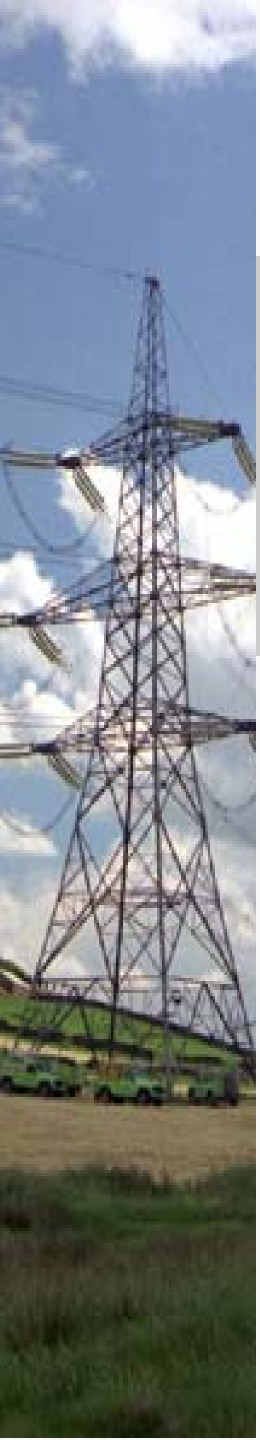
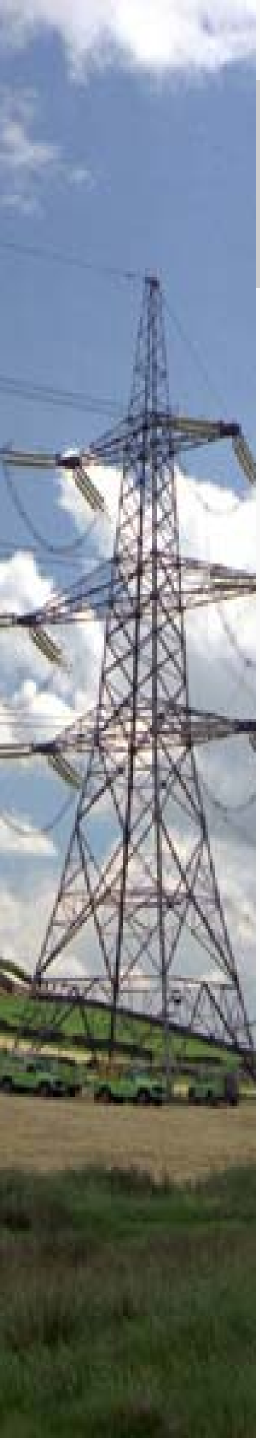


# 2002 State of the Market Report
# New York Electricity Markets

David B. Patton, Ph.D.
Potomac Economics

Independent Market Advisor

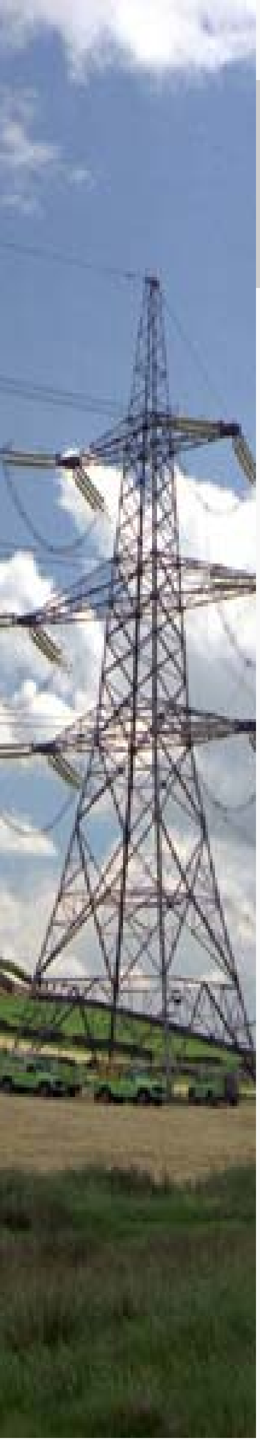
April 2003



# Introduction to the Annual Report

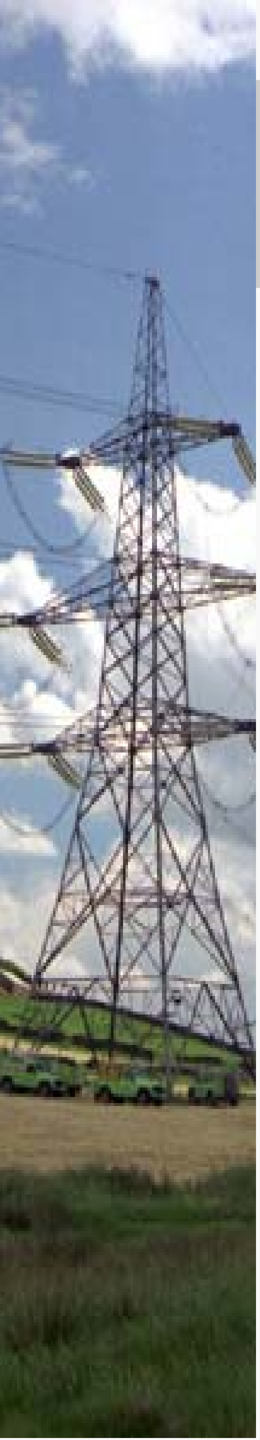
- This presentation provides highlights from the Annual Report on the New York electricity markets for 2002.

- The market assessment addresses the following areas:
  - ✓ Energy market prices and outcomes
  - ✓ Market performance
  - ✓ Market participant bidding patterns
  - ✓ Pricing during peak demand conditions
  - ✓ External transactions under peak demand and all other conditions
  - ✓ Capacity market
  - ✓ Ancillary services
  - ✓ Demand response programs



# Summary of Conclusions

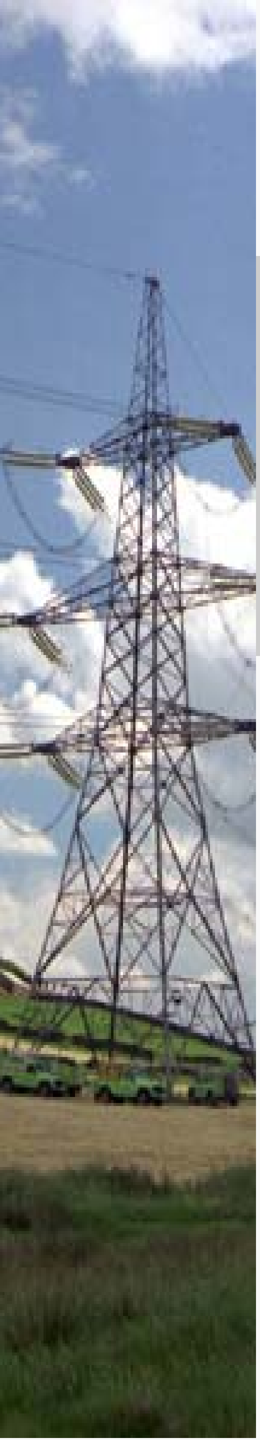
- The New York markets continued to operate competitively in 2002.
- Significant market improvements were achieved in the following areas:
  - ✓ Uplift costs were reduced substantially through improvements to the market models;
  - ✓ Prices within New York City more accurately reflected transmission congestion within the city due to load pocket modeling;
  - ✓ Out of merit dispatch was reduced through changes to operating and pricing procedures; and
  - ✓ Virtual trading and increased price-capped load bidding improved convergence between day-ahead and real-time prices.
- The report identifies areas where further improvement is needed:
  - ✓ Pricing during peak demand conditions (i.e., scarcity pricing);
  - ✓ Interchange with adjacent markets; and
  - ✓ Ancillary services market participation and pricing.



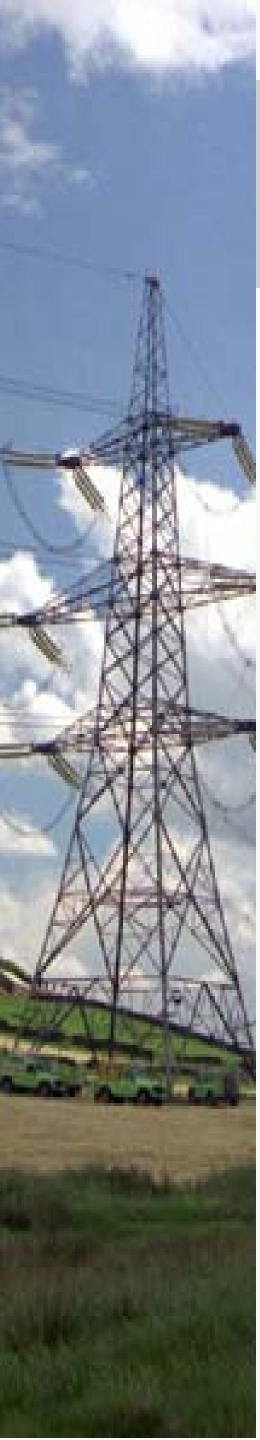
# Summary of Recommendations

Based on the analysis presented in this report, it recommends that the NYISO:

- Implement scarcity pricing provisions that would set prices at $1000 (excluding losses) in reserve-deficient areas;
- Modify the pricing rules to allow emergency demand response resources to set energy prices when they are needed to avoid a shortage, and evaluate the feasibility of increasing the bidding flexibility for demand resources.
- Coordinate the physical interchange with adjacent ISOs to maximize the utilization of the external interfaces;
- Disaggregate the virtual trading and price-capped load bidding within New York City to the load pocket level or, at a minimum, to the 345 kv/138 kv level;
- Address the virtual trading scheduling and settlement rules to ensure that they are scheduled consistent with their bid prices; and
- Avoid diverting resources from RTS as it addresses a number of scarcity pricing, ancillary services, seams, and other issues.

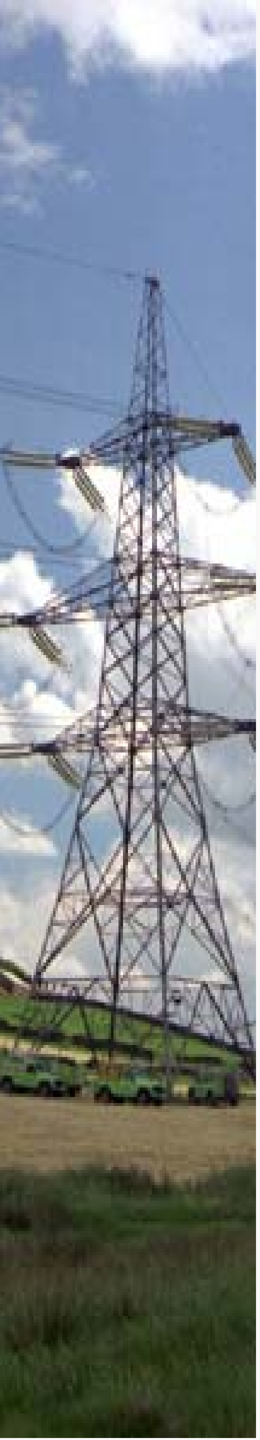


# Market Prices and Outcomes

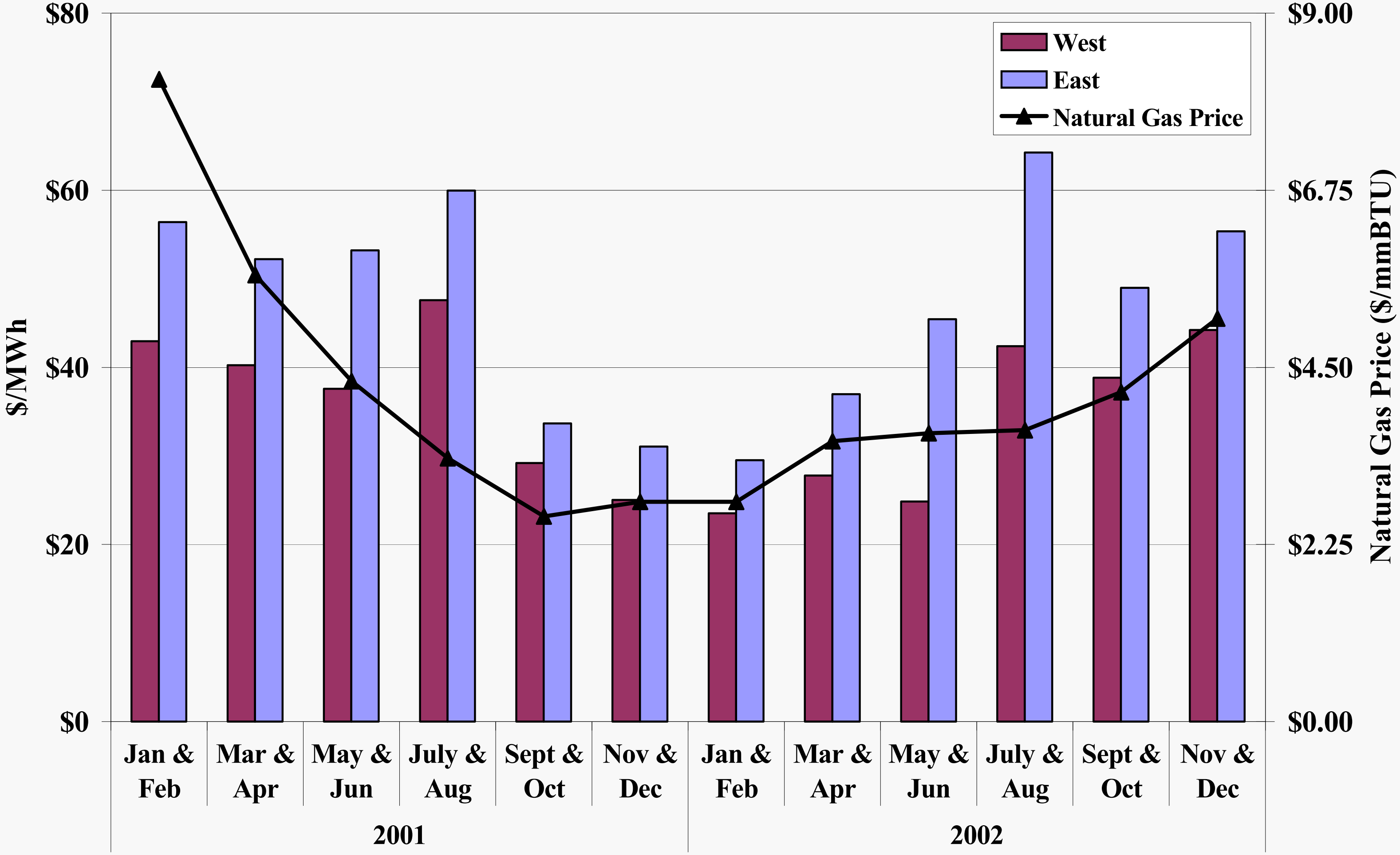


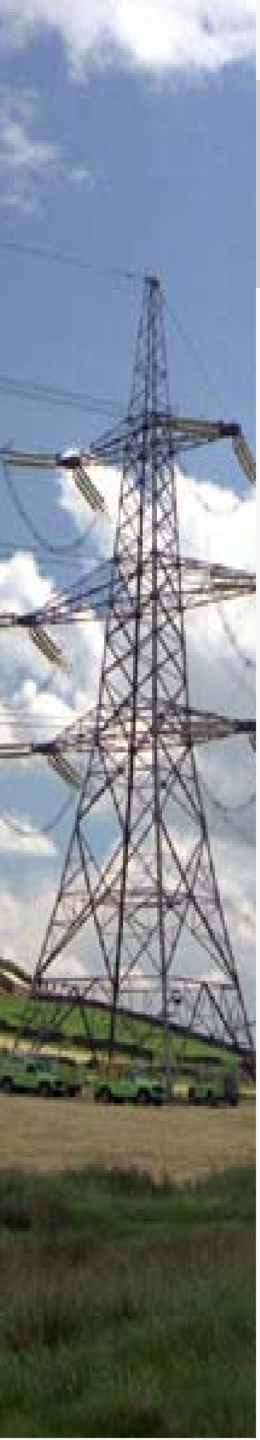
# Energy Prices in the Day-Ahead Market

- The following shows average prices during all hours in 2001 and 2002.
- The trend in electricity prices in 2001 and 2002 was driven by fuel prices.
  - ✓ In 2002, electricity prices in New York increased 86% from January to December in contrast to the decreasing trend in 2001.
  - ✓ This is primarily due to substantial increases in the prices of input fuels over the same period: fuel oil increased 71% and natural gas increased 99%.
- In 2002, peak days had far less impact on average prices than in 2001.
  - ✓ The highest-priced hour for eastern New York was $262/MWh in 2002 versus $975/MWh in 2001.
  - ✓ Prices in 3 hours on August 9, 2001 raised the average price for the month 20%.
  - ✓ The lower price volatility in 2002 was due, in part, to more active price-capped load bidding and the introduction of virtual trading.
- The average price was 41% higher in eastern New York than in western New York. This was due to:
  - ✓ Continued congestion on the Central-East and Con-Ed Cable Interfaces; and
  - ✓ The introduction of load pocket modeling, making congestion more visible within New York City (shifting costs from uplift to congestion).



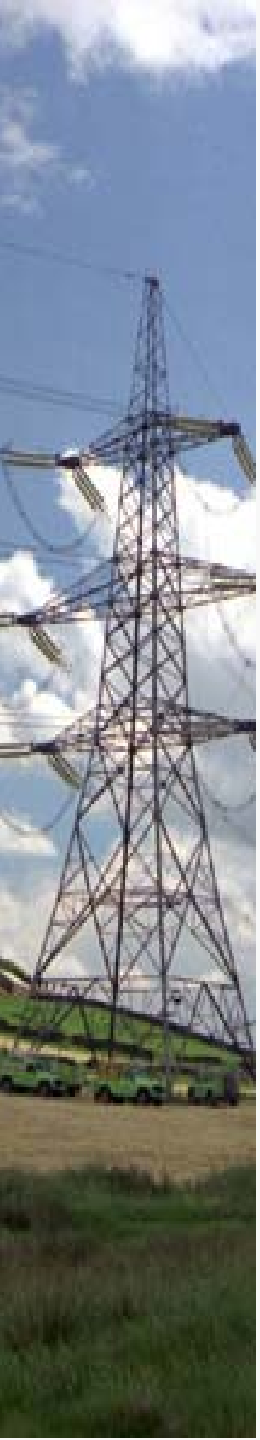
## Day-Ahead Energy Price and Fuel Price Trends
## 2001 & 2002

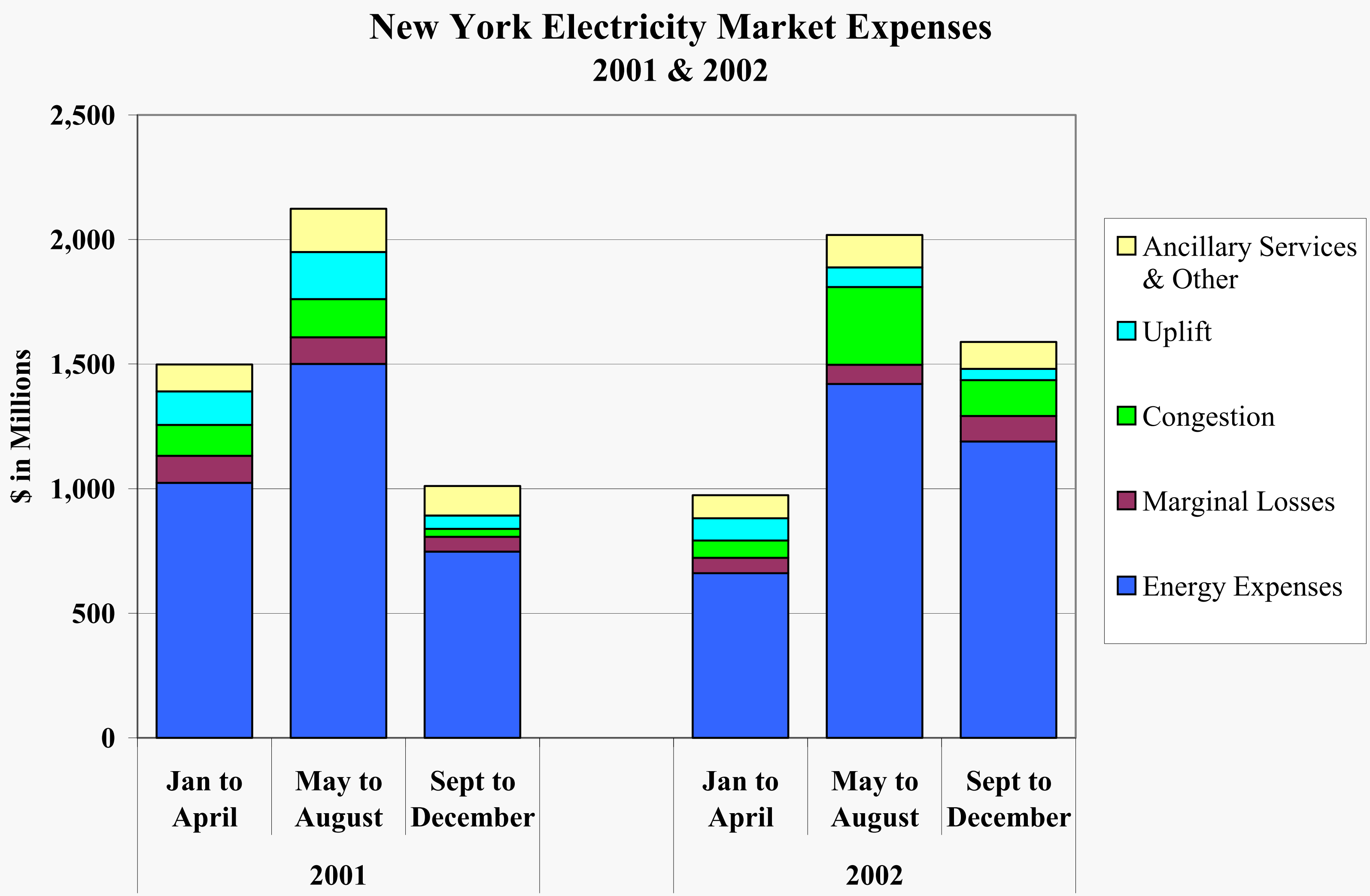




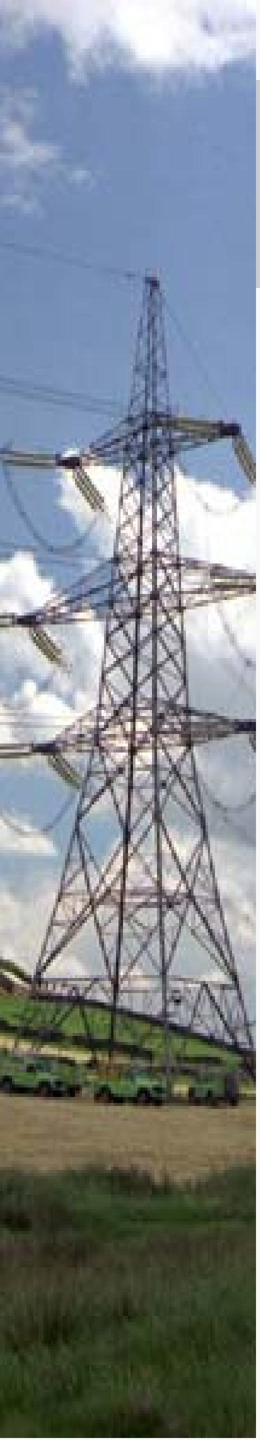
# Total Electricity Costs in the New York Markets

- The following figure shows the total seasonal expenses for market participants of the NYISO in 2001 and 2002.
- The total expenses for 2002 were approximately $4.6 billion – virtually the same as the expenses in 2001.
- Although the total expenses were the same, the figure shows that congestion expenses rose significantly and uplift costs fell sharply in 2002. These changes are described below.
- This figure does not include expenses for energy scheduled as physical bilaterals, which accounted for close to 50% of the load scheduled in 2002.



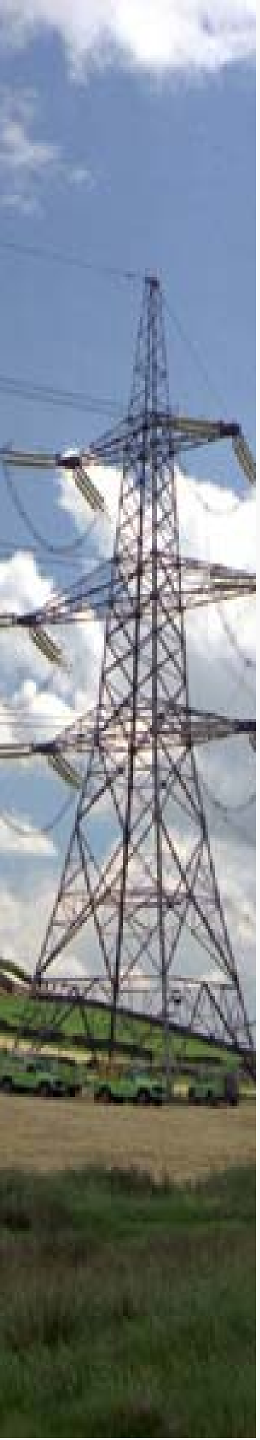


New York Electricity Market Expenses
2001 & 2002
$ in Millions
2,500
2,000
1,500
1,000
500
0
Jan to April
May to August
Sept to December
2001
Jan to April
May to August
Sept to December
2002
Ancillary Services & Other
Uplift
Congestion
Marginal Losses
Energy Expenses

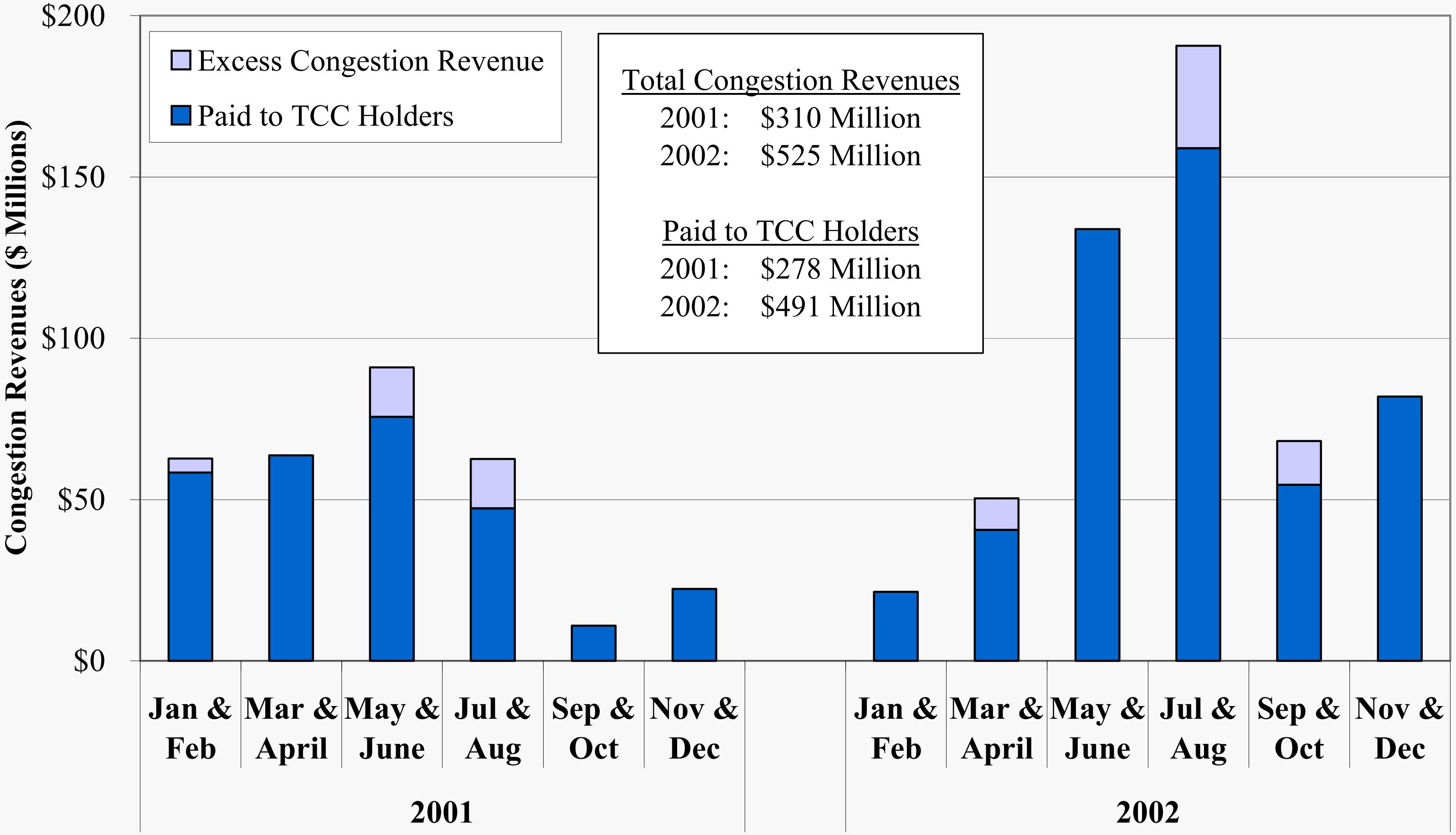


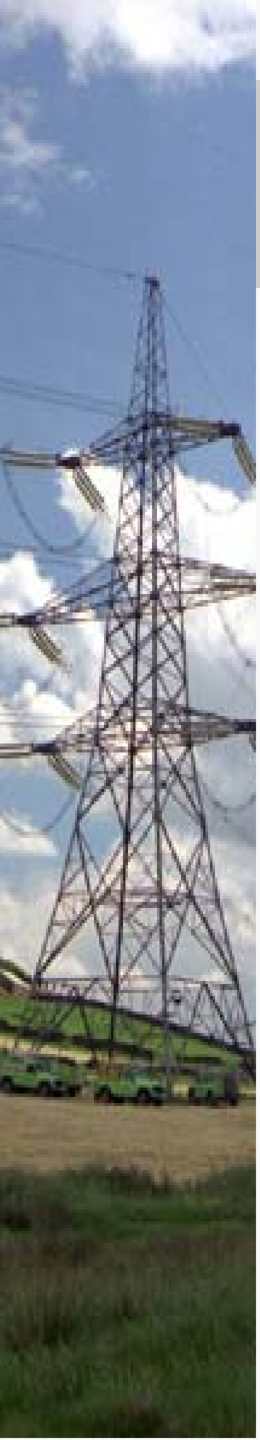
# Congestion Costs

- The following figure shows how congestion costs have increased from 2001 to 2002:
  - ✓ $310 million in 2001;
  - ✓ $525 million in 2002;
- The increase in congestion costs from 2001 to 2002 is partly due to the modeling of the load pockets within New York City.
- 90% and 94% of congestion expenses were paid out to TCC holders in 2001 and 2002, respectively.
  - ✓ Congestion expenses that are not paid to TCC holders are rebated against transmission customers' Schedule 1 charges.



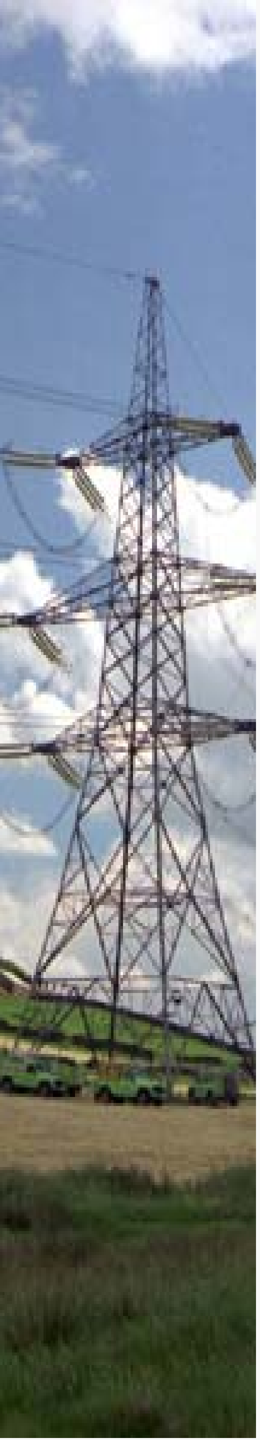
## Congestion Revenues
### 2001 & 2002

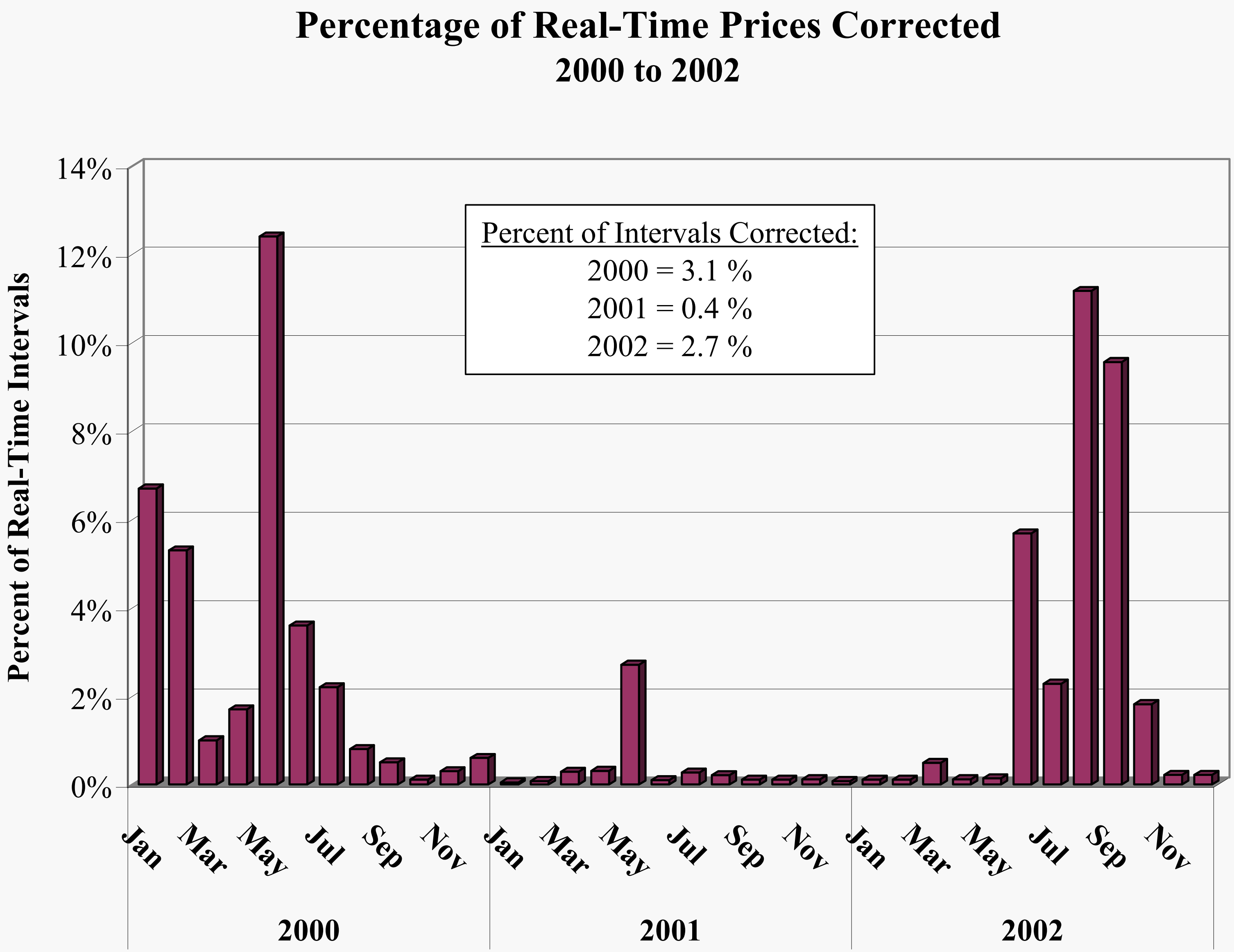


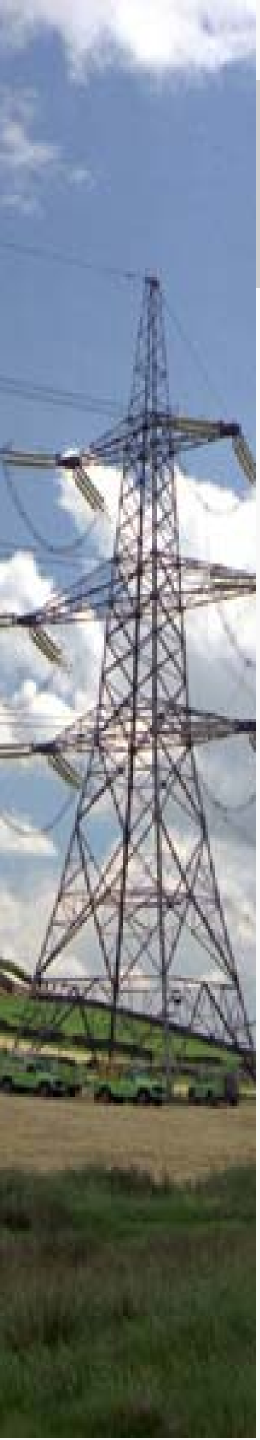


# Energy Price Corrections

- All real-time energy markets are subject to some level of price corrections to account for metering errors and other input data problems – these problems should not be frequent.
- Corrections can also result from software flaws that cause pricing errors under certain conditions – it is important to resolve these flaws as quickly as possible to maximize price certainty.
- The following figure summarizes the frequency of price corrections in the real-time energy market in 2000-2002.
  - ✓ The frequency of price corrections was relatively high in 2000, but decreased substantially until the summer of 2002.
  - ✓ The frequency increased substantially when the modeling of the New York City load pockets was introduced in June 2002.
  - ✓ Modeling discrepancies in the configuration of the grid for some of the generators in NYC caused a temporary increase in real-time price corrections.




Percentage of Real-Time Prices Corrected
2000 to 2002
Percent of Real-Time Intervals
14%
12%
10%
8%
6%
4%
2%
0%
Percent of Intervals Corrected:
2000 = 3.1 %
2001 = 0.4 %
2002 = 2.7 %
Jan
Mar
May
Jul
Sep
Nov
Jan
Mar
May
Jul
Sep
Nov
Jan
Mar
May
Jul
Sep
Nov
2000
2001
2002



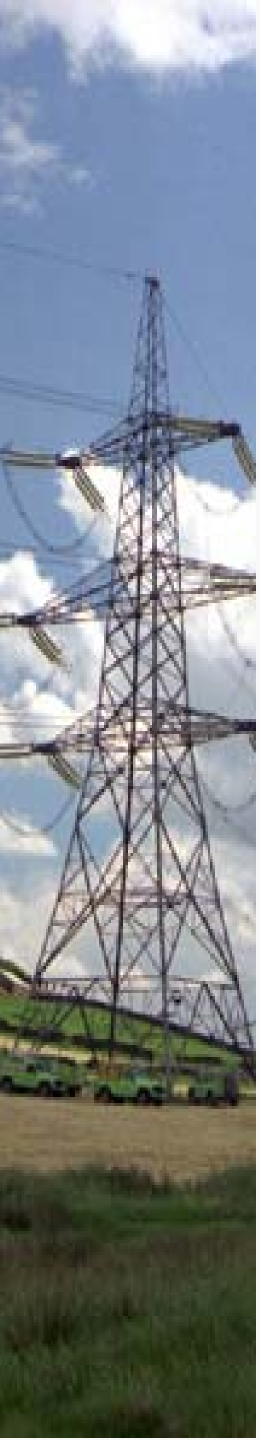
# Summary of Mitigation in 2002

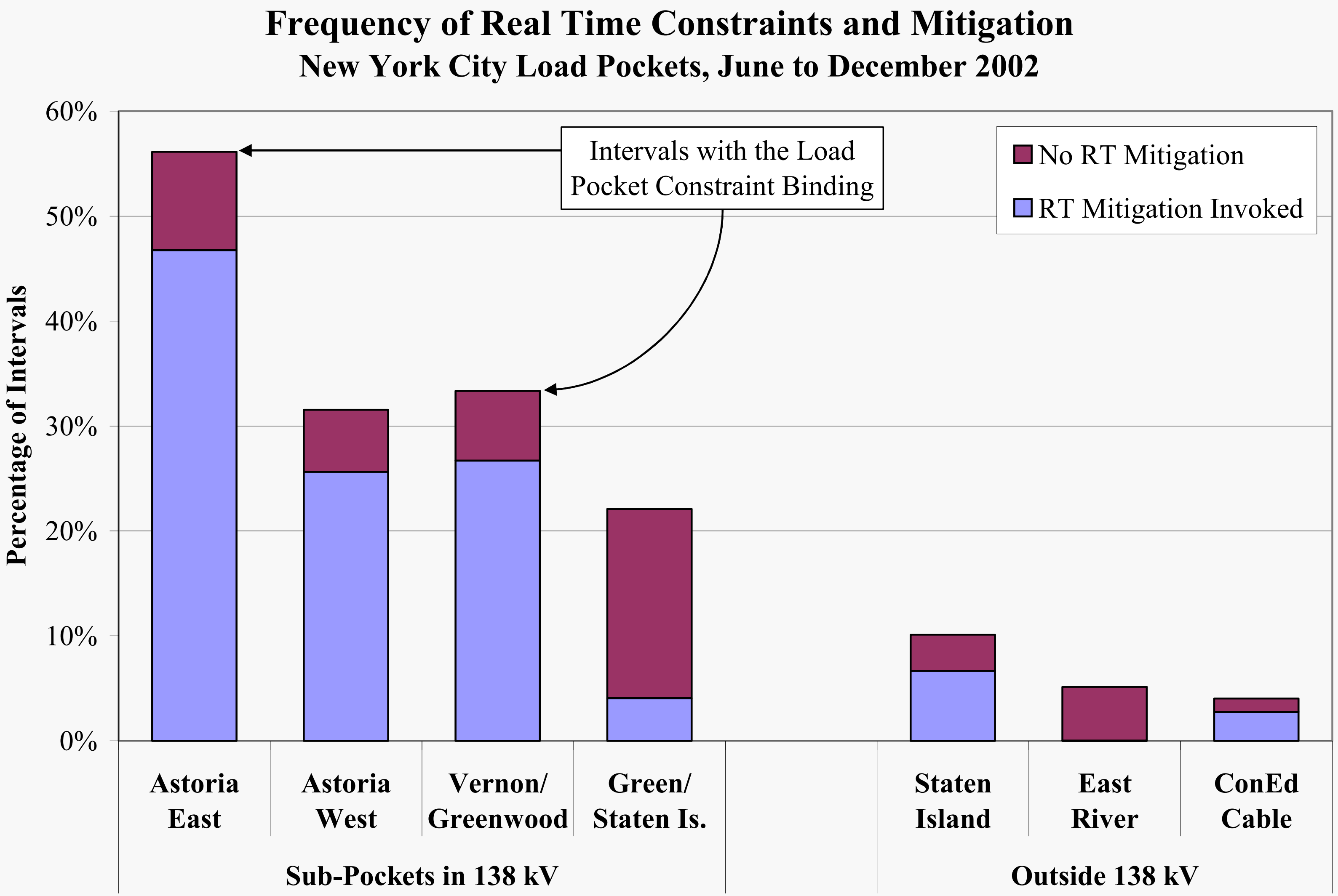
## Day-Ahead Market

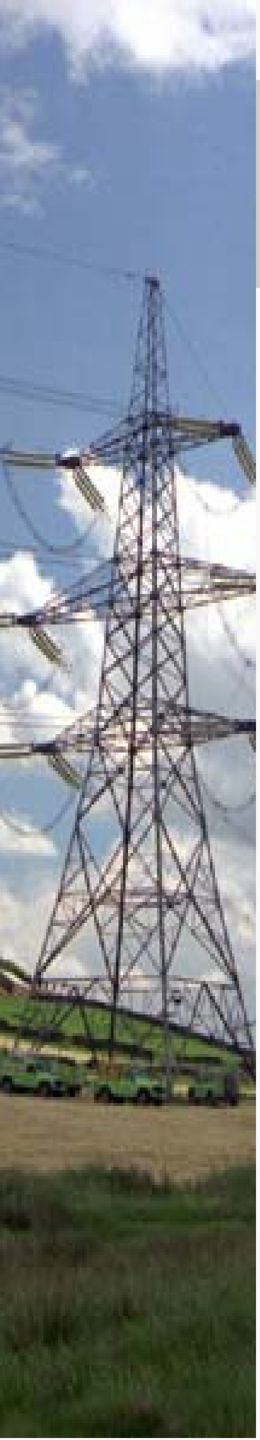
- ✓ Mitigation by the AMP did not occur in 2002.
- ✓ Mitigation of energy bids under the ConEd Mitigation for New York City occurred on every day in 2002.

## Real-Time Market

- ✓ The NYISO began modeling the load pockets in New York City in June 2002, together with mitigation measures to address locational market power in the pockets.
- ✓ The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - The constraints shown are those with a cumulative shadow price into the load pocket that exceeds the load pocket mitigation threshold.
  - When the constraints shown were binding, resources with bids exceeding its reference level by more than the load pocket's conduct threshold are subject to real-time mitigation.

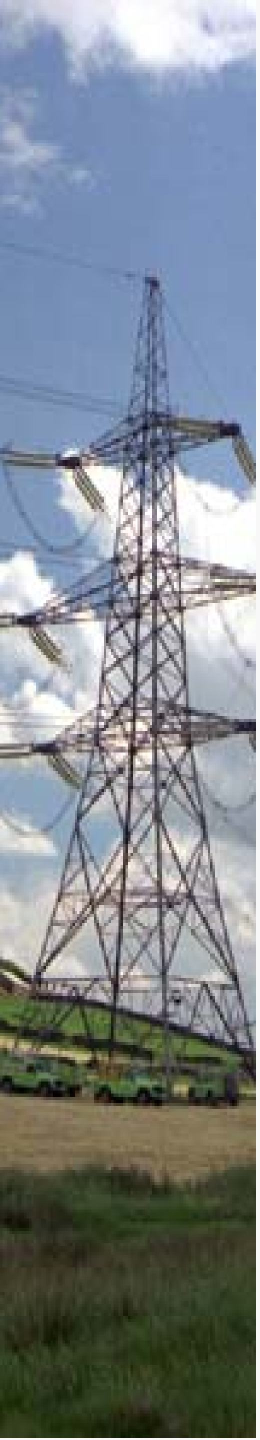


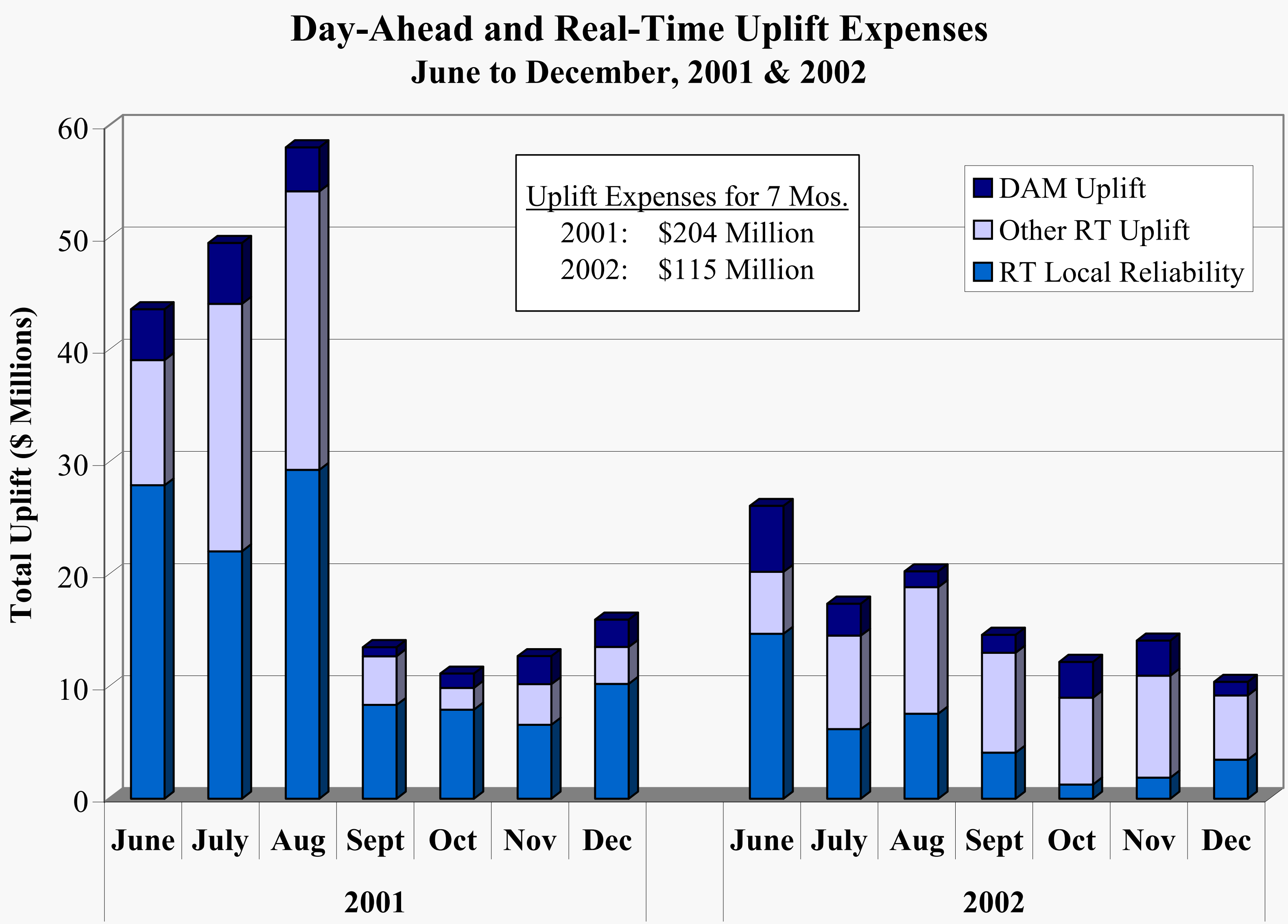

Frequency of Real Time Constraints and Mitigation
New York City Load Pockets, June to December 2002
Percentage of Intervals
60%
50%
40%
30%
20%
10%
0%
Intervals with the Load Pocket Constraint Binding
No RT Mitigation
RT Mitigation Invoked
Astoria East
Astoria West
Vernon/ Greenwood
Green/ Staten Is.
Staten Island
East River
ConEd Cable
Sub-Pockets in 138 kV
Outside 138 kV

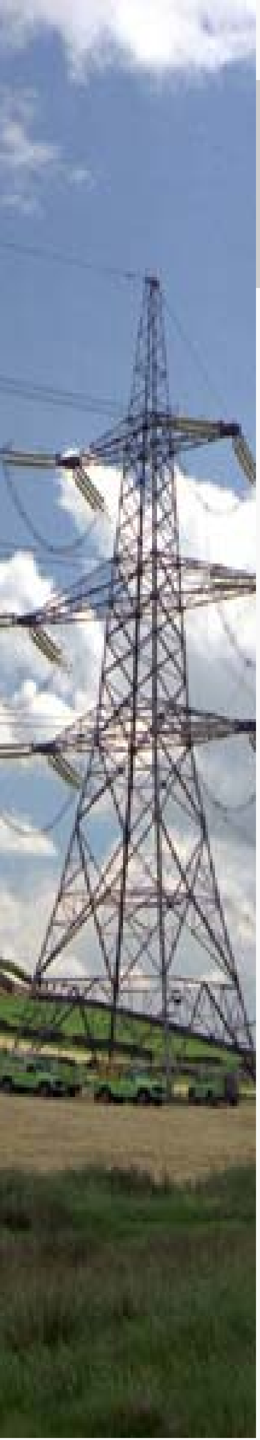


# Uplift Expenses

- Uplift expenses have fallen sharply as shown in the following figure.
  - ✓ Uplift expenses were $89 million lower in June to December 2002 than the same time period in 2001 -- a reduction of 44%.
  - ✓ High fuel prices at the end of 2002 reduced the apparent savings relative to 2001.
- This reduction in costs was comprised of reductions in the following areas:
  - ✓ <u>Real-time local reliability uplift</u>: Reduction of 82% or $73 million resulting from implementing load pocket modeling.
  - ✓ <u>Other real-time uplift</u>: Reduction of 20% or $14 million resulting from improved BME performance.
  - ✓ <u>Day-ahead uplift</u>: Reduction of 10% or $2 million resulting, in part from the load pocket modeling in the day-ahead market.

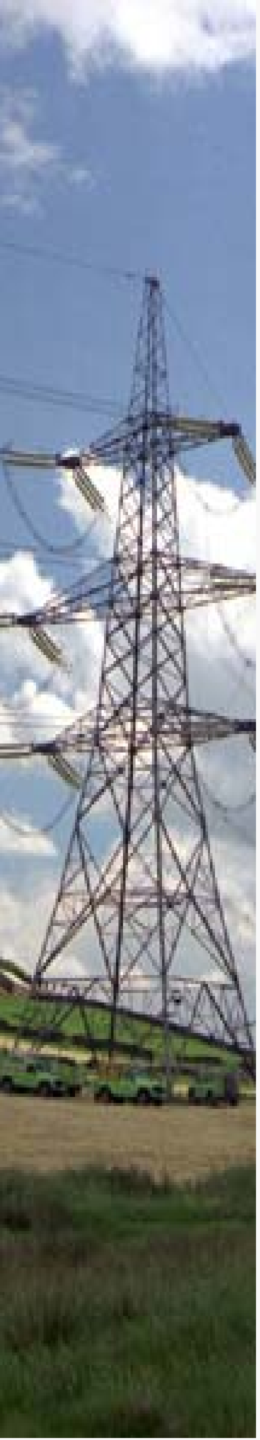



Day-Ahead and Real-Time Uplift Expenses
June to December, 2001 & 2002
Uplift Expenses for 7 Mos.
2001: $204 Million
2002: $115 Million
DAM Uplift
Other RT Uplift
RT Local Reliability
Total Uplift ($ Millions)
0
10
20
30
40
50
60
June
July
Aug
Sept
Oct
Nov
Dec
2001
June
July
Aug
Sept
Oct
Nov
Dec
2002



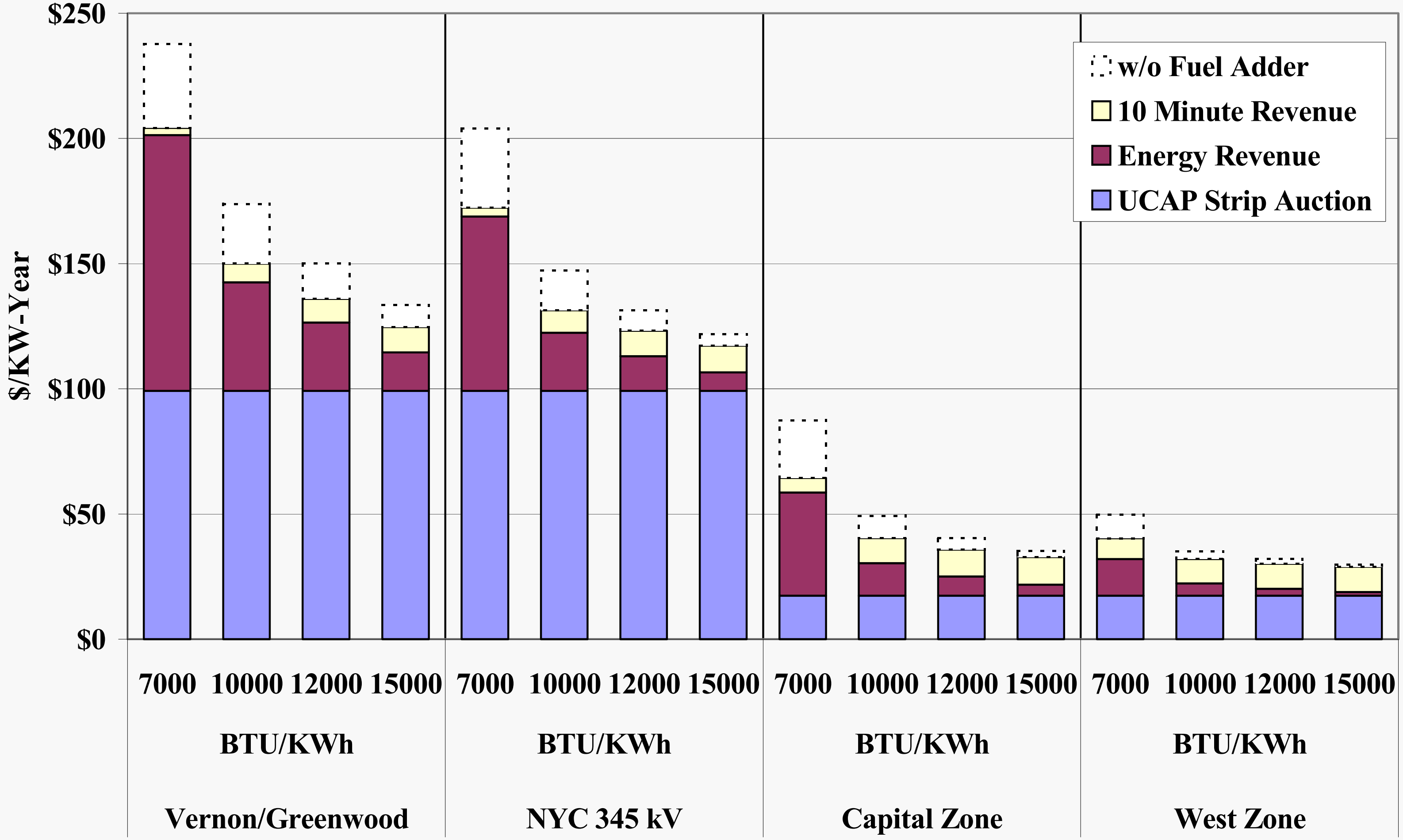
# Economic Incentives for New Investment

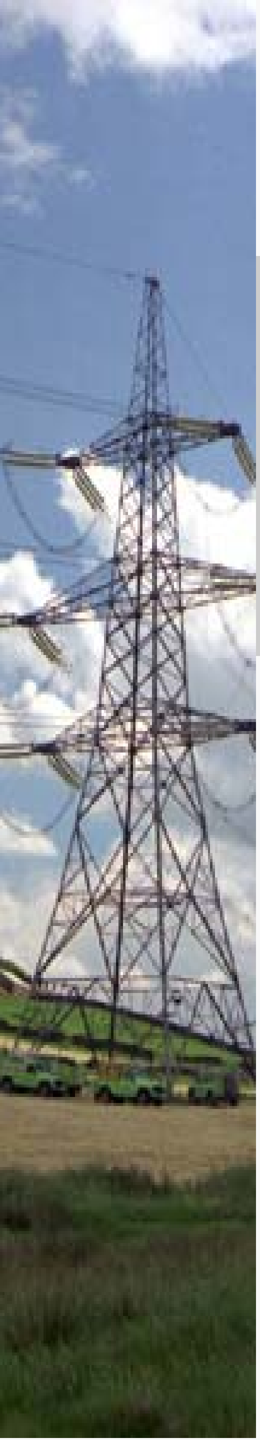
- The following analysis measures the economic signals produced by the markets in 2002. In long-run equilibrium, the market should support the entry of new generation.
- This analysis shows the net revenue the markets would provide to generators with different heat rates at various locations in New York.
- The figure also shows that the market in 2002 would not support new investment in gas turbines, although other investments may be more economic than gas turbines:
  - ✓ The annual cost of a new gas turbine is shown to be approximately \$80 per kw-year outside of NYC versus net revenue ranging from \$32 to \$40 per kw-year outside NYC in the day ahead (assuming a 10000 heat rate).
  - ✓ Costs of installing a new GT in NYC are likely significantly higher – NYISO has estimated costs of approximately \$180 per kw-year, while net revenues in 2002 ranged from \$130 to \$150 per kw-year in the two zones shown.
- The peak pricing changes being implemented for this summer should help address this issue.
- The appendix includes a similar analysis based on real-time market prices.



