2003 State of the Market Report
New York Electricity Markets

David B. Patton, Ph.D.
Potomac Economics

Independent Market Advisor

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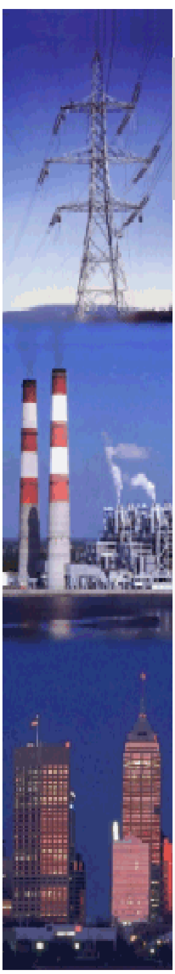
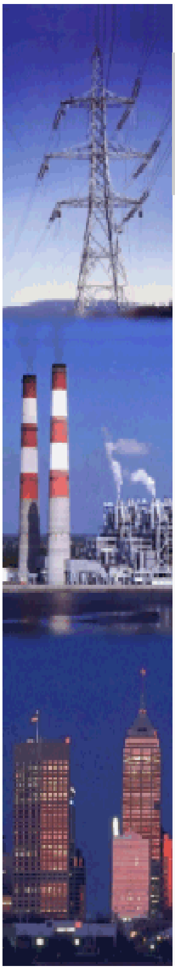


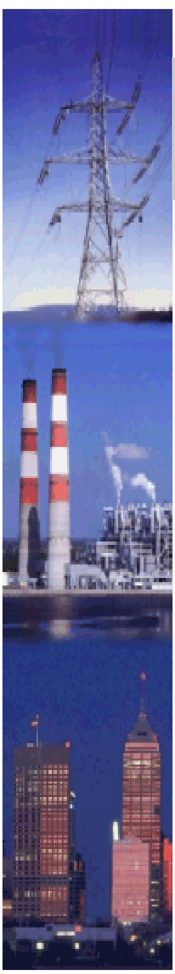
Introduction to the Annual Report

- This presentation provides highlights from the State-of-the-Market Report on the New York electricity markets for 2003.
- The market assessment addresses the following areas:
  - ✓ Energy market prices and outcomes
  - ✓ Market participant bid and offer patterns
  - ✓ External transactions scheduling
  - ✓ Capacity market
  - ✓ Ancillary services
  - ✓ Demand response programs



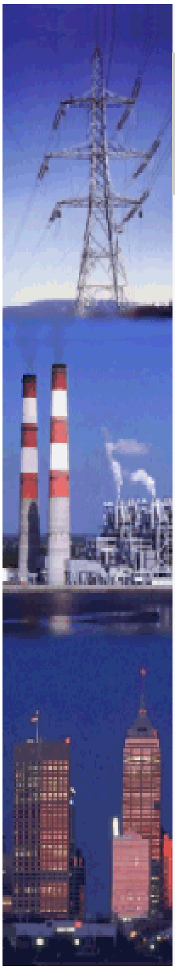
Summary of Conclusions

- The NYISO markets continued to perform competitively in 2003 with no evidence of significant economic or physical withholding.
- Energy prices were substantially higher in 2003, due primarily to higher fuel prices.
- The net revenue (market revenue – variable production costs) provided by the markets in 2003 continue to be less than the annualized costs of a new gas turbine in New York City or the rest of the state.
  - ✓ This does not indicate a market issue since external factors caused net revenues to be lower in 2003 than they are expected to be going forward.
- Although shortage pricing provisions were implemented prior to the summer 2003, mild load conditions and increased net imports from New England prevented any shortages.
- Day-ahead and real-time energy prices continued to exhibit good convergence.



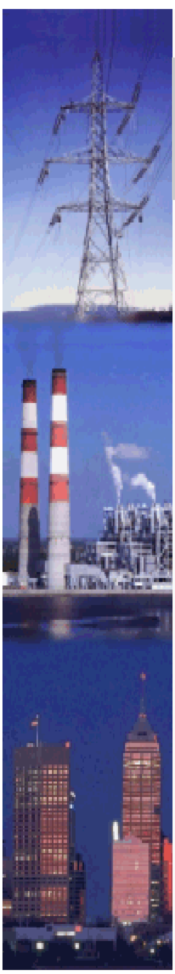
Summary of Conclusions

- Forced outage rates have fallen substantially from the time the NYISO markets were implemented through 2003.
  - ✓ This is consistent with the increased incentives a competitive market provides for high availability.
- Virtual trading volumes increased in 2003, which contributed to the good convergence between the day-ahead and real-time prices outside of NYC.
- The capacity demand curve implemented in 2003 has been successful in stabilizing capacity prices and facilitating price convergence between the various UCAP auctions.
- The NYISO's demand response programs provide a substantial amount of real-time load reductions when necessary – however, mild conditions in 2003 limited the need for such reductions.



Areas of Potential Improvement and Recommendations

- Real-time prices in adjacent regions continued to not be efficiently arbitraged.
  - ✓ Implementation of the VRD provisions that are under development with New England will address this issue.
  - ✓ Eliminating the export fees with adjacent regions would also help improve the efficiency of the interchange between markets.
- Apparent reductions in real-time transmission limits has caused substantial congestion costs in real-time.
  - ✓ Introduction of RTS should address this concern because the RTS and SCUC software will operate on the same platform.



Areas of Potential Improvement and Recommendations

- Supplemental commitments through the local reliability pass of SCUC and the SRE process continue to be significant, which can distort energy prices.
  - ✓ In the long-term, we recommend incorporating the local reliability requirements in the initial commitment.
  - ✓ In the short-run, we recommend that the operators pre-commit units that they know will be required to meet local reliability requirements.
- Price convergence in NYC is still not good, although it was improved in 2003.
  - ✓ The ability to make virtual purchases and sales within the NYC load pockets would likely improve price convergence in these areas.
  - ✓ We recommend the ISO consider allowing virtual trading in the load pockets if convergence does not improve under RTS.

Market Prices and Outcomes

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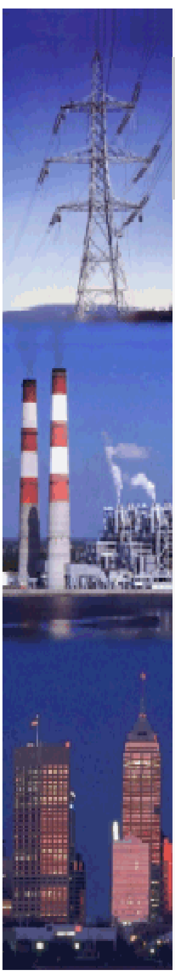
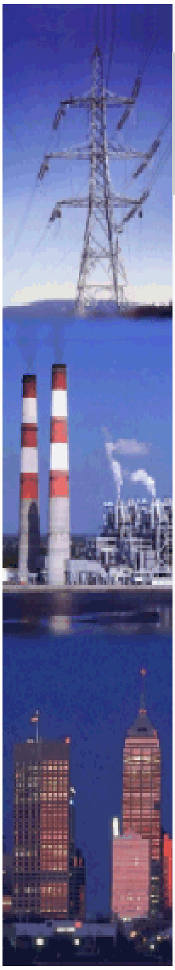
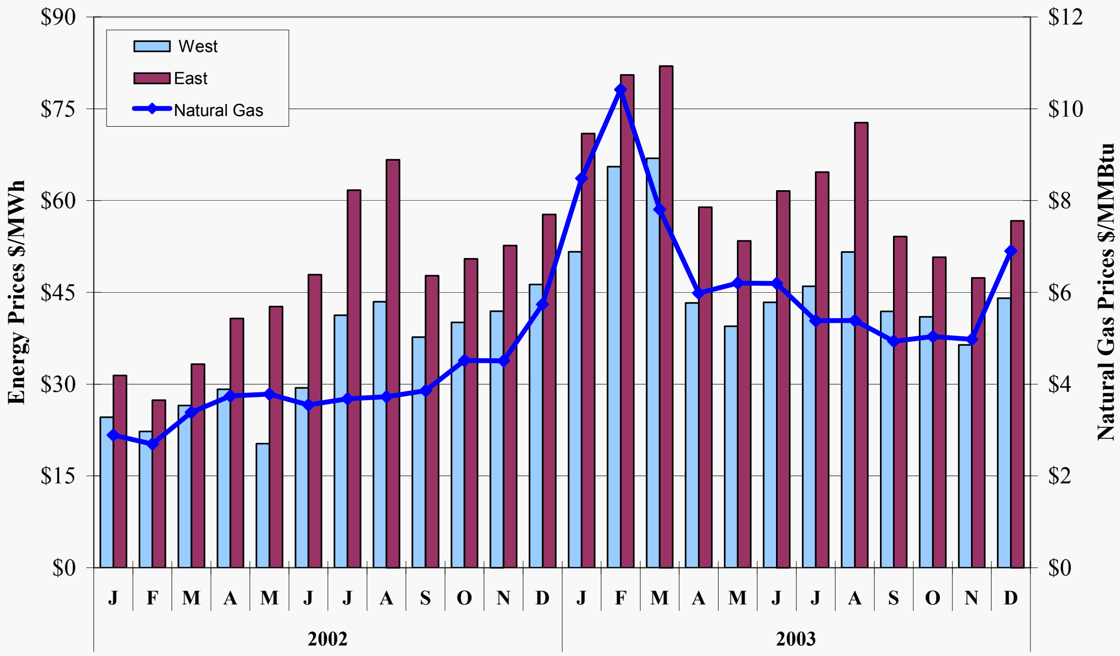


Fuel Prices and Energy Prices

- Electricity prices tend to be influenced primarily by fuel prices (the largest component of generators' marginal costs) and load levels.
- The following figure shows that monthly energy prices for 2002 to 2003 have been driven by fuel price trends, particularly natural gas prices.
- Electricity prices peaked in February and March as natural gas prices hit unprecedented levels, and peaked again in August due to summer loads.
- The increase in electricity prices in 2003 reflected a substantial increase in fuel prices from the prior year.
  - ✓ Natural gas prices averaged 70 percent higher than in the previous year.
  - ✓ Distillate oil prices increased 24 percent on average.
  - ✓ The correlation of energy prices with oil and gas prices is expected since a) fuel costs represent the majority of most generators' variable production costs, and b) oil and gas units are on the margin in most hours.

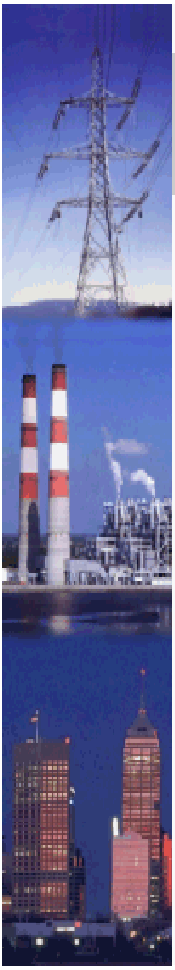


Energy and Natural Gas Prices
2002 - 2003

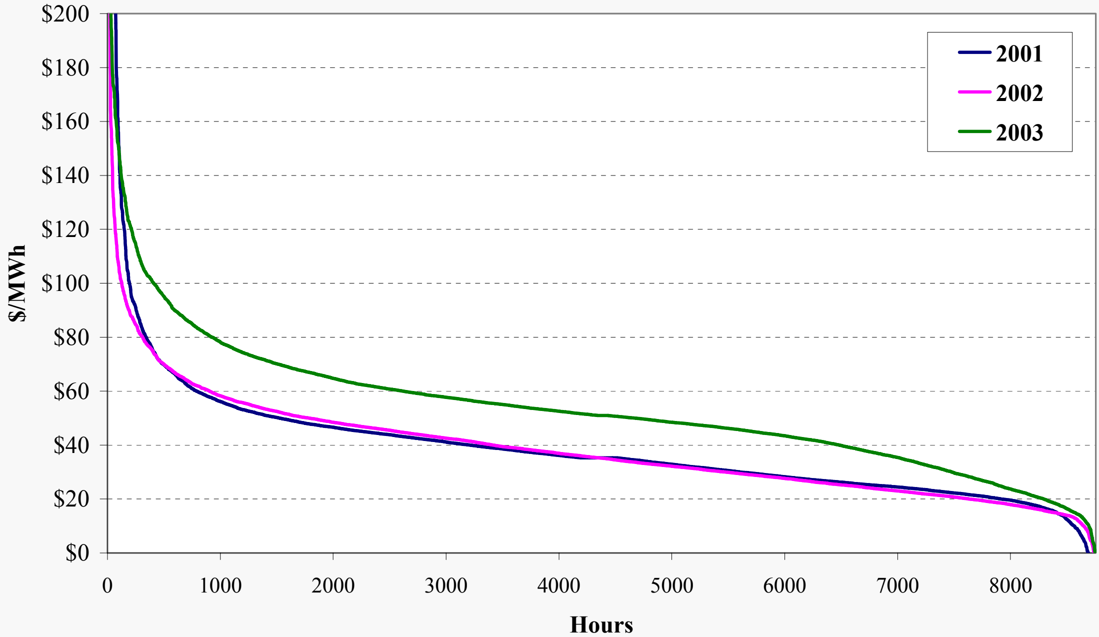


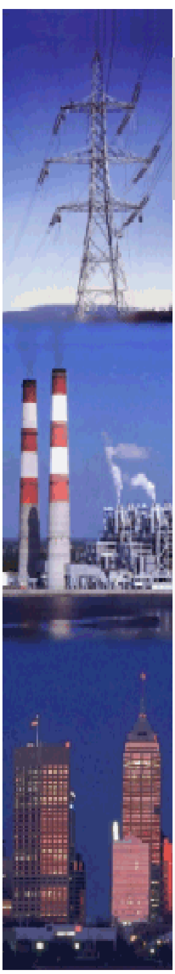
Energy Prices in 2003

- The following figures show real-time price duration curves for 2001 to 2003 in all hours and the highest priced five percent of hours in each year.
  - ✓ These curves show the number of hours when the load-weighted price for New York State is greater than the level shown on the vertical axis.
- Price levels were generally higher in 2003 than in the previous two years due to higher fuel prices:
  - ✓ In 2003, there were more than 4500 hours with prices above $50, while prices exceeded that level for less than 1800 hours in 2001 and 2002.
  - ✓ This general rise in prices over the wide array of load conditions is attributable to the higher fuel prices.
- In 2003, there were fewer price spikes than the two previous years:
  - ✓ In 2003, real-time weighted prices exceeded $500 for 3 hours, compared to 6 hours in 2002, and 11 hours in 2001.
  - ✓ The lower quantity of price spikes was primarily due to milder weather and increased imports from New England.

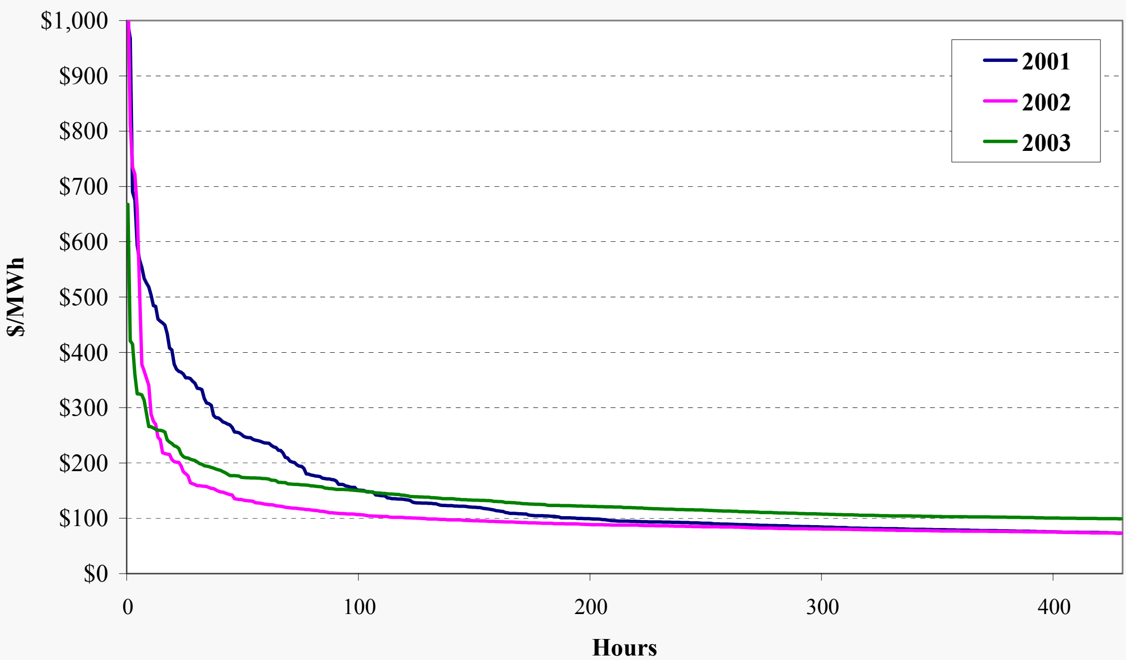


Price Duration Curves 2001 – 2003
New York State Average Real-Time Price





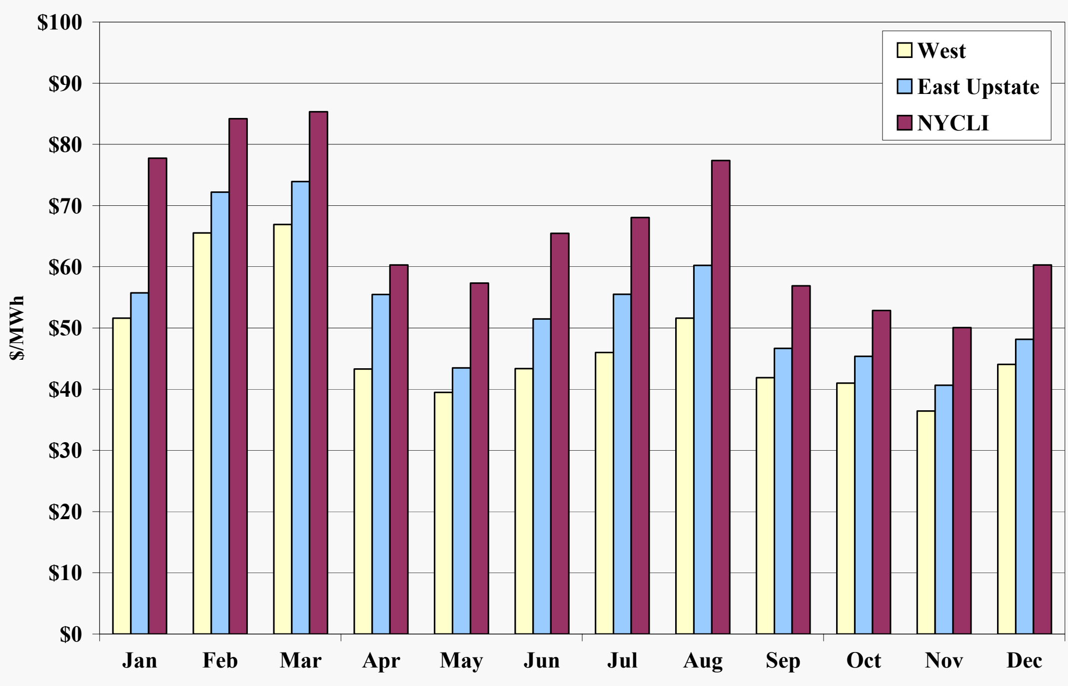
Price Duration Curves in Highest 5% of Hours
New York State Average Real-Time Price



Average Day Ahead Prices

- The next figure presents average day-ahead energy prices by month in west NY, east NY upstate, and NYC/Long Island for 2003.
- The Central-East transmission constraint separating west and east New York is often binding, causing prices in the east to exceed prices in the west by $6.50 per MWh on average.
- There are constraints into New York City, as well as local load pockets within the City, which raise average prices inside the constraints.
  - ✓ Price differences between the City and the eastern upstate region averaged more than $12.60/MWh in 2003.
  - ✓ This price difference peaked in January due to a breaker outage on the Con-Ed interface that substantially decreased transmission capacity into NYC.

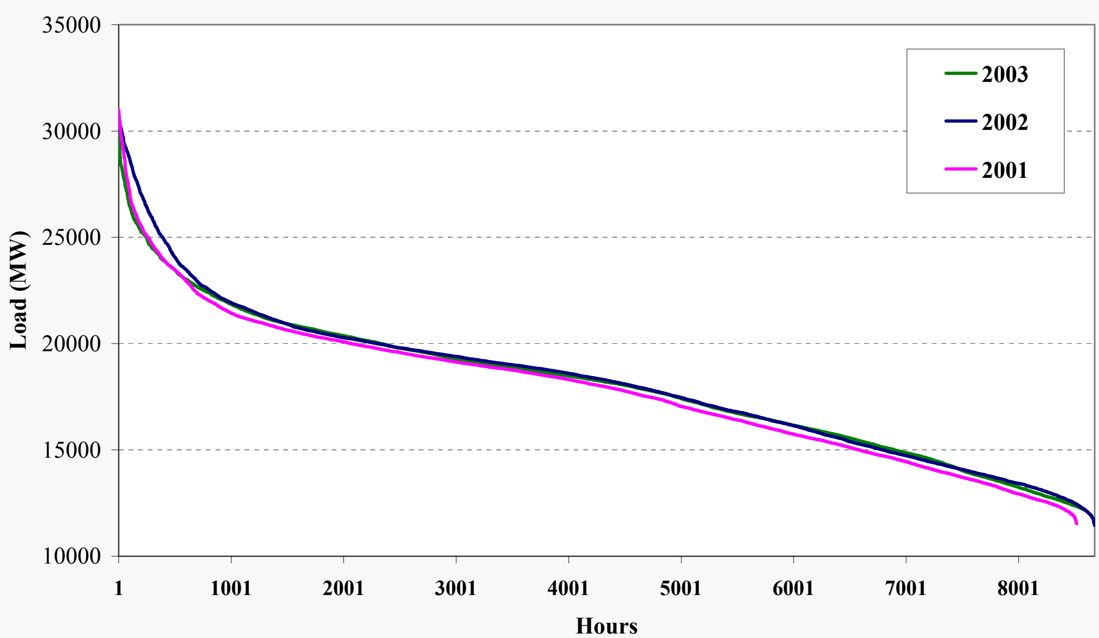
Average Day-Ahead Energy Prices



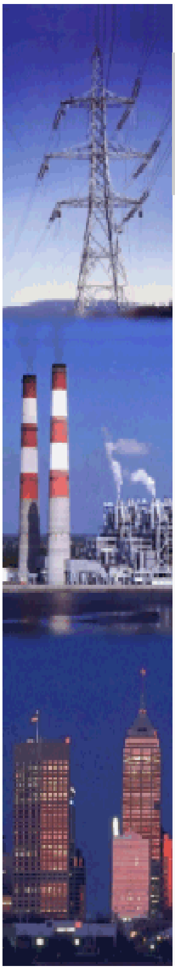
Load Profile

- The next two figures shows annual and summer load duration curves for New York.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- In 2003, peak days had far less impact on average prices than in 2002. The absence of severe price spikes was due to mild summer loads.
  - ✓ There were only 3 hours in 2003 when actual loads exceeded 30,000 MW, compared to 25 hours in 2002 and 17 hours in 2001.
  - ✓ In 2003 there were 38 hours when loads exceeded 28,000 MW compared to 133 hours in 2002 and 66 in 2001.

