2001 ANNUAL REPORT ON THE NEW YORK ELECTRICITY MARKETS

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I. EXECUTIVE SUMMARY

The New York electric markets in 2001 were marked by considerable changes, including changes in market rules to correct certain flaws detected during the first year of operation, as well as substantial changes in external factors affecting the market. The external factors included sharp declines in fuel costs over the year and the return of transmission and generation facilities that had been out of service during 2000. These changes led to lower overall energy prices and reduced congestion during 2001.

Many of the findings regarding the market's performance in 2000 continued to hold in 2001. The markets remained workably competitive, with limited instances of significant withholding or other strategic conduct. The New York ISO's ("NYISO") market power mitigation measures were sufficient to address these instances. However, the Consolidated Edison ("ConEd") mitigation applicable to New York City ("NYC") that is triggered on the presence of congestion into NYC tended to mitigate energy offers excessively. The NYISO plans to replace the ConEd mitigation measures with measures that are consistent with NYISO's conduct-impact mitigation framework applicable to the rest of New York.

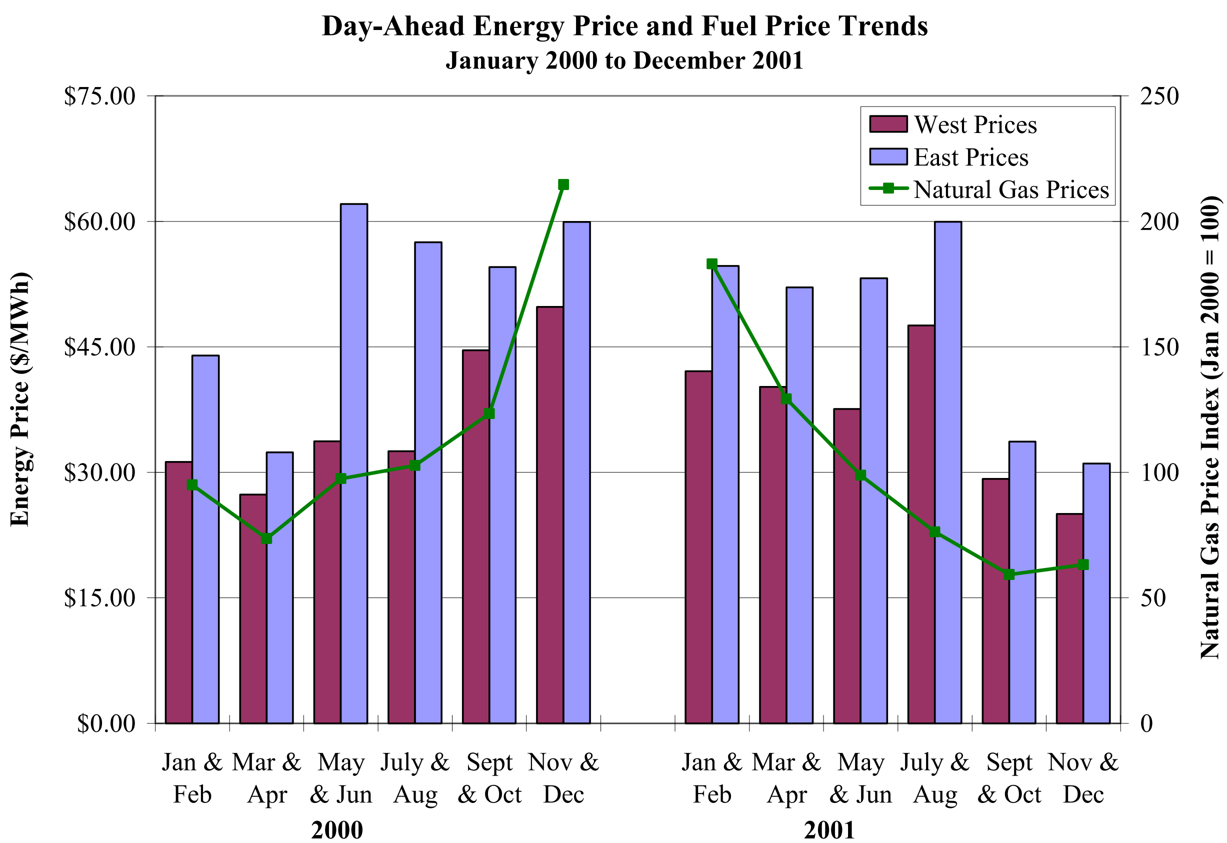
This report also evaluates and provides recommendations regarding other aspects of the New York electric markets, including the energy price convergence between the day-ahead and real-time markets, virtual trading, the ancillary services markets, the frequency of price corrections, the capacity market, and external transactions. These findings and recommendations are summarized in the following sections.

Energy Markets

The NYISO operates a day-ahead market, an hour-ahead scheduling model, and a real-time energy market. These processes dispatch generation, procure ancillary services, schedule external transactions, and set market clearing prices in the day-ahead and the real-time timeframes based on supply offers and demand bids. The day-ahead market is a forward market that commits generation to meet forecast demand and reserve requirements, and establishes day-ahead schedules for each generator. These schedules are financially binding and may be satisfied by generating or purchasing the scheduled quantity from the real-time market.

