2002 STATE OF THE MARKET REPORT
NEW YORK ISO

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TABLE OF CONTENTS

List of Figures

LIST OF TABLES

I. Executive Summary

This report examines the performance of the New York ISO wholesale electricity markets in 2002. Overall, our analysis indicates that market prices have been consistent with underlying cost factors and have not been unreasonably affected by anticompetitive conduct or by market design issues. Nonetheless, there remain market design and market operations issues that require attention and, if effectively addressed, can lead to improved market efficiency.

Total electricity costs in New York in 2002 (including energy, uplift, installed capacity, and ancillary services costs) remained at levels comparable to total costs in 2001. While they remained stable, the categories of costs shifted as a result of significant changes to market rules. The primary changes in the market rules affected uplift costs related to the hour-ahead scheduling to manage congestion in New York City. This category of costs declined substantially in 2002 as a result of various modeling improvements. Other significant changes included increased use of virtual trading and price-capped load bidding that helped improve the desirable convergence of real-time and day-ahead prices.

In assessing the 2002 market in this Report, we address the following areas:

- Energy market prices and outcomes;
- Market participant bidding patterns;
- Pricing during peak demand conditions;
- External transactions;
- Installed capacity market;
- Ancillary services; and
- Demand response programs.

While the market performed well and modeling reforms aimed at improvements in load-pocket pricing were successful, there remain areas where further improvement is needed. We identify those areas in this Report. These include pricing during peak demand conditions (i.e., scarcity pricing), improving the efficiency of trading with adjacent markets; and ancillary services market participation and pricing.

Based on our analysis, we recommend that the NYISO make the following improvements to its markets:

- Implement scarcity pricing provisions that would set prices at $1000 (excluding losses) in reserve-deficient areas;
- Modify pricing rules to allow emergency demand response resources to set energy prices when they are needed to avoid a shortage;
- 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); and
- Address scheduling and settlement rules associated with virtual trading to ensure that they are consistent with bid prices.

The following subsections provide an overview of the findings of the Report.

A. Energy Market Prices and Outcomes

Price Trends

Energy prices tracked closely to underlying fuel costs during 2002. Natural gas prices doubled and fuel oil prices increased almost 80 percent. This caused electricity prices to increase 86 percent during the year. In 2002, peak days had far less impact on average prices than in 2001. The highest priced hour for Eastern New York in the day-ahead market was $262/MWh in 2002 versus $975/MWh in 2001. There was also less price volatility in the day-ahead market in 2002 due, in part, to more active price-capped load bidding and the introduction of virtual trading.

Average energy prices were 41 percent 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 to the introduction of load pocket modeling, making congestion more visible within New York City (the latter resulted in countervailing reductions in uplift costs from congestion).

Total market expenses (including energy, ancillary services, congestion, losses, and uplift expenses) were approximately $4.6 billion, about the same as the total expenses in 2001. There was, however, a shift among categories of costs, with congestion expenses rising significantly and uplift costs falling. Congestion costs have increased from $310 million in 2001 to $525 million in 2002. This increase is primarily due to the modeling of the load pockets within New York City.

Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors and other data input problems – these problems should not be frequent. The need for corrections also arises from software flaws that can cause pricing errors under certain conditions – it is important to resolve these flaws as quickly as possible to maximize price certainty. The frequency of price corrections was relatively high in 2000. After peaking at over 12 percent in May 2000, the frequency declined significantly to under 3 percent until the summer of 2002 when it rose to over 8 percent. This increase is associated with the changes in modeling of the New York City load pockets that was introduced in June. In particular, modeling discrepancies in the configuration of the grid for some of the generators in New York City caused temporary increases in real-time prices that required correction. However, once these modeling issues were addressed, the frequency of price corrections returned to lower levels.

Market Power Mitigation

With respect to market power mitigation in the day-ahead market, mitigation by the AMP did not occur in 2002. However, mitigation of energy bids under the ConEd mitigation for New York City occurred on every day in 2002. In the real-time market, the NYISO implemented mitigation measures to address the locational market power when it introduced modeling of transmission constraints within the city that define relatively narrow load pockets. These load pockets are constrained frequently and, when they are constrained, mitigation measures are often imposed. For example, the Astoria East load pocket was constrained almost 60 percent of the market intervals during the second half of 2002 (the time period in 2002 when load pocket modeling was in effect) while mitigation was imposed in 48 percent of the intervals during this period.

Uplift Costs

Uplift costs have fallen sharply -- these costs were $89 million lower for the period of June to December 2002 relative to the same time period in 2001 -- a reduction of 44 percent. High fuel prices at the end of 2002 reduced the apparent savings relative to 2001. Cost reductions were realized in the in the following areas:

- <u>Real-time local reliability uplift</u>: Reduction of 82 percent or $73 million resulting from implementing load pocket modeling.
- <u>Other real-time uplift</u>: Reduction of 20 percent or $14 million resulting from improved BME performance.
- <u>Day-ahead uplift</u>: Reduction of 10 percent or $2 million, caused in part from the load pocket modeling in the day-ahead market.

Net Revenue Analysis

Based on an analysis of market revenue and entry costs of new generation assets, the market in 2002 would not support new investment in gas turbines, in neither New York City nor statewide. We estimate that the annual costs of a new gas turbine outside of New York City to be approximately $80 per kW-year, but prices in the day-ahead market in 2002 would have provided revenues of only $32 to $40 per kW-year. Inside New York City, the estimated capital costs of a new gas turbine are $180 per kW-year, but revenues estimates based on 2002 day-ahead prices provide revenue of between $130 and $150 per kW-year

Our analysis suggests adequate capacity in the region, but pricing provisions associated with dispatching capacity during peak demand should also be examined to determine whether inefficient prices are contributing to insufficient revenue.

Price Statistics

Our analysis of price statistics in the West, Capital, and New York City zones for 2002 shows prices in the Capital and West zones dropped from 2001 levels due to slightly lower fuel costs. New York City prices remained close to 2001 levels, although load pocket modeling increased prices from the levels that would have otherwise prevailed. Our price analysis reveals a slight premium in day-ahead prices versus real-time prices in each of the three zones (*viz*., NYC: 2.2 percent, Capital: 3.9 percent, and West: 2.6 percent). These premia are not surprising due to the higher risk to loads of purchasing in the more volatile real-time market and the lack of TCC's to hedge congestion in the real-time market. It is also not surprising because of the outage risk to generators associated with day-ahead schedules.

The price volatility dropped from 2001 levels in all three zones. The volatility in real-time prices remains roughly twice as high as in day-ahead prices. Meanwhile, prices generally converged well throughout New York State. However, convergence was not as uniform in the summer months, attributable to periods of peak demand. The scarcity pricing provisions being implemented prior to summer 2003 (and discussed more below) should make real-time energy pricing during shortages more reliable, making the arbitrage with day-ahead prices more straightforward.

Modeling Improvements in New York City

The modeling of the load pockets within NYC, which was implemented June 3 in the real-time market and June 19 in the day-ahead market, has resulted in more accurate locational prices. Due to limitations of the SCD, a simplified representation of the intra-NYC constraints is used in the real-time market while a more detailed representation is used in the day-ahead market. We found a large premium in real-time prices in the Astoria East load pocket, while analysis of other load pockets revealed a premium in day-ahead prices. Part of this can be explained because limiting price-capped load bidding and virtual trading to the zonal level in NYC restricts 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, we 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 either (i) allowing virtual trading at the load pocket level; or (ii) allowing virtual trading on the 345 kv system separately from the 138 kv system, which would be a smaller departure from the current system.

BME Modeling Improvements

Historically, there has been a lack of convergence between hour-ahead and real-time prices. This has been a concern because large price differences can distort market mechanisms. For example, large price differences can cause external transactions and off-dispatch generation to be scheduled inefficiently. They can also cause increased uplift costs that inefficiently affect real-time prices. Two main changes were made to the market rules and the BME model to improve the price convergence prior to the summer of 2002. First, the BME counts curtailable export transactions as 30-minute reserves when the shadow price of maintaining 30-minute reserves on the system reaches certain levels. Second, the market model now recognizes undispatched portions of on-dispatch units as "latent" reserves that can help free-up other units for meeting energy demand. These changes appear to have driven some remarkable results, including drastic improvement in the price convergence in Eastern New York during the highest load hours. One further observation regarding price convergence is the fact that extraordinarily high BME prices in 2001 resulted in substantial scheduling of uneconomic transactions that were not actually needed in real-time. This has improved in 2002

B. Market Participant Conduct

This Report includes an analysis of energy and load bids by New York market participants as a way of evaluating competitive performance. Potomac Economics and the NYISO monitor these statistics as well as periodically analyzing trends in order to assess competitiveness. Trends in prices have been consistent with expectations for a workably competitive market. Day-ahead prices have been less volatile and have demonstrated greater convergence with real-time prices. This is largely attributable to participants taking advantage of the capability to schedule price-capped load, virtual load, and virtual supply day-ahead. Furthermore, instances of supply withholding were limited and did not prevent the market from functioning competitively.

Withholding of Generation

Market power is generally exercised by withholding generating capacity in an attempt to raise the market-clearing price. This can be done by physically withholding capacity or economically withholding it. The challenge in analyzing participant conduct is to differentiate strategic withholding from competitive conduct. To differentiate between these two alternatives, this Report evaluates potential withholding in light of the market conditions and participant characteristics that would tend to create the ability and incentive to exercise market power.

Two key factors are most likely to be correlated with incentives to exercise market power: participant size and the level of demand. Demand levels are particularly important due to the nature of the supply in wholesale electricity markets – a flat supply curve under most conditions causes prices to be relatively insensitive to withholding while tight market conditions under peak demands cause prices to become much more sensitive to withholding.

Our analysis of competitive conduct uses the “output gap” to estimate economic withholding. The output gap is the quantity of economic capacity that is not available to the market because a supplier submits an offer price significantly above a unit’s reference level, including offer prices covering start-up costs, minimum generation costs, and incremental costs.

This output gap analysis shows that while most hours exhibit little or no withholding, the output gaps did increase substantially in a number of high-load hours, which is consistent with strategic withholding. A closer analysis reveals that a single supplier was primarily responsible for the correlation between output gap and real-time load. We also analyzed withholding patterns without this supplier and found that economic withholding is virtually nonexistent at high load levels. The price impacts associated with the conduct of this supplier was limited because of the availability of capacity on the Central-East transmission interface in New York and the interface with New England

We also analyze deratings to evaluate potential physical withholding. Deratings are the quantity of capacity not offered into the market, including long-term outages, planned maintenance outages, and forced outages. Our analysis indicates that changes in deratings were not generally correlated with conditions under which the market would likely be most vulnerable to abuses of market power. These results suggest that strategic physical withholding has not been a substantial concern, although the physical audits performed by the NYISO market monitoring unit remain an important component of the market monitoring function.

Load Bidding and Virtual Trading

The year 2002 was the first full year during which virtual trading was used in New York markets, allowing entities without physical load or resources to make purchases and sales in the day-ahead market. By making virtual transactions in the day-ahead market and settling the position in the real-time market, any participant can arbitrage price differences between the day-ahead and real-time markets. This provides a significant tool to manage risk and to improve the convergence of the day-ahead and real-time energy prices. As indicated above, the day ahead and real-time prices have exhibited improved convergence in 2002.

Our analysis reveals that 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. But the patterns were distinctly different in New York City as compared to the rest of the state. In New York City (including Long Island) virtual load exceeded virtual supply scheduling. In the rest of the state, virtual supply exceeded virtual load until the last three months of 2002. Overall, virtual loads have generally been larger than virtual supply, raising the total day-ahead schedules.

In addition, our analysis of load bidding patterns indicates that price-capped load bidding has become more prevalent since the implementation of virtual bidding in 2001. We have also found that load supplied through physical bilateral contracts has remained relatively constant.

It is important to monitor how virtual trading is being used by market participants in order to detect gaming. 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, (i.e., close to the expected real-time price) while strategic attempts to influence day-ahead prices most likely would be signaled by price-insensitive virtual bids and offers. Therefore, we 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. We found that 70 to 80 percent of the virtual demand and offer bids were price sensitive. These results are positive, showing that virtual trading has been consistent with competitive expectations.

C. Pricing under Peak Demand

Efficient pricing under peak demand conditions plays a critical role in signaling efficient capital investment decisions. This includes investment decisions to keep existing plants online and investments to build new plants. The analysis in this Report focuses on the effect of market operations and rules on pricing and market outcomes during peak demand days in 2002.

The New York markets employ several strategies to manage the system under peak conditions, including:

- Dispatching generation "out-of-merit" order;
- Committing supplemental resources not selected by the day-ahead models;
- Dispatching reserves under peak load conditions; and
- Making real-time load curtailments and emergency out-of-market purchases.

In addition to these issues, we also address external transactions at peak hours.

Out-of-Merit Dispatch

Resources are sometimes dispatched out-of-merit order for various reasons. When this occurs under peak demand conditions, it can significantly affect prevailing energy prices. Hence, minimizing the use of out-of-merit generation to manage the system is a desirable goal.

During the summer of 2002, the NYISO made changes to the pricing rules that reduced OOM dispatch during peak periods. In particular, gas turbines and other units committed for ISO reserves or ISO reliability are now eligible to set prices. When these units are committed to provide reserves, they free-up other units to provide energy and, in this way, represent the real cost to ensuring energy needs are met. NYISO is also implementing measures to ensure that ten-minute gas turbines are eligible in the market software to set prices when they are dispatched for energy.

Supplemental Resource Evaluation

A unit is committed under the Supplemental Resource Evaluation (SRE) when operators determine that the day-ahead market has not committed enough resources to ensure reliability. These measures do not affect day-ahead prices directly, but by making additional capacity available in the real-time market, real-time prices tend to be lower than if SRE had not occurred. As one would expect, our analysis of the SRE calls indicates that they generally occur when the SCUC forecast load is significantly lower than the actual peak load. However, the magnitude of the SRE calls was often significantly higher or lower than the actual shortfall.

Most of the SRE actions were called by the transmission owners to meet local reliability requirements that are not modeled by the ISO's day-ahead software. While the incidence of SREs is consistent with what would be expected under the circumstances, potential price effects should be minimized. To do so, the ISO should (1) continue to adjust SCUC to the maximum extent possible to meet local reliability requirements and minimize the need for Transmission Owners (TOs) to use SREs and (2) screen or audit the SREs called by the TOs to ensure that the units selected are needed and are the most efficient alternative.

Reserve Shortages

A further analysis of peak pricing relates to the dispatch of operating 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 were adopted prior to the summer by counting exports as 30-minute reserves under certain conditions.

Even with the improvements to the management of 30-minute reserves, in some intervals, ten-minute reserves were used to meet energy demand. Like the dispatch of OOM units, dispatching ten-minute reserves for energy will increase the supply in real-time and can prevent prices from revealing shortages. When reserves are used to meet energy demand, the reserve market, in effect, has become the marginal supplier of energy and the prices in the energy market should reflect the value of the reserve capacity that was compromised.

We evaluated peak days in summer 2002 and found that, for about 13 peak hours, the NYISO was deficient in total ten-minute reserves. During these periods, the locational prices should have reflected the shortage. Yet, 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 ten-minute reserves of $1000 per MWh.

The energy market design employed in New York does not preclude setting prices that reflect this scarcity. There are significant quantities of generating resources with offer prices (based on legitimate marginal costs) ranging from $200 to $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 has not reliably set efficient scarcity prices. This analysis of the hours when the ten-minute reserve shortages occurred underscores the need for improvements in peak pricing rules.

Load Curtailment and Emergency Power

Besides reserve shortages, there are other measure the NYISO may take at peak times to balance supply and demand. These include:

- Calling upon Emergency Demand Response resources that curtail load (at their option) and are paid 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 exports from capacity resources; and
- Purchasing emergency power from neighboring control areas.

Each of these actions can affect real-time prices by altering the supply and demand in the real-time market. In our analysis, we compare two days with typical load profiles and show how demand response and other load curtailments have significant price effects. This analysis shows the substantial effects that these actions can have on market prices during peak demand conditions.

External Transactions

We analyzed external trading at peak-demand periods to determine the extent to which participants are efficiently utilizing the interface between New York and adjacent regions. The analysis is focused on fourteen peak days from late June to the end of July, 2002. We analyzed the three main New York interfaces: New England, Ontario, and PJM.

The analysis of the New England interface shows that 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 more than one-third of the hours where constraints were not binding and the price difference exceeded ten dollars, scheduled interchange moved power toward the low priced area. The analysis of the Ontario interface also shows little evidence that participants were able to schedule transactions to arbitrage significant price differences. In almost one-half of the hours where constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the lower-priced area. The analysis of the PJM interface shows that New York usually exported to PJM during the peak hours, even when prices were substantially higher in New York.

This conclusion is reinforced by similar results in periods when price differences were greater than $100 per MWh. These results indicate that the markets have not been efficiently arbitraged under the tightest market conditions – the time when efficient arbitrage could have the greatest benefit to consumers.

Recommendations

Each of these issues can substantially distort energy prices during the highest demand condition, particularly during shortages. Hence, the Report recommends a number of pricing reforms to improve the economic signals when these conditions arise. We proposed many of these reforms last fall in our 2002 Summer Assessment. These issues are inherent in each of the operating wholesale markets and FERC's Standard Market Design (SMD). The NYISO's proposed Real-Time Scheduling (RTS) project provides the means to address this in the longer term through use of a reserve demand curve. Proposed reforms include:

- Set prices at the bid cap level in Eastern New York when the requirement there for ten-minute reserves cannot be satisfied, and at the bid-cap level statewide when the statewide requirement for ten-minute spinning reserves are deficient;
- Pay generators that are backed down to provide reserves a "lost opportunity cost" 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;
- Provide addition information to operators to ensure that ten-minute reserves committed manually are eligible to set energy prices; and
- Modify external scheduling rules to optimize the physical interchange between New York and adjacent regions.

NYISO has taken steps to address these recommendations and most will be addressed by Summer 2003.

D. Installed Capacity Market

The capacity market is intended to provide efficient economic signals for investment and retirement decisions for electric generating capacity. Capacity is procured in New York by load serving entities either through bilateral contracts or through NYISO auctions. The capacity auctions include <u>strip auctions</u> that provide a "strip" of capacity for all months of the six month season and <u>monthly auctions</u> that provide access to supplemental capacity to augment that bought in the strip auctions. Our analysis examines separately New York City and the remainder of the state.

In New York State where a surplus of capacity existed in 2002, capacity prices were less than $2/kW-year, with most prices clearing less than $1/kW-year. In New York City, capacity prices generally cleared between $4/kW-year and almost $10/kW-year. These results for New York City are reasonable, but were affected by two off-setting issues.

The first issue was an error in the translation of installed capacity to unforced capability (UCAP) that caused the market to exhibit an apparent surplus in New York City that was artificial. In a competitive capacity market, this should have caused the capacity prices to clear at the short-run marginal cost of supplying capacity, which generally should be relatively low. This error was due to the second issue: that the capacity market in New York City is relatively highly concentrated and each of the suppliers is "pivotal" (i.e., the capacity requirements cannot be met without them).

Based on this analysis, we have supported the NYISO's efforts to correct the UCAP translation error and implement a capacity demand curve that will reduce suppliers' incentives to withhold capacity and improve the economic signals provided by the New York capacity market.

E. External Transactions

In last year's Annual Report, we analyzed the utilization of interfaces between New York and adjacent regions (ISO-NE and PJM) and highlighted issues that have prompted several improvements to transaction scheduling rules. Among other things, we evaluated the arbitrage of prices between regions, something that reveals the efficiency of interface utilization. Our evaluation of this issue for the market in 2002 shows that price arbitrage improved through 2001 and early 2002 but that substantial price differences between New York and adjacent markets have continued to occur under peak demand conditions. This latter issue is addressed in the Peak Pricing section of this Report. Aside from the issues of external transactions at peak times, other issues relating to external transactions remain, including:

- Price convergence between New York and adjacent regions at all times;
- Long-term trends in price convergence and seams issues; and
- The efficiency of market participant-determined flows between regions.

Convergence Between Markets

We analyze the trading between adjacent markets during hours when transmission constraints are not binding. We find, in general, that the transmission interfaces between New York and adjacent regions continue to not be fully utilized. For example, there are still a significant number of hours when counter-intuitive transactions prevail, indicating the need for on-going efforts to improve inter-regional scheduling.

Long-term Trend

The issue of improving the efficiency of external transactions is an important one and one that has been the subject of various reforms to improve trading. We measure the progress that has been made as a result of these various reforms in two ways. First, we examine the persistence of the price differences between New York and adjacent regions to examine whether the difference has narrowed over time – something that would be expected given the efforts to address seams issues. We find, by various measures, that the price difference has narrowed considerably. The difference in prices between PJM and New York has declined by 33 percent and the price difference between New York and New England has declined by 50 percent.

We have also estimated the production costs savings that have accrued as a result of improved trading over the interface. These estimates were based on the trade between adjacent areas and the savings in production costs that result from expensive units being replaced by imports. We find that total production costs savings amounted to almost $30 million in 2002 as a result of improved transactions.

Coordination of Flows

We analyzed the actual power scheduled over the interfaces with adjacent regions to illuminate the character of any impediments. Transactions that are bid into the NYISO are either scheduled or not scheduled. Those not scheduled are divided into (i) those whose bids were not economic in New York, and (ii) those whose bids are economic in New York, but were not scheduled for other reasons (e.g. failed the checkout process, not accepted in adjacent region). We find that New York was a net importer of power from PJM in both the day-ahead market and in transactions schedules in the hour-ahead BME update. More importantly, there were almost no transactions unscheduled for reasons other than the economics in New York. For New England, NYISO is not predictably a net importer or exporter in the day-ahead market but is a modest net importer in transactions scheduled in the hour-ahead BME update. Transactions unscheduled for reasons other than the economics in New York are virtually zero, with the exception of hour-ahead exports discussed below.

For the interface with Ontario, New York is a clear net importer from Ontario in the day-ahead market and in the hour-ahead update. The most notable observation with respect to this interface is that nearly two-thirds of the unscheduled transactions are unscheduled in the BME process for reasons other than economics (averaging more than 500 MW of transactions). Similarly, the data on hour-ahead exports to New England show that, on average, 400 MW are accepted by New York but are not accepted by New England. These are generally transactions that are accepted in New York but rejected in an adjacent region's economic evaluation. This can be a concern because these transactions can occupy scarce transmission capability and cause the interface to be underutilized.

Conclusions and Recommendations

In summary, improvements have been made to address the efficiency of transactions with adjacent regions, but further improvements are needed. We recommend the NYISO coordinate the physical interchange with adjacent ISOs. This can be done by automatically adjusting the power flows between the two markets in small increments every 5 to 15 minutes. This reform would ensure that the markets are efficiently arbitraged and would eliminate the remaining seams issues in the Northeast.

It is important to emphasize that this proposal does not mean the ISO will be taking a position 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 proposed changes should improve participants' ability to transact financially between markets. To the extent that prices are rationalized between markets, the financial risk that 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.

F. Ancillary Services

Ancillary services account for only about two percent of the overall market expenses. Nonetheless, they are critical in maintaining reliable and safe operation of the grid. Ancillary services include reserve capacity, regulation, and other services that coordinate grid use among many market participants. The generation-related services (most notably reserves and regulation) are provided through NYISO-administered auctions.

In these reserve markets, offers to supply typically exceed approximate demand. For 30-minute reserves, offers typically exceed approximate demand by 220 percent. For total ten-minute reserves east of the Central-East interface, offers typically exceed approximate demand by 160 percent –although the market for ten-minute non-spinning reserves is currently subject to a requirement to sell and a bid cap. For regulation and ten-minute spinning reserves, offers typically exceed approximate demand by 90 to 100 percent.

Our analysis indicates that the share of the total market expenses that are accounted for by ten-minute and 30-minute reserves declined in 2002 from 2001. This can be explained by several factors. First, a reserves-sharing agreement with ISO-New England allowed NYISO to lower the ten-minute reserve requirement in Eastern New York from 1200 to 1000 MW at the beginning of 2002. Second, starting October 1, 2001, the NYISO began locational ancillary services prices for three regions – Long Island, Eastern New York outside Long Island, and Western New York. Prior to this change, resources in Long Island frequently set state-wide ancillary services prices. Finally, a drop in ancillary services price spikes is partly due to the latent reserves modeling change implemented in the spring of 2002. The BME model now treats 30-minute reserve capable units that do not submit bids as if they bid at zero dollars. This has helped the model avoid running into 30-minute reserves shortages when a surplus of available 30-minute capacity is capable of ramping up.

Our analysis of the regulation market shows prices have increased considerably in 2002. This may partly be explained by the fact that only 50 percent 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. The primary reasons for the increases in regulation prices were:

- Modeling changes in SCUC and BME sometimes limit the amount of regulation that may be provided by certain units -- this effectively reduces the supply available on some units, particularly during off-peak hours;

- Fuel price increases that raise the opportunity costs of hydro units and others to provide regulation; and

- Quantities offered have remained relatively steady, but bid prices during off-peak hours have increased modestly.

This Report indicates that the ancillary services markets continue to require attention. A substantial amount of capability is routinely not offered in the reserve markets. This can have significant effects on the energy market when conditions become tight in peak hours and the energy market and reserve markets compete for the same resources. This can also occur in off-peak hours when a large share of the capacity is offline. These effects result when a shortage of reserves offers causes relatively economic energy supplies to be diverted into the ancillary services markets, which can raise energy prices substantially. The sustained nature of the low offers into the reserve markets indicates that the incentives to offer in these markets are inadequate.

Based on this analysis, the Report recommends several changes to ancillary services markets. First, the pricing rules should be modified to set prices for ancillary services at the marginal system cost of procuring them. This form of pricing would cover all suppliers' opportunity cost of being held out of the energy market and would send a more accurate price signals to the market. Second, the Report supports implementation of a multi-settlement system (day-ahead and real-time) for reserves. This would compliment the current multi-settlement system for energy. A third recommendation is to establish a demand curve for reserves, which would prevent the ISO from taking excessively costly actions to maintain low value reserves and would set reserves and energy prices at efficient levels during capacity shortages. Finally, the Report supports lifting the offer cap for ten-minute non-synchronous reserves.

G. Demand Response Programs

There are currently three demand response programs in New York State:

- DADRP – The day-ahead demand response program allows resources to bid into the day ahead-market just the same as any supply resource – these resources are paid the day-ahead clearing price;
- ICAP/SCR – The special case resource program allows loads capable of curtailing within two hours whenever operators forecast a reserve deficiency to sell capacity into the UCAP market; and
- 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.

There were 27 days in 2002 when total load scheduled to be curtailed during afternoon hours (12 pm-6 pm) in the day-ahead market exceeded 20 MWh. The day with the most curtailed demand was July 1st when 100 MWh were scheduled for curtailment at an average price of $74/MWh. During the entire summer of 2002, approximately 85 percent of scheduled DADRP was bid at the minimum cap of $50/MWh. The average clearing price was $78/MWh.

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 on July 30 and slightly less on August 14th. If the EDRP and SCR were not called on August 14th, New York State would have reached a record high load. Because real-time prices were relatively low on these days, resources curtailed in real-time were paid the minimum amount of $500/MWh.

As measured in MW capability, the NYISO demand response programs are among the largest in the country. While the size of the NYISO demand response programs is a positive feature of the New York market, the changes recommended in the peak pricing section of this Report would help ensure a more effective use of these resources. The recommended changes would provide demand-response resources more flexible participation in the programs by establishing variable curtailment prices. In addition, it is critical that spot prices reflect the use of these resources, which will result in more efficient price signals during shortage conditions.

II. Market Prices and Outcomes

While New York has made various changes to its market rules and procedures over the last year, there have been no changes to the basic structure of the multi-settlement energy markets that are the central feature of the New York electricity markets. The multi-settlement system consists of a financially-binding day-ahead market and a real-time market. Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. The day-ahead and real-time markets are augmented with an hour-ahead scheduling process that updates the day-ahead commitment of resources based on forecast load for the next hour. This is the Balancing Market Evaluation (BME) model. The main functions of the BME model is to commit 30-minute gas turbines, establish dispatch levels for units that only receive hourly dispatch signals (i.e., off-dispatch units), and schedule external transactions.

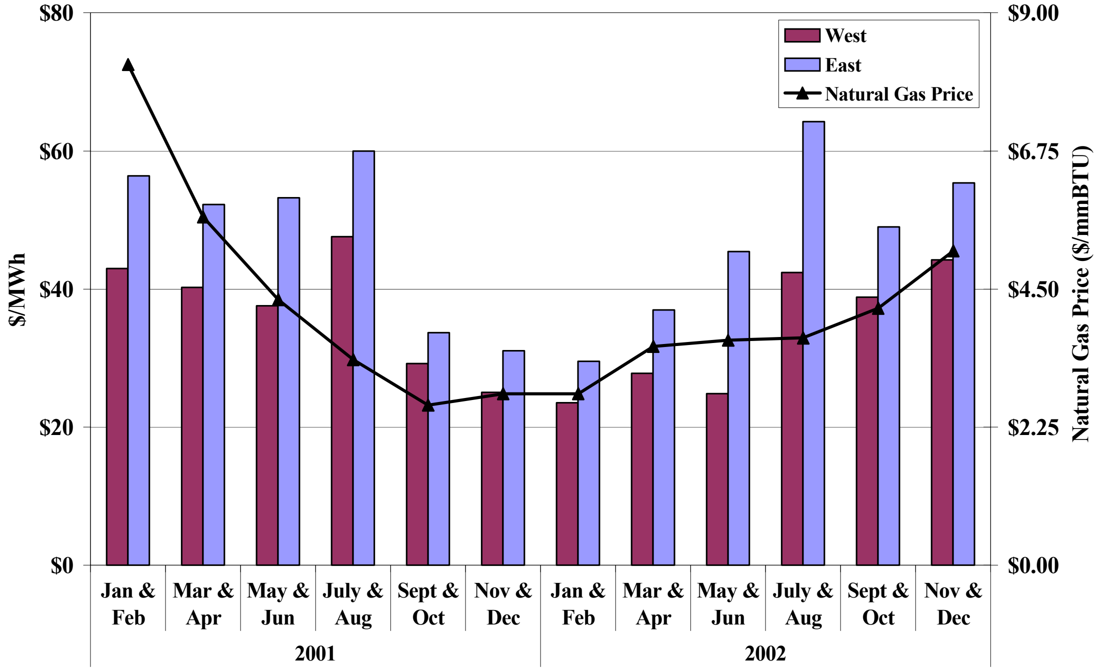
This section of the Report evaluates the performance of these markets with respect to prices and market outcomes. We evaluate the energy price trends over 2002, the overall market expenses, and the trends in individual market cost components. We also evaluate the incentives for new investment given the level of market prices.

A. Summary of 2002 Prices and Costs

The main trends in the energy market during 2002 were driven by fuel costs, which increased significantly. Figure 1 shows that day-ahead energy prices tracked underlying fuel costs closely during both 2001 and 2002. As Figure 1 shows, natural gas prices almost doubled and fuel oil prices increased almost 80 percent during 2002. This caused electricity prices to increase 86 percent between January and December, 2002.

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. There was also lower price volatility in 2002 due, in part, to more active price-capped load bidding and the introduction of virtual trading.