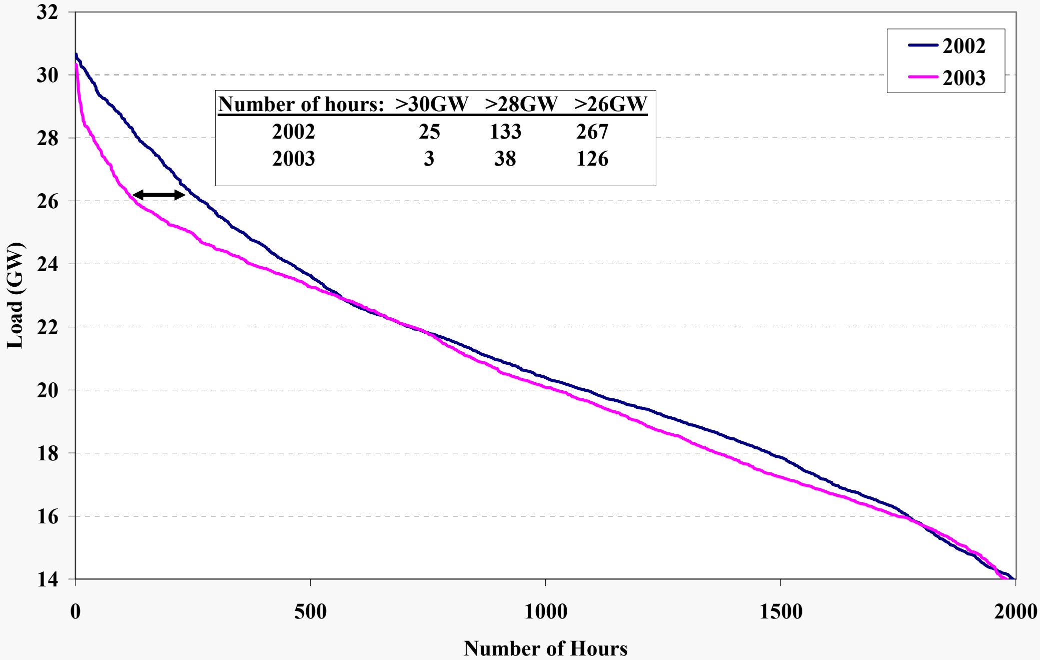
Load Duration Curves
New York State Hourly Average Load



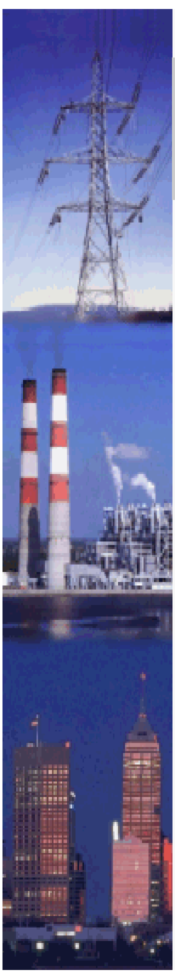
* Hours during the August 2003 blackout period are excluded.



Load Duration Curves for New York
Summer 2002 vs. Summer 2003

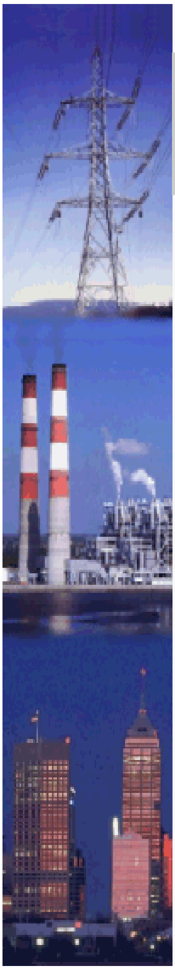


* Summer includes June to August each year. The blackout hours in 2003 are not included.



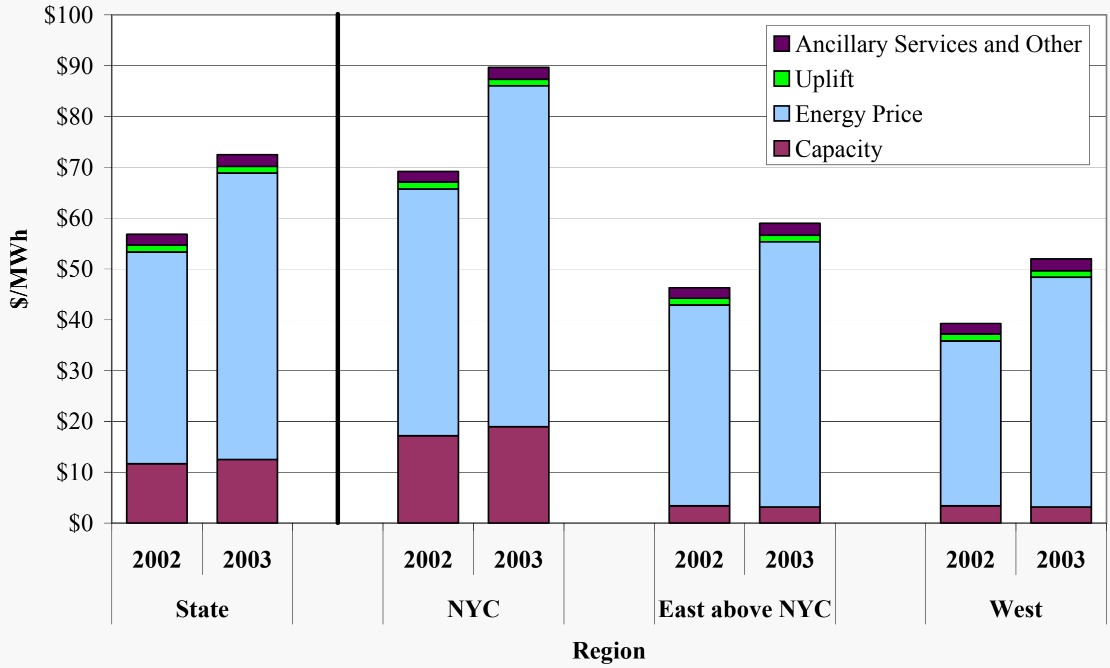
All-In Energy Prices

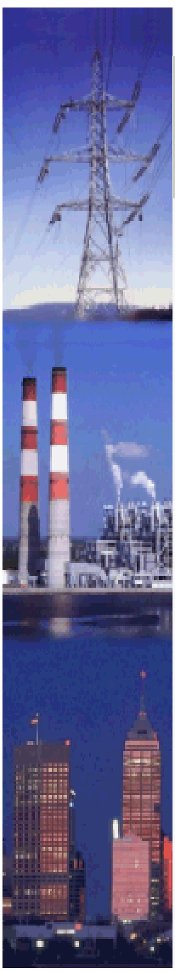
- The following figure calculates an "all-in" price that includes the costs of energy, ancillary services, capacity, and other costs.
  - ✓ The all-in price is calculated for various locations within New York since both capacity and energy prices vary substantially by location.
  - ✓ The energy prices used for this metric are real-time energy prices.
  - ✓ The capacity components are calculating multiplying the weighted average prices of capacity by the obligations for load in each area, then dividing by total consumption energy consumption.
  - ✓ For the purposes of this metric, uplift and ancillary services costs are distributed evenly for all locations.
- This figure shows that the all-in price rose for all locations in 2003.
  - ✓ This increase is primarily caused by higher energy prices in 2003, which rose 36 percent in 2003 due to higher fuel prices.
  - ✓ The capacity component also rose in 2003 due primarily to: a) rising forecasted peak load resulting in a higher obligations, and b) additional purchases under the demand curve.



Average All-In Price in 2002 and 2003

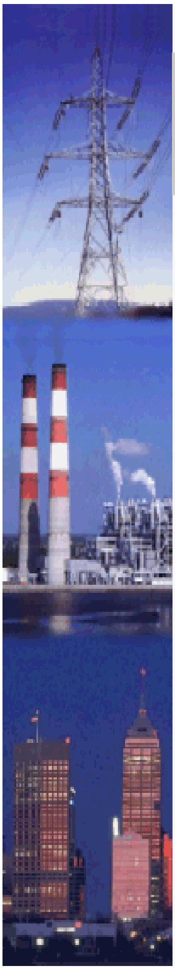
Costs per MWh of Load



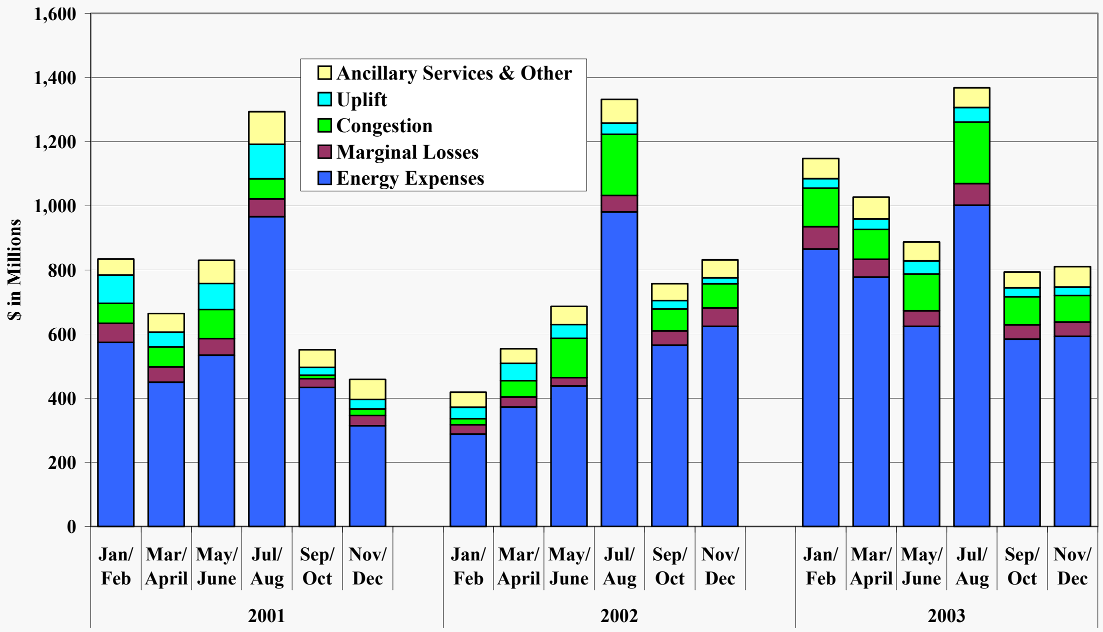


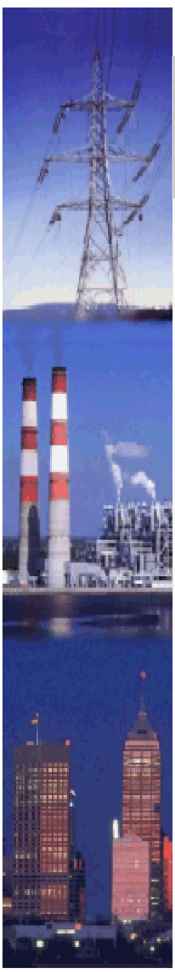
Total Electricity Costs in the New York Markets

- The following figure shows the total expenses for market participants of the NYISO from 2001 to 2003.
- The total expenses in 2003 were approximately $6 billion – an increase of almost one-third over total expenses in 2001 and 2002.
- The primary reason for the increase in total expenses was higher fuel costs in 2003, which lead to higher energy prices.
- A secondary contributor to higher expense totals was a 6% decrease in physical bilateral schedules (i.e., a larger share of settlements through the NYISO markets).
  - ✓ Physical bilateral schedules are not included in expenses for energy scheduled, only the congestion charges associated with the schedules are included in the market expenses.
  - ✓ The decrease in physical bilateral schedules does not mean forward contracting has decreased.



New York Electricity Market Expenses 2001 - 2003

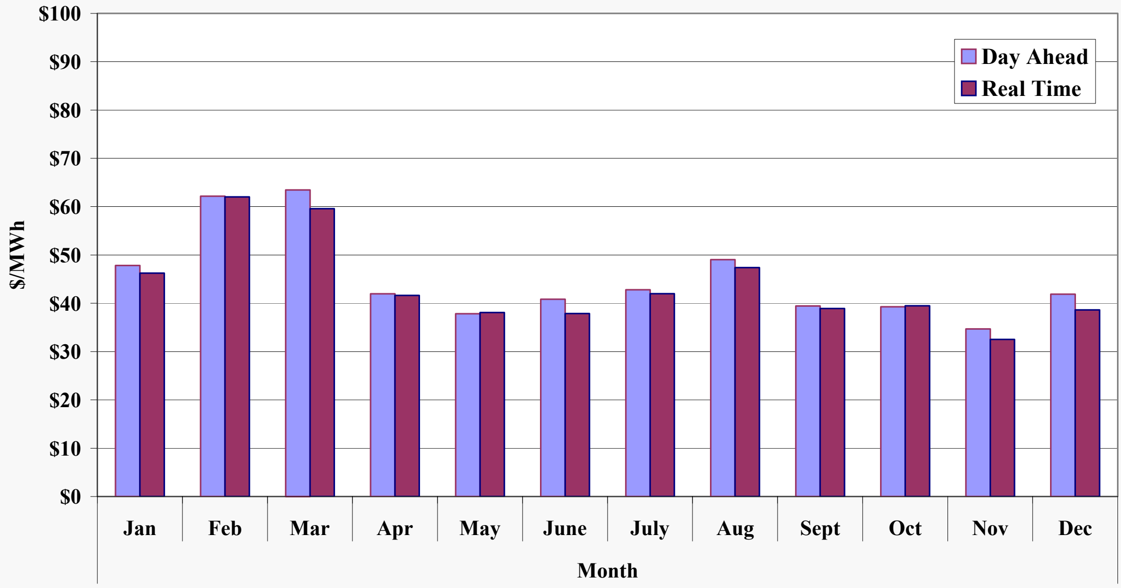




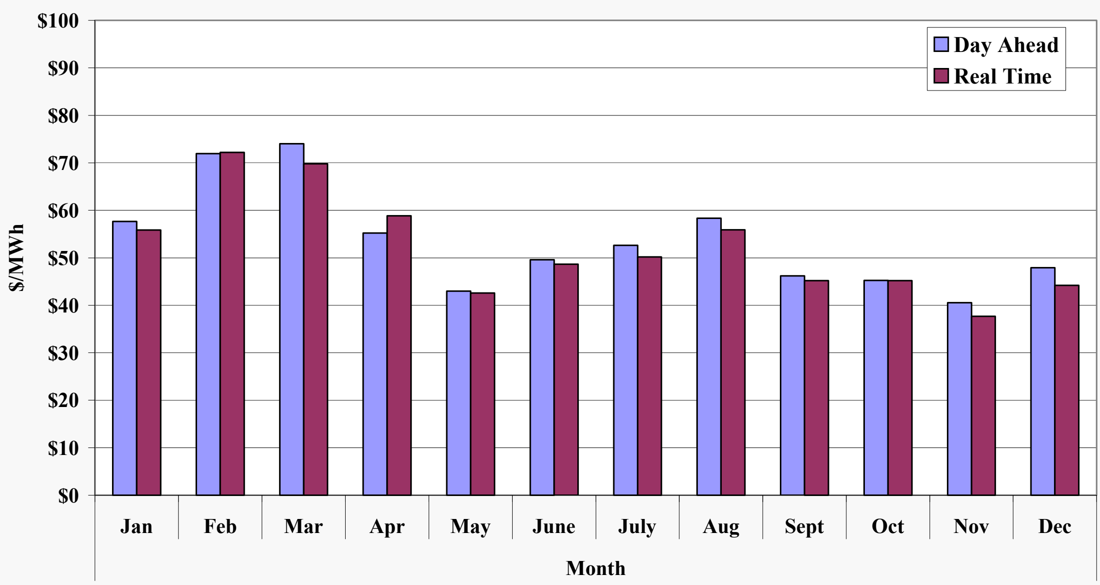
Day-Ahead and Real-Time Energy Prices

- The following three figures show monthly average day-ahead and real-time energy prices in western NY, eastern NY above NYC, and NYC.
- The results show that:
  - ✓ A slight premium in the day-ahead market remains in the areas outside of the New York City area,
  - ✓ In New York, there was a shift to a slight premium in the real-time market, while Long Island prices in both markets remained similar.
- The absolute value of the hourly divergence between day-ahead and real-time prices increased at nearly all of the locations from 2002 to 2003.
  - ✓ This is an unexpected result since more active virtual trading and reduced price volatility due to milder load conditions would be expected to have the opposite impact.
  - ✓ However, higher and more volatile natural gas prices during the year likely contributed to this result.

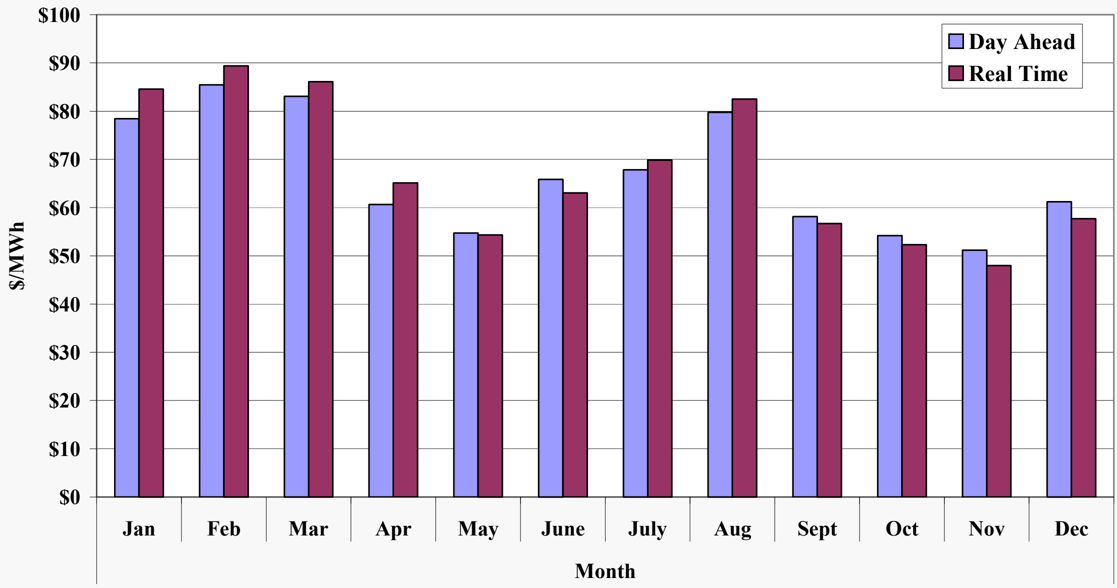
Average Monthly Day-Ahead and Real-Time Energy Prices West Zone 2003



Average Monthly Day-Ahead and Real-Time Energy Prices Capital Zone 2003

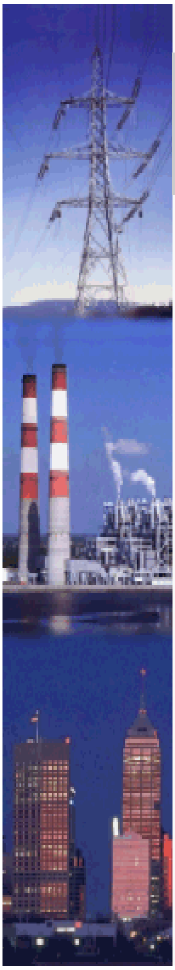


Average Monthly Day-Ahead and Real-Time Energy Prices New York City 2003

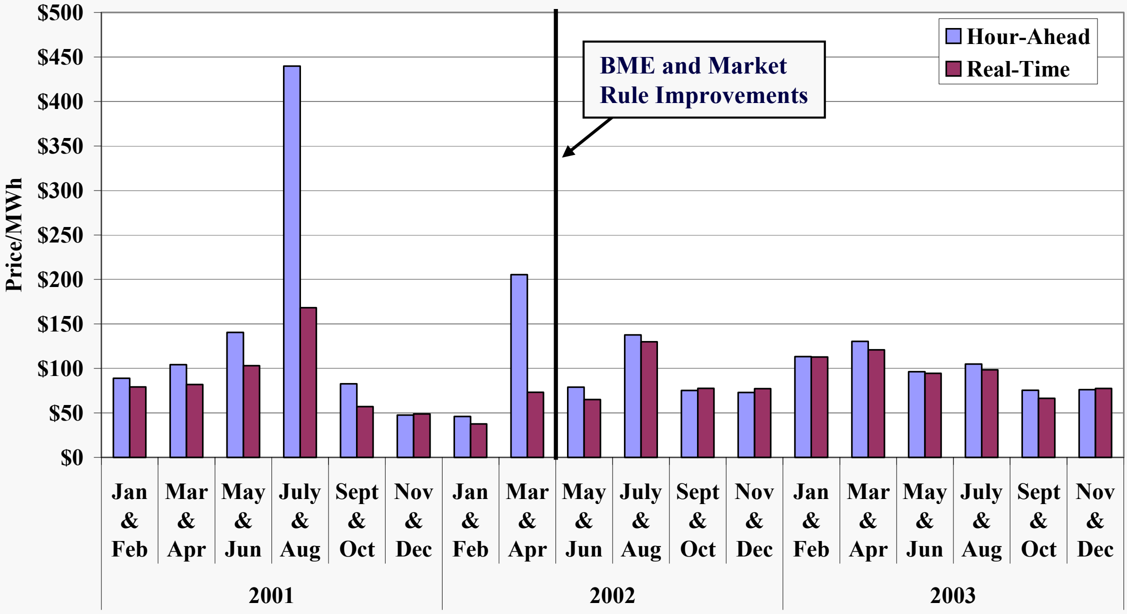


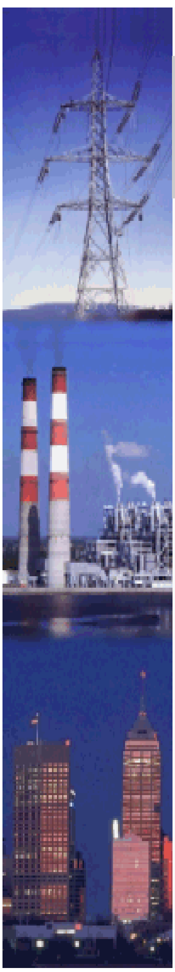
Hour-Ahead and Real-Time Prices

- Lack of convergence between hour-ahead and real-time prices can be a substantial concern because large price differences can result in:
  - ✓ External transactions and off-dispatch generation being scheduled inefficiently; and
  - ✓ Increased uplift costs and inefficient real-time prices.
- Convergence tends to be the worst in the highest demand hours when prices are most volatile.
- The following figure shows that convergence in 2003 continued to be very good, largely due to improvements made to the market rules and the BME model prior to the summer of 2002, including:
  - ✓ Counting exports as 30-minute reserves at specific shadow price levels; and
  - ✓ Crediting latent 30-minute reserves from on-dispatch units in real time.



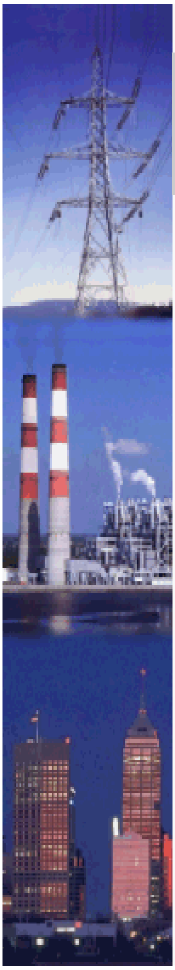
Average Hour-Ahead and Real-Time Energy Prices
East New York – Highest Peak Load Hours





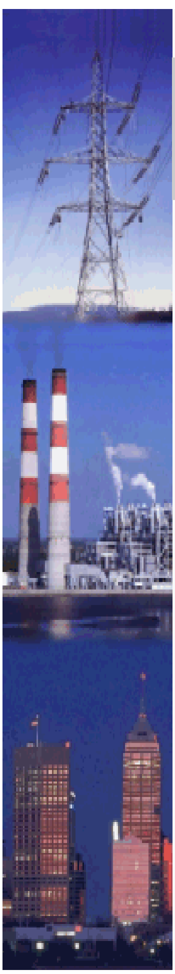
Price Convergence in the Load Pockets

- Modeling of the load pockets within NYC, which was implemented in June 2002, has resulted in:
  - ✓ More accurate locational energy prices as the prices now reflect the load pocket constraints;
  - ✓ Increases in the congestion expenses in the energy market; and
  - ✓ Decreases in uplift that had been paid to generators redispatched to resolve the load pocket constraints.
- Due to limitations of the SCD, a simplified representation of the intra-NYC constraints is used in real time while a more detailed representation is used in the day ahead.
  - ✓ This difference can contribute to divergence between the day-ahead and real-time prices within NYC.
  - ✓ Implementation of RTS, which will utilize the same platform as the day-ahead market software, should address these inconsistencies.

