2007 State of the Market Report
New York Electricity Markets

David B. Patton, Ph.D.
Potomac Economics

Independent Market Advisor

May 2008

POTOMAC ECONOMICS

Executive Summary: Introduction

- This presentation provides the results of our assessment of the performance of the New York electricity markets in 2007.
- The New York ISO ("NYISO") operates the most complete set electricity markets in the U.S. These markets provide substantial benefits:
  - ✓ Day-ahead and real-time markets jointly optimize energy, operating reserves and regulation. These markets lead to:
    - Prices that reflect the value of energy at each location on the network;
    - The lowest cost resources being started each day to meet demand;
    - Delivery of the lowest cost energy to New York's consumers to the maximum extent allowed by the transmission network.
  - ✓ Capacity markets that ensure that the NYISO markets produce efficient long-term economic signals to govern decisions to:
    - Invest in new generation and demand response resources,
    - Maintain existing resources; and
  - ✓ The market for transmission rights allow participants to hedge the congestion costs associated with using the transmission network;

Executive Summary: Introduction

- The NYISO markets are at the forefront of market design and have been a model for market development in other areas.
- The NYISO was the first RTO market to:
  - ✓ Jointly optimize energy and operating reserve markets that efficiently allocate resources to provide these products.
  - ✓ Impose locational requirements in its operating reserve and capacity markets – the locational requirements play a crucial role in signaling the need for resources in transmission-constrained areas.
  - ✓ Introduce capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals.
  - ✓ Operating reserve demand curves that contribute to efficient prices during shortage conditions when resources are insufficient to satisfy both the energy and operating reserve needs of the system.

Executive Summary: Unique Aspects of the NYISO Markets

- In addition to its leadership in the areas listed above, the NYISO remains the only market to have:
  - ✓ *An optimized real-time commitment system to start gas turbines and schedule external transactions economically* -- other RTOs rely on their operators to determine when to start gas turbines.
  - ✓ *A mechanisms that allows gas turbines to set energy prices when they are economic* -- gas turbines frequently do not set prices in other areas because they are inflexible and it distorts the prices in the real-time market.
  - ✓ *A real-time dispatch system that is able to optimize over multiple periods (up to 1 hour)*, which allows the market to anticipate upcoming needs and move resources to efficiently satisfy the needs.
  - ✓ *"Ex-ante" real-time prices that are consistent with the real-time market dispatch.* Other RTOs use an "ex-post" pricing method that can result in less efficient prices that are not consistent with dispatch signals.
  - ✓ *A mechanism that allows demand-response resources to set energy prices when they needed*, this is essential for ensuring that prices signals are efficient during shortages. DR in other RTOs has distorted real-time signals by undermining the shortage pricing.

Executive Summary

Overall Market Performance and Prices

- The energy and ancillary services (operating reserves and regulation) markets performed competitively in 2007.
  - ✓ This report shows no evidence that suppliers have been withholding generation to inflate energy or ancillary services prices.
  - ✓ Recent rule changes should address the competitive issues in the NYISO capacity market in 2008.
- Energy prices increased 6 to 12 percent in most areas outside Long Island.
  - ✓ This is primarily due to fuel prices in 2007. Natural gas prices increased 15 percent on average.
  - ✓ The increase was partly offset by:
    - – Substantial new transmission capacity that was added from New Jersey to Long Island in July 2007. The additional 660 MW of import capability led to a 3 percent decline in Long Island prices.
    - – Milder summer weather, which reduced the frequency of real-time shortages 80 percent relative to the summer of 2006.

Executive Summary

Market Performance and Prices (cont.)

- Prices between New York and adjacent markets have not been well-arbitraged.
  - ✓ This is particularly important during peak conditions when adjusting the flow is more likely to have a substantial price impact.
  - ✓ The report includes several recommendations to address this issue.
- Convergence between prices in the day-ahead and real-time markets is important because the day-ahead market plays an important role in determining which resources are started each day.
  - ✓ Convergence in the energy markets continues to be good in most areas.
  - ✓ However, price convergence at specific locations within New York City was not as good as in other areas in the State. The NYISO is considering a proposal to address this issue.
  - ✓ Convergence in the operating reserve market was better in 2007, but still needs improvement. The report includes two recommendations to address this issue.

Executive Summary

Market Performance during Shortage Conditions

- Prices that occur under shortage conditions are an important contributor to efficient long-term price signals.
- Very high prices that reflect the diminished reliability of the system ("shortage pricing") should occur when resources are insufficient to meet the energy and operating reserves needs of the system, including:
  - ✓ During operating reserve shortages;
  - ✓ When transmission constraints are not fully resolved; or
  - ✓ During activation of NYISO Reliability Based Emergency Demand Response resources.
- *Operating Reserve Shortages*: The markets produced prices reflecting shortage conditions during most reserve shortages in 2007.
  - ✓ 72 percent of the instances of physical shortages of eastern 10-minute reserves were accompanied by corresponding shortage prices.
  - ✓ The report includes a proposal to improve these results.

Executive Summary

Market Performance during Shortage Conditions (cont.)

- *Unresolved Transmission Constraints*: During such periods, the markets had fewer price corrections in 2007.
  - ✓ In June 2007, the NYISO implemented "Transmission Shortage Pricing," which greatly reduced the frequency of price corrections during such periods.
  - ✓ Reliable price signals are especially important in periods of extreme scarcity.
- *Activation of NYISO Reliability Based Emergency Demand Response*: New operating procedures improved the efficiency of prices during such periods.
  - ✓ In July 2007, the NYISO implemented the Targeted Demand Response Provider ("TDRP") program, which enables the local TO to activate small blocks of TDRP resources for local issues.
  - ✓ Previously, the TO activated resources in the entire zone when it had a local problem. This can lead to uneconomic curtailments, depressed energy prices, and increased uplift.
  - ✓ The report includes one recommendation to further improve shortage pricing during the activation of demand response.

Executive Summary

Long-Term Economic Signals

- The report shows that prices in 2007 would not support investment in new peaking generation in most locations.
  - ✓ This is consistent with short-term conditions because there is a surplus of generation in most areas and the summer weather was relatively mild.
  - ✓ Price signals will be affected over the next few years by increasing load, unit retirements and additions, and the introduction of new mitigation measures in the capacity market.
- The report shows that market signals have generally shifted in favor of investment in baseload and intermediate resources that, while more costly to build, are less costly to run and produce more electricity.
  - ✓ Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission.
  - ✓ Currently, market conditions appear most favorable for investment in combined-cycle generation, which have constituted most of the recent entry.
  - ✓ Depending on the entry costs for a CC (we do not have reliable estimates), it may economic to build a CC in some areas under the current market conditions.

Executive Summary

Capacity Market

- The capacity market plays an important role in contributing to the long-term economic signals that govern new investment and retirement decisions for generation, transmission, and demand response resources.
- The capacity market results in New York City were not highly competitive in 2006 and 2007.
  - ✓ Recently approved market power mitigation rule changes are expected to improve the competitiveness of the New York City capacity market.
- The capacity market results in the Rest of State ("ROS") have been relatively competitive, although changes in neighboring capacity markets have contributed to lower net imports and higher prices.
- Based on the 2008 Reliability Needs Assessment, additional resources will likely be needed in Southeast New York between 2012 and 2014.
  - ✓ This report includes one recommendation to address capacity price signals in this area.

Executive Summary

Uplift Costs

- Local reliability uplift charges increased by $80 million from 2006 to 2007.
  - ✓ Approximately 75 percent of the increase is associated with payments to generators that are committed for local reliability after the Day-ahead Market.
    - – In response the prior recommendations, the NYISO is developing a proposal to better integrate commitments for local reliability in the Day-Ahead Market.
    - – This should reduce the uplift and market inefficiencies that result from local reliability commitments.
  - ✓ The rest of the increase is from payments to generators that must burn fuel oil uneconomically to satisfy New York City reliability requirements.
- Non-local reliability uplift payments to generators have declined $37 million since 2005.
  - ✓ This reduction is primarily due to more efficient use of peaking resources, which can be attributed to refinements of the real-time scheduling software.
  - ✓ Lower natural gas prices have also helped reduce this category of uplift.

Executive Summary

Demand Response Programs

- Demand response resources participate in both the capacity and energy markets in New York.
  - ✓ New York has close to 1800 MW of real-time demand response resources, which satisfy a significant portion of the local and statewide capacity requirements – these quantities have grown steadily over the past eight years.
  - ✓ Real-time demand response resources can be activated to maintain operating reserves or for local reliability.
- Demand response resources set clearing prices when their activation prevents shortages at the state-level or eastern New York – this is essential for efficient short-term and long-term price signals.
  - ✓ The report includes a recommendation to allow demand response to be reflected in clearing prices under additional circumstances when appropriate.
- Since July 2007, the Targeted Demand Response Provider ("TDRP") program enables the local TO to activate demand response in individual load pockets.
- The NYISO has filed Tariff changes that would allow demand response to provide operating reserves and regulation under the same performance requirements as generators.

Executive Summary: Recommendations

1. ***Continue the work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange.***

2. ***Evaluate potential improvements real-time commitment model ("RTC") and the real-time dispatch model ("RTD") to improve their consistency and improve the management of ramp capability at the top of the hour.***

   - ✓ The RTD/RTC real-time market framework has delivered substantial benefits that are documented in this report.
   - ✓ However, the report identifies some inconsistencies between RTC and RTD that can affect the efficiency of the commitments and market outcomes.
     - In January 2008, the NYISO modified the treatment of external transactions in RTC, which should help improve consistency.
   - ✓ Additionally, ramp constraints are frequently binding at the top of the hour in the morning and evening due to changes in external schedules, hourly generation schedules and generator commitments/decommitments.
     - A re-evaluation of the assumptions and periods used in RTD and RTC could potentially improve the ramp management and lower price volatility.

Executive Summary: Recommendations

3. ***Evaluate changing two provisions in the mitigation measures that may limit competitive 10-minute reserves offers in the Day-Ahead Market.***

- ✓ The provisions limit the reference levels of some GTs to \$2.52/MWh and the offers of 10-minute spinning reserves in New York City to \$0/MWh.

4. ***Consider whether additional capacity zones are needed outside of New York City and Long Island.***

- ✓ This may be necessary to allow the markets' economic signals to reflect that resources will be needed relatively soon in Southeast New York.

5. ***Evaluate whether it is feasible to enable the NYISO Reliability Based Emergency Demand Response resources to set clearing prices in local areas when they are needed to maintain transmission system reliability.***

Executive Summary:
Enhancements Currently Under Consideration

The NYISO has work underway in response to prior recommendations. Results in 2007 continue to suggest that these changes would be beneficial.

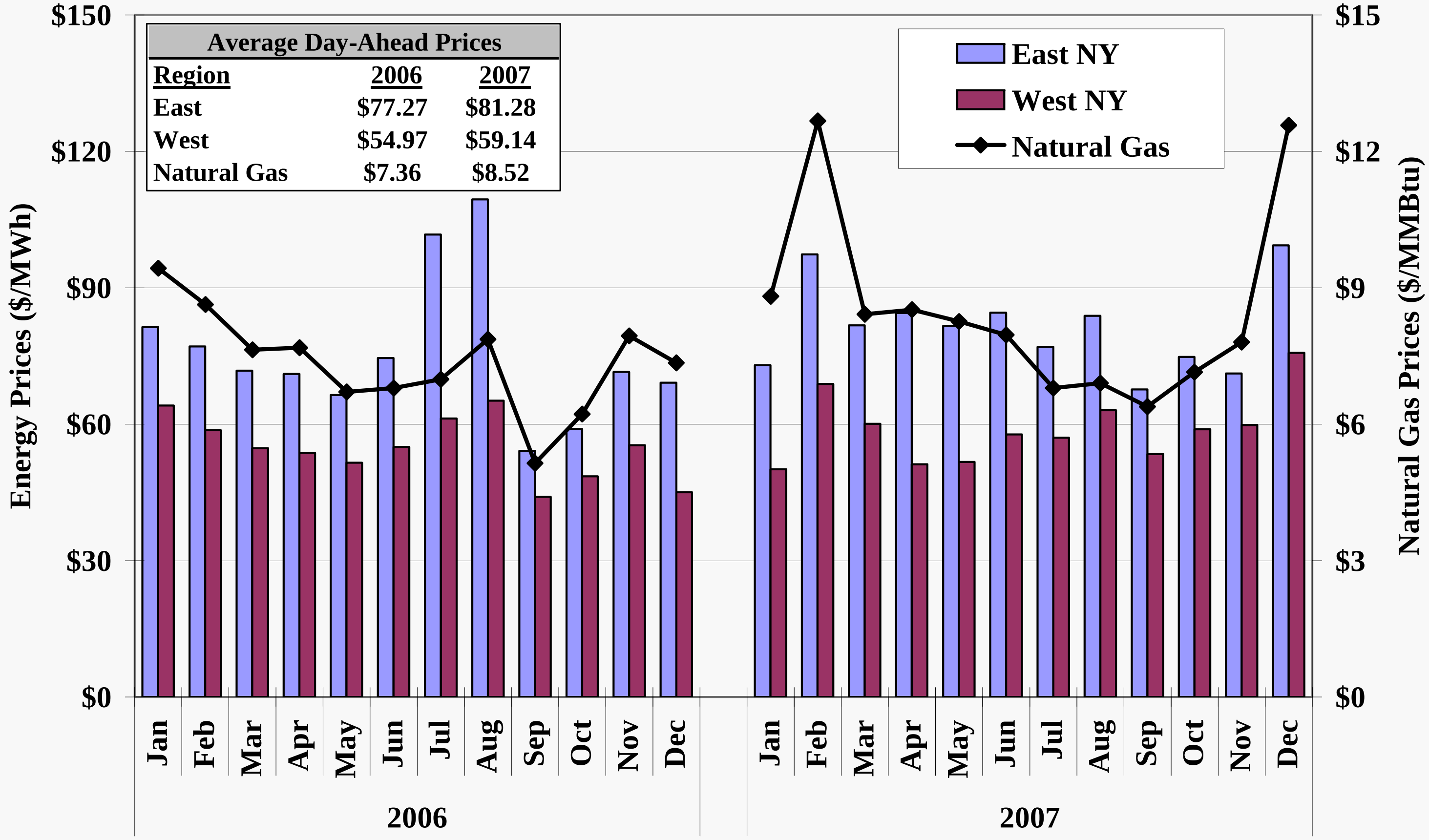
1. ***Modeling of local reliability rules in New York City to include them in the initial day-ahead commitment.***
   - ✓ Commitments by the local reliability pass of the day-ahead market and by ISO operators after the day ahead to meet local requirements in NYC can lead to uneconomic commitment and increased uplift throughout the state.
2. ***Re-calibrating the dispatch levels in the real-time market's pricing model for units that are not responding to dispatch signals.***
   - ✓ Further improvements to the consistency of the pricing and physical dispatch passes of RTD could improve the efficiency of NYISO's energy and ancillary services pricing (particularly during shortages) and reduce uplift.
3. ***Virtual trading at a more disaggregated level.***
   - ✓ This recommendation is designed to improve price convergence in the New York City load pockets.

Market Prices and Outcomes

Fuel Prices and Energy Prices

- The following figure shows monthly energy prices in 2006 and 2007.
- Fuel price fluctuations led to corresponding changes in energy prices:
  - ✓ On average, natural gas prices were 15 percent higher in 2007 than in 2006. Much of the increase is attributable to prices spikes in February and December of 2007.
  - ✓ Fuel oil prices rose steadily through the year, and averaged 20 percent higher in 2007 than in 2006.
  - ✓ Correlation of energy prices with oil and gas prices is expected since fuel costs represent the majority of most generators' variable production costs, and oil and gas units are on the margin in most hours.
- Substantial price differences continued between West NY and East NY:
  - ✓ On average, prices were about $22/MWh higher in East NY than in West NY in 2007. The price difference was similar in 2006.
  - ✓ The price difference is due primarily to congestion on flows into and within East NY, although transmission losses are also significant.
  - ✓ The Neptune line began operation in July 2007, substantially reducing congestion in East NY, particularly into Long Island.

Day-Ahead Electricity and Natural Gas Prices
2006 – 2007



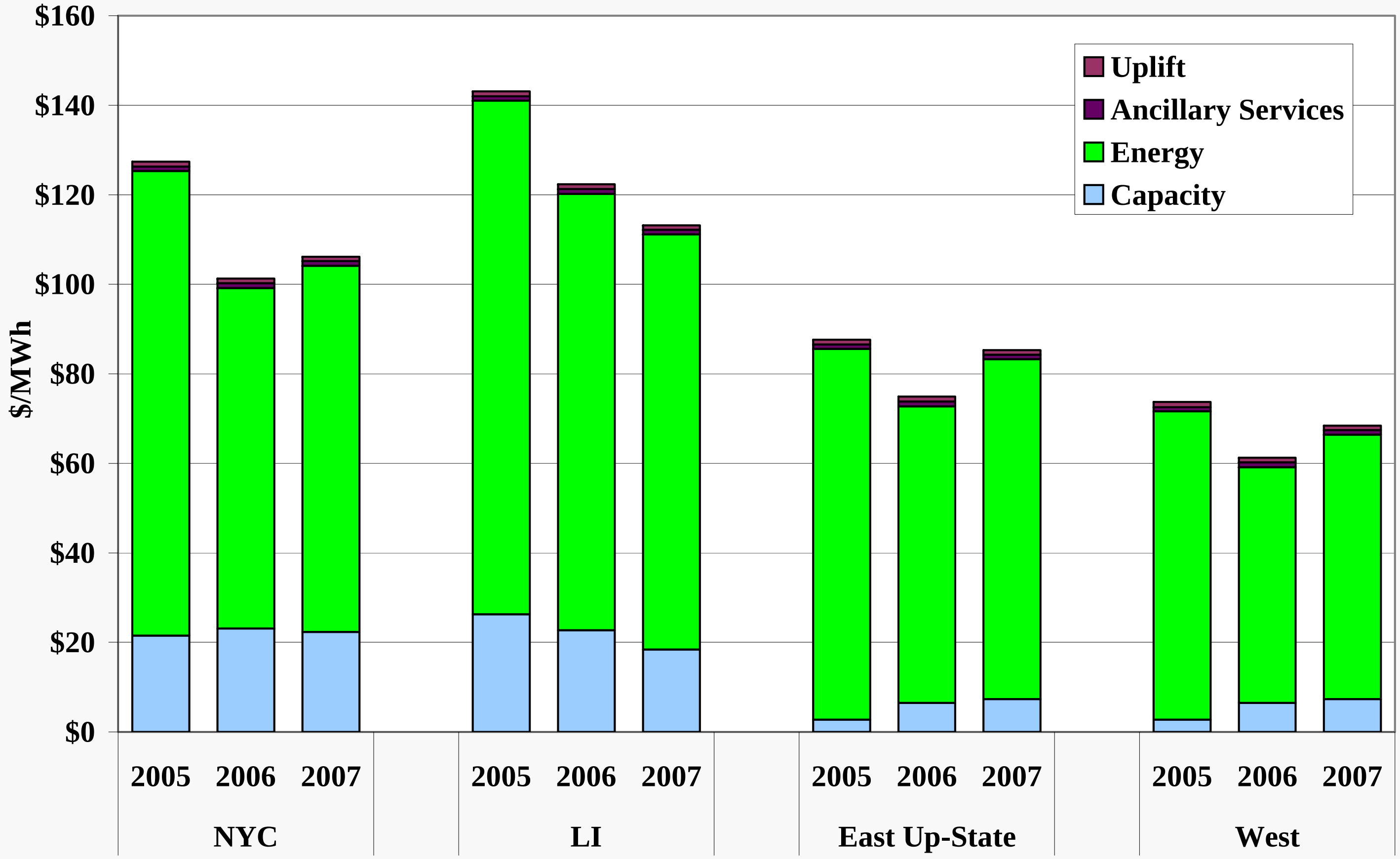
Average Day-Ahead Prices		
Region	**2006**	**2007**
East	$77.27	$81.28
West	$54.97	$59.14
Natural Gas	$7.36	$8.52

Note: The electricity prices are load-weighted averages.

All-In Energy Prices

- The following figure shows an "all-in" price that includes the costs of energy, ancillary services, capacity, and uplift for several locations in NY.
  - ✓ The capacity component is based on spot capacity prices and load obligations in each area, allocated over energy consumption in the area.
  - ✓ The energy component is based on RT energy prices in each area.
- From 2005 to 2006, the all-in price fell substantially.
  - ✓ Lower fuel prices and load levels helped reduce energy prices.
  - ✓ Capacity additions in NYC helped push down energy prices throughout NY state and particularly in NYC.
- From 2006 to 2007, the all-in prices were affected by several factors.
  - ✓ Higher fuel prices have increased generation costs.
  - ✓ Fewer peak load hours resulted in fewer RT shortage pricing events.
  - ✓ Operation of the Neptune cable has helped push down energy prices, particularly in Long Island.
- Capacity additions in NYC in 2006 did not affect capacity prices due to capacity market offer patterns, which are discussed later in this report.

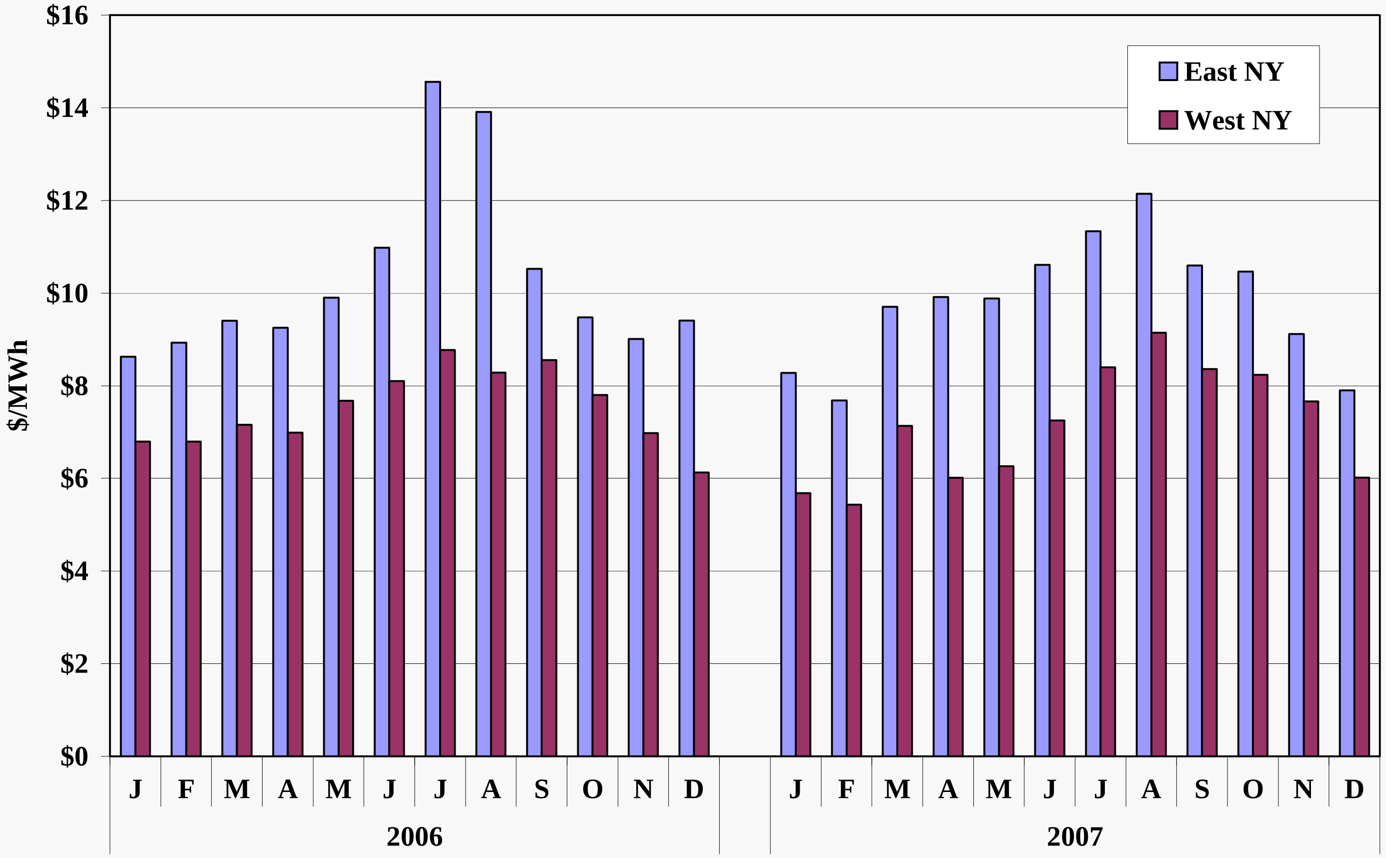
Average All-In Price
2005 – 2007



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 the marginal fuel.
  - ✓ Implied Heat Rate = (Day-Ahead Elec. Price) ÷ (Natural Gas Price)
  - ✓ This metric highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices.
- Implied heat rates rose during the summer months in 2006 and 2007 due to shortage pricing periods and other high load periods.
- Exceptionally high natural gas prices in February and December 2007 led to unusually low implied heat rates for those two months.
  - ✓ Extreme natural gas prices lead some units to switch to fuel oil and to increased imports from neighboring control areas that are less reliant on natural gas.
  - ✓ These responses lower implied heat rates calculated based on natural gas prices.

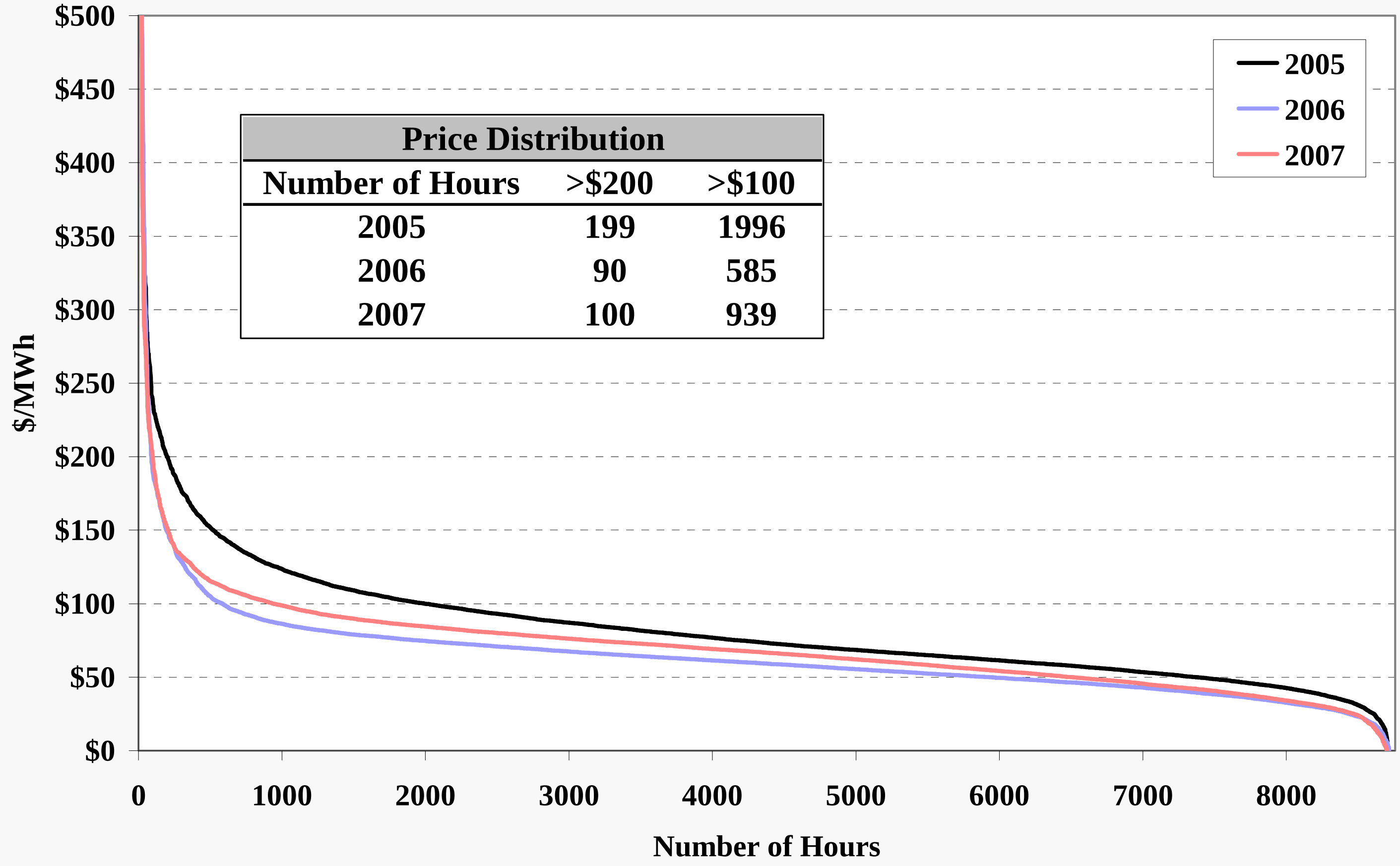
Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices
2006 – 2007



Energy Prices

- The next two figures show how hourly price levels have changed in the last three years.
- The first figure shows real-time price duration curves for 2005 to 2007.
  - ✓ These curves show the number of hours when the load-weighted price for NY State was greater than the level shown on the vertical axis.
- In 2007, prices were lower than in 2005 but higher than in 2006 in most hours due to changes in fuel prices and load patterns:
  - ✓ Natural gas prices fell sharply from 2005 to 2006 and rose from 2006 to 2007. The effects of fuel price changes on energy prices are exhibited in a wide range of hours.
  - ✓ Fewer very high load hours in 2007 resulted in fewer hours with average prices above $500, even with higher fuel prices (19 hours in 2007 vs. 25 hours in 2006).
- Wide ranging price changes are generally attributable to fuel price changes while peak differences are due to high load events.

Price Duration Curves
State-wide Average Real-Time Price, 2005 – 2007

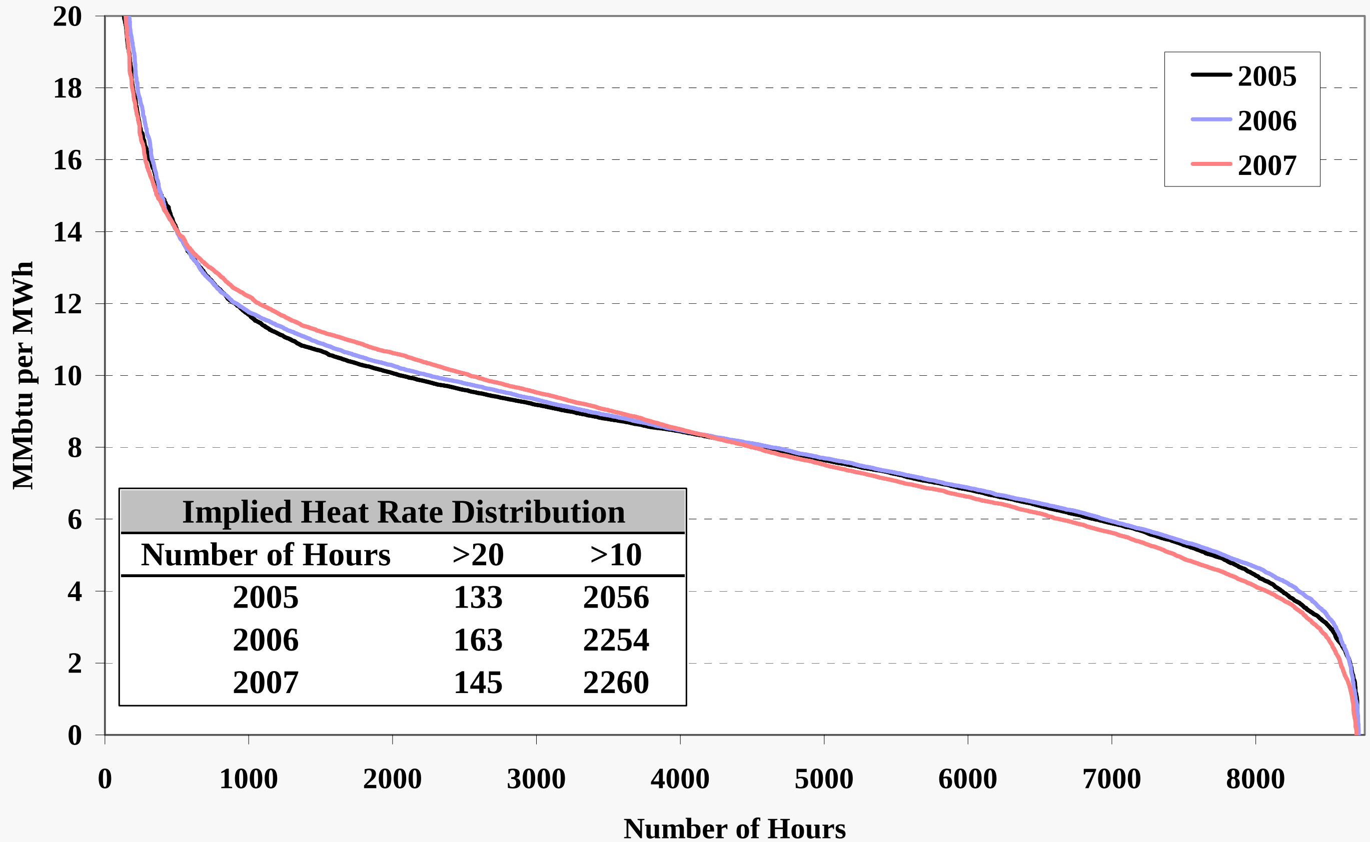


Price Distribution		
Number of Hours	>$200	>$100
2005	199	1996
2006	90	585
2007	100	939

Energy Prices

- The second figure shows duration curves for implied marginal heat rates during the same period.
  - ✓ These isolate price changes that are not caused by changing fuel prices.
- Implied marginal heat rates have been stable over the past three years.
  - ✓ This demonstrates that fuel price changes and congestion patterns are responsible for variations in power prices across the majority of hours.
- Fewer high load periods in 2007 led to fewer high-priced hours.
  - ✓ The number of high-priced hours (i.e. hours with implied marginal heat rates > 20 MMbtu per MWh) was 11 percent lower in 2007 than in 2006.
  - ✓ The number of hours with implied marginal heat rates greater than 10 MMbtu per MWh was approximately the same in 2006 than in 2007.

Implied Marginal Heat Rate Duration Curves
Based on State-wide Average Real-Time Price, 2005 – 2007



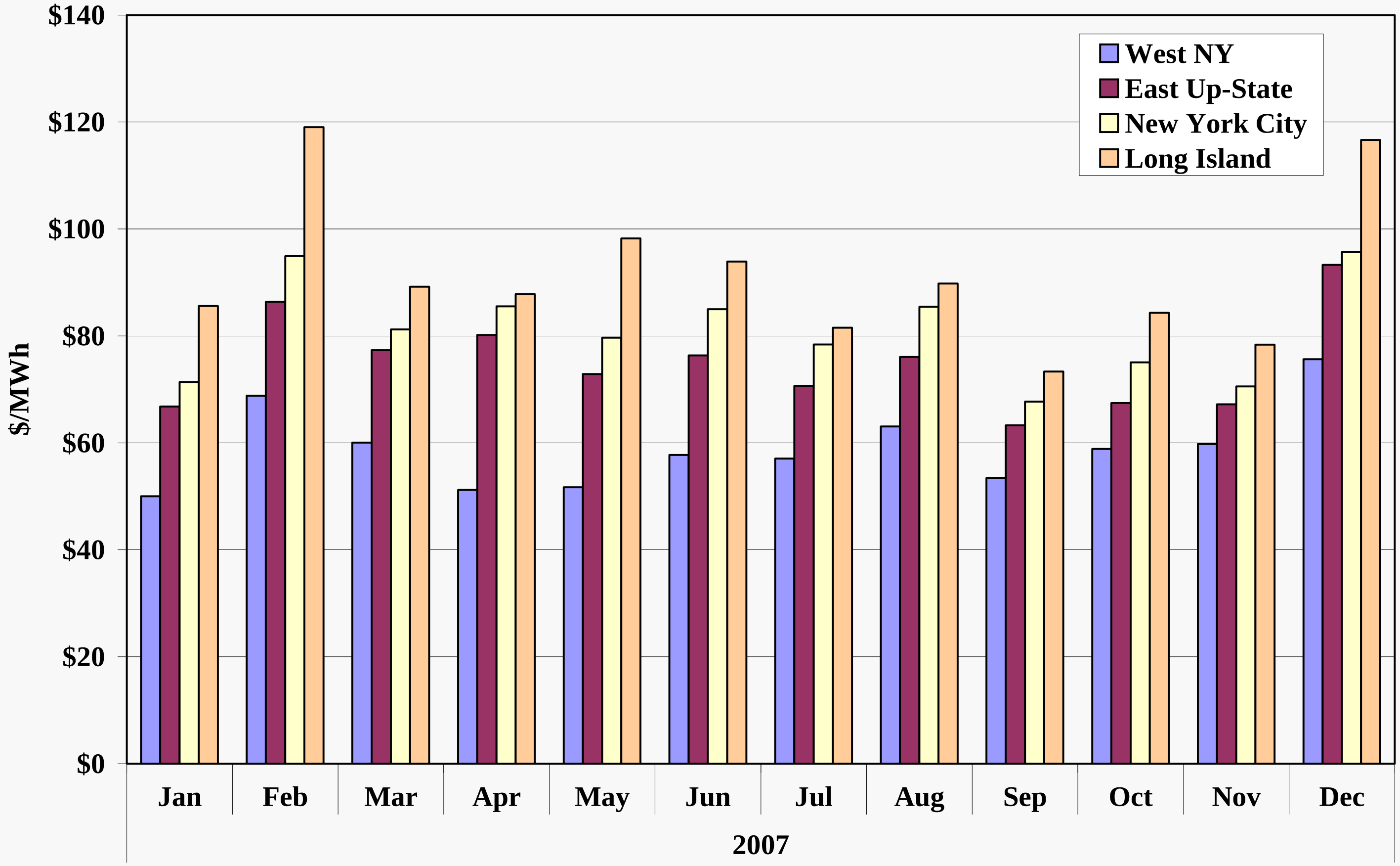
Implied Heat Rate Distribution

Number of Hours	>20	>10
2005	133	2056
2006	163	2254
2007	145	2260

Day-Ahead Energy Prices

- The next figure presents monthly average day-ahead energy prices in western NY, eastern upstate NY, NYC, and Long Island for 2007.
- Between East Upstate and West NY, the price difference is due to transmission losses and congestion across the Central-East interface and the interfaces between the Capital region and NYC/Long Island.
  - ✓ The difference rose from $12 per MWh in 2006 to $16 per MWh in 2007 primarily due to more frequent constraints on the Central-East interface.
- Constraints into New York City and Long Island, and local load pockets within these areas, raise average prices in these zones.
  - ✓ Price differences between Long Island and East Upstate NY decreased from about $27 in 2006 to $16 in 2007. The most significant cause of the decrease was the installation of the Neptune cable in July 2007.
  - ✓ Price differences between New York City and East Upstate NY averaged $6 per MWh in 2007, down from $9 in 2006 and $16 in 2005.
  - ✓ The reduced congestion into New York City was due to capacity additions in the City, improved modeling of local transmission constraints, and operation of the Neptune cable.