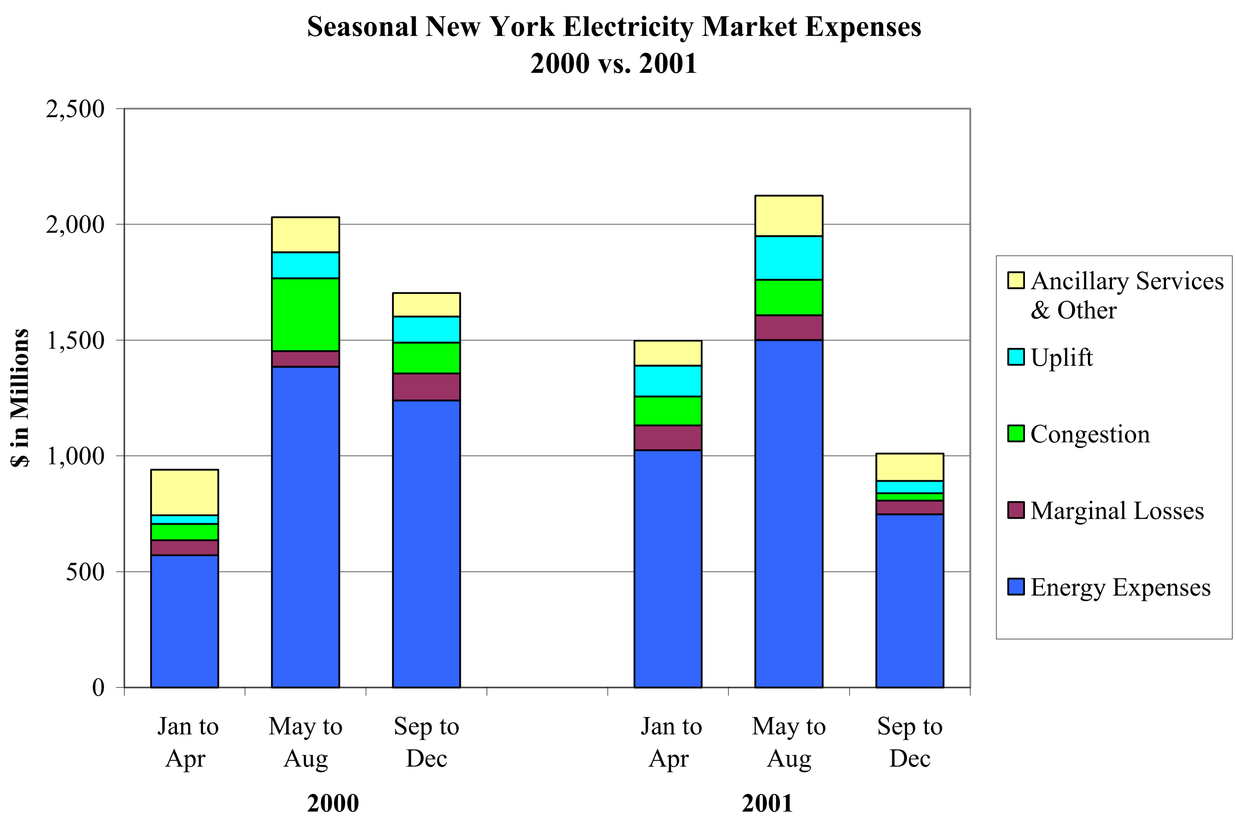
The hour-ahead scheduling process updates the day-ahead commitment of resources based on forecast load for the next hour, using the Balancing Market Evaluation ("BME") model. This model also schedules non-dispatchable resources (resources that cannot receive updated dispatch instructions each 5 minutes) and external transactions. The real-time energy market establishes the final dispatch of supply to meet demand in each five-minute interval. Each of these markets utilizes locational pricing that reflect transmission constraints and losses.

The following figure summarizes the energy price trends by showing averages of day-ahead energy prices during 2000 and 2001 in Western and Eastern New York.



Increasing fuel prices contributed to rising energy prices in 2000 while the sharp decline in fuel prices during 2001 led to reductions in energy prices of approximately fifty percent from January to December. Average energy prices in July and August 2001 rose considerably despite the decline in fuel prices. Prices were particularly high in August as demand established new records due to sustained hot weather early in the month. The peak prices occurred on August 9th when the market was in a capacity shortage with no evidence of strategic withholding by suppliers. Prices on August 9th alone raised the actual average energy prices for the month by 20 percent, illustrating the importance of these events in sending efficient price signals when the system is legitimately in shortage.

Loads in 2001 were higher throughout most of the year compared to 2000, but particularly during the summer peak periods due to the unusually cool weather in 2000 and the warm weather in 2001. These higher loads offset the declining energy prices to cause the total settlements through the NYISO markets to remain virtually unchanged from 2000. The following figure shows the total market expenses for 2001 on a seasonal basis compared to 2000 for the energy and ancillary services markets (excluding the capacity and TCC markets).



