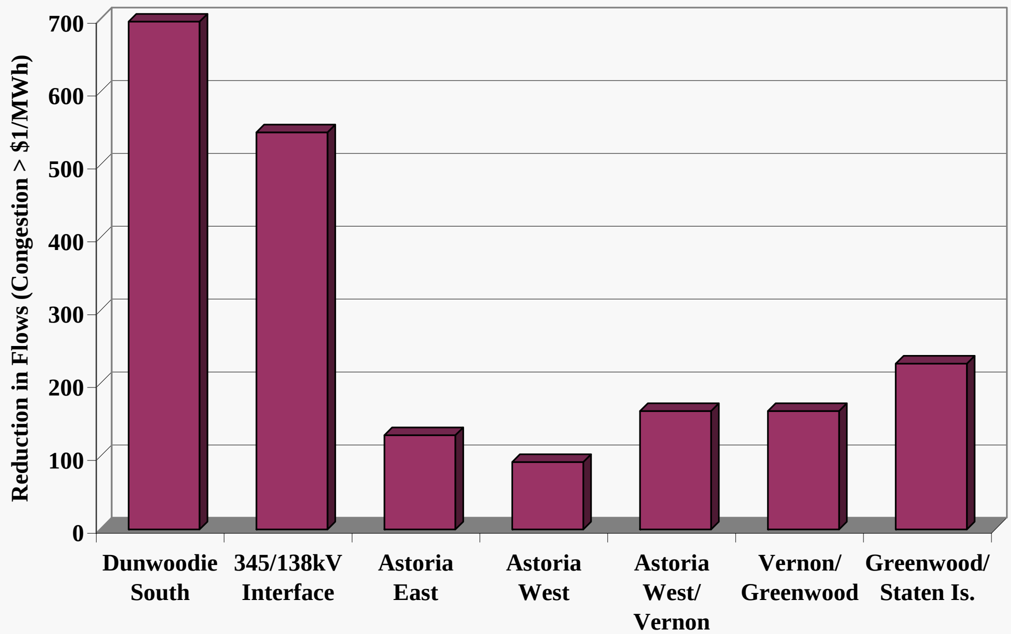
- The following two figures summarize differences in flows across seven interfaces between the day-ahead and real-time markets during hours with real-time congestion.
- The first figure shows how frequently actual real-time flows exceed day-ahead scheduled flows in hours with real-time congestion and vice versa.
  - ✓ In the vast majority of hours, the day-ahead scheduled flows exceed actual flows.
- The second figure shows the weighted average reduction from the day-ahead scheduled flow to the actual flow in real-time in hours with real-time congestion.
  - ✓ This shows systematically more flows being scheduled in the day-ahead than flow in the real-time.
- Systematic reductions from the day-ahead to the real-time in the amount of flows across an interface contributes the balancing congestion costs.

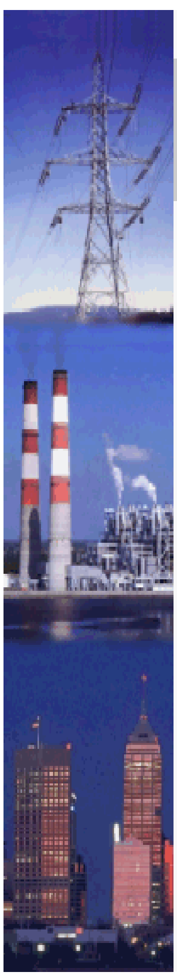
Interface Flows During Hours with Real-Time Congestion
February to December, 2005



Interface Flow Reductions After the Day-Ahead Market

During Hours with Real-Time Congestion
February to December, 2005

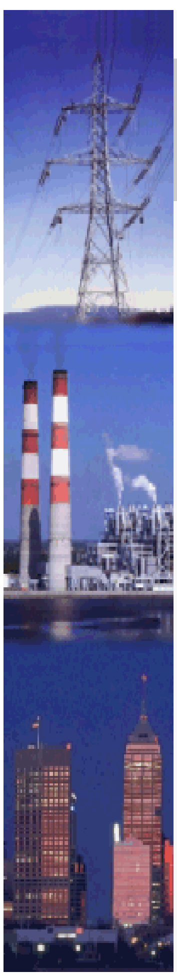




Interface Flows -- Conclusions

- The previous two charts indicate that more power is allowed to flow across major transmission interfaces in the day-ahead market than in the real-time operation of the system.
- Several factors that explain systematic differences between day-ahead and real-time transmission capability:
  - ✓ SCUC models individual lines and contingencies in the NYC area which enables higher utilization of the system than
    - – RTD currently uses closed interfaces to represent the load pocket constraints.
    - – The ISO plans for RTD to model individual lines within NYC by May 2006.
  - ✓ Reliability requirements dictate double contingency operation of the ConEd overhead transmission system during Thunder Storm Alerts. This has effectively reduced transmission capability during extreme periods of congestion in the summer of 2005.

Day-Ahead to Real-Time Convergence



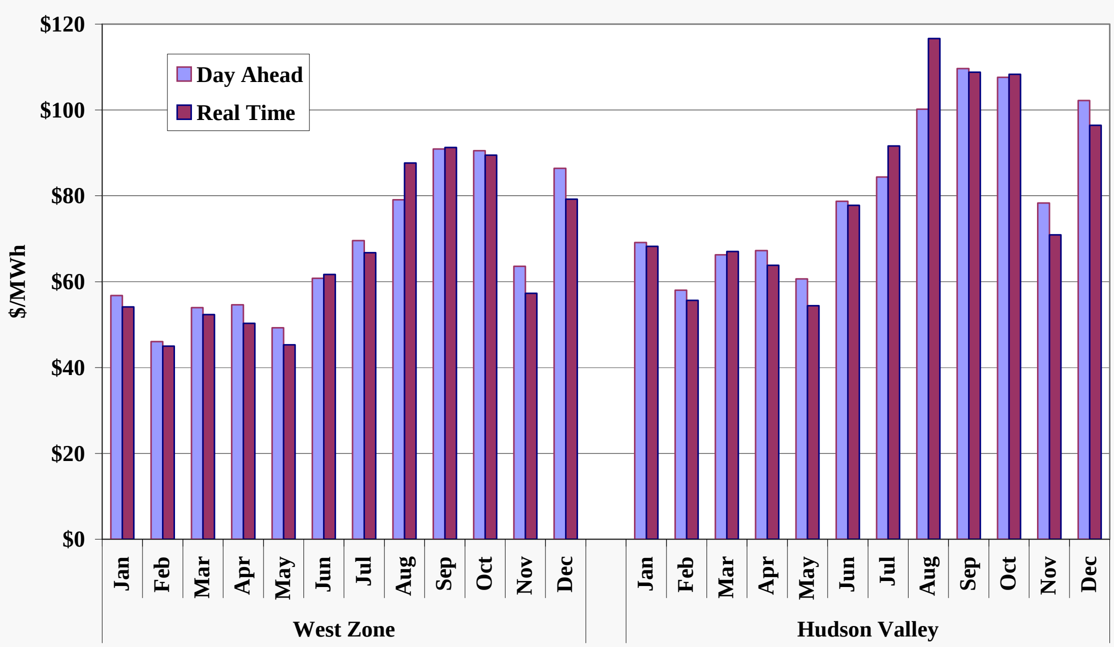
Day-Ahead and Real-Time Energy Prices

- The following two figures show monthly average day-ahead and real-time energy prices in the West zone, Hudson Valley, New York City, and Long Island from February through December 2005.
- Both before and after the summer, all four regions exhibited a slight day-ahead premium, consistent with previous years.
- During the summer, real-time prices were substantially higher than day-ahead prices, particularly August.
  - ✓ In the West Zone and the Hudson Valley, the real-time price premiums averaged 3 percent and 9 percent during the summer.
  - ✓ In New York City and Long Island, the real-time price premiums averaged 18 percent and 24 percent during the summer.

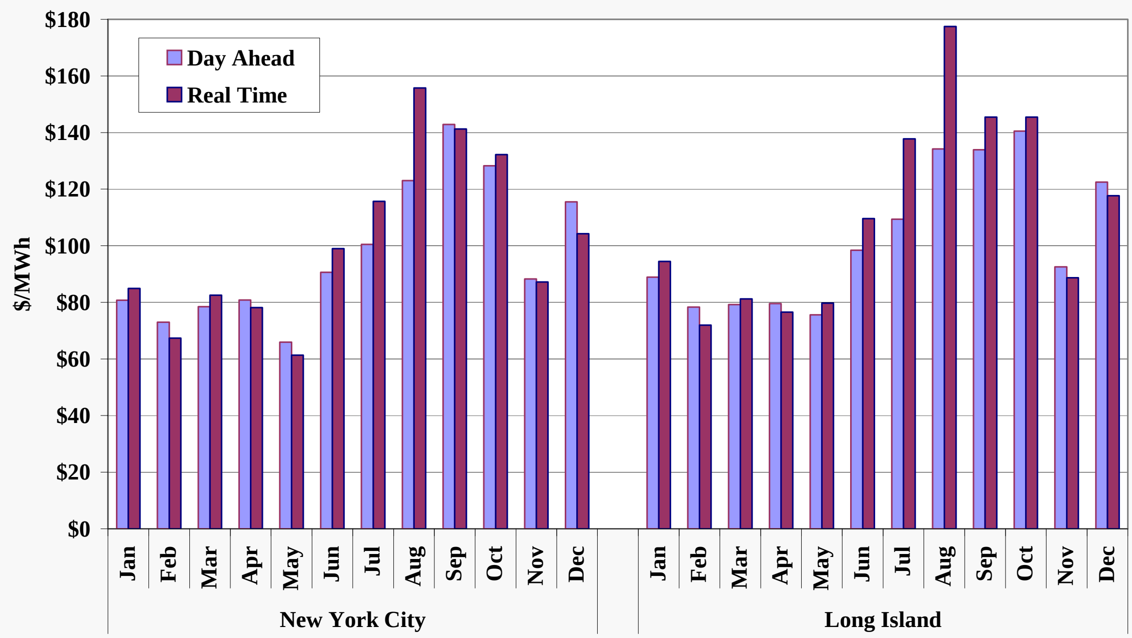
Day-Ahead and Real-Time Energy Prices

- A few real-time price spike events account for most of the real-time premium during the summer.
  - ✓ Excluding 8 afternoons with real-time premiums exceeding $175/MWh, the average premium is just 5 percent for the summer in New York City.
- A large number of price spikes were caused by Thunder Storm Alerts (“TSAs”).
  - ✓ TSAs require double contingency operation of the ConEd overhead transmission system in real-time but not in the day-ahead market.
  - ✓ TSA operation was a major reason why real-time premiums exceeded $175/MWh on 5 of the 8 afternoons.
- Substantial real-time price premiums are not likely to persist in the future as participants revise their expectation of real-time prices:
  - ✓ Higher real-time prices induce market participants to profit by scheduling additional virtual load.
  - ✓ Additional virtual load will raise prices in the day-ahead market, bringing them into better convergence with real-time prices.

Average Monthly Day-Ahead and Real-Time Energy Prices West Zone and Hudson Valley, 2005



Average Monthly Day-Ahead and Real-Time Energy Prices New York City and Long Island, 2005

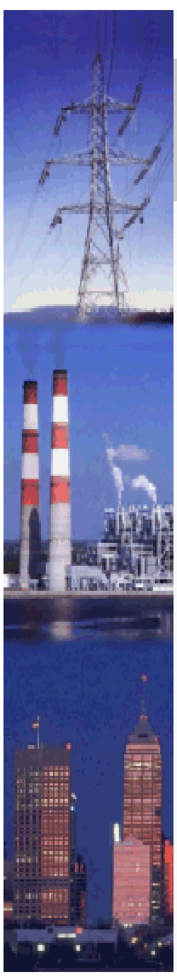


Day-Ahead to Real-Time Price Convergence

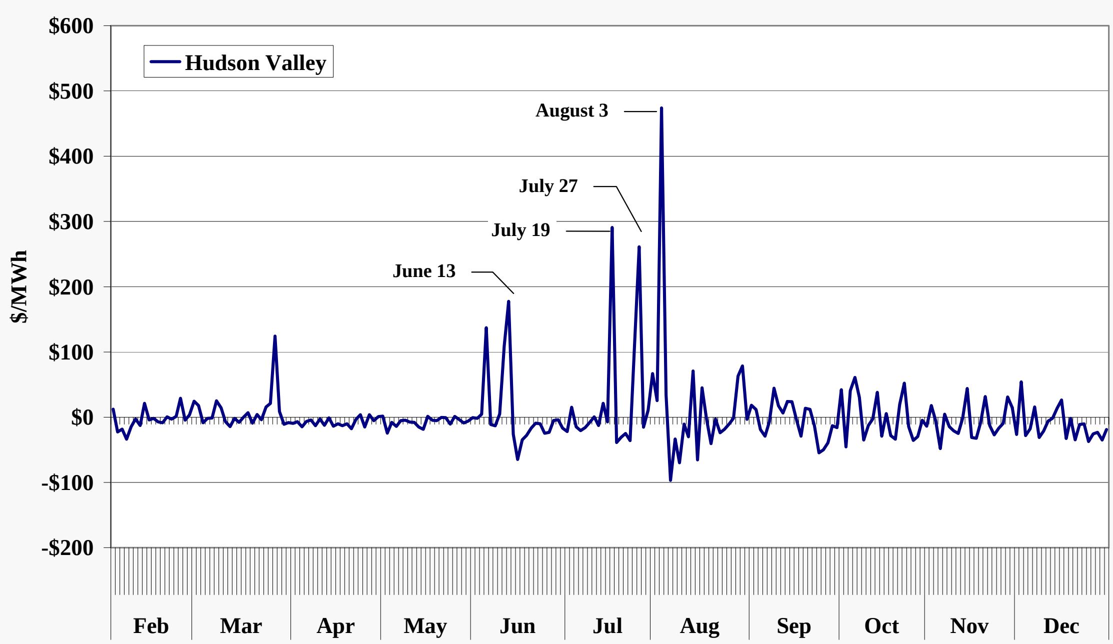
- The following two figures show the average real-time price premium on a daily basis during afternoon hours from February to December, 2005
- Day-ahead and real-time premiums occurred with similar frequency. However, there were more afternoons where the real-time price was very large. The average RT premium exceeded $100/MWh:
  - ✓ On 9 afternoons in the Hudson Valley; and
  - ✓ On 13 afternoons in New York City.
- A small number of peak pricing events are primarily responsible for the poor overall convergence.
  - ✓ Thunder Storm Alerts require double contingency operation of the ConEd overhead transmission system in real-time but not in the day-ahead market.
  - ✓ TSA operation caused the Leeds-Pleasant Valley constraint shadow prices to be above $1000/MWh in 159 intervals.
  - ✓ 51 percent of the 259 price spike intervals resulting from Eastern 10-minute reserve shortages occurred when a TSA was in effect.

Day-Ahead to Real-Time Price Convergence

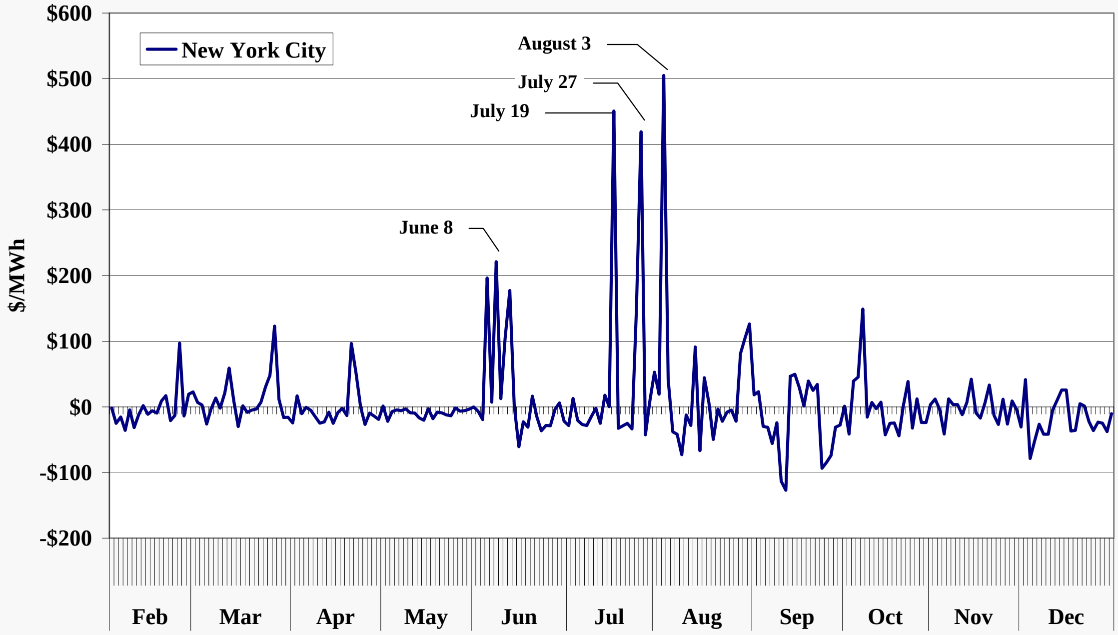
- The figure also shows that during the fall months, differences between day-ahead and real-time prices increased relative to the spring months.
  - ✓ In the Hudson Valley, the average daily difference shown in the following figure was $11/MWh during the spring and $24/MWh during the fall.
- Increased fuel prices contributed to the increased volatility of the differences between day-ahead and real-time prices.
  - ✓ Taking higher overall prices into account, the increased price divergence during the fall is less significant.
  - ✓ In the Hudson Valley, the average difference was 15 percent during the spring and 22 percent during the fall.
- During the fall, fuel prices were more volatile and likely harder to predict, leading to greater differences between day-ahead expectations and real-time outcomes.
  - ✓ The average daily change in the natural gas price was 5.5 percent during the fall, and just 2.8 percent during spring.



Average Daily Real-Time Price Premium
Hudson Valley – 1 p.m. to 7 p.m. Weekdays
February to December, 2005



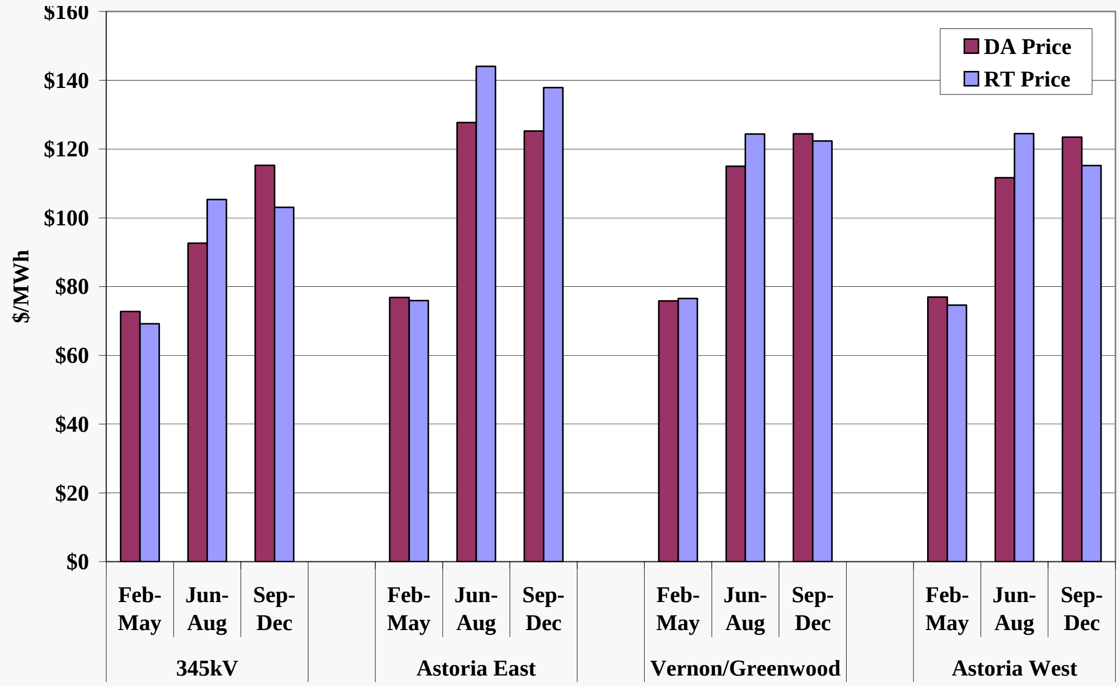
Average Daily Real-Time Price Premium
New York City – 1 p.m. to 7 p.m. Weekdays, 2005
February to December, 2005

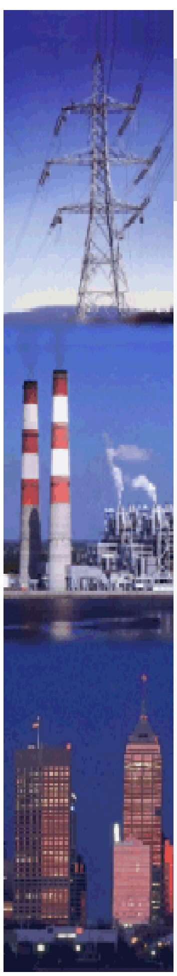


Day-Ahead and Real-Time Load Pocket Prices

- The following figure shows day-ahead and real-time prices in several areas of NYC. It shows:
  - ✓ During the summer, all four regions exhibited a substantial real-time price premium, consistent with the rest of New York state.
  - ✓ During the fall months, Astoria East exhibited a large real-time premium while the area outside the load pockets (i.e. the 345 kV system) experienced a large day-ahead premium.
- Limiting price-capped load bidding and virtual trading to the zonal level in NYC limits the ability of participants to arbitrage large price differences in specific pockets.
- A simplified representation of the intra-NYC constraints is used in real time while a more detailed representation is used in the day ahead.
  - ✓ This difference can contribute to divergence between the day-ahead and real-time prices within NYC.
  - ✓ Starting May 2006, the NYISO will use the more detailed representation in the real-time model as well.