Day-Ahead Energy Prices
2007

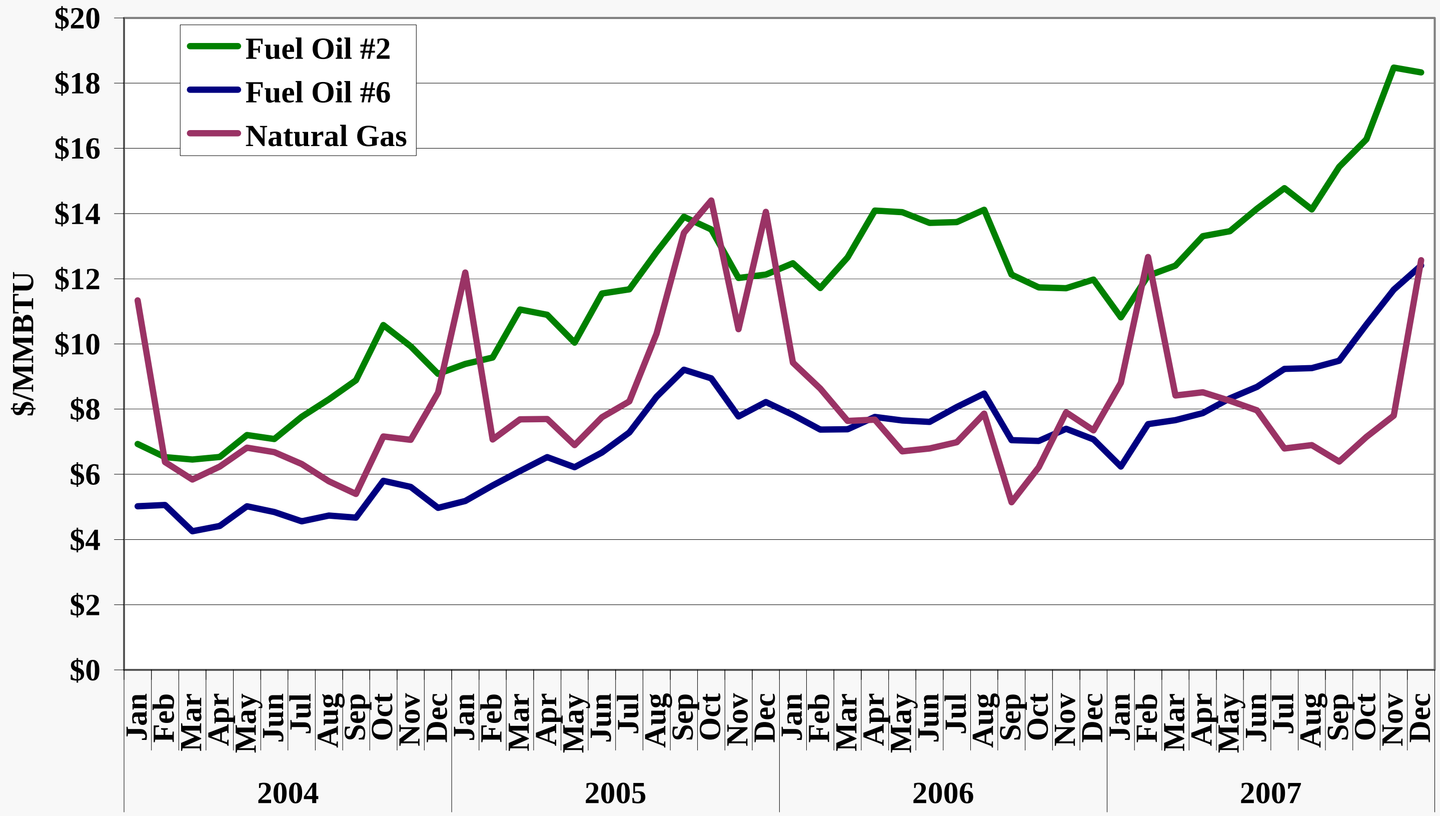


Note: The prices are load-weighted averages.

Prices of Natural Gas and Fuel Oil

- In recent years, increased fuel prices have been the primary driver of increased wholesale power costs. The following figure shows monthly average prices for fuel oil and natural gas from 2004 to 2007.
- Many units in New York have dual fuel capability, allowing them to burn the most economic fuel. Most large steam units can burn fuel oil #6 or natural gas, partly mitigating the effect of rising fuel costs on power prices.
  - ✓ Natural gas prices rose sharply during February and December to the highest levels since late 2005.
  - ✓ Fuel oil prices increased steadily during 2007, making fuel oil #6 was more expensive than gas for a substantial majority of the year.
- Use of natural gas has been limited by the Minimum Oil Burn Provisions, which require some units in NYC to burn oil to limit exposure to natural gas supply contingencies.
  - ✓ These provisions work through out-of-market payments, and thus, are not reflected in market clearing prices.
  - ✓ These provisions, which resulted in $21 million in uplift costs in 2007, are discussed in the Operations section.

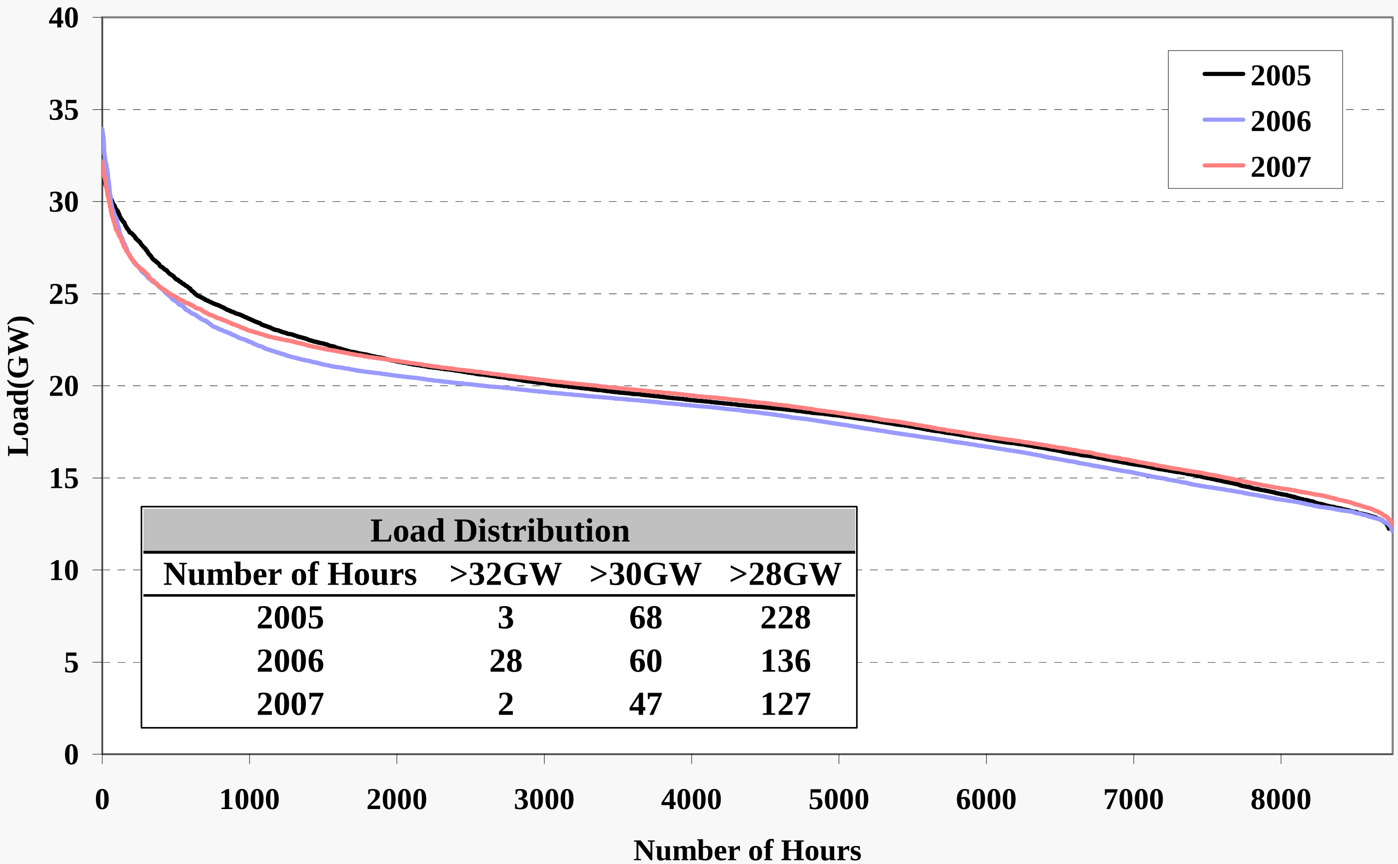
Monthly Average Natural Gas and Oil Prices
2004 – 2007



Load Profile

- Additional insight into market conditions is gained from examining load levels. The next figure shows load duration curves for 2005 to 2007.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- In most hours, load grew modestly from 2006 to 2007. However, there were considerably fewer peak load hours in 2007 due to milder summer peak temperatures.
  - ✓ Load exceeded 32 GW during just 2 hours in 2007 compared to 28 hours in 2006 and 3 hours in 2005.
  - ✓ Load exceeded 30 GW during just 47 hours in 2007 compared to 60 hours in 2006 and 68 hours in 2005.

Load Duration Curves
New York State Load, 2005 – 2007



Load Distribution

Number of Hours	>32GW	>30GW	>28GW
2005	3	68	228
2006	28	60	136
2007	2	47	127

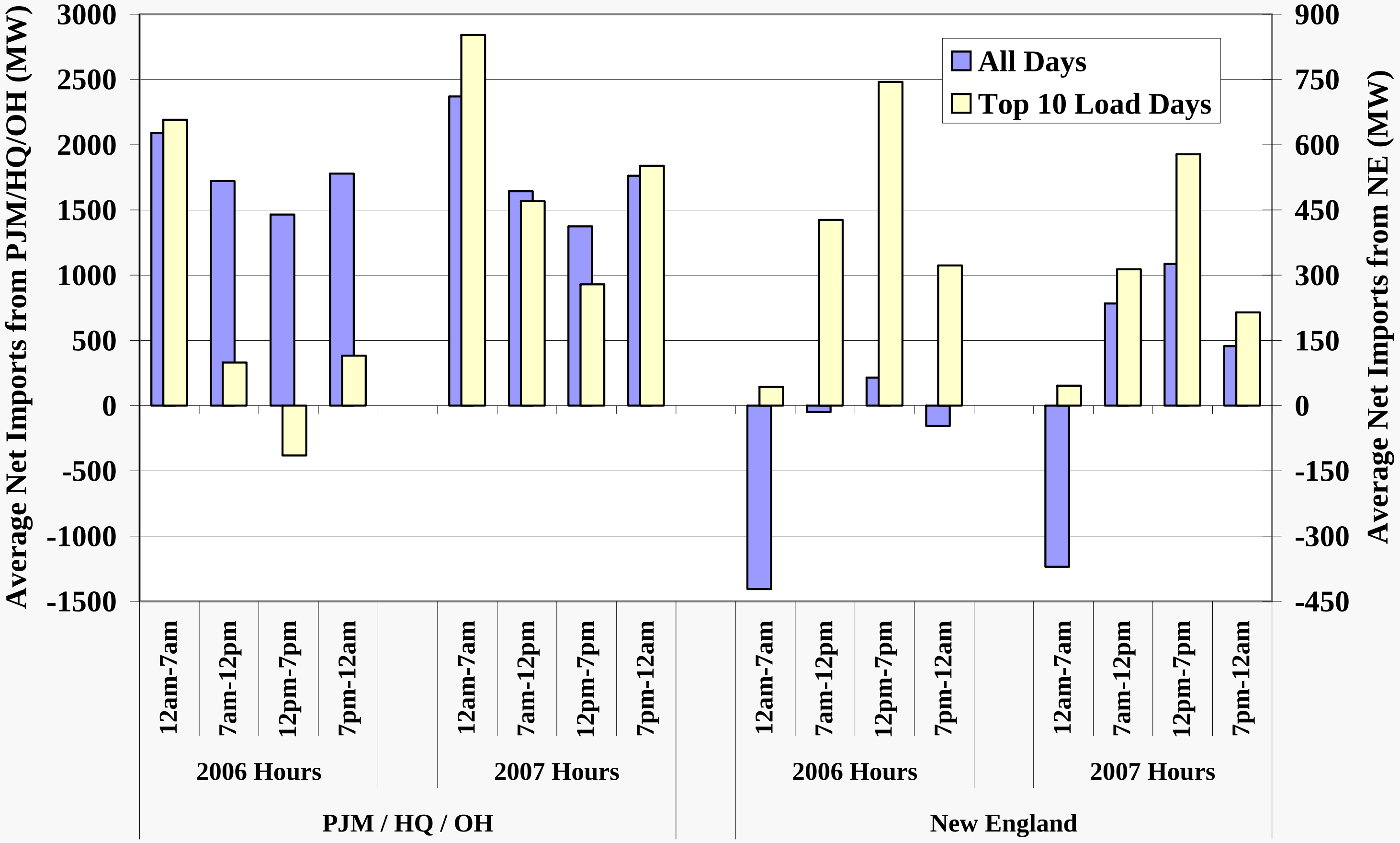
External Interface Summary

- The following two figures summarize the interchange with neighboring control areas.
- The first figure shows the average net imports across the primary interfaces with the adjacent control areas during the past two years.
  - ✓ The three interfaces with western New York are grouped together.
  - ✓ The interface with New England, which is in eastern New York, is shown separately.
- The second figure shows the three interfaces that directly connect Long Island to PJM and New England.
  - ✓ The Cross Sound Cable ("CSC") connects Long Island to Connecticut.
  - ✓ Before June 27, the Northport-Norwalk (1385) line was scheduled as a part of the primary interface with New England. Since September 10, the line has been out of service and is scheduled to return in May 2008.
  - ✓ The Neptune cable was energized on July 1, significantly increasing import capability to Long Island from New Jersey (PJM).

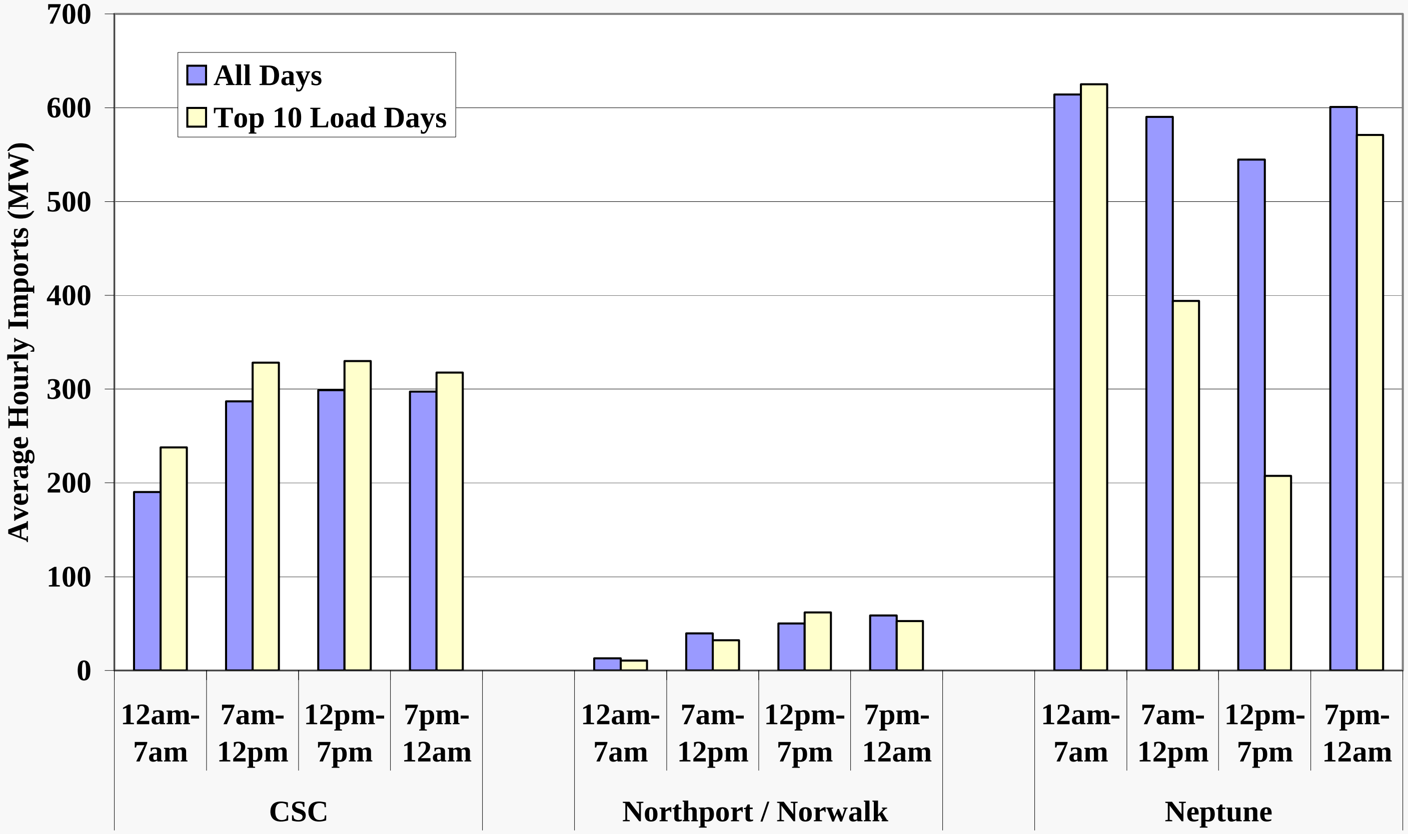
External Interface Summary

- From 2006 to 2007, net imports to New York increased substantially, particularly on high load days.
  - ✓ Across the primary interfaces with Quebec, Ontario, and PJM, net imports increased by an average of 1100 MW on high load days.
  - ✓ Across the primary interface with New England, net imports increased by an average of 180 MW, although they declined 100 MW on high load days.
  - ✓ The Neptune cable imported an average of 540 MW after July 1, 2007.
- Interchange with adjacent areas varies by load level and time of day.
  - ✓ From New England, net imports rise during day-time hours, particularly on peak days. New York is generally a net exporter at night.
  - ✓ From Quebec, net imports increase during day-time hours and peak loads.
  - ✓ From Ontario and PJM, net imports decline during day-time hours and peak load conditions.

Net Imports Across Primary External Interfaces 2006 - 2007



Net Imports to Long Island from External Areas 2007

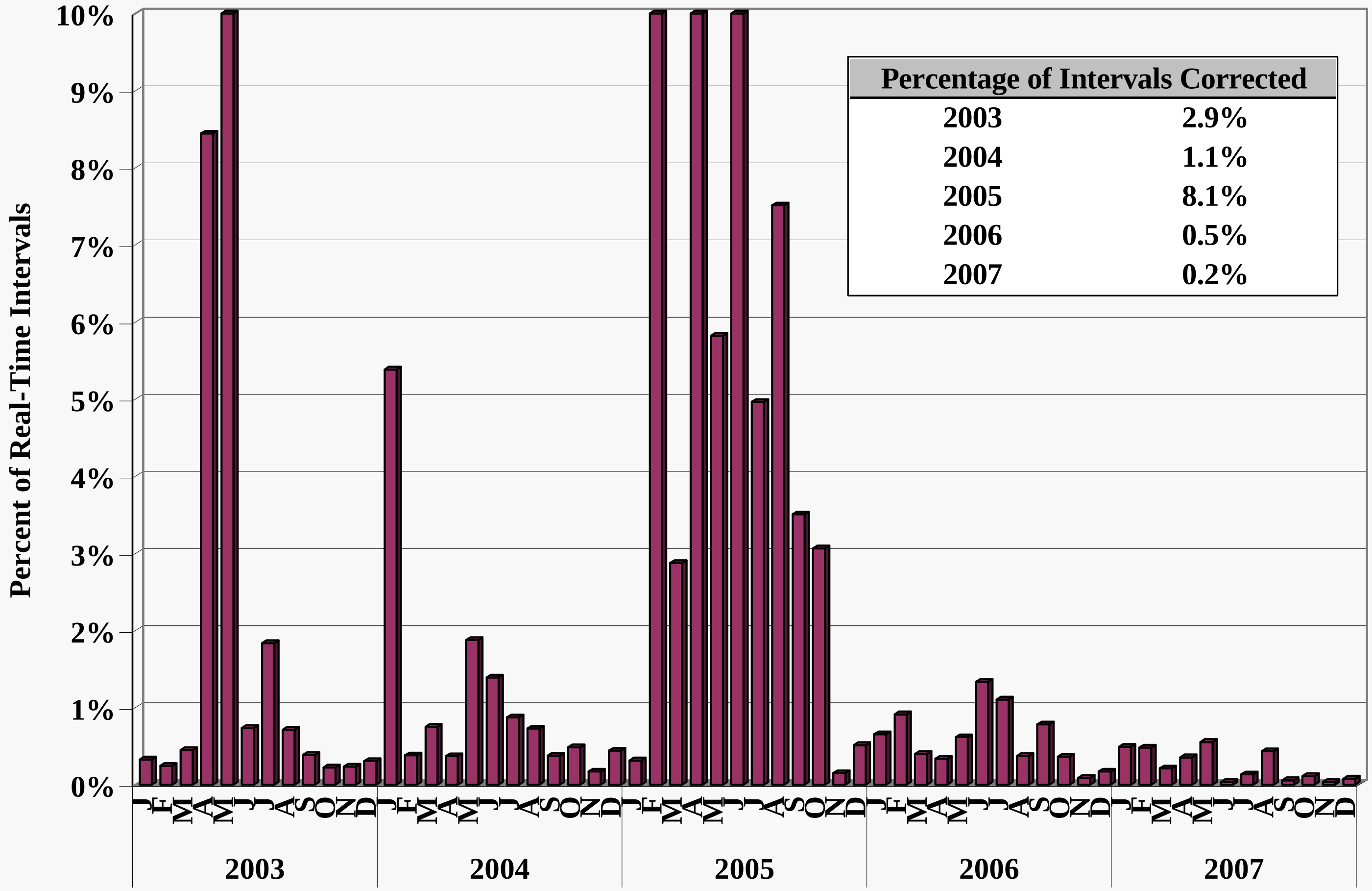


Note: Northport to Norwalk is shown for the period from June 27 to September 10. Neptune is shown for the period from July to December.

Price Corrections

- The following figure summarizes the frequency of price corrections in the real-time energy market from 2003 to 2007.
- Price corrections occur in all real-time energy markets due to:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- Fewer price corrections reduces administrative burdens and uncertainty for market participants.
  - ✓ The rate of corrections spiked in February 2005 due to software issues related to the implementation of SMD 2.0.
  - ✓ Once these software issues were addressed by NYISO, the frequency of price corrections fell below the levels prior to SMD 2.0.
- In June 2007, the NYISO further reduced the frequency of price corrections with improved modeling during transmission scarcity.
  - ✓ Efficient pricing during extreme scarcity improves investment signals.
  - ✓ The modeling change is discussed further in the Shortage Pricing section.

Frequency of Price Corrections
2003 - 2007



Long-Term Market Signals – Net Revenue Methodology

- The following two figures show the estimated Net Revenue provided by the NYISO markets over the past four years at several locations.
  - ✓ Net Revenue is the energy, ancillary services, and capacity revenue that a new generator would earn above its variable production costs.
  - ✓ Net Revenue is calculated for a hypothetical gas turbine unit and a hypothetical combined cycle unit using two methods: the Standard Method and the Enhanced Method.
- The Standard Method assumes the units sell at the Day-Ahead Market prices considering variable O&M costs, forced outage rates, and fuel costs with heat rates of:
  - ✓ 7000 BTU/KWh for the combined cycle and
  - ✓ 10500 BTU/KWh for the combustion turbine.
- The Enhanced Method also considers start-up costs, minimum run-times, and other physical limitations.

Long-Term Market Signals – Net Revenue Methodology

- The enhanced method assumes:
  - ✓ Units are committed based on day-ahead prices, considering start-up costs, and minimum run times and down-times (one hour for CTs).
  - ✓ CCs may sell energy, 10-minute and 30-minute spinning reserves; CTs may sell energy and 30 minute reserves.
  - ✓ Online units respond to real-time prices while offline CTs may be committed based on RTC (or BME prior to Feb. 2005) prices.
- The following figures summarize the results of the enhanced analysis, with a marker showing the standard net revenue analysis results for comparison. The differences in the results for the two methods are due to:
  - ✓ Reductions in net revenue due to start-up costs and minimum runtime restrictions; and
  - ✓ Gains in net revenue for online units that are responding to real-time prices;
  - ✓ Gains in revenue for offline CTs being economically committed after the day-ahead by RTC (or BME).

Long-Term Market Signals – Net Revenue Analysis

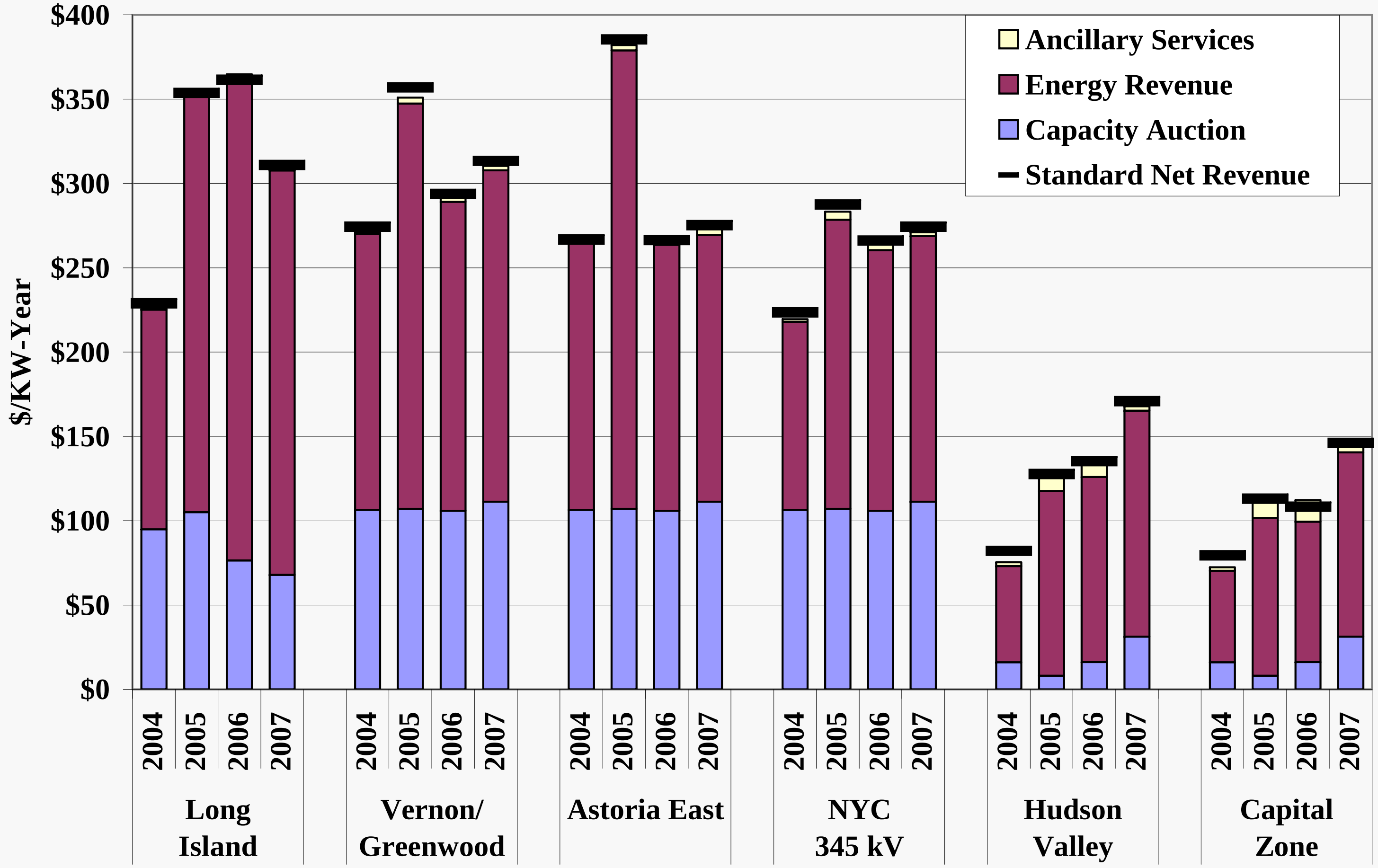
- Net revenues rose significantly from 2004 to 2005 due to higher load, more frequent shortages and better shortage pricing under SMD 2.0.
- From 2006 to 2007, net revenue levels rose moderately in the Hudson Valley and Capital zones due to:
  - ✓ Additional congestion of the Central-East interface.
  - ✓ Higher capacity prices, which are partly due to the new capacity payment mechanism implemented by ISO-New England in December 2006.
    - – After this change, 1700 MW of capacity sales shifted from New York to New England.
- In July 2007, the introduction of new supply from New Jersey across the Neptune line substantially reduced net revenues from energy and ancillary services for generators in Long Island.

Long-Term Market Signals – New York City

- Net revenues were flat in New York City due to two offsetting factors:
  - ✓ Substantially lower congestion into and within New York City reduced energy and ancillary services net revenue.
  - ✓ Rising oil prices (relative to gas prices) increased net revenues for gas-fired generation.
- Capacity net revenues in New York City continued to be affected by offer patterns that resulted in capacity from the existing resources going unsold.
  - ✓ However, FERC recently accepted a mitigation proposal that should causing prices to reflect the surplus of capacity that currently exists in the City.
  - ✓ Additional capacity sales in New York City will also affect net revenue for Upstate areas in 2008, because the additional sales in local capacity zones are counted toward the state-wide capacity requirement.
    - – In March 2008, a requirement of the Keyspan-National Grid merger caused the fraction of existing NYC capacity sold into the spot capacity market to increase, which caused the NYC spot price to equal the ROS spot price.

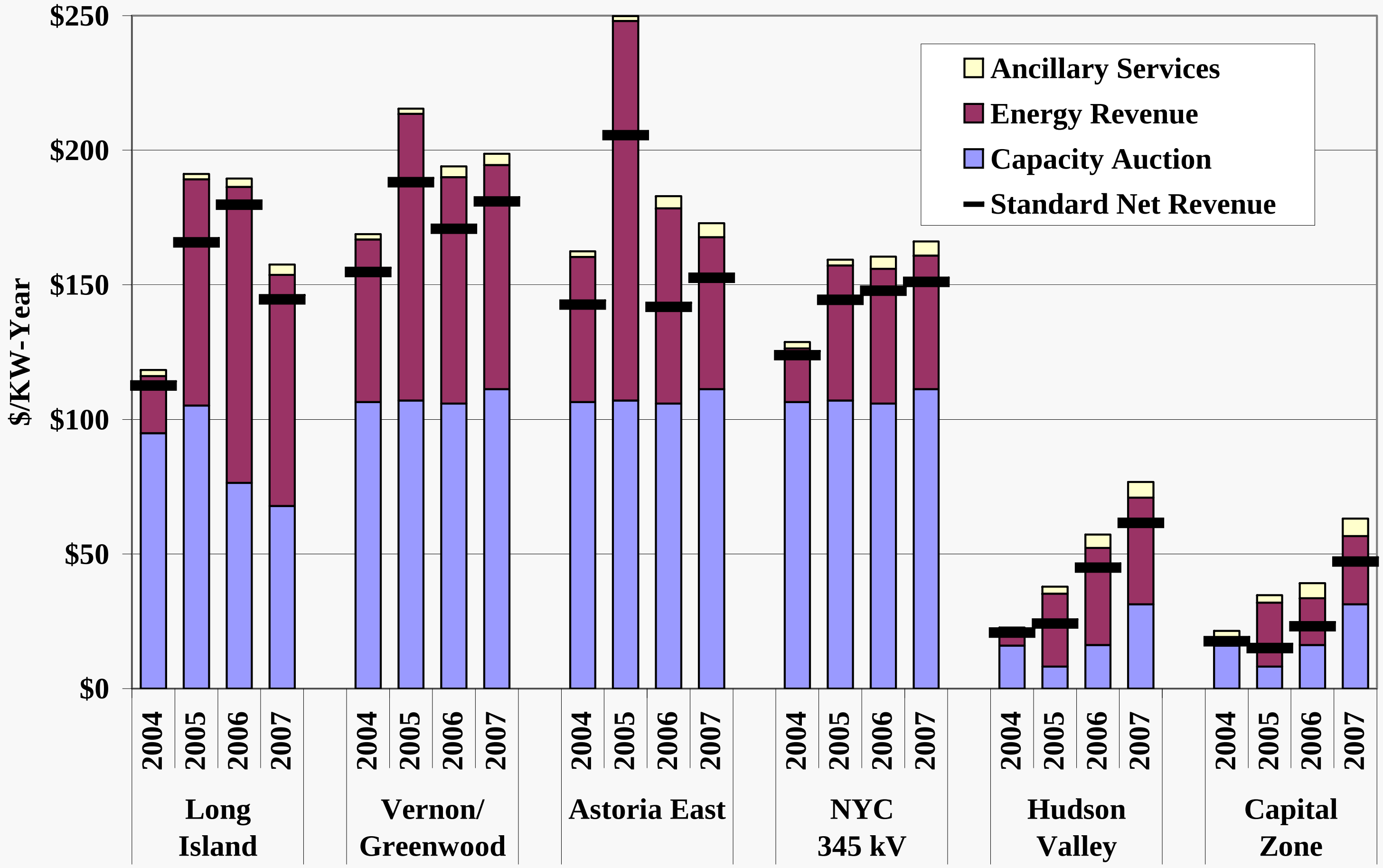
Enhanced Net Revenue Analysis

Gas Combined-Cycle Unit, 2004 – 2007



Enhanced Net Revenue Analysis

Gas Combustion Turbine, 2004 – 2007



Long-Term Market Signals – Conclusions

- Based on the net revenue levels in 2007 and Cost of New Entry ("CONE") estimates supporting the NYISO's Proposed Demand Curves:
  - ✓ Vernon/Greenwood is the only area of NYC where new CT investment would have been profitable.
- Although there are no publicly available estimates of CONE for a new CC in New York, the estimated net revenues are substantially higher for a new CC than a new CT.
  - ✓ In up-state areas, the estimated net revenues for a new CC were more than double those for a new CT in 2007.
  - ✓ In New York City, the estimated net revenues for a new CC were more than $100 per KW-month higher than those for a new CT in 2007.
  - ✓ We do not have reliable estimates of the entry costs for a CC. Depending on these costs, it may economic to build a CC in some areas under the current market conditions.