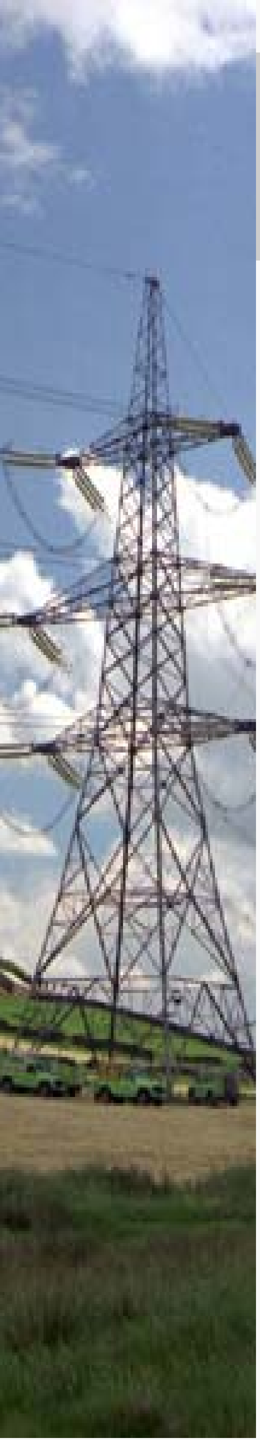
## Estimated Net Revenue in the New York Markets

### DAM - 2002



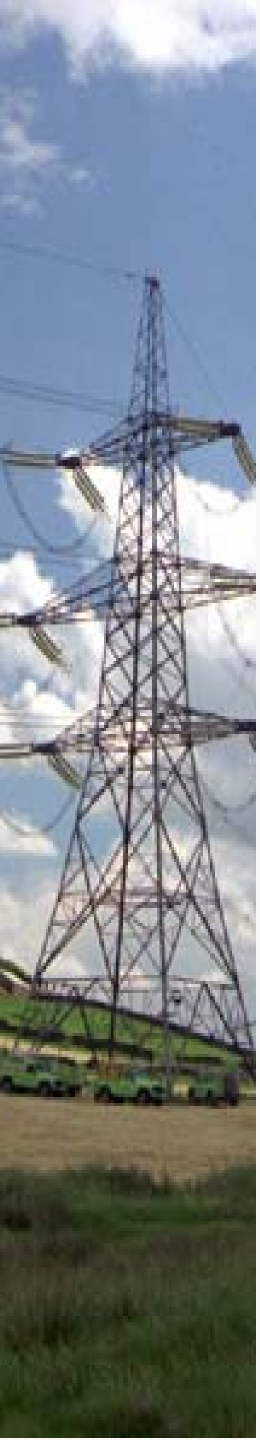


# Market Performance



# Energy Price Statistics

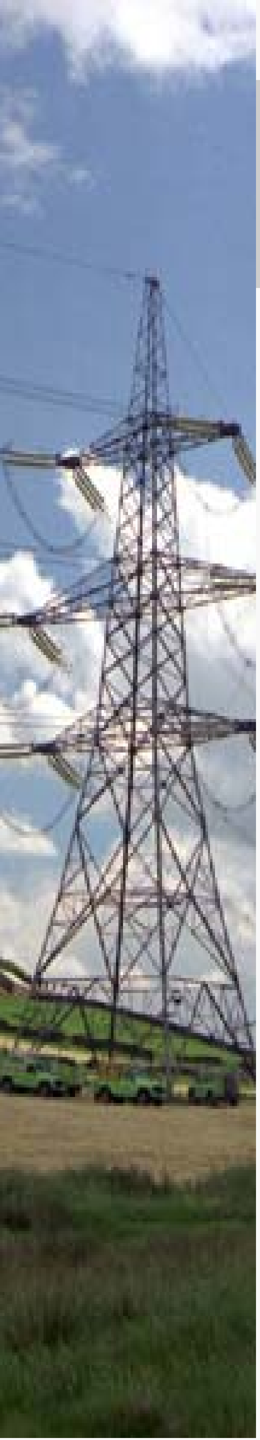
- The following table shows annual price statistics for prices in the West, Capital, and New York City zones for 2002.
  - ✓ Prices in the Capital and West zones dropped from 2001 levels due to slightly lower fuel prices;
  - ✓ New York City prices remained close to 2001 levels -- load pocket modeling increased prices from the levels that would have otherwise prevailed.
- The results show a slight premium in day-ahead prices versus real time prices in each of the three zones (NYC – 2.2%, Capital – 3.9%, West – 2.6%). These premiums are not surprising due to:
  - ✓ The higher risk to loads of purchasing in the more volatile real-time market and lack of TCC's to hedge congestion in real-time, and
  - ✓ The outage risk of generators associated with day-ahead schedules.
- The table also shows the standard deviations, which are the average of the monthly standard deviations for each hour of the day.
  - ✓ Average standard deviations dropped from 2001 levels in all three zones – decreasing the most in NYC (45% in the day ahead and 53% in the real time).
  - ✓ The volatility in the real-time prices remains roughly twice as high as day-ahead.



## Day-Ahead and Real-Time Price Statistics for Selected Zones
### January to December 2002

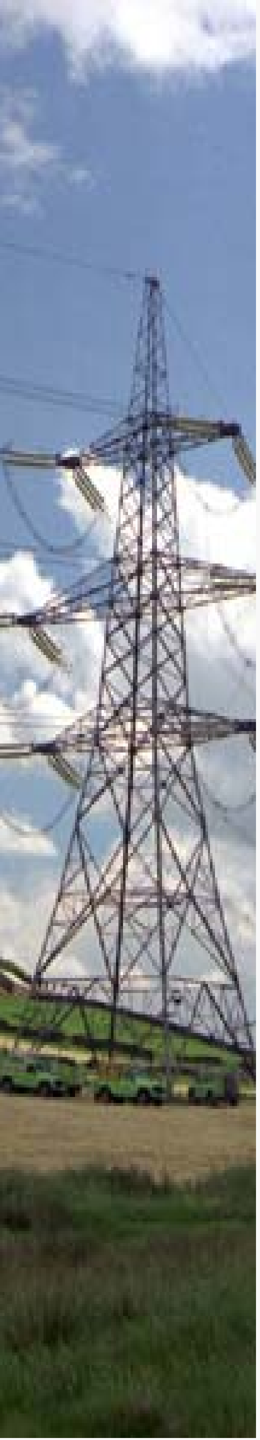
| | New York City | | Capital Zone | | West Zone | |
|---|---|---|---|---|---|---|
| | Day-Ahead | Real-Time | Day-Ahead | Real-Time | Day-Ahead | Real-Time |
| **Load Weighted Average** | $49.63 | $48.55 | $40.50 | $38.99 | $32.20 | $31.37 |
| *Compared with 2001* | *$0.51* | *-$0.59* | *-$2.67* | *-$3.74* | *-$3.82* | *-$1.49* |
| **Avg. Std. Deviation** | 8.48 | 19.63 | 8.61 | 16.91 | 6.73 | 13.58 |
| *Compared with 2001* | *-3.83* | *-10.39* | *-2.18* | *-7.66* | *-2.47* | *-2.14* |
| **Minimum** | $9.23 | -$18.69 | $8.92 | -$17.93 | $7.97 | -$125.90 |
| **Maximum** | $199.21 | $1,122.98 | $213.51 | $1,007.63 | $157.31 | $1,005.84 |

*Note*: Avg. Std. Deviation is calculated as an average of the monthly standard deviations in each of the 24 hours of the day. This eliminates the price fluctuations due to the normal load changes over the course of each day or across seasons.

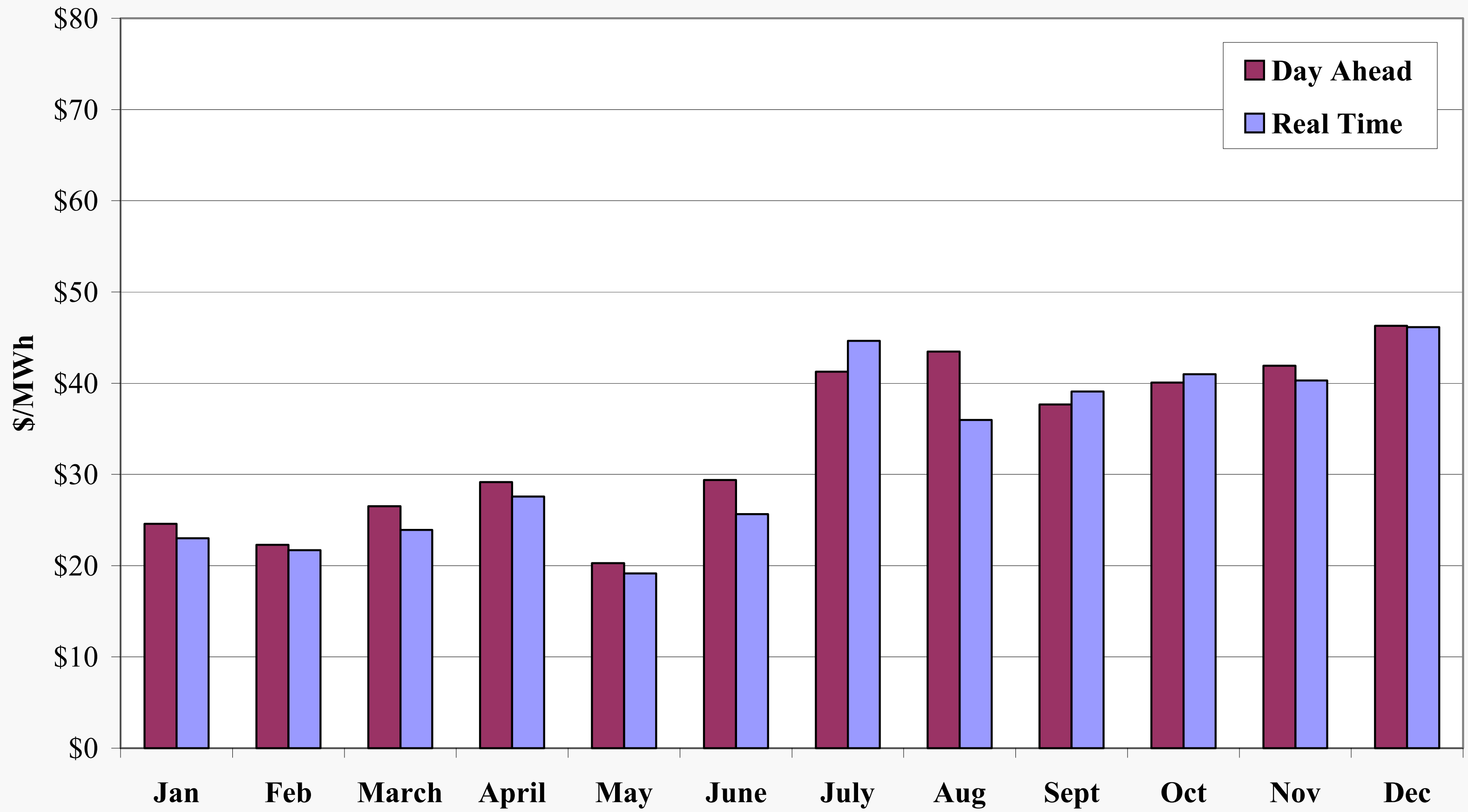


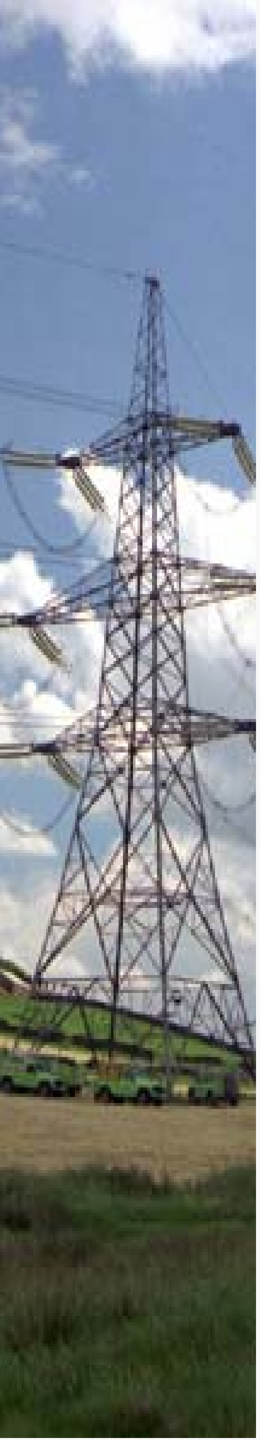
# Day-Ahead and Real-Time Energy Prices

- 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 all three areas.
  - ✓ Prices generally converged well throughout New York State.
  - ✓ However, convergence was not as uniform in the summer months during 2002, attributable to periods of peak demand.
  - ✓ The scarcity pricing provisions being implemented prior to summer 2003 should make real-time energy pricing during shortages more reliable, making the arbitrage with day-ahead prices more straightforward.
- Western New York prices were relatively low in March, April, and May due to constraints related to transmission maintenance outages, including outages required for interconnection of the Athens generating plant.

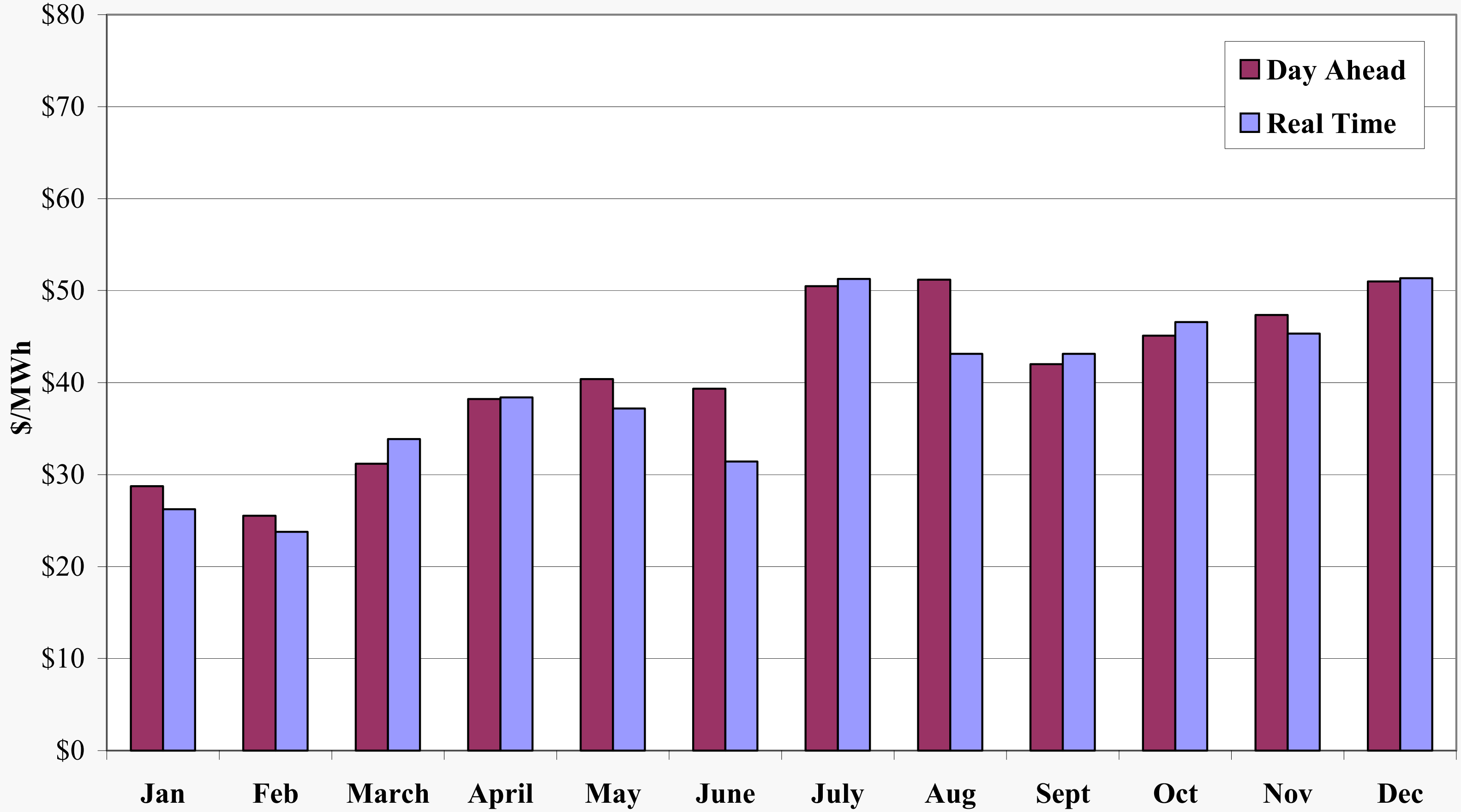


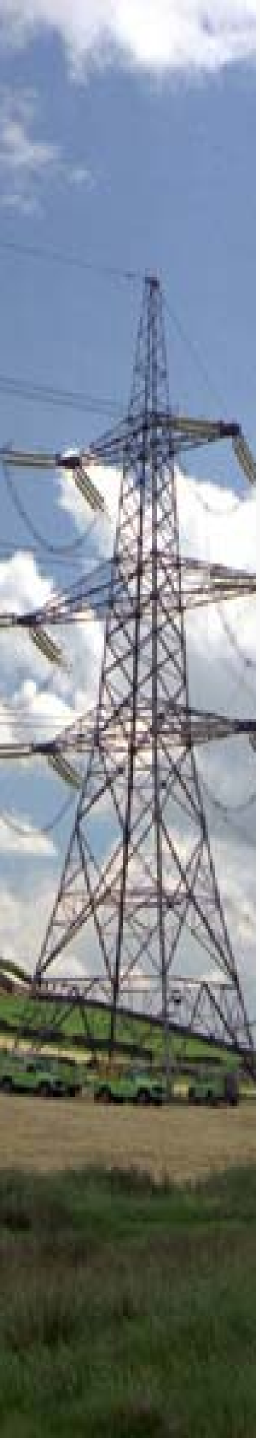
**Day-Ahead and Real-Time Energy Prices**
**West of Central East -- 2002**

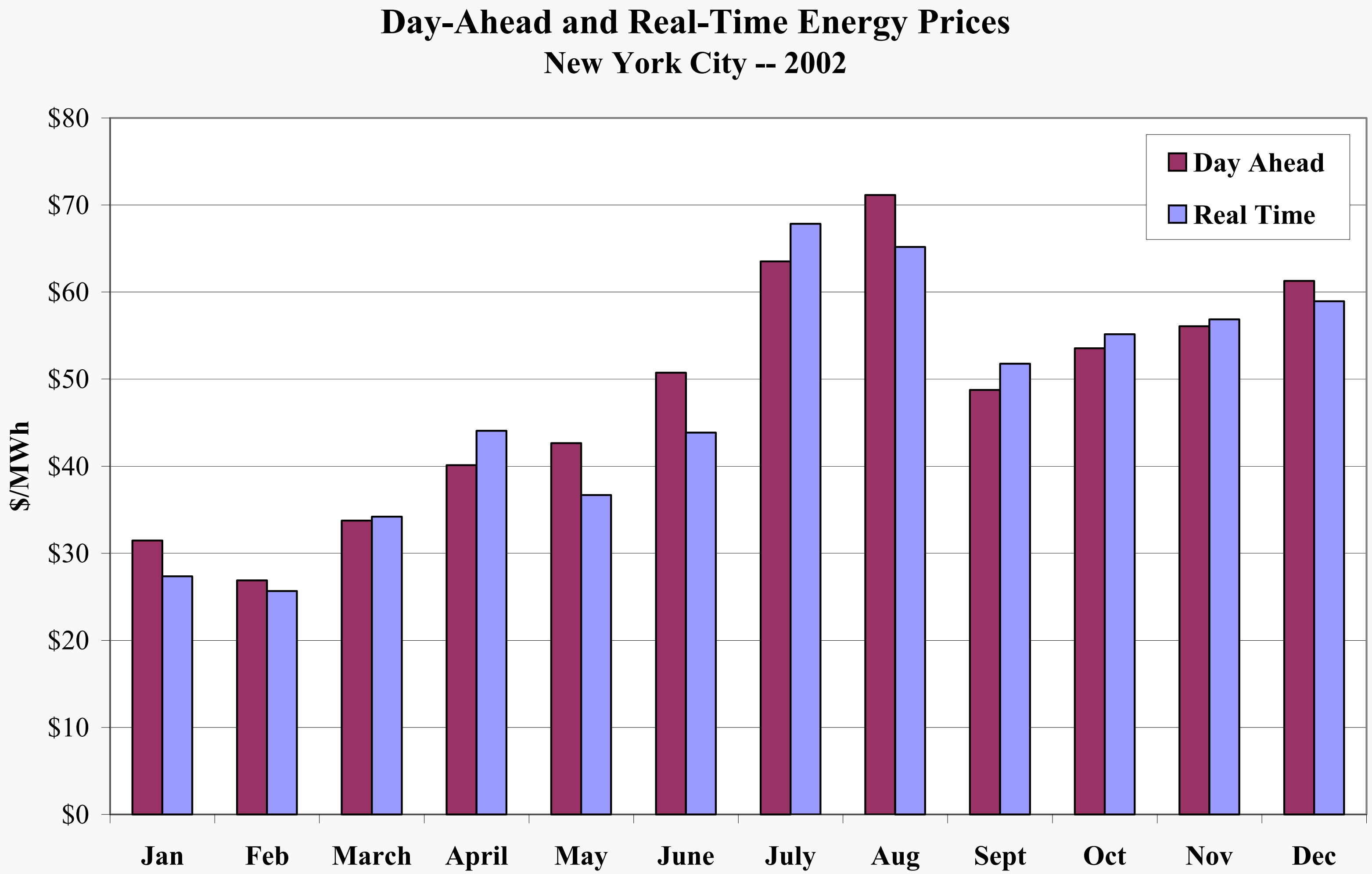


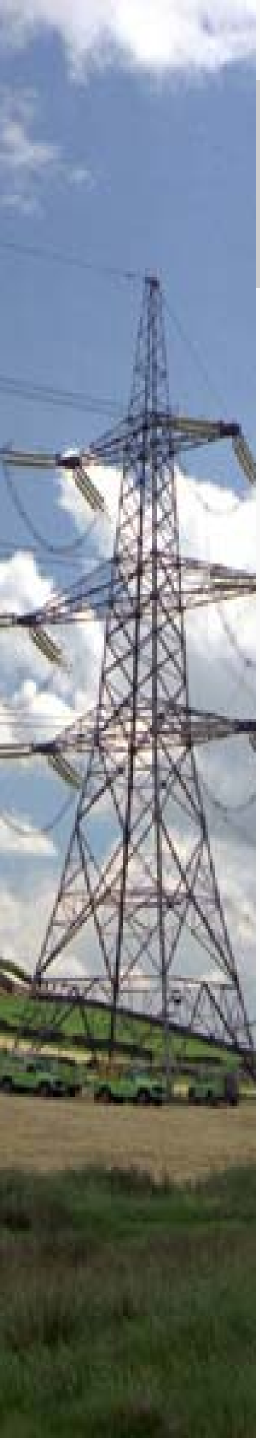


## Day-Ahead and Real-Time Energy Prices
### East Above New York City -- 2002



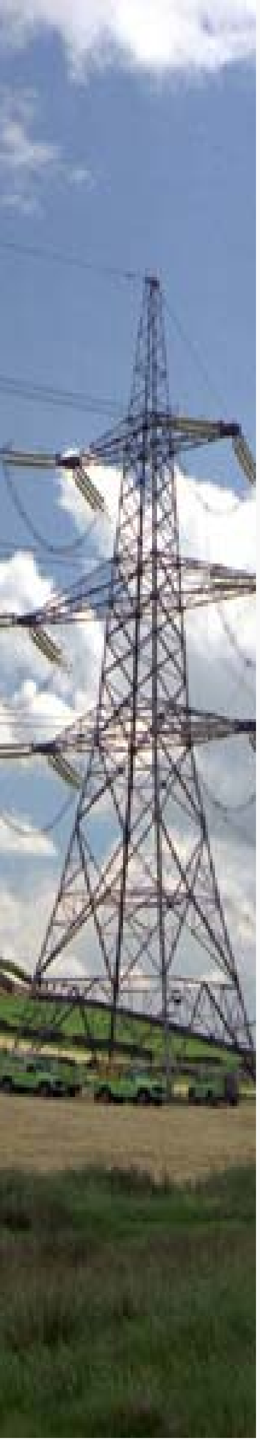



Day-Ahead and Real-Time Energy Prices
New York City -- 2002
$/MWh
$80
$70
$60
$50
$40
$30
$20
$10
$0
Day Ahead
Real Time
Jan
Feb
March
April
May
June
July
Aug
Sept
Oct
Nov
Dec



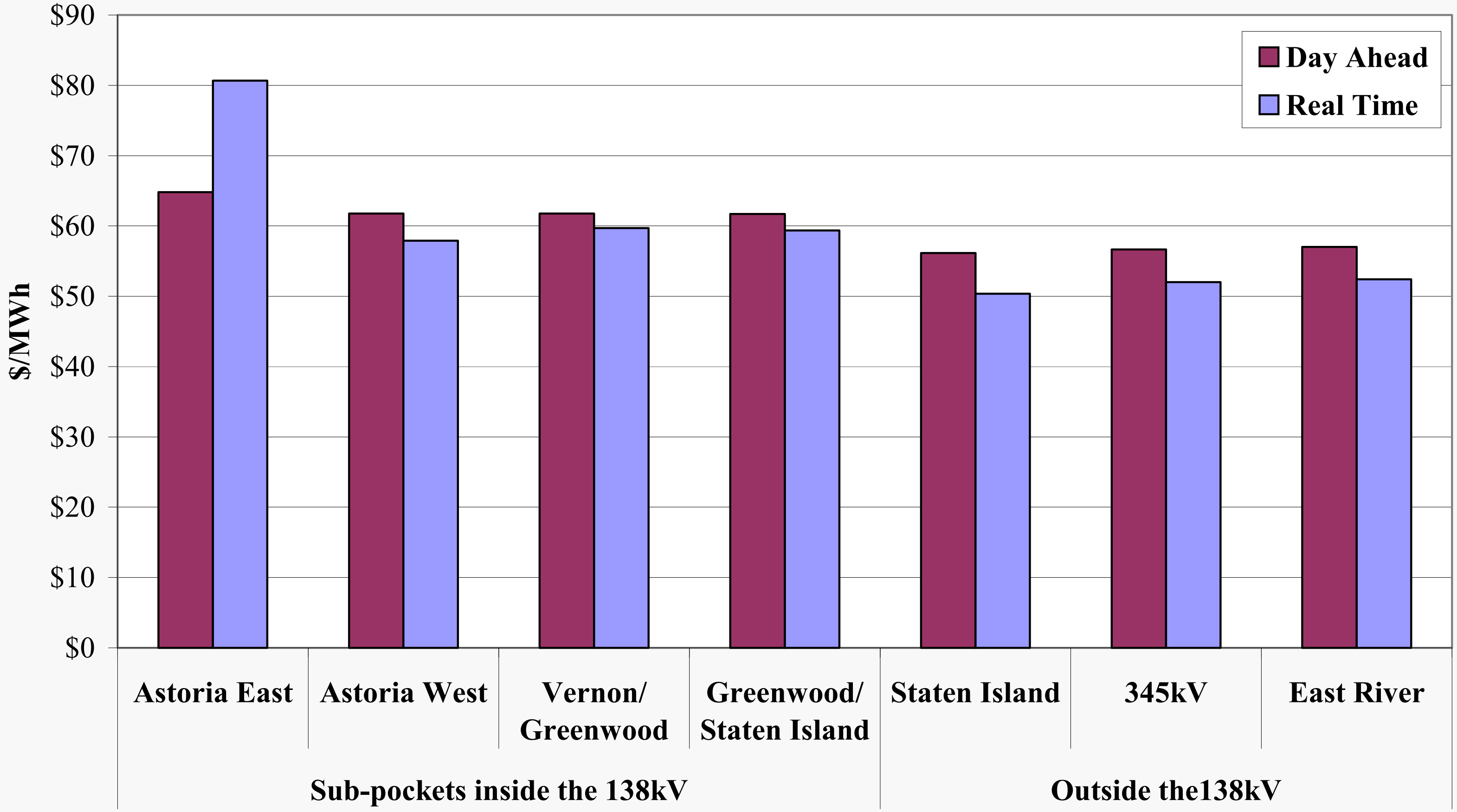
# Price Convergence in the Load Pockets

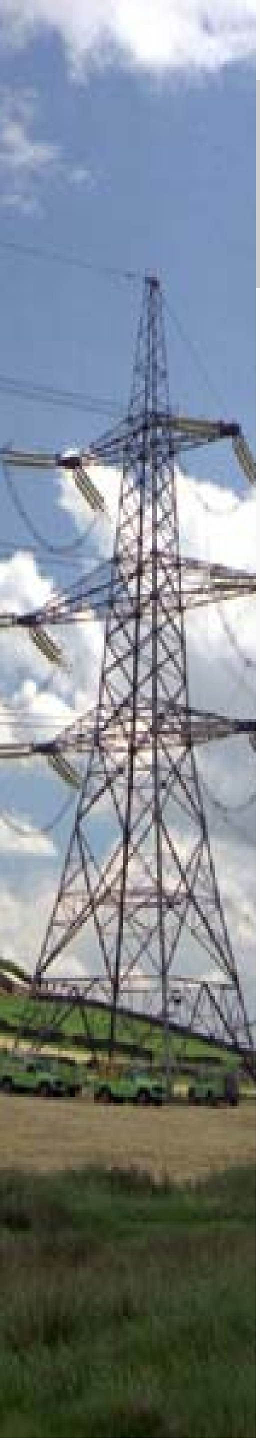
- Modeling of the load pockets within NYC, which was implemented June 3 in real time and June 19 in day ahead, has resulted in more accurate locational prices.
- Due to limitations of the SCD, a simplified representation of the intra-NYC constraints is used in real time while a more detailed representation is used in the day ahead.
- The following figure shows a large premium in real time in the Astoria East load pocket with the other pockets showing a premium in the day ahead market. Additional analysis of the Astoria East pocket is included in the Appendix.
- 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.
  - ✓ Since zonal prices are an average of all load pockets, virtual trades that improve convergence in one pocket will generally worsen convergence in other pockets.
- To improve the price convergence in New York City, I recommend:
  - ✓ The NYISO evaluate the load pocket modeling to ensure that any inconsistencies between the day-ahead and real-time modeling are minimized; and
  - ✓ The NYISO consider (i) allowing virtual trading at the load pocket level; or (ii) allowing virtual trading on the 345kv system separately from the 138 kv system, which would be a smaller departure from the current system.



## Average Day-Ahead and Real-Time Prices for NYC Load Pockets

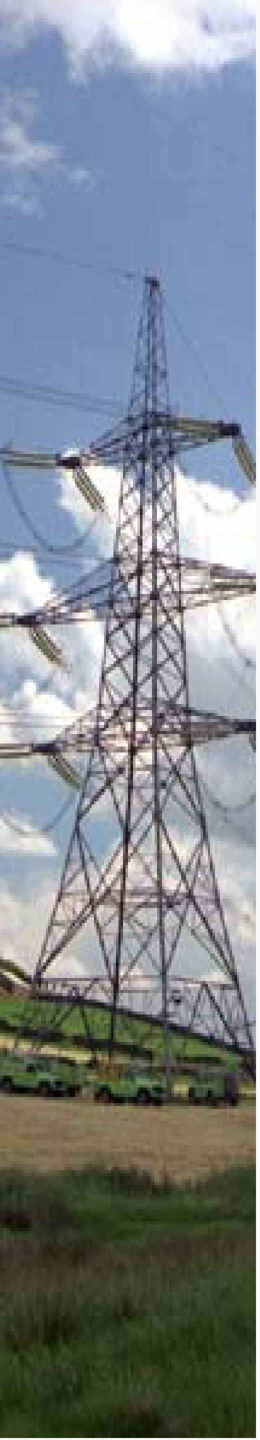
**July - December, 2002**

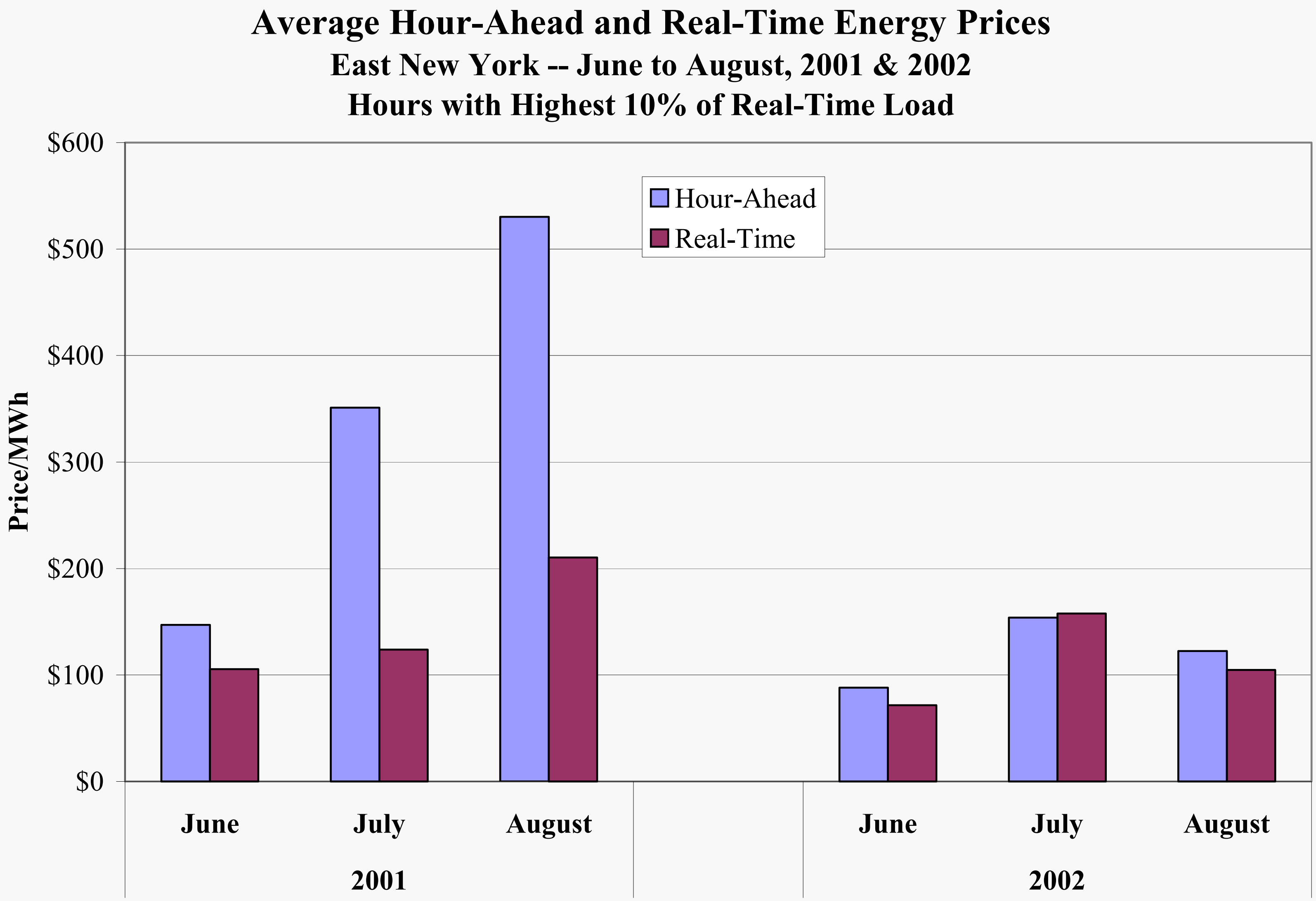


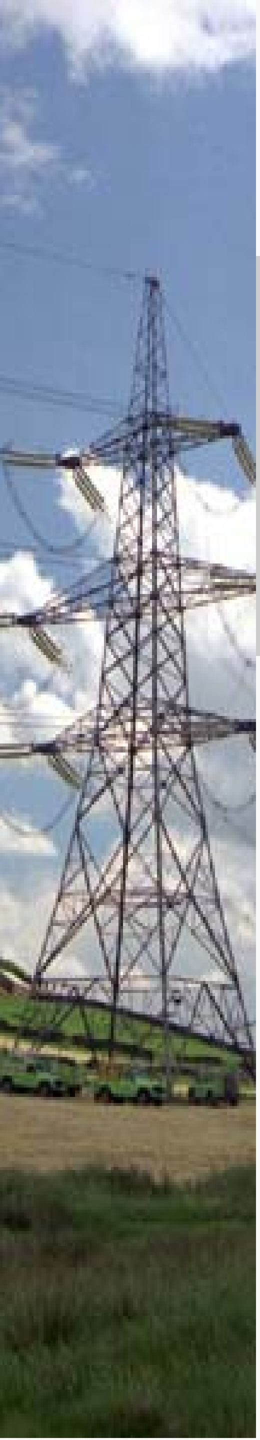


# Hour-Ahead and Real-Time Prices

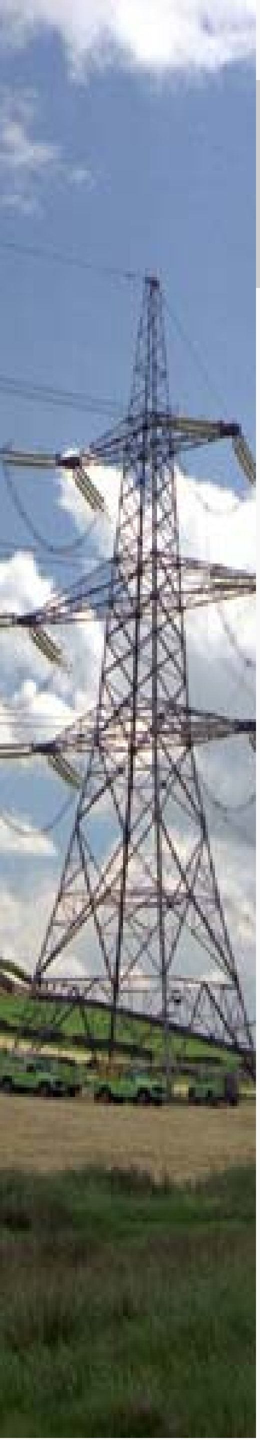
- Lack of convergence between hour-ahead and real-time prices prior to 2002 has been a concern because large price differences can result in:
  - ✓ External transactions and off-dispatch generation being scheduled inefficiently; and
  - ✓ Increased uplift costs and inefficient real-time prices.
- Several changes to market rules and the BME model were made to improve the price convergence 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.
- The following figure shows remarkable improvement in the price convergence in eastern New York during the highest load hours.
  - ✓ Extraordinarily high BME prices in 2001 resulted in substantial scheduling of uneconomic transactions.
  - ✓ The appendix includes additional scatter plots that show the improvement in hour ahead to real time convergence relative to load levels.




Average Hour-Ahead and Real-Time Energy Prices
East New York -- June to August, 2001 & 2002
Hours with Highest 10% of Real-Time Load
$600
$500
$400
$300
$200
$100
$0
Price/MWh
Hour-Ahead
Real-Time
June
July
August
2001
June
July
August
2002

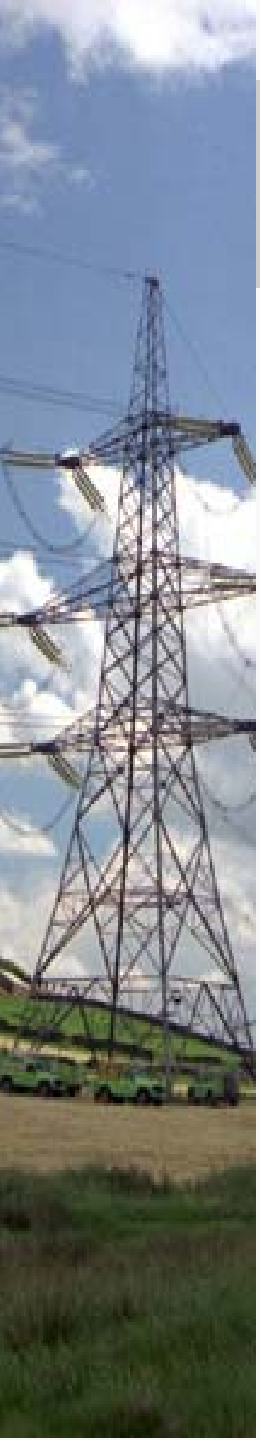


# Analysis of Bidding Patterns



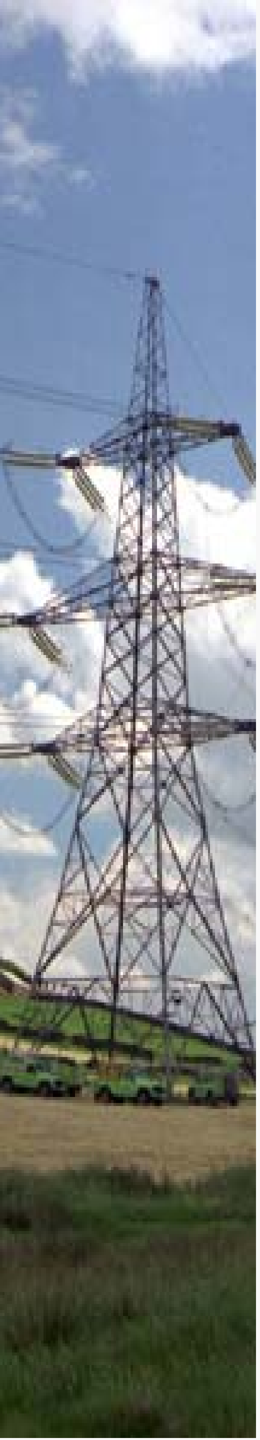
# Analysis of Offer Patterns

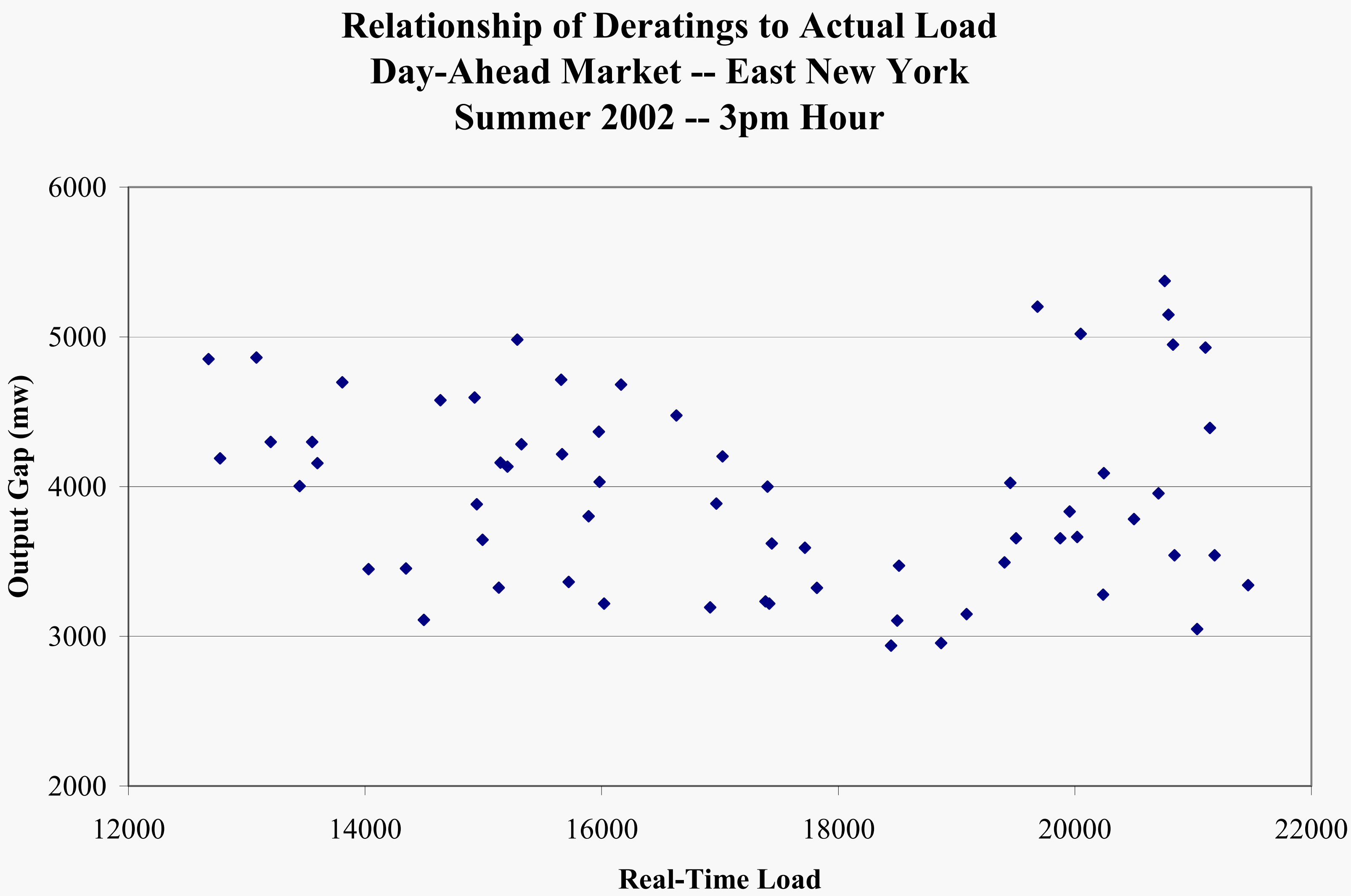
- This section of the report analyzes the patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase bid quantities during higher load 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 generator deratings.
- Deratings include planned outages, long-term forced outages, short-term forced outages, and partial deratings.

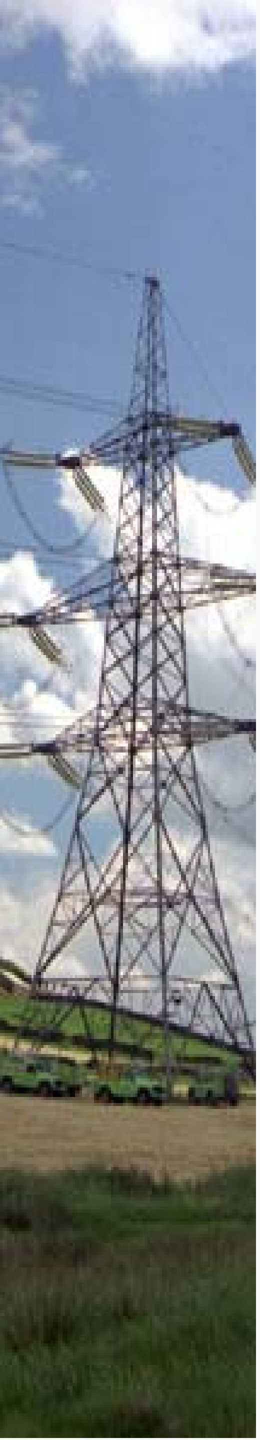


# Analysis of Offer Patterns – Deratings

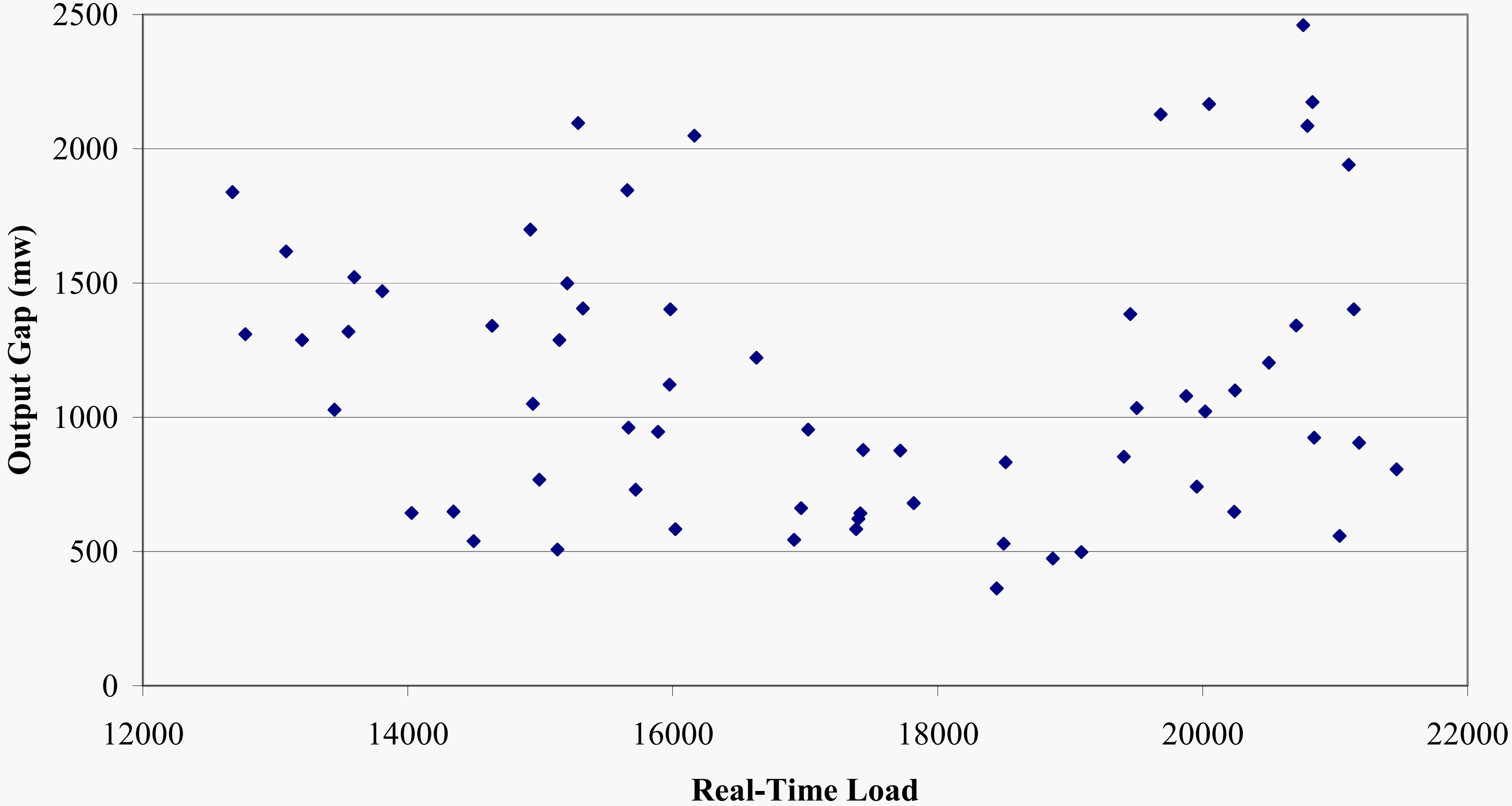
- The following figures show deratings during the summer months since maintenance is ordinarily performed during the spring or fall.
- The first figure plots total deratings versus actual load in eastern NY.
- The second figure focuses on short-term outages since these are most likely to reflect attempts to physically withhold.
- These figures show no statistically significant relationship between deratings and load levels.
- However, specific instances of high deratings at relatively high load levels have been investigated by the MMU.

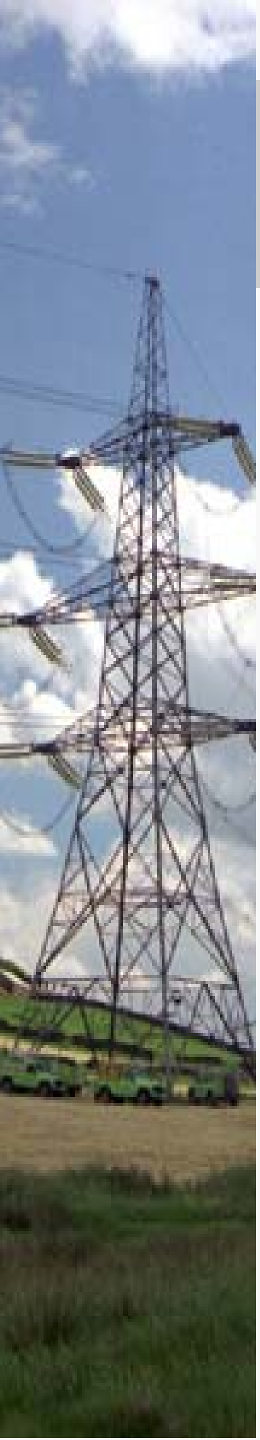



Relationship of Deratings to Actual Load
Day-Ahead Market -- East New York
Summer 2002 -- 3pm Hour
Output Gap (mw)
6000
5000
4000
3000
2000
12000
14000
16000
18000
20000
22000
Real-Time Load



**Relationship Short-Term of Deratings to Actual Load**
**Day-Ahead Market -- East New York**
**Summer 2002 -- 3pm Hour**

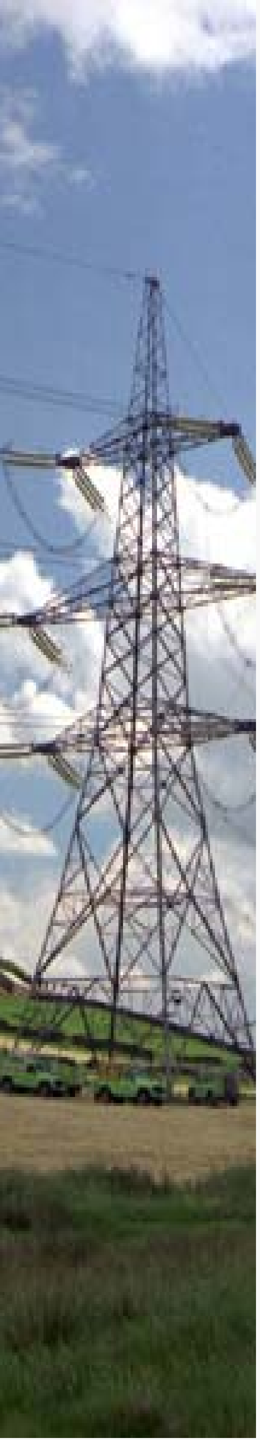


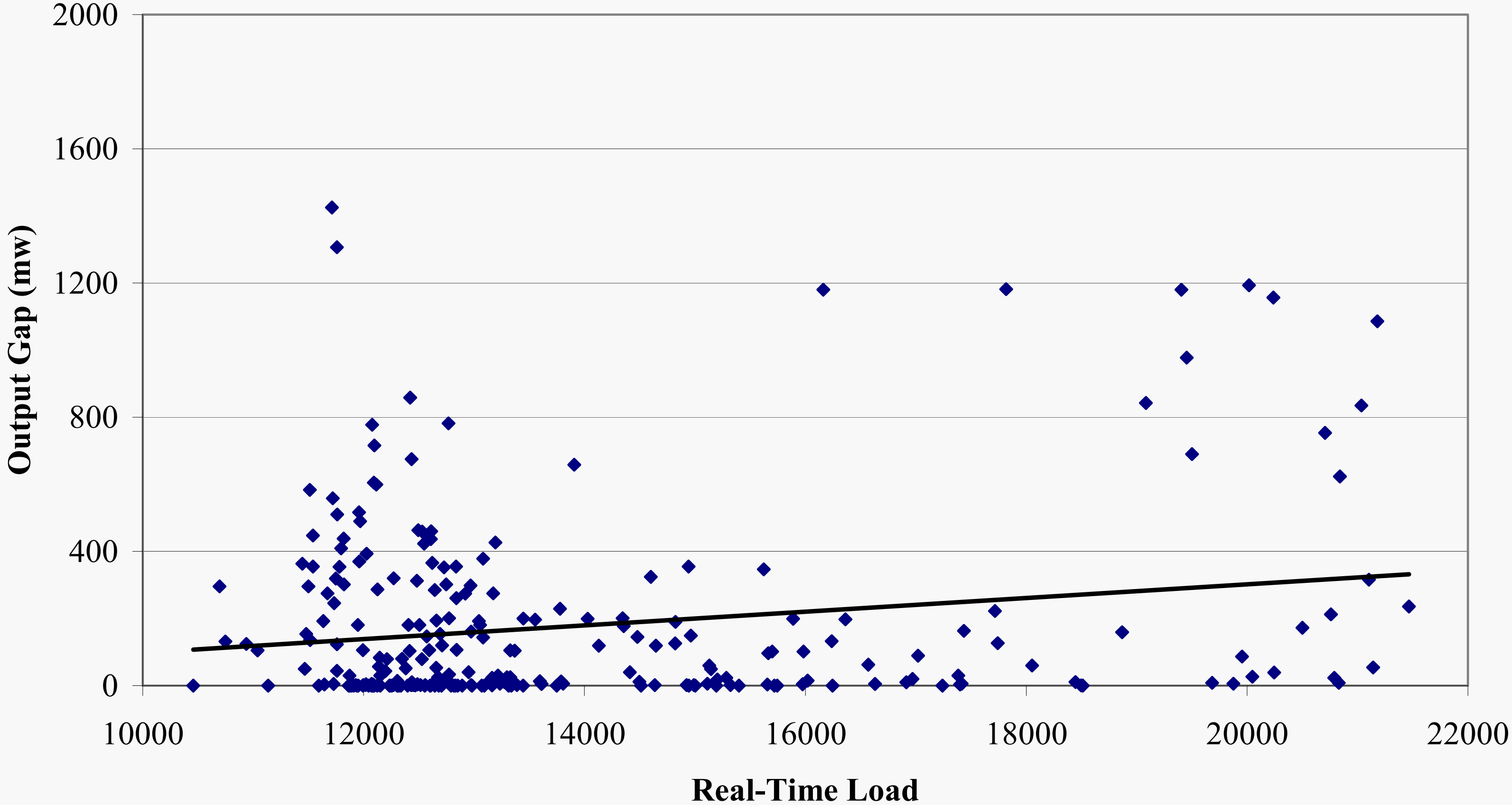


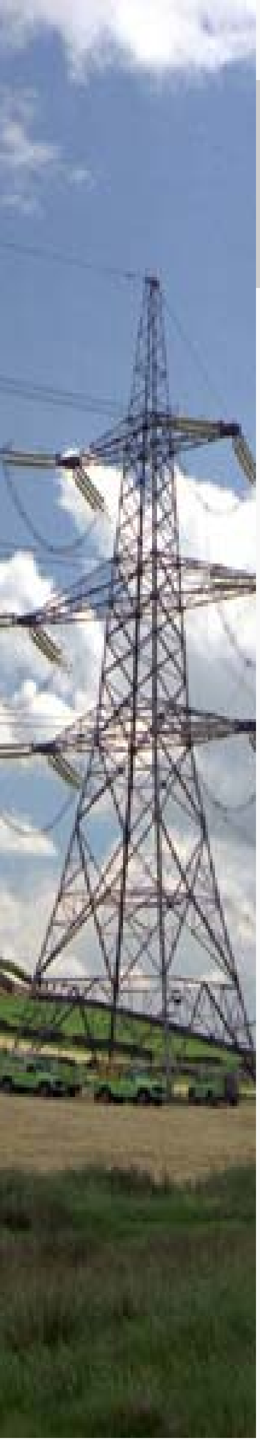
# Analysis of Offer Patterns – Output Gap

- 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 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" while bidding well above reference levels.
  - ✓ The output gap does not include capacity scheduled to provide ancillary services.
- The following figure shows the total output gap in eastern New York using thresholds $50/MWh or 100% (whichever is lower), which are lower than the conduct thresholds employed for purposes of mitigation.