Although the total market expenses did not change significantly in 2001, the seasonal distribution of the expenses did mirror the trends in energy prices and the composition of the market expenses changed. For example, congestion rents declined by 40 percent from 2000 to 2001, defined as the difference between the payments to generators and revenue collected from loads (excluding losses) plus net congestion payments made for bilateral transactions. The lower congestion costs are attributable to the following factors:

- The return of Indian Point 2 (1000 MW) in Eastern New York;
- Lower oil and gas prices that supply the generating units that are usually on the margin in Eastern New York;
- Increased imports offered from New England; and
- Reduced imports into New York across the Hydro Quebec interface.

This figure also shows that total uplift costs increased about 40 percent. This increase is primarily due to increases in out-of-merit dispatch of generation to maintain local reliability, typically in New York City. One of the modifications to the market that is being made in 2002 is to modify the NYISO market models to secure the transmission constraints within NYC that are now managed with out-of-merit dispatch. These constraints create “load pockets” which are areas within New York City that are isolated by a constraint -- i.e., generation within the load pocket is generally required to manage the constraint.

These modeling changes will reduce the uplift and improve the accuracy of the locational prices within the City. This report includes an analysis of potential energy price and uplift effects of the modeling changes by quantifying the likely change in results for 2001. These results showed that the energy prices in NYC would have been approximately 13 percent higher during the summer, though this increase is largely offset by decreases in uplift charges.

Assessment of Energy Bids and Offers

This report includes an analysis of energy bids by LSEs and energy offers by suppliers in the NYISO markets to evaluate the competitive performance of the markets. Both the NYISO and Potomac Economics screen these bids and offers into the energy and ancillary services markets on a daily or hourly basis to detect potential attempts to exercise of market power. This ongoing monitoring is complemented by the periodic analysis of trends in energy bids and offers to assess the competitiveness of the New York energy market.

Market power in electricity markets is generally exercised by withholding supplies in an attempt to raise the market-clearing price. A resource can be physically withheld by claiming the unit is unavailable or not offering it when it would be economic to run, or economically withheld by bidding the unit at a price higher than its marginal cost (including opportunity costs) to reduce the unit's output.

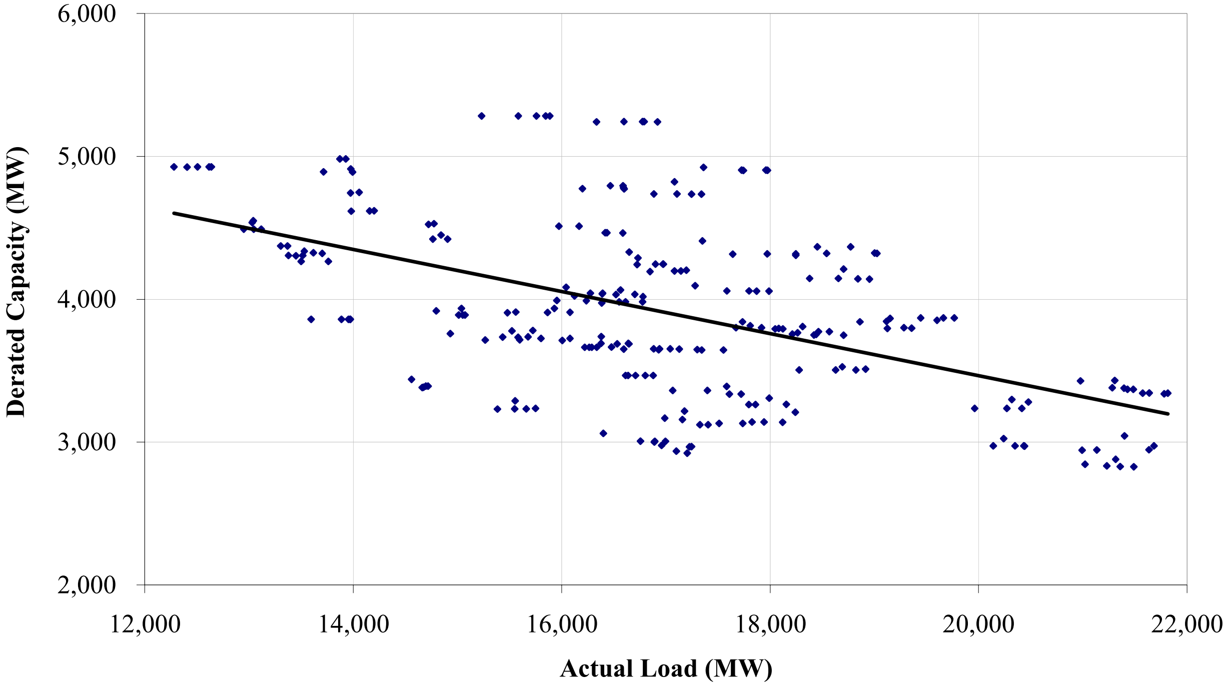
The critical task in a withholding analysis is to differentiate strategic withholding from competitive conduct that could appear to be physical or economic withholding. For example, a forced outage of a generating unit may be either legitimate or a strategic attempt to raise prices by physically withholding the unit. To differentiate between these two alternatives, this report evaluates the potential withholding in light of the market conditions and participant characteristics that would tend to create the ability and incentive to exercise market power. Economic theory indicates that the two key factors most likely to be correlated with incentives to exercise market power are participant size and the energy demand level.

