# Six Month Assessment of the NYISO Markets Under SMD2

David B. Patton, Ph.D.
Potomac Economics Ltd.

Independent Market Advisor

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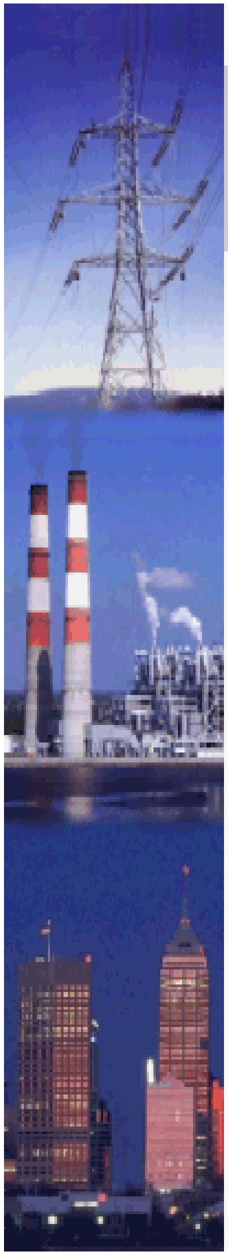
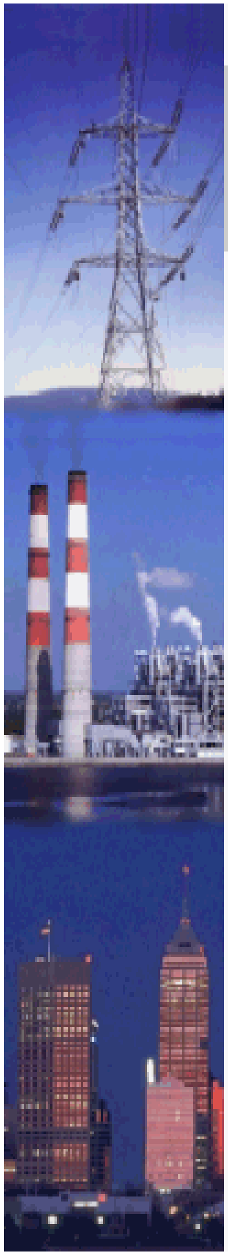


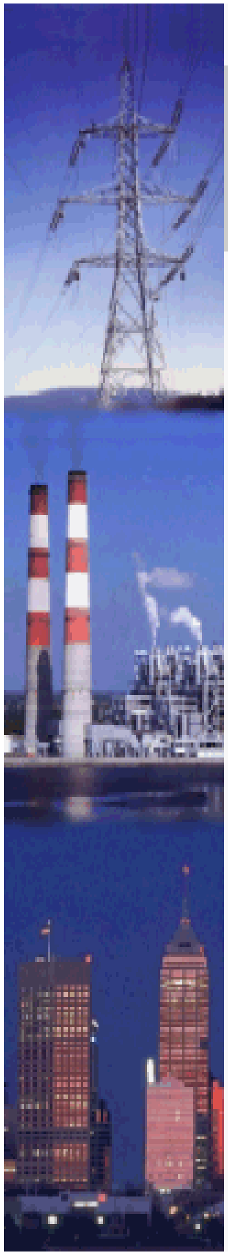
# Introduction

- 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 presentation summarizes our evaluation of the operation and performance of the New York wholesale markets during the first six months of SMD2.
- Many of the analyses contained in this report will be extended to the end of 2005 in the 2005 State of the Market Report.



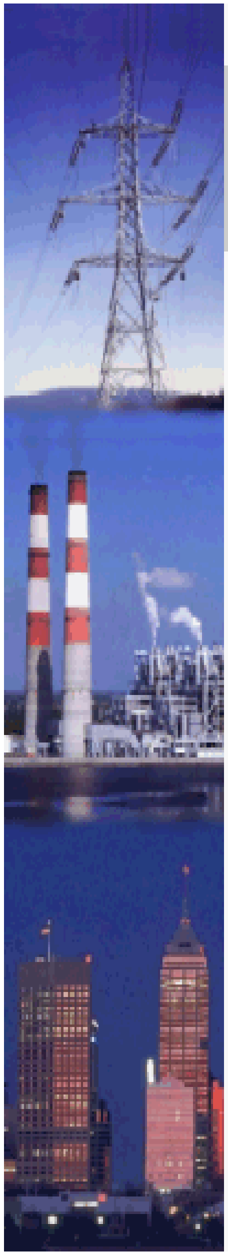
# Summary of Conclusions

- Under SMD2, co-optimization of the energy and reserves markets using the demand curves for ancillary services has substantially improved the efficiency of pricing for energy and ancillary services.
  - ✓ The real-time model can re-allocate energy and ancillary services to respond to changes in supply and demand on a five minute basis.
- The new “real-time commitment” model (“RTC”), is a major improvement over the former BME model.
  - ✓ RTC runs every 15 minutes, looking ahead two hours and 30 minutes when making scheduling and commitment decisions;
  - ✓ Use of the new model has resulted in better convergence between “hour-ahead” and real-time prices; and
  - ✓ Gas turbine commitment and external transaction scheduling have become more efficient under RTC, leading to reductions in uplift.



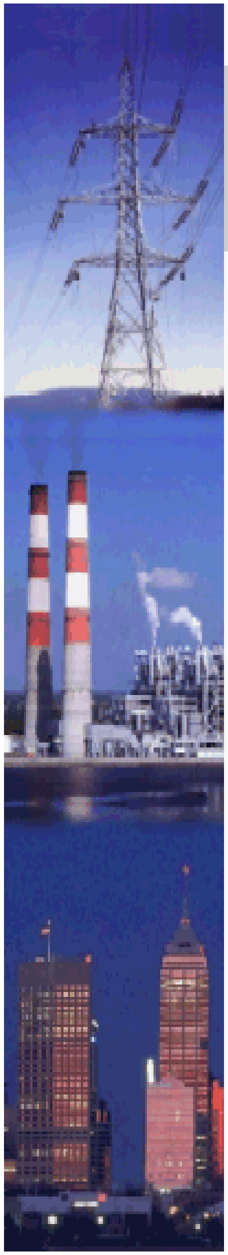
## Summary of Conclusions

- From February to August 2005, electricity prices were substantially higher than in the same months of 2004. The rise is primarily due to:
  - ✓ Increased fuel costs, including a 26 percent increase in the average price of natural gas; and
  - ✓ More frequent peak pricing events due to hotter summer weather.
- 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.
  - ✓ However, these improvements were partly mitigated by peak summer conditions and higher overall levels of congestion that led to increased uplift from balancing congestion costs.



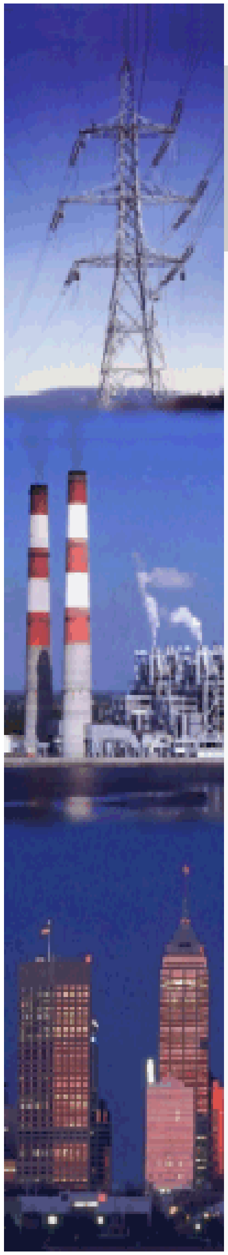
# Summary of Conclusions

- We evaluated market outcomes during periods of shortage for 10-minute reserves in eastern New York. This is the most important reserves product based on the cost of meeting the requirement.
  - ✓ 99 percent of peak pricing events occurred during periods of actual shortage.
    - – However, roughly 10 percent of the shortages would not have occurred if RTD had recognized certain available offline reserves.
  - ✓ There were 267 intervals (i.e., approx. 20 hours) when physical shortages occurred that were not fully reflected in prices, primarily due to differences between the physical dispatch and the pricing dispatch.
  - ✓ 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.



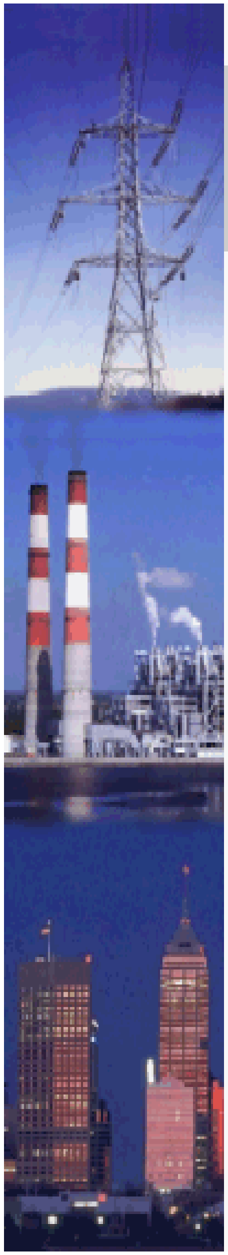
# Summary of Conclusions

- Convergence between day-ahead and real-time prices for energy and ancillary services was poor compared with previous years.
  - ✓ For the first time, average day-ahead prices were considerably lower than average real-time prices.
  - ✓ 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-scheduling of load (including net virtual load) in the day-ahead market during July and August also contributed to the lack of convergence.
- Since the start of the NYISO markets, inconsistencies between day-ahead and real-time have contributed to balancing congestion costs that are uplifted to the market.
  - ✓ Under SMD2, improvements were made to the accuracy of day-ahead transmission loss modeling that have reduced balancing congestion costs.
  - ✓ However, some inconsistencies remain between the day-ahead and real-time markets.
  - ✓ Tighter conditions and higher fuel prices increased overall congestion levels, also increased balancing congestion uplift.



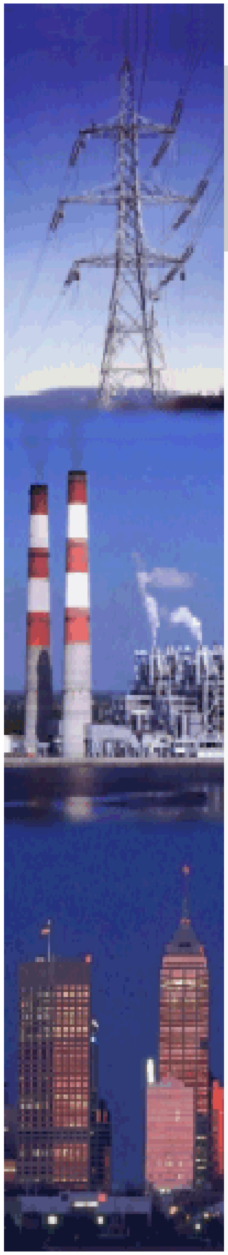
# Summary of Conclusions

- 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. During 21 hours when the Capital Zone price exceeded $200/MWh:
  - ✓ The average price on the New York side of the border was $286/MWh higher than the New England side.
  - ✓ The average level of flow into New York was 204 MW even though the total transfer capability generally exceeds 1000 MW.
- 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.



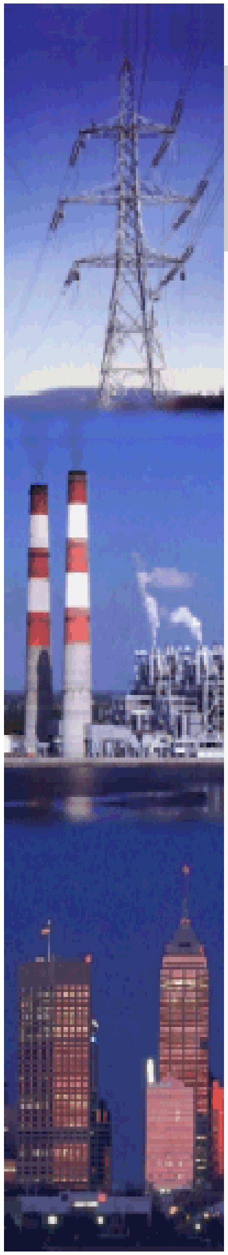
# Areas of Potential Improvement and Recommendations

- Day-ahead to real-time price convergence is likely to improve as market participants gain experience with the current market.
  - ✓ If convergence does not improve, we will be evaluating in the State of the Market Report to be issued later this Spring whether expanding virtual trading to include reserves would improve market performance.
- Good convergence in load pockets is unlikely to be achieved without modeling changes and/or virtual trading in the load pockets.
  - ✓ Work is underway to model individual transmission lines and contingencies in NYC, rather than just simplified interfaces in the real-time market.
  - ✓ This will allow greater utilization of the transmission system within New York City and improve economic efficiency.
  - ✓ Additionally, since the SCUC models individual lines, the inconsistent modeling in real time contributes to the balancing congestion costs that are uplifted to the market.
  - ✓ Hence, we recommend the completion of the work on operating procedures necessary to model individual transmission elements in RTD.
  - ✓ If that does not achieve good convergence in the load pockets, we recommend the expansion of virtual trading to the NYC load pockets.



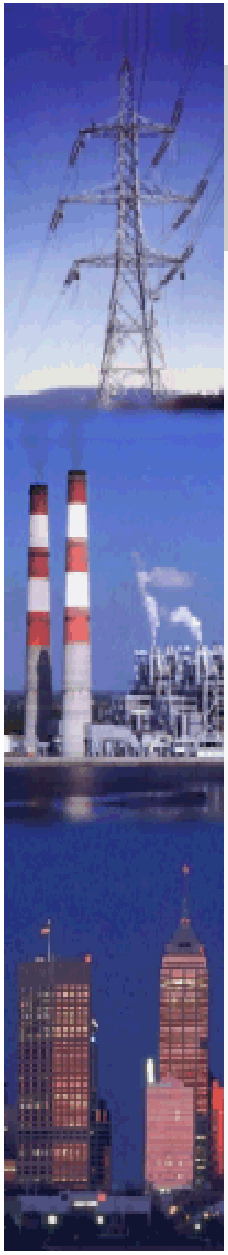
# Areas of Potential Improvement and Recommendations

- Since the initial implementation of SMD2, RTD has re-allocated energy and ancillary services among on-line units every five minutes.
  - ✓ Off-line quick-start gas turbines were incorporated into the five minute co-optimization in August.
  - ✓ However, off-line quick-start non-GT units are not considered for non-spinning reserves by RTD if they are not scheduled by RTC.
- We recommend that the NYISO evaluate whether it is operationally feasible to allow RTD to schedule off-line quick-start non-GT units for non-spinning reserves, even if they are not already scheduled by RTC.
  - ✓ This change will help ensure that shortage prices occur only when all available resources are being used to provide energy or reserves.



# Areas of Potential Improvement and Recommendations

- The implementation of RTD has greatly improved the efficiency of price signals for energy and reserves in real-time.
  - ✓ However, there are sometimes significant inconsistencies between the physical conditions in the market and the market prices.
  - ✓ There are cases where eastern New York is:
    - Short of 10-minute reserves when real-time prices do not reflect the shortage; and
    - Real-time prices indicate a shortage of 10-minute reserves when there is no physical shortage of reserves.
  - ✓ In the SOM the Market Report, we will be fully evaluating the relationship between the physical dispatch and the pricing passes of RTD, identifying potential improvements in the current hybrid pricing methodology.
- Transmission constraint shadow prices can reach extremely high levels for brief periods when there are not sufficient resources to resolve the congestion.
  - ✓ 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

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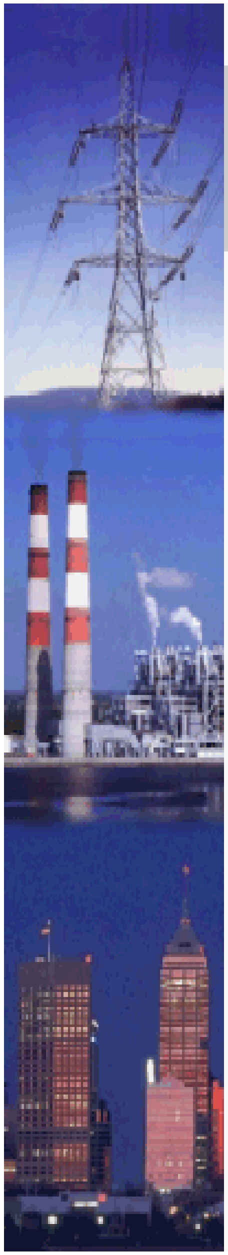
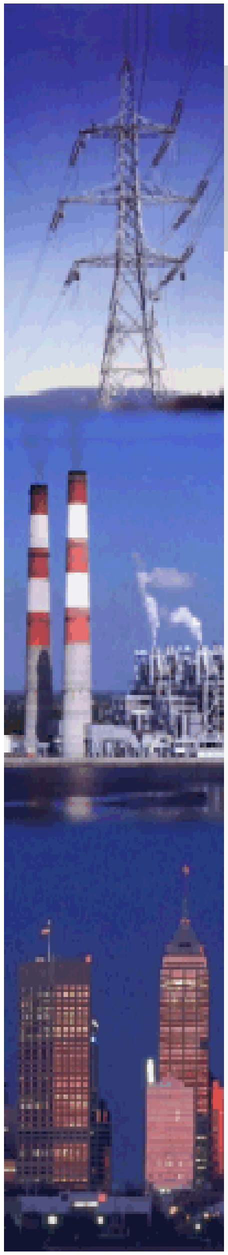
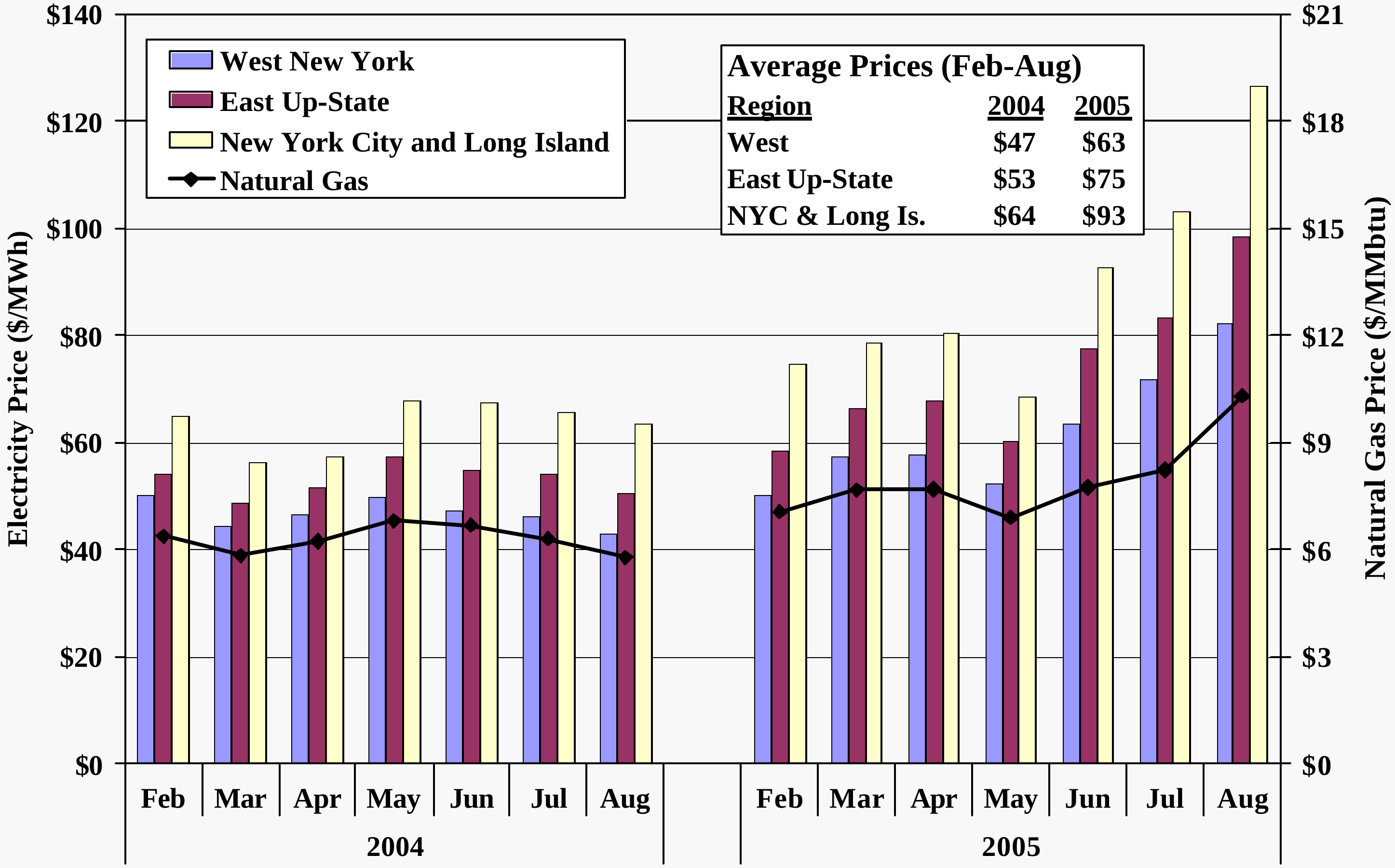


# Fuel Prices and Energy Prices

- The following figure shows monthly energy prices for the first seven months of SMD2 in 2005 compared to the same period in 2004.
- Rising fuel prices led to corresponding increases in electricity prices in 2005:
  - ✓ Natural gas prices were an average of 26 percent higher during the period shown in 2005 compared with the same period in 2004.
  - ✓ The 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.
- Prices rose significantly in 2005 due to hot summer weather, while the summer of 2004 was comparatively mild.
- The table in the figure shows that regional price differences, resulting from congestion and losses, were larger in 2005. NYC and Long Island prices exceeded Western New York prices by:
  - ✓ 36 percent in 2004; and
  - ✓ 51 percent in 2005.

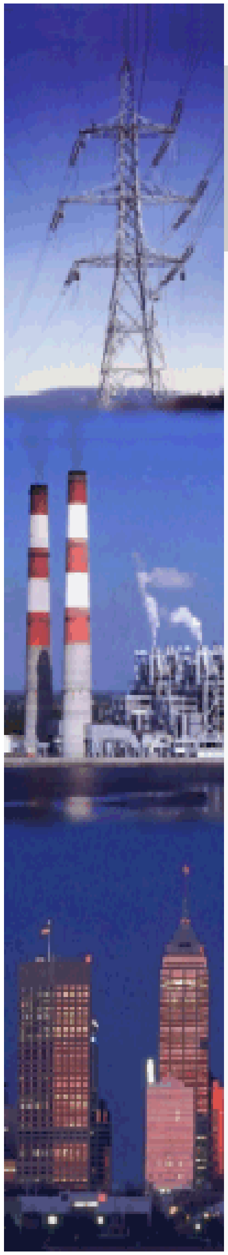


# Energy and Natural Gas Prices
## February to August, 2004 to 2005



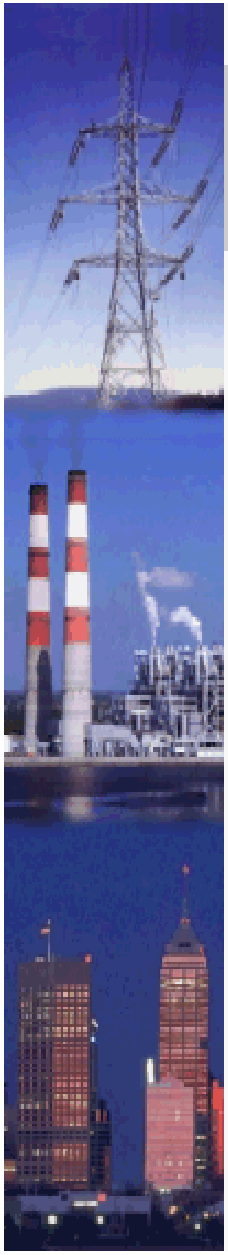

Average Prices (Feb-Aug)

| Region | 2004 | 2005 |
|---|---|---|
| West | $47 | $63 |
| East Up-State | $53 | $75 |
| NYC & Long Is. | $64 | $93 |

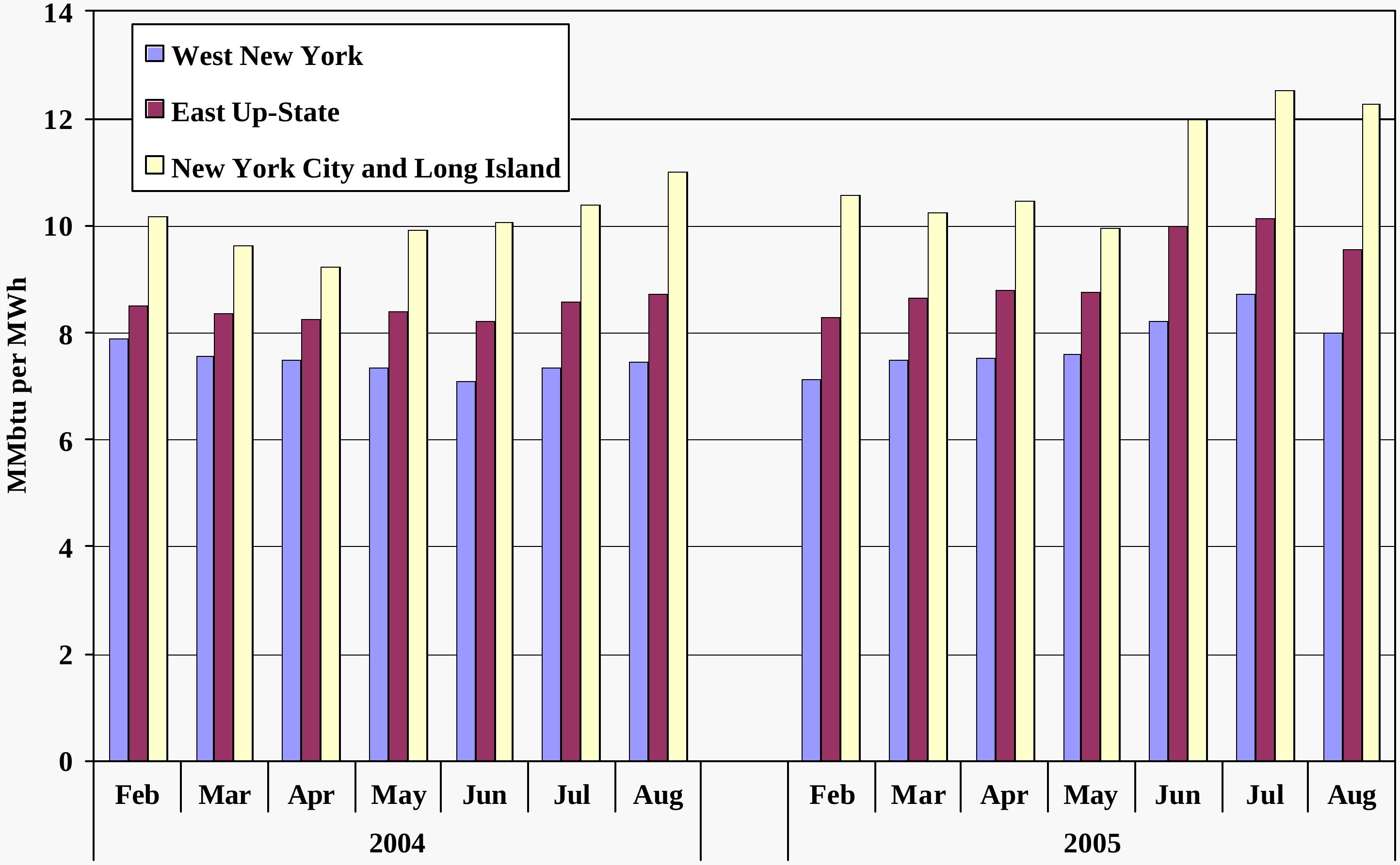


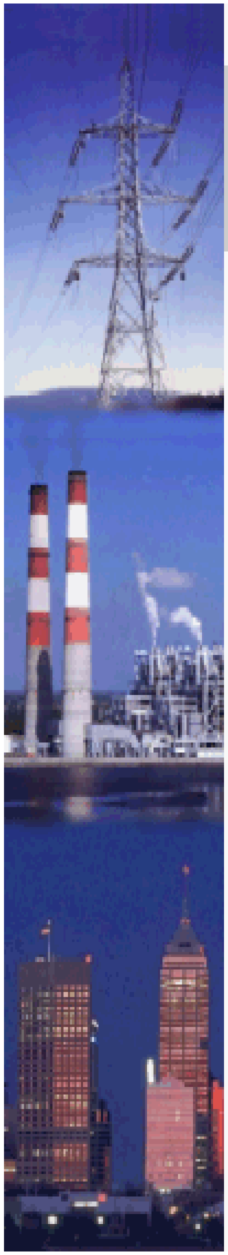
# Fuel Prices and Energy Prices

- 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:
  - ✓ Implied heat rates increased by 10 to 20 percent during the study period in 2005 due to high summer demand;
  - ✓ An increase in regional price differences in 2005 due to additional congestion and losses.



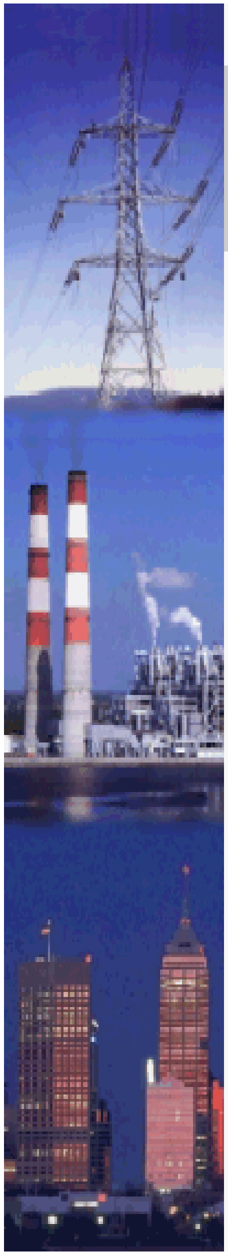
# Average Implied Marginal Heat Rate
## Based on Day-Ahead Electricity and Natural Gas Prices
## February to August, 2004 – 2005





# Load Profile

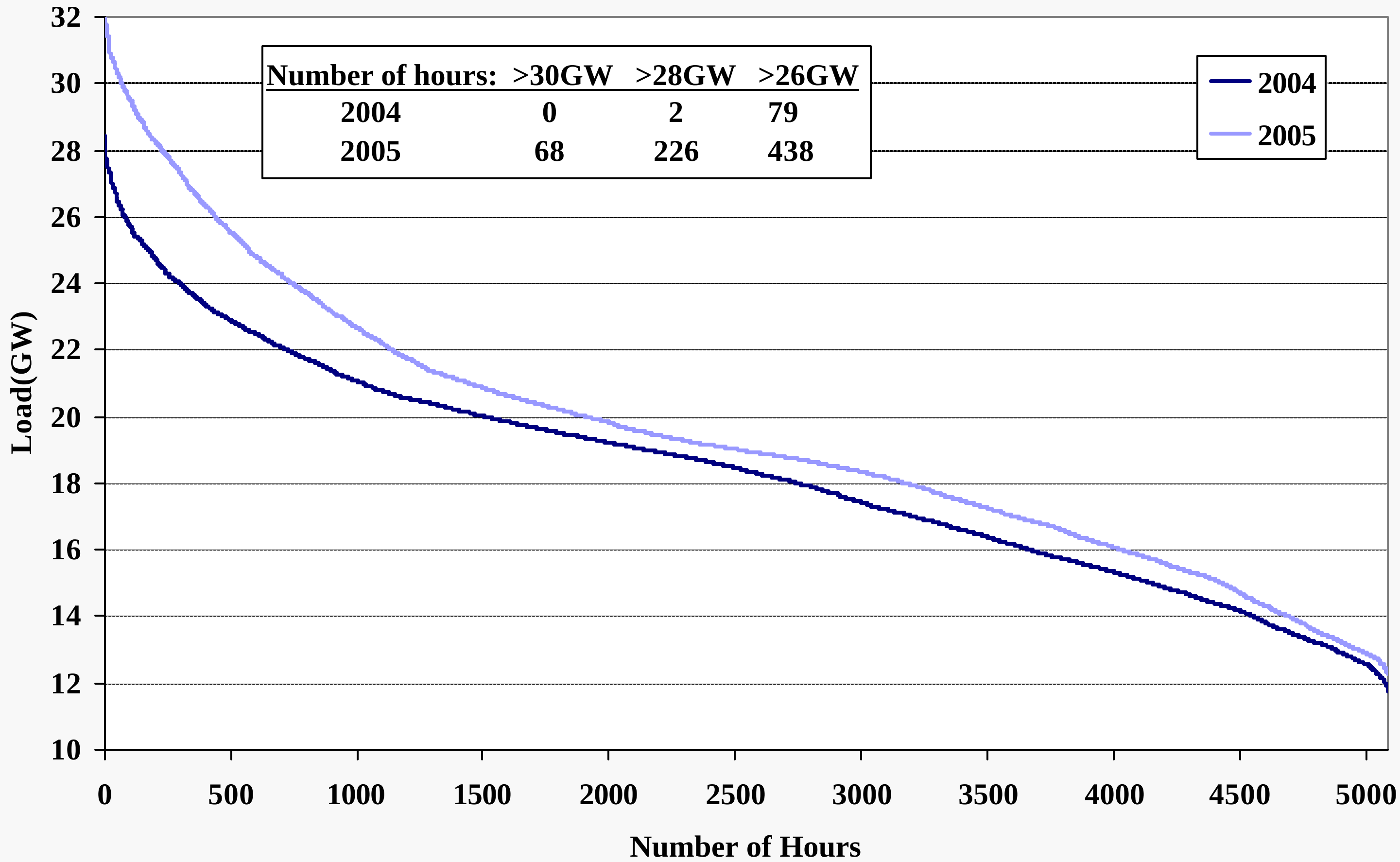
- The next figure shows load duration curves for February to August, 2004 and 2005.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- The absence of severe price spikes during 2004 was primarily due to mild summer demand
- In 2005, 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 226 hours when actual loads exceeded 28 GW, and just 2 of these hours in 2004.