Day-Ahead and Real-Time Load Pocket Prices
February to December, 2005



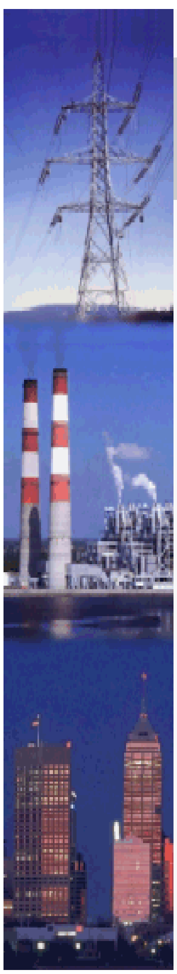


Real-Time Transmission Price Spikes

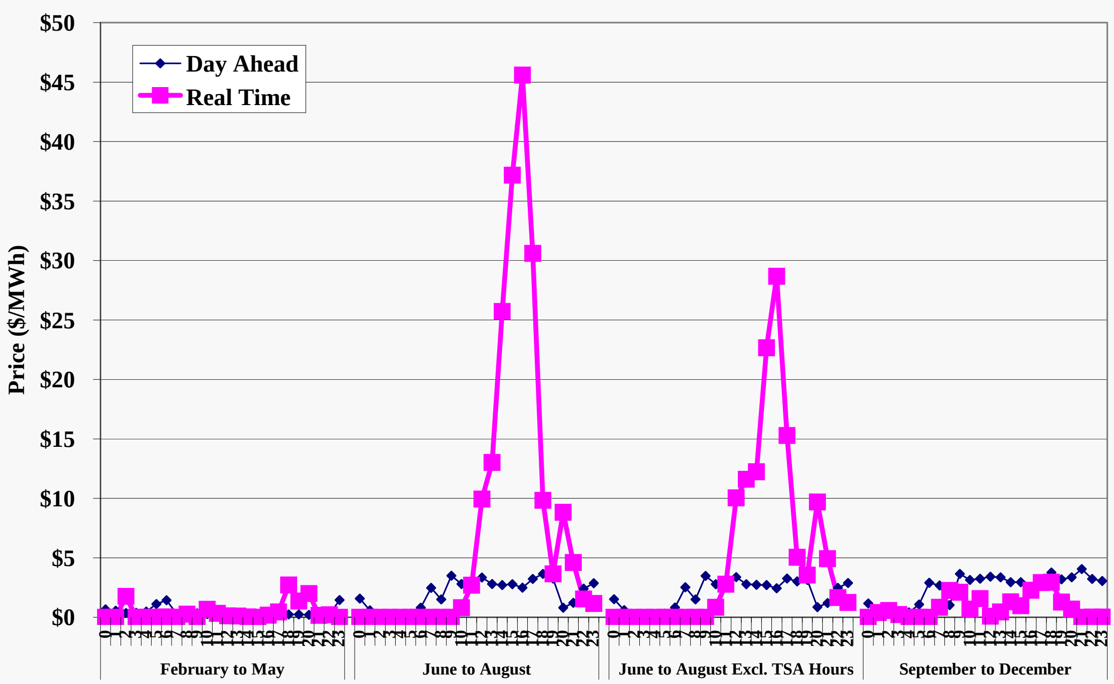
- Real-time transmission price spikes occur when the re-dispatch costs necessary to resolve a transmission constraint reach extremely high levels.
  - ✓ During 2005, there were 562 intervals when shadow prices exceeded $1,000/MWh on one or more constraints and 238 intervals when they exceeded $2,000/MWh.
  - ✓ These contribute significantly to the severity of real-time energy price spikes.
- These spikes typically occur for brief periods when there is not sufficient ramp capability within a constrained area.
  - ✓ This may result in large amounts of re-dispatch that provide little reliability benefit.
  - ✓ In some of these intervals, the real-time model cannot solve because of insufficient resources.
- Like ancillary services demand curves, transmission demand curves could be used to prevent costly re-dispatch when there is little reliability benefit.
  - ✓ Therefore, we recommend that the NYISO continue to evaluate the impact on reliability of using transmission demand curves.

Ancillary Services Price Convergence

- The following chart shows day-ahead and real-time eastern 10-minute reserves prices by hour of the day for February-May, June-August, and September-December, 2005.
- The NYISO requires 1,000 MW of 10-minute reserves east of the Central-East Interface. The market models include an economic demand curve value of $500/MWh on meeting this requirement.
- From June to August, prices were significantly higher than other times of year:
  - ✓ During daytime hours, average day-ahead prices ranged from $3 to $5/MWh, while average real-time prices ranged from $0 to $47/MWh.
  - ✓ The figure shows that the lack of converge between day-ahead and real-time prices was substantially effected by a small number of TSA events.
- During the summer, real-time prices were generally higher than day-ahead prices for energy and reserves. This pattern was reversed in the fall as day-ahead prices energy and reserves rose above real-time prices.
  - ✓ The next section examines changes in ancillary services offers that contributed to this reversal.

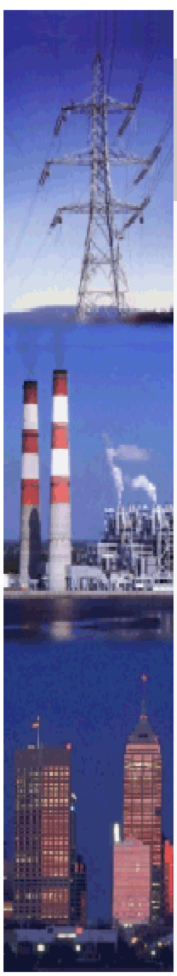


10-Minute Total Reserve Prices in East NY by Hour of Day February to December, 2005

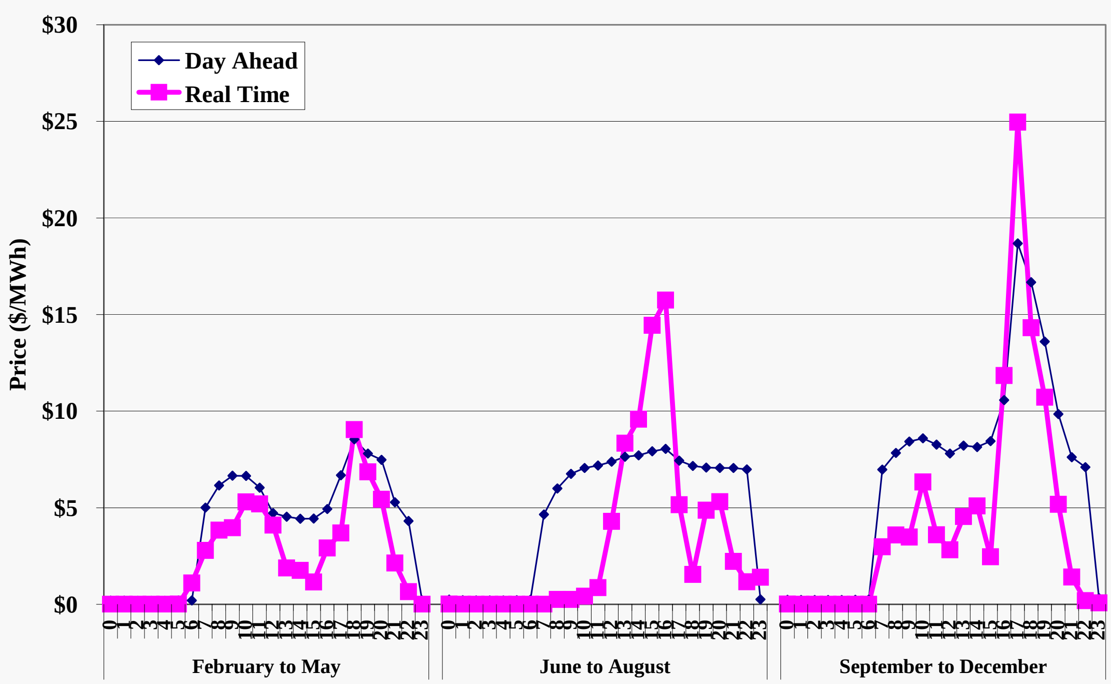


Ancillary Services Price Convergence

- The following figure shows day-ahead and real-time western 10-minute synchronous reserves price that depends primarily on the state-wide 10-minute synchronous reserves requirement of 600 MW.
  - ✓ Currently, the economic value of this requirement is set at $500/MWh.
  - ✓ During the Spring, day-ahead prices were generally slightly higher than real-time prices.
  - ✓ During the Summer, day-ahead prices substantially exceeded real-time prices during off-peak hours while real-time prices were much higher in the afternoon peak hours on average.
  - ✓ During the fall, day-ahead and real-time prices rose relative to the summer.
- Day-ahead spinning reserves prices are based on the offers of individual generators as well as the opportunity costs of providing reserves rather than energy. Thus, the following two factors explain the rise in prices during the fall:
  - ✓ Higher fuel prices led to higher opportunity costs for on-line generation.
  - ✓ There has been a rise in offer prices which is examined in the next section.



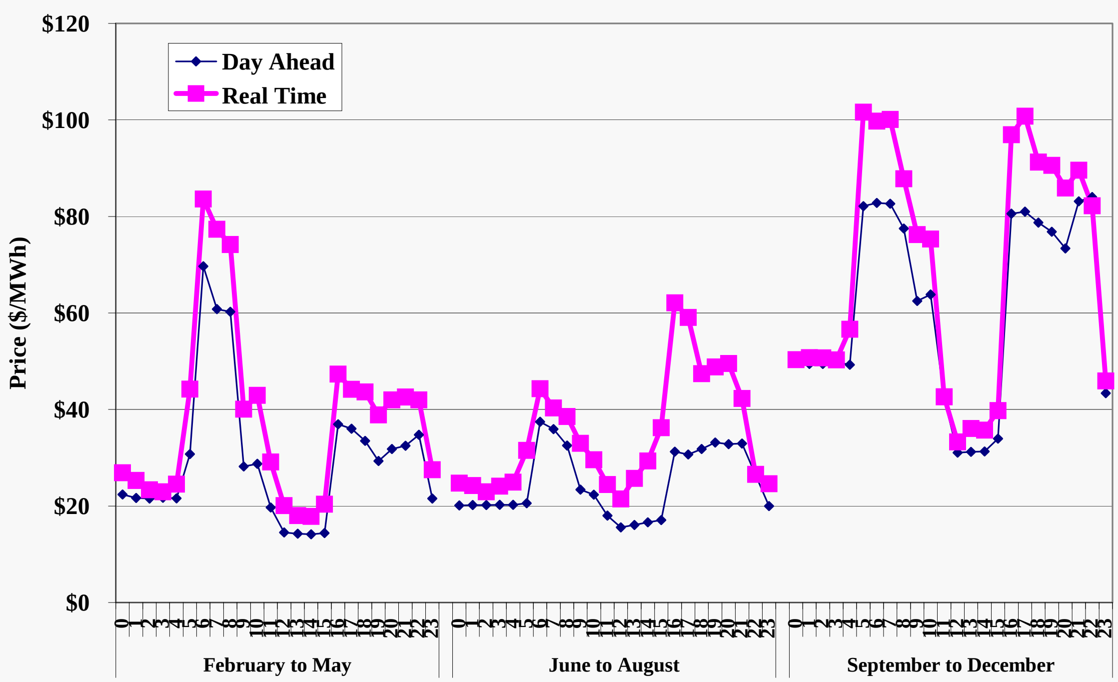
10-Minute Spinning Reserve Prices in West NY by Hour of Day February to December, 2005



Ancillary Services Price Convergence

- The following figure summarizes convergence between day-ahead and real-time prices for regulation.
- State-wide regulation prices depend on a requirement of 275 MW during ramping hours to as low as 150 MW during other hours.
  - ✓ Currently, the economic value of this requirement is set at $250/MW for the first 25 MW and $300/MW thereafter.
  - ✓ Day-ahead and real-time regulation prices are highly correlated across the day. However, real-time prices are consistently $3 to $10/MWh higher.
- The marked price increase from the summer to the fall is partly due to a rise in regulation offer prices. Regulation offers are discussed in following section.
- Higher fuel prices also contributed to the increased regulation prices by increasing the opportunity costs of inexpensive energy providers.

Regulation by Hour of Day
February to December, 2005



Ancillary Services Price Convergence Conclusions

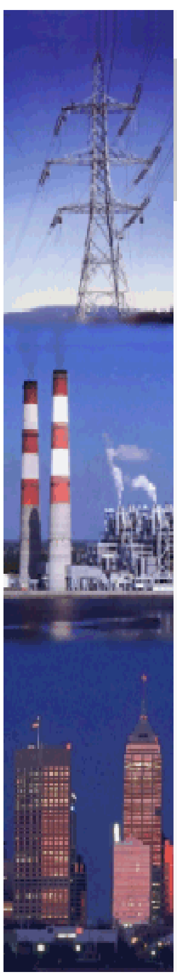
- Price spikes related to reserves shortages occur more frequently in the real-time than in the day-ahead market.
  - ✓ Because sufficient capacity is offered into the day-ahead market, reserves shortages never occur in the day-ahead market.
  - ✓ Unforeseen conditions such as forced outages and short term ramp constraints can occur resulting in real-time reserves shortages.
  - ✓ Under-forecasted demand in the day ahead can lead to under-commitment that can lead to real-time reserves shortages.
- Pervasive real-time price premiums for reserves may give generators an incentive to raise their day-ahead reserves offers, which can reduce the efficiency of the day-ahead commitment.
  - ✓ The following section examines ancillary services offer patterns for evidence that real-time premiums are having an effect.

Ancillary Services Markets

POTOMAC ECONOMICS

Ancillary Services Market Rule Changes

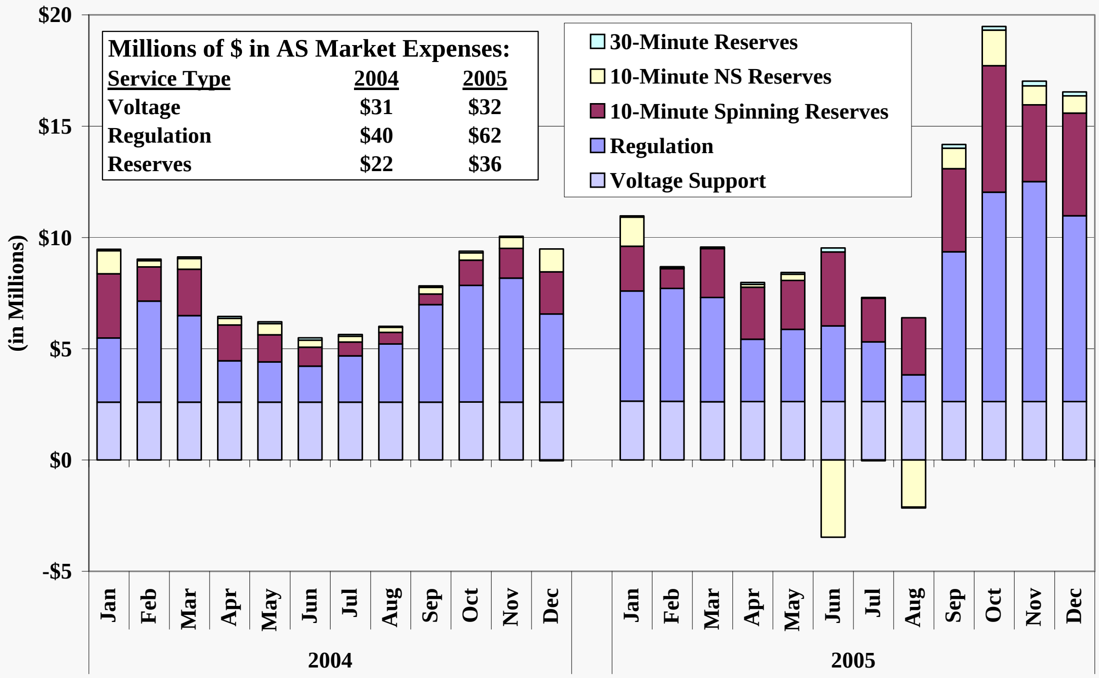
- The design of the ancillary services markets changed substantially with the implementation of SMD2. The new design includes the following key elements:
  - ✓ Co-optimization of regulation and reserves with energy in both the day-ahead and real-time markets.
  - ✓ Use of demand curves for ancillary services to better reflect the value of ancillary services and energy in prices under shortage conditions.
  - ✓ AS prices are now based on the marginal cost to the system of providing the service. This is equal to the sum of the marginal AS provider's:
    - (i) availability bid price, plus
    - (ii) the opportunity cost of not providing another product such as energy.
  - ✓ In real-time, all dispatchable generators must offer to provide reserves with a $0/MWh availability bid.
  - ✓ A two-settlement system for ancillary services, whereby day-ahead obligations must either be:
    - (i) satisfied in real-time, or
    - (ii) purchased back from the ISO by the supplier at the real-time price.



Ancillary Services Costs

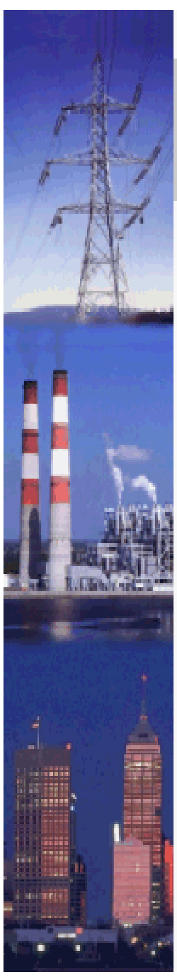
- The following figure shows the ancillary services expenses, including expenses for regulation, voltage support, and various operating reserves.
- Ancillary services expenses were higher overall during 2005 due to a 54 percent increase in regulation costs and a 62 percent increase in reserves procurement costs.
- The higher costs are driven by higher prices that are attributable to the following:
  - ✓ The new market design fully reflects the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.
  - ✓ Higher fuel prices, particularly from September to December, increased opportunity costs of using low-cost generators to provide ancillary services rather than energy.
  - ✓ There was a significant rise in regulation offer prices in September, leading to a substantial rise in regulation prices.
- In several months, non-synch reserves costs were negative.
  - ✓ This occurred when generators sold reserves at low day-ahead prices and bought back their obligations in real-time at higher prices during reserves shortages.

Ancillary Services Costs
2004 - 2005



Millions of $ in AS Market Expenses:

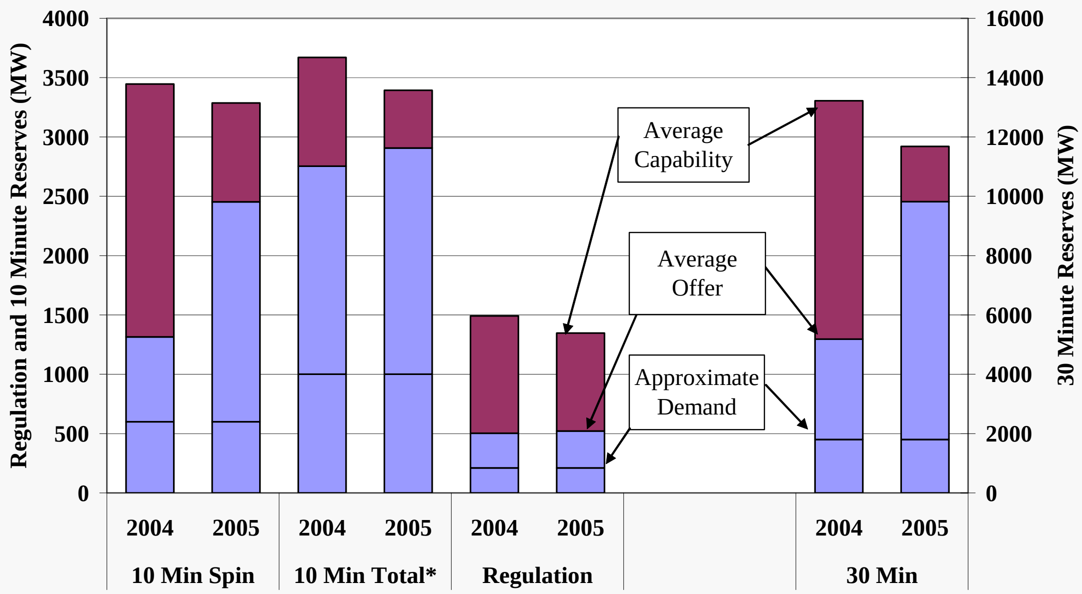
Service Type	2004	2005
Voltage	$31	$32
Regulation	$40	$62
Reserves	$22	$36



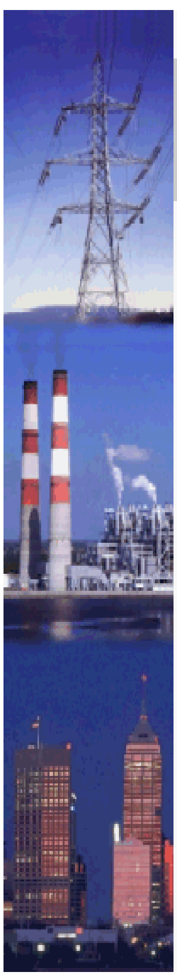
Day-Ahead Capacity and Offers

- The following figure summarizes supply and demand for several ancillary services market requirements: (i) state-wide 10-minute spinning reserves, (ii) eastern 10-minute total reserves, (iii) state-wide regulation, and (iv) state-wide 30-minute reserves.
- There was a substantial rise in the quantity of offers in 2005 due to improved incentives under SMD2.
  - ✓ Prior to SMD2, generators ran the risk of selling reserves in the day-ahead market when it would have been more profitable to sell energy.
  - ✓ Under SMD2, generators are always selected to provide whichever is more profitable (based on the offer they submit).
- Regulation participation is still relatively low and did not change significantly after the implementation of SMD2.
  - ✓ Some generators must incur fixed costs to enable their facilities to provide regulation and may rationally choose not to make the necessary investment.