Demand levels are particularly important due to the nature of the supply in wholesale electric markets – a flat supply curve under most conditions cause prices to be relatively insensitive to withholding while tight market conditions under peak demands cause prices to become much more sensitive to withholding. However, in a workably competitive market, suppliers should increase their supply to maximize their sales under the higher prices that are expected during these peak conditions. Hence, potential indicators of withholding are examined relative to the energy loads to determine the offer patterns are consistent with workable competition or with strategic withholding.

For example, total deratings (includes various forms of outages and other deratings) in Eastern New York are shown in the figure below. This figure only includes the peak hours during the Summer 2001 in order to exclude the effects of planned outages during the spring and fall or in off-peak hours (planned outages that occur in these hours would increase the deratings in low load hours, distorting the trend shown in the figure). Eastern New York is shown because this corresponds to the constrained market hour where withholding is more likely to result in material increases in energy prices.

This figure shows that outages and other deratings are minimized under the highest demand conditions when the incentive to withhold would be the highest, which is consistent with the conclusion that the New York market has been workably competitive. This conclusion is supported by the other analyses presented in this report.

Relationship of Hourly Deratings to Actual Load
Day-Ahead Market -- East New York
Summer 2001 -- Peak Hours*



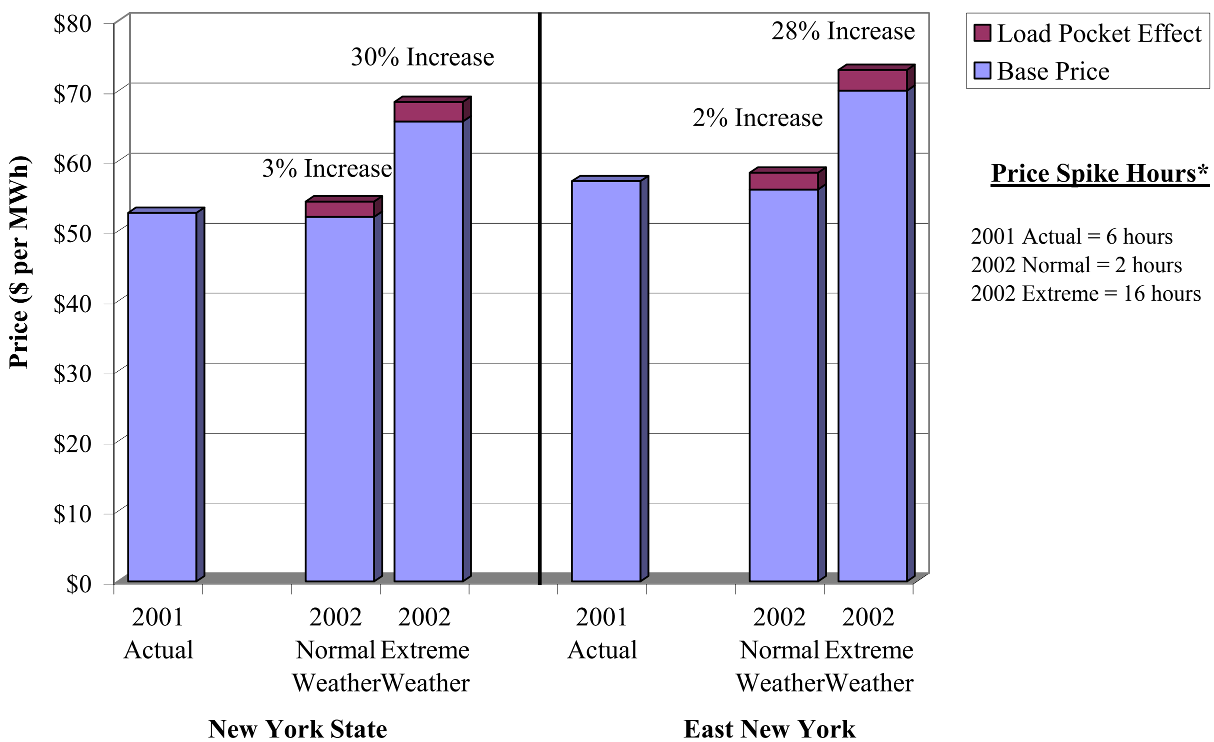
It is important to note that this type of analysis does not exclude the possibility that discrete instances of physical withholding occurred via specific outages or deratings. Therefore, NYISO's physical-audit program designed to verify that outages and significant deratings are legitimate remains an important program to detect and deter this conduct.

Forecast for Summer 2002

This report provides a forecast of the energy prices for the upcoming summer, reflecting expected changes in market rules, market resources, loads, and other factors. The figure below shows the results of this analysis for a normal weather case and an extreme weather case in Eastern New York and the State.

Both the normal and extreme weather cases are based on NYISO load forecasts, with the extreme weather case showing a peak demand level that is 900 MW greater than the normal forecast. Fuel prices are assumed in each of the forecasts to be unchanged from last summer since the current fuel price forecasts are close to last summer's average levels.