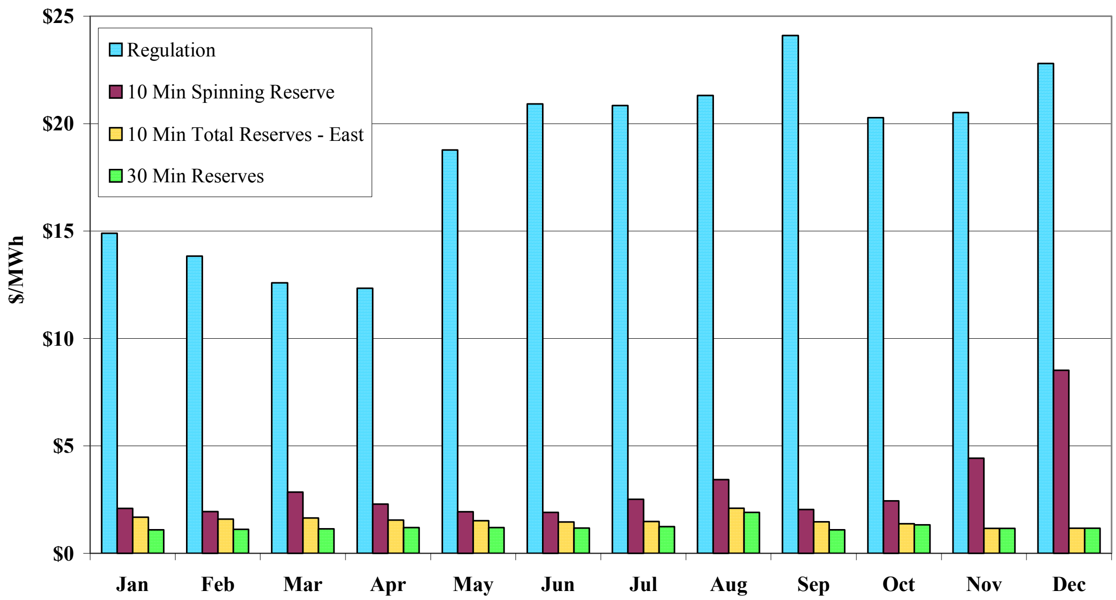
Figure 1
Day-Ahead Energy Price and Fuel Price Trends
2001 - 2002



The average day-ahead energy price was 41 percent 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 in the market software that made the congestion component of spot prices more accurate within New York City (resulting in countervailing reductions in uplift costs from congestion).

Section VII evaluates the ancillary services market in more detail. Figure 2 shows monthly average ancillary service prices. Consistent with the design of the market, the higher value products are priced at higher levels (regulation and ten-minute spinning reserves are priced highest). The ancillary services are priced locationally, but the only locational-specific requirements are on Long Island (30 and ten-minute reserves) and in Eastern New York (ten-minute total reserves). Prices for Long Island are not shown in the figure. The locational constraint on ten-minute total reserves has not been binding, which is why the average prices for this service is close to 30-minute reserve prices.

Figure 2
Monthly Average Ancillary Service Prices
Day-Ahead Market -- 2002

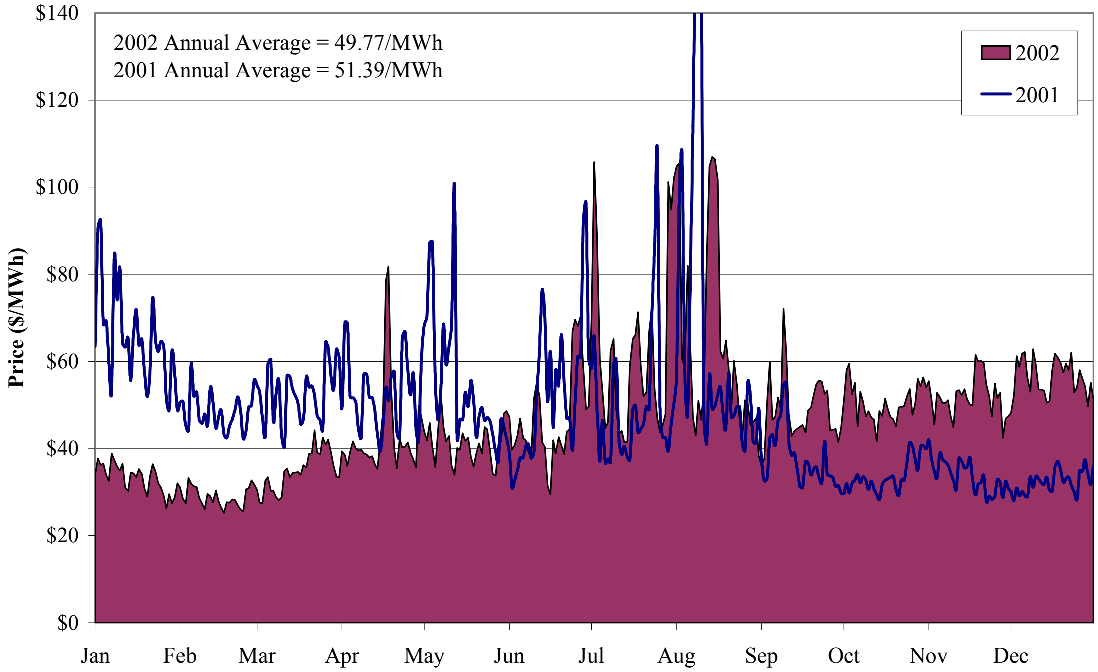


Source: NYISO Market Monitoring and Performance Unit.

Figure 3 calculates an "all-in" price that includes the costs of energy and ancillary services in the day-ahead and real-time markets. The same fuel price pattern is evident, which shows prices generally decreasing in 2001 and increasing in 2002. The all-in price fell by approximately 3 percent in 2002. The figure also shows that the daily prices have been less volatile in 2002 during the peak periods.

Total market expenses (including energy, ancillary services, congestion, losses, and uplift expenses) were approximately $4.6 billion, about the same as the expenses in 2001. Figure 4 shows a comparison of total market expenses in 2002 and 2001. As a result of declining energy prices over 2001 and increasing energy prices in 2002, the relative expenses between seasons shifted. In 2001, the first four months had higher energy costs than the last four months while the opposite was true for 2002.

Figure 3
Average Daily Total Price – Energy and Ancillary Services
2001-2002



Source: NYISO Market Monitoring and Performance Unit

Figure 4 also reveals that costs shifted among categories, especially between uplift and congestion. Congestion costs have increased from $310 million in 2001 to $525 million in 2002. Much of this increase was off-set by lower uplift costs. This shift is primarily due to the modeling of the load pockets within New York City in the market software. These model revisions more explicitly recognize the transmission constraints within the City. This resulted in the ISO ceasing its reliance on out-of-merit generation dispatch to manage congestion.

When out-of-merit calls are used to manage congestion, generators are paid their bid through uplift payments. By more precisely defining load pockets, the LBMPs within the New York City load pockets now indicate the need for dispatch of expensive generation inside the load pockets. The cost of congestion is reflected in the spot market prices, rather than being included in uplift, which is less transparent. This provides substantial benefit to the market because the areas that rely on expensive generation are more accurately seeing these costs, creating incentives to build new generation or increase transmission capability with adjacent areas.

Figure 4
New York Electricity Market Expenses
2001 - 2002

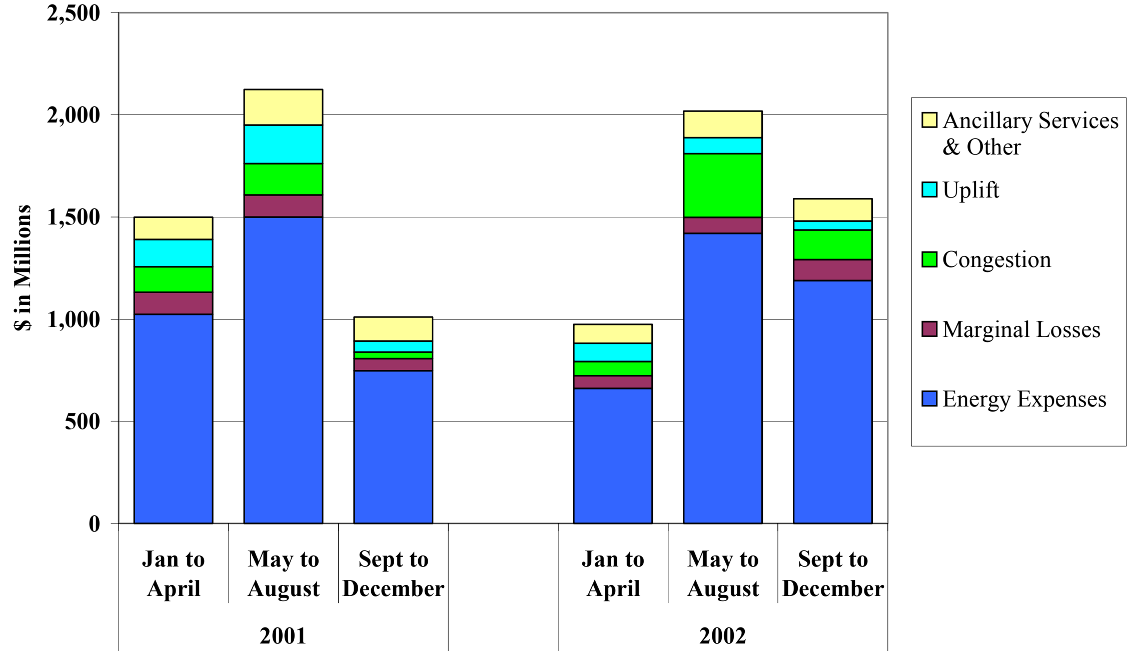


Figure 5
Congestion Revenues
2001 - 2002

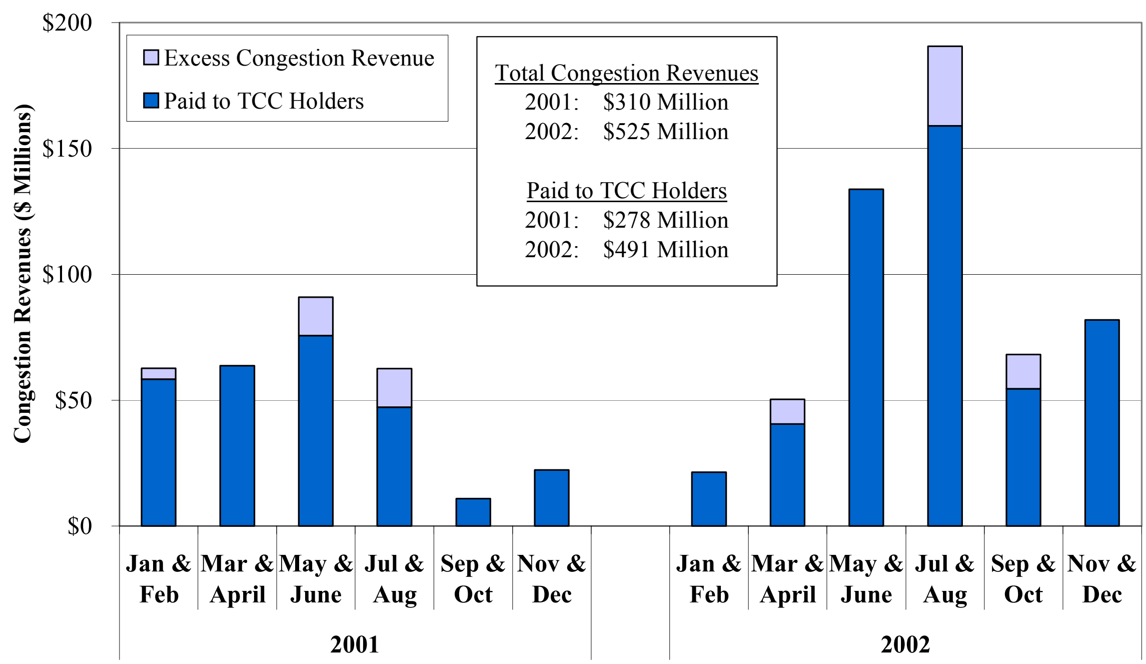


Figure 5 shows the trend in congestion costs paid by NYISO participants in 2001 and 2002. It also shows the total amount that was paid to holders of Transmission Congestion Contracts (TCCs). Market participants may purchase TCCs, which allow the holder to collect the congestion revenue between two points. For instance, a 10 MW TCC originating at the Capital Zone and terminating at the New York City Zone would be paid ten times the price difference between the two locations. When TCC rights are designed accurately, the total revenue should approximate the total congestion costs. This is the case in NYISO where the TCC revenues were 94 percent of the total congestion costs in 2002.

B. Price Comparisons

Our zonal price analysis for the West, Capital, and New York City zones for 2002 shown in Table 1 indicates that prices in the Capital and West zones dropped from 2001 levels due to slightly lower fuel costs. New York City prices remained close to 2001 levels – load pocket modeling increased prices from the levels that would have otherwise prevailed.

Table 1
Day-Ahead and Real-Time Price Statistics for Selected Zones
January - 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

Table 1 also reveals a slight premium in day-ahead prices versus real-time prices in each of the three zones (by zone this premium is: NYC: 2.2 percent, Capital: 3.9 percent, and West: 2.6 percent). This premium is not surprising because of the higher risk to loads of purchasing in the more volatile real-time market and the lack of TCC's to hedge congestion in real-time. This latter factor may cause purchasers to value day-ahead commitments that insure against unexpected outages that can lead to unpredictable congestion costs. Similarly, the day-ahead premium also reflects generators' outage risk in the sense that units scheduled in the day-ahead market may not be able to perform and, thus, risk having to fulfill their obligations in real-time. Because such an outage is likely to increase prices, the generator risks having to fulfill its day-ahead commitments at higher real-time prices. The volatility of prices dropped from 2001 levels in all three zones. The volatility in the real-time prices remains roughly twice as high as the volatility in the day-ahead prices.

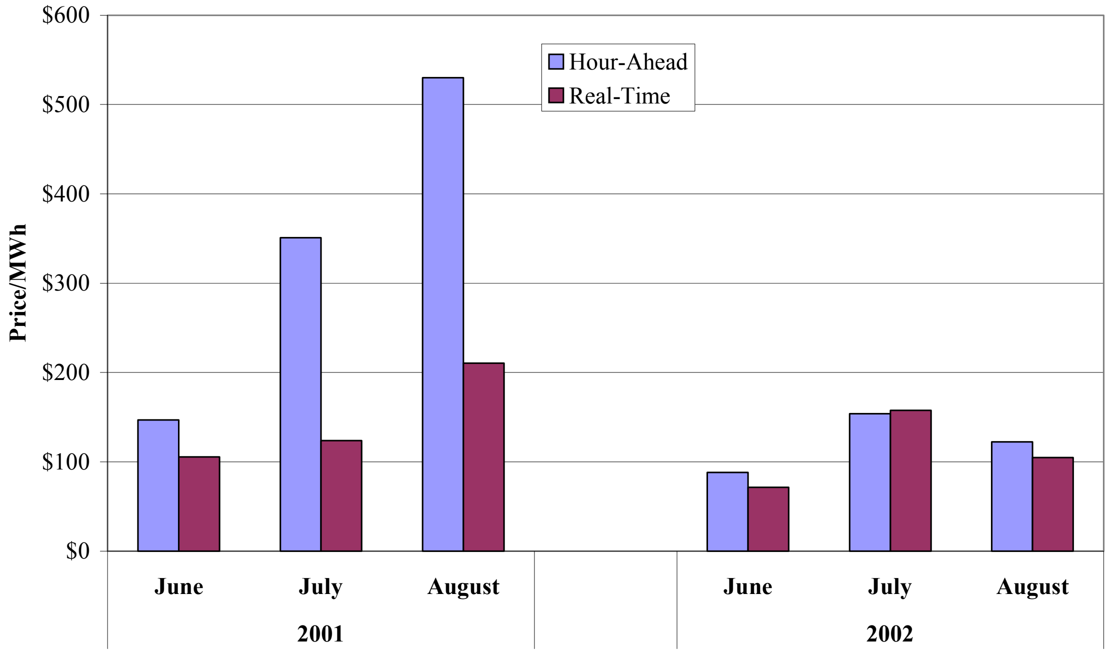
C. Hour-Ahead to Real-Time Price Convergence

Historically, there has been a lack of convergence between hour-ahead and real-time prices in New York. This has been a concern because large price differences can distort market mechanisms, including causing external transactions and off-dispatch generation to be scheduled inefficiently. It also can cause increased uplift costs that inefficiently affect real-time prices. Two main changes were made to the market rules and the BME model to improve the price convergence prior to the summer of 2002.

First, the BME has been enabled to recognize curtailable export transactions as 30-minute reserves when the cost of maintaining 30-minute reserves on the system rises to certain levels. Second, the market software now recognizes undispatched portions of on-dispatch units that bid into the energy market as "latent" reserves that can help free-up other units for meeting energy demand. These changes appear to have driven some significant results, including drastic improvement in the price convergence in Eastern New York during the highest load hours. Figure 6 reveals this trend.

One further observation regarding price convergence is the fact that extraordinarily high BME prices in 2001 resulted in substantial scheduling of uneconomic import transactions that were not actually needed in real-time. This contributed to inflated uplift costs in 2001 and has not occurred in 2002 due to the improved price convergence.

Figure 6
Average Hour-Ahead and Real-Time Energy Prices
East New York – June to August, 2001-2002
Hours with Highest 10 percent of Real-Time Load

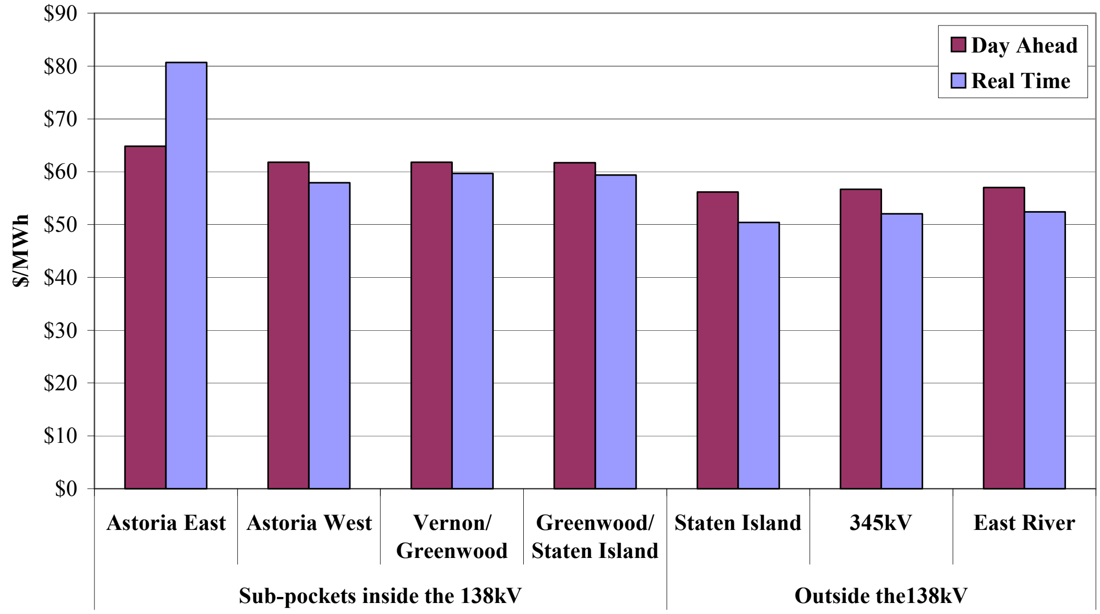


D. Price Convergence in Load Pockets

The modeling of the load pockets within NYC, which was implemented on June 3, 2002 for the real-time market and on June 19 for the day-ahead market, has resulted in more accurate locational prices. Contrary to the zonal price statistics, we find a large premium in real-time prices in the Astoria East load pocket while the other pockets showed a premium in day-ahead prices larger than the premia in zones outside New York City.

This is likely explained by price-capped load bidding and virtual trading. Price-capped load and virtual load and supply bids are submitted at the zonal level. Therefore, bids and offers (and therefore prices) will reflect the zonal average supply and demand conditions in the day-ahead market. In real-time, prices will reflect actual demand and supply conditions in the load pockets. Because the Astoria East load pocket has higher prices, in general, than the other load pockets in NYC, the average zonal (day-ahead) price will be lower than the (real-time) load pocket price.

Figure 7
Average Day-Ahead and Real-Time Prices for NYC Load Pockets
July-December, 2002



To improve the price convergence in load pockets, this Report recommends:

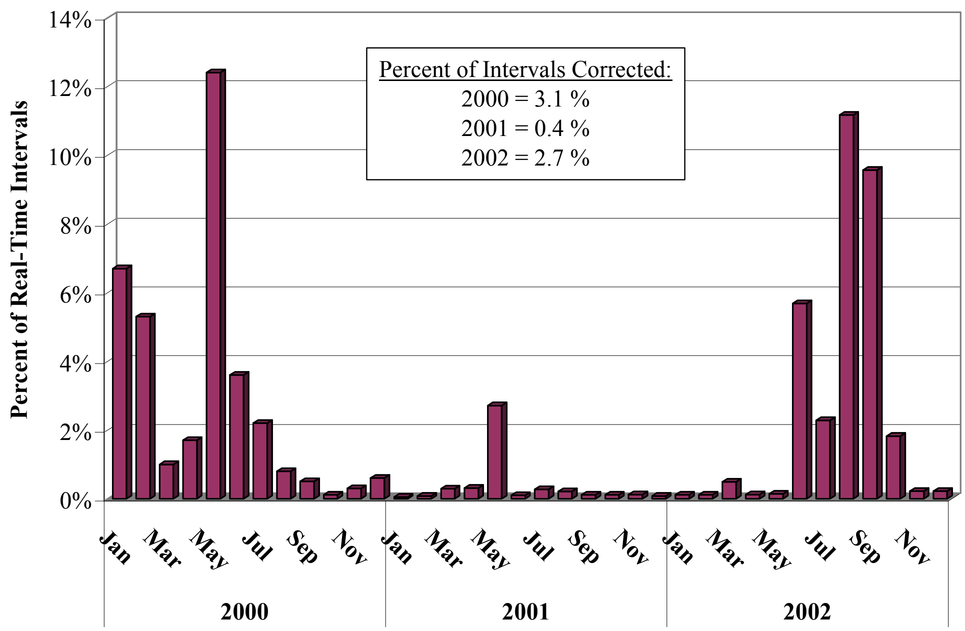
- The NYISO evaluate the load pocket modeling to ensure that any inconsistencies between the day-ahead and real-time modeling are minimized; and
- The NYISO consider (i) allowing virtual trading at the load pocket level; or (ii) allowing virtual trading on the 345 kv system separately from the 138 kv system, which would be a smaller departure from the current system.

E. Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors and other data input problems. Accurate prices are critical not only for the obvious need to settle market transactions fairly, but also for sending reliable real-time price signals to participants that have to make continual buy and sell decisions. Therefore, the incidence of these problems should be minimized. Price corrections are required when flaws in the market software or flaws in operator procedures cause prices to be posted erroneously. It is important to correct these errors as quickly as possible.

The frequency of price corrections was relatively high in 2000, but has been decreasing steadily until the summer of 2002. The frequency of price corrections after the beginning of June 2002 increased substantially as a result of the introduction of changes to the modeling of New York City load pockets. Additionally, modeling discrepancies in the configuration of the grid for some of the generators in New York City caused a temporary increase in the need for real-time price corrections. Figure 8 shows the frequency of price corrections for 2000-2002. Once the modeling issues related to the introduction of load pocket modeling were addressed, the level of corrections returned to the low frequency that had occurred prior to the Summer of 2002.

Figure 8
Percentage of Real-Time Prices Corrected
2000 - 2002



F. Market Power Mitigation

The NYISO market power monitoring and mitigation plan provides for mitigation of participant bid parameters (i.e., energy bids, start-up and no-load bids, and physical parameters). When these bidding parameters exceed pre-defined *conduct* thresholds, a participant's bid parameters may be mitigated if the conduct results in sufficient impact on the energy price. Mitigation is applied to both the day-ahead and the real-time market. In the day-ahead market, the modeling software is capable of evaluating the impact of conduct that exceeds the thresholds and subsequently mitigating the bid parameters if the impact is significant according to pre-defined impact thresholds. This procedure in the day-ahead market is known as Automated Mitigation Procedures (AMP). AMP is not in place in the real-time market. Market monitoring and mitigation in the real-time market is conducted by the NYISO Market Monitoring and Performance staff.

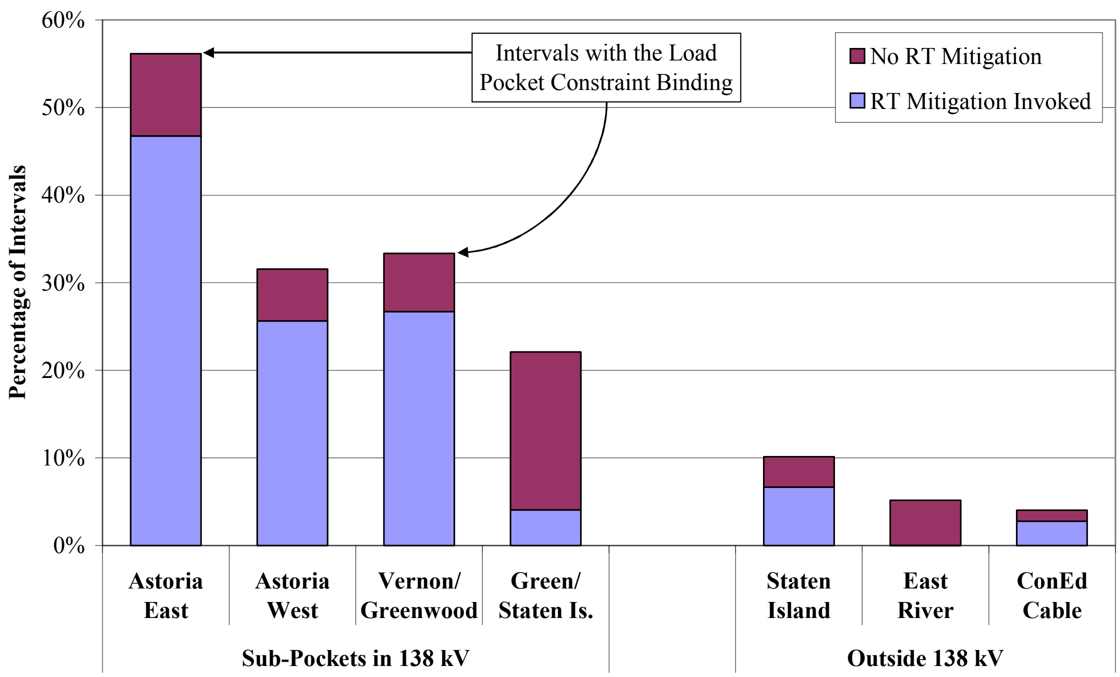
There are also special mitigation procedures set up in the New York City area where congestion is a frequent problem. In the day-ahead market, when the dispatch model detects congestion into New York City that exceeds certain thresholds, units inside New York City are mitigated to a reference level based on variable production expenses. These mitigation procedures are referred to as the Consolidated Edison or "ConEd" mitigation procedures as they were developed by ConEd when it divested its generation. Bids mitigated in the day-ahead market in accordance with the ConEd procedures are carried forward to the BME model and the real-time market up to the day-ahead mitigated quantity while the mitigation does not apply to the output above that amount.

In the BME model and in the real-time market, units in certain load pockets within the City are subject to mitigation on that portion of their unit not already mitigated by the ConEd procedure. This mitigation only applies when the cost of congestion into the load pockets exceeds established economic thresholds (that vary inversely with the frequency of constraints into the load pocket) and the suppliers' bids exceed this conduct threshold. These mitigation procedures were introduced at the same time as the load-pocket modeling changes noted above.

In the day-ahead market, mitigation by the AMP did not occur in 2002. However, mitigation of energy bids under the ConEd mitigation for New York City occurred on every day in 2002. Furthermore, the load pockets that are subject to the new modeling changes frequently are constrained and when they are constrained, the new mitigation measures are frequently imposed. For example, the Astoria East load pocket was constrained almost 60 percent of the market intervals during the second half of 2002 (the time period in 2002 when the load-pocket modeling was in effect) while mitigation was imposed in 48 percent of the intervals during this period.

The load pockets in New York City are defined by the New York City transmission infrastructure. The New York City transmission system is divided between the 345 kV system and the 138 Kv system. The 345-kV system transmits power along two main north-south corridors through the western part of New York City. The lines start at the ConEd cable connection with up-state New York near the Bronx. One main corridor runs into and through Manhattan Island and south to Staten Island while the second runs along the western edges of the boroughs of Queens and Brooklyn and south to Staten Island. The 138 kV system follows a somewhat parallel route to the east connecting with upstate New York in the Bronx and feeding power along a southeasterly route through Queens, Brooklyn. The load pockets on the 138 kV system are more prone to congestion than those on the 345 kV system, as Figure 9 shows.

Figure 9
Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets, June – December -- 2002

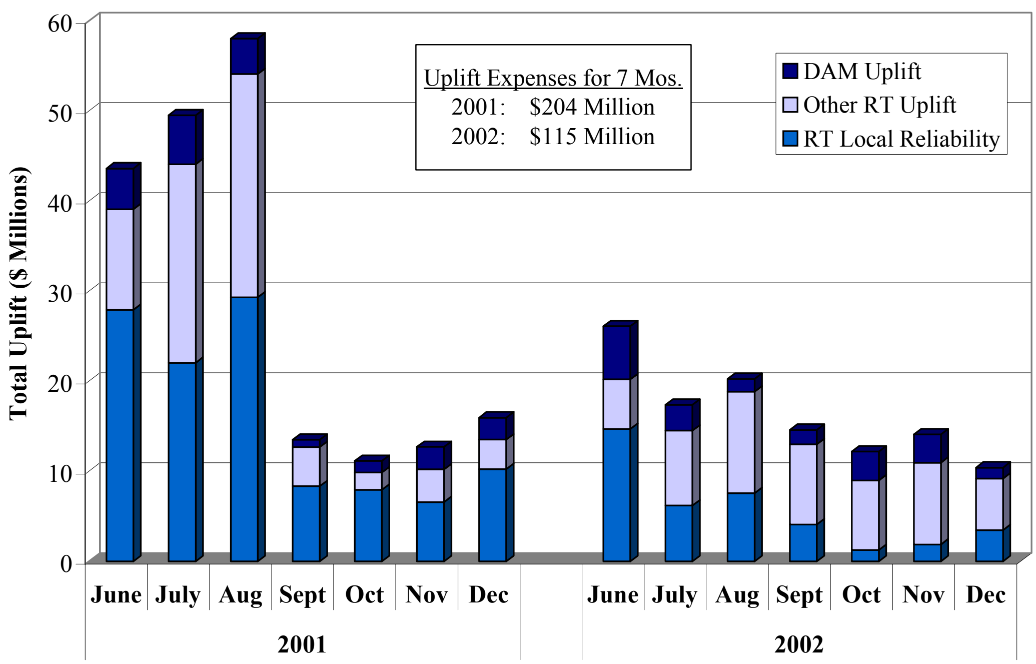


This figure also shows both the portion of the intervals when transmission constraints into each load pocket were binding and the portion of the intervals when mitigation was imposed. The fraction of constrained intervals in which mitigation was imposed varies substantially across the load pockets due to the level of competition in some of the load pockets and the severity of the congestion.

G. Uplift Costs

Uplift costs are paid to suppliers that are required to operate to support the ISO's reliability and security responsibilities and whose bid costs are not covered at market prices. As Figure 10 shows, uplift costs paid in 2002 fell sharply. It shows total uplift costs were $89 million lower in the June to December period of 2002 than the same time period in 2001. This is a reduction of 44 percent. High fuel prices at the end of 2002 reduced the apparent savings relative to 2001 because uplift costs, in large part, depend on the operating cost of generators, something that increased as a result of higher fuel costs.