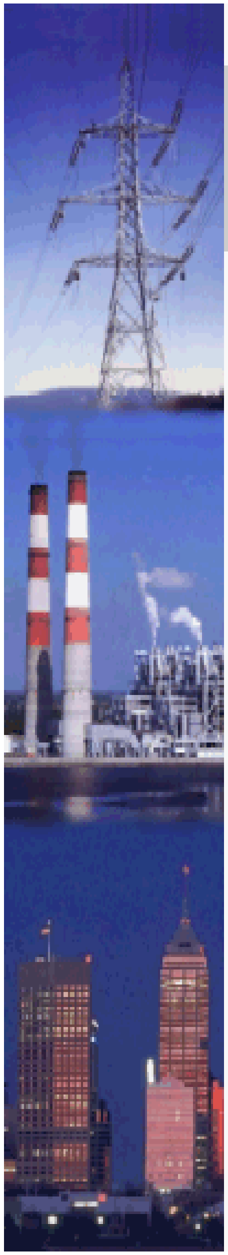
# Load Duration Curves*

## New York State Hourly Average Load

## February to August, 2004 to 2005

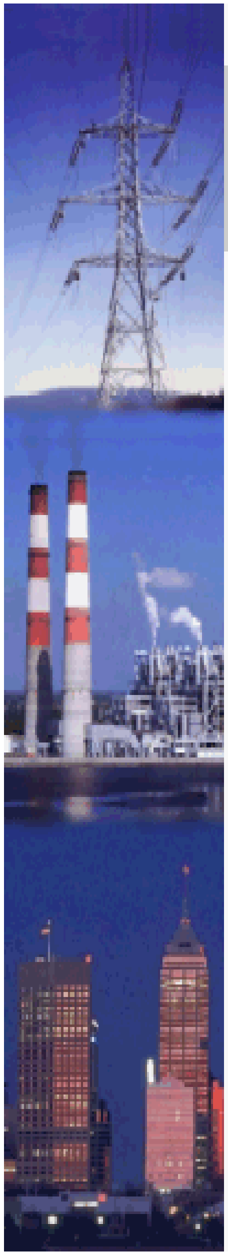



* Includes real-time demand and transmission losses.

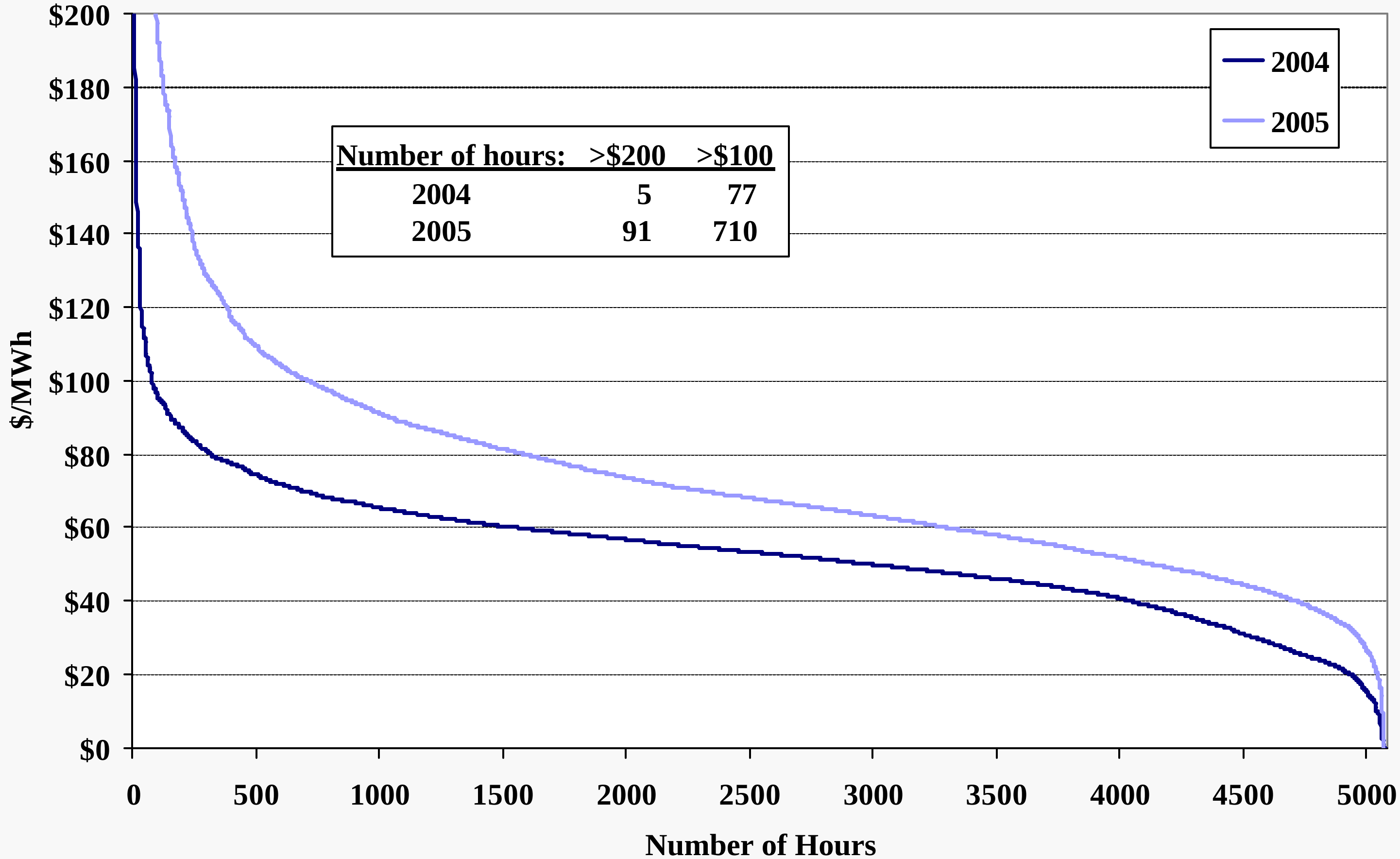


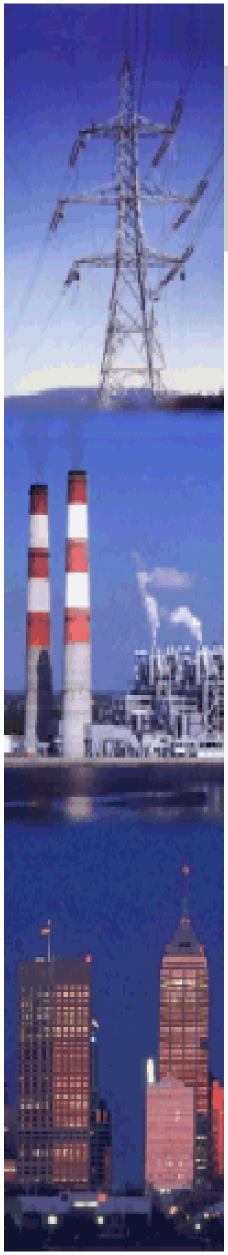
# Energy Prices

- The first of the two following figures shows real-time price duration curves for February to August, 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, particularly due to more frequent price spikes:
  - ✓ In 2005, there were 710 hours with prices above $100, compared to 77 such hours in 2004.
  - ✓ In 2005, there were 91 hours with prices above $200, compared to 5 such hours in 2004.
- To isolate the peak prices that are not caused by high gas prices, the second figure shows duration curves for implied heat rates during the same period:
  - ✓ In 2005, high summer demand led to 123 hours where implied heat rates exceeded 20 MMbtu/MWh, whereas in 2004, only 26 such hours occurred.
  - ✓ Outside of peak conditions, implied heat rates were comparable between 2004 and 2005.

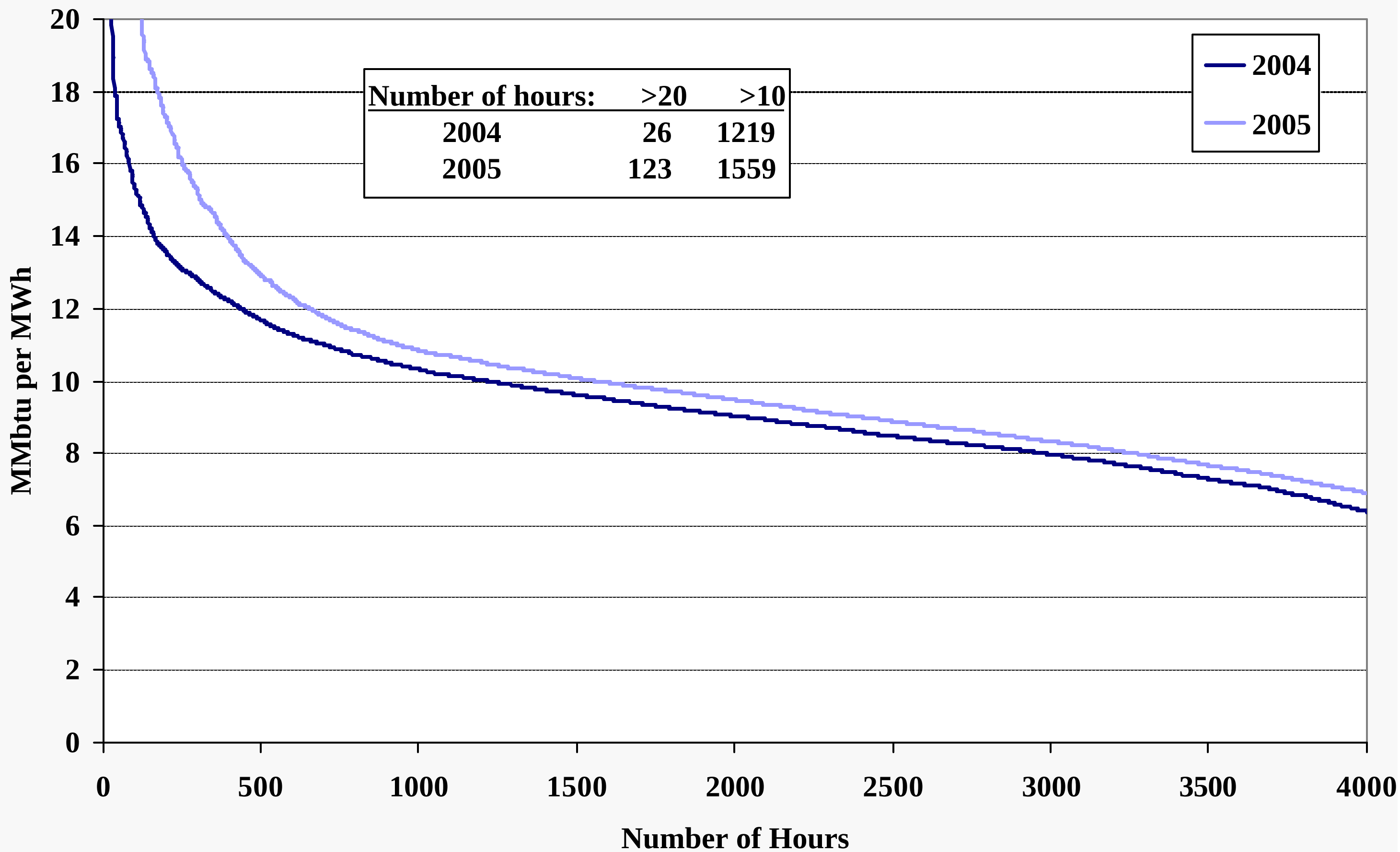


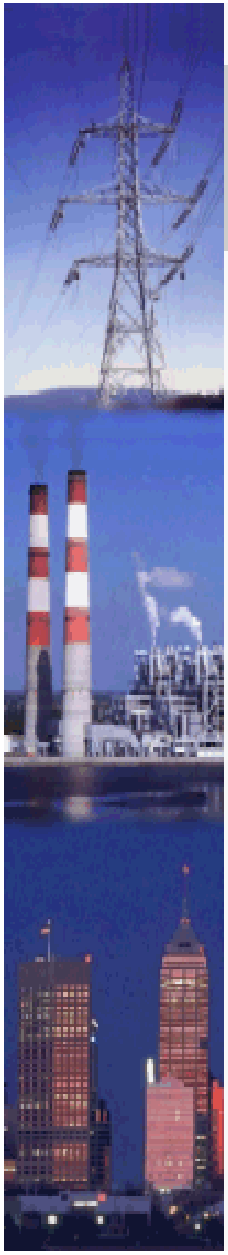
# Price Duration Curves
## New York State Average Real-Time Price
## February to August, 2004 to 2005





# Implied Heat Rate Duration Curves
## Based on New York State Average Real-Time Price
## February to August, 2004 to 2005

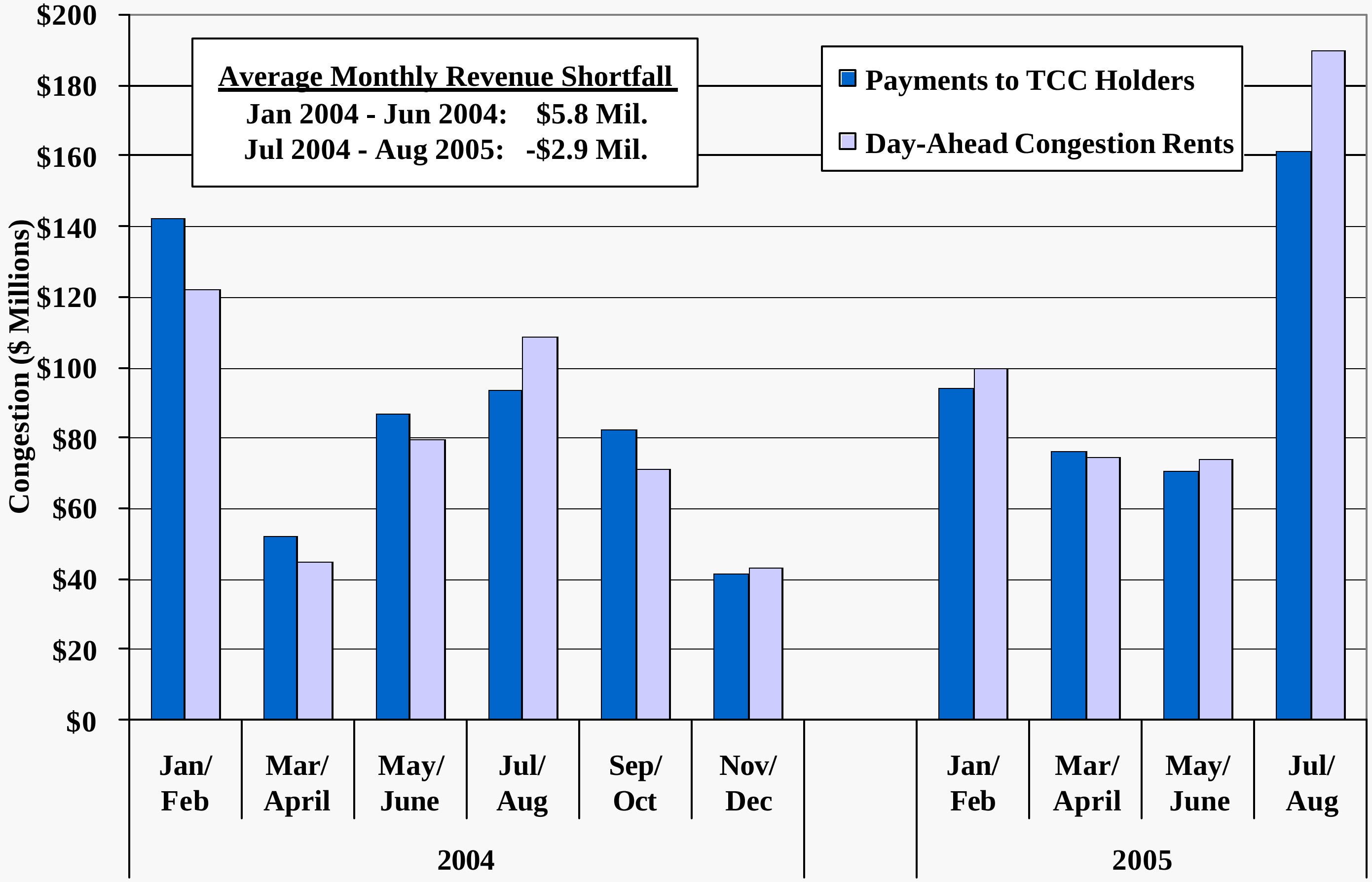


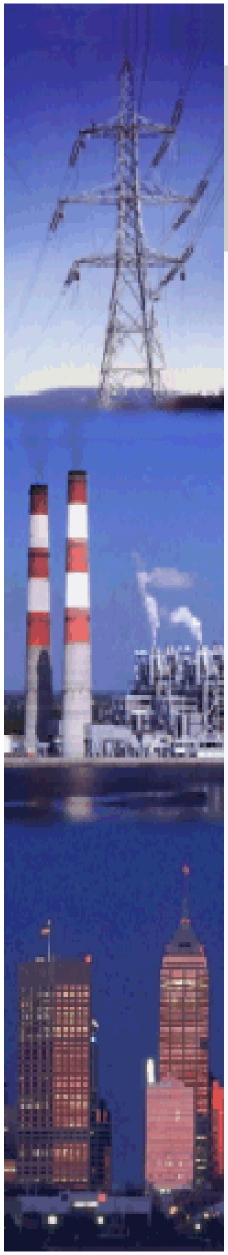


# Congestion Revenue and TCC Obligations

- 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 occurs when the transmission capability assumed in the TCC auction exceeds 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 the following changes to reduce the shortfalls:
  - ✓ Allow up to a 5% reduction in the quantity of TCCs offered in the auction by each transmission owner;
  - ✓ Assessing shortfall costs resulting from maintenance to individual transmission owners has likely improved their incentives to minimize these costs.
- The only shortfalls during the 2005 study period were in March/April, which are primarily due to transmission outages reflected in the DAM market that were not included in the TCC auction. Maintenance outages are most frequently scheduled in off-peak seasons.

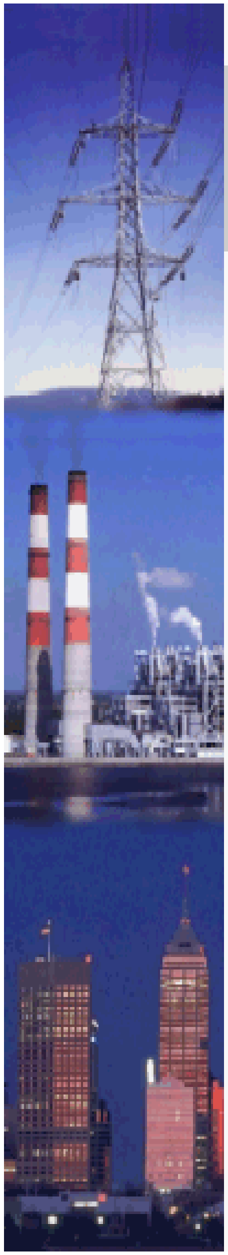
# Day-Ahead Congestion Rents and TCC Payments
## January 2004 to August 2005





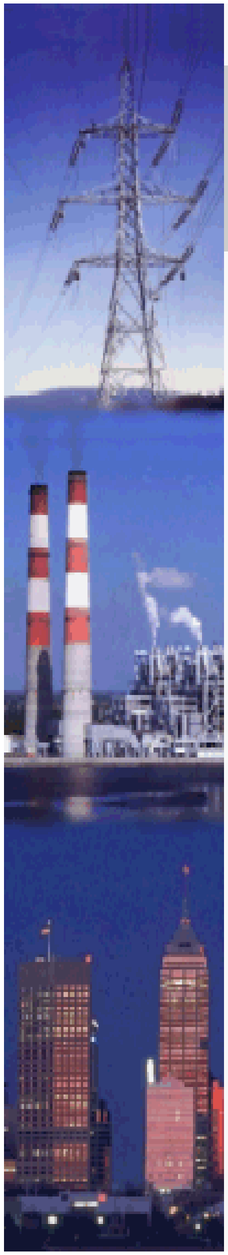
# Uplift Charges to All of New York State

- 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 day-ahead market and rebated (or charged) to loads.
  - ✓ Balancing Congestion Costs – When transmission is oversold through the day-ahead market, NYISO customers must buy back the excess in real-time.

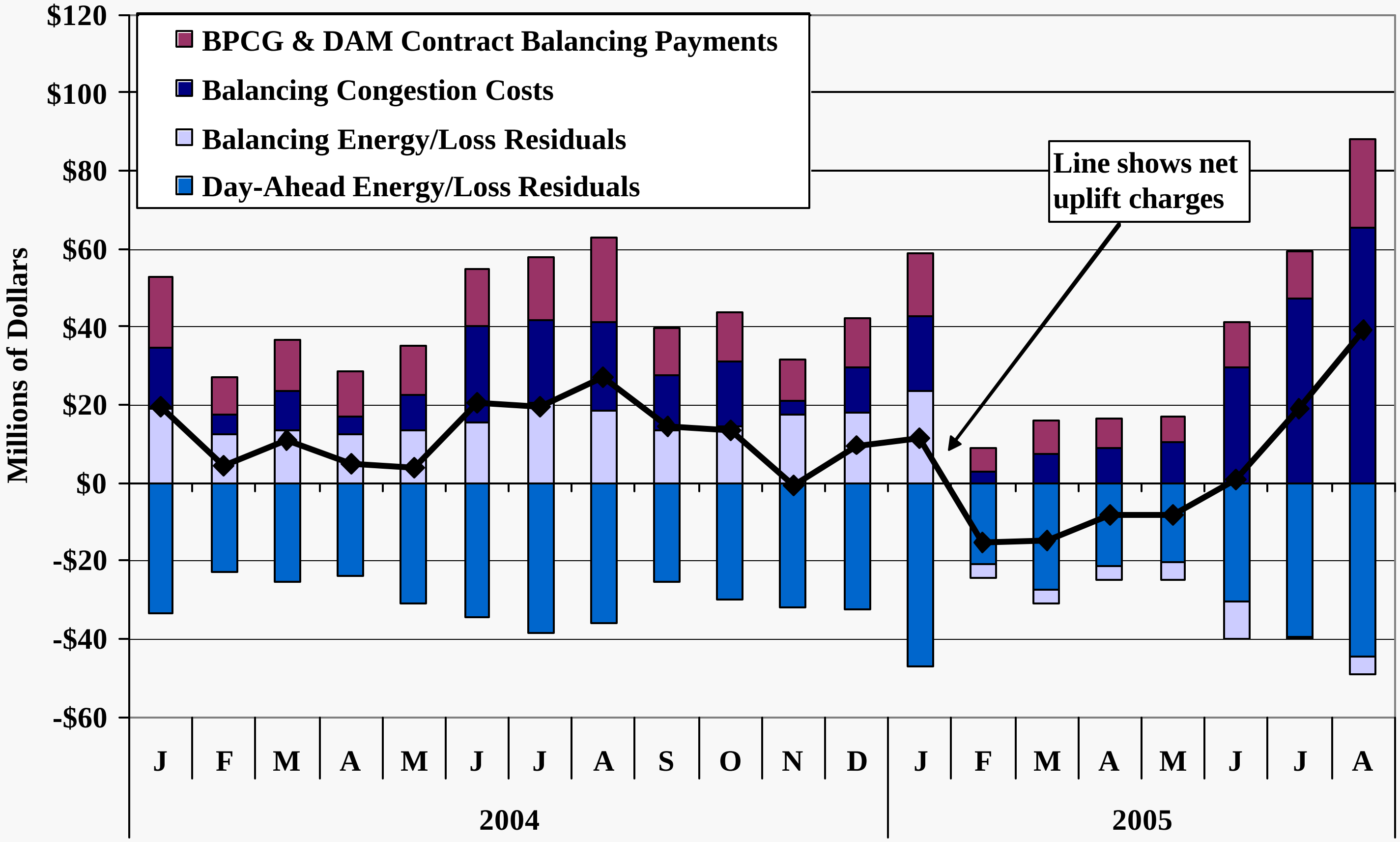


# Uplift Charges to All of New York State

- The figure shows a significant decline in net uplift charges immediately after the implementation of SMD2.
  - ✓ From February through May, 2005, there was a net surplus of $46 mil.
  - ✓ In the same four months of 2004, there was a net charge of $24 mil.
- The initial 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:
  - ✓ Total congestion was higher in 2005, contributing to an increase in balancing congestion costs.
  - ✓ Thunder Storm Alerts led to real-time pricing events under de-rated transmission limits that significantly contributed to the balancing congestion costs. A portion of these costs are assessed to the local TO.

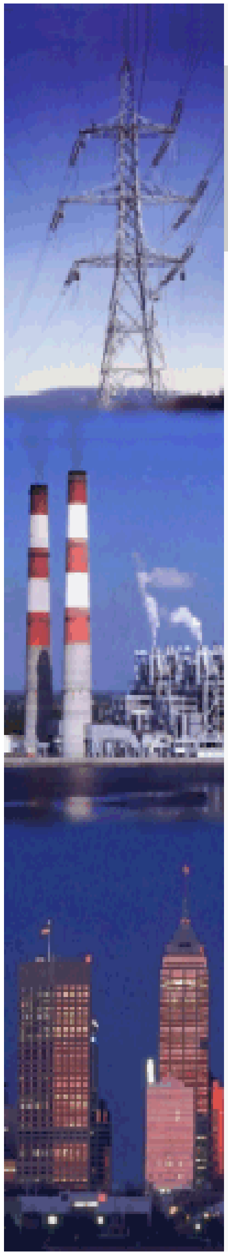


# Uplift Charged to NYCA
## January 2004 to August 2005



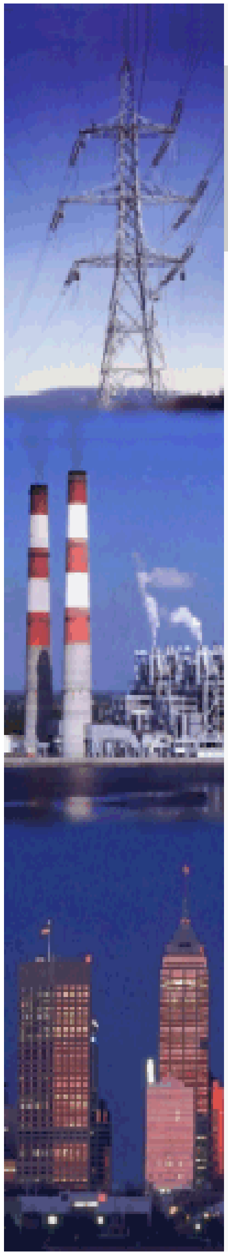

Note: The portion of Balancing Congestion Costs attributed to Thunder Storm Alerts is charged to the local TO.

# Day-Ahead to Real-Time Convergence



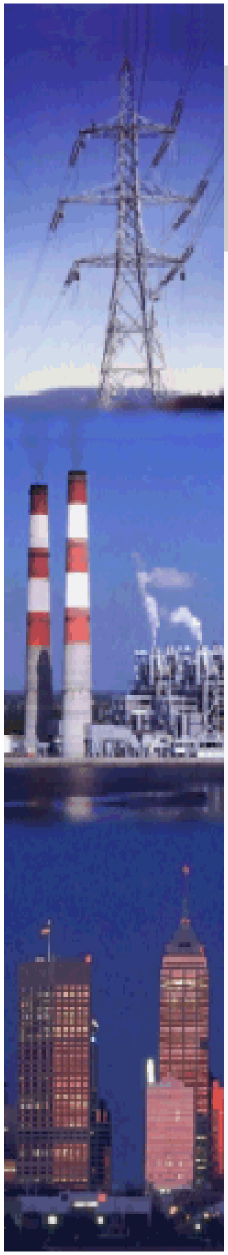
# Day-Ahead and Real-Time Energy Prices

- 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 August 2005.
- Prior to 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.

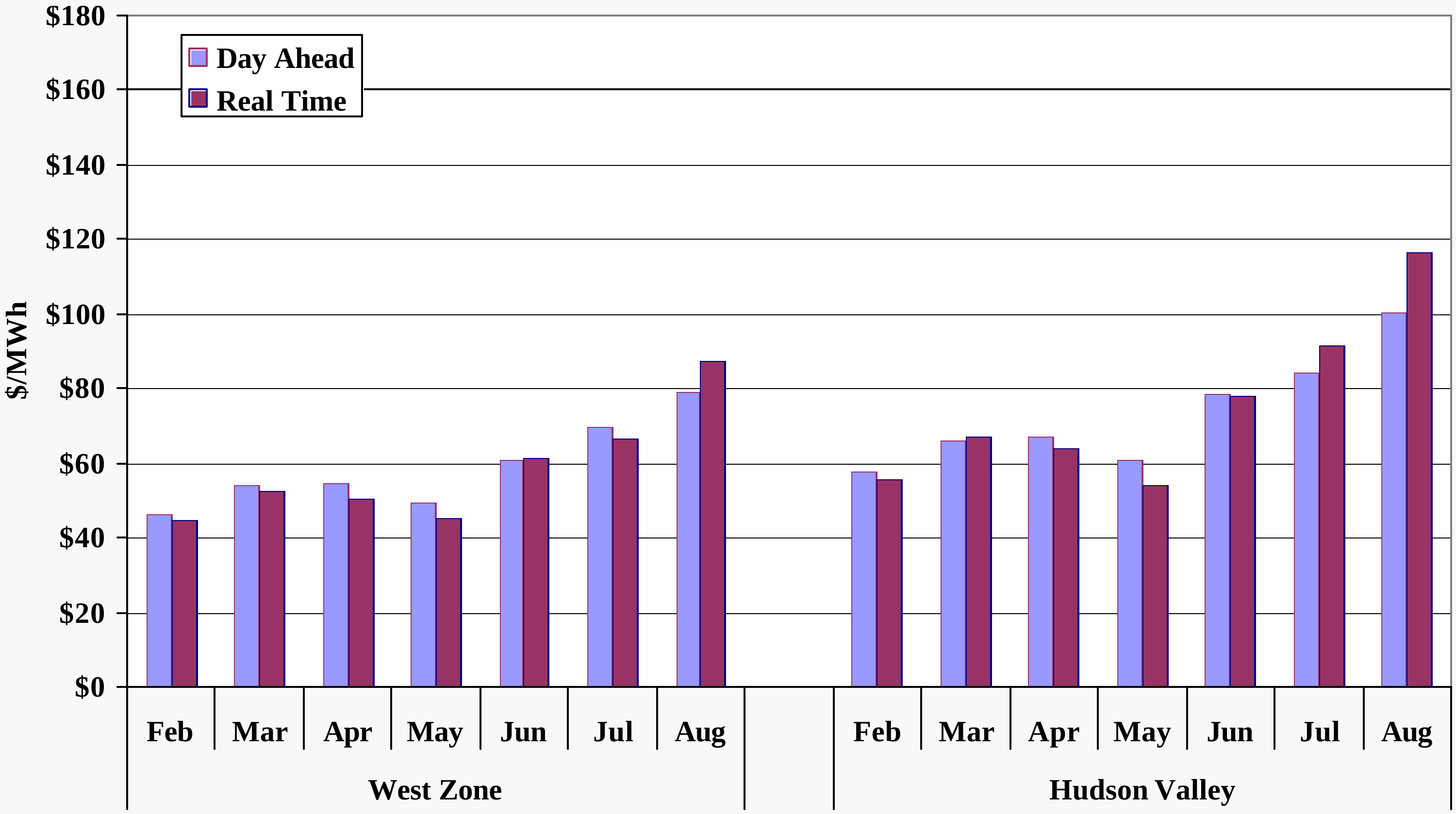


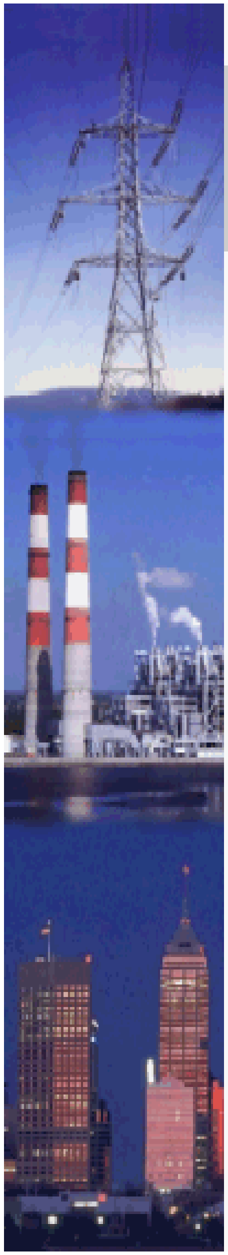
# Day-Ahead and Real-Time Energy Prices

- 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.