Summer 2002 Energy Price Forecast
June to August -- All Hours



* Price spike hours are defined as hours with projected prices greater than $500 per MWh. Hours shown are for East New York.
Sources: NYISO actual day-ahead price data and load forecasts; Potomac Economics analysis. All Prices shown are load-weighted.

This figure shows that average prices in Eastern New York and the State are both projected to be slightly higher under normal weather conditions. This increase is due largely to the projected increases in energy prices in New York City as a result of modeling changes described above, which is reflected in the weighted averages from both Eastern New York and the State. To be clear, the load pocket effect will have no effect on locational prices outside of NYC.

The anticipated reduction in uplift costs from the improved modeling of NYC is not included in these energy price estimates, but should be included when considering the potential change in electricity costs to loads. The figure also shows that the frequency of price spikes is a key determinant of the average summer price levels – the increase in load in the "extreme weather" case increases the number of shortage hours from 2 to 16, resulting in a 25 percent increase in average energy prices.

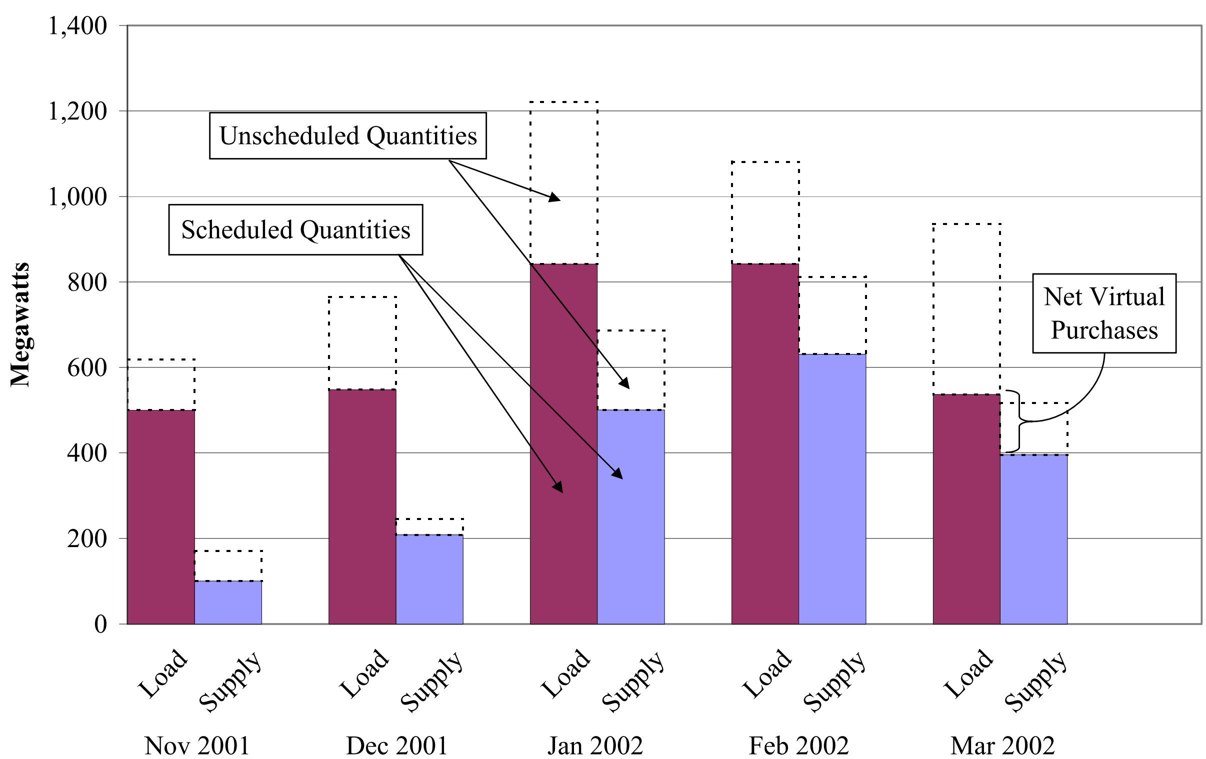
Virtual Trading

Virtual trading began in November 2001, allowing entities that do not serve load to make purchases in the day-ahead market. Such purchases are subsequently sold into the real-time spot market. Likewise, entities without physical generating assets can make power sales in the day-ahead market that are purchased in the real-time market. By making virtual energy sales or purchases in the day-ahead market and settling the position in the real-time, any market participant can arbitrage price differences between the day-ahead and real-time markets.

For example, a participant can make virtual purchases in the day-ahead if the prices are lower than it expects in the real-time market, and sell the purchased energy back into the real-time market. The result of this transaction would be to raise the day-ahead price slightly and, thus, improve the convergence of the day-ahead and real-time energy prices.

The following figure shows the quantities of virtual load and supply that have been offered and scheduled on a monthly basis in New York. In each of the months, virtual purchases were larger on average than virtual sales.

Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
New York State -- November 2001 to March 2002



Both the virtual purchases and sales represent a relatively small share of the total energy market activity, although this figure reveals that virtual trading activity rose initially before leveling off in March. The figure also shows that virtual suppliers, in particular, have become much more active in the spring of 2002.