Figure 10
Day-Ahead and Real-Time Uplift Expenses
June to December, 2001 - 2002



As explained above, uplift costs also declined in part due to reduced payments for out-of-merit generation to manage congestion in the New York City load pockets that are now reflected in the congestion component of the spot market price. The payments to manage congestion in the load pockets through out-of-merit generation were paid out of real-time reliability uplift, which declined $73 million in 2002 — an 82 percent reduction.

Changes to the BME to more accurately schedule units and imports for the real-time market saved $14 million (a 20 percent reduction) in other uplift associated with the real-time market. Finally, the day-ahead uplift was $2 million less – a 10 percent reduction. The savings in both of these categories likely would have been larger if fuel prices had not risen sharply in the final months of 2002.

H. Net Revenue Analysis

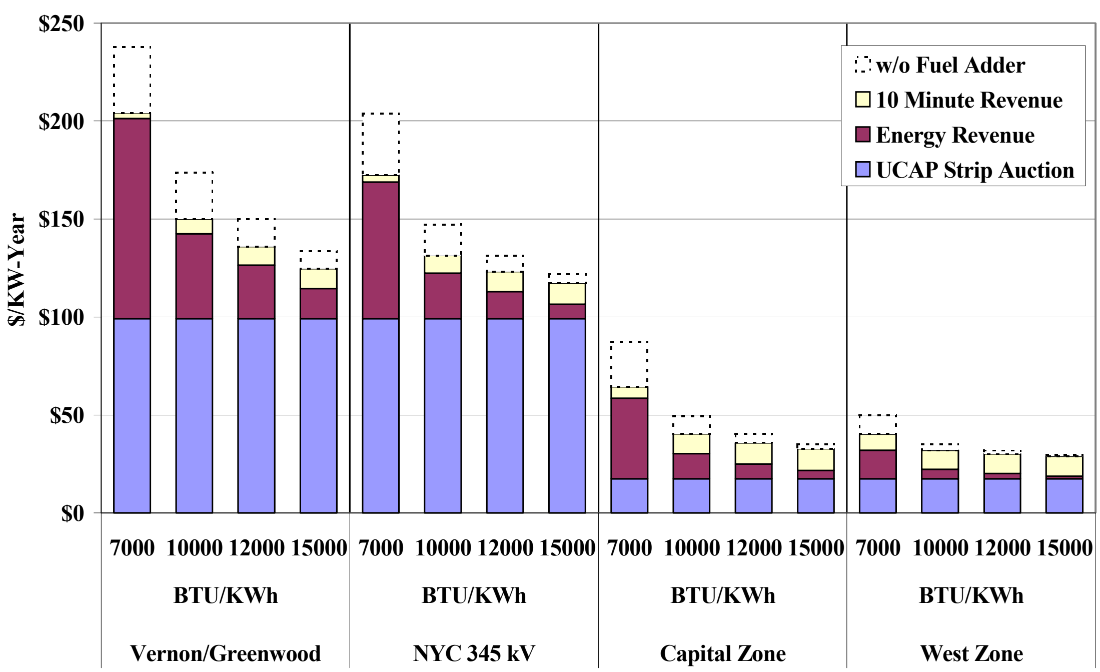
Entry of new generation (and retirement of existing generation) is governed by revenues from the energy, ancillary services, and capacity markets, which must cover variable costs and provide a return on invested capital for entry to occur. In the short-run, if prices do not provide sufficient revenue to justify entry, then one may conclude that (i) new capacity is not needed; (ii) load conditions have been lower than expected; (iii) generator availability has been higher than expected; or (iv) market rules are causing revenues to be reduced inefficiently. Likewise, if prices provide excessive revenues in the short-run, one may conclude that (i) new capacity is needed; (ii) loads have been higher than expected; (iii) generator availability has been lower than expected; or (iv) market rules or market power has caused prices to clear high than competitive levels. This section analyzes the net revenues that would have been produced in 2002 for generators with different characteristics in various locations to evaluate these factors.

We estimate the annual cost of a new gas turbine to be approximately $80 per kW-year outside of New York City. Assuming a heat rate of 10,000 btu/kWh, such a unit would earn between $32 to $40 per kW-year in the day-ahead market outside of New York City based on 2002 prices. This is clearly not sufficient to induce entry. Inside New York City, the costs of installing a new gas turbine are likely significantly higher. The NYISO has estimated the annual costs at approximately $180 per kW-year. Using the same heat rate assumption, net revenues inside New York City would range between $130 and $150 per kW-year at 2002 price levels, making investments in new generation there also unlikely to be profitable.

More generally, Figure 11 shows estimated revenues for a range of plant efficiencies and at four zones within New York – Vernon/Greenwood, New York City, Capital, and West. Outside of New York City, i.e., Capital and West zones, even the most efficient gas turbines would be unprofitable. The 7000 heat rate corresponds to a new combined-cycle unit. Due to its efficiency, it would realize a high net revenue. However, the annual entry costs are also significantly higher at more than $100/kW-year outside of New York City versus the gas turbine capital costs of $80/kW-year.

The totals in Figure 11 (which exclude the shadow box on the top of each bar) are calculated based on the assumption that intraday gas prices during the afternoon of peak days are 20 percent higher than day-ahead gas prices. If the generator purchased gas day-ahead or incurred no premium in the intra-day gas market, the total revenue would be equal to the bar including the shadow box. Nonetheless, this additional revenue would still not be adequate to support entry.

Figure 11
Estimated Net Revenue in the New York Markets
Day-Ahead Market -- 2002



Based on this analysis, the energy market in 2002 would not support new investment in gas turbines, in neither New York City nor statewide. This suggests adequate capacity in the region, but pricing provisions associated with dispatching capacity during time of peak demand should also be examined to determine whether inefficient prices are contributing to insufficient revenue. This latter topic is addressed in detail in a latter section.

I. Load and Price Duration Curves

Figure 12 and Figure 13 show the differences in load levels and hourly prices from 2001 to 2002. Figure 12 shows a load duration curve. The points on this curve indicate (on the x-axis) the number of hours that the load was below designated load level (on the y-axis). In most hours, load levels in New York were 100 to 300 MW higher in 2002 than in 2001. Due to hotter weather in 2002, the average loads in the top 1000 load hours were generally 500 to 1000 MW higher than in 2001, although the 2001 peak was 300 MW higher.

Figure 12
Load Duration Curves for New York State
2001 -- 2002

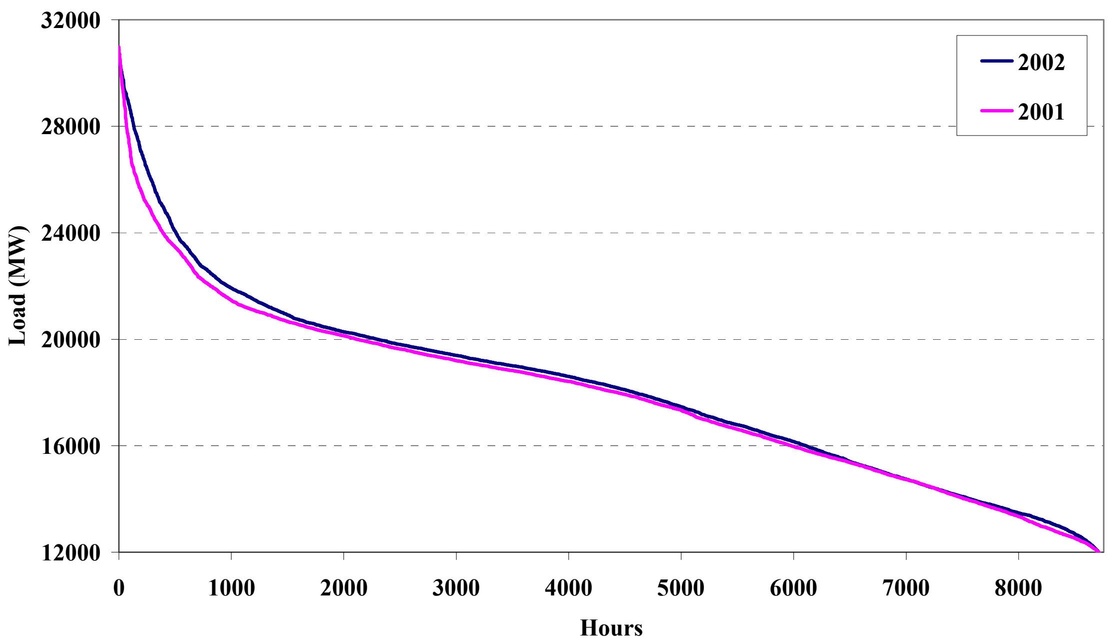
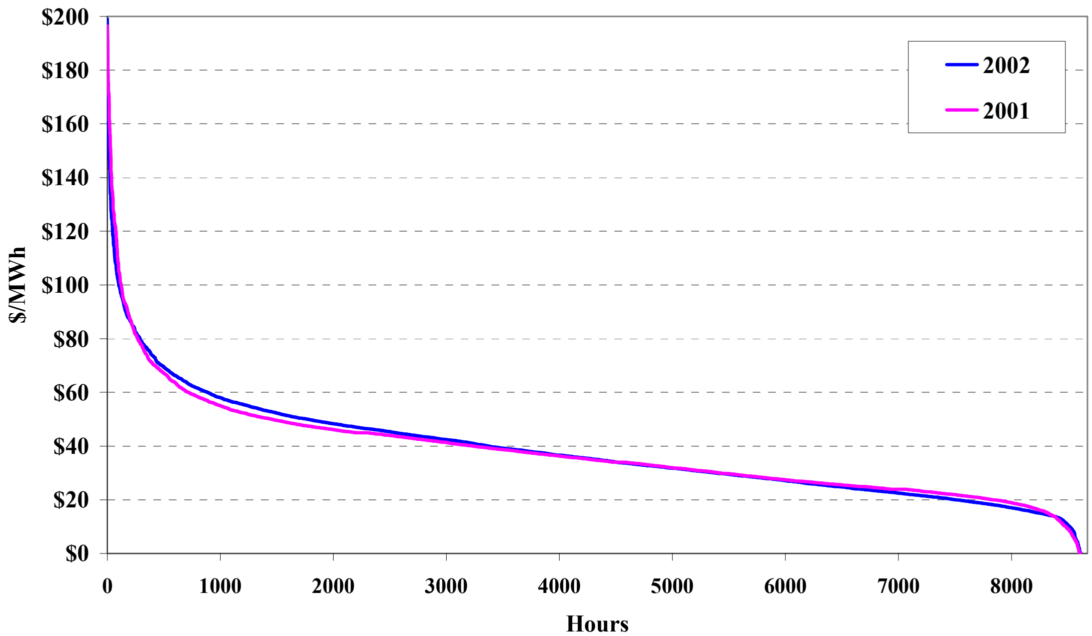


Figure 13 is a price duration curve. This curve shows prices were very similar in the two years, although prices in 2002 were higher in the highest-priced 2000 hours. This was due primarily to fuel price increases in 2002 with only modest effects related to the higher load in 2002. However, prices were notably lower under peak conditions in 2002 (i.e., shortage conditions).

Figure 13
Load-Weighted Price Duration Curves for New York State
2001 -- 2002



III. Analysis of Energy Bids and Offers

In this section we evaluate the competitive performance of the New York electricity markets by examining the degree to which the conduct of market participants is consistent with workable competition. In particular, on the supply side, the analysis seeks to identify potential attempts to withhold generating resources as part of a strategy to increase prices. On the demand side, we evaluate load-bidding behavior to determine whether LSEs have procured load in a manner consistent with competitive expectations. We also make a particularly close evaluation of whether the behavior of virtual traders has enhanced market efficiency or led to manipulation of prices.

A. Supply Offers

In general, the supply curve in wholesale electricity markets is relatively flat at moderate load levels and steeply sloped at high load levels. This characteristic of supply has important implications for market power.

Market power is generally exercised in electricity markets by withholding supplies from the market in an attempt to raise the market-clearing price. Withholding may take two forms – physical withholding or economic withholding. Physically withholding is accomplished by derating a resource or simply not offering the resource into the market when it is economic. Economic withholding occurs when a supplier raises the offer price of a resource to reduce its output below competitive levels or otherwise raise the market price.

The critical task in a withholding analysis is to differentiate strategic withholding from competitive conduct that could appear to be physical or economic withholding. Due to measurement errors and other factors, any screen for withholding is inevitably going to inaccurately identify some conduct that is competitive and justified. 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, we evaluate 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. Under competitive conditions, suppliers should increase their offer quantities during the highest load periods to sell more power at the higher peak prices and maximize their profits. Alternatively, a supplier that possesses market power will find withholding to be profitable during periods when the market supply curve becomes steep (i.e., at high-demand periods). Therefore, examining the relationship between the measures of potential withholding and demand levels will allow us to test whether the conduct in the market is consistent with workable competition.

To measure economic withholding, we calculate the hourly “output gap”. The output gap is the quantity of capacity that, while economic to run at the market clearing price for that hour, is not available to the market because a supplier submits one or more bid components that are substantially above the unit’s reference levels. This withholding can be accomplished through high start-up cost bids, minimum generation bids, and/or incremental energy bids. Essentially, the output gap only includes capacity that is not being used for energy or ancillary services. However, units that are dispatched and that also set the clearing price (while at the same time bidding substantially above their reference levels) are also included in the output gap. This is because such bidding behavior has the effect of raising price. The following two figures show the relationship between the output gap and load levels.

Figure 14 shows the real-time output gap in Eastern New York. In this figure, we calculate the output gap as that capacity that was offered at a price exceeding the applicable reference levels by the lesser of $50/MWh or 100 percent. The real-time output gap includes both capacity that is withheld in real-time and capacity from resources that were not committed as a result of economic withholding in the day-ahead market. We calculate the output gap for a single peak hour for each day (3 pm) in order to focus the analysis on periods most susceptible to the exercise of market power. In addition, the figure includes only Eastern New York because the periods of scarcity and high prices generally occurs when Eastern New York is isolated as a result of congestion on the Central-East interface. While this analysis is mainly for illustrative purposes, other forms of this analysis have been conducted for the state, for other time periods, and at other thresholds.

Figure 14
Relationship of Output Gap to Actual Load
Real-Time Market – East New York ($50/100 percent Threshold)
2002 – 3 pm Hour

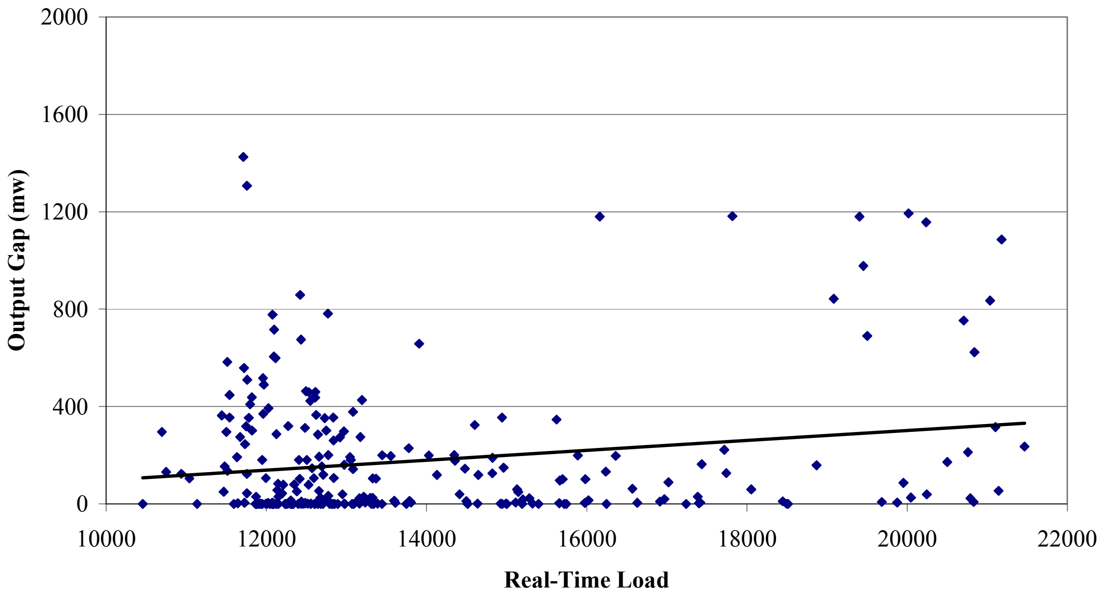
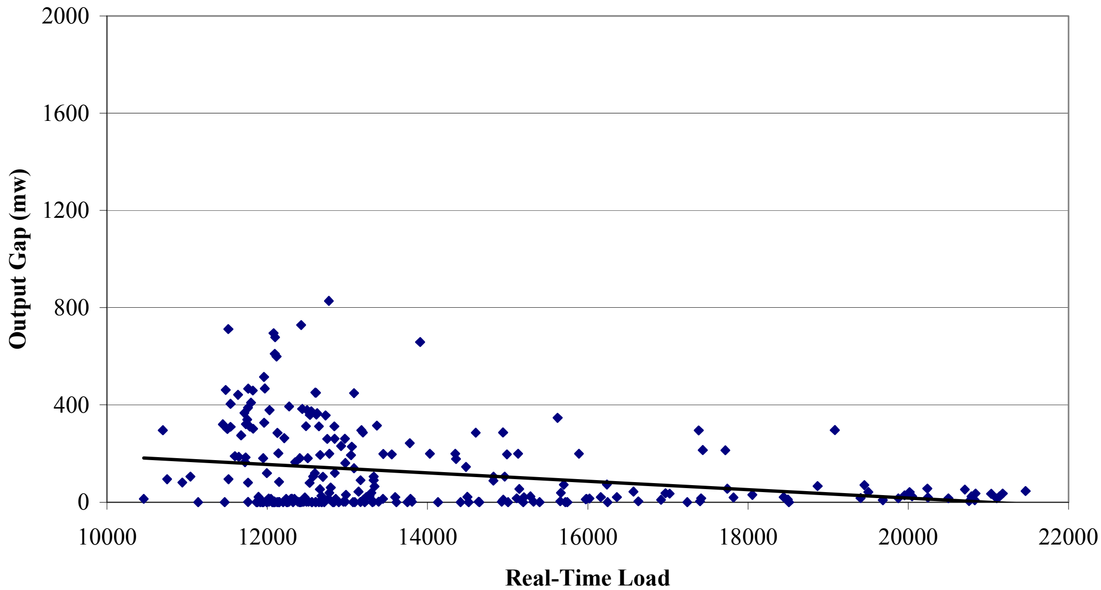


Figure 14 shows that the output gap was zero in a large number of hours, at both high and low load levels. Furthermore, on the vast majority of days, the output gap was quite small as a percentage of total capacity. However, there were 17 days during 2002 where the output gap exceeded 800 MW. The real-time load was quite high on most of these days, correlating with conditions that are conducive to strategic conduct. Figure 14 also shows a trend line which exhibits a small but significant positive relationship between the output gap and real-time load.

Figure 14 reveals potential economic withholding during certain hours when attempts to exercise market power are most likely to be effective. A closer evaluation of the data indicates a single supplier is primarily responsible for much of the output gap that causes the high correlation with real-time load. Figure 15 shows the output gap data excluding this particular supplier. Without this supplier, the output gap relationship to load levels looks quite different – it decreases to negligible levels under extreme load conditions. Figure 15 also shows the trend line which exhibits a small but significant negative relationship between the output gap and real-time load.

Figure 15
Relationship of Output Gap to Actual Load
Real-Time Market – Eastern New York ($50/100 percent Threshold)
2002 – 3 pm Hour – Excl. One Supplier



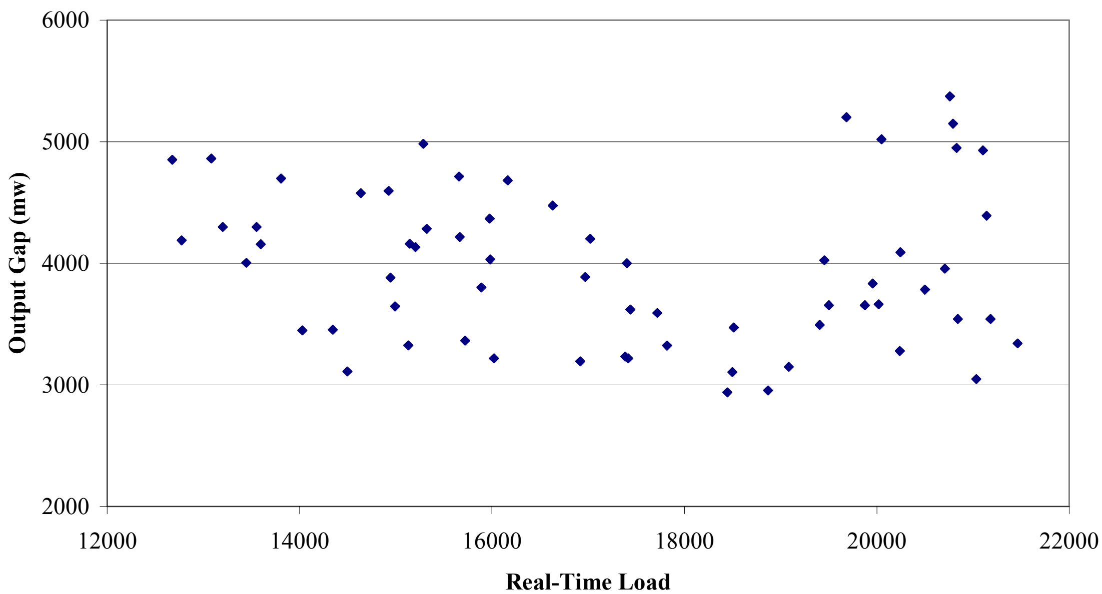
The sharp contrast between Figure 14 and Figure 15 clearly indicates that a single supplier has exhibited anomalous behavior consistent with attempts to exercise market power. Aside from this single supplier, which we examine more closely below, the data do not suggest strategic economic withholding in the wholesale markets in 2002.

We also conducted the analysis using an alternative conduct threshold (*viz.*, output gap defined as capacity bid above reference levels by an amount exceeding the lesser of $100/MWh or 300 percent). This higher conduct threshold is one used by the AMP in the day-ahead market software. Under this threshold, there were only two hours when the output gap was non-negligible (amounting to 600 MW and 1100 MW), although both hours coincided with very high load levels. These two instances did not result in mitigation by the AMP because the conduct did not have a large impact on day-ahead prices. The reason is that demand is fairly elastic in the day-ahead market due to several thousand megawatts of price sensitive price-capped load bids and virtual offers. This elasticity will blunt the price impact of an attempt to withhold even large amounts of capacity.

To analyze potential physical withholding, Figure 16 and Figure 17 show the analogous results for deratings. Potential physical withholding is analyzed by assessing the relationship in peak hours between actual load and capacity deratings and outages. This is referred to as *potential* physical withholding because some or all of this amount may be derated for justifiable reasons. For example, capacity may be derated because of a legitimate forced or planned outage. The data cannot be adjusted for these non-strategic deratings and, hence, the patterns of deratings must be assessed to determine whether they are consistent with physical withholding.

For this analysis, only the summer peak hours are included to eliminate the effects of planned outages that are generally scheduled during the spring and fall. Outages exceeding 30 days are assumed not to be strategic and are excluded from this analysis. Figure 16 shows the quantity of potential physical withholding in the 3 pm hour of each day in the analysis.

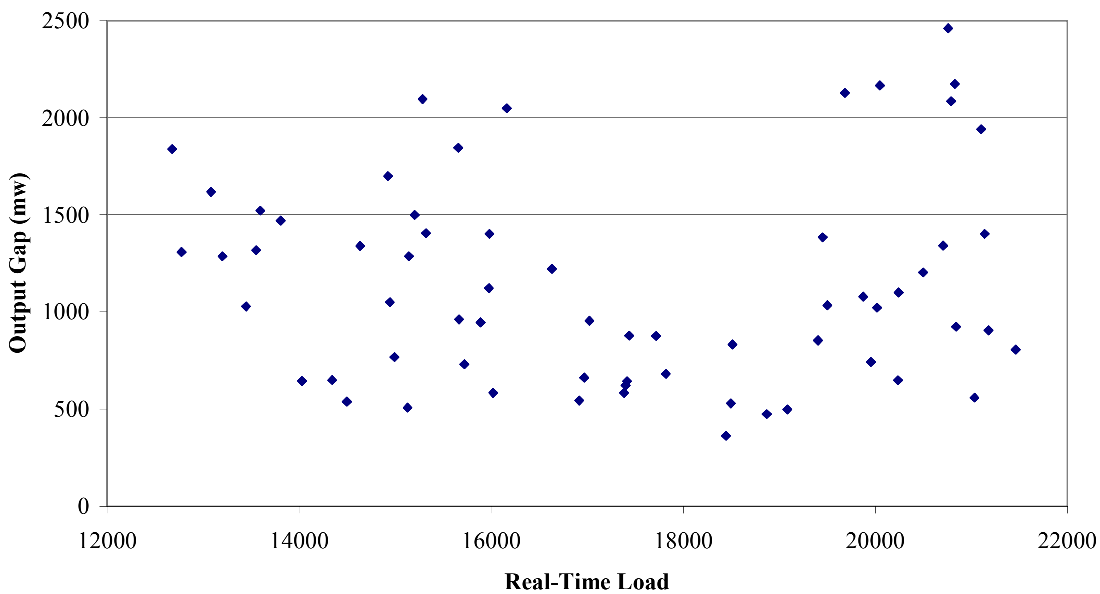
Figure 16
Relationship of Deratings to Actual Load
Day-Ahead Market – Eastern New York
Summer, 2002 – 3 pm Hour



The figure does not show any clear relationship between deratings and real-time load. It appears to show a decrease in deratings as load increases from 12000 MW to 19000 MW, although there are a number of hours with substantial deratings when load is greater than 19000 MW. This could be an indication of strategic attempts to physically withhold, although deratings and short-term outages are more likely at high load levels when base load units are instructed to operate at emergency levels and rarely-used peaking resources are called upon.

We evaluated the data in a different light by excluding the capacity controlled by the particular supplier we had identified above that appeared to be engaging is some degree of economic withholding. Figure 17 shows the quantity of short-term deratings excluding those attributable to this particular supplier. Excluding this supplier does not lead to a different conclusion regarding whether deratings have been correlated with real-time load. If part of the slight rise in deratings at peak load levels is due to instances of strategic withholding, they are relatively small as a share of total market capacity. Overall, the lack of clear strategic withholding is consistent with the hypothesis that the New York markets have been workably competitive. Since it is possible that discrete instances of physical withholding have occurred or could occur in the future, the NYISO's physical audit program to investigate outages and deratings remains an important part of market monitoring.

Figure 17
Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market – Eastern New York
Summer, 2002 – 3 pm Hour



The conduct of the particular supplier that exhibited relatively high quantities in the output gap statistics warrants further scrutiny. The following table summarizes market conditions on afternoons where this supplier's bidding behavior increased the output gap statistics significantly. In particular, Table 2 shows days when this supplier had an output gap exceeding 250 MW measured at the $50/100 percent conduct threshold.

Table 2
Peak Hours During Summer 2002 when the Supplier's Output Gap was Relatively Large

		Prices in Supplier's Zone		Real-Time Load in Eastern New York		Intervals with
Market Date	**Supplier's Real-Time Output Gap**	**Day-Ahead**	**Real-Time**	**Peak Hour**	**Rank Over All Days**	**10-Minute Reserves Deficiency**
June 24	693	$70.00	$75.34	19234	22	0
June 26	969	$81.22	$88.32	20033	20	24
June 27	1173	$75.58	$103.03	20019	15	0
June 28	1173	$61.67	$40.87	17825	27	0
July 2	811	$133.97	$204.34	21155	5	22
July 9	1173	$68.82	$66.62	19406	21	0
July 22	677	$66.77	$76.10	19674	19	0
July 23	740	$61.70	$64.99	20803	10	0
July 24	1160	$50.66	$38.35	16198	37	0
July 29	1070	$95.80	$662.98	21375	2	56
July 30	597	$112.01	$63.50	20902	6	3
July 31	1130	$146.53	$101.36	20422	13	30
August 14	300	$134.27	$105.91	21104	4	3

Note: Output gap is shown for only the 3pm hour.

Table 2 shows that the hours with substantial output gap levels for the given supplier occurred disproportionately on high load days during the summer, including five of the top ten high load days. However, it is difficult to know how this effected real-time prices. Average real-time prices exceeded $110/MWh on only two of the 13 afternoons, although real-time prices likely would have been lower on July 2nd and July 29th if this supplier made more of its capacity available. This supplier would have had a more substantial impact on prices if Eastern New York had been transmission constrained in these hours. The Central-East interface was binding in only 20 percent of the intervals and the New England interface had an average of 1050 MW of unused import capability on these afternoons. Instead of raising prices drastically in these hours, the strategic withholding by this supplier resulted in more flow from Western New York and New England.

The supplier's conduct may have had a small impact on reliability on certain days. There were ten-minute reserve deficiencies in Eastern New York on six of these days totaling 138 intervals (approximately nine hours). Once scarcity pricing is implemented in New York, these deficiencies will have a greater impact on real-time prices.

B. Demand Bids

In addition to strategic conduct by *suppliers* that could result in artificially inflated energy prices, conduct by large *buyers* also is important to market efficiency. Therefore, an important focus of the market monitoring function is to examine whether bidding by LSEs is consistent with workable competition. This section summarizes and evaluates the load bidding that occurred during 2002. Figure 18 shows the monthly composition of the day-ahead load bidding relative to the actual state-wide load. Figure 19 makes the same comparison for New York City and Long Island.

The components of the total purchases shown in these figures include the following:

Physical Bilateral Contracts. These are schedules that the NYISO provides to participants that allow them to settle transmission charges (i.e., congestion and losses) with the ISO and to settle on the commodity privately with their counterparty. It does not represent the entirety of the bilateral contracting in New York, however, because participants have the option of constructing identical arrangements by other means that would settle through the NYISO. In particular, participants may sign a "contract-for-differences" (CFD) with a counterparty to make a bilateral purchase.

When the CFD is combined with a transmission congestion contract (TCC), the participant can create a fully-hedged forward energy purchase. Therefore, the trends in the quantity of physical bilateral contracts scheduled with the NYISO do not indicate the full extent of forward contracting.

Day-Ahead Fixed Load. This represents load scheduled in the day-ahead market for receipt at a specific bus regardless of the day-ahead price. It is the equivalent of a load bid with an infinite bid price, which is difficult to rationalize from an economic perspective.

Price-Capped Load Bidding. This represents load bid into the day-ahead market with a bid price indicating the maximum amount the LSE is willing to pay. For example, an LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead market at its location clears above $60, the energy would not be purchased in the day-ahead market. If the load is actually realized in real-time, it would be served with energy purchased in the real-time market. This is a more rational form of load-bidding than the non-price sensitive fixed load schedules. However, price-capped load bidding is only allowed at the zonal level while fixed load bidding is allowed at the bus level. Figure 18 and Figure 19 show bids that were scheduled and bids that were unscheduled.

Net Virtual Purchases. This quantity is equal to the virtual load purchases minus the virtual supply sales. Virtual trading was introduced in the NYISO markets in November 2001, and so this Report analyzes the first full cycle in which market participants have been able to buy and sell without physical assets.