External Interface Scheduling

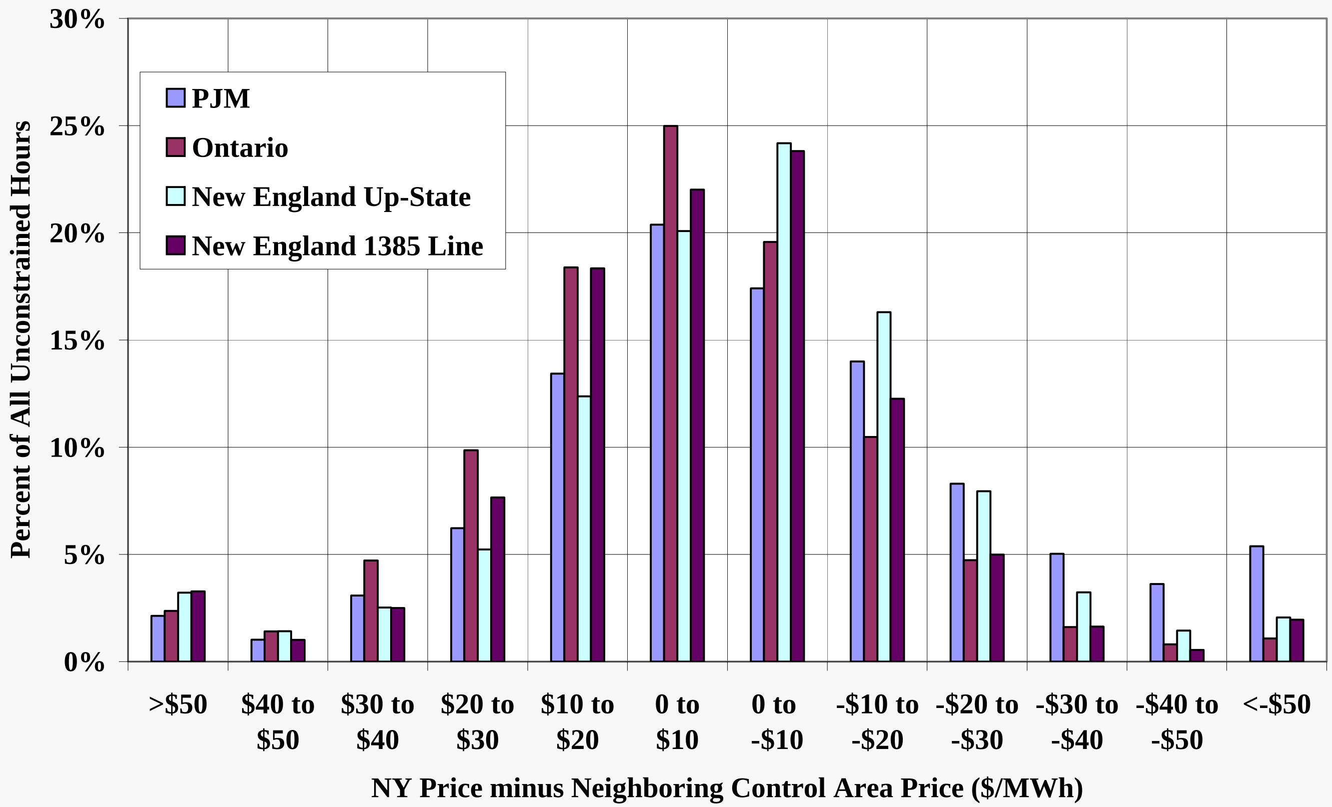
External Interface Scheduling – Introduction

- Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.
- Efficient use of transmission interfaces between regions is beneficial in at least two ways:
  - ✓ By promoting competition in the same way as efficient use of transmission resources within each control area: it allows customers to be served by external resources that are lower-cost than available native resources.
  - ✓ By lowering the cost of maintaining reliability in each control area.
- This section examines three issues related to scheduling between regions:
  - ✓ Convergence of prices between New York and neighboring control areas.
  - ✓ Benefits of external interface scheduling by market participants.
  - ✓ Benefits of ISO-coordinated interchange between control areas.

External Interface Scheduling – Price Convergence Between Control Areas

- When interfaces are used efficiently, prices in adjacent areas should be consistent unless transmission constraints limit scheduling between regions.
- The following figure summarizes price differences between NY and neighboring control areas during unconstrained hours. For every interface, the price differences are substantial, exceeding $10/MWh between:
  - ✓ PJM and NY in 62 percent of unconstrained hours;
  - ✓ Ontario and NY in 55 percent of unconstrained hours;
  - ✓ New England and Up-state NY in 56 percent of unconstrained hours; and
  - ✓ New England and NY across the 1385 line in 54 percent of unconstrained hours.
- This reinforces the importance of efforts to improve real-time interchange between New York and adjacent regions.
  - ✓ Efficient scheduling is particularly important during reserve shortages when flows between regions have the largest economic and reliability consequences.

RT Price Convergence Between NY and Adjacent ISO Markets Unconstrained Hours, 2007



Note: The Neptune and Cross Sound Cable proxy busses are omitted because they depend on a separate system for allocating transmission reservations.

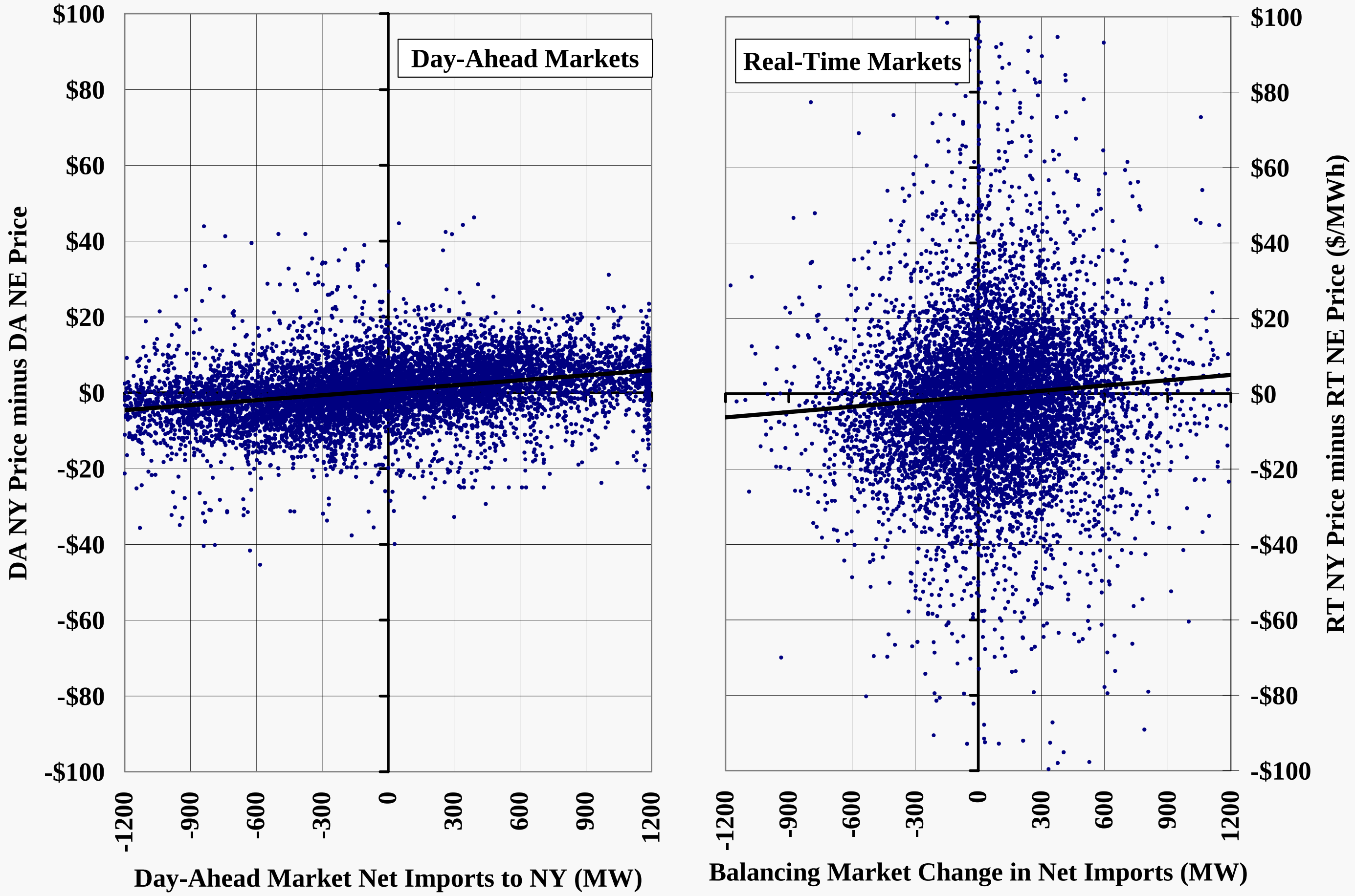
External Interface Scheduling – Market Participant Scheduling

- It has proven difficult to achieve RT price convergence with adjacent markets through the transaction scheduling of market participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.
  - ✓ Furthermore, transaction costs from uplift allocations and export fees reduce or eliminate the expected profits from arbitrage.
- The following two figures suggest that reducing barriers to scheduling by market participants would result in more efficient scheduling between regions.
  - ✓ The first figure contains two scatter plots showing scheduled flows versus price differences between New England and up-state NY.
  - ✓ The second figure illustrates the consistency of real-time price differences between NY and New England in the two hours leading up to each real-time five-minute interval.

External Interface Scheduling – Market Participant Scheduling

- The following figure shows scheduled flows versus price differences between New England and up-state NY on an hourly basis.
  - ✓ The left side shows DA scheduling and pricing.
  - ✓ The right side shows scheduling and pricing of incremental changes that occur in the Real-Time market (relative to the DA schedules).
- The trendlines show statistically significant positive correlations between the price difference and direction of scheduling in the DA and RT markets, which indicates:
  - ✓ On average, participants schedule transactions toward the higher price region, which improves efficiency. Total net profits from cross-border scheduling in 2007 was \$14.1 million in the DA and \$4.5 million in the RT (not including transaction costs).
  - ✓ Removing barriers to scheduling should enable MPs to schedule more efficiently.
- The plots show a wide dispersion of results in the RT market, illustrating the difficulty of predicting changing RT market conditions.
  - ✓ 45 percent of points in the RT are in the unprofitable quadrants (upper left and lower right), indicating hours when market participants shifted scheduled flows in the unprofitable direction (from the high-priced to the low-priced market).
  - ✓ Overall, this figure indicates that there remains considerable room for improvement in the real-time market.

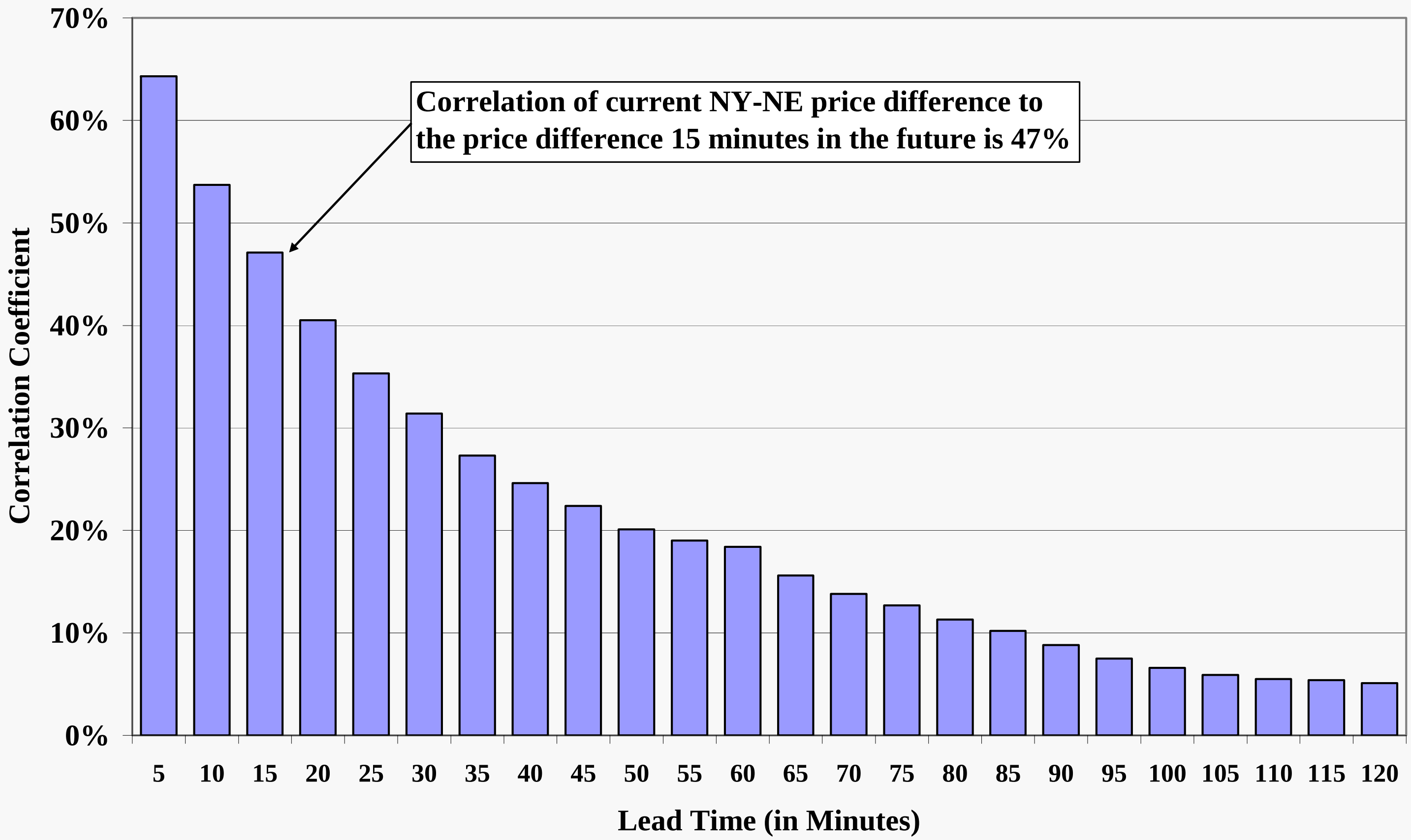
Efficiency of Scheduling in the Day-Ahead and Real-Time Interface Between Up-state NY and New England, 2007



External Interface Scheduling – Market Participant Scheduling

- The following figure shows how the current five-minute price difference between NY and New England is useful for predicting the price difference over the subsequent 120 minutes.
- The correlation coefficient increases as the lead time is reduced below 120 minutes. However, this under-estimates the predictability of price differences between control areas because:
  - ✓ Market participants can use more sophisticated techniques for forecasting; and
  - ✓ RTC's advisory prices help market participants schedule transactions more efficiently.
- Currently, market participants submit transactions 75 minutes before the start of an hour, which is 75 to 135 minutes before the power actually flows.
- This analysis suggests that reduced lead times would enable market participants to schedule more efficiently.

Efficiency of Reducing Scheduling Lead Time
Correlation of Price Difference to Lead Time
New York – New England Interface, 2007



External Interface Scheduling –
Conclusions about Market Participant Scheduling

- Steps have been taken to reduce barriers to arbitrage between markets:
  - ✓ Export fees were eliminated between NY and New England in 2005.
- However, significant barriers still exist:
  - ✓ Uplift for supplemental commitment is allocated to transactions between NY and adjacent markets.
  - ✓ Export fees are allocated to transactions with PJM and Ontario.
  - ✓ The analyses in this section indicate that reduced barriers would substantially improve efficiency.
- Additional steps have been discussed that would better enable market participants to schedule transactions between markets efficiently. We recommend continued efforts to:
  - ✓ Eliminate export fees with the PJM and Ontario.
  - ✓ Reduce the scheduling lead times with adjacent markets.

External Interface Scheduling – Coordination of Interchange by the ISOs

- The elimination of all barriers would enable participants to arbitrage more efficiently, but it would not result in full convergence. Full convergence would likely require coordination by the ISOs.
  - ✓ Under the current process, market participants submit bids and offers to each ISO based on their expectations of price differences. The ISOs use the bids and offers to curtail transactions when capability is limited.
  - ✓ Active coordination by the ISOs would be needed to optimize flows across the interface.
- Efficient use of transmission interfaces between regions promotes competition by allowing customers to be served by external resources that are lower-cost than available native resources.
  - ✓ During peak demand conditions, efficient scheduling is especially important. Frequently during price spikes, a small amount of additional imports can substantially reduce the magnitude of the spike.

External Interface Scheduling – Coordination of Interchange by the ISOs

- Coordination of flows between New England and up-state New York would benefit consumers on both sides of the interface.
- We performed simulations to estimate the benefits of optimal hourly scheduling of the interface. The results are summarized in following table.
  - ✓ Production cost savings average $19 million annually.
  - ✓ Net consumer savings average $159 million annually.
- The net consumer savings are concentrated on a small share of the total hours when changes in flows would have had large consequences.
  - ✓ The 99 hours with reserve shortages of at least two intervals account for 28 percent of the net consumer savings.

Estimated Benefits of Coordinated External Interface Scheduling Up-state Interface with ISO-New England, 2006 & 2007

	2006	2007
Estimated Production Cost Net Savings (in Millions)	**$17**	**$21**
Estimated Consumer Net Savings (in Millions):		
New York Customers	**$59**	**$177**
New England Customers	**$61**	**$22**
Total for New York and New England Customers	**$120**	**$199**
During Reserve Shortage Hours	**$16**	**$75**

External Interface Scheduling – Coordination of Interchange by the ISOs

- Prices between New York and adjacent markets continue to not be arbitraged effectively during unconstrained periods.
- Reducing barriers will help, but coordination by the ISOs is needed for full price convergence.
- We recommend the ISOs develop a process of adjusting flows to converge RT price differences.
  - ✓ Even a solution that is used under limited conditions, such as reserve shortages, is likely to result in substantial consumer savings.
- Additionally, we support efforts to coordinate congestion management with PJM.
  - ✓ This would result in a more efficient nodal prices and congestion charges.

Convergence of Day-Ahead and Real-Time Prices

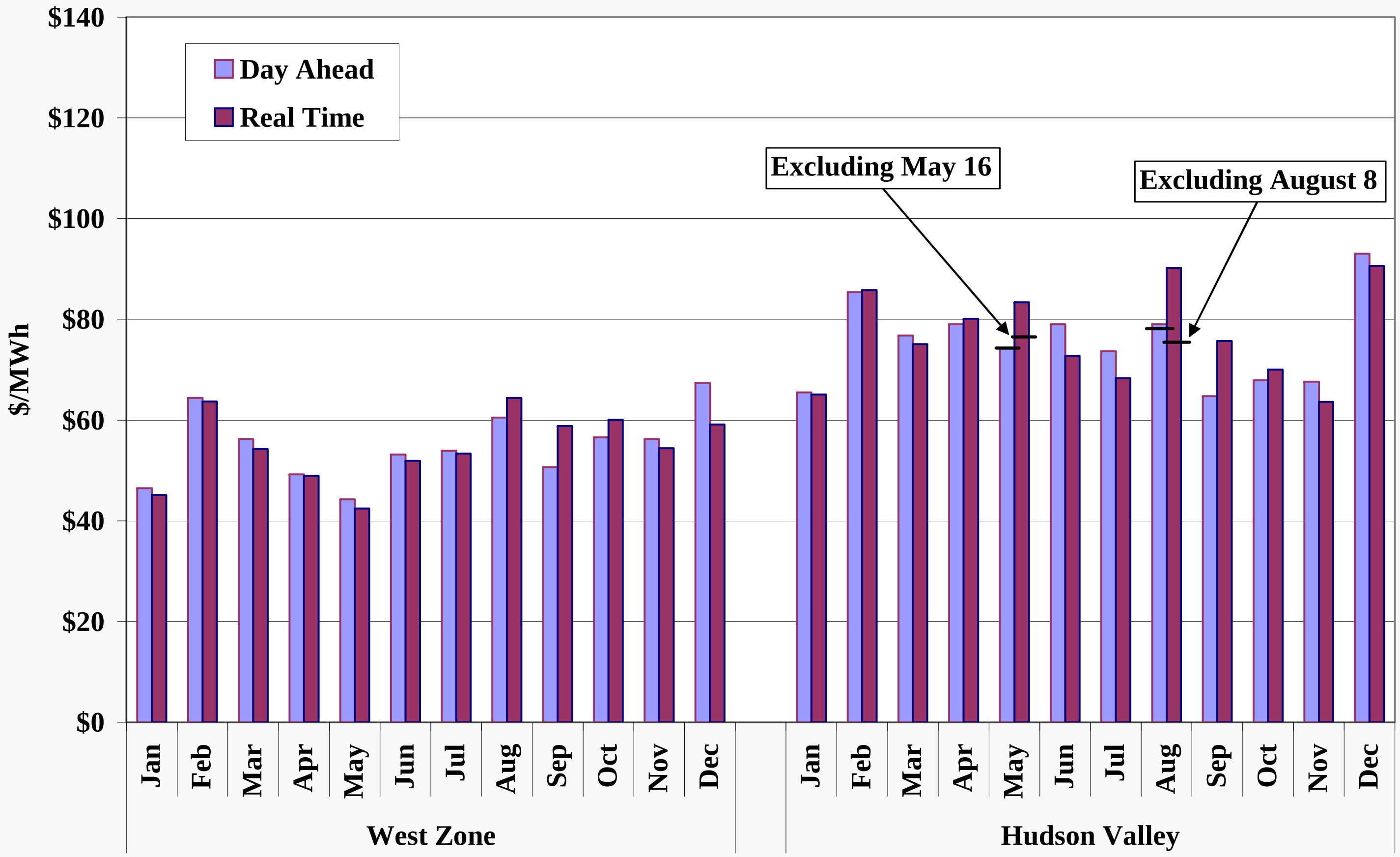
Day-Ahead and Real-Time Prices

- This section of the report examines the degree of consistency between DA and RT prices.
  - ✓ Convergence between DA and RT prices is important because most generation is committed in the DA Market -- good price convergence leads to the most economic commitment of resources to serve load in RT.
  - ✓ Good convergence also helps maintain efficient incentives for generators. Persistent systematic differences between DA and RT prices undermine incentives of generators to offer at marginal cost.
- There are two kinds of inconsistency between DA and RT prices:
  - ✓ Random variations between DA and RT prices due to unanticipated changes in energy supply and load; and
  - ✓ Persistent systematic differences between the average level of DA prices and the average level of RT prices.
- The analyses in this section of the report look for persistent systematic differences between DA and RT prices.

Day-Ahead and Real-Time Energy Prices

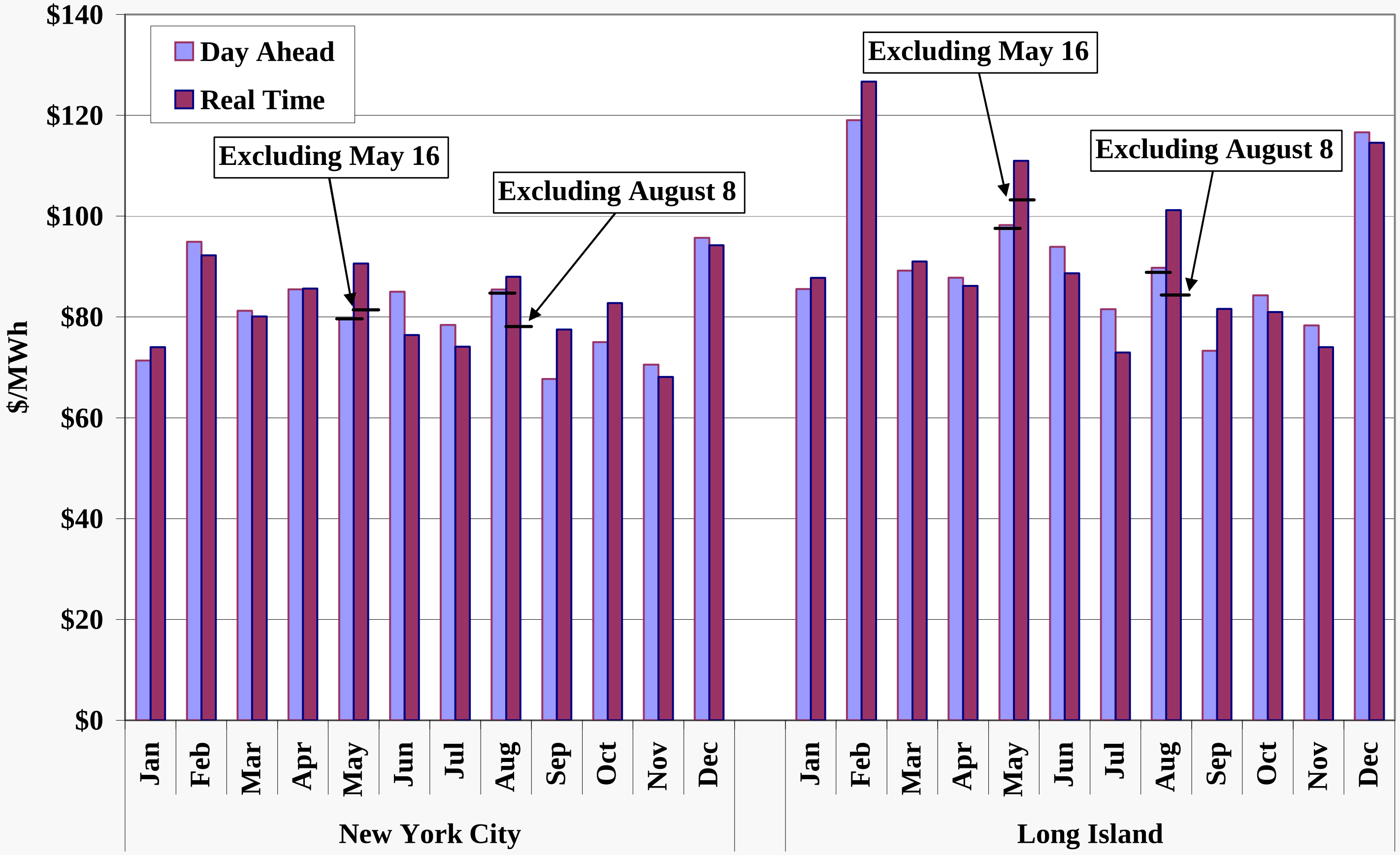
- The following two figures show monthly average DA and RT energy prices in several zones in 2007. The figures show:
  - ✓ Individual months exhibit substantial DA or RT price premiums, some of which are consistent across different regions. For example, in May, the RT premium exceeded 10 percent in most of eastern NY.
- Substantial DA or RT price premiums in individual months can occur when RT conditions differ from expectations.
  - ✓ RT premiums can arise when RT scarcity is not anticipated in the DA market. For example, the DA market did not foresee acute RT congestion through the Hudson Valley on May 16, resulting in a RT premium for the entire month.
  - ✓ DA premiums, such as in June and July 2007, typically arise when the DA market anticipates some RT scarcity, but less occurs than expected.
  - ✓ Random or otherwise unpredictable events can lead to intermittent DA or RT price premiums in individual months.
- To illustrate the effects a single day can have, the figures show the average DA and RT prices in the eastern zones if May 16 and August 8 are excluded.

Average Monthly Day-Ahead and Real-Time Energy Prices
West Zone and Hudson Valley, 2007



Note: The prices are load-weighted averages.

Average Monthly Day-Ahead and Real-Time Energy Prices
New York City and Long Island, 2007



Note: The prices are load-weighted averages.

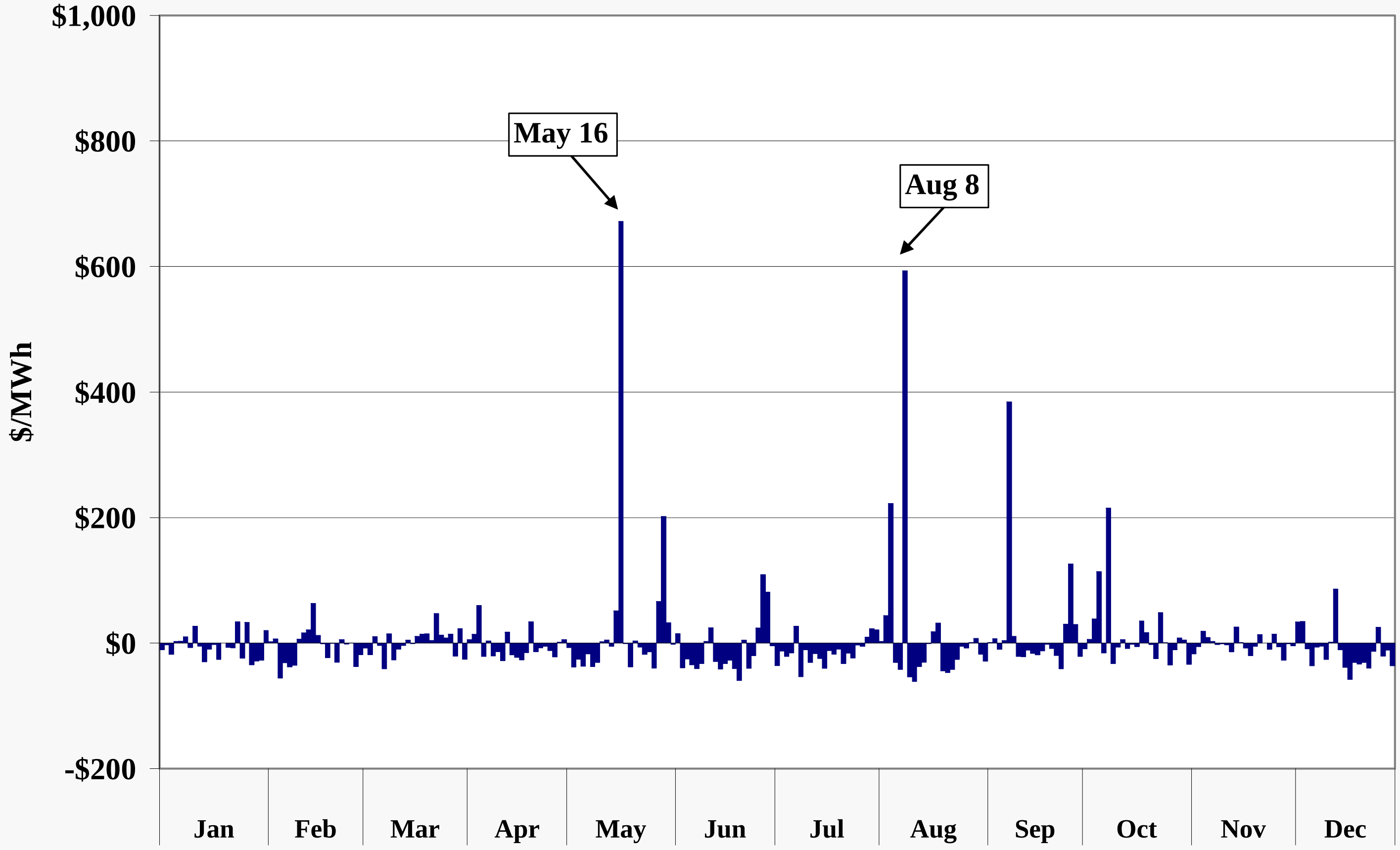
Day-Ahead and Real-Time Energy Prices

- The following two figures show average daily RT price premiums for weekday afternoon hours for NYC and Long Island.
- Even when average DA and RT prices are consistent in a particular month, the following figures show substantial differences on individual days.
- Market participants buy and sell in the DA Market based in part on their expectations of RT Market outcomes. DA decisions naturally involve several uncertainties:
  - ✓ Demand can be difficult to forecast with precision; the availability of supply may change due to forced outages or numerous other factors.
  - ✓ Special operating conditions, such as TSAs, may alter the capability of the transmission system in ways difficult to arbitrage in DA markets.
- In general, DA prices reflect the probability-weighted expectation of infrequent high-priced events in the RT Market.

Day-Ahead and Real-Time Energy Prices

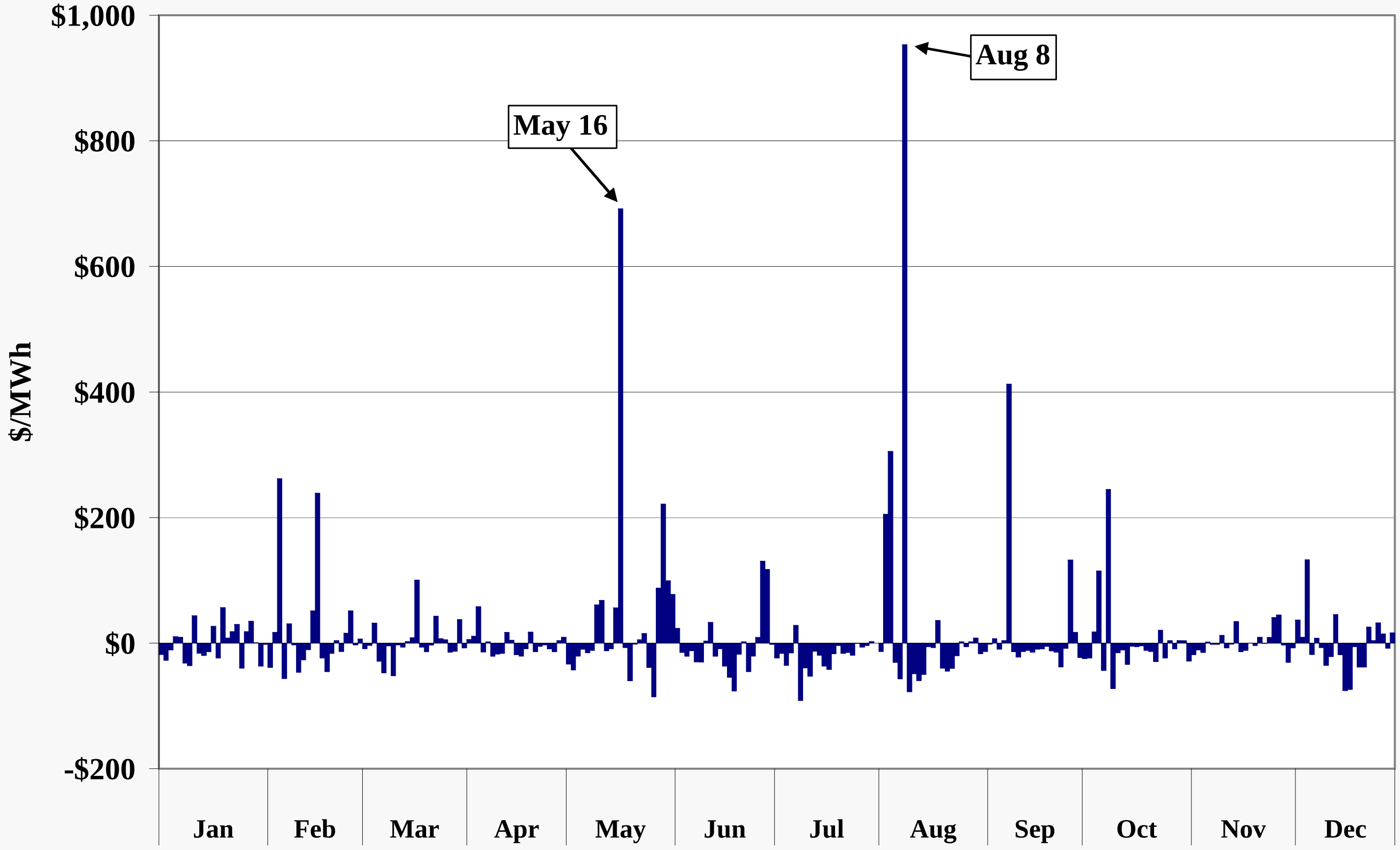
- Average DA prices are higher than average RT prices on the majority of afternoons shown in the following figures:
  - ✓ In both NYC and Long Island, DA prices were higher than RT prices on almost 64 percent of afternoons.
- However, high-price events are more frequent in the RT Market:
  - ✓ No afternoons produced an average DA price premium greater than $100 per MWh in NYC or Long Island.
  - ✓ The RT price premium exceeded $100 per MWh on 9 afternoons in NYC and 15 afternoons in Long Island.
- The two days with the largest RT price premium are labeled in the figures.
  - ✓ May 16’s RT price premium reflects RT congestion through Hudson Valley from unforecasted weather patterns.
  - ✓ August 8’s RT price premium resulted from shortage pricing conditions on the peak load day for 2007.

Average Daily Real-Time Price Premium
New York City, 1 p.m. to 7 p.m. Weekdays, 2007



Note: The prices are load-weighted averages.

Average Daily Real-Time Price Premium
Long Island, 1 p.m. to 7 p.m. Weekdays, 2007



Note: The prices are load-weighted averages.