Summary of Ancillary Services Capacity and Offers in the Day-ahead Market 2004 & 2005



*Eastern side of the Central-East Interface only



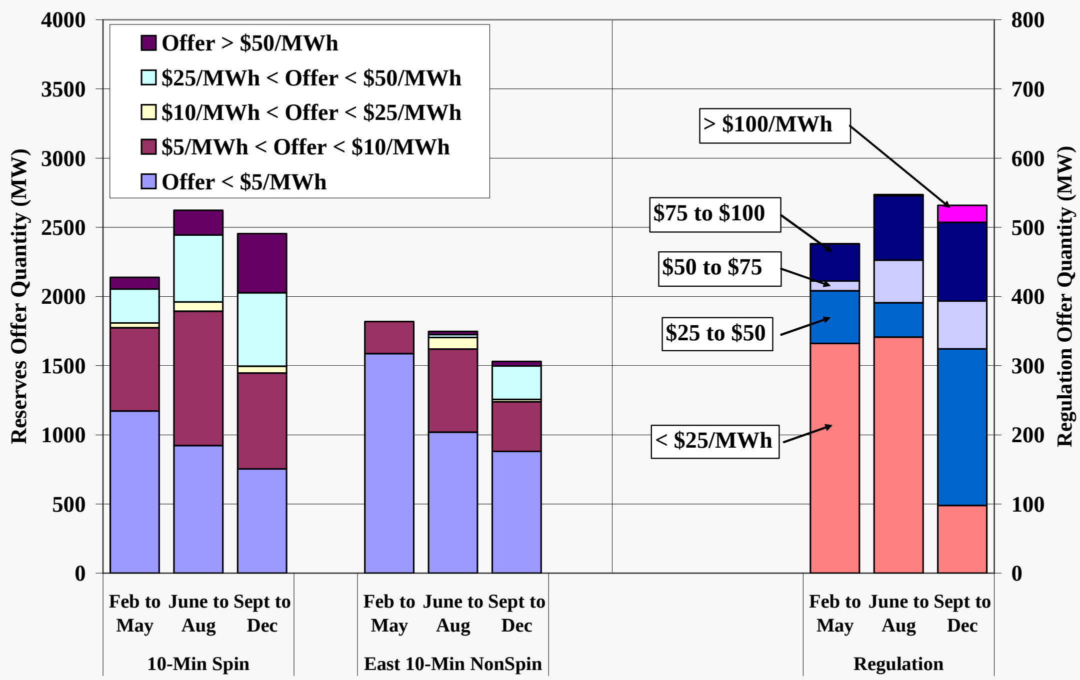
Day-Ahead Ancillary Services Offers

- The following figure summarizes day-ahead offers to supply three ancillary services market requirements during the spring, summer, and fall.
  - ✓ Offer quantities are shown in categories according to offer price level.
- While the previous figure indicates participation in ancillary services markets increased substantially in 2005, the next figure shows a general rise in offer prices during 2005.
  - ✓ 10-Minute Spin – The average amount priced under $5/MWh was approximately 1170 MW during the spring, but this fell to 750 MW by the fall.
  - ✓ Eastern 10-Minute – From the spring to the fall, there was a 710 MW reduction in offers priced below $5/MWh.
  - ✓ Regulation – Most of the capacity offered at less than $25/MWh during the spring and summer increased to $25 to $50/MWh in the fall.

Day-Ahead Ancillary Services Offers

- Higher regulation offer prices contributed to a significant rise in regulation clearing prices from September through December.
  - ✓ The rise in regulation offers is attributable to changes by two market participants in September and October. The rise in offers from these market participants was not sufficient to warrant mitigation of regulation offers under the NYISO Tariff.
- Due to limited participation from regulation-capable capacity, the ownership of resources that participate in the market is relatively concentrated.
  - ✓ In the short-term, this may provide incentives for certain market participants to raise their offer prices above marginal cost.
  - ✓ In the long-term, we expect that additional supply would enter the market if prices rose above competitive levels for a sustained period.
- The rise in spinning and non-spinning reserves offer prices was less dramatic than for regulation. However, the rise in offer prices likely contributed to day-ahead reserves prices being higher in the fall than in the spring.

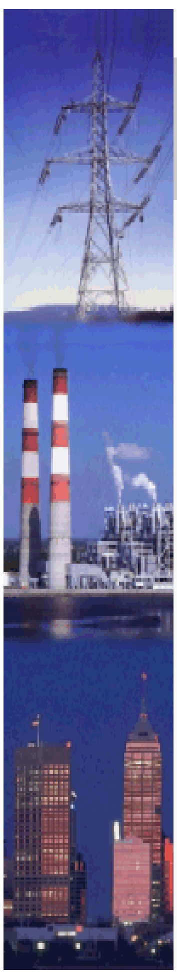
Summary of Ancillary Services Offers by Season
February to December, 2005



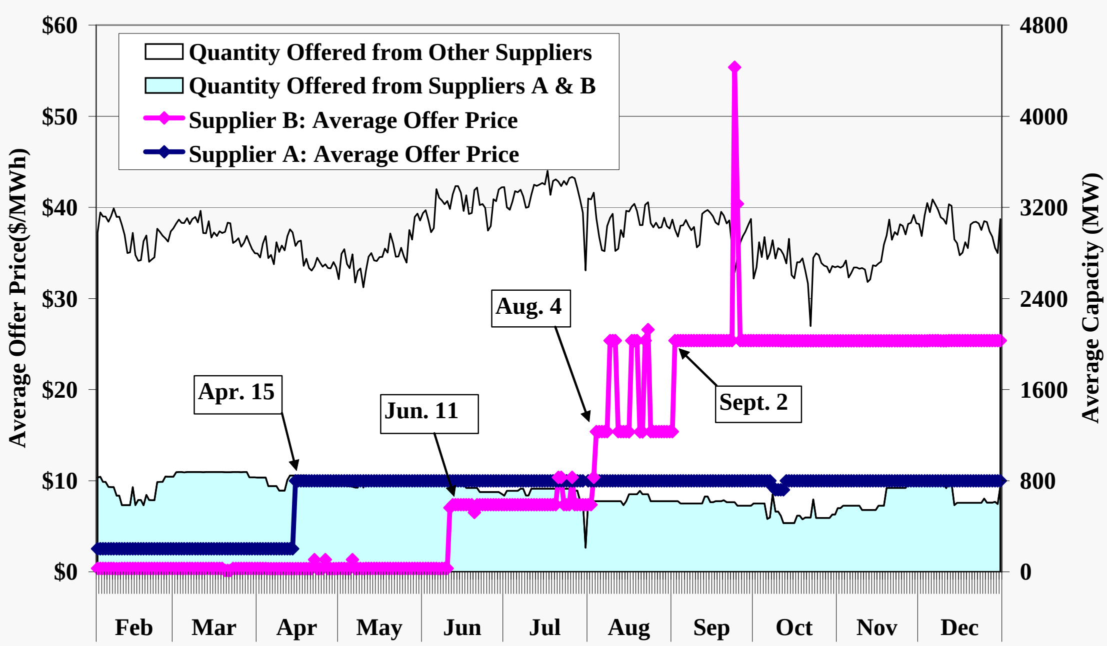
Note: Spinning and non-spinning offers are an average of 1pm to 7pm, while regulation includes all hours.

Day-Ahead Reserves Offers

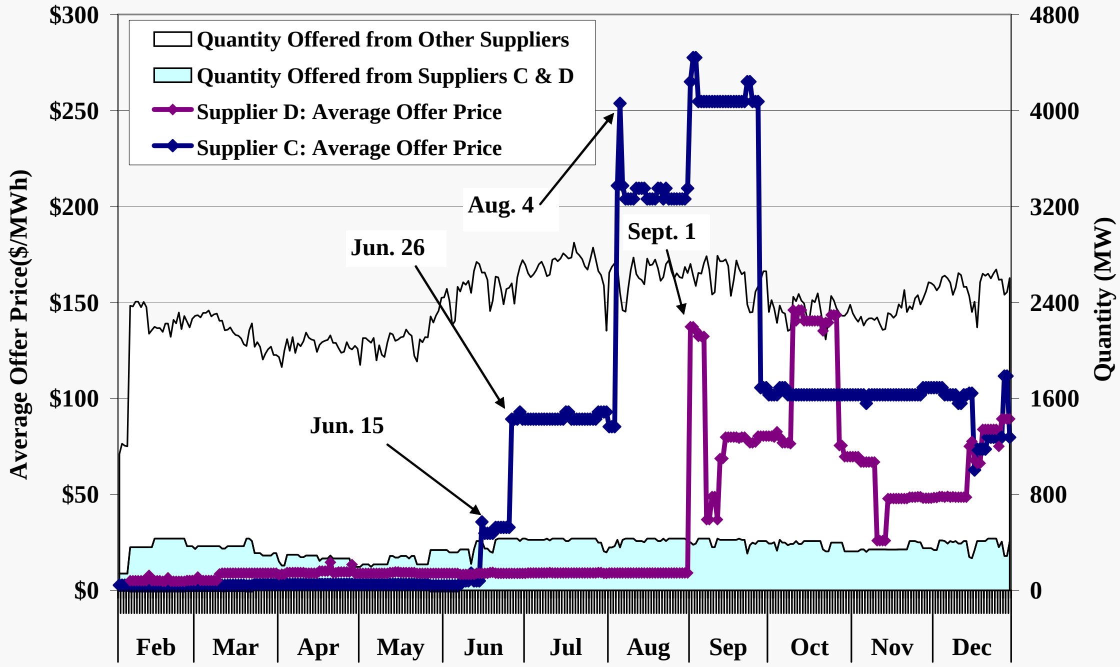
- The general rise in reserves offer prices is largely explained by increases by several market participants. The following two figures summarize offers from:
  - ✓ Two suppliers of 10-minute non-spin in eastern NY; and
  - ✓ Two suppliers of 10-minute spin in eastern NY.
- Both figures show large quantities offered at less than $5/MWh for several months after the start of SMD2 that rose substantially in subsequent months.
- During the summer, large offer price increases are focused on a handful of days, primarily in the second week of June, August 4th, and the beginning of September.
  - ✓ Most of these days followed immediately after significant real-time price spike events where real-time reserves prices were far larger than day-ahead reserves prices.
- The two suppliers of spinning reserves shown in the east adjusted their offers at very high levels a number of times during the fall.



Eastern 10-Minute Reserves Offer Prices and Quantities Selected Suppliers in Afternoon Hours Day-Ahead Market, February to December, 2005



State-wide 10-Minute Spinning Reserves Offers Selected Suppliers in Afternoon Hours Day-Ahead Market, February to December, 2005



Reserves Offers Conclusions

- The pattern of offer prices raises concerns that market participants may be submitting reserves offers above marginal costs, which could lead to:
  - ✓ Prices above competitive levels for reserves.
  - ✓ Inefficient commitment of resources in the day-ahead market.
- One explanation for rising offers is that the market participants might be strategically raising their offer prices in order to exercise market power.
  - ✓ However, we expect that an attempt to exercise market power would have the greatest effect when conditions are tight.
  - ✓ If rising offers reflect attempts to withhold, it is unclear why offer prices remained elevated throughout the fall.
  - ✓ Furthermore, the real-time market helps discipline competitors in the day-ahead market, particularly since these same suppliers must offer $0/MWh in real-time.
  - ✓ Lastly, the offer price increases have not increased reserves prices significantly (i.e., higher than real-time prices on average).

Reserves Offers Conclusions

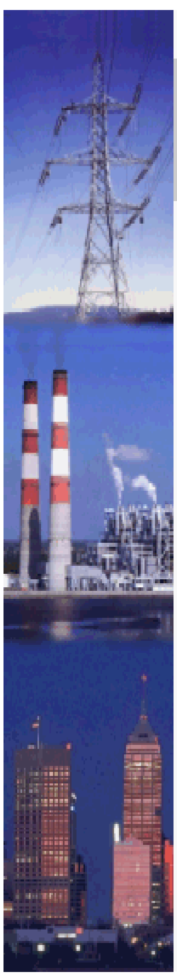
- Another explanation is that rising offer prices is a means to avoid day-ahead sales at low levels that do not reflect the potential for real-time shortages (causing large opportunity costs).
  - ✓ During the summer of 2005, there was poor convergence between the day-ahead market and real-time market in the peak hours when shortages sometimes occurred.
  - ✓ Most of the increase in offers occurred shortly after a shortage-induced price spike.
  - ✓ In addition, if the generator doesn't meet its obligation in real-time, it may have to buy back reserves at extreme real-time prices.
- With better convergence between real-time and day-ahead prices, which we expect in 2006, the incentive to raise day-ahead offers should diminish.
  - ✓ If the convergence remains poor such that the suppliers continue to have an incentive to raise their offers, the NYISO should consider the feasibility of introducing virtual trading of ancillary services in the day-ahead market.
  - ✓ This change would promote convergence of ancillary service prices and reduce physical suppliers' incentive to raise their offers.
  - ✓ However, it would need to be carefully studied to ensure it will not have unintended consequences on the day-ahead commitment.

Analysis of Bids and Offers

POTOMAC ECONOMICS

Analysis of Offer Patterns

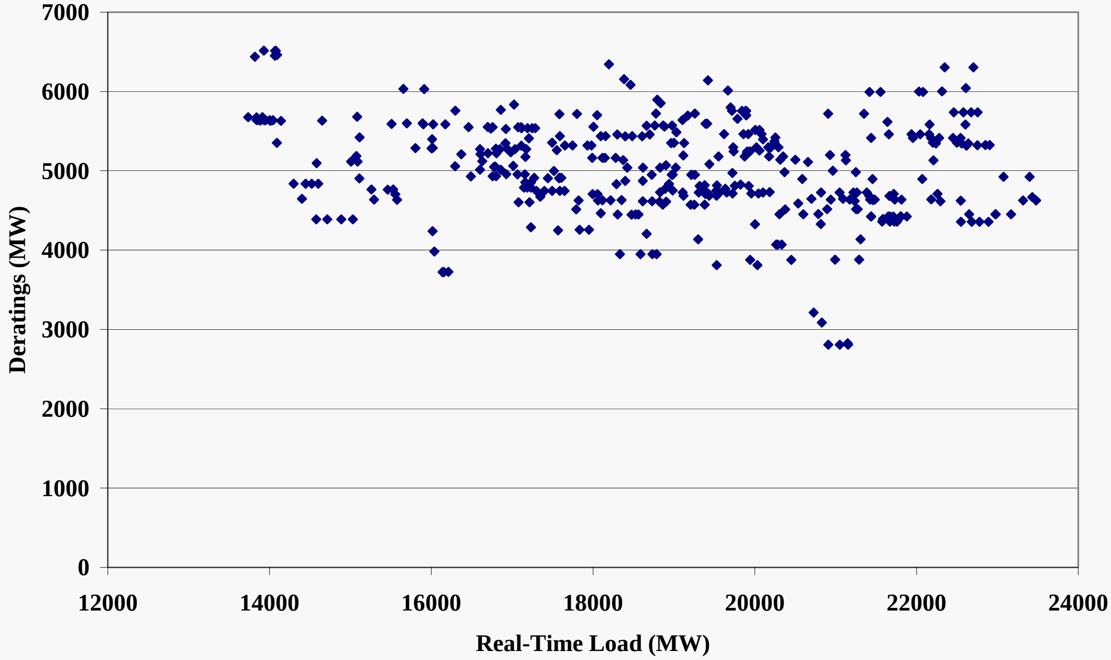
- This section of the report analyzes the patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase offer quantities during higher load periods to sell more power at the higher peak prices;
  - ✓ Suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest.
  - ✓ Hence, this analysis allows one to discern quantities that may reflect attempts to withhold resources to raise prices.
- The first analysis is of potential physical withholding, analyzing total generation deratings (including planned forced outages, and partial deratings).



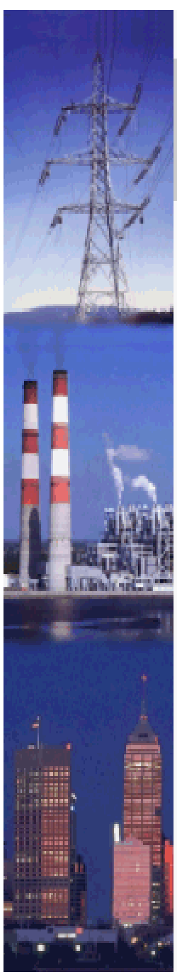
Analysis of Offer Patterns – Deratings

- The following two figures plot the total deratings and short-term deratings versus actual load in eastern NY during peak hours in the summer.
  - ✓ The figures focus on eastern NY because this area, which includes two-thirds of the State’s load, has limited import capability and is more vulnerable to the exercise of market power.
  - ✓ We focus this analysis on the summer to exclude the effects of planned outages that typically occur during off-peak seasons, and because market power is most likely during the higher load conditions in the summer.
  - ✓ The short-term deratings shown in the second figure are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages.
- These figures show that deratings are least frequent when load reaches high levels, which is consistent with workable competition.

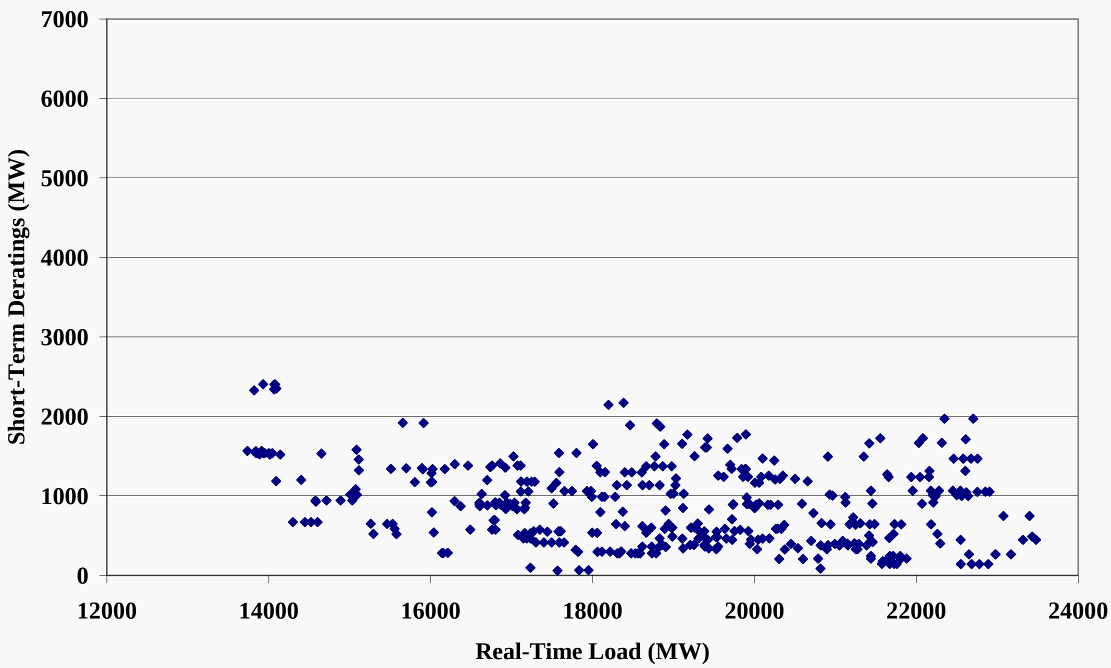
Relationship of Deratings to Actual Load Day-Ahead Market – East New York Peak Hours*, Summer 2005



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.



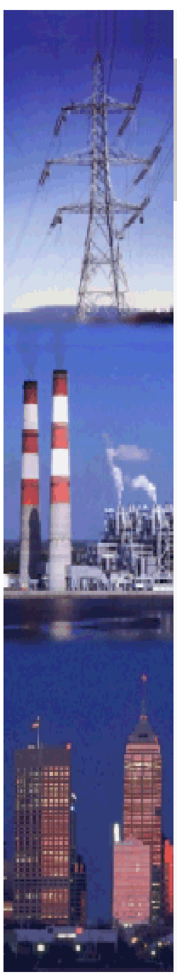
Relationship of Short-Term Deratings to Actual Load Day-Ahead Market – East New York Peak Hours*, Summer 2005



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Analysis of Offer Patterns – Output Gap

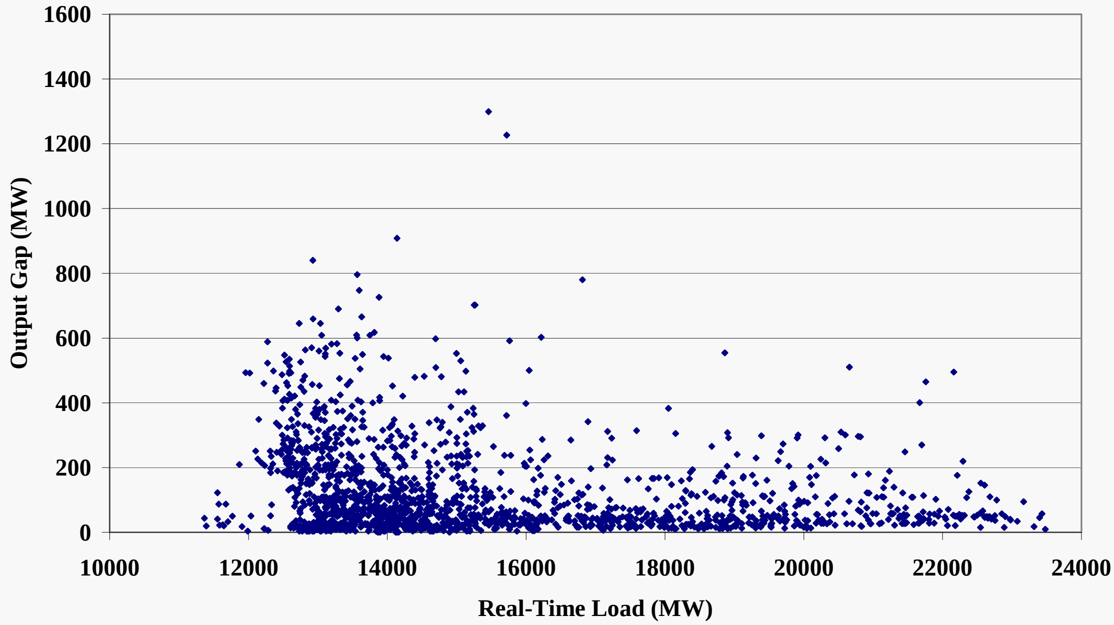
- The second analysis is intended to assess potential economic withholding, employing a measure called an "output gap".
- The output gap is the quantity of economic capacity that does not produce energy or ancillary services because a supplier submits an offer price well above a unit's reference level.
- The output gap:
  - ✓ Addresses all components of a supplier's offer, including start-up, minimum generation, and incremental energy offers.
  - ✓ Includes units that "set the price".
  - ✓ Excludes capacity scheduled to provide ancillary services.
- It is particularly notable that the output gap measured at the lower threshold declines and is very low during high load periods, because this conduct would not be subject to mitigation.