## Relationship of Output Gap at Low Threshold to Actual Load
## Real-Time Market -- East New York
## 2002 -- 3pm Hour



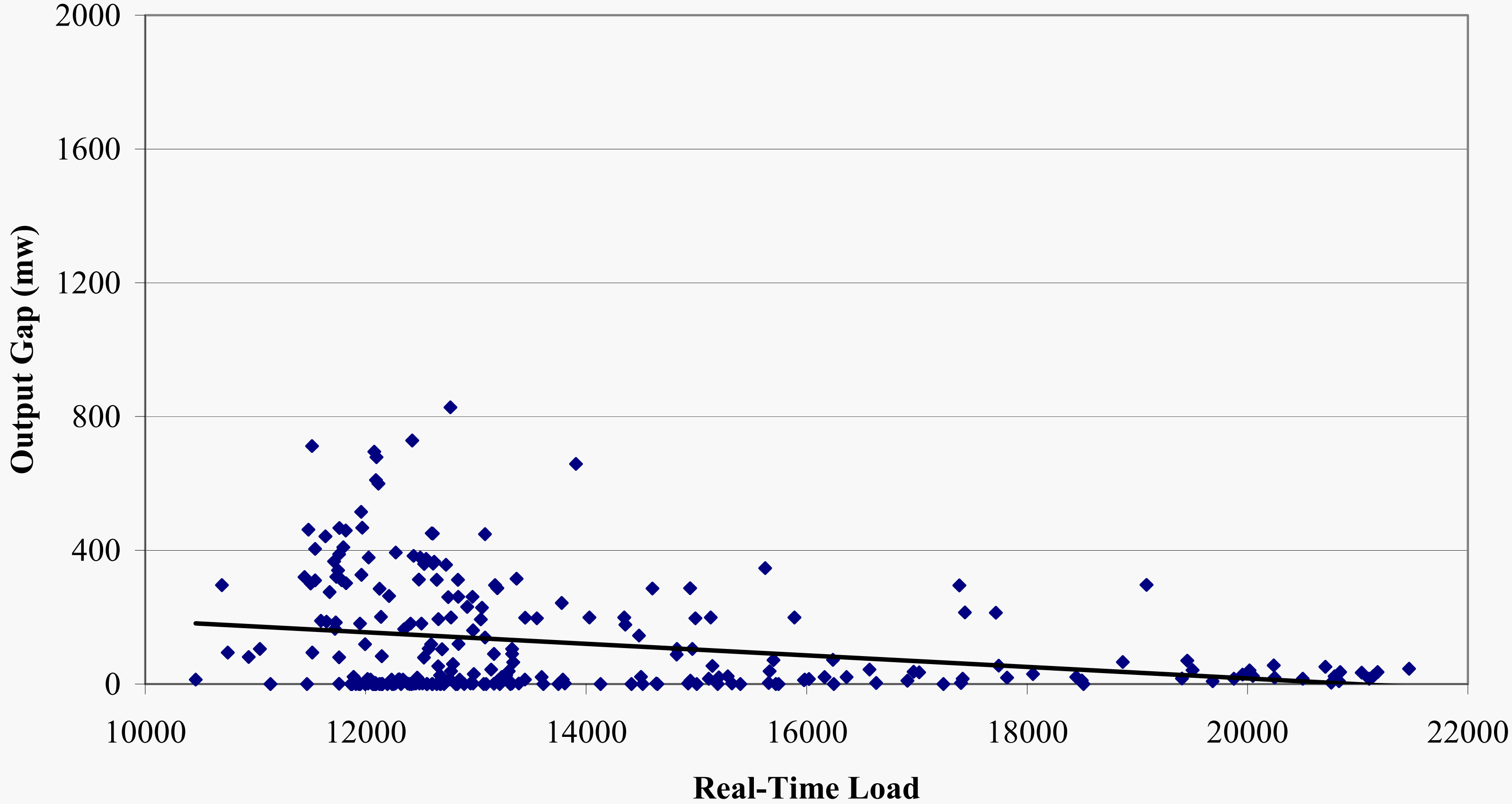


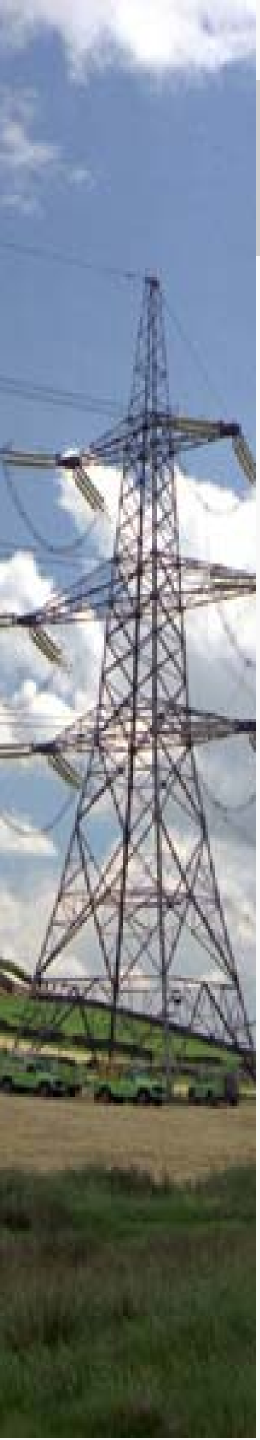


# Analysis of Offer Patterns – Output Gap

- The previous figure shows the output gap was above 800 megawatts on seventeen days during 2002.
- The real-time load was quite high on most of these days, while others occurred during April on days where emergency demand response was called.
- Much of the output gap shown on the high load days is related to the conduct of a single supplier. This conduct was investigated and, in most cases, it did not substantially affect clearing prices.
- The following figure shows the output gap at the low threshold when this supplier is excluded. Without this supplier, the output gap quantities are:
  - ✓ Close to zero under the highest load conditions.
  - ✓ Negatively correlated with the actual load.

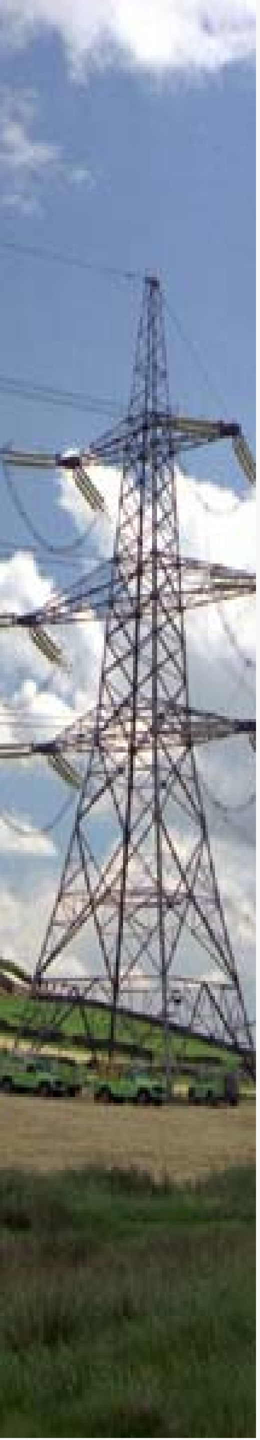
## Relationship of Output Gap at Low Threshold to Actual Load
## Real-Time Market -- East New York
## 2002 -- 3pm Hour -- Excl. One Supplier





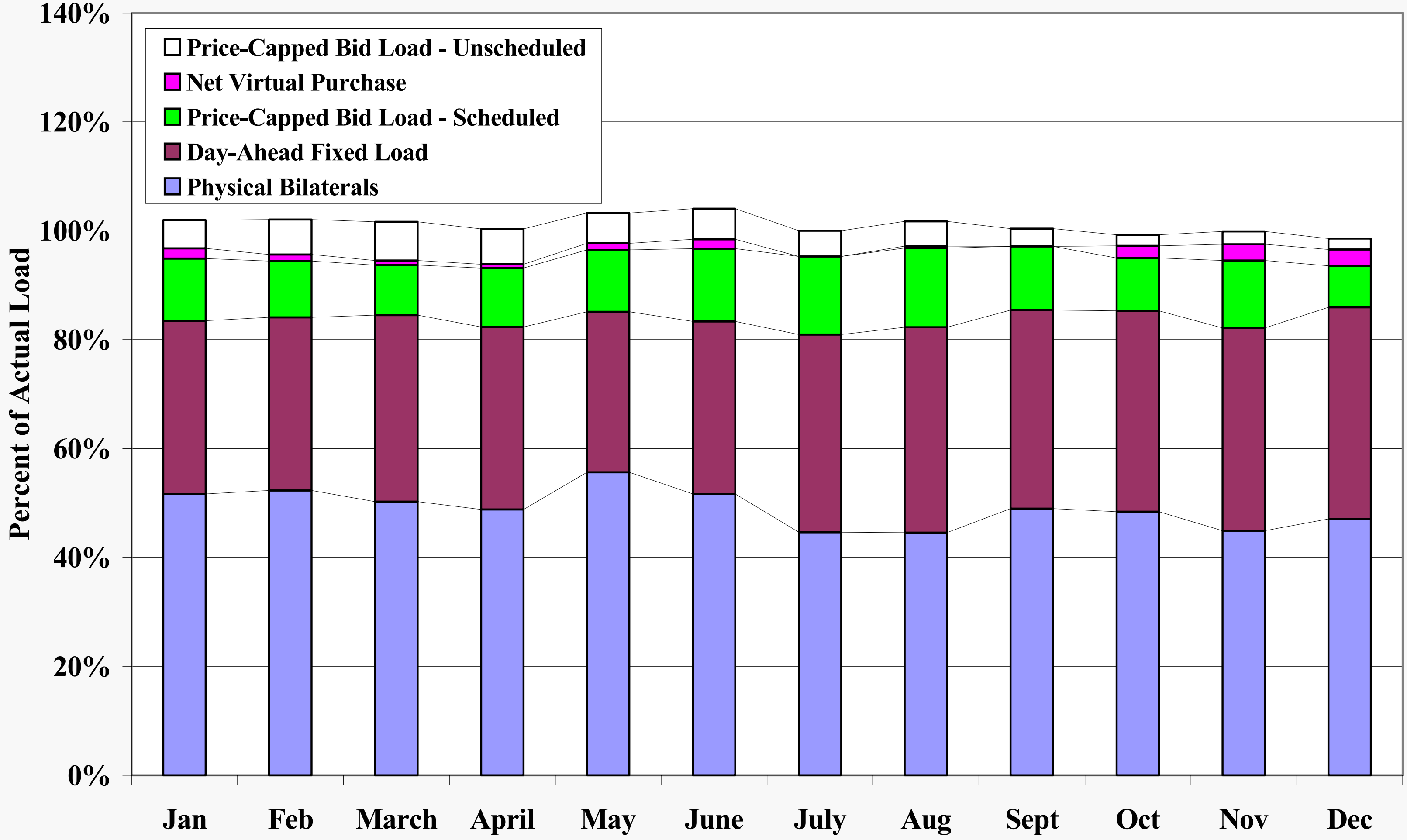
# Analysis of Load Bidding Patterns

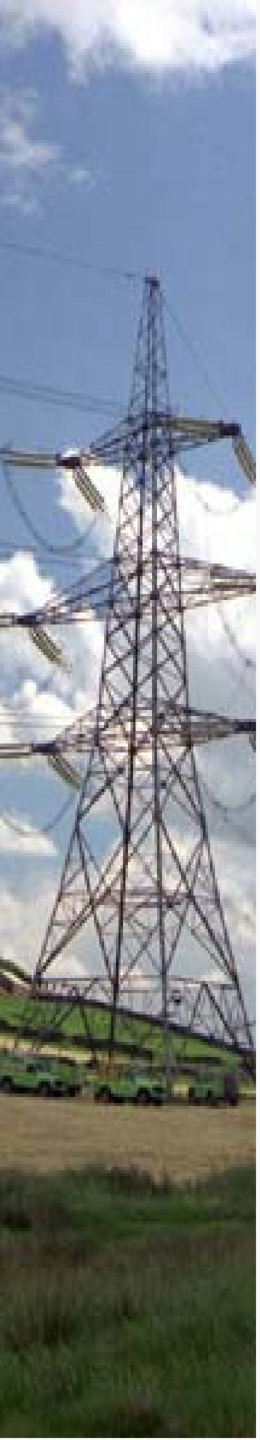
- The NYISO also monitors the bidding patterns of load-serving entities as specified in the monitoring and mitigation plans.
- The following figures show the load bidding patterns during 2002 in the entire state and in New York City.
- These figures show the following:
  - ✓ Price-capped load bidding has become more prevalent since the implementation of virtual bidding in November 2001.
  - ✓ The percentage of the actual load supplied through physical bilaterals has been relatively constant throughout the state.
    - – Physical bilaterals do not include all bilaterals since those structured as “Contract for Differences” will be shown as day-ahead bid load.
  - ✓ Virtual trading has generally increased through the year, particularly in NYC and Long Island, where the net virtual load peaked at more than 8 percent of the day-ahead load in October.
- The appendix includes a more detailed analysis of hourly under or over-scheduling in the DAM relative to actual load levels to detect potential attempts to artificially influence day-ahead prices.



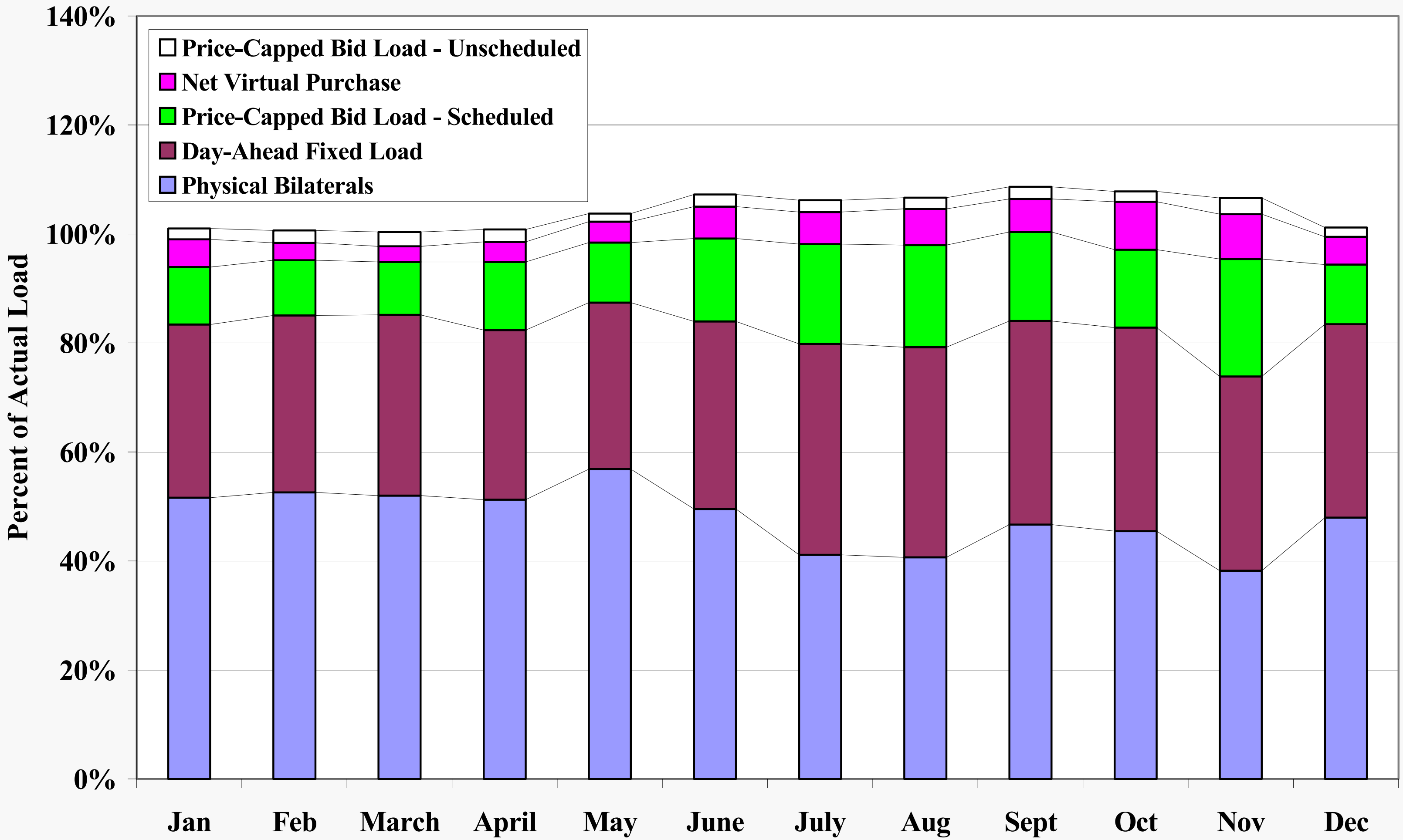
# Composition of Day Ahead Load Bids as a Proportion of Actual Load

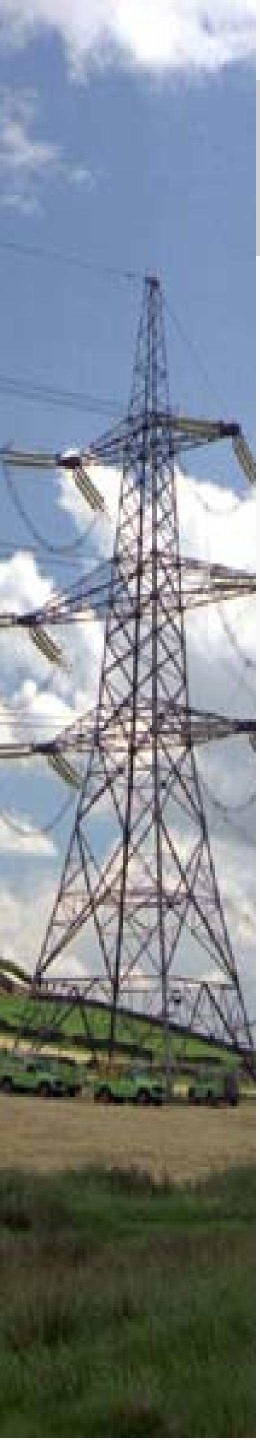
## New York State -- 2002





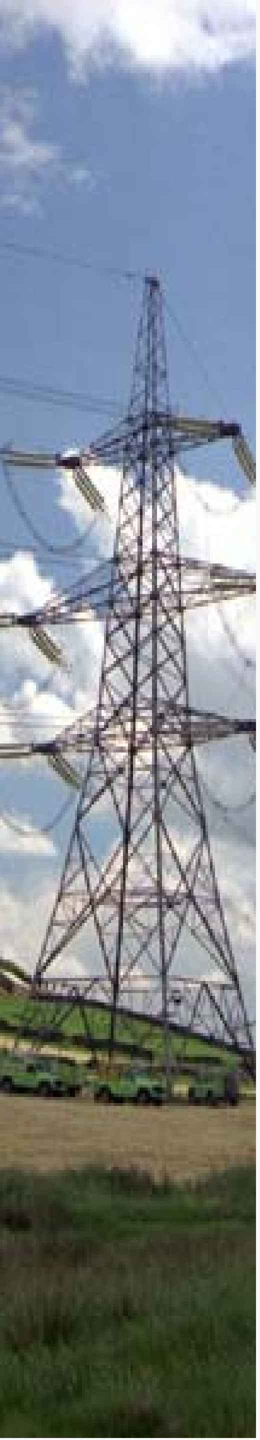
## Composition of Day Ahead Load Bids as a Proportion of Actual Load
### New York City and Long Island -- 2002



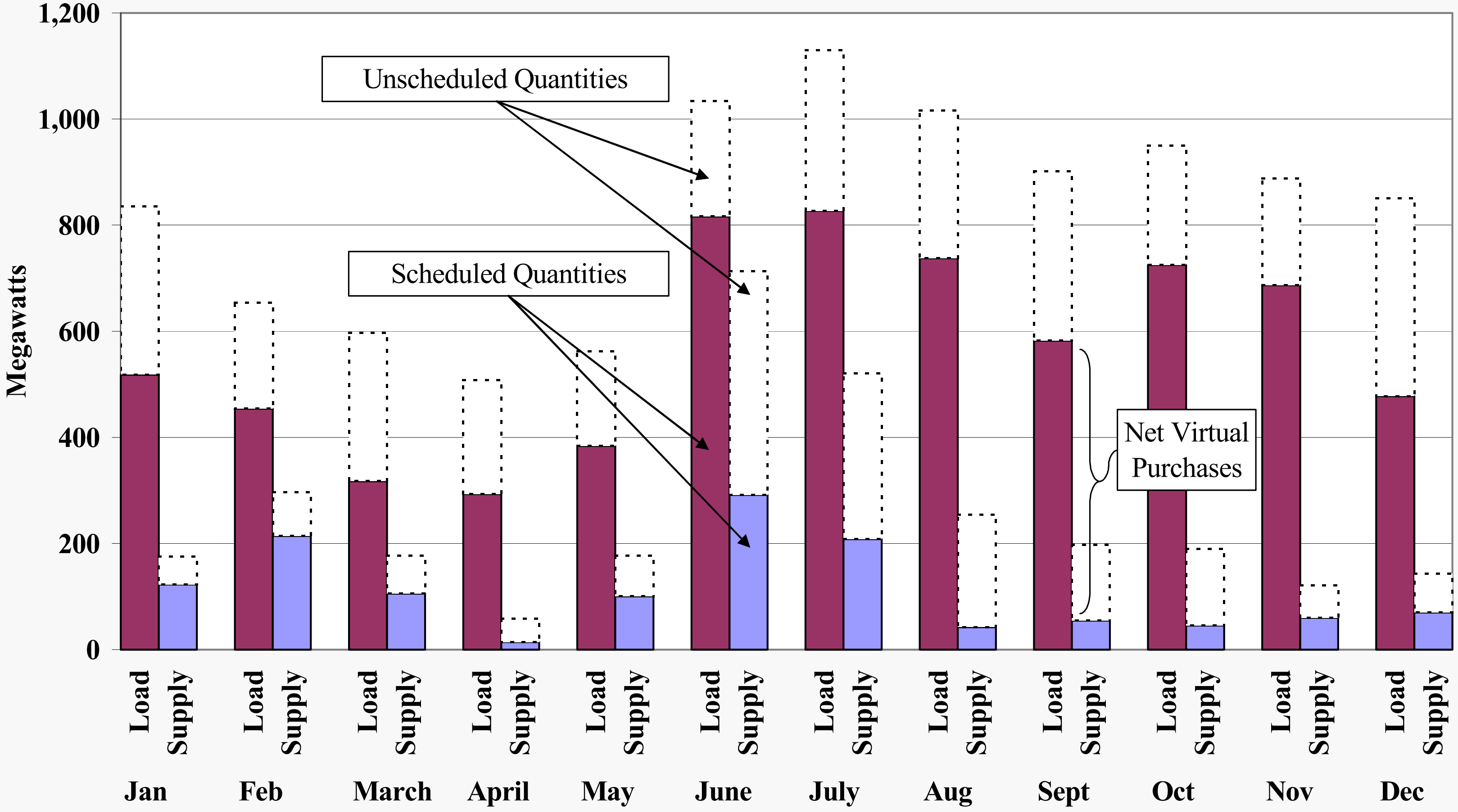


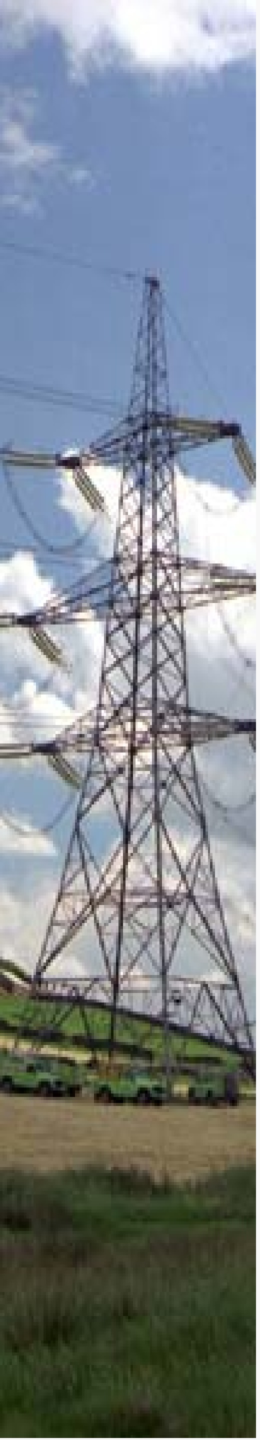
# Virtual Bidding Patterns

- Virtual bidding 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.
- This figure shows the following:
  - ✓ The magnitude of the virtual load offers and supply bids, as well as the quantities scheduled, increased significantly during the Summer 2002 and remained at high levels through the end of the year;
  - ✓ Virtual load far exceeded virtual supply scheduling in NYC and Long Island;
  - ✓ Virtual supply far exceeded virtual load scheduling in up-state New York until the last three months of 2002; and
  - ✓ Virtual loads have generally been larger than virtual supply, raising the total day-ahead schedules as shown in the prior figures and, in part, displacing some of the price-capped load bids by the LSEs.



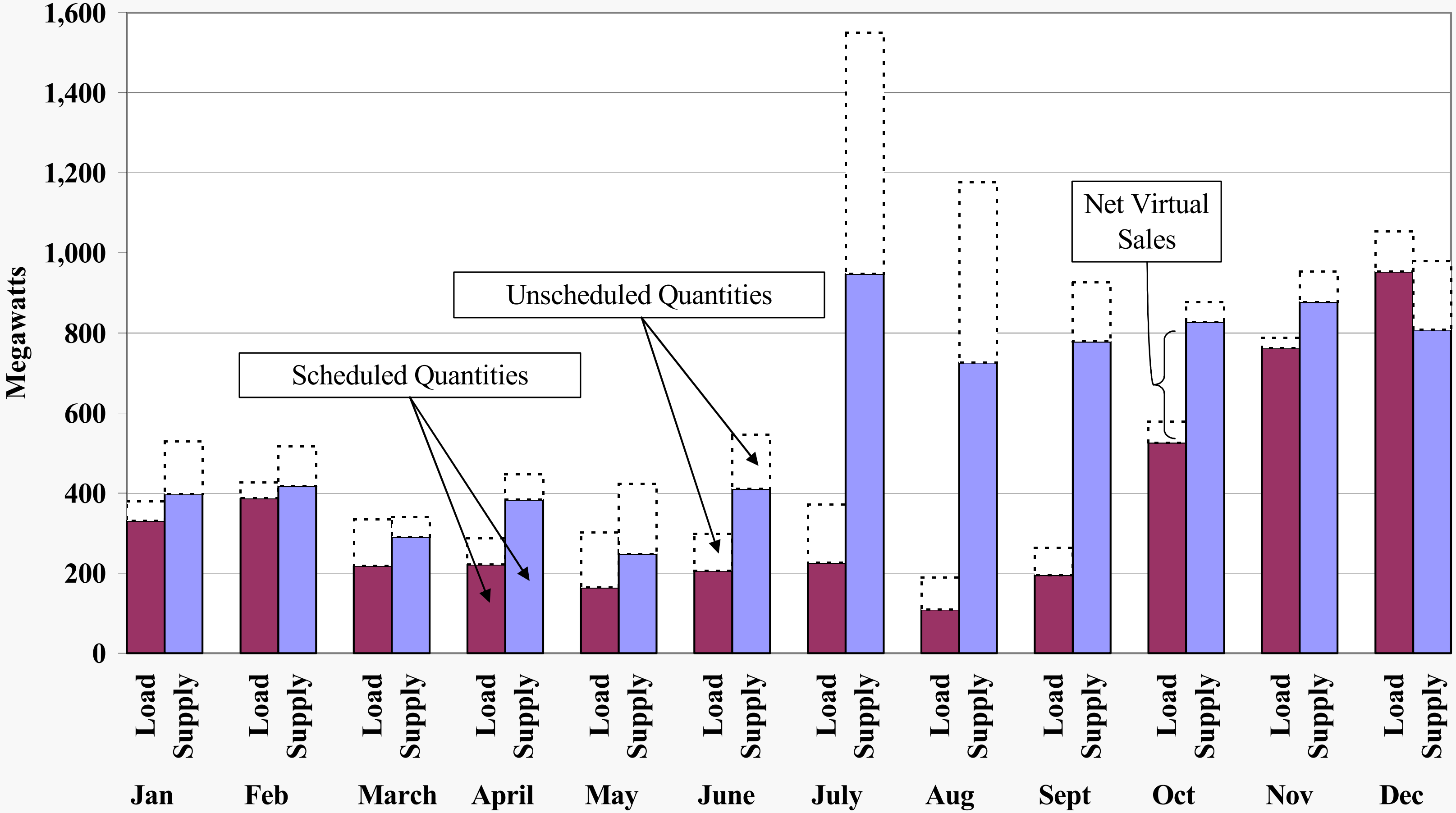
## Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
### New York City and Long Island -- 2002

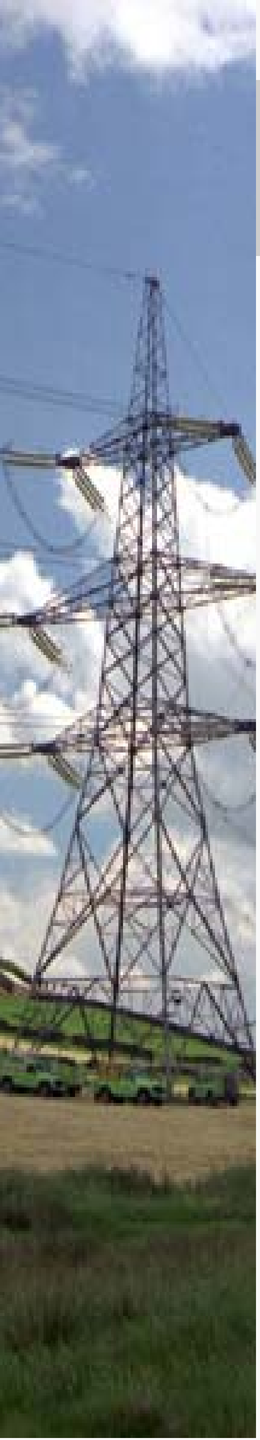




**Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled**

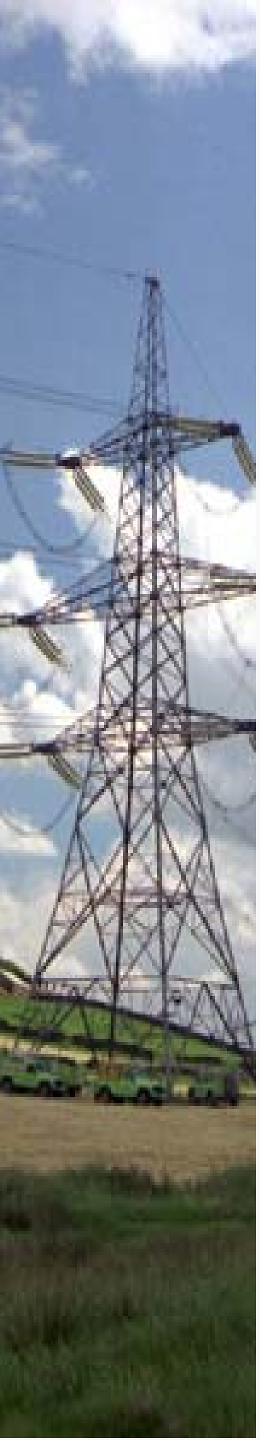
**Outside NYC and Long Island -- 2002**

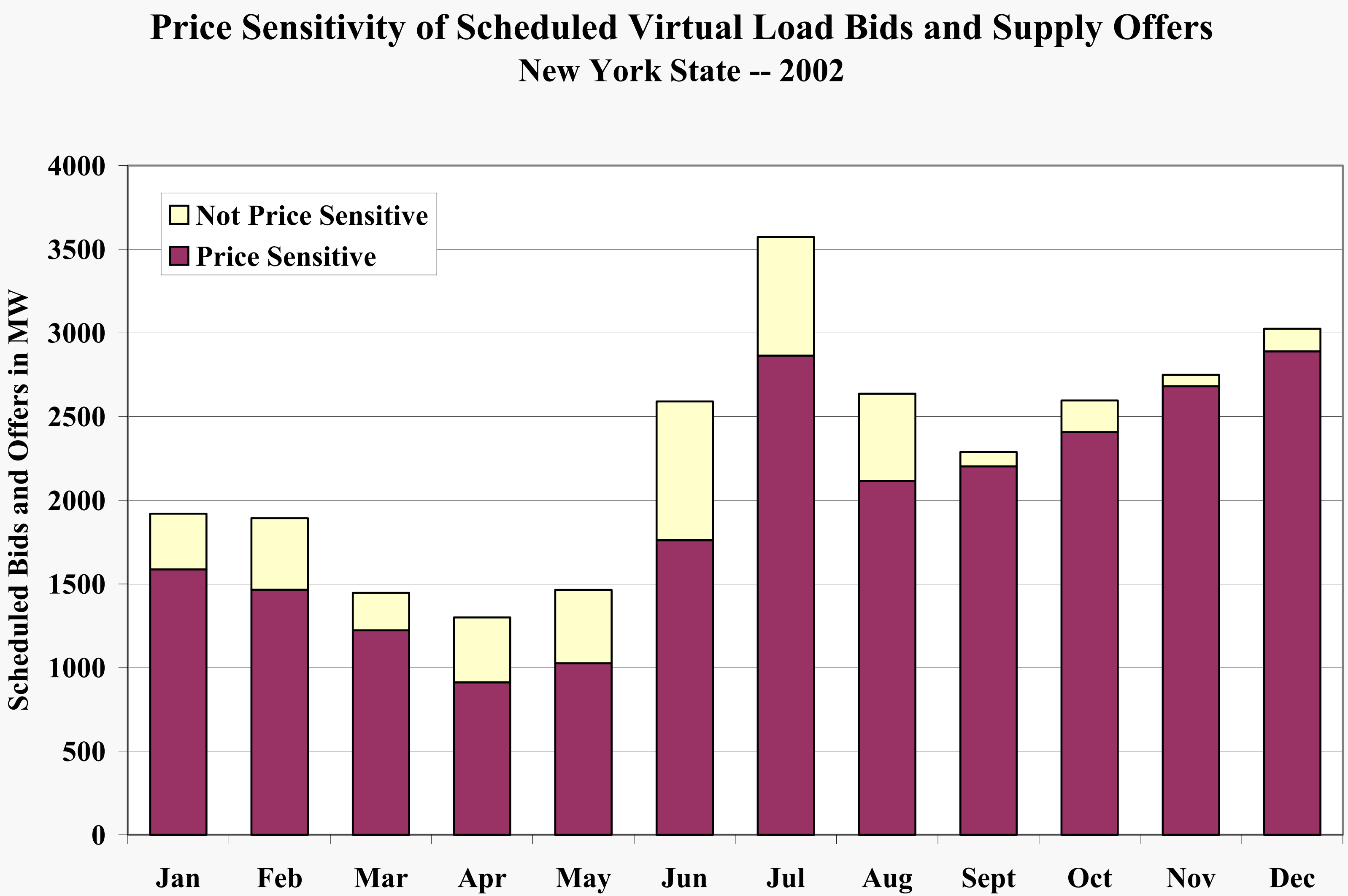




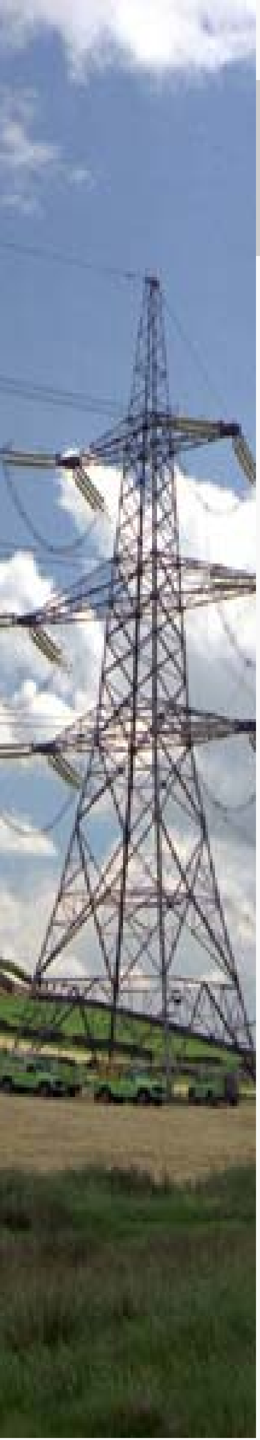
# Virtual Trading Patterns

- Some have raised concerns that virtual traders might schedule uneconomic transactions in order to manipulate day-ahead prices.
  - ✓ Price manipulation strategies should be undermined by other participants.
- We monitor for this by determining the share of the virtual bids and offers that are not price sensitive, which would be consistent with such strategies.
  - ✓ Bids are considered price-sensitive for this analysis if they have a bid 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, increasing the price elasticity of demand in the day-ahead market.
  - ✓ The portions of virtual bids and offers that were price-sensitive generally range from 70-90 percent, with the highest proportions occurring during the last four months of 2002.



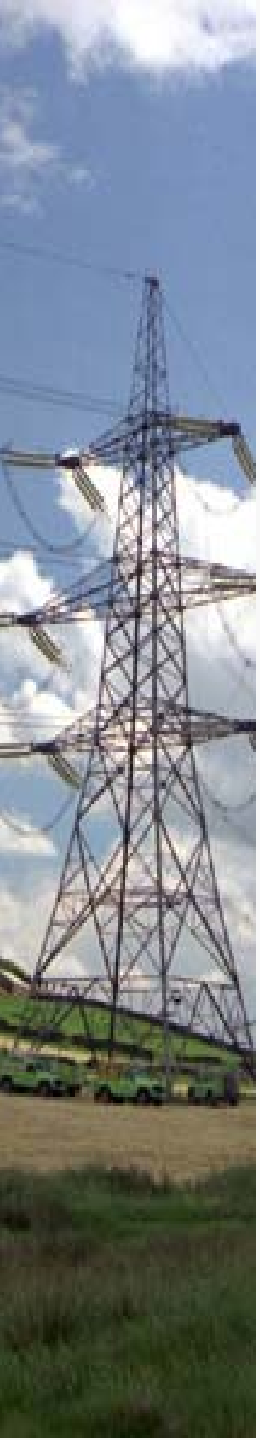


Price Sensitivity of Scheduled Virtual Load Bids and Supply Offers
New York State -- 2002
Scheduled Bids and Offers in MW
4000
3500
3000
2500
2000
1500
1000
500
0
Not Price Sensitive
Price Sensitive
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sept
Oct
Nov
Dec

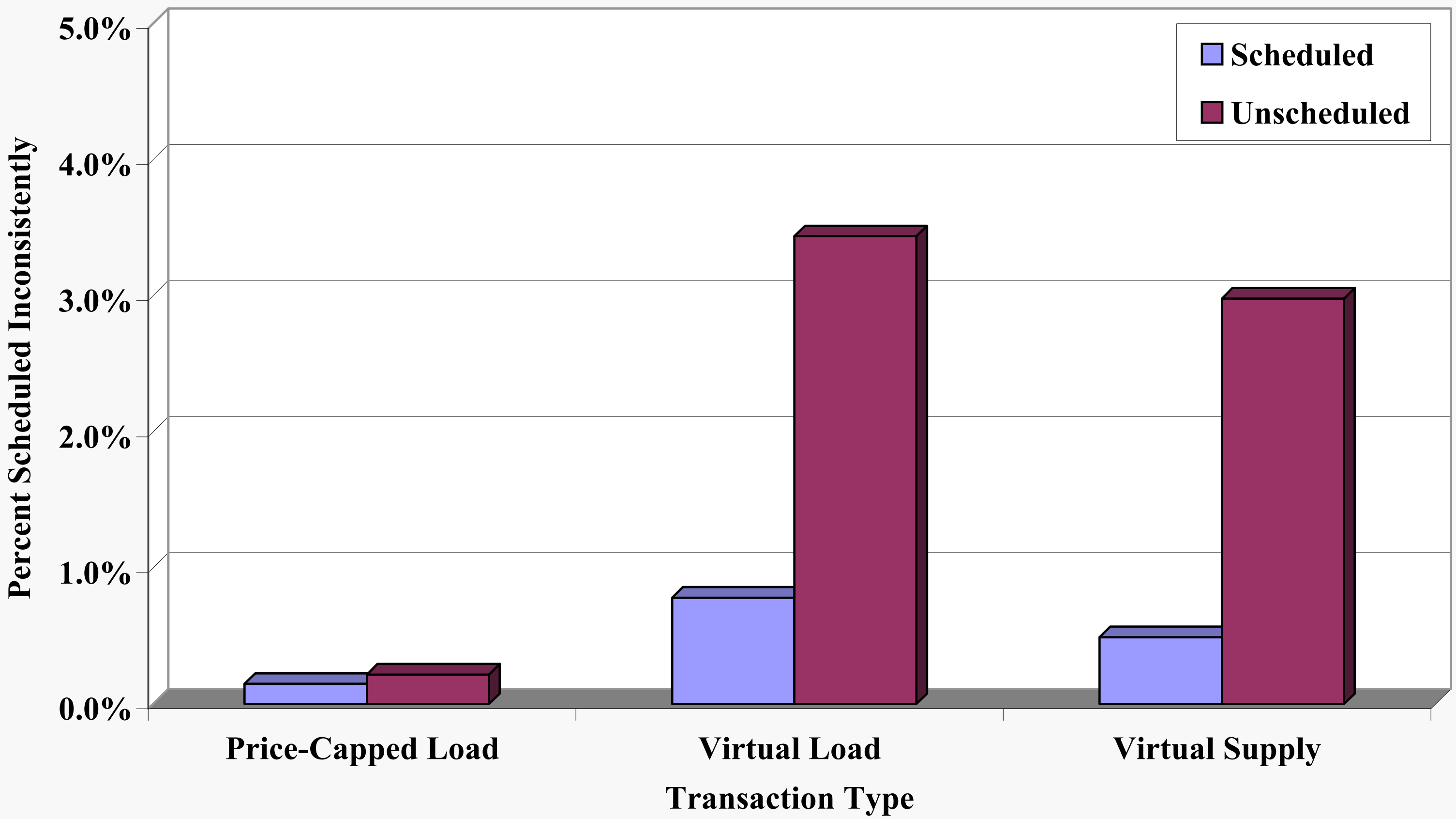


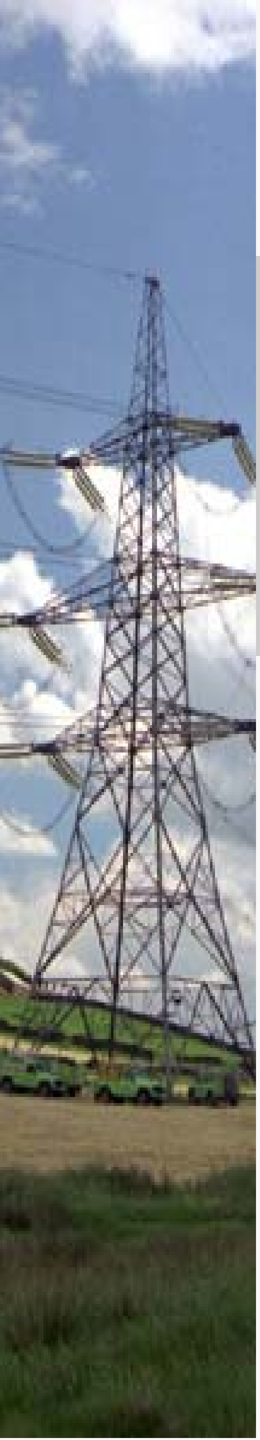
# Virtual Trading Scheduling Consistency

- A final virtual trading issue is that a portion of the virtual trades have not been scheduled consistently with bid prices, these quantities are shown on the following figure for 2002.
  - ✓ Inconsistent virtual load schedules occur when a virtual load is (i) accepted when the market price is *higher* than the bid price or (ii) not accepted when the market price is *lower* than the bid price.
  - ✓ Inconsistent virtual supply schedules occur when a virtual supply is (i) accepted when the market price is *lower* than the bid price or (ii) not accepted when the market price is *higher* than the bid price.
  - ✓ Inconsistent schedules are important because they will undermine the confidence of participants in virtual trading.
- This has occurred because of an inconsistency between the pricing criteria used to schedule virtual trades and price-capped load bids and the determination of final prices for settlement.
- Based on these results, I recommend that the NYISO make it a high priority to modify the virtual supply, virtual load, and price-capped load settlement rules to eliminate this scheduling inconsistency.

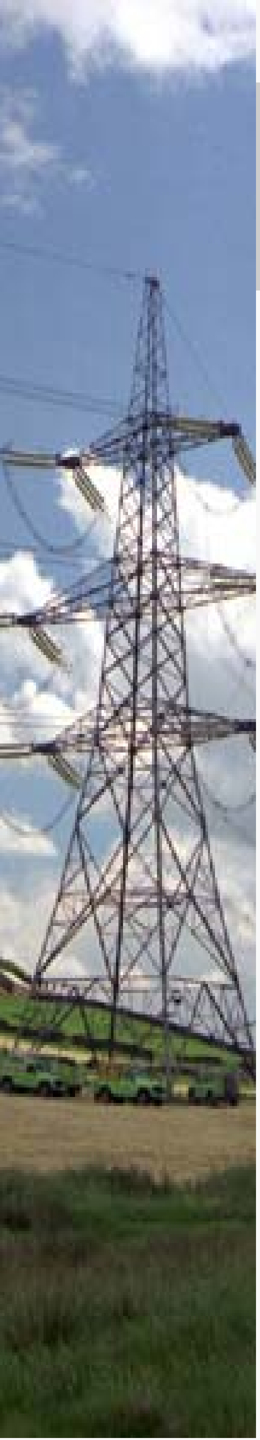


## Percent of Virtual Trades and Price-Capped
### Load Bids Scheduled Inconsistently
### Measured by % of trades - 2002



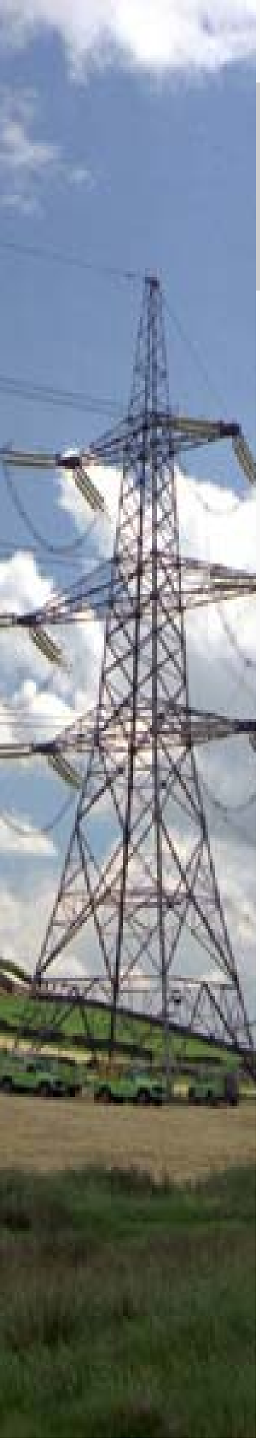


# Pricing During Peak Demand Conditions



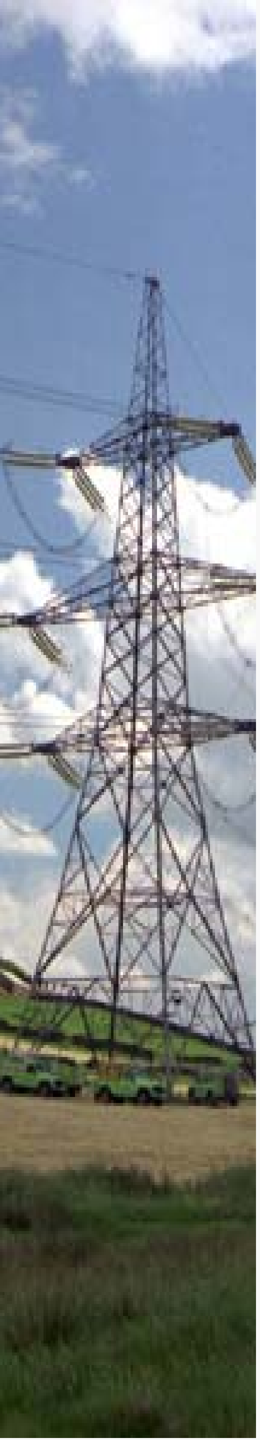
# Introduction

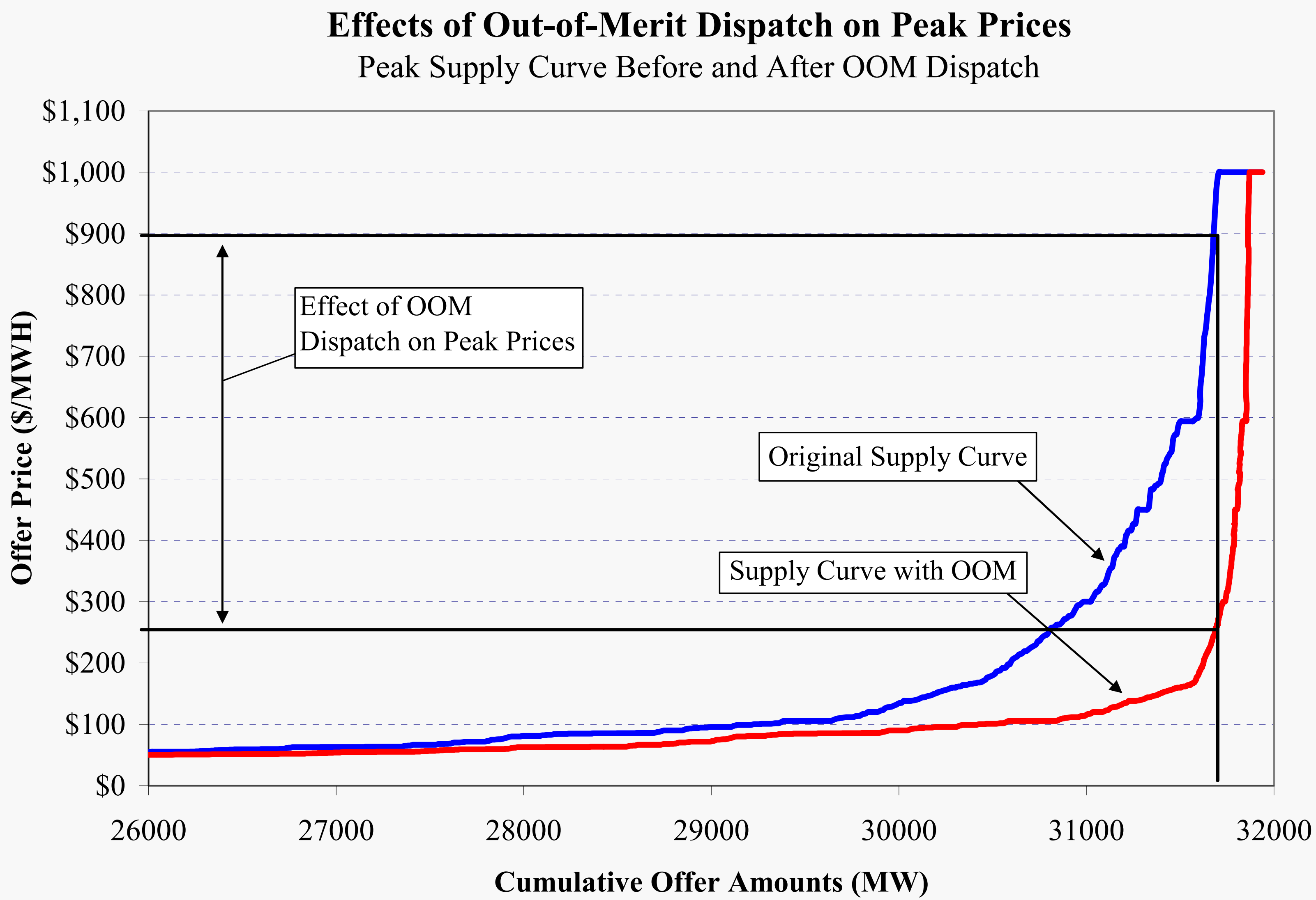
- This section evaluates the price signals established under peak demand conditions in 2002, which play a critical role in:
  - ✓ Allowing existing high-cost units to recover their costs of remaining on the system; and
  - ✓ Establishing efficient incentives for new investment.
- The analysis in this section focuses on 14 days with high demand conditions from late June to the middle of August, analyzing two essential areas:
  - ✓ The effect of market operations during these periods;
  - ✓ The efficiency of external transactions.



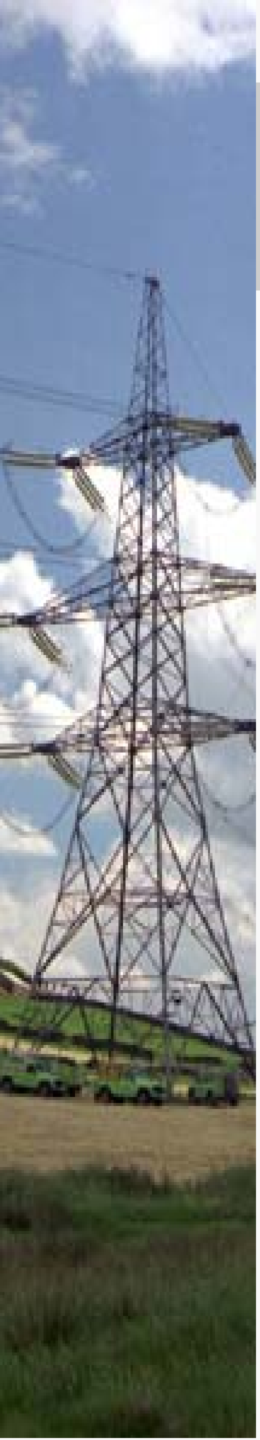
# Peak Pricing

- Market operations can affect peak pricing by altering the supply conditions through the following actions:
  - ✓ Dispatching generation “out-of-merit”;
  - ✓ Committing supplemental resources not selected by the day-ahead or hour-ahead models;
  - ✓ Dispatching reserves under peak load conditions;
  - ✓ Real-time load curtailment and emergency out-of-market purchases.
- Reliability requires that operators have the ability to take these actions, but they should be taken only when necessary and the pricing rules should minimize adverse effects on prices.
- The following figure illustratives how out-of-merit dispatch can affect peak prices.
  - ✓ Out-of-merit dispatch (“OOM”) occurs when a unit is dispatched whose energy bid exceeds the price at its location – this can be caused by the physical parameters of the unit (e.g., min. run-time) or by operator action.
  - ✓ The figure shows 1000 MW of OOM on a typical NY supply curve.