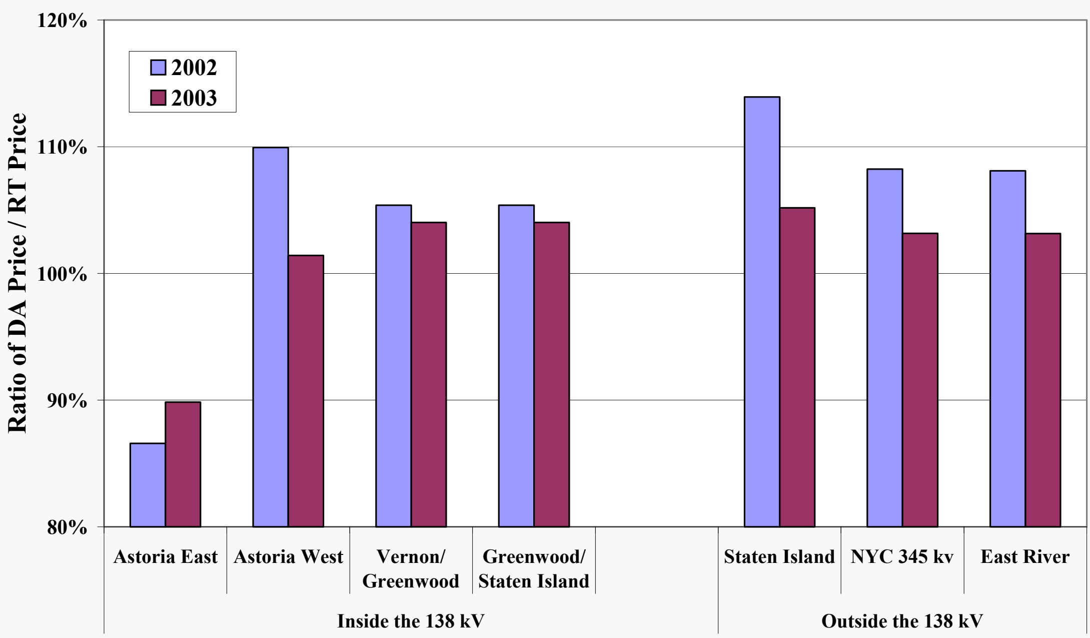


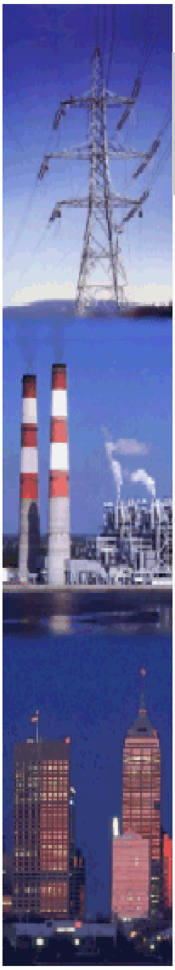
Price Convergence in the Load Pockets

- The following figure shows the ratio of day-ahead and real-time prices in the load pockets in NYC, which indicates:
  - ✓ A large premium in real time in the Astoria East load pocket with the other pockets showing a premium in the day ahead market.
  - ✓ However, these premiums did decline in 2003 relative to 2002.
- Limiting price-capped load bidding and virtual trading to the zonal level in NYC limits the ability of participants to arbitrage large price differences in specific pockets.
- If price convergence issues persist in New York City after the implementation of RTS, I recommend the NYISO consider:
  - ✓ Allowing virtual trading at the load pocket level; or
  - ✓ Allowing virtual trading on the 345kv system separately from the 138 kv system, which would be a smaller departure from the current system.



Day-Ahead and Real-Time Energy Prices in NYC 2002 and 2003

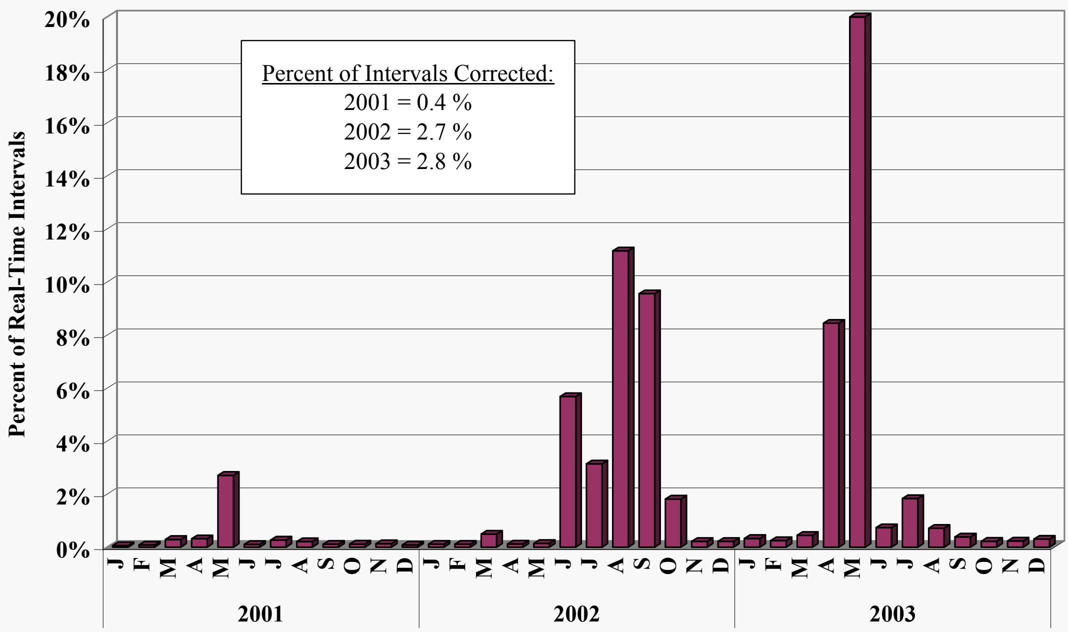


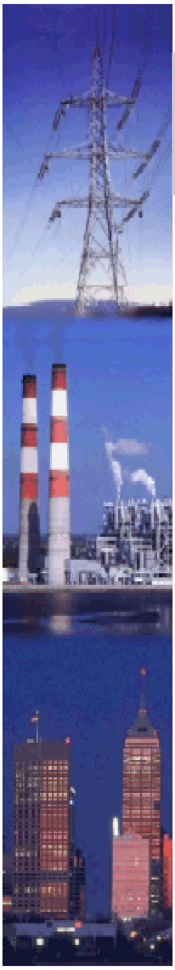


Energy Price Corrections

- All real-time energy markets are subject to some level of price corrections to account for:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- The following figure summarizes the frequency of price corrections in the real-time energy market in 2001-2003.
  - ✓ The rate of corrections declined steadily until the summer of 2002.
  - ✓ The frequency increased substantially when the modeling of the New York City load pockets was introduced in June 2002.
  - ✓ In 2003, price corrections occurred for most intervals on 14 days in April and 7 days in May. These corrections resulted in slight changes to the NYC zonal prices that had been calculated with incorrect weightings.

Percentage of Real-Time Prices Corrected
2001 - 2003

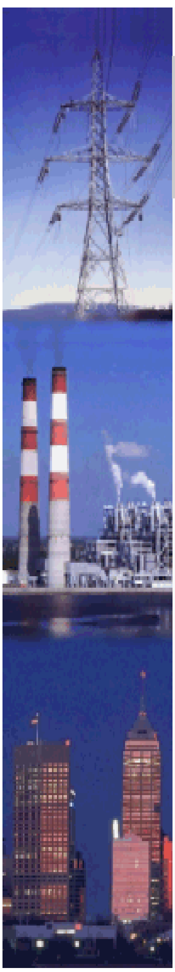




Summary of Mitigation in 2003

Day-Ahead Market

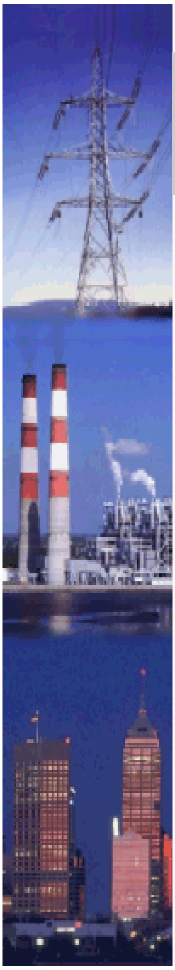
- Mitigation under the automated mitigation procedures (“AMP”) did not occur in 2003.
  - ✓ The AMP is only applied outside New York City;
  - ✓ The AMP software only runs when energy prices outside the City are greater than $150 per MWh since the probability of the impact test being satisfied at lower pre-mitigation prices is extremely low.
  - ✓ The conduct and impact tests in the relatively high priced hours were not satisfied, so mitigation was not warranted.
- Mitigation under the ConEd mitigation measures for New York City occurred frequently, including every day in the summer of 2003.
  - ✓ The ConEd measures for New York City are triggered if there is congestion into NYC in the day-ahead market in any hour.



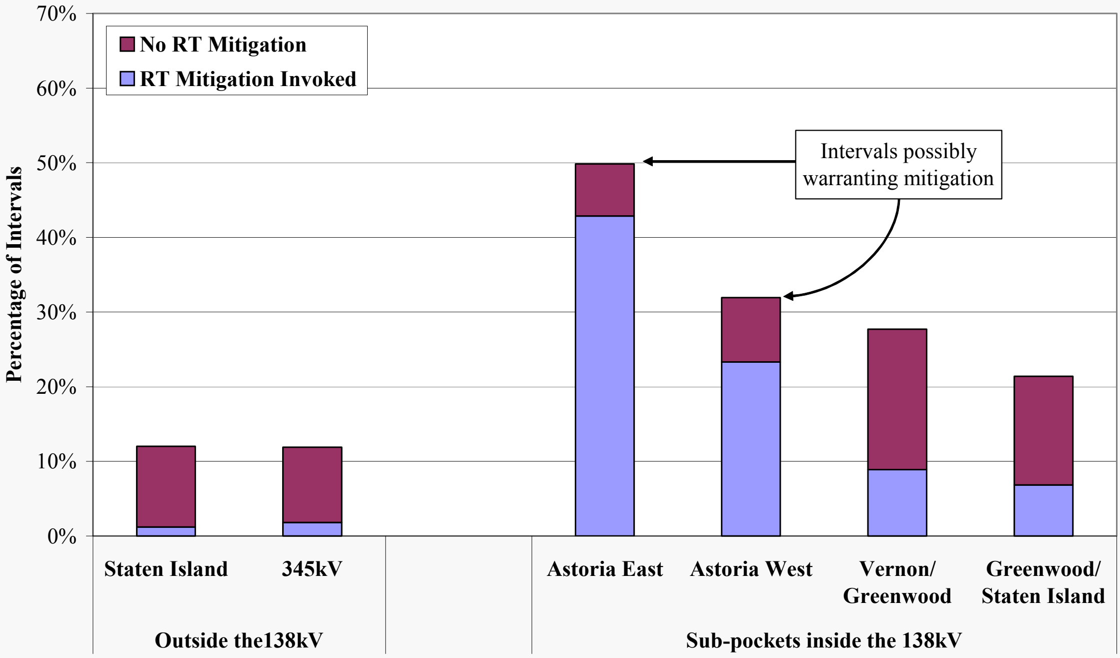
Summary of Mitigation in 2003

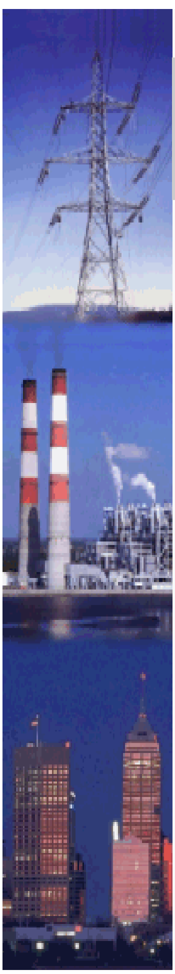
Real-Time Market

- Mitigation measures to address locational market power in the NYC load pockets were implemented when the modeling changes were made to model the constraints into the load pockets.
- The local market power mitigation measures for NYC are triggered when there are binding constraints into a load pocket.
- The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - ✓ The columns show the percent of intervals with a cumulative shadow price into the load pocket that exceeds the load pocket mitigation threshold.
  - ✓ The figure also shows the share of those intervals in which one or more units in the given load pockets were mitigated.
  - ✓ Mitigation was most frequent in the smallest, most congested load pockets that have the lowest mitigation thresholds and the most severe potential market power.



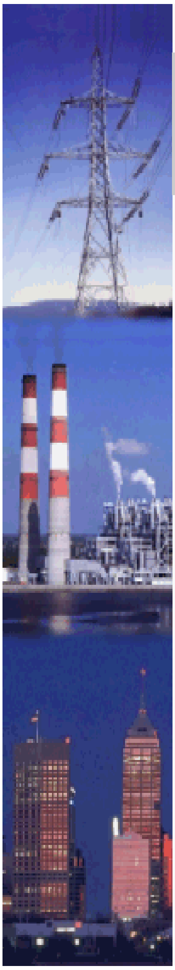
Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets in 2003





Economic Incentives for New Investment

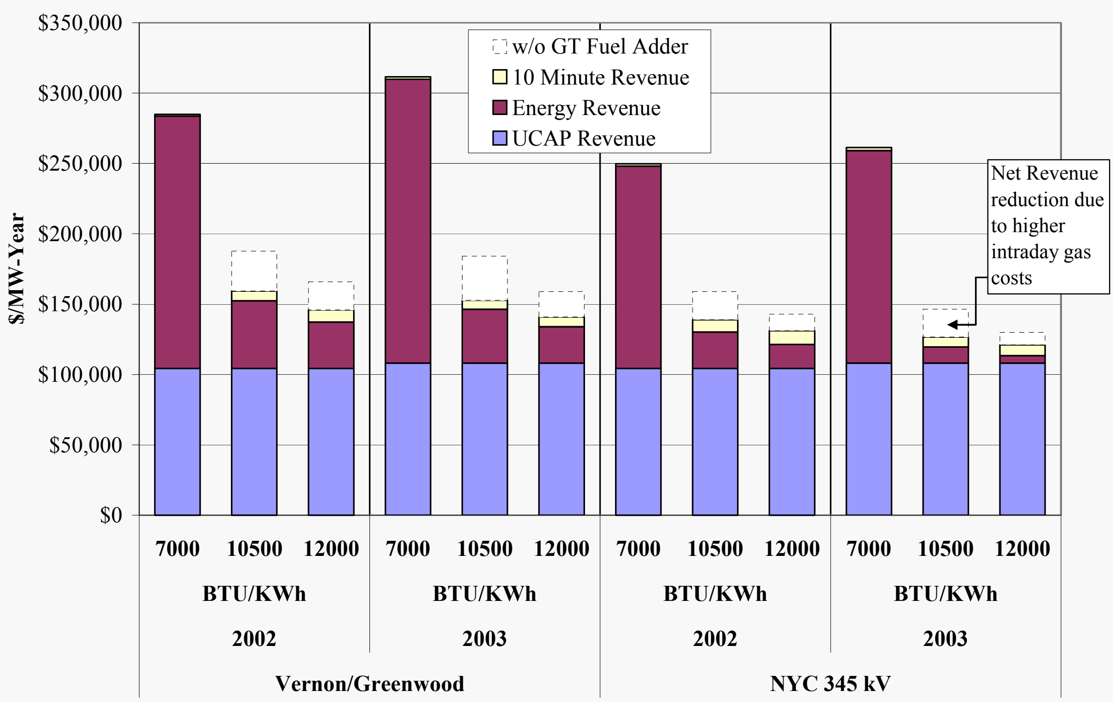
- In long-run equilibrium, the market should support the entry of new generation by providing sufficient net revenues (revenue in excess of production costs) to finance new entry.
- We calculated the net revenue the markets would have provided to different types of units at various locations in 2003. The types of units are:
  - ✓ Gas combined-cycle: heat rate assumed of 7000 BTU/KWh.
  - ✓ New gas turbine: heat rate assumed of 10500 BTU/KWh.
  - ✓ Older existing gas turbine: heat rate assumed of 12000 BTU/KWh.
- For the gas turbines, the following figures show the effect on the suppliers' net revenue of incurring higher costs to purchase natural gas intraday.
  - ✓ Given the infrequency with which gas turbines are dispatched, turbine owners generally will not purchase gas day ahead.
  - ✓ Hence, a gas turbine's net revenue will be reduced by the dashed areas shown in the figure.



Economic Incentives for New Investment

- The first of the two net revenue figures below shows the net revenue in 2003 for two locations within NYC.
- Even though prices were higher in 2003, the net revenue for gas-fired units were mixed in 2003 due to gas price increases.
- These results indicate that the market in 2003 did not produce sufficient net revenue to support investment in a new gas turbine in NYC.
  - ✓ A new gas turbine in NYC would have recovered approximately 60 to 75 percent of the net revenue require annually to support the investment.
- The results for a new combined-cycle unit are less clear.
  - ✓ Net revenue for a new CC in NYC ranges from $250,000 to $300,000 per MW-year.
  - ✓ The required net revenue for a new CC in NYC is unknown.

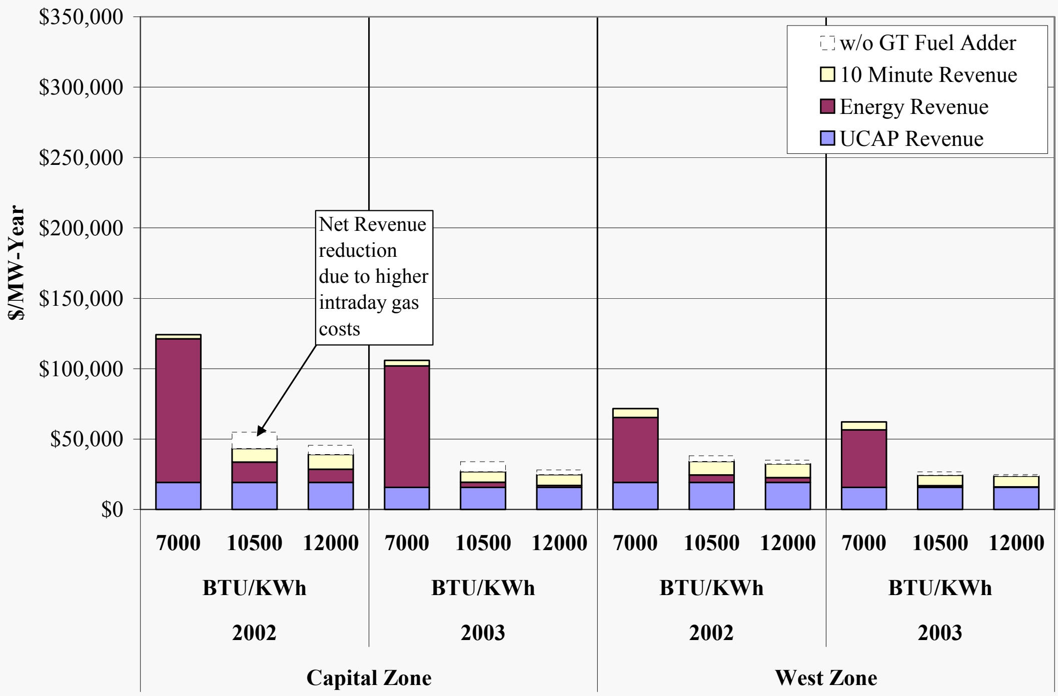
Estimated Net Revenue in the New York City Day-Ahead Market – 2002 to 2003



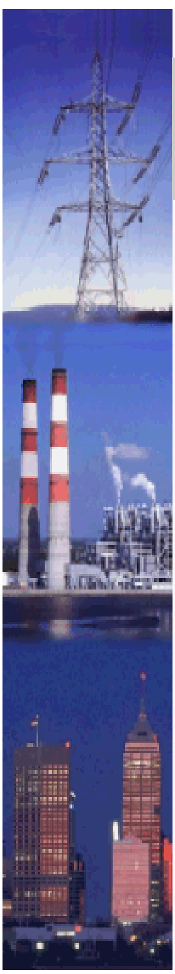
Economic Incentives for New Investment

- The next figure shows the net revenue in eastern and western New York.
- These results indicate that the market in 2003 did not produce sufficient net revenue to support investment in a new gas turbine or CC upstate.
  - ✓ A new gas turbine upstate would have recovered approximately 33 to 42 percent of the net revenue require annually to support the investment.
  - ✓ A new gas CC upstate would have recovered approximately 60 to 95 percent of the net revenue require annually to support the investment.
- However, the net revenue results for NYC and upstate NY do not raise significant long-term concerns because:
  - ✓ The lack of shortages in 2003 reduced the net revenue substantially;
  - ✓ Natural gas units were not likely the most economic source of new capacity in 2003 – net revenue for CC's and other fuel types increased;
  - ✓ The UCAP demand curve is phasing-in, increasing the expected capacity revenue in 2004; and
  - ✓ Upstate NY has a capacity surplus, limiting the need for new gas turbines outside NYC.

Estimated Net Revenue in Upstate New York Day-Ahead Market – 2002 to 2003



Analysis of Bid and Offer Patterns



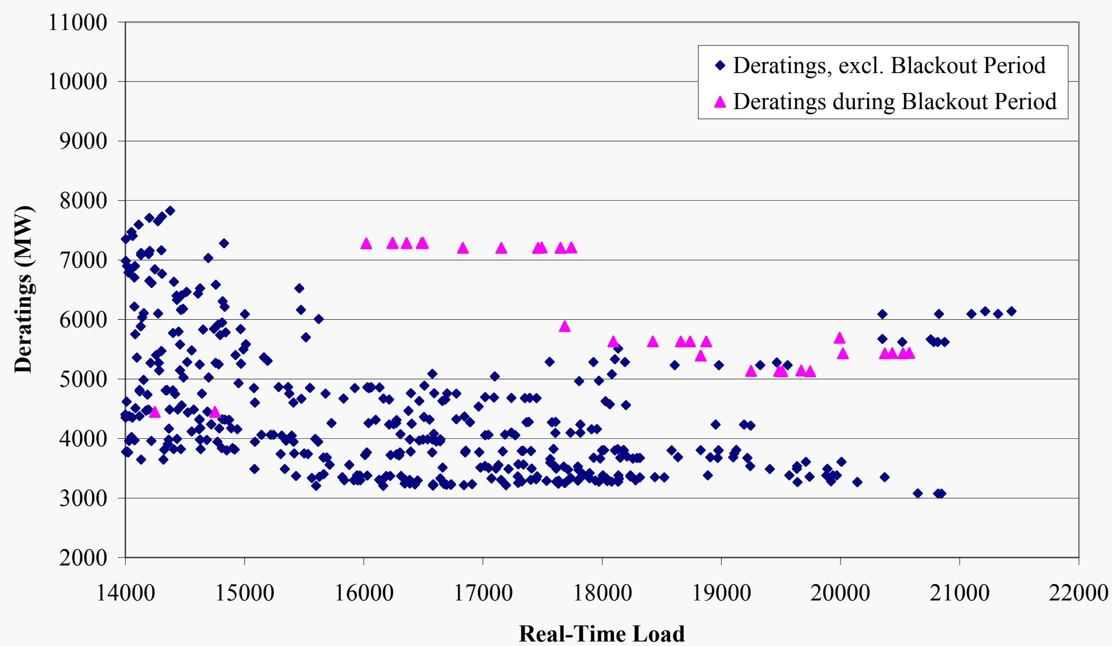
Analysis of Offer Patterns

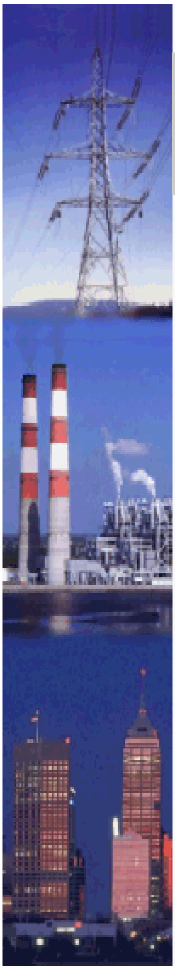
- This section of the report analyzes the patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase offer quantities during higher load periods to sell more power at the higher peak prices;
  - ✓ Suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest.
- The first analysis is of potential physical withholding, analyzing total generation deratings, which include: planned outages, long-term forced outages, short-term forced outages, and partial deratings.

