2010 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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Table of Contents

List of Figures

List of Tables

I. Executive Summary

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2010. The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

- Day-ahead and real-time markets that jointly optimize energy, operating reserves and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals to govern decisions to invest in new generation, transmission, and demand response resources (and maintain existing resources); and
- A market for transmission rights that allows participants to hedge the congestion costs associated with using the transmission network.

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to meet the system's demands at the lowest cost.

The coordination provided by the markets is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered. In addition, the markets provide transparent price signals that facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions. Relying on private investment shifts the risks and costs of poor decisions and project management from New York's consumers to the investors. Indeed, moving away from costly regulated investment was the primary impetus for the move to competitive electricity markets.

The NYISO markets are at the forefront of market design and have been a model for market development in other areas. The NYISO was the first RTO market to:

- Jointly optimize energy and operating reserves, which efficiently allocates resources to provide these products.

- An optimized real-time commitment system to start gas turbines and schedule external transactions economically. Most other RTOs still rely on operators to start gas turbines.
- Impose locational requirements in its operating reserve and capacity markets. The locational requirements play a crucial role in signaling the need for resources in transmission-constrained areas.
- Introduce capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals.
- Operating reserve demand curves that contribute to efficient prices during shortage conditions when resources are insufficient to satisfy both the energy and operating reserve needs of the system.

In addition to its leadership in these areas, the NYISO remains the only market to have:

- A mechanism that allows gas turbines to set energy prices when they are economic. Gas turbines frequently do not set prices in other areas because they are inflexible, which distorts real-time energy prices.
- A real-time dispatch system that is able to optimize over multiple future periods (approximately one hour). The market anticipates upcoming needs and moves resources to efficiently satisfy the needs.
- An optimized real-time commitment system that starts fast-starting units and schedules external transactions economically. Most other RTOs rely on their operators to determine when to start gas turbines and fast-starting units.
- A mechanism that allows demand-response resources to set energy prices when they are needed. This is essential for ensuring that price signals are efficient during shortages. Demand response in other RTOs has distorted real-time signals by undermining the shortage pricing.

In summary, these markets provide substantial benefits to the region by ensuring that the lowest-cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. The remainder of this executive summary discusses the performance and outcomes of the NYISO markets in 2010.

A. Overview of Market Trends and Highlights

This sub-section provides an overview of key market trends and highlights from 2010. Wholesale electricity prices averaged approximately $54 per MWh in 2010, up roughly 20 percent from 2009. Electricity prices rose primarily because both fuel prices and load levels increased in 2010. Average natural gas prices rose 11 percent from 2009 to 2010, while average diesel oil, residual fuel oil, and eastern coal prices each rose roughly 30 percent. Average load increased more than 3 percent and the annual peak load rose 9 percent from 2009 to 2010, driven by much hotter summer weather and by improved economic conditions. Accordingly, the frequency of real-time operating reserve shortages in Eastern New York rose from 52 intervals in 2009 to 174 intervals in 2010. Other factors that contributed to the increase in energy prices in 2010 included retirement of the Poletti generating unit (which required more frequent operation of high-cost peaking units during high load conditions), lower imports from Quebec, and lower production from hydro-electric resources.

Transmission congestion costs increased modestly from 2009 to 2010, consistent with the increase in natural gas prices. Natural gas is the primary fuel in eastern New York, so increases in natural gas prices tend to increase flows from western New York, which is much less reliant on natural gas. In addition, higher natural gas prices generally increase the costs of redispatching resources to manage congestion. Day-ahead congestion revenue rose 11 percent from 2009 to 2010.

Capacity prices rose in New York City and fell outside New York City from 2009 to 2010. Average monthly spot prices rose 93 percent to $9.22 per kW-month in New York City, fell 33 percent to $1.67 per kW-month in Long Island, and fell 34 percent to $1.47 per kW-month in NYCA. The capacity price increases in New York City was primarily due to the retirement of the Poletti generating unit in February 2010, although this was partly offset by the reduction in the installed capacity requirement associated with the lower annual peak load forecast for 2010. These factors also affected clearing prices outside New York City, but the Poletti retirement had a much smaller effect outside New York City. Capacity prices outside New York City were also affected by several significant capacity additions.

The remainder of this Executive Summary provides a detailed summary of our assessment of the wholesale market. We conclude the Executive Summary with a list of recommended market enhancements and a discussion of recently implemented enhancements.

B. Summary of Prices and Competitive Performance of the Market

1. Summary of Prices in 2010

Wholesale electricity prices in the day-ahead market averaged approximately $43 per MWh in Western New York and $59 per MWh in Eastern New York, both up roughly 20 percent from 2009. The increase in electricity prices was primarily due to the increases in all key fuel prices:

- Natural gas prices rose 11 percent on average from 2009 to 2010;
- Diesel oil and residual oil prices rose 29 and 30 percent on average, respectively; and
- Eastern coal prices rose 29 percent on average.