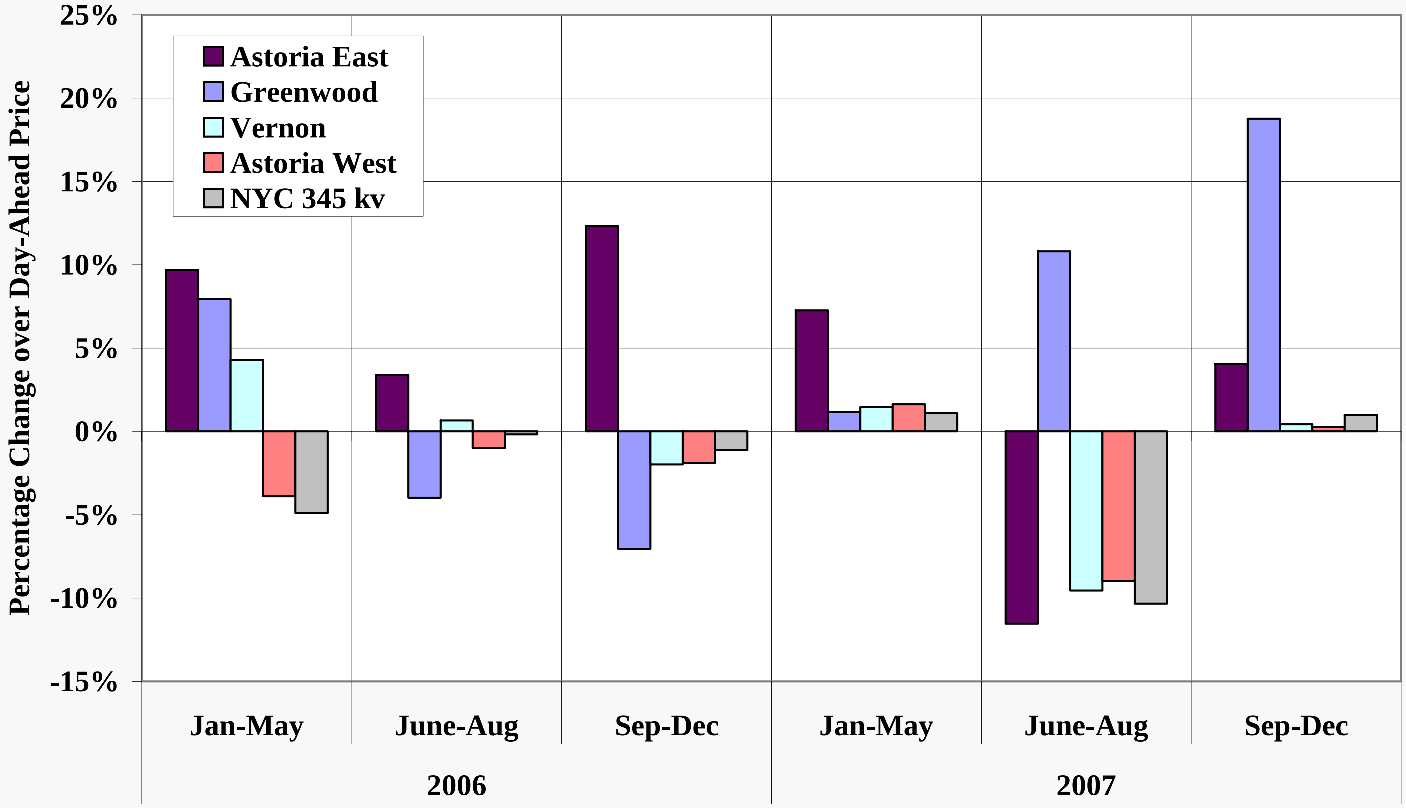
Day-Ahead and Real-Time Load Pocket Prices

- The following figure shows the average RT price premium at several locations in NYC on a seasonal basis during 2006 and 2007.
  - ✓ Four locations are sub-load pockets in the 138kV system and one location is in the 345kV system.
- When the RT premium varies substantially across locations within NYC, it reflects that DA congestion patterns are different from RT patterns.
  - ✓ For example, from Sept. to Dec. 2007, average DA prices were consistent with average RT prices in most areas. However, RT events led to substantial RT congestion into the Greenwood area that was not reflected in the DA market.
- DA and RT price premiums were smaller in 2006 and 2007 than in previous years. The following factors helped improve convergence:
  - ✓ New capacity was installed in Astoria West in January 2006 and in Astoria East in May 2006. This has substantially reduced congestion within New York City.
  - ✓ Since May 2006, the NYISO has increasingly used a more detailed network model for RT scheduling, which was previously used in the DA Market only. This has improved the consistency of congestion in the DA and RT markets.

Day-Ahead and Real-Time Load Pocket Prices

- Even when the same network model is used in both markets, congestion patterns may differ between the DA and RT for the following reasons.
  - ✓ Generators that are not scheduled DA may change their offers. This is common during periods of fuel price volatility or when gas is more easily procured DA.
  - ✓ Transmission constraints that are sensitive to the level of demand may become more or less acute after the DA market due to differences between expected load and actual load.
  - ✓ Transmission forced outages may occur and transmission maintenance schedules may change unexpectedly.
  - ✓ Generators may be committed or decommitted after the DA market, which changes transmission flows.
- The NYISO is considering two prior recommendations that are expected to improve convergence in NYC load pockets.
  - ✓ Better integrate local reliability requirements in the DA market, which should reduce the need for commitment after the DA market.
  - ✓ To disaggregate virtual trading. Currently, it is limited to the zonal level, which prevents market participants from arbitraging price differences within NYC.

Average Real-Time Price Premium in NYC Load Pockets 2006-2007



Note: The prices are load-weighted averages. Individual generator buses were used to represent the areas listed in the figure: Astoria GT 2/1 for Astoria East, Gowanus GT 1/1 for Greenwood, Ravenswood 1 for Vernon, Astoria GT 10 for Astoria West, and Poletti for the New York City 345kV area.

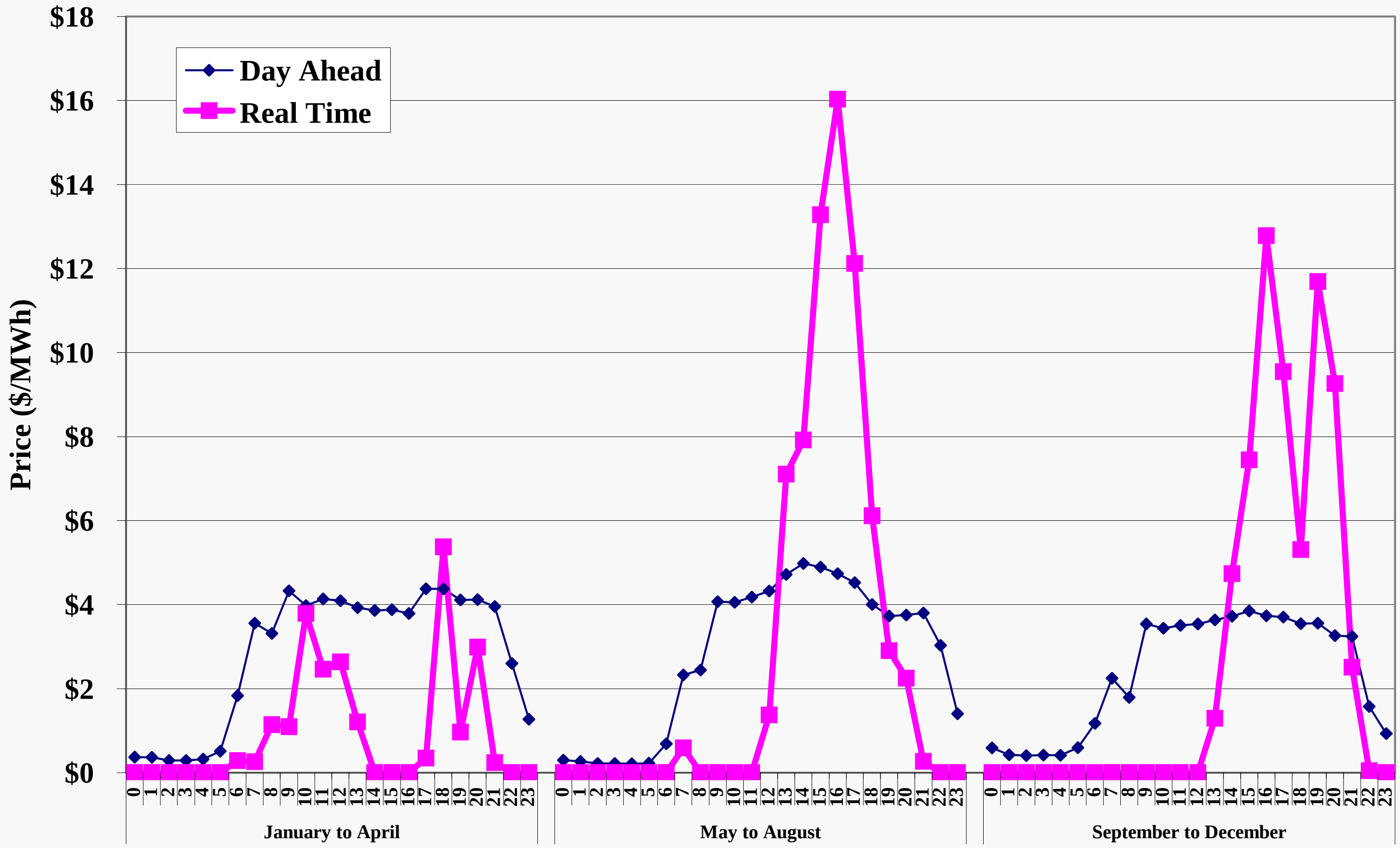
Day-Ahead and Real-Time Ancillary Services Prices

- The following figures summarize DA and RT clearing prices for the two most important reserve products in NY state.
  - ✓ The first figure shows 10-minute reserve prices in eastern NY, which are primarily based on the requirement to hold 1,000 MW of 10-minute reserves east of the Central-East Interface.
  - ✓ The second figure shows 10-minute spinning reserve prices in western NY, which are primarily based on the requirement to hold 600 MW of 10-minute spinning reserves in NY state.
  - ✓ Average prices are shown by season and by hour of day.
- The market models use “demand curves” that place an economic value of $500/MWh on meeting each of these requirements.
- Both figures show that average DA prices are systematically higher or lower than RT prices under various circumstances.
  - ✓ Average RT prices tend to be higher during the afternoon peak, and average DA prices tend to be higher at other times.

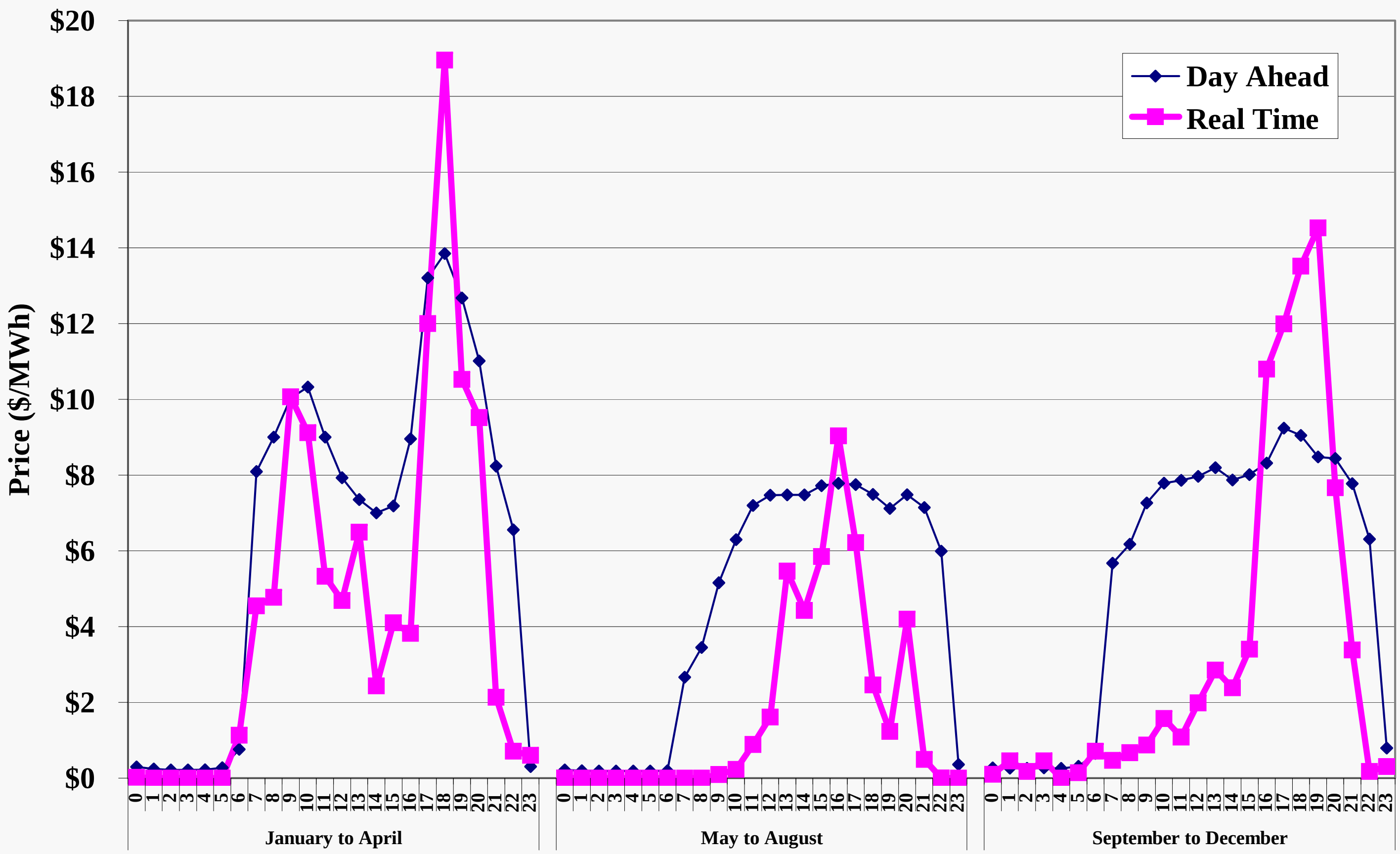
Day-Ahead and Real-Time Ancillary Services Prices

- RT reserve prices are generally volatile, making them difficult for the DA market to predict.
  - ✓ Eastern RT 10-minute reserves prices are normally close to $0, reflecting the excess available reserves from off-line quick-start GTs. However, RT prices can spike during periods of tight supply and high energy demand.
  - ✓ 10-minute spinning reserves prices are less volatile, but still prone to unexpected spikes.
- DA reserve prices tend to fluctuate based on the expected likelihood of a RT price spike.
- Convergence between DA and RT ancillary services prices has gradually improved since the introduction of the SMD 2.0 markets in 2005.
  - ✓ However, convergence may be inhibited by DA offer limitations, which are discussed in the next section.

10-Minute Total Reserve Prices in East NY
by Hour of Day, 2007



10-Minute Spinning Reserve Prices in West NY by Hour of Day, 2007



Ancillary Services Markets

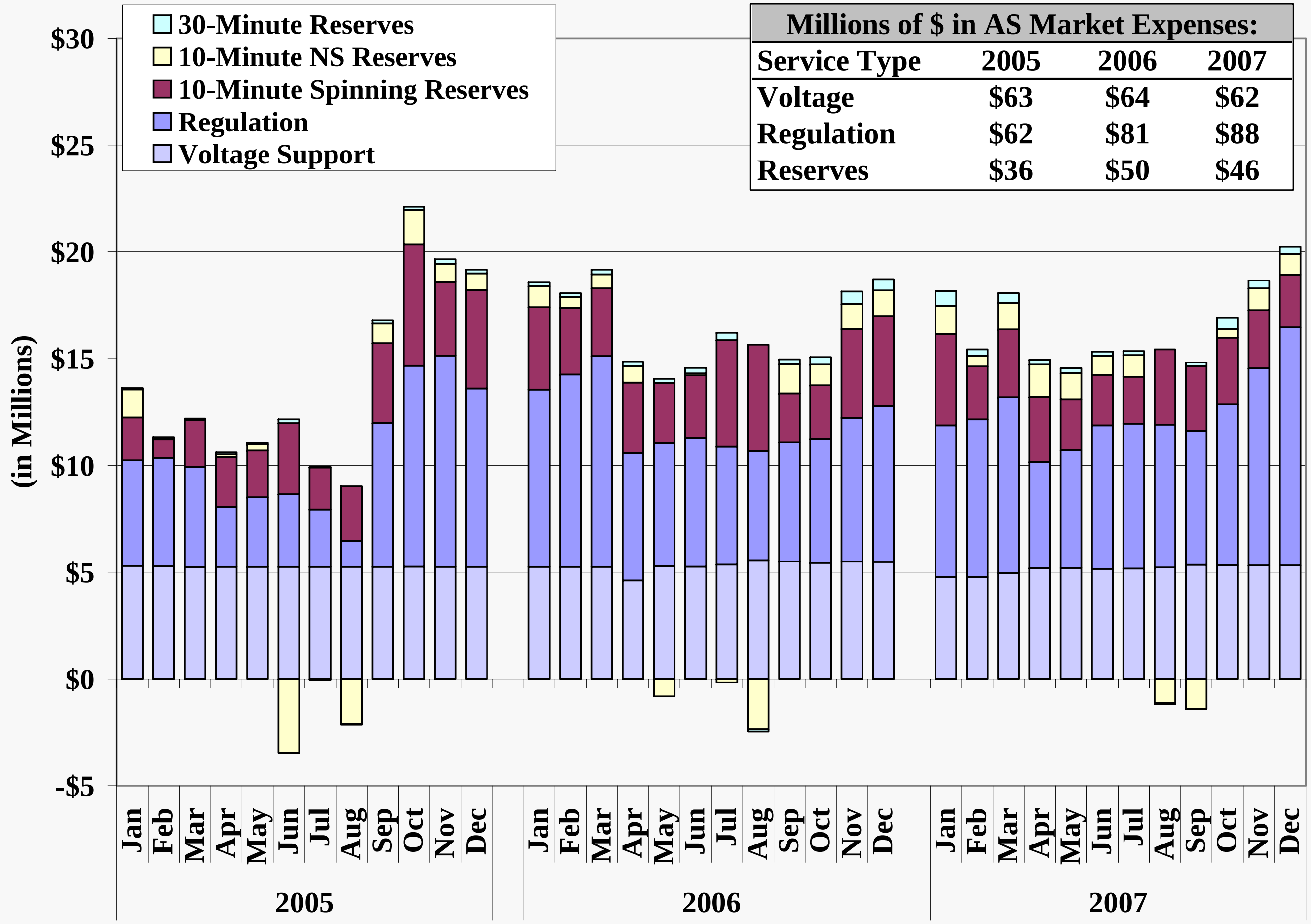
Ancillary Services Market Design

- Since the implementation of SMD 2.0 in 2005, the ancillary services markets have included 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 reflect the value of ancillary services and energy in prices under shortage conditions.
  - ✓ AS prices are based on the marginal cost of providing the service to the system, which equals the sum of the marginal AS provider's:
    - (i) availability offer price and
    - (ii) 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 offer.
  - ✓ A two-settlement system for ancillary services, whereby day-ahead schedules must either be provided in real-time or purchased back from the ISO's real-time market.

Ancillary Services Expenses

- The following figure shows monthly expenses for five categories of ancillary services from 2005 to 2007.
- Total expenses increased approximately 20 percent from 2005 to 2006 but did not change substantially from 2006 to 2007.
- The following factors have contributed to increased expenses since 2005.
  - ✓ High fuel prices in late 2005 and late 2007 lead to higher opportunity costs for low-cost units providing ancillary services.
  - ✓ Regulation offer prices rose substantially in September 2005, although the effect was partly mitigated by the entry of new supply in spring 2006.
- Convergence between DA and RT reserve prices affects expenses for 10-minute spinning and non-spinning reserves.
  - ✓ The ISO purchases the required quantity of reserves in the DA market, so expenses depend primarily on DA prices rather than RT prices.
  - ✓ Expenses for reserves increased after 2005 because DA ancillary services prices rose relative to RT ancillary services prices.

Ancillary Services Expenses
2005 – 2007



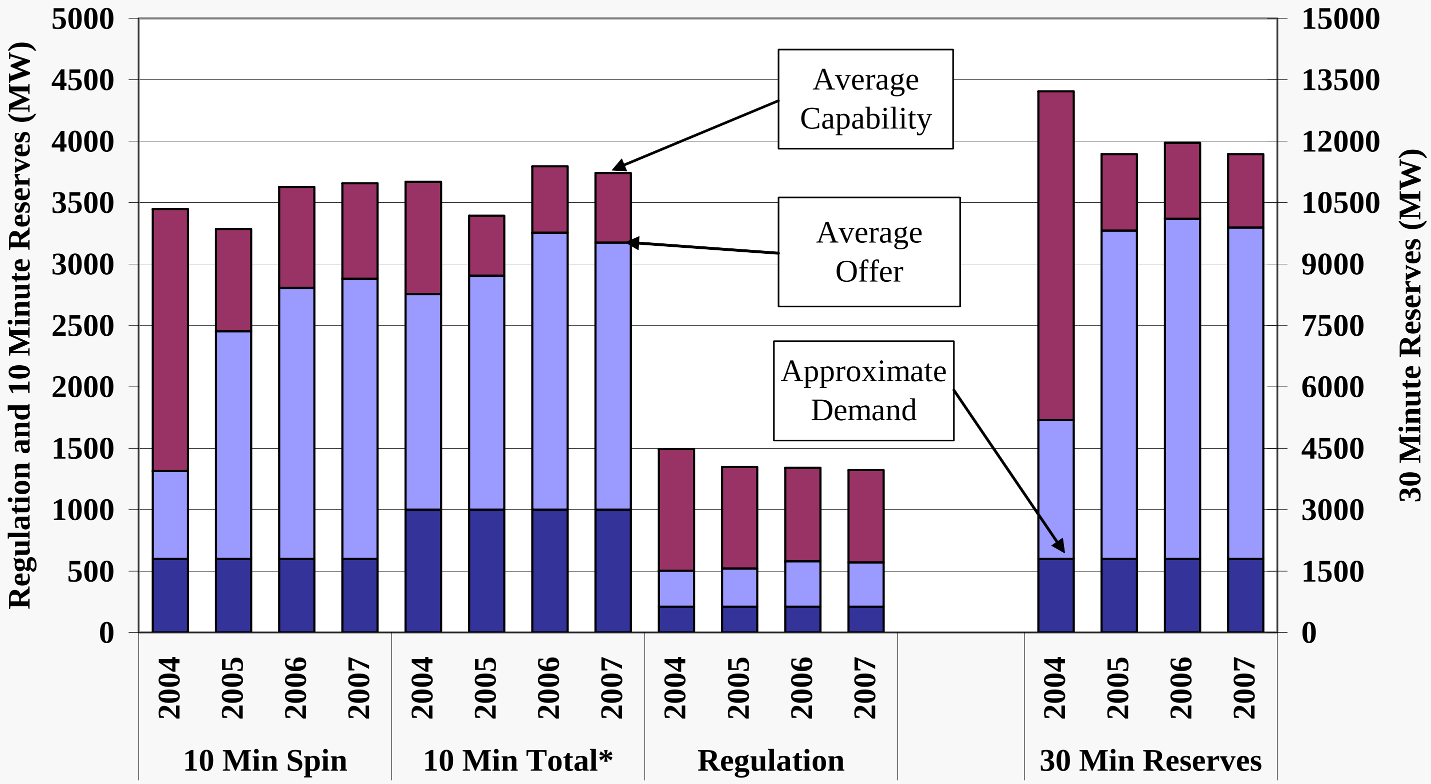
Millions of $ in AS Market Expenses:

Service Type	2005	2006	2007
Voltage	$63	$64	$62
Regulation	$62	$81	$88
Reserves	$36	$50	$46

Day-Ahead Capacity and Offers

- The following figure summarizes supply and demand for several ancillary services market requirements: (i) 10-minute spinning reserves, (ii) 10-minute total reserves in eastern New York, (iii) regulation, and (iv) 30-minute reserves.
- In 2005, improved incentives from the co-optimization under SMD 2.0 led to a substantial rise in 10-minute spinning reserve and 30-minute reserve offer quantities.
  - ✓ Previously, generators ran the risk of selling reserves in the DA market when it would have been more profitable to sell energy.
  - ✓ Under SMD 2.0, generators are selected to provide whichever is more profitable (based on the offer they submit).
- In 2006, the introduction of new combined cycle capacity in NYC led to increased supply of 10-minute spinning reserves and eastern 10-minute reserves.
- Some regulation-capable capacity is not offered to the market, which may be due to costs incurred to offer regulation or non-economic barriers.

Ancillary Services Capability and Offers
Day-ahead Market, 2004-2007



*Eastern side of the Central-East Interface only

Day-Ahead Ancillary Services Offers

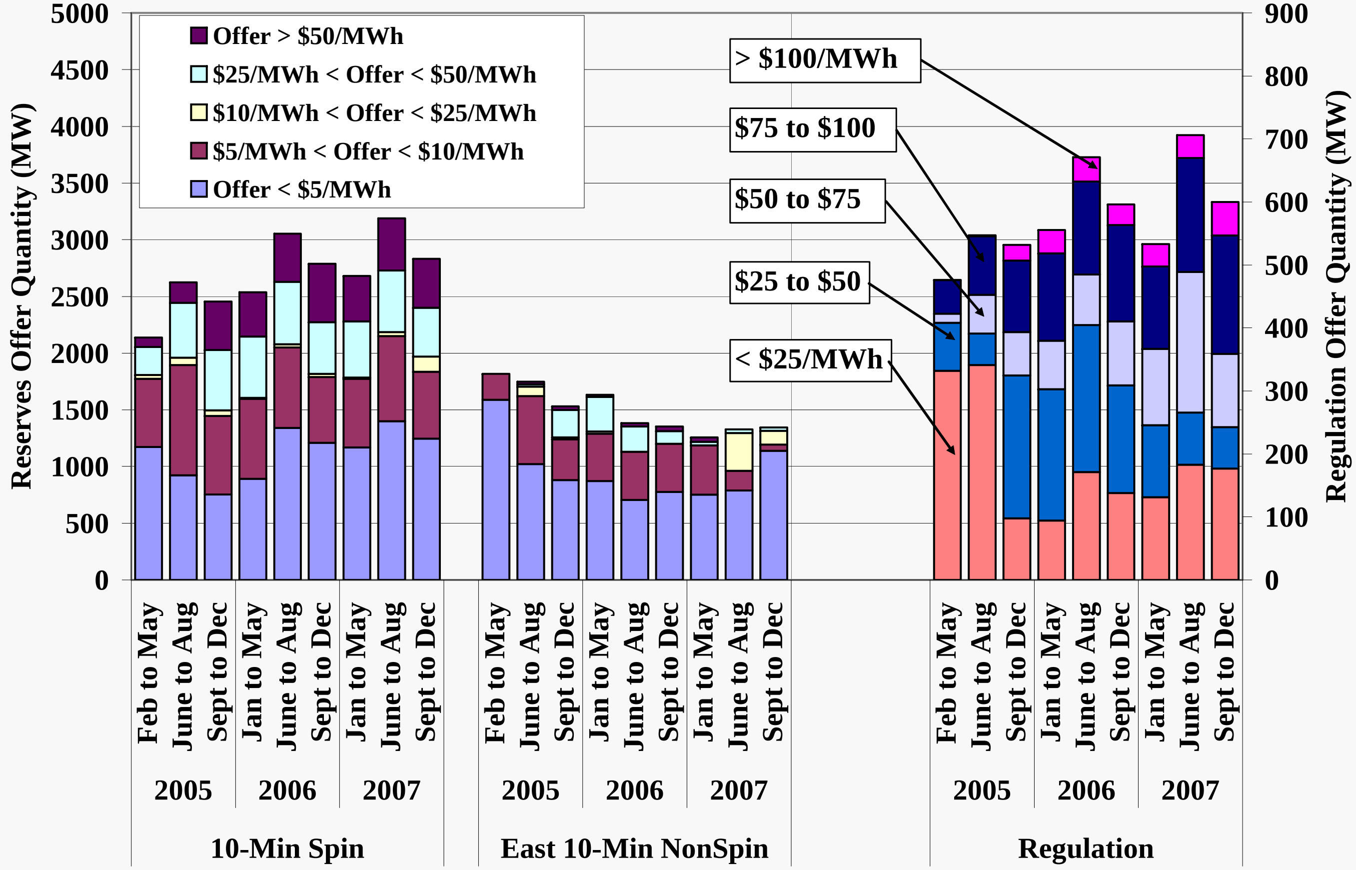
- To evaluate trends in offer prices and quantities, the following figure summarizes day-ahead offers to supply three categories of ancillary services from 2005 to 2007.
  - ✓ Offer quantities are shown according to offer price level.
- Regulation Offer Patterns:
  - ✓ Higher offer prices beginning in September 2005 and further increases in 2007 have contributed to a rise in regulation clearing prices and expenses.
  - ✓ The rise in offers was not sufficient to warrant mitigation of regulation offers under the NYISO Tariff.
  - ✓ The effects of higher offer prices were partially offset by the entry in June 2006 of approximately 100 MW of low-priced offers from generators that did not previously offer regulation.
  - ✓ Due to limited participation in the regulation market, the ownership of resources that participate in the regulation market is relatively concentrated.

Day-Ahead Ancillary Services Offers

- Statewide 10-Minute Spinning Reserves Offer Patterns:
  - ✓ In 2005, the quantity of 10-minute spinning reserves offered at $5/MW or less trended down as many market participants raised their offer prices.
  - ✓ In 2006, the quantity of offers rose due to the installation of new combined cycle capacity in New York City.
    - – NYC units are required to offer 10-minute spinning reserves at $0/MW.
    - – This requirement prevents them from arbitraging the RT reserve prices.
- Eastern 10-Minute Non-Spinning Reserves Offer Patterns:
  - ✓ Offer quantities have decreased and offer prices have increased since 2005.
  - ✓ Generators may want to avoid being scheduled in the DA market during periods when DA prices are systematically lower than RT prices.
  - ✓ Offer price increases may be limited by the mitigation rules, which restrict the reference levels of 10-minute non-spin reserve providers to $2.52/MWh or less.
  - ✓ Decreases in the capability offered are limited by the ICAP rules, which require Non-PURPA ICAP units that have 10-minute non-spin reserve capability to offer it in the DA market.

Summary of Ancillary Services Offers

Day-Ahead Market, 2005-2007



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

Ancillary Services Markets – Conclusions and Recommendations

- Co-optimization of energy and ancillary services has improved the incentives to participate in the ancillary services markets.
- Convergence of DA and RT prices has been poor for certain reserve products.
  - ✓ Average DA prices are systematically higher or lower than RT prices under various circumstances.
  - ✓ Systematically low DA prices increase the opportunity cost of selling reserves in the day-ahead market.
  - ✓ The wide-spread rise in 10-minute reserve offer prices has helped improve convergence between DA and RT. However, the higher reserve offer prices can undermine the efficiency of DA commitment.
- We recommend reconsideration of two provisions in the mitigation measures that may limit competitive offers in the DA market. The provisions:
  - ✓ Limit GTs to a 10-minute Non-Spinning Reserve reference level of $2.52/MWh.
  - ✓ Require steamers in NYC to offer 10-minute Spinning Reserves at $0/MWh.
- If price convergence does not continue to improve over time, we recommend that the ISO evaluate the feasibility of virtual trading of ancillary services, which should correct the systematic differences between DA and RT prices.

Analysis of Energy Bids and Offers

Analysis of Energy Offer Patterns

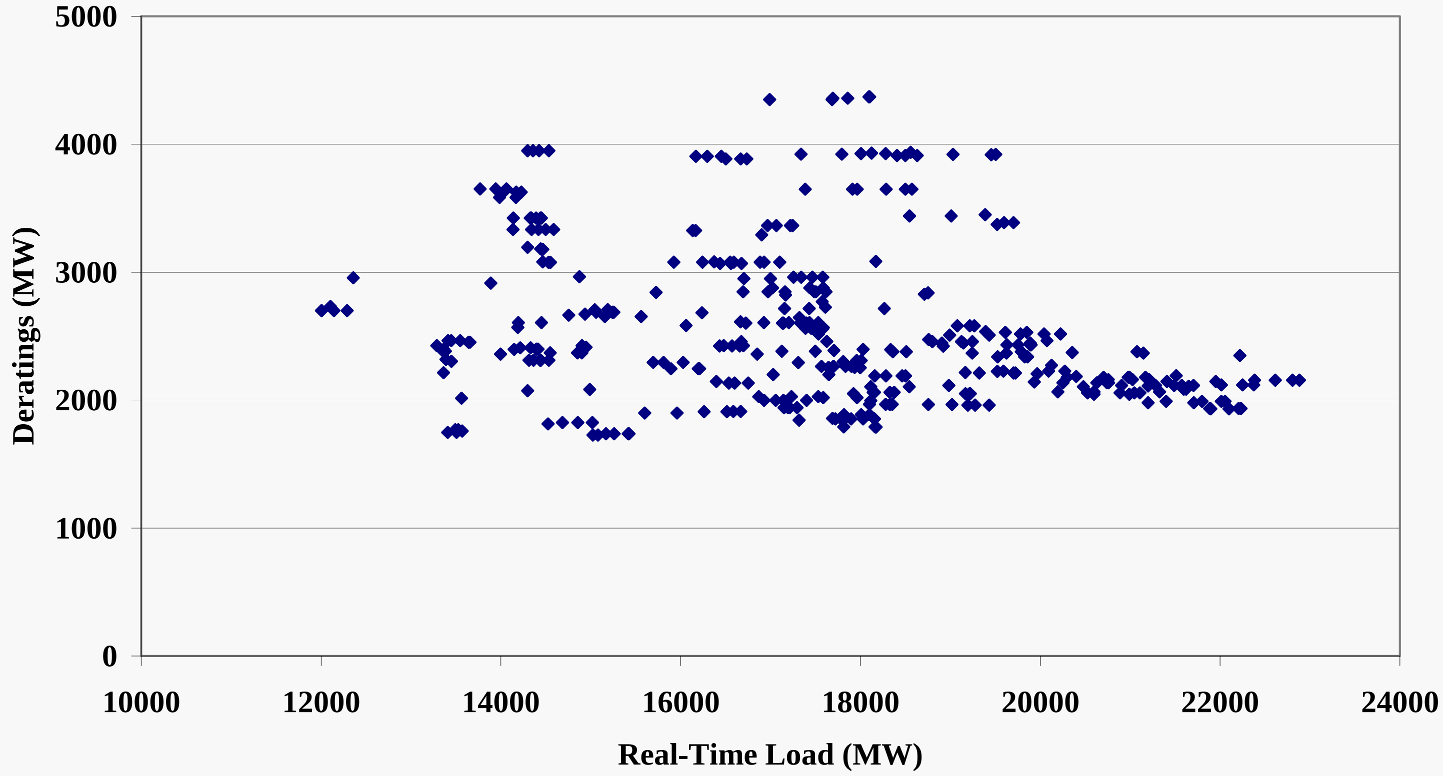
- This section of the report analyzes the patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase offer quantities during higher load 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 highlights market participant behavior that may reflect attempts to withhold resources to raise prices.
- The first analysis examines potential physical withholding, which includes total generation deratings (including planned outages, 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.
  - ✓ Deratings in the first figure are measured relative to the most recent DMNC test value, while short-term derating in the second figure exclude quantities that are derated for 30 days or more.
  - ✓ The short-term deratings are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages.
- The deratings and short-term deratings decline during the highest load conditions, which is consistent with expectations for a competitive market.