Analysis of Offer Patterns – Output Gap

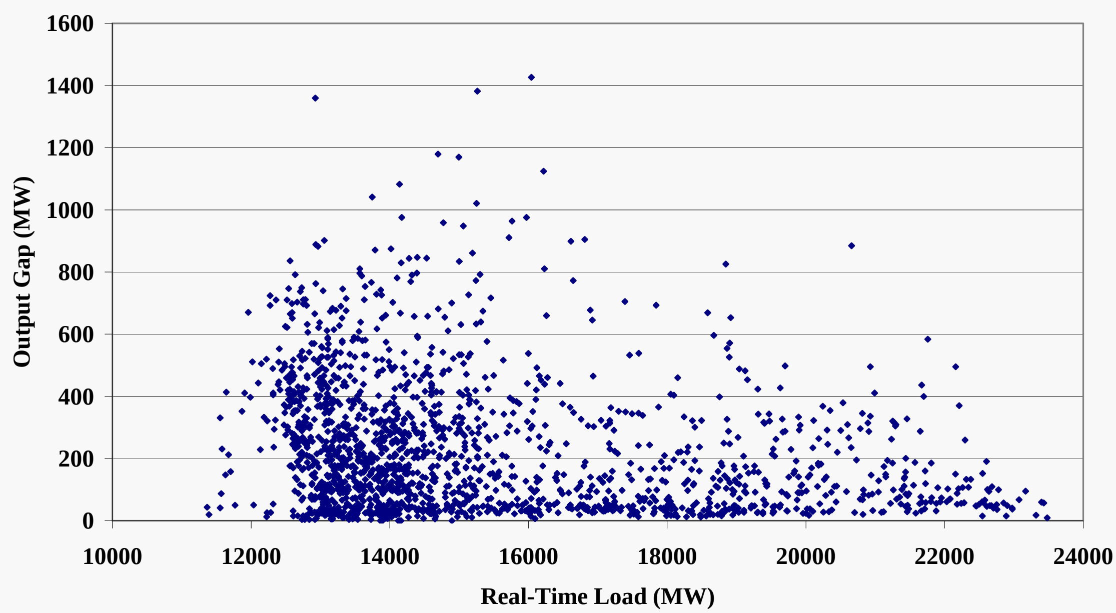
- The following figures shows the real-time output gap in eastern New York during peak hours using:
  - ✓ Standard conduct thresholds of $100/MWh or 300% (whichever is lower).
  - ✓ Low thresholds, $50/MWh or 100% (whichever is lower), and
- These figures both show that output gap decreases substantially under the highest load conditions.
  - ✓ This is an important result because prices are most vulnerable to market power under peak load conditions.
  - ✓ These results indicate that economic withholding was not a significant concern in 2005.

Output Gap at Mitigation Threshold vs. Actual Load
Real-Time Market – East New York
Peak Hours*, 2005



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

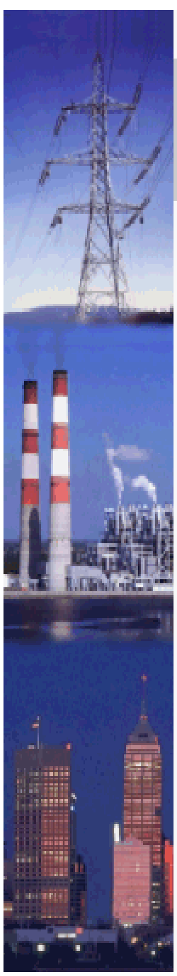
Output Gap at Low Threshold vs. Actual Load
Real-Time Market – East New York
Peak Hours*, 2005



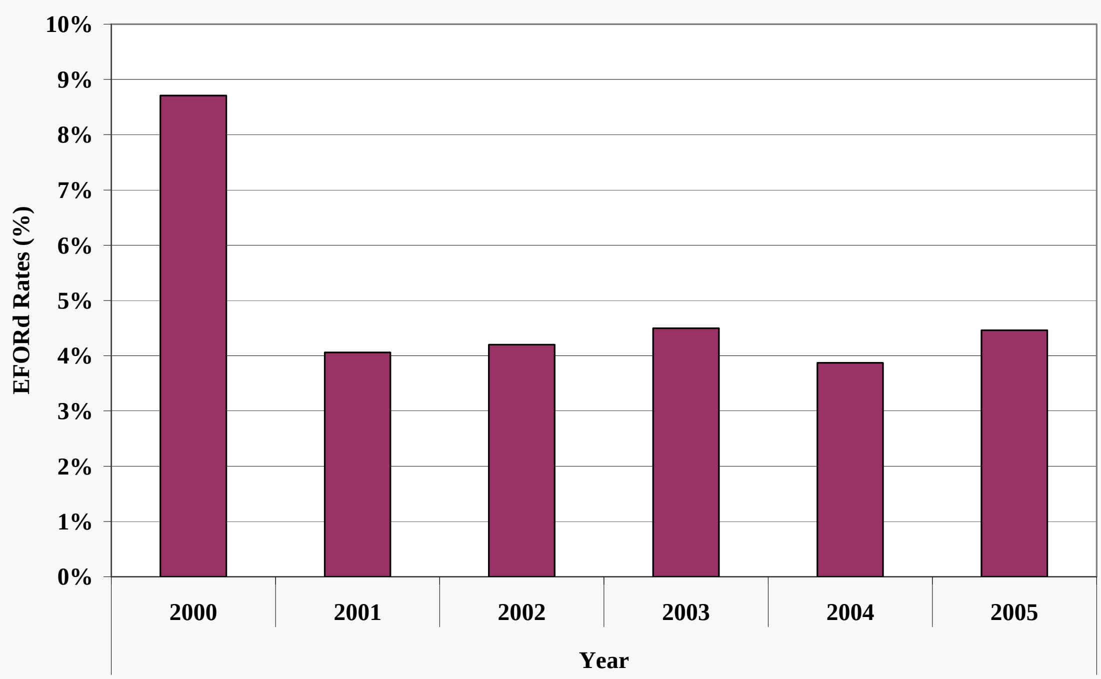
* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Forced Outages

- The next figure shows the trend in the equivalent forced outage rate from just after the beginning of the operation of the New York markets.
  - ✓ The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time a unit is unavailable due to forced outages, expressed as equivalent hours of full forced outage at its maximum net dependable capability.
- EFORd was relatively high in 2000 due to the outage of an Indian Point nuclear unit.
- After the Indian Point outage, the EFORd has been consistently close to 4 percent – much lower than the outage rates that prevailed prior to the implementation of the NYISO markets.
- The potential physical withholding issues associated with these outages are evaluated in the next section.



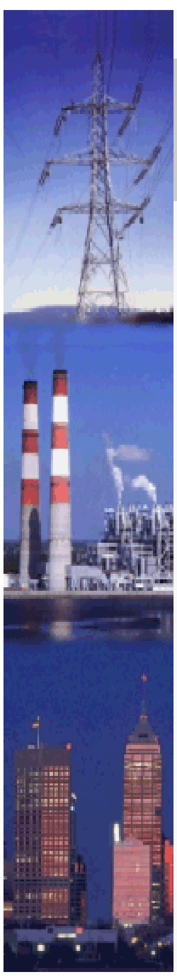
Forced Outages
2000 - 2005



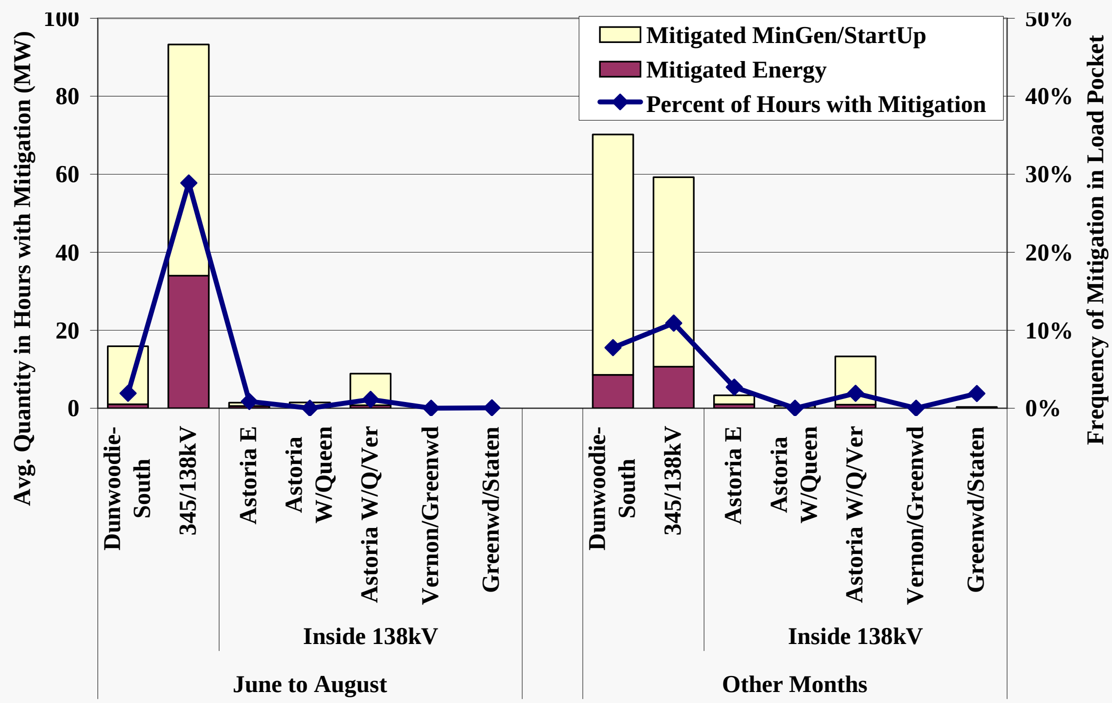
Based on calculations provided by NYISO Market Monitoring and Performance

Summary of Day-Ahead Mitigation

- Local market power mitigation measures are triggered when constraints are binding into a load pocket to address market power in the NYC load pockets.
- The conduct and impact framework focus more effectively on potential market power in the NYC load pockets than the ConEd measures that were used until May 2004.
  - ✓ This prevents mitigation from occurring when it is not necessary to address market power.
  - ✓ It also allows high prices to occur during legitimate periods of shortage.
- The following figure summarizes the frequency of mitigation in NYC.
  - ✓ The line shows, for each load pocket constraint, the percent of hours when mitigation was imposed on one or more units.
  - ✓ The bars indicate the average amount of capacity mitigated in hours when mitigation occurred.
  - ✓ Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Energy) and the non-flexible portions (i.e. Mingen/Start-Up).
- Mitigation was most commonly associated with the constraints into New York City (i.e. Dunwoodie-South) and the 138 kV system.

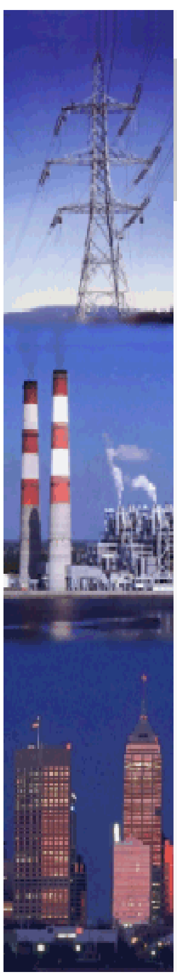


Summary of Day-Ahead Mitigation
February to December, 2005

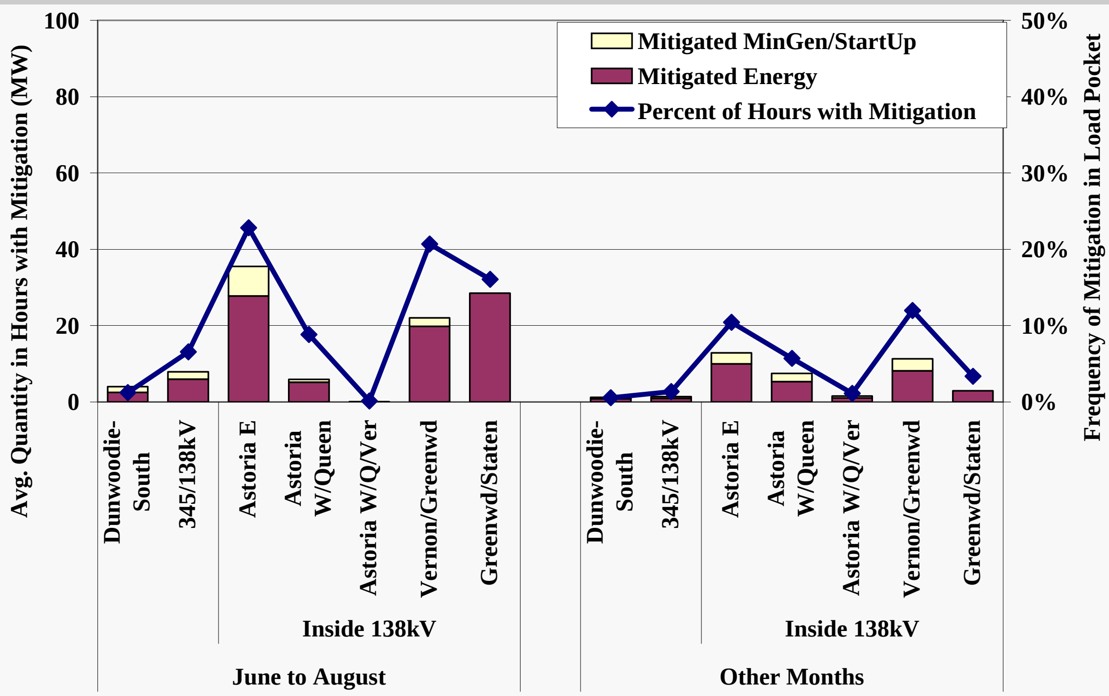


Summary of Real-Time Mitigation

- While the previous figure summarizes mitigation in the day-ahead market in New York City, the following figure summarizes real-time mitigation.
- Real-time mitigation was more commonly associated with the sub-load pockets inside the 138 kV system than day-ahead mitigation which was generally done for the larger load pockets.
  - ✓ This reflects patterns of congestion shown earlier in this report.
  - ✓ The real-time market had significantly more congestion between areas inside New York City than the day-ahead market.
  - ✓ Higher levels of congestion give rise to more frequent conditions when mitigation is warranted.
- Outside of the sub-load pockets, mitigation was less frequent than in 2004.
  - ✓ There is a different mitigation methodology under SMD that is more targeted.
  - ✓ Two new units came on-line in New York City during 2005.
  - ✓ Certain units committed and/or dispatched out-of-merit or through the SRE process were not subjected to mitigation in real-time.

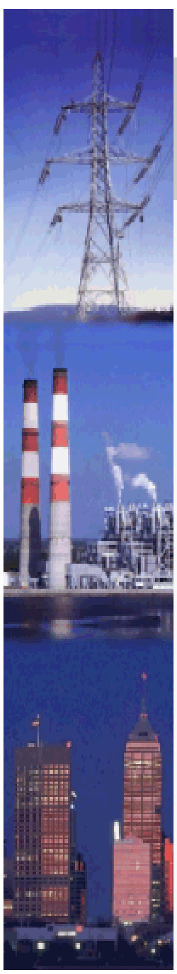


Summary of Real-Time Mitigation
February to December, 2005

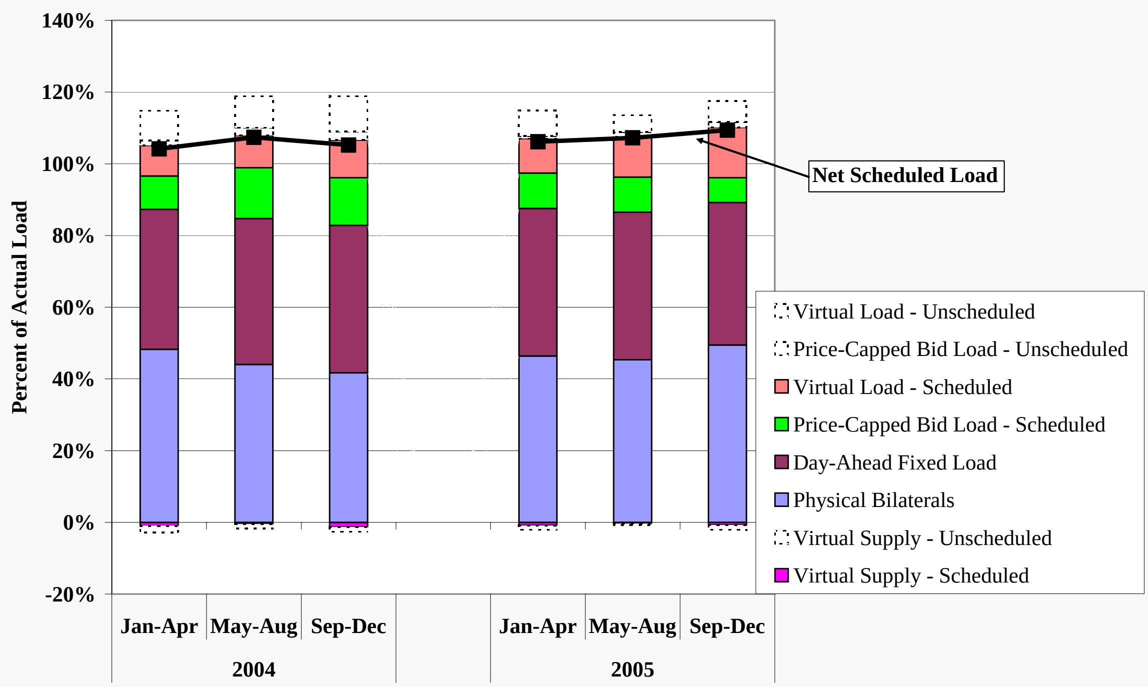


Analysis of Load Bidding Patterns

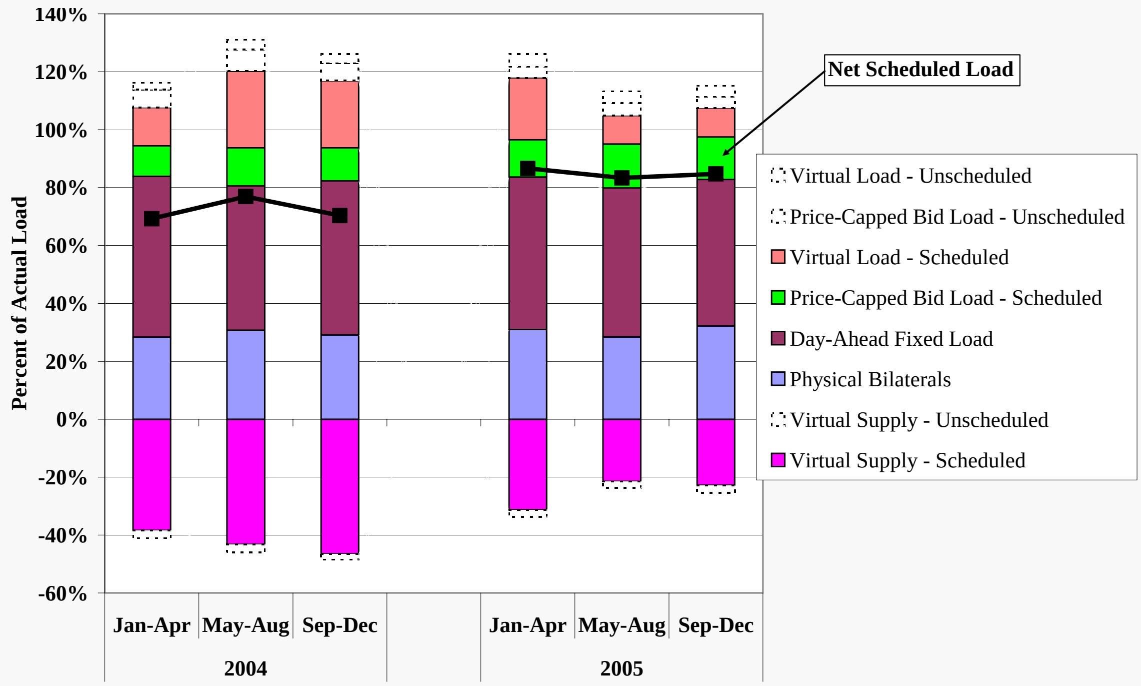
- The following figures show day-ahead load schedules and offers as a fraction of real-time load during 2004 and 2005 at various locations in New York.
  - ✓ Virtual supply effectively nets out an equivalent amount of scheduled load, thus it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Load is generally over-scheduled in New York City and Long Island and under-scheduled in up-state New York.
  - ✓ This implies a higher level of imports to constrained areas in the day-ahead market than in real time. In 2005, the day-ahead market used a more detailed model of the In-City system, which allowed more imports.
  - ✓ This pattern of scheduling is consistent with prior years and generally contributes to better price convergence.
- For New York State as a whole, load was under-scheduled in the day-ahead market by an average of 5 percent, which contributed to the lack of convergence between day-ahead and real-time prices during the summer.