In a competitive market, suppliers will face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs for most generators. The continuing close correspondence of energy prices and fuel prices in New York demonstrates the competitiveness of NYISO's markets.

Wholesale electricity prices were also driven higher by hotter summer weather and improved economic conditions, which led to substantially higher average and peak load levels in 2010:

- Average load increased 3 percent from 2009 to 2010.
- Peak load exceeded 30 GW for 69 hours in 2010, up significantly from 13 hours in 2009.
- Annual peak reached 33.5 GW on July 6th, which was 9 percent higher than the 2009 peak load and just 1 percent lower than the all-time peak (33.9 GW on August 2, 2006).

The higher peak load levels in 2010 contributed to more frequent real-time operating reserve shortages. Shortages in Eastern New York increased from 52 intervals in 2009 to 174 intervals in 2010, resulting in a concomitant increase in high real-time prices.

The average price difference between Western New York and Eastern New York rose slightly from 36 percent in 2009 to 37 percent in 2010. Although congestion costs increased in 2010, west-to-east congestion was less frequent because:

- Imports from neighboring areas into Western New York decreased, which reduced the overall flow from West to East; and

- Clockwise loop flows around Lake Erie that tend to load the west-to-east transmission interfaces in New York decreased notably in 2010.[1]

2. Competitive Performance of the Market

We analyze the competitive performance of the overall market in New York, as well as a number of constrained areas within the market. We find that the markets performed competitively in 2010. Electricity prices rose in 2010 due to increases in fuel prices and load levels. A close relationship between electricity prices and fuel prices and load levels is expected in a competitive market, since fuel costs constitute the vast majority of the marginal cost of producing electricity.

In certain constrained areas, most of which are in New York City, some suppliers have local market power because their resources are needed to manage congestion or satisfy local reliability requirements. In these cases, however, the market power mitigation measures effectively limit their ability to exercise market power. In New York City, the mitigation measures are automated, which limits the potential harm from attempts to exercise market power. In other areas, the mitigation measures are generally not automated. Outside New York City, new mitigation measures were approved to address the conduct of generators that raise their offer prices above competitive levels when they are committed for reliability. The new mitigation measures were applied to three specific generators in September 2009 and to all generators committed for reliability outside New York City in October 2010.

3. Long-Term Economic Signals

A well-functioning wholesale market establishes transparent price signals that provide efficient incentives to guide generation and transmission investment and retirement decisions. We evaluate the long-term price signals by calculating the net revenue that a new unit would have received from the NYISO markets and comparing it to the levelized Cost of New Entry ("CONE"). Net revenue is the total revenue that a generator would earn in the New York markets less its variable production costs.

[1] Loop flows refer to unscheduled power flows generally resulting from scheduling in other control areas (i.e., loop flow = actual power flow minus scheduled power flow). Clockwise loop flows travel through New York from Ontario to PJM and tend to load the Central East interface.

In the Installed Capacity Demand Curve Reset Process, the levelized Cost of New Entry ("CONE") for a new peaking unit was estimated at $219 per kW-year in New York City, $194 per kW-year on Long Island, and $107 per kW-year in upstate New York for the 2010/11 Capability Year. There were no areas of New York where the net revenue levels in 2010 were close to the estimated levelized CONE for a new combustion turbine. This is not surprising, given the prevailing surplus capacity in New York City, Long Island, and the rest of the state.

In most areas of Eastern New York, the estimated net revenues for a new combined-cycle unit were $40 to $70 per kW-year higher than those for a new combustion turbine in 2010. Recently filed information suggests that the CONE for a new combined cycle unit is similar to the CONE for a new combustion turbine. Because the energy net revenues are substantially higher for a new combined cycle unit, investment in this unit type is more likely to be profitable than investment in a new peaking unit under current market conditions. Accordingly, recently filed estimates of Net CONE (i.e., the capacity market revenues needed to make new investment profitable) for a new combined cycle unit are 46 percent lower than the net CONE for a new combustion turbine unit in New York City.[2]

These estimates indicate that a new combined cycle unit is far more economic than a new combustion turbine unit under current conditions, raising a significant concern regarding the ICAP Demand Curves. If the default unit selected as the basis for the ICAP Demand Curve has a substantially higher net CONE than the net CONE for the most economic new unit, the Demand Curve will provide incentives to over-invest in new resources and maintain an inefficiently high capacity surplus. To avoid this, we recommend that the NYISO consider modifying the generator technology used to establish the ICAP Demand Curves.

2 See *Compliance Filing and Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, dated March 29, 2011, Attachment IV. Since this filing, it was determined that the demand curve unit would be eligible for property tax abatement in New York City. If a combined-cycle unit were eligible for the same property tax abatement, the percentage difference between the Net CONE of a combustion turbine and a combined cycle would be even larger than 46 percent.