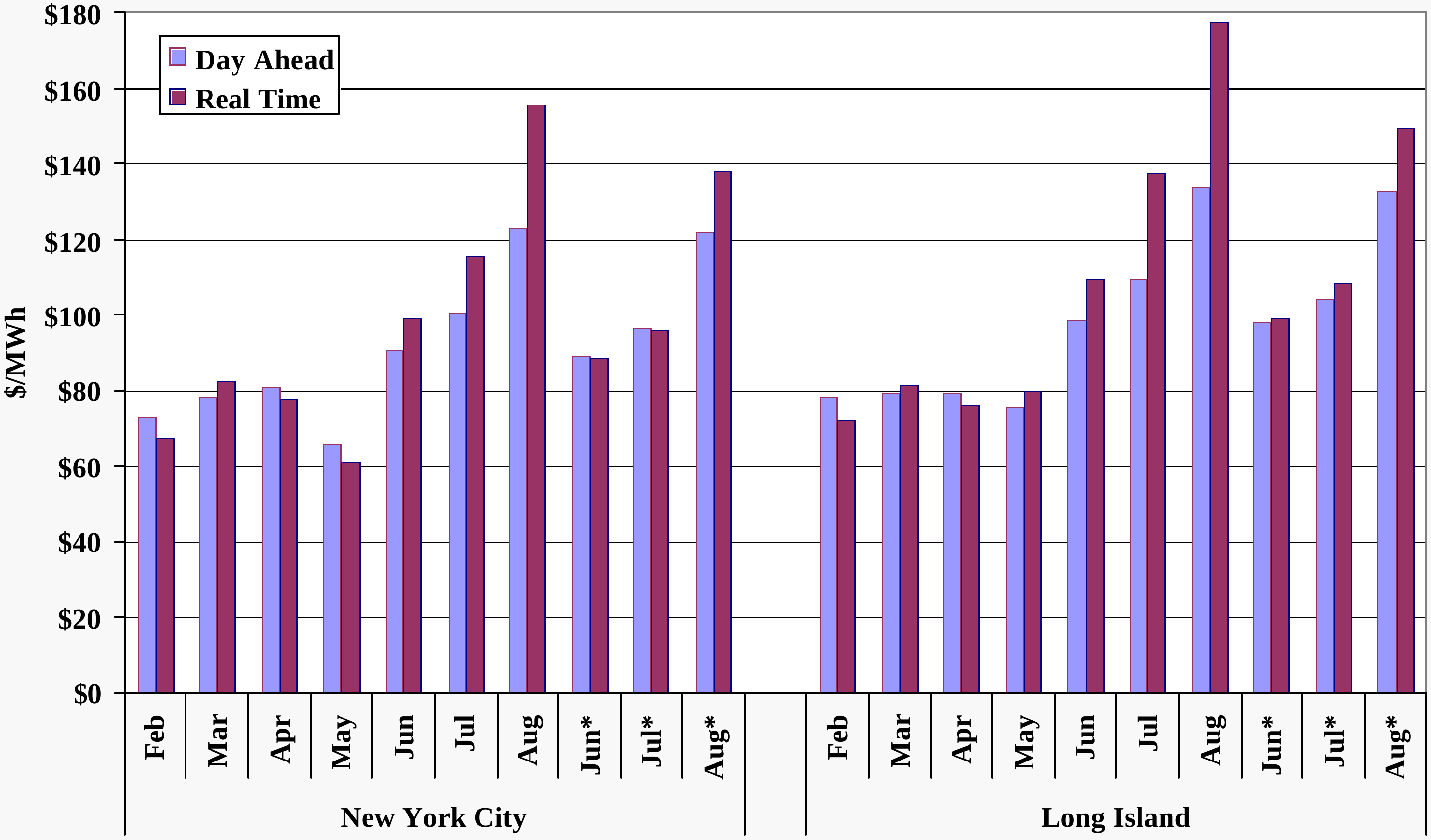


## Average Monthly Day-Ahead and Real-Time Energy Prices West Zone and Hudson Valley, February to August, 2005

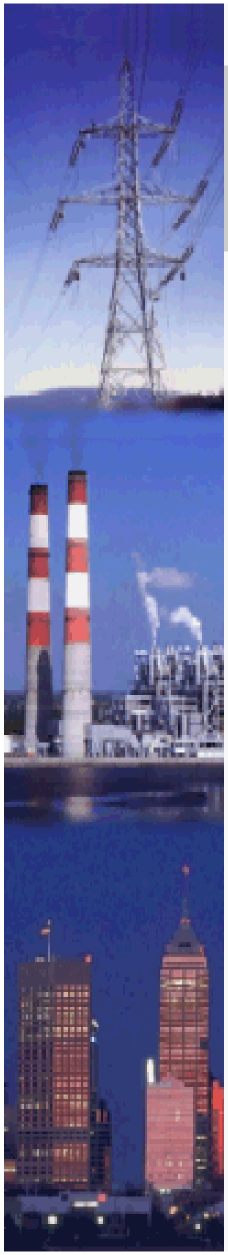




# Average Monthly Day-Ahead and Real-Time Energy Prices New York City and Long Island, February to August, 2005

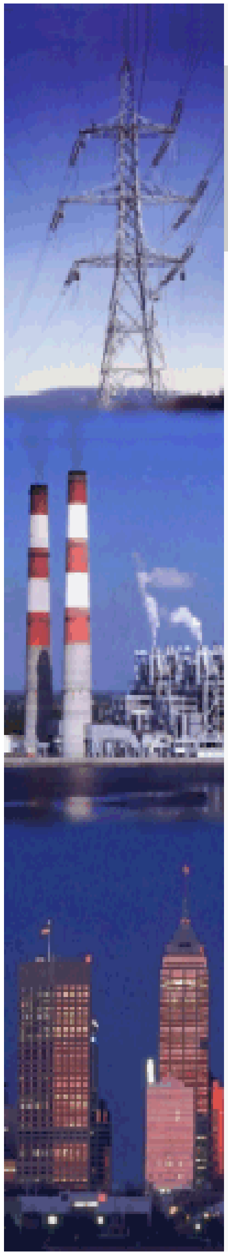



* These bars exclude the eight afternoons with more than a $175/MWh real-time price premium. These eight are June 6, 8, & 13, July 19 & 27, and August 3, 13, & 14.

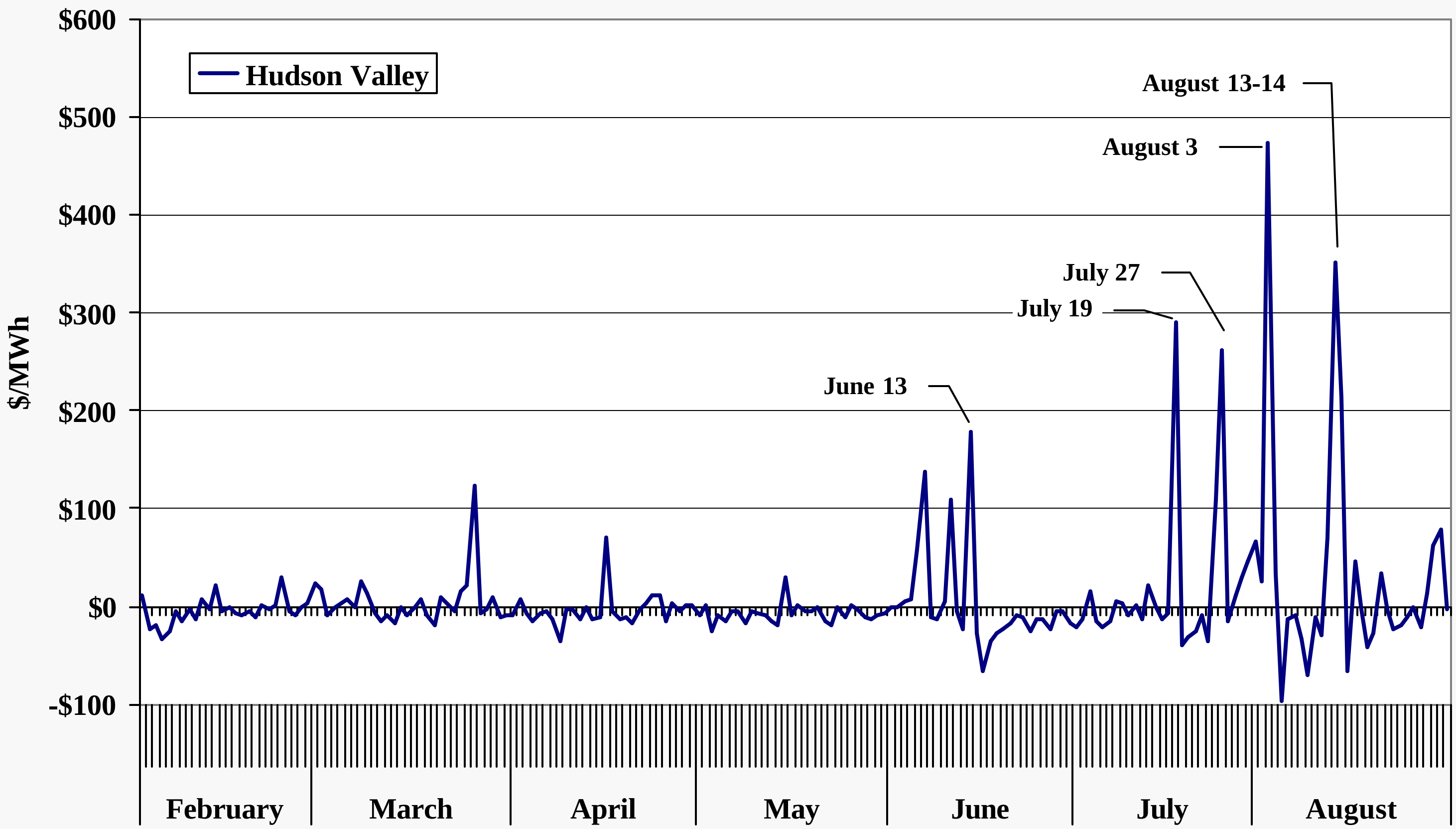


# Day-Ahead to Real-Time Price Convergence

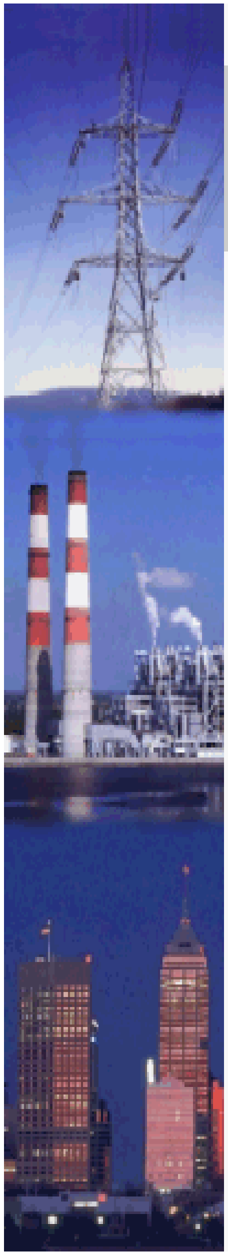
- The following two figures show the average real-time price premium on a daily basis during afternoon hours from February to August, 2005
- Day-ahead and real-time premiums occurred with similar frequency. However, there were more afternoons where the real-time price was very large. The average RT premium exceeded $100/MWh:
  - ✓ On 9 afternoons in the Hudson Valley; and
  - ✓ On 12 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 155 intervals.
  - ✓ 54 percent of the 243 price spike intervals resulting from Eastern 10-minute reserve shortages occurred when a TSA was in effect.

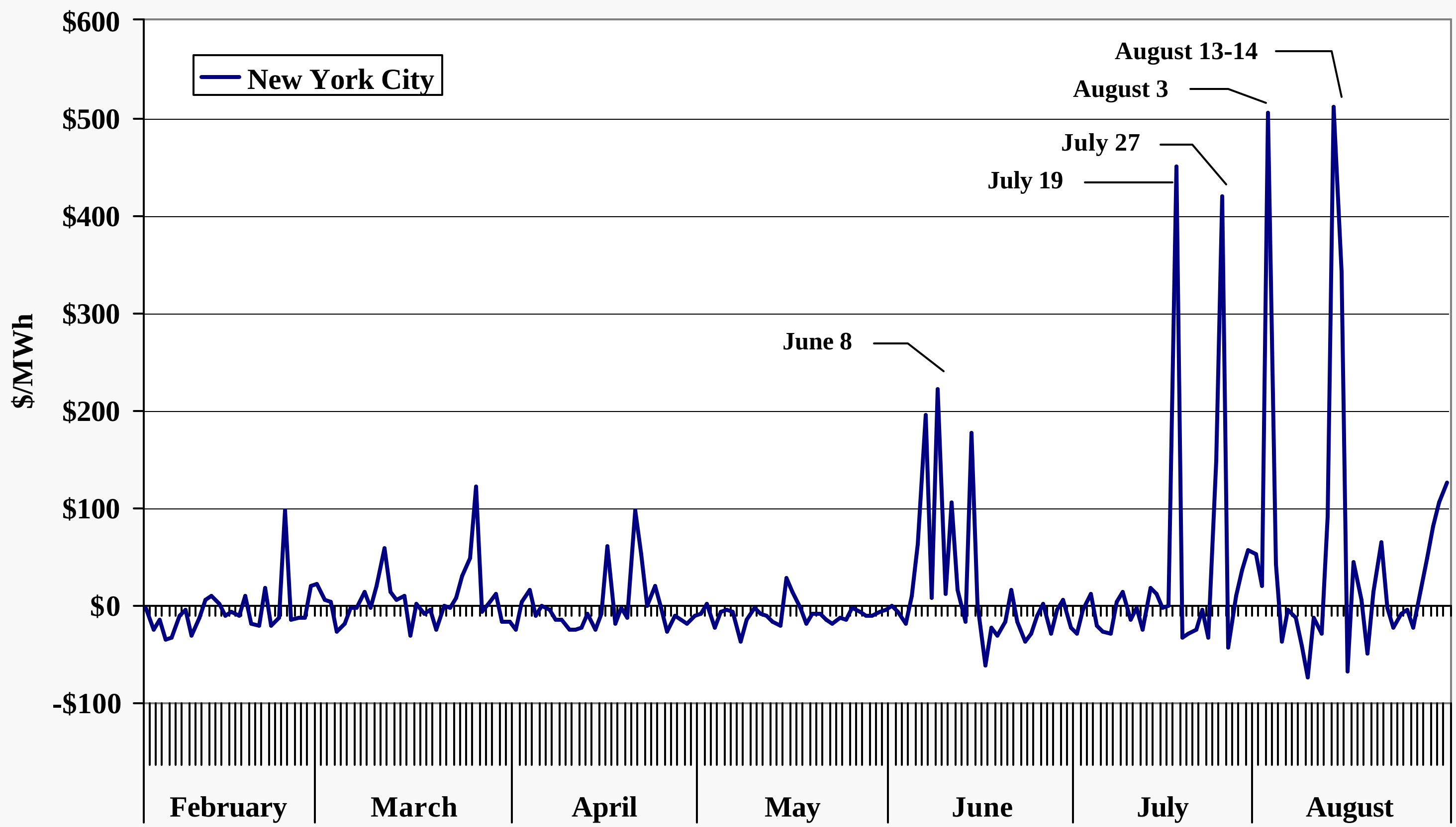


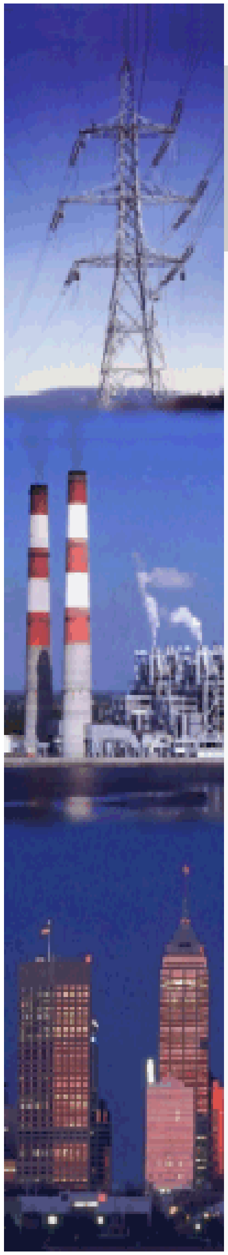
# Average Daily Real-Time Price Premium
# Hudson Valley – 1 p.m. to 7 p.m.
# February to August, 2005



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

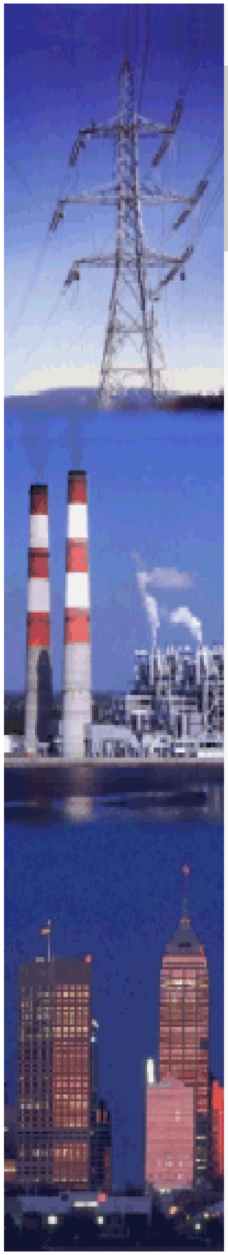






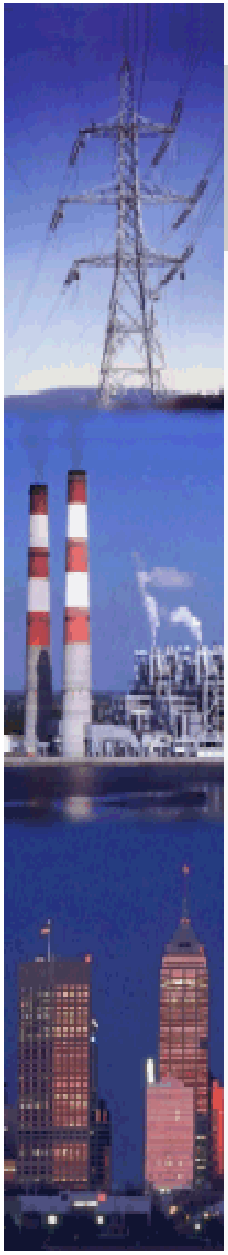
# Real-Time Transmission Price Spikes

- Real-time transmission price spikes occur when the re-dispatch costs necessary to resolve a transmission constraint reach extremely high levels.
  - ✓ Between February and August, there were 370 intervals when shadow prices exceeded $1,000/MWh on one or more constraints and 218 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 bring little or no reliability benefits.
  - ✓ Moreover, in many of these intervals, the real-time model cannot solve because of insufficient resources, leading to a high rate of price corrections.
- Like ancillary services demand curves, 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 its efforts to evaluate the impact on reliability of using transmission demand curves.

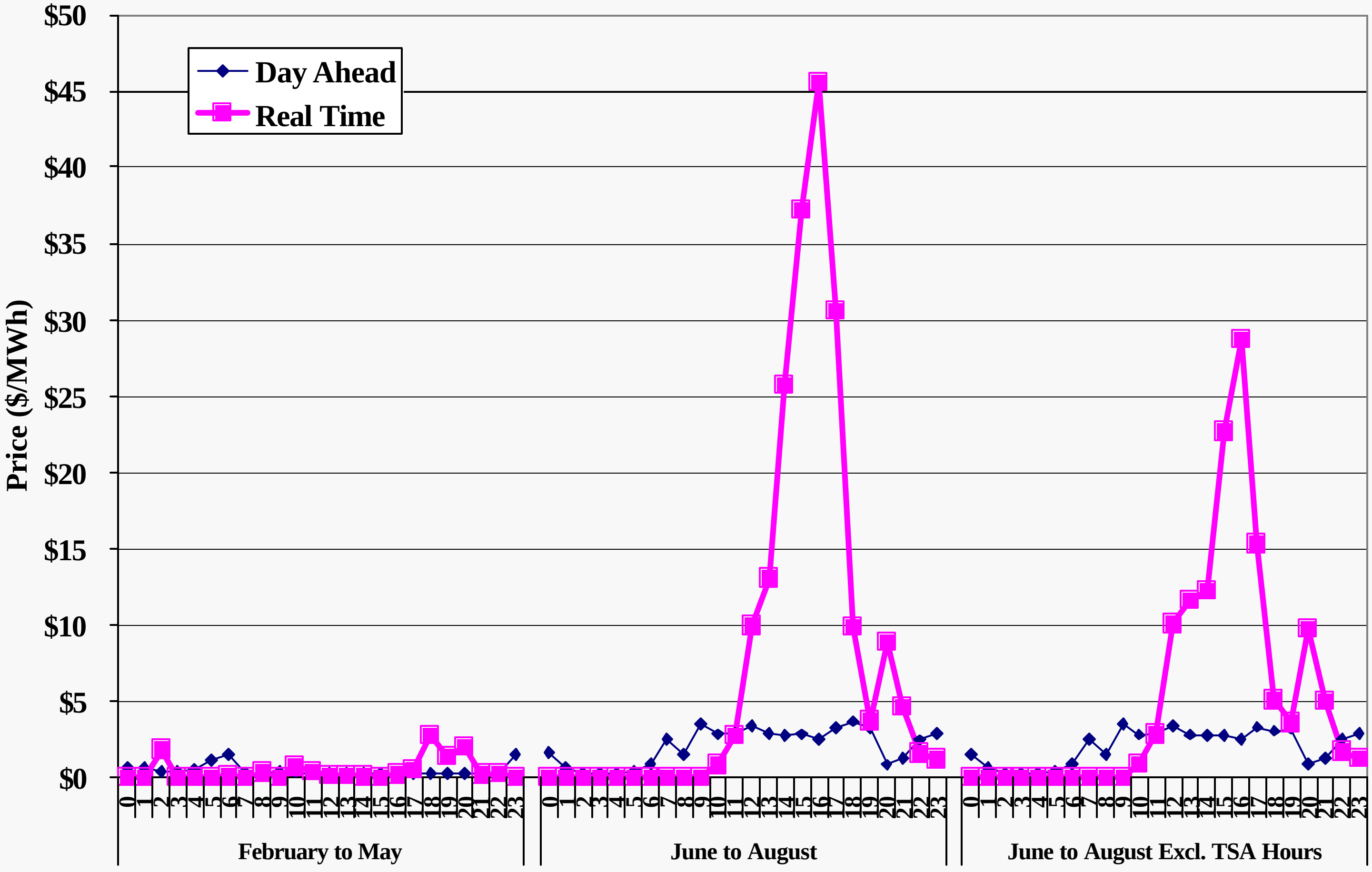


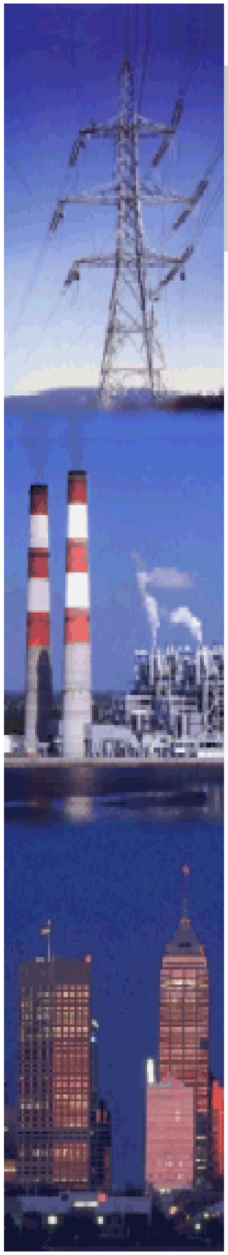
# Ancillary Services Price Convergence

- The following chart shows day-ahead and real-time eastern 10-minute reserves prices by hour of the day for February-May and for June-August 2005.
- The NYISO requires 1,000 MW of 10-minute reserves east of the Central-East Interface. The market models put an economic demand curve value of $500/MWh on meeting this requirement.
- From June to August, prices were significantly higher than earlier in the year:
  - ✓ Average day-ahead prices ranged from $3 to $5/MWh between 9 am and 8 pm.
  - ✓ Average real-time prices were close to zero in most hours but rose to $47/MWh in the hour from 4 pm to 5 pm.
- 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.
  - ✓ Real-time price spikes during TSA events account for 44 percent of the difference between average day-ahead and real-time prices.
- Since energy and reserves are co-optimized, reserve price spikes are accompanied by energy price spikes.



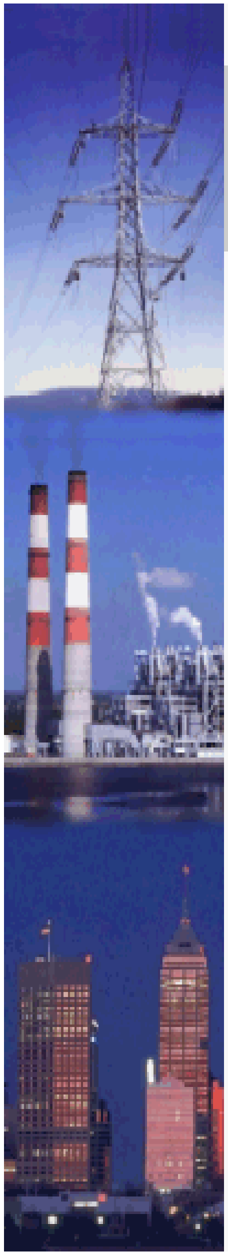
# 10-Minute Total Reserve Prices in East NY by Hour of Day February to August, 2005



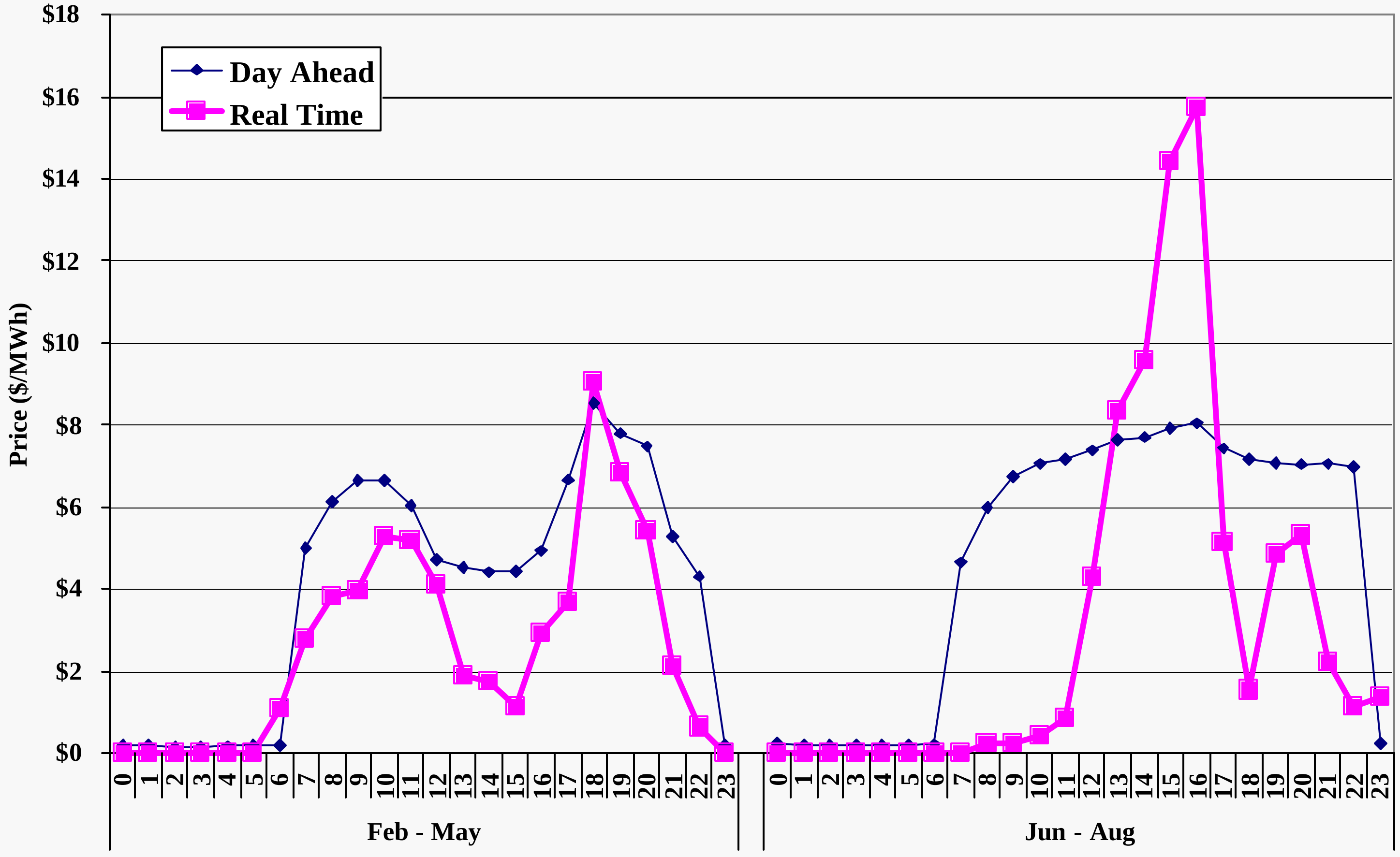


# Ancillary Services Price Convergence

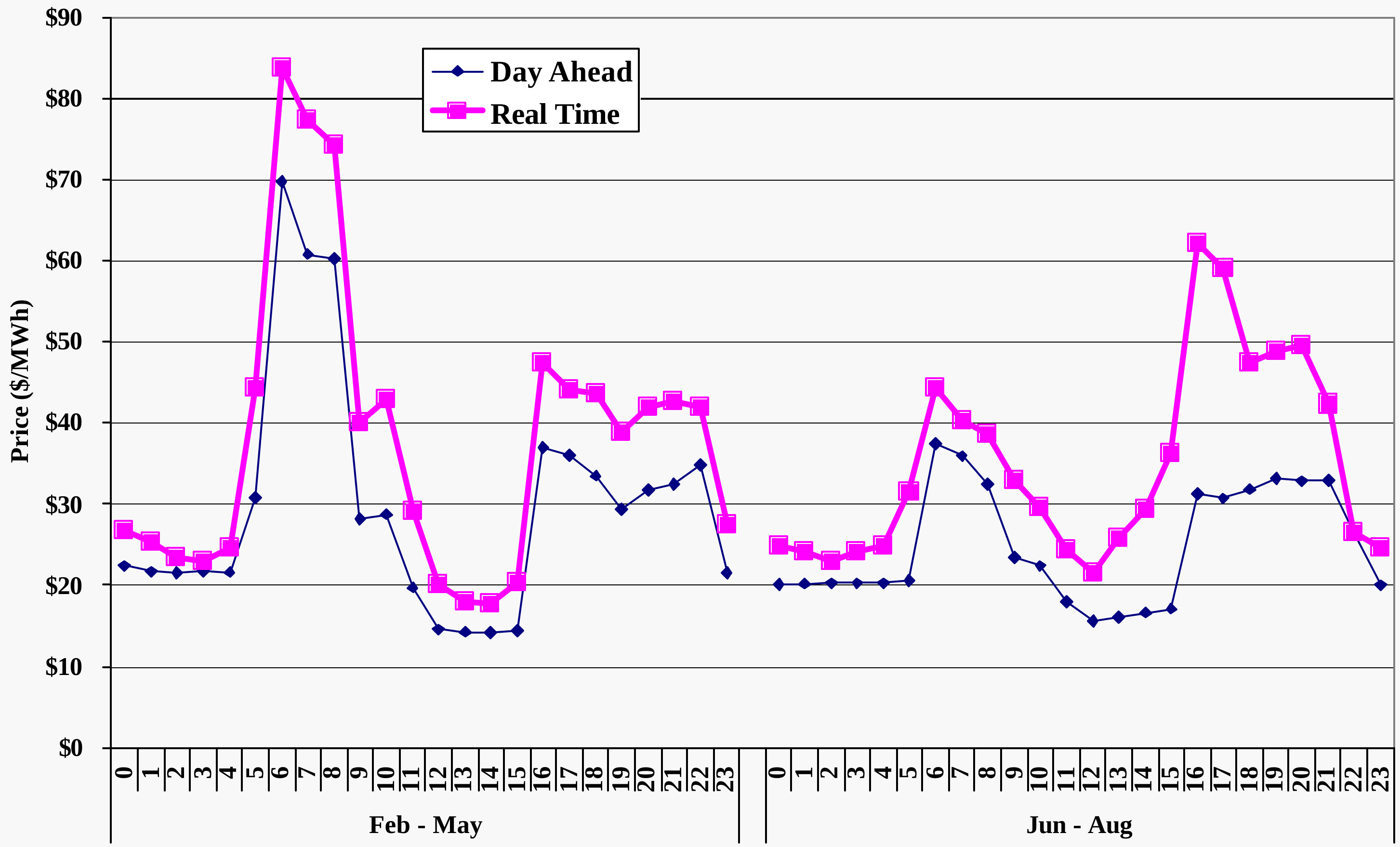
- The following two figures summarize convergence between day-ahead and real-time prices for other ancillary services.
- The first figure shows the western 10-minute synchronous reserves price which depends primarily on the state-wide 10-minute synchronous reserves requirement of 600 MW.
  - ✓ Currently, 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.
- The second figure shows state-wide regulation prices which depend on a requirement of 200 to 275 MW.
  - ✓ Currently, the economic value of this requirement is set at $300/MWh.
  - ✓ Day-ahead and real-time regulation prices are highly correlated across the day. However, real-time prices are consistently $3 to $10/MWh higher.`