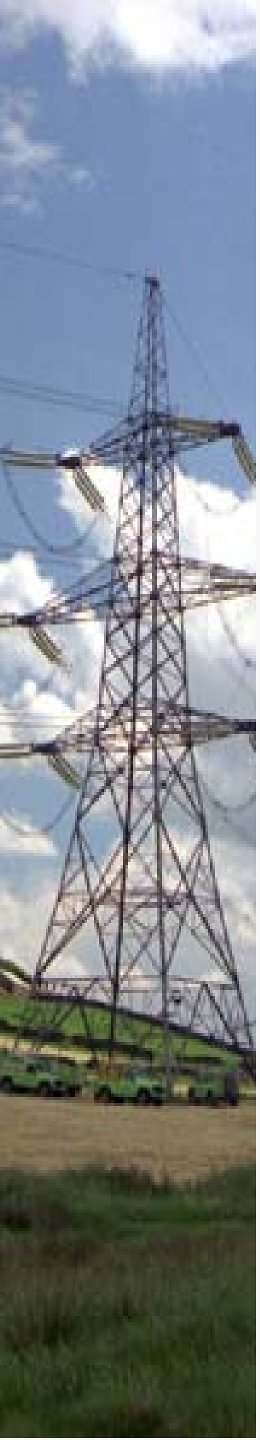


Effects of Out-of-Merit Dispatch on Peak Prices
Peak Supply Curve Before and After OOM Dispatch
Offer Price ($/MWH)
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$0
Effect of OOM Dispatch on Peak Prices
Original Supply Curve
Supply Curve with OOM
26000
27000
28000
29000
30000
31000
32000
Cumulative Offer Amounts (MW)

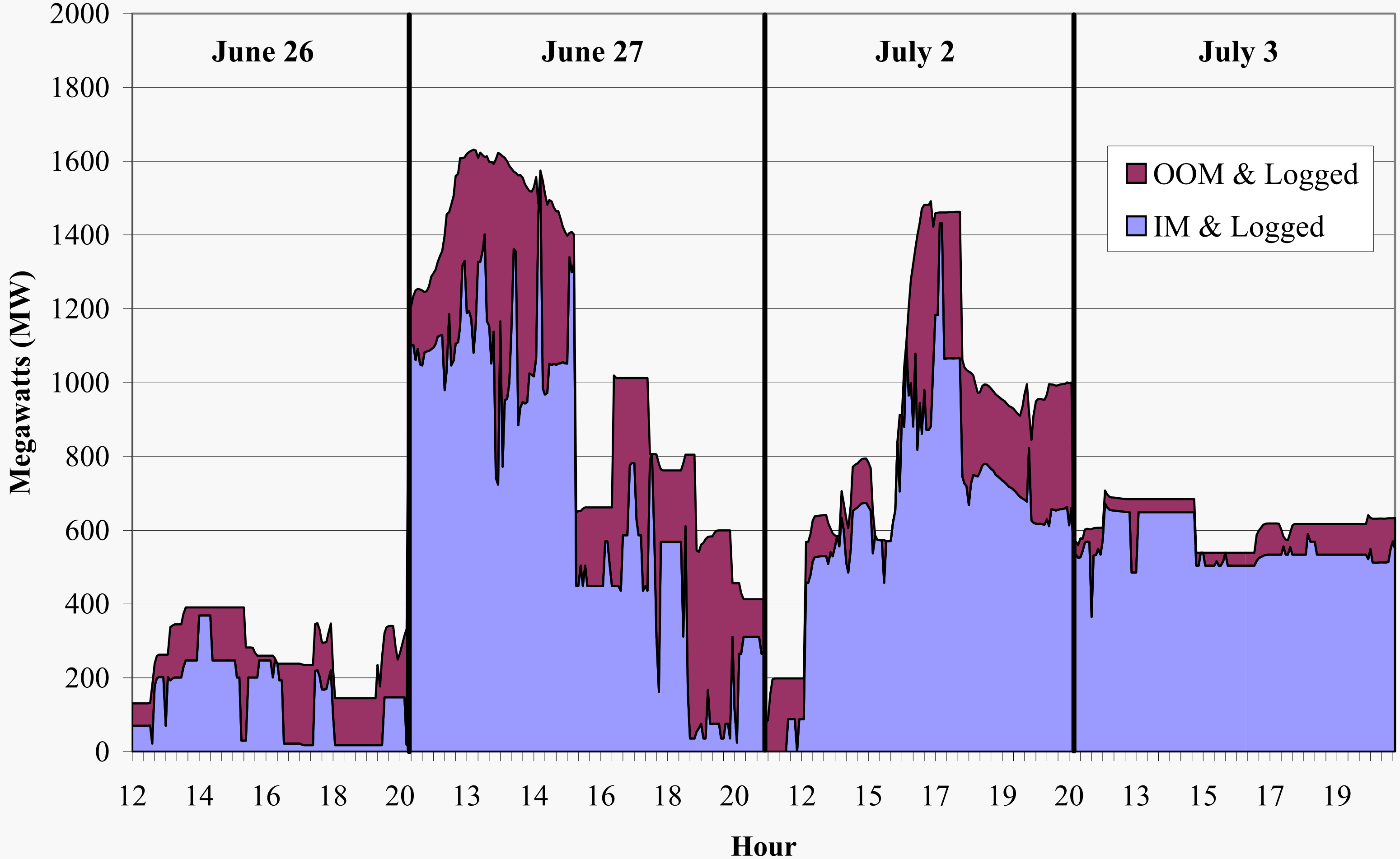


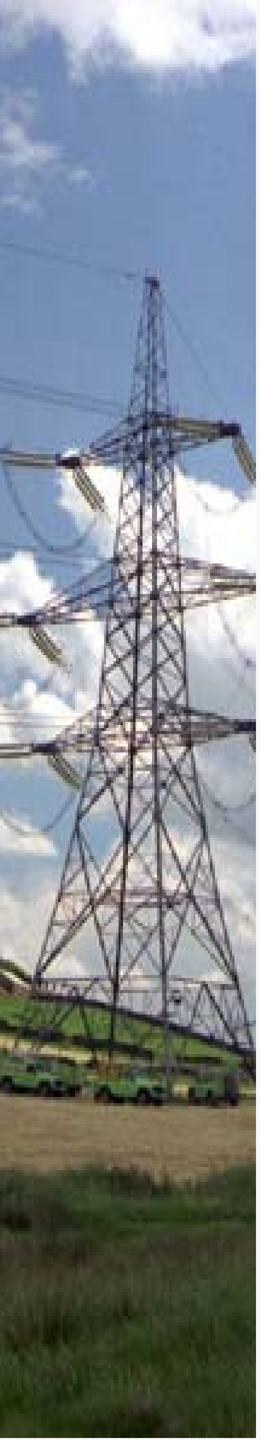
# Out-of-Merit Analysis

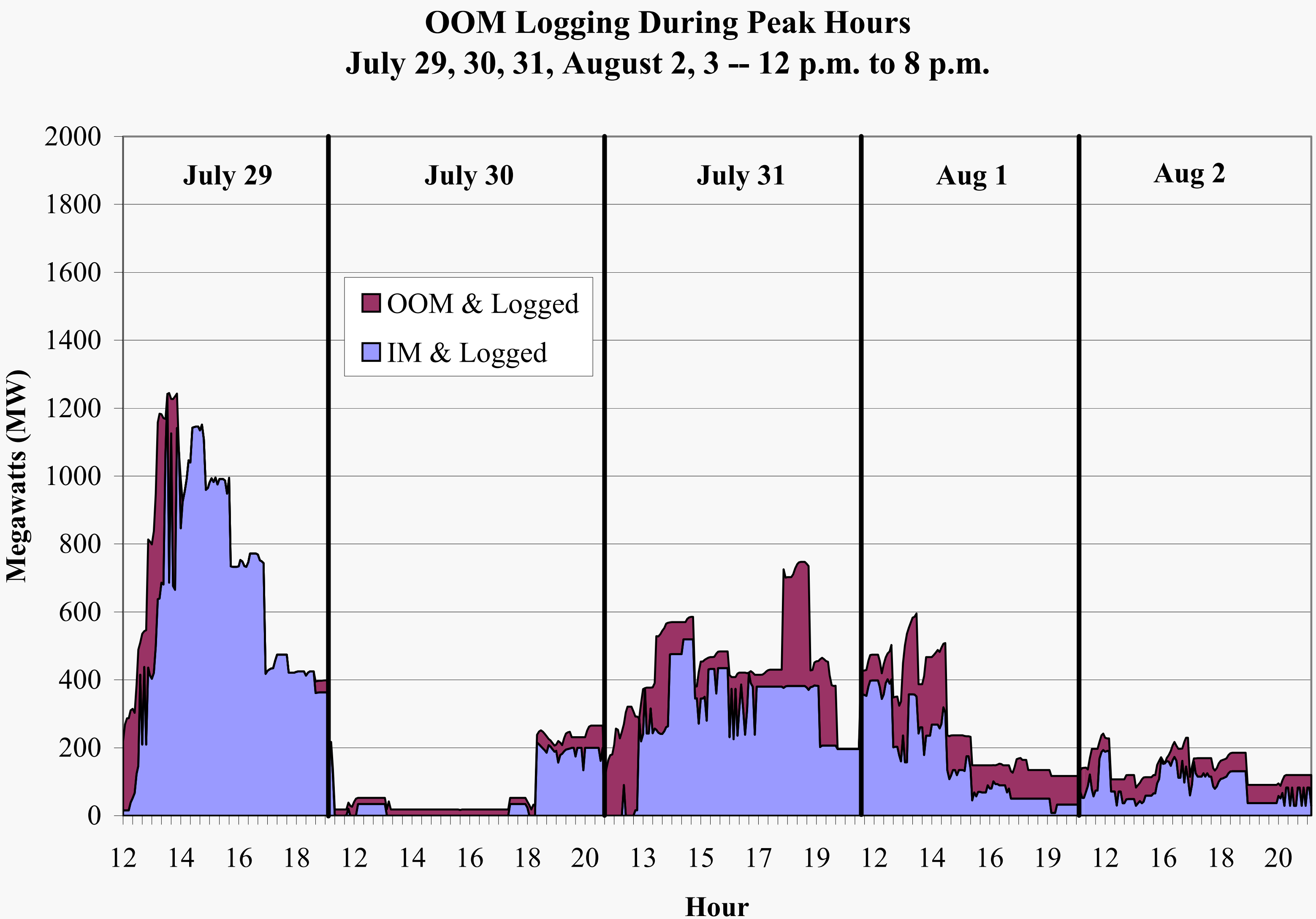
- When OOM actions are taken by the operator, they are logged and reported on the NYISO website.
- When an operator dispatches a resource OOM, the resource loses its eligibility to set energy prices.
  - ✓ However, in many cases these resources turn out to be economic (i.e., in merit).
  - ✓ Only units that are “logged” and are economically OOM will affect prices.
- The following three figures show that most resources logged as OOM are actually economically in-merit on the peak days.



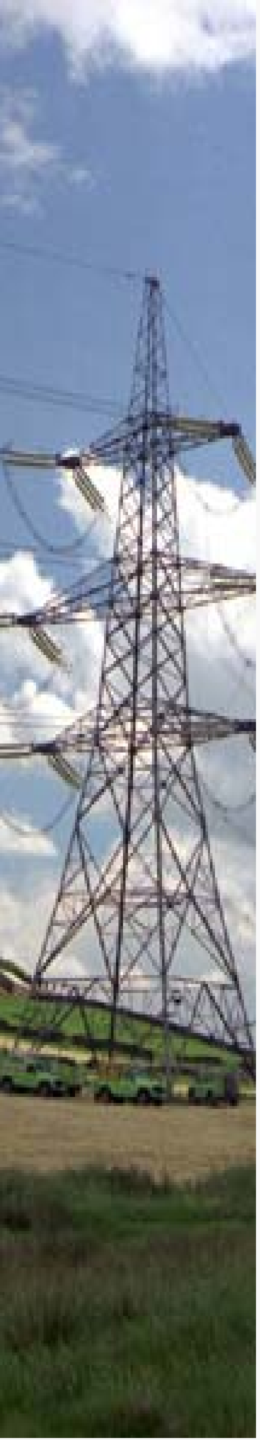
## OOM Logging During Peak Hours
## June 26, 27, July 2,3 -- 12 p.m. to 8 p.m.



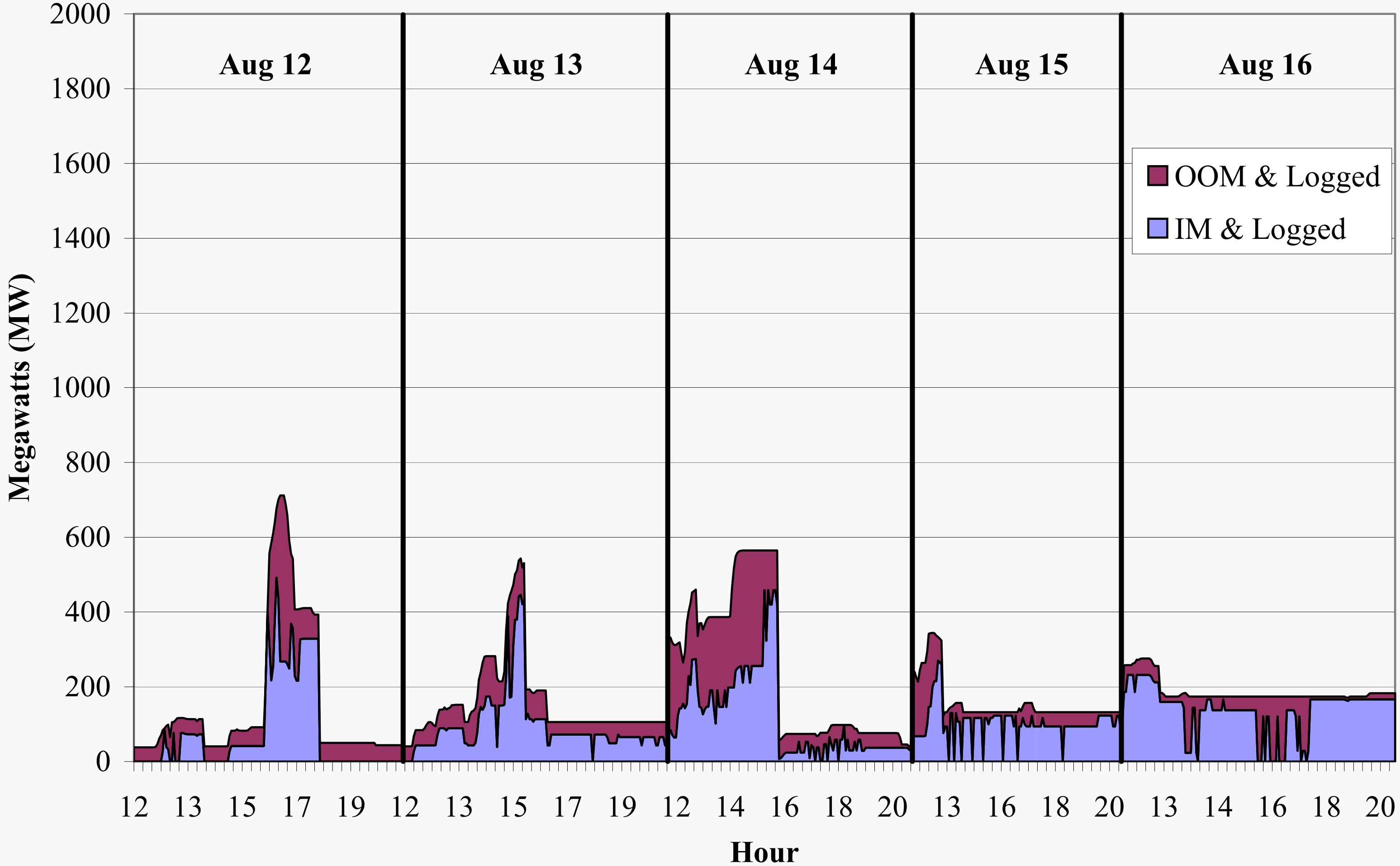


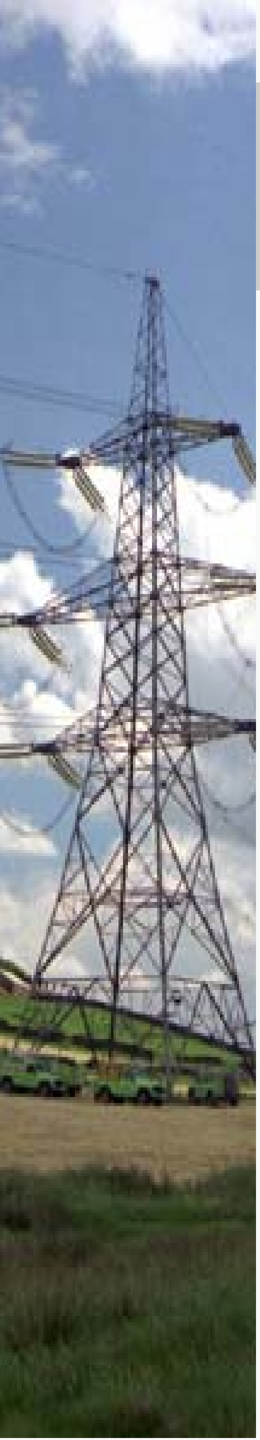


OOM Logging During Peak Hours
July 29, 30, 31, August 2, 3 -- 12 p.m. to 8 p.m.
July 29
July 30
July 31
Aug 1
Aug 2
OOM & Logged
IM & Logged
Megawatts (MW)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
12 14 16 18 12 14 16 18 20 13 15 17 19 12 14 16 19 12 16 18 20
Hour



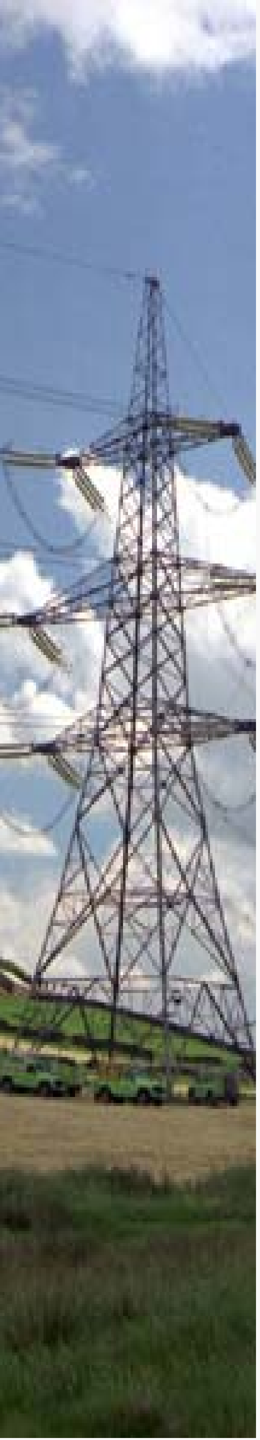
## OOM Logging During Peak Hours
## August 12-16 -- 12 p.m. to 8 p.m.



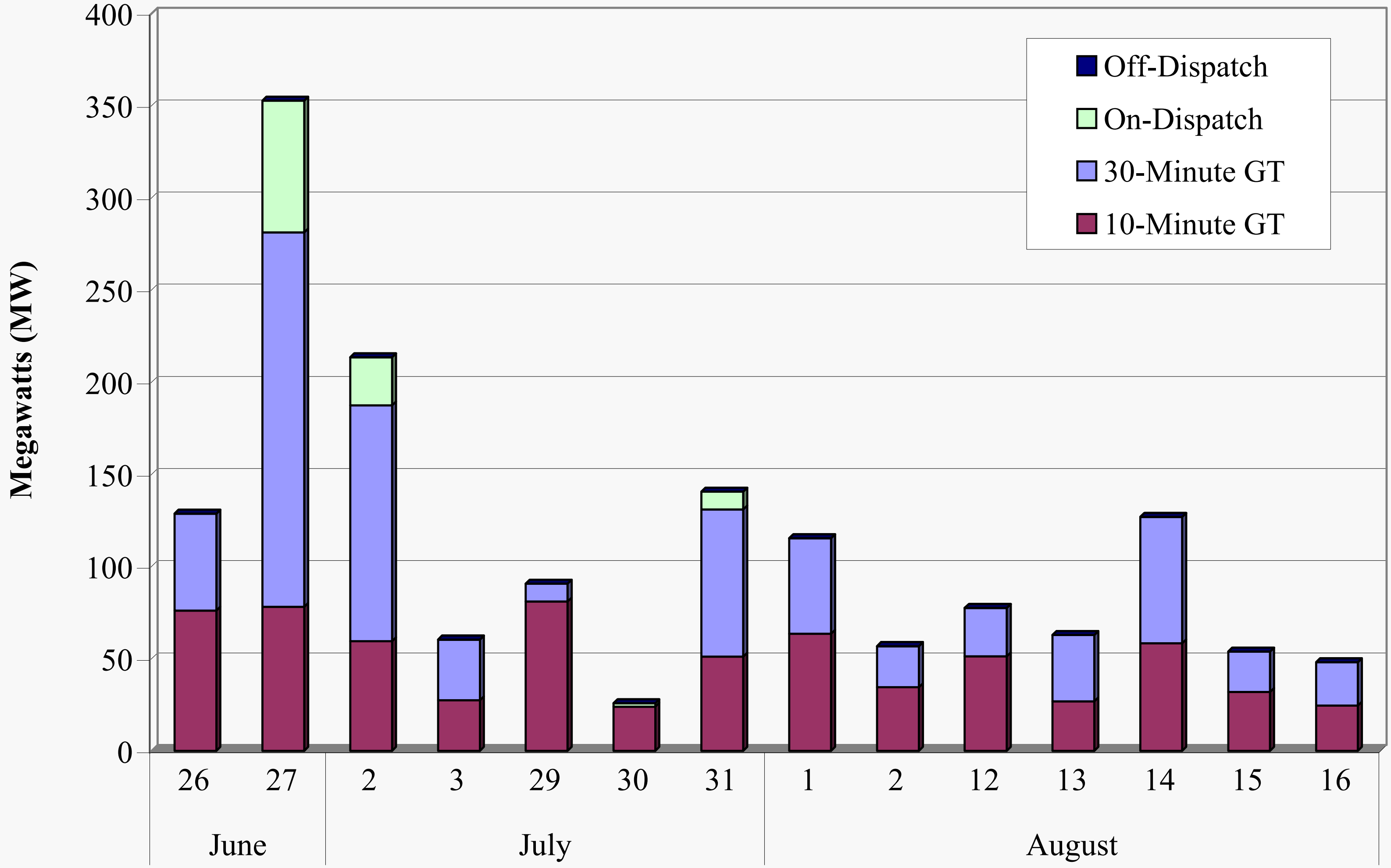


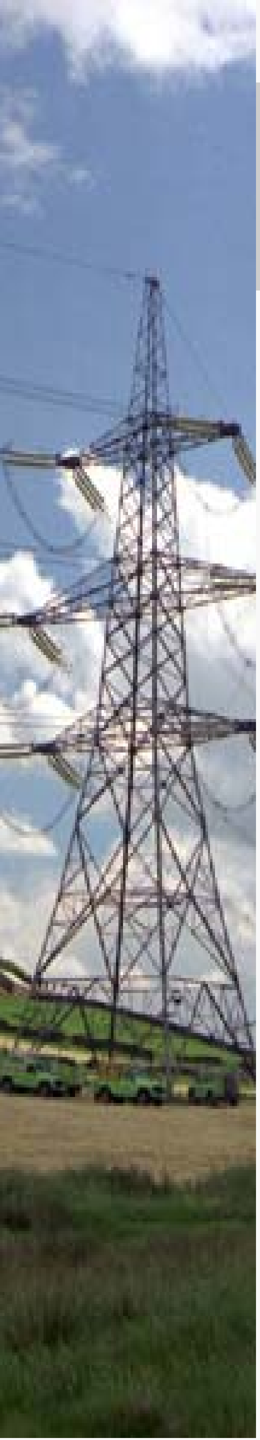
# Out-of-Merit Analysis

- The first figure below shows the types of units that are economically OOM and logged by the operators on the peak days.
- These values show that the economically OOM resources are generally gas turbines.
- Steam units are usually in-merit even when they are logged by the operators.



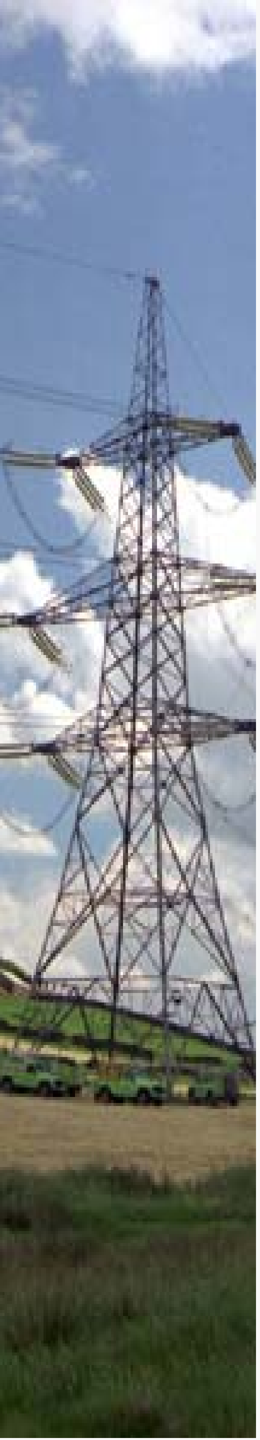
## Average Economically Out-of-Merit Generation by Type
## Peak Days -- 12 p.m. to 8 p.m.



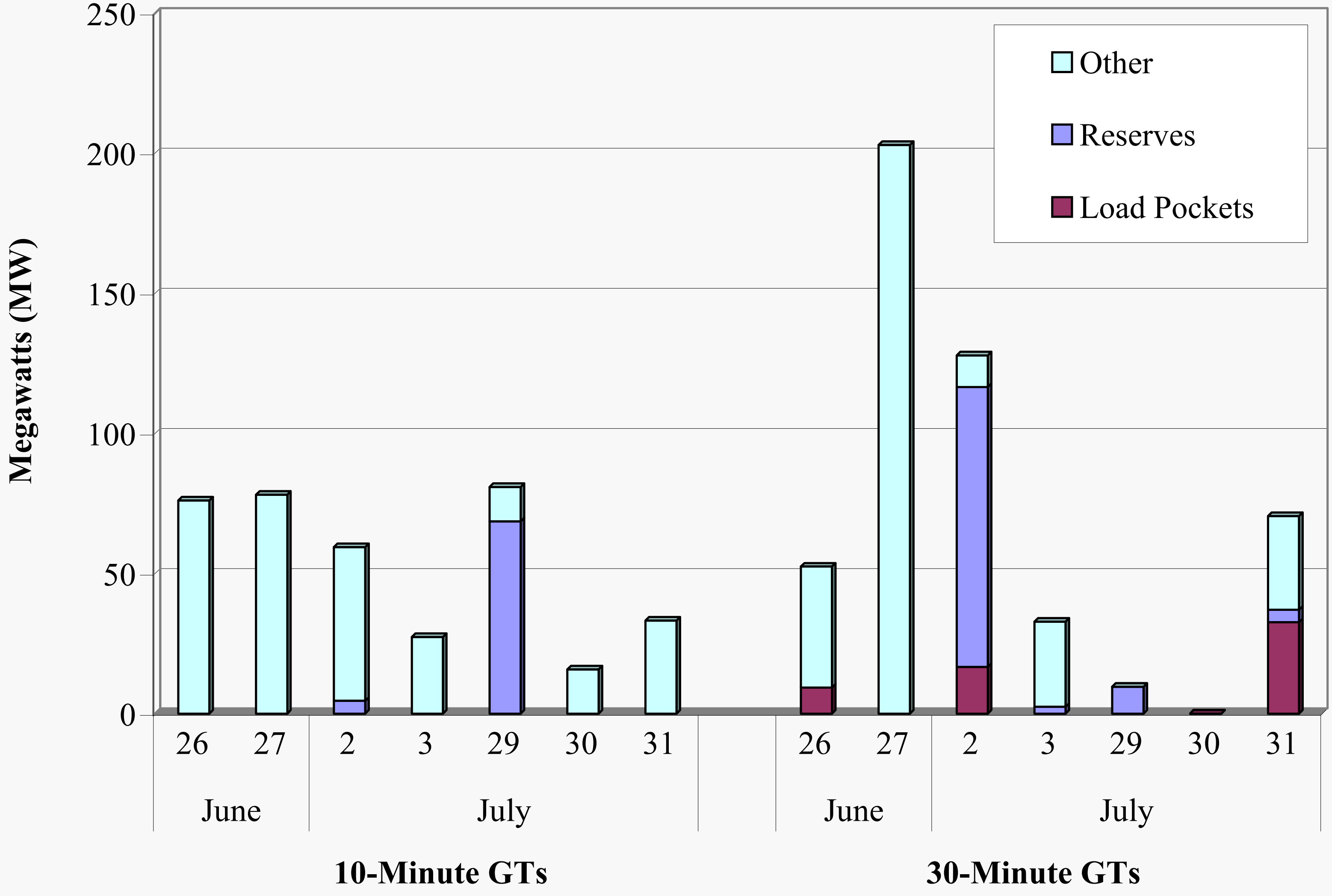


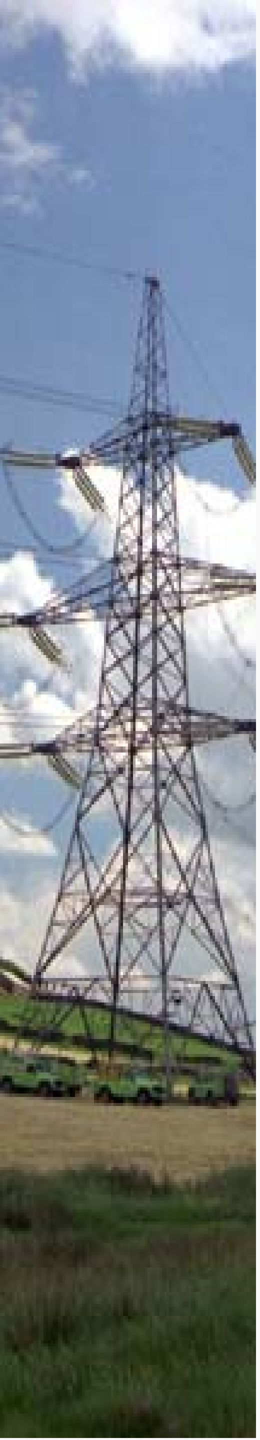
# Out-of-Merit Analysis

- The next two figures show the reasons cited by operators when logging gas turbines out-of-merit.
- Logically, units logged as OOM for “reserves” or “load pockets” should be able to set energy prices, while units logged for “other” should not.
  - ✓ This is because units OOM for reserves in load pockets make other units available to provide reserves, representing a market value of energy.
- During the Summer of 2002, the NYISO modified its real-time scheduling systems to allow gas turbines and other units committed for ISO reserves or ISO reliability to be eligible to set prices.
- These actions have resulted in substantial reductions in economic OOM quantities during the peak conditions in August versus the peak days in June and July.



**Out-of-Merit Logs by Unit Type During Peak Hours**
**Peak Days -- 12 p.m. to 8 p.m.**





**Out-of-Merit Logs by Unit Type During Peak Hours**
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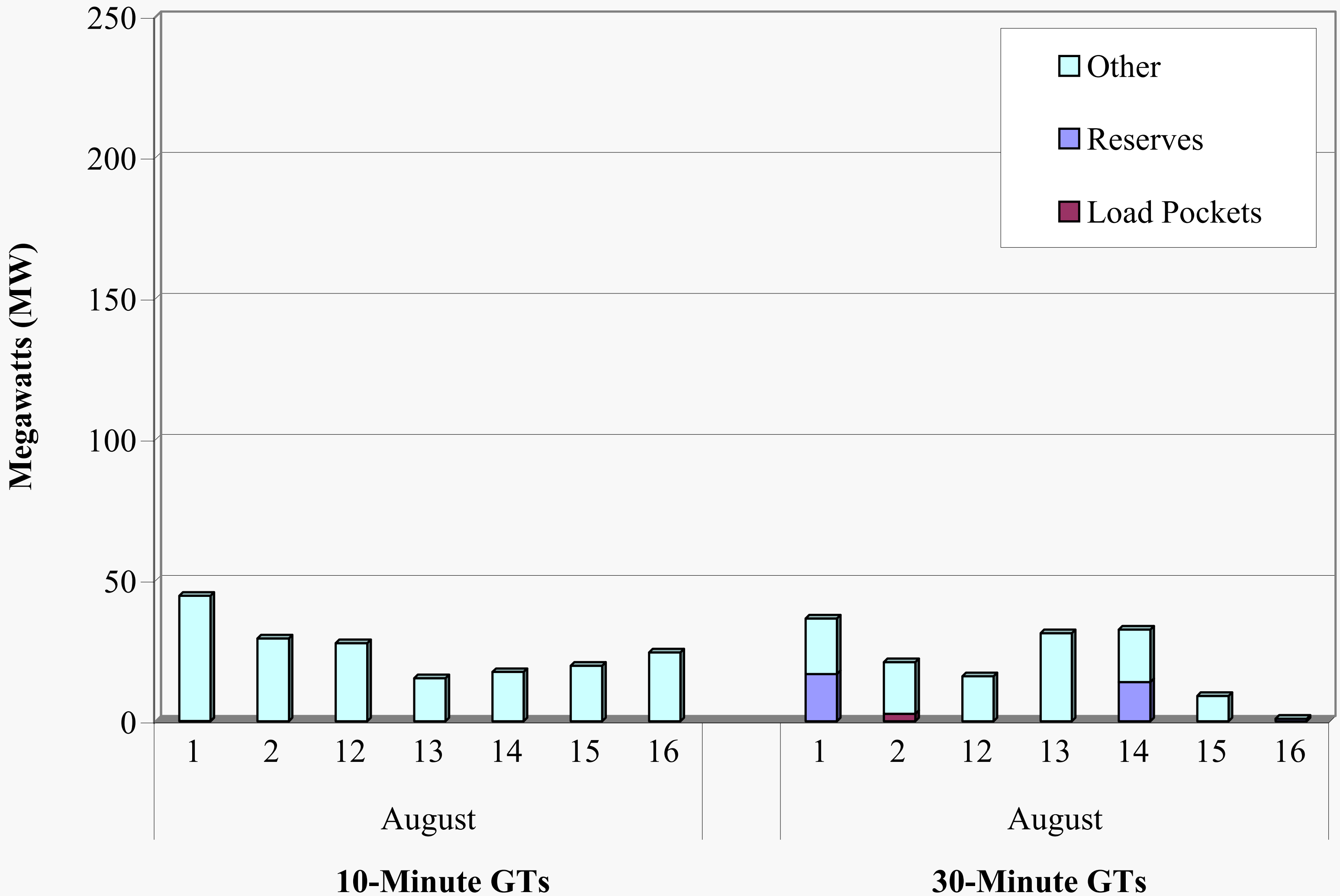
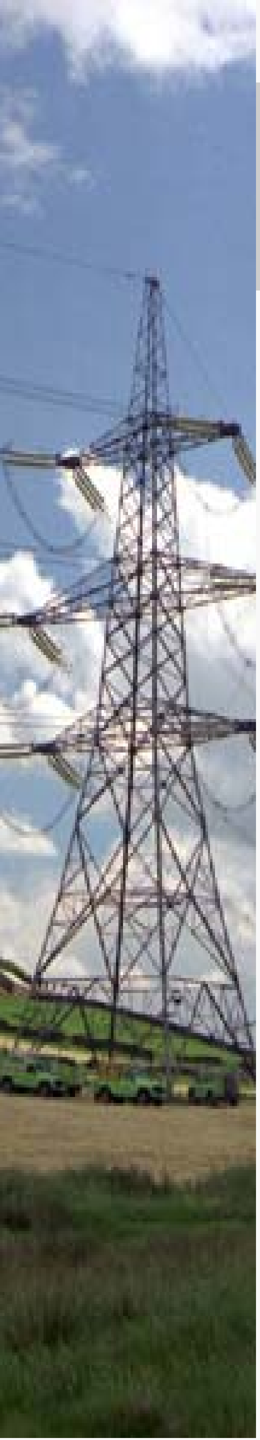
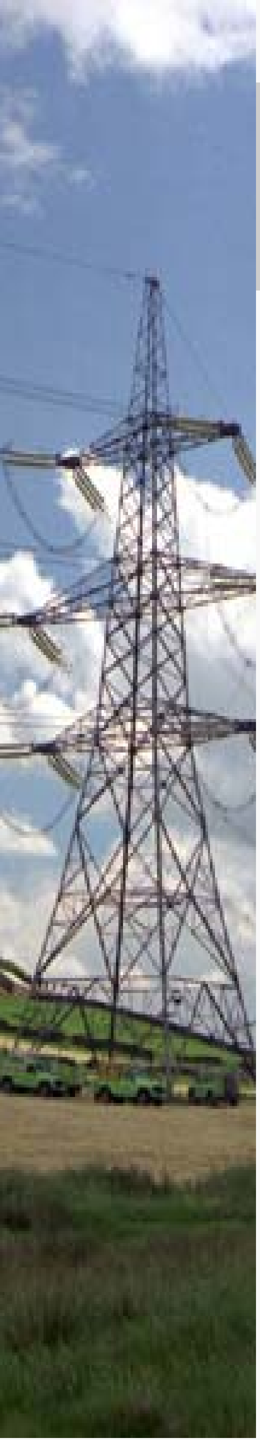




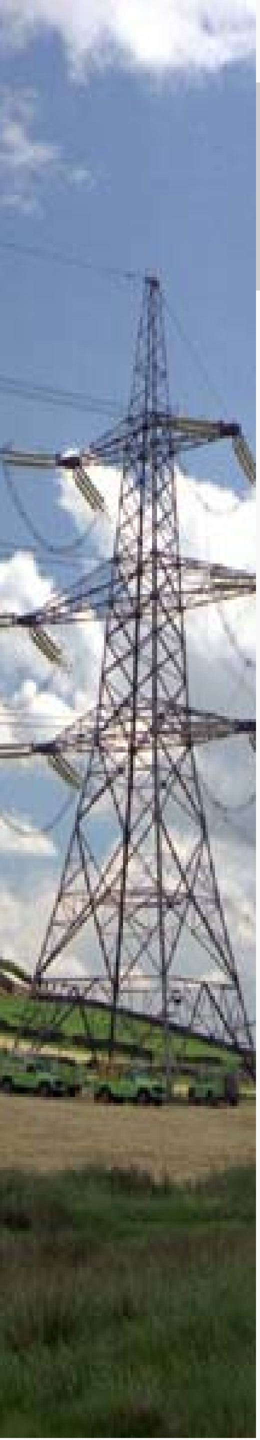
# Out-of-Merit Analysis

- Finally, 10-minute GTs become eligible to set energy prices when they begin producing energy and operators unblock their lower limit.
- In some cases, delays in unblocking the GTs occurred that caused the GTs to operate OOM.
- Unfortunately, these delays are most likely under peak conditions when operators are the busiest maintaining the reliability of the system.
- To minimize such delays, the NYISO is modifying operating procedures and information available to the operators to allow the limits to be unblocked as soon as practicable.



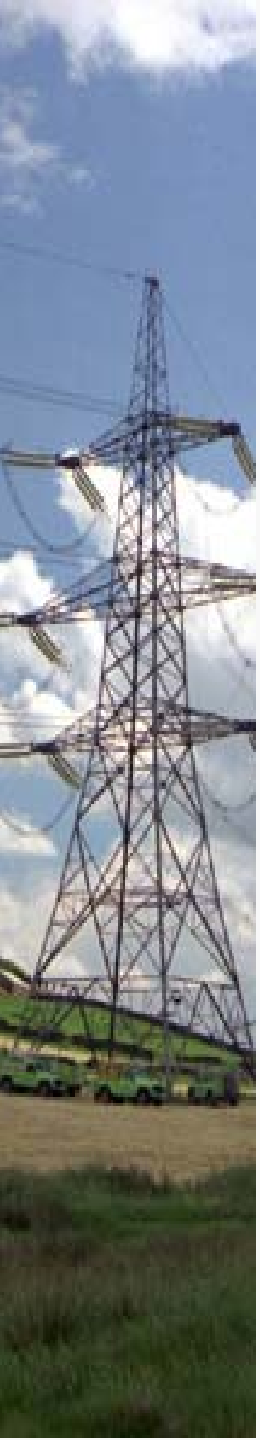
# Supplemental Resource Evaluation

- When the operator commits resources outside of the SCUC and BME models, these are logged and reported on the NYISO website.
- This does not directly affect the day-ahead price, but makes additional resources available in real-time, and, therefore, may reduce real-time prices.
- Supplemental commitment should generally be necessary when the day-ahead market assumptions are modified after the market concludes – (e.g., operators expect loads higher than the SCUC forecast).
- When this occurs, the same economic criteria should be employed as is employed for supplemental commitments made by SCUC to meet the forecasted load (i.e., minimize start-up and min-gen costs).

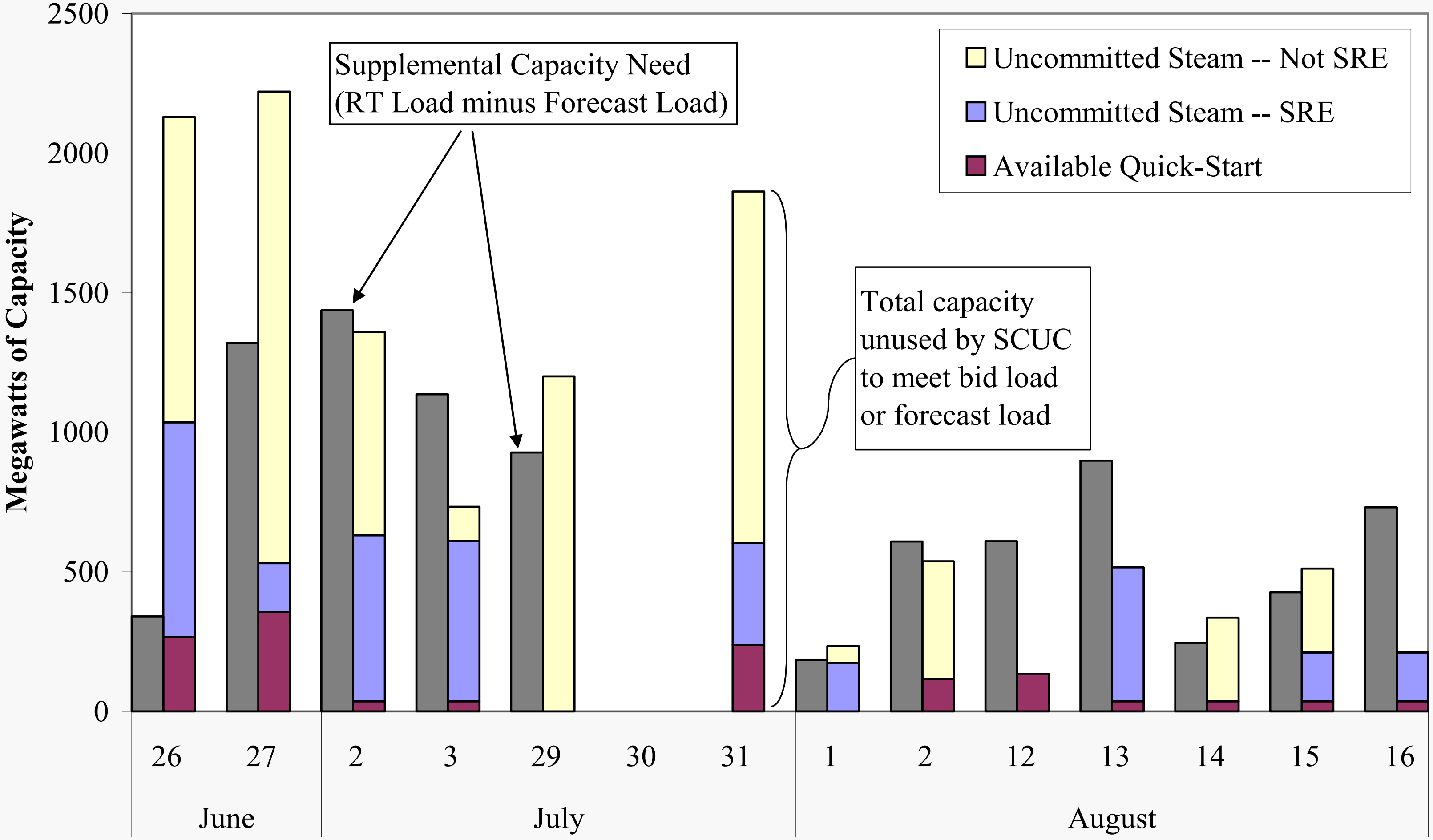


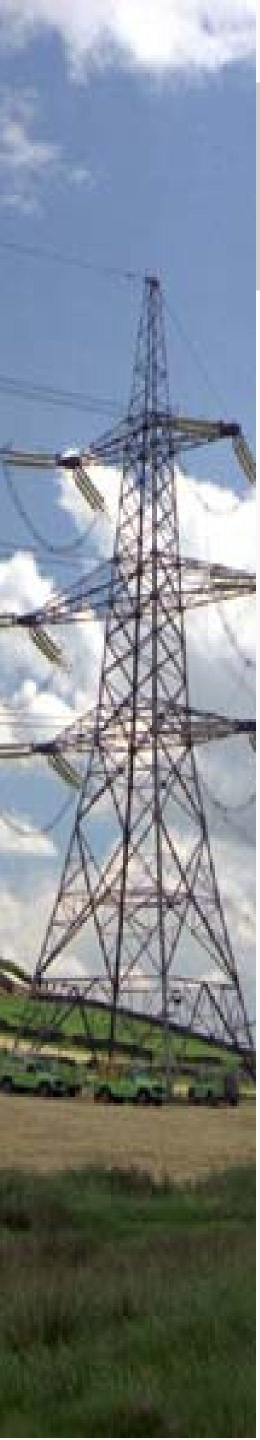
# Supplemental Resource Evaluation

- The following figure shows the quantity of resources that were committed through the SRE process on the peak days.
- This analysis indicates that the SRE quantities were generally consistent with conditions in which:
  - ✓ The actual load exceeded the SCUC load forecast by a significant margin;
  - ✓ Substantial gas turbine capacity was not available to meet the increase in expected load;
- Most of the SRE actions were called by the transmission owners to meet local reliability requirements, rather than by the ISO. To minimize potential price effects from these calls, the ISO should
  - ✓ Continue to adjust SCUC to meet local reliability requirements and minimize the need for TO SREs; and
  - ✓ Screen or audit the SREs called by the TOs to ensure that the units selected are needed and are the most efficient alternative.



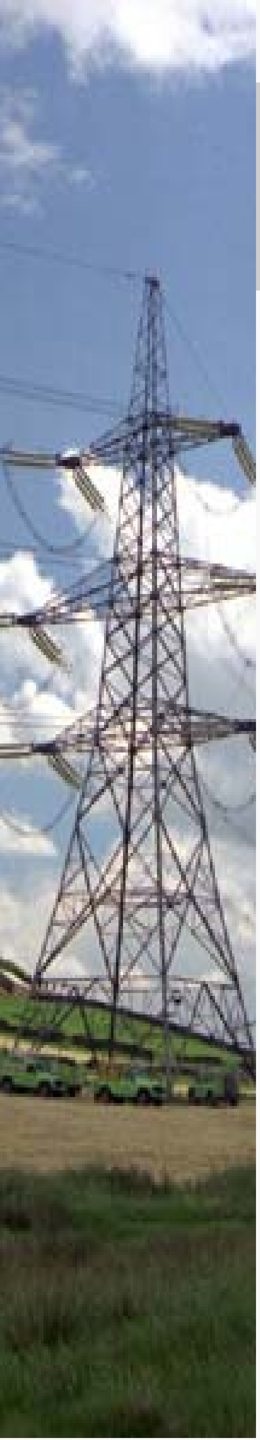
## Supplemental Capacity Needs and Resources Not Used by SCUC
## Eastern NY, Peak Hours on High Demand Days





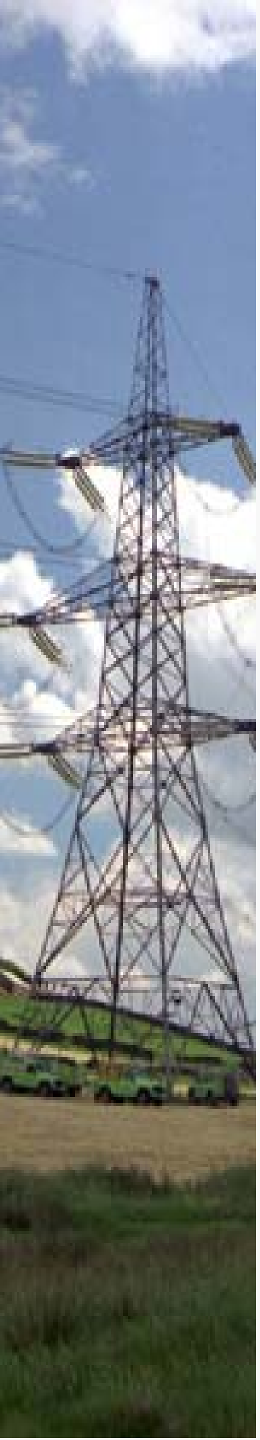
# Reserve Shortages

- The final analysis of peak pricing relates to the dispatch of reserves in the energy market.
- When the system enters shortage conditions, trade-offs are sometimes necessary to ensure the requirements of the energy market are reliably met.
  - ✓ One of the trade-offs is to allow operating reserves to be dispatched to provide energy.
  - ✓ Provisions to allow this trade-off for 30-minute reserves was adopted prior to the summer by counting exports as 30-minute reserves at certain shadow price levels.
  - ✓ In some cases, dispatching 10-minute reserves was necessary to meet the demand in the energy market.
- Like OOM dispatch, dispatching reserves for energy will increase the supply in real-time and can prevent prices from revealing shortages.
- In a sense, the reserve market has become the marginal supplier in this case and the prices in the energy market should reflect the value of the reserve that was sacrificed.

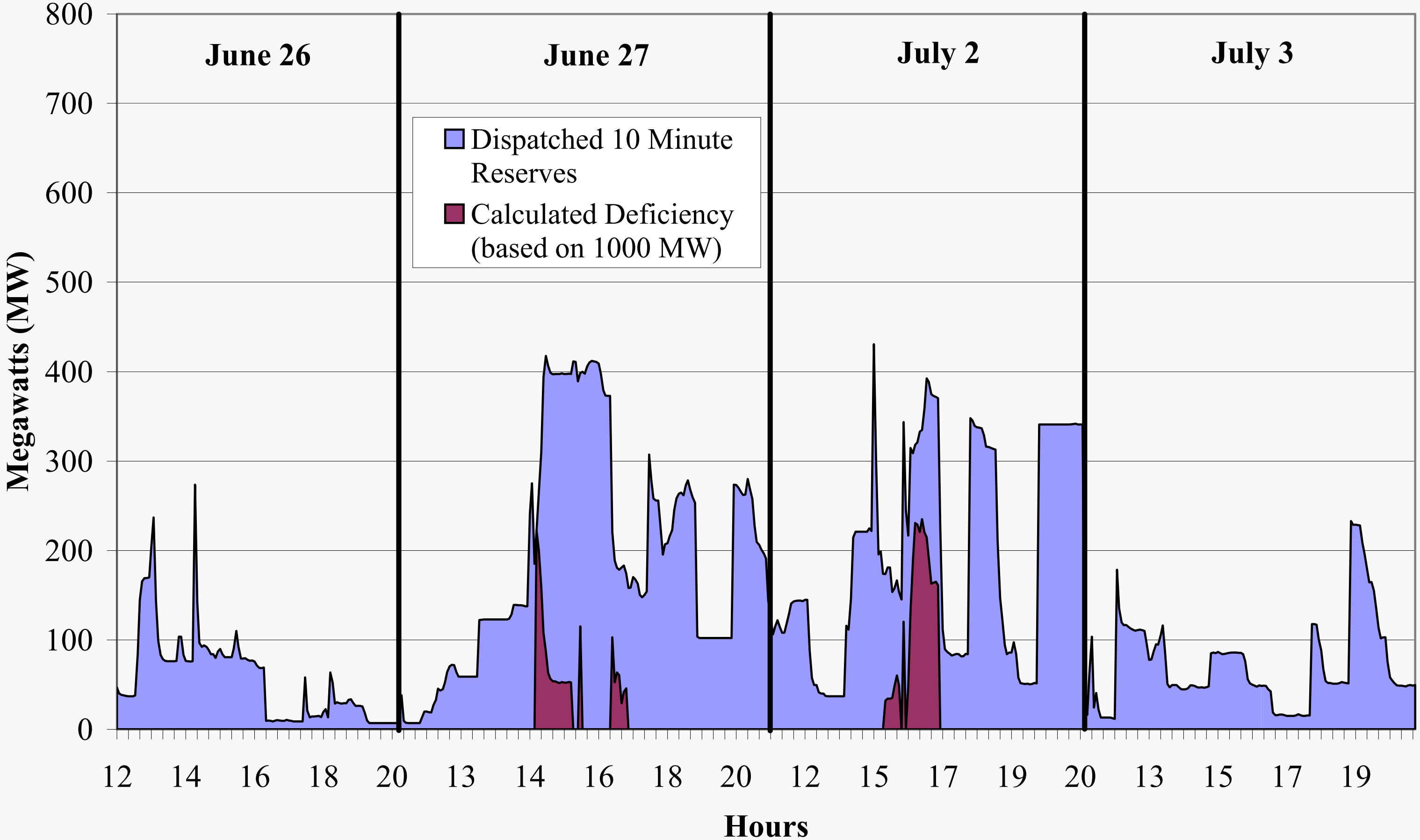


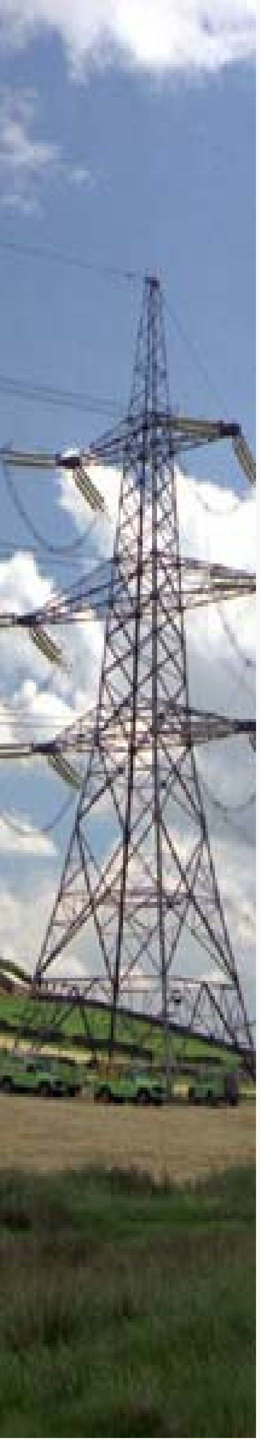
# Reserve Shortages

- For each of the peak days, the following figures show:
  - ✓ The quantity of total 10-minute reserves designated by BME in Eastern NY in each SCD interval.
  - ✓ The deficiency, if any, of total 10-minute reserves in eastern New York (requirement = 1000 MW).
- Because other resources are often available in real-time that can provide 10-minute reserves, dispatching 10-minute reserves designated by BME does not always produce a reserve deficiency (the other resources effectively become the reserves).
  - ✓ However, the figures show that there were 151 intervals (almost 13 hours) on these days when the NYISO was deficient in total 10-minute reserves.

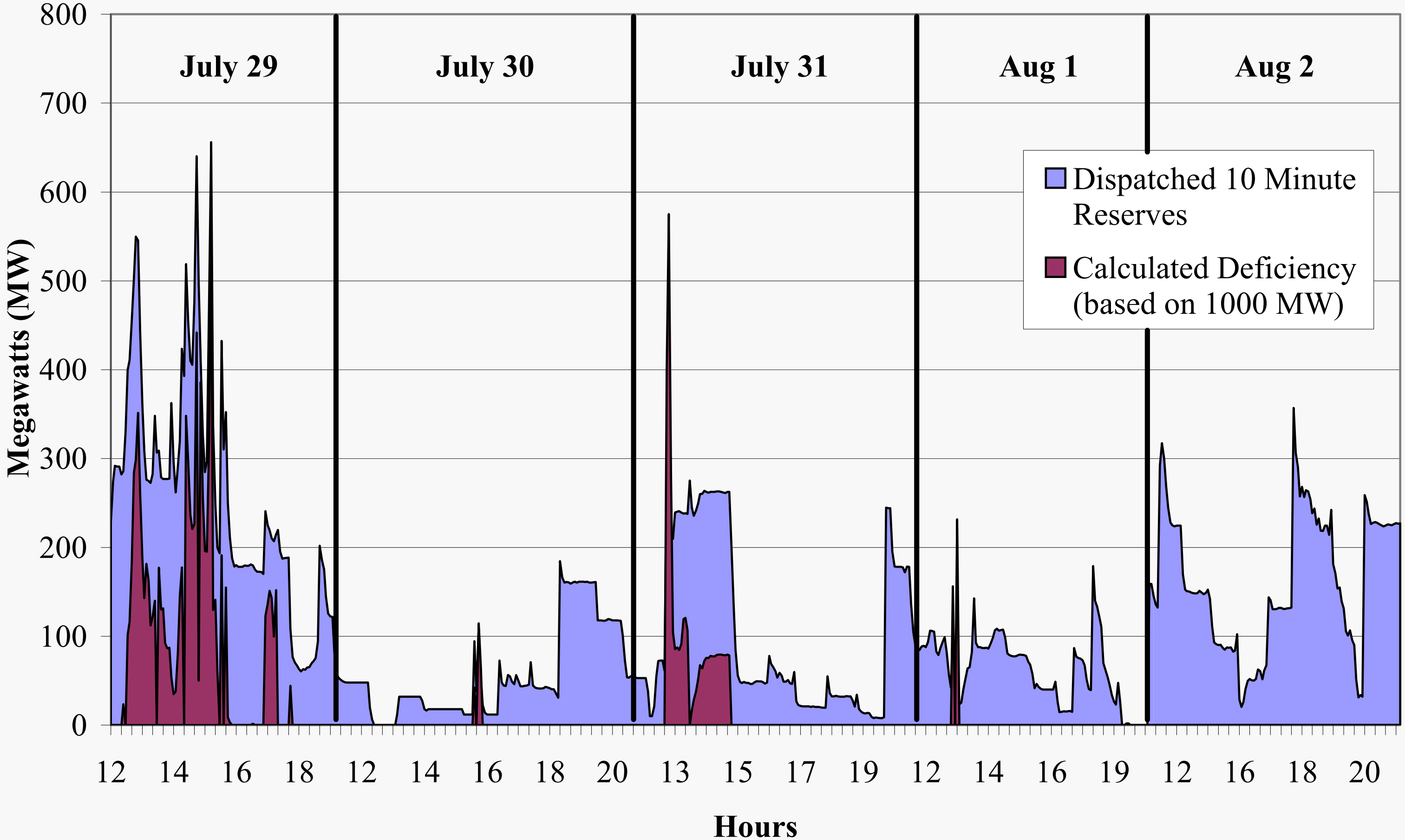


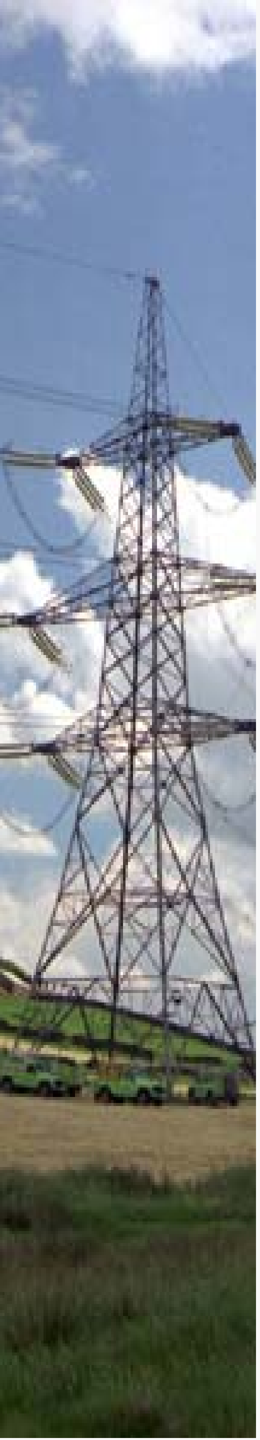
## Dispatch of 10-Minute Total Reserves in Eastern New York
## June 26, 27, July 2, 3 -- 12 p.m. to 8 p.m.