Figure 18
Composition of Day-Ahead Load Bids as a Proportion of Actual Load
New York State -- 2002

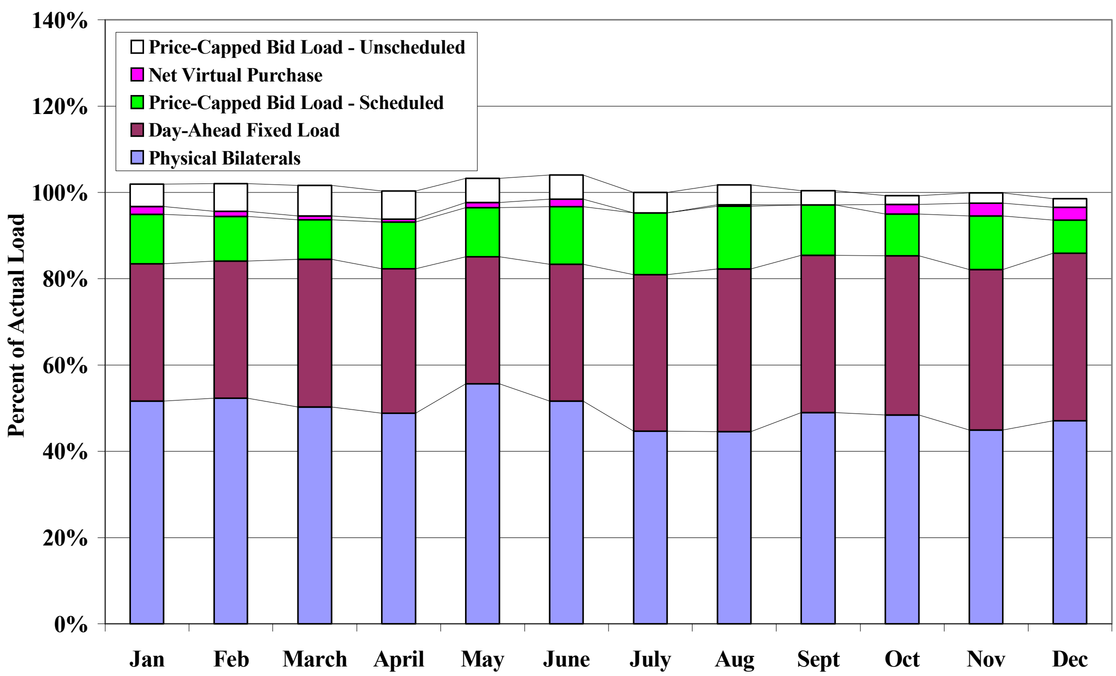


Figure 18 shows the state-wide load-bidding composition on a monthly average basis for 2002. Roughly 50 percent of load has been served by physical bilateral transactions settled through the NYISO. Physical bilateral contracts do not constitute all bilateral contracts because there are many financial bilateral transactions not settled through the NYISO. Rather, as noted above, these are usually structured as contracts for differences where the transacting parties settle congestion costs between one another. Approximately one third of load scheduled through the NYISO is scheduled through non-price-sensitive fixed-bid load. Much of this fixed-bid load may be associated with financial bilateral transactions.

Ten to fifteen percent of load is scheduled through day-ahead price-capped load bids. These allow LSEs to protect themselves from day-ahead price fluctuations by simply purchasing less as the day-ahead market price increases. While virtual supply volumes were close to matching virtual load volumes at the state level, there was still a small margin of net virtual load in most months. Figure 18 shows that approximately 95 percent of load is scheduled prior to real-time as opposed to previous years where close to 100 percent of load was scheduled before real-time.

The primary competitive concern related to under-scheduling is that large LSEs may intentionally reduce their purchases in the day-ahead market (shifting the purchases to real-time) to depress prices in that market and lower their overall purchase costs. This is a poor explanation for the under-scheduling, however, because convergence of day-ahead and real-time prices improved substantially in 2002. One possible reason for the under-scheduling by LSEs is that the NYISO load forecasts were systematically lower than real-time loads in 2002. In fact, the average state-wide load forecast was almost two percent lower than real-time load.

Another possible reason for under-scheduling is that suppliers may have a tendency to make more capacity economically available in the real-time market than in the day-ahead market. This is because forward contracts may carry a risk-premium for suppliers.

Figure 19
Composition of Day-Ahead Load Bids as a Proportion of Actual Load
New York City and Long Island -- 2002

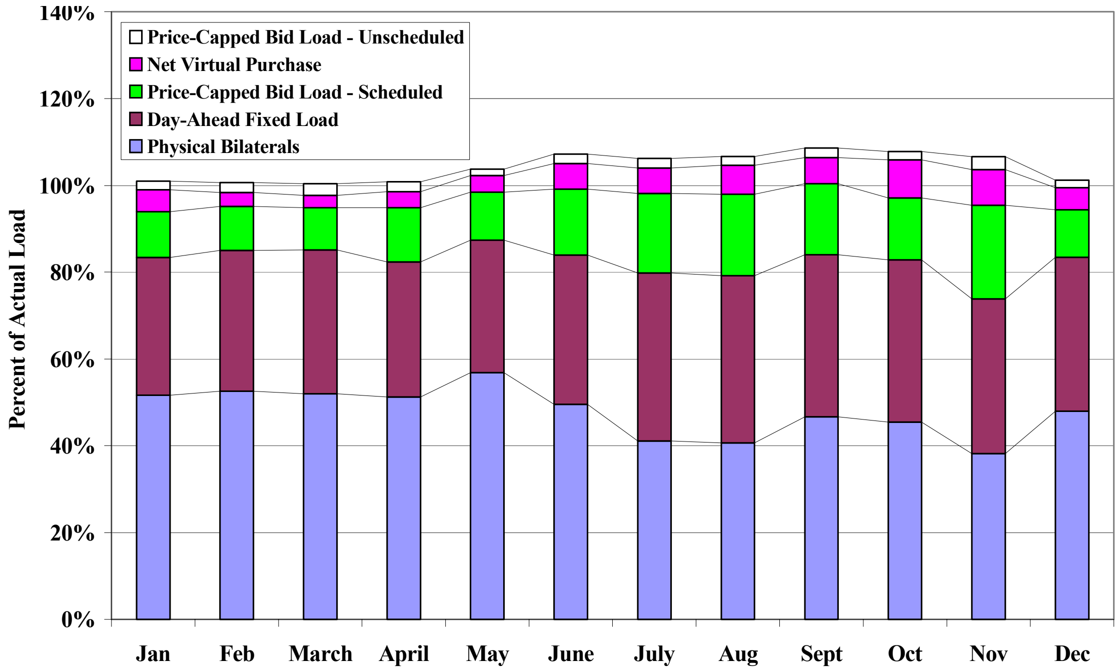


Figure 19 shows the composition of load-bidding on a monthly average basis in New York City and Long Island in 2002. The LSEs in New York City and Long Island schedule load prior to real-time in proportions comparable to LSEs in the rest of the state. More than 80 percent are either physical bilateral contracts or day-ahead fixed-bid load, and these, combined with price-capped bid load, account for close to 100 percent of real-time load. Figure 19 shows that net virtual purchases in New York City and Long Island were large enough that the total quantity of load scheduled day-ahead exceeded real-time load by as much as six percent in one month. This also implies that there were net virtual sales in the remainder of New York State.

The introduction of virtual trading (discussed more below) has reduced the incentive for LSEs to systematically under-schedule load. This is because under-scheduling by the LSEs that would tend to depress prices in the day-ahead market should be countered by increased virtual load purchases. Nevertheless, this will continue to be monitored to ensure that changes in the load bidding and scheduling practices do not compromise market efficiency.

C. Virtual Trading

Virtual trading was introduced in 2001 to allow participation in the day-ahead market by entities other than LSEs and generators. Virtual trading can facilitate economic efficiency by improving arbitrage between the day-ahead and real-time markets as well as allowing flexibility for all participants in managing risk.

By making virtual energy sales or purchases in the day-ahead market and settling the positions in the real-time market, any 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 market 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 to improve its convergence with the real-time energy price.

Figure 20
Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
New York City and Long Island -- 2002

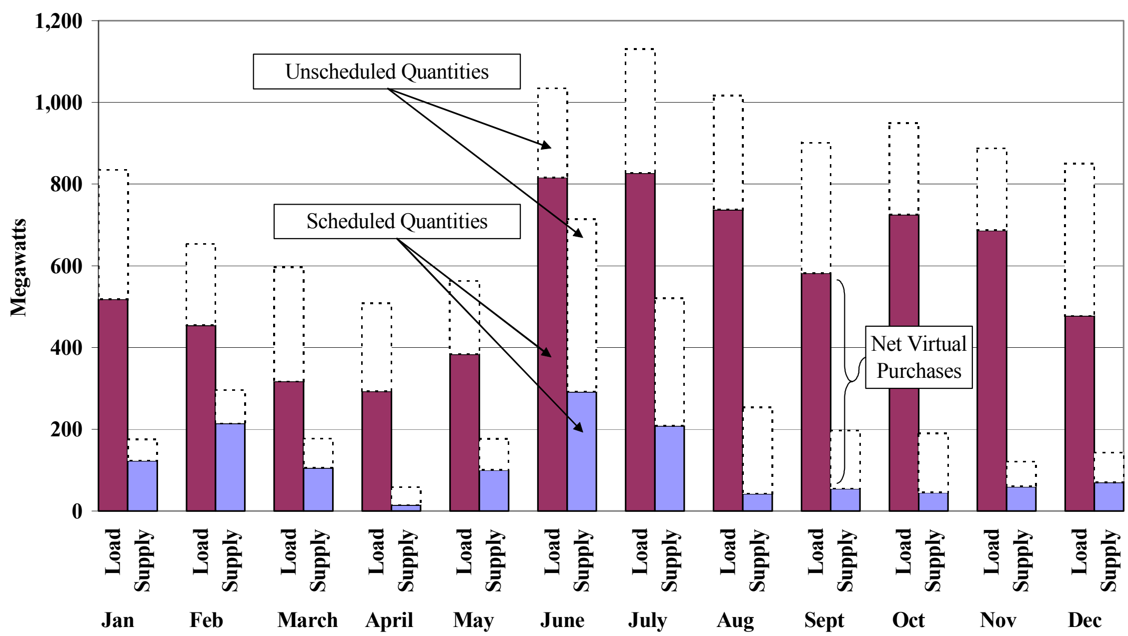


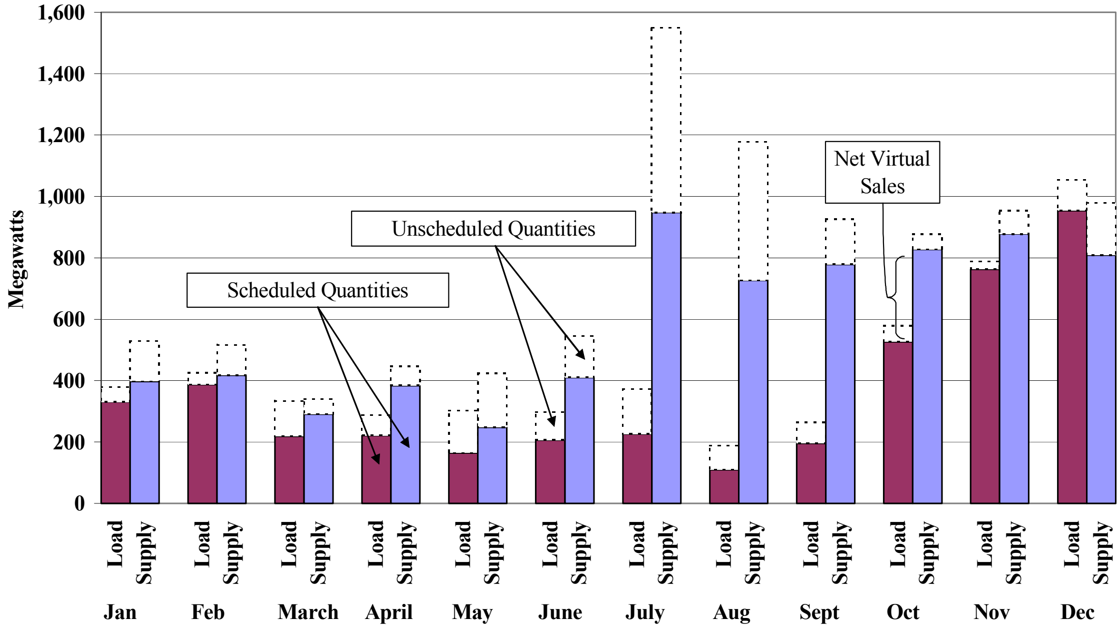
Figure 20 shows the quantities of virtual load and supply that were offered and scheduled on a monthly basis in New York City and Long Island in 2002. In each of the months, virtual purchases were larger on average than the virtual sales. The magnitude of virtual load offers and schedules increased significantly during the summer of 2002 and remained high through the fall and winter. On the other hand, virtual supply offers and schedules were much smaller on average. In fact, there was an average of less than 150 MW of virtual sales in all except for three months during 2002.

Figure 21 shows the quantities of virtual load and supply that were offered and scheduled on a monthly basis in the remainder the state in 2002. In every month except for December, virtual sales were larger on average than the virtual purchases. The average quantity of virtual sales has varied between 700 MW and 1000 MW since July 2002. While virtual load schedules averaged 100 MW to 200 MW during the summer of 2002, they rose to average levels comparable to virtual sales.

Although the virtual trading quantities comprise a relatively modest portion of the New York wholesale market, it is important to assess how virtual trading is being used by market participants. As described above, virtual purchases and sales in the day-ahead market should generally be motivated by a desire to arbitrage price differences between the day-ahead and real-time markets or to hedge the risk of trading in these markets. In both cases, the price at which a participant is willing to make virtual sales and purchases in the day-ahead market should not vary substantially from its expectation of the energy price in the real-time market (i.e., virtual bids and offers should be "price sensitive").

For example, a participant that believes the day-ahead market might be lower-priced than the real-time market would place a virtual load bid. If this bid were price insensitive (e.g., bid price = $500), the participant would be expressing a willingness to purchase power in the day-ahead market even when it is priced much higher than the expected real-time price. Hence, price insensitive bids are not a rational means to arbitrage price differences between the day-ahead and real-time market.

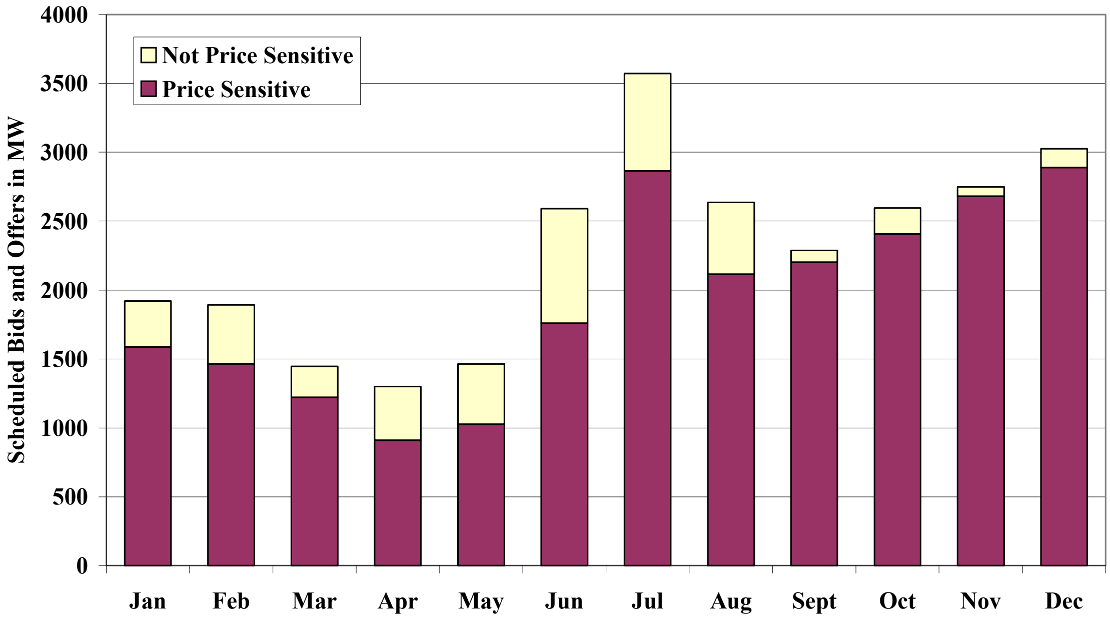
Figure 21
Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
Outside New York City and Long Island -- 2002



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. Such strategies could include making a large virtual load purchase in a constrained zone in order to cause congestion in the day-ahead market that would benefit the owner of TCC's or other market positions. Therefore, we have assessed the extent to which virtual offers and bids have been price sensitive.

For simplicity, we identified price insensitive bids as those bid at more than three times the clearing price. Likewise, price insensitive virtual supply bids were defined as those bid at prices less than one-third of the clearing price. Using these definitions, the shares of the scheduled virtual bids and offers that are price sensitive versus price insensitive in each month are shown in Figure 22.

Figure 22
Price Sensitivity of Scheduled Virtual Load Bids and Supply Offers
New York State -- 2002

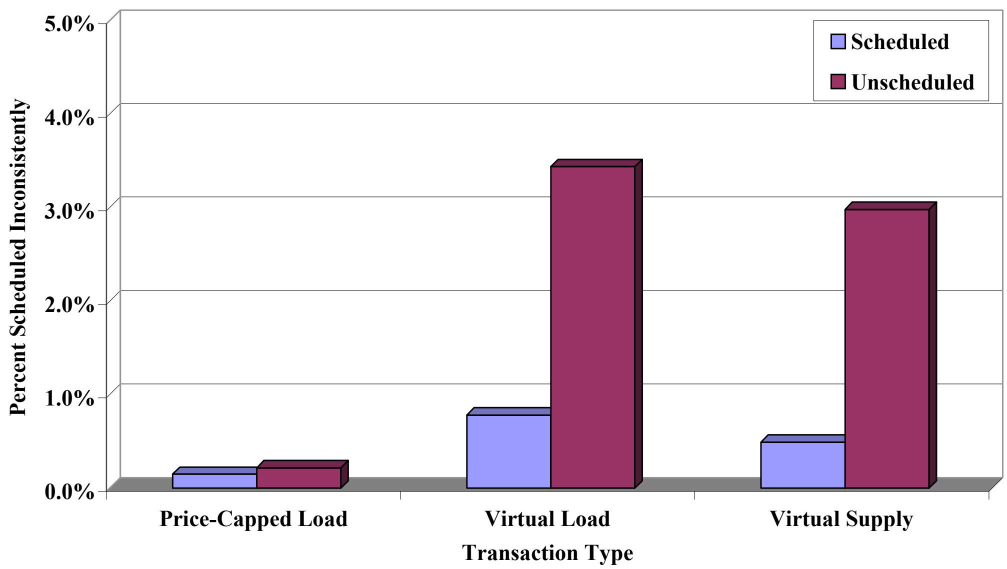


These results show that virtual trading activity has been dominated by price sensitive bids and offers, particularly since the summer of 2002. Price sensitive bids and offers are not only large as a proportion of total virtual bids and offers, 70 to 90 percent, they have also become quite large in magnitude. Figure 22 shows that the quantity of price-sensitive bids and offers has averaged 2000 MW to 3000 MW state-wide since July 2002. This suggests several things. First, if there have been concerted attempts to manipulate prices, they have been a relatively insignificant component of the virtual trading. Second, the substantial increase in competitive virtual trading will greatly increase the robustness of the day-ahead market against attempts by a single participant to manipulate prices or exercise market power.

The previous figures show that participation in virtual trading grew substantially during 2002, indicating that it will be a significant factor in the future. However, a concern that arose among market participants was that a small portion of virtual trades have not been scheduled in accordance with their bid price. To analyze this concern, we define inconsistent load schedules to be occurring when price-capped and virtual load bids are (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.

Similarly, inconsistent virtual supply schedules occur when virtual supply offers are (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. These quantities that are scheduled or unscheduled inconsistently are shown in Figure 23.

Figure 23
Percent of Virtual Trades and Price-Capped
Load Bids Scheduled Inconsistently
Measured by percent of Trades -- 2002



The figure above shows that 0.2 percent of price-capped load not scheduled actually should have been scheduled. This is quite small. However, 3.3 percent of unscheduled virtual load and 2.9 percent of unscheduled virtual supply *should* have been scheduled. Conversely, 0.2 percent of scheduled price-capped load, 0.8 percent of scheduled virtual load, and 0.4 percent of scheduled virtual supply *should not* have been scheduled. Inconsistent scheduling is important because it may undermine the confidence participants have in virtual trading. This phenomenon has occurred because of an inconsistency between the pricing criteria used to for scheduling and the determination of prices for settlement. It should be a priority to modify the settlement rules to eliminate the inconsistencies causing this problem.

IV. Pricing at Peak Demand

Prices under peak demand conditions provide critical market information to participants. In the short-run, peak prices signal the need for imports from other regions in response to shortage conditions. Similarly, owners of peaking generation plants and demand response resources, whose primary value is to be available at these times, also respond to peak prices in providing these resources to the market. In the longer term, accurate price signals at peak times play a key role in governing investment in new generation and demand response capabilities.

The analysis in this section focuses on fourteen peak-demand days which occurred during the period spanning late June to the middle of August. We analyze two aspects of the market during these time periods that can have important impacts on pricing: (1) market operations and (2) external transactions.

A. Market Operations

Aside from operating the spot markets, a primary role of the ISO's market operations is to ensure safe and reliable grid operation. Many of the ISO's operating functions in this regard can have a substantial impact on market outcomes. Market operations affect peak pricing primarily by altering supply conditions in an attempt to resolve congestion and ensure reliability. This is done through a number of actions including the following:

- Dispatching generation "out-of-merit" order;
- Committing supplemental resources not selected by the day-ahead market;
- Dispatching reserves under peak load conditions; and
- Making real-time load curtailments and emergency out-of-market purchases.

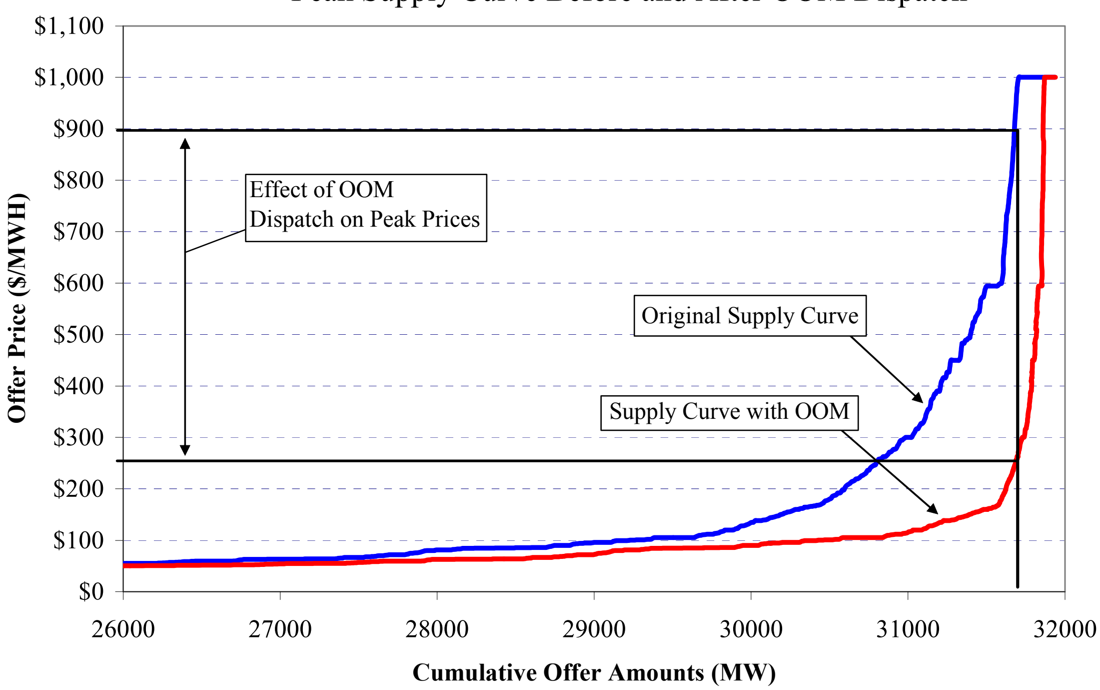
Reliability requires that operators have the ability to take these actions, but they should be taken only when necessary and the pricing rules should minimize adverse effects on prices.

1. Market Operations: Dispatching out-of-Merit

A resource is Out-of-Merit (OOM) order when it is dispatched even though its energy bid exceeds the price at its location. This can be caused by the physical parameters of the unit (e.g., minimum run-time that requires the unit to run after is has become uneconomic) or by operator action. Action taken by an operator is almost always done to resolve transmission congestion.

OOM actions have an impact on prices because OOM units are ineligible to set prices and they replace units in the bid stack that have bid lower.[1] This effect is well-known and is illustrated in Figure 24, which depicts 1000 MW of OOM dispatch on a typical NYISO supply curve.

Figure 24
Effects of Out-of-Merit Dispatch on Peak Prices
Peak Supply Curve Before and After OOM Dispatch



Because only a portion of OOM resources turn out to be uneconomic once the entire dispatch is determined, it is useful to understand the extent to which this occurs. Figure 25, Figure 26, and Figure 27 show the relationship between all OOM units and OOM units that actually turn out to be uneconomic. The figures show that most resources logged as OOM during the 14 peak days in our analysis are actually economically in-merit.

Figure 25
Out-of-Merit Logging During Peak Hours
June 26, 27, July 2, 3 – 12 pm to 8 pm

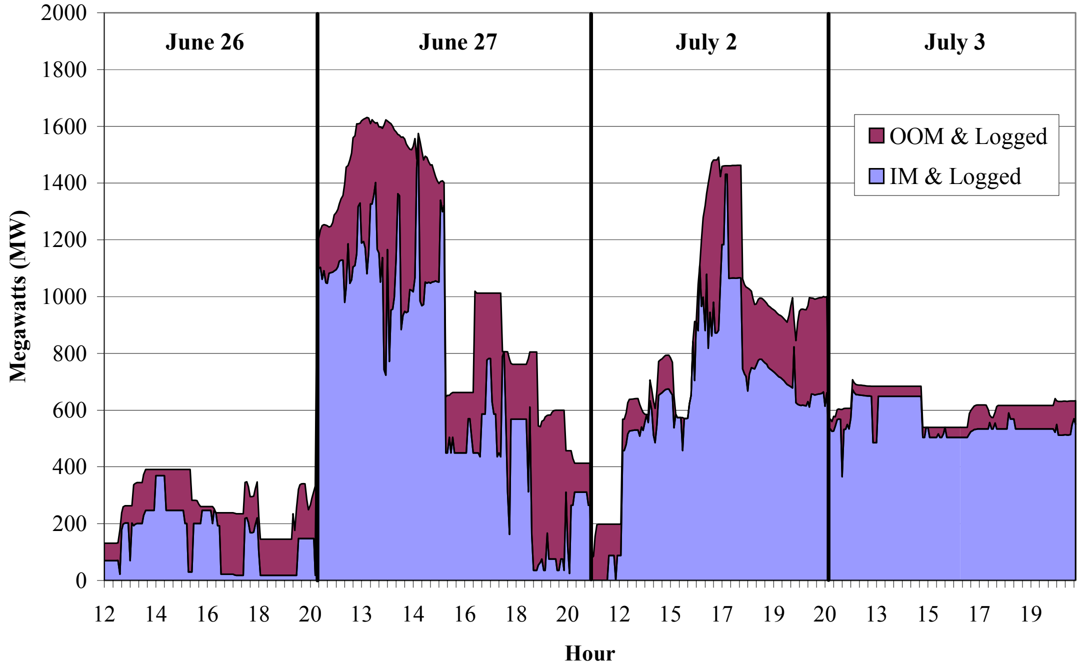


Figure 26
Out-of-Merit Logging During Peak Hours
July 29, 30, 31, August 2, 3 – 12 pm to 8 pm

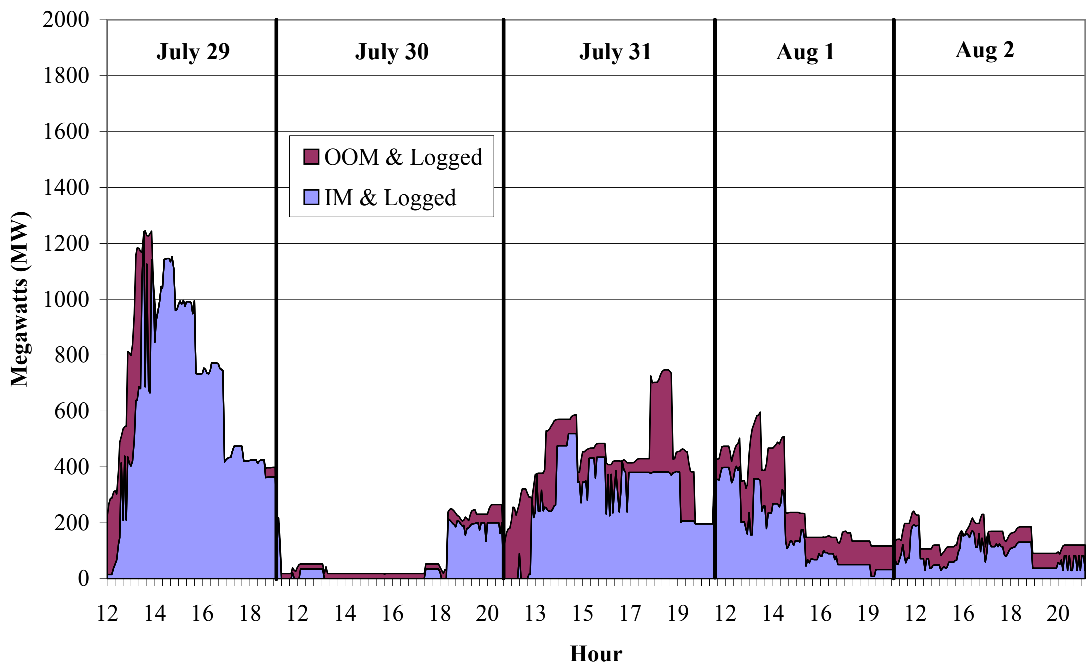
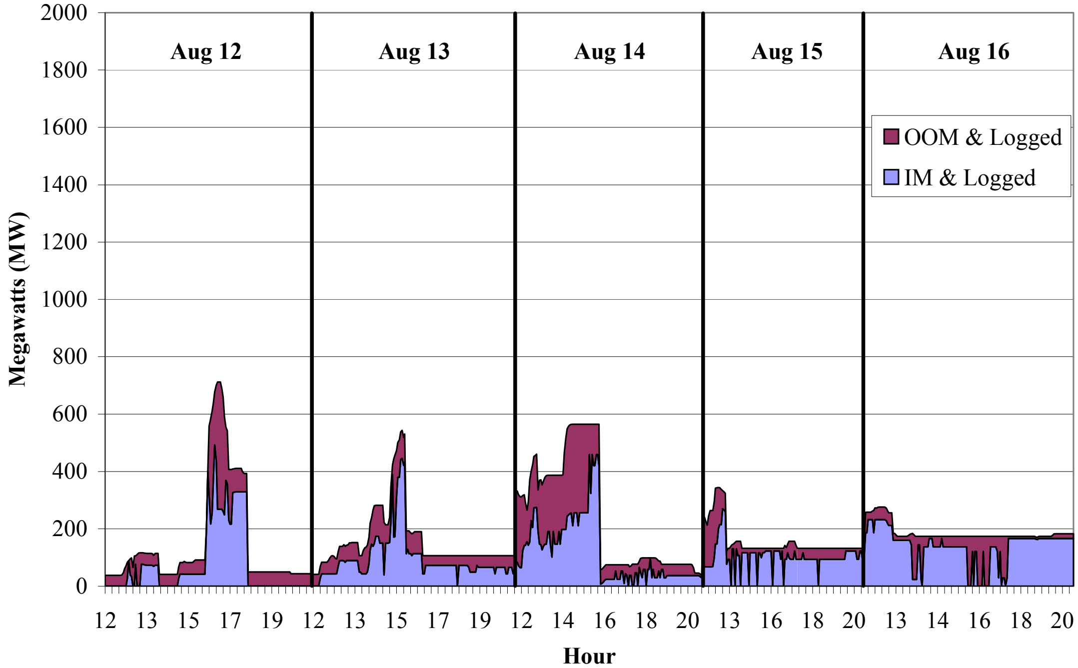


Figure 27
Out-of-Merit Logging During Peak Hours
August 12-16 – 12 pm to 8 pm



A further analysis of OOM resources shown in Figure 28 reveals the following:

- OOM units that turn out to be economic are generally gas turbines;
- Steam units are usually in-merit even when they are logged as OOM by the operators;

Gas Turbines (GTs) are logged as OOM for one of three reasons: to provide reserves, to resolve congestion in a load pocket, or for "other reasons". and Figure 30 show the relative frequency of each category of OOM GTs. Logically, GTs logged as OOM for "reserves" should be able to set energy prices. This is because GTs are dispatched at their full capacity and cannot provide reserves but can only unload other units that are producing energy. Therefore, by bringing on GTs for reserves, the marginal cost to the system of maintaining reserves is the marginal cost of running the GT. Because each energy resource is contributing to satisfying the binding reserve constraint by allowing resources to be held for reserves, the marginal value of energy is at least the bid price of the GT.