Although the virtual trading quantities remain relatively modest, it is important to assess how virtual trading is being used by market participants. Virtual bids and offers designed to arbitrage price differences between the day-ahead and real-time markets or hedge the risk of trading in these markets should be price sensitive. Price insensitive bids that demonstrate a willingness to make virtual purchases or sales at uneconomic prices relative to the expected real-time price may signal a strategic attempt to influence day-ahead prices. Therefore, this report assessed the extent to which virtual offers and bids have been price sensitive, finding that virtual trading activity has been dominated by price sensitive bids and offers.

Over the 5 month time period studied, more than 98 percent o\f virtual demand bids were price sensitive while 89 percent of virtual supply offers were price sensitive. Although these results show that virtual trading have been consistent with competitive expectations, it is too early to draw firm conclusions regarding this activity. Inefficient or strategic virtual trading activities will only be effective when these strategies influence prices, which is more likely during peak summer conditions that have not been experienced yet. Therefore, these issues should be reassessed after the summer season.

Day-Ahead and Real-Time Price Convergence

In a well functioning market, prices produced by each of the models (day-ahead, hour-ahead, and real-time) will tend to converge. The analysis in this report shows that day-ahead prices remain slightly higher on average than real-time prices. This can be attributed to the fact that prices in the real-time market are more volatile than in the day-ahead market.

This higher variance in the real-time can cause prices in the day-ahead to exceed average real-time prices since a) the day-ahead purchases serve as a hedge against real-time price fluctuations for LSE's, and b) day-ahead sales by generators may impose an incremental risk on large generators relating to experiencing on outage after the day-ahead commitment and having to purchase replacement power in the real-time market.

The convergence between the day-ahead and real-time prices improved significantly in 2001, particularly in the fall as loads and fuel prices decreased significantly, leading to more stable prices. In addition, the introduction of virtual trading in November 2001 and more active use of price-capped load bids by LSEs has likely improved the price convergence, although the experience with virtual trading is too limited to draw a firm conclusion.

The table below summarizes the energy price statistics in three New York areas on an annual basis. This table shows less than a 1 percent day-ahead premium in the two Eastern zones (NYC and Capital) with a 10 percent premium in Western New York, which is substantially improved from 2000. One contributing factor leading to the larger price differences in the West is the reduced day-ahead congestion on the Central-East interface.

Day-Ahead and Real-Time Pricing Statistics for Selected Zones
January to December 2001

	New York City		**Capital Zone**		**West Zone**	
	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time
Mean	$44.67	$44.49	$39.90	$39.69	$33.87	$30.76
Compared with 2000	*-$4.16*	*-$5.85*	*-$4.92*	*-$2.36*	*-$0.59*	*$0.88*
Avg. Std. Deviation	$12.25	$30.68	$10.68	$24.64	$9.15	$15.82
Compared with 2000	*-$4.58*	*-$15.38*	*-$6.20*	*-$2.60*	*-$0.12*	*-$3.15*
Minimum	$0.11	-$169.37	$0.10	-$167.80	$0.10	-$152.35
Maximum	$1,024.91	$1,034.01	$976.15	$1,078.35	$912.28	$949.50

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.

Additionally, the table shows the average standard deviations measuring the volatility of prices in each market area. These results indicate that the volatility in the real-time prices remains roughly twice as high as in day-ahead prices, although volatility fell significantly in New York from 2000 to 2001. The reduction in price volatility in both the day-ahead and real-time markets is due primarily to lower fuel prices and the reduced congestion into Eastern New York.

Hour-Ahead and Real-Time Convergence

There continued to be significant differences between the outcomes of the hour-ahead commitment model that schedules external transactions and off-dispatch generation and the real-time market model in super-peak hours. These differences did not occur under most market conditions. However, when the market approached a capacity deficiency under super-peak conditions (less than 1 percent of the hours of the year), differences in the models assumptions resulted in inconsistent results. Ultimately, this caused inefficient transaction scheduling in these hours and increased uplift.

The inefficient transactions scheduling generally resulted in the hour-ahead model scheduling too many imports and too few exports. As a result, the real-time energy prices in some of the super-peak hours were substantially reduced, compromising the ability of the real-time prices to efficiently reflect scarcity conditions. In addition, on one day during 2001 when New England was capacity deficient, this problem reduced scheduled exports to New England and substantially raised the energy price in New England.