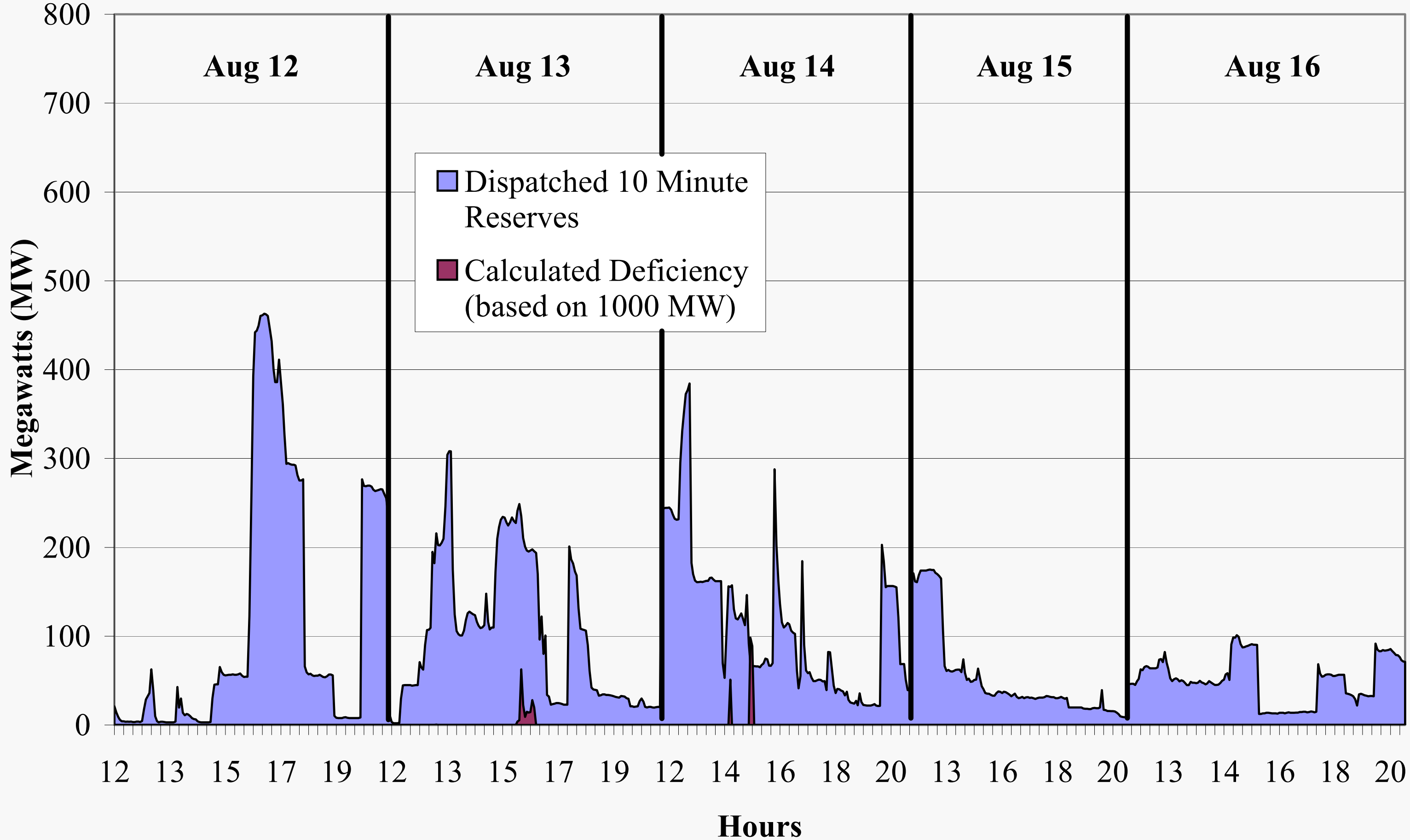


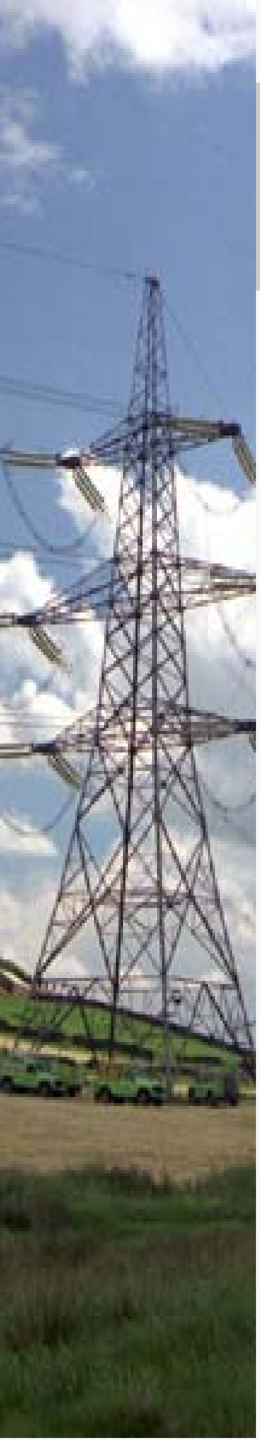
## Dispatch of 10-Minute Total Reserves in Eastern New York
## July 29, 30, 31, Aug 1, 2 -- 12 p.m. to 8 p.m.





**Dispatch of 10-Minute Total Reserves in Eastern New York**
**August 12-16 -- 12 p.m. to 8 p.m.**





# Pricing During Reserve Deficiencies

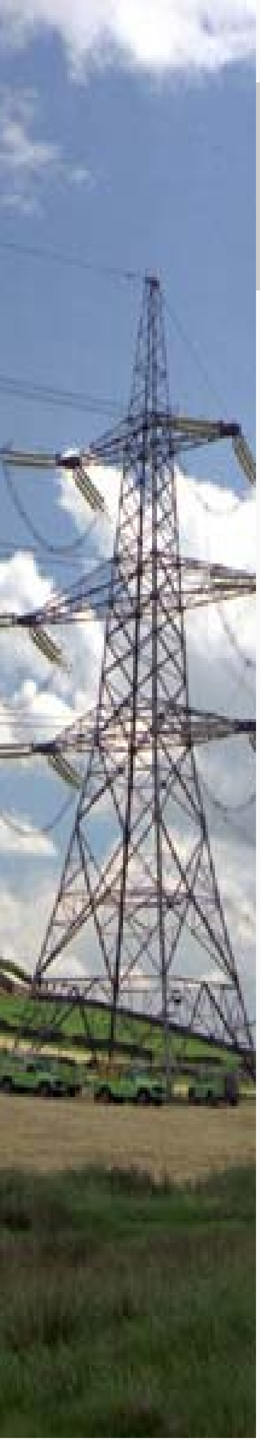
- The locational pricing market design employed in New York does not preclude efficient scarcity pricing.
  - ✓ There are significant quantities of generating resources with offer prices (based on legitimate costs) ranging from $200 to the safety-net bid cap at $1000 per MWh. When these resources are dispatched to meet energy demands, they will set energy prices at relatively high levels.
  - ✓ However, when operating reserves are released, the NYISO markets will not reliably set efficient scarcity prices.
- The following table shows the actual prices in eastern New York that prevailed in the intervals exhibiting a 10-minute operating reserve deficiency, showing:
  - ✓ Real-time energy prices were relatively unpredictable during these intervals, ranging from $99 to $1097 per MWh.
  - ✓ In only one quarter of the hours was the price above $500 per MWh.
  - ✓ Most of the prices in these intervals range from $100 to $200 per MWh – well below the implicit value of 10-minute reserves of $1000 per MWh.

## Average Real-Time Prices in Eastern New York During Periods with 10-Minute Reserve Deficiency

| | *Hour* | *Price ($/MWh)* |
|---|---|---|
| June 27 | 15 | $210 |
| | 16 | $106 |
| | 17 | $115 |
| July 2 | 15 | $580 |
| | 16 | $228 |
| July 29 | 12 | $157 |
| | 13 | $143 |
| | 14 | $740 |
| | 15 | $837 |
| | 16 | $1,097 |
| | 17 | $812 |
| | 18 | $227 |

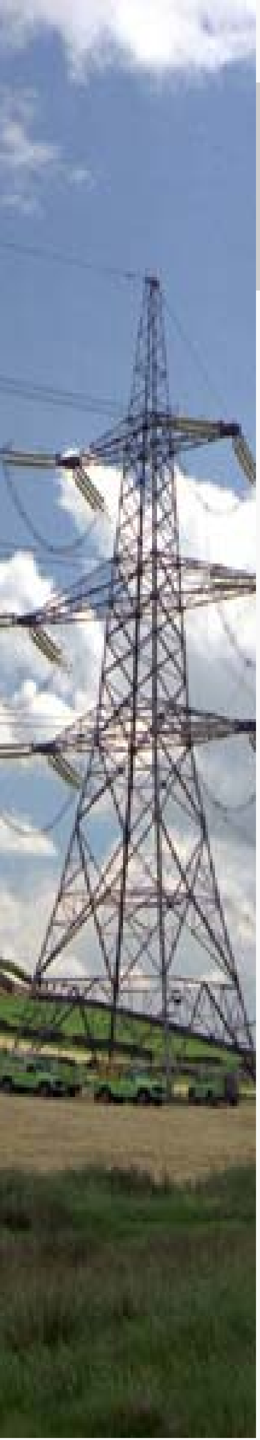
| | *Hour* | *Price ($/MWh)* |
|---|---|---|
| July 30 | 16 | $121 |
| July 31 | 13 | $265 |
| | 14 | $99 |
| August 1 | 13 | $101 |
| August 13 | 13 | $130 |
| | 16 | $144 |
| August 14 | 14 | $101 |
| | 15 | $103 |

Note: Prices are averages of only the deficient intervals during the 20 hours shown. The intervals of shortages in these hours sum to approximately 13 full hours of deficiency.



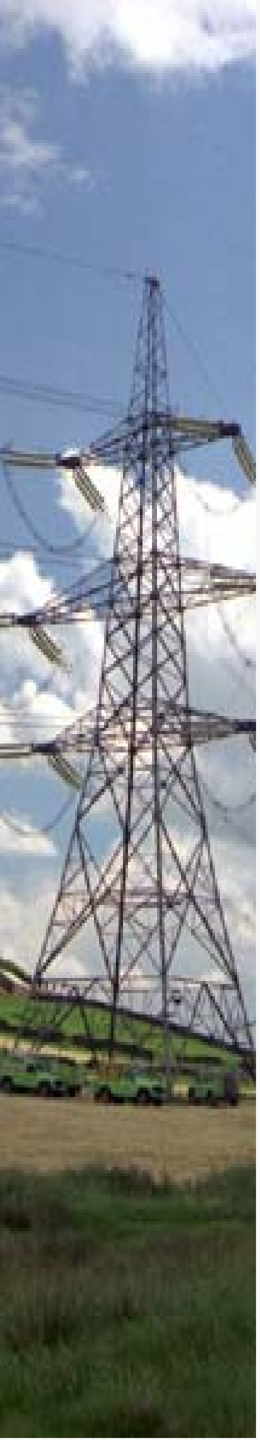
# Load Curtailment and Emergency Power

- There are several other ways that the operators may curtail load or call on additional resources:
  - ✓ Calling upon Emergency Demand Response resources, which have the option to curtail load for the higher of $500/MWh or the real-time price;
  - ✓ Calling upon Special Case Resources which have the obligation to curtail load if the operator forecasts a reserve deficiency. These resources are compensated with ICAP payments;
  - ✓ Curtailing of exports from capacity resources; or
  - ✓ Purchasing emergency power from neighboring control areas.
- Each of these actions can affect real-time prices by altering the supplies available to the SCD.

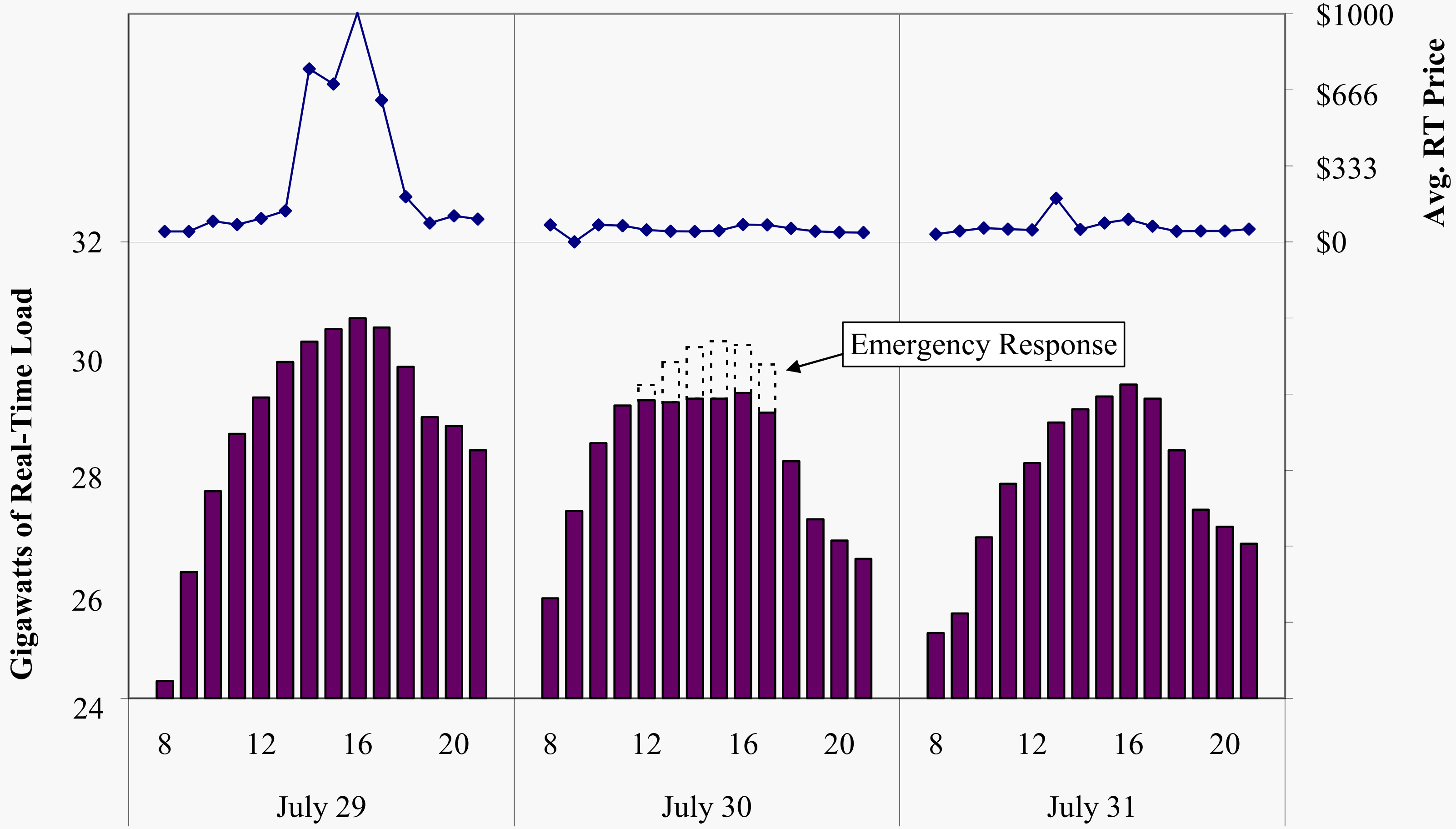


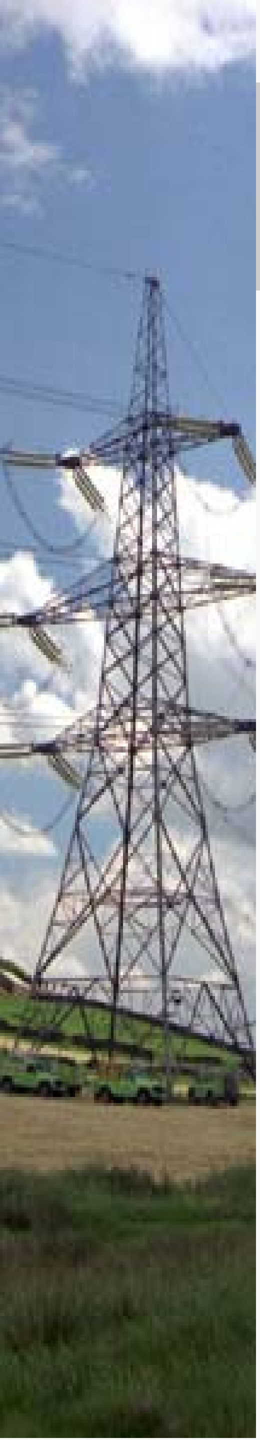
# Load Curtailment and Emergency Power

- The following figure show actual loads and real-time prices on July 30th when the Emergency Demand Response program was invoked.
- The figure also shows an estimate of the demand reduction that was achieved on July 30th.
  - ✓ The actual reduction by EDRP is less than the amount shown, which would include reductions associated with the SCR resources and reductions resulting from other load reduction programs (e.g., closing govt. offices).
- Prices under peak conditions can be relatively sensitive to changes in supply or demand conditions, which is consistent with the change in prices from the 29th to the 30th when EDRP was called.
- In addition, EDRP capacity is relatively costly with the participants paid $500 per MWh for each MWh curtailed.



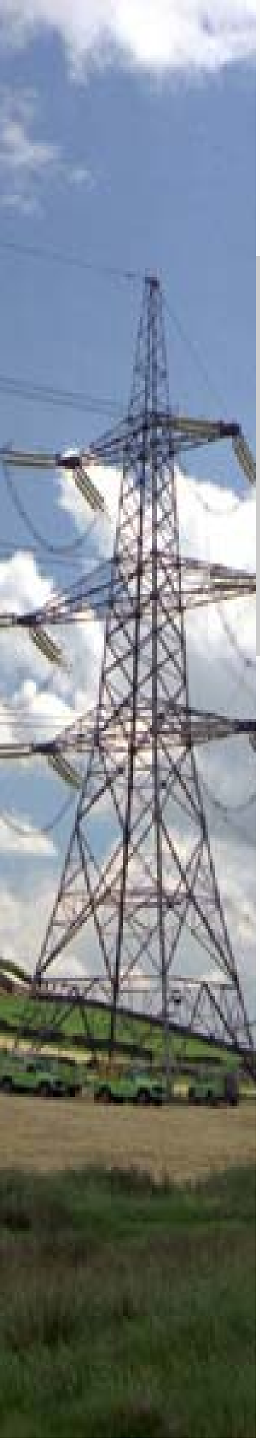
## Real-Time Load, Prices, and Emergency Demand Response
## New York State



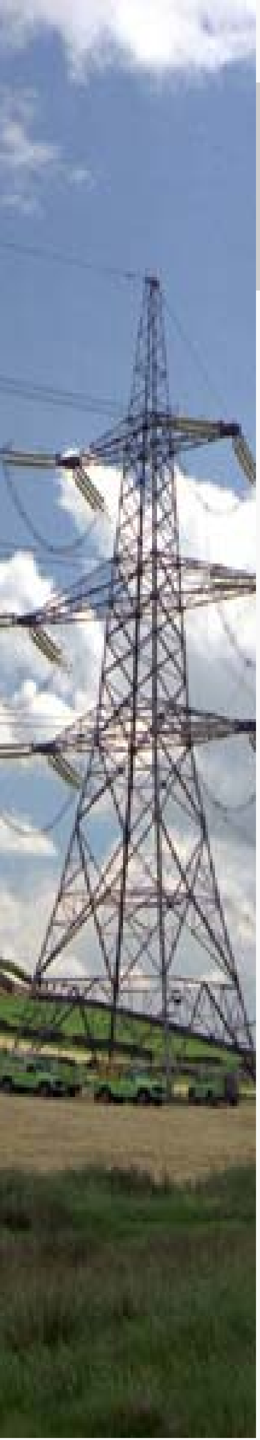


# Peak Pricing Recommendations

- The analysis in this section shows that shortages occurred during a number of hours in which the energy prices did not reveal the shortage value of power.
- This problem is inherent in each of the operating wholesale markets and FERC's Standard Market Design ("SMD"). The NYISO's RTS provides the means to address this in the longer term through use of a reserve demand curve.
- Based on this we recommended changes in the Summer 2002 Review to:
  - ✓ Set prices at the bid cap level in eastern New York when the eastern requirement for 10-minute reserves cannot be satisfied, and statewide when the statewide requirement for 10-minute spinning reserves are deficient;
  - ✓ Pay generators backed down to provide reserves a "lost opportunity cost" payment equal to the energy price minus their bid during reserve deficiencies;
  - ✓ Allow EDRP and SCR resources to set energy prices at the level of their payment for curtailing when they are economic and allow them to submit a wider array of curtailment bid prices; and
  - ✓ Provide addition information to operators to ensure that 10-minute reserves committed manually are eligible to set energy prices.
- Most of these recommendations will be addressed prior to Summer 2003.

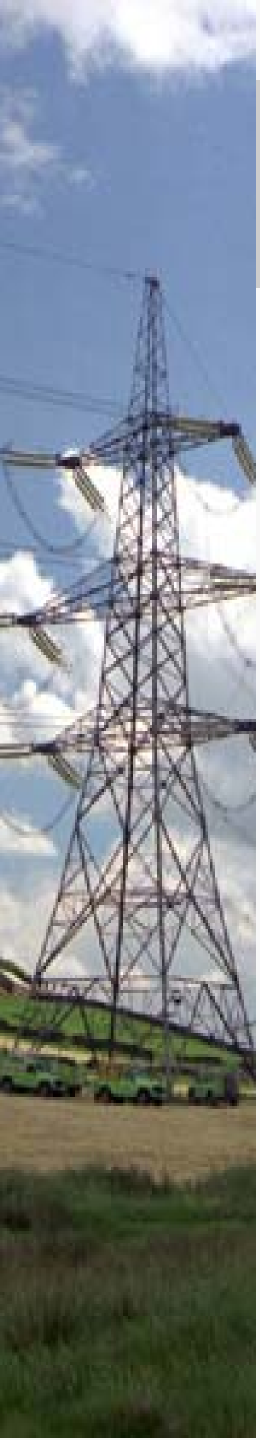


# External Transactions



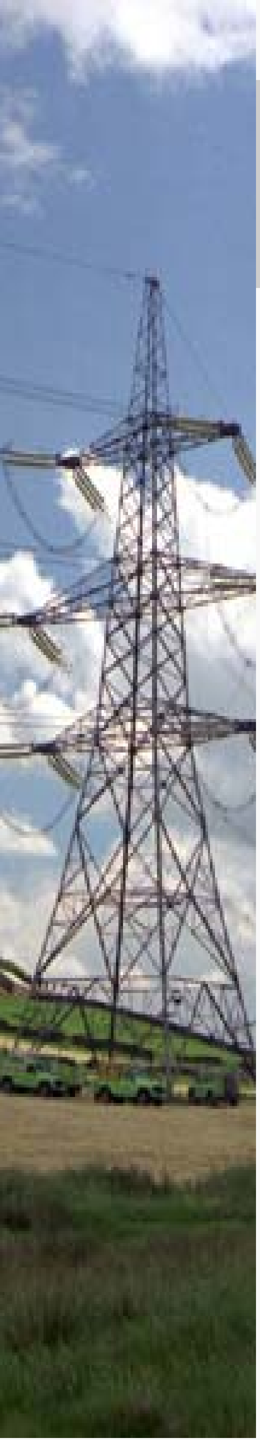
# Introduction

- The 2001 Annual Report analyzed the utilization of interfaces between New York and the adjacent markets (ISO-NE and PJM).
  - ✓ Several changes in the transaction scheduling rules and procedures have been made that have improved the utilization of the interfaces.
  - ✓ The arbitrage of the prices between markets has improved through 2001 and early 2002.
  - ✓ However, substantial price differences between New York and adjacent markets have continued to occur under peak demand conditions.
- The analysis in this section addresses three areas:
  - ✓ External transaction scheduling and price convergence during peak demand conditions;
  - ✓ External transactions during all hours; and
  - ✓ Long-term trends in price convergence and seams issues.



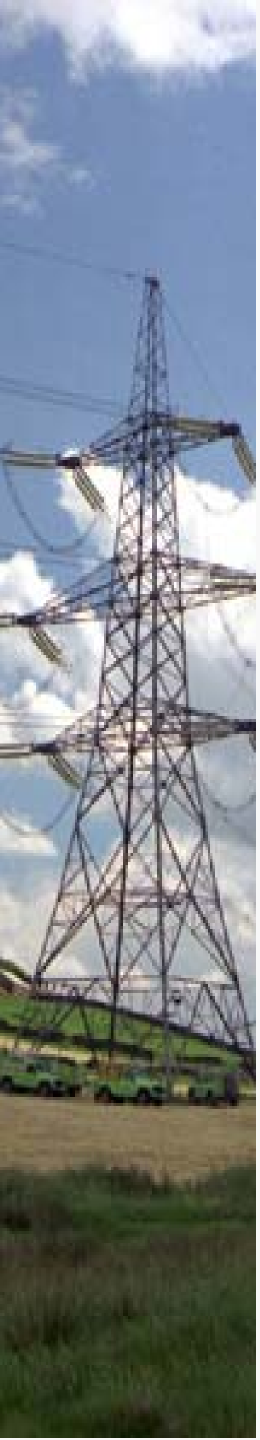
# External Transactions During Peak Periods

- This analysis examines peak demand periods to determine the extent to which participants are efficiently arbitraging the market prices.
  - ✓ This analysis is focused on eight peak days from late June to the end of July 2002.
  - ✓ To exclude the effects of physical constraints, the analysis excludes hours when the interface constraints or DNI constraint were binding.
- The following would indicate that the interfaces have been scheduled efficiently:
  - ✓ When constraints are not binding, the difference in prices between neighboring control areas should be close to zero;
  - ✓ To the extent that price differences exist, electricity should generally flow from low-priced control areas to high-priced ones; and
  - ✓ Market participants should act quickly to arbitrage large price differences.



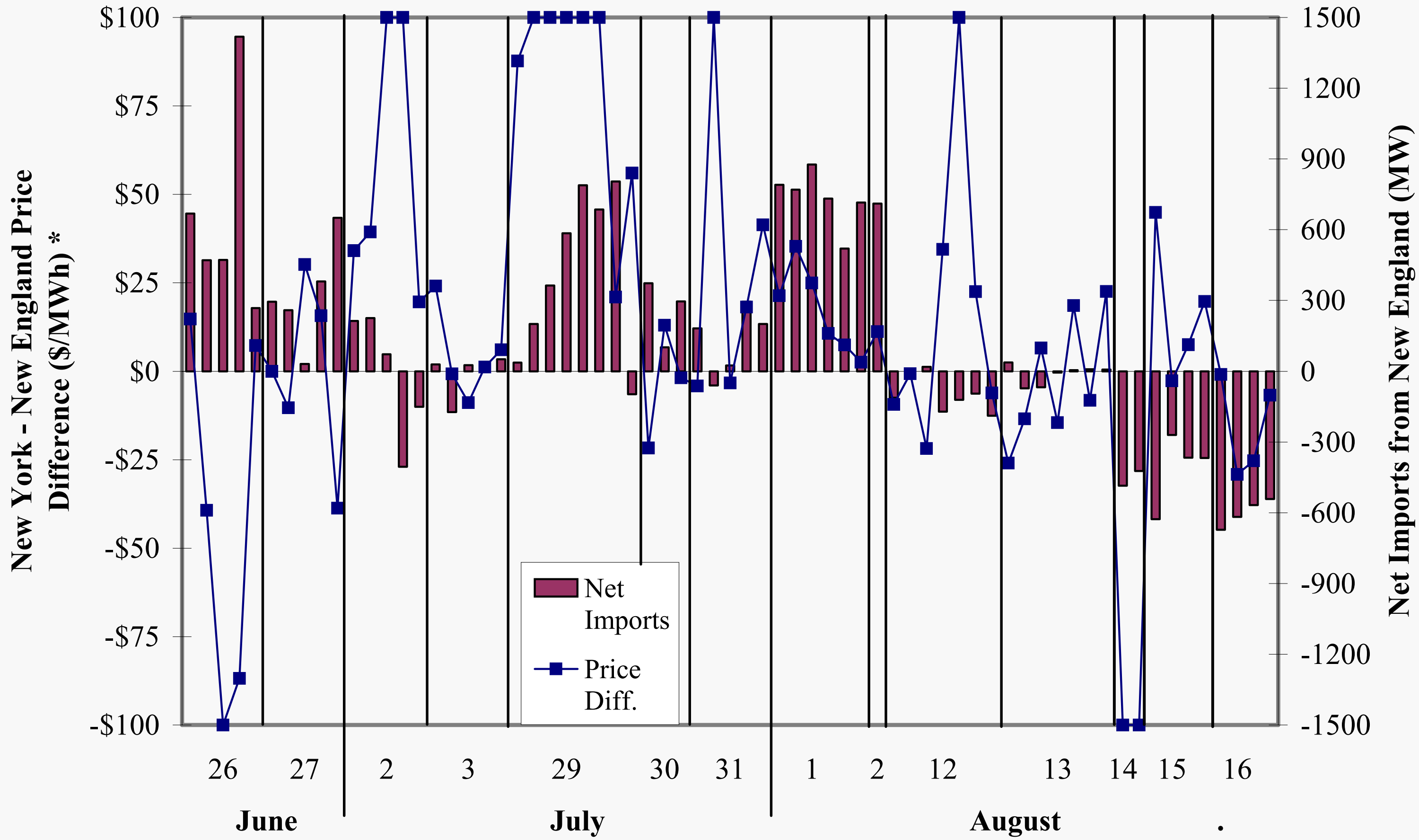
# External Transactions During Peak Periods

- The following figures show the scheduled net interchange and price difference between New York and the adjacent markets during the peak hours.
- The price differences shown are bounded by \$100 and -\$100 in these figures to better show the smaller price differences. Additional figures focus particularly on the largest price differences on these days.
- The analysis of the New England interface shows:
  - ✓ There is little evidence that participants responded efficiently to the large price differences that existed on the peak demand days, however transmission outages did prevent exports from New England during some of these hours (e.g., July 2);
  - ✓ In 36% of the hours when constraints were not binding and the price difference exceeded \$10, scheduled interchange moved power toward the low priced area;
  - ✓ On July 29th, participants responded to price signals by scheduling additional imports from New England, but not enough to effectively arbitrage the substantial price differences that continued for six consecutive hours; and
  - ✓ There is only a .20 correlation coefficient between the price difference and scheduled interchange.

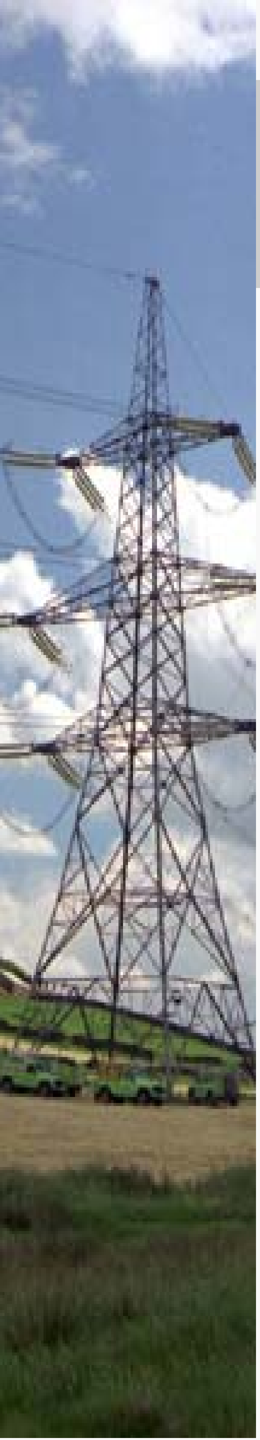


**Relationship of Real-Time Prices to Net Imports from New England**

Unconstrained Hours from 12 p.m. to 8 p.m. on Peak Days



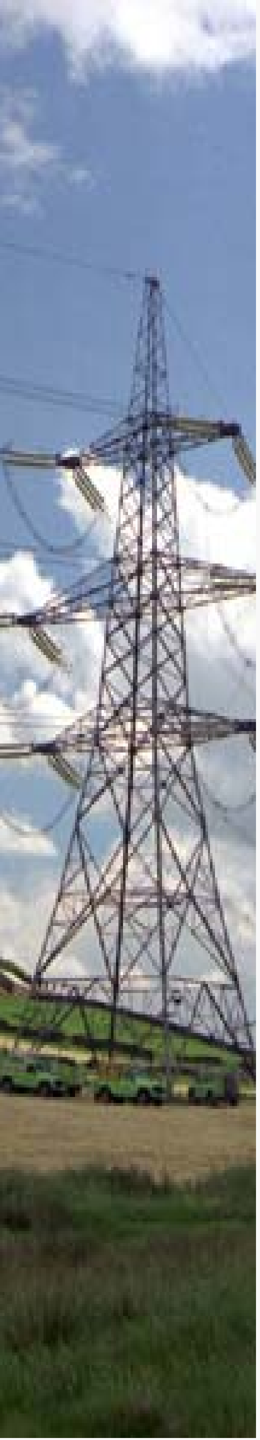

*Price differences are bounded at $100 and- $100. In certain hours, these were as high as $938 and as low as- $643.



# Analysis of Seams

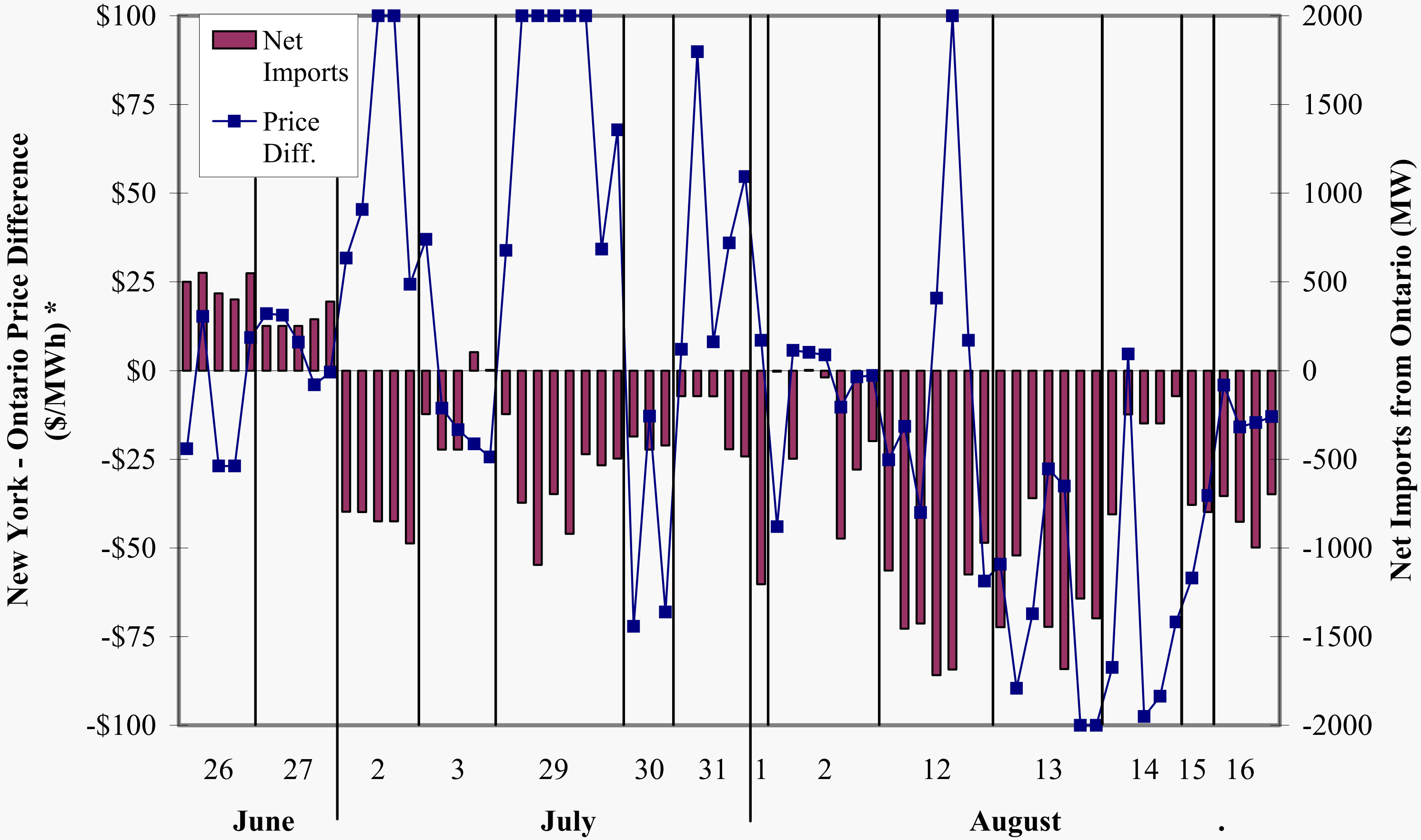
- The analysis of the Ontario interface shows:
  - ✓ There is little evidence that participants were able to schedule transactions to arbitrage significant price differences;
  - ✓ In 44% of the hours when constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the low priced area; and
  - ✓ There is a negative correlation between price differences and scheduled interchange on this interface.

- The analysis of the PJM interface shows:
  - ✓ New York usually exported to PJM during the peak hours period, even when prices were substantially higher in New York; and
  - ✓ There is a slight negative correlation between the price difference and scheduled interchange.

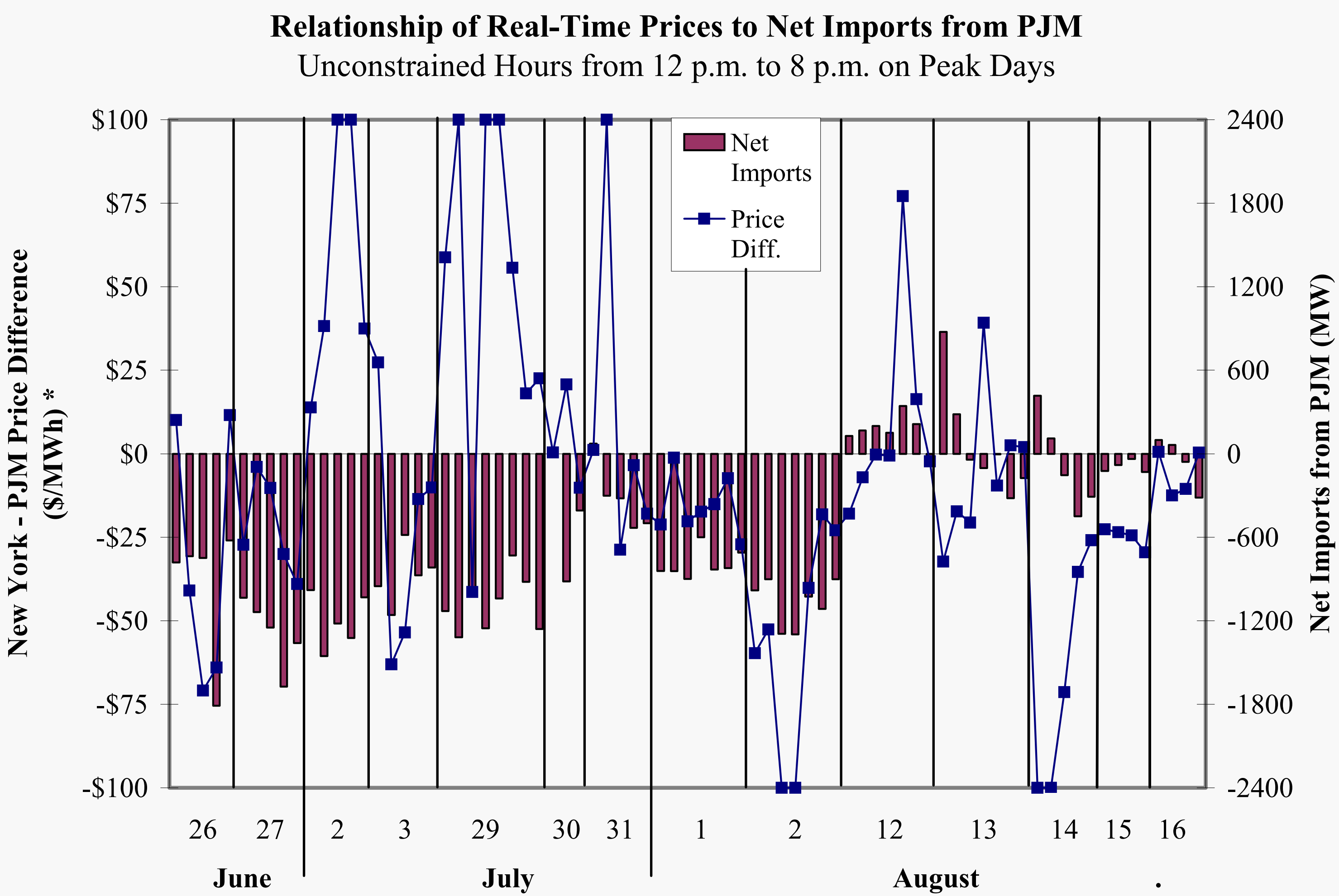


**Relationship of Real-Time Prices to Net Imports from Ontario**

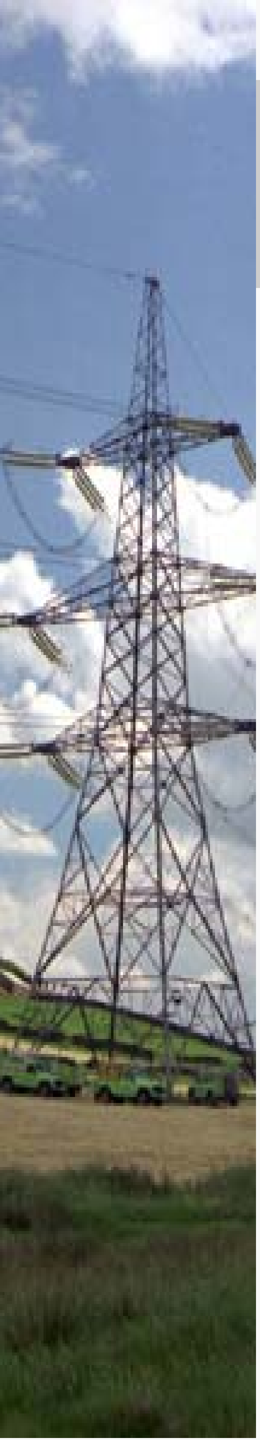
Unconstrained Hours from 12 p.m. to 8 p.m. on Peak Days




*Price differences are bounded at $100. In certain hours, these were as high as $944 and as low as- $530.

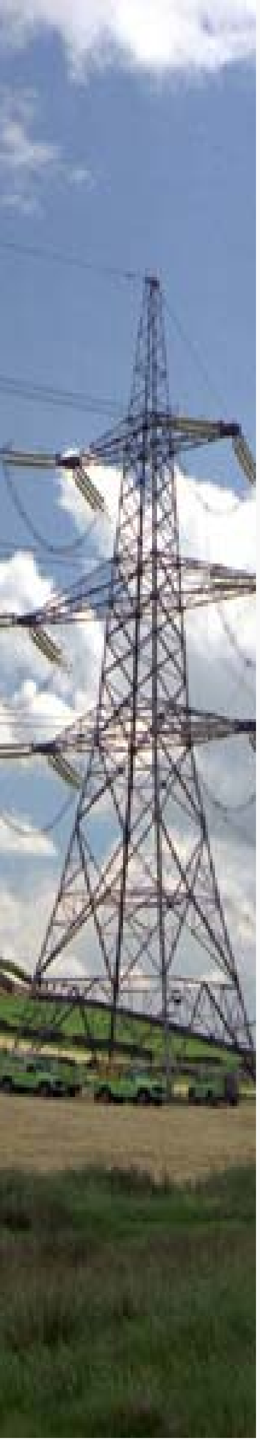



*Price differences are bounded at $100. In certain hours, these were as high as $695 and as low as -$256.



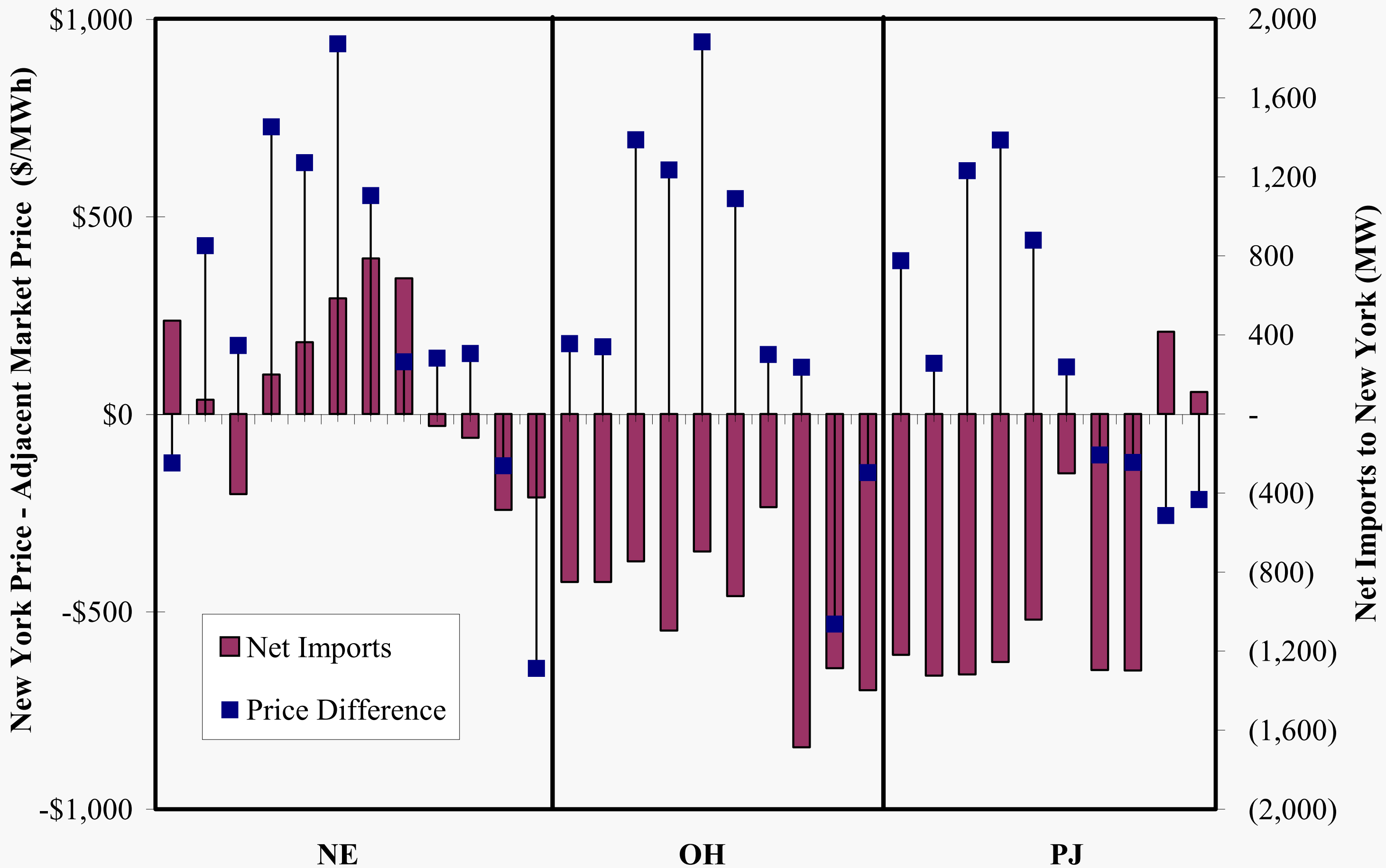
# Analysis of the Largest Price Differences

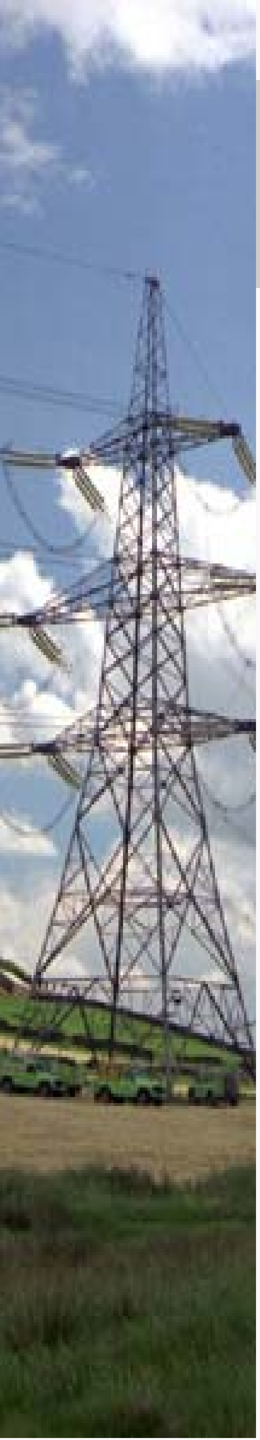
- The economic incentives provided by the markets, as well as the costs of scheduling transactions inefficiently, are the largest when the difference in prices between the markets is the highest.
  - ✓ Therefore, the following two figures focus on those hours when a price difference of more than $100 existing between New York and the adjacent markets.
- This analysis indicates that:
  - ✓ In more than 63 percent of these hours, the net interchange reflects power scheduled from the higher-priced market to the lower-priced market;
  - ✓ Power was scheduled toward the lower-priced market in nearly every hour on the PJM and Ontario interfaces, contributing to the large price differences.
  - ✓ Hence, the markets have not been efficiently arbitraged under the tightest market conditions, which affects the market in New York and in the adjacent areas.



## Relationship of Real-Time Prices to Net Imports from Adjacent Areas

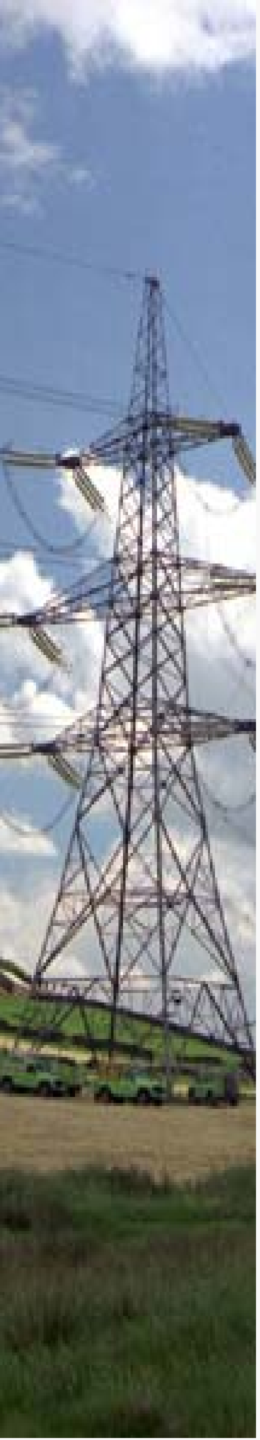
Unconstrained Hours with Price Differences > $100 per MWh





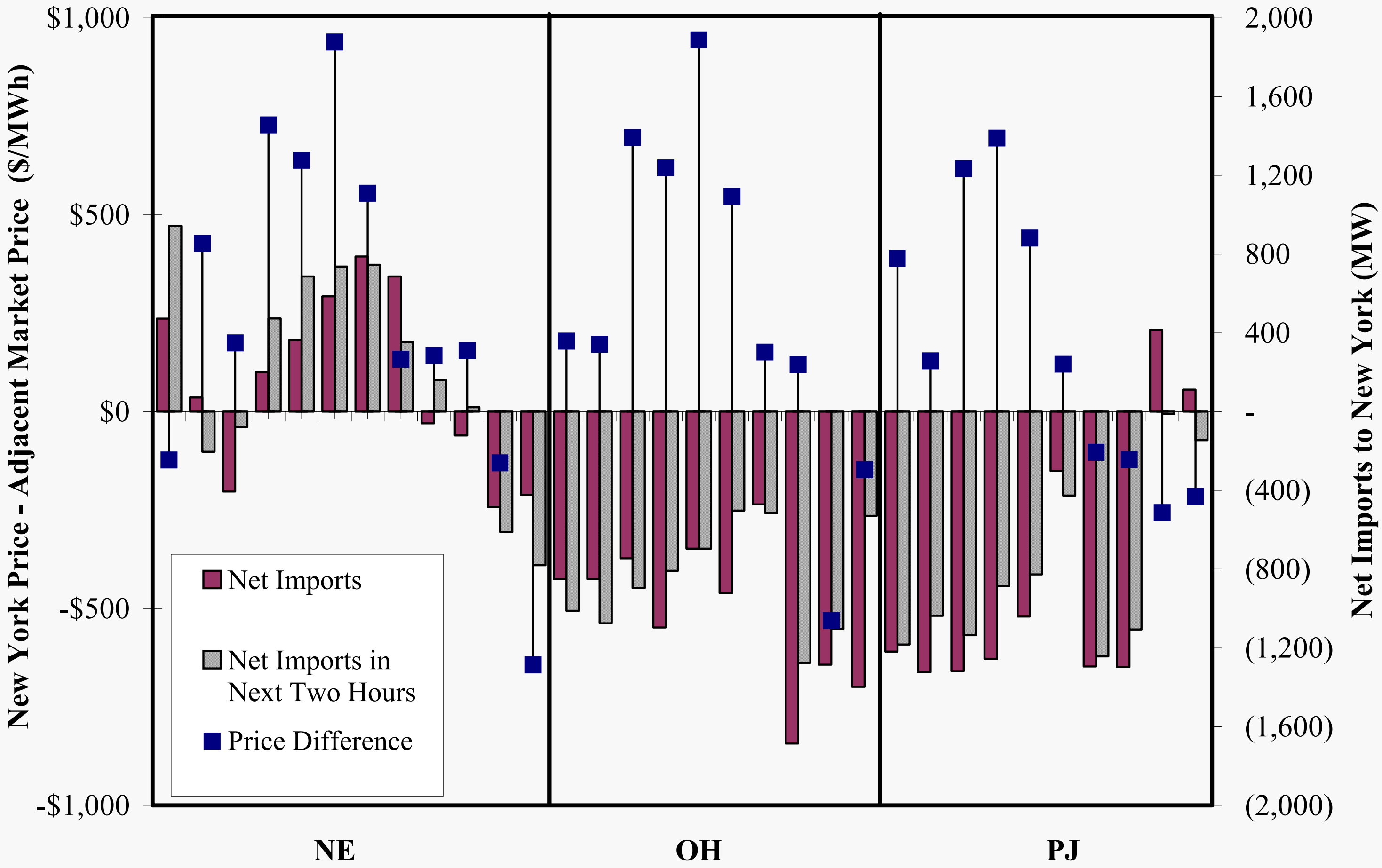
# Analysis of the Largest Price Differences

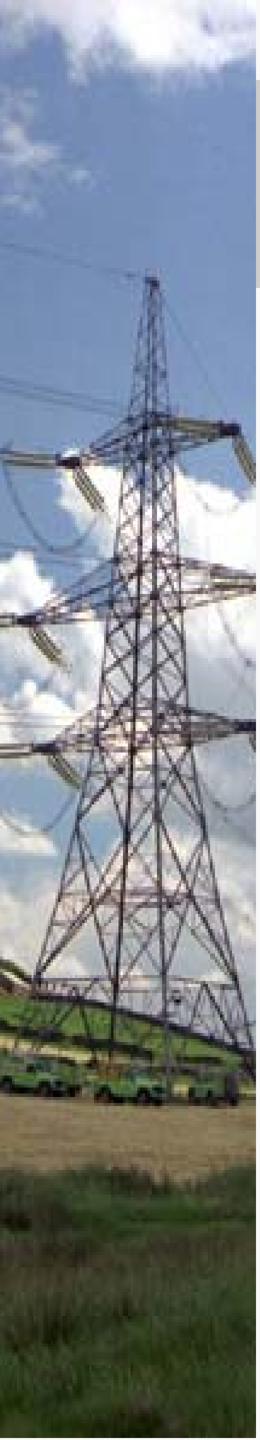
- However, large price differences can arise quickly and their duration is uncertain – hence, they are difficult for participants to predict in advance when hourly transactions are scheduled.
- Therefore, to assess the responsiveness of the transactions to these price differences, we analyze the net interchange in the two hours following the large price differences.
- This analysis is presented in the following figure and shows that the interchange changed only slightly in response to the large price differences. Sometimes these changes were the wrong direction.



## Relationship of Real-Time Prices to Net Imports from Adjacent Areas

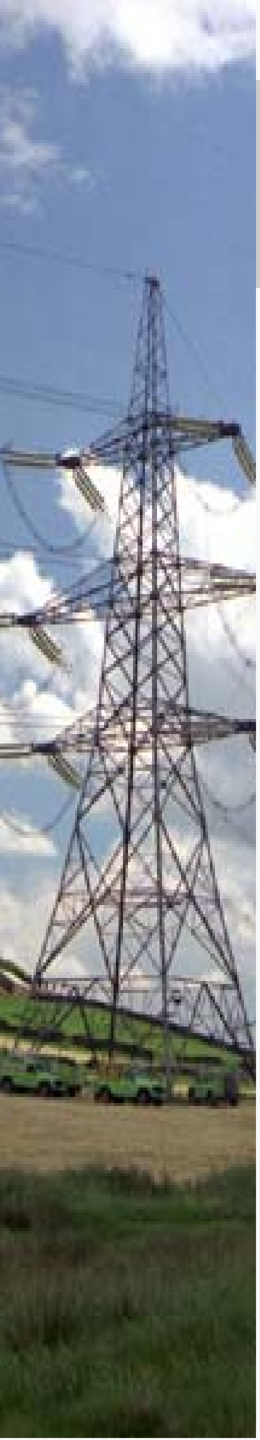
Unconstrained Hours with Price Differences > $100 per MWh





# Seams Conclusions

- The external transactions during recent peak periods have often resulted in inefficient scheduled flows between New York and adjacent markets. Some factors explaining these results likely include:
  - ✓ Participants must schedule with two separate ISOs more than an hour in advance of the real-time. Therefore, participants must anticipate the price differences;
  - ✓ These price differences can arise and dissipate quickly under peak conditions, creating substantial uncertainty and risk for participants scheduling transactions between control areas;
  - ✓ BME may not recognize the same relative economics between the markets (as the real-time markets) when scheduling price-sensitive imports and exports; and
  - ✓ Some of the differences could be related to conditions when the lower-priced market is in a shortage conditions, restricting exports, but not reflecting the shortage in its energy prices.