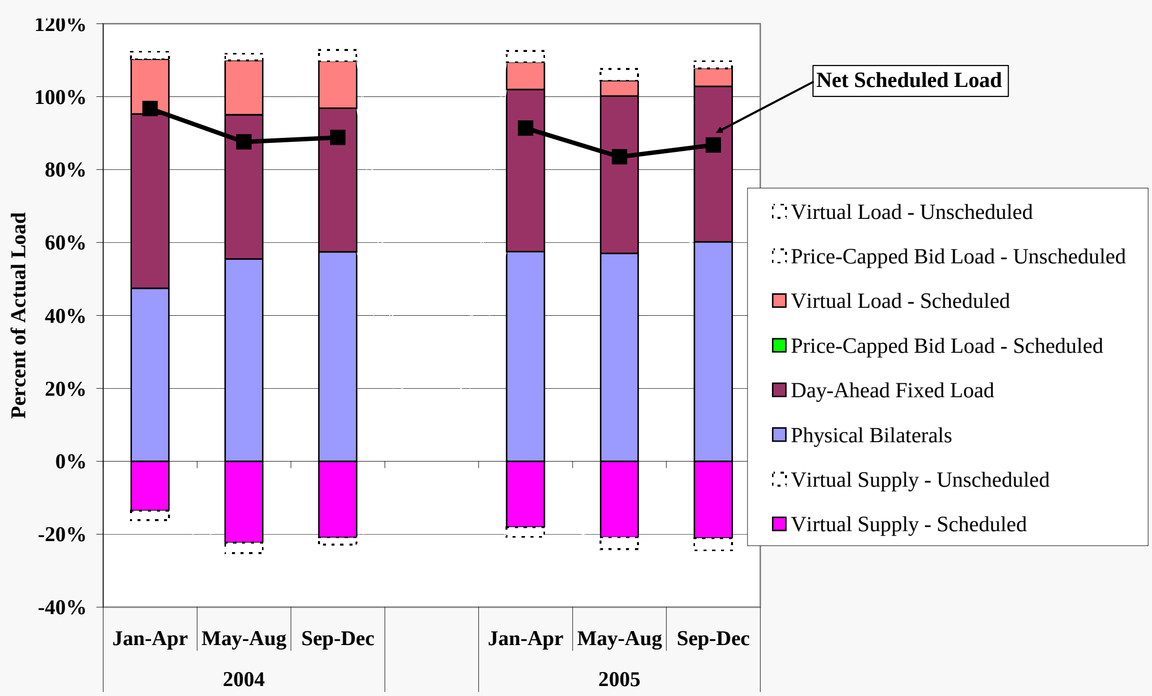
Composition of Day Ahead Load Schedules as a Proportion of Actual Load in New York City 2004 - 2005



Composition of Day Ahead Load Schedules as a Proportion of Actual Load in East Up-State New York 2004 - 2005

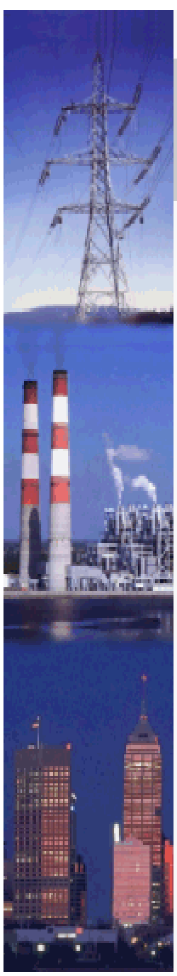


Composition of Day Ahead Load Schedules as a Proportion of Actual Load in West Up-State New York 2004 - 2005

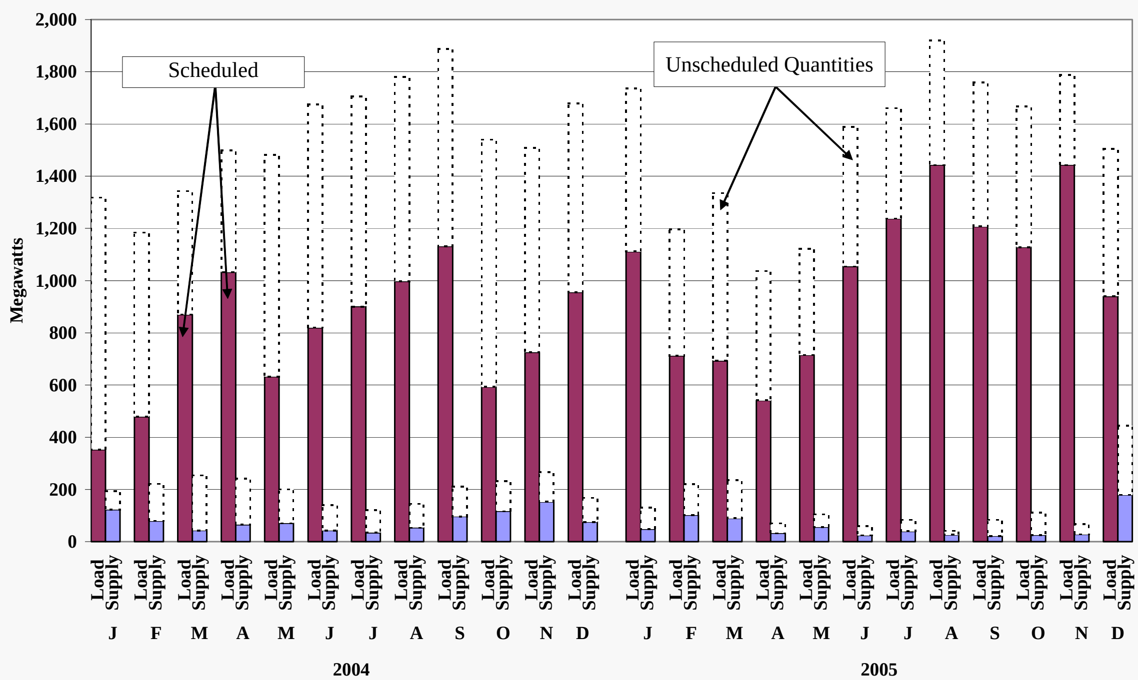


Virtual Trading Patterns

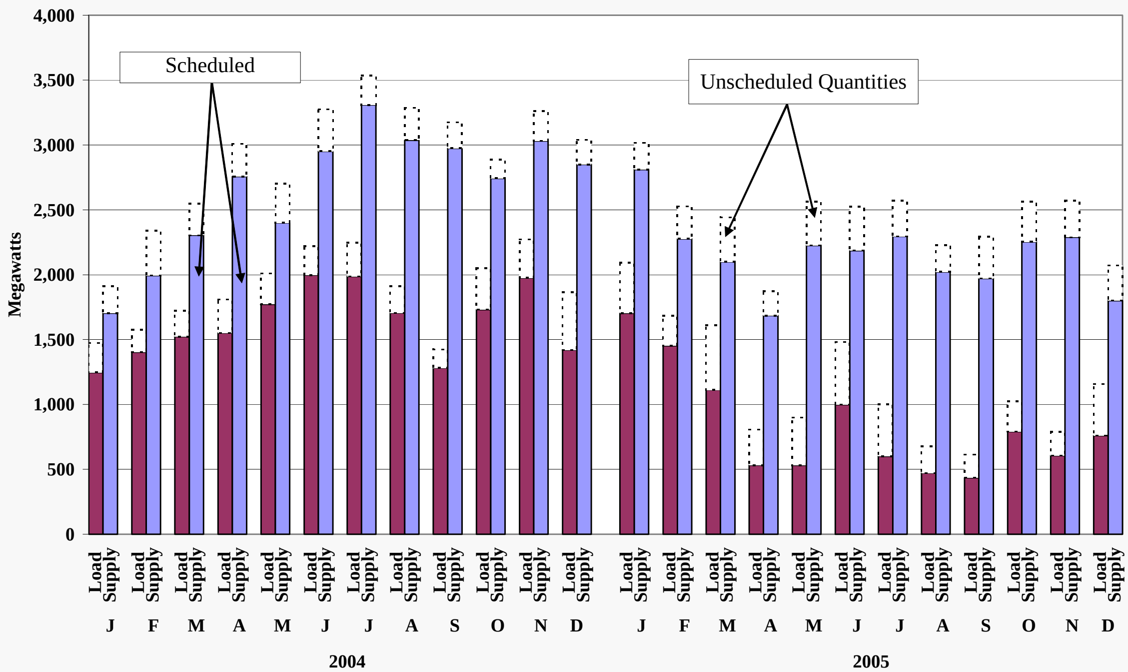
- Virtual trading allows participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the virtual bids and offers that have been offered and scheduled on a monthly basis in upstate and downstate areas.
- These figures indicate:
  - ✓ Virtual load and supply offers and schedules were generally lower in Up-State New York in 2005 than in 2004.
  - ✓ Virtual load schedules rose during the summer of 2005 and remained at unusually high levels during the fall months.
  - ✓ The pattern of substantial net virtual sales upstate and virtual purchases downstate continued in 2005.
    - – This is consistent with participants arbitraging price differences associated with the higher day-ahead imports (i.e. transmission capability) into downstate areas.
- Increased virtual load in down-state areas in the summer 2005 may be a response to substantial real-time price premiums.



Average Hourly Virtual Load and Supply
New York City and Long Island
2004 - 2005



Average Hourly Virtual Load and Supply
Outside New York City and Long Island
2004 - 2005



Market Operations – Real Time Commitment

Market Operations – Real-Time Commitment

- The NYISO upgraded its real-time commitment model as part of the SMD2 implementation:
  - ✓ The RTC model commits gas turbines, and schedules generation, ancillary services, and external transactions. It runs every 15 minutes and is a significant improvement over its predecessor, the hourly BME model.
- Convergence between RTC and actual real-time dispatch is a substantial concern because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, primarily gas turbines; and
  - ✓ Inefficient scheduling of external transactions.
- When excess resources are committed or scheduled, the results are increased uplift costs and depressed real-time prices
  - ✓ Alternatively, committing insufficient resources leads to unnecessary scarcity and price spikes.
- This section includes several analyses that evaluate the consistency between RTC and actual real-time outcomes.

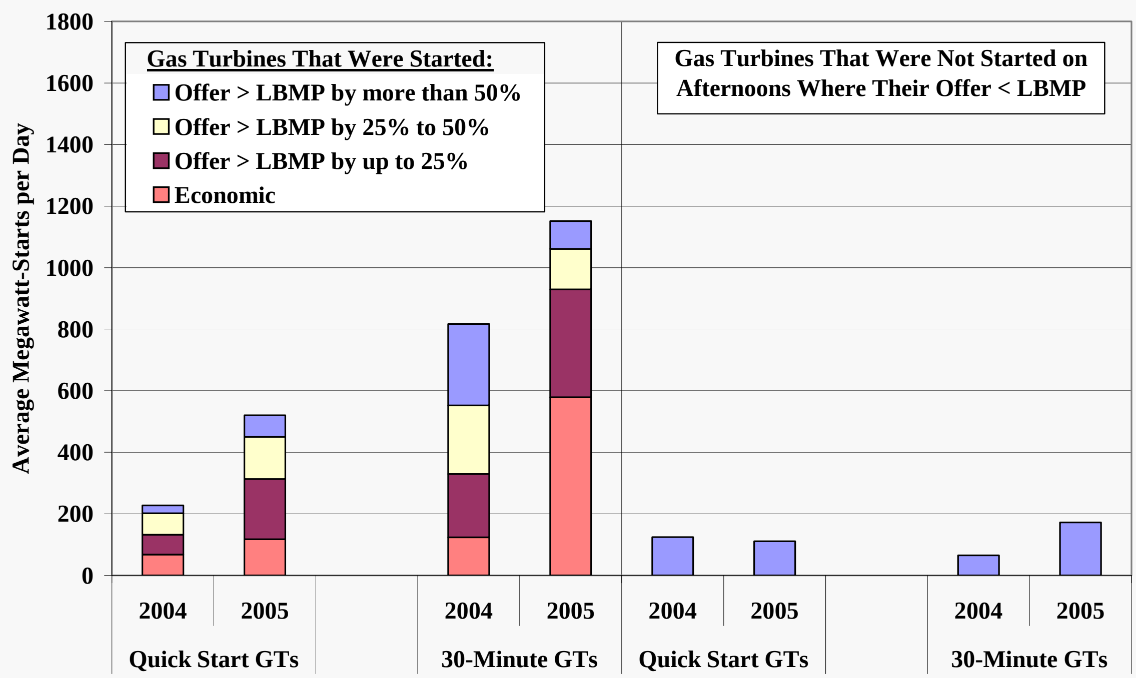
Efficiency of Gas Turbine Commitment

- The following figure measures the efficiency of GT commitment by comparing the offer price (energy plus start-up) to the real-time LBMP over the period of time the unit is initially committed for.
  - ✓ The left panel shows the average volume of gas turbines being started whose energy + start-up costs (amortized across the commitment period) are:
    - (a) < LBMP (clearly economic);
    - (b) > LBMP by up to 25 percent;
    - (c) > LBMP by 25 to 50 percent; and
    - (d) > LBMP by more than 50 percent.
  - ✓ The right panel shows the quantity gas turbines that were likely economic, but not started (i.e. the LBMP > Energy plus start-up offer).
- Some of the GTs with offers greater than the LBMP in the left panel are also economic, because GTs that are started efficiently may sometimes not recover their start-up costs.

Efficiency of Gas Turbine Commitment

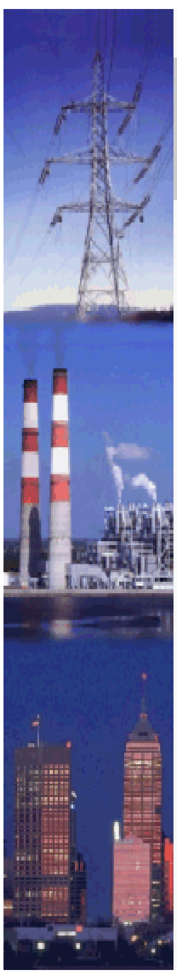
- The figure shows that gas turbine commitment has been far more efficient under SMD2 than during the previous year due to the 15-minute commitment under SMD2. The figure indicates that:
  - ✓ A much higher share portion of the GT commitments occur in the economic categories.
  - ✓ To the extent GT commitments are not economic, they were generally closer to being economic under SMD2.
  - ✓ The category of uncommitted economic GTs is generally small, indicating that GTs are nearly always started when they are economic.
  - ✓ The improvement in commitment of 30-minute GTs was the most substantial, which is expected given that they had primarily been committed by the BME previously.
- In addition, RTD was modified to include the capability of starting quick start resources in August 2005, and should further improve the dispatch of these resources.
  - ✓ Quick start GTs were used much less frequently after the summer months, providing only limited information regarding the change in efficiency.
  - ✓ We will assess the efficiency benefits of this new capability after the summer of 2006.

Efficiency of Gas Turbine Commitment
Comparison of SMD and SMD2
June to December, 2004 & 2005

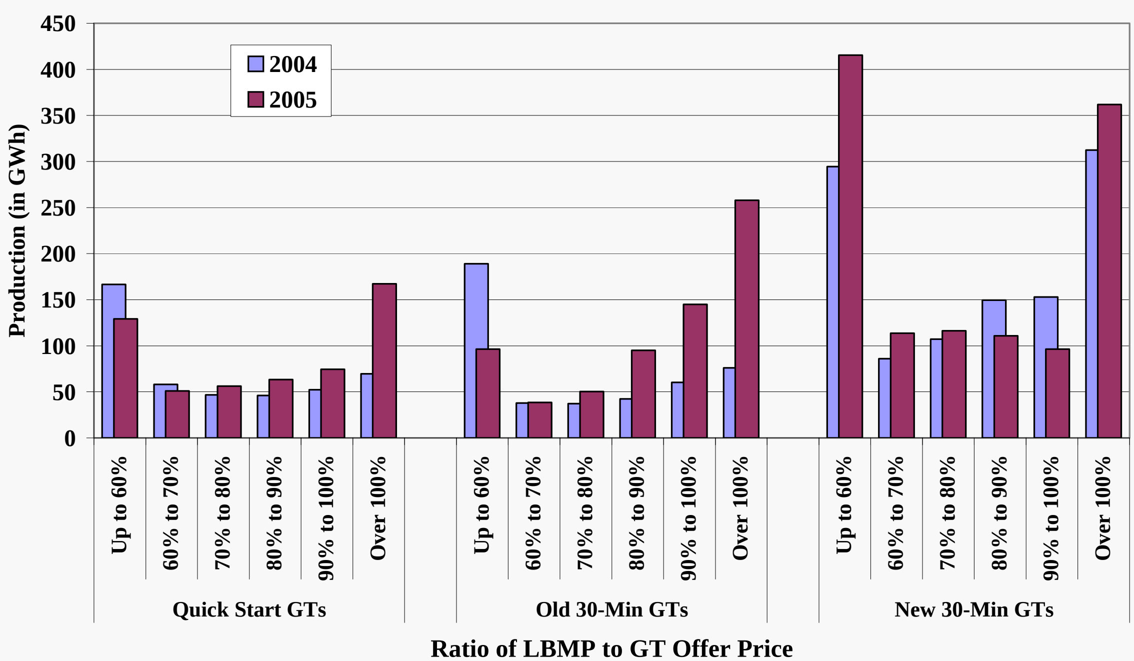


Efficiency of Gas Turbine Production

- The next figure summarizes the efficiency of GT production by comparing the offer price (energy plus average start-up) to the average hourly real-time LBMP when GTs are running.
- This assessment differs from the previous analysis in two ways:
  - ✓ It includes all hours when gas turbines are running. The previous analysis evaluates the initial decision to start a gas turbine.
  - ✓ It compares hourly average LBMPs to offer prices, which can be misleading if a GT runs in the highest priced portion of a particular hour.
- The figure shows:
  - ✓ Production was higher for each type of gas turbine in 2005 than in 2004.
  - ✓ Older GTs show significant shift away from production in hours where the LBMP is substantially lower than the GT's offer price, and more production when the GT offer is economic or close to it.
- Newer gas turbines (i.e. ones installed since 2001) have much lower running costs than older ones.
  - ✓ These account for 14 percent of GT capacity, but 52 percent of the total output from GTs.



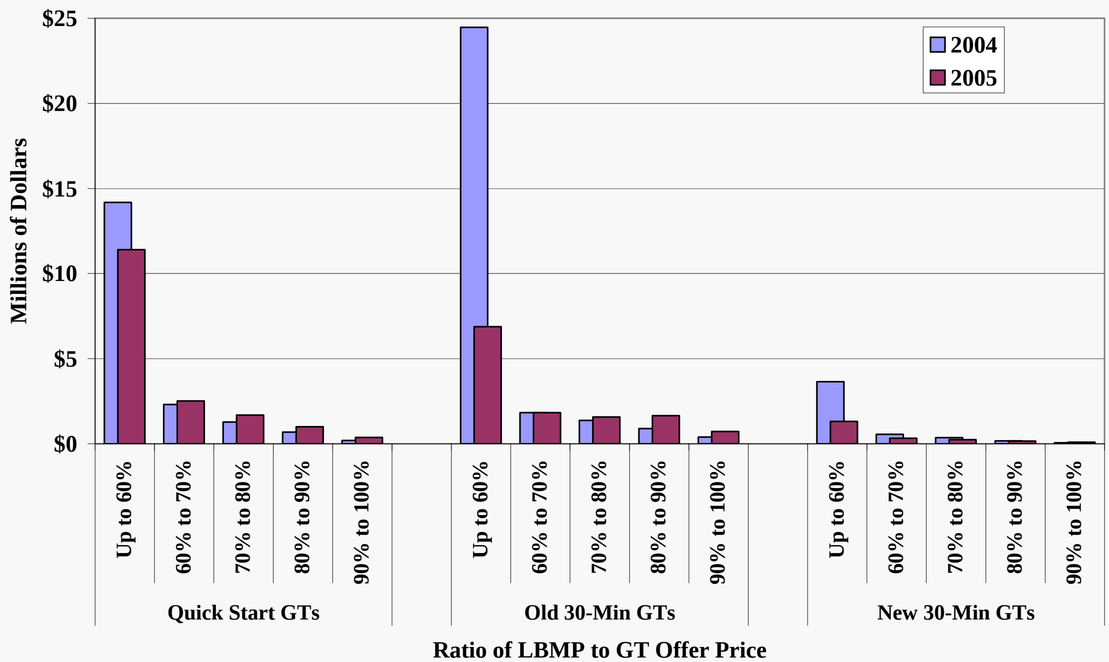
Efficiency of Production by Gas Turbines Based on Comparison of LBMPs and Offer Prices February to December, 2004 & 2005



Efficiency of Gas Turbine Production

- Gas turbines that do not earn sufficient revenue to compensate them for as-bid costs receive make whole payments (i.e. BPCG payments).
  - ✓ BPCG payments are paid based on a daily comparison of as-bid costs and revenues earned from the market, but we have estimated these on an hourly basis for the purposes of this analysis.
- The following figure summarizes BPCG payments according to the ratio of the LBMP to the GT's offer price.
- The figure shows:
  - ✓ The majority of BPCG payments come from hours when the LBMP is less than 60 percent of the GT's offer price.
  - ✓ In 2005, there was a dramatic reduction in BPCG payments associated with hours where the LBMP was less than 60 percent of the GT's offer price, particularly for older 30-minute GTs

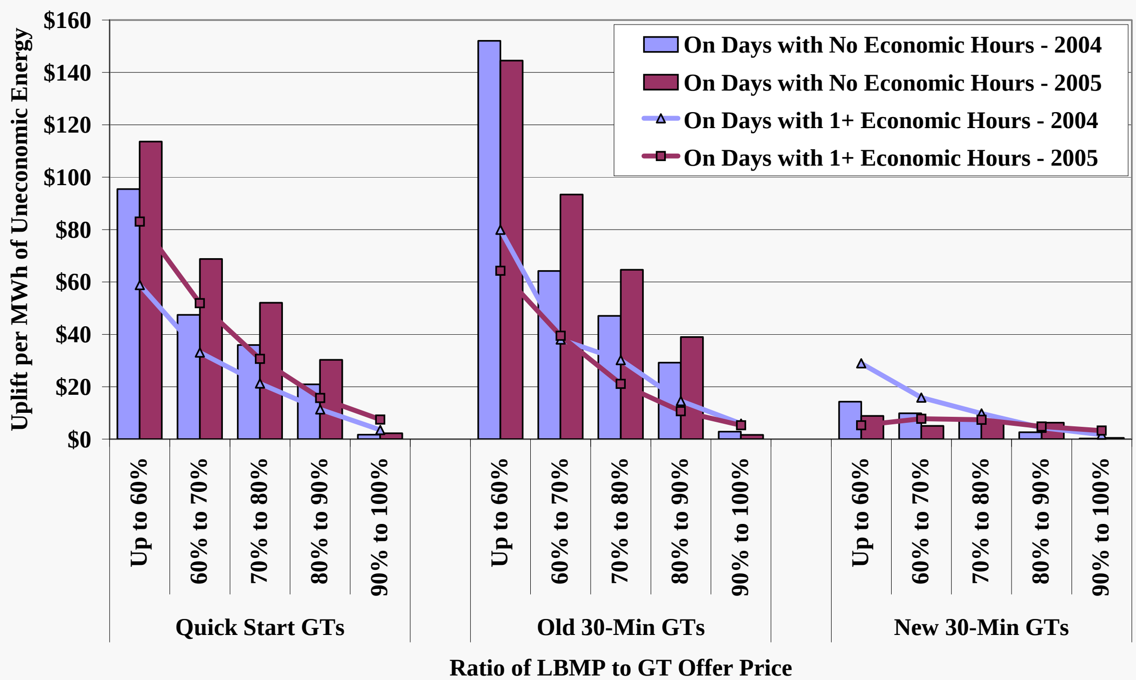
Summary of BPCG Payments to Uneconomic GTs February to December, 2004 & 2005



Efficiency of Gas Turbine Production

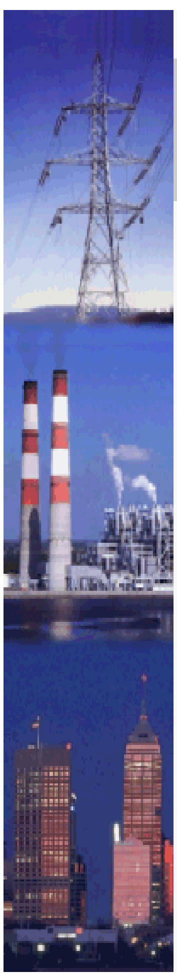
- The following figure shows BPCG payments per megawatt-hour of uneconomic production according to the ratio of the LBMP to the GT's offer price.
- Average BPCG payments are shown separately for hours that occurred on days when at least one other hour was economic.
  - ✓ Since BPCG payments are calculated on a daily basis, gains from high-priced hours go to defray losses from low-priced hours.
- The figure shows:
  - ✓ Due to the rise in fuel prices, in 2005, the payments were generally higher per megawatt-hour of uneconomic production than in 2004.
  - ✓ Payments are significantly lower per megawatt-hour on days when at least some hours were economic.
- In spite of higher BPCG payments per unit of uneconomic production, overall uplift costs were lower in 2005 due to a reduction in the volume of uneconomic production.