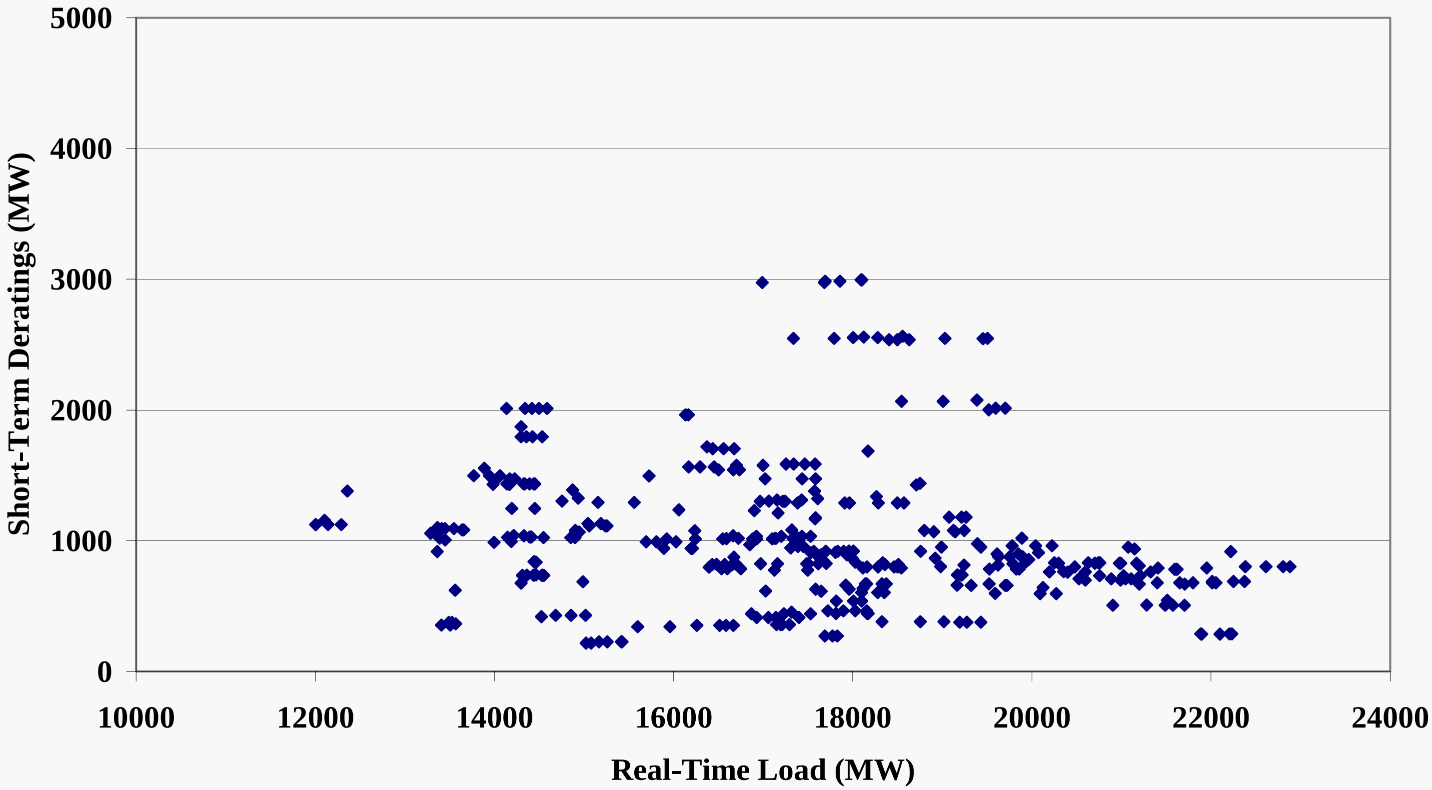
Derating versus Actual Load in Eastern New York

Day-Ahead Market, Peak Hours*, Summer 2007



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

Short-Term Deratings versus Actual Load in Eastern NY
Day-Ahead Market, Peak Hours*, Summer 2007



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

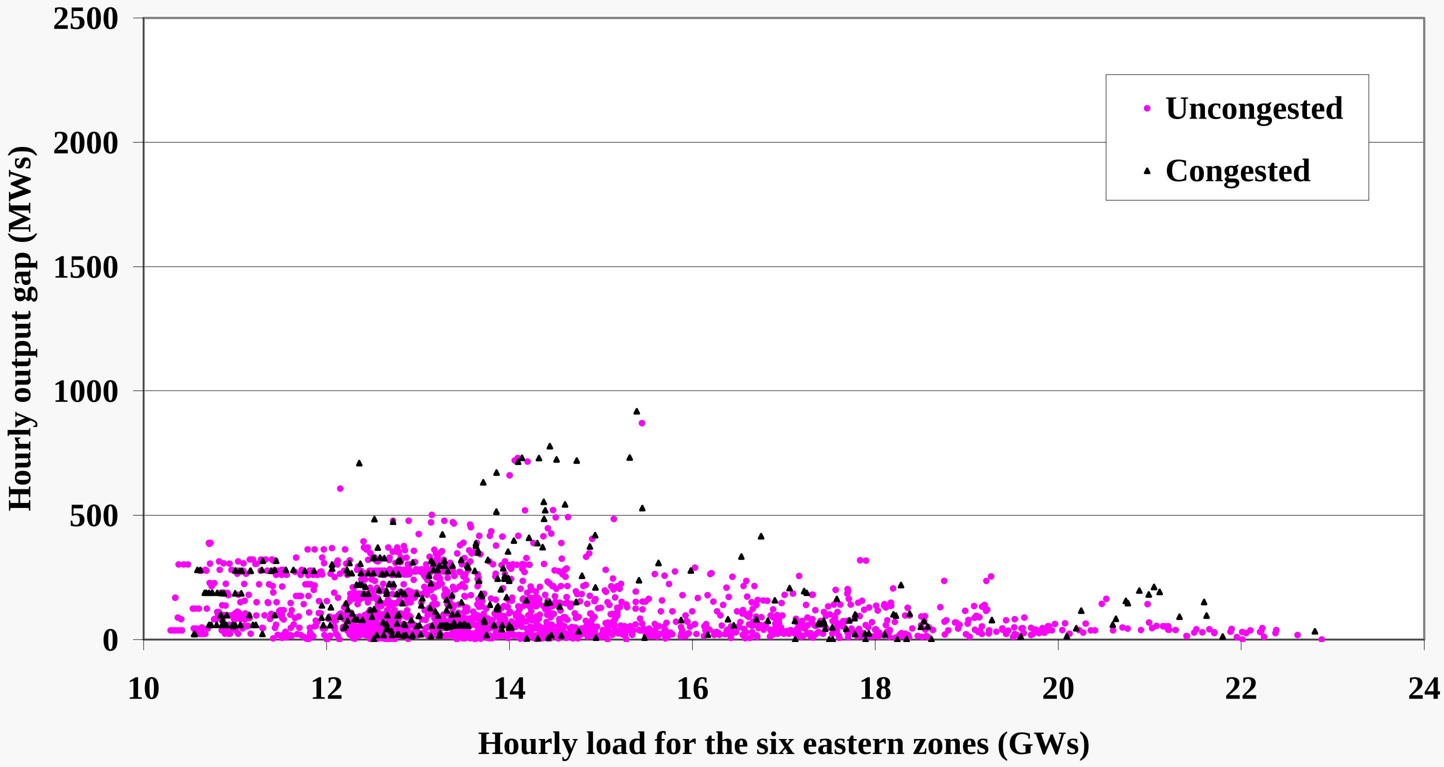
Analysis of Offer Patterns – Output Gap

- The second analysis examines 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.
  - ✓ Excludes capacity that is more economic to provide ancillary services.
- Like the prior analysis of deratings, output gap that tends to rise with load indicates potential competitive problems, while output gap that declines with load indicates competitive outcomes.

Analysis of Offer Patterns – Output Gap

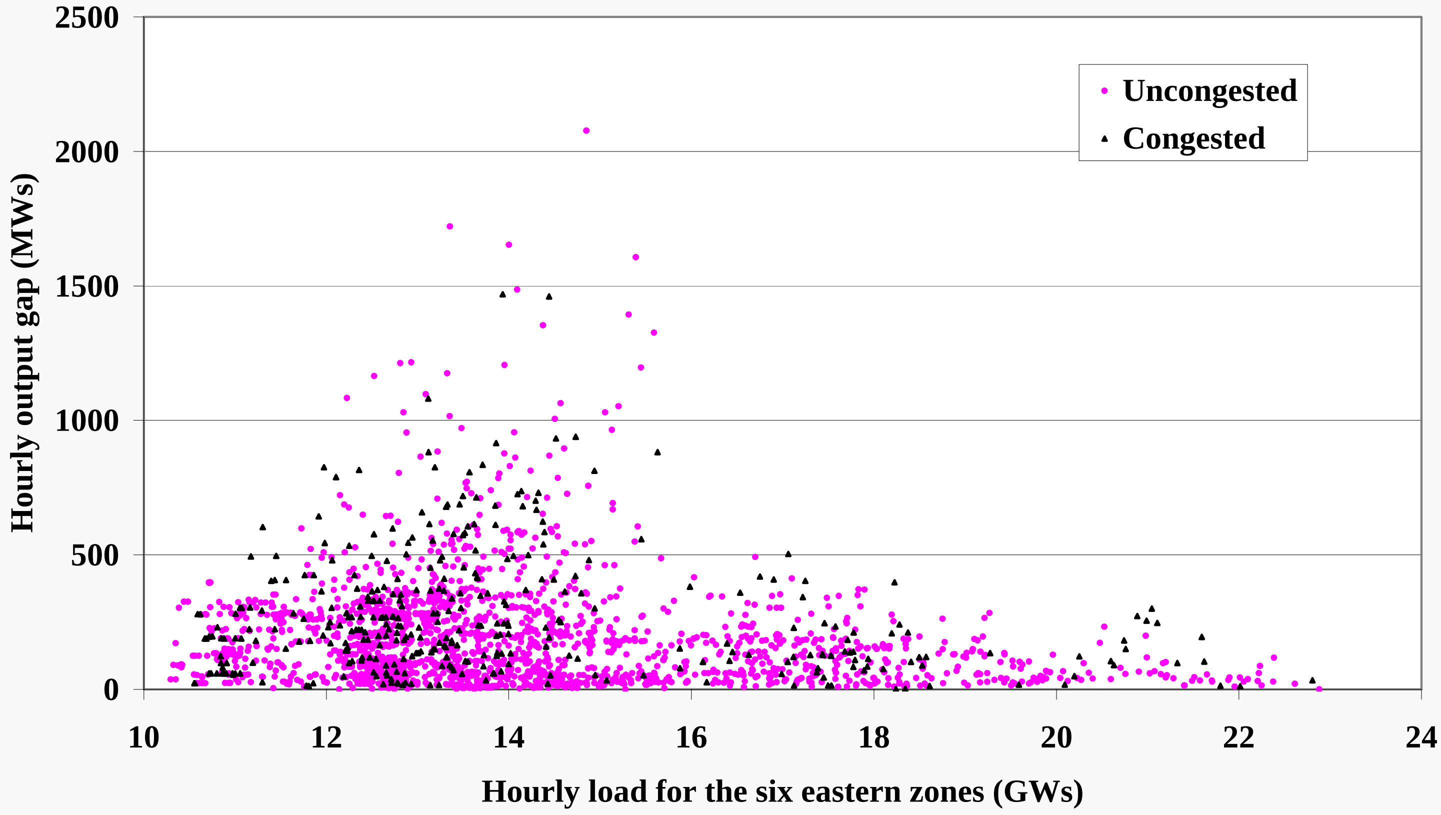
- The following two figures show the real-time output gap in eastern New York during peak hours:
  - ✓ The first chart uses the standard conduct threshold used for mitigation outside New York City, which is the lower of $100/MWh or 300 percent.
  - ✓ The second chart uses a lower conduct threshold of $50/MWh or 100 percent (whichever is lower).
- Congested hours and non-congested hours are indicated separately to show whether the output gap increases during periods of congestion.
- These figures indicate that the output gap decreases under the highest load conditions.
  - ✓ This is an important result because prices are most vulnerable to market power under peak load conditions.
  - ✓ These results are consistent with the expectations for a competitive market.
  - ✓ These results are particularly notable for the lower threshold because this conduct is not subject to mitigation.

Output Gap at Mitigation Threshold vs. Actual Load in East NY Real-Time Market, Peak Hours*, 2007



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

Output Gap at Lower Threshold vs. Actual Load in East NY Real-Time Market, Peak Hours*, 2007



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

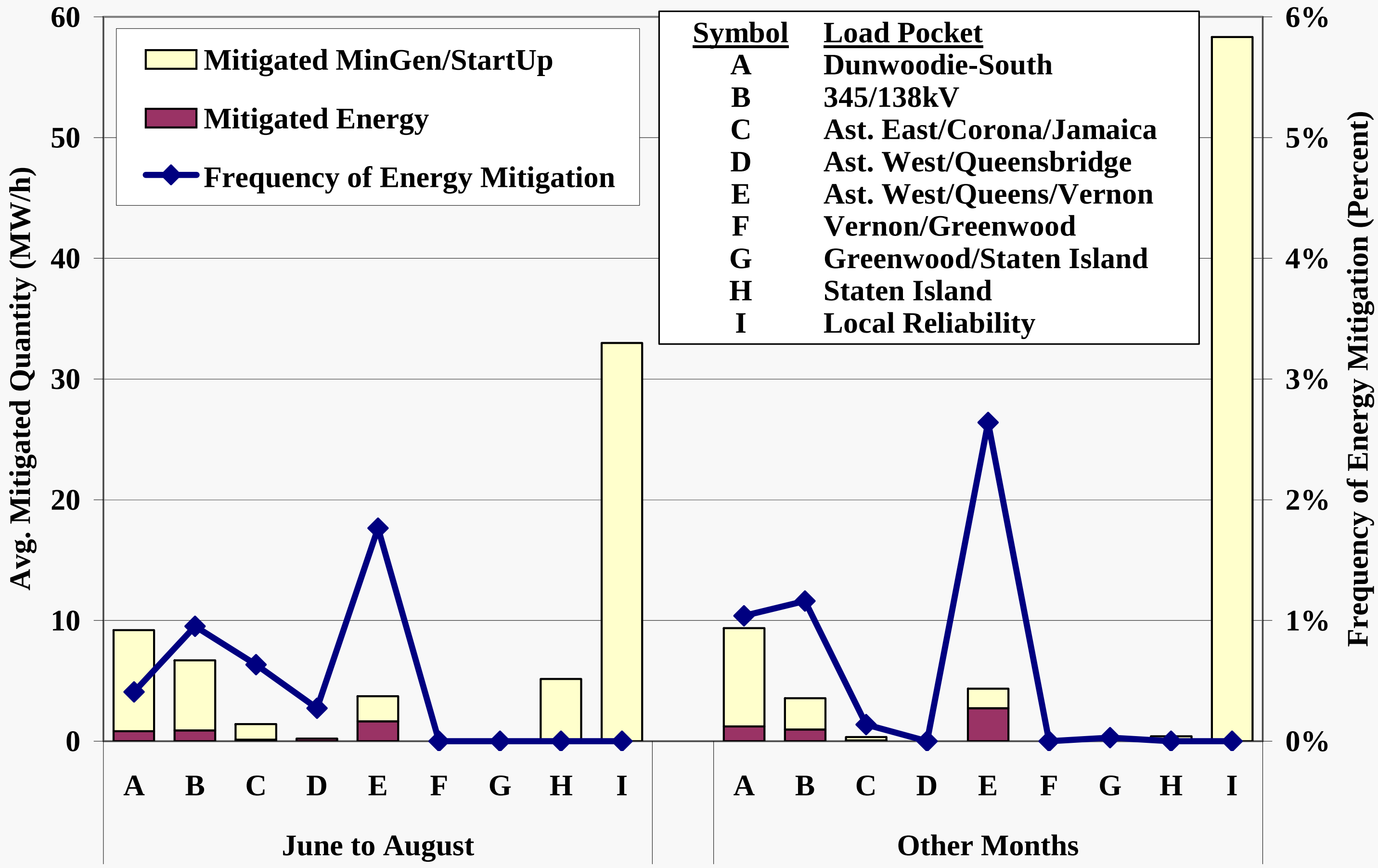
Summary of Day-Ahead Mitigation

- The market power mitigation measures are based on the conduct and impact framework, which is triggered when constraints bind into NYC load pockets.
  - ✓ This Framework prevents mitigation when it is not necessary to address market power and allows high prices during legitimate periods of shortage.
- The following two figures summarize the amount of mitigation that occurs in NYC in the DA market and in the RT market.
  - ✓ 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).
  - ✓ The bars show the average amount of capacity mitigated in hours when mitigation was imposed.
  - ✓ The lines show the percent of hours when energy offer mitigation was imposed on one or more units in each category. Start-Up and Mingen offer mitigation is more frequent.
  - ✓ Mitigation of GT capacity is shown in: (i) the Energy category when the energy offer is mitigated and (ii) the Mingen/Start-Up category when only the start-up offer is mitigated.

Summary of Real-Time Mitigation

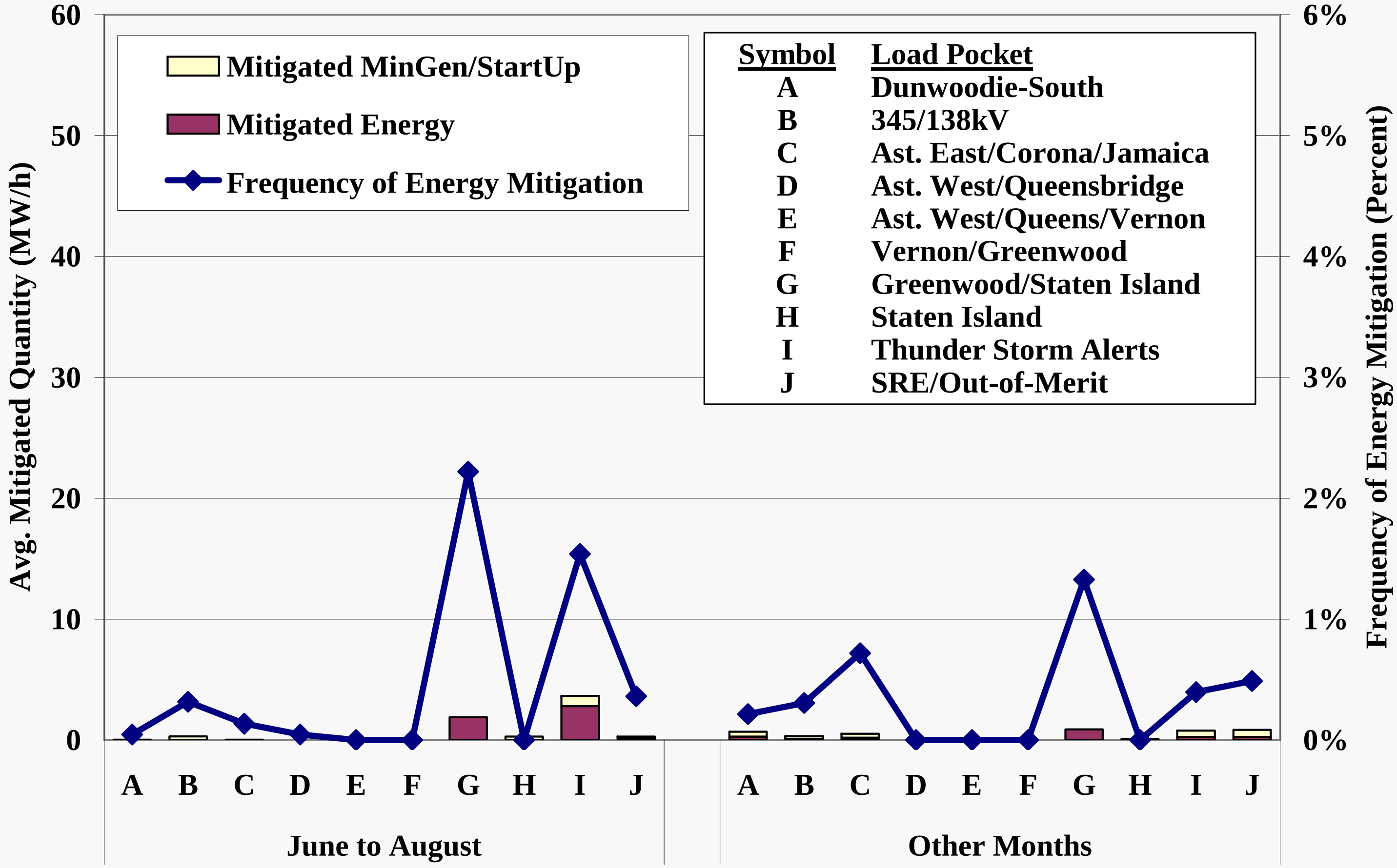
- In the DA market, the majority of mitigated capacity is on generators committed to satisfy Local Reliability Requirements (“LRR”).
  - ✓ The Start-Up and Mingen offers of LRR units are mitigated whenever they exceed the reference level.
- In the RT market, the majority of mitigation occurs when constraints bind into the Greenwood/Staten Island load pocket, which is located in the 138 kV system.
  - ✓ The RT market experienced more congestion into the Greenwood/Staten Island load pocket than the DA market.
  - ✓ Higher levels of congestion give rise to more frequent conditions when mitigation is warranted.
- Despite relatively frequent congestion and high levels of market concentration in the load pockets, mitigation did not occur often.

Summary of Day-Ahead Mitigation
New York City -- 2007



Symbol	Load Pocket
A	Dunwoodie-South
B	345/138kV
C	Ast. East/Corona/Jamaica
D	Ast. West/Queensbridge
E	Ast. West/Queens/Vernon
F	Vernon/Greenwood
G	Greenwood/Staten Island
H	Staten Island
I	Local Reliability

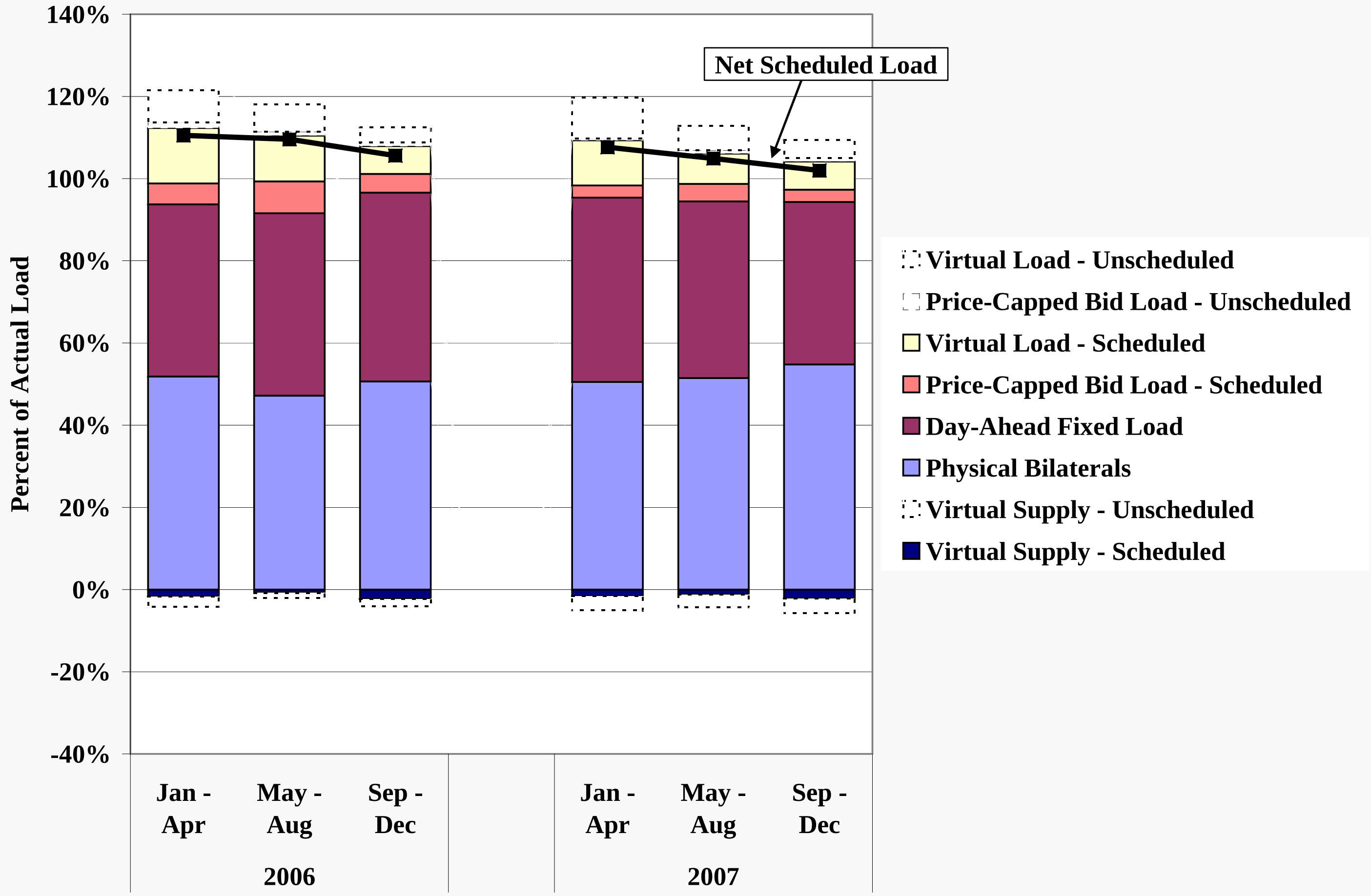
Summary of Real-Time Mitigation
New York City -- 2007



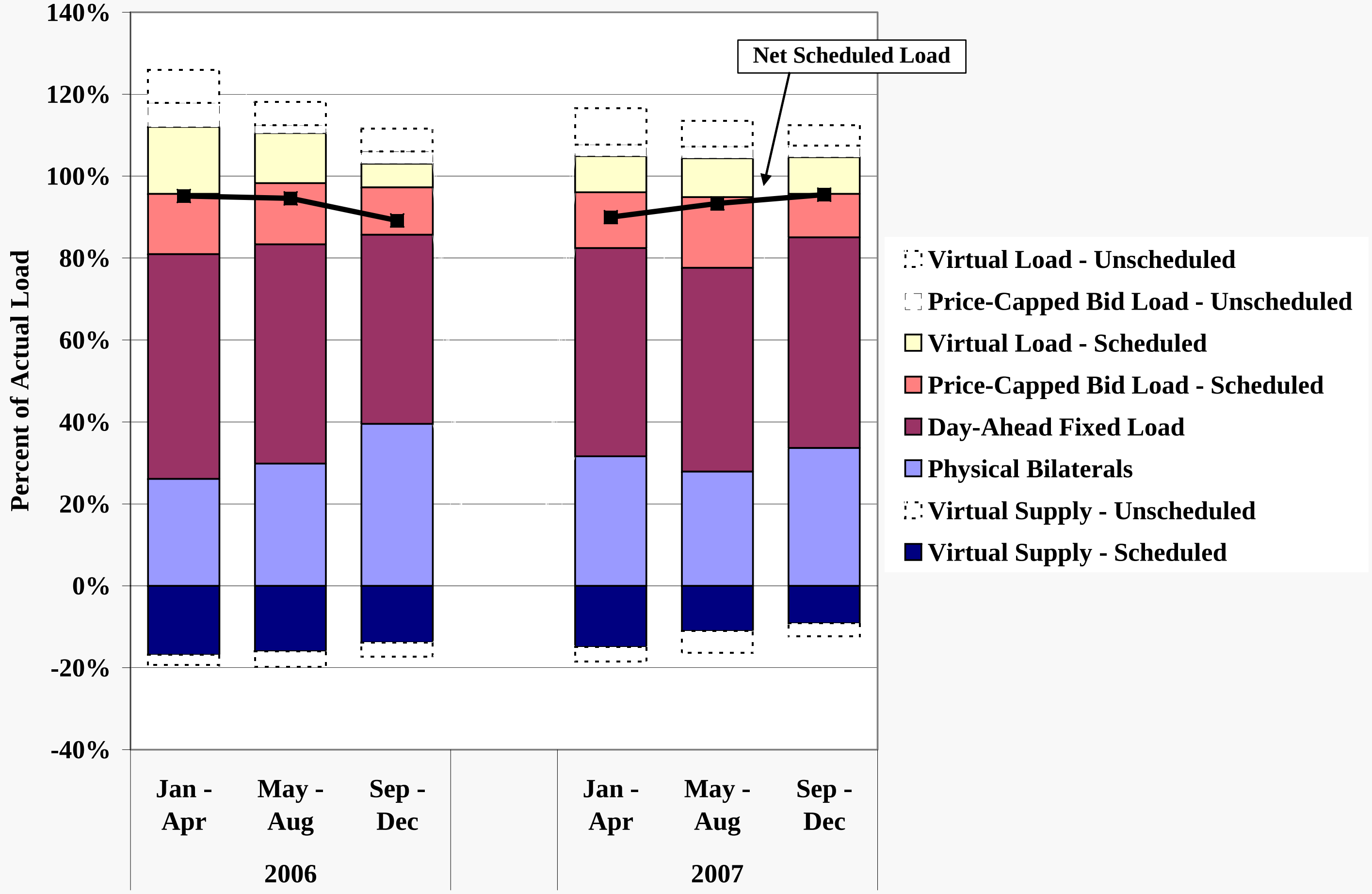
Load Bidding Patterns in the Day-Ahead Market

- The following three figures summarize the quantity of DA load scheduled as a percent of RT load in 2006 and 2007 in three regions of NY state.
  - ✓ Virtual supply nets out an equivalent amount of scheduled load, so it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- On a state-wide basis, the average amount of load scheduled in the DA market is consistent with the average amount of RT load.
  - ✓ Consistency between the DA scheduled load and RT load is a positive sign for market efficiency.
- For years, load has generally been over-scheduled in NYC and Long Island and under-scheduled in up-state NY.
  - ✓ This implies that, on average, the DA market schedules more imports into NYC and Long Island than the RT market.
  - ✓ The NYISO has increasingly used the same detailed model of the NYC transmission system in RT operations as in the DA market, and this has helped reduce such regional inconsistencies.

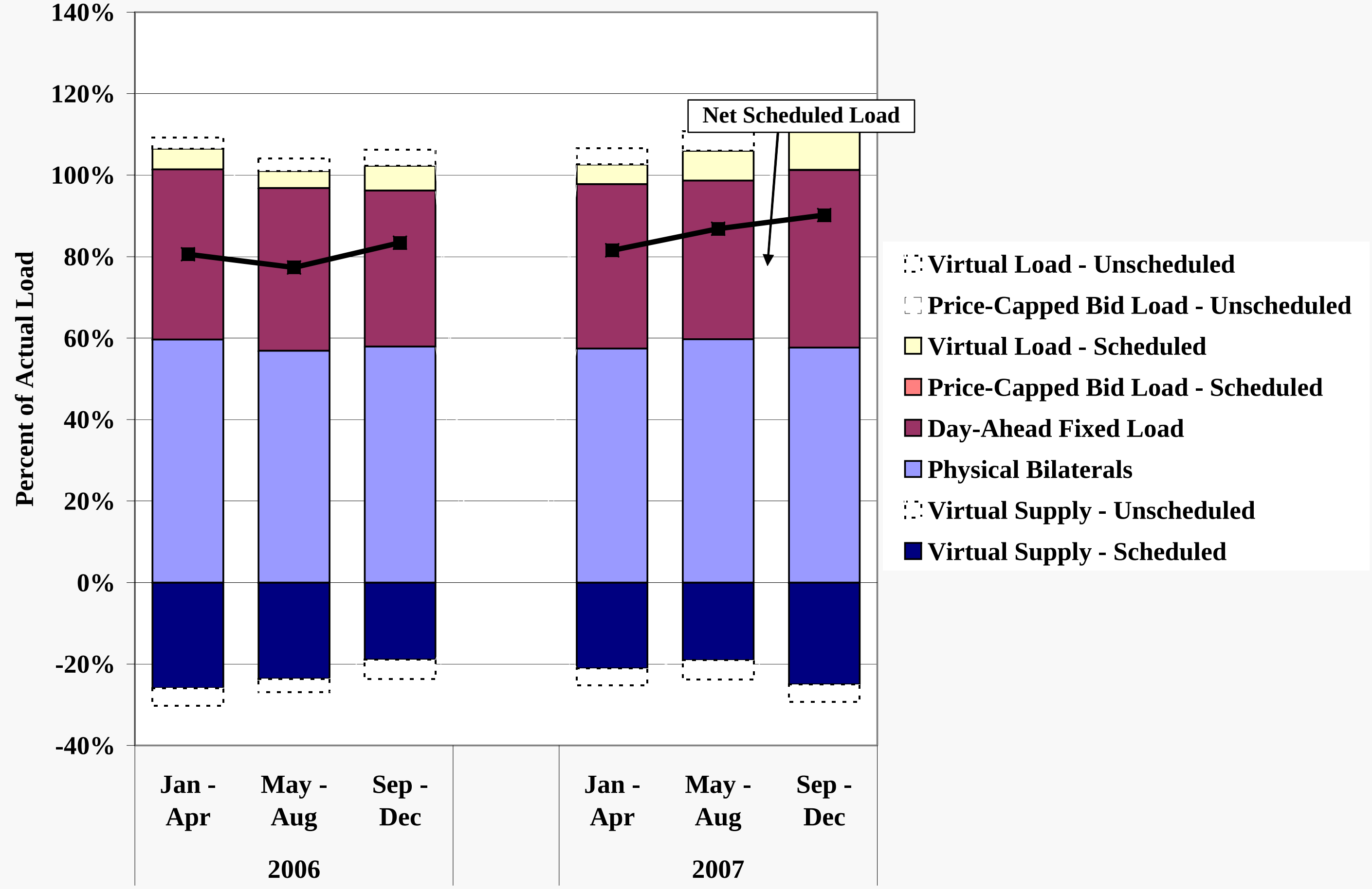
Composition of Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2006 - 2007



Composition of Day-Ahead Load Schedules versus Actual Load East Up-State New York, 2006 - 2007



Composition of Day Ahead Load Schedules versus Actual Load West Up-State New York, 2006 - 2007

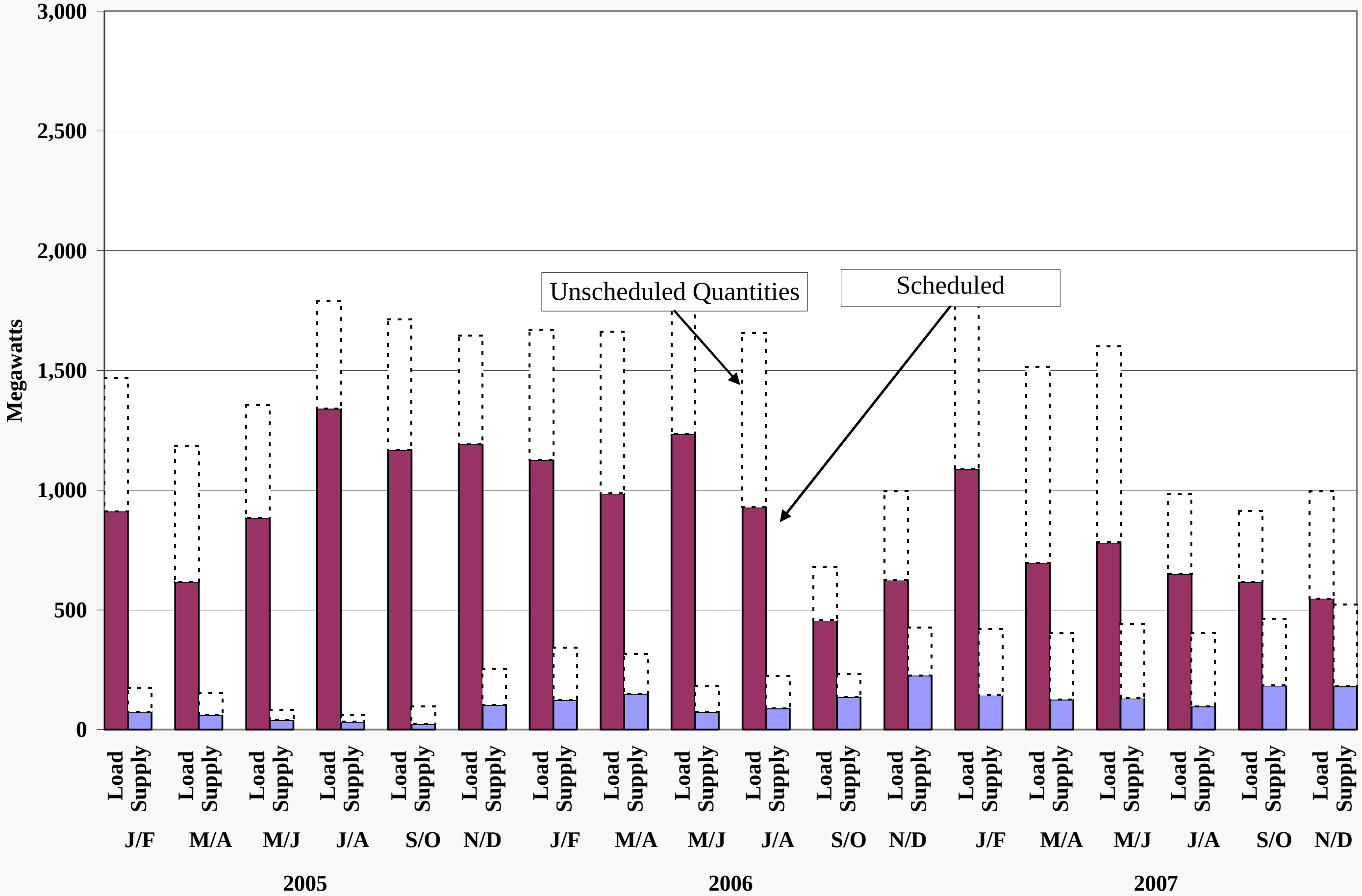


Virtual Trading Patterns

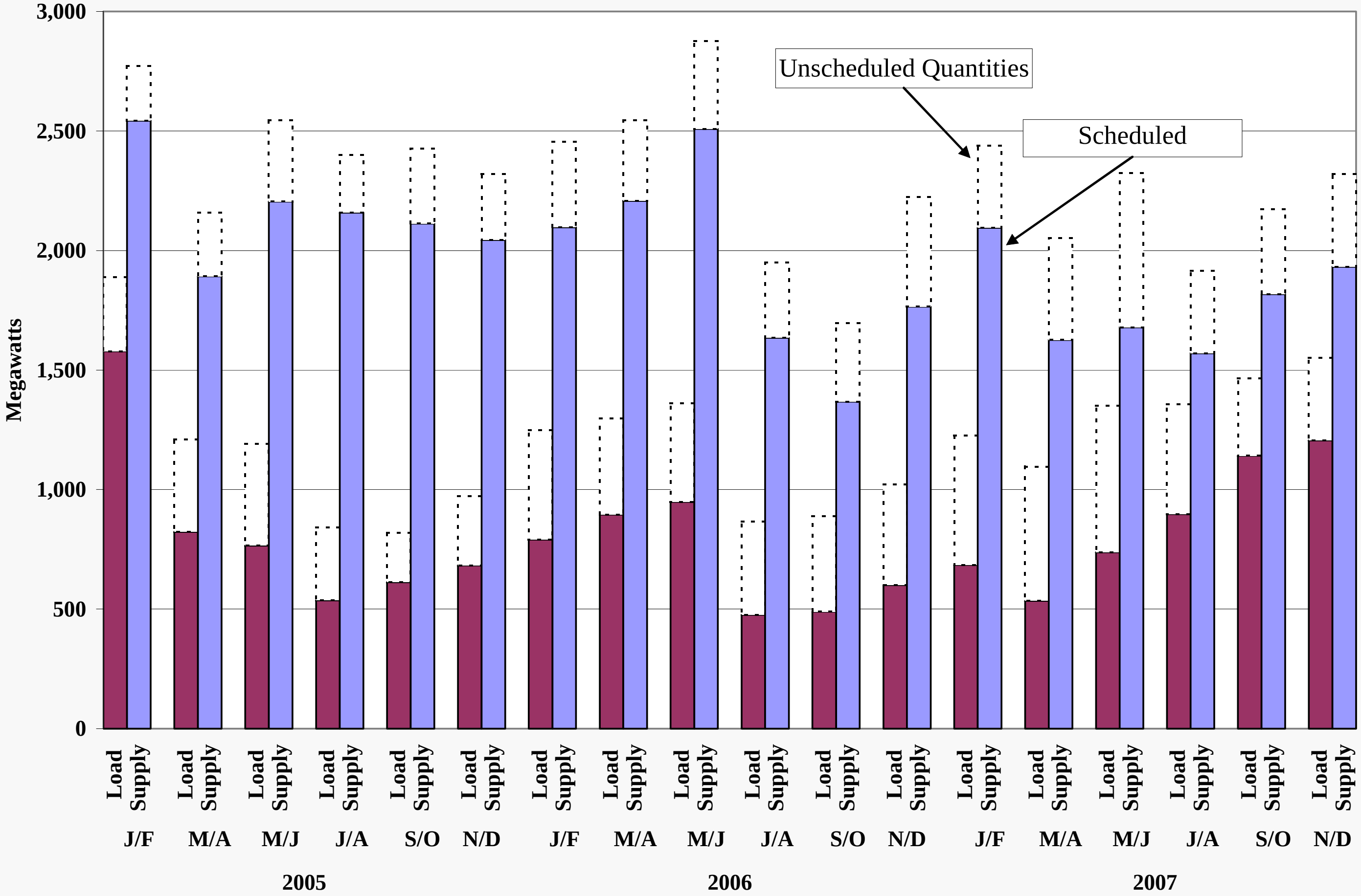
- Virtual trading allows participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the virtual bids and offers that have been offered and scheduled on a bi-monthly basis in upstate and downstate areas from 2005 to 2007.
- There have been substantial net virtual sales upstate and virtual purchases downstate during the past three years.
  - ✓ This is consistent with the pattern of imports into downstate areas being higher in the DA market than in the RT market.
  - ✓ The average net sales upstate and average net purchases downstate have diminished over the past three years.
    - – The average net virtual sale upstate declined from 1320 MW in 2005 to 920 MW in 2007.
    - – The average net virtual purchase downstate declined from 960 MW in 2005 to 580 MW in 2007.
    - – This trend is partly due to improved constraint modeling in NYC.