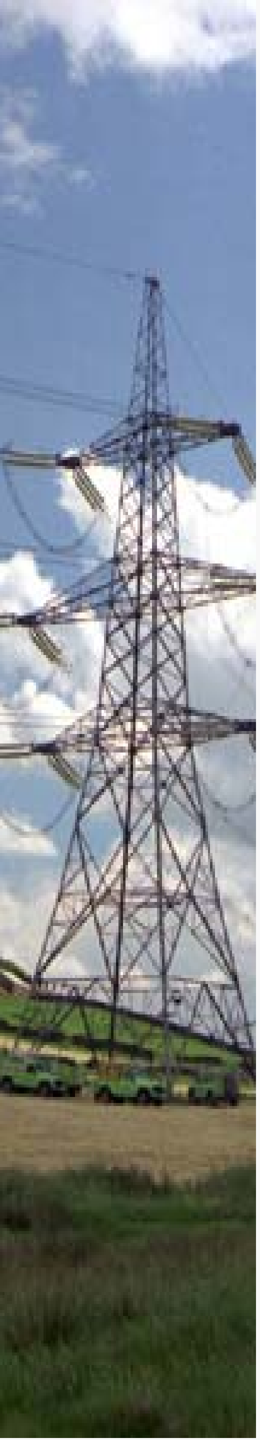


# Utilization of the Interfaces in All Hours

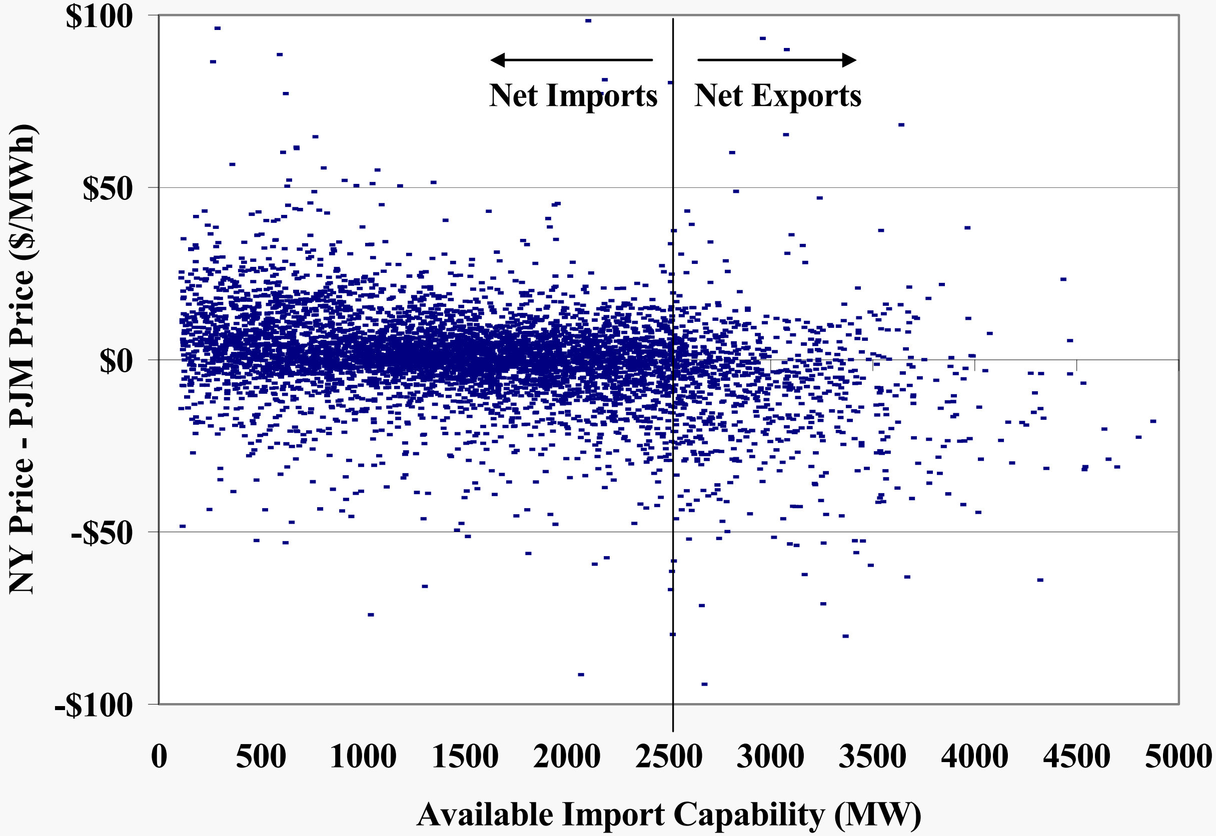
- The following four figures plot the hourly difference in prices between New York and neighboring markets against the available import capability during hours when transmission constraints are not binding.
- The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
- The available import capability is computed in the following manner:

  *Total Transfer Capability - Net Scheduled Import*

  - ✓ Therefore, when the NYISO is exporting (net scheduled import is negative), the available import capability will exceed the total transfer capability;
  - ✓ The vertical line is shown at the approximate TTC level for each interface -- so higher points (to the right) generally represent exports while lower points (to the left) generally represent imports.
- The counter-intuitive net schedules are a) net exports when NYISO prices exceed the adjacent market or b) net imports when NYISO prices are lower than adjacent prices.



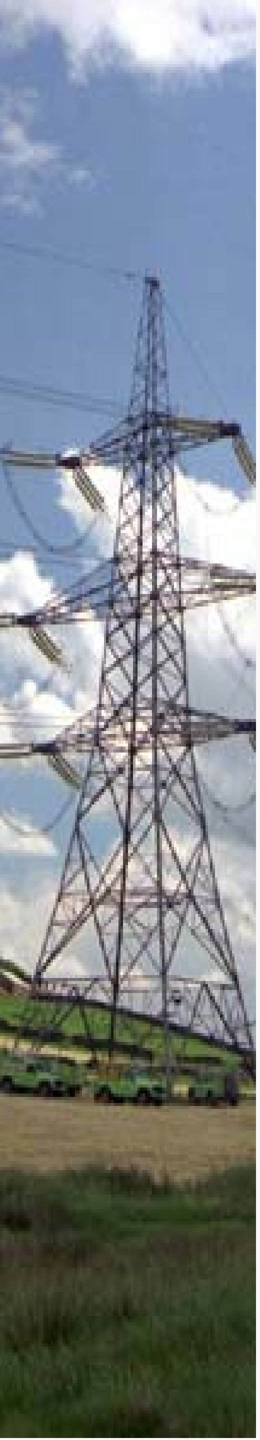
## Difference Between West Zone and PJM Price*
### Real-Time Prices vs. Hour-Ahead Schedules
### Unconstrained Hours - 2002



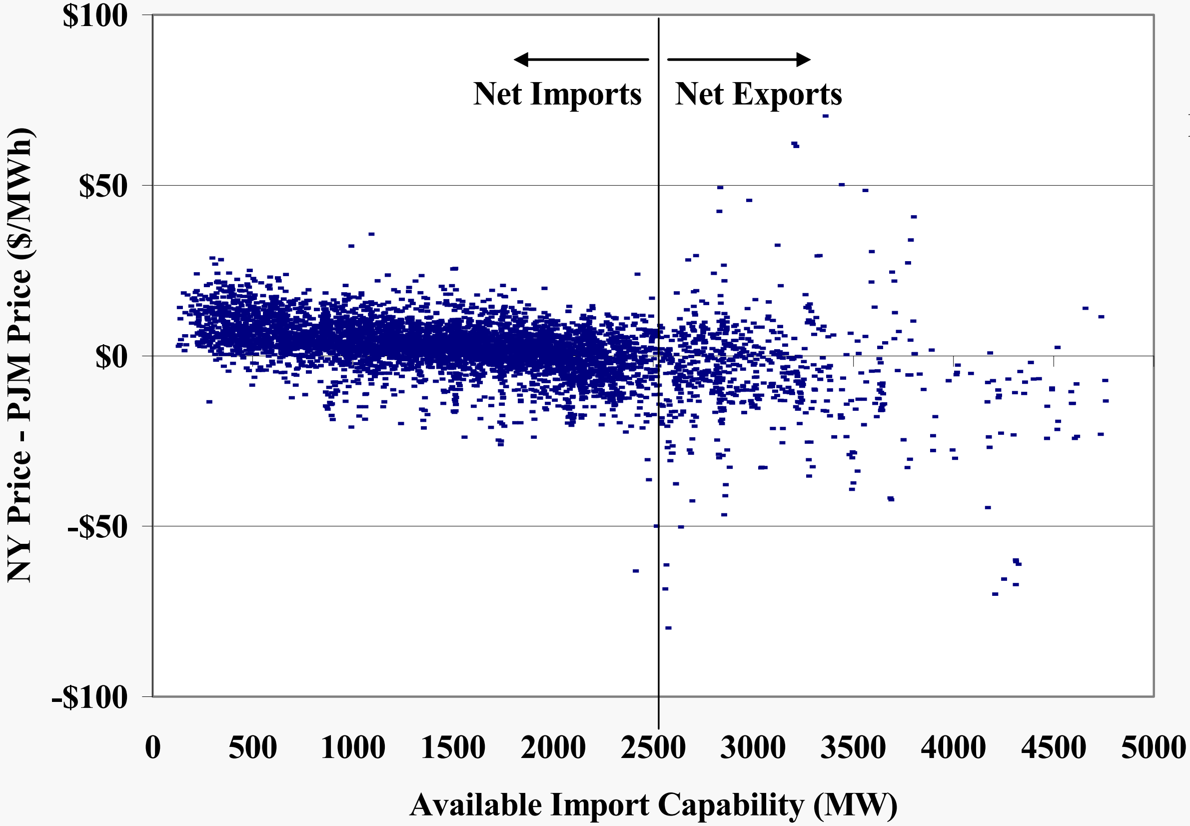

**Monthly Price Statistics**

| Month | Mean | Std Dev |
|---|---|---|
| Jan | $0.69 | $7.13 |
| Feb | $0.17 | $7.65 |
| Mar | -$1.77 | $10.12 |
| Apr | $0.04 | $11.40 |
| May | -$2.95 | $11.16 |
| Jun | -$3.32 | $12.10 |
| Jul | $5.57 | $55.82 |
| Aug | -$5.21 | $23.40 |
| Sept | $5.03 | $37.66 |
| Oct | $7.34 | $14.95 |
| Nov | $9.47 | $16.26 |
| Dec | $7.74 | $22.92 |

* PJM Western Hub Price



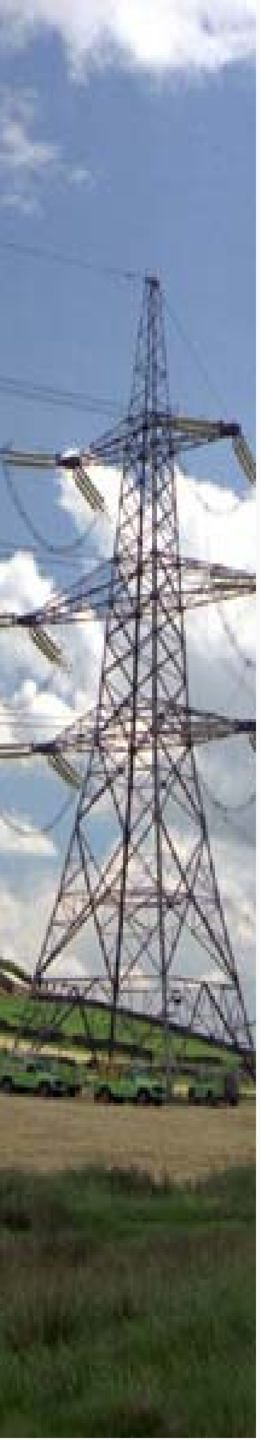
## Difference Between West Zone and PJM Price*
### Day-Ahead Market
### Unconstrained Hours - 2002




**Monthly Price Statistics**

| Month | Mean | Std Dev |
|---|---|---|
| Jan | $2.21 | $3.56 |
| Feb | $0.66 | $3.71 |
| Mar | $1.01 | $5.39 |
| Apr | $0.40 | $9.99 |
| May | -$1.46 | $7.26 |
| Jun | -$0.65 | $7.76 |
| Jul | $1.48 | $11.57 |
| Aug | $3.08 | $13.61 |
| Sept | $6.24 | $8.18 |
| Oct | $6.32 | $7.48 |
| Nov | $9.51 | $6.09 |
| Dec | $5.42 | $8.77 |

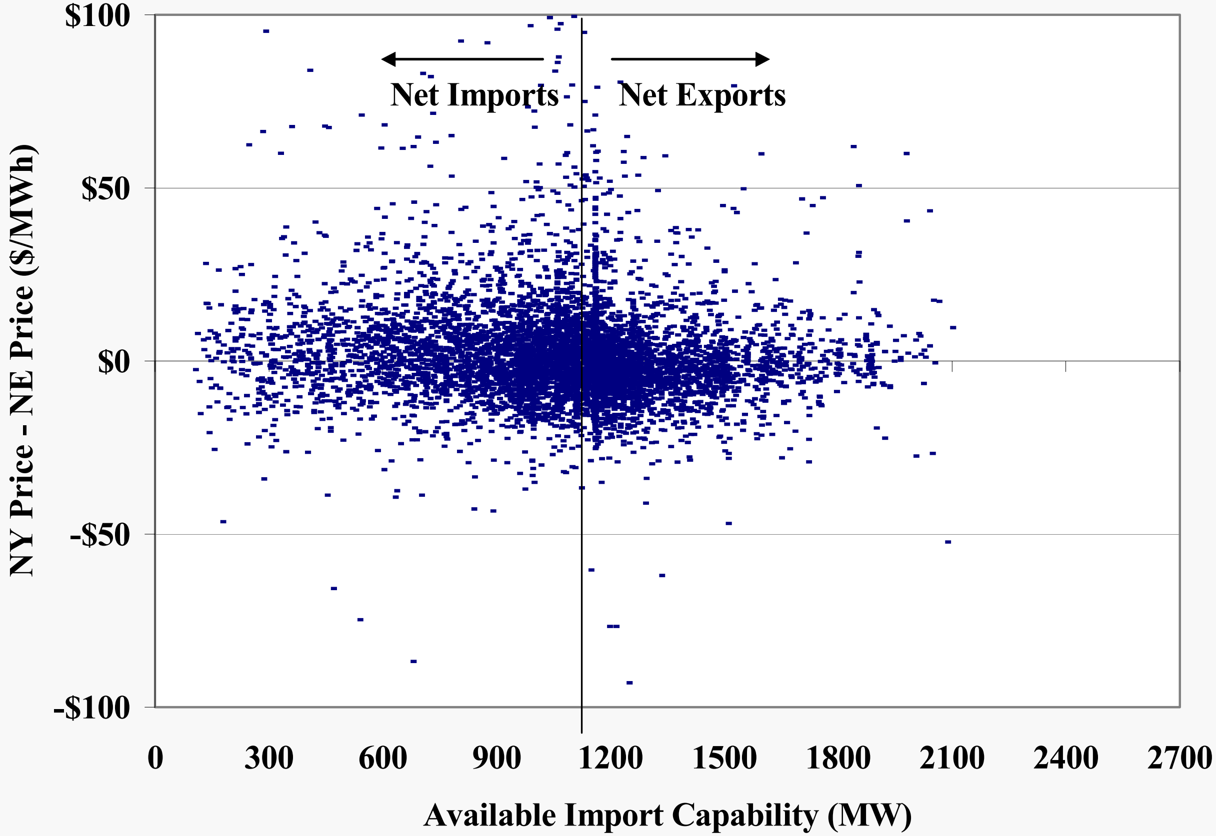
* PJM Western Hub Price



# Difference Between Capital Zone and New England Price

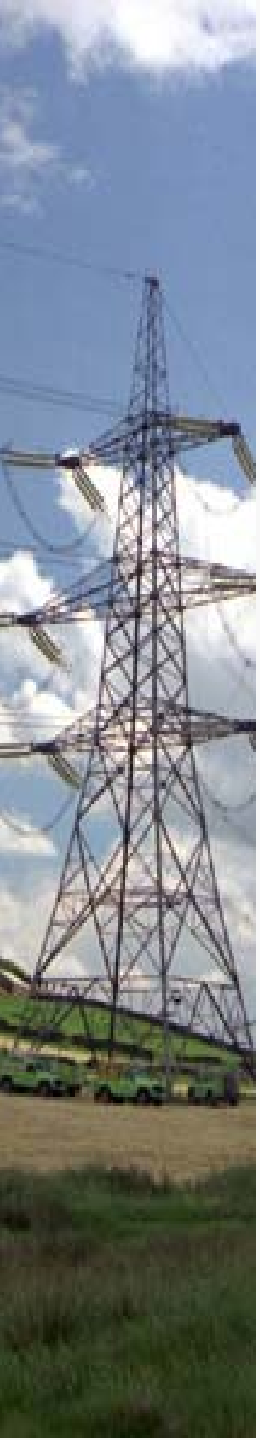
## Real-Time Prices vs. Hour-Ahead Schedules

## Unconstrained Hours - 2002

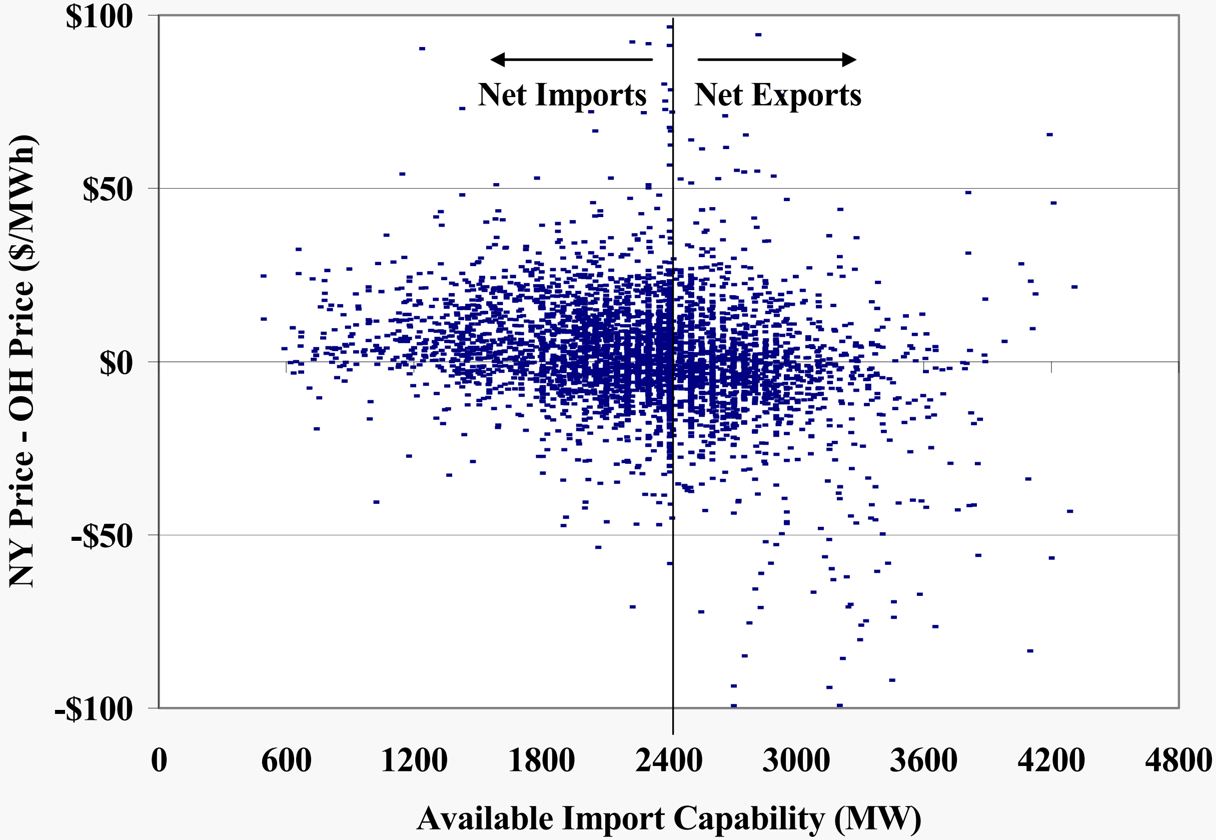



**Monthly Price Statistics**

| Month | Mean | Std Dev |
|---|---|---|
| Jan | -$0.51 | $7.77 |
| Feb | -$2.00 | $7.80 |
| Mar | $3.39 | $18.74 |
| Apr | $4.30 | $13.29 |
| May | $1.53 | $16.20 |
| Jun | -$1.04 | $11.36 |
| Jul | $10.59 | $74.21 |
| Aug | -$4.37 | $32.61 |
| Sept | -$0.13 | $34.15 |
| Oct | $3.57 | $16.41 |
| Nov | $4.36 | $15.57 |
| Dec | $3.96 | $20.92 |



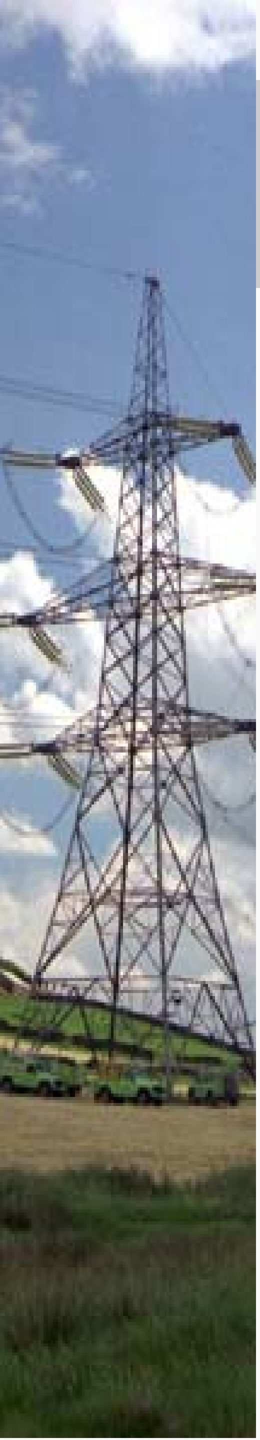
## Difference Between West Zone and Ontario Price*
### Real-Time Prices vs. Hour-Ahead Schedules
### Unconstrained Hours - May to December - 2002




**Monthly Price Statistics**

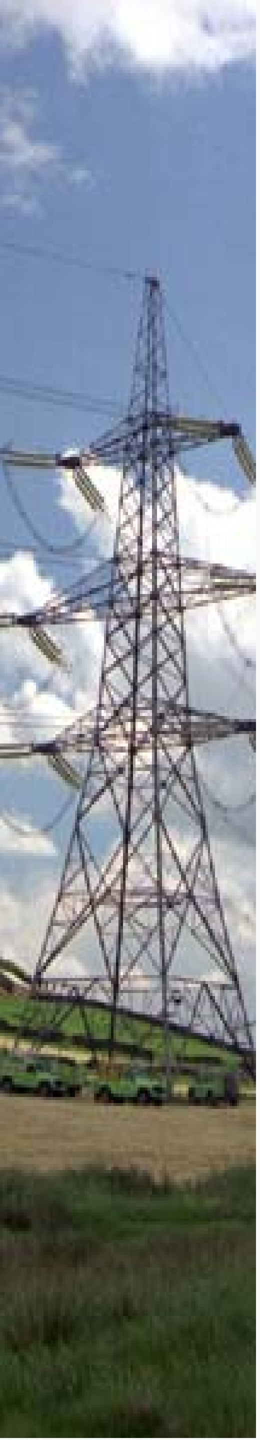
| Month | Mean | Std Dev |
|---|---|---|
| May | $0.82 | $7.93 |
| Jun | $0.91 | $11.47 |
| Jul | $3.79 | $68.50 |
| Aug | -$5.88 | $29.18 |
| Sept | -$10.49 | $54.19 |
| Oct | $6.42 | $14.30 |
| Nov | $5.84 | $15.35 |
| Dec | $5.42 | $21.81 |

* Price difference measured in US dollars

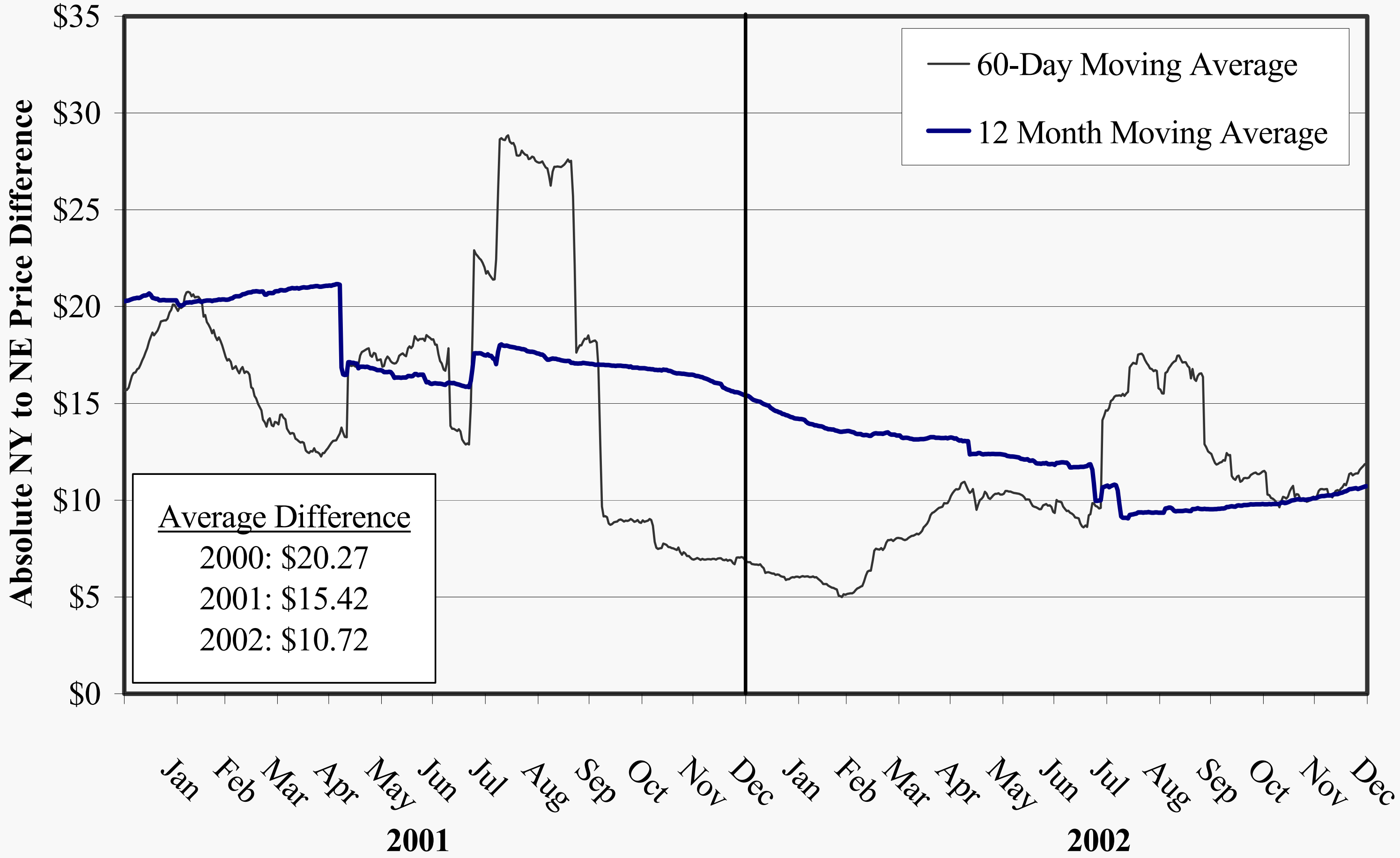


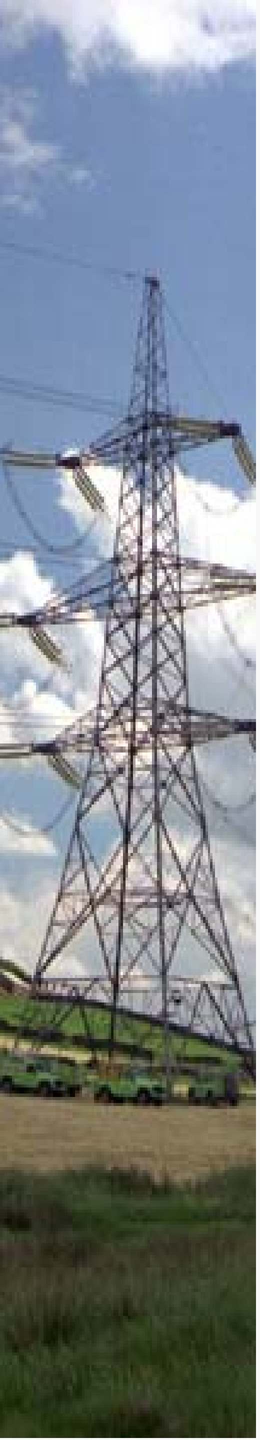
# Tracking Changes in the Inter-ISO Seams

- The following figures show a method of measuring how effectively seams issues have been addressed by changes to market rules and procedures.
- The figures evaluate how well the real-time prices between New York and other markets have been arbitraged by participants.
  - ✓ Both figures show a 12-month and 60-day moving average of the absolute price differences experienced between New York and an adjacent market.
  - ✓ Only uncongested hours are included in the analysis (additional transactions to arbitrage prices cannot be scheduled when the interface is fully scheduled).
  - ✓ Sharp movements in the moving averages generally correspond to periods of price spikes in one of the markets, resulting in extremely large differences.
  - ✓ The average annual difference shown on the figure for 2000, 2001 and 2002 are equal to the 12 month moving average as of December 31 of each year.
- Both figures indicate that significant improvements in the seams issues have been made over the past three years.



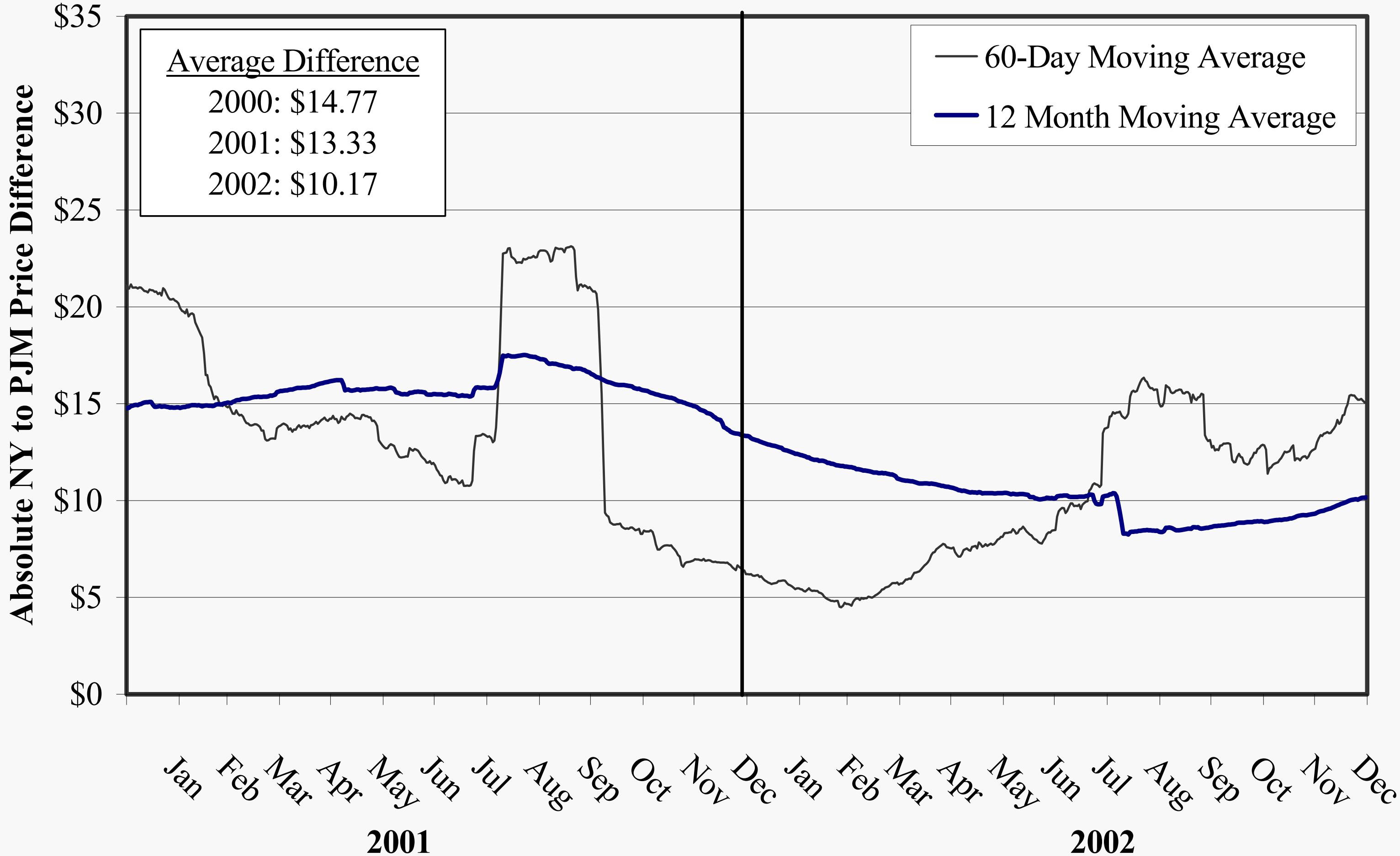
## Average Price Difference Between New York and New England During Uncongested Hours
### Moving Average -- 2000 through 2002

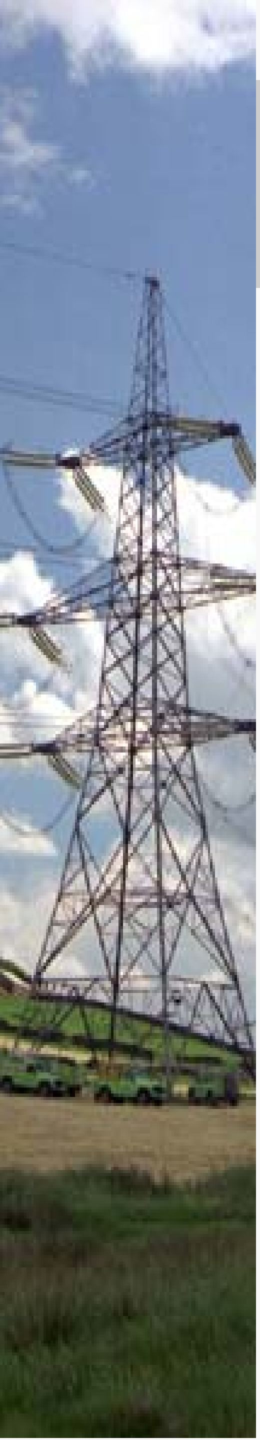




# Average Price Difference Between New York and PJM During Uncongested Hours

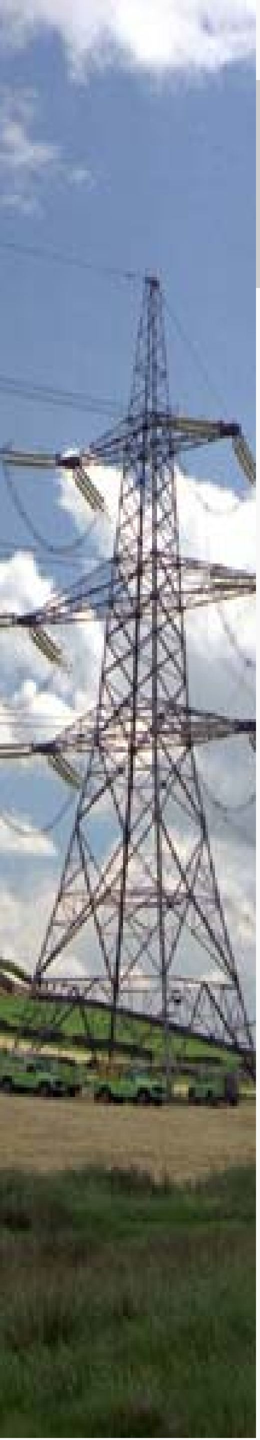
## Moving Average -- 2000 through 2002





# Tracking Changes in the Inter-ISO Seams

- The improvements that have been realized over the past two years have resulted in significant efficiency improvements.
- We have assessed these efficiency improvements by estimating the production cost savings that have been achieved over the past three years.
  - ✓ Production cost savings are achieving by improving the efficiency of the dispatch in the broad region (i.e., displacing high cost generation with lower cost generation).
  - ✓ We first calculated the total potential production cost savings that could be achieved in the region in each year from perfect interchange between the areas, based on the available supply in each market.
  - ✓ The savings achieved over time is the cumulative decrease in the total production costs as the markets have moved closer to the "perfect interchange" case.
- The savings estimated in 2001 is $22 million while the cumulative savings in 2002 grew to close to $50 million.



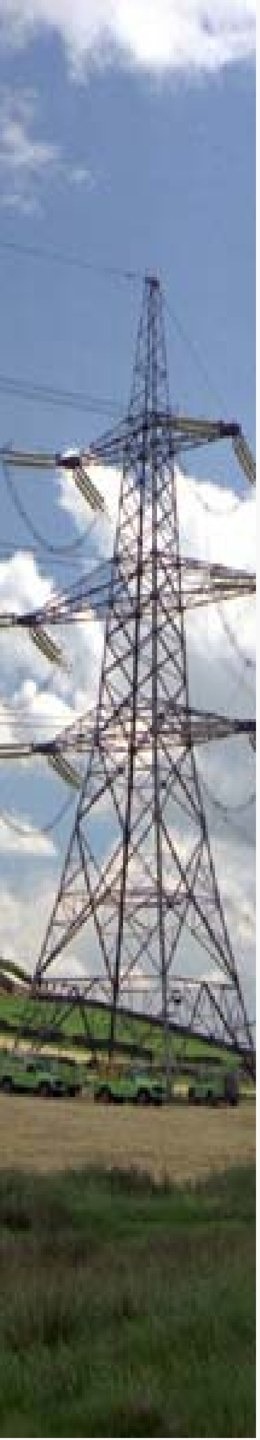
# NYISO Scheduling of External Transactions

- The following bar figures show the average hourly number of megawatts of scheduled and unscheduled external transactions. Unscheduled transactions are divided into:

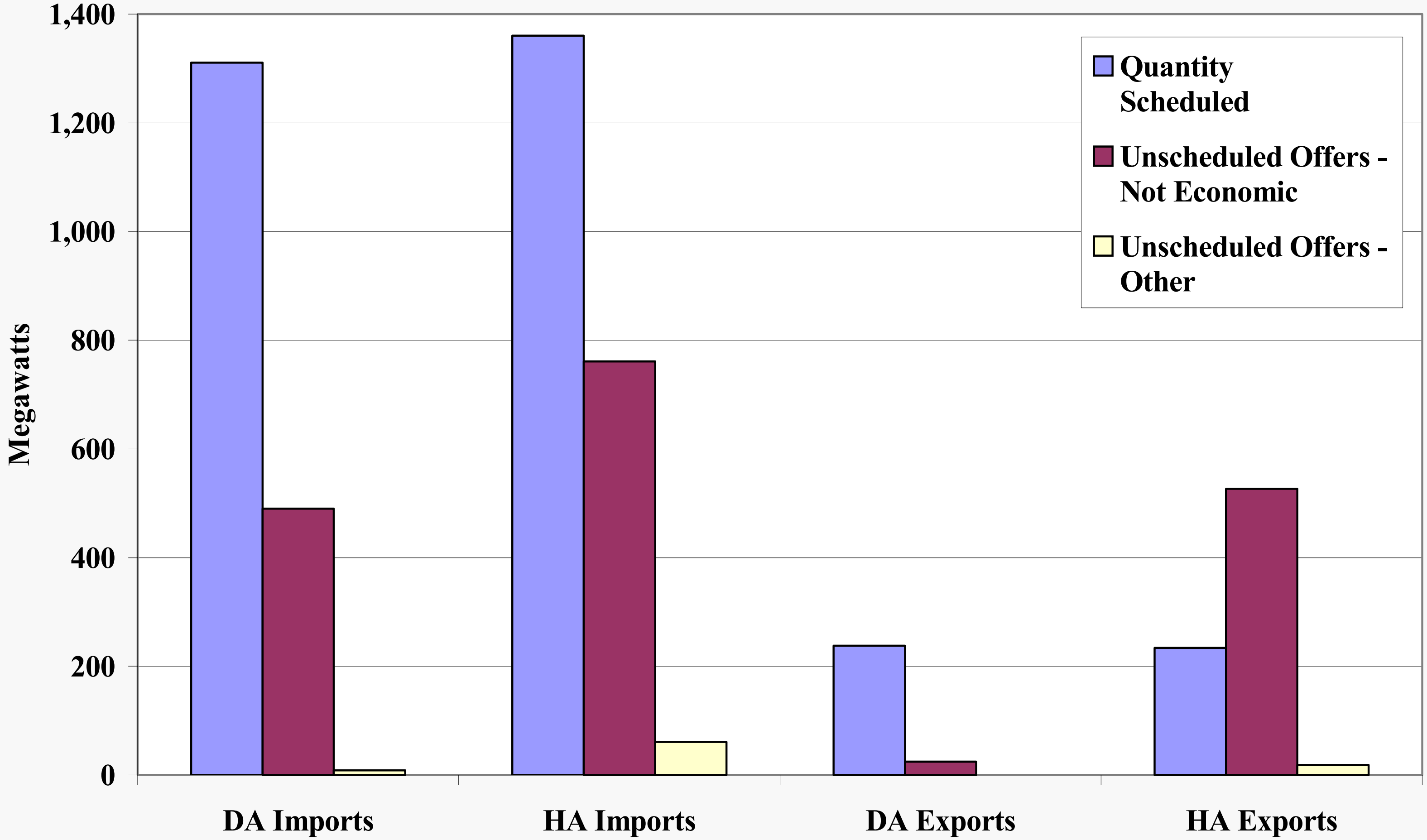
  (i) those that were not economic in New York, and

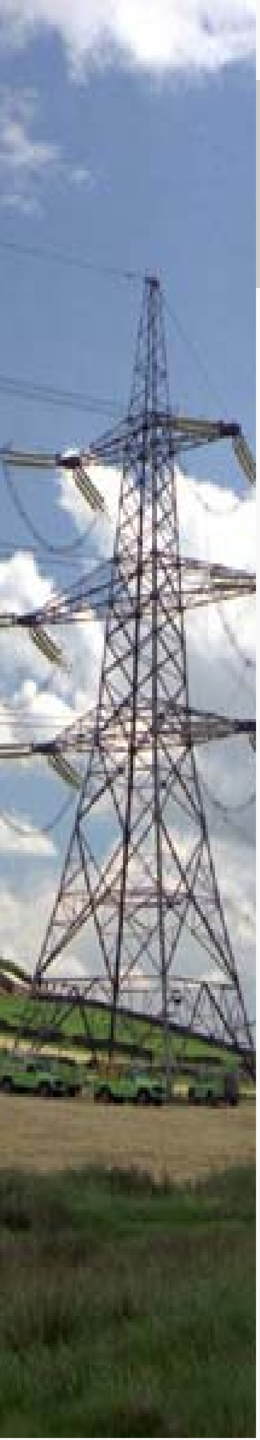
  (ii) those that were economic in New York, but were not scheduled for other reasons (e.g. failed the checkout process, not accepted in adjacent market).

- The first figure is the analysis for New York and PJM, showing:
  - ✓ New York was a net importer of power from PJM in both the day ahead and hour ahead;
  - ✓ Scheduled imports and scheduled exports are both virtually the same in the hour ahead as in the day ahead, although unscheduled quantities are greater in the hour ahead; and
  - ✓ There were almost no transactions unscheduled for reasons other than the economics in New York.



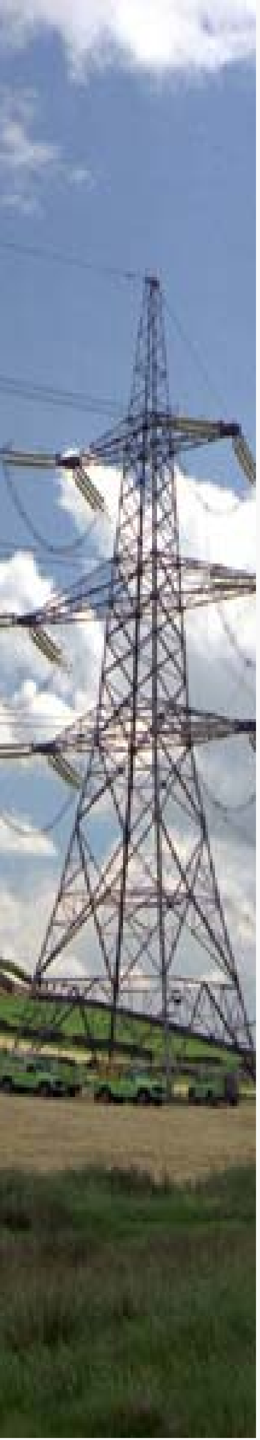
## Transaction Offers and Schedules Across the PJM Interface
## 2002



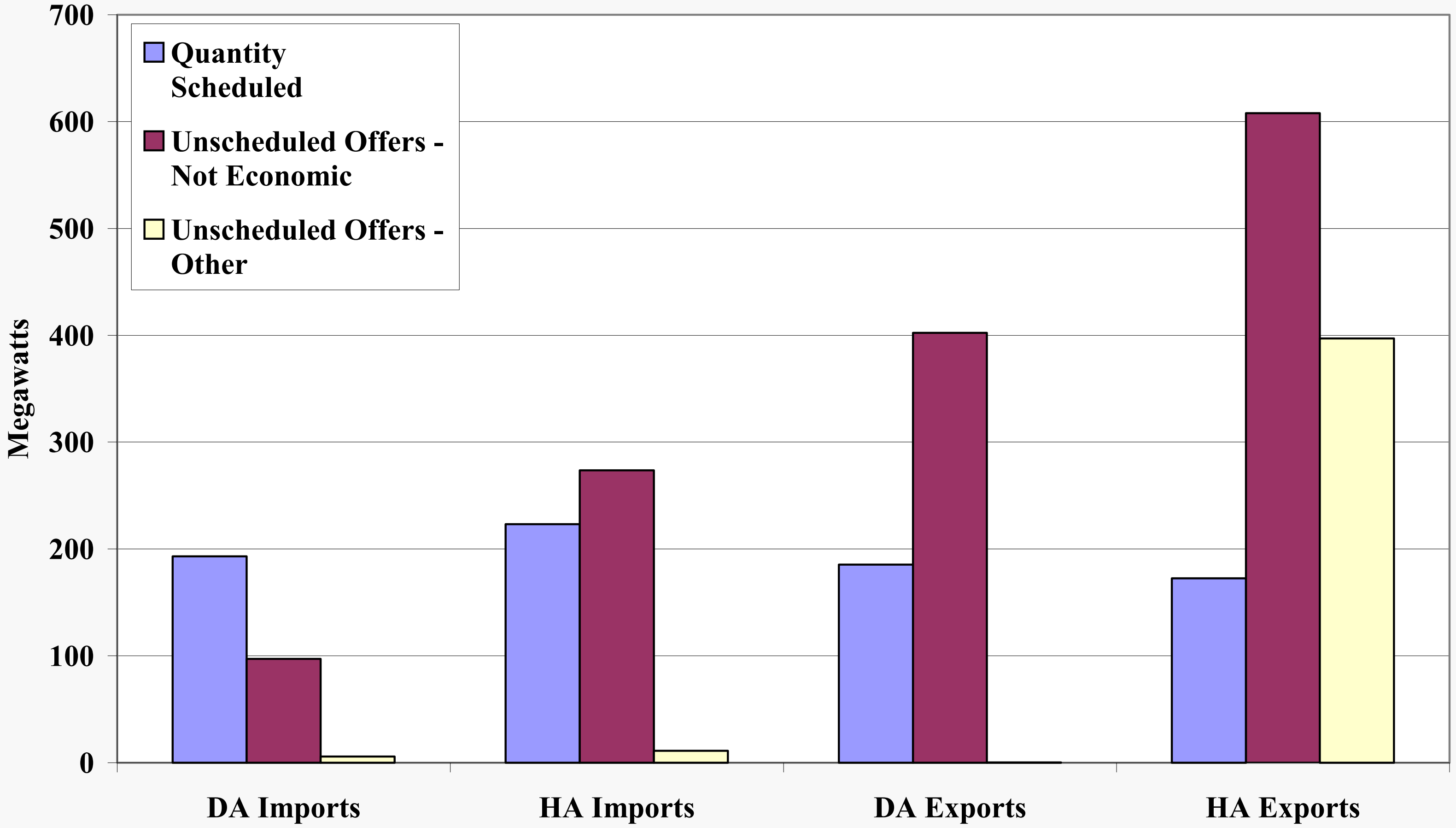


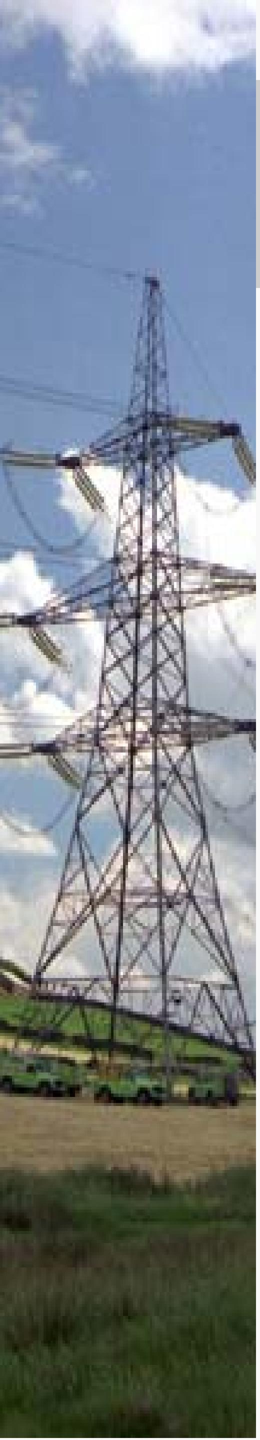
# NYISO Scheduling of External Transactions

- The following figure for New York and New England shows:
  - ✓ Average day ahead imports and exports are virtually the same – i.e., New York is not predictably a net importer or exporter in the day ahead;
  - ✓ In real time, New York's average imports rise and exports decrease by small amounts, making New York a modest net importer on average;
  - ✓ More exports are unscheduled than imports, with the largest share of unscheduled transactions being hour-ahead exports (averaging more than 1000 MW); and
  - ✓ Transactions unscheduled for reasons other than the economics in New York are virtually zero, with the exception of hour ahead exports (averaging 400 MW).



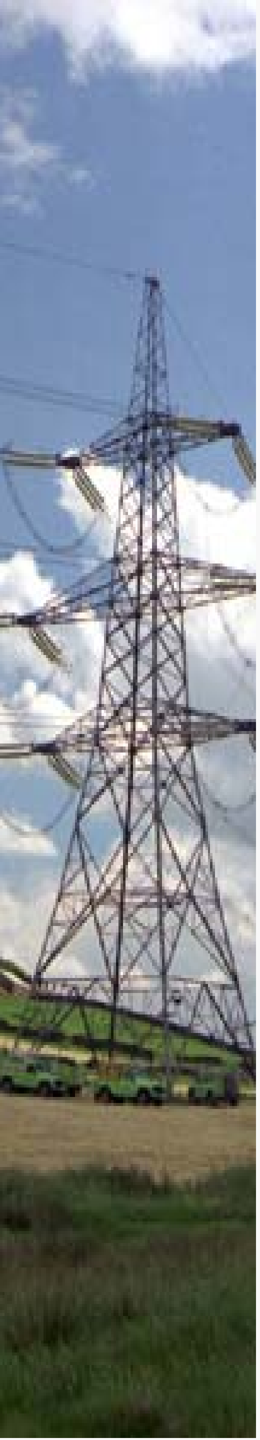
## Transaction Offers and Schedules Across the New England Interface
### 2002



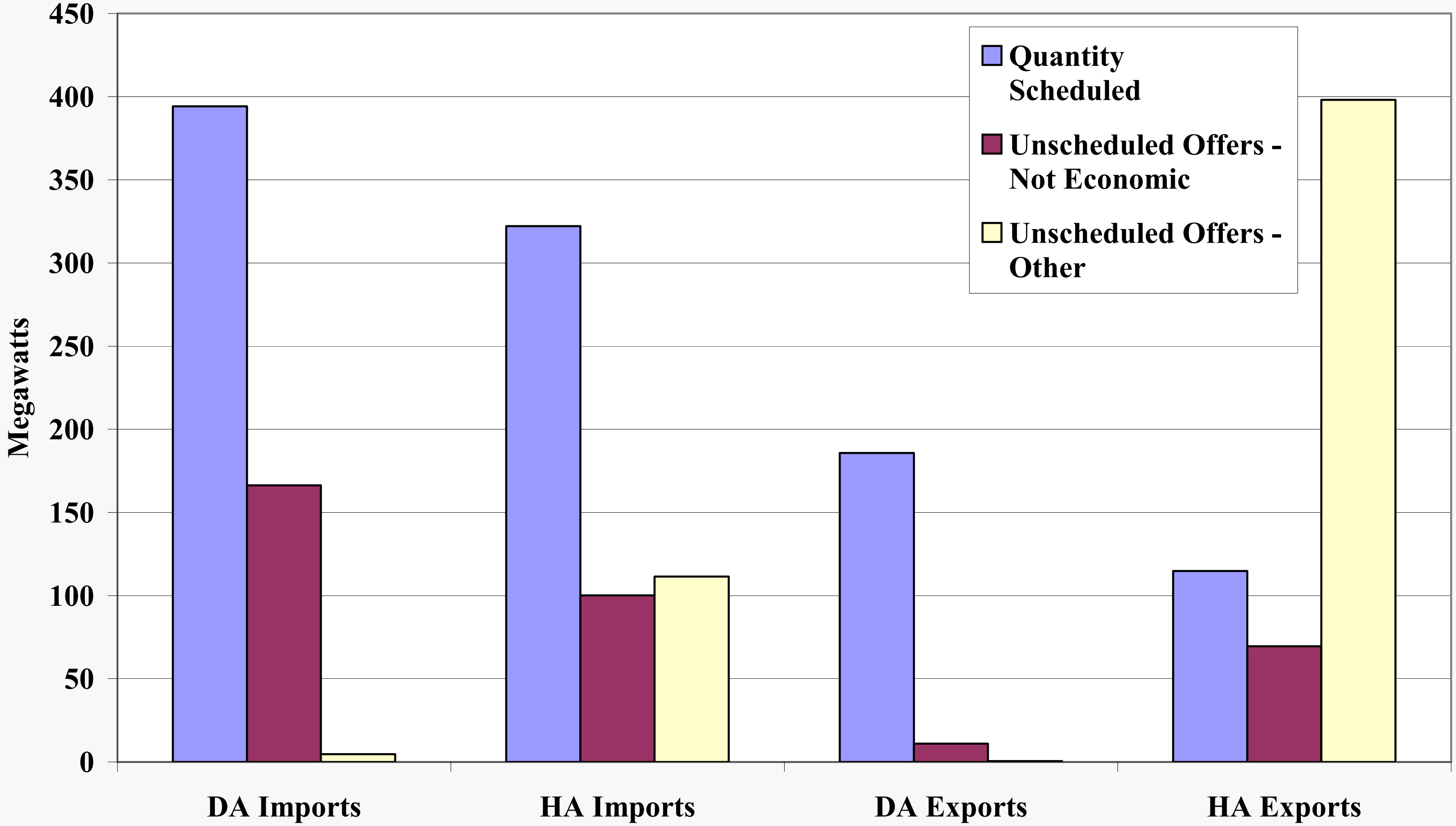


# NYISO Scheduling of External Transactions

- The figure for New York and Ontario shows:
  - ✓ New York is a clear net importer from Ontario in the day ahead and real time; and
  - ✓ Nearly two-thirds the unscheduled transactions are unscheduled in the hour ahead for reasons other than economics (averaging more than 500 MW of transactions).
- Transactions unscheduled for reasons other reasons:
  - ✓ Are generally transactions that are accepted in New York, but rejected in an adjacent market's economic evaluation performed by an adjacent market; and
  - ✓ Can be a concern because these transactions can occupy scarce transmission capability and cause the interface to be underutilized.
- Coordinating the interchange with adjacent market areas would eliminate this under-utilized capacity when the interface is constrained in the BME.

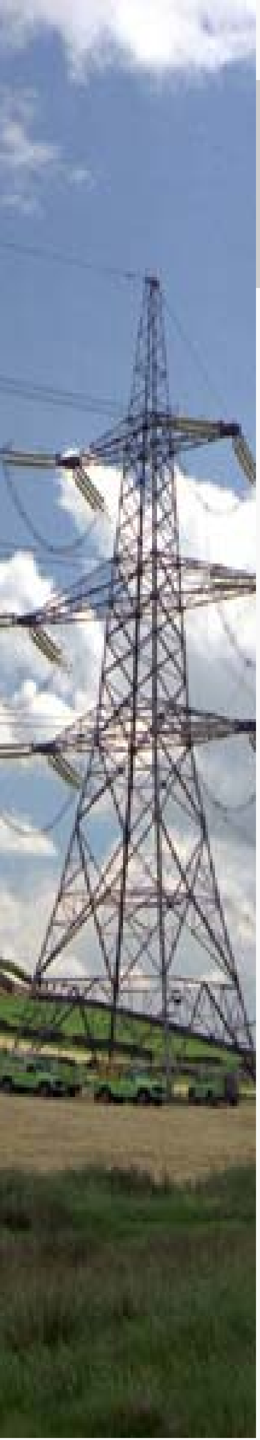


**Transaction Offers and Schedules Across the Ontario Interface**
**2002**



# External Transaction Recommendations

- Improvements have been made to address the seams issues, but further improvements are needed.
- To address these issues, I have recommended:
  - ✓ The New York ISO and the adjacent ISOs coordinate their physical interchange by automatically adjusting it in small increments every 5 to 15 minutes based on the prices at the interface between the two markets;
  - ✓ These adjustments should continue until the prices equalize or until the interface constraint is binding;
  - ✓ The adjustments would be incremental to the transactions scheduled by the participants in the day-ahead or prior to real-time;
  - ✓ Congestion revenue will be collected when the interface is constrained – a transmission right (CRR) could be created to receive these revenues; and
  - ✓ Although not necessary, I would recommend eliminating the export fees. The interface congestion revenue (or CRR auction revenue) would provide an offset for this revenue.



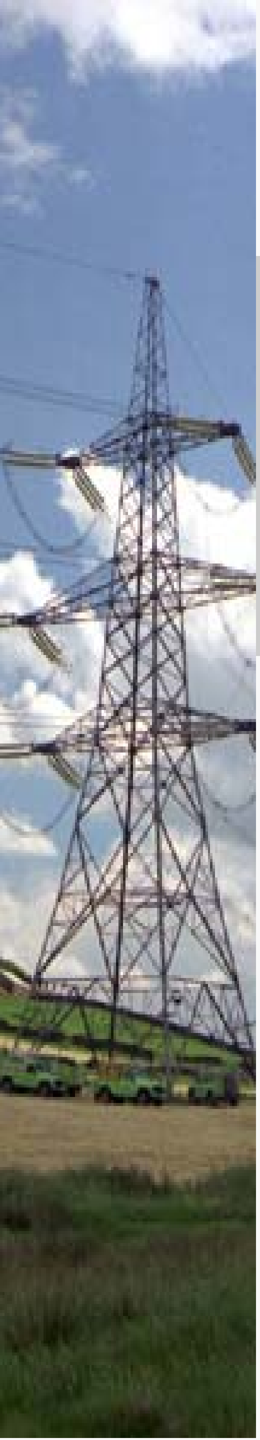
# Coordinated Interchange Recommendation

**This does not mean that the ISOs will be taking positions in the market**

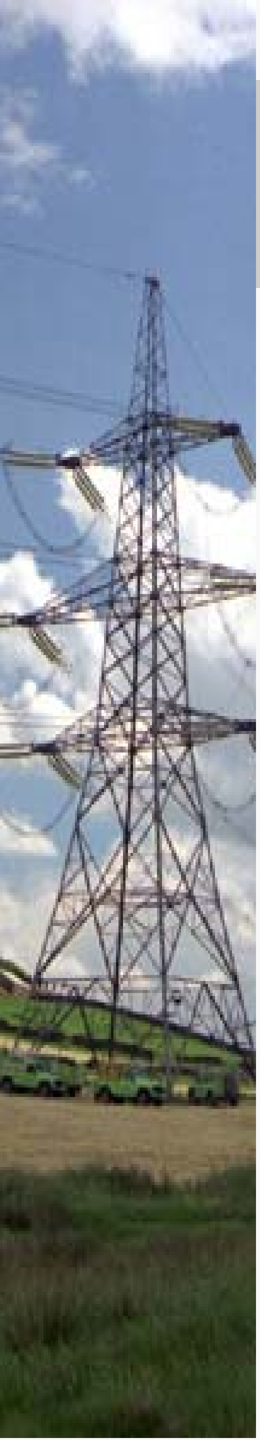
- Allowing the ISOs to dispatch the seam is analogous the ISO's dispatch of internal generation to manage flows on internal interfaces – the physical flow would be determined entirely by the load and generator bids in the two regions.
- Coordinating the dispatch would be similar to and capture most of the benefits of a single dispatch in the Northeast.
- The scheduling changes would actually <u>reduce</u> the ISOs' participation in the market.
  - ✓ The ISOs schedule imports and exports more than an hour prior to the market.
  - ✓ If these schedules turn out to be uneconomic, the ISO must pay the supplier its bid price, uplifting the costs of the uneconomic purchase to loads.