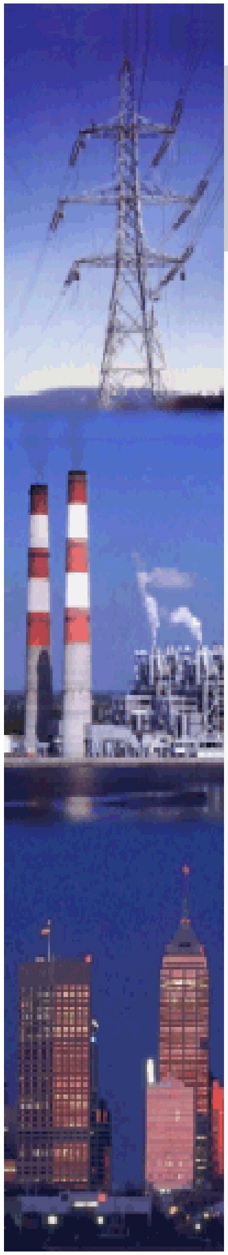


# 10-Minute Spinning Reserve Prices in West NY by Hour of Day February to August, 2005



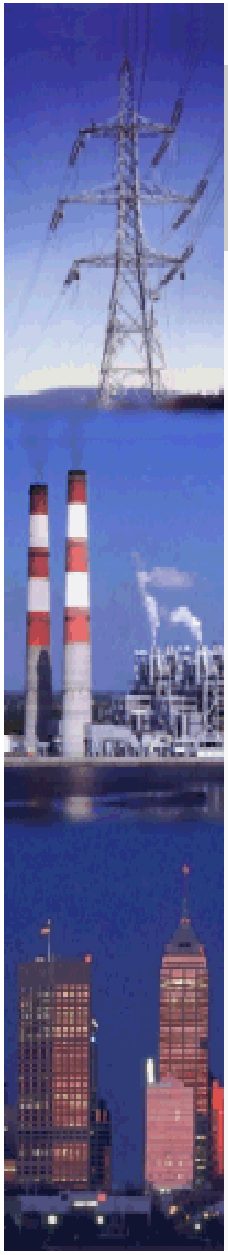
# 10-Minute Spinning Reserve Prices in East NY by Hour of Day February to August, 2005





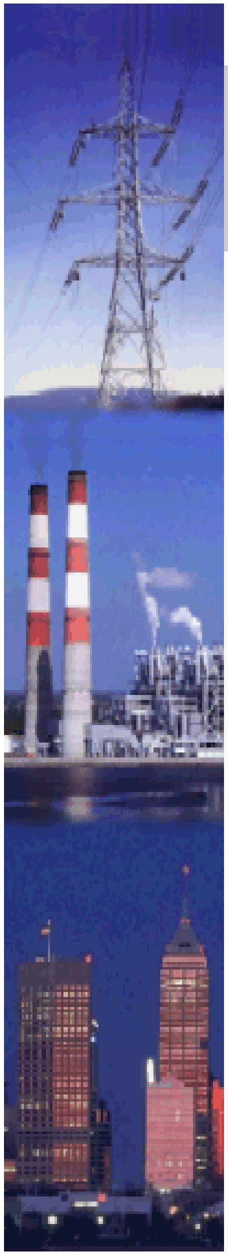
# Ancillary Services Price Convergence Conclusions

- 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 affect generators day-ahead reserves offers, which can reduce the efficiency of the day-ahead commitment.
- We will evaluate the importance of this potential concern and some potential means for improving the convergence of ancillary services prices in the State of the Market Report to be issued later this spring.

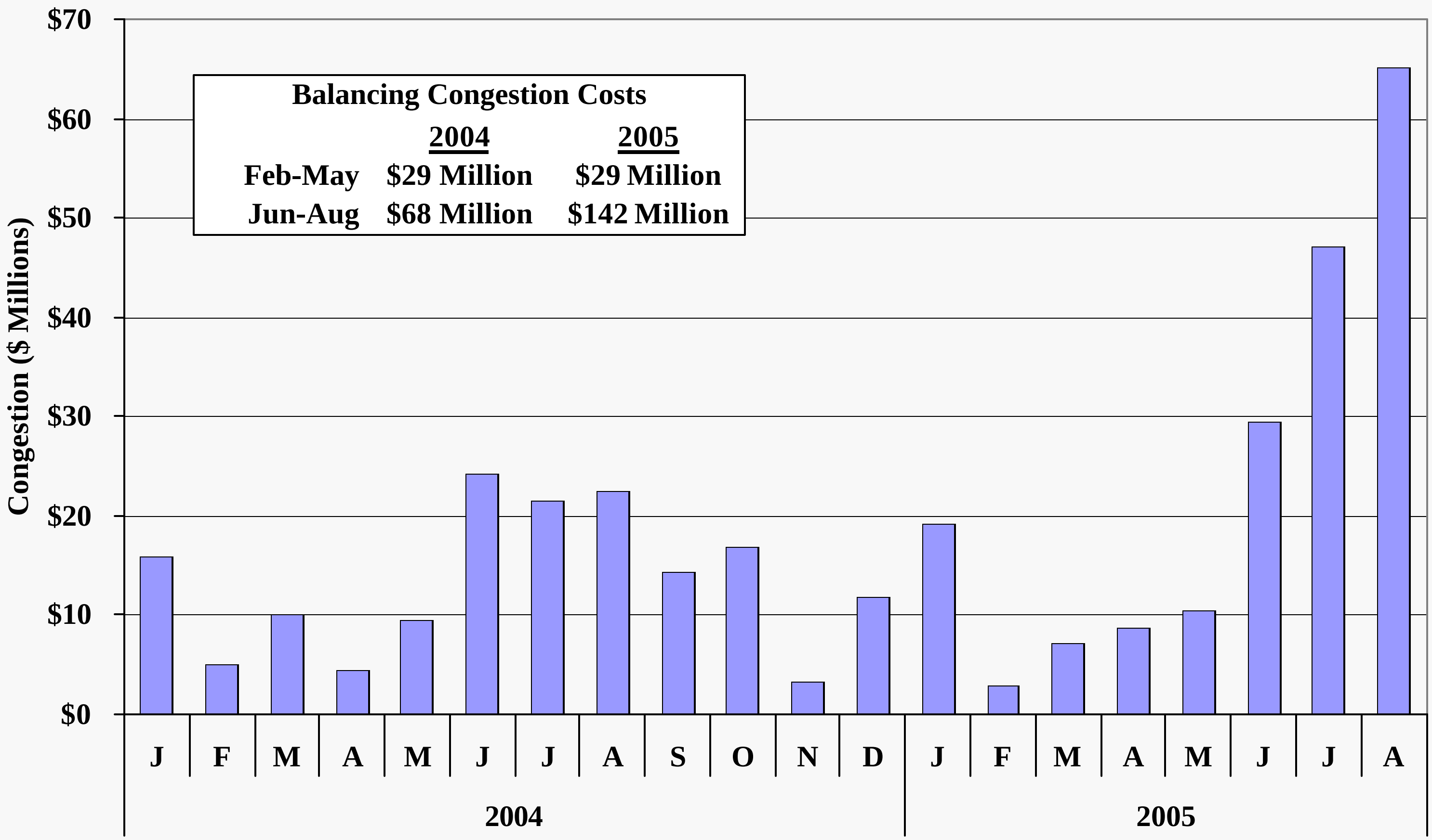


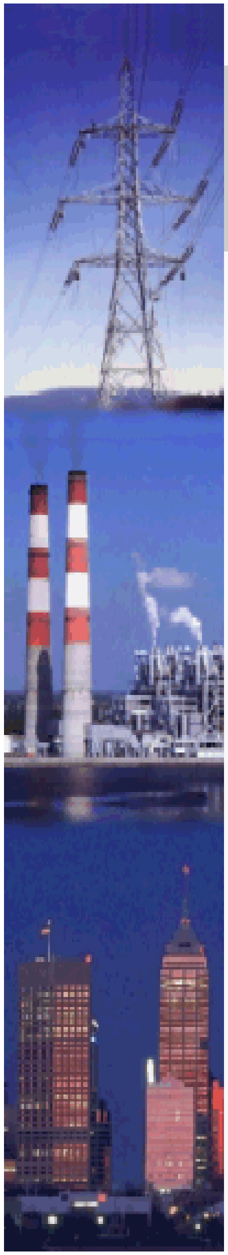
# Balancing Congestion Shortfall

- 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 transmission is oversold through the day-ahead market, 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.



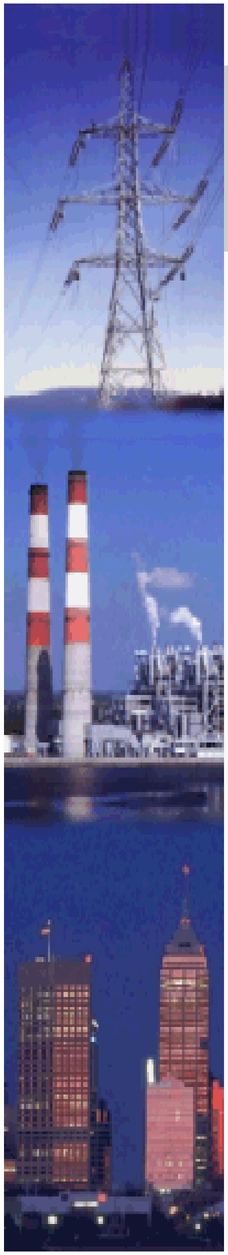
# Balancing Congestion Costs
## January 2004 to August 2005



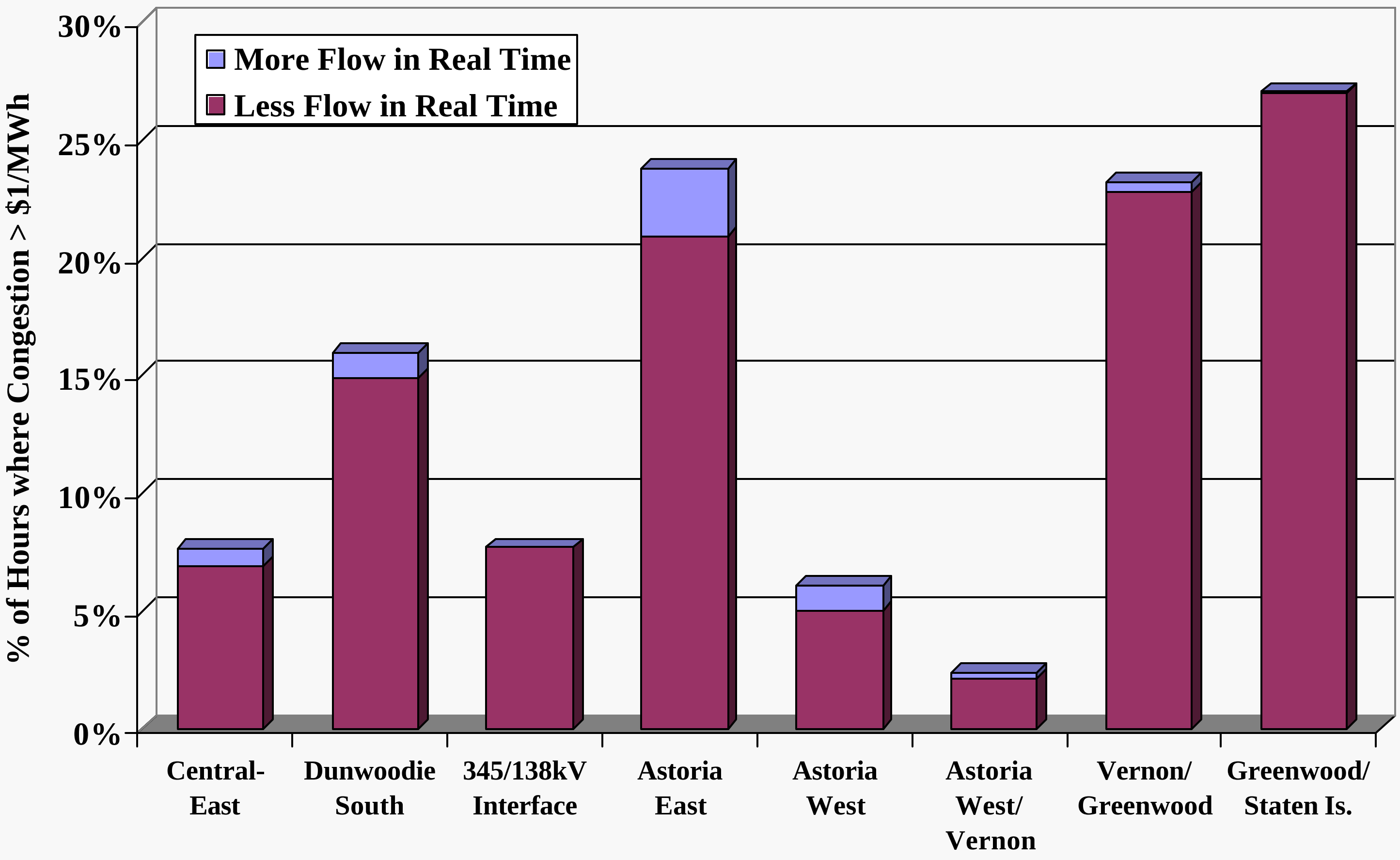


# Interface Flows

- The following 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 lines individual lines and contingencies in the NYC area which enables more effective utilization of the transmission system than RTD which generally uses closed interfaces. The ISO plans to secure the NYC area in RTD in this manner by Summer 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.

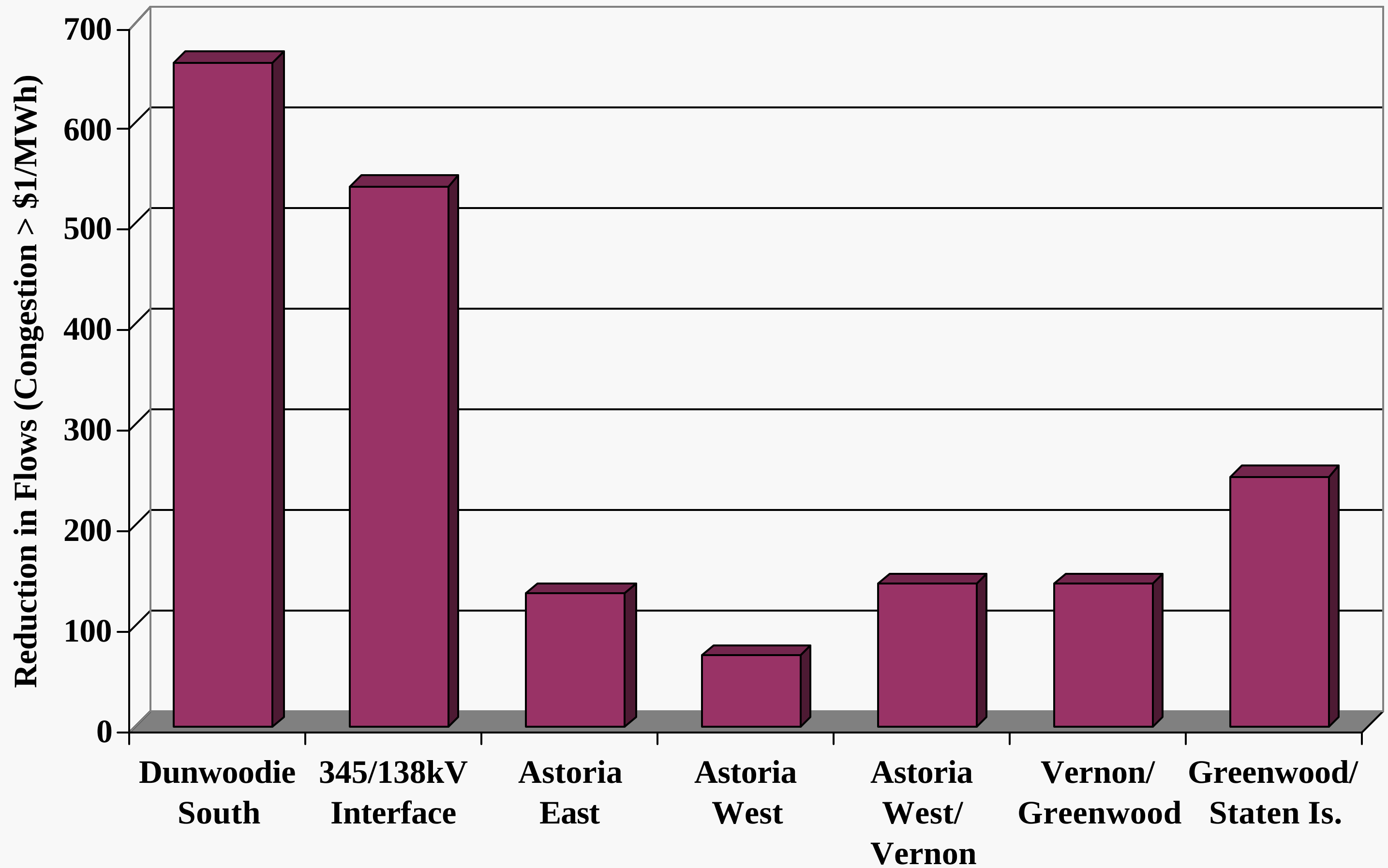


# Interface Flows During Hours with Real-Time Congestion
## February to August, 2005



# Interface Flow Reductions After the Day-Ahead Market

## During Hours with Real-Time Congestion
## February to August 2005



# Day-Ahead Load Scheduling Patterns

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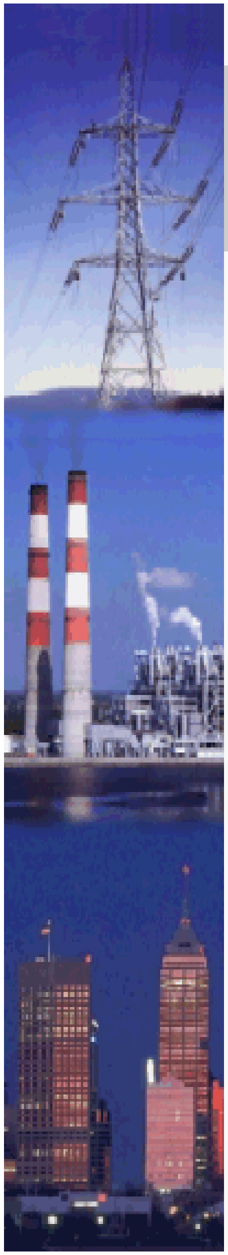
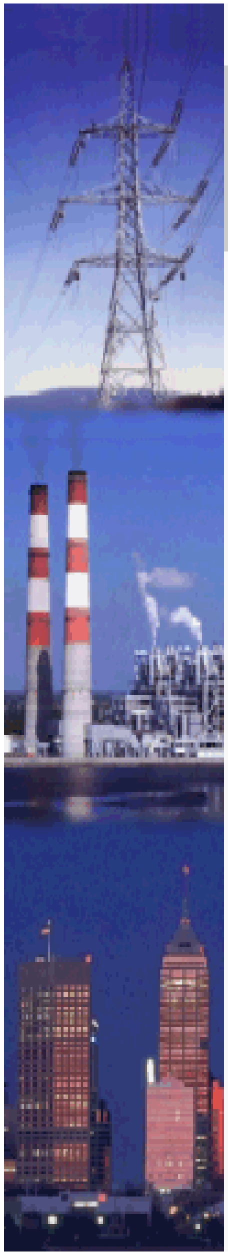
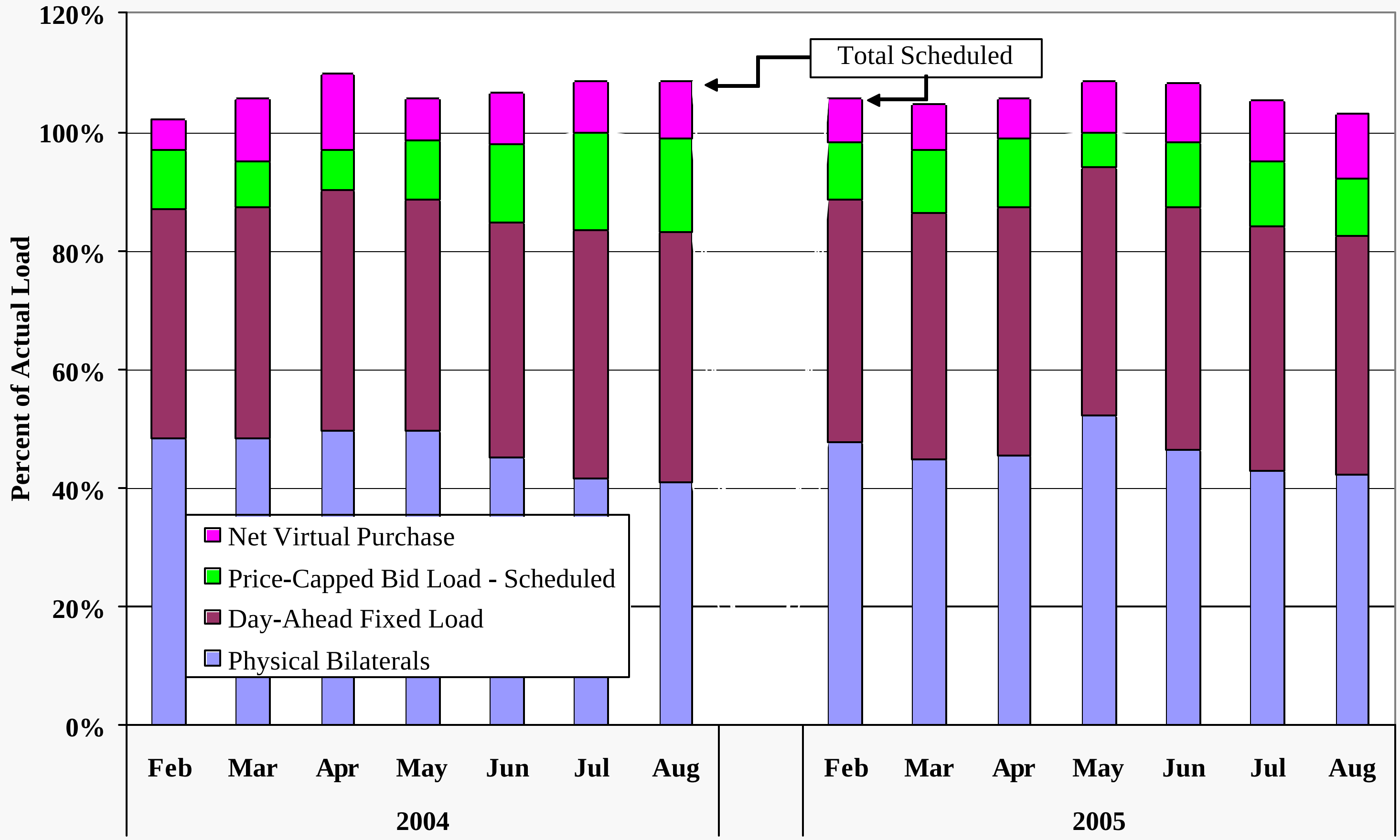


# Analysis of Load Bidding Patterns

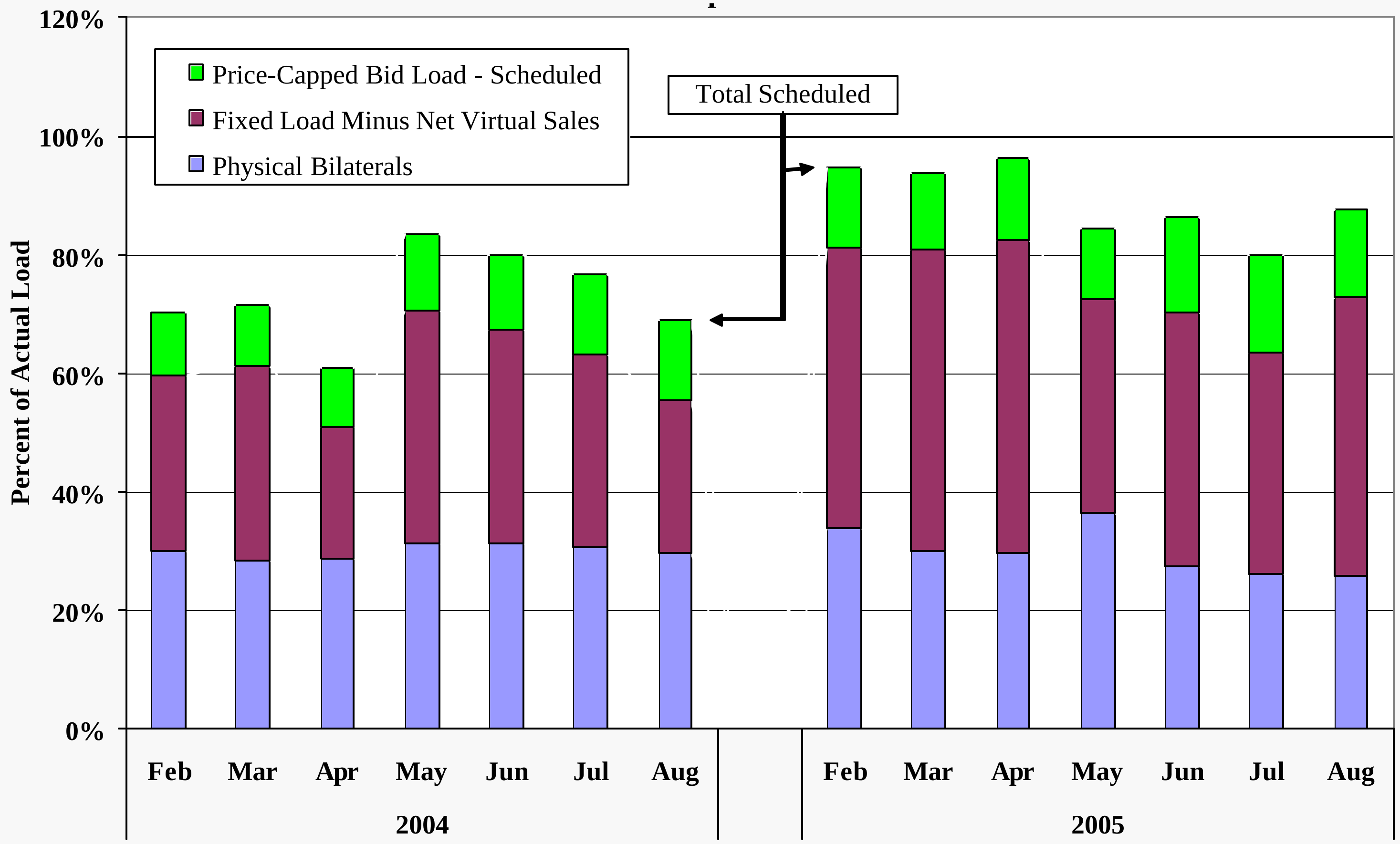
- The following figure shows the load scheduled day-ahead as a fraction of real-time load during 2004 and 2005 at various locations in New York.
  - ✓ In this case, scheduled load includes virtual load minus virtual supply.
- Load is generally over-scheduled in New York City and Long Island and under-scheduled in up-state New York.
  - ✓ This implies a higher level of imports to transmission constrained areas in the day-ahead market than in the real-time market.
- For New York State as a whole, load was under-scheduled day-ahead by an average of:
  - ✓ 2 to 3 percent from February to June, 2005; and
  - ✓ 7 percent during July and August, 2005.
- Under-scheduling during the summer contributed to the lack of convergence between day-ahead and real-time prices.