Figure 28
Average Economically Out-of-Merit Generation by Type
Peak Days – 12 pm to 8 pm

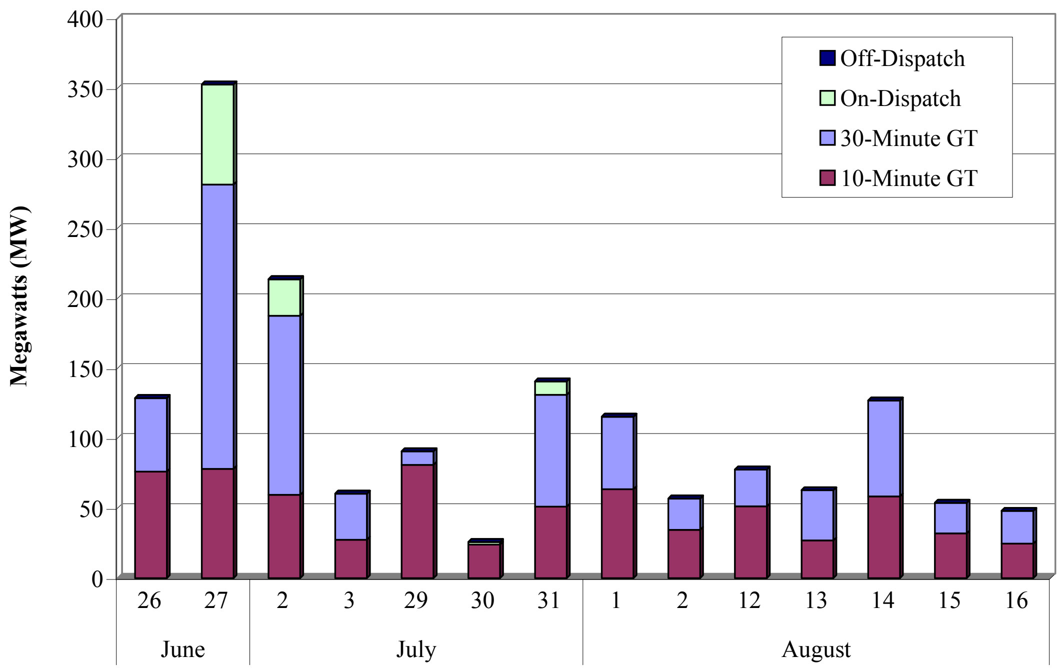
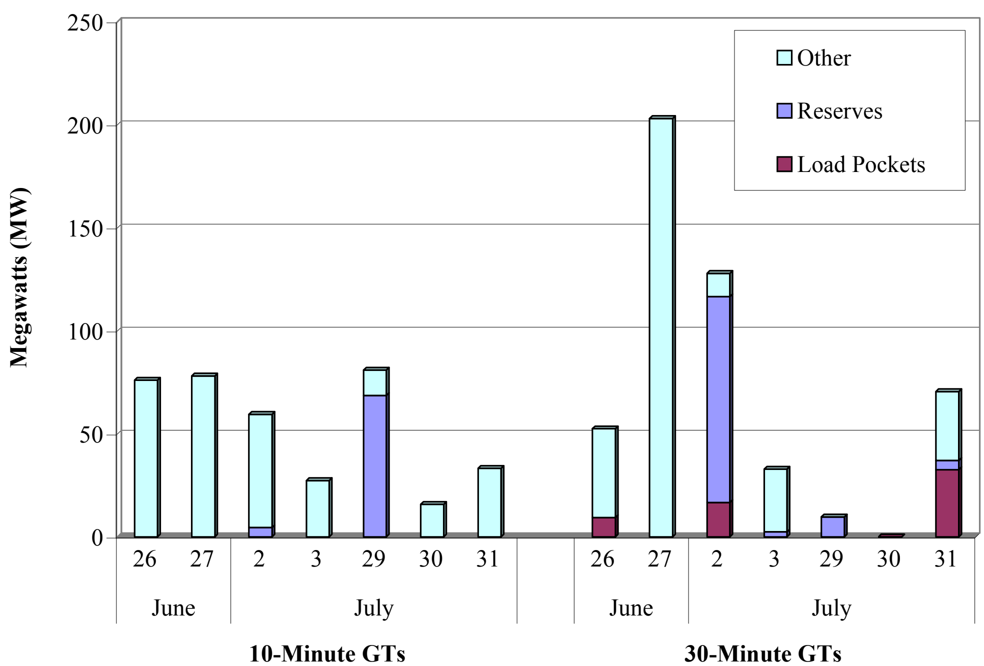
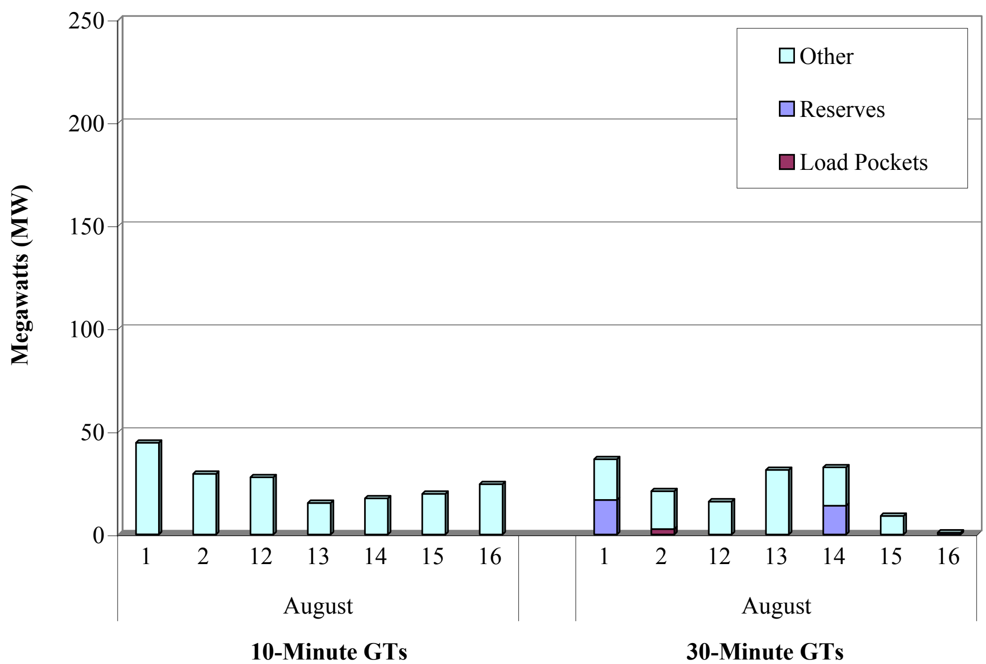


Figure 29
Out-of-Merit Logs by Unit Type During peak Hours
Peak Days – 12 pm to 8 pm



Units OOM for "load pockets" also should be able to set energy prices because in load pockets there is typically no unloaded generation that is cheaper than the GTs at times when the GTs are needed to resolve a transmission constraint. In reality, then, the GT is providing incremental energy. Indeed, during the Summer of 2002, the NYISO modified its real-time scheduling systems to allow GTs and other units committed for ISO reserves or ISO reliability to be eligible to set prices. These actions have resulted in substantial reductions in OOM quantities during the peak conditions in August (after the modifications were made) versus the peak days in June and July.

Figure 30
Out-of-Merit Logs by Unit Type During Peak Hours
Peak Days – 12 pm to 8 pm



Finally, the process of committing ten-minute GTs can cause units to run OOM. Operators generally raise the lower operating limit of these units (i.e., "blocking" their limit) to cause the model to send a dispatch signal at full output. Because units are ineligible to set prices when operating at their lower limit, GTs can initially not be eligible to set energy prices. Ten-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 busy 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.

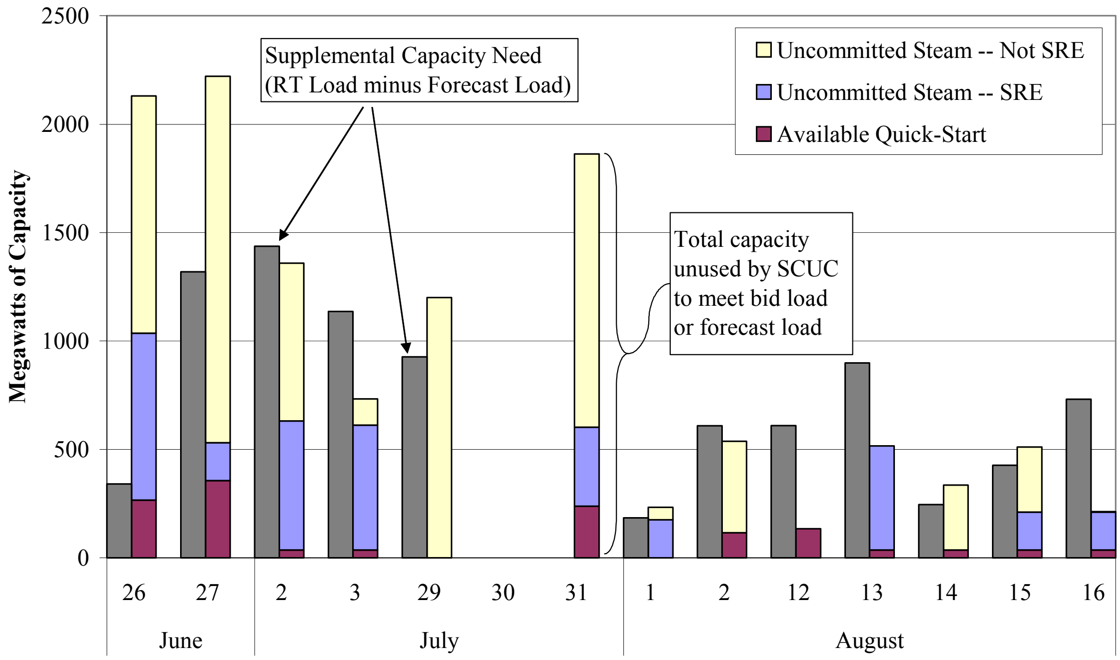
2. Market Operations: Supplemental Resource Evaluation (SRE)

The NYISO commits resources in the day-ahead market using the SCUC software. The SCUC commits units based on the NYISO day-ahead market forecast. When operators assess the SCUC run, they may commit additional resources to be on-line for the next day. This is known as Supplemental Resource Evaluation (SRE) and generally will occur when the day-ahead market assumptions are modified after the market concludes (e.g., operators expect loads to be higher than the day-ahead forecast).[2]

When the operators undertake SRE commitments these actions are logged and reported on the NYISO website. Such supplemental commitments do not directly affect the day-ahead prices, but instead makes additional resources available in real-time, and, therefore, may reduce real-time prices as a result of additional units operating at minimum generation level. Because of the potential for price distortion as a result of these actions, it is important to evaluate the SRE process and its impact. Figure 31 shows the quantity of resources that were committed through the SRE process on the peak days.

The figure reveals two notable patterns. First, SRE commitment quantities were generally consistent with conditions under which actual load exceeded the SCUC load forecast by a significant margin. In more than half of the peak hours analyzed, the day-ahead forecast was over 500 MW short of actual load conditions in real-time. In three hours it was over 1000 MW short. Second, uncommitted GT capacity was unavailable to meet the difference between forecast and actual load in the next day. These facts together suggest that some level of SRE commitments was consistent with the anticipated needs. However, the correspondence between what was committed under SRE and what was actually needed in real-time was poor.

Figure 31
Supplemental Capacity Needs and Resources Not Used by SCUC
Eastern NY - Peak Hours on High Demand Days



For example, on June 26 there was only a relatively small shortfall of about 400 MW between the day-ahead forecast and actual load, yet available "quick-start" GT units and SRE capacity exceeded 1000 MW. On the 27th, the forecast was off by over 1000 MW yet only about 500 MW of SRE capacity and quick-start GT capacity was available. Part of this lack of correspondence lies in the variability of load forecasts. Also, most of the SRE actions were called by the Transmission Owners to meet local reliability requirements, rather than by the ISO.

SRE commitments made by Transmission Owners are not directly related to anticipated load requirements, but to local reliability issues. Because these actions are not initiated by the ISO, the potential for adverse incentives arise that can distort the market. To minimize potential price effects from SRE actions, the ISO should continue to adjust SCUC to meet local reliability requirements and thereby minimize the need for Transmission Owners to initiate SRE commitments. The ISO also should develop screens or audits for SRE commitments made by Transmission Owners to ensure that the units selected are needed and are the most efficient alternative. For example, when Transmission Owners make SRE commitments, the same economic criteria should be employed as is employed for supplemental commitments made by SCUC or BME to meet the forecasted load (to minimize start-up and minimum generation costs).

3. Market Operations: Dispatch of Operating Reserves

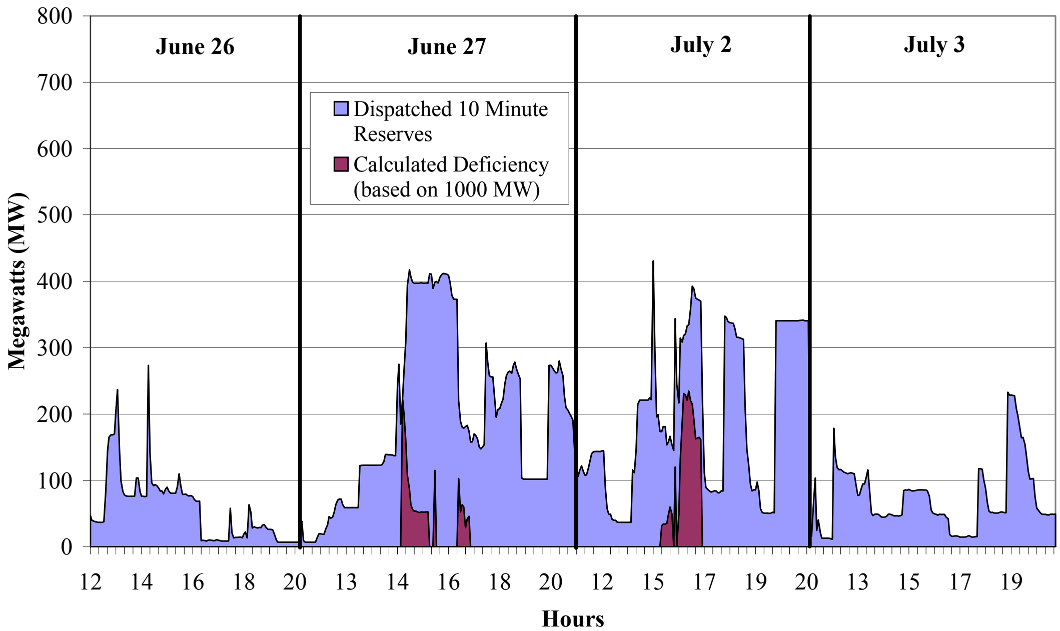
When the system is in shortage (that is, when available capacity is not sufficient to meet both energy and reserve requirements), the ISO may take a number of extraordinary actions to avoid loss of load. One action is to relax the reserve requirements so the system can meet energy needs. Prior to this summer, the ISO adopted polices to allow certain exports to count as reserves at times when the cost of procuring 30-minute reserves (i.e., the shadow price) increased to specific levels reflecting the perceived value of the 30-minute reserves. In some cases, ten-minute reserves were dispatched to meet the demand in the energy market.

When ten-minute reserve capacity is released and dispatched for energy, the supply will increase in the real-time energy market, resulting in reduced energy prices. When ten-minute reserves are compromised, the reserve market has effectively become the marginal supplier of energy and the energy price should reflect the value of the reserves compromised. We discuss below changes in pricing rules that would allow the market to signal the reserve shortage.

For each of the peak days in our analysis, we compared the designation of ten-minute reserves (a function performed by the BME model) with the ten-minute reserves actually maintained in the real-time dispatch by the SCD software. When the BME model designates the units to provide reserves, it blocks the capacity from being used to supply energy in the SCD. However, units designated for ten-minute reserves may be released in order to avoid an energy shortage. It is important to understand that releasing reserves will not always result in a ten-minute reserve deficiency. This is because while some units designated for ten-minute reserves are dispatched for energy, other units not designated but able to provide reserves may remain unloaded in real-time, effectively replacing the resources that were dispatched. Therefore, we measure reserve deficiency based on the amount of on-line generation that is unloaded and capable of proving ten-minute reserves.

We analyzed Eastern New York, the area east of the Central-East interface, where the ten-minute reserve requirement is 1000 MW. Figure 32 - Figure 34 show the extent to which actual ten-minute reserves were dispatched in Eastern New York and whether this coincided with an actual reserve deficiency. The charts show that there were 151 intervals (almost 13 hours) on these days when the NYISO was deficient in total ten-minute reserves. On July 29 and July 31 the deficiency was significant in some intervals, ranging up to 500 MW – close to one-half of the ten-minute reserve requirement.

Figure 32
Dispatch of Ten-Minute Total Reserves in Eastern New York
June 26, 27, July 2, 3 – 12 pm to 8 pm



In light of the incidence of ten-minute reserves shortages during these peak hours, NYISO should continue pursuing scarcity pricing policies that result in prices that better reflect these shortages. The NYISO spot market design lends itself to efficient scarcity pricing. There are significant quantities of generating resources with offer prices (based on legitimate marginal 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 during shortage conditions, the NYISO markets will not reliably set efficient scarcity prices.

Figure 33
Dispatch of Ten-Minute Total Reserves in Eastern New York
July 29, 30, 31, August 1, 2 – 12 pm to 8 pm

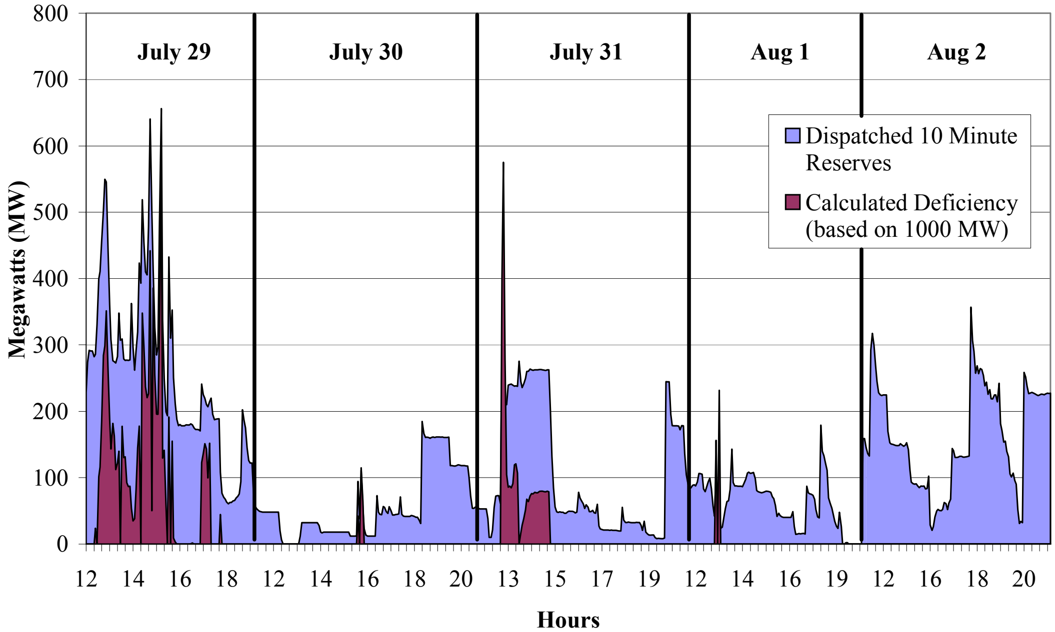


Figure 34

Dispatch of Ten-Minute Total Reserves in Eastern New York

August 12-16 – 12pm to 8pm

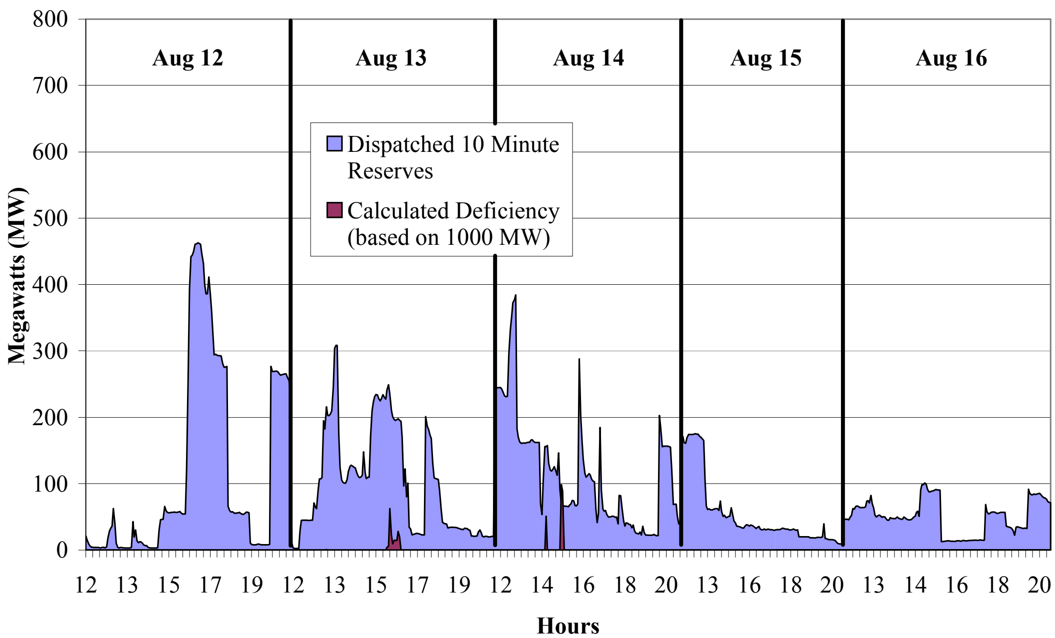


Table 3 shows the actual prices in Eastern New York that prevailed in the intervals exhibiting a ten-minute operating reserve deficiency. The Table shows that real-time energy prices were relatively unpredictable during these intervals, ranging from \$99 to \$1097 per MWh, with most of the prices in these intervals ranging between \$100 and \$200 per MWh. In only about 25 percent of the hours was the price above \$500 per MWh.

Table 3
Average Real-Time Prices in Eastern New York
During Periods with Ten-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
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

When ten-minute reserves are deficient, energy demand is being satisfied by the ten-minute reserve capacity. In these circumstances, each megawatt of capacity procured by the ISO, whether in the form of energy or reserves, provides an additional megawatt of ten-minute reserves. Therefore, energy is as least as valuable as the marginal value of the ten-minute reserves that it allows the operator to maintain and, hence, the incremental cost of providing energy is equivalent to the economic value of the ten-minute reserve. Therefore, efficient scarcity pricing should assign an energy price equal to the economic value of ten-minute reserves.

The economic value of ten-minute reserves (and hence the energy price during shortages) is implicitly established by the $1000 NYISO bid cap. This is true for the following reasons. First, the reserve requirements are *requirements* so the LMP model and ISO must dispatch all available energy resources (up to the $1000 bid cap) in order to maintain the required reserves. Hence, required reserves are valued at no less than the bid cap. Second, suppliers with available energy resources with costs higher than the bid cap that cannot provide reserves (such as an external supplier) may not offer it into the LMP market. Hence, required reserves are valued at no more than the $1000 bid cap.

To further understand the interaction of energy and reserves, it is important to view from an economic perspective what is happening when the shortage conditions occur. Shortage conditions can be interpreted in one of two ways. First, they can be viewed as the market not clearing. Although energy demand is met, the reserve requirements are not met. These reserve requirements are important market requirements in the sense that in non-shortage hours, the market software explicitly recognizes the reserve requirements (i.e., the models are prevented from dispatching the operating reserves). When markets cannot clear, it is generally demand that will ration the supply and set prices. The relevant demand in this case is the demand for operating reserves, which is valued at $1000 per MW as described above. To confirm the conclusion that energy is valued at this level during shortage conditions, one must determine what the market operator would have paid an incremental energy supplier to provide one MW of energy (allowing the operator to restore one MW of its operating reserves). Under the current market design, the ISO will pay up to $1000 for this energy.

The second interpretation of the shortage condition is that the operating reserves have become the marginal source of supply to the energy market. With limited exceptions, the operator will continue to dispatch increasing quantities of its operating reserves to meet the energy demand. If one considers the reserves as a source of energy supply, then determining the proper energy price requires that the value of the operating reserves be represented in an "offer price" for energy.

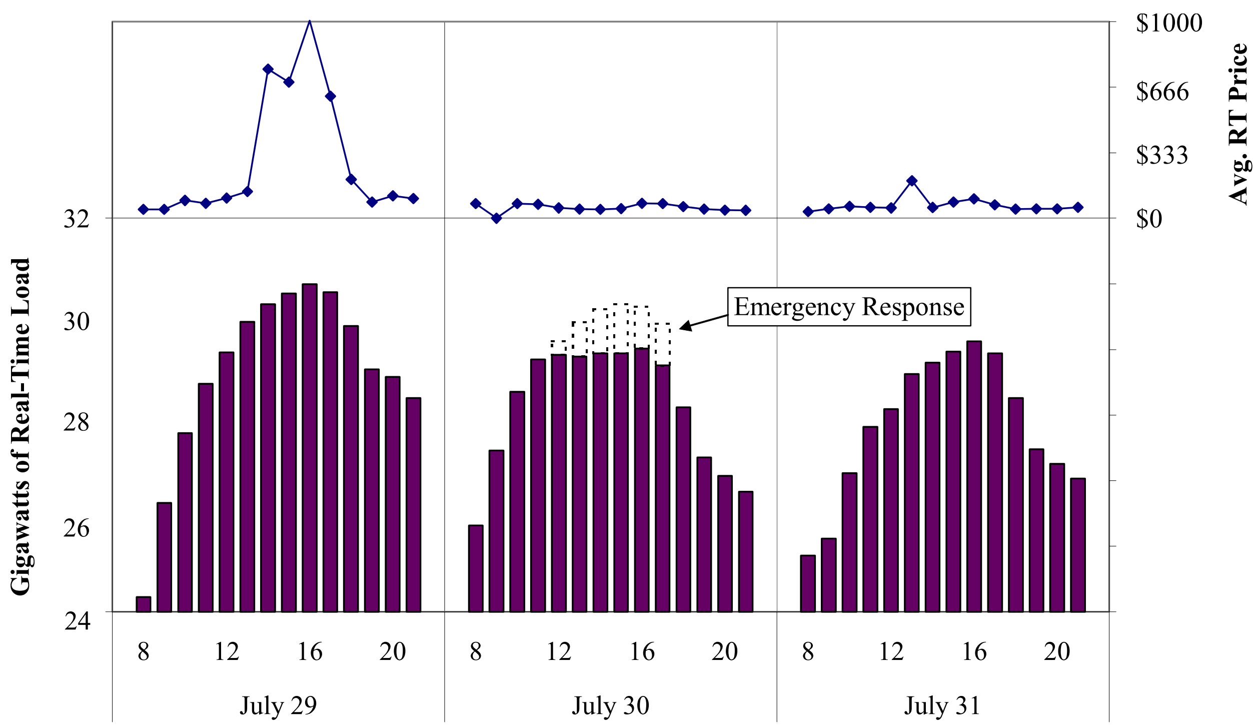
When the economic relationship between the reserves and energy markets is not explicitly recognized in the market rules, spot energy prices that are determined during capacity shortages are not likely to reflect the full value of energy. As discussed below, to satisfy these efficiency concerns, energy prices should be set at the bid cap when ten-minute reserves are deficient.

4. Market Operations: Load Curtailment and other Emergency Actions

There are several other ways that the NYISO may take action at peak times that impact market outcomes. These relate to the previous discussion related to avoiding shortages and include:

- 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, because they are compensated in the ICAP market, have the obligation to curtail load if the operator forecasts a reserve deficiency;
- Curtailing exports from capacity resources; and
- Purchasing emergency power from neighboring control areas.

Figure 35
Real-Time Load, Prices, and Emergency Demand Response
New York State



When any of these four actions are taken, prices are affected because the real-time supply is altered. As an illustration of the potential impact, Figure 35 shows actual loads and real-time prices on July 29-30 as well as our estimate of the achieved demand reduction on July 30, which exceeded 1000 MW. The actual reduction by EDRP is less than the amount shown. The amount shown includes reductions associated with the Special Case Resources and reductions resulting from other load curtailment programs (e.g., closing government offices). Nonetheless, as compared to July 29 and July 31, the load reduction on the 30th had a substantial impact on prices. This illustrates the sensitivity of prices to changes in supply or demand at peak times.

5. Market Operations: Summary and Recommendations

Our analysis shows that shortages occurred during a number of hours in which the energy prices did not efficiently reflect demand and supply conditions. These issues are inherent in each of the operating wholesale markets in the U.S. as well as in FERC's Standard Market Design. The NYISO has proposed effective changes by way of the development of its reserve demand curve in its RTS software.

Our analysis of this issue in the 2002 Summer Review prompted several recommended changes, including:

- Setting prices at the bid cap level in Eastern New York when the requirement there for ten-minute reserves cannot be satisfied, and setting price at the bid cap on a statewide basis when the statewide requirement for ten-minute spinning reserves are deficient;

- Paying generators that backed down to provide reserves a "lost opportunity cost" payment equal to the energy price minus their energy bid during reserve deficiencies;

- Allowing EDRP and SCR resources to set energy prices at the level of their payment for curtailing when they are economic and allowing them to submit a wider array of curtailment bid prices; and

- Providing addition information to operators to ensure that ten-minute reserves committed manually are eligible to set energy prices.

We anticipate that most of these recommendations will be addressed prior to Summer 2003 and will help address this important issue.

B. External Transactions

External transactions raise important peak-demand pricing issues, as well as numerous issues under general load conditions. This subsection emphasizes external transactions at peak times and the impact on prices. Section VI addresses general issues associated with external transactions.