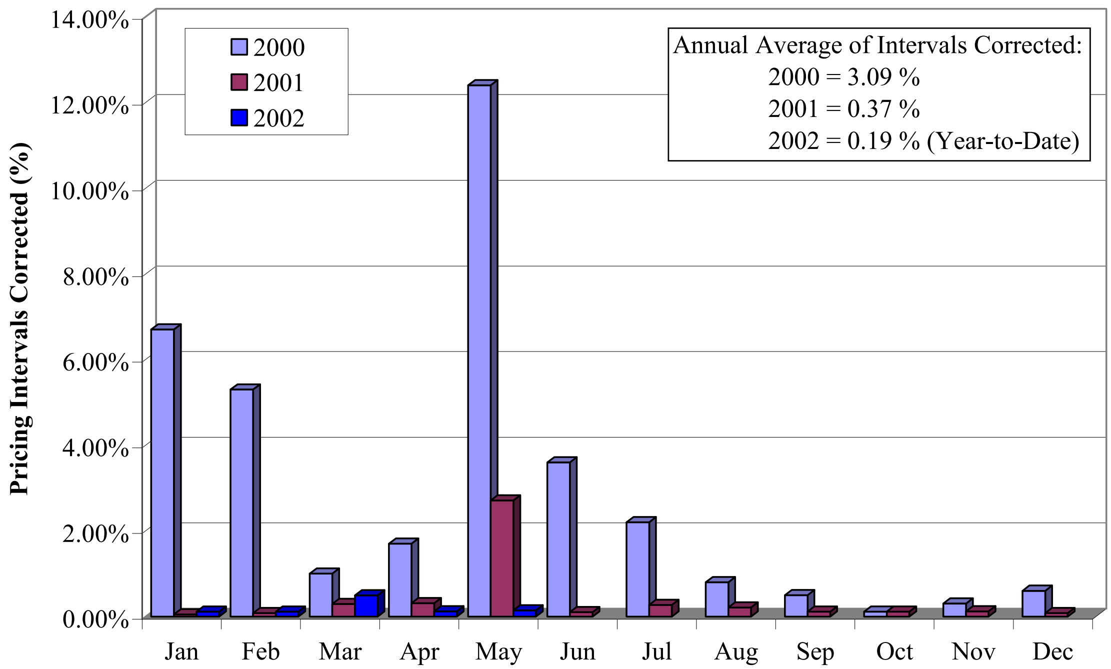
Changes are being implemented by the NYISO to address this concern by the Summer of 2002, subject to FERC approval. This issue will continue to be monitored to ensure that these changes are effective under all market conditions.

Price Corrections

All real-time markets are subject to some level of price corrections associated with inaccuracies in metering information, input data errors, or communications problems. In addition, software problems can result in pricing errors that occur only under certain conditions. It is important to quickly address these sources of price corrections to in order to minimize the overall level of corrections and maximize price certainty. Efficient market outcomes rely, in part, on market participants responding to the real-time price signals produced by the ISO's markets.

This report summarizes the real-time price correction trends from 2000 into early 2002, which is shown in the following figure. This figure shows that after its first year of operation, the frequency of price correction decreased considerably, and has been reduced further into 2002 with less than 0.2 percent of real-time intervals corrected.

Percentage of Real-Time Prices Corrected
January 2000 to May 2002



External Transactions

Several modifications have been implemented during 2001 and early 2002 by the ISOs in the region to improve transaction scheduling between the control areas. These changes include:

- Implementing reserve sharing with ISO-NE;
- Development of the Collaborative Scheduling System to exchange the scheduling process and communications between PJM and New York;
- Modify market rules and scheduling processes to facilitate capacity sales between each of the ISOs.
- Allowing multi-hour block transactions that allow transactions to be submitted in New York with a minimum run-time to reduce scheduling risks;
- Establishing a pre-scheduling process in New York to reduce scheduling risks associated with long-term transactions;
- Implementing an inter-ISO congestion management pilot program with PJM to allow redispatch of generation in one ISO to resolve congestion in the adjacent system.
- Modifying the rules for scheduling short-notice exports from New England, and

- Revising the Hour-Ahead model as described above to schedule external transactions more efficiently.

Given the timing of many of these changes, they are not reflected in the 2001 results. Therefore, improvements in the trading patterns between New York and the adjacent markets are expected in 2002. Nevertheless, the patterns of external transactions with adjacent regions exhibited some have improvement from 2000 although the analysis continues to indicate that barriers to trading exist between the ISO areas. These barriers are most significant on the interface with New England where it is most difficult for participants to predict the efficient level and direction of flow. Hence, this report recommends that resolving the remaining seams issues be a high priority.