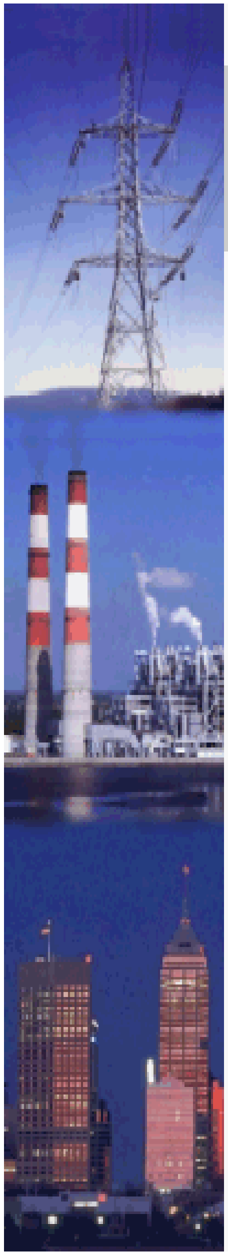


# Composition of Day Ahead Load Schedules as a Proportion of Actual Load in New York City and Long Island February to August, 2004 & 2005

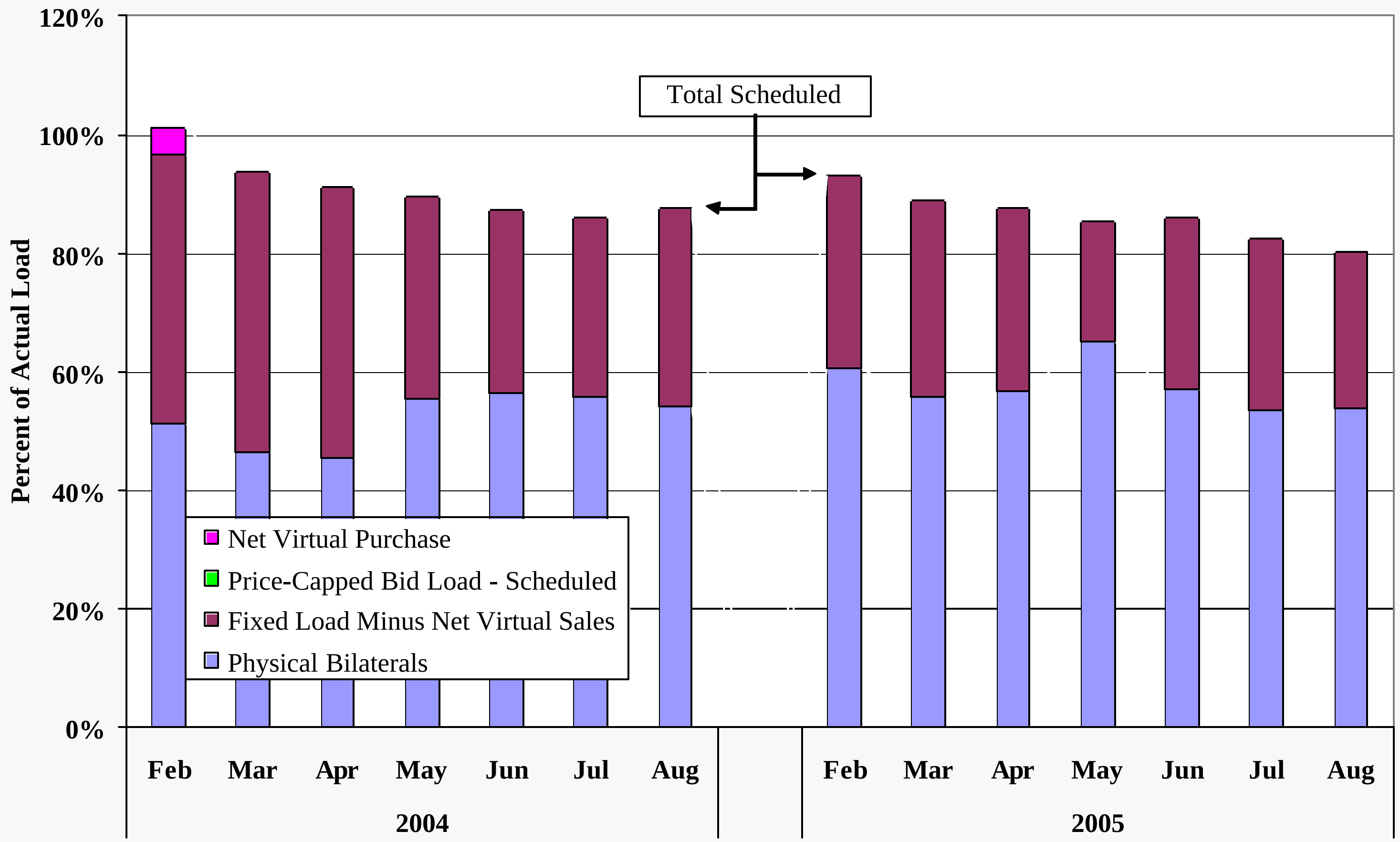


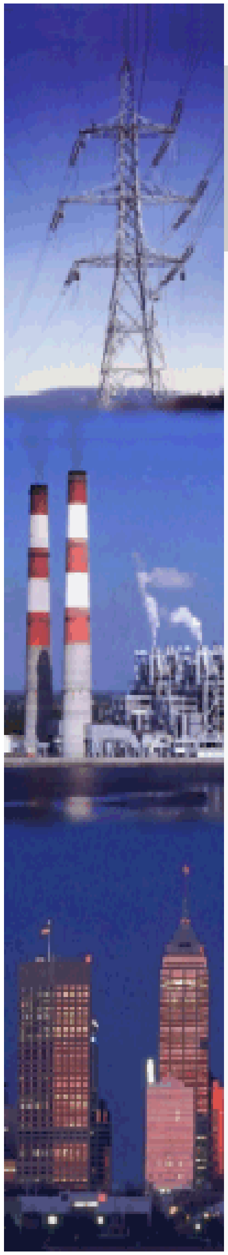
# Composition of Day Ahead Load Schedules as a Proportion of Actual Load in East Up-State New York February to August, 2004 & 2005





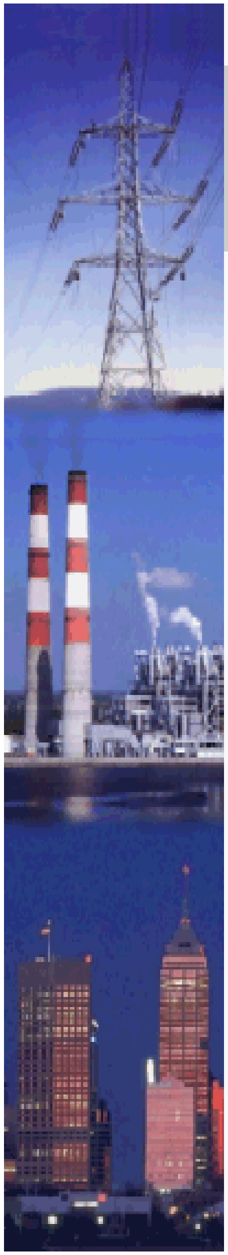
# Composition of Day Ahead Load Schedules as a Proportion of Actual Load in West Up-State New York February to August, 2004 & 2005



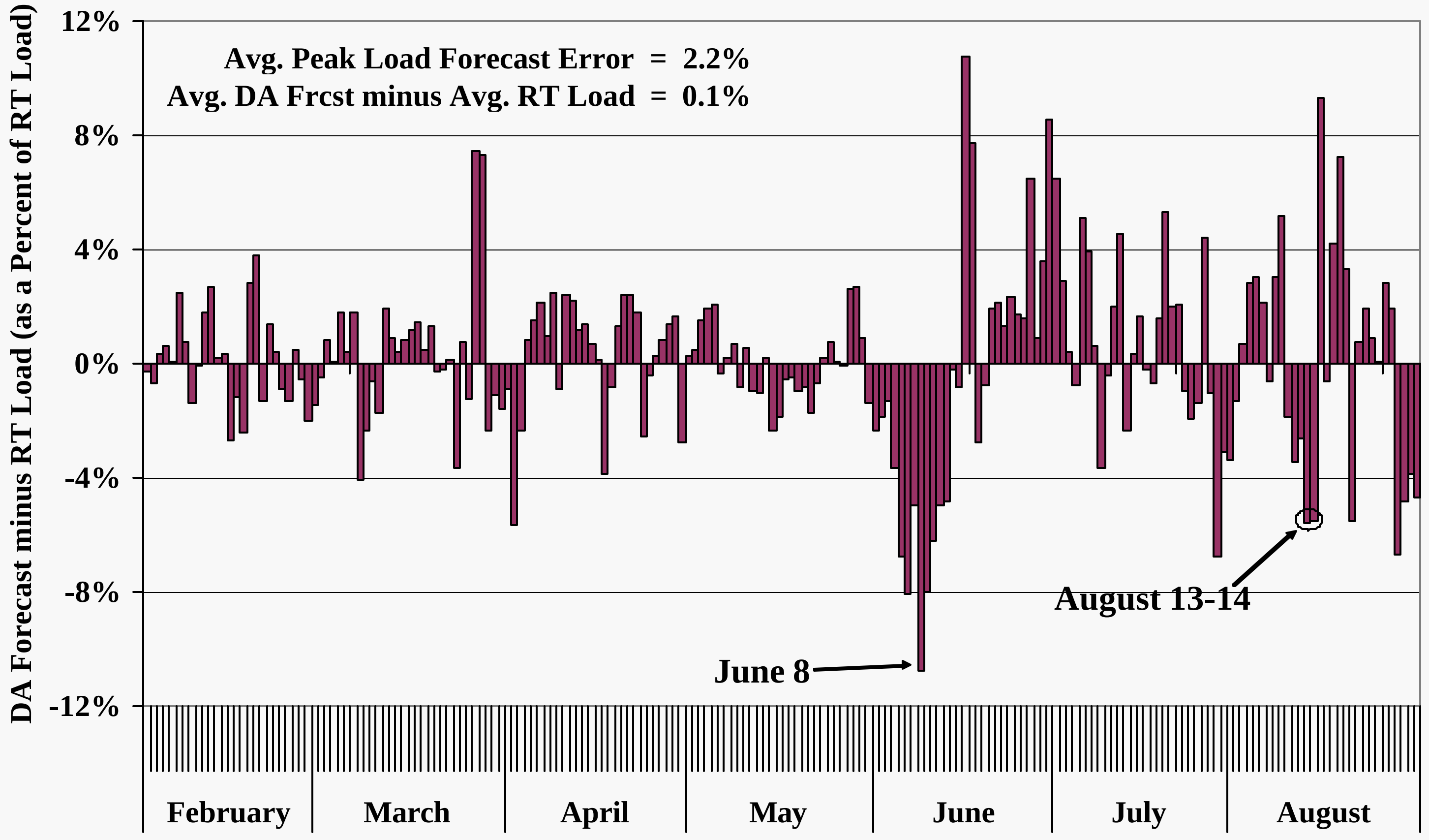


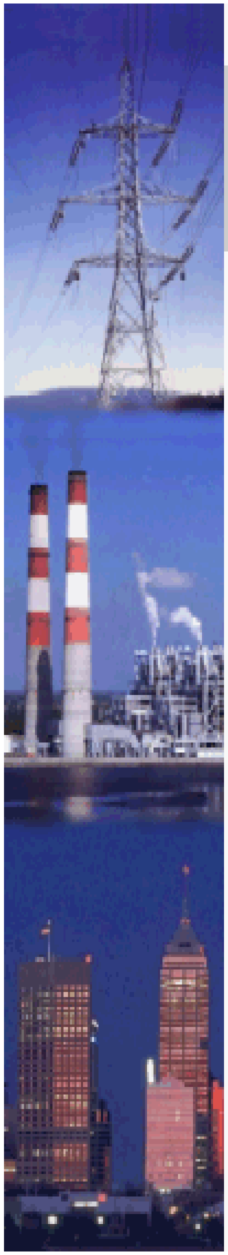
# Day-Ahead Load Forecasting

- The following figure summarizes differences between the day-ahead load forecast and actual real-time load for daily peak hours.
- Accurate load forecasting is important for market efficiency for several reasons:
  - ✓ The day-ahead commitment software commits sufficient capacity to satisfy forecast load plus ancillary services.
  - ✓ Load bidding, virtual trading, and external transaction scheduling are influenced by market participants' expectations of load. Therefore, accurate load forecasting tends to improve convergence.
- The figure indicates no systematic bias in the daily peak load forecast, and the average error is consistent with other control areas.
- Even though load forecasting has been relatively good, isolated instances of under-forecasting can may have contributed some of the real-time shortages.
  - ✓ This is expected and does not raise significant concerns, given the overall accuracy of the NYISO's day-ahead load forecasting.



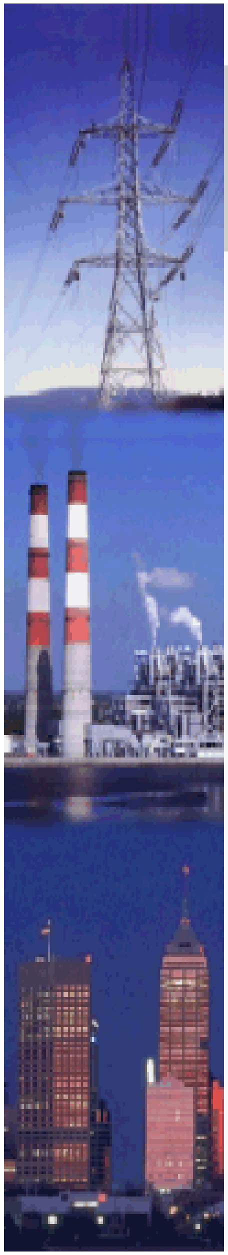
# Day-Ahead Load Forecast Error in Daily Peak Hour February to August, 2005



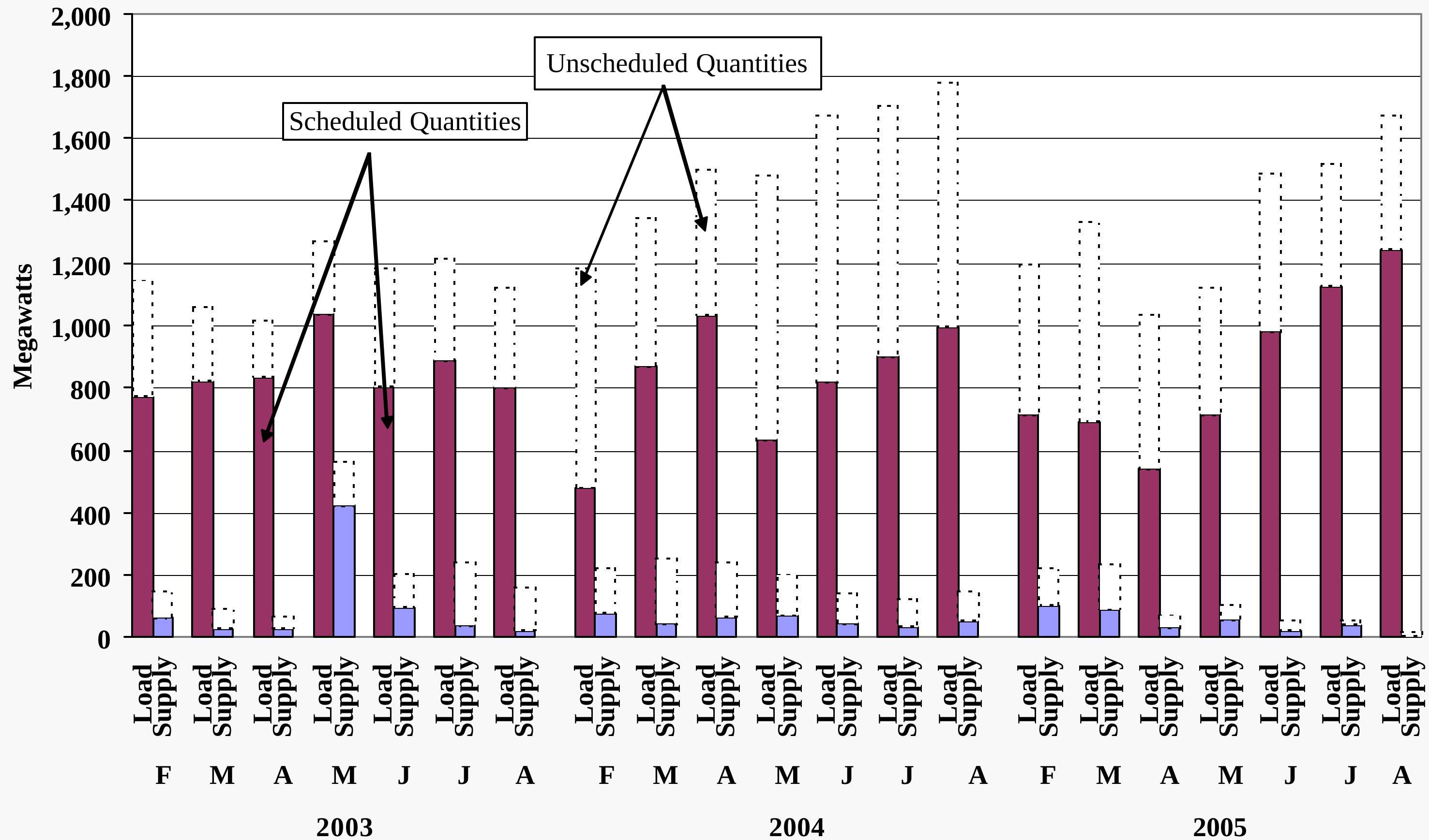


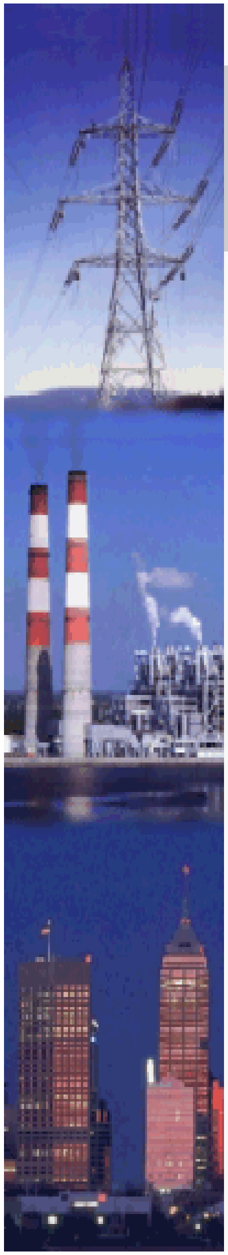
# Virtual Trading Patterns

- Virtual trading allows participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the quantities of virtual load and supply that have been offered and scheduled on a monthly basis in New York City and Long Island as well as areas of up-state New York.
- These figures indicate:
  - ✓ Virtual trading activity tends to be highest during the summer when real-time load is highest and prices are most volatile.
  - ✓ Virtual supply offers and schedules increased substantially in Up-State New York in 2005.
  - ✓ 63 percent of virtual bids and offers in New York City and Long Island were scheduled in 2005.
  - ✓ 82 percent of virtual bids and offers in up-state New York were scheduled in 2005.

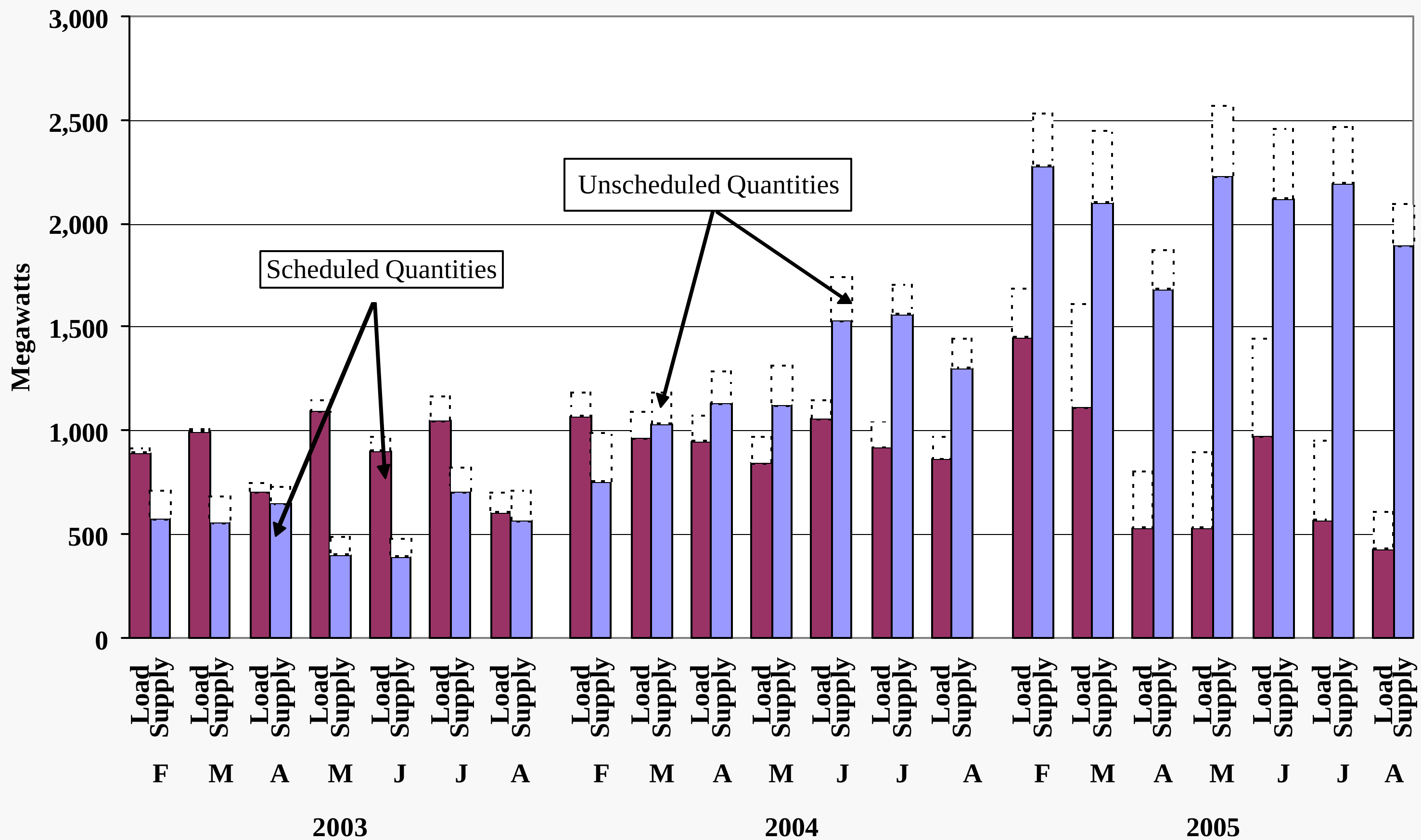


# Average Hourly Virtual Load and Supply
## New York City and Long Island
## February to August, 2003 to 2005





# Average Hourly Virtual Load and Supply
## Outside New York City and Long Island
## February to August, 2003 to 2005



# Hour-Ahead to Real-Time Convergence

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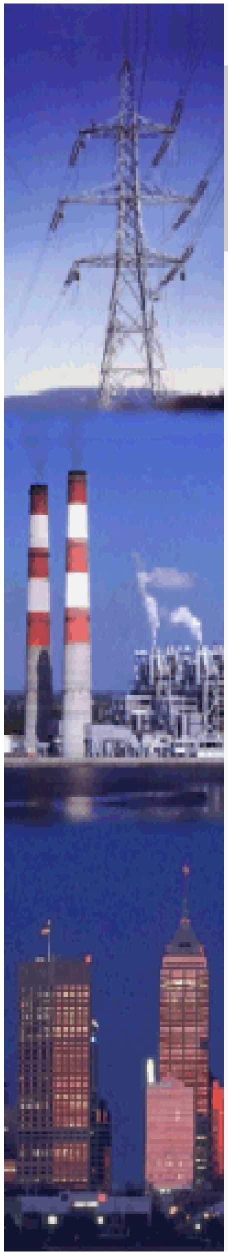
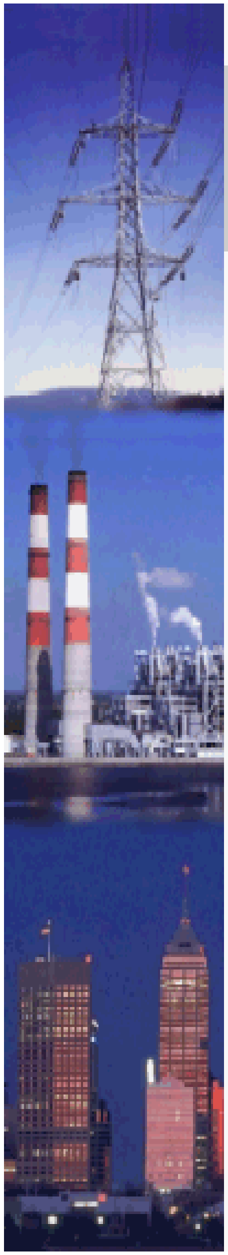


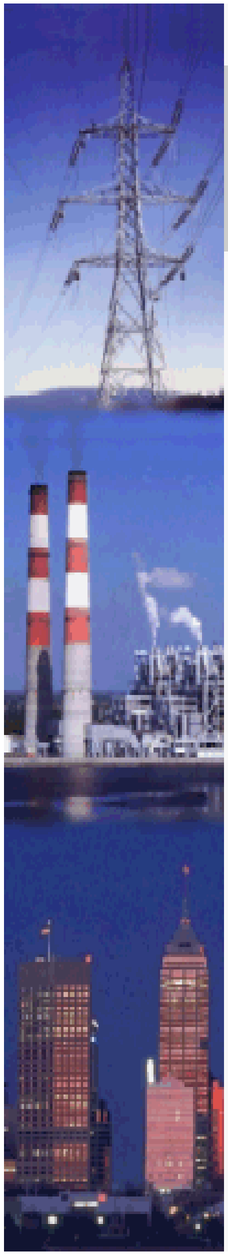
# Hour-Ahead to Real-Time Convergence

- NYISO upgraded its two real-time models:
  - ✓ 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.
  - ✓ The RTD model produces a 5-minute dispatch, co-optimizing energy with ancillary services using a forward looking multi period optimization. This replaced the SCD that scheduled energy only for a single interval.
- Lack of convergence between "hour-ahead" and real-time (interval) prices can be a substantial concern because it can result in:
  - ✓ Uneconomic commitment and scheduling of non flexible generating resources, including gas turbines;
  - ✓ External transactions being scheduled inefficiently; and
  - ✓ Increased uplift costs and inefficient real-time prices.
- The implementation of RTD and RTC has led to substantial improvements in price convergence and the efficiency of real-time scheduling and dispatch.



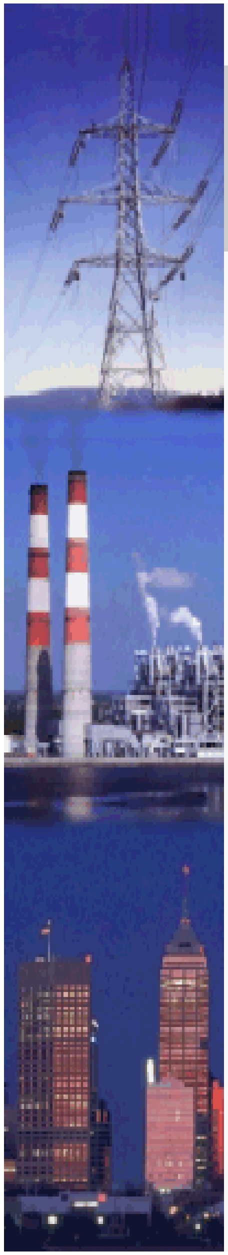
# "Hour-Ahead" and Real-Time Prices

- The following table summarizes differences between "hour-ahead" and real-time prices.
  - ✓ The BME which produced hourly advisory prices in the hour ahead of real-time.
  - ✓ We continue to refer to "hour-ahead" prices under RTC, although the RTC runs every 15 minutes.
- The table indicates significant improvements in convergence:
  - ✓ The average difference between hour-ahead and real-time prices in New York City decreased from 22 percent in 2004 to 14 percent in 2005.
  - ✓ This is particularly notable given the substantial increase in real-time price volatility.
    - – The average hourly real-time price change in New York City increased from 14 percent in 2004 to 21 percent in 2005.



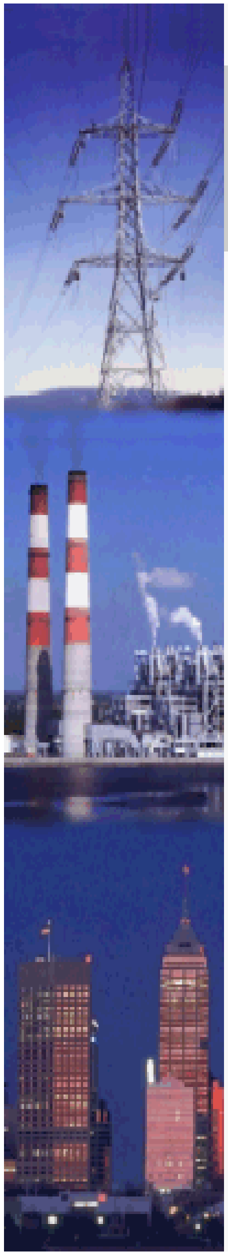
# “Hour-Ahead” to Real-Time Price Convergence Statistics
## February to August, 2004 to 2005

| | NYC | | Hudson Valley | | West Zone | |
|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2004 | 2005 | 2004 | 2005 |
| Average Real-Time Price | $61.33 | $87.66 | $47.69 | $70.02 | $41.38 | $55.88 |
| Average HA minus Average RT Price | $8.55 | $4.87 | $3.18 | $5.26 | $1.01 | $4.66 |
| Average HA to RT Price Difference | $13.68 | $12.23 | $8.04 | $9.89 | $6.45 | $7.78 |
| Volatility (Average Hourly Change in RT Price) | $8.61 | $18.44 | $7.63 | $15.47 | $6.60 | $11.57 |
| As a Percent of the Real-Time Price | | | | | | |
| Average HA minus Average RT Price | 14% | 6% | 7% | 8% | 2% | 8% |
| Average HA to RT Price Difference | 22% | 14% | 17% | 14% | 16% | 14% |
| Volatility (Average Hourly Change in RT Price) | 14% | 21% | 16% | 22% | 16% | 21% |

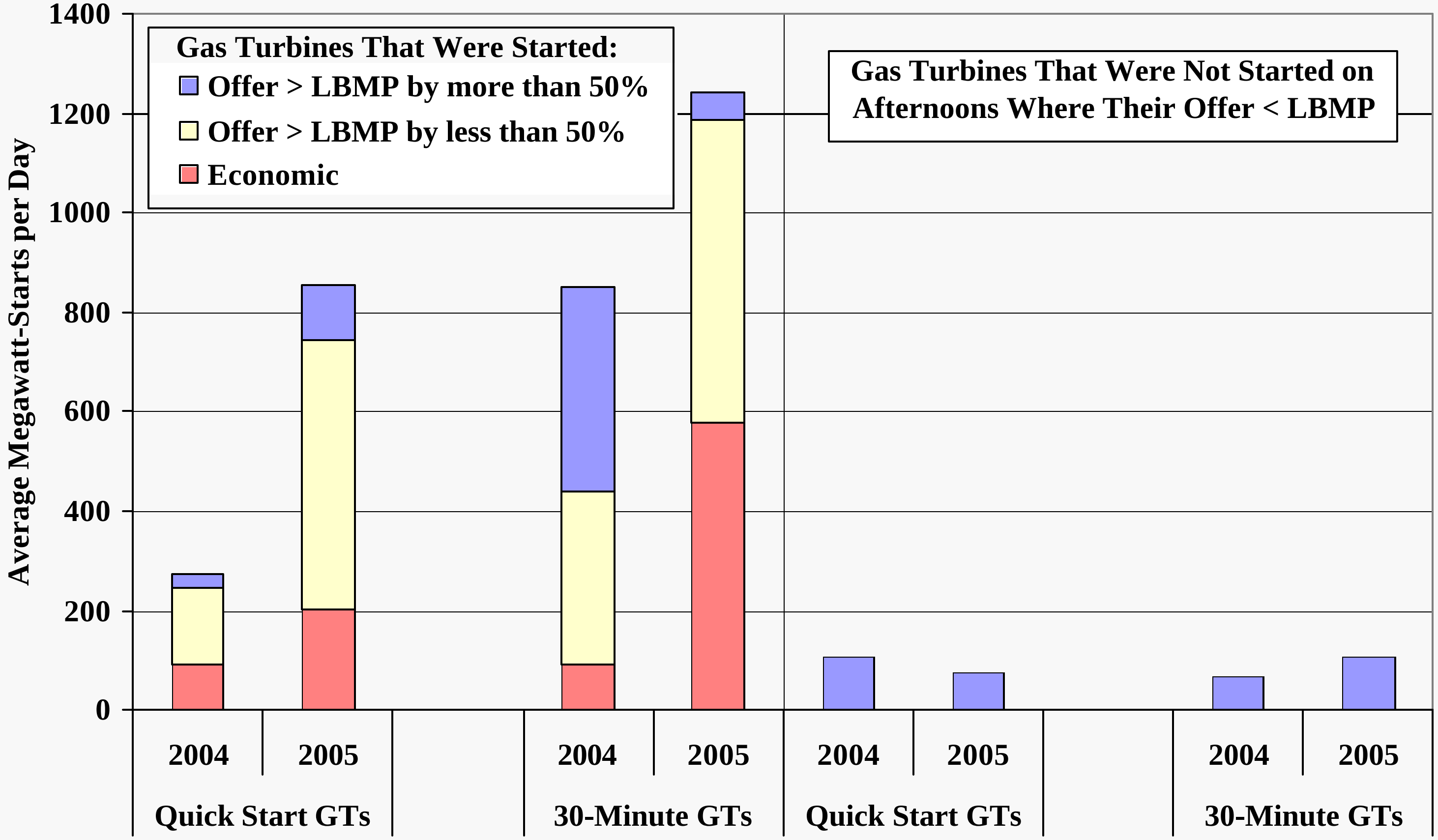


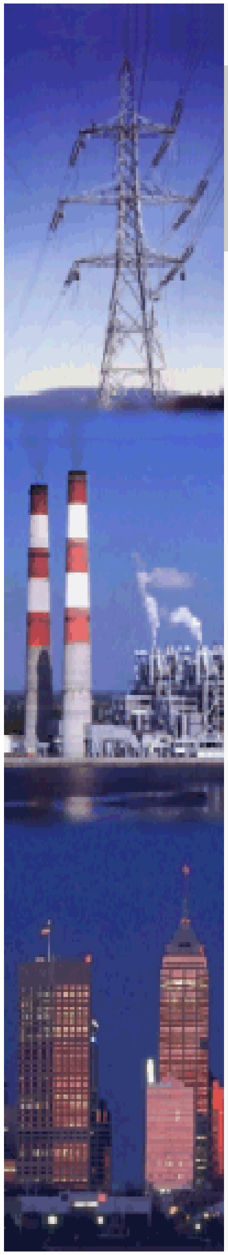
# Efficiency of Gas Turbine Commitment

- The following figure measures the efficiency of GT commitment by comparing the offer price (energy plus start-up) to the real-time LBMP.
- The left panel shows the average volume of gas turbines being started whose energy + start-up costs are a) < LBMP (clearly economic); b) > LBMP by less than 50 percent; and c) > LBMP by more than 50 percent.
- Some of the GTs in the second category are also economic, because GTs that are started efficiently may sometimes not recover their start-up costs.
- The right panel shows the quantity gas turbines that were likely economic, but not started (i.e. the LBMP > Energy plus start-up offer).
- The figure shows that gas turbine commitment has been far more efficient under SMD2 than during the previous summer due to the 15-minute commitment under SMD2. In particular, the figure indicates that:
  - ✓ A much higher share portion of the GT commitments occur in the economic categories.
  - ✓ The category of uncommitted economic GTs is generally small, indicating that GTs are nearly always started when they are economic.
- In addition, RTD was modified to schedule quick start resources in August 2005, which should further improve the dispatch these resources.