BPCG Payments per Unit of Uneconomic GT Production February to December, 2004 & 2005



Efficiency of Gas Turbine Production - Conclusions

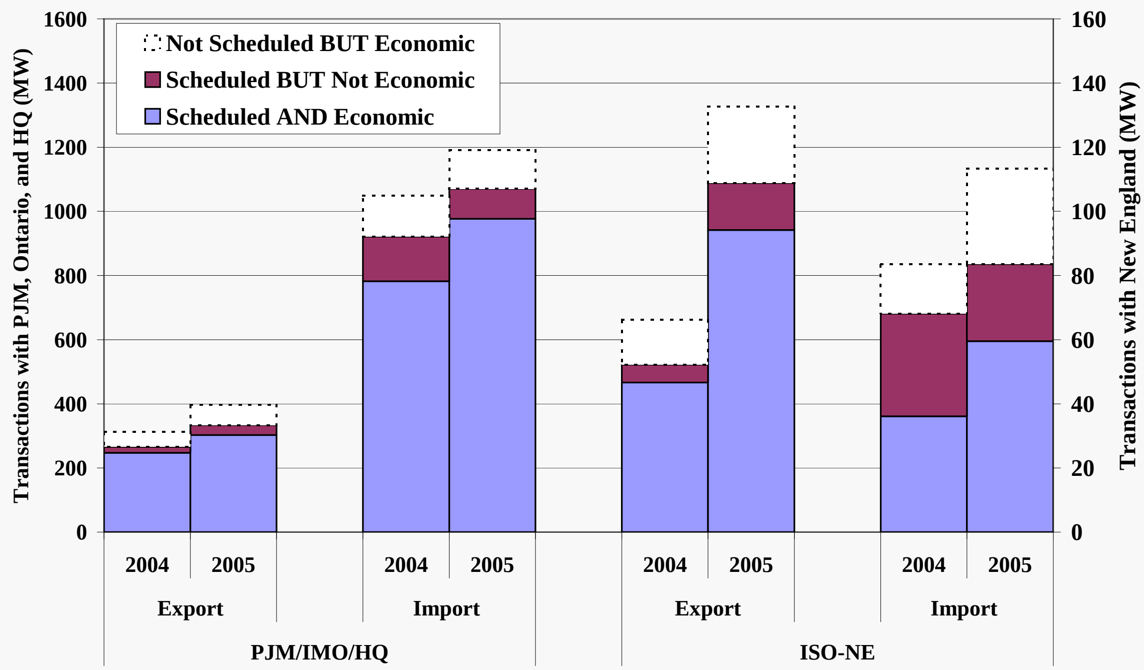
- The series of analyses comparing gas turbine efficiency in 2004 and 2005 leads to several conclusions regarding SMD2 relative to the prior period:
  - ✓ The frequency of uneconomic commitment and production decreased, resulting in lower BPCG payments, especially for older 30-minute gas turbines.
  - ✓ BPCG payments were higher per unit of inefficient production, largely due to higher fuel prices.
- We estimated the uplift savings from more efficient gas turbine commitment under SMD2 from February to December, 2005. This was done by estimating the BPCG payments that would have occurred using the old software based on the following criteria:
  - ✓ The rate of commitment efficiency in 2004 compared to 2005.
  - ✓ In 2005, LBMPs were generally higher relative to gas turbine offer prices, which helped push uplift down.
  - ✓ In 2005, higher fuel prices led to higher payments per unit for a particular degree of inefficient commitment.
- Estimated uplift savings were $22 million from February to December, 2005.
  - ✓ Of the estimated savings, $18 million came from more economic commitment of older 30-minute gas turbines.



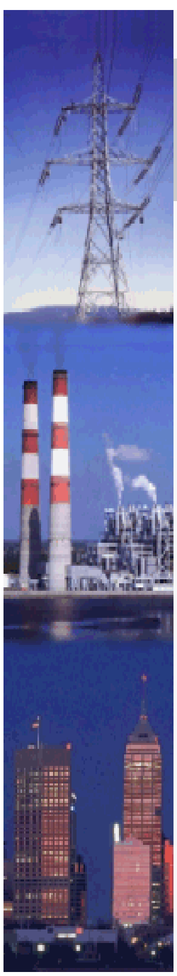
Efficiency of Real-Time Interface Scheduling

- The following figure measures the efficiency of external transaction scheduling by comparing the import and export offer prices to the real-time LBMP at the border. Three categories of price sensitive offers are shown including those that are:
  - ✓ Both scheduled by RTC and economic at the real-time price;
  - ✓ Scheduled by RTC but not economic at the real-time price;
  - ✓ Not scheduled by RTC but would have been economic at the real-time price.
- The first category represents efficient scheduling while the second and third categories are inefficient.
  - ✓ The growth of efficient scheduling of price sensitive offers has outpaced the growth of inefficient scheduling.
- Most real-time transactions are offered in a non-price sensitive manner, so the portion of transactions offered between $0 and $900/MWh is small relative to the total transfer capability of the external interfaces.

Efficiency of External Transaction Scheduling Based on Price Sensitive Offers* 2004 & 2005



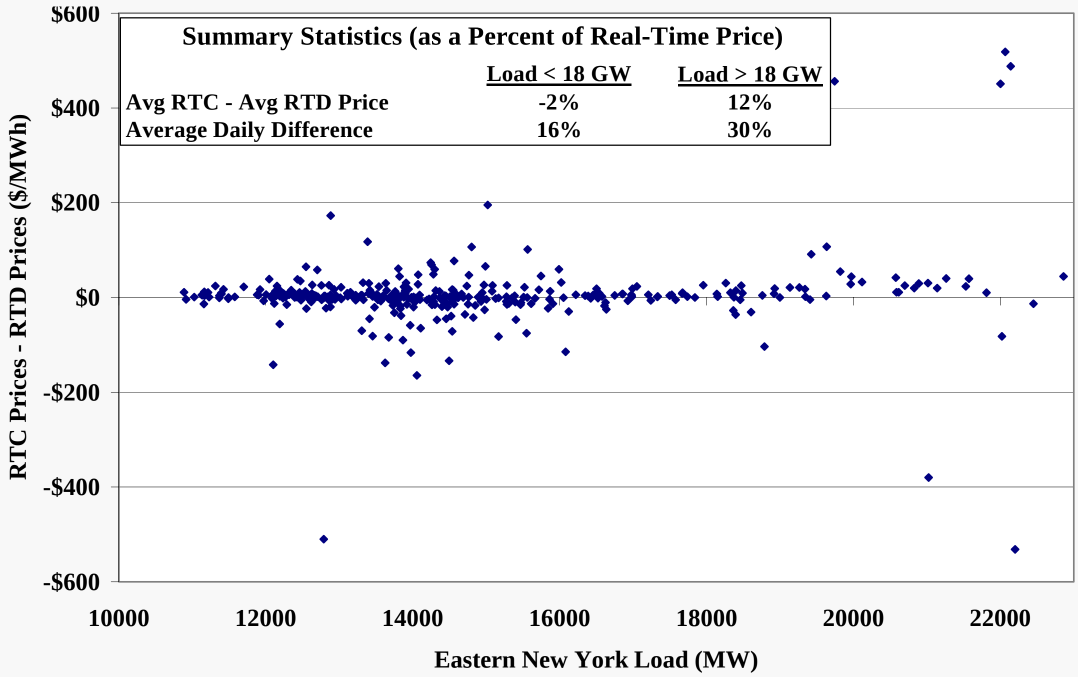
* Includes real-time offers to import or export that are priced between $0 and $900/MWh.



Comparison of RTC and RTD Prices

- The following scatter plot summarizes differences between RTC and RTD prices during the peak load hour of each day.
  - ✓ RTC runs every 15 minutes, and each RTC run produces advisory prices at 15 minute intervals over a 2 hour and 30 minute horizon.
  - ✓ The following figure compares real-time prices with the RTC prices for the interval that is closest to the time when RTC runs.
- This following figure provides a general measure of convergence between RTC and RTD. Convergence tends to be better when load in Eastern NY is less than 18 GW.
  - ✓ At these load levels, the supply curve is relatively flat, so small differences between supply scheduled by RTC and RTD do not cause large inconsistencies in prices.
- Convergence was significantly worse when load exceeded 18 GW.
  - ✓ At these load levels, the supply curve becomes steeper, so differences in the quantity supplied between RTC and RTD lead to larger pricing inconsistencies.
  - ✓ On these days, the RTC prices were systematically higher by 12 percent.

Comparison of RTC and RTD Prices in the Peak Load Hour Eastern New York, February to December, 2005

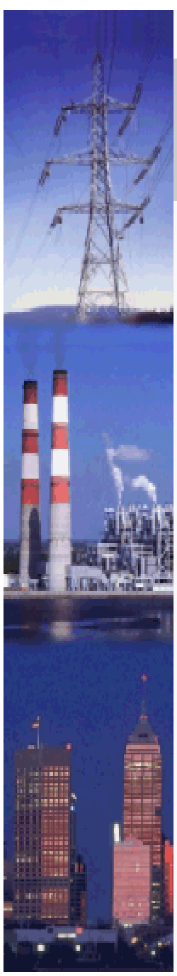


Market Operations – Real Time Scheduling and Shortage Pricing

POTOMAC ECONOMICS

Reserve Shortages and Shortage Pricing

- SMD2 enhanced the scheduling and pricing for energy and ancillary services.
- RTD now co-optimizes procurement of energy and ancillary services. This has several advantages:
  - ✓ The software efficiently allocates resources to provide energy and ancillary services every five minutes.
  - ✓ This incorporates the costs of maintaining reserves into the price of energy, whereas these costs were not considered prior to SMD2.
  - ✓ Demand curves rationalize the pricing of energy and reserves during shortage periods by setting limits on the costs that can be incurred to maintain reserves.
- This section evaluates the consistency between Eastern 10-minute reserves pricing done by the new software and the actual physical scarcity of Eastern 10-minute reserves.
  - ✓ The real-time software maintains 1000 MW of 10-minute reserves inside Eastern New York up to a cost of $500/MWh.
  - ✓ Eastern 10-minute reserves had the highest market value of any reserves product during 2005.



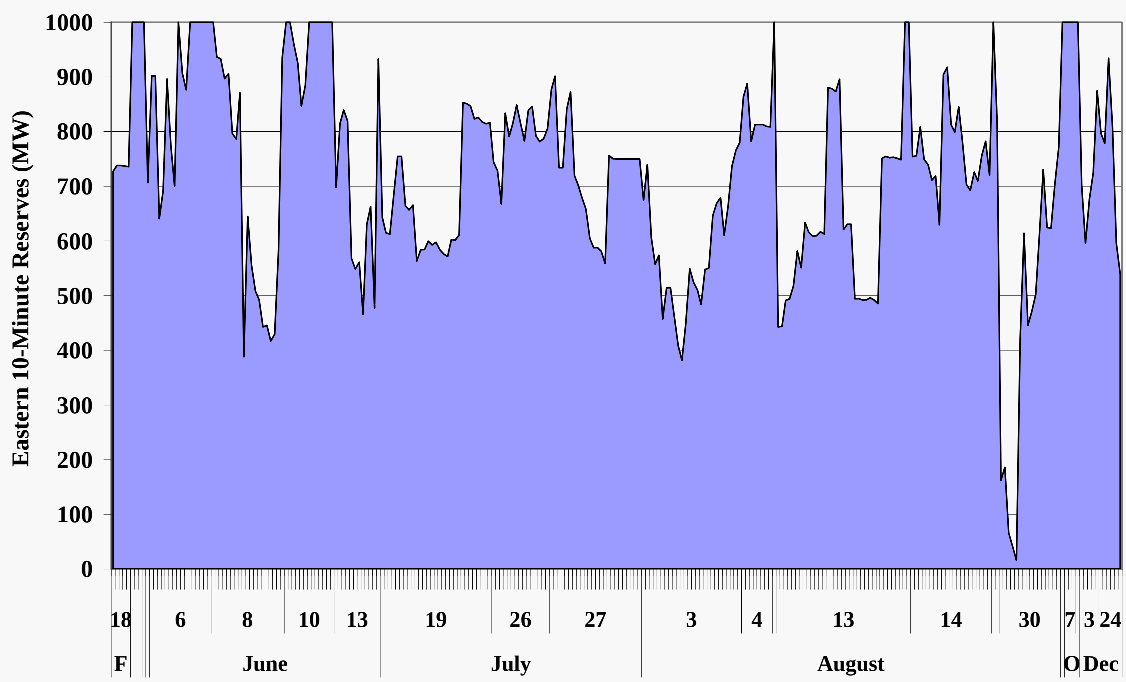
Reserve Shortages and Shortage Pricing

- Under SMD2, co-optimization of energy and reserves has been integrated with the Hybrid Pricing approach. Hybrid Pricing of gas turbines has been a key element of the real-time market software since 2002.
  - ✓ The inflexibility of gas turbines creates challenges for pricing energy efficiently when the gas turbines are the marginal source of supply.
  - ✓ 34 percent of dispatchable capacity in New York City and 50 percent of the dispatchable capacity in the 138kV load pocket are gas turbines.
  - ✓ Thus, Hybrid-Pricing is particularly important to setting efficient price signals in NYC.
- Hybrid Pricing treats gas turbines as flexible resources for pricing purposes, which results on certain inconsistencies between the pricing dispatch and the physical dispatch of the system. However, these inconsistencies should be limited such that:
  - ✓ Under physical shortage conditions, prices should reflect scarcity; and
  - ✓ High prices are only set when the system is physically in shortage.

Reserve Shortages and Shortage Pricing

- The following chart shows the amount of Eastern 10-minute reserves that were physically scheduled during shortage pricing intervals since the start of SMD2.
  - ✓ The figure shows 263 intervals with shortage pricing of Eastern 10-minute reserves.
  - ✓ Based on the amount of physically available 10-minute reserves, Eastern New York was short in 89 percent of these intervals.
- In a previous assessment of the NYISO markets under SMD2, we showed a similar figure with a category of capacity that was available but not scheduled due to a design flaw.
  - ✓ However, it was actually not scheduled for reserves in the physical dispatch due to a software error in RTD rather than flaw in the market design.
  - ✓ In the following figure, the total quantity of available 10-minute reserves has been adjusted to include this capacity.

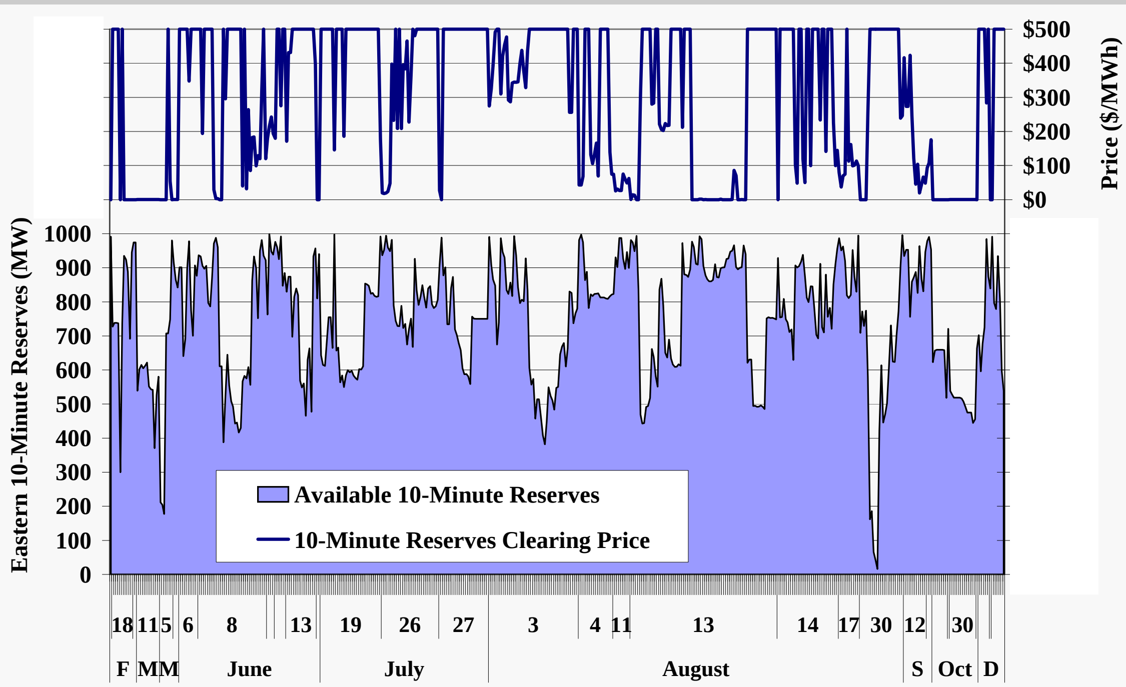
Scheduling of 10-Minute Reserves in the East
During Shortage Pricing Intervals – February to December, 2005



Reserve Shortages and Shortage Pricing

- The following figure shows available reserves during physical shortages of Eastern 10-minute reserves as well as a line indicating intervals with Eastern 10-minute reserves shortage pricing.
- There were a 235 intervals with physical reserves shortages but no Eastern 10-minute reserves shortage pricing.
  - ✓ The shortage was less than 100 MW in 43 percent of these intervals;
  - ✓ The shortage was less than 200 MW in 68 percent of these intervals; and
  - ✓ The average Eastern 10-minute reserves price was $113/MWh during these intervals.
- As with the previous figure, the following figure shows the total quantity of available 10-minute reserves. This includes the capacity not designated as reserves due to a software issue.
  - ✓ In a previous assessment, we identified 92 additional intervals as short of scheduled reserves that are not shown in the following figure because the total amount of *available* reserves exceeds 1000 MW (even though some of these reserves were not scheduled due to the RTD software error).

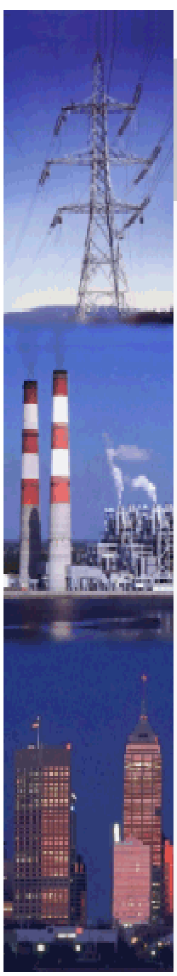
Scheduling and Pricing of 10-Minute Reserves in the East* During Physical Shortage Intervals – February to December, 2005



* In cases where the East 10-Minute Non-Spin price exceeds $500/MWh, the figure shows $500/MWh.

Reserve Shortages and Shortage Pricing Conclusions

- The dispatch software implemented under SMD2 has significantly improved the efficiency of energy and ancillary services pricing.
  - ✓ It replaced software that did not consider how ancillary services affect the cost of energy.
  - ✓ It reduces system costs by re-allocating ancillary services every five minutes.
  - ✓ Beginning August 16, additional improvements were made to allow off-line quick-start GTs to be co-optimized by RTD for providing energy and reserves .
- There were software issues that resulted in inefficient dispatch instructions during the shortages.
  - ✓ These issues did not affect prices.
  - ✓ The NYISO has resolved these software issues.
- Our recommendations regarding the hybrid pricing process that are provided below will help ensure that the prices are set at shortage levels when the system is in physical shortage.

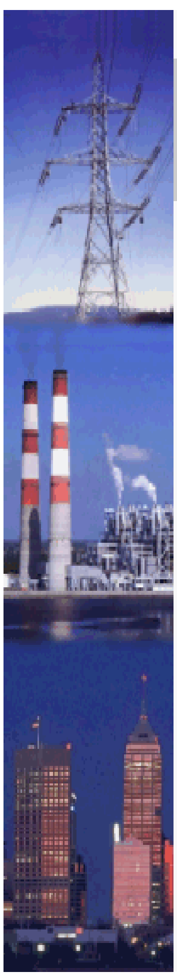


Hybrid Pricing – Introduction

- Hybrid Pricing generally enables the real-time software to calculate efficient prices, especially in areas that are primarily served by GTs.
- Hybrid pricing utilizes a pricing dispatch and a physical dispatch that can differ significantly, which can affect whether the pricing dispatch perceives a physical shortage in 10-minute reserves.
  - ✓ The pricing pass treats GTs as flexible resources for pricing purposes. In some cases, this flexibility allows the pricing pass to increase the quantity of energy and reserves that are available in 10 minutes above what is physically feasible.
  - ✓ When units do not follow dispatch instructions, it causes additional inconsistencies between the physical and pricing passes in the amount of capacity that can be ramped in 10-minutes.
  - ✓ There are certain inconsistencies between the physical and pricing passes in the output limits (ratings) used for gas turbines.
- The following analyses evaluate the significance of factors that contribute to inconsistencies between pricing and dispatch.

Hybrid Pricing – Deviations

- The next figure summarizes major sources of deviations between the physical dispatch and ideal dispatch of RTD in the first 11 months of SMD2.
  - ✓ *GT Pricing Logic*: RTD's pricing pass treats on-line GTs as flexible from zero to maximum output, while the physical pass always includes them at their maximum. Thus, the pricing pass may count less energy from these units.
  - ✓ *Not Following Dispatch*: Physical dispatch instructions are "ramp-constrained" by the most recent observed physical output of the unit, whereas the pricing dispatch level is constrained by the last pricing dispatch level plus or minus the ramp limit.
    - – Thus, the pricing pass may count *more* energy from units that persistently *under*-produce.
    - – And, the pricing pass may count *less* energy from units that persistently *over*-produce.
  - ✓ *Inconsistent Output Limits*: Inconsistencies between the offer amount and the actual production level can arise, particularly when high ambient temperatures reduce the maximum output level of GTs.
    - – The physical dispatch pass uses the actual production level while the pricing pass uses the offer quantity.
    - – Thus, the pricing pass generally counts more production from these units than the physical pass.