Hourly Virtual Bidding of Load and Supply

New York City and Long Island, 2005-2007



Hourly Virtual Bidding of Load and Supply
Outside New York City and Long Island, 2005-2007



Transmission Congestion

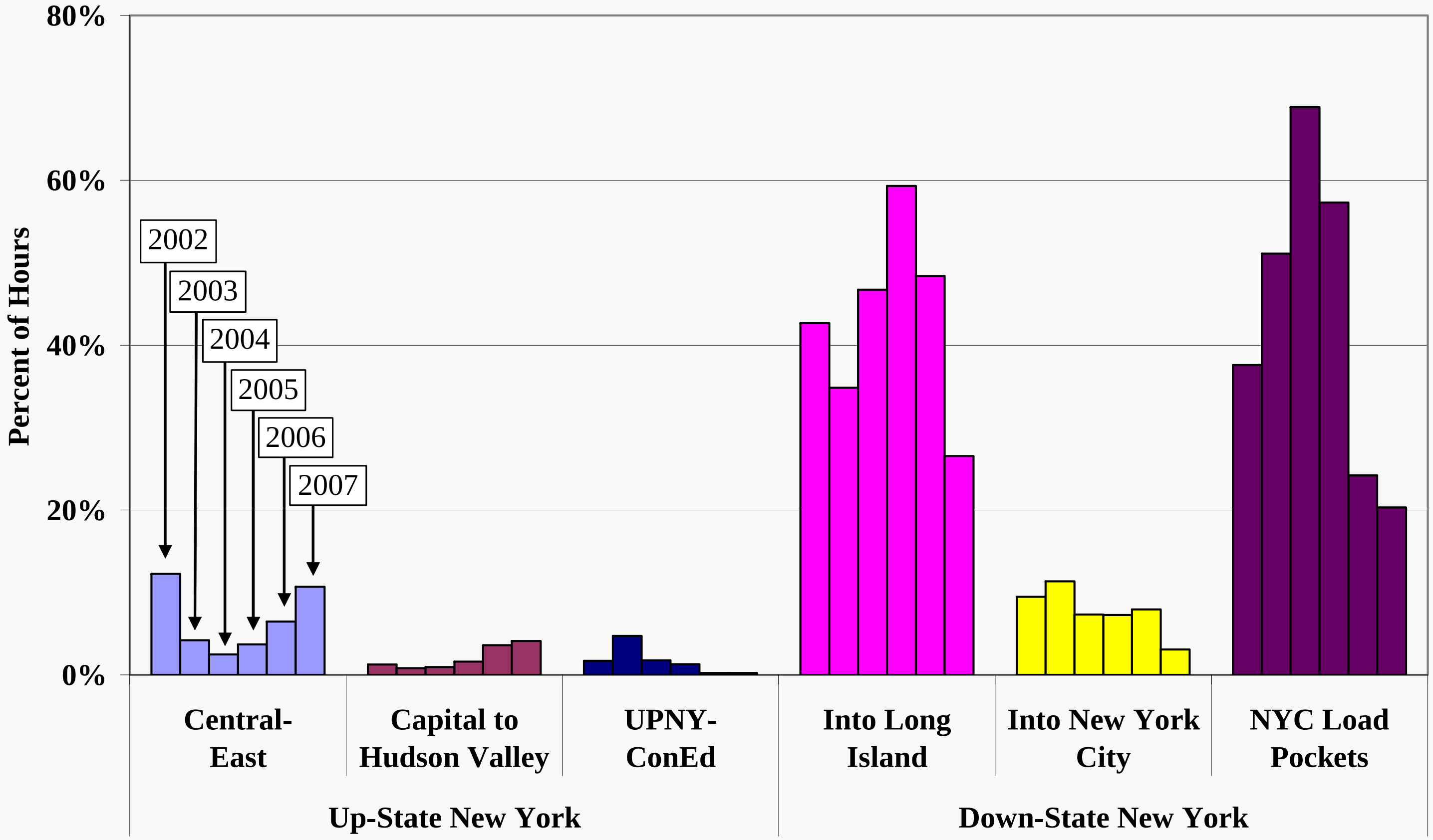
Real-Time Congestion on Major Interfaces

- The following figures summarize the extent of transmission congestion on select interfaces in up-state and down-state NY.
  - ✓ The first figure shows the frequency of congestion.
  - ✓ The second figure summarizes the value of transfers across congested interfaces, which is based on the volume of flows across the interface and the RT price differences between regions.
- These figures show that congestion into downstate areas decreased significantly in 2007 due to the following factors:
  - ✓ The Neptune Cable, which began operation in July 2007, dramatically reduced congestion into Long Island and, to a lesser extent, within NYC.
  - ✓ The value of congestion within NYC load pockets increased due to more frequent congestion into the Greenwood area.
  - ✓ Increasing use of the a detailed network model for RT dispatch in NYC since May 2006 has led to more effective use of the transmission system.

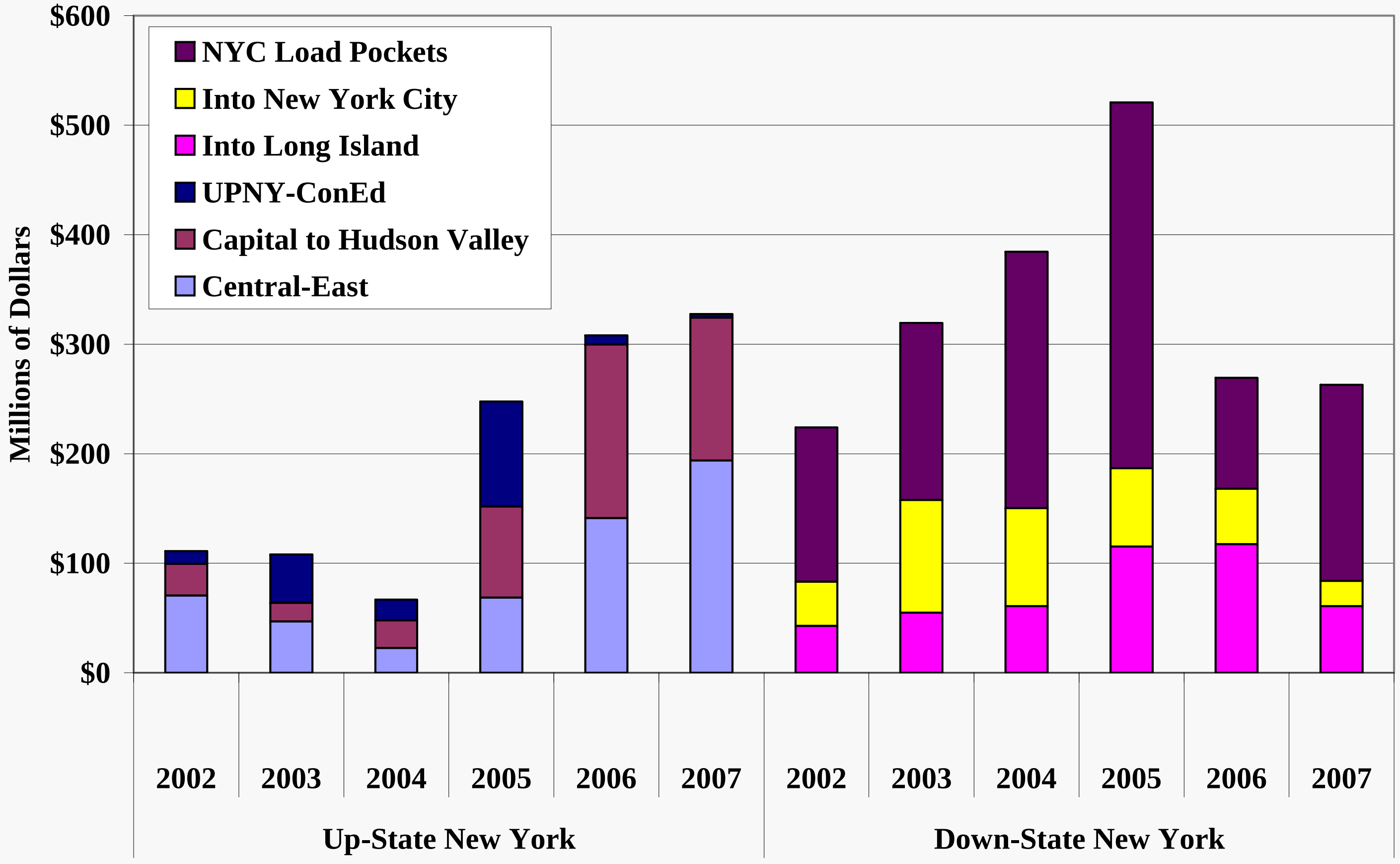
Real-Time Congestion on Major Interfaces

- Factors that reduced congestion in 2007 were offset by rising fuel costs. Fuel price fluctuations generally lead to proportional changes in the value of flows across constrained interfaces.
- The Central-East Interface exhibited more frequent constraints from voltage limitations in 2007.
  - ✓ Higher net imports to Western NY from HQ, Ontario, and PJM have contributed to increased congestion.
- TSAs and eastern 10-minute reserve shortages are infrequent, but they have a significant impact on the value of constrained interfaces.
  - ✓ Intervals with TSAs accounted for $60 million of the value of up-state congestion in 2005, $80 million in 2006, and $65 million in 2007.
  - ✓ Shortage intervals (without TSAs) accounted for an additional $12 million in 2005, $40 million in 2006, and $18 million in 2007.
  - ✓ These events primarily affected the congestion costs on lines from the Capital area through Hudson Valley.

Frequency of Real-Time Congestion on Major Interfaces 2002 – 2007



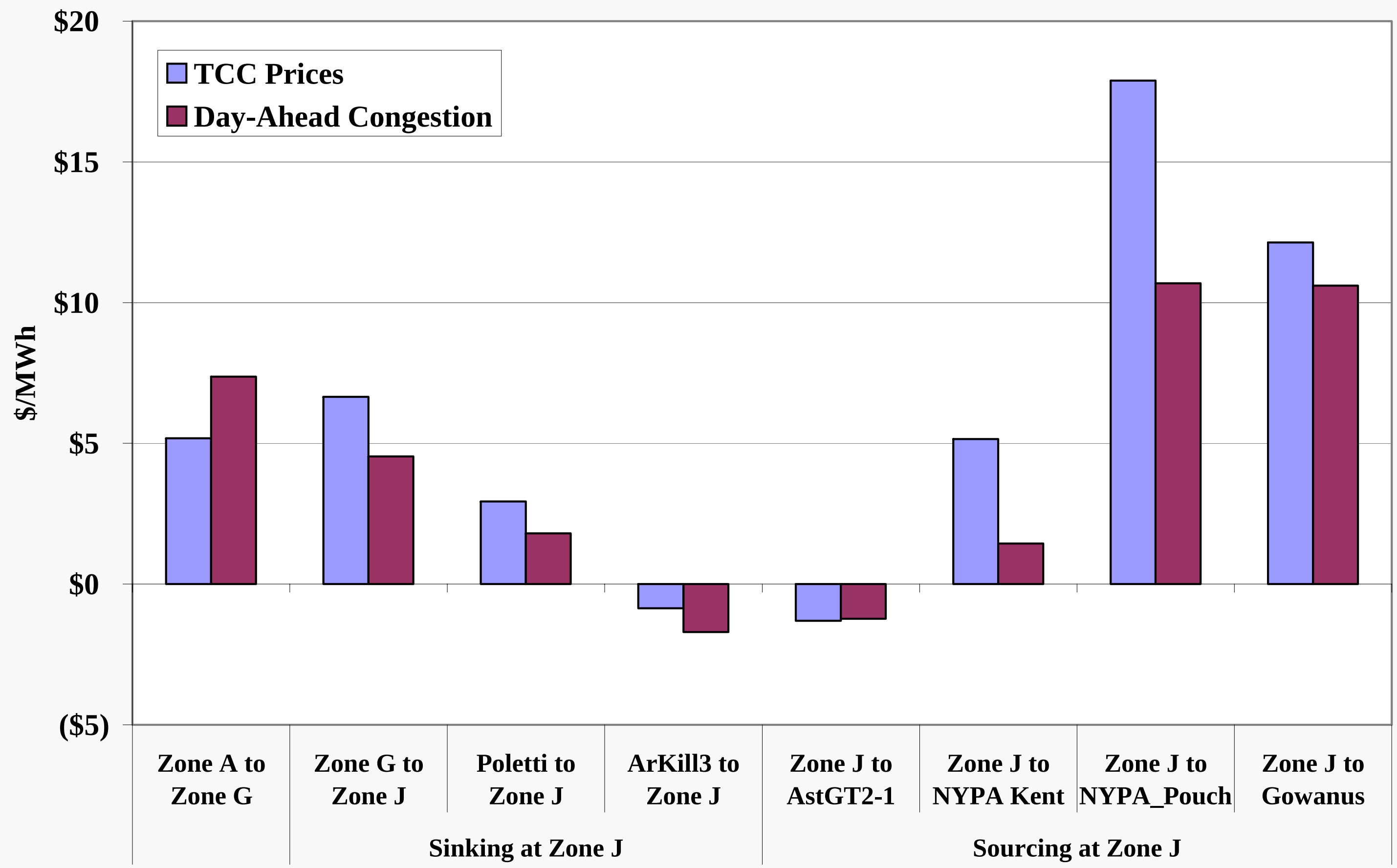
Value of Real-Time Congestion on Major Interfaces
2002 – 2007



TCC Prices and Day-Ahead Congestion

- The next two analyses evaluate the TCC markets. A TCC entitles the holder to the DA congestion price difference between two points.
  - ✓ Hence, TCC prices reflect expectations of DA market congestion.
- The next figure compares TCC auction prices for the 2007 Summer Capability Period to DA congestion during the period. A comparison of prices is shown:
  - ✓ Between three locations commonly used for bilateral trading: Zone A (West Zone), Zone G (Hudson Valley), and Zone J (NYC).
  - ✓ To Zone J, from points on the 345kV system in Zone J.
  - ✓ From Zone J, to points in load pockets on the 138kV system in Zone J.
- The TCC auctions under-valued west to east congestion (i.e. Zone A to Zone G) and over-valued Hudson Valley to NYC congestion (i.e. Zone G to Zone J).
  - ✓ This reflects a shift in congestion from the Hudson Valley corridor to the Central-East interface relative to expectations in the TCC auctions.
- The TCC auctions over-valued congestion from Zone J into Vernon/Greenwood and Greenwood/Staten Island (i.e. NYPA Pouch, NYPA Kent, and Gowanus).

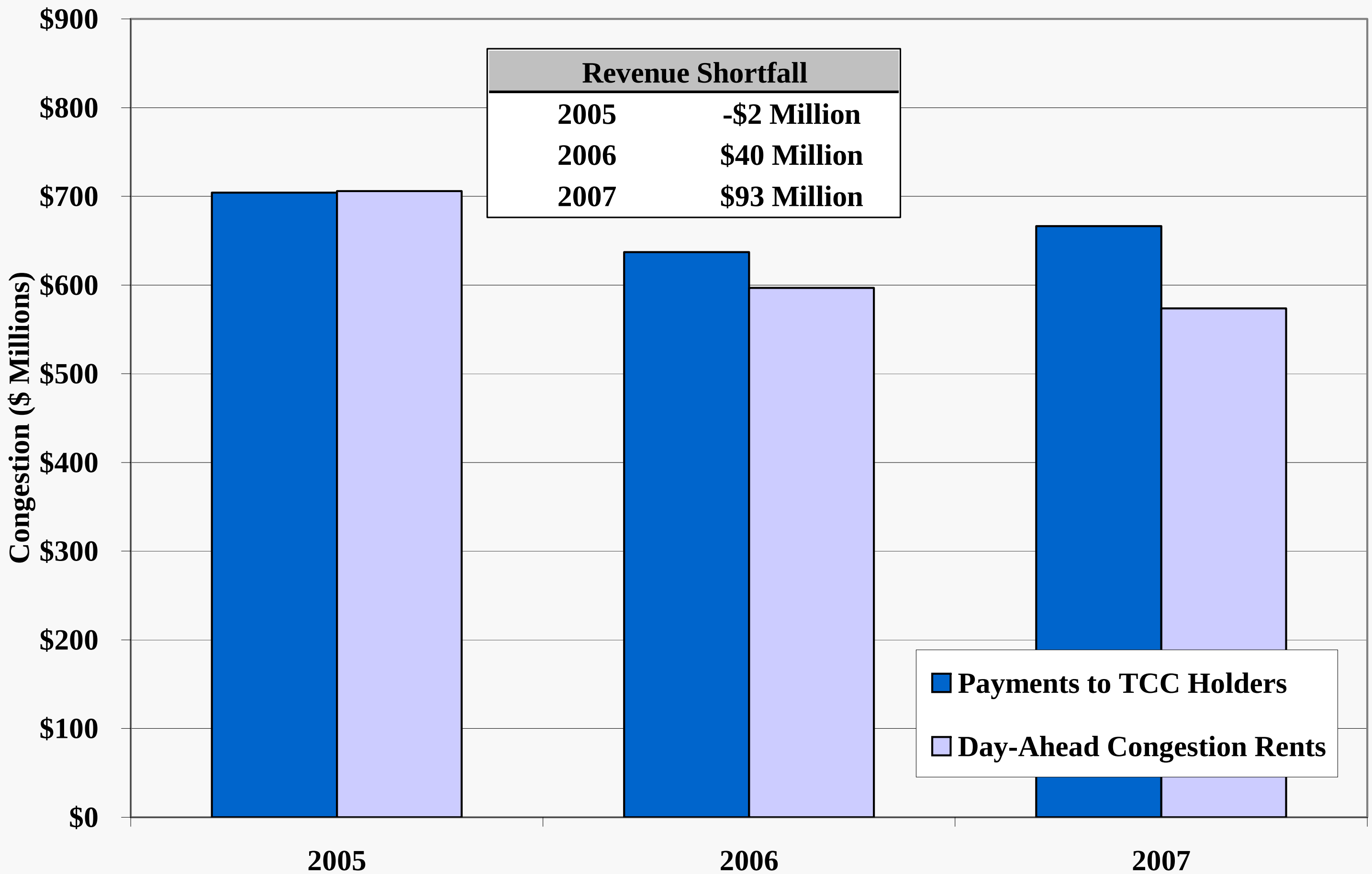
TCC Prices and Day-Ahead Congestion
May to October 2007



Day-Ahead Congestion Revenue and TCC Payments

- The next figure shows the DA congestion rents and payments to TCC holders.
  - ✓ DA congestion rents are collected by the NYISO when power is scheduled across constrained interfaces in the DA. The amount collected is based on the quantity scheduled across the interface and the DA prices between regions.
  - ✓ The holders of TCCs are paid by the NYISO based on the contract-quantities and the DA prices between regions.
  - ✓ Shortfalls arise when DA congestion rents do not fully fund TCC payments. This occurs when contract-quantities are higher than DA scheduled quantities.
- DA congestion rents have fallen since 2005.
  - ✓ Congestion has been reduced by declining summer load conditions, new units in New York City, and new transmission capacity from New Jersey to Long Island.
  - ✓ Fuel price fluctuations resulted in lower congestion in 2006 and higher congestion in 2007.
- Shortfalls in day-ahead congestion revenue rose to $93 million in 2007.
  - ✓ A contributing factor is that some TOs did not schedule transmission outages in the TCC auction. Resulting shortfalls are assigned to the TO.

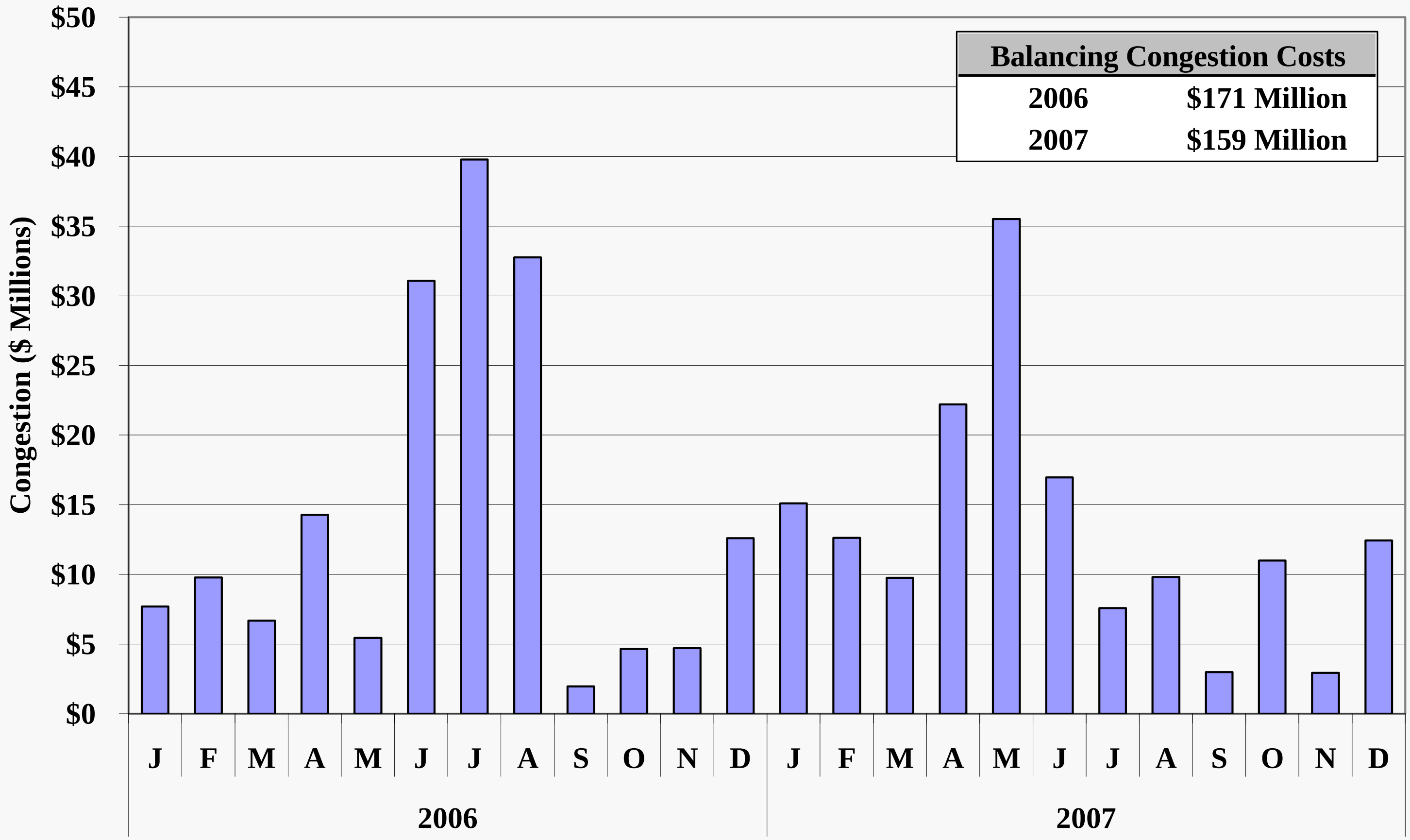
Day-Ahead Congestion Revenue and TCC Payments 2005 - 2007



Balancing Congestion Shortfall

- The following figure shows the congestion revenue shortfalls that were incurred in the balancing market.
- Balancing congestion shortfalls arise primarily from reductions between the DA and RT markets in the transfer capability of the transmission system.
  - ✓ When DA scheduled flows exceed RT transmission capability, the NYISO must buy back the excess in real-time.
  - ✓ Reductions in RT transmission capability from TSA operation contribute significantly to balancing congestion shortfalls.
- Balancing congestion costs fell substantially following the spring of 2007 due to several factors:
  - ✓ The increased use of line modeling in NYC load pockets has improved consistency between DA and RT transmission modeling.
  - ✓ Since June 2007, improvements to RT pricing and dispatch during periods of transmission scarcity have reduced revenue shortfalls when they are most costly.
  - ✓ Since July 2007, the introduction of new transmission capability in Long Island has reduced overall congestion.

Balancing Congestion Costs
2006-2007



Market Operations –
Real Time Commitment and Scheduling

Market Operations – Real-Time Commitment

- The Real-Time Commitment model (“RTC”) commits generators with short lead times such as GTs and schedules external transactions.
  - ✓ It re-evaluates just ahead of the RT market every 15 minutes, which is a significant improvement over its predecessor, the BME model.
- Convergence between RTC and actual RT dispatch is important because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, primarily GTs; and
  - ✓ Inefficient scheduling of external transactions.
- When excess resources are committed or scheduled, the results are increased uplift costs and depressed RT 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 RT outcomes.

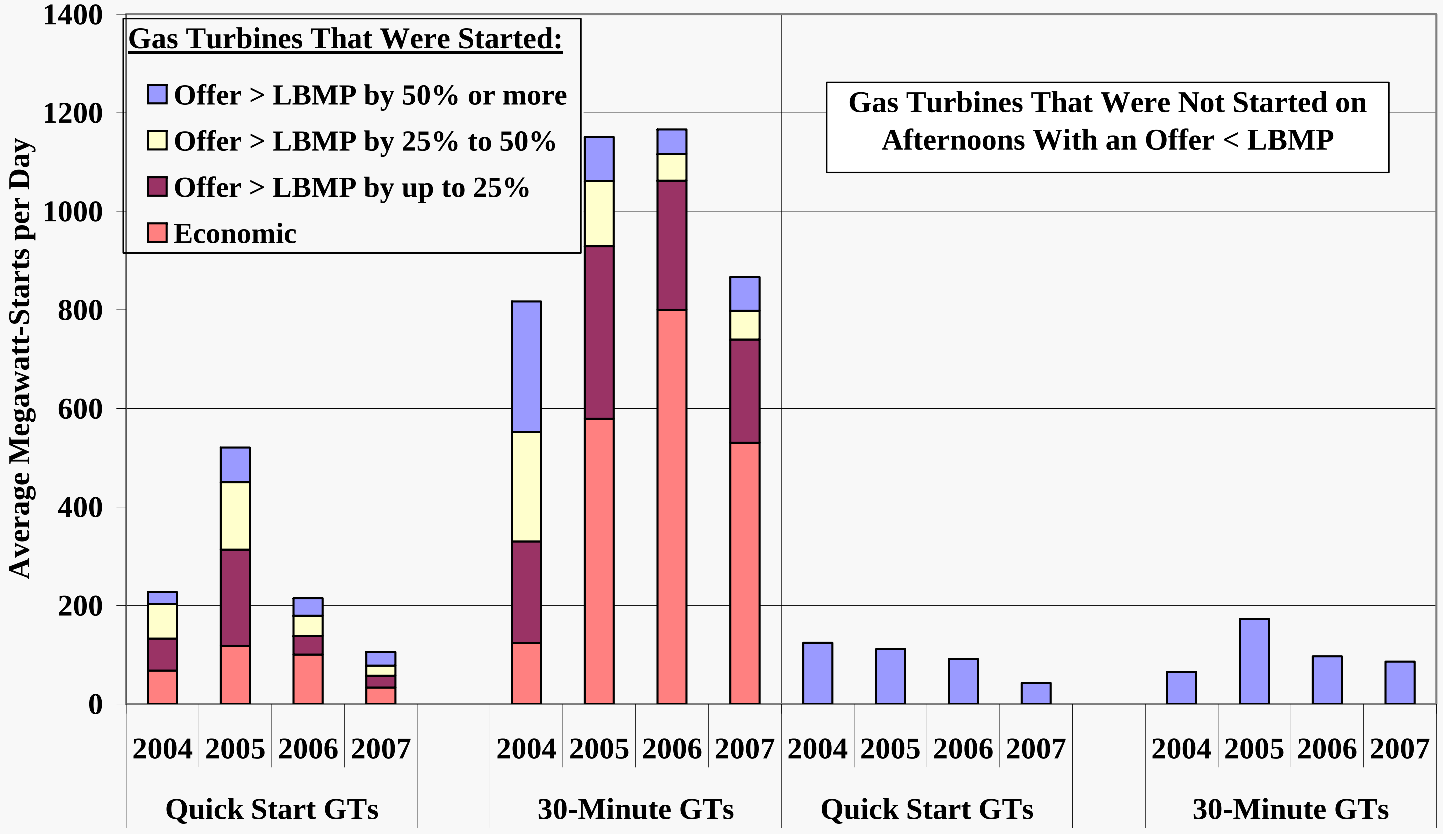
Efficiency of Gas Turbine Commitment

- The next figure measures the efficiency of GT commitment by comparing the offer price (energy plus start-up) to the RT LBMP over the initial commitment period.
  - ✓ The left panel shows the average volume of GTs being started whose energy + start-up costs (amortized over the commitment period) are:
    - (a) < LBMP (clearly economic);
    - (b) > LBMP by up to 25 percent;
    - (c) > LBMP by 25 to 50 percent; or
    - (d) > LBMP by more than 50 percent.
  - ✓ The right panel shows the quantity GTs that were likely economic, but not started (i.e. the LBMP > Energy plus start-up offer).
- Some GTs with offers greater than the LBMP in the left panel are also economic, since GTs that are started efficiently sometimes do not recover their start-up offer.
- This analysis shows that the GT commitment efficiency has improved substantially since 2004.
  - ✓ A larger share of the GT commitments are economic.
  - ✓ To the extent GT commitments are not economic, they are becoming more consistent with LBMPs.
  - ✓ The amount of uncommitted GTs that would have been economic is generally small and has declined relative to the number of starts.

Efficiency of Gas Turbine Commitment

- The implementation of RTC and RTD in 2005 and on-going improvements to the models have led to more efficient commitment of GT resources.
  - ✓ In August 2005, RTD was modified to allow it to start quick start resources.
  - ✓ Since May 2006, RTD and RTC have increasingly relied on a detailed model of transmission capability in NYC instead of simplified interface constraints.
    - – RTD re-dispatches generators more efficiently to manage congestion.
    - – RTC may need to commit generation before constraints actually bind. The detailed modeling better enables RTC to anticipate congestion and leads to better commitment.
- The figure shows the number of starts for GTs has declined, which is due to:
  - ✓ The newly installed combined cycle generation in NYC, which has reduced the need to run GTs in certain NYC load pockets;
  - ✓ The newly installed Neptune cable, which has reduced the need to run GTs in Long Island;
  - ✓ The increasing price spread between of distillate fuel oil and natural gas, which has led some GTs to be economic in fewer hours; and
  - ✓ Milder summer load conditions.

Efficiency of Gas Turbine Commitment
June to December, 2004-2007



Comparison of RTC and RTD Prices

- This section examines the overall consistency of RTC and RTD prices.
  - ✓ 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 analyses compare RTC prices with the RTD prices for the interval that is closest to the time when RTC runs.
- The comparison of RTC and RTD prices provides a general indication of convergence between RTC and RTD. However, there are periods when RTC prices consistently higher or lower than RTD prices.
- Inconsistent RTC and RTD prices are a concern because they can lead to uneconomic commitment of generation and inefficient scheduling of external transactions.
  - ✓ Excess commitment and scheduling results in increased uplift costs and depressed real-time prices;
  - ✓ Failing to commit economic resources leads to unnecessary transient price spikes.

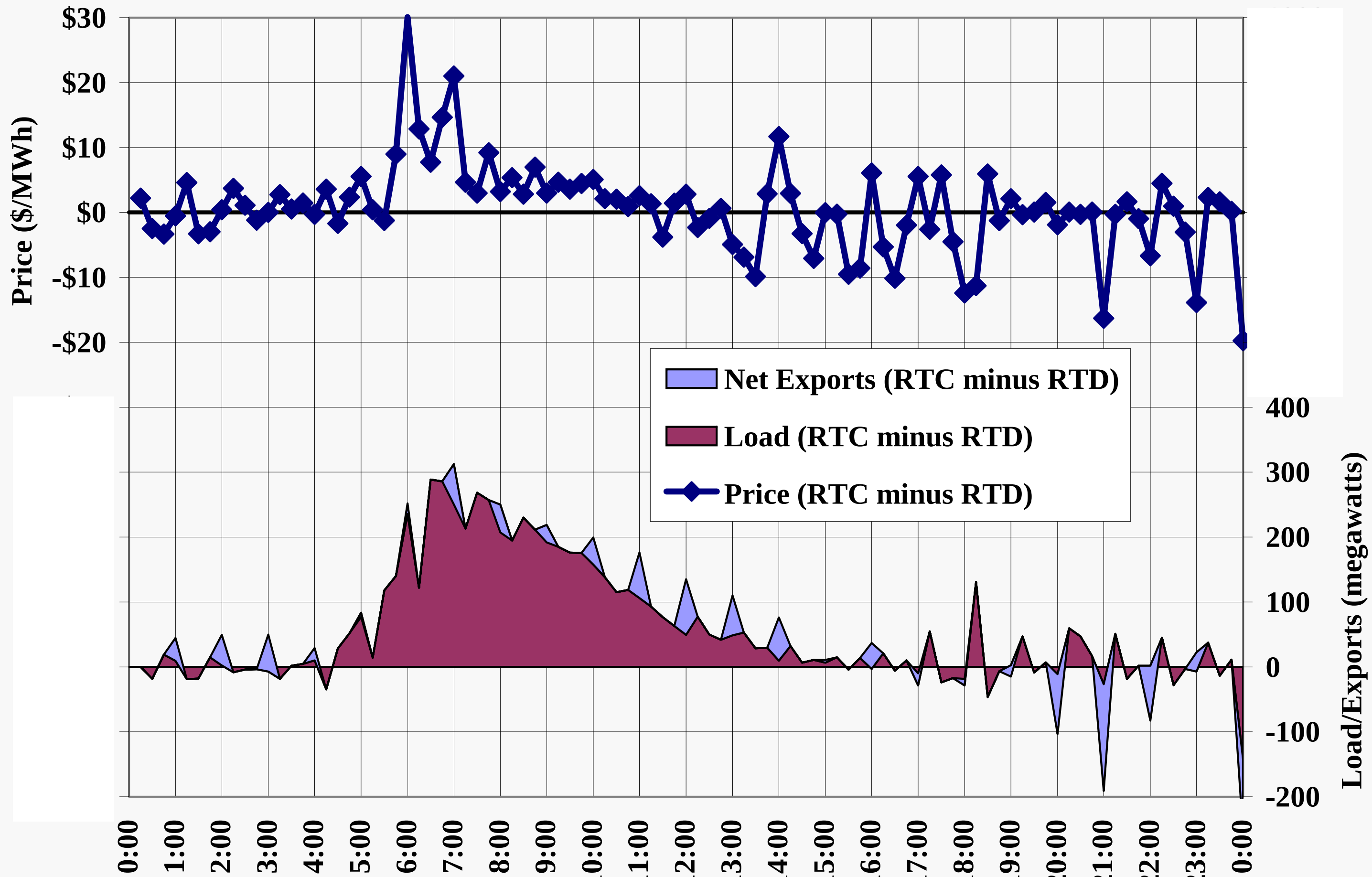
Comparison of RTC and RTD Inputs

- The first figure shows the differences between RTC and RTD in loads, net exports, and prices at 15-minute intervals during the day in the Summer.
- Loads and net exports are inputs that jointly determine the quantity of internal resources that must be scheduled by RTC and RTD.
  - ✓ Increasing load and net exports requires additional internal generation, which leads to higher prices.
  - ✓ Net exports and loads are stacked in the figure to show their cumulative effect.
- RTC load is consistently higher than RTD load during the morning ramp period, which leads to correspondingly higher RTC prices.
  - ✓ RTC schedules resources at time *t* using the highest of the load forecasts of time *t*, *t+5 minutes*, and *t+10 minutes*.
  - ✓ As a result, RTC load is approximately ten minutes ahead of the load forecast during the morning ramp period.