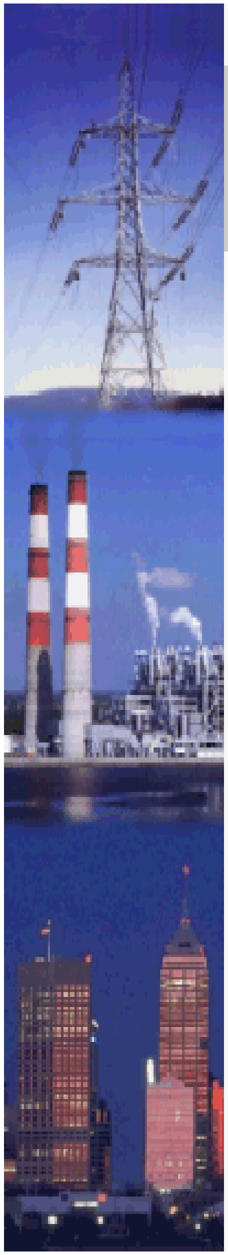
# Efficiency of Gas Turbine Commitment
# Comparison of SMD and SMD2
# June to August, 2004 & 2005



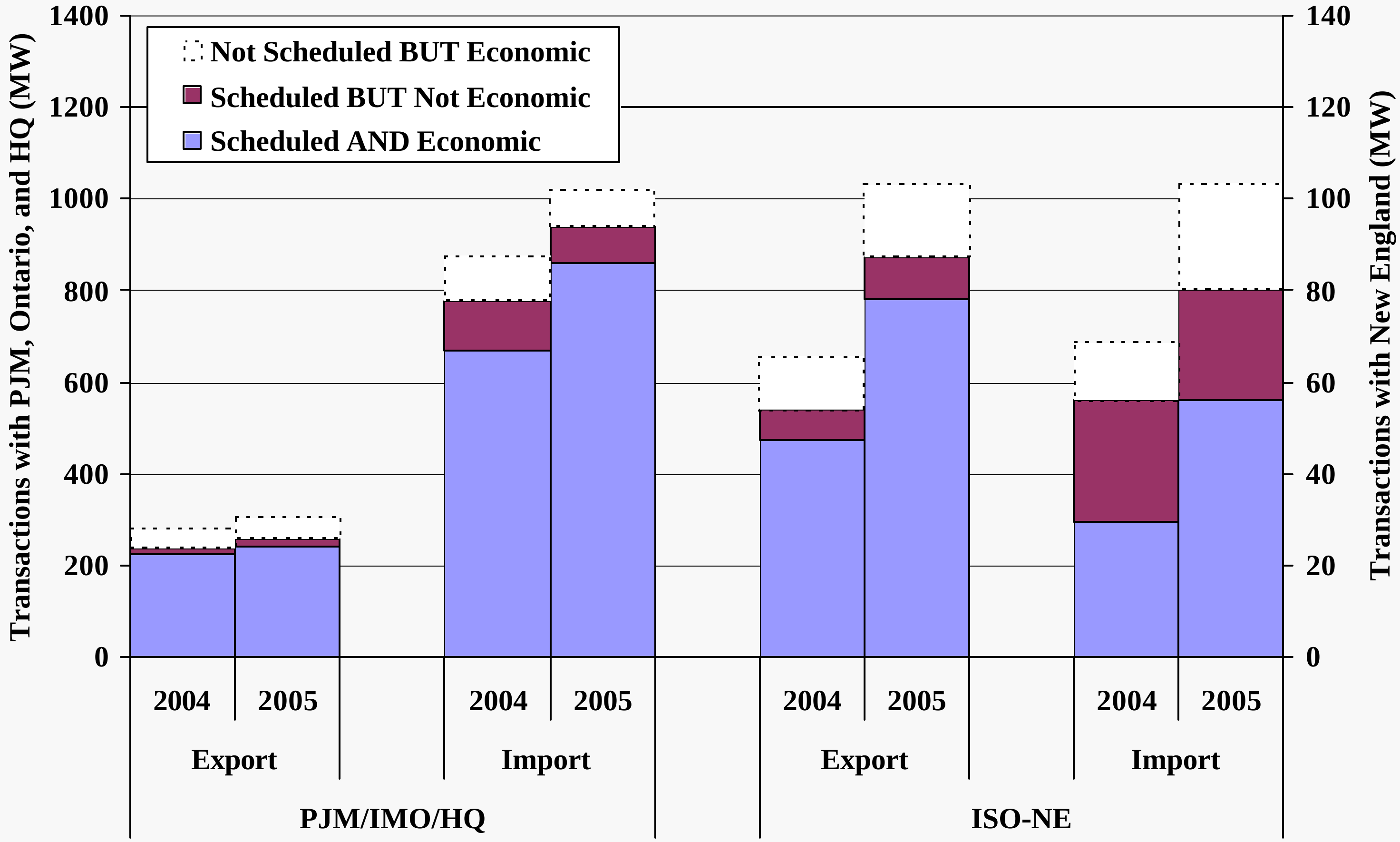


# Efficiency of Real-Time Interface Scheduling

- 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.

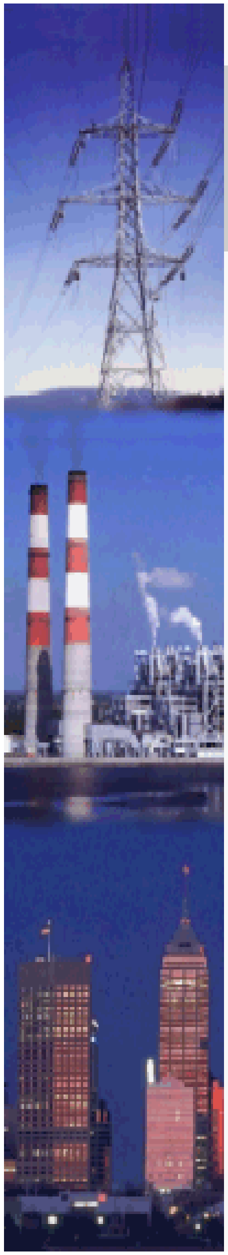


# Efficiency of External Transaction Scheduling Based on Price Sensitive Offers*
# February to August, 2004 & 2005



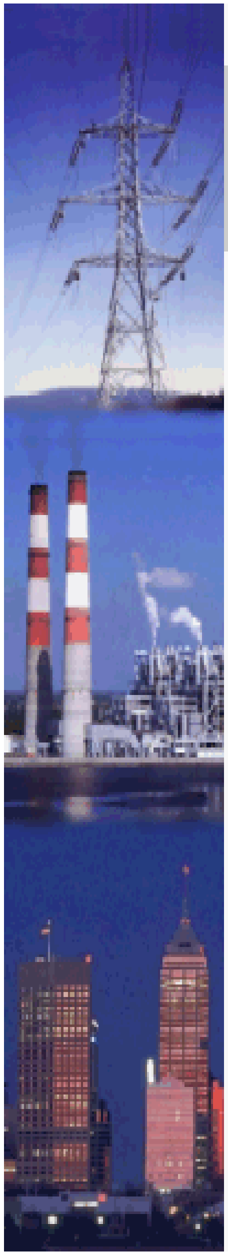

* Includes real-time offers to import or export that are priced between $0 and $900/MWh.

# Frequency of Mitigation



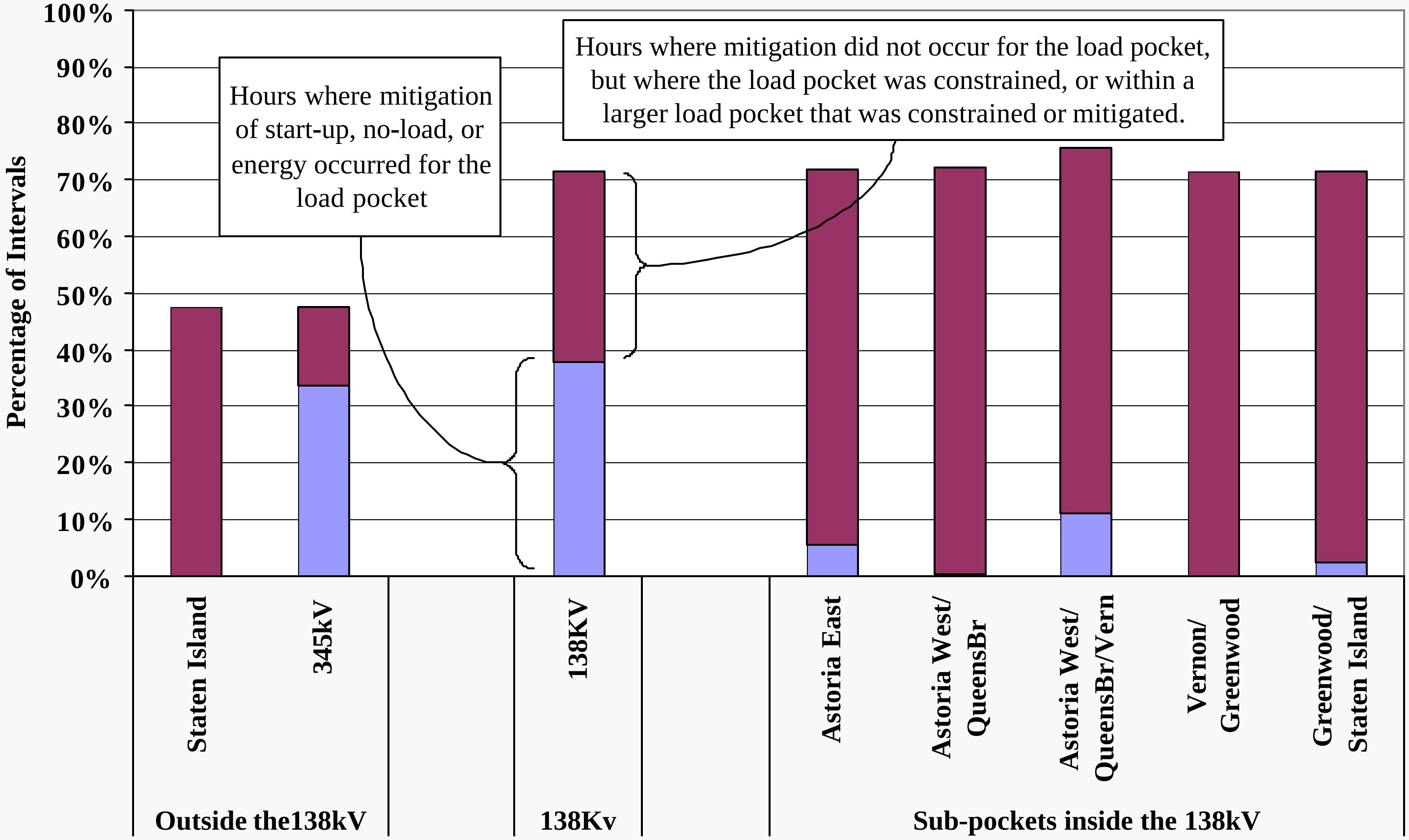
# Summary of Real-Time Mitigation

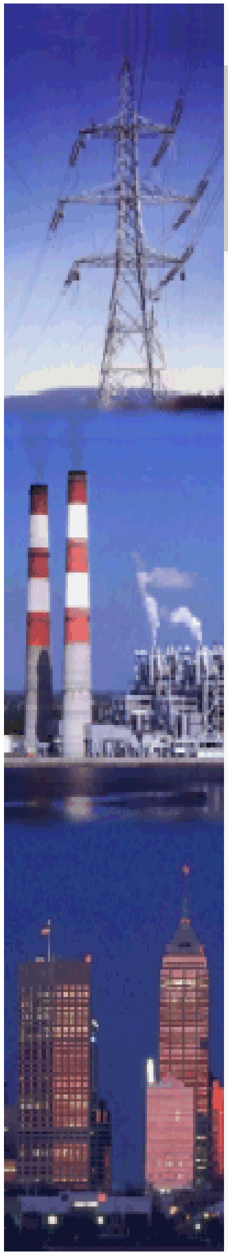
- Local market power mitigation measures are triggered when constraints are binding into a load pocket to address market power in these load pockets within NYC.
- The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - ✓ The columns in the figure show the percent of intervals with a constraint binding such that mitigation could be warranting.
  - ✓ Of those intervals, the lower portion of the columns shows portion of the intervals in which one or more units in the given load pockets were mitigated.
- Mitigation was most frequent in the smallest, most congested load pockets that have the most severe potential market power.
- In more competitive areas outside of the load pockets, mitigation was much 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.



# Frequency of Real-Time Constraints and Mitigation

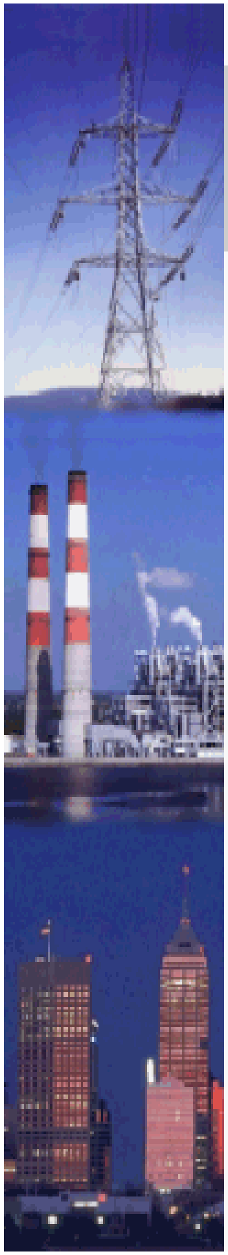
## New York City Load Pockets – February to August, 2005



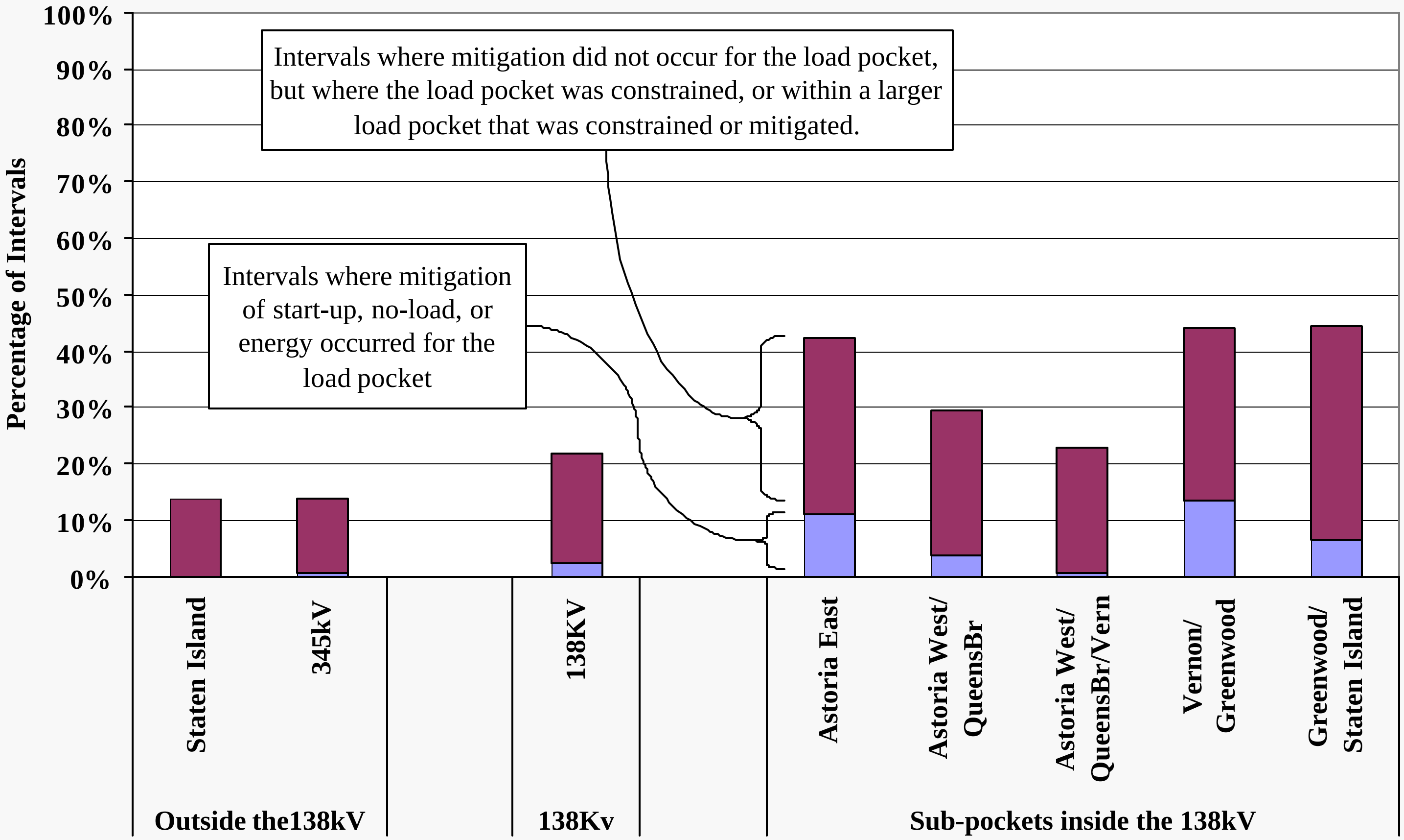


# Summary of Day-Ahead Mitigation

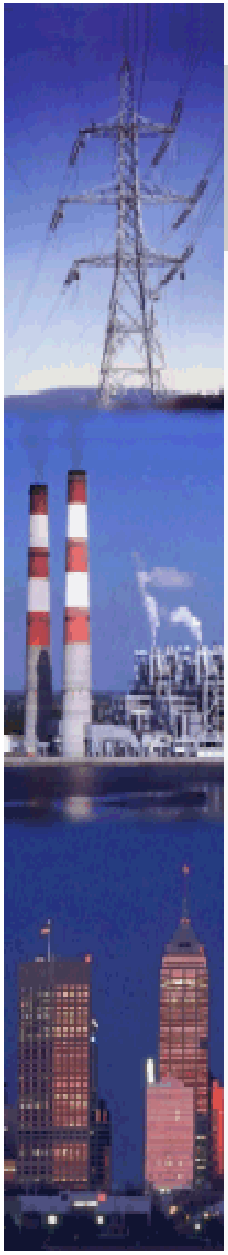
- The conduct and impact framework focus more effectively on potential market power in the NYC load pockets than the ConEd measures which were used until May 1, 2004.
  - ✓ This prevents mitigation from occurring when it is not necessary to address market power.
  - ✓ Allows high prices to occur during legitimate periods of shortage.
- The following figure shows that mitigation has become much less frequent under the conduct and impact framework in NYC.
  - ✓ Like the prior figure, the total column shows the percent of the hours in which constraints are binding while the lower portion of the column shows the percent of hours when mitigation was actually imposed.
  - ✓ Outside of the 138kV load pocket in NYC, there was congestion in 48 percent of hours while mitigation occurred in just 33 percent of hours.
  - ✓ Within the load pockets, mitigation was most commonly associated with the constraint into the 138 kV system and into the Astoria West/ Queensbridge/Vernon load pocket.



## Frequency of Day-ahead Constraints and Mitigation
## New York City Load Pockets, January to August, 2005

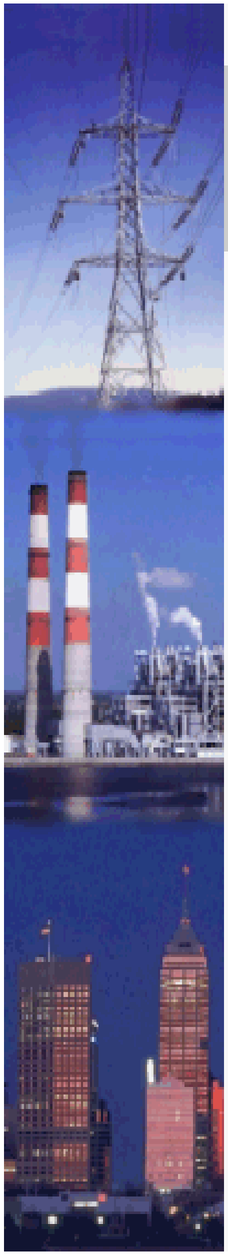


# Reserve Shortages and Shortage Pricing



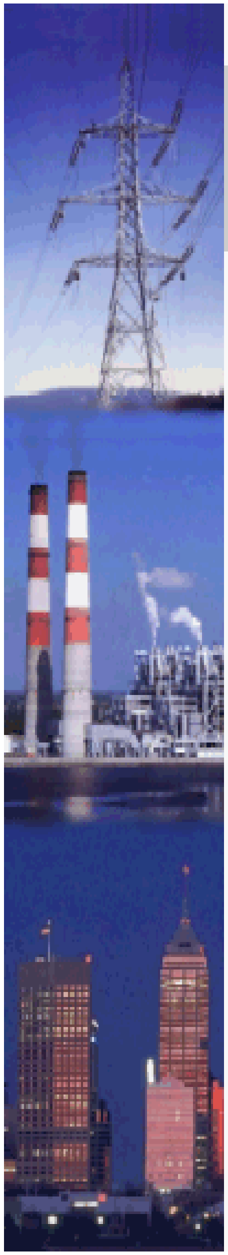
# Reserve Shortages and Shortage Pricing

- Under SMD2, the NYISO enhanced the way it schedules and determines prices 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 the first seven months of SMD2.



# 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 marginal cost pricing.
  - ✓ 34 percent of dispatch-able capacity in New York City and 50 percent of the dispatch-able capacity in the 138kV load pocket is made up of gas turbines. Thus, Hybrid-Pricing is particularly important to setting efficient price signals in NYC.
- Hybrid Pricing works by treating gas turbines as flexible resources for pricing purposes requiring 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.

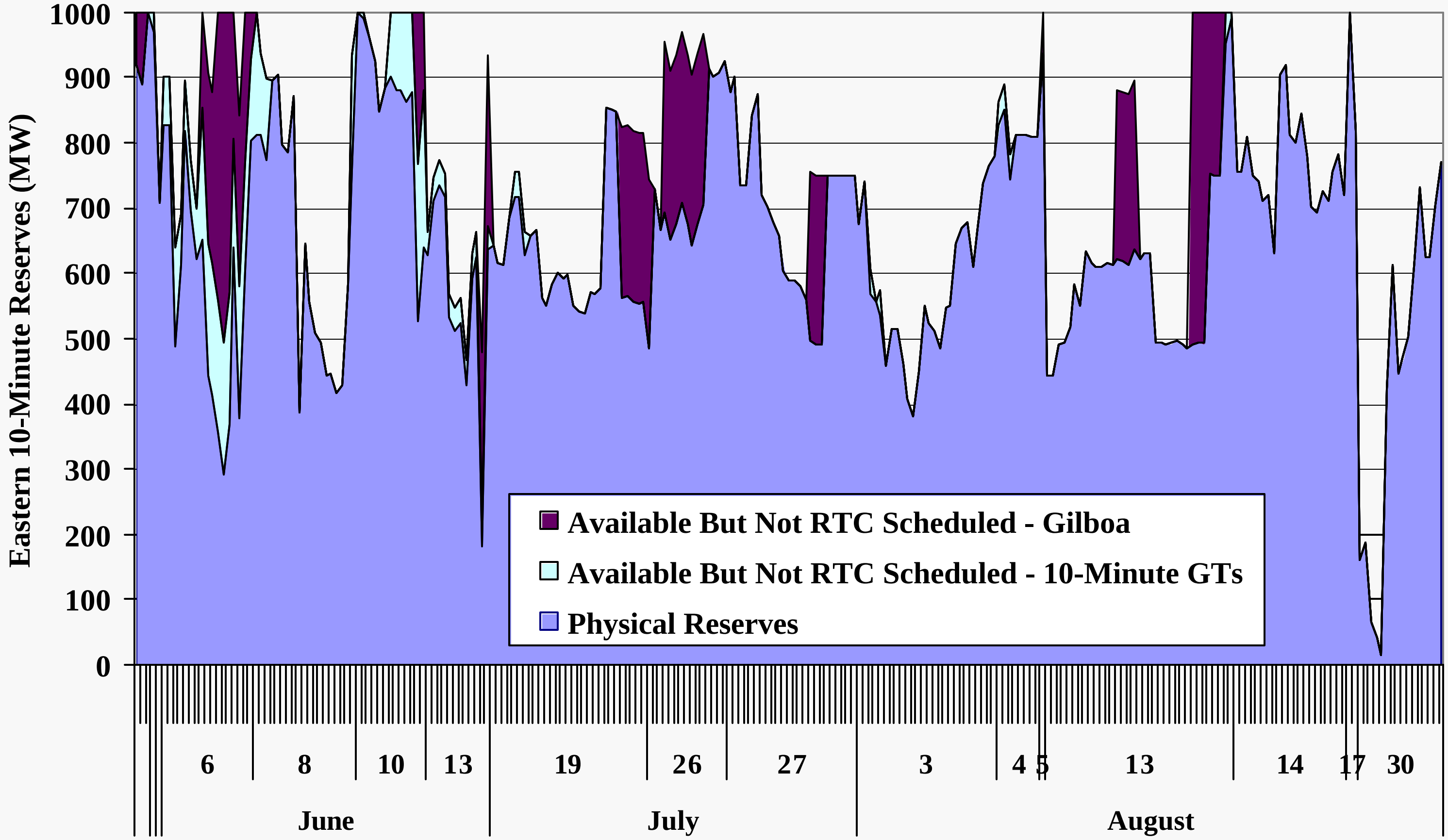


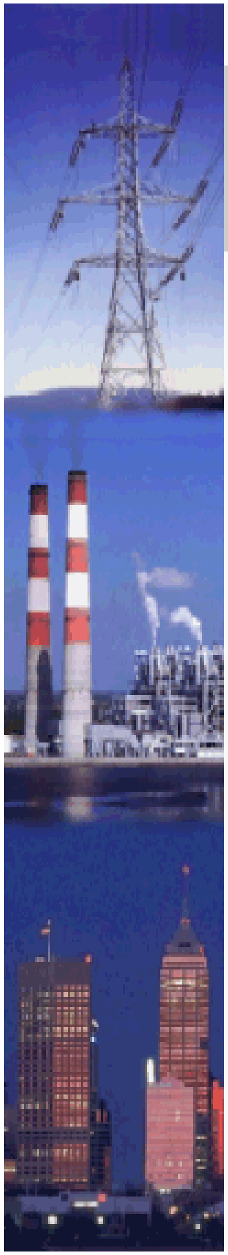
# Reserve Shortages and Shortage Pricing

- 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 243 intervals with shortage pricing of Eastern 10-minute reserves.
  - ✓ Based on physical schedules, Eastern New York was short in 99 percent of these intervals.
- However, the figure shows 10-minute non-spinning capacity on gas turbines and Gilboa units that could not be scheduled by RTD because they were not scheduled by RTC.
  - ✓ Including these GTs in RTD would have prevented 10 of the physical shortage intervals shown.
  - ✓ Including these Gilboa units in RTD as well would have prevented an additional 12 of the physical shortage intervals shown.
- Starting August 16, 2005, RTD is able to utilize off-line quick-start GTs for energy or reserves. However, under these circumstances, the software is still unable to schedule the Gilboa units.

# Scheduling of 10-Minute Reserves in the East

## During Shortage Pricing Intervals – February to August, 2005

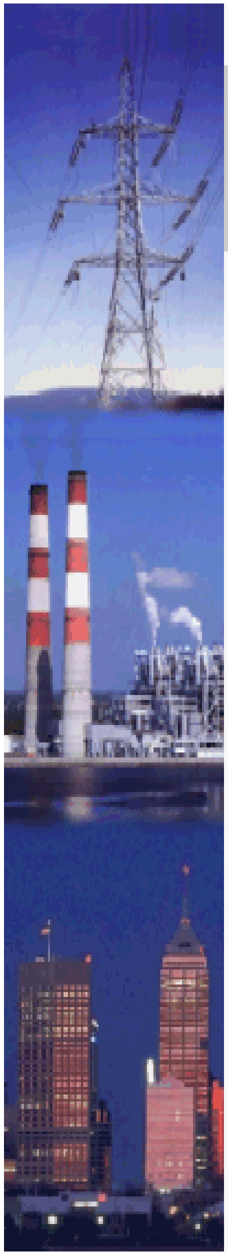


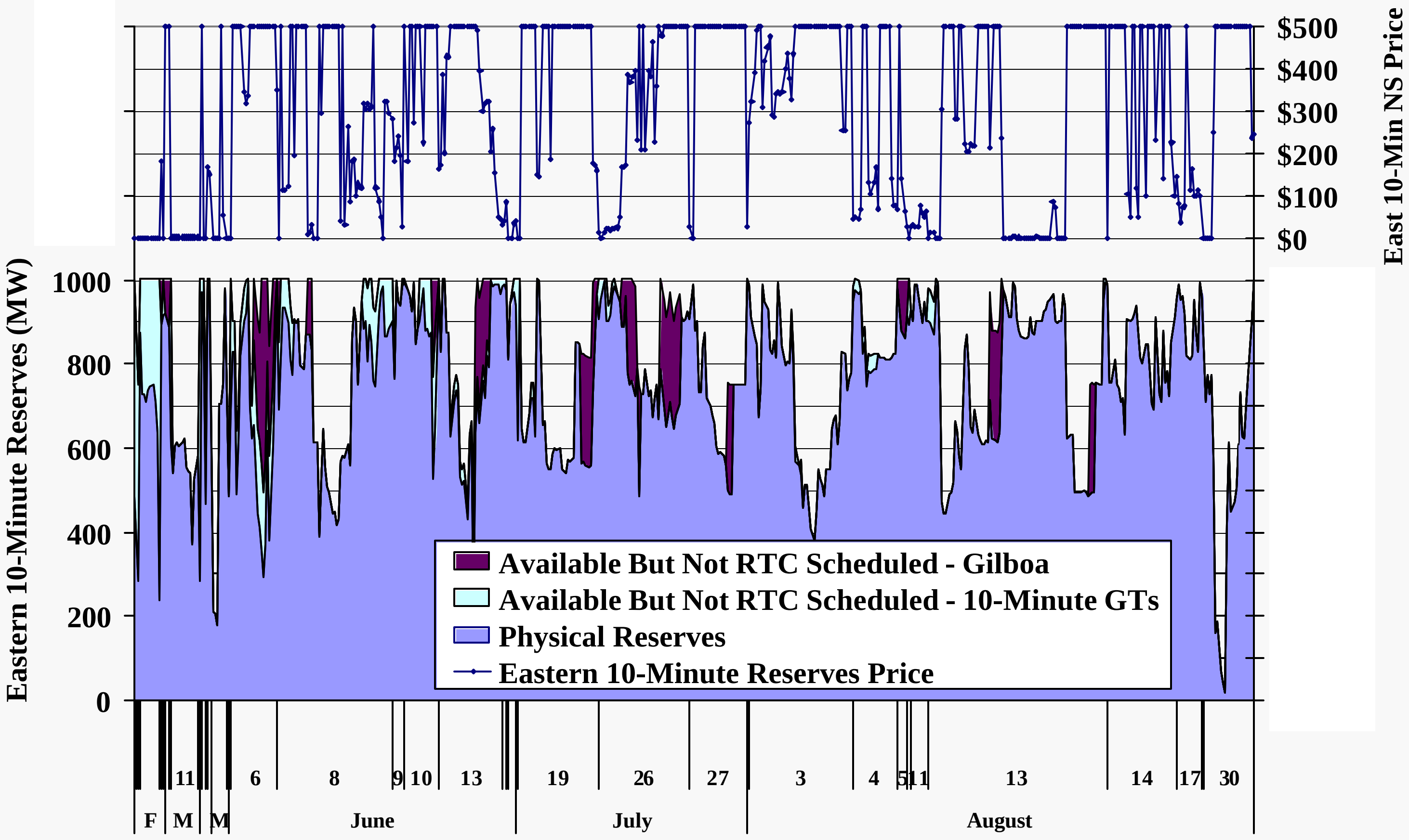


# Reserve Shortages and Shortage Pricing

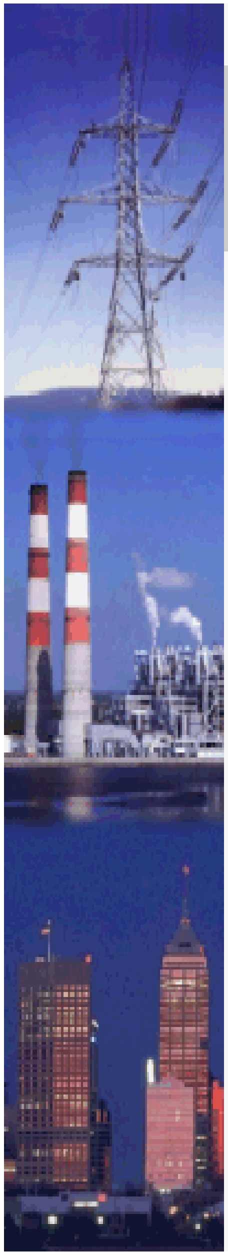
- The following figure shows reserves allocations during physical shortages of Eastern 10-minute reserves as well as a line indicating intervals with Eastern 10-minute reserves shortage pricing.
- There were a 267 intervals with physical reserves shortages but no Eastern 10-minute reserves shortage pricing.
  - ✓ The shortage was less than 100 MW in 43 percent of these intervals;
  - ✓ The shortage was less than 200 MW in 69 percent of these intervals; and
  - ✓ The average Eastern 10-minute reserves price was $130/MWh during these intervals.
- There were a small number of intervals that would not have been physically short of reserves if RTD could schedule quick start resources not scheduled by RTC.
  - ✓ Including the GTs would have prevented 68 of the physical shortage intervals shown.
  - ✓ Including the GTs and Gilboa would have prevented an additional 39 of the physical shortage intervals shown.