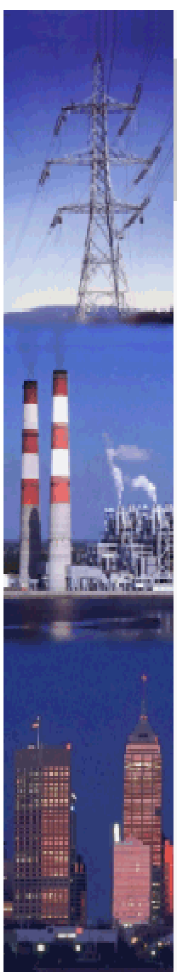


Hybrid Pricing – Deviations

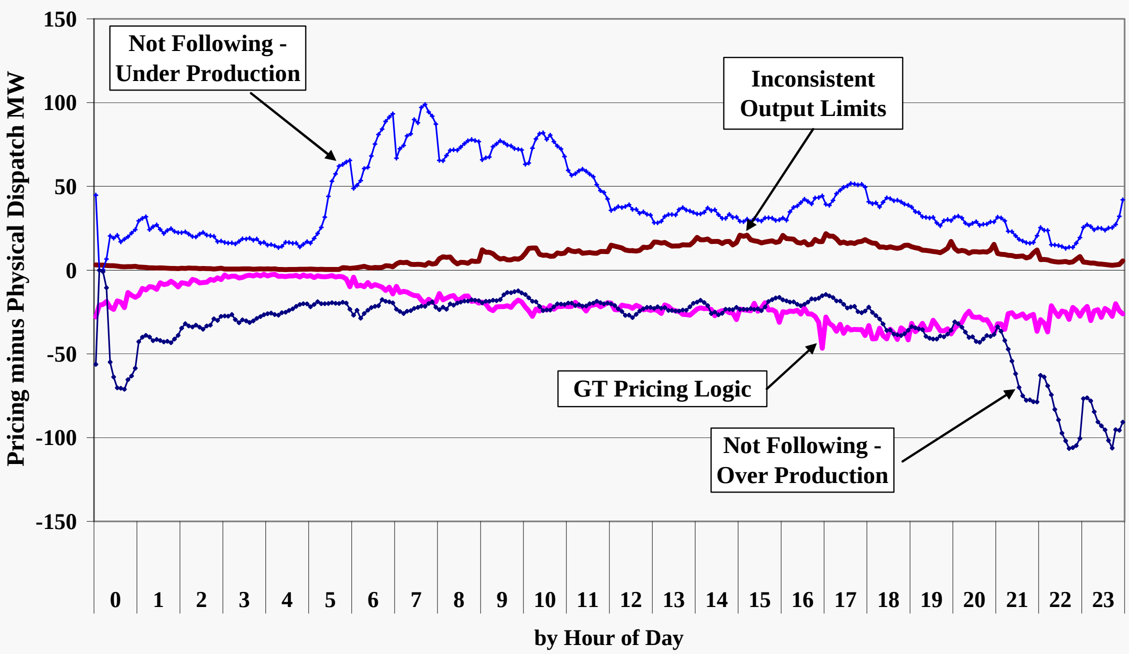
- The hybrid pricing logic is designed to allow GTs to set price when their energy is needed to satisfy load and resolve transmission constraints.
  - ✓ The resulting differences between production levels in the physical and pricing passes is correlated with the total amount of GT production.
  - ✓ These differences also become larger during the evening ramp-down as GTs are typically coming off-line.
- Two conclusions may be drawn from the following figure regarding generators (other than GTs) not following dispatch instructions:
  - ✓ Under-production is greatest in the morning ramp-up hours (i.e. 5am to 11am).
  - ✓ Over-production is greatest in the evening ramp-down hours (i.e. 9pm to 1am).

Hybrid Pricing – Deviations

- The figure also shows that inconsistent output limits, generally associated with ambient temperature deratings of GTs, are the most closely correlated with load. This is to be expected since:
  - ✓ The restrictions are generally proportional to the amount of GT production, which increases with load; and
  - ✓ The deratings are largest when ambient temperatures are the highest, which is also correlated with peak demand during the summer.
- Inconsistencies between the physical and pricing dispatches are necessary under the hybrid pricing methodology.
  - ✓ However differences due to over and under-production, and to GT deratings are unnecessary.
  - ✓ These differences can distort the real-time energy prices.



Sources of Deviation Between the Physical and Pricing Dispatch February to December, 2005

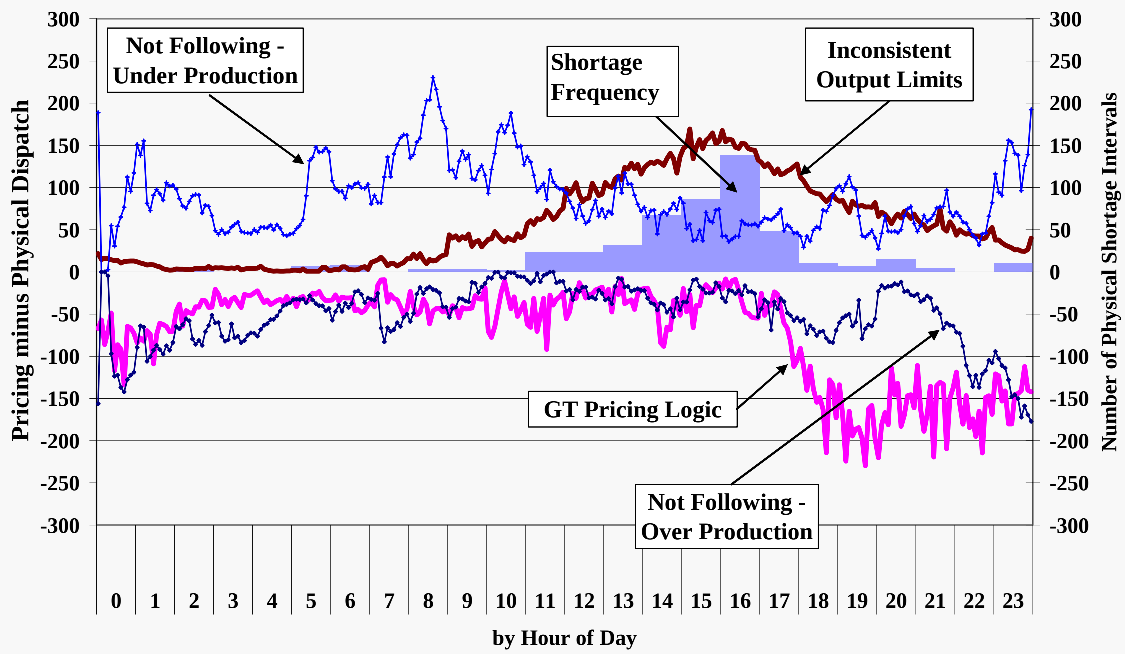


Note: Units are counted as not following dispatch if they lag behind their instruction for three consecutive ramp-constrained intervals.

Hybrid Pricing – Peak Conditions

- The following figure examines major sources of deviations between the pricing and physical passes on the ten days with most frequent shortage conditions.
  - ✓ These are the periods that are the most sensitive to differences between the physical and pricing treatment by RTD.
- The figure shows that most shortage intervals occur between 2pm and 6pm.
  - ✓ In this period, deviations associated with resources not following instructions and the hybrid pricing of GTs are at a minimum.
  - ✓ The most significant contributor to deviations during these periods is the inconsistent output limitations of GTs.
    - – The net impact is that the pricing pass has an average of 150 MW of additional resources available to it during afternoons of the days with most frequent shortages.

Sources of Deviation Between the Physical and Pricing Dispatch
Ten Days with Most 10-Minute Reserves Shortages in 2005



Note: Units are counted as not following dispatch if they lag behind their instruction for three consecutive ramp-constrained intervals.

Hybrid Pricing – Conclusions

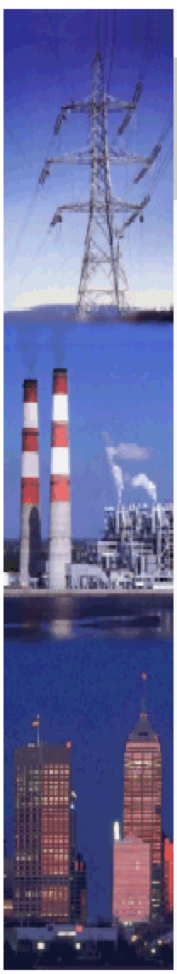
- Some differences between the pricing and physical dispatches in RTD are necessary to implement the hybrid pricing regime. However, unnecessary differences will generally lead to inaccurate prices and increased uplift.
- Improving the consistency of the pricing and physical dispatch passes of RTD will improve the efficiency of New York’s energy and ancillary services pricing (particularly during shortages) and reduce uplift.
  - ✓ In the short-term, we recommend that the NYISO implement the automated derates of gas turbines in the pricing dispatch that are currently included in the physical dispatch. The NYISO plans to implement this change by June 2006.
  - ✓ In the longer-term, we recommend the NYISO re-calibrate the dispatch levels in the pricing pass for units that are not responding to dispatch signals.

Market Operations – Supplemental Commitment and Out of Merit Dispatch

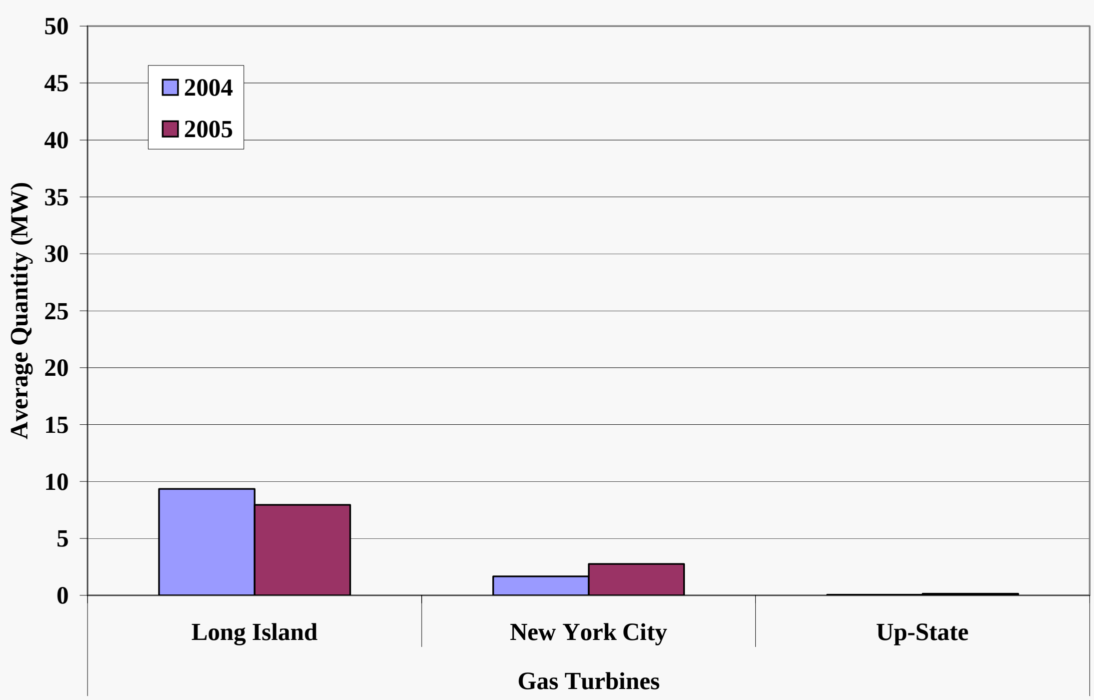
POTOMAC ECONOMICS

Real-Time Out of Merit Dispatch

- The next analysis focuses on the dispatch of gas turbines out-of-merit ("OOM") for local reliability reasons. Reasons include:
  - ✓ OOM units requested by the TO for local security;
  - ✓ OOM units requested by the ISO for local security;
  - ✓ Units that are OOM for voltage support; and
- OOM units are shown in the figure if their offer price is higher than the LBMP.
- OOM dispatch quantities of gas turbines have generally been low since the introduction of load pocket modeling in New York City in 2002.



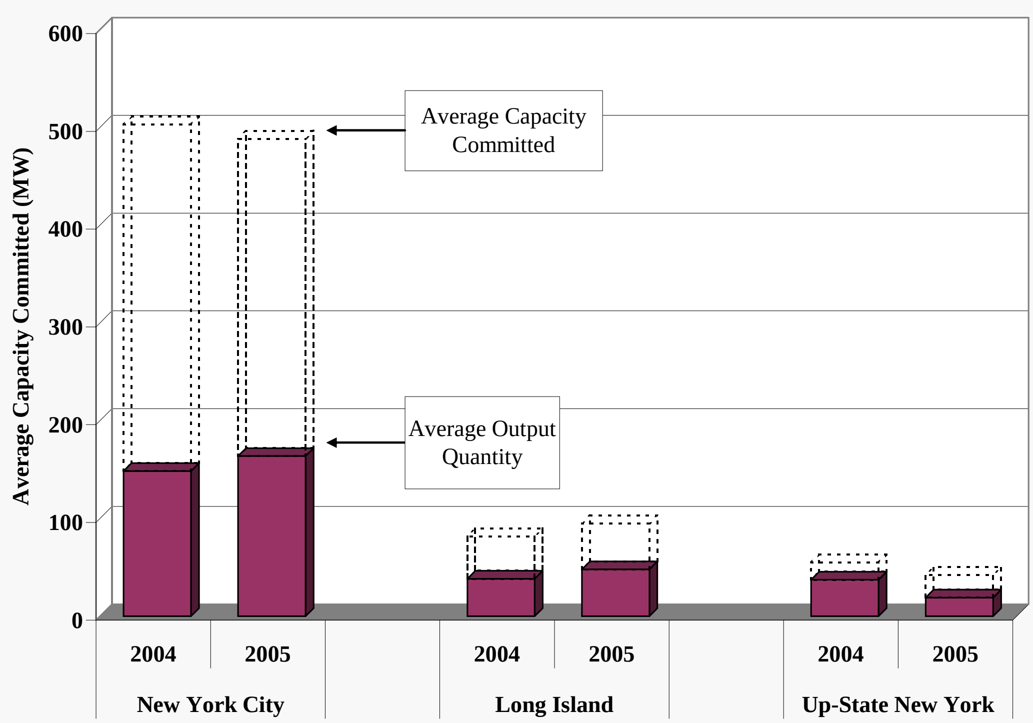
Out-of-Merit Dispatch of GTs for Local Reliability 2004 - 2005



Supplemental Resource Evaluation

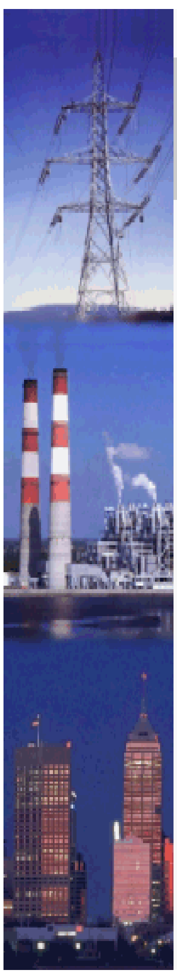
- The next analysis evaluates supplemental commitments made by the NYISO after the day-ahead market, which are important because they influence the real-time market results.
- The average quantity of capacity committed through SRE in New York City has increased slightly in 2005.
  - ✓ A major reason for SREs are nitrous oxides (NOx) emission limits that require certain baseload units to operate in order for gas turbines to operate.
- Since SREs are ordinarily called by individual transmission operators, the uplift associated with them constitutes a large share of RT Local Reliability Uplift, and is allocated to the local area.

Supplemental Resource Evaluation Commitment 2004 & 2005

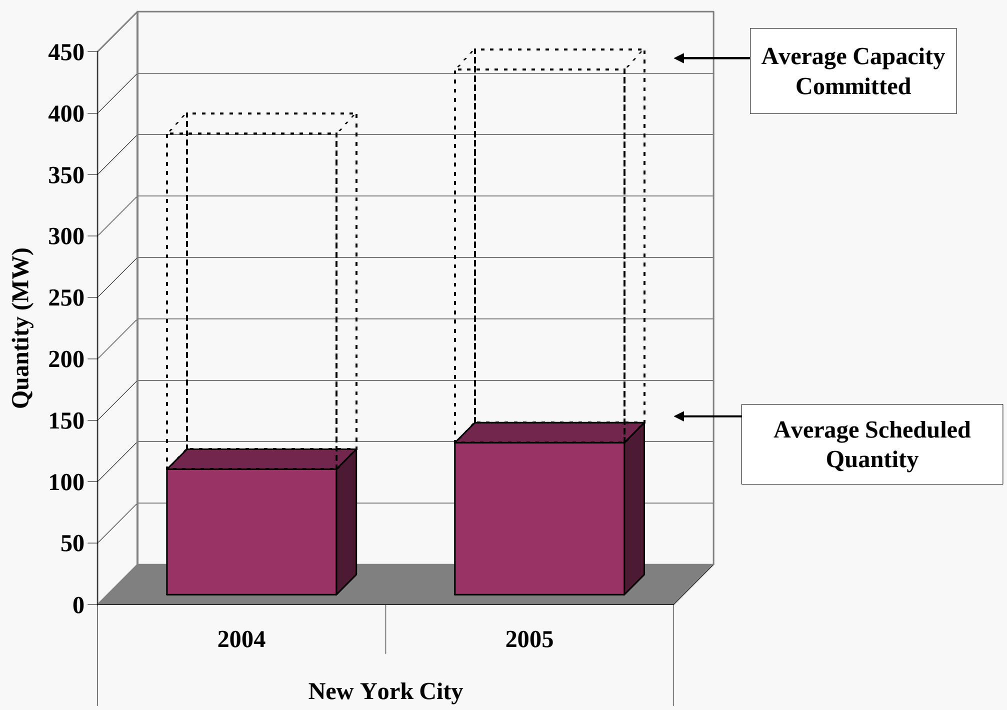


Day-Ahead Local Reliability Commitment

- The next analysis focuses on commitments made in the day-ahead market (i.e., by SCUC) to meet local reliability requirements.
- These commitments are not made because they are economic to serve day-ahead load. However, they are important because they tend to:
  - ✓ Reduce prices from levels that would result from a purely economic dispatch; and
  - ✓ Can increase non-local reliability uplift – a portion of the uplift caused by these commitments is incurred to make guarantee payments to other generators that will not cover their as-bid costs at the reduced price levels.
- The following figure shows the average quantity of these commitments.
  - ✓ The average energy scheduled for local reliability was approximately 120 MW during the period shown in 2005, a modest increase over 2004.



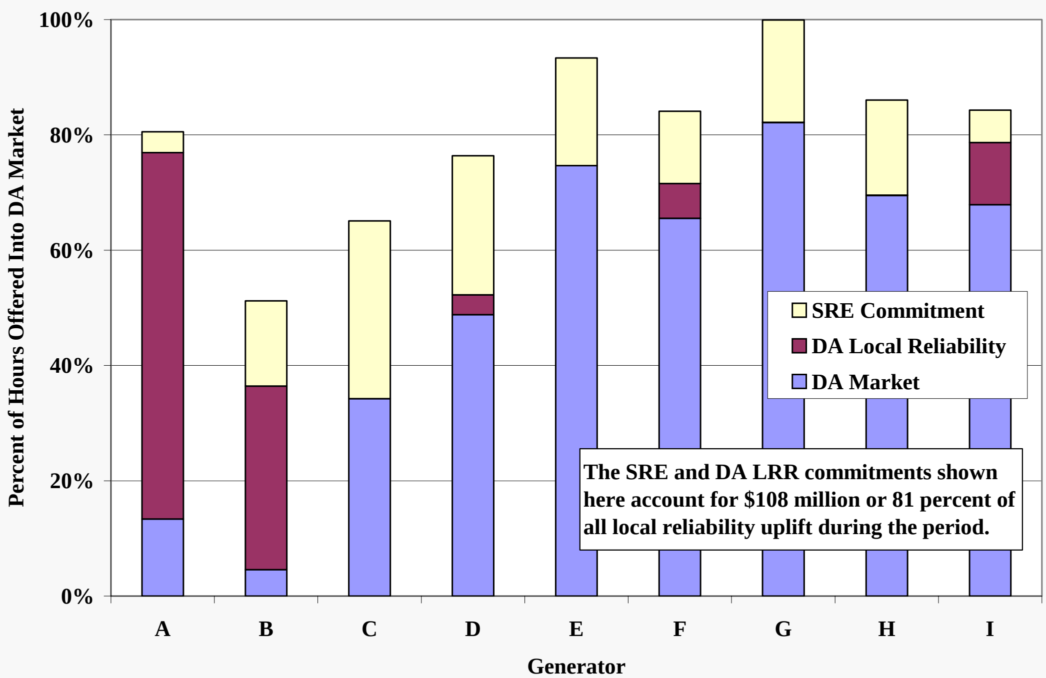
SCUC Local Reliability Pass Commitment February to December, 2004 & 2005



Units Frequently Committed for Local Reliability

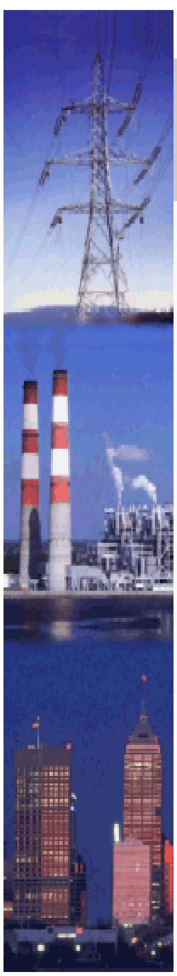
- To further evaluate both the local reliability and SRE commitments, we analyze them at the individual unit level.
- The following figure shows nine units committed very frequently for local reliability or through the SRE process in NYC and Long Island.
  - ✓ The values shown are the hours that each unit is committed as a percent of the hours that the unit is available to the day-ahead market (i.e., not on outage).
  - ✓ Commitment of these units for local reliability accounted for 81 percent of all local reliability uplift costs during the period.
  - ✓ Six of these units are in NYC and three are on Long Island.
- When these units were available but not committed economically, they were generally committed in the local reliability pass of SCUC or through SRE at least half the time.
  - ✓ It would be more efficient for these units to be committed within the economic pass of SCUC because it may cause SCUC to not commit units in other locations, which would reduce uplift and improve energy prices.