The 2001 Annual Report analyzed transactions between New York and the adjacent regions (ISO-NE and PJM) and found that improvements in trading could occur if certain changes to scheduling rules and procedures were to be made. These changes have been implemented and have improved the utilization of the interfaces. While these changes have improved the arbitrage of prices, substantial price differences between New York and adjacent regions have persisted under peak demand conditions.

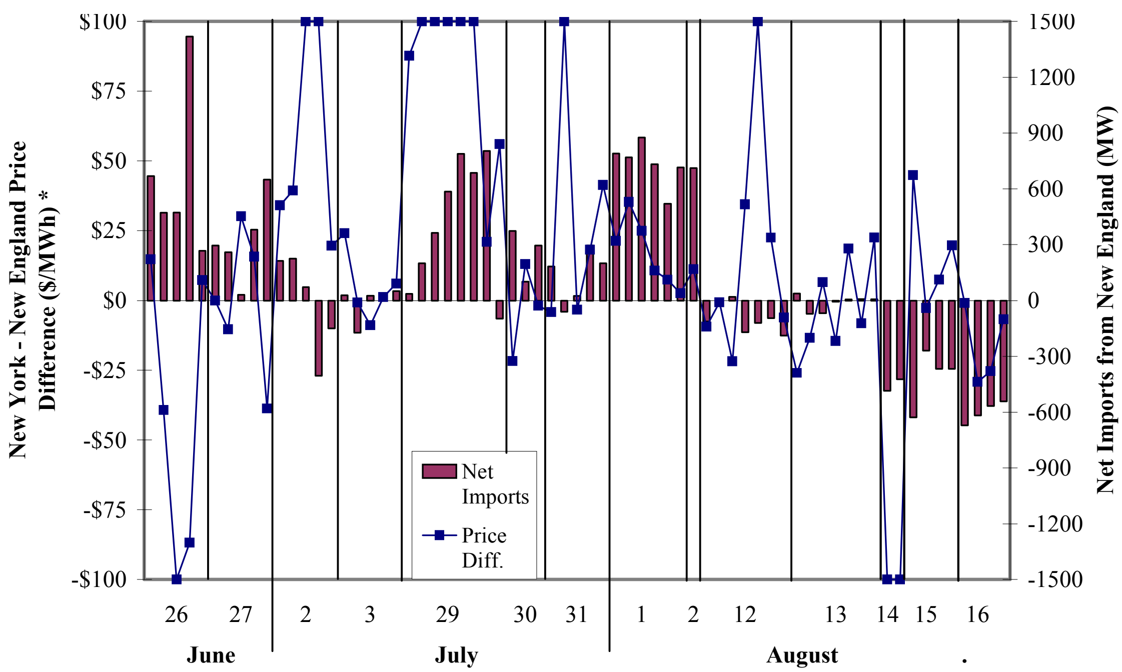
This analysis examines peak demand periods to determine the extent to which participants are efficiently arbitraging prices during these periods. This analysis is focused on certain hours during eight peak days from late June to the end of July 2002. We evaluate the extent to which prices were arbitraged during each hour by comparing prices between New York and adjacent regions and examining whether prices converged.

Prices may fail to converge even in well-functioning markets if transmission constraints prevent desirable flows from occurring. Therefore, to exclude the effects of transmission constraints, our analysis excludes hours when interface constraints or the DNI constraint (which limits the net change in power flows between operating control areas) were binding. In the non-constrained peak hours that we evaluate, an efficiently utilized interface should exhibit certain characteristics. First, the difference in prices between adjacent regions should be close to zero. Second, to the extent price differences exist between adjacent regions, electricity should generally flow from low-priced regions to high-priced ones. Finally, when large price differences arise, market participants should act quickly to arbitrage them.

Figure 36 shows a series of peak hours during 2002, indicating the scheduled net interchange and the price difference between New York and New England. To better show the activity at times when price differences are relatively small, price differences are bounded between $100 and -$100 (prices outside of this range are recorded at the bounds, e.g., a price above $100 is shown as $100 – we analyze large price differences for these hours separately, below).

The figure reveals little evidence that participants responded efficiently to the price differences that existed at these hours.[3] Overall, in over 1/3 of the hours where constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the low priced area, something that should not happen in an efficient dispatched of regional capacity.

Figure 36
Relationship of Real-Time Prices to Net Imports from New England
Peak Days - Unconstrained Hours from 12 pm to 8 pm

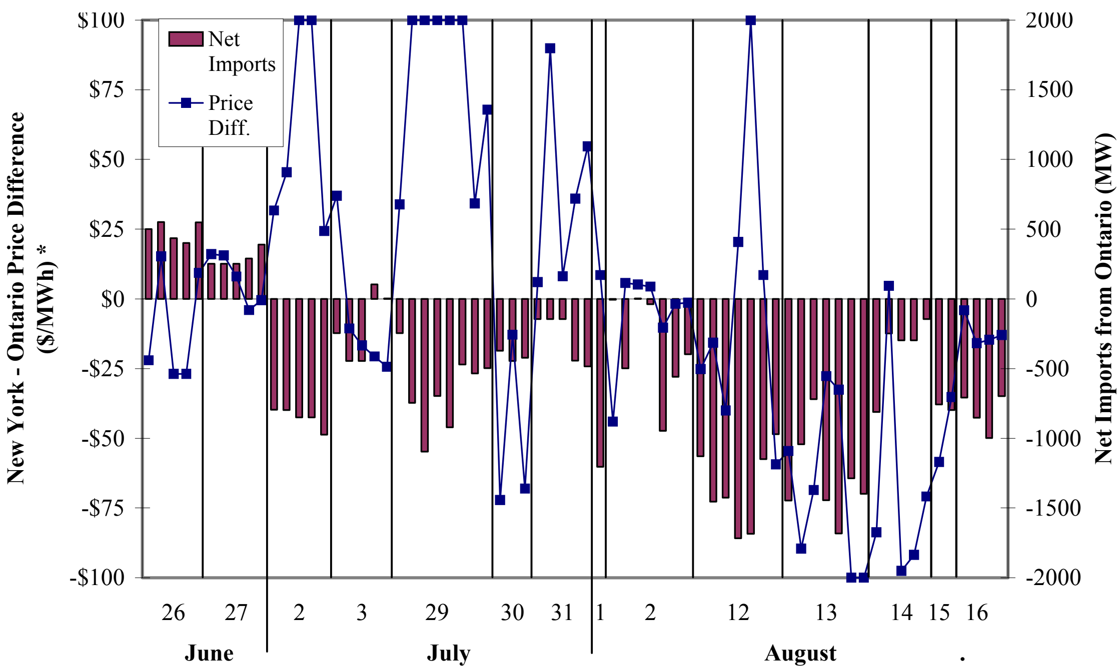


On July 29th, participants responded to price signals by scheduling additional imports from New England, but not enough to effectively arbitrage the substantial price differences that continued for six consecutive hours. Furthermore, there is only a .20 correlation coefficient between the price difference and scheduled interchange.

We conducted similar analysis for the interface with Ontario. This analysis is summarized in

Figure 37. Like the New England interface, there is little evidence that participants were able to schedule transactions to arbitrage significant price differences. In 44 percent of the hours where constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the lower-priced region. Furthermore, price differences and scheduled interchange are negatively correlated on this interface, something that is counter to what should occur under efficient scheduling.

Figure 37
Relationship of Real-Time Prices to Net Imports from Ontario
Peak Days - Unconstrained Hours from 12 pm to 8 pm



Finally, the analysis of the PJM interface (Figure 38) also indicates poorly arbitraged prices at peak hours. For most of the hours studied, New York exported to PJM, even when prices were substantially higher in New York. Like the Ontario interface, there is a negative correlation between the price difference and scheduled interchange.

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 markets is the highest. Therefore, we examined hours when a price difference of more than $100 existed between New York and the adjacent regions.

Figure 38
Relationship of Real-Time Prices to Net Imports from PJM
Peak Days - Unconstrained Hours from 12 pm to 8 pm

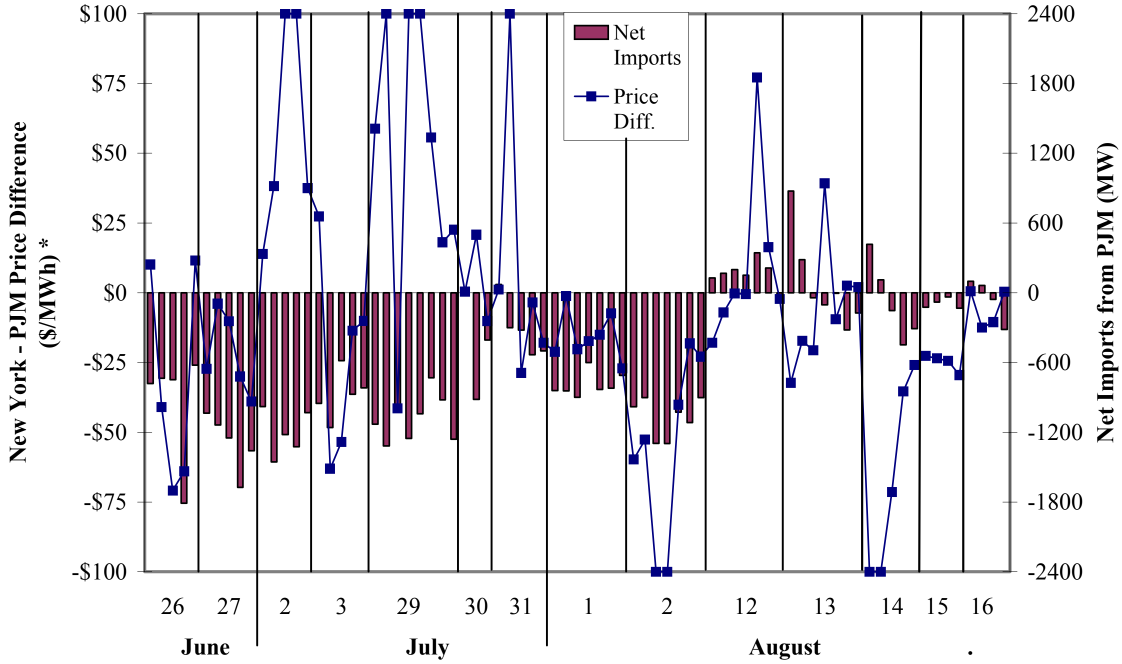
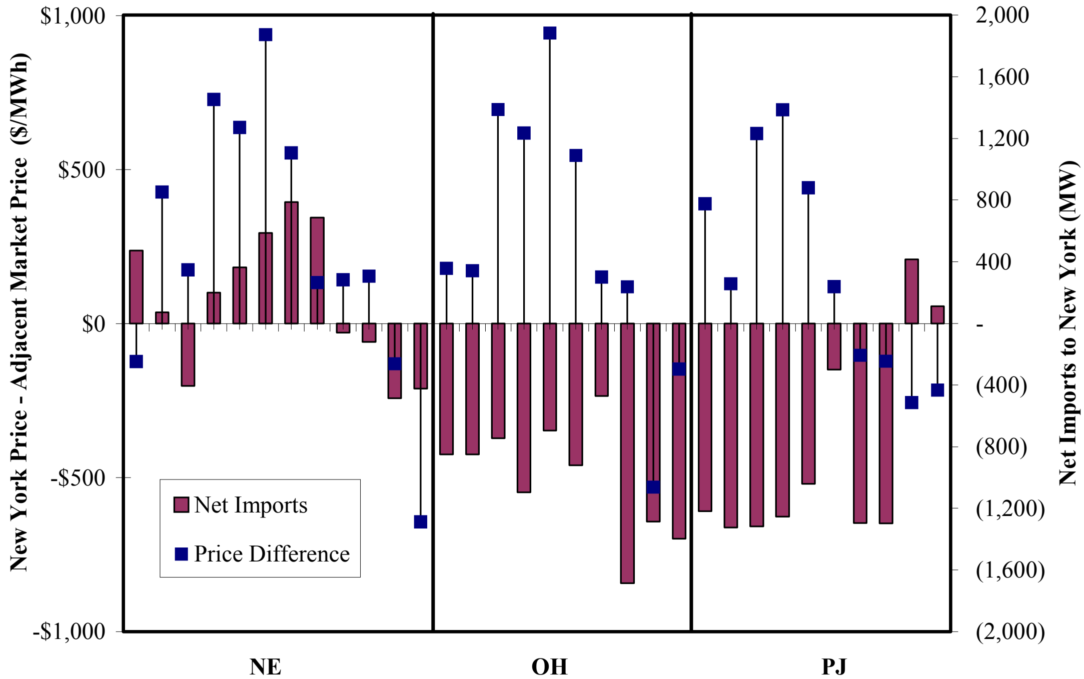


Figure 39 shows hours in which the price difference between New York and adjacent regions exceeded $100. In more than one-half of these hours, the net interchange reflects power scheduled from the higher-priced market to the lower-priced market, something that is contrary to what is expected under efficient regional dispatch. On the PJM and Ontario interfaces, power was scheduled from the higher-priced region to the lower-priced region in nearly every hour, contributing to the large price differences.

Because large price differences can arise quickly, it may be difficult for participants to predict it far enough in advance to schedule an hourly transaction to take advantage of the price difference. Moreover, because the duration of the large price differences can be uncertain, strategies to exploit the differences will be accompanied by substantial risk.

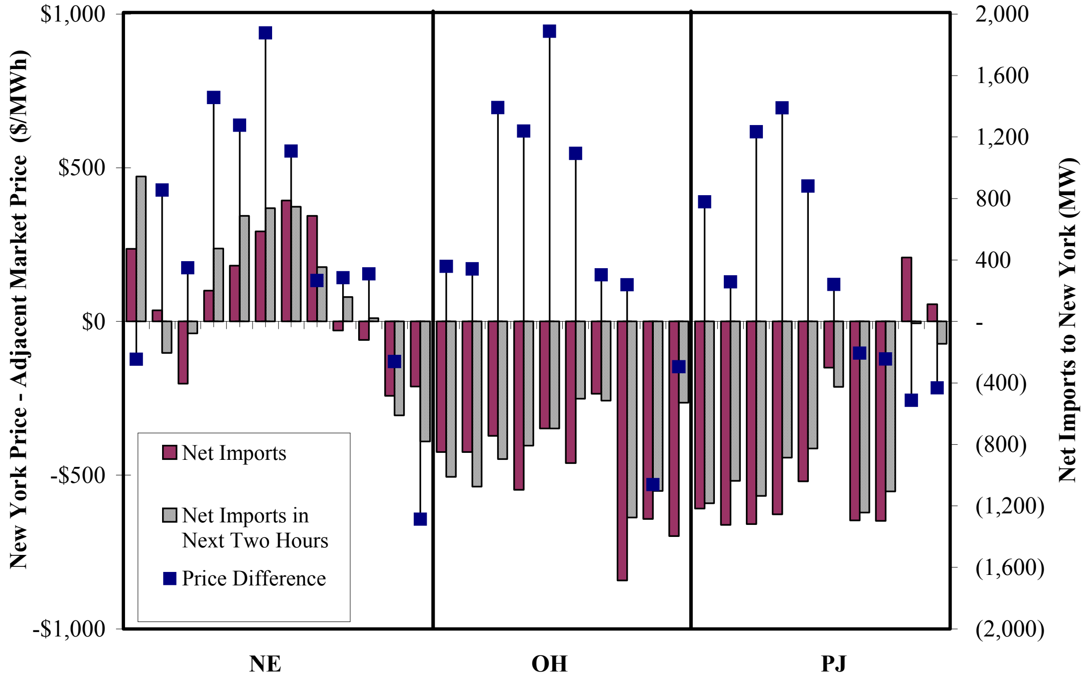
Figure 39
Relationship of Real-Time Prices to Net Imports from Adjacent Areas
Unconstrained Hours with Price Differences >$100 MWh



Therefore, to assess the responsiveness of the transactions to these price differences, we analyze the net interchange in the two hours following an hour with a large price difference. This analysis is presented in Figure 40 and shows that the interchange responded only slightly in response to the large price differences. In some instances, the interchange volume increased in the direction of the lower-priced region.

The above analysis indicates that for peak hours, when transmission or DNI constraints did not affect the ability of power to flow between regions, scheduled flows between New York and adjacent regions was not efficient.

Figure 40
Relationship of Real-Time Prices to Net Imports from Adjacent Areas
Unconstrained Hours with Price Differences >$100 MWh



Some factors explaining the foregoing 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 the energy prices.

In Section VI we discuss external transactions in more detail and provide recommendations that could improve efficiency.

V. CAPACITY MARKET

This section assesses the design and competitive performance of the capacity market. The NYISO implemented a change to the design of its capacity market at the end of 2001. Since that time, LSEs have been required to purchase unforced capacity (UCAP) rather than installed capacity (ICAP). The difference is that UCAP is adjusted to reflect forced outages. Thus, an unreliable unit with a high probability of a forced outage would not be able to sell as much UCAP as a reliable unit of the same installed capacity. This is beneficial to consumers because it creates a mechanism that attaches an explicit value to investments in reliability.

The New York Reliability Council has recommended certain installed capacity margins for the NYISO in order to achieve NERC's one-day-in-ten-years outage standard. Since these recommendations are stipulated in terms of ICAP, the NYISO uses a control area-wide forced outage rate to convert this recommendation into UCAP terms. Likewise, suppliers sell capacity from each of their units on a similarly adjusted basis. So a unit with 100 MW of nameplate capacity and a forced outage probability of seven percent would be able to sell 93 MW of unforced capacity. This gives suppliers a strong incentive to maintain their units for reliable performance.

To assess whether New York's capacity market has been workably competitive, it is necessary to examine the attributes that should be present in a competitive capacity market. First, LSEs should be willing to pay up to the deficiency price (i.e., the capacity price cap) to purchase capacity when the market is short of capacity. Second, generators lacking market power in the capacity market (i.e., serving as a price-taker with no influence on the capacity prices) should choose to sell their capacity when the capacity price is above the marginal cost of selling the capacity. Marginal costs in this context include all costs of selling capacity in the New York market, including opportunity costs. They would include expected cost associated with the capacity recall provision, the day-ahead bidding requirement, and the foregone opportunity of selling capacity in neighboring markets. In addition, units that will retire for economic reasons without a sufficient capacity payment may offer their capacity at its avoidable fixed cost going forward. This offer would only be rational for a unit whose best alternative opportunity is to shut down, which is likely to be a very small portion of the capacity in New York.

Absent relatively high capacity prices outside of New York, the marginal costs of providing capacity in New York – while not zero – should be relatively modest. This has been evident in the capacity offer patterns of generators in the New York market over the past two years. In a competitive capacity market, therefore, prices should decrease to marginal cost when a capacity surplus emerges. The following analysis shows the results of the capacity market over the past two capability periods (from May 2002 to April 2003) to determine whether its performance has been consistent with the competitive expectations.

Figure 41 shows the capacity market results for the State over the twelve months ending April 2003. The amounts shown in this figure include all capacity sold by New York capacity suppliers, whether it is sold into the New York capacity market or sold by New York generators into neighboring markets. Therefore, the hollow portion of each bar represents the in-State capacity not sold in any market. With regard to the capacity prices, the figure shows both the 6-month strip auction price for each capability period, and the monthly deficiency auction price. As a general rule, if the hollow portion (unsold capacity) of each bar is large, the price for that month is expected to be low, whereas if the hollow portion is small, the price for that month should be close to the deficiency price.

The figure shows that most of the capacity requirement is satisfied by internal generation, although external suppliers and alternative capacity suppliers (including special case resources and load management) each provide a significant amount of capacity in this market. The figure shows that during the summer capability period, there was a 1200 MW increase in the quantity of internal capacity that was sold between May and October. This is due to an increase in capacity exports to neighboring control areas. The figure also shows that the total quantity of available capacity shifts upward in the winter capability period (in spite of a reduction of imports and special case resources). This is because the capacity ratings of most fossil units increase in the winter, and this additional capacity is reflected by lower capacity prices during the winter. Both strip prices and monthly prices have remained relatively low throughout the period which is consistent with the fact that a state-wide surplus exists.

Figure 41
Unforced Capacity Market – New York State
May, 2002 – April, 2003

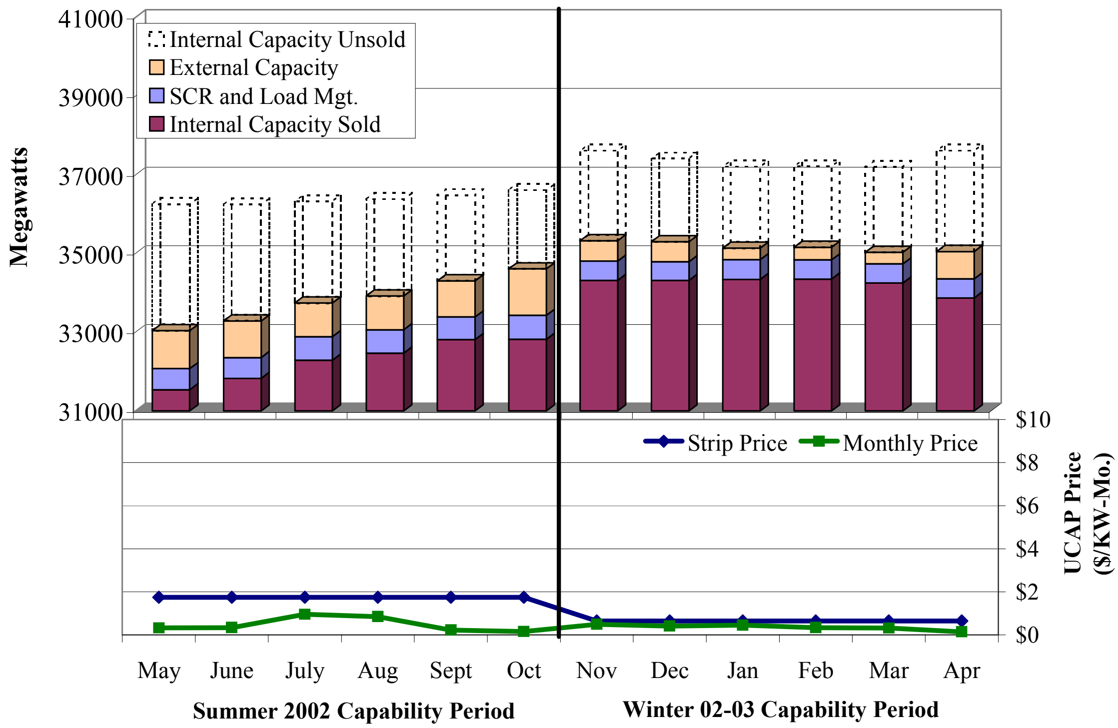
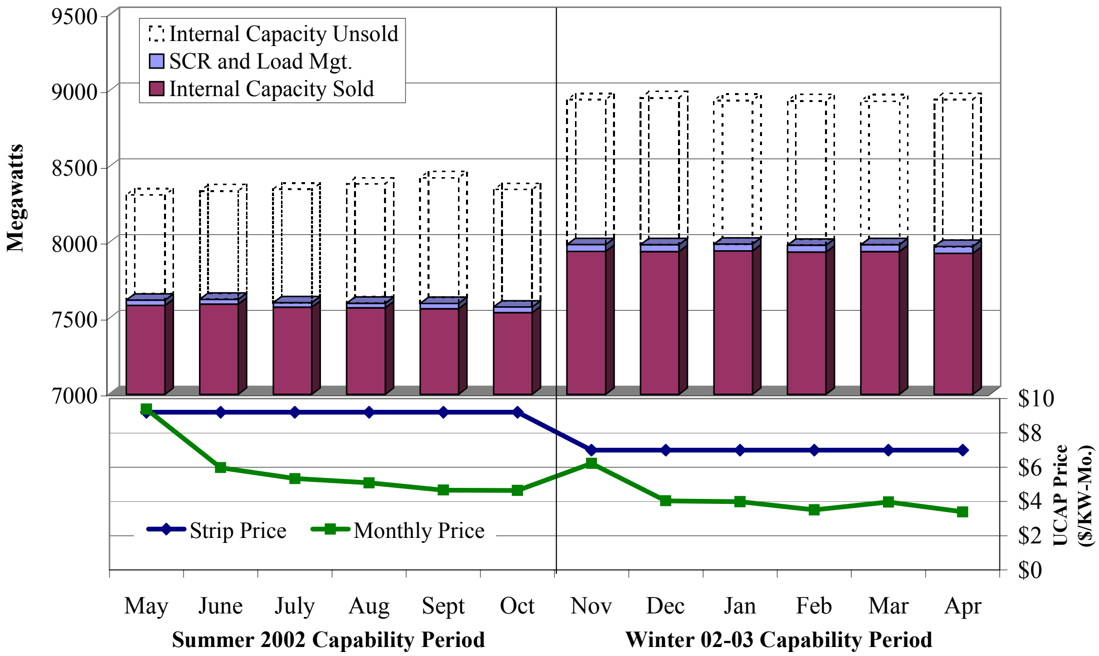


Figure 41 shows that the quantity of capacity sold in the summer was less than in the winter due to an error in calculating the unforced capacity requirement. The installed capacity requirement was converted to an unforced capacity number using a historic forced outage rate covering a long time period. This is not consistent with the shorter-term forced outage rate used to calculate the unforced capacity that may be offered by each generating unit. Since forced outage rates have generally declined in New York since the deregulation of wholesale markets, the outage rate used to calculate the requirement was too large, resulting in a depressed UCAP requirement. This error was remedied prior to the winter capability period.

Figure 42 shows the same analysis for the capacity market in New York City. Like the prior figure, these data include all capacity sold from generators located within New York City even if this capacity is ultimately scheduled to meet the state-wide requirement or exported to other markets.

Figure 42
Unforced Capacity Market – New York City
May, 2002 – April, 2003



Like the state-wide quantity of unsold internal capacity, this figure shows that there was a surplus in New York City. Throughout the summer and winter capability periods, 9 to 12 percent of the available capacity was unsold. However, the average monthly auction prices during these periods, which ranged from $3.50/kW-month to $9.38/kW-month, are not correlated with the quantity of unsold capacity. In a competitive market, prices are expected to vary inversely with the surplus of capacity, but the locational capacity market for New York City has not been consistent with competitive expectations. This can be attributed to the higher concentration of supply in New York City and the fact that some suppliers are pivotal. However, the error in calculating the unforced capacity requirement resulted in the procurement of approximately 400 MW less in the summer capability period than in the winter.

Locational capacity requirements are a valuable component of the capacity market because they provide a clear signal where capacity is needed for reliability purposes. The generation commitment practices to support the local reliability of transmission constrained areas can inefficiently reduce the locational energy price in such areas, making locational capacity requirements or locational reserve requirements more important.

The primary drawback to locational capacity or locational reserve requirements is that they must be satisfied by those supplies in the constrained areas. Because of this, it is more likely that one or more of the suppliers will be “pivotal” in satisfying the requirement. A pivotal supplier is one whose capacity is needed to meet the requirement. Such a supplier, therefore, has the ability to withhold the excess supply to keep the market at the deficiency price level. In most cases, it is rational for the pivotal supplier to bid in this manner – accepting a higher price for a lower quantity of capacity sales rather than selling most or all of its capacity at the marginal cost level.

Locational capacity requirements in New York City provide a valuable economic signal. But to diminish the potential for the exercise of market power, the NYISO has implemented changes to the design of the market. Specifically, the capacity market will utilize a “demand curve.” Rather than procuring a pre-specified fixed amount of UCAP up to the deficiency price, the demand curve specifies a maximum price that will be paid for a given amount of unforced capacity. The new framework will be less susceptible to the exercise of market power by improving the incentives of capacity owners to offer it competitively.

In addition to this change, efforts are on-going to standardize the capacity markets in the Northeast and facilitate the trading of capacity between regions. This includes consideration of a proposal to establish a sufficiently forward-looking capacity requirement so that new generation developers could bid against existing generators. These efforts to standardize the capacity markets are valuable and should continue.

Finally, it is also important to minimize the uncertainty surrounding the capacity market. One of the primary justifications for the capacity market is that it can promote efficient investment patterns in generation over the long-term. However, the economic signals sent by the capacity market will not have the desired effect in guiding new investment if the signals are subject to substantial uncertainty over the longer-run. In other words, uncertainty caused by instability in the rules governing the capacity market can cause investors to discount the capacity market signals, resulting in significant costs to consumers from forgoing the full the long-term benefits.

VI. External Transactions

This section evaluates the extent to which prices have been efficiently arbitraged between New York and adjacent regions by analyzing the price differences between the markets and the utilization of the interfaces. While the interfaces are still not fully-utilized, this section shows that trading has improved significantly as a result of several market design changes. Although there have been improvements, the process where market participants are responsible for scheduling flows between New York and other control areas may be inherently inefficient. Therefore, further changes should be made that will remedy the lack of efficient price convergence at the seams between control areas.

A. Convergence Between Markets

Absent transmission constraints, trading should occur between neighboring markets to cause prices to converge. In other words, when prices are higher in New England than New York, exports to New England should continue until the interface is fully scheduled or until prices have converged and no economically viable exports remain. The series of scatter plots shown below in Figure 43 - Figure 46 show the relative differences in prices between New York and neighboring markets and the corresponding power flows between the markets.

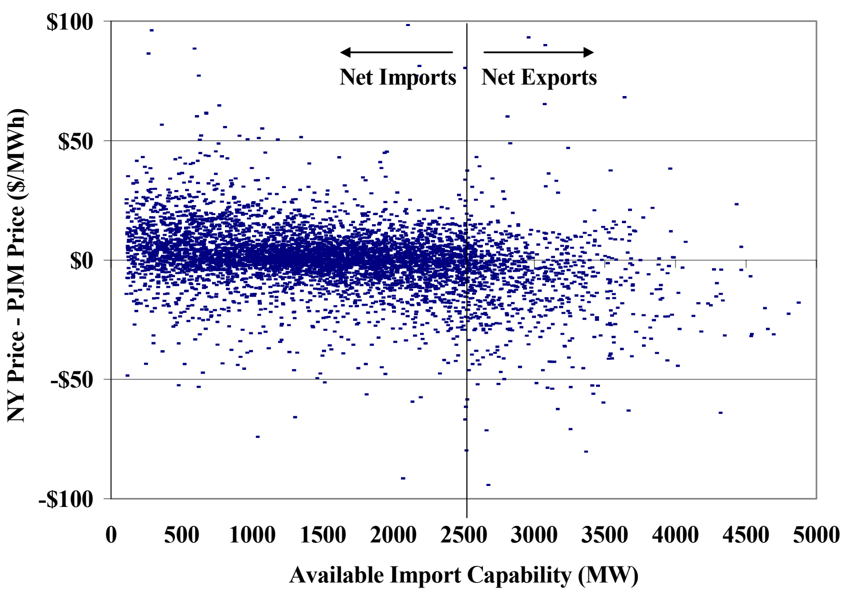
The vertical axis in each figure shows the hourly difference between the price in New York and the price in the adjacent region. The top half of each figure, therefore, reflects hours where the price in New York was higher than the price in the neighboring region. The horizontal axis shows available import capability into New York from the adjacent region. Available import capability is total transfer capability minus net scheduled imports. Therefore, when the NYISO is exporting (net scheduled imports are negative), the available import capability will exceed the total transfer capability. In other words, when power is being exported from New York, the available import capability on an incremental basis is greater than the physical transfer capability because participants may counter-schedule imports against the prevailing exports.

The vertical line intersecting the horizontal axis represents the approximate total transfer capability level for each interface. Hence, the two right quadrants represent net exports while the two left quadrants show net imports.