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



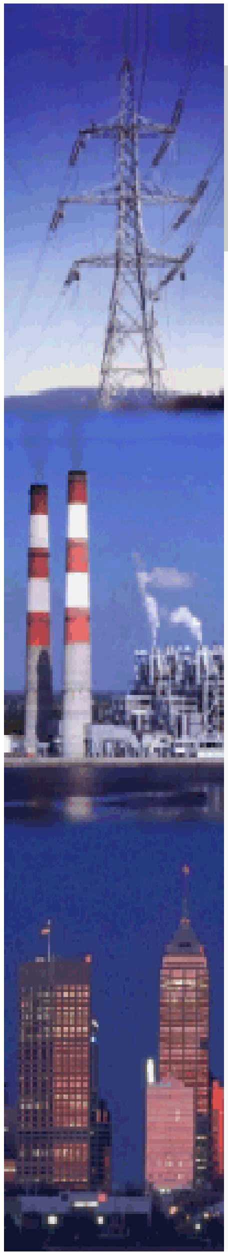



* In cases where the East 10-Minute Non-Spin price exceeds $500/MWh, the figure shows $500/MWh.



# 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 .
- Some of the physical shortages identified above would not have occurred if offline Gilboa units could be selected to provide reserves by RTD (even if not scheduled by RTC).
  - ✓ Hence, we recommend that the NYISO allow RTD to schedule these units to provide non-spinning reserves, even if the unit is not scheduled by RTC and the energy remains unavailable to RTD.
- There were software issues that resulted in inefficient dispatch instructions during the shortages.
  - ✓ These issues did not affected prices.
  - ✓ The NYISO has resolved these software issues.



# Reserve Shortages and Shortage Pricing Conclusions

- Hybrid Pricing generally enables the real-time software to calculate efficient prices, especially in areas that are primarily served by GTs.
- Inconsistencies between the pricing and dispatch passes arise in the availability of Eastern 10-minute reserves because:
  - ✓ The pricing pass treats GTs as flexible resources for pricing purposes.
  - ✓ In some cases, this flexibility allows the pricing pass to increase the total 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.
- In the 2005 State of the Market Report, we will evaluate the significance of each of the two factors that contribute to inconsistencies between pricing and dispatch.

# External Transactions

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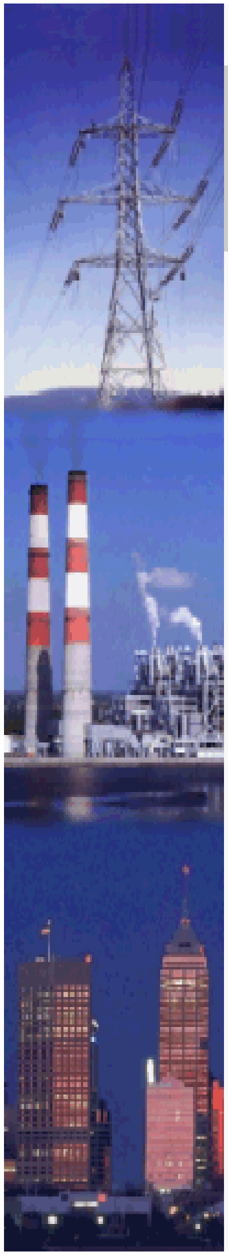
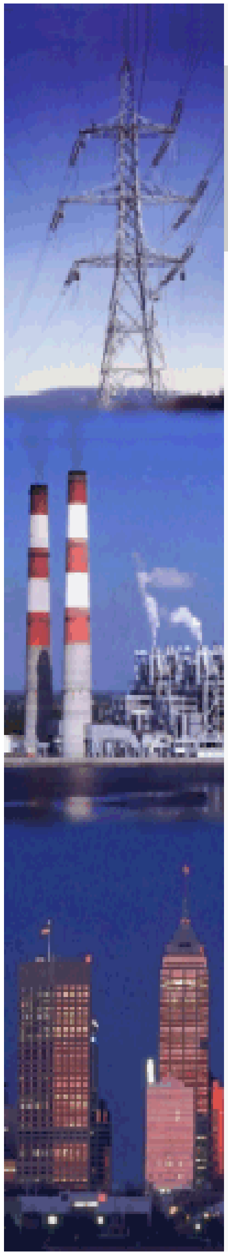


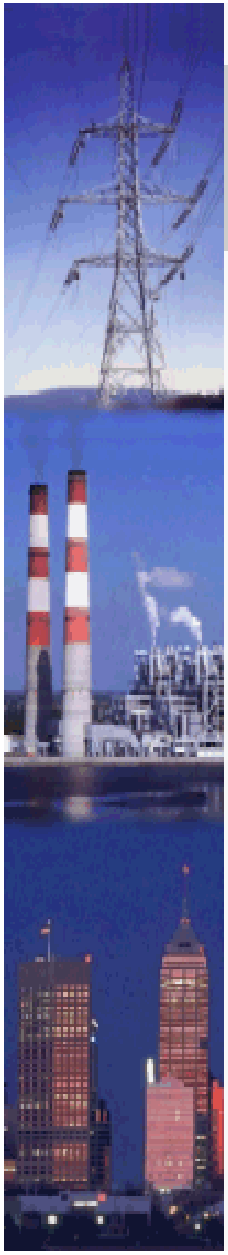
# Utilization of the Interfaces in All Hours

- 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.



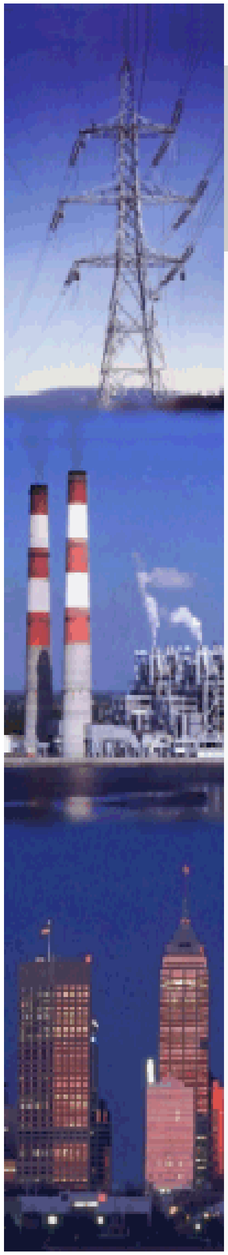
# Utilization of the Interfaces in All Hours

- 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.

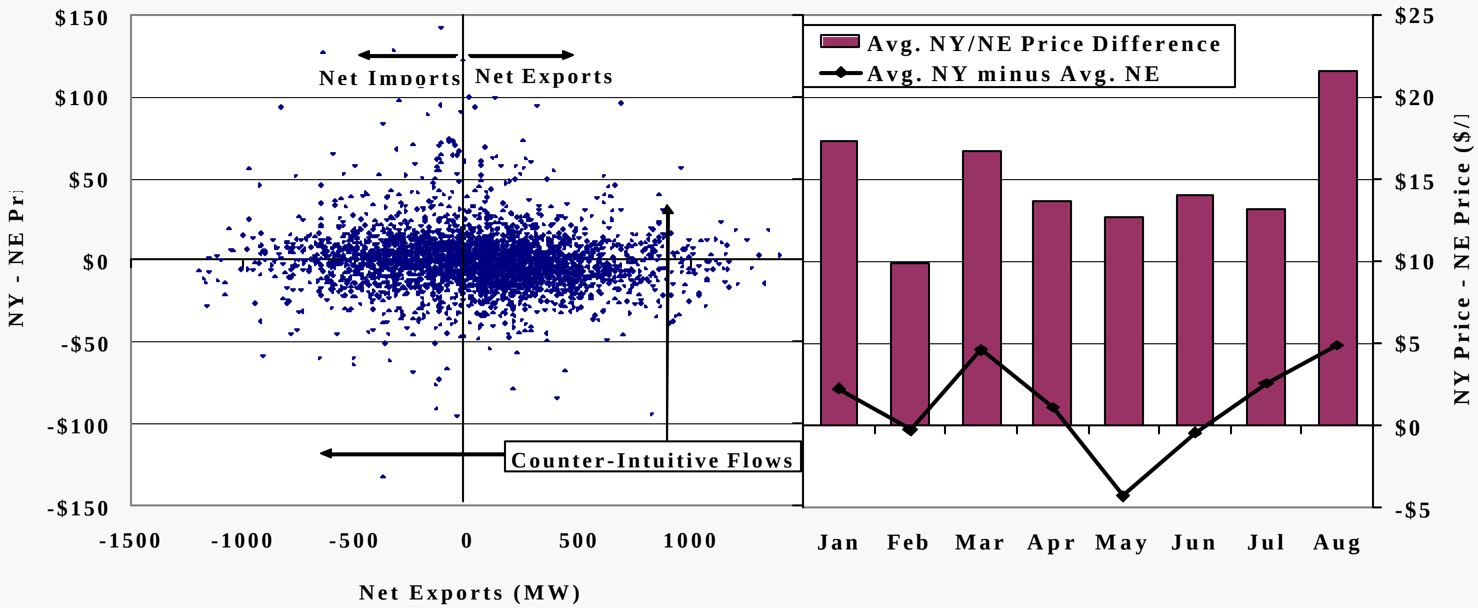


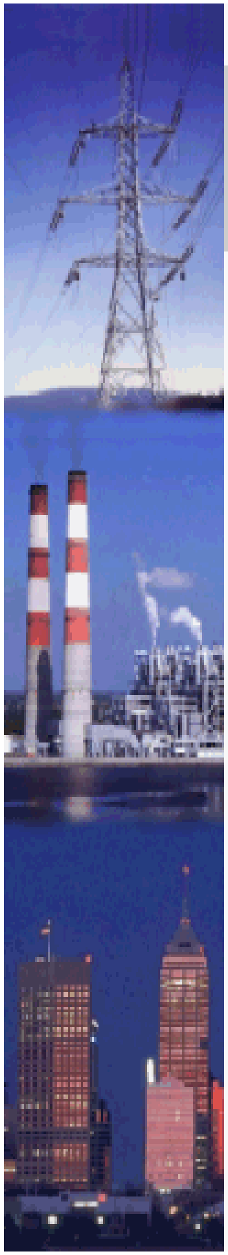
# Utilization of the Interfaces in All Hours

- 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.

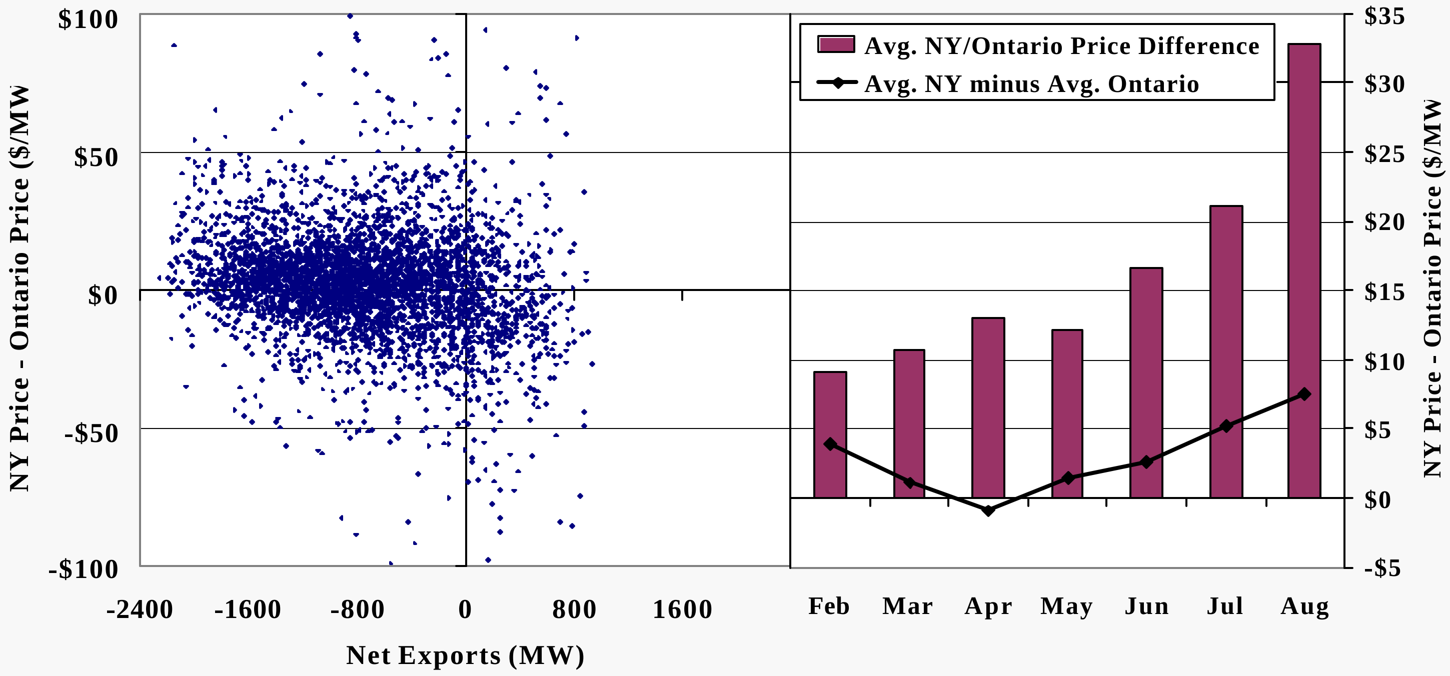


# Real-Time Prices and Interface Schedules Eastern NY and New England

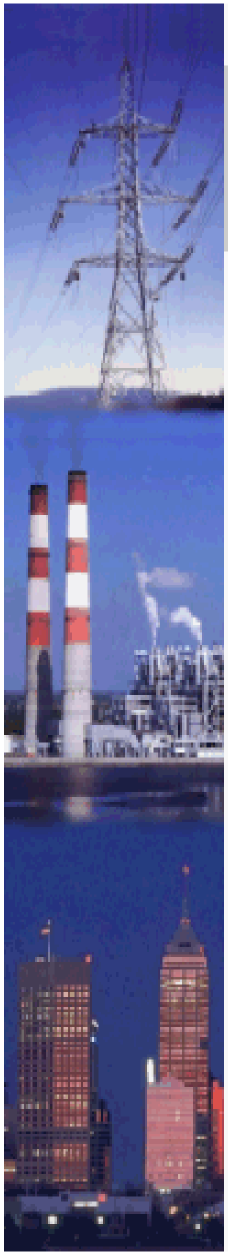




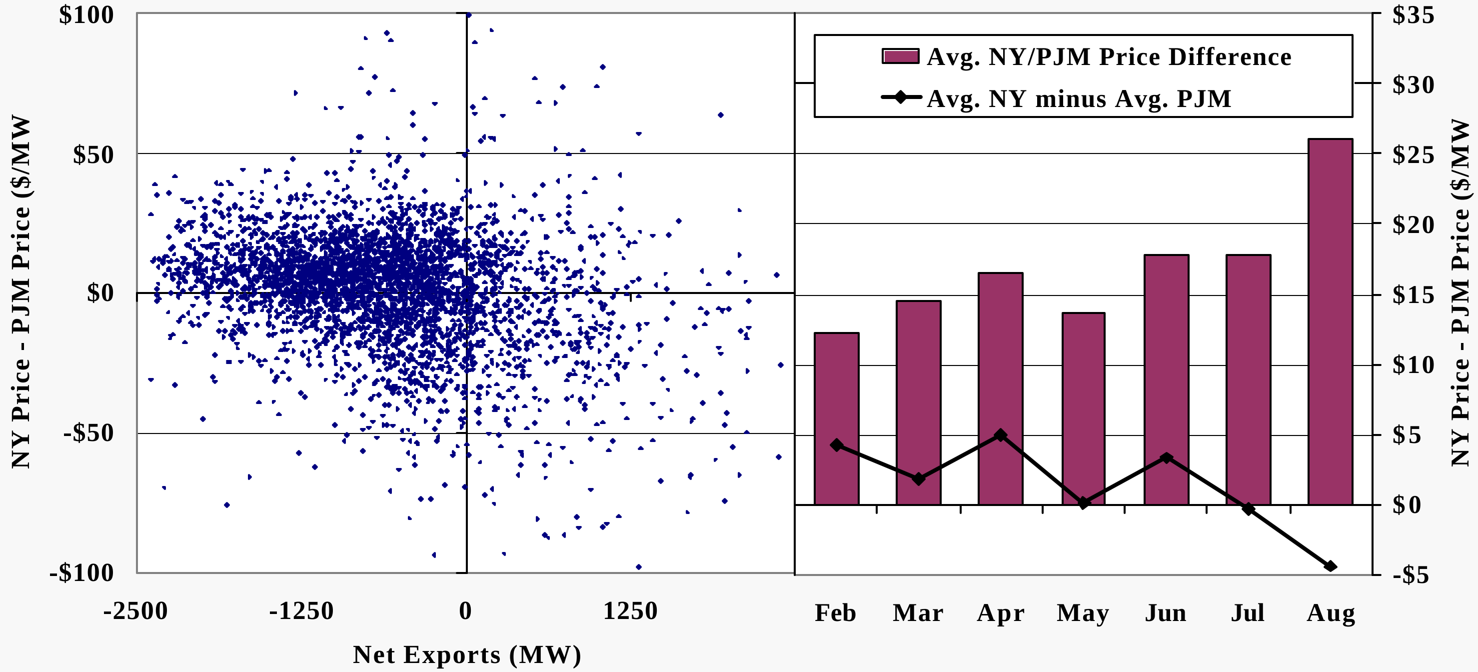
# Real-Time Prices and Interface Schedules*
# West NY and Ontario

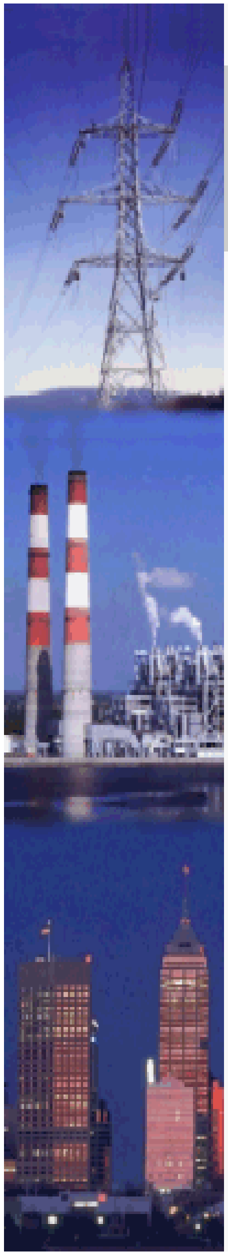



* Price difference measured in US dollars



# Real-Time Prices and Interface Schedules
# NY West Zone and PJM



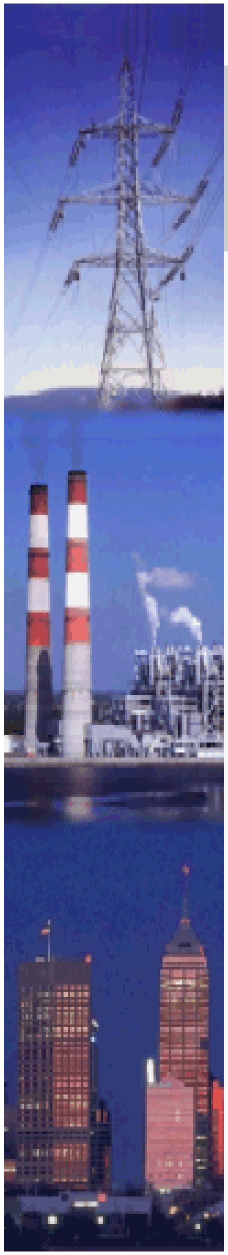


# Price Convergence Between Adjacent Markets

- The following table shows the average difference in prices between New York and neighboring markets against net exports during hours when transmission constraints are not binding.
  - ✓ The table compares convergence statistics from 2005 with the same period in 2004.
- The results suggests that the real-time markets continue to not be efficiently arbitraged by participants:
  - ✓ The price difference continues to average more than 20 percent between New York and adjacent control areas during unconstrained periods.
  - ✓ The table does not indicate improved arbitrage between New York and New England since the elimination of export fees at the beginning of 2005.

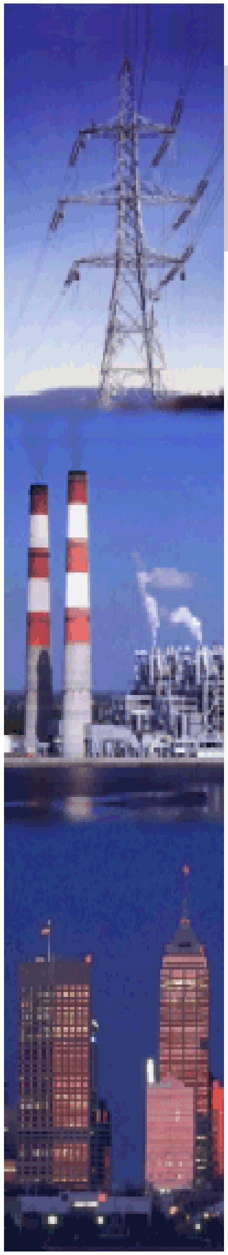
# Convergence of Real-Time Prices with Adjacent Markets
## Unconstrained Hours – Feb. to Aug. 2004 & 2005

| | 2004 | 2005 |
|---|---|---|
| **NY border price vs. NE border price** | | |
| **Avg NY price minus Avg NE price** | -$1.98 | $0.69 |
| **Avg price difference between NY and NE** | $9.43 | $14.48 |
| **Avg price difference as a percent of NY price** | 21% | 23% |
| **NY border price vs. PJM border price** | | |
| **Avg NY price minus Avg PJM price** | $0.08 | $1.58 |
| **Avg price difference between NY and PJM** | $11.78 | $16.75 |
| **Avg price difference as a percent of NY price** | 27% | 30% |
| **NY border price vs. OH border price** | | |
| **Avg NY price minus Avg OH price** | $8.69 | $2.74 |
| **Avg price difference between NY and OH** | $13.96 | $16.10 |
| **Avg price difference as a percent of NY price** | 34% | 29% |

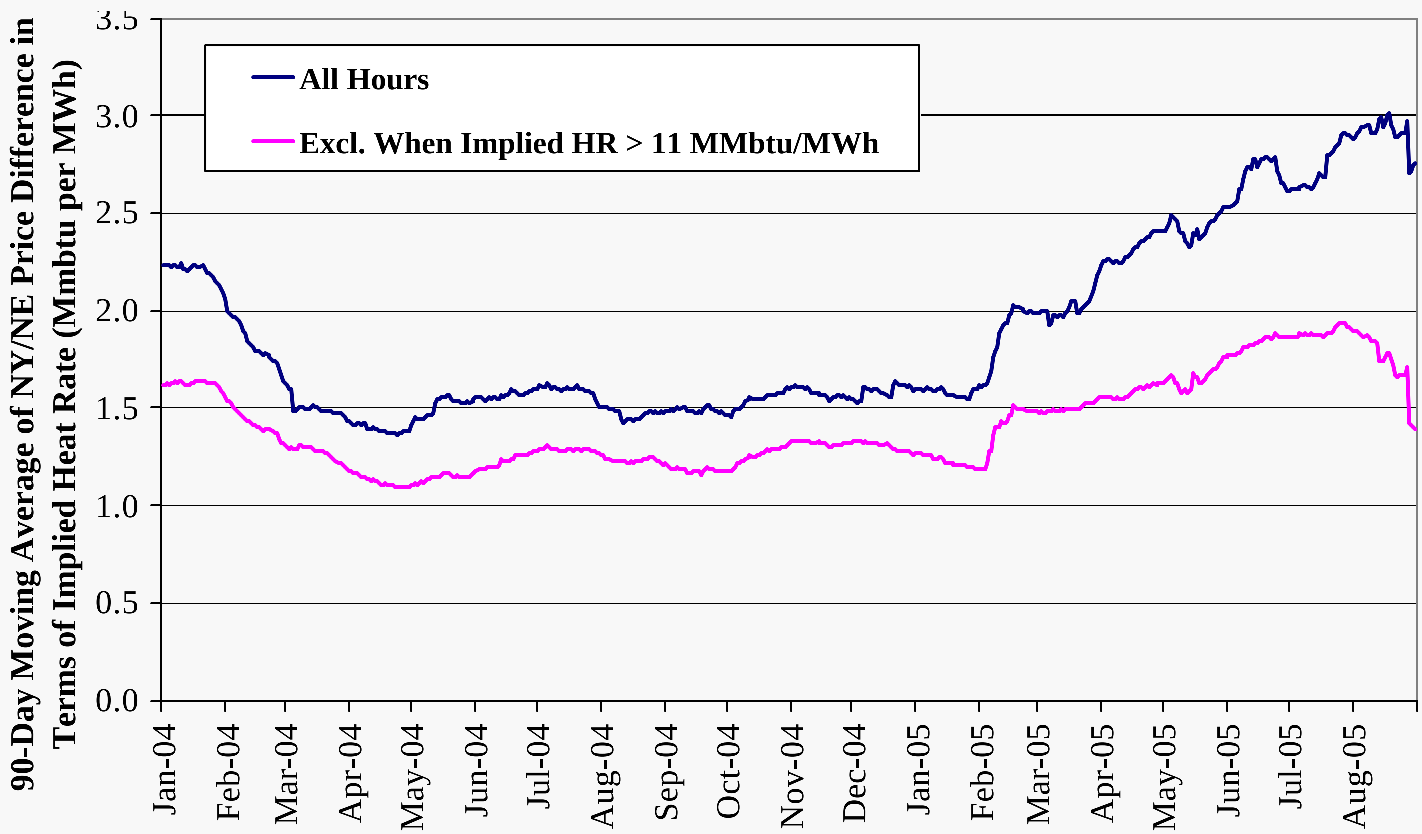


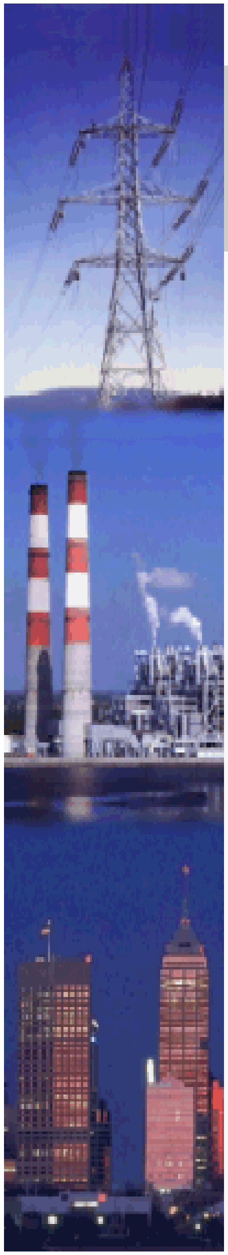
# Price Convergence Between Adjacent Markets

- The following figure shows a 90-day moving average of the real-time price difference with New England to evaluate the arbitrage of the two markets.
  - ✓ The real-time price difference is expressed in terms of the implied heat rate in order to adjust for fluctuations in the price of natural gas.
    - With this measure, a 1 MMBTU per MWH difference when gas prices are $10 per MMBTU would correspond to a price difference of $10 per MWh.
  - ✓ Transmission constrained hours are also excluded from the moving average.
  - ✓ The lower line in the figure excludes price spikes to show the changes price convergence that occurred under typical non-shortage conditions.
- The moving average was relatively flat across 2004, including the summer when the weather was extremely mild.
- After the elimination of export fees in the beginning of January 2005, price convergence improved slightly until February 2005.
- Price convergence worsened after the implementation of SMD2 in February, due most likely to the significant increase in price volatility.



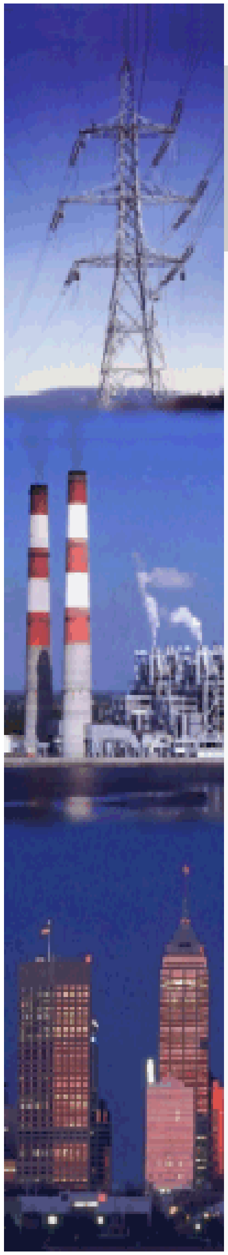
# Average Difference in Prices During Non-Constrained Hours
## Between New York and New England – Jan. 2004 to Aug. 2005



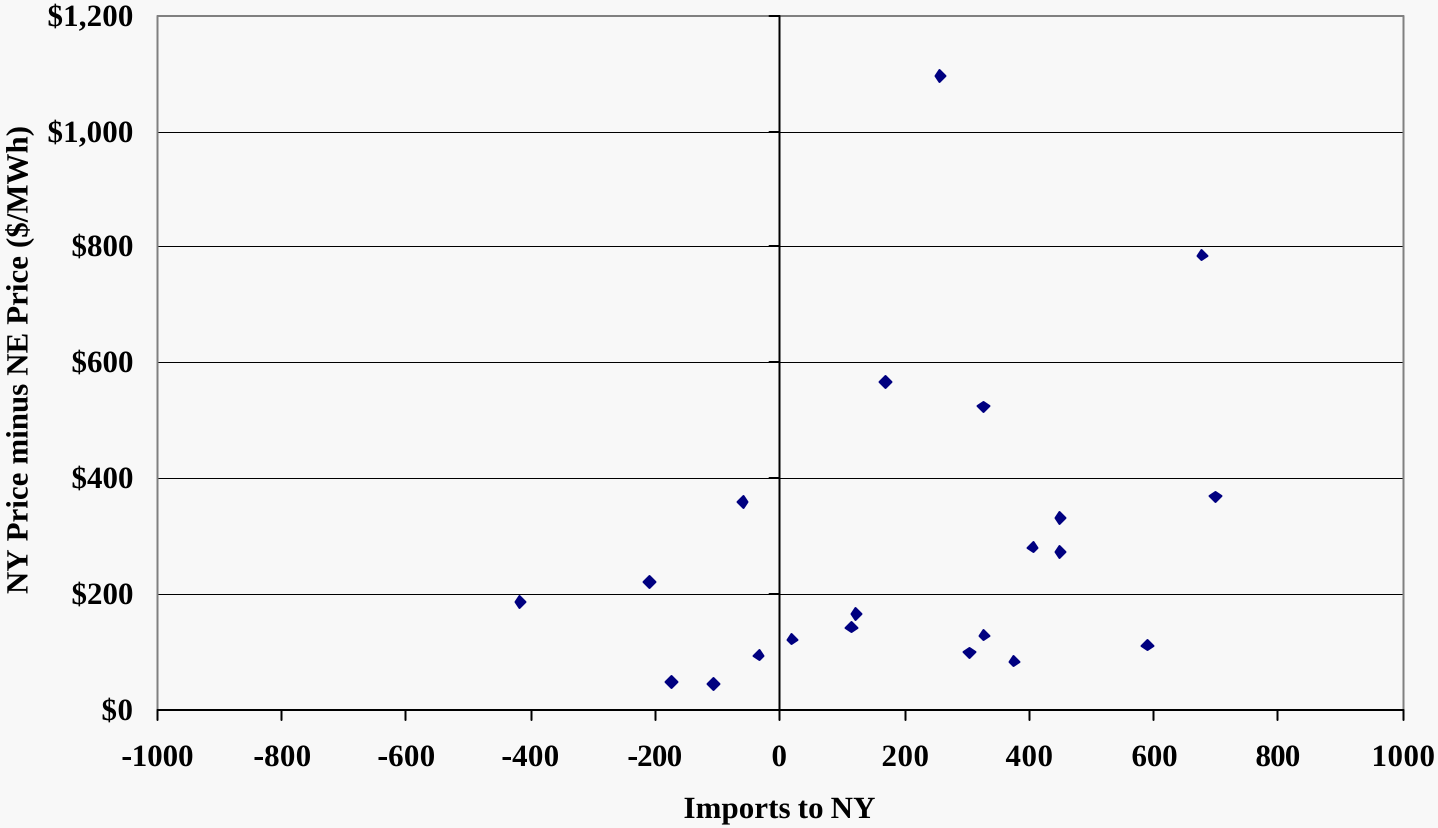


# Interface Utilization During Scarcity Conditions

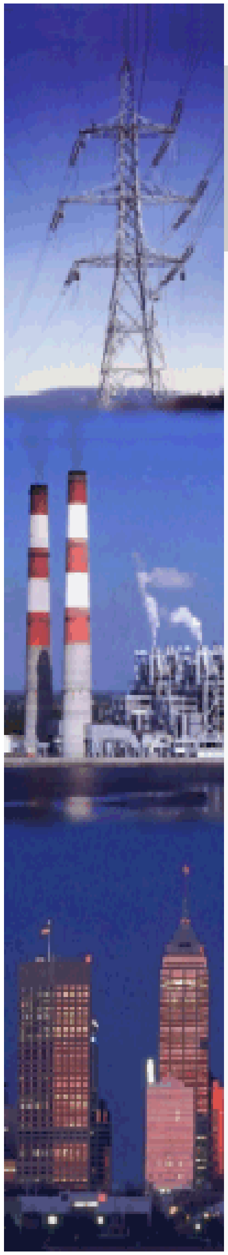
- During peak demand conditions, it is especially important to efficiently schedule flows between control areas.
- The following chart examines the difference between New York and New England real-time border prices in unconstrained hours where the Capital Zone price exceeded $200/MWh.
- Price convergence has been especially poor during peak demand conditions:
  - ✓ 10 of 21 hours show a price difference of more than $200/MWh.
  - ✓ 17 of 21 hours show a price difference of more than $100/MWh.
  - ✓ In 7 of the hours shown, power was flowing out of New York.
- 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 During 21 Unconstrained Eastern NY Price Spike Hours* February to August, 2005

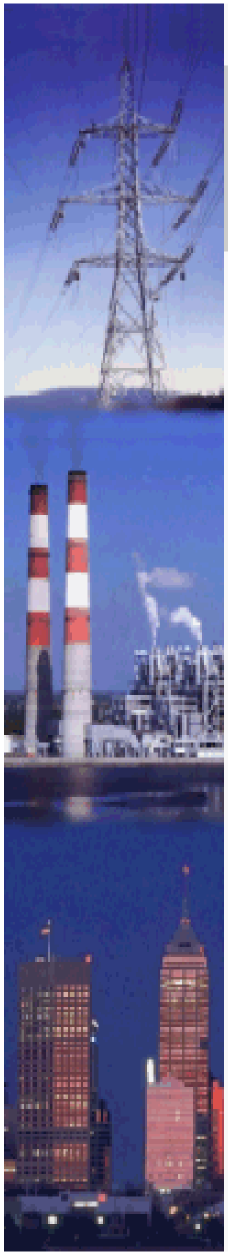



* Includes hours when the RT Capital zone price exceeded $200/MWh.