Units Most Frequently Committed by SRE and the Local Reliability Pass of SCUC in NYC and Long Island February to December, 2005



Supplemental Commitment Conclusions

- Supplemental commitments have a number of significant market effects:
  - ✓ Inefficiently reducing prices in the day-ahead and real-time markets;
  - ✓ When they occur in a constrained area, they will inefficiently dampen the apparent congestion into the area; and
  - ✓ Increasing uplift as units committed economically will be less likely to recover their full offer production costs;
- Local reliability commitments increased slightly from 2004 to 2005, but have increased significantly since 2002.
- To reduce the inefficiency and uplift associated the supplemental commitments we recommend:
  - ✓ In the short-run, that the ISO allow operators to pre-commit units needed for NOx compliance or other local reliability needs; and
  - ✓ In the long-run, that the local reliability and NOx constraints be included in the initial economic commitment pass of SCUC.

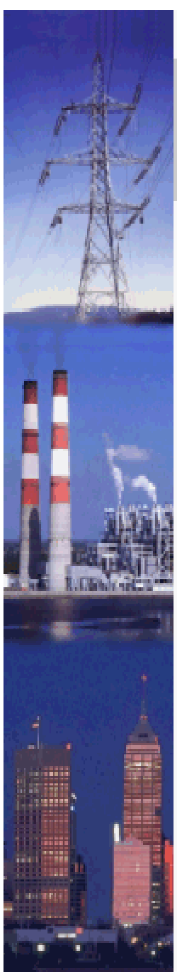


Supplemental Commitment Conclusions

- Both of these recommendations will require the NYISO to work with participants to revise the cost allocation methodology for uplift associated with the local reliability requirements.
  - ✓ Currently, the uplift costs associated with payments made to units supplementally committed to meet the requirements are allocated locally.
  - ✓ Payments made to other units due to the price changes caused by the supplemental comments are allocated throughout NYCA.
  - ✓ When the recommendations are implemented, a methodology would need to be developed to identify units due to the local reliability requirements.

Capacity Market

POTOMAC ECONOMICS



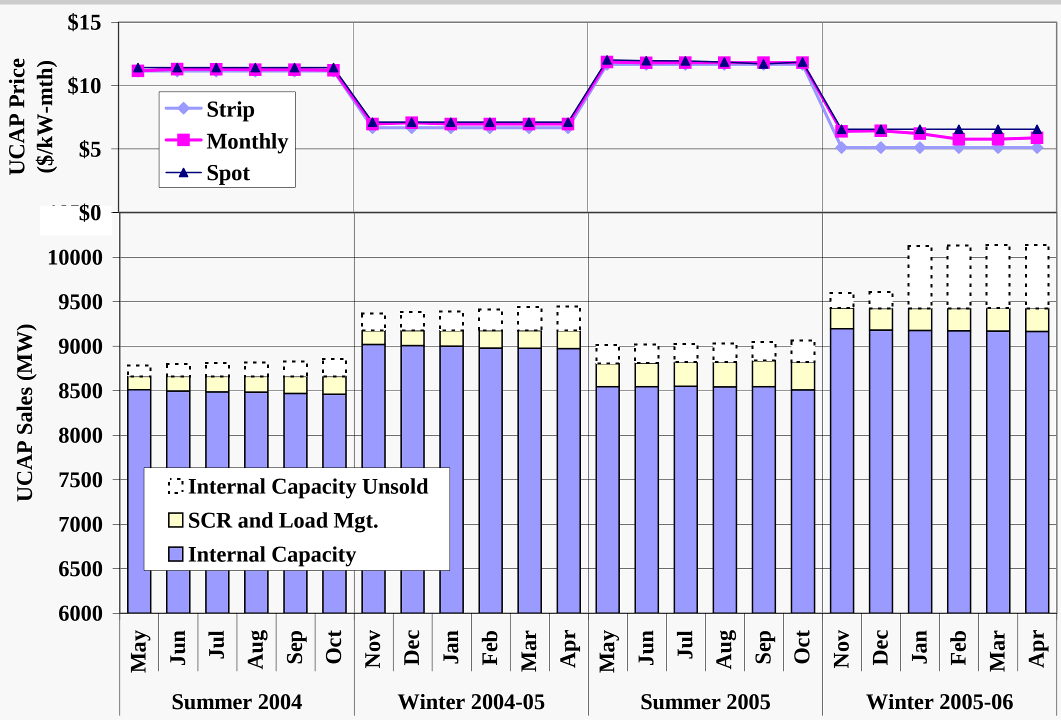
Capacity Market – Background

- The capacity market complements the energy and ancillary services markets to provide efficient economic signals for investment and retirement decisions.
- LSEs have several ways to satisfy their capacity obligations. They can:
  - ✓ "Self-schedule" their own generating capacity;
  - ✓ Purchase capacity through bilateral contracts; or
  - ✓ Participate in voluntary forward auction markets run by the NYISO.
- LSEs must purchase additional capacity in the final spot auction if they have remaining obligations.
  - ✓ LSEs that have purchased more than their obligation prior to the spot market, may sell the excess in the final spot auction.
- To improve the performance of the capacity markets, a demand curve was introduced in May 2003 in the monthly deficiency auction.
  - ✓ Each LSE's capacity obligation is determined by the intersection of supply in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).

Capacity Market – New York City

- The following figure shows the resources available to provide UCAP in New York City versus the amounts actually scheduled. The figure also shows the UCAP prices that cleared in the NYISO-run auction markets.
- Substantial new capacity became available in New York City during this period.
  - ✓ Approximately 275 MW came on-line before the Summer 2005 Capability Period.
  - ✓ Approximately 500 MW came on-line in January 2006.
  - ✓ Demand response has increased by approximately 150 MW over the 24 months shown.
- After the addition of new capacity in January 2006, there was virtually no increase in the amount of scheduled UCAP, and correspondingly, no reduction in clearing prices from the In-City suppliers' price cap.
  - ✓ This occurred because a significant amount of existing capacity went unsold in the UCAP market.
  - ✓ The capacity market in NYC is highly concentrated and these results are consistent with suppliers' incentives

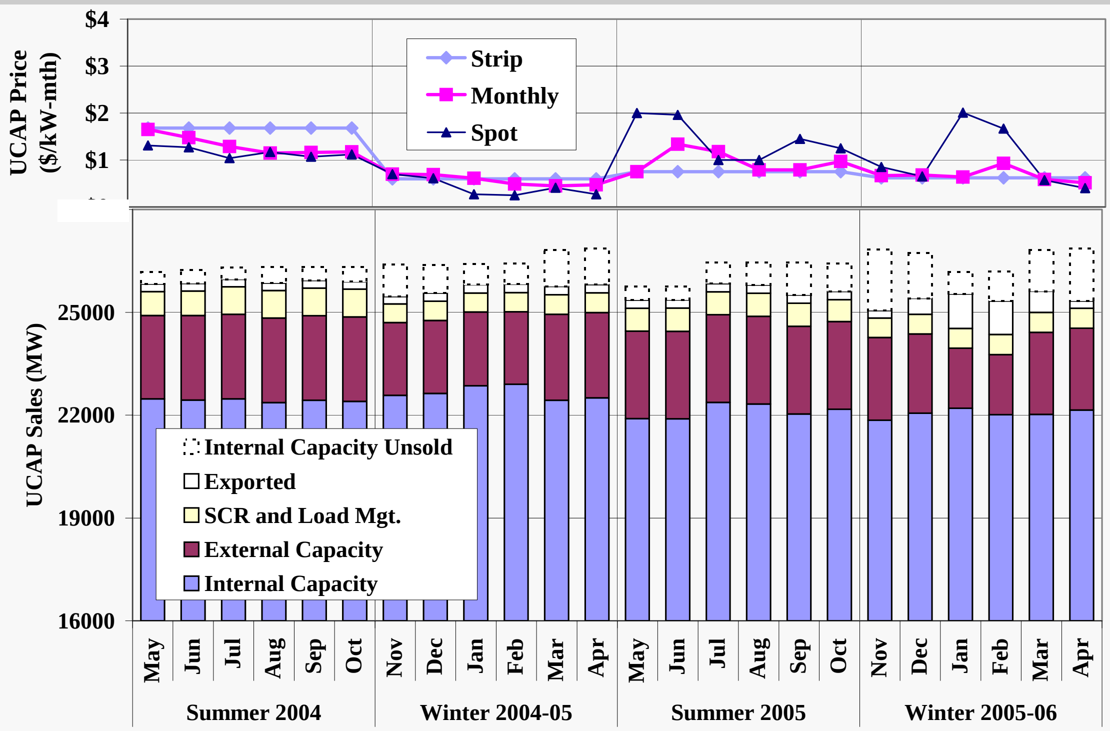
UCAP Sales – New York City



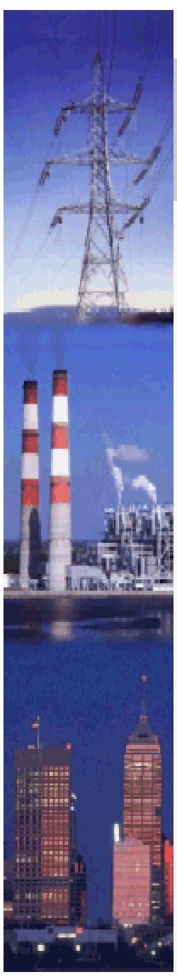
Capacity Market – Rest of New York State

- The following figure shows the available resources to provide UCAP outside New York City and Long Island versus the amounts actually scheduled and the clearing prices in the NYISO-run auctions.
- In up-state New York the amount of available UCAP has fluctuated due to:
  - ✓ The retirement of approximately 600 MW and installation of 700 MW.
  - ✓ The level of imports from other control areas has varied between 1,750 MW and 2,550 MW.
  - ✓ Demand response has increased by modestly over the period.
  - ✓ The UCAP that can be provided from individual resources varies with changes in the effective forced outage rate of the resource.
- While New York is a net importer of capacity, exports from New York rose in January and February 2006, leading to a rise in the spot auction price.

UCAP Sales – Rest of New York State



External Transactions



Efficient Utilization of the External Interfaces

- The performance of the wholesale electricity markets depends not only on the efficient utilization of the internal resources, but also the efficient utilization of the transmission interfaces between NY and other areas.
- The figures in this section contain our analysis of utilization of these interfaces.
- When the interfaces are efficiently utilized, one would expect that the hourly prices in adjacent areas would not differ greatly except when the interface capability is fully used (the interface constraint is binding).
- The following three figures plot the hourly difference in prices between New York and neighboring markets against net exports during hours when transmission constraints are not binding.

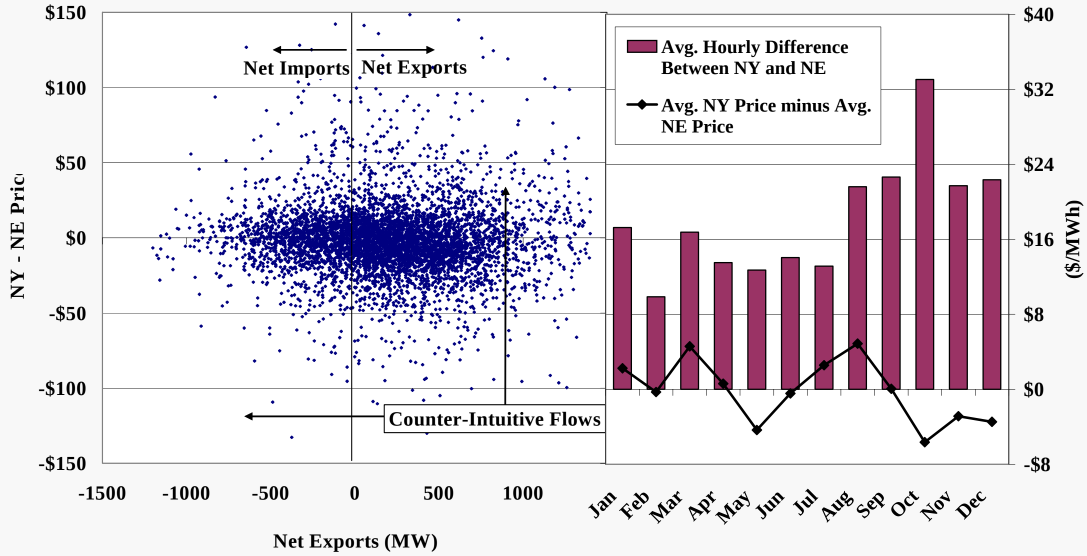
Efficient Utilization of the External Interfaces

- On the left side of the first three figures:
  - ✓ The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
  - ✓ The net exports are shown on the x-axis with positive values reflecting net exports from New York and negative values representing net imports.
  - ✓ Two "counter-intuitive" quadrants are shown where power is scheduled *from* the higher priced market *to* the lower priced market.
- On the right side of these three figures, the monthly average price differences between New York and the adjacent market are shown.
- These figures show that the real-time markets continue to not be efficiently arbitraged by participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.

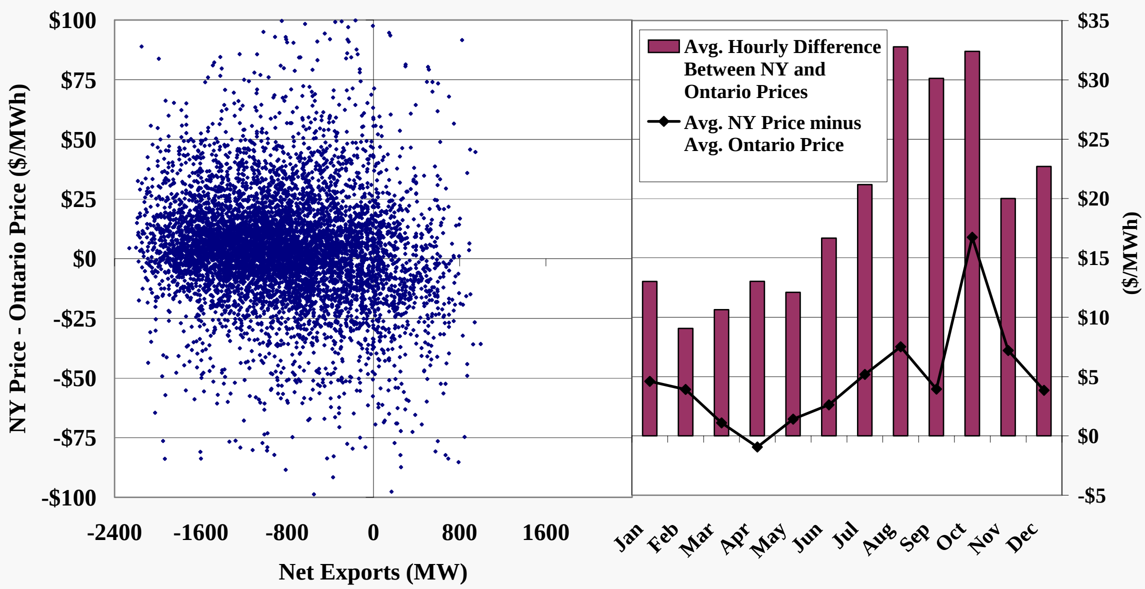
Efficient Utilization of the External Interfaces

- These results reinforce the importance of the provisions being developed to improve real-time interchange between New York and New England.
- These provisions will be particularly important when the capacity surpluses in the Northeast are eliminated – when optimizing the flow between areas will have larger economic and reliability consequences.
- Fees assessed to transactions between control areas tend to inhibit convergence.
  - ✓ At the beginning of 2005, export fees between New York and New England were eliminated, which should facilitate arbitrage of the adjacent markets.
  - ✓ Exports from New York and New England scheduled after the day-ahead market continue to be allocated charges for certain ISO/RTO operating costs.
    - – Prior to the fall of 2005, the method used by the ISO-NE for allocating these charges to exports could result in very large charges (on a per MWh basis) for some market participants.
    - – In the fall of 2005, the ISO-NE addressed this problem by allowing market participants to choose an alternative method which allocates on a per MWh basis.
  - ✓ Transactions from New York to New England scheduled after the day-ahead market continue to be allocated uplift for certain types of supplemental commitment by both ISOs. However, neither ISO assesses these charges to transactions that flow from New England to New York.

Real-Time Prices and Interface Schedules
Comparison of NY and NE Border Prices
Unconstrained Hours, 2005

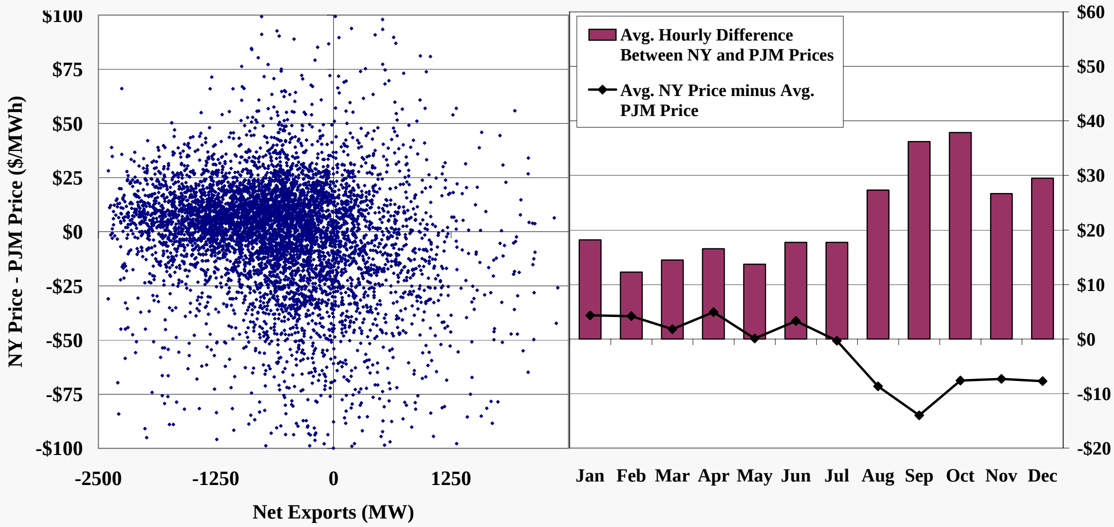


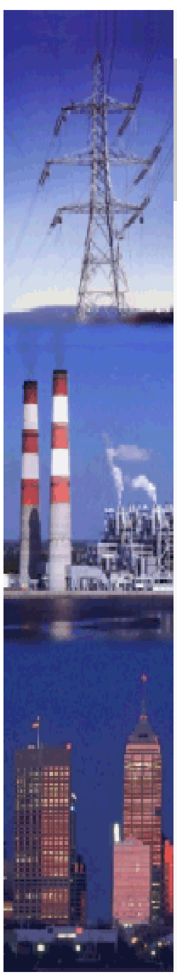
Real-Time Prices and Interface Schedules*
Comparison of NY Border and Ontario Prices
Unconstrained Hours, 2005



* Price difference measured in US dollars

Real-Time Prices and Interface Schedules Comparison of NY and PJM Border Prices Unconstrained Hours, 2005

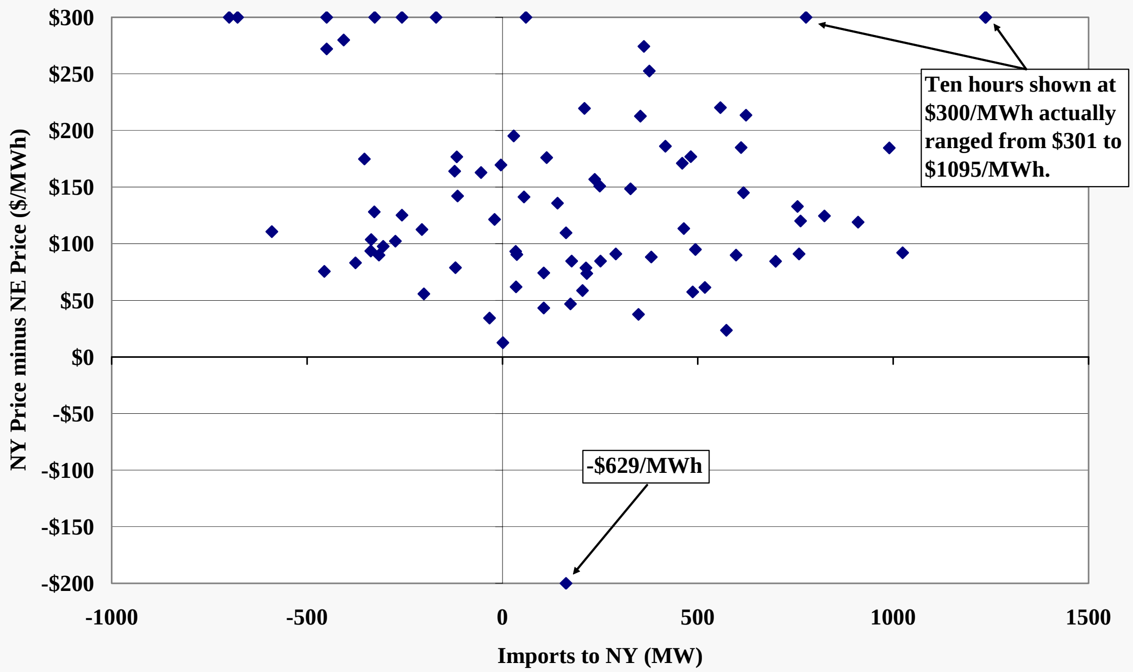




Interface Utilization During Scarcity Conditions

- During peak demand conditions, it is especially important to efficiently schedule flows between control areas.
- The following chart examines the difference between New York and New England real-time border prices in unconstrained hours where the Capital Zone price exceeded $200/MWh.
- Price convergence has been especially poor during peak demand conditions:
  - ✓ 18 of 82 hours show the NY price is higher by more than $200/MWh.
  - ✓ 50 of 82 hours show the NY price is higher by more than $100/MWh.
  - ✓ In 29 of the hours shown, power was flowing out of NY, even though the NY price was higher.
- Frequent during peak demand conditions, a small amount of additional imports can substantially reduce the magnitude of a price spike. This underscores the potential benefits of ITS (Intra-hour Transaction Scheduling) especially during peak demand periods.

Interchange and Price Differences Between NY and NE
Unconstrained Eastern NY Price Spike Hours*
2005



* Includes hours when the RT Capital zone price exceeded $200/MWh.