Comparison of RTC and RTD Inputs

- Systematic differences between RTC and RTD prices tend to be larger at the top of the hour (i.e. at :00) than in the middle of the hour (i.e. at :15, :30, or :45).
- These brief systematic differences between RTC and RTD prices are partly driven by different assumptions that RTC and RTD use about net exports.
  - ✓ RTD assumes each interface “ramps” at a constant rate from five minutes before the top of the hour to five minutes after (i.e. from :55 to :05)
  - ✓ RTC assumes each interface meets the next hour schedule at the top of the hour (i.e., at :00).
  - ✓ This leads to larger differences at the top of the hour.
- The analysis suggests that differences between RTC and RTD values of load and net exports play a significant role during ramping hours.
  - ✓ Such differences can lead to either uneconomic commitments or unnecessary transient price spikes.

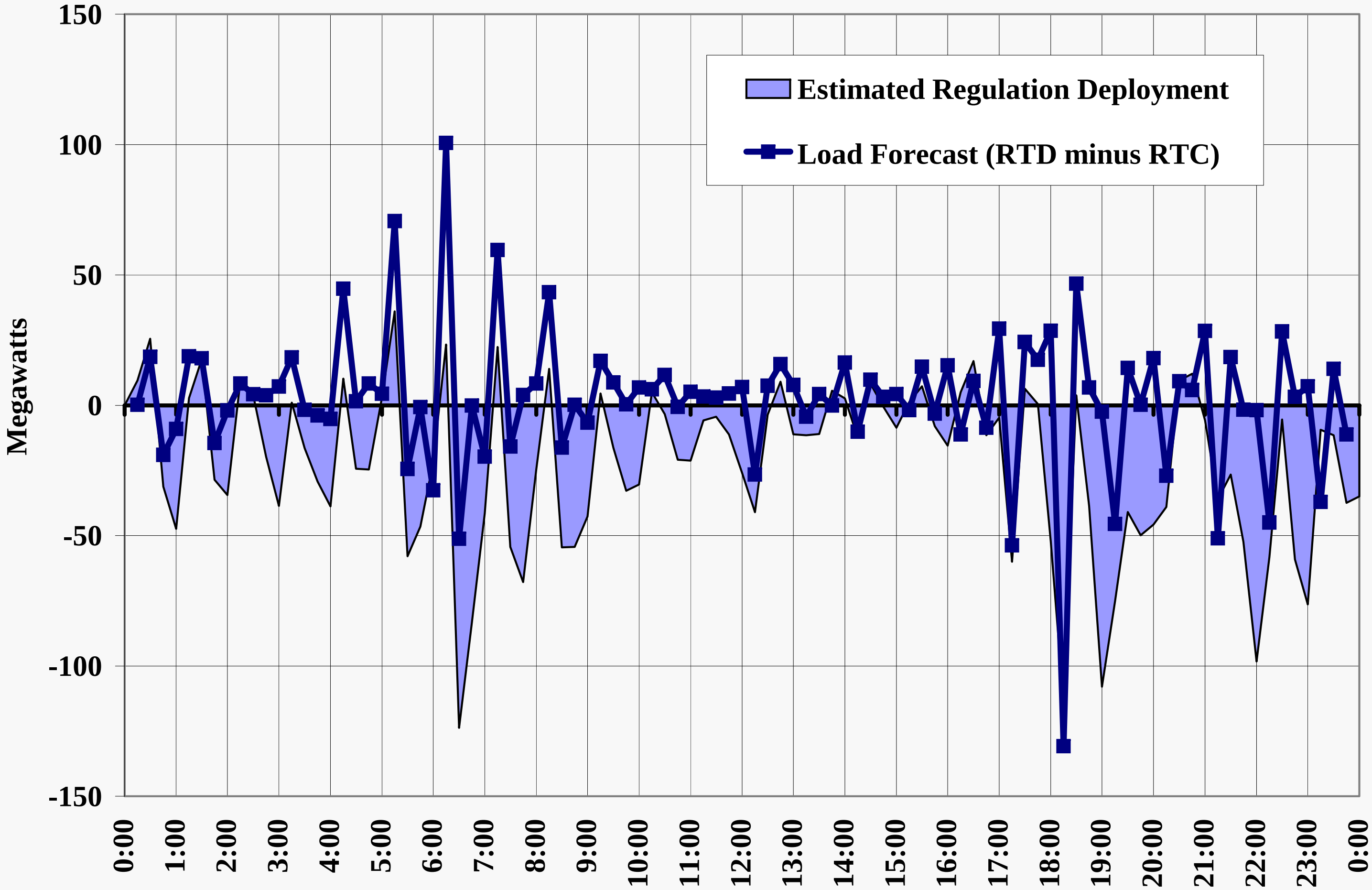
Consistency of Prices, Load, and Net Exports in RTC and RTD by Time of Day, Summer 2007



Comparison of RTC and RTD Inputs

- The following analysis compares differences between the load forecasts used by RTC and RTD and the net estimated regulation deployment by time of day.
- This figure shows a correlation between variations in regulation deployment and the difference between the load forecasts used by RTD and RTC.
- For example, at 5:15:
  - ✓ Regulating units are usually being instructed to increase output relative to 5:00.
  - ✓ The difference between the RTD load forecast and the RTC load forecast shifts in the positive direction.
  - ✓ The additional load scheduled by RTD reduces the amount of regulation that must ultimately be deployed.
- To minimize regulation deployment, the operators make incremental adjustments to the load forecast, which reduces the need for regulation.
  - ✓ Lower regulation requirements lead to lower regulation procurement costs.
  - ✓ Reduced deployment of regulation results in less out-of-merit generation.
- Because RTC looks further into the future than RTD, adjustments to the load forecast are reflected “sooner” in RTD than in RTC.

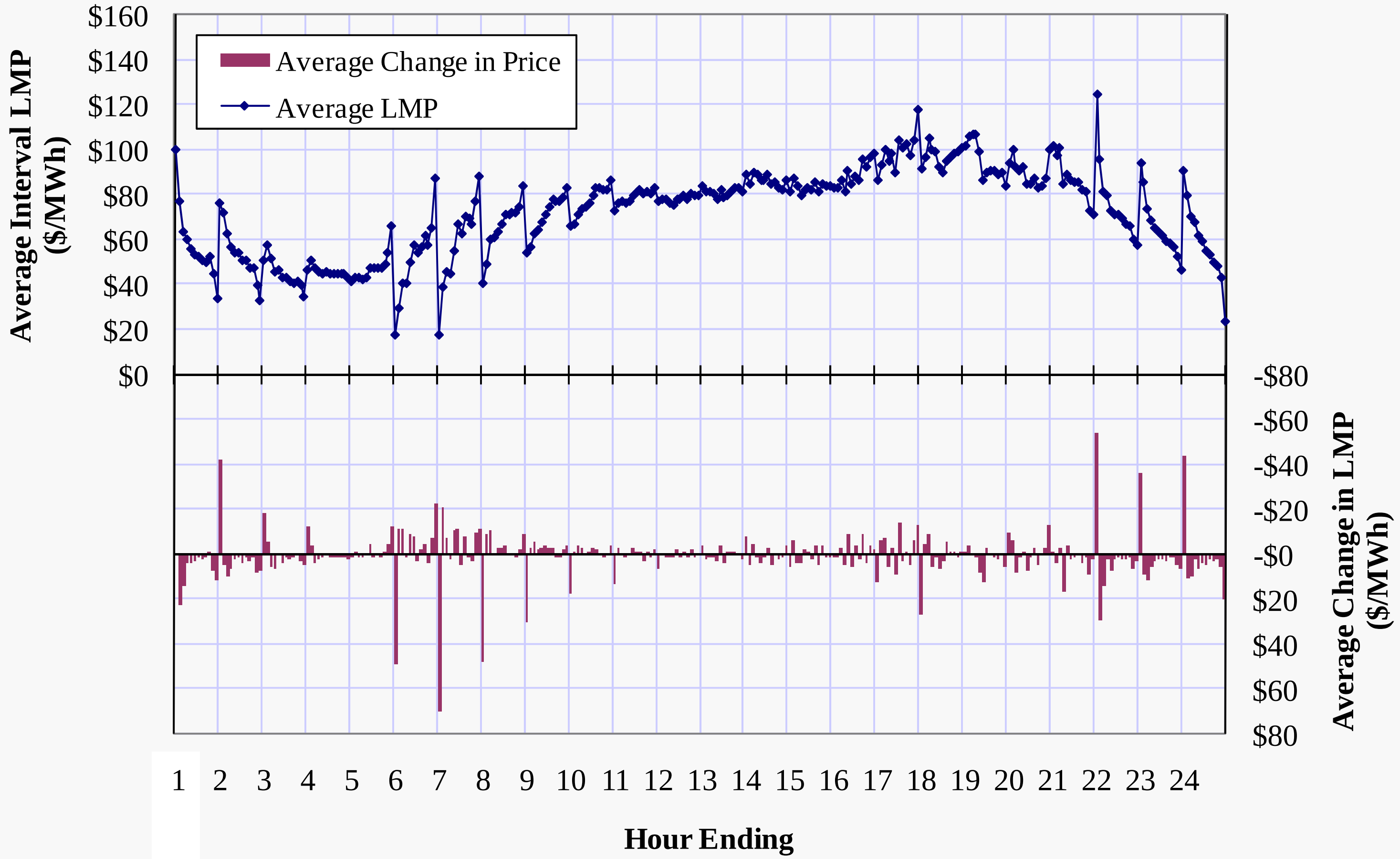
RTC and RTD Load Forecasts and Regulation Deployment
by Time of Day, Summer 2007



Five Minute Pricing by Time of Day

- The following figures shows the average prices in each five minute interval during the day in 2007 -- the data shown is for the Hudson Valley zone, although the results would be very similar for any other zone.
- This figure shows that prices are generally more volatile at the top of the hour during ramp up and ramp down hours.
  - ✓ The upward and downward price spikes in these hours reflect relatively frequent ramp rate constraints that are caused by how RTC and RTD manage:
    - Changes import and export schedules;
    - The commitment and decommitment of generating units (particularly slow-ramping baseload units); and
    - Changes in hourly generation schedules.
  - ✓ Ramp constraints can occur if RTC and/or RTD use unrealistic assumptions regarding how quickly output will change associated with changes in schedules or the startup/shut down of generating units.
  - ✓ This pattern helps explain the regulation deployments shown in the prior figure;
- We recommend the NYISO review its RTD and RTC assumptions and period definitions to improve the ramp management at the top of the hour.

Five Minute Pricing by Time of Day



Comparison of RTC and RTD – Conclusions

- The analyses in this section indicate that three factors are undermining convergence during ramping hours:
  - ✓ RTC schedules resources at time *t* using the highest of the load forecasts at time *t*, *t+5 minutes*, and *t+10 minutes*. This leads to higher RTC prices than RTD prices during the morning ramp period.
  - ✓ RTC and RTD use different assumptions about the level of exports. RTD assumes that each interface "ramps" at a constant rate from five minutes before the top of the hour to five minutes after. RTC assumes that each interface meets the next hour schedule at the top of the hour.
    - In January 2008, the NYISO changed RTC to assume the interface is halfway between its previous hour and next hour schedule at the top of the hour. This should reduce the inconsistency.
  - ✓ The load forecast is adjusted in real-time to reduce the need for regulation deployment, which results in differences between RTC and RTD load.
- We recommend the NYISO evaluate whether consistency between RTC and RTD could be improved by further addressing these or other factors.

Market Operations –
Pricing and Shortage Conditions

Reserve Shortages and Shortage Pricing

- RTD co-optimizes procurement of energy and ancillary services. This is beneficial in several ways:
  - ✓ 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 SMD 2.0.
  - ✓ 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 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.
  - ✓ The Eastern 10-minute reserves requirement has been the most costly to maintain since the introduction of real-time ancillary services markets.

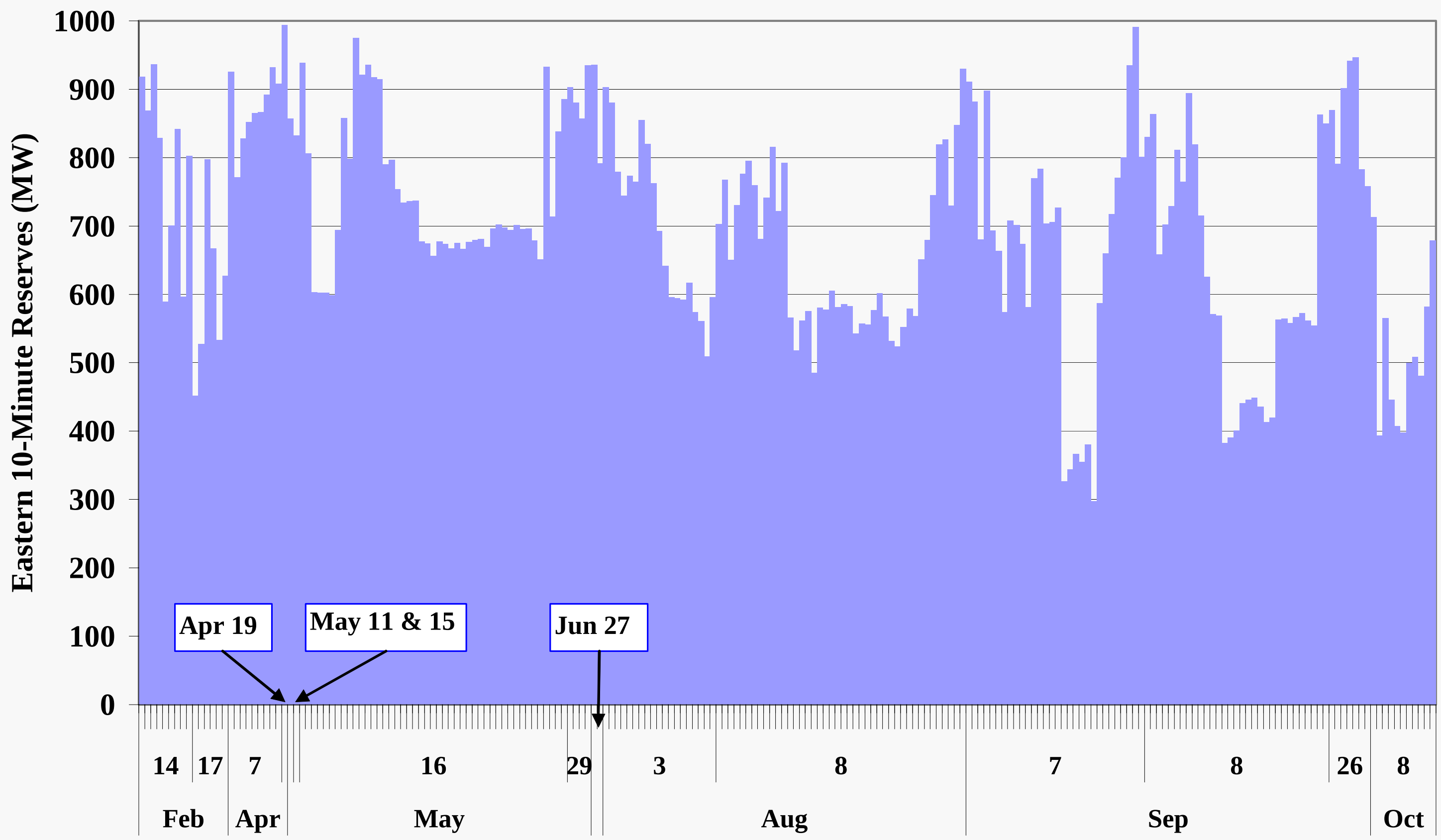
Reserve Shortages and Shortage Pricing

- Co-optimization of energy and reserves is integrated with the Hybrid Pricing approach in the market software. The Hybrid Pricing approach allows gas turbines to set clearing prices.
  - ✓ The inflexibility of gas turbines creates challenges for pricing energy efficiently when the gas turbines are the marginal source of supply.
  - ✓ 28 percent of dispatchable capacity in New York City and 42 percent of the dispatchable capacity in the 138kV load pocket are gas turbines.
  - ✓ Thus, Hybrid-Pricing is particularly important to setting efficient price signals inside NYC.
- Hybrid Pricing treats gas turbines as flexible resources for pricing purposes, which results in certain inconsistencies between the pricing dispatch and the physical dispatch. However, these inconsistencies should be limited such that:
  - ✓ Under physical shortage conditions, prices reflect scarcity; and
  - ✓ Shortage 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 in 2007.
- Based on the amount of physically available 10-minute reserves, Eastern NY was in a physical shortage in 100 percent of these intervals.
  - ✓ The pricing and physical dispatch passes of RTD have been very consistent during periods when shortage pricing was invoked.
  - ✓ Hence, shortage pricing in Eastern NY has occurred during true shortages.
- Milder summer load conditions in 2007 led to a reduction in the number of shortage pricing intervals.
  - ✓ During the summer months, the frequency declined from 326 intervals in 2006 to 63 intervals in 2007.
  - ✓ The overall frequency of shortage pricing declined from 376 intervals in 2006 to 219 intervals in 2007.

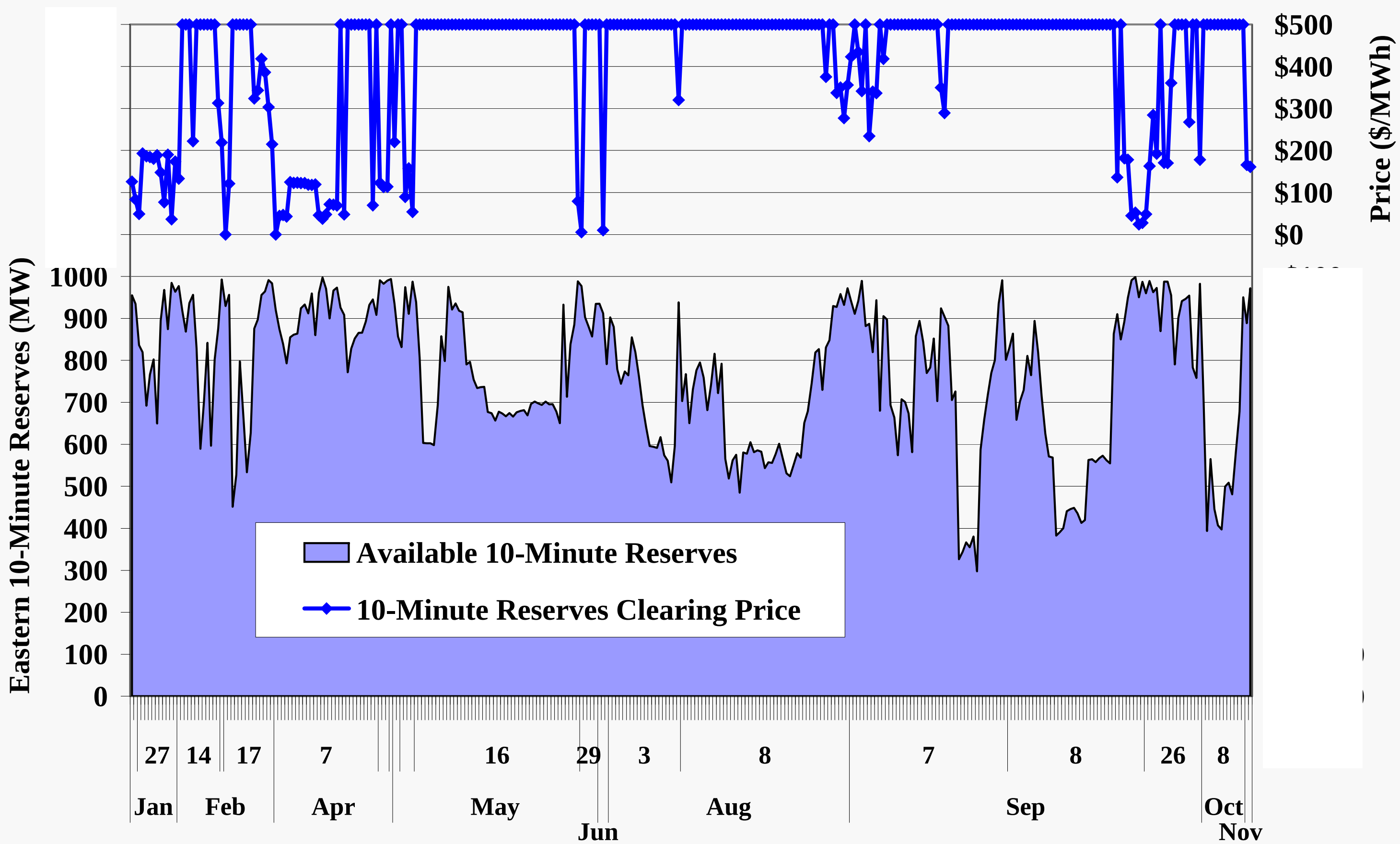
Scheduling of 10-Minute Reserves in the East
During Shortage Pricing Intervals – 2007



Reserve Shortages and Shortage Pricing

- The following figure shows the price and quantity of available Eastern 10-minute reserves during physical shortages of Eastern 10-minute reserves.
- 28 percent of the 312 intervals with physical shortages of Eastern 10-minute reserves did not exhibit shortage pricing in 2007.
  - ✓ The Eastern 10-minute reserve price averaged $174/MWh in these intervals.
  - ✓ The shortage was less than 100 MW in 73 percent of these intervals;
- In 2007, the consistency between the pricing dispatch and the physical dispatch passes of RTD during eastern 10-minute reserve shortage periods declined slightly from 2006 but was still much better than 2005.
  - ✓ In 2006, 19 percent of intervals with physical reserve shortages had no Eastern 10-minute reserves shortage pricing.
  - ✓ In 2005, 50 percent of intervals with physical reserve shortages had no Eastern 10-minute reserves shortage pricing.

Scheduling and Pricing of 10-Minute Reserves in the East During Physical Shortage Intervals – 2007



Note: 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 SMD 2.0 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.
- Prior to the summer of 2006, two software changes were made that better enable the real-time market model to set efficient clearing prices.
  - ✓ In mid-August 2005, enhancements were made to allow off-line quick-start GTs to be co-optimized by RTD for providing energy and reserves.
  - ✓ In May 2006, a change was made to allow the physical and pricing passes of RTD to be more consistent regarding the ratings of gas turbines in high ambient temperature conditions.
- A significant number of intervals remain when the physical dispatch pass perceives a shortage of reserves while the pricing dispatch pass does not. The following section discusses factors that contribute to remaining inconsistencies.

Hybrid Pricing

- Hybrid Pricing consists of a Physical Dispatch, which governs the deployment of resources, and a Pricing Dispatch, which determines the prices of energy and ancillary services.
  - ✓ This approach enables the real-time software to calculate efficient prices, especially in areas that are primarily served by GTs.
- The Hybrid Pricing approach works by allowing the Pricing Dispatch to treat on-line GTs as flexible from zero to maximum, while the Physical Dispatch always includes them at their maximum output level.
  - ✓ Thus, the Pricing Dispatch may count less energy from GTs, but only when they are not economically in-merit, which is generally not the case during reserve shortages.
- However, differences between the Pricing Dispatch and Physical Dispatch can also arise when resources do not follow dispatch instructions. This is discussed on the following slide.

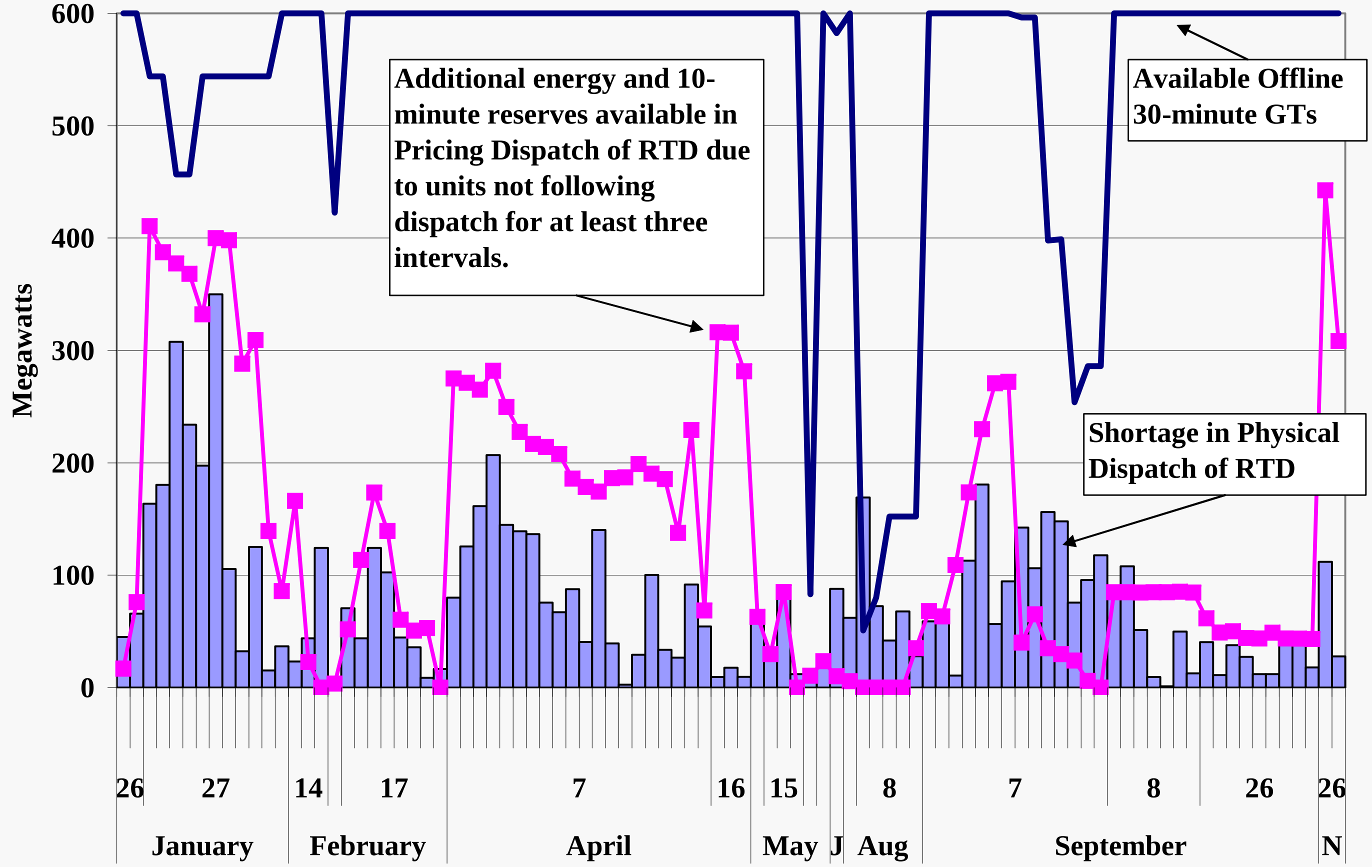
Hybrid Pricing

- In RTD, Physical Dispatch instructions are “ramp-constrained” by the expected physical output of the unit plus or minus what can be ramped in one interval, while the Pricing Dispatch level is ramp-constrained by the last pricing dispatch level plus or minus the ramp limit.
  - ✓ Thus, the Pricing Dispatch may count *more* energy from units that persistently *under*-produce.
  - ✓ And, the Pricing Dispatch may count *less* energy from units that persistently *over*-produce.
- In RTC, the Pricing Dispatch, which determines the commitment of 30-minute GTs, is ramp-constrained in the same manner as the Pricing Dispatch of RTD.
  - ✓ Hence, when units persistently under-produce, RTC may not anticipate a physical shortage.
  - ✓ As a result, RTC may under-commit 30-minute GTs.
  - ✓ In many cases, a physical shortage could be prevented by the economic commitment of 30-minute GTs.

Hybrid Pricing

- The following figure summarizes the potential effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the intervals when there was a physical shortage and no shortage pricing.
  - ✓ The bars indicate the shortage quantity in the Physical Dispatch of RTD.
  - ✓ The pink line indicates the additional energy and 10-minute reserves available in the Pricing Dispatch due to inconsistencies in the treatment of units not following dispatch instructions.
  - ✓ The blue line indicates the amount of offline 30-minute GT capacity, which would have been able to come online if a shortage had been anticipated by RTC.
- In 70 percent of these intervals, the additional supply available to the Pricing Dispatch was greater than the physical shortage quantity.
- Hence, the inconsistent treatment of units not following dispatch instructions may explain the majority of the instances when the Physical Dispatch perceived a shortage of reserves while the Pricing Dispatch pass did not.
  - ✓ If units not following dispatch instructions were treated consistently, some of these physical shortages would not have occurred due to the availability of offline 30-minute GT capacity.

Impact of Units Not Following Dispatch Instructions
Shortage Intervals without Shortage Pricing, 2007



Note: In cases where the amount of available offline 30-minute GTs exceeds 600 MW, the figure shows 600 MW.

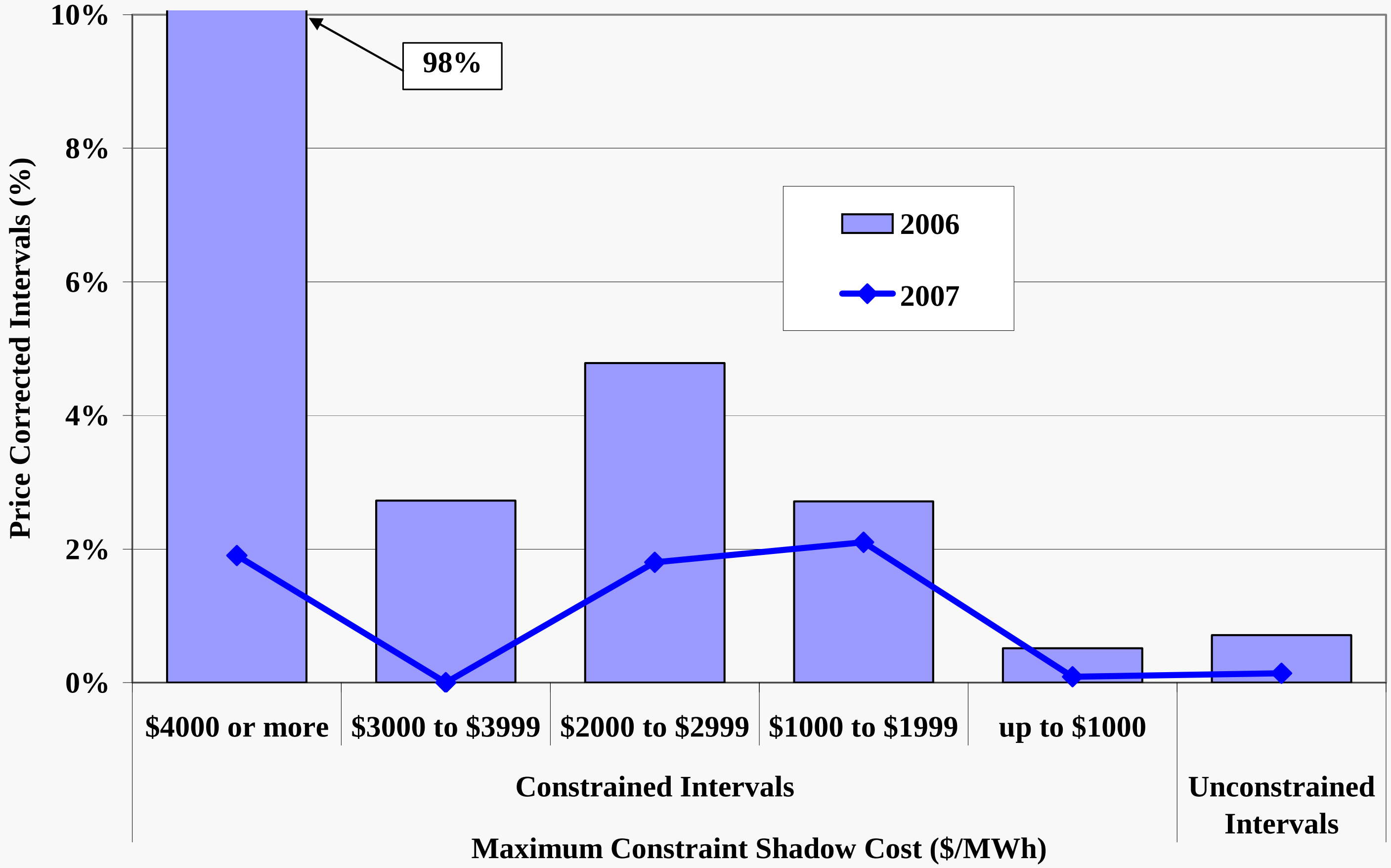
Hybrid Pricing – Conclusions

- Some differences between the Pricing Dispatch and the Physical Dispatch are necessary for Hybrid Pricing. However, unnecessary differences will generally lead to inaccurate prices and increased uplift.
- The consistent treatment of GTs under ambient temperature restrictions, which was implemented in May 2006, has greatly improved the efficiency of prices during Eastern 10-minute reserves shortages.
- Additional improvements to the consistency of the Pricing Dispatch and the Physical Dispatch of RTD and RTC should lead to:
  - ✓ More efficient pricing of energy and ancillary services (particularly during shortages), thereby reducing uplift; and
  - ✓ Fewer physical shortages because RTC will be more likely to start 30-minute GTs in anticipation of a shortage.
- We recommend the NYISO assess the feasibility of re-calibrating the ramp limits in the Pricing Dispatch for units that are not following dispatch signals.

Real-Time Pricing During Transmission Scarcity

- In June 2007, the NYISO improved pricing and dispatch during intervals with acute transmission constraints by implementing a shadow cost limit of $4,000/MWh.
- The following figure summarizes the rate of price corrections during intervals when marginal re-dispatch costs reach high levels.
  - ✓ The shadow cost limit has dramatically reduced price corrections.
  - ✓ Reliable price signals are particularly important during periods of extreme scarcity.
- In addition, the shadow cost limit should not undermine reliability.
  - ✓ Historically, when shadow costs exceeded $4,000/MWh, the re-dispatch provided little or no reliability benefit.
- We will continue to evaluate congestion management under the new methodology including the appropriateness of the $4,000/MWh limit.

Price Correction Frequency by Shadow Price June to December, 2006 & 2007



Demand Response and Shortage Pricing

- Operators are able to curtail load by activating EDRP and SCR resources. They must give advanced notice of at least two hours and if they curtail resources, it must be for no less than four hours.
- When called by the operators:
  - ✓ EDRP resources are paid the higher of $500/MWh or the clearing price.
  - ✓ SCR resources are paid the higher of their strike price, which is typically $500/MWh, or the clearing price.
- Demand response resources must be called in advance based on projections of operating conditions, and since they are not dispatchable by the real-time model, there is no guarantee that they will be "in-merit."
  - ✓ After EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time, clearing prices can be well below $500/MWh.
  - ✓ The NYISO has partially addressed this concern by implementing pricing rules that allow EDRP and SCR resources to "set price" when their curtailment enables the ISO to avoid a shortage of eastern or state-wide reserves.