Analysis of Offer Patterns – Deratings

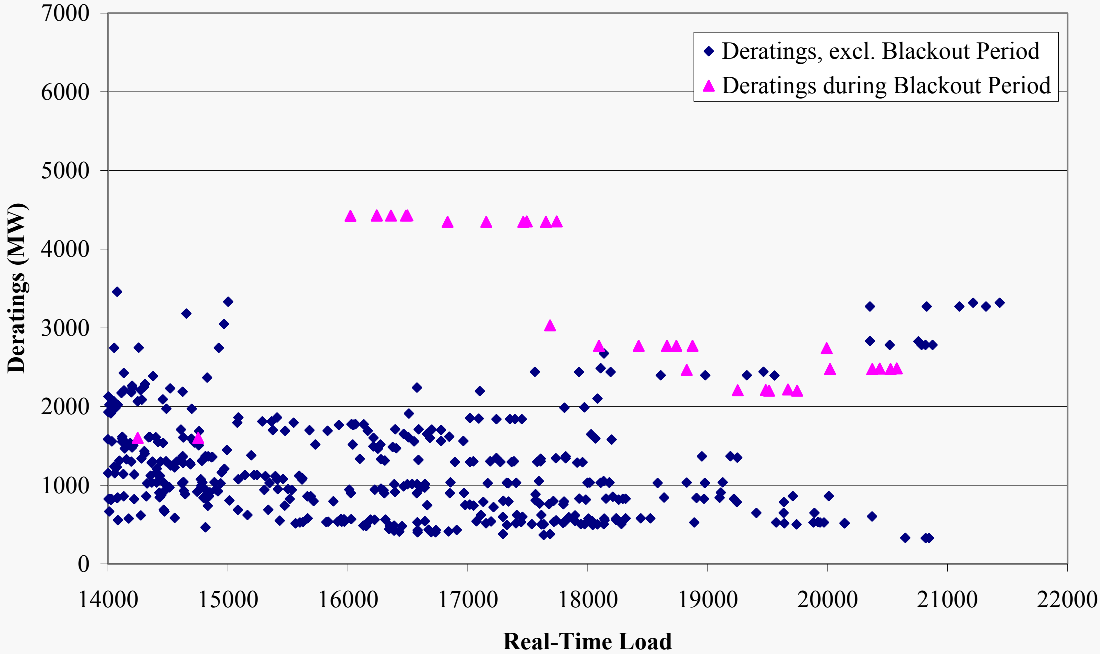
- The following two figures plot the total deratings and short-term deratings versus actual load in eastern NY during peak hours.
  - ✓ In both figures, the purple triangles show the hours during the blackout restoration period in the days following the blackout.
  - ✓ The figures focus on eastern NY 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.
  - ✓ The short-term deratings shown in the second figure are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages.
- These figures show no statistically significant relationship between deratings and load levels.
- However, there were specific instances of high deratings at relatively high load levels.

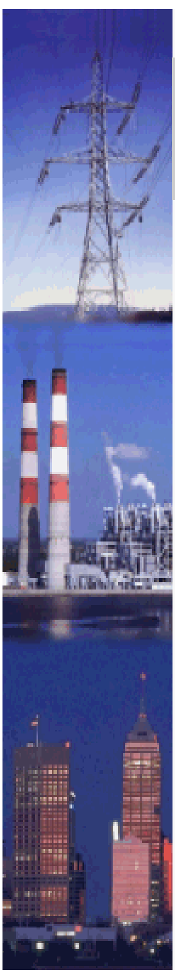
Relationship of Deratings to Actual Load
Day-Ahead Market – East New York





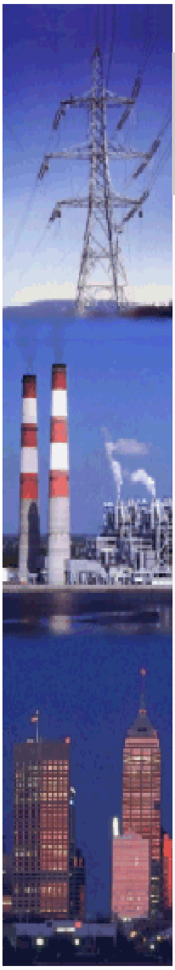
Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market – East New York



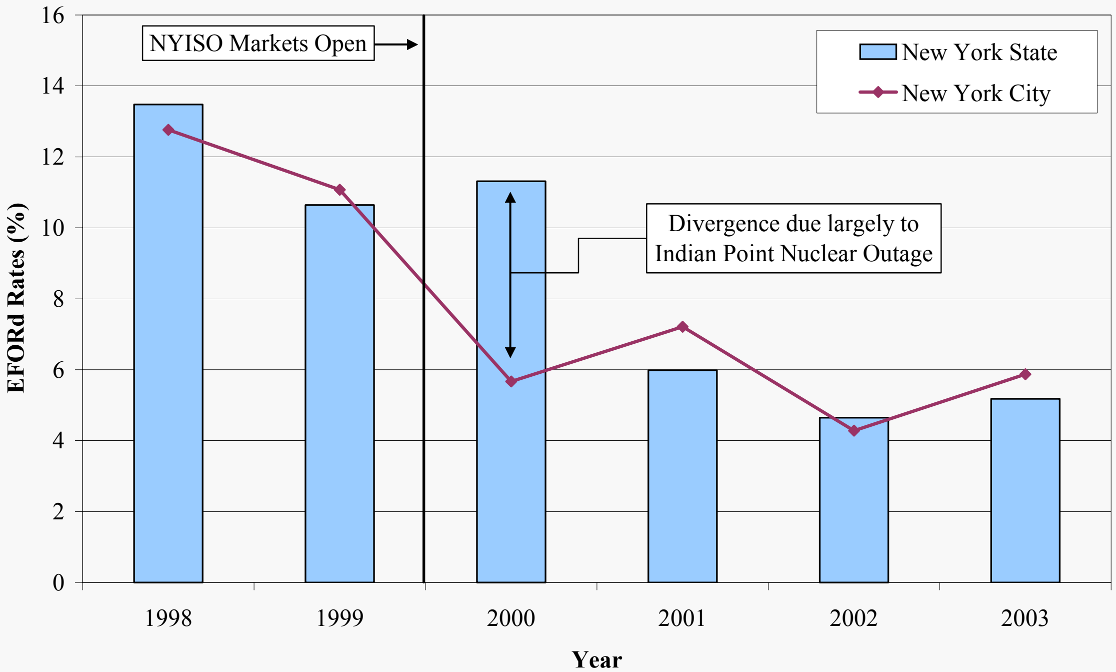


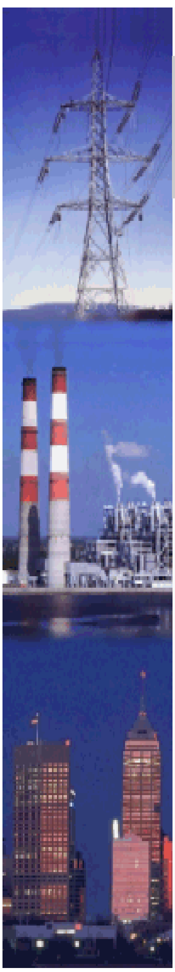
Forced Outages

- The next figure presents the trend in the equivalent forced outage rate from the beginning of the operation of the New York markets.
  - ✓ The Equivalent Forced Outage Rate (EFOR) is the portion of time a unit is unavailable due to forced outages, expressed as equivalent hours of full forced outage at its maximum net dependable capability.
- EFOR declined substantially following the implementation of the NYISO markets.
  - ✓ This is consistent with the incentives the deregulated markets provide to maximize availability, particularly during high load conditions.
  - ✓ EFOR declined again after the change from ICAP to UCAP in the fall of 2001, which increased the incentive to minimize forced outages since a unit's UCAP amount reflects its forced outage rates.



Equivalent Forced Outage Rates
1998 to 2003





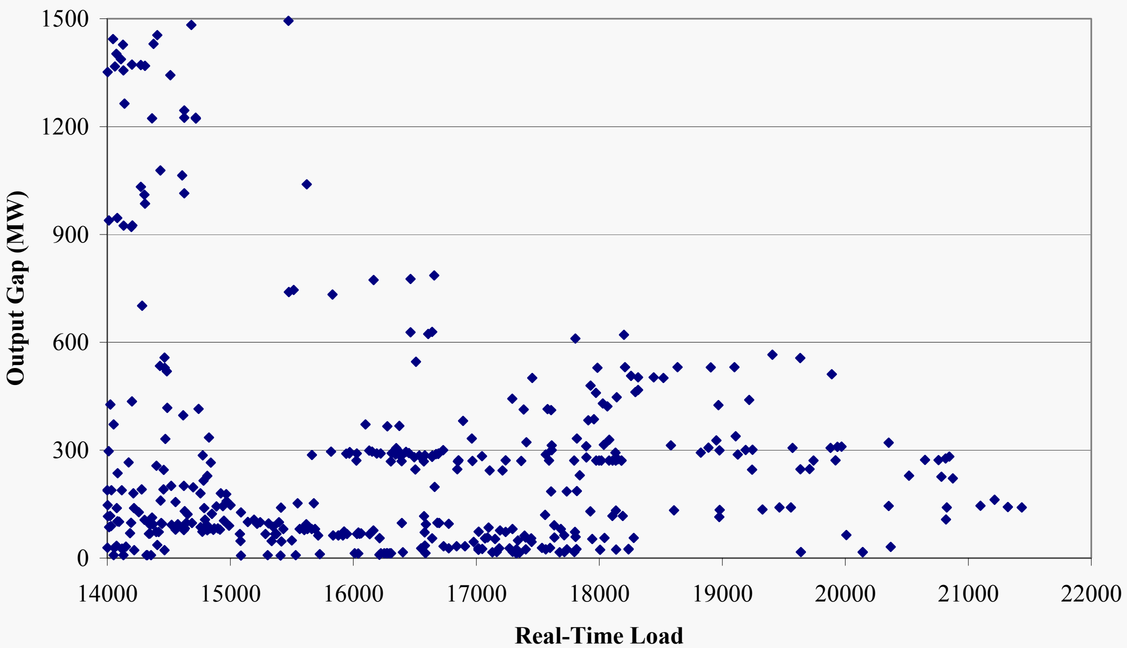
Analysis of Offer Patterns – Output Gap

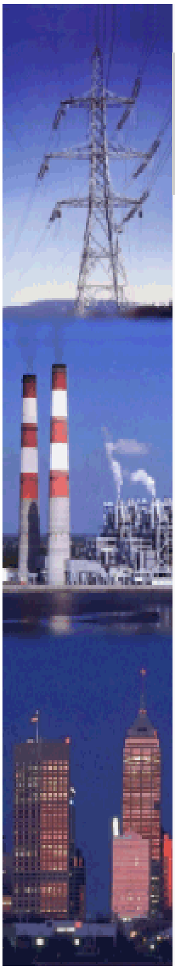
- The second analysis is intended to assess potential economic withholding, employing a measure called an "output gap".
- The output gap is the quantity of economic capacity that does not produce energy or ancillary services because a supplier submits an offer price well above a unit's reference level.
- The output gap:
  - ✓ Addresses all components of a supplier's offer, including start-up, minimum generation, and incremental energy offers.
  - ✓ Includes units that "set the price".
  - ✓ Excludes units scheduled to provide ancillary services.

Analysis of Offer Patterns – Output Gap

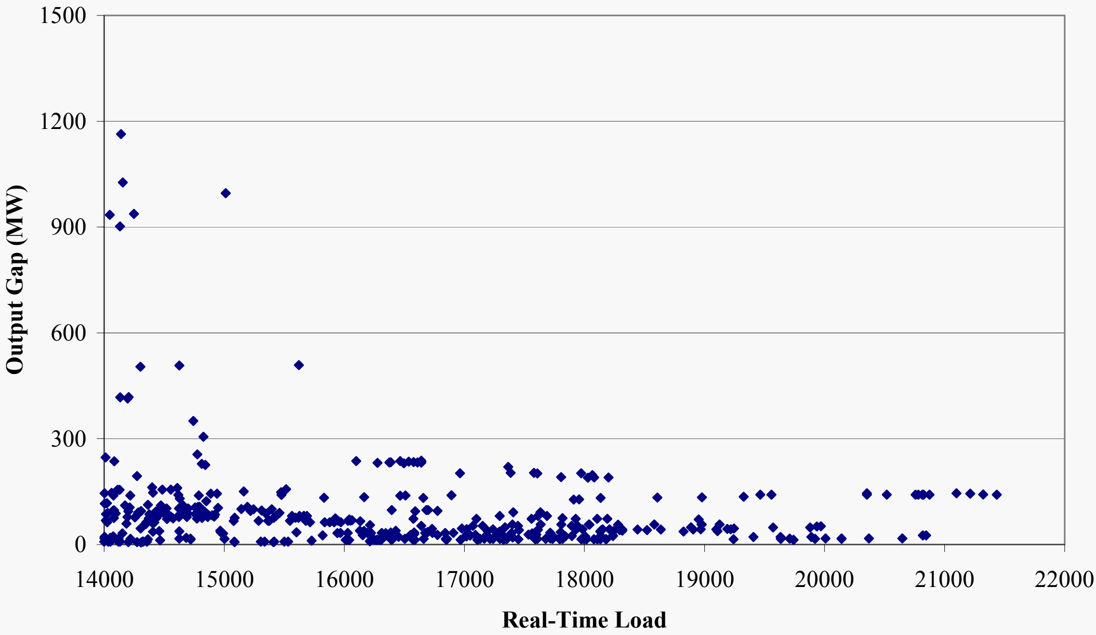
- The following figures shows the real-time output gap in eastern New York during peak hours using:
  - ✓ Low thresholds, \$50/MWh or 100% (whichever is lower), and
  - ✓ Standard conduct thresholds of \$100/MWh or 300% (whichever is lower).
- These figure both show that output gap decreases to extremely low levels under the highest load conditions.
  - ✓ This is an important result because prices are most vulnerable to market power under peak load conditions.
  - ✓ These results indicate that economic withholding was not a significant concern in 2003.

Output Gap at Low Threshold vs. Actual Load Real-Time Market – East New York





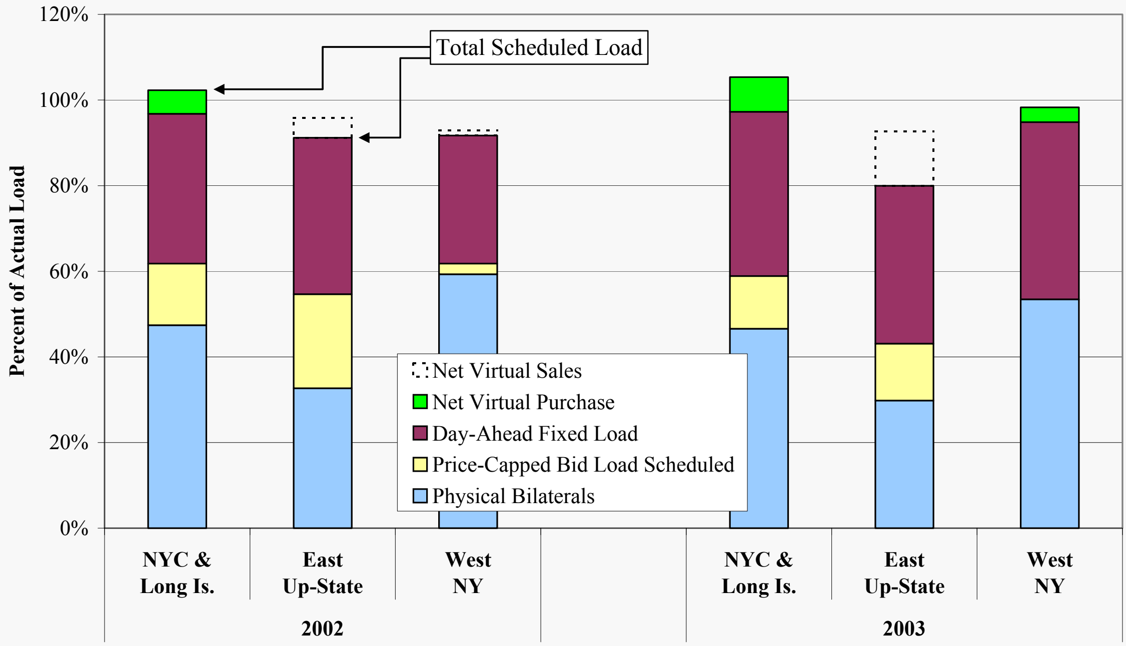
Output Gap at Mitigation Threshold vs. Actual Load Real-Time Market – East New York



Analysis of Load Bidding Patterns

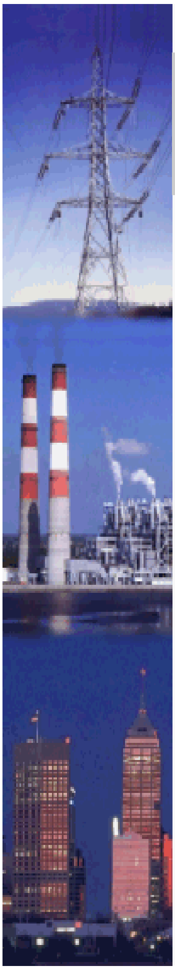
- The following figure shows the load bidding patterns during 2002 and 2003 in the entire state and in New York City.
- The share of load scheduled through price-capped load bids decreased from 14 percent statewide to 8 percent in 2003.
  - ✓ This is a concern because price-capped load bids protect loads against uneconomic purchases and mitigate market power in the day-ahead market.
- The share of the actual load supplied through physical bilaterals has been relatively constant at slightly less than 50 percent.
  - ✓ This does not mean that over 50 percent of the load is incurring the spot prices in the NYISO energy markets.
  - ✓ Physical bilaterals do not include all bilaterals. In particular, financial bilaterals such as "contracts for differences" are settled privately and generally would show as day-ahead fixed load.

Composition of Day Ahead Load Schedules as Proportion of Actual Load - 2002-2003

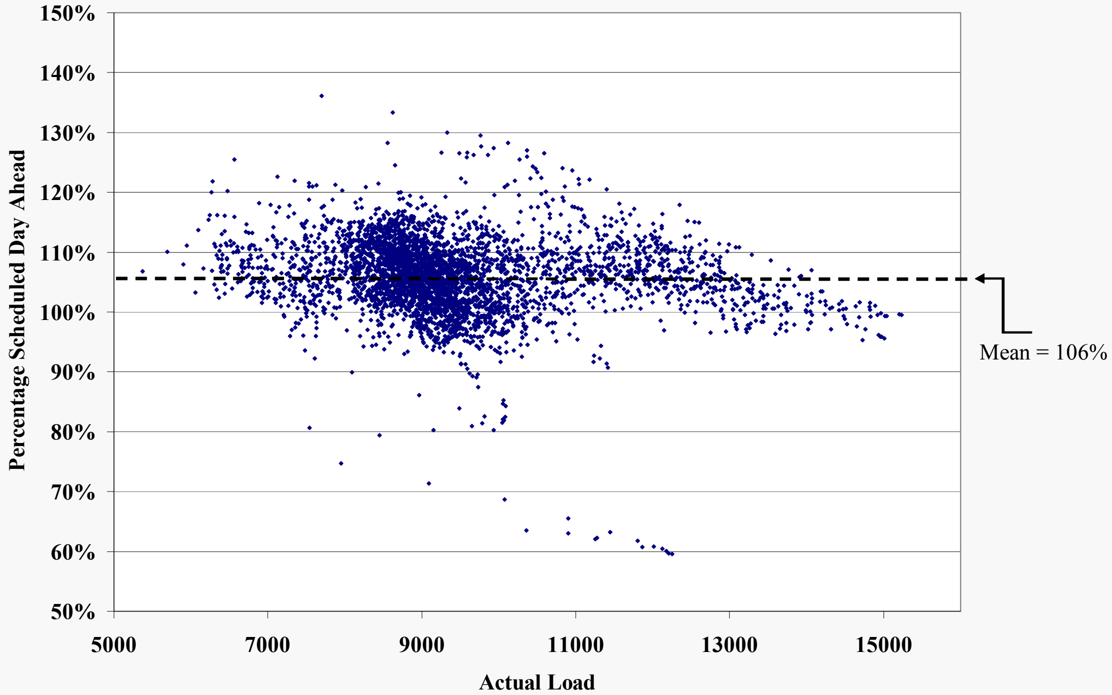


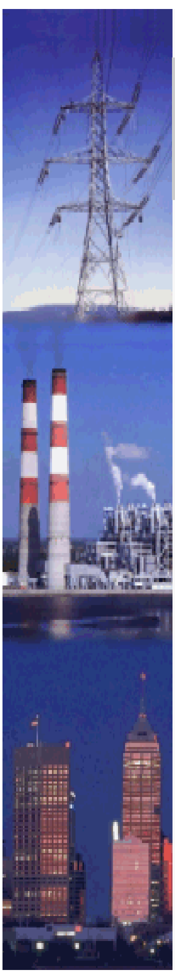
Day-Ahead Load Scheduling

- In order to further evaluate the pattern of load bidding, we analyzed day-ahead hourly load schedules (including virtual load bids) as a percentage of real-time load for peaks hours during 2003.
  - ✓ New York City and Long Island tend to over-schedule load day-ahead. However, the trend line shows that this pattern diminishes in the highest load hours.
  - ✓ Load scheduled day-ahead in Eastern up-state New York is more variable and is usually substantially under-scheduled. This under scheduling decreases with increases in load.
  - ✓ In Western New York, the data reveals that day-ahead load is under-scheduled on average, and that this under scheduling becomes more acute as load rises.
- These results are consistent with the differences between the day-ahead and real-time transmission limits (particularly into and within NYC) that are discussed in the next section.