If transactions were scheduled efficiently between regions, it is expected that the points in each of the charts would be relatively closely clustered around the horizontal line – indicating little or no price difference between New York and the adjacent region in the absence of a physical transmission constraint. Moreover, one would not expect net exports to occur when the New York price substantially exceeds the price in the neighboring region. Likewise, one would not expect net imports to occur when the New York price is substantially less than the price in a neighboring region.

Figure 43 shows the hour-ahead import capability for PJM and New York in the real-time market during 2002 in unconstrained hours, together with monthly statistics describing relative prices in the two areas. The hour-ahead import capability is shown because the BME is what actually schedules external transactions based on a projection of what will occur in real-time. Real-time prices are shown because these are used to financially settle transactions that are scheduled by the hour-ahead model.

Figure 43
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

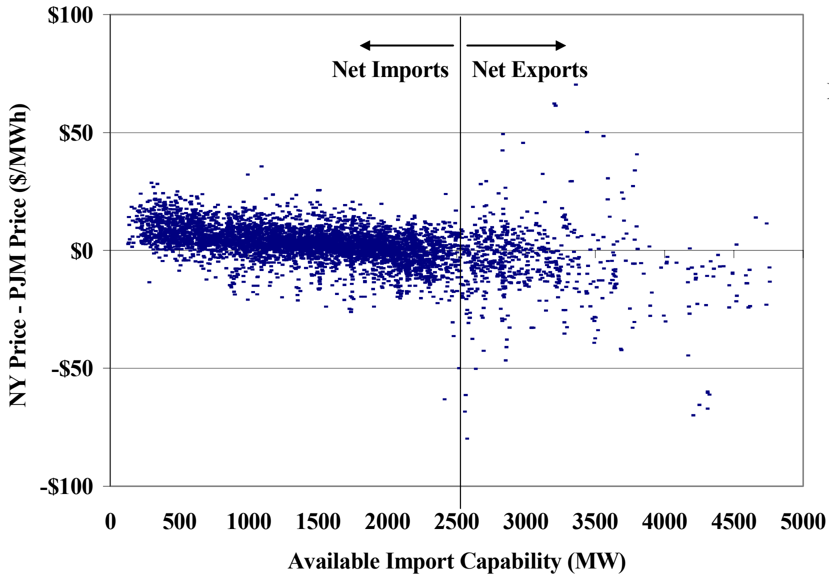
* PJM Western Hub Price

Because PJM is electrically located west of the Central-East Interface, the price difference shown in Figure 43 is the difference between the price in the NYISO West Zone and the PJM Western Hub prices. The New York prices were higher on average than the PJM prices. The monthly statistics show that the mean price differences and standard deviations were quite low early in 2002, volatile in the summer, and divergent in the last three months of the year. New York sustained higher real-time prices in the last three months of the year, although volatility did not rise above summer levels. Western Pennsylvania is heavily dependent on coal-fired capacity while New York is dependent on a mix of fuels that include oil and gas. Thus, the fluctuations in oil and gas prices naturally caused New York generation costs to rise compared with PJM. However, efficient trading would have caused prices to converge in non-transmission-constrained hours.

Several factors prevent real-time prices from being fully arbitraged between New York and adjacent regions. First, market participants do not operate with perfect foreknowledge of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible. Second, differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage. Third, there are substantial transmission fees and other transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Lastly, risks associated with curtailment and congestion will reduce participants' incentives to engage in external transactions at small price differences.

The arbitrage of the day-ahead prices in PJM and New York has been more effective than the real-time arbitrage. This is expected because the resources needed to support the transactions are generally easier to arrange and because day-ahead prices tend to be less volatile than real-time prices. Further, there is no check-out process in the day-ahead market that can result in a transaction being curtailed if it is not scheduled in the adjacent market. Figure 44 shows the results of PJM/New York trading for the day-ahead market.

Figure 44
Difference Between West Zone and PJM Price
Day-Ahead Market
Unconstrained Hours -- 2002



Monthly Price Statistics

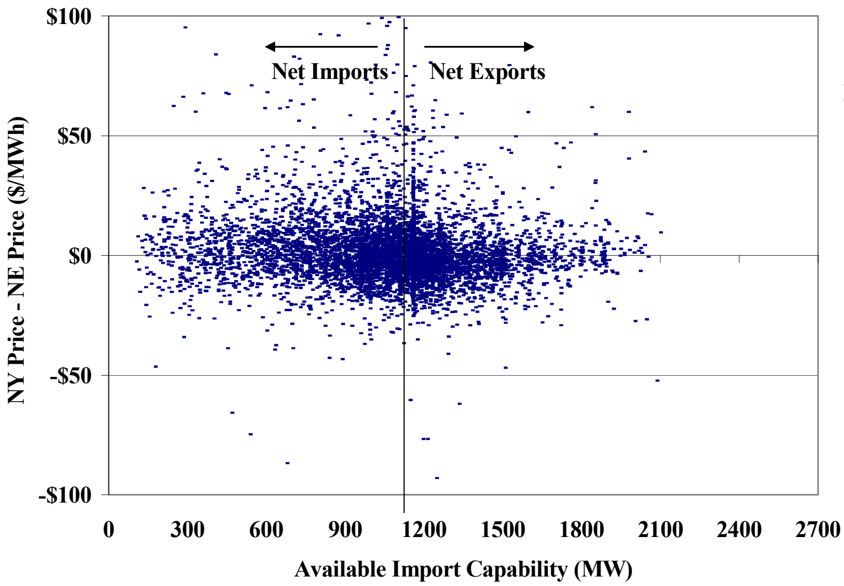
Month	Mean	Std Dev
Jan	$2.21	$3.56
Feb	$0.66	$3.71
Mar	$1.01	$5.39
Apr	$0.40	$9.99
May	-$1.46	$7.26
Jun	-$0.65	$7.76
Jul	$1.48	$11.57
Aug	$3.08	$13.61
Sept	$6.24	$8.18
Oct	$6.32	$7.48
Nov	$9.51	$6.09
Dec	$5.42	$8.77

* PJM Western Hub Price

Although the day-ahead market exhibits better convergence between markets, the general trends shown in the figure above are similar to those observed in Figure 43. The prevailing direction of flow is still from PJM to New York. The data shown in the day-ahead scatter plot are much closer to the horizontal line, indicating that the volatility of price differences is far less in the day-ahead market. Correspondingly, the monthly standard deviations of the price difference are much lower in the day-ahead market than in the real-time market. However, the trend of higher prices in Western New York than in Western Pennsylvania is similar to the real-time market.

The New England and Ontario interfaces have not been as well utilized as the PJM interface. Although the interface capability is smaller and trading activity is lower with New England than with PJM, trading with New England is more economically significant because New England imports serve the congested Eastern New York area. The analysis of trading between the New York and New England markets is shown in Figure 45.

Figure 45
Difference Between Capital Zone and New England Price
Real-Time Prices vs. Hour-Ahead Schedules
Unconstrained Hours -- 2002



Monthly Price Statistics

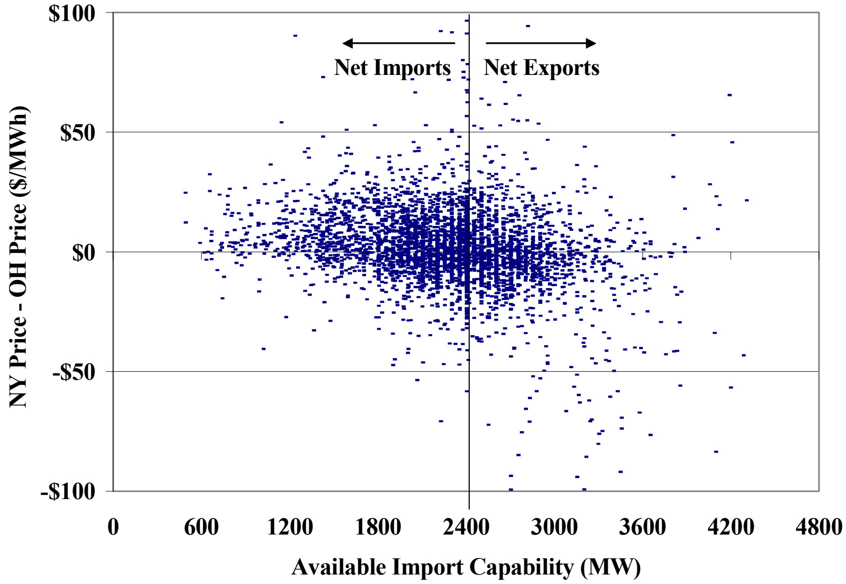
Month	Mean	Std Dev
Jan	-$0.51	$7.77
Feb	-$2.00	$7.80
Mar	$3.39	$18.74
Apr	$4.30	$13.29
May	$1.53	$16.20
Jun	-$1.04	$11.36
Jul	$10.59	$74.21
Aug	-$4.37	$32.61
Sept	-$0.13	$34.15
Oct	$3.57	$16.41
Nov	$4.36	$15.57
Dec	$3.96	$20.92

This figure shows that there are many hours where New York exports power to New England and many hours where the opposite is true. However, in the overwhelming majority of instances, only a small portion of the interface capability is being used, even in hours where there are substantial price differences. The majority of points in the PJM charts were in a narrow band around $0/MWh. But Figure 45 shows a much larger portion of unconstrained hours when the price difference is substantial – the price difference was greater than $5/MWh in 59 percent of unconstrained hours. However, the monthly price statistics suggest that there is not a predictable sustained price disparity, because the monthly average difference was ordinarily less than $5/MWh. Market participants have not been able to optimize the flow over the seam between New York and New England although the efficiency gains from doing so would be substantial.

In May of 2002, the Canadian province of Ontario began a partially deregulated wholesale electricity market with a single zonal market clearing price and centralized dispatch by the Independent Electricity Market Operator (IMO). This development has had an impact on how external transactions are scheduled to and from Western New York. The data in Figure 46 show

how well market participants have arbitraged the interface with Ontario during uncongested hours since the start of Ontario market.

Figure 46
Difference Between West Zone and Ontario Price
Real-Time 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

This figure shows that New York imports from Ontario slightly more often than it exports. However, in most unconstrained hours, the flow in either direction is small, even in hours where there are substantial price differences. As with the New England interface, this figure shows that the interface with Ontario has not been arbitraged as well as the one with PJM. Many data points are a significant distance from the horizontal line at $0/MWh. In fact, the price difference was greater that $5/MWh in 61 percent unconstrained hours and in 38 percent of these hours the flow was from the higher-priced region to the lower-priced region, indicating that market participants have yet to fully utilize the transmission interface between the regions.

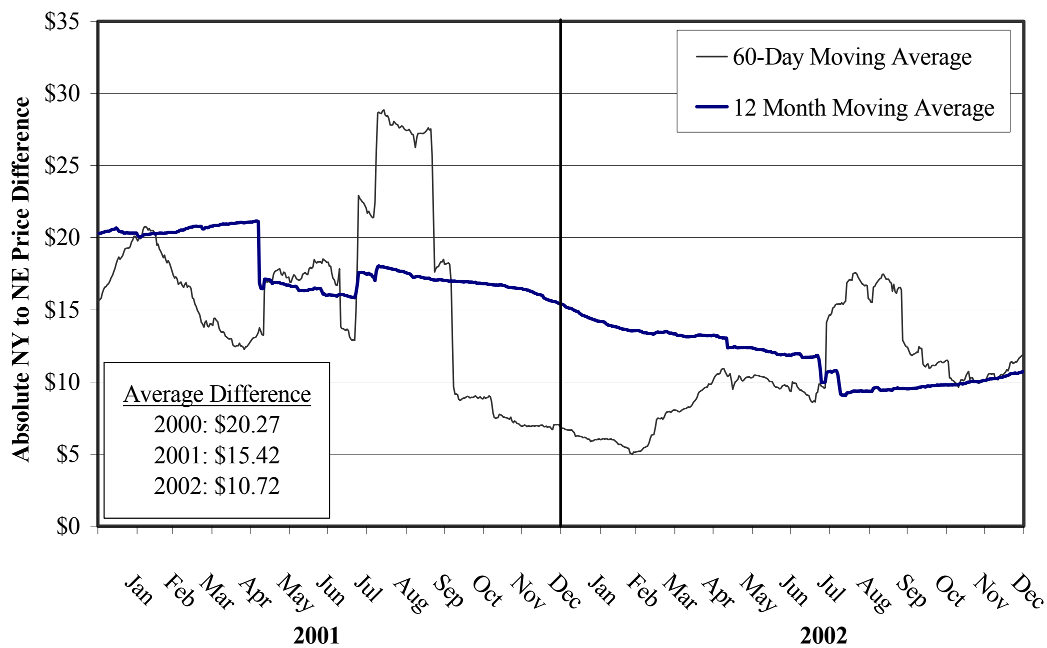
B. Improvements to Convergence

While the scheduling of imports and exports between control areas has not produced fully-efficient results, several rule changes and market design adjustments have led to improvements. For instance, a short-notice scheduling rule that had prevented real-time imports from New England was eliminated. In addition, the NYISO implemented substantial improvements to the

BME model at the beginning of 2002 that have, among other things, improved the efficiency of external transactions scheduling. The BME now designates 30-minute reserves more effectively, which has resulted in better price convergence with the real-time model. While this is seemingly unrelated to external transactions, the more accurate the prices are in the BME model, the more likely it is to schedule the set of imports and exports that will result in price convergence between control areas.

The following two charts assess how efficiently flows have been scheduled between New York and New England and between New York and PJM over the past three years. Figure 47 summarizes the average real-time price difference between New York (using the Capital zone prices) and New England during uncongested hours. We use both a 60-day rolling average as well as a 12-month rolling average.

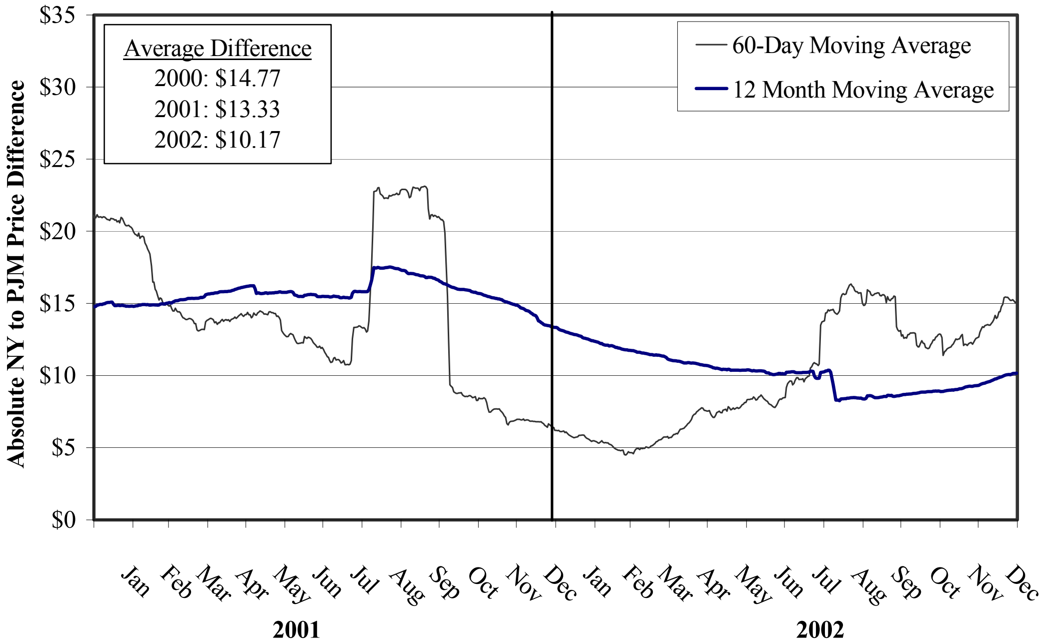
Figure 47
Average Price Difference Between New York and New England
Moving Average, 2000 – 2002
Uncongested Hours



There sharp movements in the moving averages generally correspond to periods of price spikes in one of the markets. Although the averages fluctuate considerably, the general trend is downwards over time. The average annual price differences for 2000, 2001, and 2002 are equal to the 12 month moving averages as of December 31st of each year. These 12-month averages are highlighted in the lower left corner of the figure. The average price difference has dropped from more than $20/MWh in 2000 to less than $11/MWh in 2002. Therefore, price convergence has improved markedly as the seams issues on the New England interface have been addressed.

Figure 48 shows data summarizing the average real-time price difference between New York (using the West zone price) and PJM during uncongested hours using a 60-day rolling average as well as a 12-month rolling average.

Figure 48
Average Price Difference Between New York and PJM
Moving Average, 2000 – 2002
Uncongested Hours



As with the New England interface, this figure shows sharp movements in the rolling averages corresponding to periods of price spikes in one of the markets. The averages fluctuate substantially, but the general trend is downwards over time. The average annual price differences during unconstrained hours for 2000 and 2002 are $14.77/MWh and $10.17/MWh, respectively. Like the New England interface, price convergence has improved significantly over the past two years.

The analysis depicted in the previous two figures assesses how efficiently flows have been scheduled to arbitrage prices between New York and New England and New York and PJM over the past three years. To the extent prices do not converge, it is because high-cost units are being dispatched unnecessarily in the higher-priced control area. It is inefficient for a $60/MWh generating unit in the Capital zone to run when the marginal generator in New England is $45/MWh and the interface in unconstrained. If the interfaces were fully-utilized, the operators in New England would ramp-up so that the New York operators could turn down the $60/MWh unit. In this example, an additional megawatt produced in New England would allow the New York unit to reduce its output and save $15 in system-wide production costs. The previous figures imply that while arbitrage has not been perfect, there have been substantial production cost savings from improved arbitrage.

We performed an analysis that quantifies production cost savings as a result of improved inter-regional dispatch since 2000. First, we calculated the total potential production cost savings that could be achieved in the region in each year from perfect interchange between control areas, based on available supply in each market. The production cost savings from year-to-year is the decline in unrealized gains from perfect interchange. In 2001, the unrealized gains from full arbitrage were $21 million less than in 2000, and in 2002, the unrealized gains were $50 million less than in 2000. However, the markets still exhibit persistent price differences, indicating that the transmission capacity between the regions is under-utilized.

C. Transaction Scheduling

Flows between markets are coordinated by market participants that must schedule the transaction in both markets. When market participants arbitrage price differences by scheduling external transactions, they will lower the overall cost of serving load in the region. As indicated in the previous analyses, market participants have not been fully successful in arbitraging prices between markets.

New York employs an economic system for scheduling external transactions (i.e., a bid-based auction). Market participants do not need to own generation assets or hold a physical transmission right, their transactions are scheduled based on bid prices. Although New York has an economic system, it still checks with its neighbors to certify that the market participant arranged for withdrawal or receipt in that control area as well. Transactions scheduled with the NYISO, but not with the neighboring control, area are eliminated.

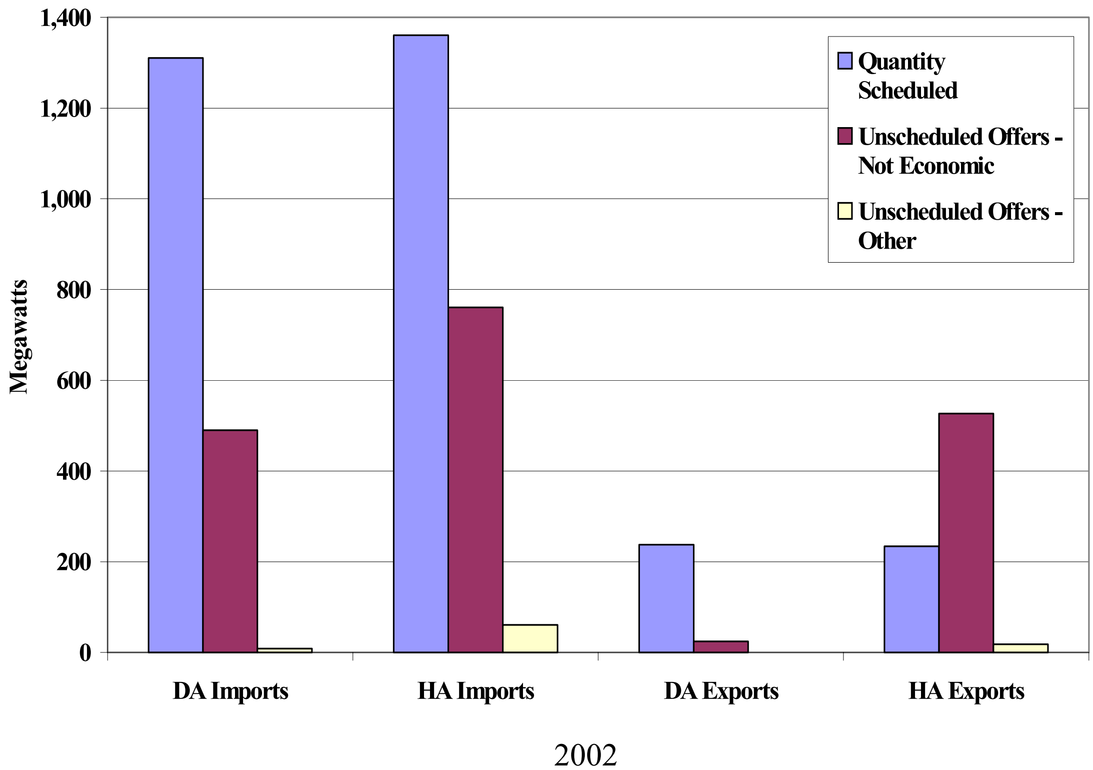
While some control areas adjacent to New York employ a full or partial economic system for external transactions, others have a physical scheduling system. PJM allows market participants to physically reserve transmission capacity on external interfaces to schedule transactions. Market participants in PJM can base the reservation on a strike price submitted to the day-ahead market, but after that time, there are no price-sensitive transactions.

In order for a market participant to schedule flows from PJM to the NYISO, the participant must reserve export transmission capacity in PJM and submit an import offer priced below the proxy bus price in New York. Thus, on the New York side we observe a set of import offers and export bids that are scheduled by the SCUC and/or the BME models based on their economic priority implied by their bids. We observe in the New York data that transactions are almost always scheduled to or from PJM based on the economic priority of their bids in New York. Figure 49 shows this analysis.

The figure shows the quantities scheduled, unscheduled due to economic priority, and unscheduled even though the transaction was offered at an economic price. These quantities are shown separately for day-ahead import offers, hour-ahead import offers, day-ahead export bids, and hour-ahead export bids. Transactions that are scheduled day-ahead are resubmitted to the hour-ahead model, typically at an extreme price so that transaction will also be scheduled for real-time. This is why the average hour-ahead schedules are very similar to the day-ahead averages, because most scheduled transactions were originally scheduled day-ahead.

The figure shows that on-average very small quantities of imports and exports are evaluated contrary to their bid price. In instances when they are evaluated contrary to their bid price, either transmission capability was not available in PJM or the participant withdrew the transaction. When the participant is responsible for canceling the transaction after it is accepted by the BME, the participant must settle the transaction at the real-time price, thus providing a disincentive to intentionally cause a transaction not to flow after being approved by New York.

Figure 49
Transaction Offers and Schedules Across the PJM Interface



In 2002 and prior to its implementation of Standard Market Design, the ISO-New England employed a combination of economic and physical scheduling of external transactions. New England scheduled some imports based on economic criteria similar to the method in New York, while exporters from New England had to arrange for physical transmission in order to schedule flows to New York.

When market participants scheduled flows from New York to New England in 2002, this involved scheduling the transaction with each ISO. The New York model would accept an export bid if priced above the New England proxy bus price. The New England operator would accept the import offer if priced below the projected New England energy clearing price. In order for power to flow, both control areas had to accept the transaction.

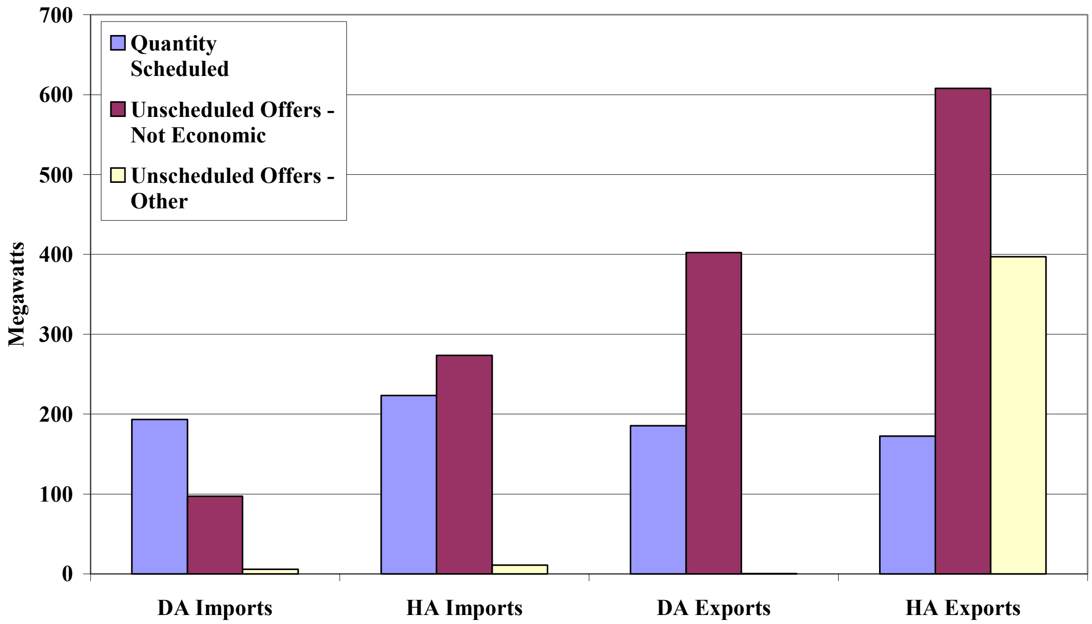
This scheduling process could result in under-utilization of the interface. For example, suppose that the New York model must choose whether to allocate scarce capability on the New England interface to an export priced at $100/MWh or an export priced at $150/MWh, both of which have also been bid to the ISO-NE as imports at $100/MWh and $150/MWh, respectively. Further assume that the Eastern New York price is $80/MWh but the New England price is $120/MWh. In this case, the New York model would allocate scarce transmission capability to the $150/MWh transaction, driving the price at the border to $150/MWh. However, the New England operator would refuse to schedule the import given that its price on the border is $120/MWh.

Thus, no transaction would take place to help the New York and New England prices converge even though unused transmission capability exists and the export at $100/MWh would have been efficient to schedule. It is also important to note that in this hour the interface would be technically designated as export congested, although unused transmission capability existed because the transaction that was allocated the export capability was not ultimately scheduled.

Figure 50 shows the quantities scheduled, unscheduled due to economic priority, and unscheduled even though the transaction was offered at an economic price. These quantities are shown separately for day-ahead import offers, hour-ahead import offers, day-ahead export bids, and hour-ahead export bids on the New England interface.

Average day-ahead imports and exports from New England are virtually the same. In other words, New York is neither a net importer nor a net 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. Virtually none of the imports or day-ahead exports is unscheduled for reasons other than economics. However, on average, of 400 MW of hour-ahead exports are left unscheduled even though the bids indicate they should have been scheduled. These are primarily transactions that are offered at a price that is not economic in New England.

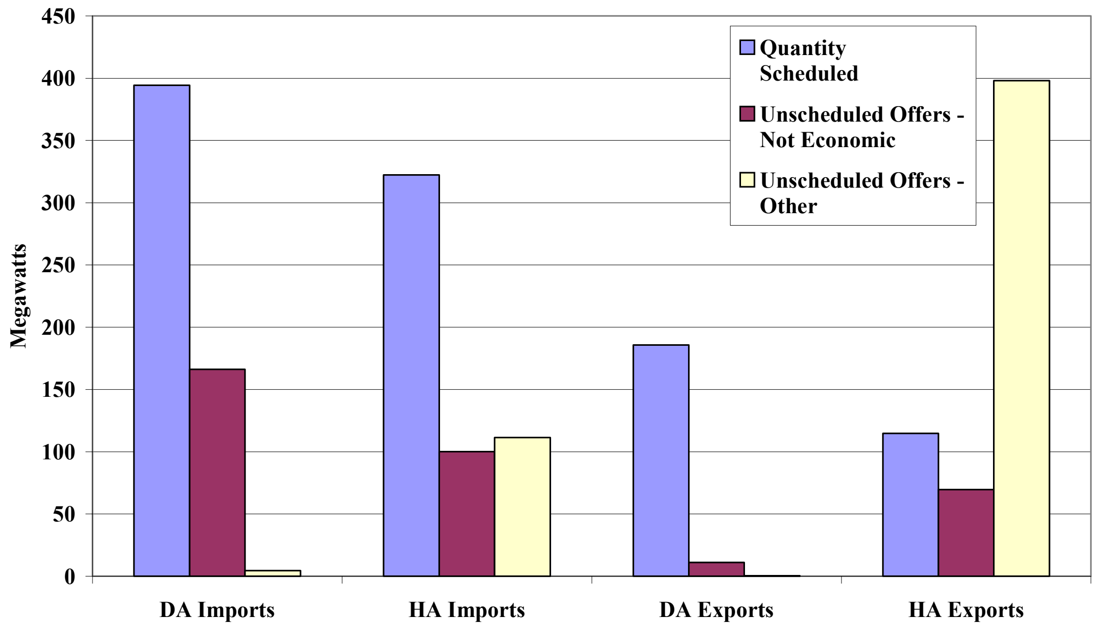
Figure 50
Transaction Offers and Schedules Across the New England Interface
2002



As noted above, in May of 2002, the Canadian province of Ontario began a partially deregulated wholesale electricity market with a single zonal market clearing price and centralized dispatch. This development has had an impact on how external transactions are scheduled to and from Western New York. Ontario uses an economic scheduling system in order to schedule imports and exports. In principle, potential exporters submit demand bids at the border, whereas prospective importers offer supply at the border. Prospective imports and exports are evaluated by the market operator less than one hour ahead of time (i.e. an offer submitted for 11am to noon is evaluated shortly after 10am). Since the New York hour-ahead model evaluates transactions just before this, it is possible for a transaction to be accepted by New York but rejected by Ontario. This is shown to be true by the analysis in Figure 51.

Figure 51 shows the quantities scheduled, unscheduled due to economic priority, and unscheduled even though the transaction was offered at an economic price. These quantities are shown separately for day-ahead import offers, hour-ahead import offers, day-ahead export bids, and hour-ahead export bids on the Ontario interface. On this interface, we find that the average day-ahead scheduled imports and exports exceeds the average hour-ahead schedules. These typically occur when a day-ahead scheduled transaction is also scheduled by the hour-ahead model but fails the check-out process with Ontario. Ordinarily these transactions are deemed not economic by the Ontario operators. On average, nearly 400 MW of exports that are economic according to the New York economic model are not accepted by Ontario. The average quantity of exports scheduled to Ontario is only slightly more than 100 MW.

Figure 51
Transaction Offers and Schedules Across the Ontario Interface
2002



Inter-control area transactions that only clear one market create an impediment to the efficient dispatch of both markets. These transactions reserve scarce transmission capability that will go unused. The Ontario interface has approximately 2000 MW of transfer capability, although the flow between New York and Ontario rarely reaches this level. Thus, congestion rarely occurs on the Ontario interface.