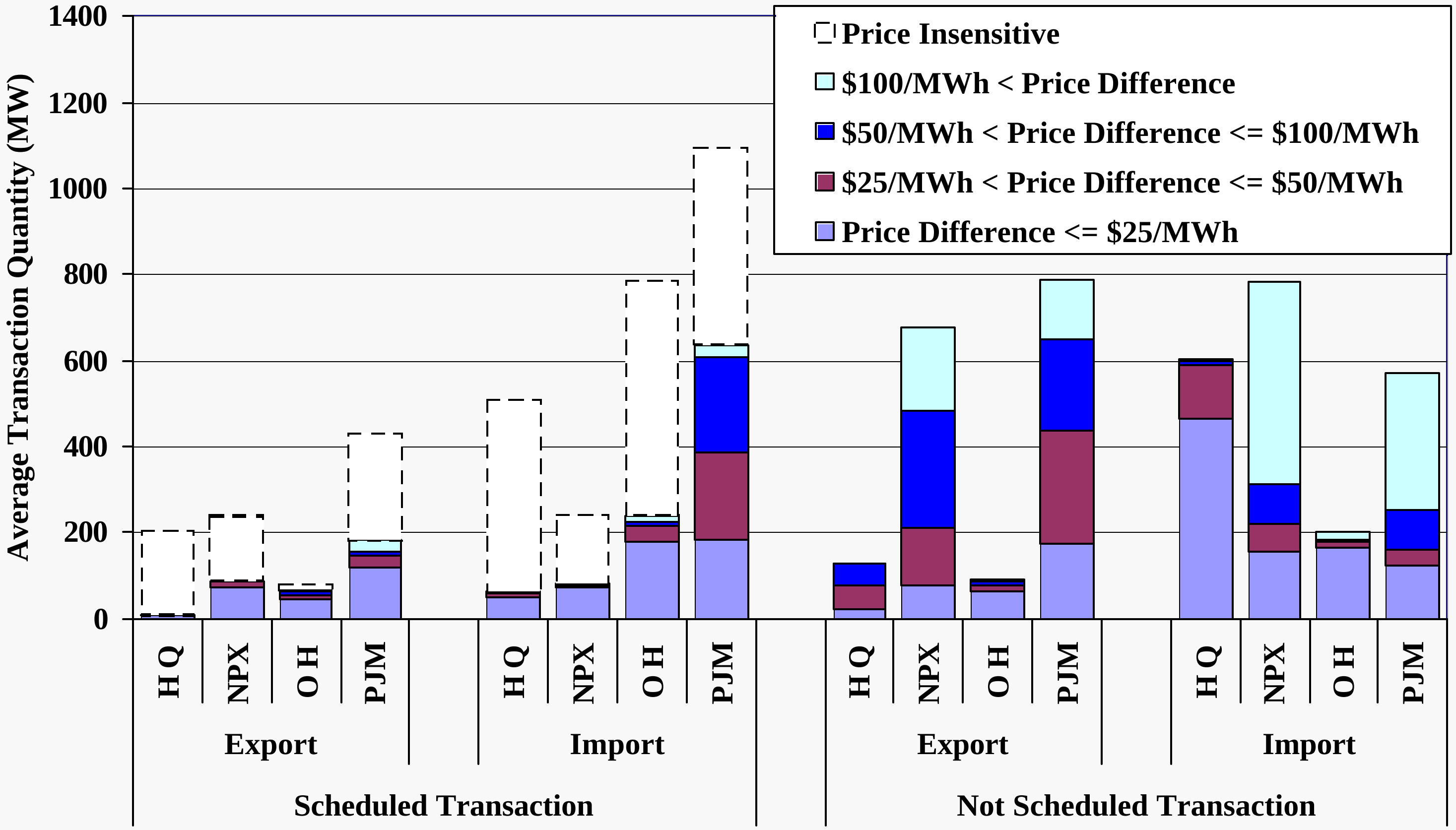


# Price Sensitivity of External Transaction Offers

- New York and adjacent markets rely on market participants to schedule transactions between control areas. Market participants can profit by helping to optimize flows between control areas.
- As discussed in previous reports, uncertainty, imperfect information, and required offer lead times inhibit market participants from prevent perfect arbitrage.
- The following figure shows the volume of price sensitive transactions offered in real-time between New York and adjacent control areas.
  - ✓ For each interface, the total amount of transactions scheduled price sensitively is relatively small relative to the transfer capability of the interface.
  - ✓ Less than 200 MW of gross imports and exports are scheduled between New York and New England in a price sensitive manner in real-time.

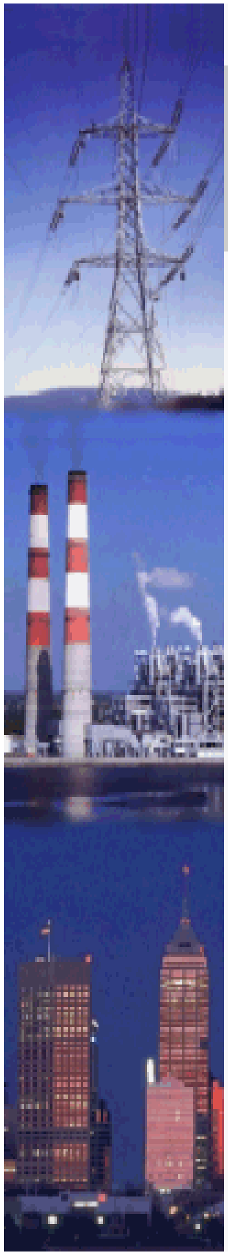


# Price Sensitivity External Transaction Offers
## Real-Time Market – February to August 2005



# Market Operations

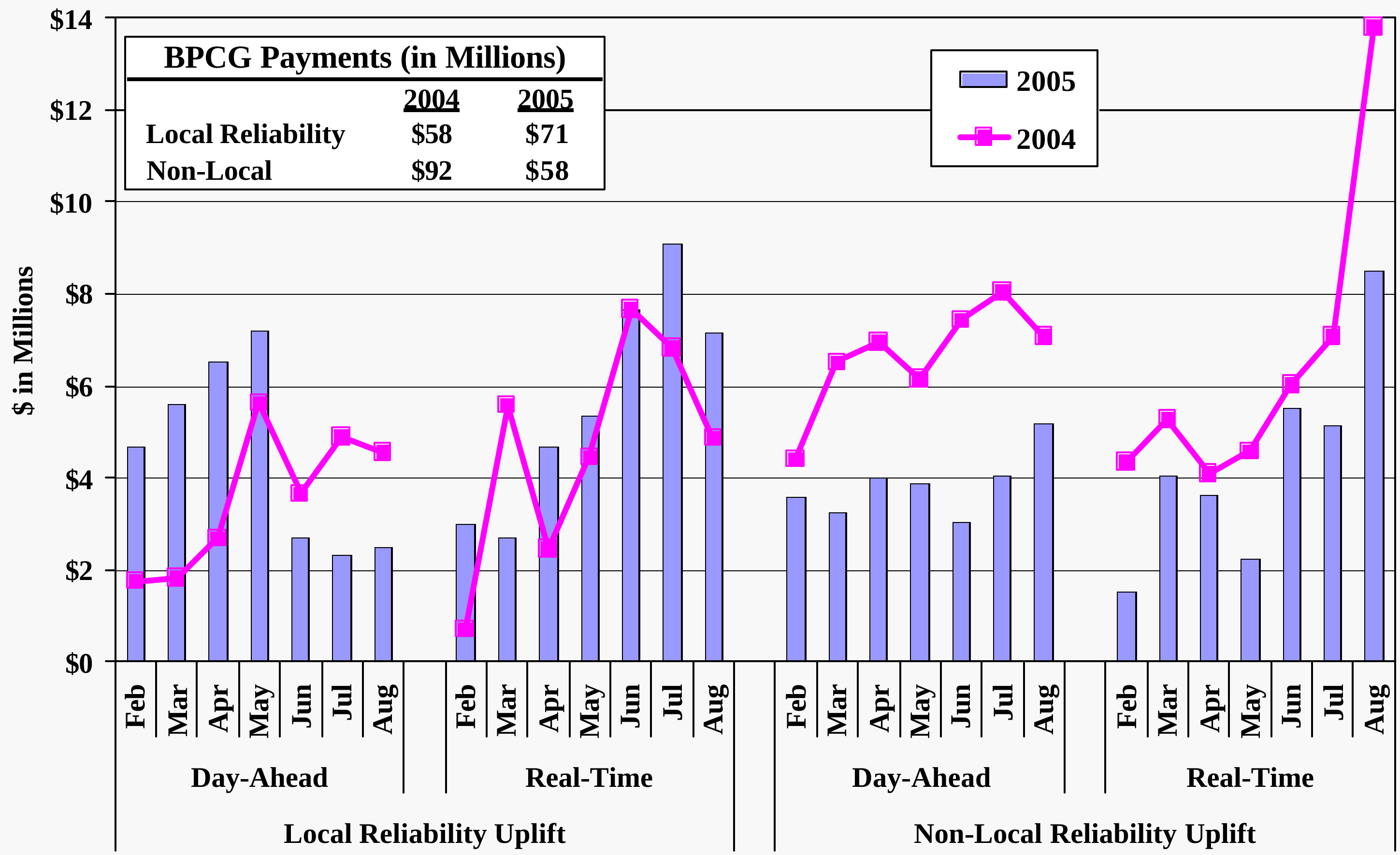
POTOMAC ECONOMICS

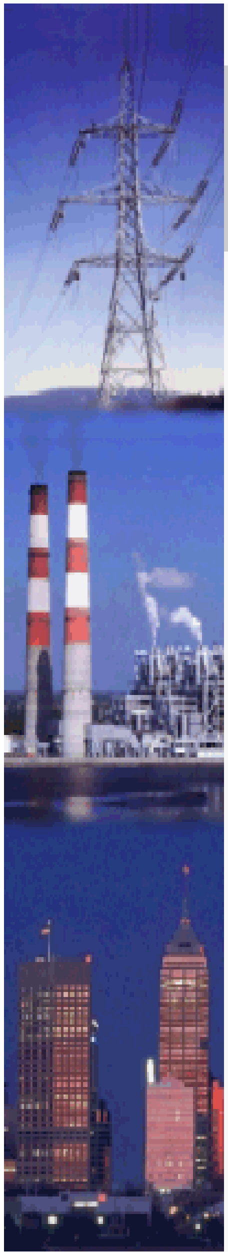


# Uplift Expenses from BPCG Payments

- The next figure shows the day-ahead and real-time uplift costs from BPCG payments from February to August, 2004 and 2005.
- The figure shows a 22 percent increase in uplift for local reliability commitment and dispatch which assigned to the local load serving entity. This is primarily composed of:
  - ✓ Day-ahead uplift from commitments made by SCUC’s local reliability pass;
  - ✓ Real-time uplift from SRE commitments made by the local TO; and
  - ✓ Real-time uplift from OOM units called by the local TO.
- The figure shows a 37 percent reduction in uplift for non-local reliability reasons. This is largely due to improvements in the efficiency of gas turbine commitment and external transaction scheduling by RTC relative to the BME model.

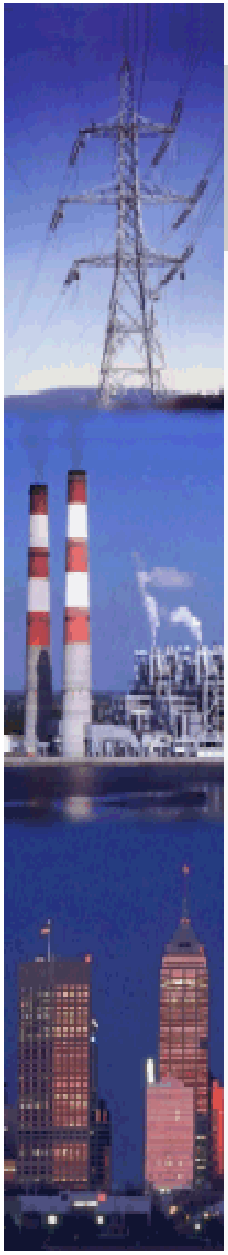
# Day-Ahead and Real-Time Uplift from BPCG Payments
## February to August, 2004 & 2005



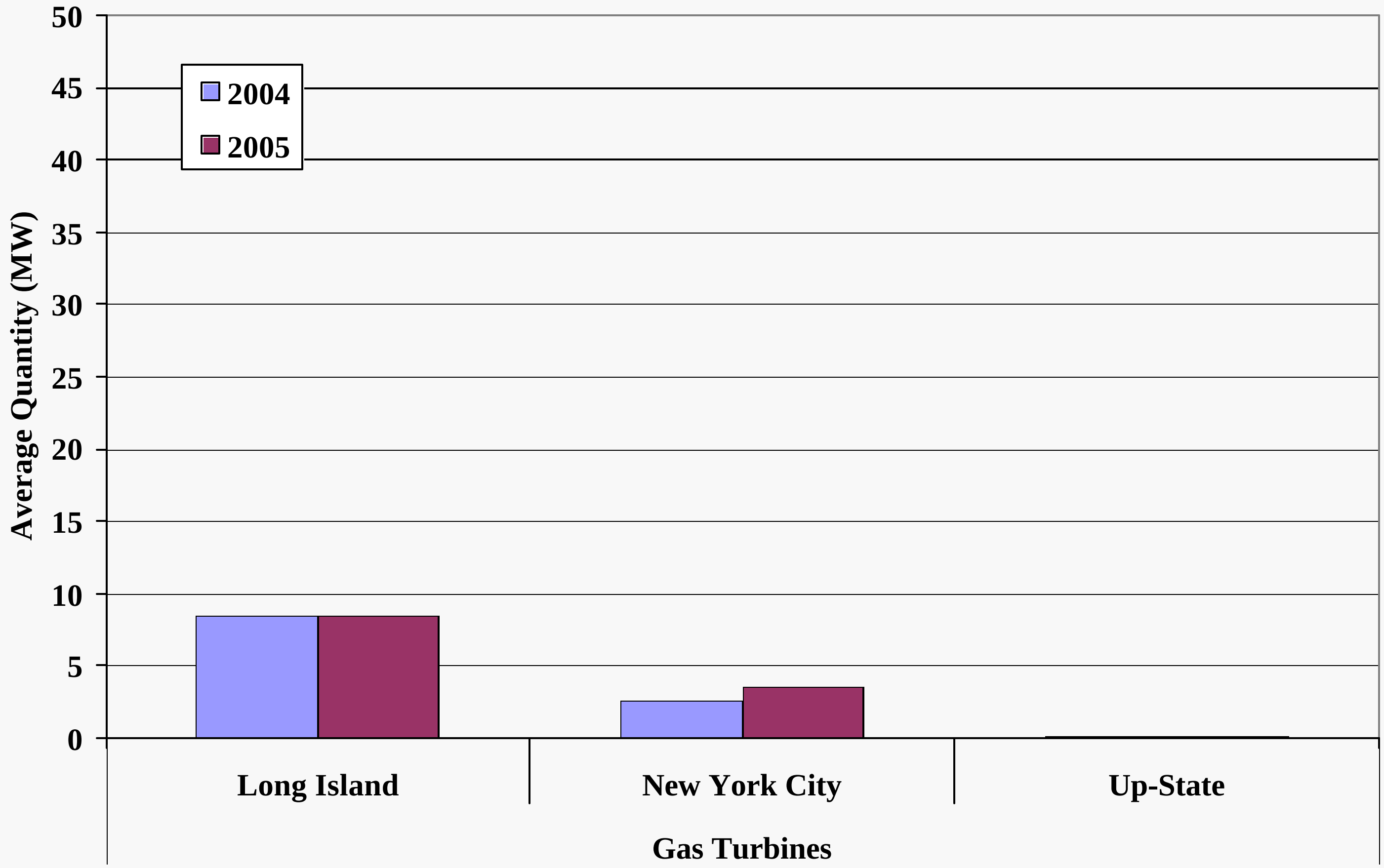


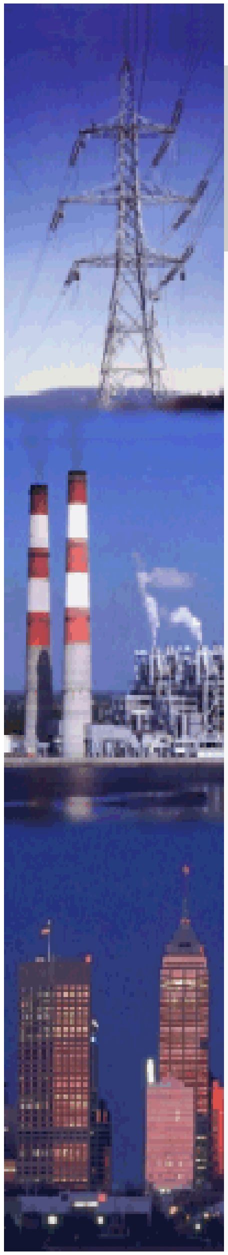
# Real-Time Out of Merit Dispatch

- 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 logged by the NYISO and if their offer price is higher than the LMP.
- OOM dispatch quantities of gas turbines have generally been low since the introduction of load pocket modeling in New York City in 2002.



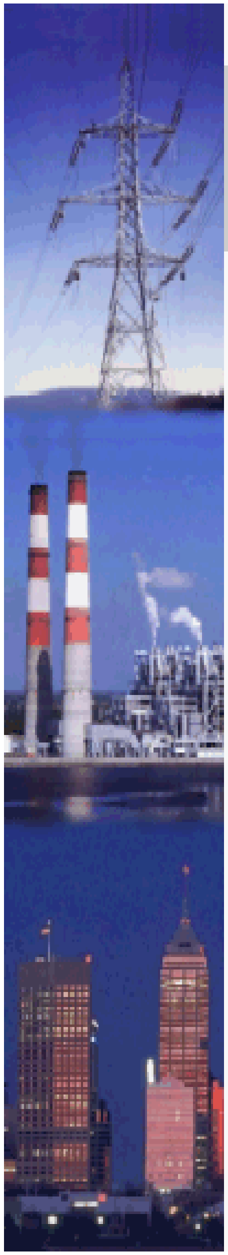
# Out-of-Merit Dispatch of GTs by Transmission Owners
## February to August, 2004 & 2005



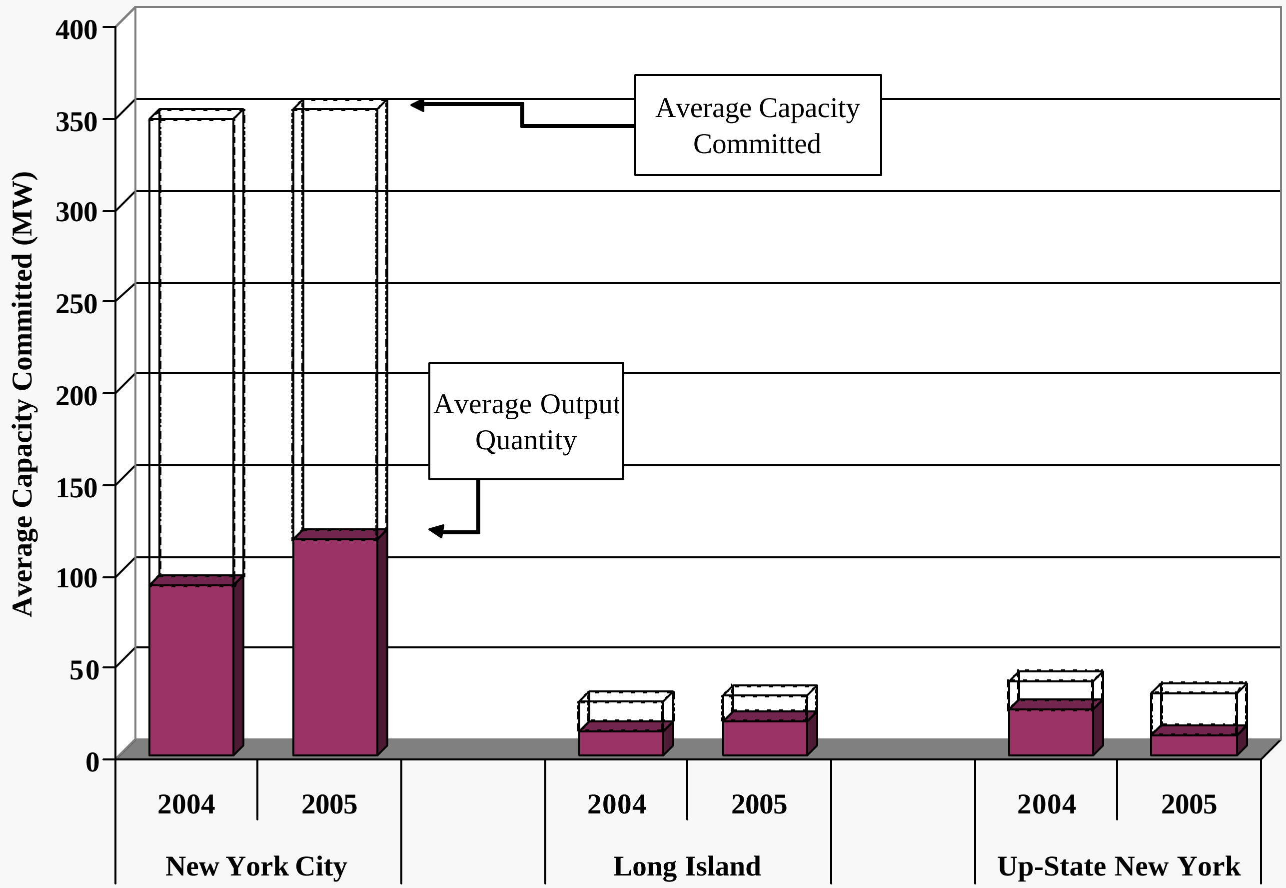


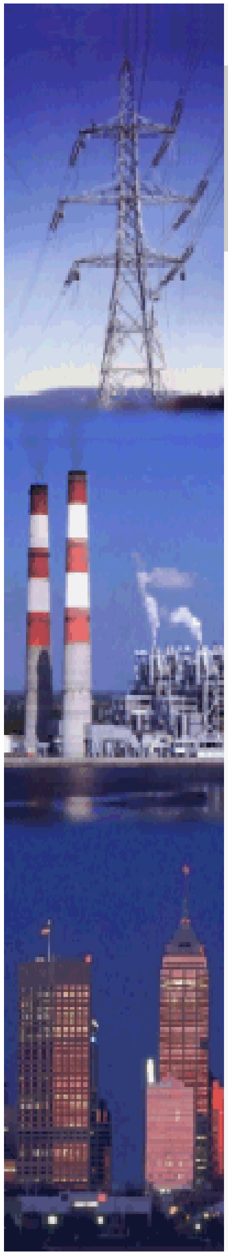
# Supplemental Resource Evaluation

- 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.



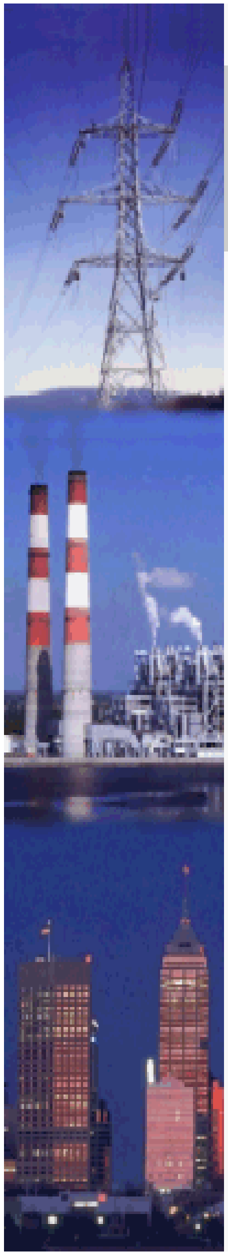
# Supplemental Resource Evaluation Commitment February to August, 2004 & 2005



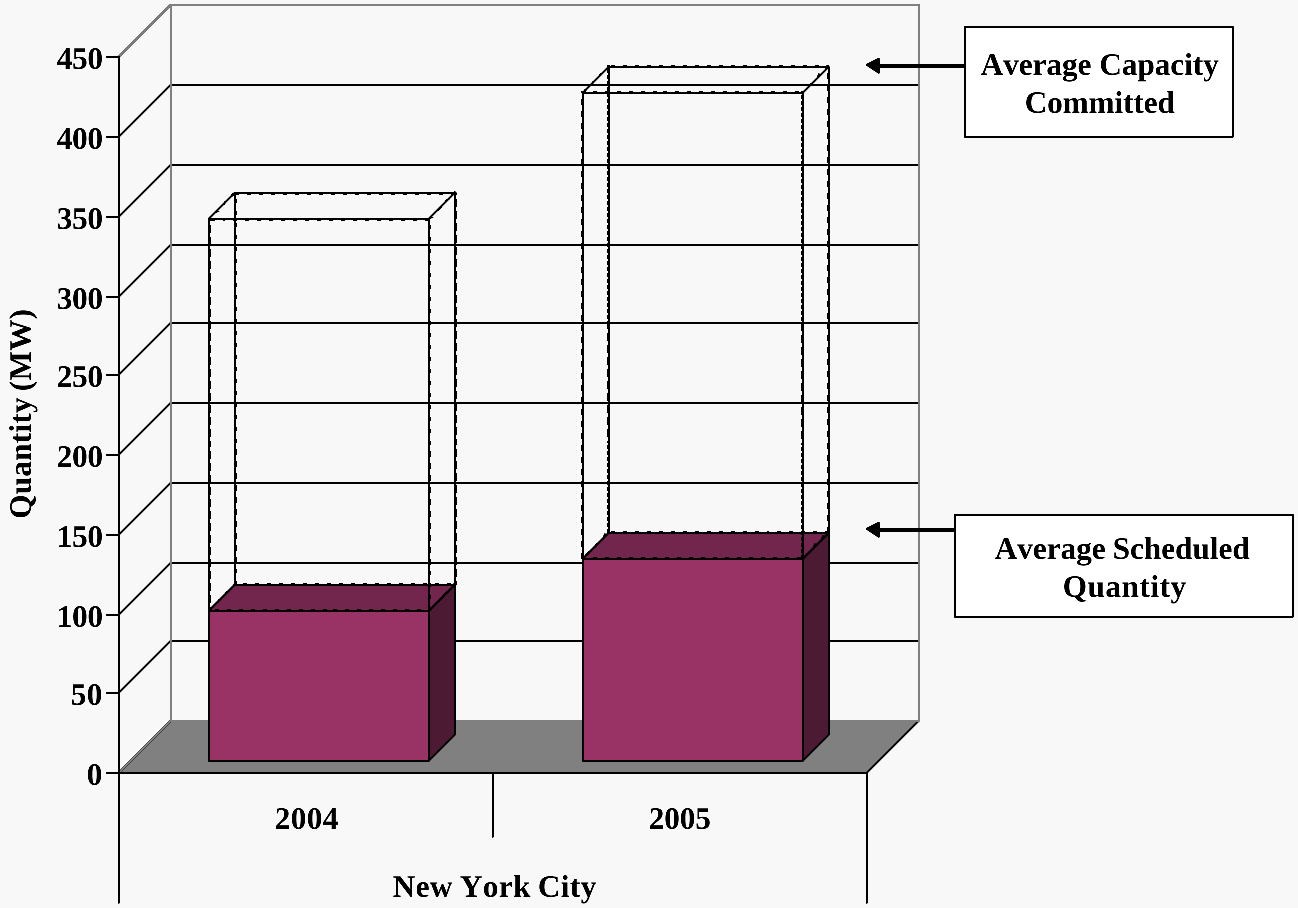


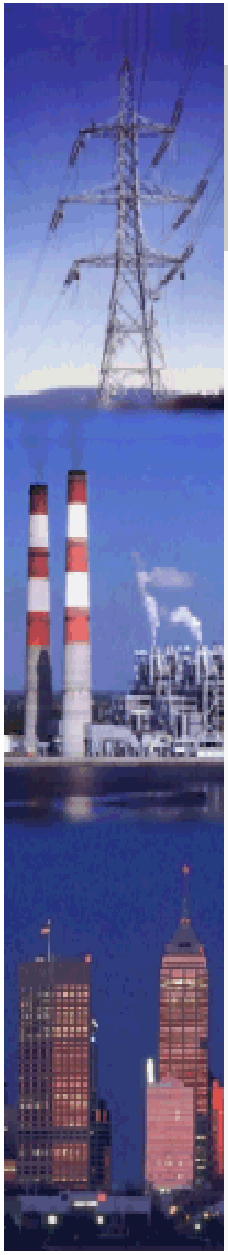
# Day-Ahead Local Reliability

- 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 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.



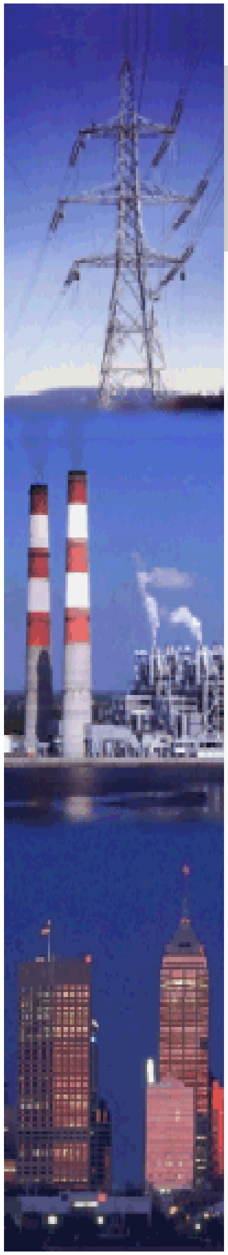
# SCUC Local Reliability Pass Commitment
# February to August, 2004 & 2005





# 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 comments 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, units specifically committed due to the local reliability requirements will be difficult to identify.
  - ✓ One potential means to identify costs that should be allocated locally would be to conduct a parallel economic commitment without the local reliability requirements to identify the commitment changes (and uplift costs) associated with the requirements.