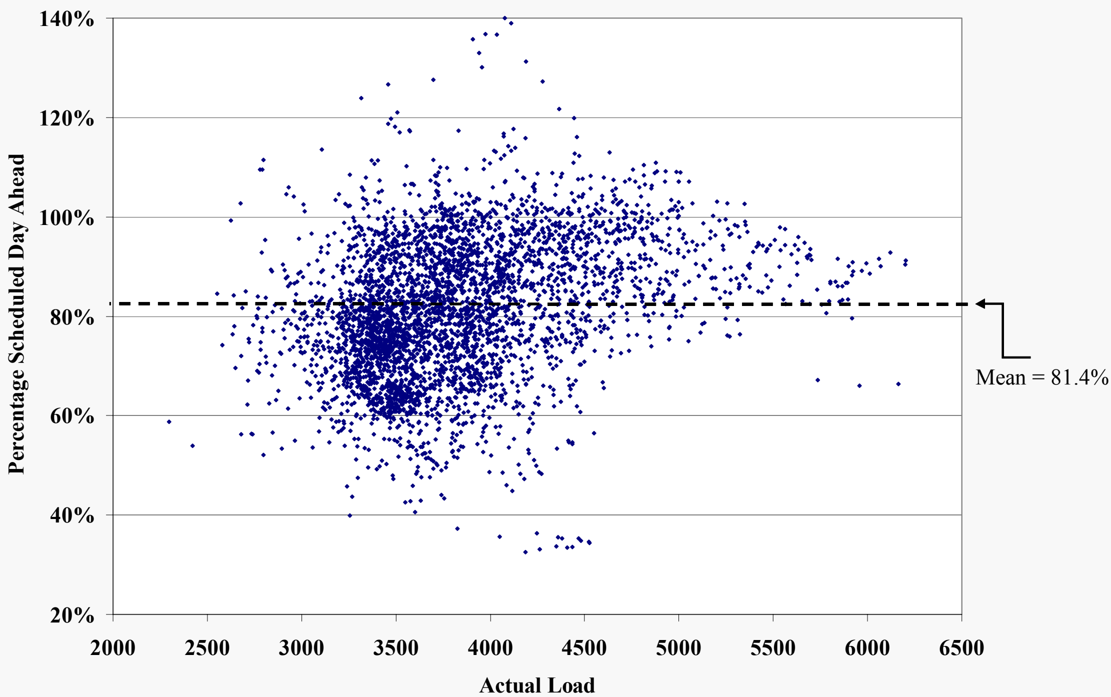


Load Scheduled Day-Ahead v. Real-Time Load
NYC and Long Island – Peak Hours in 2003

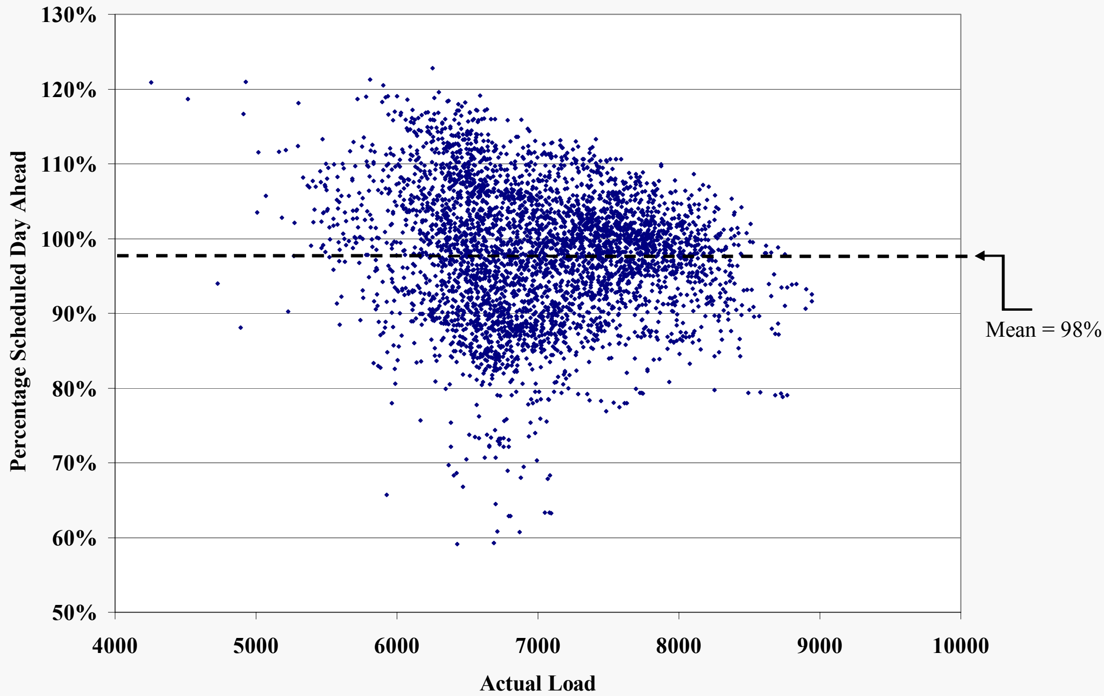




Load Scheduled Day-Ahead v. Real-Time Load
East Up-State New York – Peak Hours in 2003

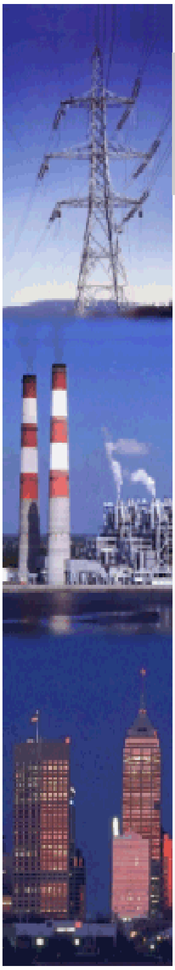


Load Scheduled Day-Ahead v. Real-Time Load West New York – Peak Hours in 2003

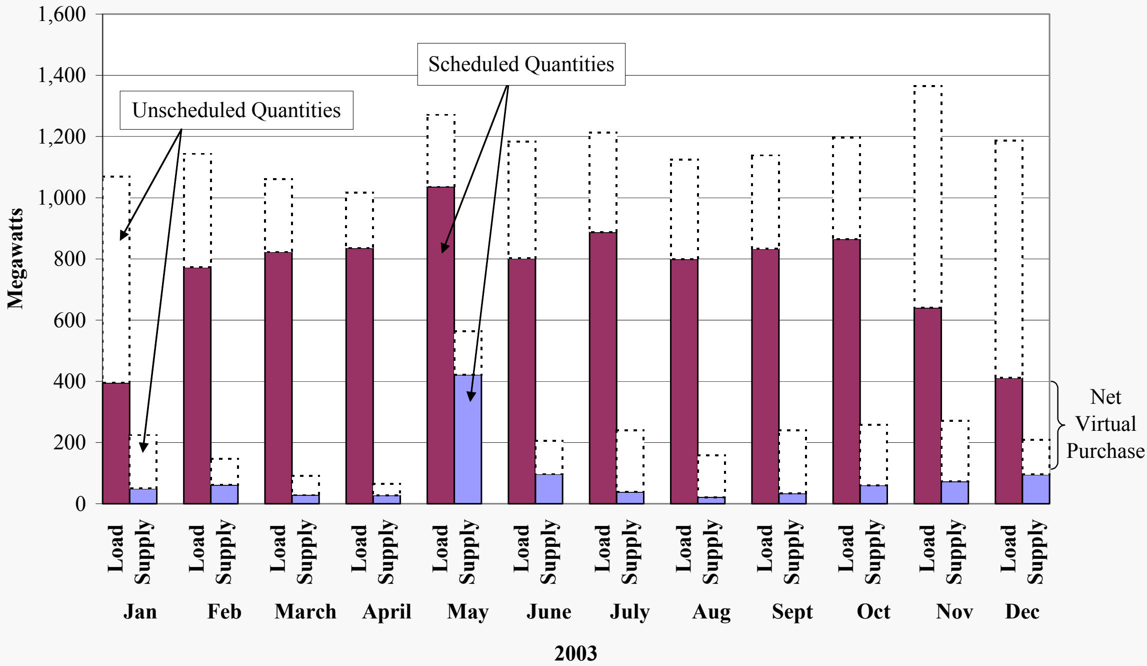


Virtual Trading Patterns

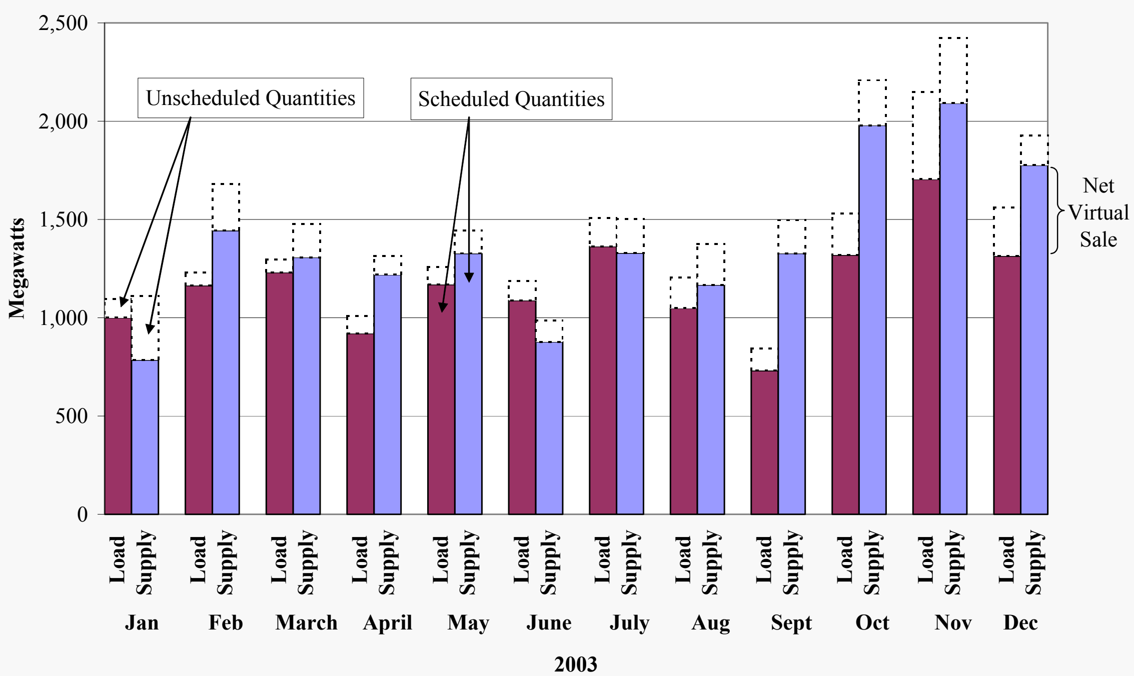
- Virtual trading was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the quantities of virtual load and supply that have been offered and scheduled on a monthly basis in the State and in New York City and Long Island.
- These figures shows the following:
  - ✓ Both scheduled virtual load and supply increased by more than 100 percent in 2003 from 2002 levels.
  - ✓ Virtual load increased by more than 1000 MW per hour on average.
  - ✓ Virtual purchases increased by more than 750 MW per hour on average.
  - ✓ Most of the growth in virtual trading has occurred outside the New York City.



Hourly Virtual Load and Supply
New York City and Long Island - 2003



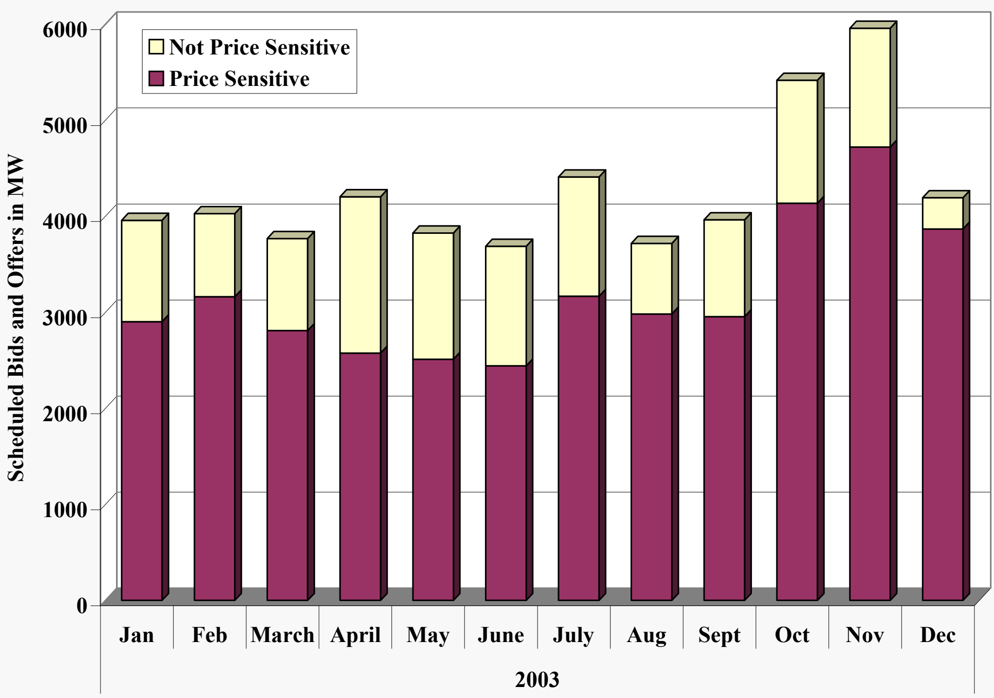
Hourly Virtual Load and Supply
Outside New York City and Long Island - 2003

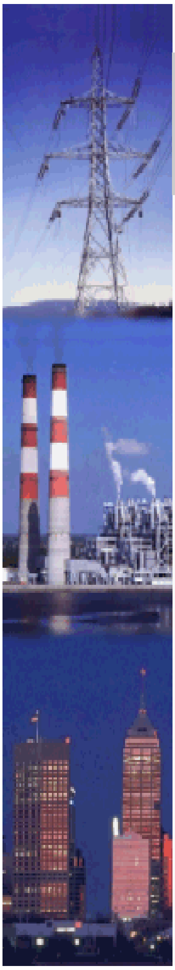


Virtual Trading Patterns

- Concerns have been raised that virtual traders might schedule uneconomic transactions in order to manipulate day-ahead prices.
  - ✓ Price manipulation strategies should be undermined by other participants responding to arbitrage opportunities.
- We monitor for this by determining the share of the virtual bids and offers that are price sensitive, which would be consistent with such arbitrage.
  - ✓ Bids and offers are considered price-sensitive for this analysis if they have a price from 30 percent to 300 percent of the actual day-ahead price.
  - ✓ The average quantity of price sensitive bids and offers nearly doubled between January and December 2002, and continued to increase in 2003.
  - ✓ 75 percent of virtual bids and offers were price-sensitive in 2003.
  - ✓ Price insensitive bids and offers are not a problem as long as a sizable majority of bids and offers are price sensitive.

Price Sensitivity of Virtual Load Bids and Supply Offers
New York State - 2003





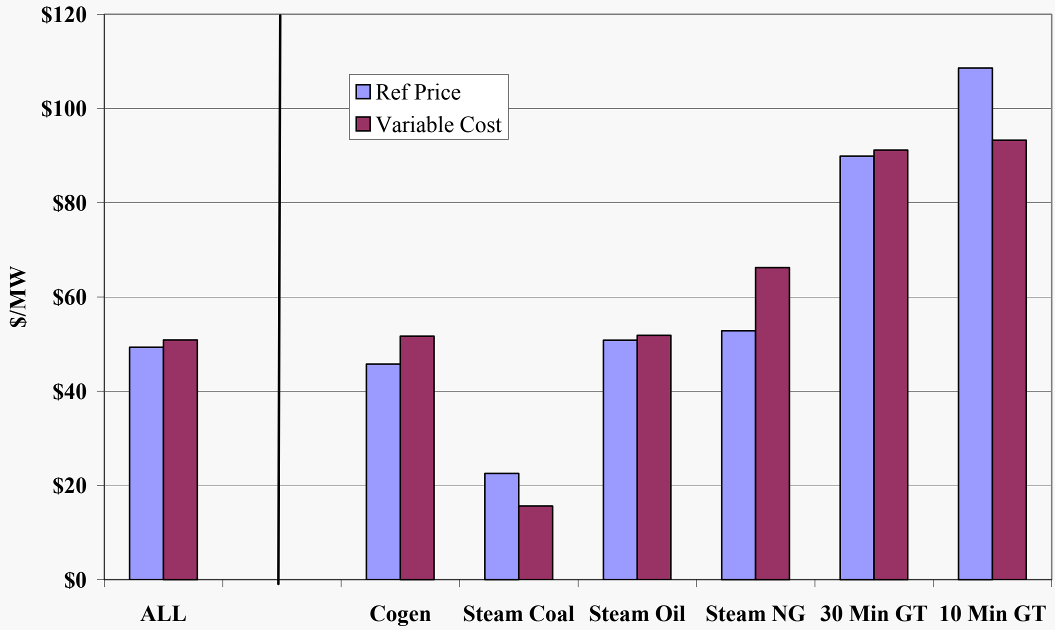
Analysis of Reference Prices

- The final analysis in this section evaluates the reference prices that are the basis for the market mitigation in New York.
  - ✓ This analysis focused on the references prices that are based on the accepted offers into the New York market.
  - ✓ The monitoring plan calls for the calculation of reference prices based on the accepted offers from the units over the previous 90 days during comparable periods, adjusted for changes in fuel prices.
  - ✓ The choice of the lower of the median or average of accepted offers was designed to reduce the incentive to inflate reference prices.
- To assess how well the reference prices are reflecting marginal costs, we compare the reference prices for different types of units to estimated variable production costs.

Analysis of Reference Prices

- The following figure shows the relationship between offer-based reference prices and estimated variable production cost for various types of units.
  - ✓ The analysis compares the average offer-based reference prices from the real-time market over the normal output range of each unit to the average estimated variable costs over the same range.
  - ✓ The comparison was conducted for one day in each month during 2003.
  - ✓ Overall, we found that reference prices statewide, on a weighted average basis, were 3.0% below average variable cost.
  - ✓ When cogeneration units were eliminated from the analysis, reference prices were 1.2% below average variable cost.

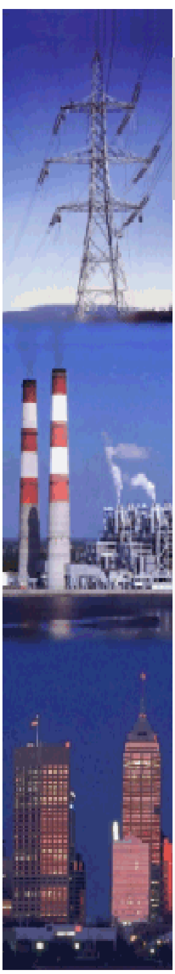
Reference Prices and Variable Costs



Analysis of Offer Behavior

- We also performed some econometric analyses to investigate whether suppliers attempt to change their offers to influence their reference levels.
- The offer behavior of a group of 93 generation units in the real-time market outside New York City was examined.
  - ✓ Generation offers were regressed against market prices and a fuel escalation factor to account for the fact that higher energy prices will cause generators to offer higher.
  - ✓ A positive relation between offers and market prices may indicate strategic attempt to raise a unit's reference prices, but it may also reflect other factors.
- With few exceptions, these tests showed little correlation between offer prices and market prices. This is not unexpected given the costs and benefits of this strategy.
  - ✓ The vast majority of units showing a positive relationship are owned by a single supplier.

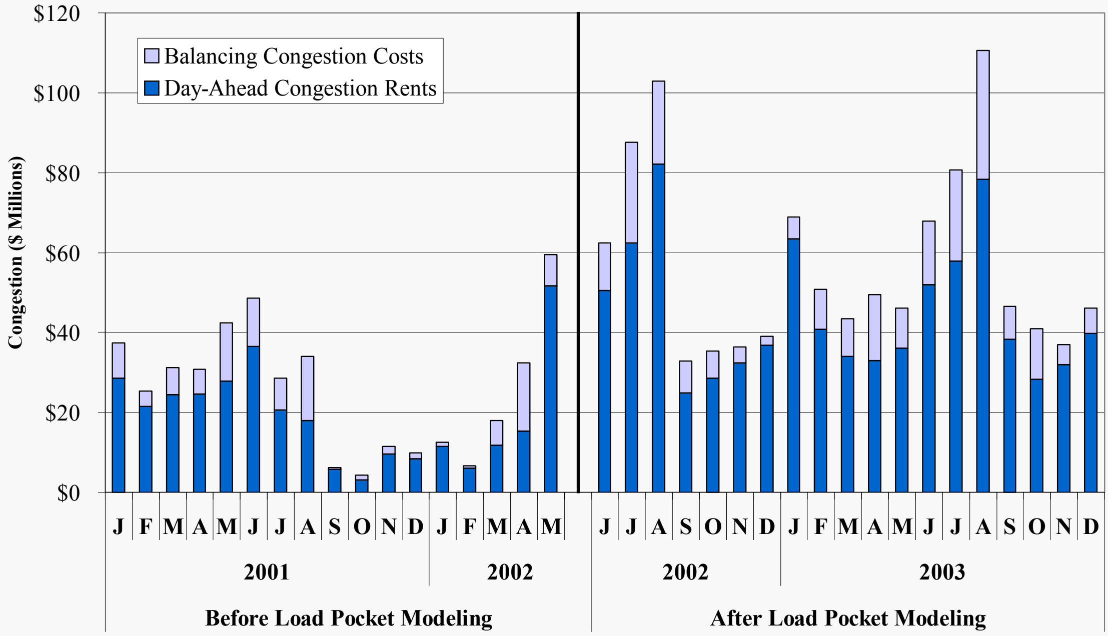
Market Operations



Congestion Costs

- The following figure shows monthly congestion costs collected in the day-ahead market and the real-time market (i.e., balancing congestion costs).
- This figure shows that congestion costs have increased from 2001 to 2003:
  - ✓ $310 million in 2001
  - ✓ $525 million in 2002
  - ✓ $688 million in 2003
- The increase in congestion costs from 2001 to 2003 is partly due to the modeling of the load pockets within New York City, which began in June 2002.

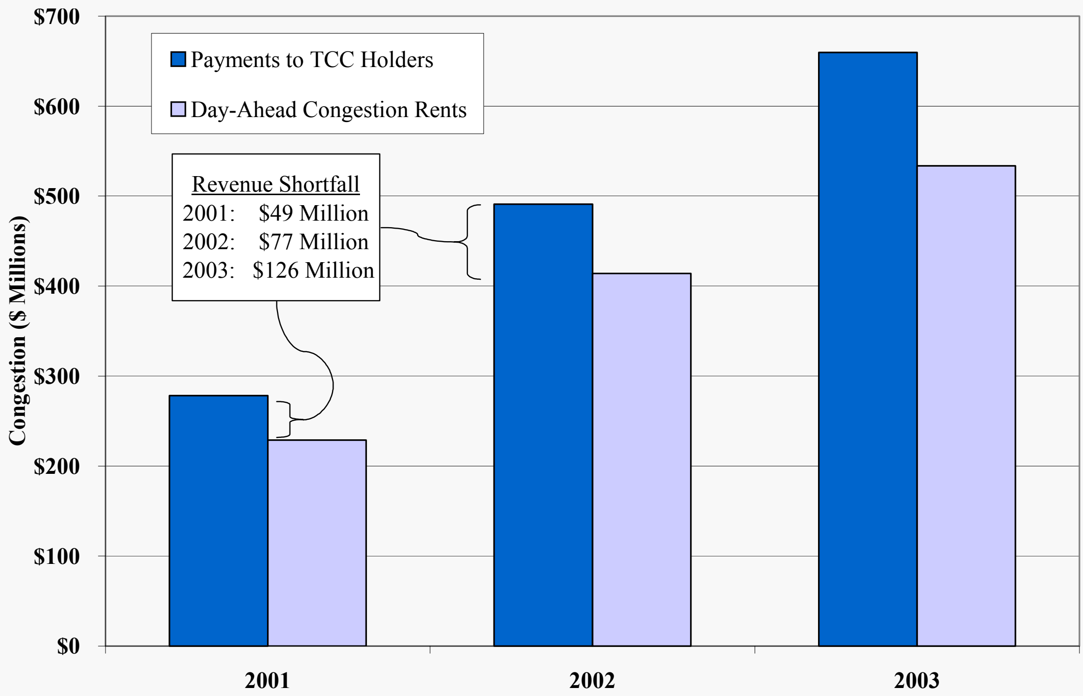
Monthly Congestion Expenses 2001 - 2003



Congestion Revenue and TCC Obligations

- To evaluate the NYISO congestion costs, we analyzed several metrics.
- First, we compared the day-ahead congestion costs paid by market participants to the TCC payments made to market participants.
  - ✓ In a well-functioning system, these values should be roughly equal.
  - ✓ Congestion revenues were lower in all three years as compared to payments to TCC holders.
  - ✓ These "shortfalls" have generally been related to transmission outages that cause transmission capability in the day-ahead market to be less than was assumed when the TCCs were sold.
  - ✓ The NYISO has implemented changes to address these shortfalls by allowing up to a 5% reduction in the quantity of TCCs offered in the auction by each transmission owners.