D. Conclusions and Recommendations

Since the beginning of deregulation in New York's wholesale electricity market, market participants have been responsible for determining physical flows between markets by scheduling external transactions. Ideally, market participants will take advantage of opportunities to arbitrage price differences between control areas and thereby optimize flows between them. Over the past several years, modeling improvements and rule changes have led to substantial declines in price differences between control areas during non-transmission constrained hours. Furthermore, our analysis indicates that the economic scheduling process is functioning properly. However, significant price differences remain in hours where no congestion is present. To address this issue, we have recommended that the ISOs in New York and New England fundamentally change the way they schedule interchange. In particular, New York and New England should implement a proposal that is now referred to as Virtual Regional Dispatch (VRD).

VRD is a process where the ISOs will 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. When there is a real-time price difference between adjacent markets, the dispatch model in the lower-priced area should ramp-up generation while the dispatch model in the higher-priced area should ramp-down generation. These adjustments should continue until the prices equalize or until the interface constraint is binding. Participants would not be prevented from scheduling transactions across the interface prior to real-time, because adjustments by the dispatch models would be incremental to participant-scheduled transactions. In principle, this is comparable to the ISOs' determination of the flows over internal interfaces based on generator and load bids.

Under this proposal, transmission congestion contracts (TCCs) could be created spanning the interface between the two control areas. With these TCCs, market participants would be able to engage in fully-hedged bilateral contracts between New York and New England. New England and New York transmission owners would receive revenue from the sale of any inter-control area TCCs that could offset the revenue currently collected through export fees. Generally, market participants will also benefit from VRD because it will lead to less volatility and more predictability in the New York to New England prices. Ultimately, the VRD proposal will eliminate the remaining seams issues and achieve most of the benefits of a single dispatch in the Northeast.

VII. ANCILLARY SERVICES

In conjunction with the day-ahead and real-time energy markets, the NYISO also operates ancillary services markets. These include three operating reserve markets and a regulation market. This section reviews the competitive performance of these markets and the issues that have arisen over the past year. This section also summarizes the modifications that have been introduced to improve the performance of these markets, modifications that will be implemented in the future, and recommendations for additional improvements.

A. Ancillary Services Markets

New York procures three types of operating reserves: ten-minute spinning reserves, ten-minute total reserves (can be spinning or non-synchronous reserves (NSR)), and 30-minute reserves. Ten-minute spinning reserves are held on generating units that are on-line and can provide additional output within 10 minutes. Ten-minute total reserves can be supplied by ten-minute spinning resources or ten-minute NSR, which are typically gas turbines that are not on-line but can be turned on and be producing within 10 minutes. 30-minute reserves may be supplied by any unit that can be ramped up in 30-minutes or that can be on-line and be producing within 30 minutes.

The NYISO receives availability bids from each generator that indicate the minimum price they are willing to accept to provide each reserve product. The marginal cost of procuring reserves includes both the availability bids and the opportunity costs in other markets (i.e., holding economic resources out of the energy market is part of the costs of maintaining operating reserves). Both of these costs are considered in the simultaneous optimization of the reserve designation and energy dispatch. However, reserve prices are set in each market by the highest accepted availability bid – while opportunity cost payments are made to the providers of regulation and spinning reserves in the real-time market and to the providers of ten-minute NSR in the day-ahead market. Currently, the NYISO operates only a day-ahead market for reserves, although it reallocates the reserves hourly during the operating day.

In each hour, the New York ISO purchases 1800 MW of operating reserves. Of this 1800 MW, at least 1200 MW must be ten-minute reserves (at least 600 MW must be spinning reserves and the balance may be either spinning or non-spinning). Consequently, the NYISO may purchase up to 600 MW of 30-minute reserves. There is no limit on how much spinning reserves is purchased – all 1200 MW of total ten-minute reserves (indeed, all 1800 MW of the total operating reserves) could be spinning reserves. Hence, ten-minute spinning reserves are the highest-valued reserve while 30-minute reserves are the lowest-valued reserve.

The reserves markets are cleared simultaneously with the energy market to minimize total bid-production costs. In this process, the price for lower-valued reserves often clears below the price for higher-valued reserves. For example, the ten-minute NSR price generally clears below the price of ten-minute spinning reserves because the ISO must purchase reserves from more expensive spinning reserve units to meet the 600 MW spinning reserve requirement.

The procurement of reserves is also subject to locational requirements to ensure that they will be fully available to respond to possible system contingencies. As discussed above, the most congested interface in the state is the Central-East Interface that limits economic transfers from Western New York, PJM, Ontario, and Hydro Quebec to Eastern New York and New England. Because of this constraint, maintaining reliability requires that a substantial portion of the reserves be procured in Eastern New York. Likewise, the interface between Long Island and the rest of New York has resulted in a requirement that specified amounts of operating reserves be purchased from generating units on Long Island.

For total ten-minute reserves (spinning and NSR) 1000 MW must be purchased east of the Central-East constraint. This does not imply, however, that the 600 MW minimum of ten-minute spinning reserves must be purchased in Eastern New York. In fact, only 300 MW of 10 minute spinning reserves must be purchased there. When ten-minute NSR resources are relatively inexpensive, more than 400 MW may be purchased in the east (e.g., 700 MW) with the balance of the eastern requirement supplied from ten-minute spinning resources (300 MW) and the rest of the 600 MW ten-minute spinning requirement purchased in Western New York (300 MW). This example shows that some ten-minute spinning reserves may be procured in Western New York even given the locational requirement for Eastern New York. Nevertheless, the eastern requirement does limit the quantity of ten-minute reserves that may be purchased in Western New York where roughly half of the state's spinning reserve capability is located. Prior to 2002, this requirement was 1200 MW, however, it was lowered to 1000 MW after the NYISO and ISO-NE entered into a reserve-sharing agreement. The locational reserve requirements for Long Island oblige the NYISO to designate at least 60 MW of ten-minute spinning, 120 MW of total ten-minute, and 540 MW of total reserves (ten-minute and 30-minute) on Long Island.

The NYISO sets prices for reserves that can vary for Western New York, Eastern New York, and Long Island when the locational reserve requirements are binding. This change allows reserve prices to be set by the marginal reserve supplier to satisfy each of these locational reserve requirements. The primary result of this locational pricing is that higher prices for the ten-minute reserves will emerge in the East when the locational requirements are binding and the Long Island requirements will not cause reserve prices to increase in the rest of the State.

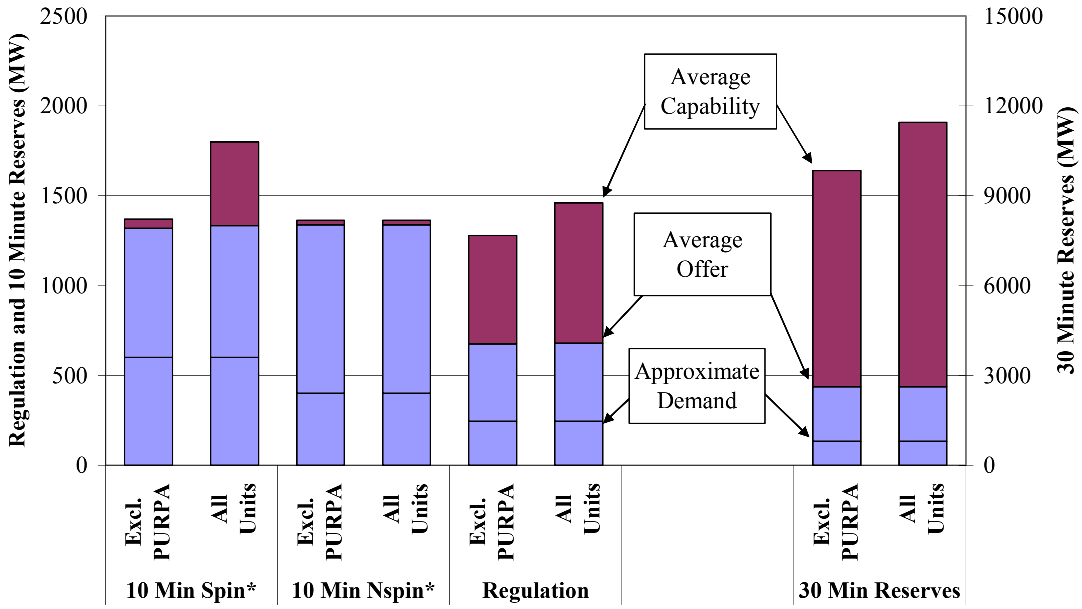
Regulation capability can be purchased from anywhere within the NYCA. The NYISO purchases 275 MW of regulation during high ramp hours and 200 MW during low ramp hours. The amount of regulating capability a generating resource may sell is equal to the amount of output it can produce within 5 minutes (ramp rate per minute times 5). In addition, to qualify as a regulating unit, the unit must be able to receive and respond to a continual dispatch signal and have the ability to ramp at a rate of 1 percent of the unit's total capability per hour.

B. Offer Patterns

Our findings in previous analyses in New York have indicated that a substantial portion of the available reserve capability was not offered into the New York reserve markets. Offering into the ancillary services markets is not mandatory, with the exception the ten-minute NSR in Eastern New York. This section reassesses the ancillary services offer patterns to determine whether participation in this market has improved.

Figure 52 summarizes the average levels of capacity, offers to supply, and demand for all three day-ahead reserves markets as well as the day-ahead regulation market.

Figure 52
Ancillary Services Capability and Offers



*Eastern side of the Central-East Interface Only.

Because of the nature of the locational requirements discussed above, ten-minute reserves are shown only for the region east of the Central-East Interface. In addition, the results of this analysis are shown with and without the PURPA units because a large portion of this capacity may be contractually limited from supplying the reserves markets.

The figure shows good participation in the ten-minute spinning reserves market with nearly all non-PURPA units offering their full ten-minute spinning capability. The offer level in the ten-minute NSR market remains the highest of all of the markets due to the offer requirement imposed in 2000 with the $2.52 per MWh offer cap.

However, participation in the regulation and 30-minute reserves markets remains poor. The average quantity of regulation being offered to the market is approximately half of the total capability, and the average quantity of 30-minute operating reserves being offered is approximately one quarter of the total capability. Generally, this is not a significant concern given the excess reserve and regulation capability that is available. However, under peak load conditions, a large amount of capacity is purchased for energy in the day-ahead market and can cause tight conditions in the day-ahead ancillary services markets.

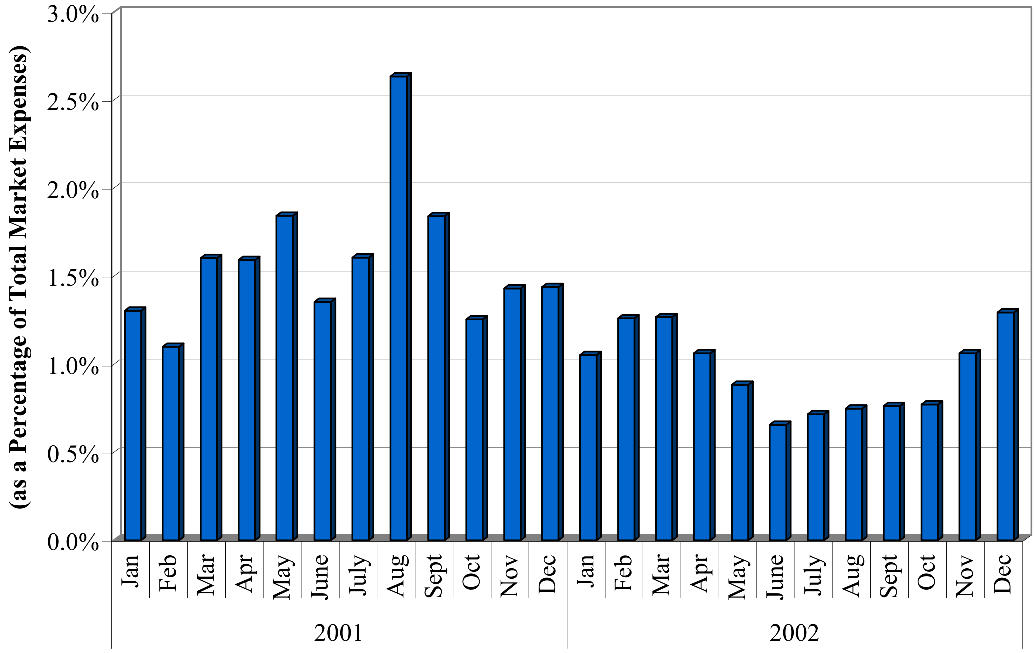
The low level of offers into some of the ancillary services markets leads not only to increased prices for ancillary services, but also to higher energy prices by forcing the NYISO to make inefficient tradeoffs between energy and reserves. Conditions become tight in the ancillary services markets in peak hours as the energy market and reserves markets compete for the same resources. When this occurs, the shortage of reserve offers raises energy prices by causing capacity that is economic to serve the energy demand to be diverted to provide ancillary services in lieu of resources that are less economic for providing energy and should be providing reserves (but cannot be designated because they submitted no ancillary services offer).

C. Ancillary Services Costs

Figure 53 shows operating reserves costs as a percentage of total market expenses on a monthly basis in 2001 and 2002. Reserves costs ranged between 1.1 percent and 1.9 percent of total market expenses in eleven of twelve months in 2001. In August 2001, reserves costs accounted for 2.6 percent of total market expenses with more than two-thirds of this from the peak days of August 7th through August 10th. Reserves accounted for 1.7 percent of total market expenses in calendar year 2001, but this dropped to 0.9 percent in 2002, ranging as low as 0.7 percent in the summer months.

Figure 53 also shows that New York spent substantially less on operating reserves in 2002 than in 2001, particularly during the summer months. Three market design changes were responsible for the cost savings. First, as mentioned above, the NYISO signed a reserve-sharing agreement with ISO-NE. As a result, it is no longer necessary for the NYISO to procure as much ten-minute capability in the East. The requirement for the East was reduced from 1200 MW to 1000 MW, although the state-wide requirement is still 1200 MW. This has led to savings in day-ahead and real-time reserves procurement for two reasons. First, in some instances the last 200 MW of ten-minute reserves can be quite expensive, leading to higher reserves prices. Second, LSEs save by purchasing a lower quantity. Although not shown in the figure above, LSEs also benefit from lower energy prices because there are fewer occasions when infra-marginal generators must be set aside to provide ten-minute reserves in the East.

Figure 53
Expenses for Reserves Procurement
2001 - 2002

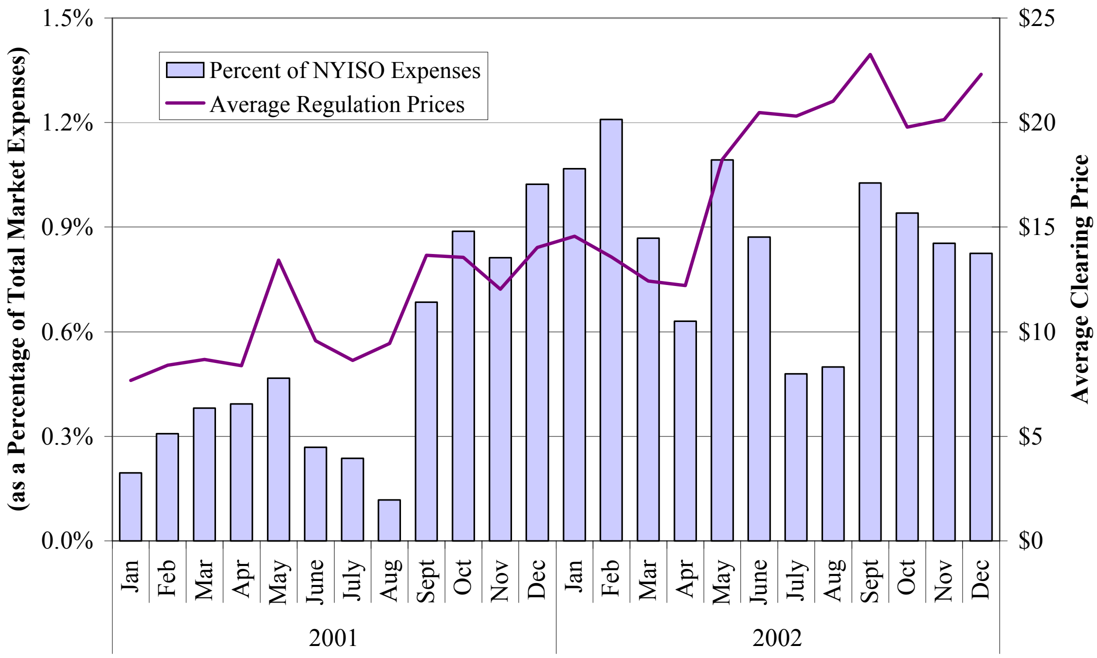


The second market design change that has led to lower ancillary service costs started October 1, 2001, when the NYISO began posting locational ancillary services prices for Long Island, Eastern New York (excluding Long Island), and Western New York. Prior to this change, resources in Long Island sometimes set state-wide ancillary services prices at higher levels than would have prevailed otherwise. Likewise, resources in the East frequently set reserves prices for the West when units in the West were available for less than the clearing price.

The third market design change relates to hour-ahead scheduling. The BME model now recognizes latent 30-minute reserves on un-dispatched portions of on-line resources. These are resources that are available to the real-time model for energy but did not submit a 30-minute reserves availability bid. Since these resources clearly are available to the real-time model, recognizing them as such prevents the BME model from setting irrationally high prices for reserves when plenty of 30-minute capability is available.

Figure 54 shows the average price for regulation service in 2001 and 2002. It also shows the share of total market expenses that are accounted for by regulation service. While regulation costs are a very small part of total market expenses, they have increased substantially over the past two years. Furthermore, regulation prices increased considerably in 2002 over 2001.

Figure 54
Average Clearing Price and Expenses for Regulation Procurement
2001 – 2002



The figure shows that regulation expenses were quite small until September 2001. Prior to this, regulation composed 0.2 to 0.5 percent of total market expenses, and regulation prices were usually less than $10/reg. Average monthly prices ranged from $12/reg to $15/reg between September 2001 and April 2002. During the summer and at the end of 2002, regulation prices have generally ranged from $20/reg to $25/reg. While regulation costs still usually account for less than one percent of total market expenses, the rise in regulation prices is a concern.

The trend in regulation expenses differs from the trend in regulation prices in certain respects. First, regulation prices tend not to spike in the same way as energy and reserves prices. Hence, when total market expenses rise during the summer, regulation accounts for a smaller share. Second, the cost of providing regulation is not affected by fuel prices to the same extent as energy prices. So when total market expenses rose due to fuel price increases at the beginning of 2001 and at the end of 2002, regulation was a smaller share of the total market expenses.

Conversely, the apparent period of high regulation expenses from September 2001 to March 2002 was primarily due to low fuel prices driving down total market expenses.

Figure 54 shows that there was a small rise in average regulation prices beginning in September 2001 resulting from a rise in prices bid by market participants. A single generator with the capability of supplying all the regulation demanded by the NYISO typically sets the price. This generator's offer prices increased modestly, leading to higher regulation prices. This should not be construed as market power because there are a number of participants with regulating capacity, and state-wide regulation capability exceeds actual demand by more than 400 percent as shown in Figure 52 from the previous section. However, nearly half of all regulation capability is not offered into the market. Presumably if prices rise sufficiently, market participants not currently offering regulation capability will begin to do so.

Figure 54 shows a substantial price increase that occurred after changes to the SCUC and BME models in May 2002. Previously, units could be scheduled with unequal amounts of up-regulation and down-regulation, whereas now units must be scheduled for equal amounts. For example, if a generator with a minimum generation level of 300 MW and an energy schedule of 350 MW offers 200 MW of inexpensive regulation, only 100 MW of regulation will be awarded. The minimum generation level limits the amount of down-regulation that may be awarded to 50 MW—the difference between the energy schedule and the minimum generation level. Due to the modeling change, the generator is limited to providing 50 MW of up-regulation, although it is capable of providing more. Although this modeling change has led to a substantial rise in regulation prices, it has also helped pricing and scheduling convergence between the BME and SCD models. This constraint on regulation awards will no longer be necessary after the implementation of RTS which is discussed in the next section.

As discussed above, energy and ancillary services markets compete for the same resources. This may result in an inexpensive unit being set aside to provide ancillary services rather than energy. For example, suppose a regulation-capable unit offers energy for \$20/MWh and regulation for \$10/reg. Suppose that the energy price will be \$50/MWh whether or not this unit produces energy, and the regulation price will be \$18/reg unless this unit is taken for regulation, in which case the regulation price will be \$10/reg. In this case, the most efficient allocation is for this unit to provide energy rather than regulation, even though regulation prices may be higher as a result. Regardless of prices, these dispatch criteria result in the lowest production costs. This scenario is a realistic one since many of the regulation capable resources are relatively low-cost base load units.

D. Recommendations and Conclusions

The market for ten-minute non-spinning reserves has functioned well since the imposition of a $2.52 offer cap and an offer requirement at the beginning of 2000. However, several changes have occurred in the market since that time. There was a reduction in the Eastern New York ten-minute requirement leading to considerably less market power in Eastern New York. Modeling improvements have allowed the Blenheim-Gilboa pumped storage unit to provide a larger amount of ten-minute reserves. FERC also has expanded the mitigation authority of the NYISO, so that now it is able to prospectively mitigate ancillary services bids. This new authority will allow the NYISO to apply an offer cap to only the units that economically withhold ten-minute capability, rather than capping all units at $2.52 regardless of whether they are exercising market power. Given the changes that have taken place in the ten-minute reserves market since the imposition of the bid cap, we have recommended that the cap be conditionally lifted. The NYISO filed proposed tariff revisions in May 2003 that, among other things, would eliminate this bid cap.

The continuing low level of participation in ancillary services markets indicates that the incentives to offer into these markets are inadequate. The most significant disincentive to participate in ancillary services markets is the potential for substantial foregone opportunities in the energy market. Although some of the markets provide for lost opportunity cost payments to ensure that ancillary services suppliers are not harmed by being selected to provide reserves or regulation, these provisions only partially address this issue.

Therefore, we recommend that the NYISO modify the pricing rules for ancillary services to more completely account for the potential opportunity costs of selling reserves. This can be accomplished by setting the price for each ancillary service at its shadow price, which is calculated by the NYISO market software. The shadow price is the marginal cost of supplying an additional MW of the ancillary service, which would equal the highest ancillary services cost for any resource designated for ancillary services. A resource's ancillary services cost is defined as its availability bid plus opportunity cost.

This change in the ancillary services pricing provisions would ensure that a supplier selected for reserves or regulation is, at a minimum, not economically harmed by not being scheduled to provide energy. This reform would also improve the accuracy of the price signals for reserves. In addition, implementing a full multi-settlement system for ancillary services with day-ahead and real-time prices will ensure that suppliers receive accurate economic incentives to provide reserves in both time frames. Further, the multi-settlement system will preclude generators from receiving compensation for reserves in the day-ahead market and for energy in the real-time market.

Finally, the NYISO and its stakeholders should work to develop 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 would allow the spot energy markets to produce prices that reflect capacity shortages without generators having to raise their offer bids. In other words, when the market is in a capacity shortage that causes the market to clear on the reserve demand curve, both reserves and energy prices should be set at an amount corresponding to the marginal value of reserves. Ensuring that efficient prices are established when the market is in shortage (i.e., capacity deficient) is an essential component of the overall economic signals provided by the market.

Most of these changes are being addressed through the implementation of the RTS in early 2004. RTS promises substantial benefits beyond the improvements in the ancillary services markets.

VIII. DEMAND RESPONSE PROGRAMS

There are currently three demand response programs in New York State – the Day-Ahead Demand Response Program (DADRP), the ICAP/Special Case Resource (ICAP/SCR) program, and the Emergency Demand Response Program (EDRP). This section summarizes the programs and provides some summary statistics about them. We do not address the role of these programs in setting prices, this was addressed in Section IV.

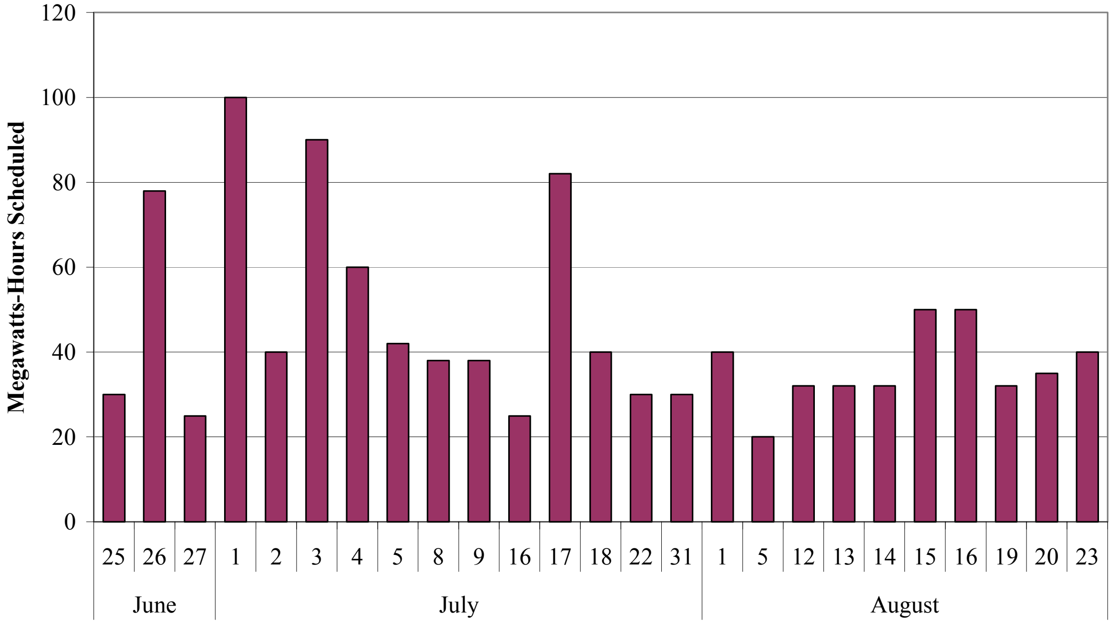
A. Day-Ahead Demand Response Program (DADRP)

DADRP allows LSEs with curtailable load to offer such load resources into the day-ahead market in the same manner as other supply resources can be offered. If the offer clears in the day-ahead market, the LSE must curtail its load in accordance with the accepted offers and is paid day-ahead clearing price for each MW of curtailed load.

To evaluate the frequency of curtailments in accordance with the DADRP, Figure 55 shows the total load that was scheduled to be curtailed under the DADRP for hours between 12 pm and 6 pm in the day-ahead market. To focus only on the days when a significant amount was scheduled, the figure only includes days when more than 20MWh were scheduled during the 12 pm - 6 pm time period.

The day with the highest volume of scheduled DADRP curtailments was July 1st when 100 MWh were scheduled for curtailment between 12 pm and 6 pm at an average price of $74/MWh. We note that during the summer of 2002, approximately 85 percent of scheduled DADRP was bid at the minimum bid floor of $50/MWh. The average clearing price was $78/MWh.

Figure 55
Day-Ahead Scheduled Demand Response
New York State - Select Days, 12 pm to 6 pm



B. ICAP/SCR and EDRP

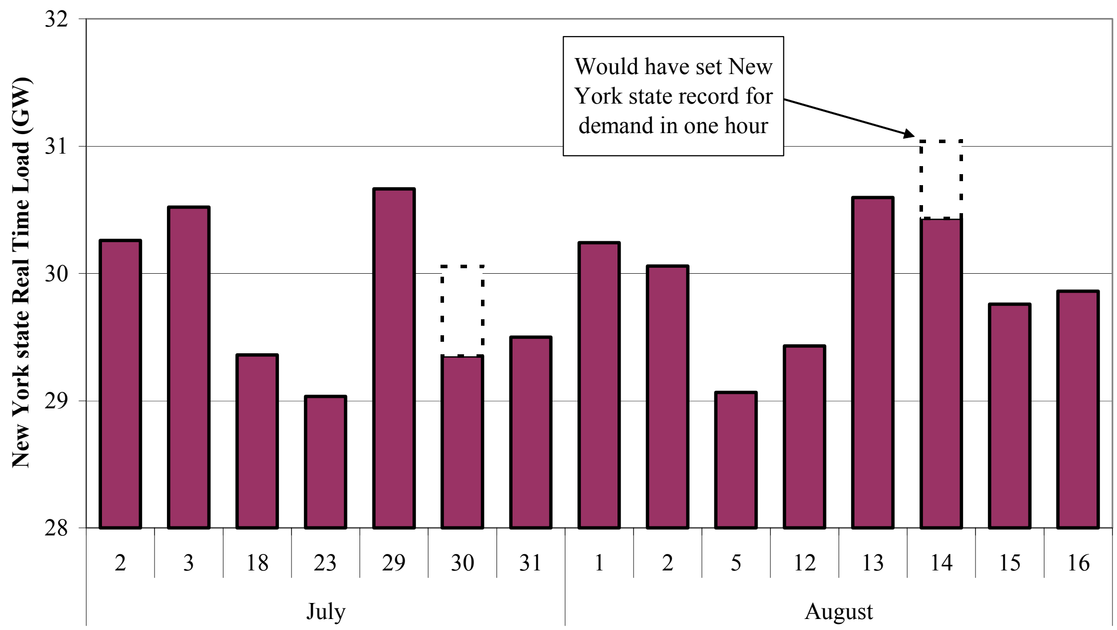
The ICAP/SCR program allows participants with curtailable load to make sales to LSEs to satisfy LSE ICAP requirements. These sales are made either through bilateral contract or through the NYISO capacity auctions. ICAP/SCR resources are curtailed in order to avoid reserve shortages. The NYISO will provide a 24-hour notice if it anticipates a need to make curtailments to meet reserve requirements. These curtailments may or may not be called. However, there is a two-hour notice given when the NYISO determines, indeed, the resources will be curtailed.

EDRP also provides the NYISO with resources to meet potential reserve shortfalls. These curtailable load resources are given two-hours notice and are paid the higher of $500/MWh or the LMBP) for each hour called.

ICAP/SCR and EDRP and resources were called state-wide on two days during 2002, July 30th and August 14th. The NYISO achieved 650 MW of actual demand reduction on July 30th and slightly less on August 14th.

Figure 56 shows the peak hour on each of the 15 highest load days in 2002, which includes July 30th and August 14th when ICAP/SCR and EDRP resources were called. The figure shows that without emergency demand response on August 14th, a new record-high load would have been set for New York State. Because real-time prices were relatively low on these days, resources that were curtailed in real-time were paid minimum amount of $500/MWh.

Figure 56
Emergency Demand Response
Peak Hours on 15 Highest Load Days – 2002



As measured in MW capability, the NYISO demand response programs are among the largest in the country. While the size of the NYISO demand response programs is a positive feature of the New York market, the changes recommended in the peak pricing section of this Report would help ensure a more effective use of these resources. The recommended changes would provide demand-response resources more flexible participation in the programs by establishing variable curtailment prices. In addition, it is critical that spot prices reflect the use of these resources, which will result in more efficient price signals during shortage conditions.

END NOTES

1 While OOM resources are ineligible to set energy prices, in many cases these resources turn out to be economic (i.e., in merit). Only units that are economically OOM will affect prices.

2 The SRE process is conducted in the day-ahead market. In the day-of, the NYISO may direct resources to be turned-on that were not committed by SCUC. These resources are designated as OOM. The exception is if the resources are turned on because of designation by the BME. BME-designated resources are eligible to set the real-time energy price.

3 We note that transmission outages can reduce the interface capability from New England and prevent exports from New England during some of these hours. While our initial data set was screened to eliminate hours when constraints existed, this was based on normal interface rating (i.e., in the absence of transmission facilities outages). On July 2, a forced transmission outage reduced transfer capability even though the data reflected that the normal rating was not binding.