Demand Response and Shortage Pricing

- Since July 2007, the local TOs have been able to activate Targeted Demand Response Providers (“TDRP”).
  - ✓ This program allows TOs to call TDRPs in specific local areas for distribution system reliability.
  - ✓ TDRPs are simply EDRPs and SCRs that choose to participate.
  - ✓ In NYC, there are nine distinct local areas where TDRPs can be called.
- TDRPs were called twice during the summer of 2007 to address local issues in a NYC load pocket rather than a large-scale shortage of reserves.
  - ✓ The ability to call TDRPs greatly reduced the inefficiencies of “out-of-merit” demand response resources by limiting curtailment to the affected area.
  - ✓ On July 19, approximately 10 percent of NYC resources were activated, and, on August 3, approximately 15 percent of NYC resources were activated.
  - ✓ Previously, the operators would have activated all of the resources in the NYC zone, which would have resulted in far more “out-of-merit” resources.
- We recommend the NYISO consider the development of rules to enable demand response resources to set prices in local areas when they are needed to avoid a local shortage on the transmission system.

Market Operations –
Uplift and Supplemental Commitment

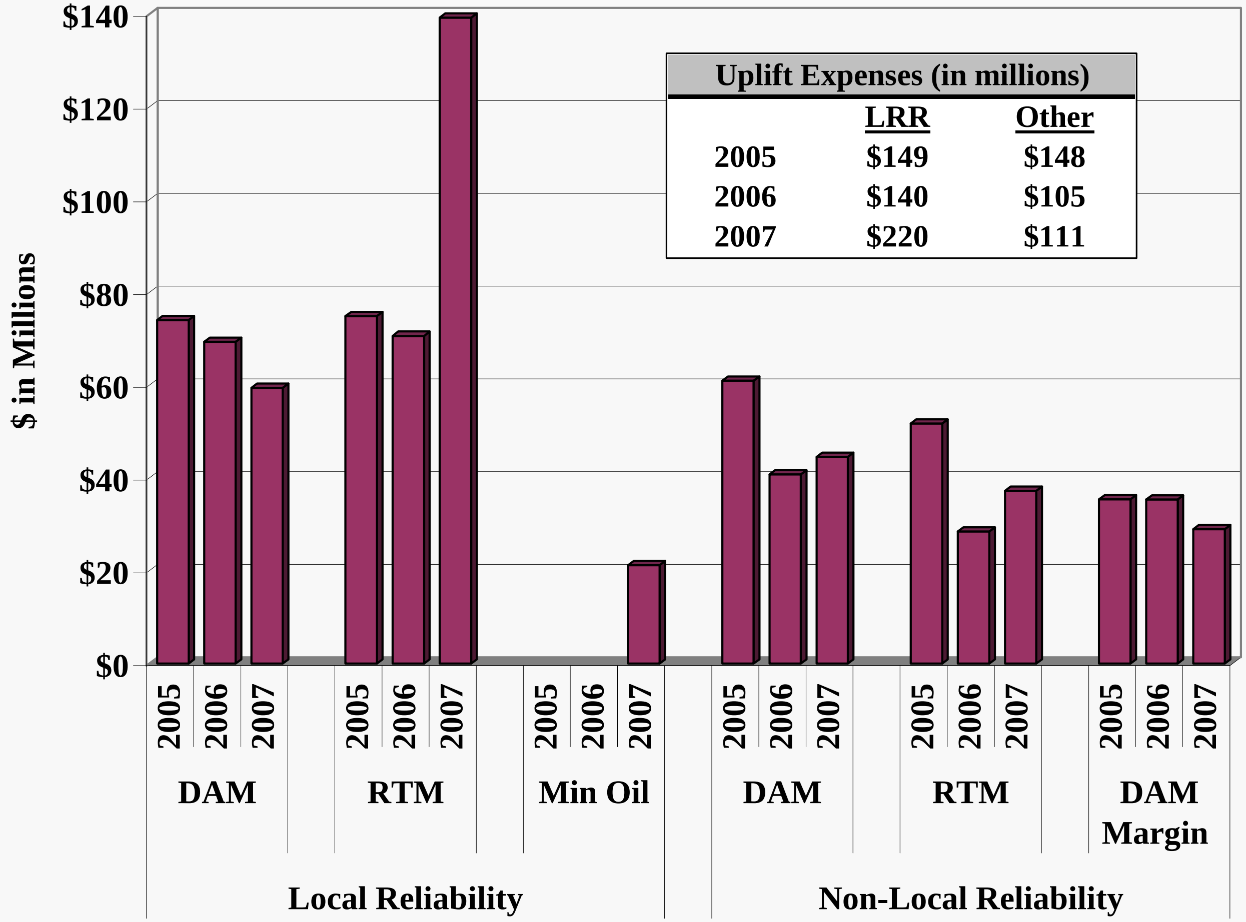
Uplift Expenses from Guarantee Payments

- The next figure shows uplift costs associated with guarantee payments over the past three years.
- The figure shows that total uplift rose due to an increase in local reliability uplift of $80 million from 2006 to 2007.
  - ✓ $20 million of the increase is associated with commitments needed to satisfy minimum oil burn requirements.
  - ✓ The remaining increase is associated with a 75 percent increase in the Supplemental Resource Evaluation (“SRE”) commitment occurring after the day-ahead market to satisfy local reliability requirements.
    - – These SREs are called by the local TO.
    - – The increase in SREs is partly associated with reduced economic commitments of oil-fired generation that are needed for local reliability.

Uplift Expenses from Guarantee Payments

- Minimum Oil Burn uplift arises when units must burn oil to maintain reliability in the ConEd territory because of the potential for natural gas supply disruptions.
- Minimum Oil Burn uplift has risen for two reasons:
  - ✓ Because of the increased spread between oil and natural gas prices.
  - ✓ There was no process for compensating generators for the additional costs incurred to meet this reliability requirement.
- Non-local reliability uplift decreased 25 percent from 2005 to 2007 due primarily to reduced natural gas prices and improvements in the efficiency of GT operation.

Uplift Expenses from Guarantee Payments
2005 to 2007



Uplift Expenses (in millions)

	LRR	Other
2005	$149	$148
2006	$140	$105
2007	$220	$111

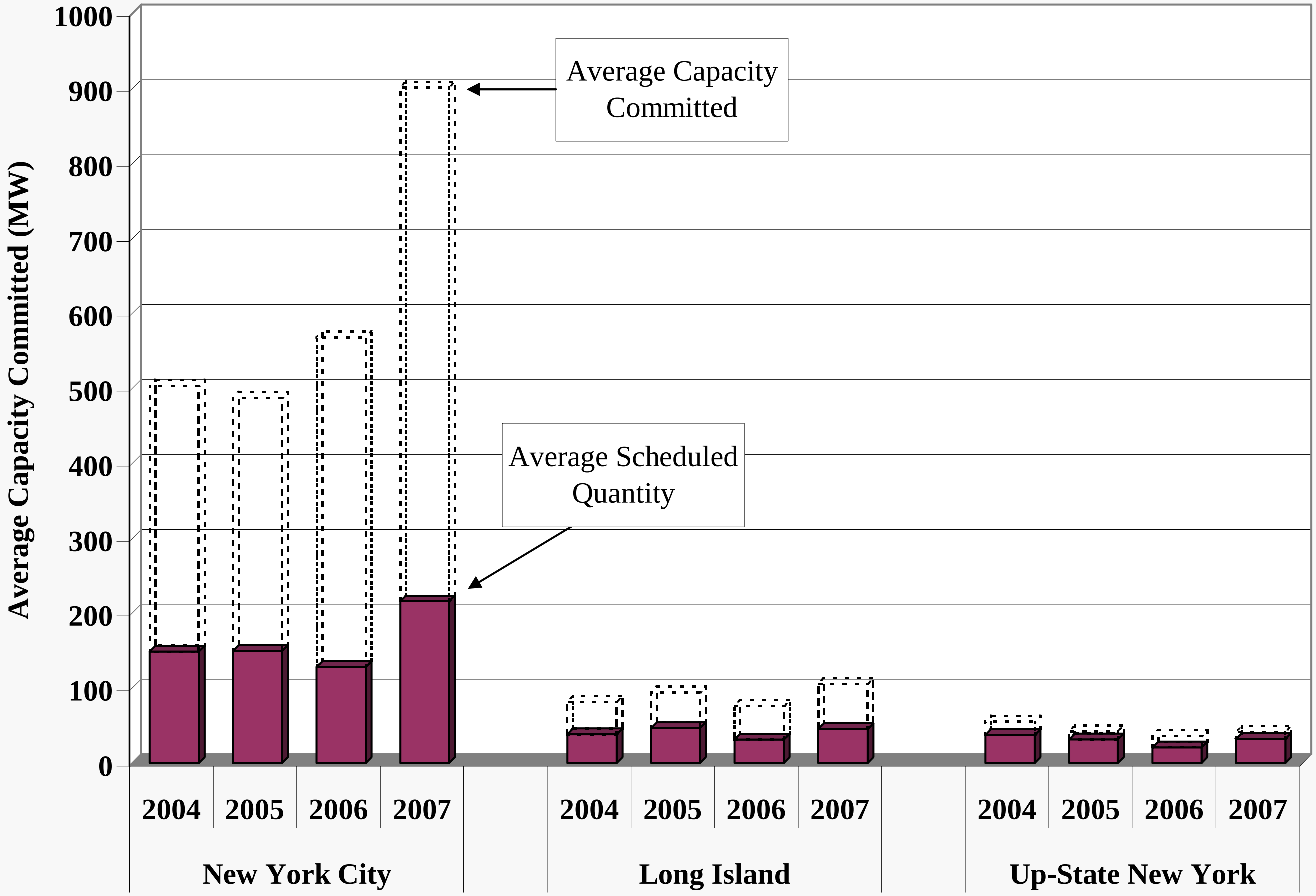
Supplemental Commitment

- This section evaluates supplemental commitments during 2007.
- Supplemental commitment occurs when a generator is not committed in the economic pass of the day-ahead market but is needed for local reliability. Supplemental commitment primarily occurs in two ways:
  - ✓ The Day-Ahead Local Reliability Pass of SCUC commits generators after the economic commitment but before clearing prices are determined.
    - – Uplift generated from these units makes up the entirety of day-ahead local reliability uplift.
  - ✓ The Supplemental Resource Evaluation (“SRE”) process is used to commit generators after the day-ahead market.
    - – Uplift generated from these units makes up nearly all real-time local reliability uplift.

Supplemental Resource Evaluation

- The following figure summarizes supplemental commitments made by the NYISO after the day-ahead market.
  - ✓ They are important because they influence the real-time market results.
  - ✓ To the extent that they are anticipated by the day-ahead market, they will also influence day-ahead market results.
- The average quantity of capacity committed through the SRE process in New York City increased by approximately 75 percent in 2007.
  - ✓ The increased need for SREs was partly due to reduced economic commitment of oil-fired generators that are needed for local reliability.
  - ✓ The market impact of such commitments is primarily determined by the amount of energy they produce, which averaged 215 MW in 2007.
  - ✓ These units also provide substantial quantities of 10-minute and 30-minute reserves.
- SREs are called by individual TOs, so the resulting uplift is allocated to the local area.

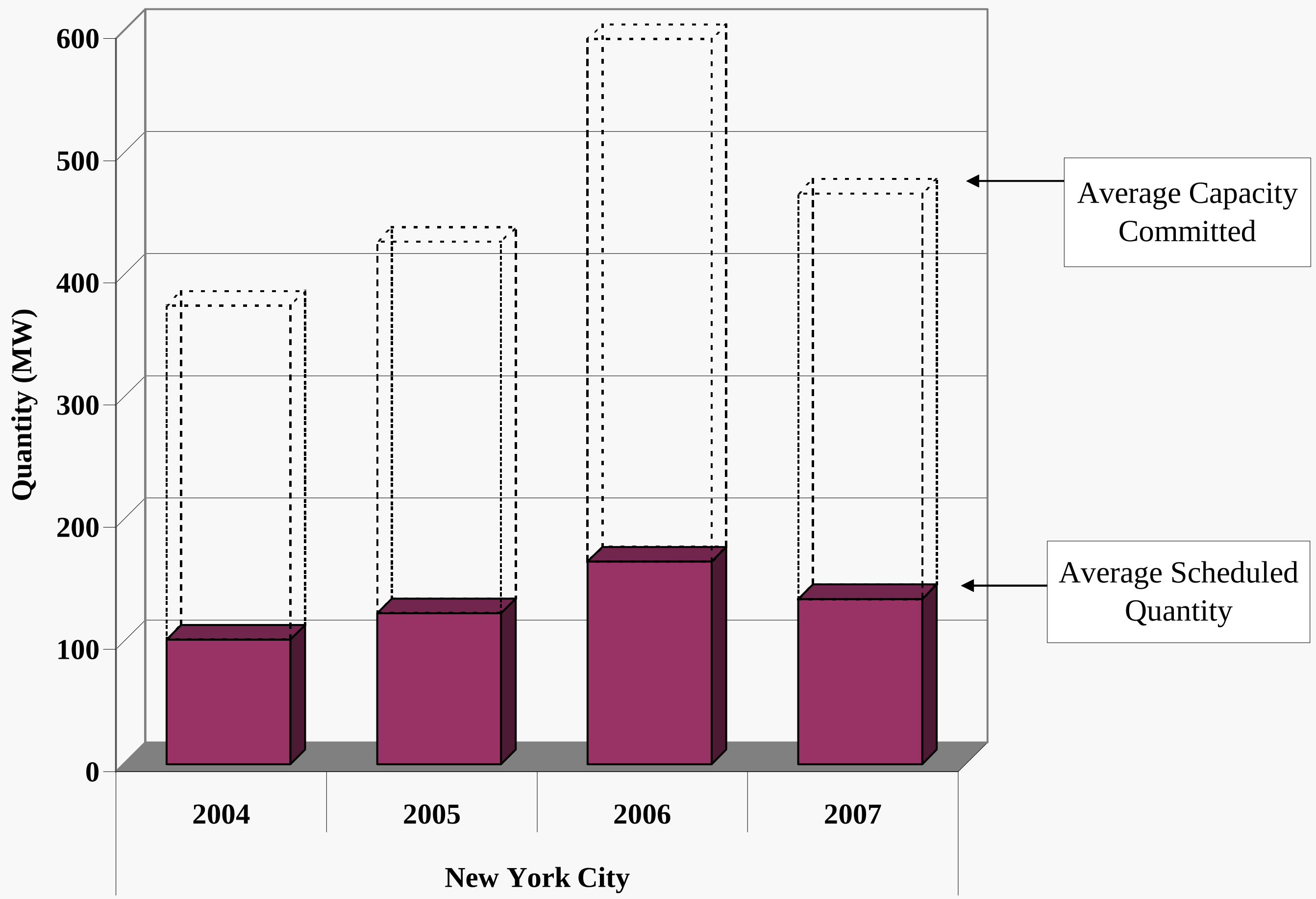
Supplemental Resource Evaluation Commitment 2004-2007



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 generally not economic at day-ahead market prices. They affect the market because they:
  - ✓ 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, which increased in 2006 and declined in 2007.
  - ✓ The market impact of such commitments is primarily determined by the amount of energy they are scheduled to provide, which averaged 140 MW in 2007.

SCUC Local Reliability Pass Commitment
2004 – 2007



Supplemental Commitment Conclusions

- Local reliability commitments have been rising for several years.
  - ✓ The average amount of capacity committed for local reliability in NYC exceeded 1300 MW in 2007, but only 350 MW was scheduled for energy.
- 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 on units committed economically, which are less likely to recover their full offer production costs;
- We had previously recommended that the NYISO incorporate local reliability constraints that require supplemental commitments into the economic commitment pass of SCUC, which will enable the ISO to maintain reliability with the least possible effect on the market.
  - ✓ The NYISO is currently developing the methodology and cost allocation rules to implement this recommendation.

Capacity Market

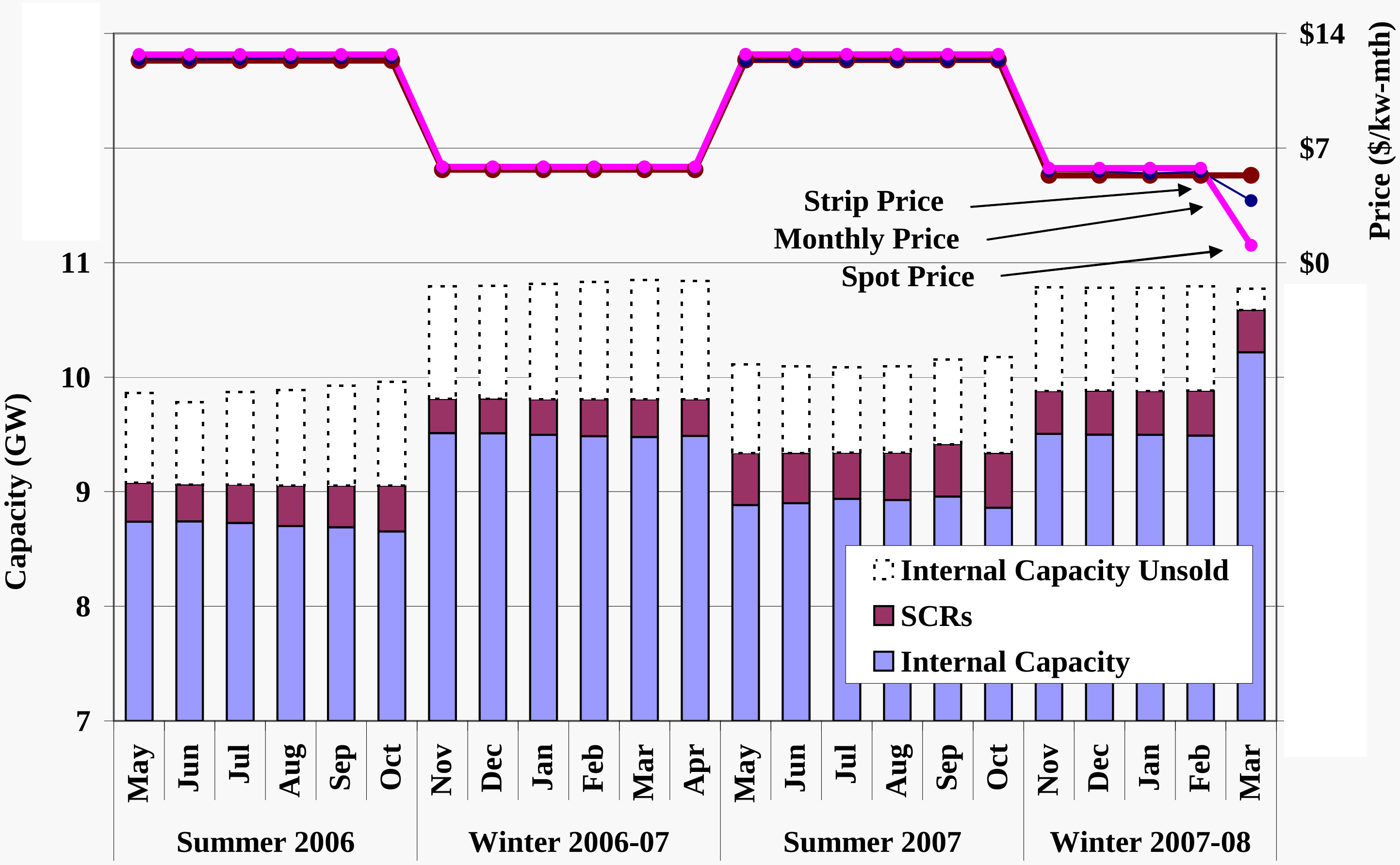
Capacity Market – Background

- 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 ICAP market forward auctions run by the NYISO.
- LSEs must purchase additional capacity in the Monthly ICAP Spot Market Auction if they have remaining obligations.
  - ✓ LSEs that have purchased more than their obligation prior to the Spot Market Auction, may sell the excess in the Spot Market Auction.
- To enhance the competitiveness of the capacity markets, a demand curve is used in the final Monthly ICAP Spot Market Auction.
  - ✓ Each LSE’s capacity obligation is determined by the intersection of supply in the Spot Market Auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).

Capacity Market – New York City

- For NYC, the following figure shows the resources available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the NYISO-run auctions.
- After the additions of new capacity in 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.
  - ✓ A significant amount of existing capacity did not clear in the UCAP market due to the suppliers’ offer prices.
  - ✓ In March 2008, the amount of unsold capacity was virtually eliminated, and the NYC spot auction price dropped to the price level for Rest-of-State (i.e, up-state areas). This resulted from conditions placed on the merger of National Grid and KeySpan-Ravenswood by the Public Service Commission.
- In March 2008, FERC ordered NYISO to implement market power mitigation measures for buyer-side and seller-side market power. These measures should be implemented by summer 2008 and we will evaluate their effectiveness.

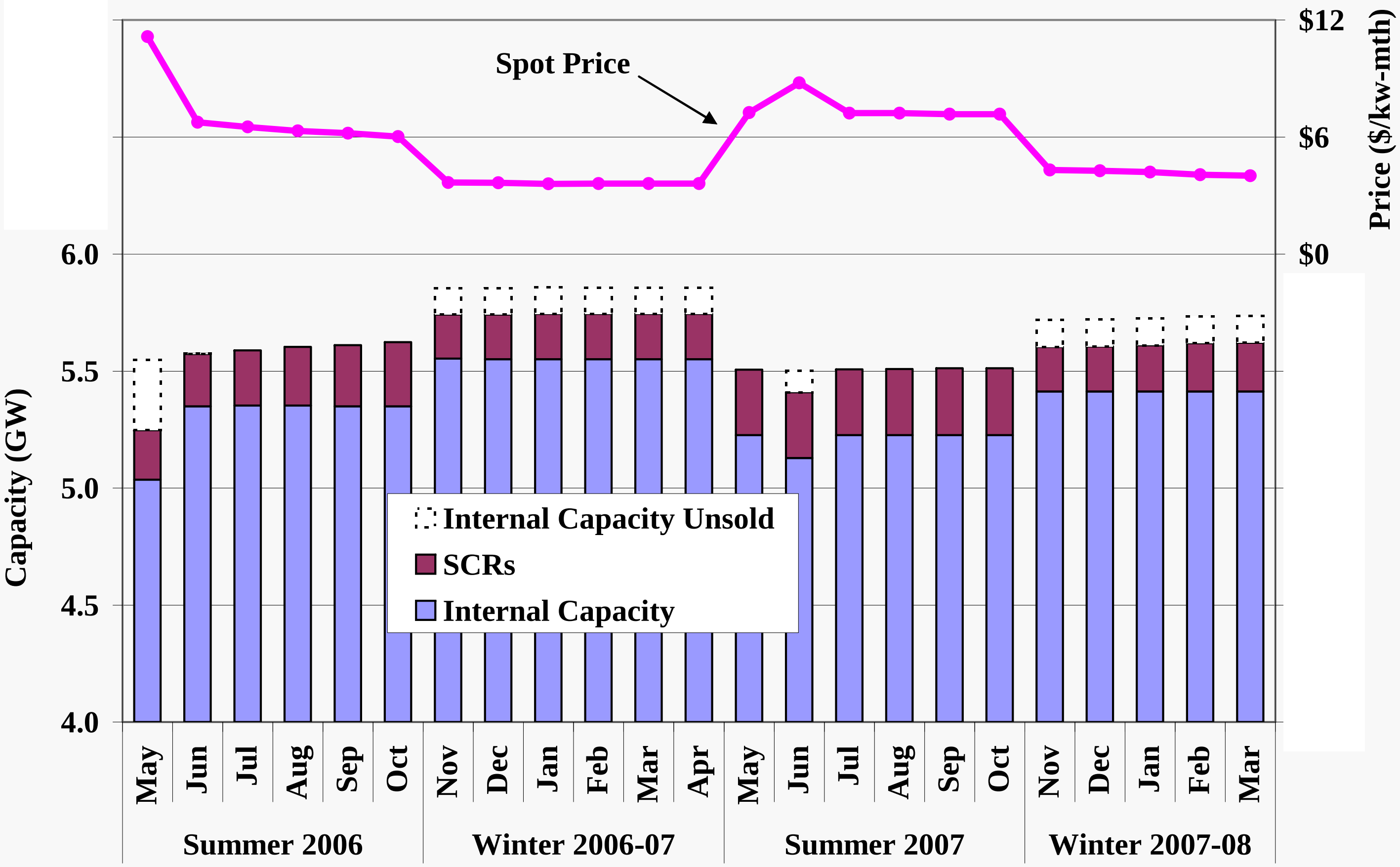
UCAP Sales – New York City
May 2006 to March 2008



Capacity Market – Long Island

- For Long Island, the following figure shows the resources available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the NYISO-run auctions.
- Seasonal changes in capability account for the most significant variations in prices during the period.
- In May 2006, the spot price was higher than in subsequent months because a portion of capacity qualified to sell in Long Island was not offered to the market.
- Aside from seasonal changes, the amount of Long Island capacity qualified to sell UCAP did not change significantly during the period.
  - ✓ Demand response increased 70 MW over the period.
  - ✓ The operation of the Neptune cable has not yet led to a rise in the amount of capacity qualified to sell into Long island.

UCAP Sales – Long Island
May 2006 to March 2008



Note: UDRs are included in "Internal Capacity"

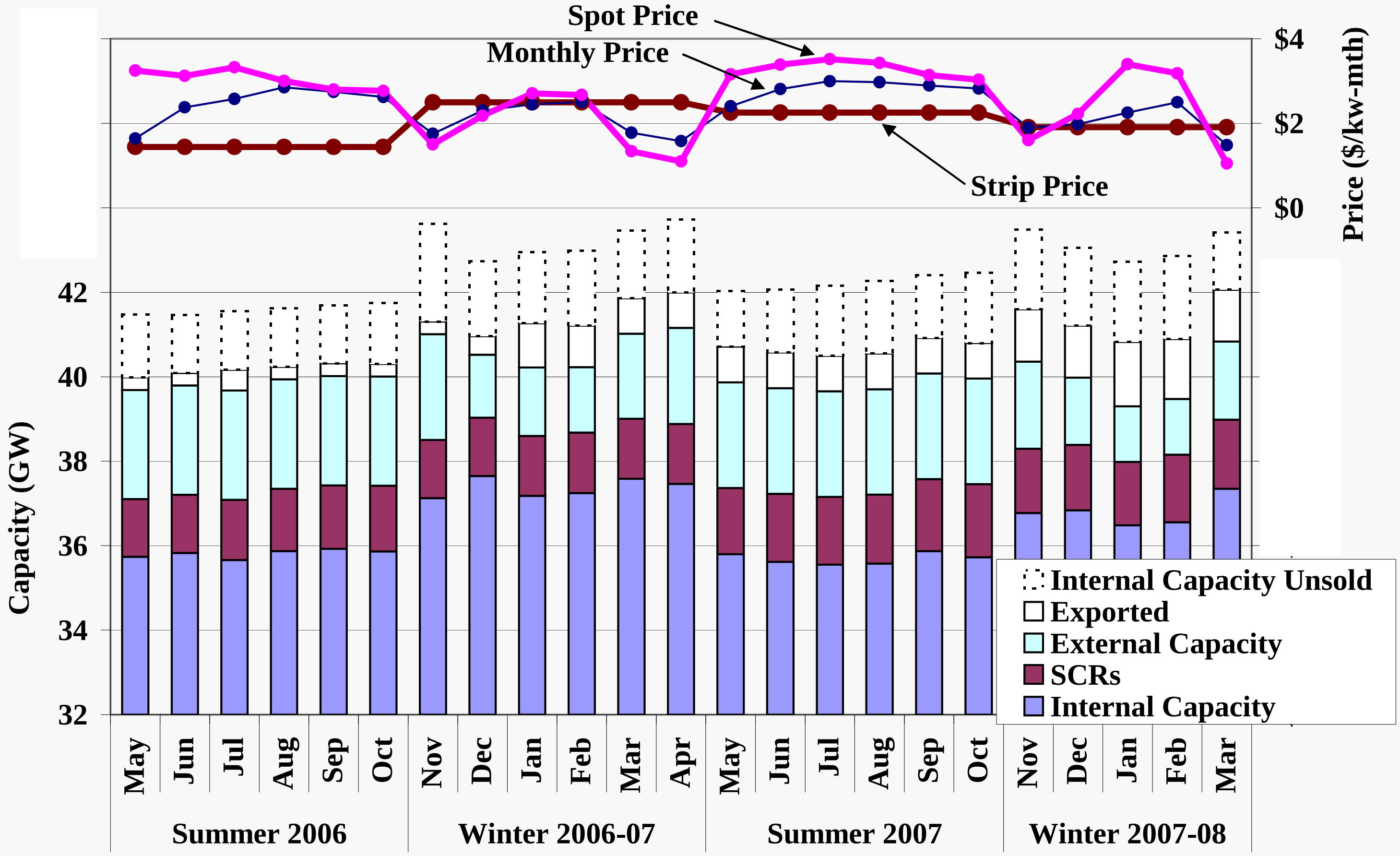
Capacity Market – New York State

- The following figure shows the resources available to provide UCAP to New York State versus the amounts actually scheduled and the UCAP prices that cleared for the Rest-Of-State area in the NYISO-run auctions.
- The UCAP available from resources in up-state New York varied due to:
  - ✓ Seasonal changes is capability.
  - ✓ Demand response increased 370 MW over the period.
- The price for the Rest-Of-State area is affected by sales of capacity in local capacity zones because local capacity also satisfies NY State requirements.
  - ✓ In March 2008, the increased UCAP sales in NYC contributed to the spot price decline from February to March 2008.
- The state-wide UCAP requirement declined from 118 to 116.5 percent of the peak load forecast in 2007, helping to reduce capacity prices.
  - ✓ The requirement will be further reduced to 115 percent in 2008.

Capacity Market – New York State

- Most fluctuations in capacity prices are related to variations in the quantities of imports and exports.
  - ✓ In the summer capability periods, net imports declined from 2290 MW in the summer of 2006 to 1650 MW in the summer 2007; and
  - ✓ In the winter capability periods, net imports ranged as high as 2210 MW in November 2006 and as low as -200 MW in January 2008.
- Market rule changes in neighboring control areas have affected the UCAP market in New York.
  - ✓ In December 2006, New England began to pay over $3/kW-month for UCAP.
  - ✓ This led to a 1700 MW swing in net imports of UCAP to New York State from New England and Quebec from November 2006 to January 2007.
  - ✓ The price of capacity in PJM's RPM has risen to levels that might lead to future reductions in net imports from PJM.

UCAP Sales – New York State
May 2006 to March 2008



Note: UDRs are included in "Internal Capacity"

Capacity Market Configuration

- The capacity market provides investment signals to meet planning requirements for New York State. Local capacity region prices guide investment to areas where it is most valuable.
  - ✓ The current local capacity regions are: New York City (Zone J), Long Island (Zone K), and Rest-of-System (Zones A to I).
  - ✓ The value of the capacity is reflected in the clearing price of each region.
- There are indications that new capacity is needed and would be more valuable in Southeast New York (Zones G to I) than in Zones A to F.
  - ✓ Based on the 2008 Reliability Needs Assessment, additional resources will likely be needed in Southeast New York between 2012 and 2014, which is several years before they will be needed in Zones A to F.
  - ✓ Recent analysis by NYISO suggests that new capacity in ROS in Zones A to F will no longer be deliverable to Southeast New York by 2012.
- In addition to the needs in Southeast New York, it is important to consider the economic incentives being provided by the system to build there.

Capacity Market Configuration

- Based on the Net Revenue Analysis, market signals currently reflect a modest difference in the value of capacity between Zone F and Zone G.
  - ✓ For a CT, net revenue was $77 per kW-year in zone G vs $63 per kW-year in zone F in 2007, which are substantially lower than the estimated entry costs for a new peaking resource in the ROS.
  - ✓ For a CC, net revenue was $168 per kW-year in zone G vs $147 per kW-year in zone F in 2007.
  - ✓ Given that the costs of building in Southeast NY are likely higher than in other ROS areas, this difference may not give suppliers adequate incentives to build in Southeast NY.
  - ✓ Further, if the ROS surplus remains while capacity margins in Southeast NY decrease to unreliable levels, the ROS capacity price will not provide efficient incentives for potential investors in Southeast NY.
- Based on the project needs and these economic signals, the NYISO should consider whether additional capacity zones are needed in Southeast NY.

Demand Response Programs

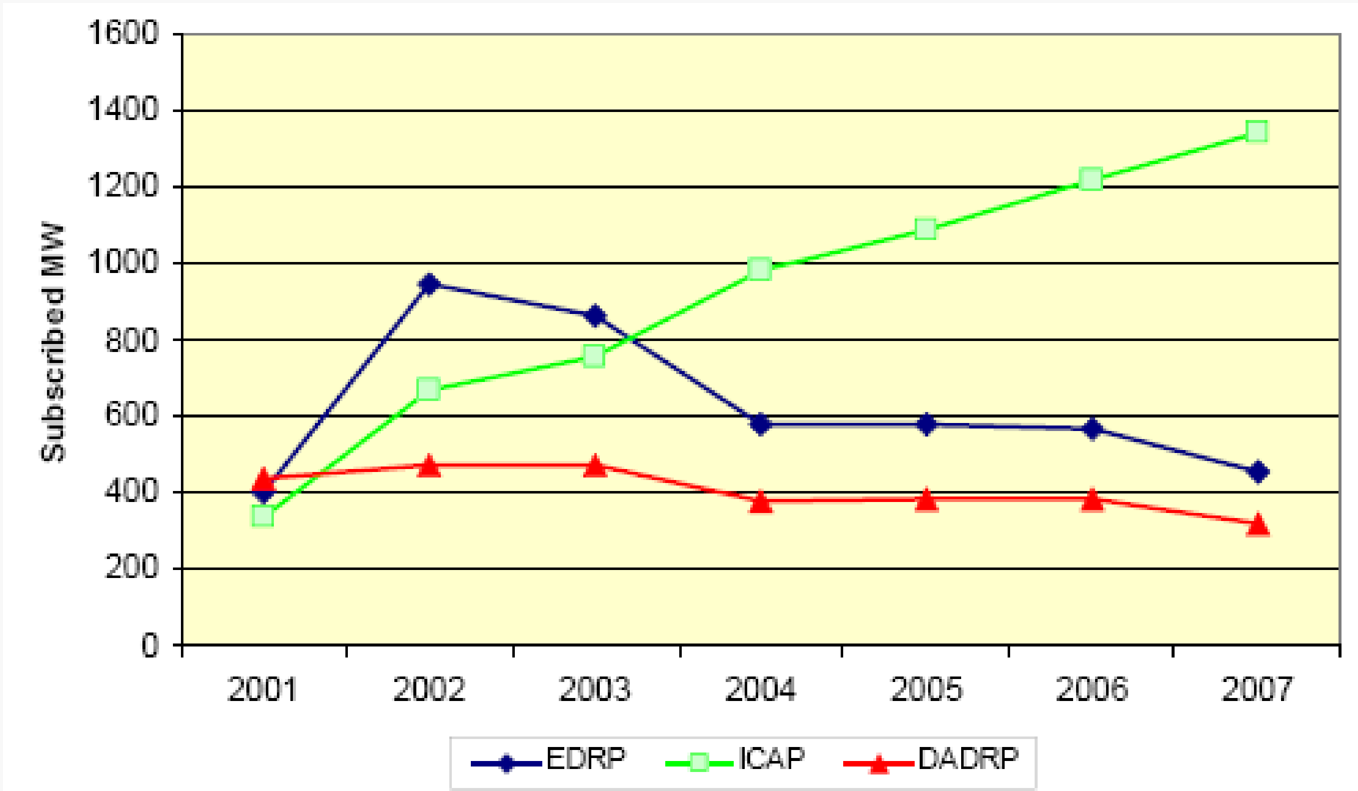
Demand Response Programs

- The NYISO has four programs that allow retail loads to participate in wholesale market operations:
  - ✓ Three programs curtail loads in real-time for reliability reasons:
    - – Emergency Demand Response Program (“EDRP”) resources are paid the higher of $500/MWh or the clearing price when called by the ISO for reliability.
    - – Special Case Resources (“SCRs”) are paid the higher of their strike price, which is typically $500/MWh, or the clearing price when called by the ISO for reliability.
    - – Targeted Demand Response Program (“TDRP”) resources are EDRP resources and SCRs that curtail when called by the local TO.
  - ✓ Day-Ahead Demand Response Program (“DADRP”) resources offer to curtail in the day-ahead market with a floor price of $75/MWh.
- EDRP and SCRs are reflected in clearing prices when their activation prevents reserve shortages at the state-level or eastern New York.
  - ✓ FERC’s NOPR notes that New York is the only market that allows emergency demand response resources to set clearing prices.

Demand Response Programs

- The following figure summarizes the growth in participation in the NYISO's demand response programs from 2001 to 2007.
  - ✓ EDRP resources and SCRs are able to participate in the TDRP program.
- The SCR resources are the most valuable in New York because SCRs are able to sell UCAP in the ISO's capacity market.
  - ✓ SCR registration has grown consistently in each year since 2001, providing considerable benefits by reducing the cost of meeting New York's planning reserve margin requirements.
- There has been a steady migration of resources from the EDRP program to the SCR program because SCRs can sell UCAP.
  - ✓ However, the sum of the resources in both programs have continued to rise each year since 2004.
- The NYISO has filed Tariff changes to allow demand response to provide operating reserves and regulation under the same performance requirements as generators.

Registration in NYISO Demand Response Programs
2001 to 2007



Note: This figure is reproduced from the NYISO's January 15, 2008 Demand Response Compliance Report.