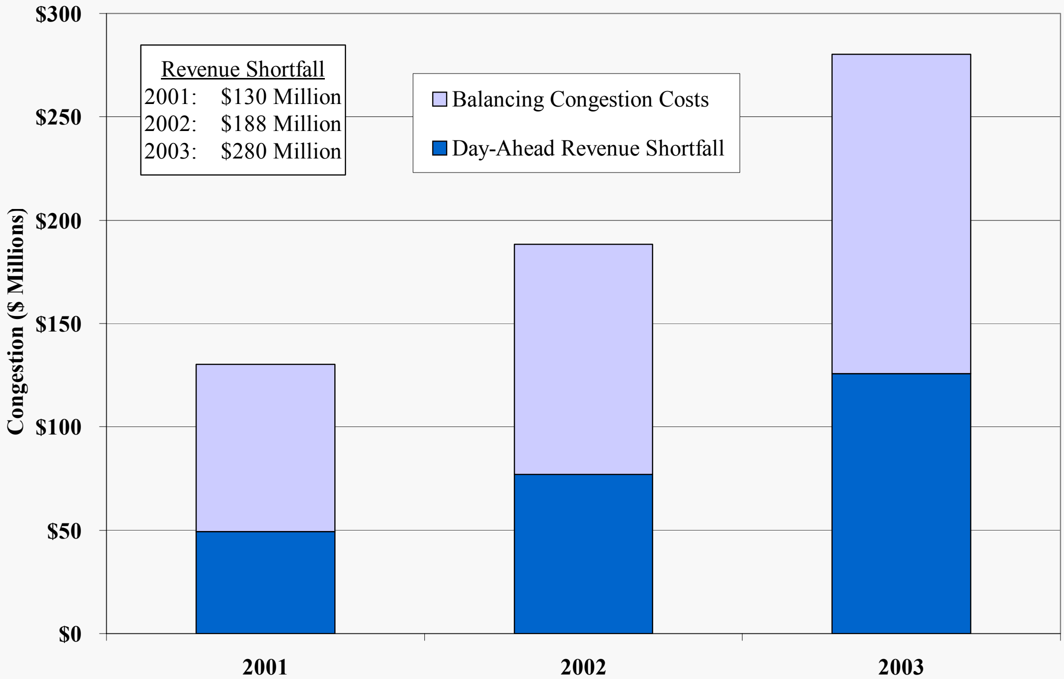
Day-Ahead Congestion Costs and TCC Payments



Congestion Shortfall

- We also examined the amount of congestion revenue shortfall incurred in the day-ahead market and the balancing market.
- The real-time spot market can result in congestion payments from the NYISO or to the NYISO.
  - ✓ The primary cause of positive real-time congestion costs are changes in transmission limits between the day-ahead and real-time markets.
  - ✓ When transmission capability increases in real-time, there tends to be net negative congestion payments.
  - ✓ If transmission outages are random, the magnitude and direction of these congestion payments should be distributed randomly and should sum to zero over time.
- However, as the following figure shows, the real-time congestion costs have been positive and increasing over time.
  - ✓ Positive real-time congestion costs can arise when a day-ahead contract cannot be fully executed due to a decrease in transmission availability.

Day-Ahead Shortfalls and Real-Time Congestion
2001 - 2003



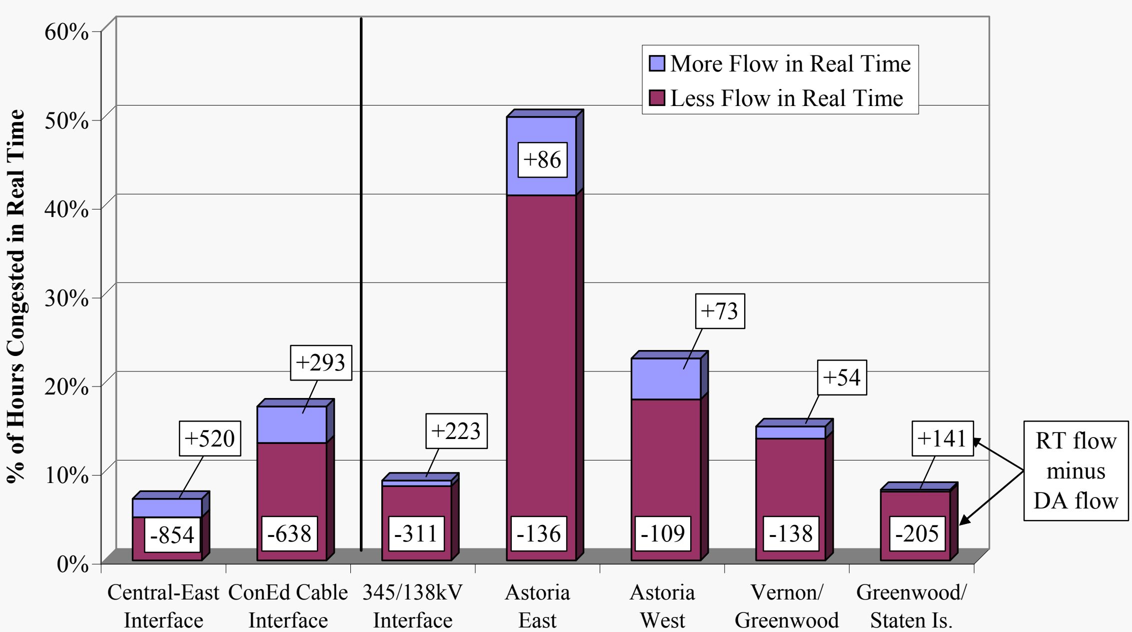
Real-Time Congestion and Interface Flows

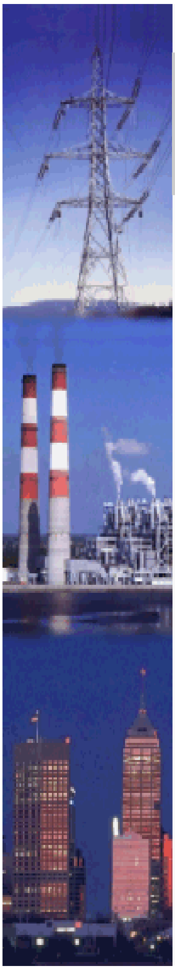
- The primary causes of incremental congestion costs in real time are changes in real-time transmission limits and loop flows.
- To evaluate the consistency of the transmission limits in the day-ahead and real-time markets, the next figure shows:
  - ✓ The portion of the hours congested over the primary transmission interfaces in real time, and
  - ✓ The change in flows from day ahead to real time.
- The height of each bar indicates the percent of hours in which real-time congestion existed.
  - ✓ These bars are divided to show the portion of hours in which the real-time flows were greater or less than day-ahead flows.

Real-Time Congestion and Interface Flows

- The values that are shown for each bar indicate the average change in real-time versus day-ahead flows.
  - ✓ The lower portion of each bar contains a negative number, indicating a reduction in real-time flows compared to day-ahead flows – these reductions indicate reductions in transmission limits.
- The figure shows that the limits into and within NYC generally decrease in the real-time market by substantial amounts.
- These results are consistent with the real-time congestion costs, as well as the over-scheduled load in NYC and under-scheduled load outside of NYC in the day-ahead market.
- The RTS will improve the consistency of the transmission limits and other assumptions because both the RTS and SCUC models operate on a common software platform.

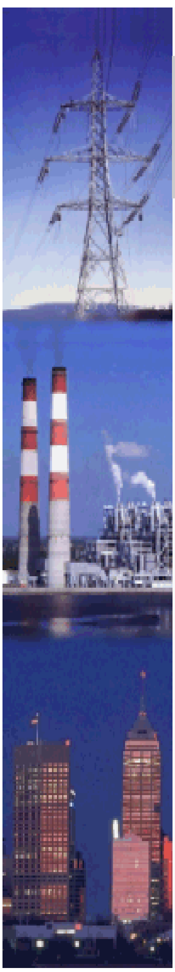
Real-Time Congestion and Interface Flows 2003



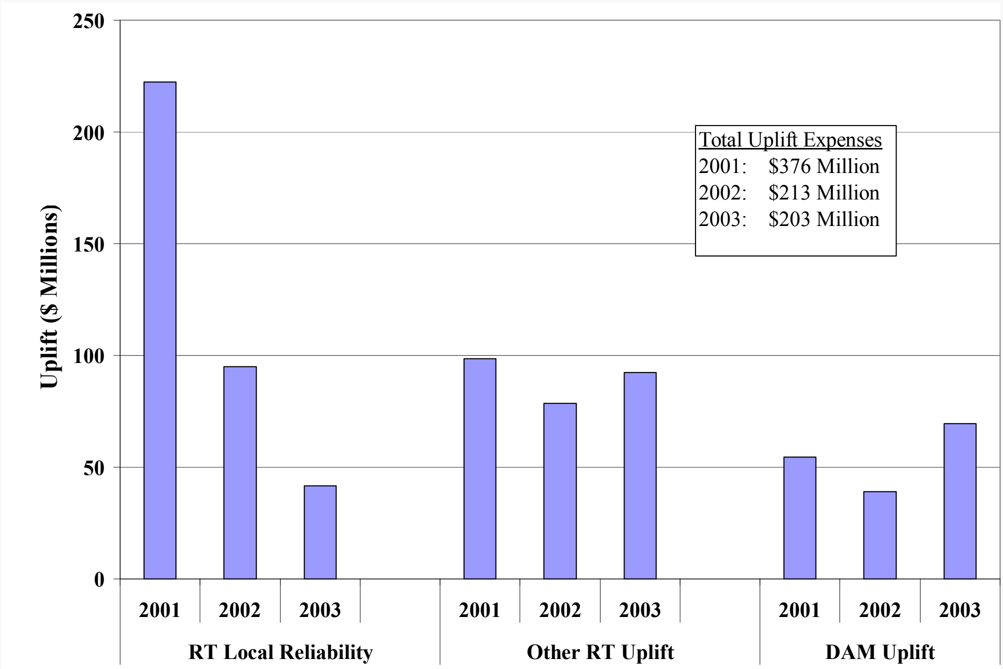


Uplift Expenses

- Uplift costs have fallen sharply since 2001, although high fuel prices at the end of 2002 and in 2003 reduced the apparent savings relative to 2001.
  - ✓ Despite higher fuel costs, total uplift costs declined slightly in 2003.
- Real time local reliability uplift has declined the most, due to load pocket modeling.
  - ✓ Previously, the redispach costs to manage load pocket congestion had been collected through uplift.
- Day ahead market uplift increased in 2003. This is uplift paid to units committed by SCUC, mostly in the local reliability pass of SCUC.
- Units committed in the initial commitment receive the majority of the guarantee payments that result in uplift.
  - ✓ These guarantee payments increase when supplemental commitments for local reliability cause day-ahead prices to decrease.



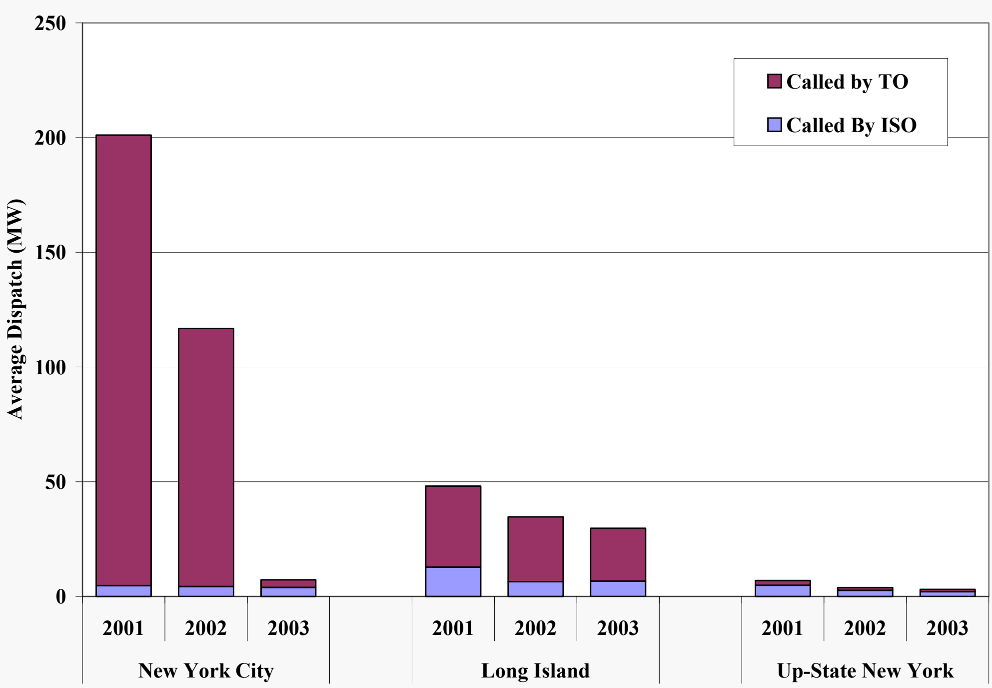
Day-Ahead and Real-Time Uplift Expenses 2001 - 2003



Real-Time Out of Merit Dispatch

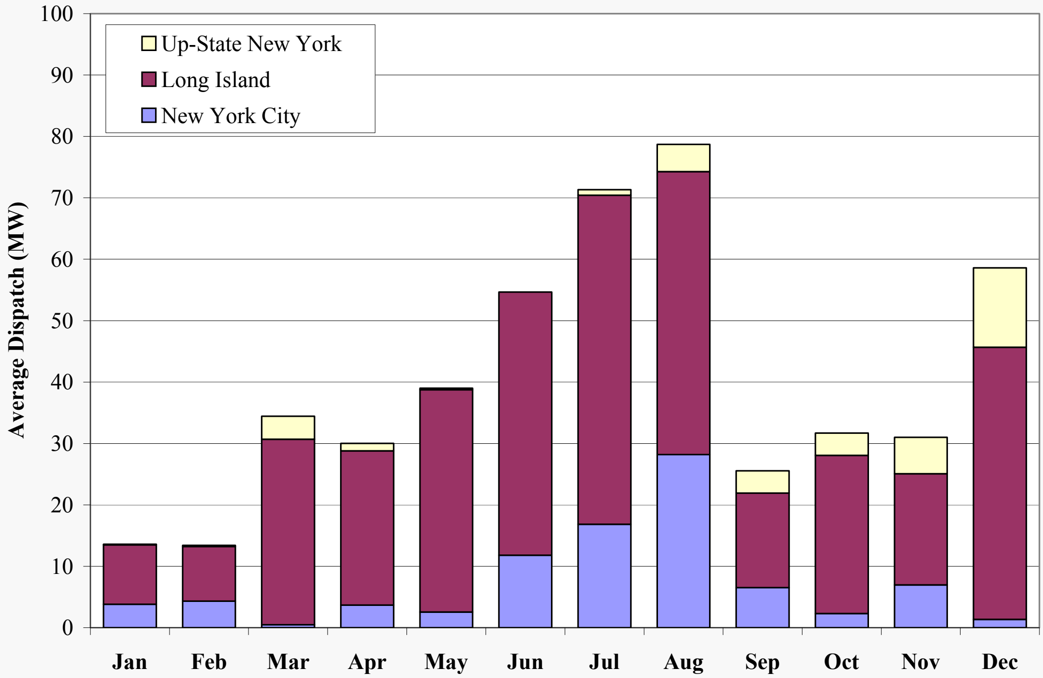
- OOM resources are units logged by the NYISO as OOM (generally manually dispatched), whose offer price is higher than the LMP.
  - ✓ Minimizing OOM dispatch is important because it inefficiently depress energy prices and mask congestion.
- Prior to load pocket modeling, OOM dispatch in New York City accounted for approximately 80% of resources dispatched OOM.
  - ✓ Uplift paid to OOM units is only considered local reliability uplift if the dispatch of the unit is specifically logged as local reliability.
- Long Island units now account for two-thirds of OOM dispatches.
- The following figure shows the average quantity of OOM resources in different locations in New York. This figure shows:
  - ✓ OOM quantities have fallen substantially in 2003.
  - ✓ Changes in price-setting rules and operating procedures have caused the ISO-called OOM dispatch to fall by more than two-thirds.

Average Out-of-Merit Dispatch Quantities 2001 - 2003



Note: August 2003 blackout hours excluded.

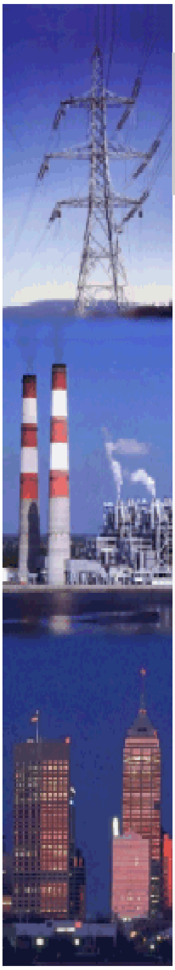
Average Out-of-Merit Dispatch Quantities 2003



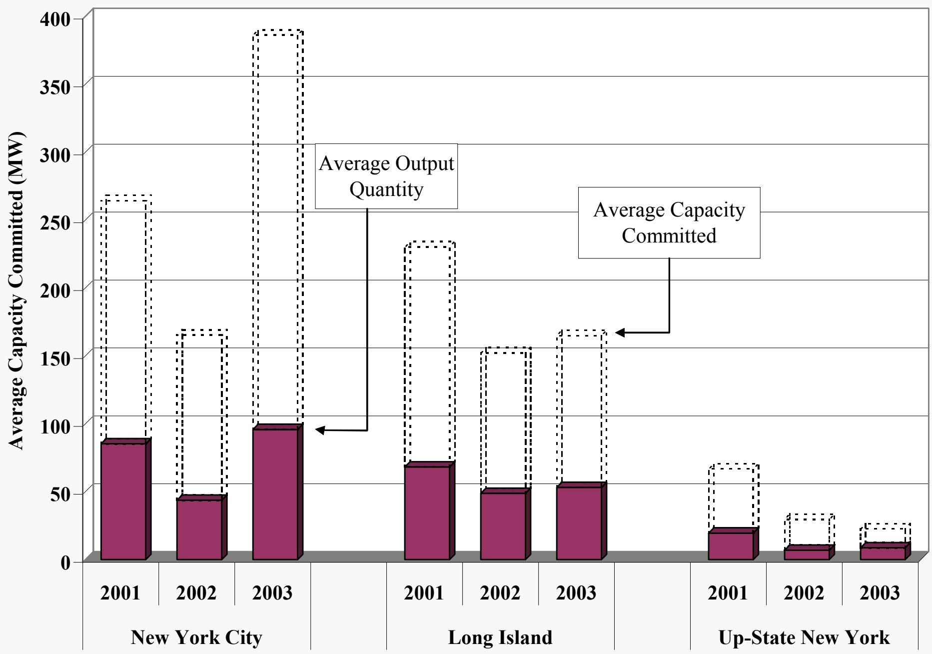
Note: August 2003 blackout hours excluded.

Supplemental Resource Evaluation

- Improvements in day-ahead modeling and commitment has reduced the quantity of SREs outside of New York City since 2001.
- However, the average quantity of capacity committed through SRE in New York City more than doubled in 2003 relative to 2002.
  - ✓ A major reason for the SREs are nitrous oxides (NOx) emission limits that require certain baseload units to operate in order to allow gas turbines to operate.
  - ✓ Additional SREs were required to meet NOx emission limits due to lower DAM commitments.
- To evaluate how the SREs contribute to uplifts costs, we performed an analysis of uplift 14 days in May 2003.
  - ✓ Uplift associated with the SREs called on these days were not accounted for as local reliability uplift.
  - ✓ SRE units accounted for 60% of non-local reliability uplift.



Supplemental Resource Evaluation Commitment 2001 - 2003

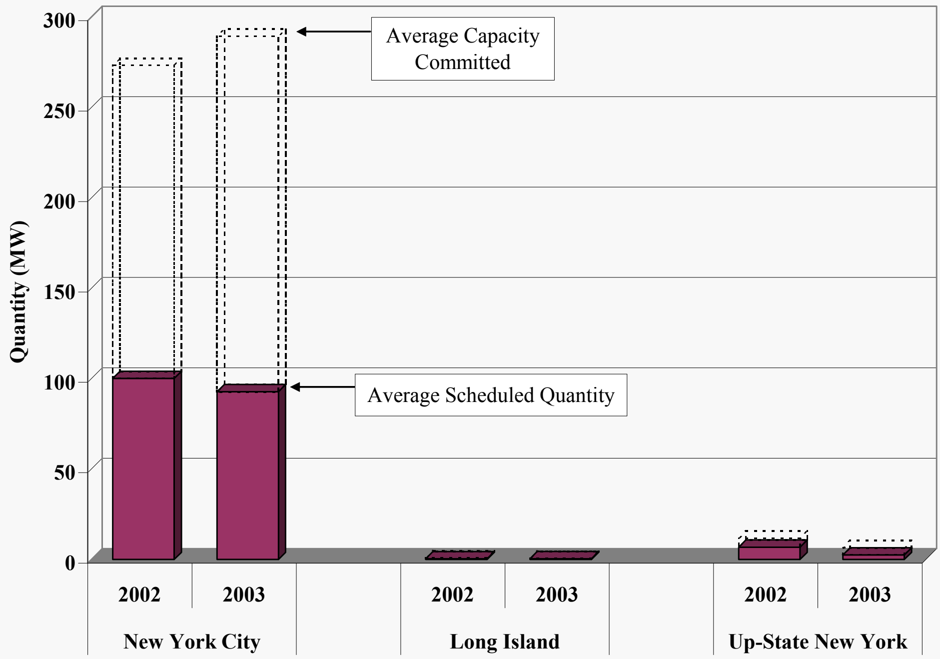


Note: August 2003 blackout hours excluded.

Day-Ahead Local Reliability

- The following figure shows the average quantity of commitments made by the SCUC for local reliability day-ahead.
  - ✓ The average capacity committed for local reliability was more than 290 MW in 2003, receiving day-ahead schedules of approximately 100 MW.
  - ✓ Virtually all of the local reliability commitments made by SCUC involved two units in New York City.
- These commitments are important because they tend to:
  - ✓ Reduce prices from levels that would result from a purely economic dispatch; and
  - ✓ Can increase uplift – a portion of the uplift resulting from these commitments is incurred to make guarantee payments to other generators that will not cover their as-bid costs at the reduced price levels.

SCUC Local Reliability Pass Commitment
June 2002 – December 2003

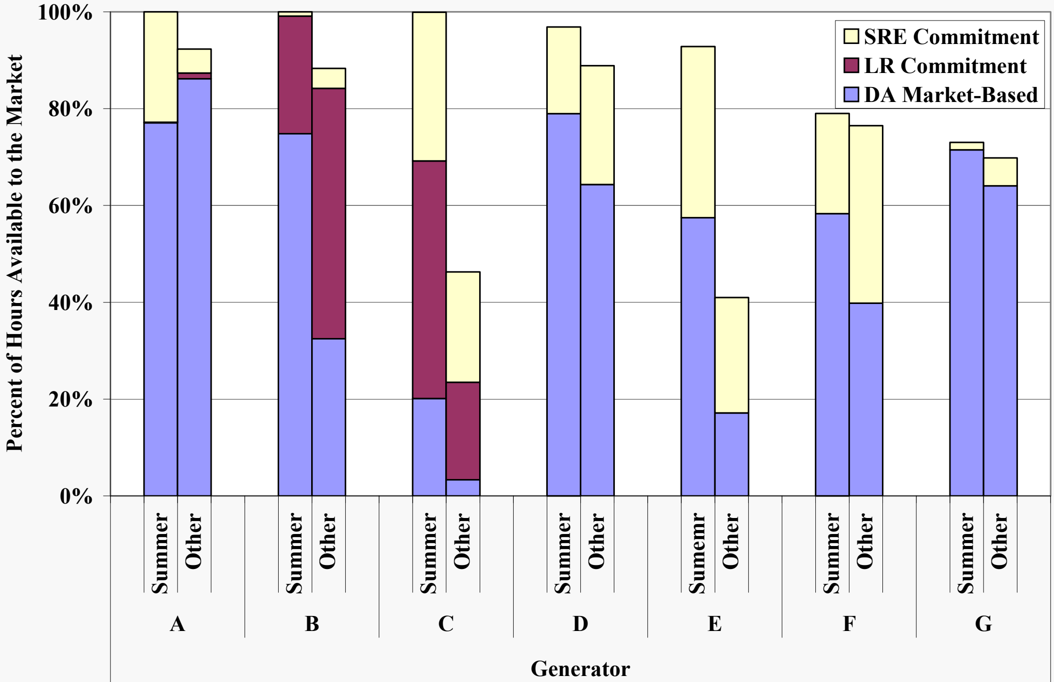


Note: August 2003 blackout hours excluded.