**The proposed changes should improve participant's ability to transact:**

- To the extent that prices are rationalized between markets, the financial risk participants face will be reduced.
- If CRRs are created for the interface, participants will have the ability to engage in completely hedged financial transactions throughout the Northeast.

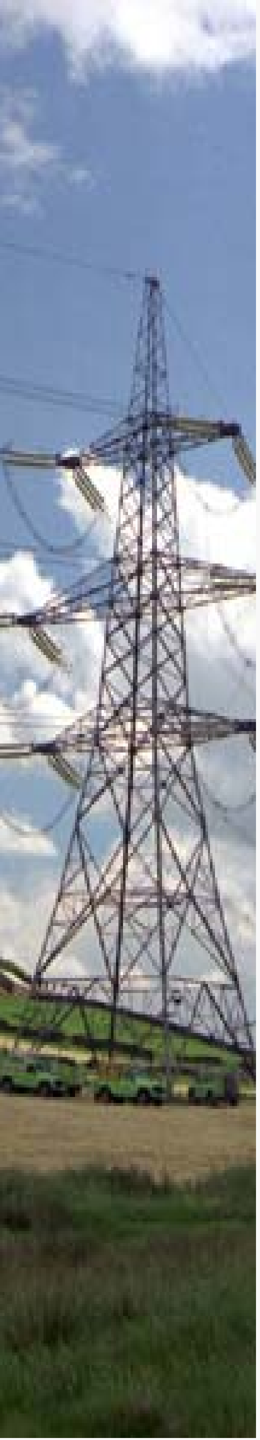


# Capacity Market



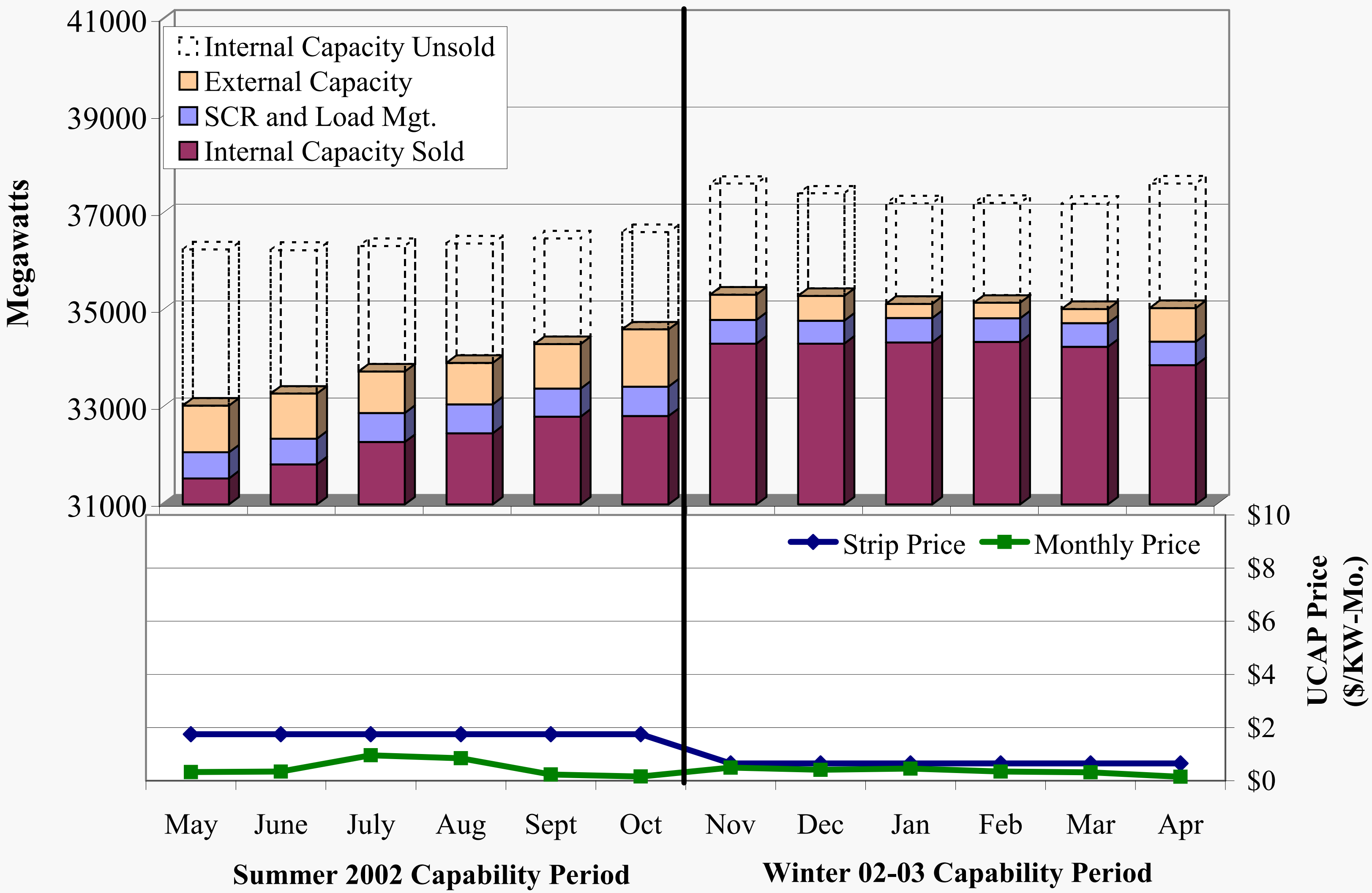
# Capacity Market – New York State

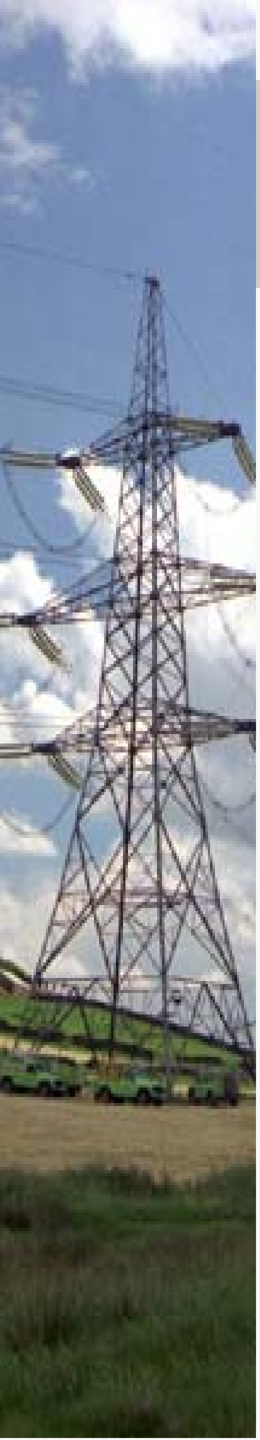
- The capacity market is intended to provide efficient economic signals for investment and retirement decisions for capacity in New York.
- The following figure shows the scheduled capacity amounts and the capacity prices for resources outside New York City and Long Island.
- The amounts include capacity quantities sold outside of New York State – i.e., unsold amounts were not sold within or outside of New York.
- Both the strip prices and monthly prices have remained very low, consistent with the surplus that exists statewide.
  - ✓ Because the marginal cost of supplying capacity is very low, a significant surplus should cause the prices to clear at comparably low levels.
  - ✓ The statewide capacity prices are consistent with these expectations.
  - ✓ Improving this market dynamic is the intent of the capacity demand curve that is pending at FERC.
- The figure shows that capacity scheduled increase through the summer capability period as increasing quantities were exported to serve adjacent capacity markets.
- Lastly, the figure shows that the quantity sold in the summer was less than in the winter.  This was due to an unforced capacity translation error discussed below.



## Unforced Capacity Market - New York State

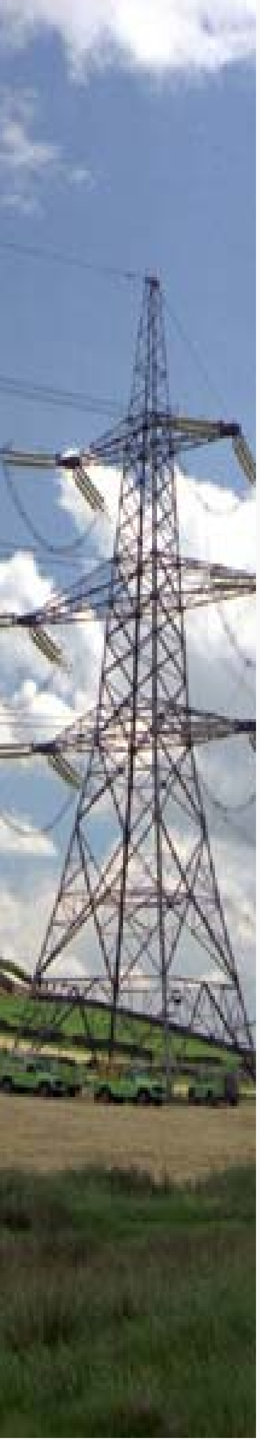
May 2002 to April 2003





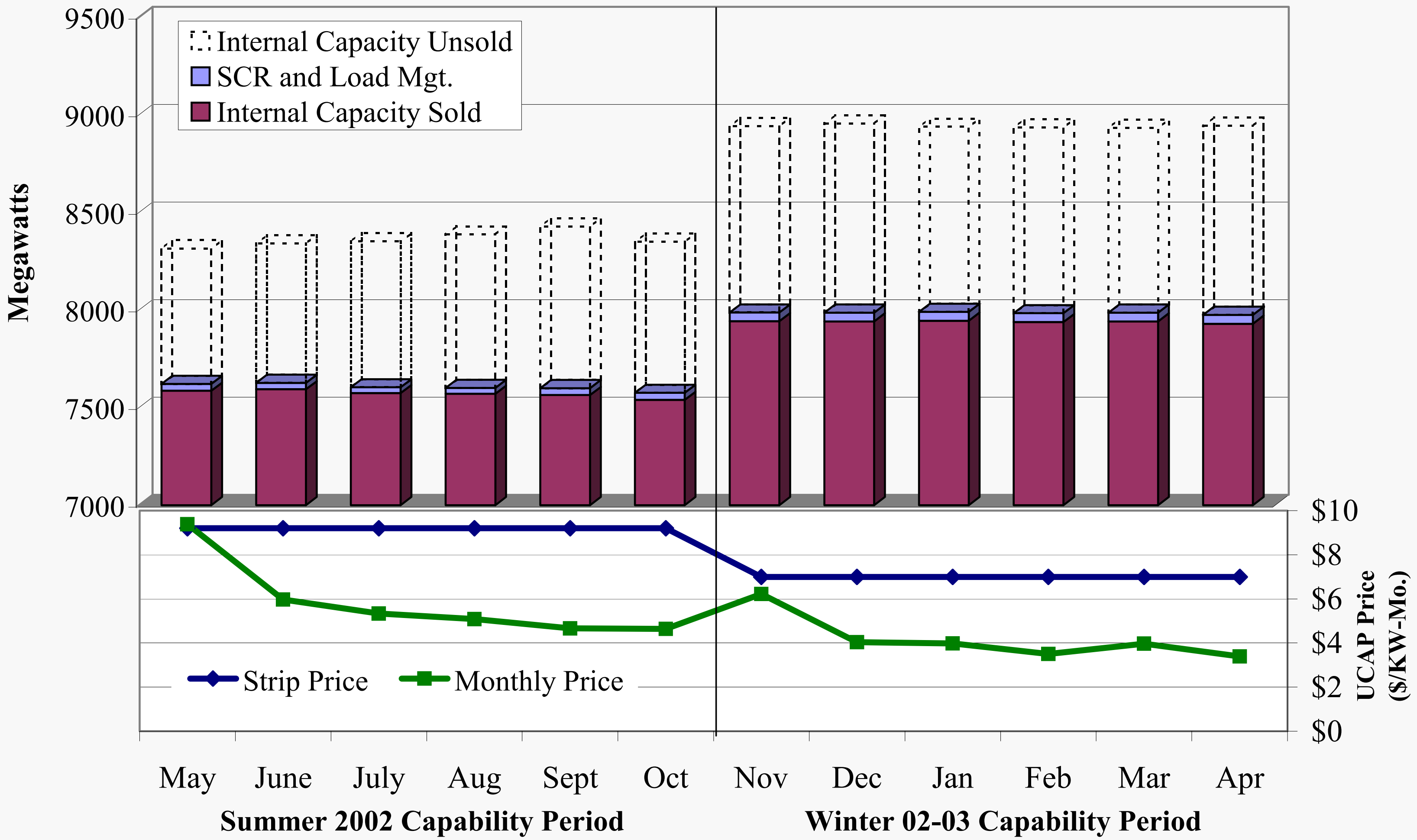
# Capacity Market – New York City

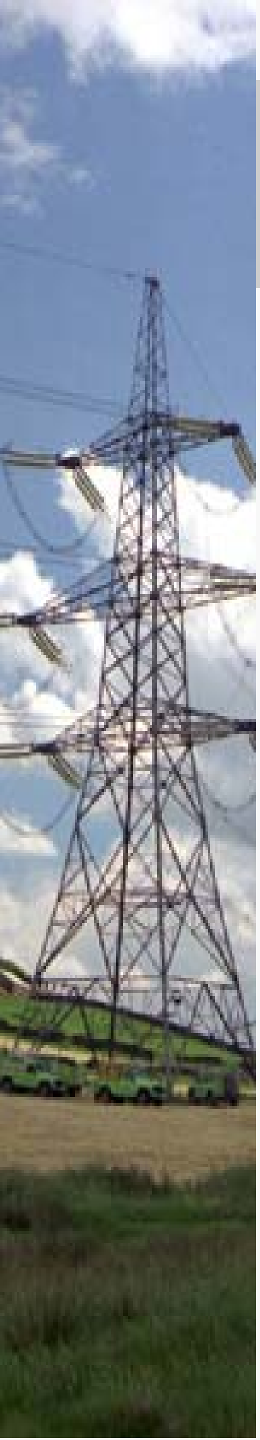
- The following figure show the capacity prices and amounts designated in New York City (not limited to amounts sold to meet the NYC requirement).
- The figure shows that, in total, 500 to 600 megawatts of additional capacity were available in the winter capability period due primarily to seasonal changes in the DMNC values.
- Like the statewide figure, this figure shows that there was substantial surplus, particularly in the Winter capability period. In competitive capacity markets (e.g., statewide) the price should decrease sharply when there is a surplus.
  - ✓ The figure shows that prices in New York City were not consistent with competitive expectations.
  - ✓ These results are attributable to the higher concentration of supply available to meet the capacity requirement within New York City.
- Market power associated with meeting the locational capacity requirements has been addressed by a price cap on capacity sold by the owners of the divested generation within New York City.
  - ✓ However, the capacity demand curve proposal pending at FERC will improve the incentives of capacity suppliers within the city.



**Unforced Capacity Market - New York City**

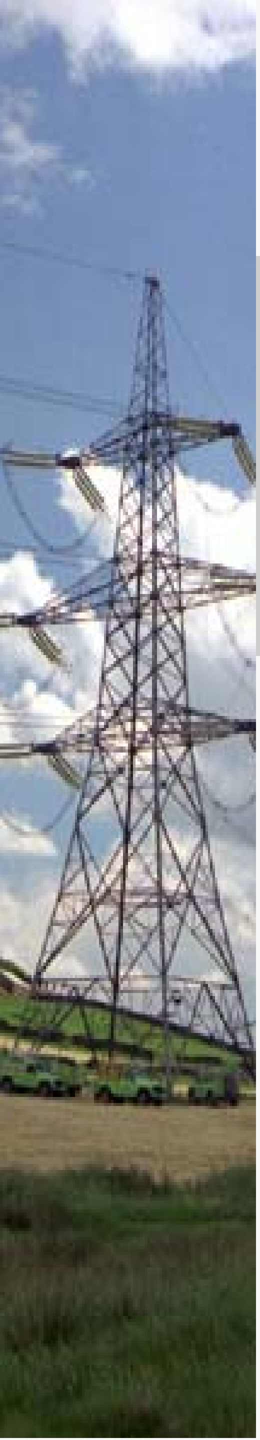
**May 2002 to April 2003**



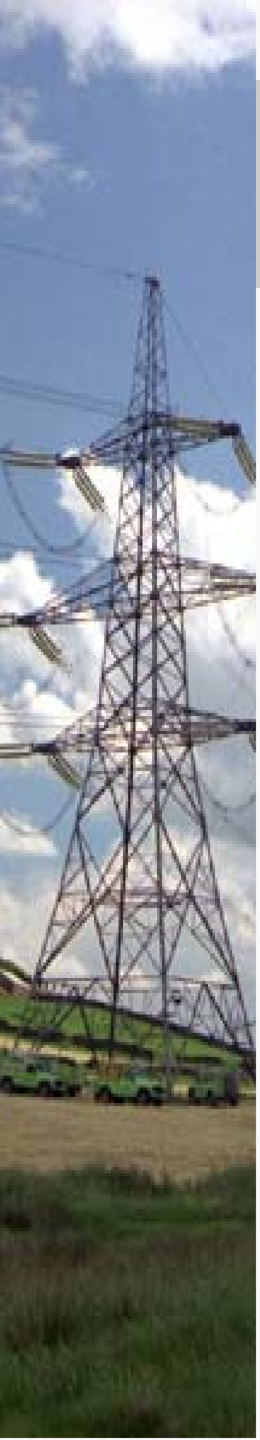


# Capacity Market – Other Issues

- The figures above also show that the quantities sold by resources sold in the summer were substantially lower than in the winter.
- This difference is primarily due to an inconsistency in translating the installed capability requirements to the unforced capacity measure implemented in the summer 2002 capability period (and corrected prior to the winter period).
- The inconsistency pertained to the forced outage probability used to translate the UCAP capability and requirement amounts.
  - ✓ UCAP is a capacity measure that explicitly accounts for forced outages.
  - ✓ A long-term average forced outage probability was used to translate the installed capability requirement to a UCAP requirement while units' short-term actual forced outage rates were used to translate the UCAP capability.
  - ✓ The long-term average forced outage rate was roughly twice the short-term rate.
  - ✓ This resulted in the NYISO procuring fewer capacity resources during the summer capability period and, hence, in a larger capacity surplus in the period.
- With this correction made and given additional load growth over the past year, New York City is projected to have virtually no suplus in the summer 2003 capability period.

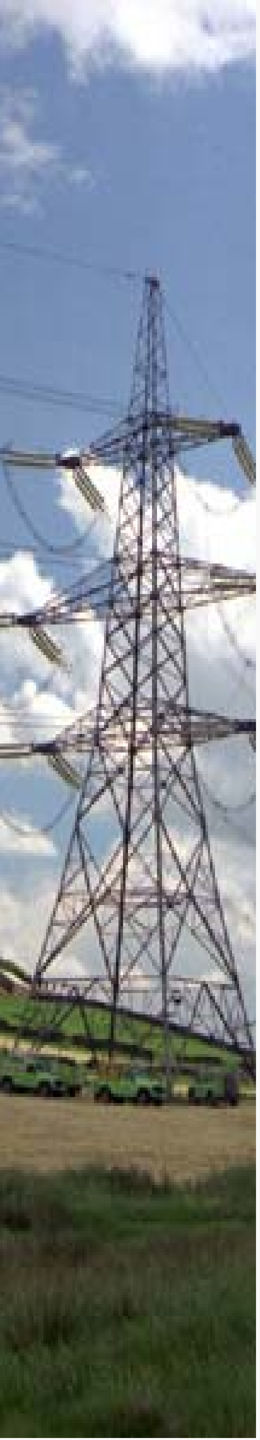


# Ancillary Services Markets

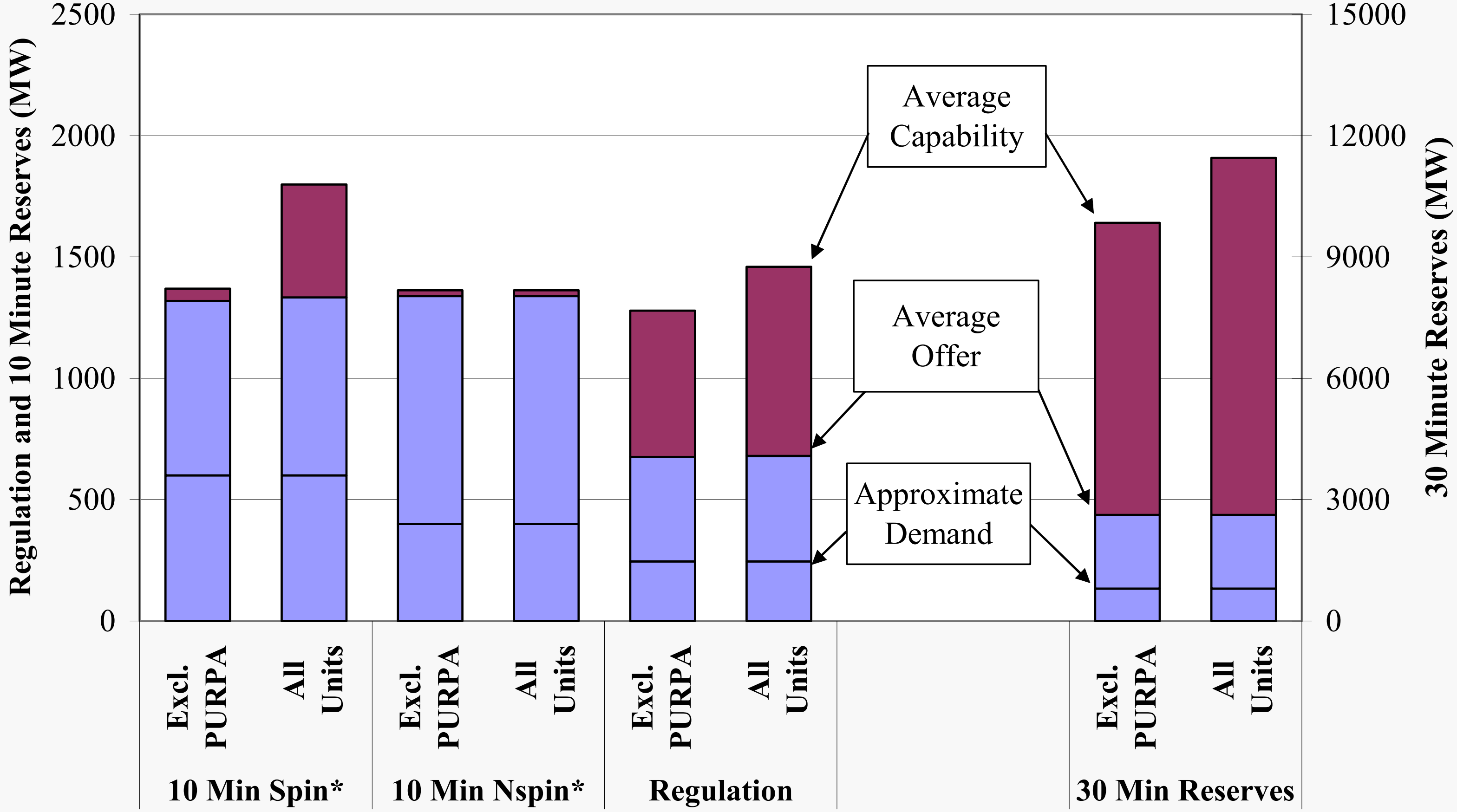


# Ancillary Services

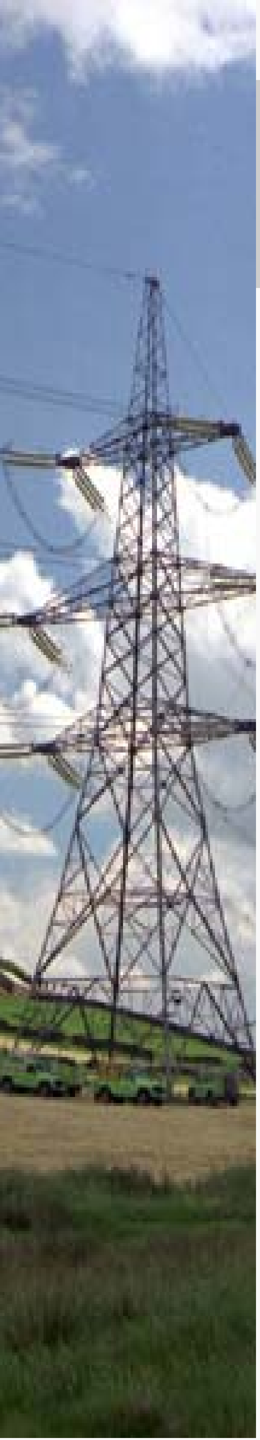
- Ancillary services markets are generally not tight because offers to supply typically exceed approximate demand:
  - ✓ For 30 minute reserves, offers typically exceed approximate demand by 220 percent.
  - ✓ For total 10-minute reserves east of the Central-East interface, offers typically exceed approximate demand by 160 percent -- although this market for 10-minute non-spinning reserves is currently subject to a requirement to sell and a bid cap.
  - ✓ For  regulation and 10 minute spinning reserves, offers typically exceed approximate demand by 90 to 100 percent – but ignores the fact that some 10 minute spinning reserves can be purchased in the West.
- However, 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

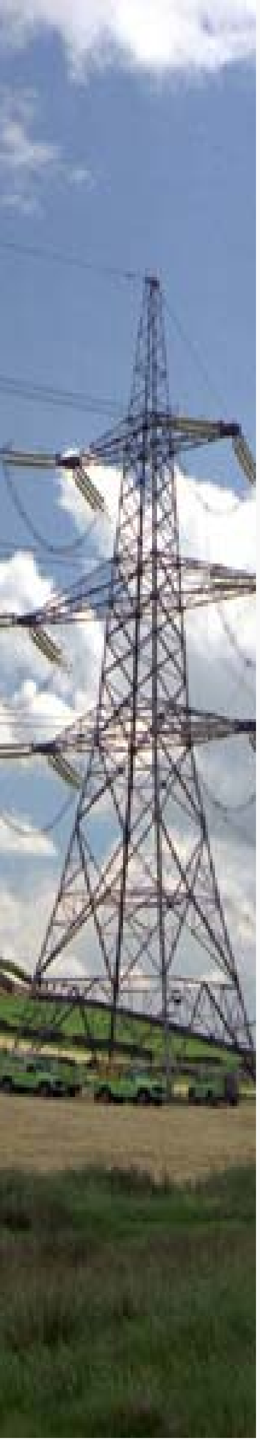



*Eastern side of the Central-East Interface Only.

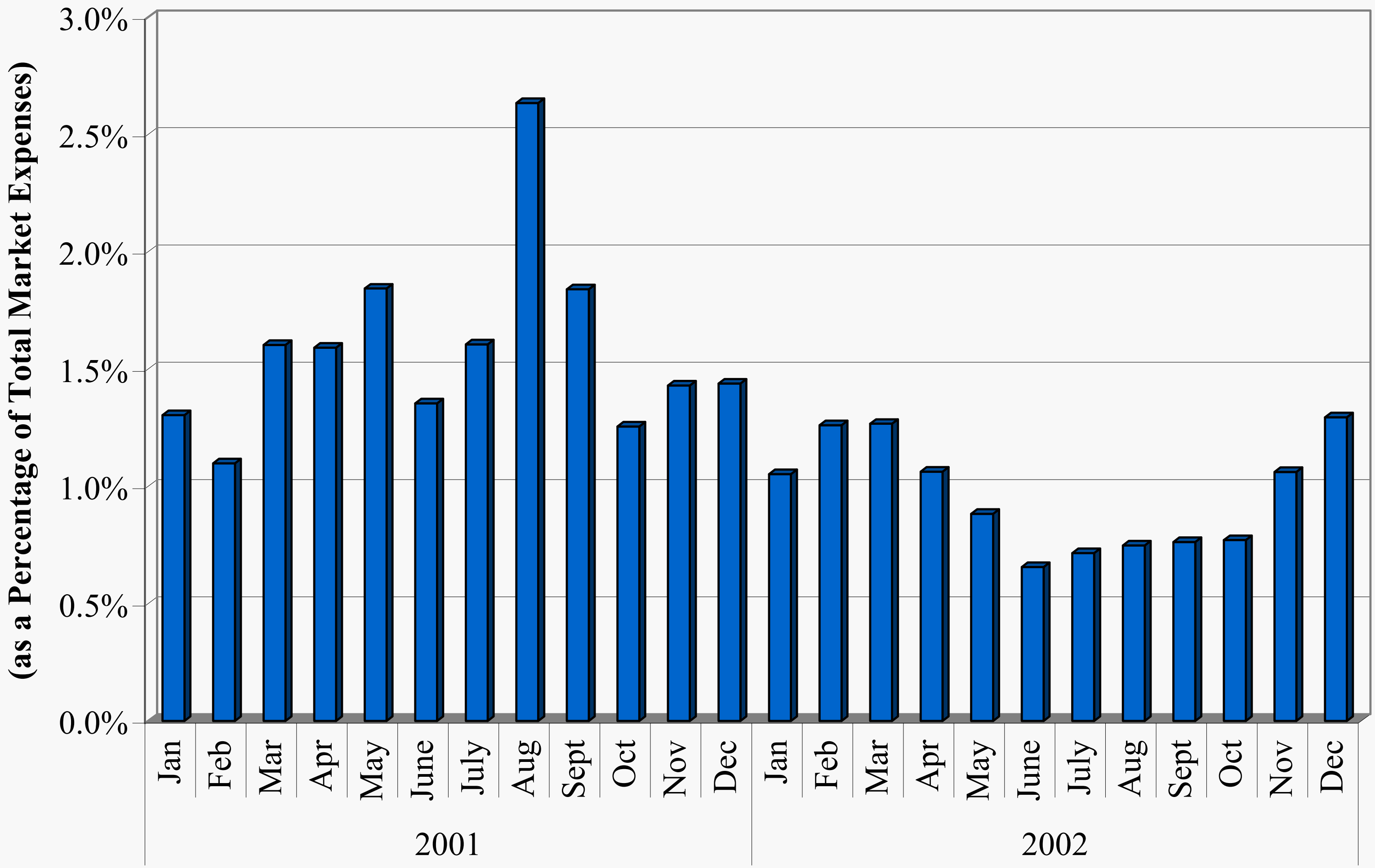


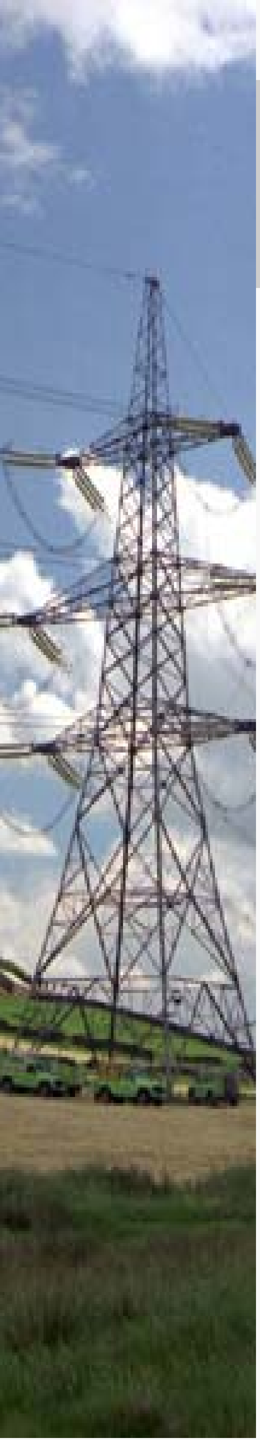
# Ancillary Services

- 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 lower in 2002 than in 2001 for several reasons:
  - ✓ Following a reserves-sharing agreement with ISO-New England, the NYISO was able to lower the 10-minute reserve requirement in East New York from 1200 to 1000 megawatts at the beginning of 2002.
  - ✓ Starting October 1, 2001, the NYISO began posting locational ancillary services prices for: Long Island, East New York (excl. Long Island), and West New York. Prior to this change, resources in Long Island frequently set state-wide ancillary services prices at higher levels that would have prevailed otherwise.
  - ✓ Recognizing latent 30 minute reserves on un-dispatched portions of on-line resources in real time has reduced need to procure additional ancillary services from more costly resources. This change was implemented in the spring of 2002.



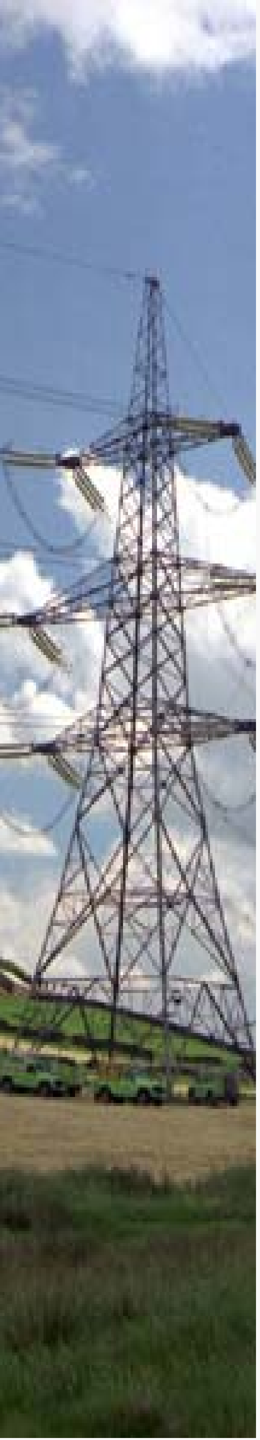
**Expenses for Reserves Procurement**
**2001 & 2002**

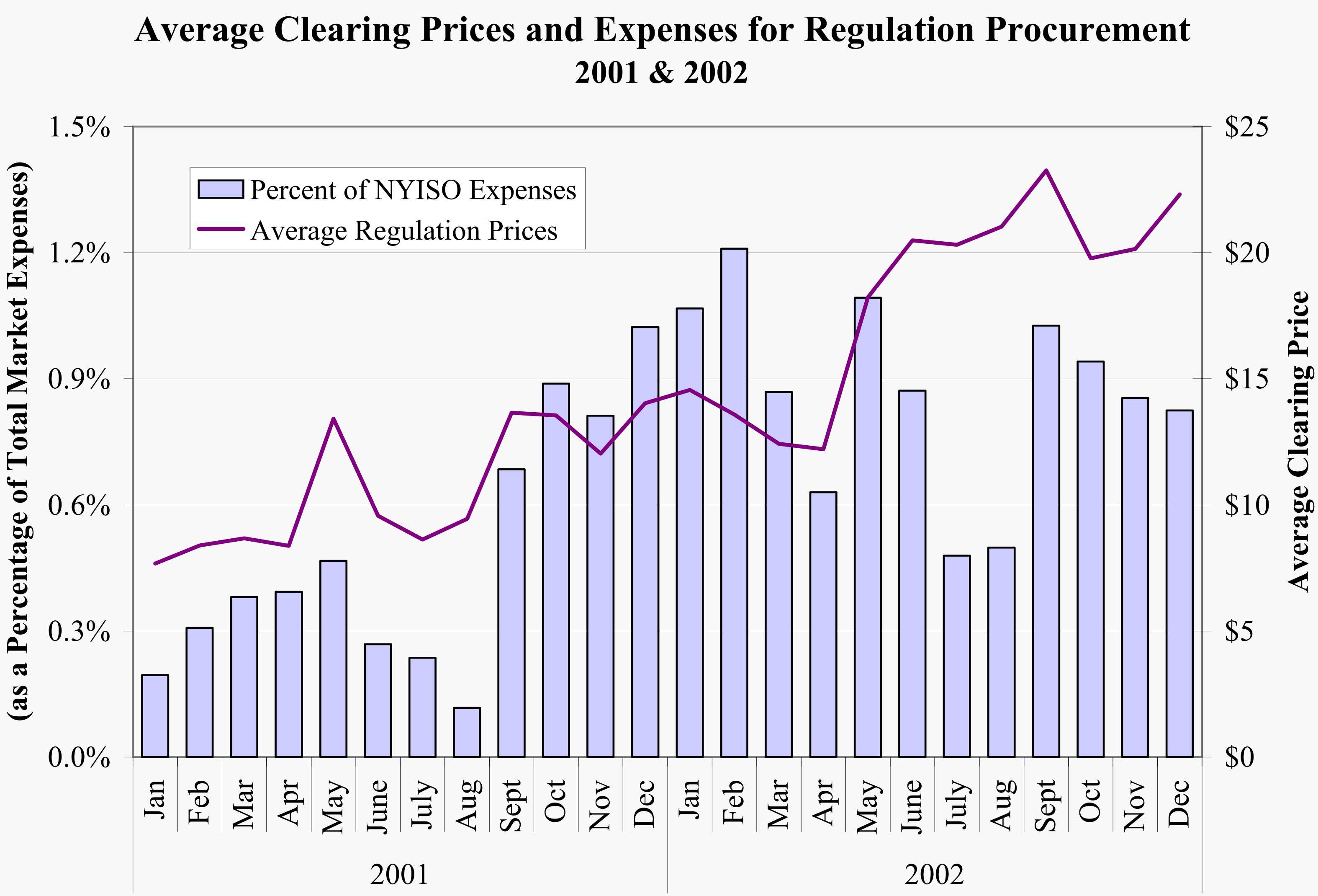


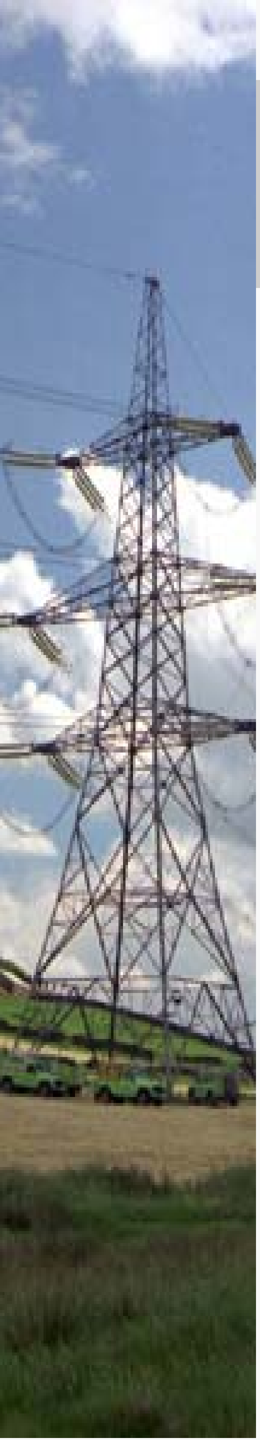


# Ancillary Services

- The following figure shows the average price for regulation service in 2001 and 2002. The figure also shows the share of the total market expenses that are accounted for by regulation.
- Regulation prices have increased considerably over 2001 and 2002. An earlier figure showed that only 25% of the capacity capable of providing regulation is actually bid into the market.
- Regulation costs still remain a relatively small part of the total electricity market expenses for the NYISO (less than 1 percent).
- 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 effectively reduced the supply available on some units, particularly off-peak.
  - ✓ Fuel price increases that increase the opportunity costs of hydro units and others to provide regulation.
  - ✓ Quantities offered have remained relatively steady, but bid prices during off-peak hours have increased modestly.

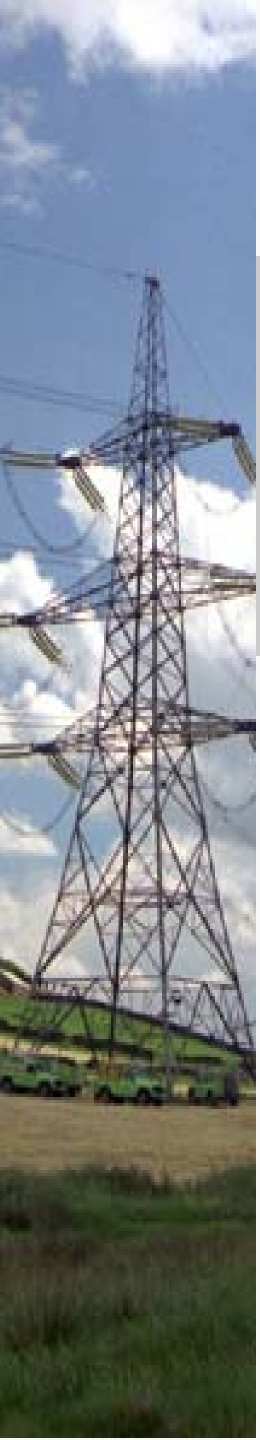



Average Clearing Prices and Expenses for Regulation Procurement
2001 & 2002
Percent of NYISO Expenses
Average Regulation Prices
(as a Percentage of Total Market Expenses)
Average Clearing Price
1.5%
1.2%
0.9%
0.6%
0.3%
0.0%
$25
$20
$15
$10
$5
$0
Jan
Feb
Mar
Apr
May
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
June
July
Aug
Sept
Oct
Nov
Dec
2001
2002

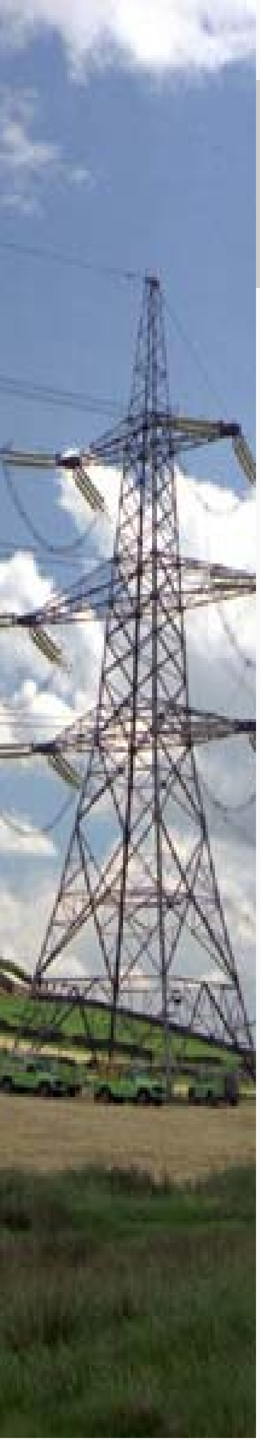


# Ancillary Services Recommendations

- A substantial amount of capability continues to routinely not be offered in the reserve markets, which indicates that the incentives to offer in these markets are inadequate.
- To address this concern, 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 – equal to the highest sum of availability bid and opportunity cost of selling energy; and
  - ✓ Implement multi-settlement markets for reserves and regulation.
  - ✓ These reforms will ensure that a supplier selected for reserves or regulation is, at a minimum, not economically harmed by not being scheduled in the energy market and would improve the accuracy of the price signals for reserves.
- These changes are planned as part of the new Real-Time System (“RTS”) to be implemented in 2004.
- I recommend that the NYISO allocate its available resources to implementing RTS rather than making interim changes to the ancillary services markets.
- Hence, I have no additional recommendations for the ancillary services markets at this time beyond implementing RTS.

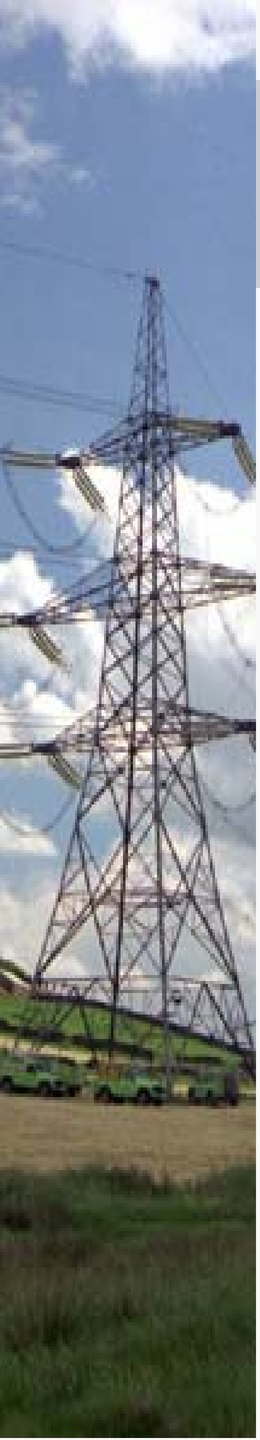


# Demand Response Programs



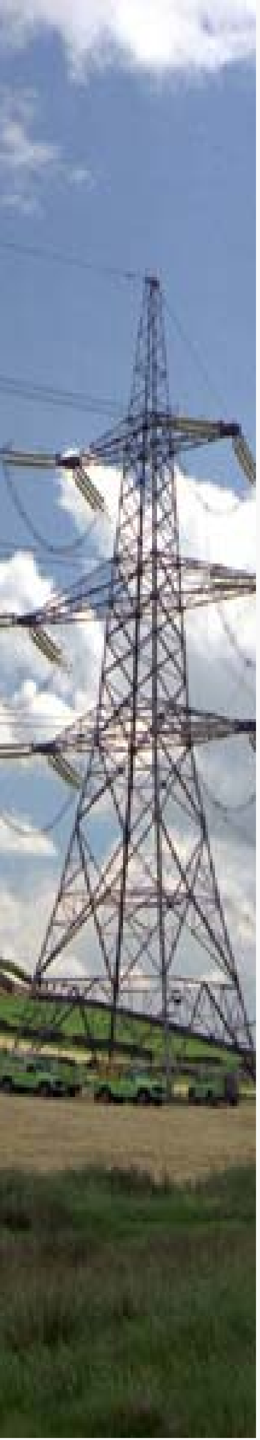
# Demand Response Programs

- The New York ISO has some of the most effective demand response programs in the country at achieving actual reductions of load in real time.
- There are currently three demand response programs in New York State:
  - ✓ Day-Ahead Demand Response Program (DADRP) – This program schedules physical demand reductions for the following day, allowing resources to bid 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. EDRP resources that do not curtail are not penalized.
- The EDRP program achieves the largest reductions. The payments made under this program are designed to overcome the fact that most loads do not directly incur the real-time wholesale price and, therefore, lack the incentive to reduce consumption when prices rise sharply.

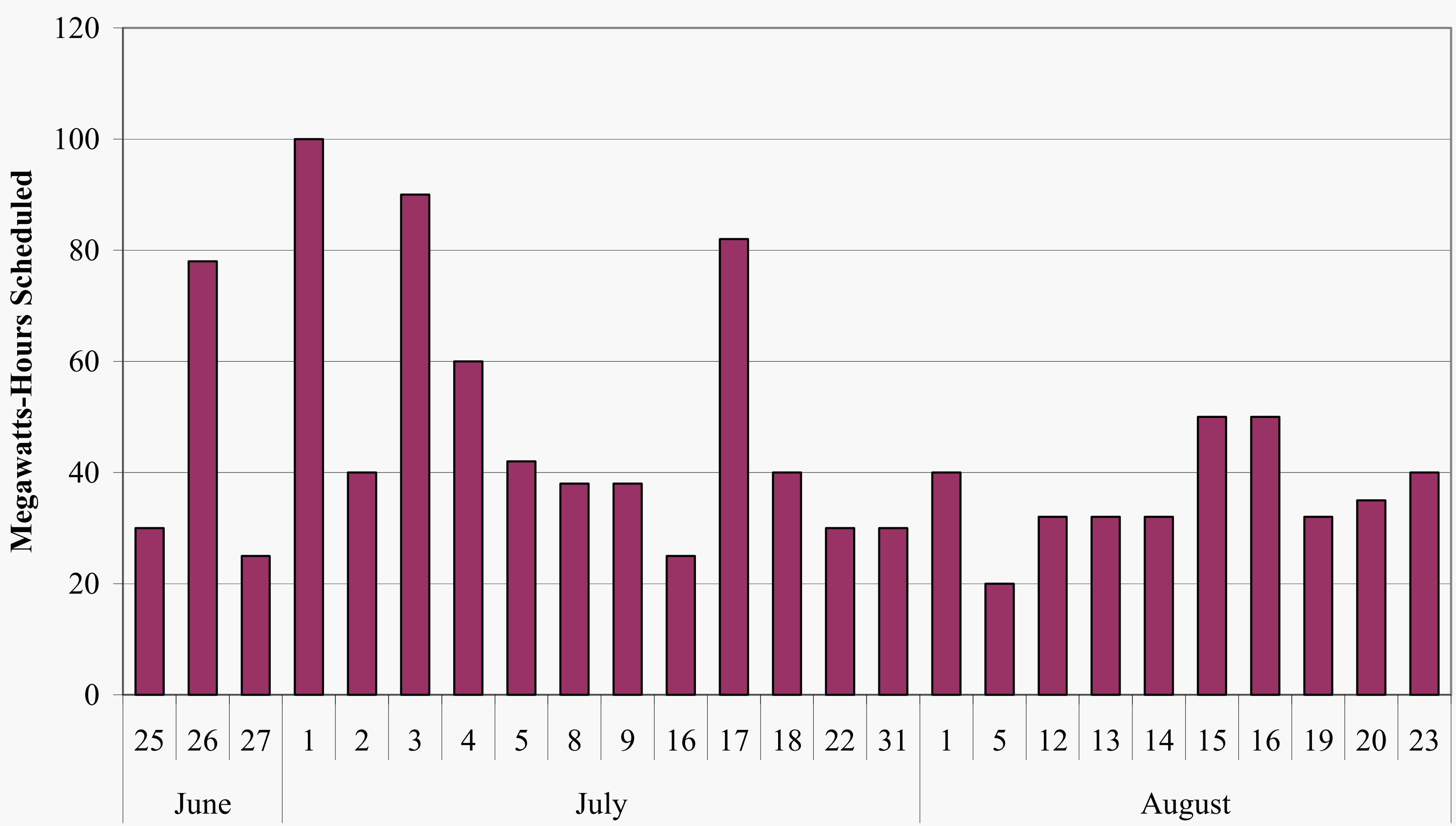


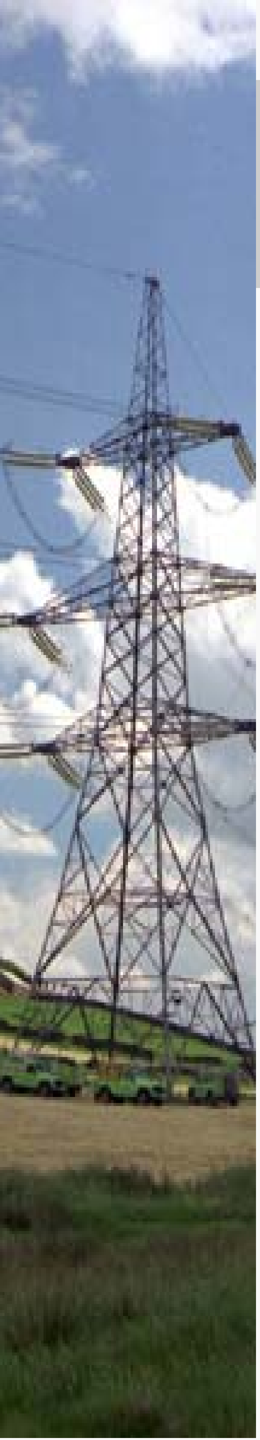
# Day-Ahead Demand Response

- Demand can respond to day-ahead prices by deferring its purchases to the real-time by submitting price-capped load bids. Although activity in this area increased considerably in 2002, this does not reduce physical consumption.
- 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:
  - ✓ The following figure shows the total load scheduled to curtail between 12pm and 6pm in the day-ahead market on days with scheduled curtailments greater than 20 MWh during the summer of 2002.
  - ✓ These quantities are very low, averaging less than 10 MW per hour (i.e., less than 60 MWh during the 12pm to 6pm periods)
  - ✓ During the summer of 2002, approximately 85% of scheduled DADRP was bid at the minimum cap of $50/MWh. The average clearing price was $78/MWh.



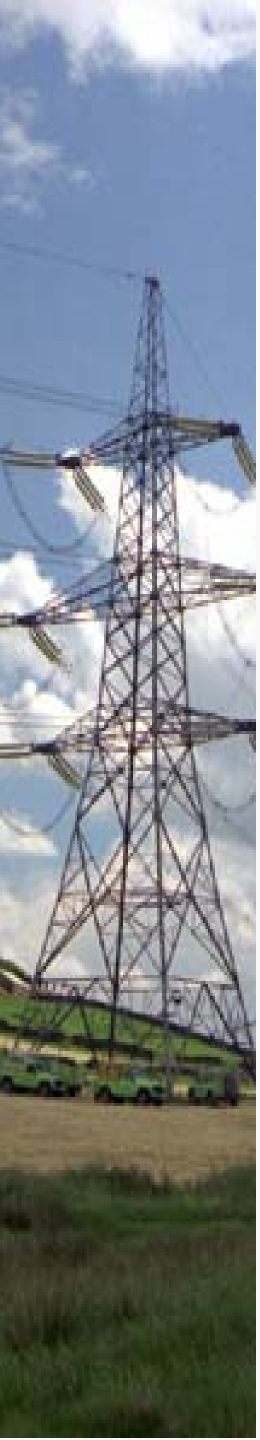
## Day-Ahead Scheduled Demand Response
### Select Days, 12pm to 6pm, All New York State



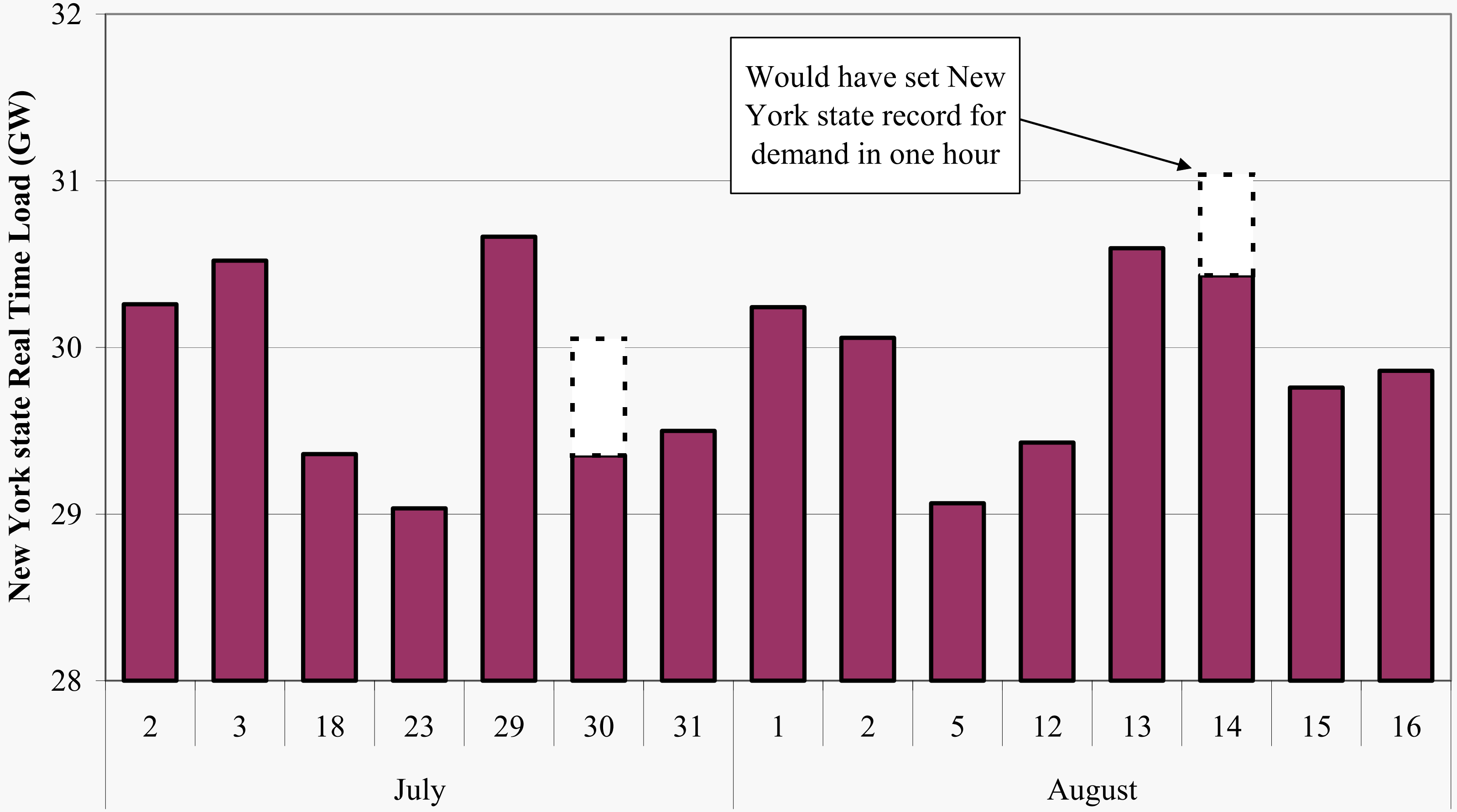


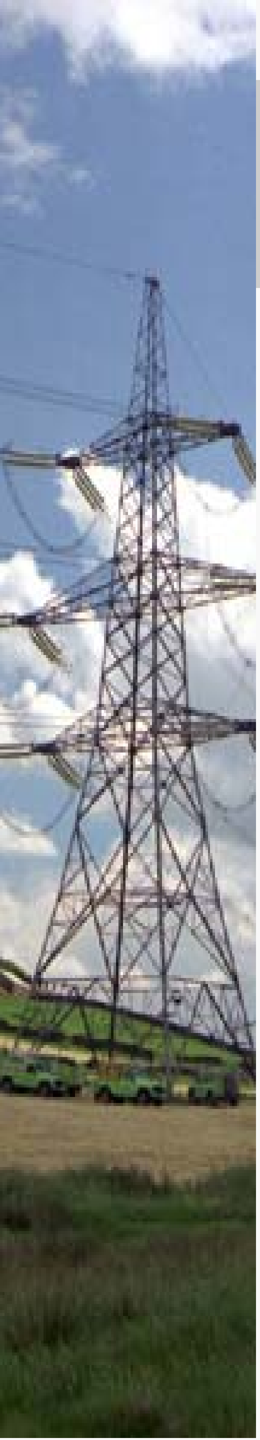
# EDRP and SCR Programs

- EDRP and SCR resources were called state-wide on two days during 2002, July 30th and August 14th.
  - ✓ The NYISO achieved 650 MW of actual demand reduction from the EDRP participants on July 30 and slightly less on August 14th.
  - ✓ Additional demand reductions were achieved from (i) SCRs not participating in the EDRP program, and (ii) utility and state demand reduction programs.
  - ✓ We estimate that close to 1000 MW of actual demand reduction was achieved on July 30th from all sources.
- The following figure shows the peak hour on each of the 15 highest load days in 2002.
  - ✓ The figure shows that without the EDRP response on August 14th, a new peak load record would have been established for New York state.
- Since real-time prices were relatively low on these days, resources that curtailed in real-time were paid $500/MWh.