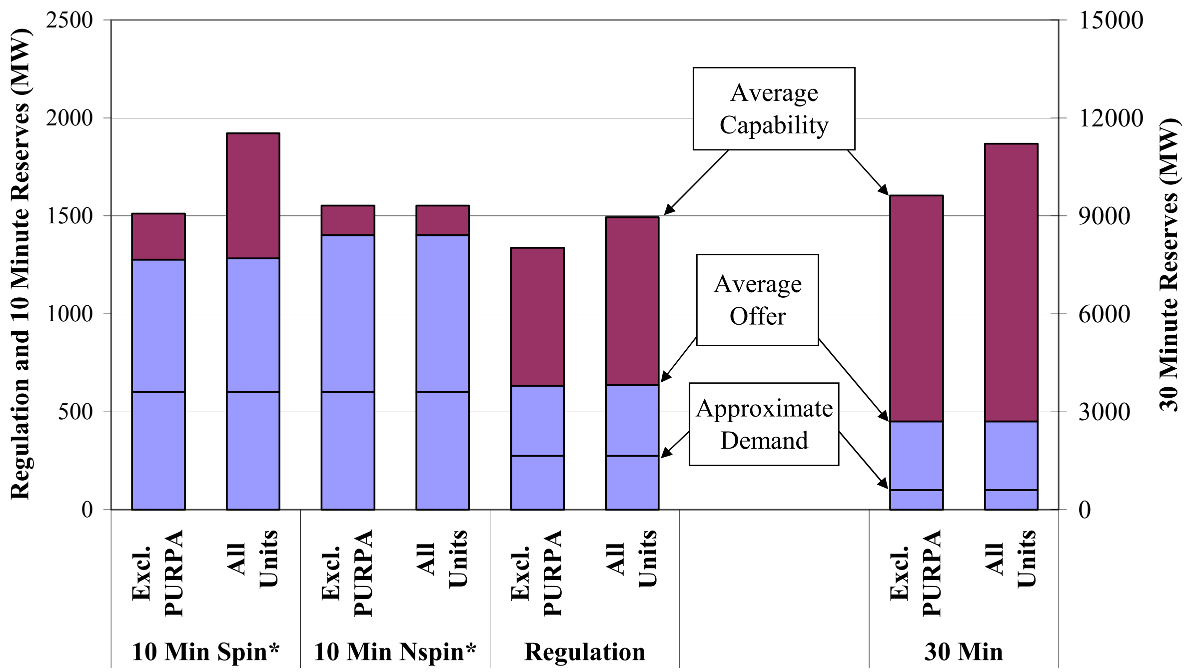
Ancillary Services

Ancillary services markets are an important component of the New York Electric market although they continue to account for approximately 2 percent of the overall market expenses. The ancillary services markets play an important role in allocating resources between energy and operating reserves. By simultaneously optimizing the selection of resources for reserves and energy based on each resource's energy offer and availability offers in the various ancillary services markets, the NYISO markets ensure that the prices of each product will be internally consistent and efficient.

Selecting resources to provide ancillary services in a non-simultaneous, non-optimize manner will distort energy and reserve prices. Setting resources aside for reserves before the dispatch of the energy market can inflate prices in the energy market if these resources would have been economic as energy providers and other more expensive resources could have provided the reserves. Alternatively, designating reserves after the energy market dispatch can lead to prices that are too low in energy market and too high in the reserve market as resources that would be superior reserve providers are dispatched for energy. This can also lead to inefficient scheduling of external transactions. Hence, establishing competitive and efficient ancillary services markets is a key for ensuring that the prices and schedules in the energy market are efficient.

These efficiency benefits of simultaneously optimizing the ancillary services and energy markets are achieved when the offer patterns in these markets are competitive. Therefore, this report evaluates the offer patterns in each of the ancillary services markets. These results are summarized in the following figure for all units and for non-PURPA units (resources with PURPA contracts are often limited contractually in their ability to sell ancillary services). This figure shows that on average, most of the 10-minute reserve resources are made available to the NYISO markets while a considerable portion of the 30-minute reserve and regulation capability is not offered.

Ancillary Services Capability and Offers



*Eastern side of the Central-East Interface Only.

Under most conditions, the resources that are not offered in these markets will not have a significant effect on prices since the NYISO's demand for operating reserves and regulation is generally considerably less than the amount offered. However, under peak conditions when the system requires all available resources to meet its energy and operating reserve requirements, the withholding of this capability from the reserves markets can cause the NYISO to make inefficient trade-offs between reserves and energy – distorting prices in both markets.

The persistence of these offer patterns over the past two years indicates a flaw in the incentives to offer into these markets. Therefore the report proposes a number of pricing reforms for ancillary services. First, pricing should compensate all reserve suppliers for the lost opportunity to make sales in the energy market when selected to provide reserves. This can be accomplished by setting the price of each reserve at the shadow price of meeting the reserve requirement (i.e., the marginal cost to the system of supplying the reserve). Second, a multi-settlement system is recommended that would establish financially binding prices and schedules for each of the ancillary services in the day-ahead and real-time timeframes.

Third, this report recommends that the NYISO implement a demand curve for operating reserves. This would serve two purposes. First, it would prevent the NYISO models from taking uneconomic actions to maintain relatively low-value reserves. Second, it will allow the New York energy markets to reflect capacity shortages without generators having to raise their offer prices. In other words, when the market is in a capacity shortage causing the market to clear on the reserve demand curve, both reserves and energy prices should be set at the scarcity levels corresponding to the marginal value of reserves.

Ensuring that efficient prices are established when the market is in shortage is an essential component of the overall economic signals provided by the market. The demand curve for reserves will allow predicable and reliable prices to be set under these conditions in advance of achieving broader demand participation in the real-time energy market. These recommendations are being considered in the context of the real-time scheduling system ("RTS") that is planned to replace the current hour-ahead/real-time scheduling and dispatch system. This system will provide improvements in a number of other areas as well, such as external transactions scheduling and intra-day resource commitments.

Lastly, the report includes a competitive analysis of the 10-minute non-synchronous reserves ("10-minute NSR") in New York, which supports a recommendation to remove the current offer cap. The report recommends, however, that the requirement for Eastern suppliers of 10-minute NSR to offer their resources into the day-ahead reserves market be retained and that the existing mitigation measures be employed to mitigate significant attempts to economically withhold the 10-minute NSR resources.