Units Committed for Local Reliability

- We have also evaluated supplemental commitment at the individual unit level. The following figure shows the seven units with the highest commitment rates that are frequently for local reliability.
  - ✓ The values shown are the hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage) in the summer (June – August) and non-summer days.
  - ✓ The units in the figure accounted for more than 80% of the SREs and 99% of local reliability commitment by SCUC.
  - ✓ Four of these units are in NYC and three are on Long Island.
- Four of these units analyzed appeared to be needed almost every day during the summer.
  - ✓ When these units were not committed economically in SCUC they were generally committed in the local reliability pass of SCUC or through an SRE.

Units Most Frequently Committed in 2003 through SRE or the Local Reliability Pass in SCUC



Note: August 2003 blackout hours excluded.

Supplemental Commitment Conclusions

- Supplemental commitments have a number of significant market effects:
  - ✓ Inefficiently reducing prices in both the day-ahead market and real-time market;
  - ✓ When they occur in a constrained area, they will inefficiently dampen the apparent congestion into the area; and
  - ✓ Increasing uplift as units committed economically will be less likely to recover their full offer production costs;
- In the long-run, it would be superior to include local reliability constraints into the initial economic commitment pass of SCUC.
- In the short-run, I recommend that the ISO allow operators to pre-commit units needed for NOx compliance.
  - ✓ This would only affect 3 to 4 units; pre-committing these units would reduce divergence between day-ahead and real-time prices.

Reserve Shortages

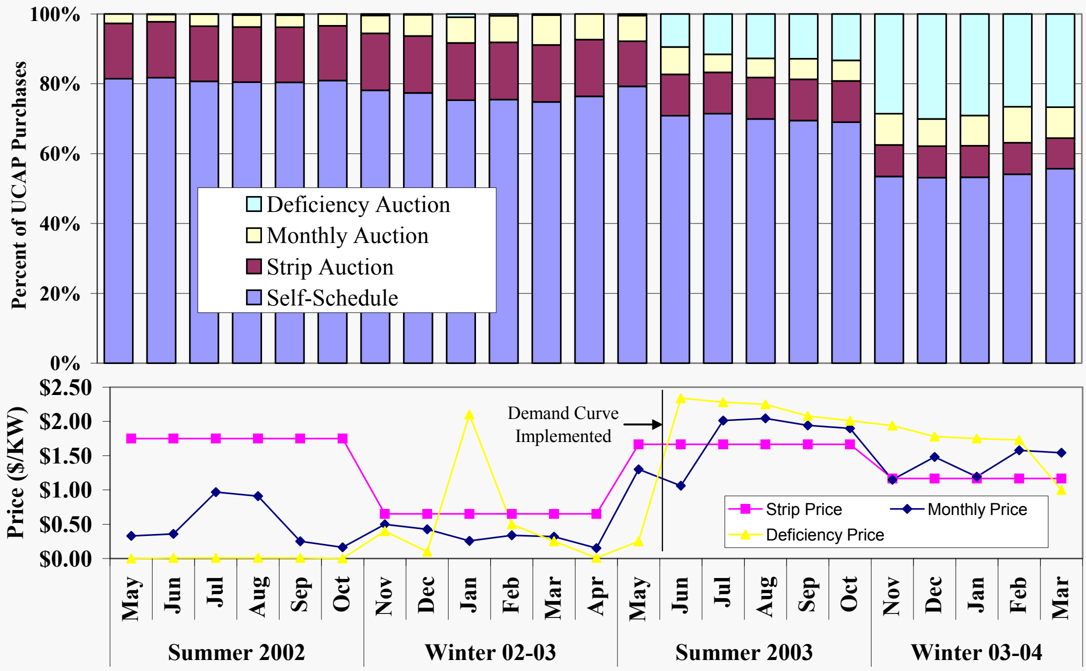
- Reserve Shortage Pricing (“scarcity pricing”) became effective in June, 2003.
  - ✓ Sets the LBMP at $1000/MWh when a 10-minute reserve shortage persists and a short-term response will not immediately remedy the situation.
  - ✓ The NYISO also can ask for load reductions from SCR and EDRP resources and pay up to $500 for these load reductions.
- Real-time energy price during scarcity conditions will be the higher of:
  - ✓ the LBMP set by the SCD;
  - ✓ the price set under Reserve Shortage Pricing (if activated);
  - ✓ or the price set pursuant to the rules of SCR/EDRP Pricing.
- Scarcity pricing was never triggered in 2003 due to mild weather and increased imports from New England.

Capacity Market

Capacity Market – New York State

- The capacity market is intended to provide efficient economic signals for investment and retirement decisions for capacity in New York.
- To improve the performance of the capacity markets, a demand curve was implemented in May 2003.
- The following figure shows UCAP prices in the "rest-of-state" area (i.e., the capacity requirements of the state after the local requirements of NYC and Long Island are satisfied.
  - ✓ It also shows the proportion of UCAP self-scheduled and purchased in the various UCAP auctions.
- This figure shows that the capacity demand curve:
  - ✓ Stabilized the capacity prices and substantially improved the consistency of prices in the strip, monthly, and deficiency auctions.
  - ✓ Caused a larger share of the capacity to be sold in the deficiency auction, whose thin volumes had contributed to erratic prices in this auction.

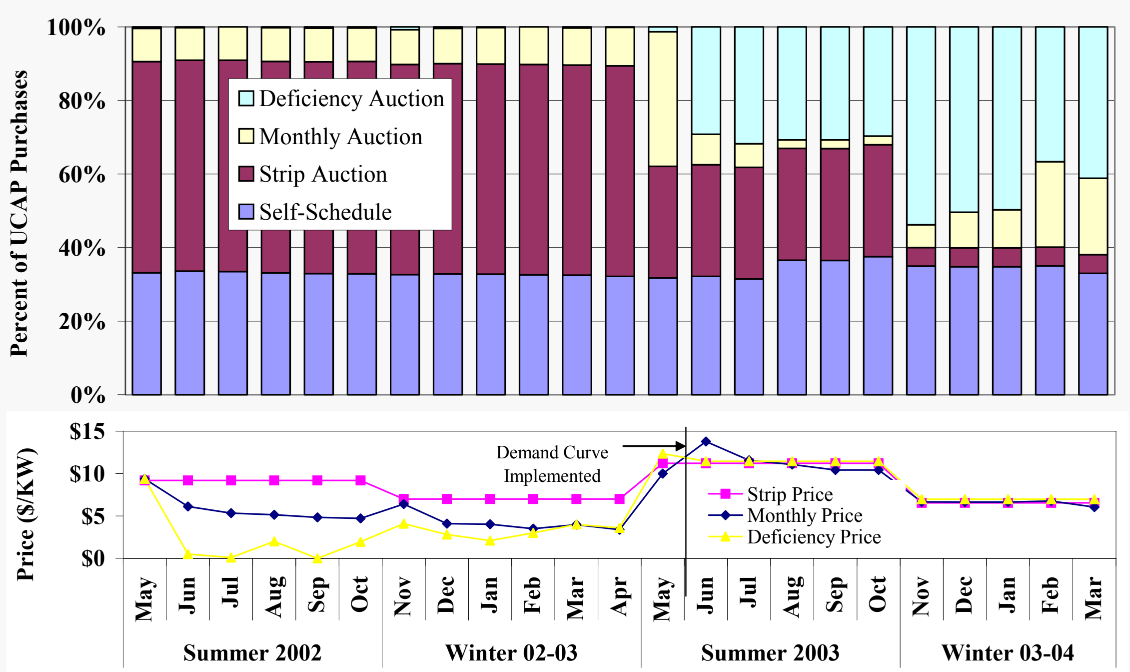
Unforced Capacity Market – Rest of State



Capacity Market – New York City

- The following figure shows UCAP prices and the proportion of UCAP self-scheduled and purchased in the various UCAP auctions for NYC.
- The figure shows that the demand curve had a similar impact in NYC as it did in the rest of the state:
  - ✓ Prices in the three auctions converged;
  - ✓ Prices were higher in summer 2003 as the City's capacity level was at its minimum required level; and
  - ✓ Purchases in the deficiency auction displaced purchases in the strip auction.

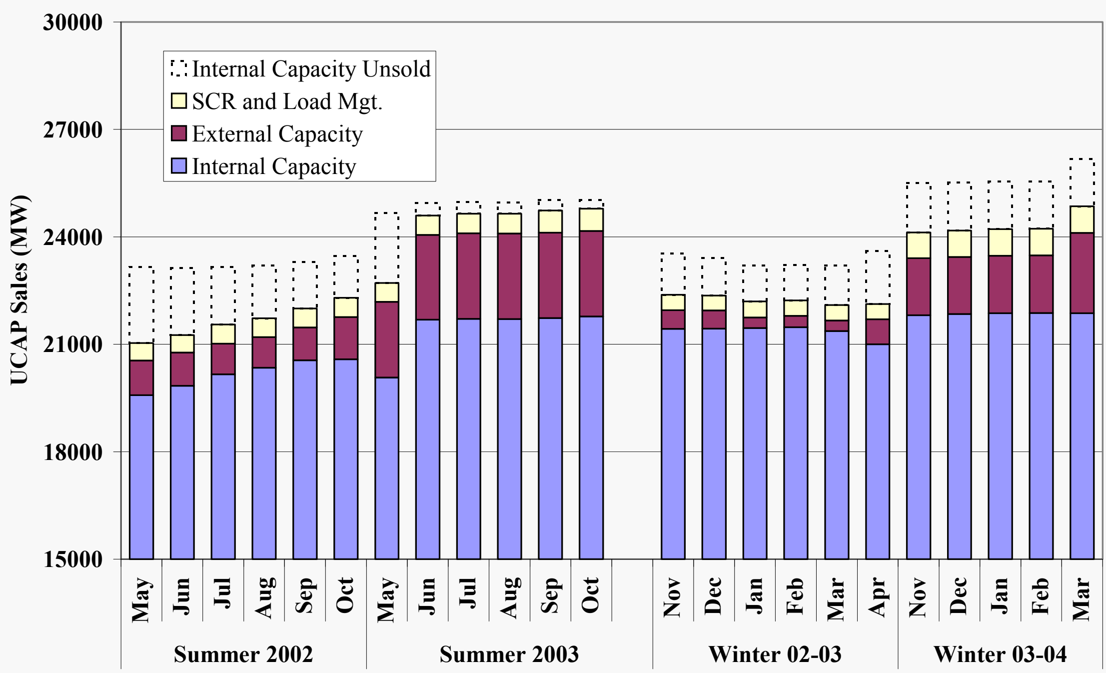
Unforced Capacity Market – New York City



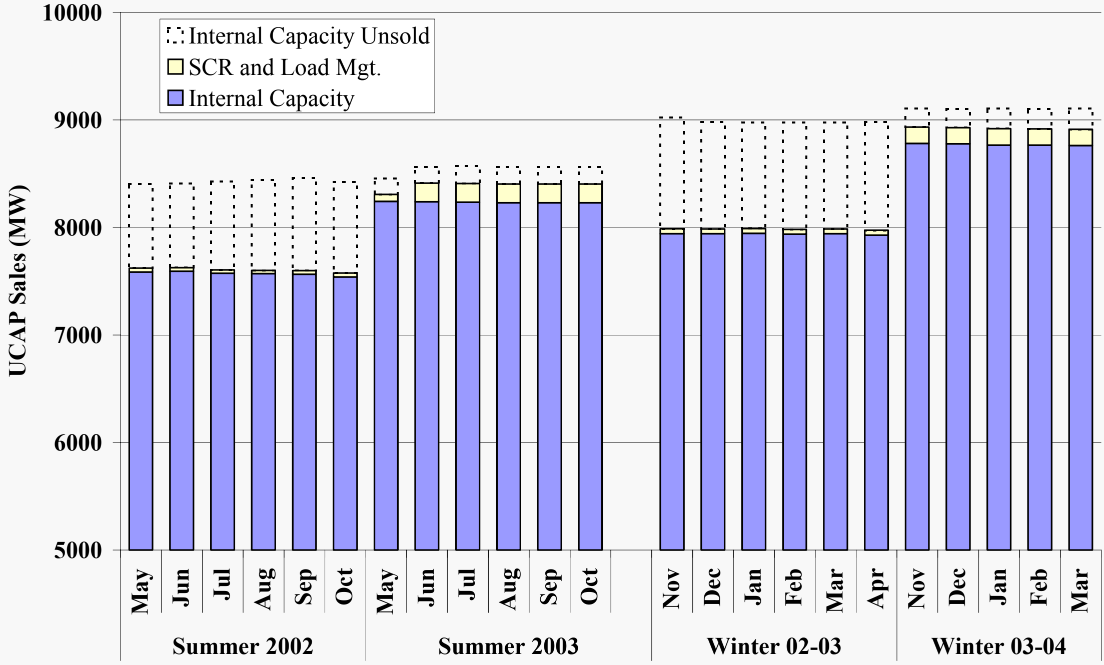
Capacity Market

- The prior figures showed where the UCAP is scheduled or purchased.
- The following figures shows the source of UCAP supplies before and after the implementation of the capacity demand curve in NYC and the state.
- In New York State:
  - ✓ The capacity demand curve contributed to higher purchases in the rest-of-state.
  - ✓ A substantial share of the additional UCAP came from external sources.
- In New York City:
  - ✓ The increased UCAP purchases are primarily due to increased requirements in the City rather than the demand curve.
  - ✓ Virtually all of the capacity in the City was sold.

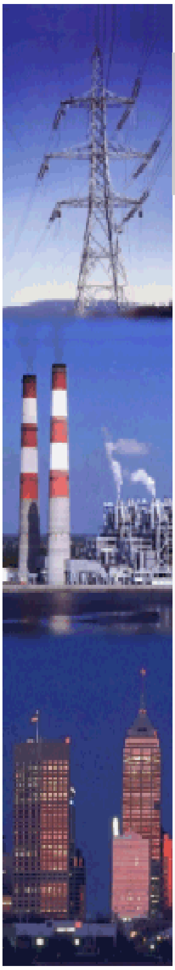
UCAP Sales – New York State



UCAP Sales – New York City



External Transactions



Utilization of the Interfaces in All Hours

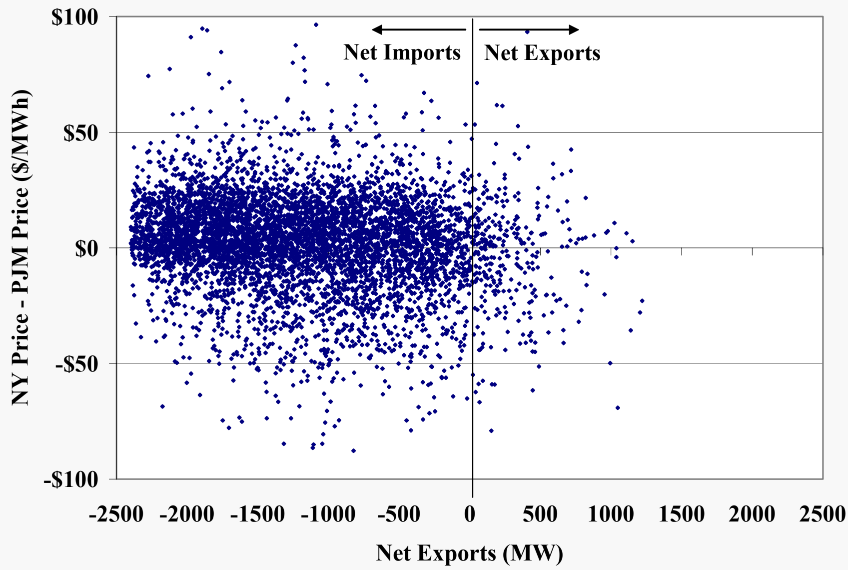
- The following four figures plot the hourly difference in prices between New York and neighboring markets against net exports during hours when transmission constraints are not binding.
- The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
- The net exports are shown on the x-axis with positive values reflecting net exports from New York and negative values representing net imports.
- Of the four quadrants shown in each figure, there are two "counter-intuitive" quadrants. Points in these quadrants are hours where:
  - ✓ The price is higher in New York and NYISO is exporting power; and
  - ✓ The price lower in New York and NYISO is importing power.

Utilization of the Interfaces in All Hours

- These figures show that the real-time markets continue to not be efficiently arbitraged by participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.
- The analysis also shows that the arbitrage of the day-ahead prices between New York and PJM was much better than the real-time arbitrage.
- These results reinforce the importance of the virtual regional dispatch provisions being developed to improve the real-time interchange between New York and New England.
  - ✓ The figure for the New England interface shows that hours exhibiting net imports and net exports are relatively evenly divided.
- Additionally, FERC's requirement to eliminate export fees will also help improve the arbitrage of the adjacent markets

Difference Between West Zone and PJM Price
Real-Time Prices v. Hour-Ahead Schedules

Unconstrained Hours - 2003



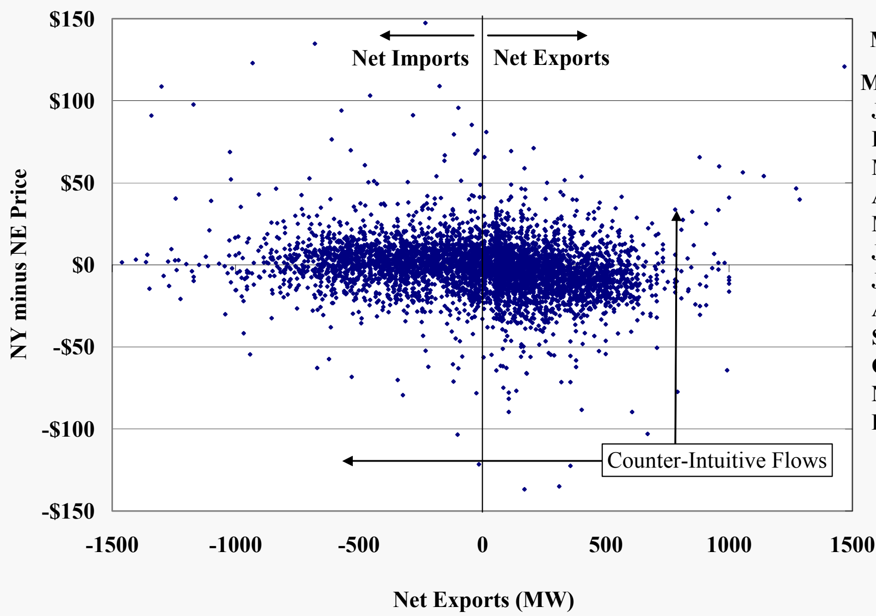
Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$0.14	$22.61
Feb	$8.45	$32.61
Mar	$0.76	$34.75
Apr	$2.19	$28.45
May	$3.80	$15.46
Jun	$4.34	$19.28
Jul	-$4.43	$20.12
Aug	$4.07	$31.30
Sept	$6.41	$14.89
Oct	$9.04	$15.03
Nov	$1.74	$20.42
Dec	$0.10	$18.93

* PJM Western Hub Price

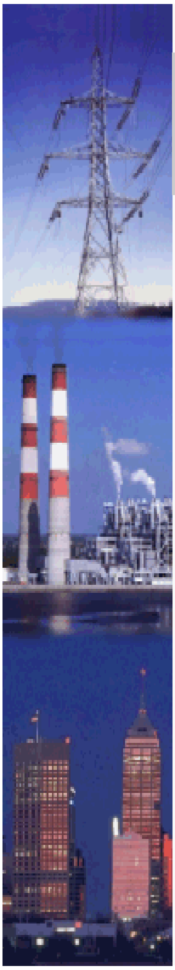
Price Difference Between New England and New York
Real-Time Prices and Net Export Schedules

March to December, 2003, Unconstrained Hours



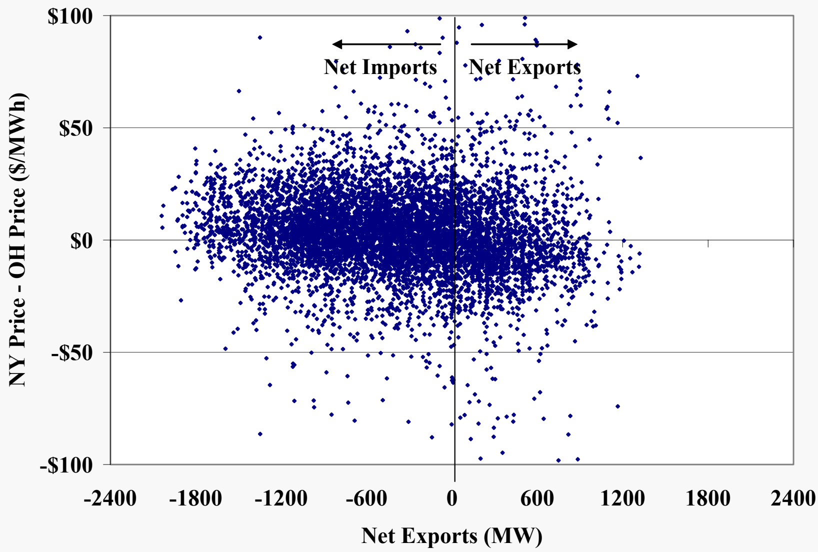
Monthly Price Statistics

Month	Mean	Std Dev
Jan	N/A	N/A
Feb	N/A	N/A
Mar	-$1.78	$30.53
Apr	$6.21	$28.18
May	-$5.24	$16.49
Jun	-$3.11	$16.93
Jul	$0.77	$11.33
Aug	$4.10	$18.94
Sept	-$0.71	$11.77
Oct	-$0.34	$12.59
Nov	-$7.37	$15.86
Dec	-$7.28	$14.38



Difference Between West Zone and Ontario price
Real-Time Prices v. Hour-Ahead Schedules

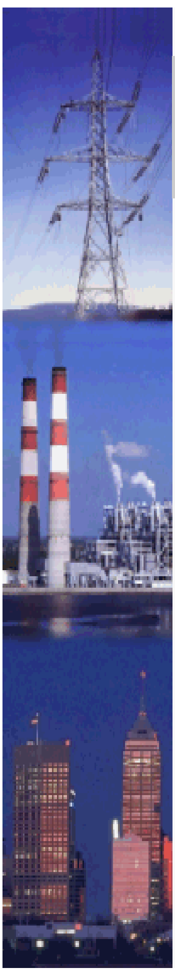
Unconstrained Hours - 2003



Monthly Price Statistics

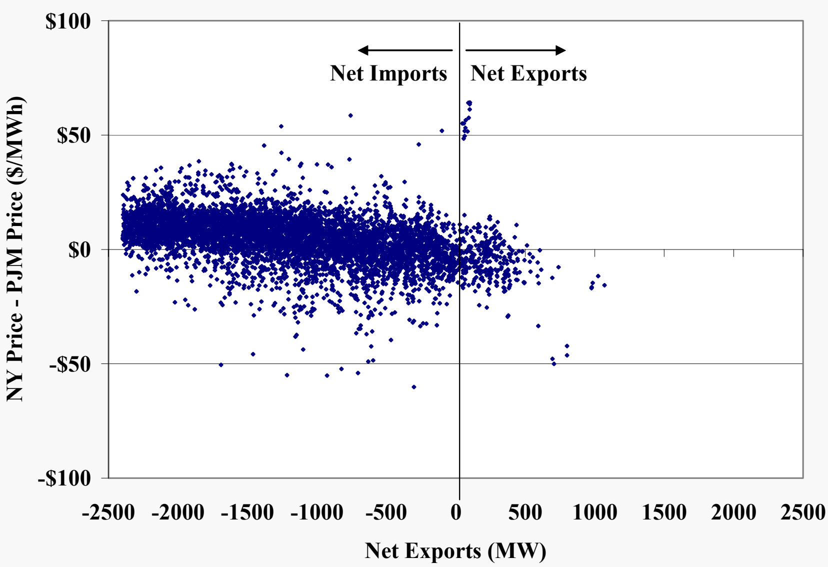
Month	Mean	Std Dev
Jan	$5.15	$21.69
Feb	$1.66	$34.52
Mar	$2.27	$30.89
Apr	$0.53	$28.35
May	$5.06	$17.18
Jun	$6.19	$18.14
Jul	$10.12	$13.13
Aug	$9.27	$29.79
Sept	$1.97	$14.54
Oct	-$4.81	$15.24
Nov	$0.26	$17.98
Dec	$1.89	$16.07