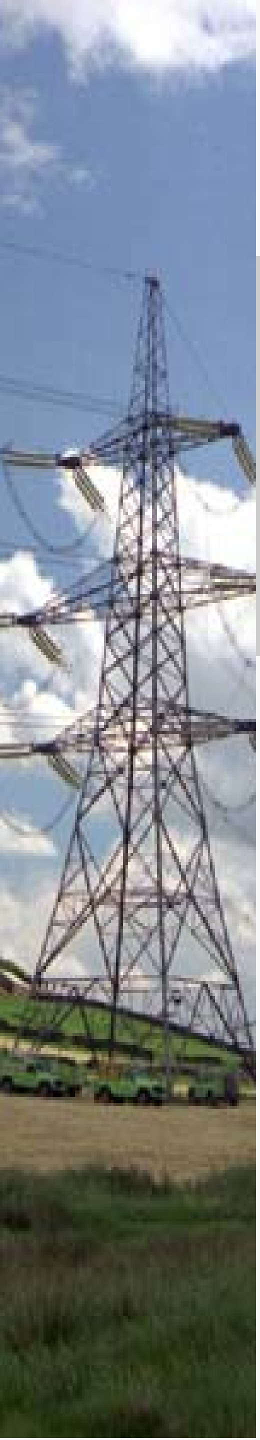
## Emergency Demand Response During Peak Hours
### Peak Hours on 15 Highest Load Days in 2002



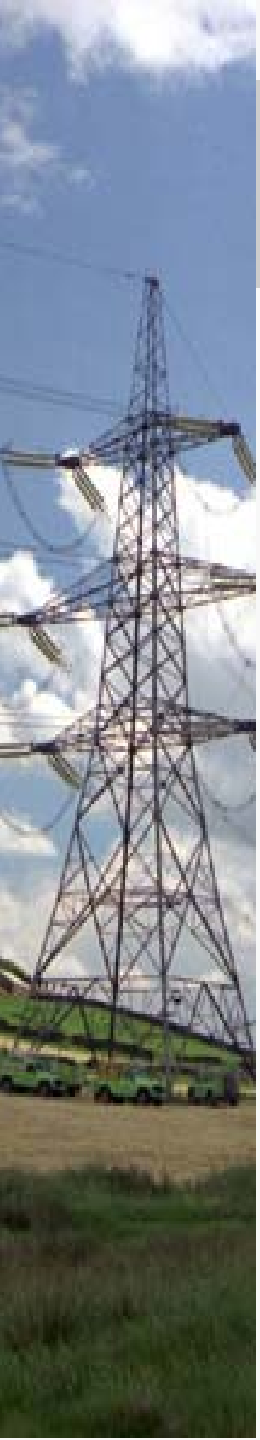


# Demand Response Recommendations

- The NYISO should continue to explore alternatives for making the participation in the demand response programs more flexible and useful, including:
  - ✓ Allowing participants to enter more variable bid prices (or establishing multiple levels of bid floors for the EDRP payments);
  - ✓ Shortening the notification timeframe to reduce the uncertainty regarding the need for the demand response resources;
- I would also recommend that the NYISO explore broadening the applicability of the EDRP approach to peak demand periods beyond clear reliability conditions, including:
  - ✓ Introducing provisions to call the EDRP resources when they are the most economic resources, even when they are not strictly needed for reliability.

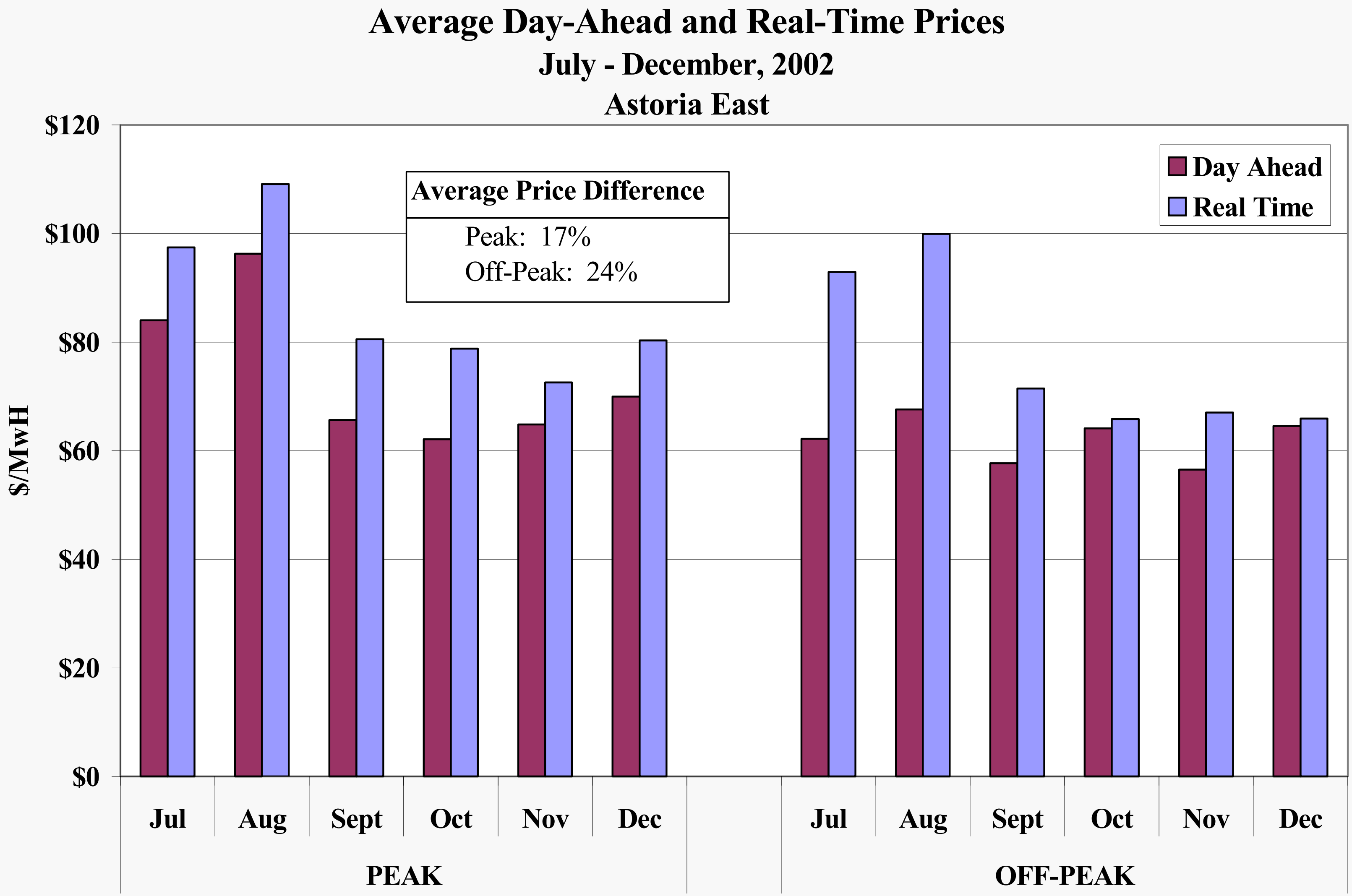


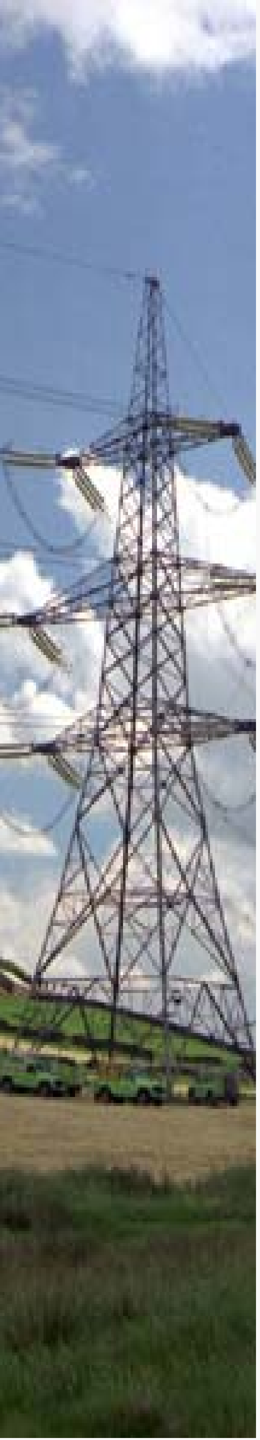
# Appendix

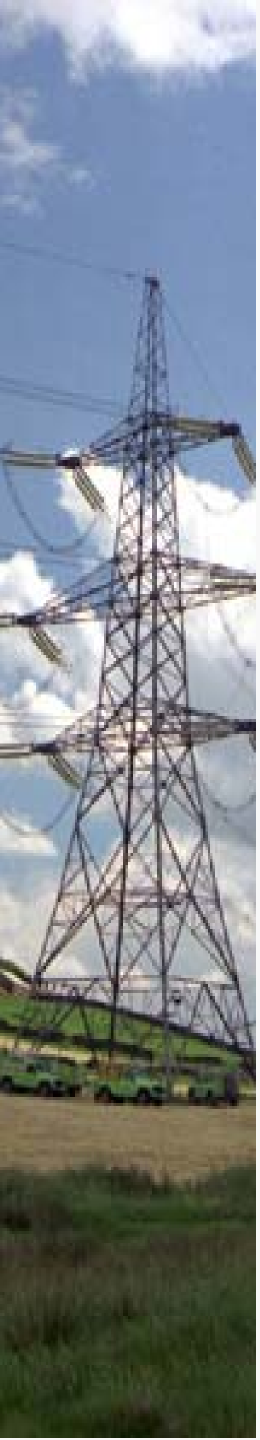


# Price Convergence in Astoria East Load Pocket

- Day-ahead and real-time price convergence has been poor in the Astoria East load pocket, where there seems to be a persistent premium in the real-time market.
- The following figure shows average day-ahead and real-time prices during peak and off-peak periods in the last six months of 2002. Real-time prices have been consistently higher throughout the period.
- The subsequent figure shows average day-ahead schedules and real-time dispatch points. The lack of price convergence in this pocket is due to persistent under-scheduling day-ahead.
- In this case, virtual trading at the load pocket level would likely result in higher day-ahead schedules and more adequate resource commitment in Astoria East. This, in turn, would be very helpful in ensuring that day-ahead and real-time prices converge properly.


Average Day-Ahead and Real-Time Prices
July - December, 2002
Astoria East
$/MwH
$120
$100
$80
$60
$40
$20
$0
Average Price Difference
Peak: 17%
Off-Peak: 24%
Day Ahead
Real Time
Jul
Aug
Sept
Oct
Nov
Dec
PEAK
OFF-PEAK

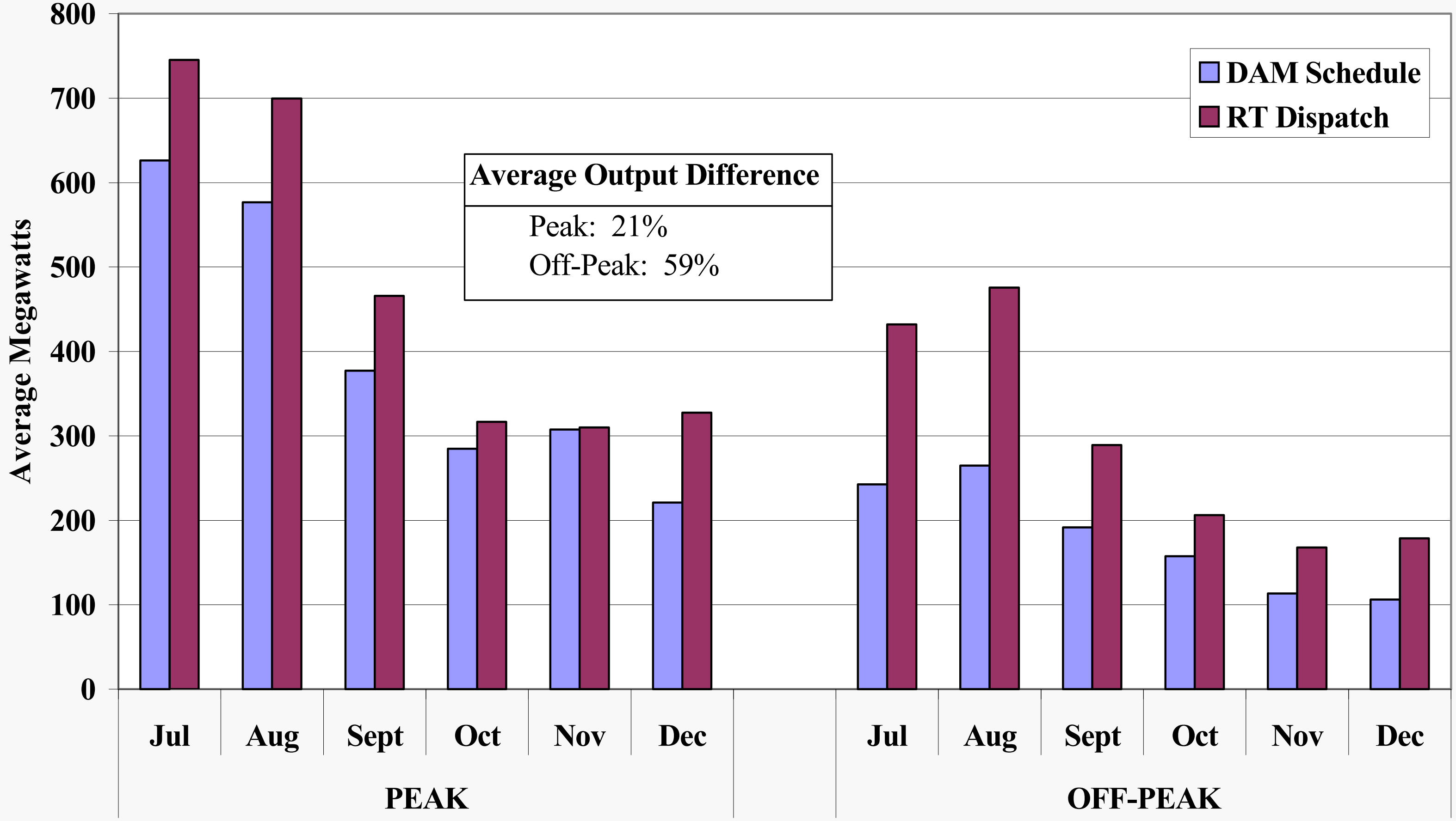


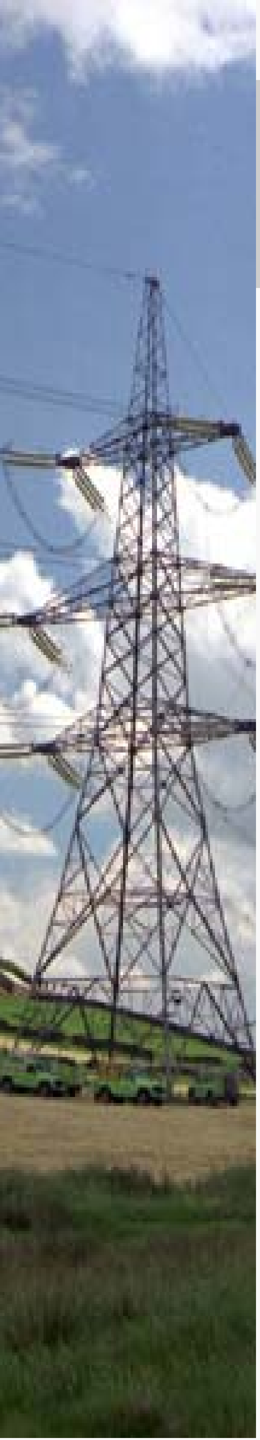


## Average Day-Ahead Schedules and Real-Time Output

### Astoria East LP -- July to December, 2002

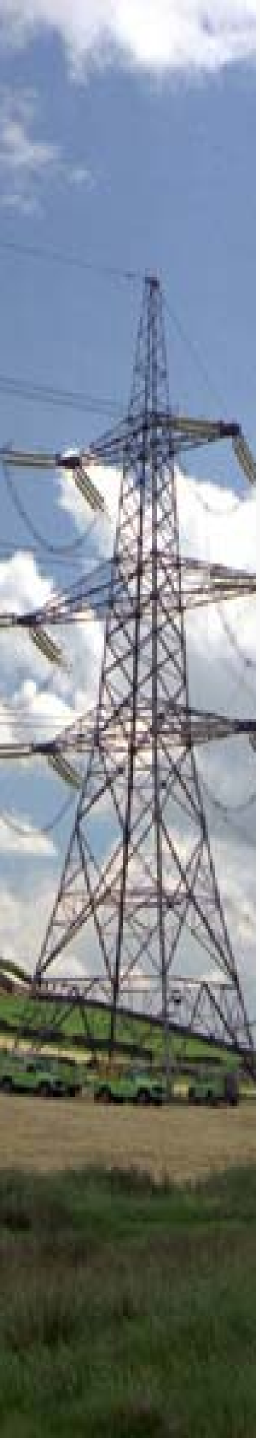
### Hours Unit is Available Day-Ahead and Real-Time





# Hour-Ahead and Real-Time Prices

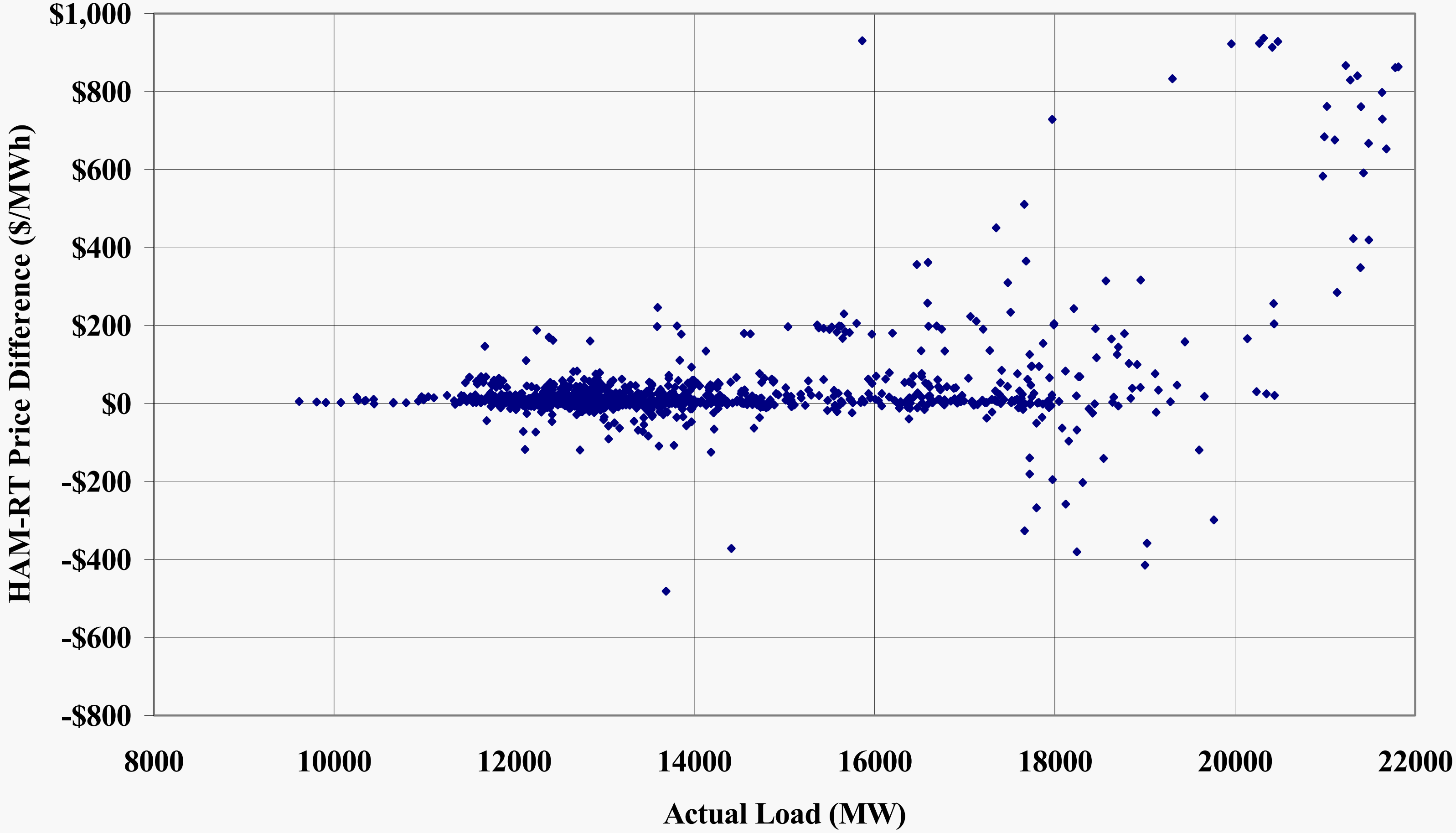
- The following four figures show remarkable improvement in the price convergence from 2001 to 2002 in a wider range of hours due to these changes.
- Better convergence has resulted in more efficient scheduling of non-dispatchable resources and external transactions.
  - ✓ In eastern New York, the primary source of inefficiently scheduled resources is the interface with New England.  Inflated BME prices cause high-priced imports to be scheduled and crowd-out dispatchable capacity, thereby depressing real-time prices and generating uplift payments.
  - ✓ In New York City, the primary source of inefficiently scheduled resources is 30-minute gas turbines.  Inflated BME prices cause these peaking units to be brought on and crowd-out dispatchable peaking units, thereby depressing real-time prices and generating uplift payments.

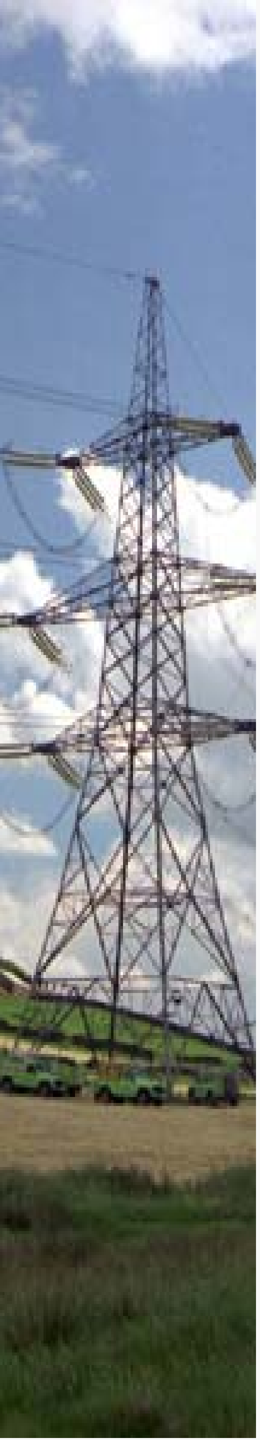


## Relationship of Price Differences to Actual Load

### Hour Ahead Prices Minus Real Time Prices

### East New York -- 2001, Peak Hours*

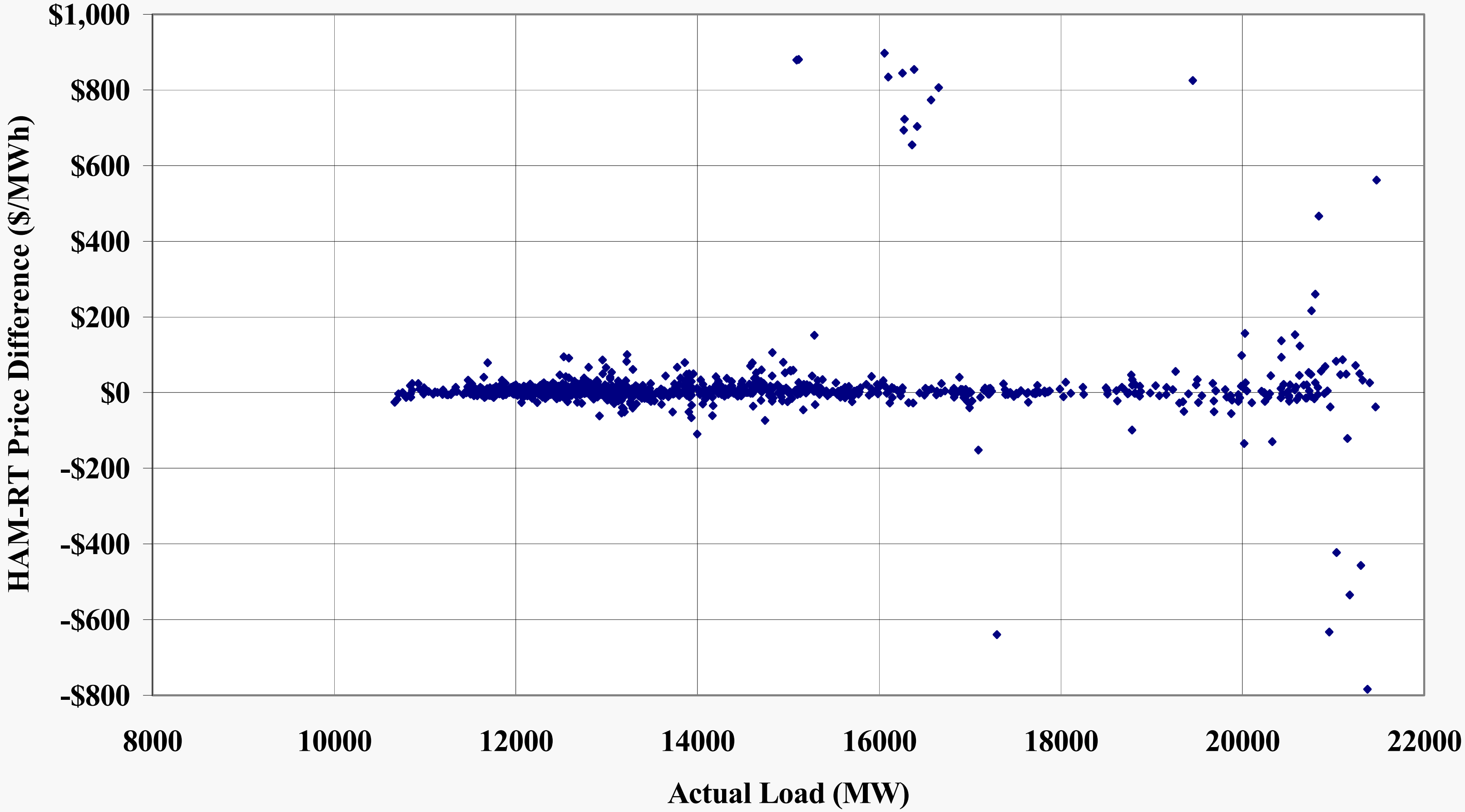


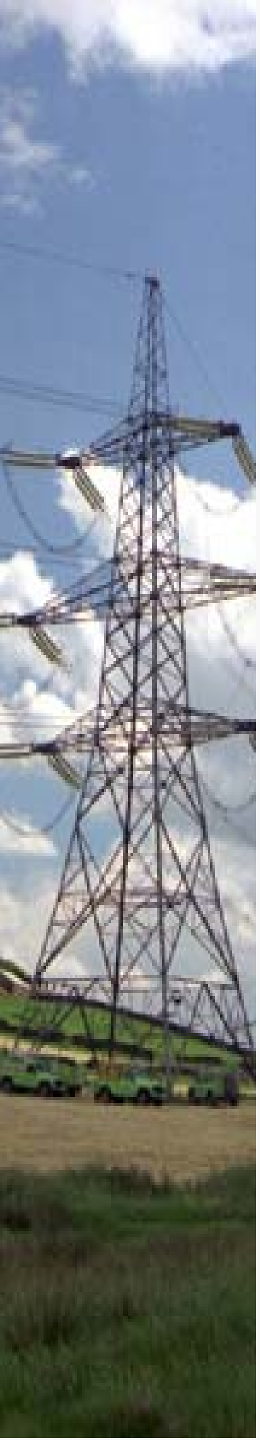


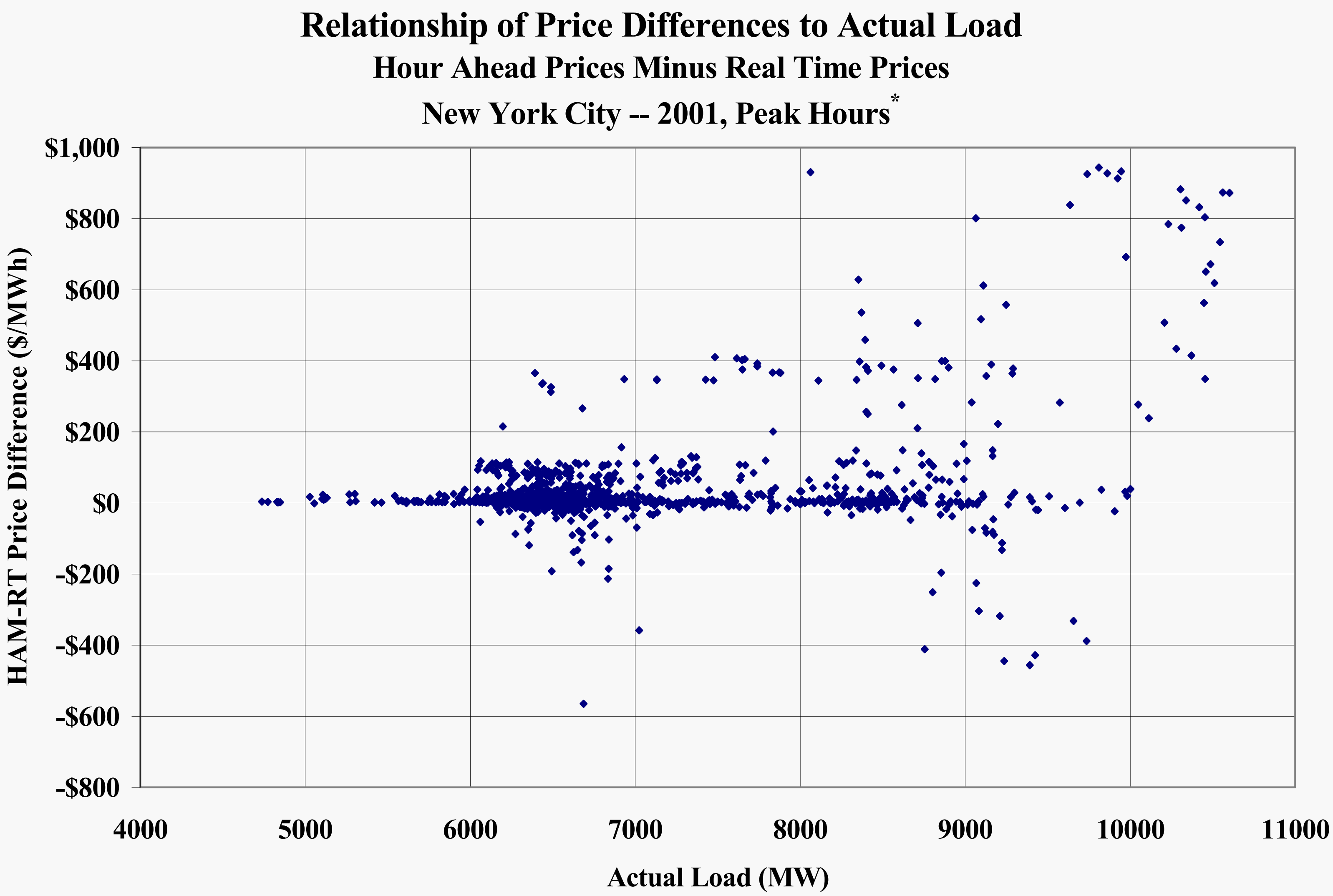
# Relationship of Price Differences to Actual Load

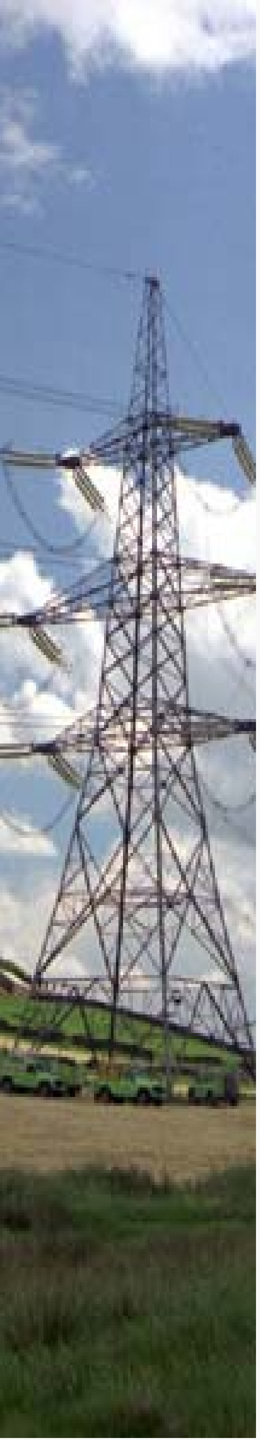
## Hour Ahead Prices Minus Real Time Prices

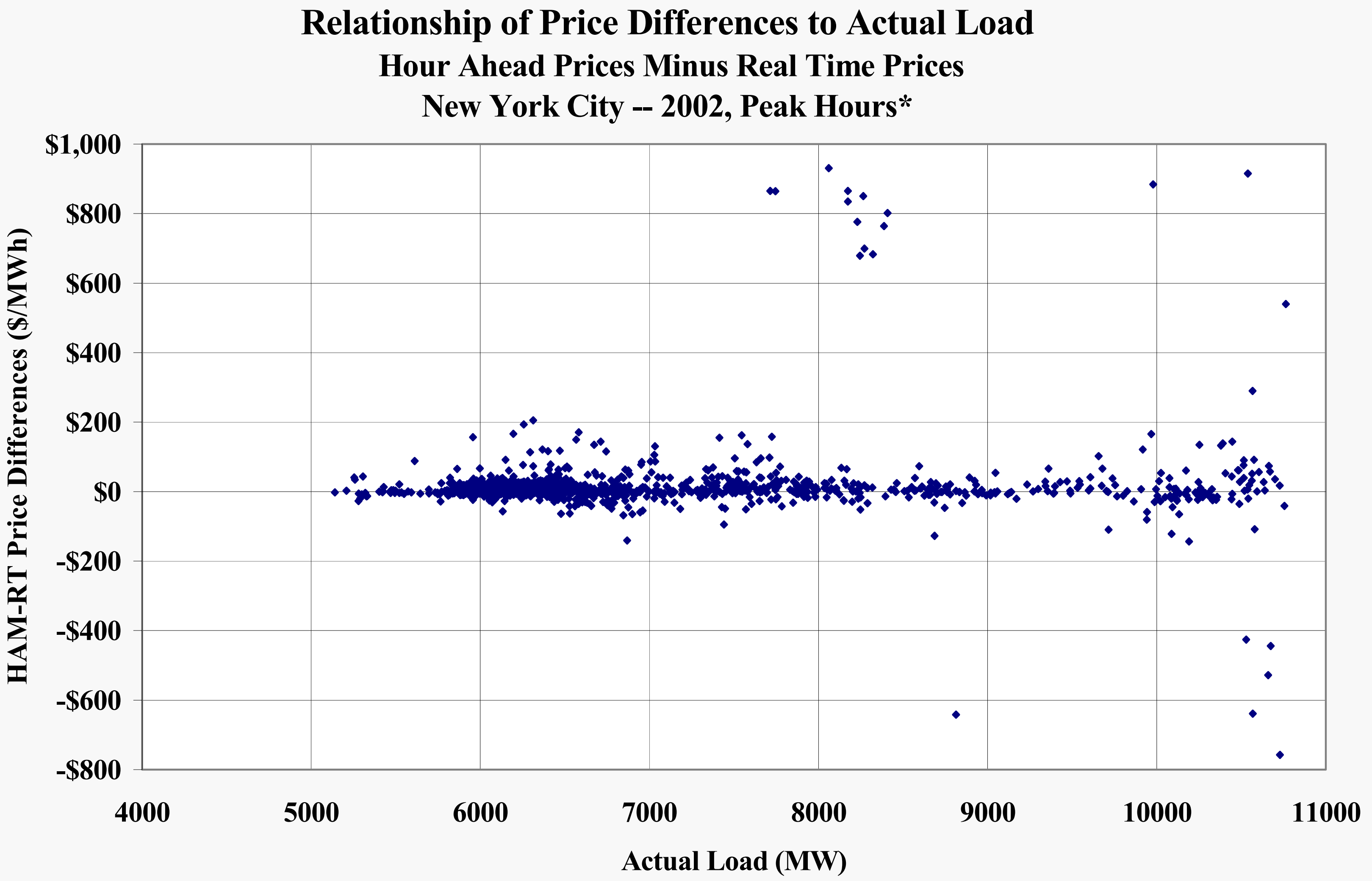
## East New York -- 2002, Peak Hours*

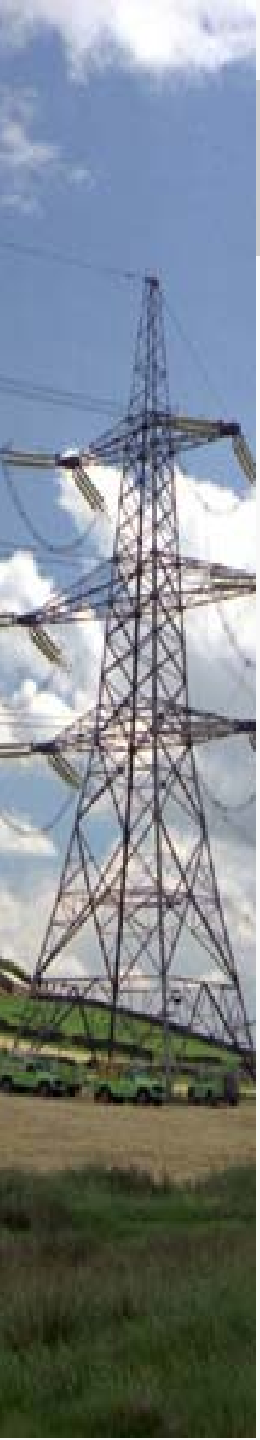





Relationship of Price Differences to Actual Load
Hour Ahead Prices Minus Real Time Prices
New York City -- 2001, Peak Hours*
HAM-RT Price Difference ($/MWh)
$1,000
$800
$600
$400
$200
$0
-$200
-$400
-$600
-$800
4000
5000
6000
7000
8000
9000
10000
11000
Actual Load (MW)

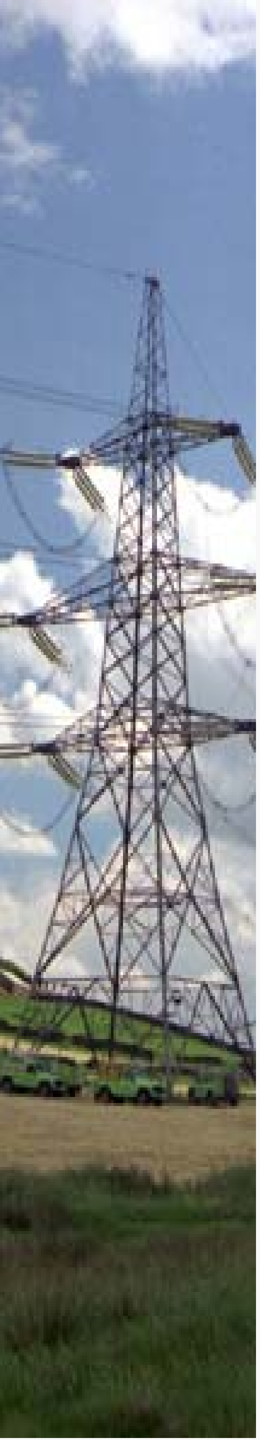



Relationship of Price Differences to Actual Load
Hour Ahead Prices Minus Real Time Prices
New York City -- 2002, Peak Hours*
HAM-RT Price Differences ($/MWh)
$1,000
$800
$600
$400
$200
$0
-$200
-$400
-$600
-$800
4000
5000
6000
7000
8000
9000
10000
11000
Actual Load (MW)



# Hourly Price Differences

- The following table shows the average of the absolute value of the hourly difference between day-ahead and real-time prices in 2001 and 2002.
  - ✓ In 2001, the average price difference was $15.98/MWh in the New York City zone and $18.75/MWh in Long Island.
  - ✓ In 2002, the average price difference was $12.63/MWh and $14.19/MWh in New York City and Long Island, respectively.
  - ✓ In 2002, each of the five zones showed improvement in price convergence of between 13% and 24.3%.
- The improvement is primarily related to the implementation of virtual trading and increased use of price-capped load bidding.

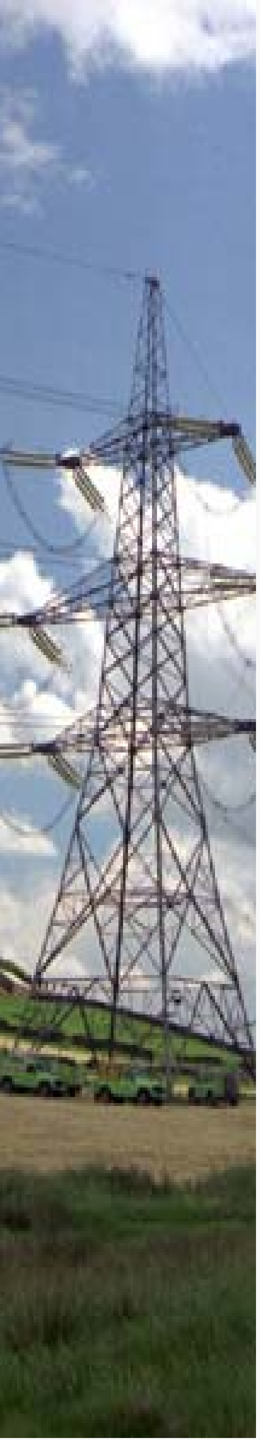


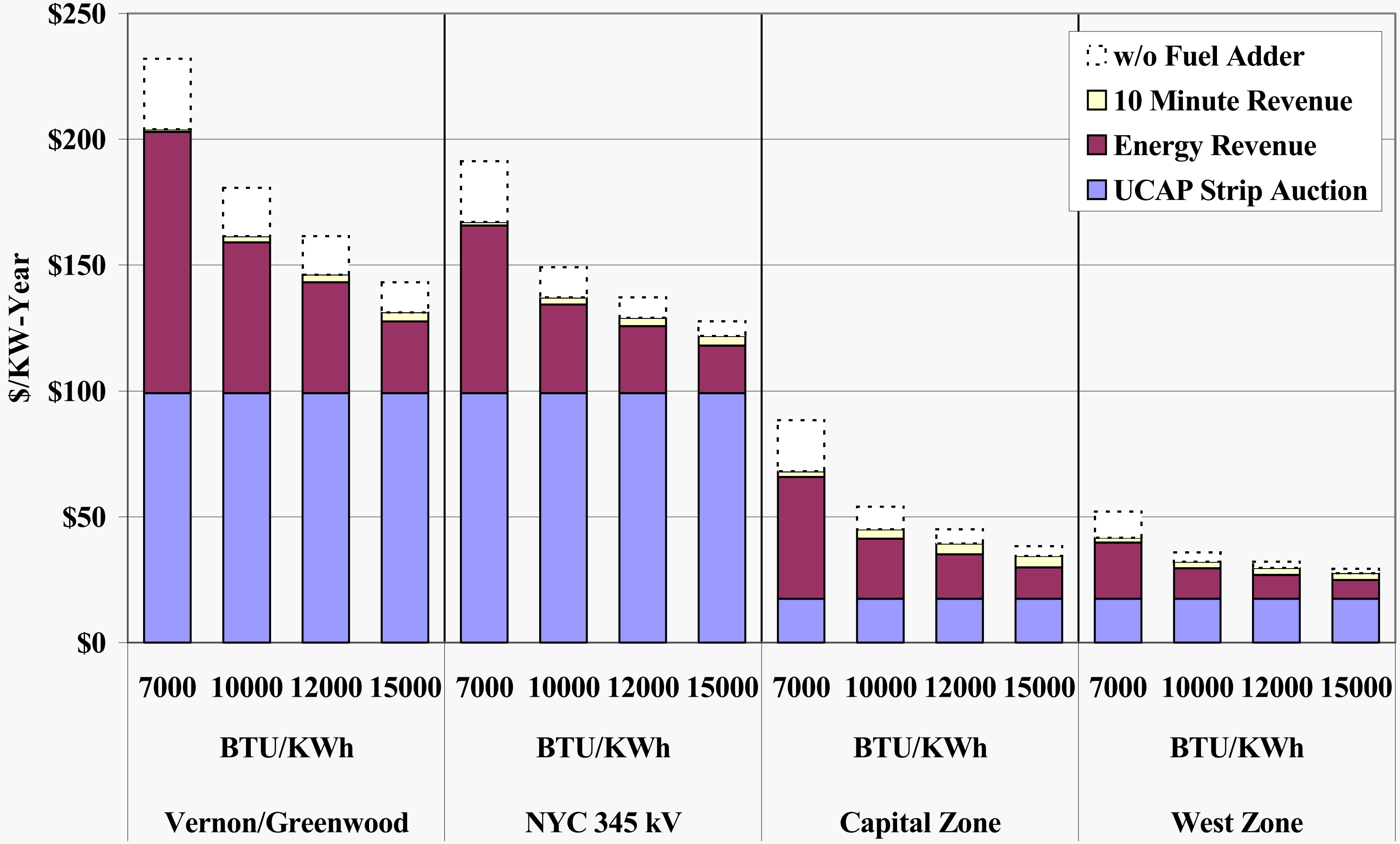
# Average Day-Ahead and Real-Time Price Differences

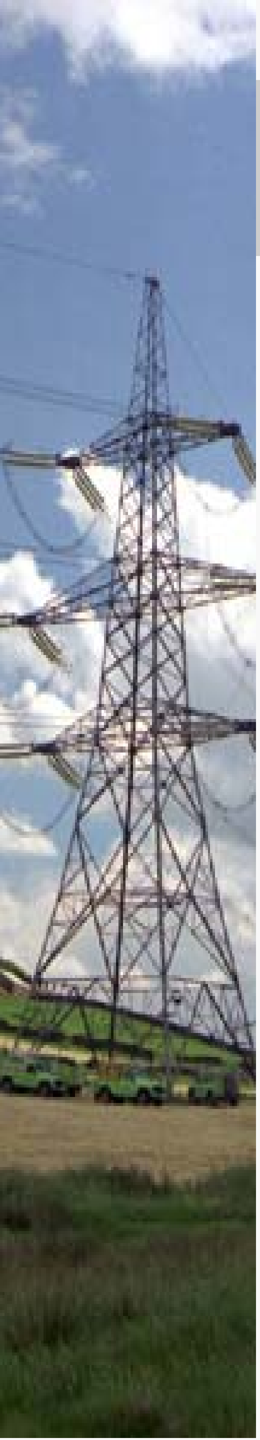
| | Average Price Difference | | Improvement in |
|---|---|---|---|
| | 2001 | 2002 | Price Convergence |
| **Capital** | $13.00 | $11.32 | 13.0% |
| **Hudson Valley** | $13.06 | $10.93 | 16.3% |
| **West** | $9.70 | $8.44 | 13.0% |
| **Long Island** | $18.75 | $14.19 | 24.3% |
| **New York City** | $15.98 | $12.63 | 21.0% |

*Note* : Prices were calculated as load weighted averages

## Estimated Net Revenue in the New York Markets
### RT - 2002

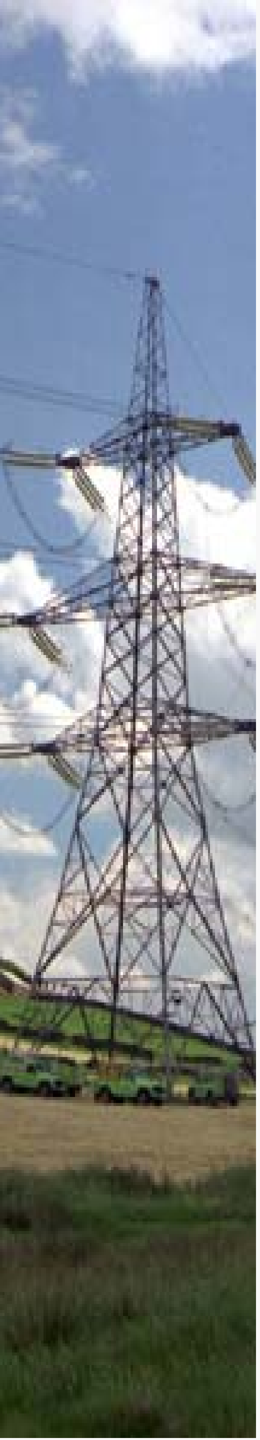


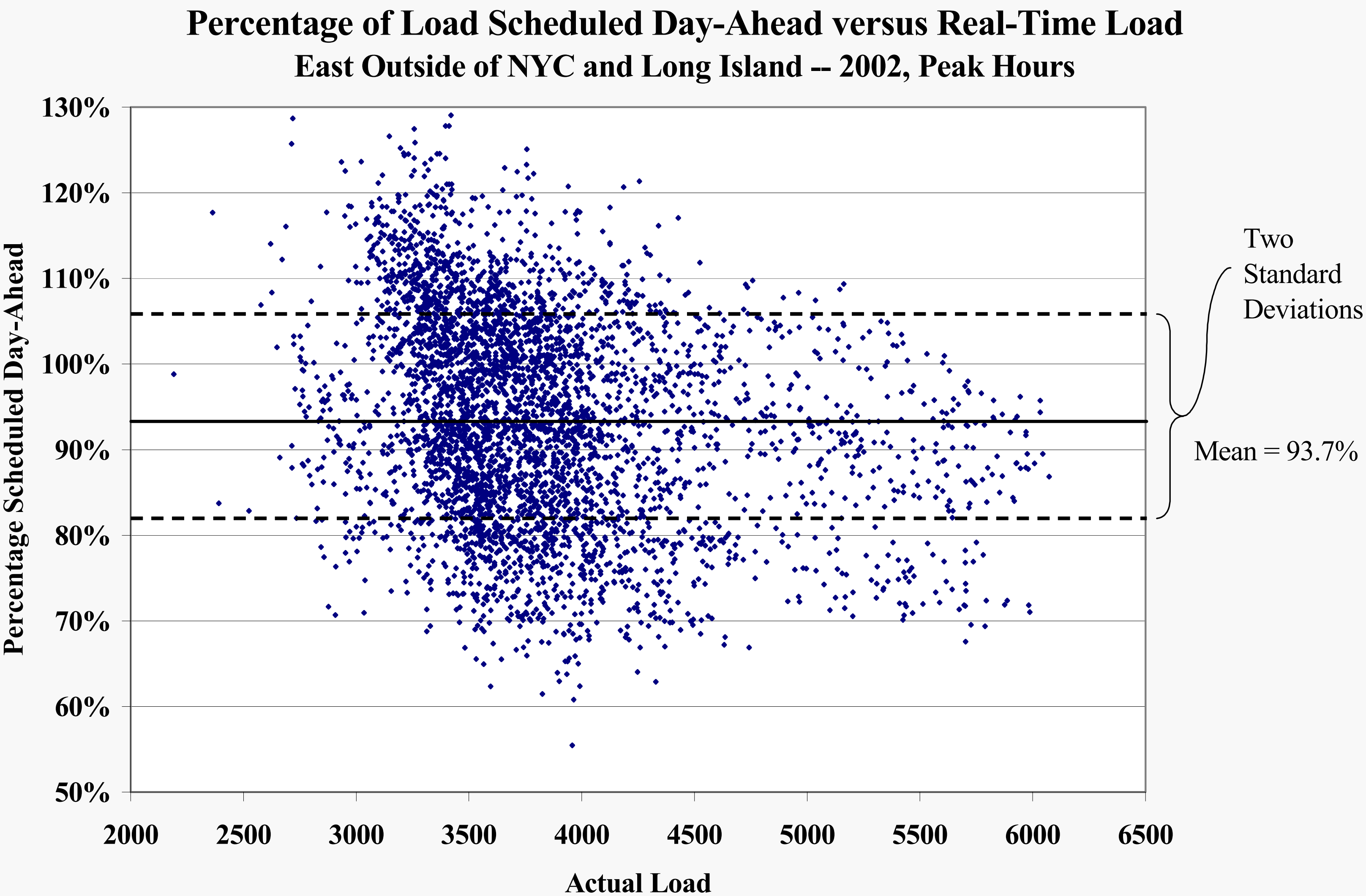




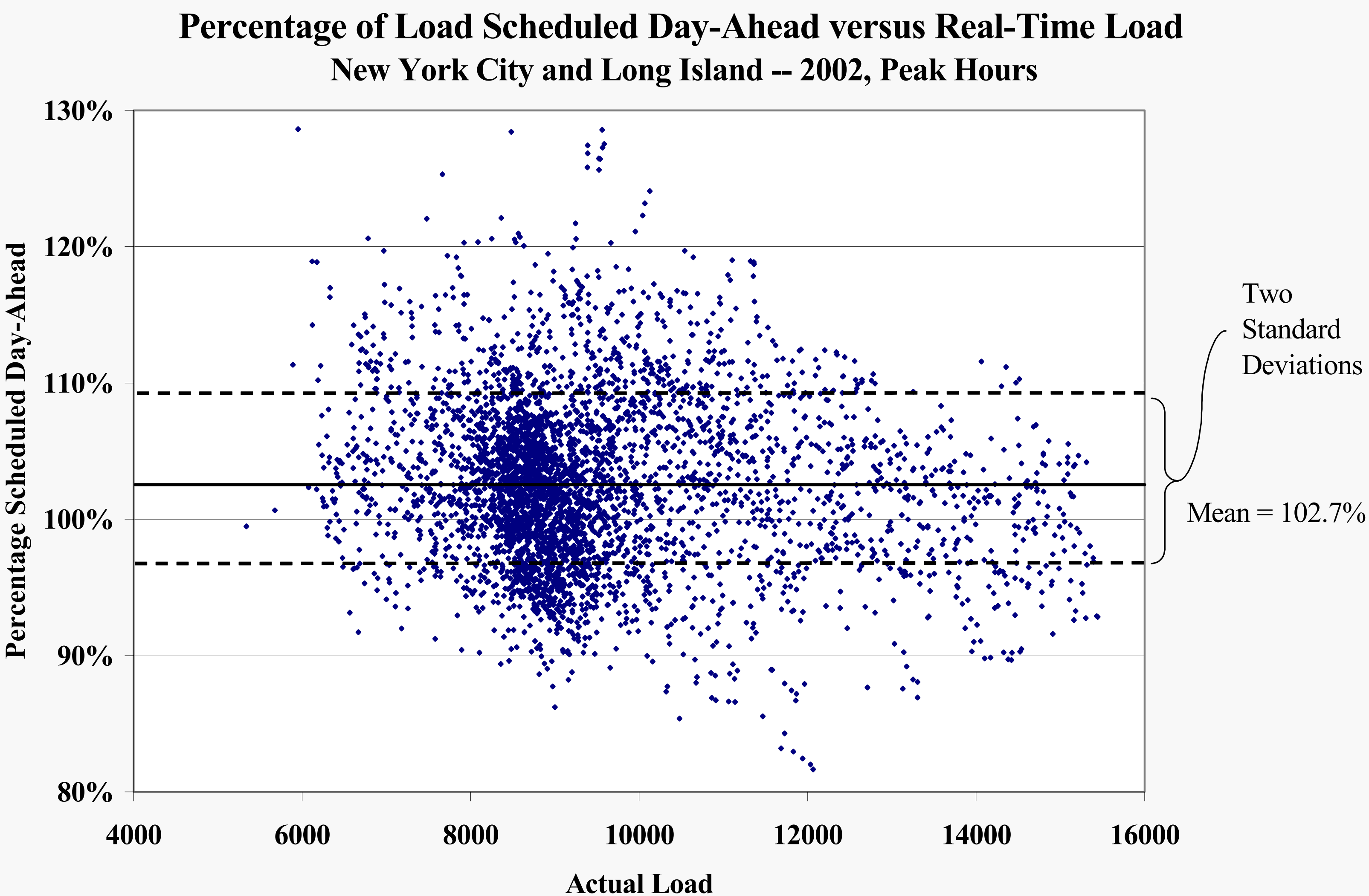
# Analysis of Load Bid Patterns

- The following scatter diagrams show the load bidding patterns during 2002 in three areas.
- This figure shows the following:
  - ✓ Under-scheduling of load is pronounced throughout up-state New York, while loads in New York City and Long Island usually over-schedule relative to their real time load.
  - ✓ There does not appear to be a systematic variation between over- and under-scheduling and real time load conditions.
- While the zones west of Central-East substantially under-schedule, concerns are diminished by the fact that load bidders in the west experience greater competitive discipline from neighboring control areas than areas east of Central-East and in New York City and Long Island.

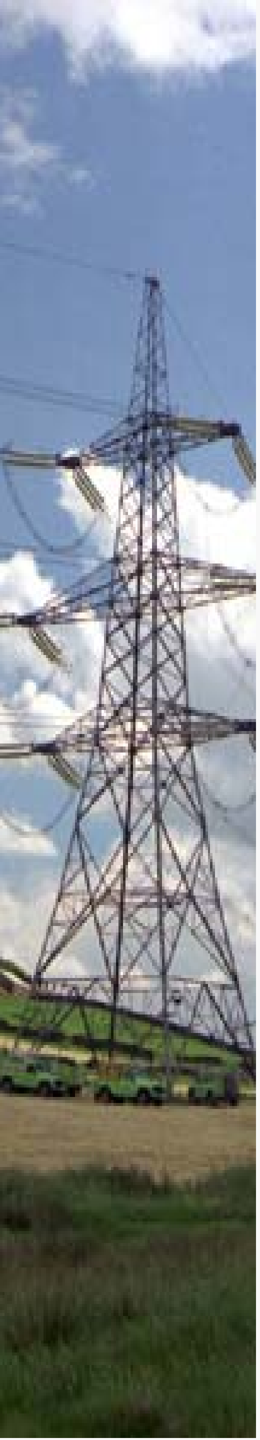




Percentage of Load Scheduled Day-Ahead versus Real-Time Load
East Outside of NYC and Long Island -- 2002, Peak Hours
Percentage Scheduled Day-Ahead
130%
120%
110%
100%
90%
80%
70%
60%
50%
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
Actual Load
Two Standard Deviations
Mean = 93.7%



Percentage of Load Scheduled Day-Ahead versus Real-Time Load
New York City and Long Island -- 2002, Peak Hours
130%
120%
110%
100%
90%
80%
Percentage Scheduled Day-Ahead
4000
6000
8000
10000
12000
14000
16000
Actual Load
Two Standard Deviations
Mean = 102.7%



## Percentage of Load Scheduled Day-Ahead versus Real-Time Load
### West New York -- 2002, Peak Hours