* Price difference measured in US dollars



Difference Between West Zone and PJM Price
Day-Ahead Market

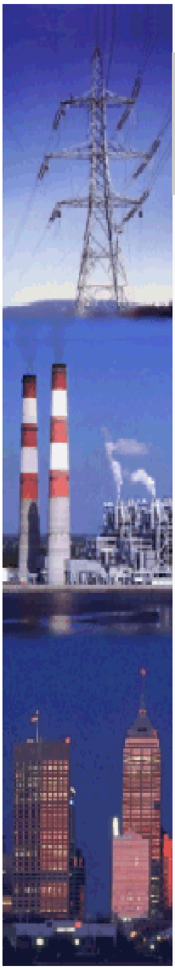
Unconstrained Hours - 2003



Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$0.49	$11.01
Feb	$10.03	$11.36
Mar	$1.31	$16.37
Apr	$2.59	$9.77
May	$2.56	$7.28
Jun	$3.99	$11.09
Jul	-$0.89	$11.59
Aug	$7.89	$13.56
Sept	$8.61	$5.96
Oct	$11.44	$6.92
Nov	$5.03	$6.27
Dec	$3.72	$8.17

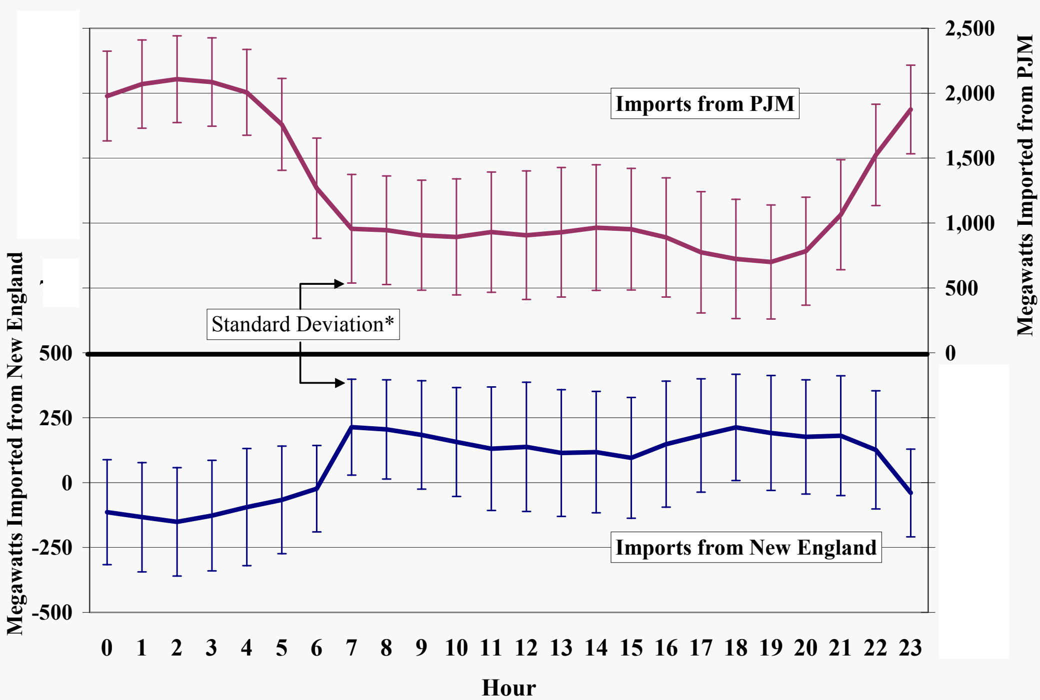
*** PJM Western Hub Price**



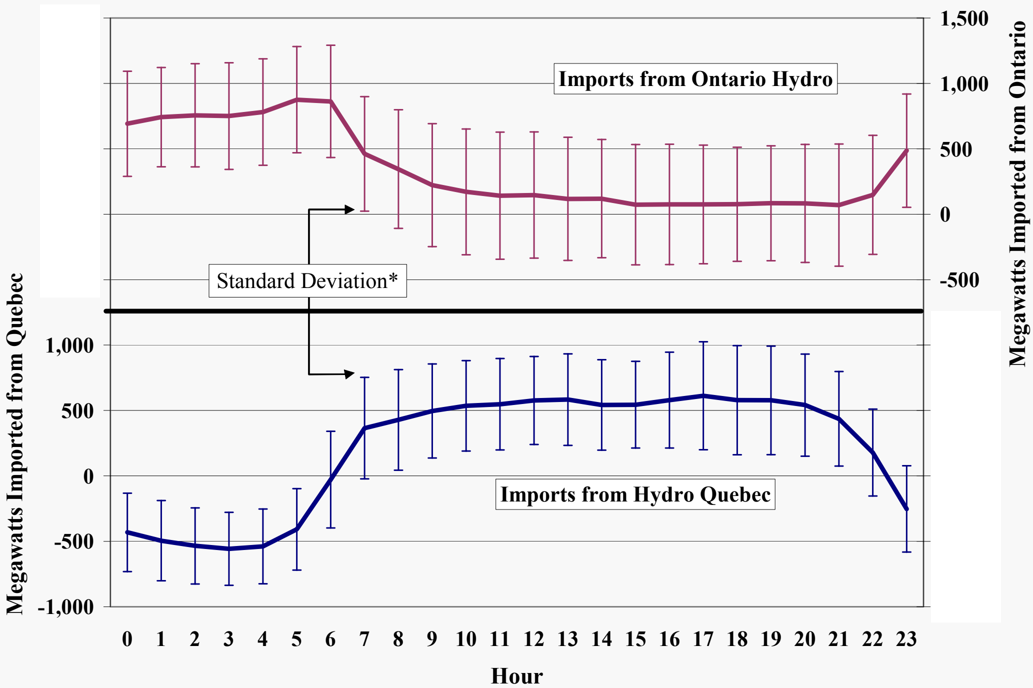
Imports into New York

- The next two figures show how imports vary across an average day from different adjacent regions.
  - ✓ Imports from PJM are highest during the night-time hours, while New York is a net exporter to New England during this period.
  - ✓ During the day, New York imports from both regions. Though PJM exports a smaller quantity to New York during the day than at night, it is still much larger than supply obtained from New England.
  - ✓ Hydro-Quebec is a net importer at night from New York in similar quantities to the net imports to New York from Ontario.
  - ✓ During the day Hydro-Quebec exports substantial quantities of power to New York while imports from Ontario fall close to zero.
- The change in schedules that occur during the 16 peak hours are consistent with most schedules being made to support longer-term bilateral agreements (rather than arbitrage of hourly prices).

Average Net Imports from LMP Markets by Hour of Day Weekdays, 2003



Average Net Imports from Canada by Hour of Day
Weekdays, 2003

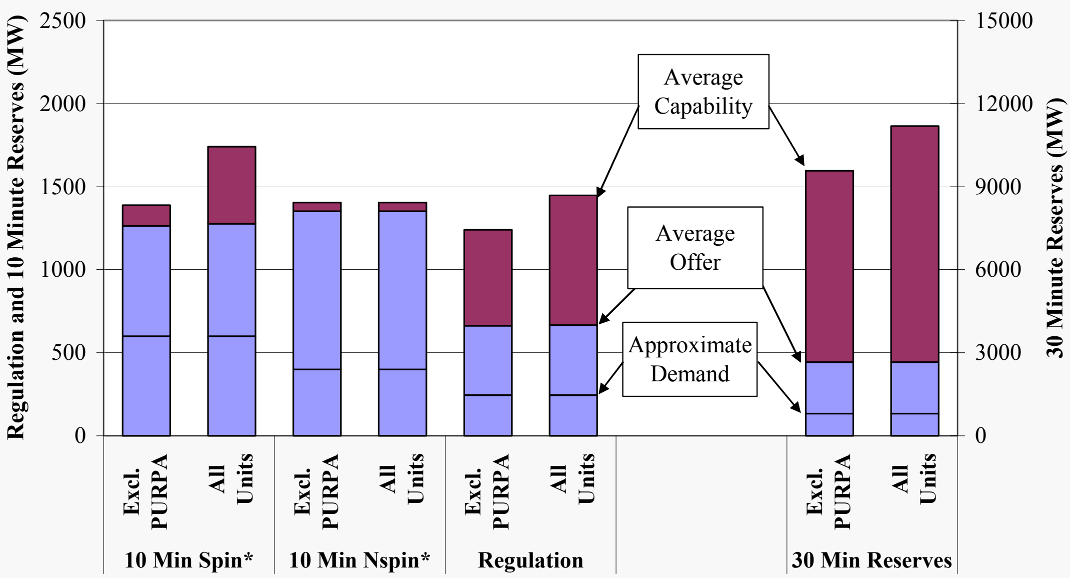


Ancillary Services Markets

Ancillary Services

- A substantial portion of the capability of certain services is not offered in the day-ahead ancillary services markets, particularly for 30-minute reserves and regulation.
- However, ancillary services markets are generally not tight because offers to supply typically exceed approximate demand:
  - ✓ For 30 minute reserves, offers typically exceed approximate demand by 230 percent.
  - ✓ For total 10-minute reserves (spin and non-spin) east of the Central-East interface, offers typically exceed approximate demand by 160 percent.
  - ✓ For regulation and 10-minute spinning reserves, offers typically exceed approximate demand by 100-170 percent – but ignores the fact that some 10-minute spinning reserves can be purchased in the West.
- Since these markets are jointly optimized and the same resources are offered in multiple markets, energy and other AS markets can bid resources away from a given service resulting in relatively tight conditions.

Ancillary Services Capability and Offers

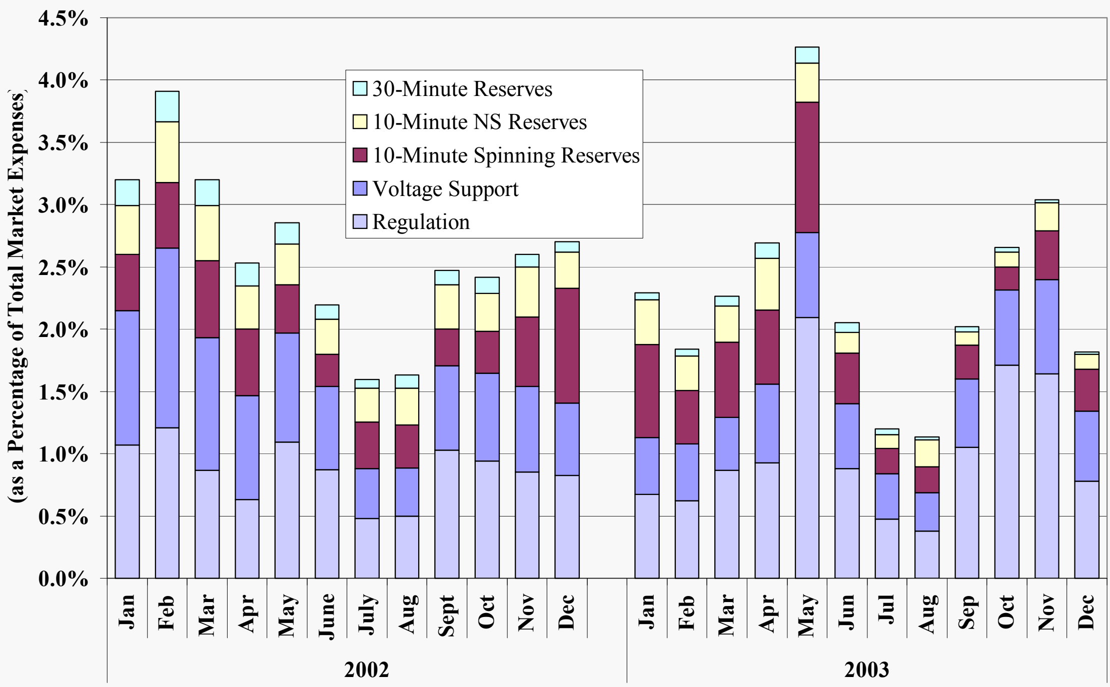


*Eastern side of the Central-East Interface only

Ancillary Services Costs

- Ancillary services expenses include expenses for regulation, voltage support, and various operating reserves.
- These costs tend to be smaller as a percent of total market expenses in the summer than in other seasons because of the relatively high energy prices during the summer.
- Ancillary services costs declined slightly as a percentage of total market expenses from 2002 to 2003.
  - ✓ However, the amount spent on ancillary services increased by $20 million to almost $130 million.
- Increased expenditures for ancillary services was primarily due to the higher cost of regulation.

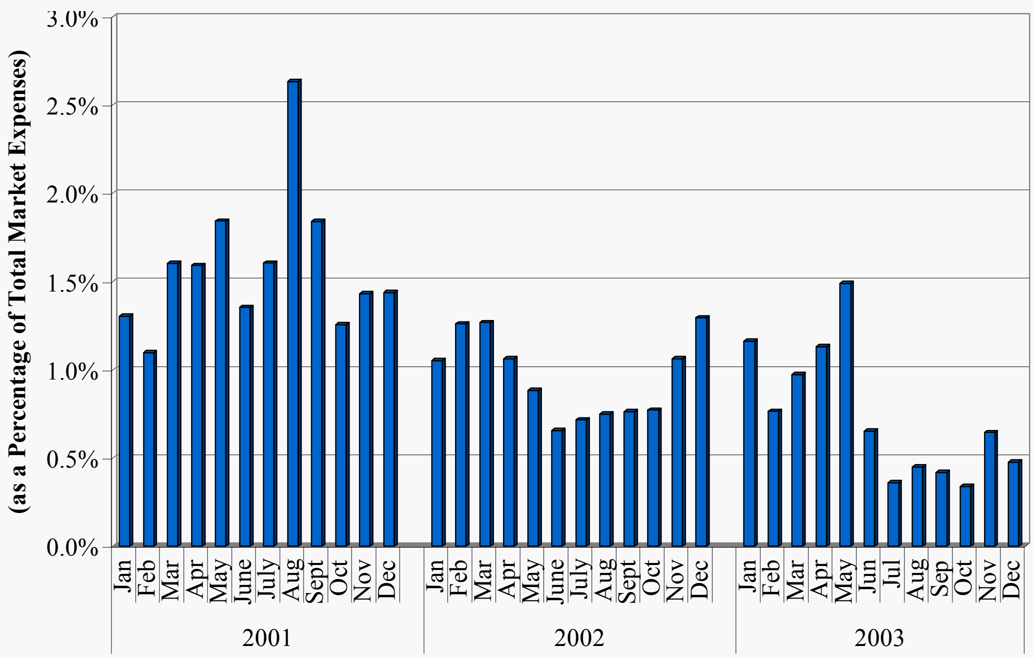
Expenses for Ancillary Services 2002 - 2003



Ancillary Services

- The following figure shows the share of the total market expenses that are accounted for by 10-minute and 30-minute reserves.
- Expenses for reserves were slightly higher in 2003, but remained lower than in 2001.
  - ✓ Reserves costs accounted for 1.7 percent of total market expenses in calendar year 2001, but this dropped to 0.9 percent in 2002, and 1.0 percent of total market expenses in 2003.
  - ✓ The cost of 10-minute spinning reserves rose by 27 percent, because of higher natural gas prices.
  - ✓ Costs for non-synchronous 10-minute reserves fell by 10 percent, and 30-minute reserve costs fell by 40 percent, due to fewer peak periods with high reserve prices.

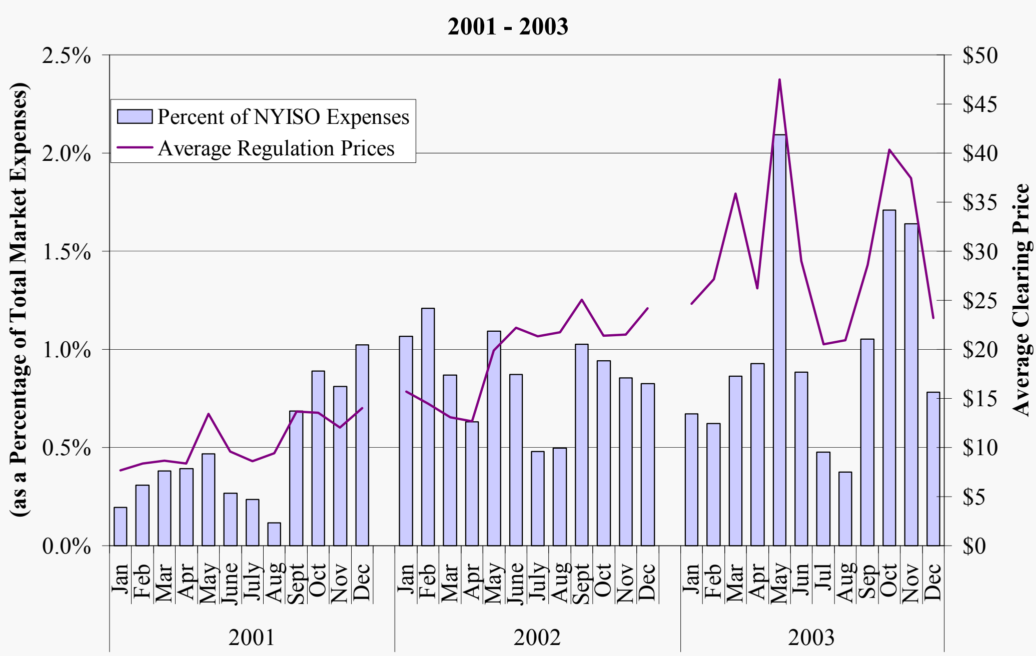
Expenses for Reserves Procurement
2001 - 2003

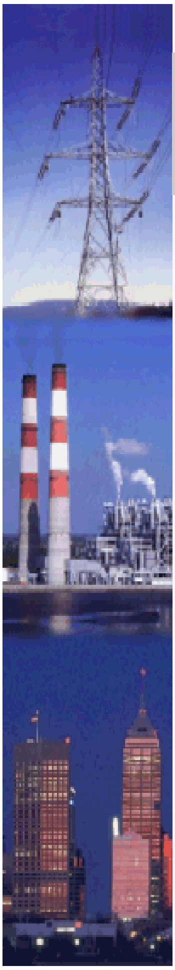


Ancillary Services

- The following figure shows the average price for regulation service from 2001 through 2003. The figure also shows the share of the total market expenses that are accounted for by regulation.
- Regulation prices have increased considerably over this period. The primary reasons for the increases in regulation prices were:
  - ✓ Modeling changes in SCUC and BME to recognize that units' minimum generation level may limit the range in which a unit can regulate down. This reduced the supply available on some units, particularly off-peak.
  - ✓ Fuel price increases that increase opportunity costs to provide regulation.
  - ✓ Quantities offered have remained relatively steady, but offer prices during off-peak hours have increased modestly.
- Regulation costs still remain a relatively small part of the total electricity market expenses for the NYISO (little more than 1 percent).

Average Clearing Price and Expenses for Regulation



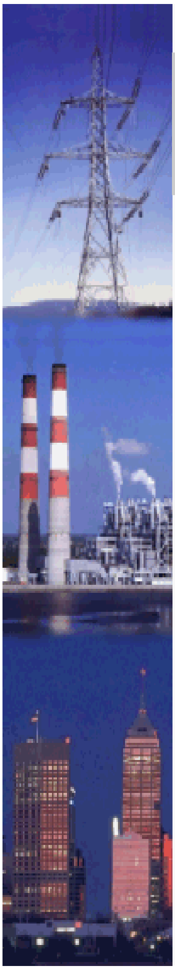


Ancillary Services Recommendations

- To address the failure to offer a substantial amount of capability in the reserve markets, I had recommended in prior market reports that the NYISO:
  - ✓ Modify the pricing for ancillary services to set the price for each at its marginal cost to the system; and
  - ✓ Implement multi-settlement markets for reserves and regulation.
- These changes are part of the new Real-Time System (“RTS”) to be implemented in Fall 2004.
- I recommend that the NYISO allocate its available resources to implementing RTS rather than making interim changes to the ancillary services markets.

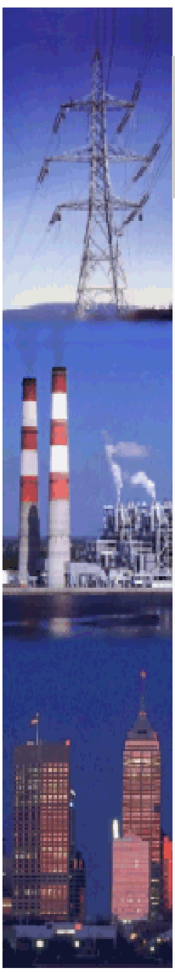
Demand Response Programs

POTOMAC ECONOMICS



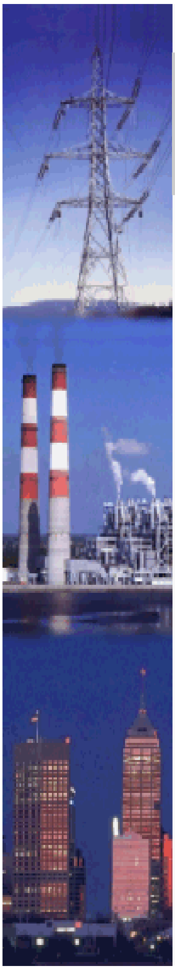
Demand Response Programs

- The New York ISO has some of the most effective demand response programs in the country.
- There are currently three demand response programs in New York:
  - ✓ Day-Ahead Demand Response Program (DADRP) – This program schedules physical demand reductions for the following day, allowing resources to offer into the day ahead market as any supply resource. These resources are paid the day-ahead clearing price.
  - ✓ Special Case Resources (SCR) – These are loads that must curtail within two hours. They are called when operators forecast a reserve deficiency and may sell capacity in the capacity market comparably to supply resources.
  - ✓ Emergency Demand Response Program (EDRP) – The emergency demand response program pays loads that curtail on two hours notice the higher of $500/MWh or the real-time clearing price.



Day-Ahead Demand Response Program

- The day-ahead program that schedules physical reductions in load for the following day is the day-ahead demand response program.
- The quantities participating in this program are very low:
  - ✓ There were 3983 hours with day-ahead demand response bids.
  - ✓ The average quantity bid was less than 4 MW per hour, and the average quantity scheduled was approximately half a megawatt.
  - ✓ There were 91 hours when day-ahead demand response bids reached at least 10 MW, with a high of 12 MW, and these bids were accepted in 25 hours.
  - ✓ The largest bids were by one company, responsible for 82% of all demand response bids by volume, and were centered around July 4, Thanksgiving and Christmas week.
- The low participation may be due to the alternatives available for demand to bid in the markets (virtual trading and price-capped load bidding).



Emergency Demand Response

- Emergency Demand Response and Special Case Resources were utilized only during the two day period after the blackout.
- These calls for demand response were made to limit demand as the system was restored to full power.
  - ✓ Approximately 800 MW were available on August 15 for a 14 hour period, at a cost of \$5.5 million (or ~\$500 per MWh).
  - ✓ 470 MW were made available on August 16 for a 8 hour period, at a cost of approximately \$1.8 million.