C. Transmission Congestion and TCCs

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy demand. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources. Market participants can hedge congestion charges in the day-ahead market by owning TCCs, which entitle the holder to payments corresponding to the congestion charges between two locations. This report evaluates the overall congestion patterns, as well as day-ahead and real-time congestion shortfalls.

Day-ahead congestion revenues rose 11 percent from 2009 to $419 million in 2010, due primarily to:

- Increased fuel prices, which increased the redispatch costs incurred to manage the power flows over congested interfaces between regions; and
- Higher load levels, which increased transmission flows into import-constrained areas.

However, these effects were partly offset by reduced imports to Western New York and lower loop flows around Lake Erie that tend to increase the west-to-east flows over a number of New York's key interfaces.

While overall day-ahead congestion increased in 2010, day-ahead congestion shortfalls fell 8 percent from 2009 to $89 million in 2010.[3] The NYISO has a process for allocating the day-ahead shortfalls resulting from transmission outages to specific transmission owners, although just 37 percent of day-ahead congestion shortfalls were allocated in this manner in 2010. An inconsistency between the TCC model and the day-ahead market model was identified that accounted for 39 percent of the day-ahead shortfalls in 2010. The modeling inconsistency was addressed beginning with the Summer 2011 Capability Period, so day-ahead congestion

[3] Day-ahead congestion shortfalls occur when day-ahead congestion revenues collected by the NYISO are less than entitlements of TCC holders. Shortfalls arise when the quantity of TCCs sold on a path exceeds the transfer capability of the path modeled in the day-ahead market when it is congested.

shortfalls are expected to decrease beginning in May 2011. NYISO is working to identify other factors that contribute to day-ahead congestion shortfalls.

Our analyses of the TCC prices compared to day-ahead congestion indicated that the TCC prices reflected a reasonable expectation of day-ahead conditions. None of the differences between the TCC prices and day-ahead congestion were indicative of an issue with the market's performance.

Balancing congestion shortfalls decreased 30 percent from 2009 to $46 million in 2010.[4] This reduction was mainly attributable to the improved operations to better manage reliability during TSA events and the NYISO's procedures to promptly evaluate and address the causes of balancing congestion residuals.[5] Other factors contributed to this reduction in 2010, including less frequent use of simplified interfaces into New York City load pockets in the real-time market and decreased clockwise circulation around Lake Erie.

D. Day-Ahead Market Performance

The day-ahead market enables participants to make forward purchases and sales of power for delivery in the real-time, allowing participants to hedge their portfolios and manage real-time price volatility. In a well-functioning market, we expect that day-ahead and real-time prices will not systematically diverge. This is because if day-ahead prices are predictably higher or lower than real-time prices, market participants will shift some of their purchases and sales to arbitrage the prices.

Price convergence is desirable because it promotes the efficient commitment of generating resources, procurement of natural gas, and scheduling of external transactions. We find that convergence between day-ahead and real-time energy prices continues to be good at the zone level due, in part, to efficient scheduling by virtual traders. Virtual trading helps align day-ahead prices with real-time prices and is particularly beneficial when modeling inconsistencies would

4 Balancing congestion shortfalls occur when day-ahead scheduled flows over a facility exceed what can flow over the facility in real-time. In this case, the NYISO must redispatch generation to reduce the flow over the constraint, the costs of which are recovered through uplift.

5 The NYISO improved its operations during TSA events in late July 2010, including better recognition of the effects of imports on congestion management in the real-time transaction scheduling process.

otherwise cause day-ahead and real-time prices to diverge. Such price divergence ultimately raises costs by undermining the efficiency of the resource commitments in the day-ahead market.

At the zonal level, price convergence outside Southeast New York (i.e., West Zone to Capital Zone) improved from 2009 to 2010, which was due to fewer extreme negative price events. Convergence in Southeast New York remained relatively poor. The difference in average prices between the day-ahead and real-time markets was around 1 percent outside Southeast New York and ranged from 2 to 6 percent in Southeast New York. The poorer performance in Southeast New York is generally due to TSA events that are difficult to predict and can cause sharp increases in real-time prices.

Convergence generally improved at the nodal level from 2009 to 2010 in most areas of New York City. Several factors contributed to the improvement by reducing inconsistencies between the day-ahead and real-time markets:

- SRE commitments (which increase commitment after day-ahead market) were less frequent in 2010 in New York City. This improved the consistency of committed supply between day-ahead and real-time.
- Simplified New York City interface constraints (which are never used in the day-ahead market) were used less frequently in real-time to manage congestion.

The NYISO is developing an approach to allow virtual trading at a more granular level than the zonal virtual trading that is currently allowed. This change should further improve the convergence between day-ahead and real-time prices.

We find that convergence between day-ahead and real-time operating reserve prices has improved in recent years, but is still poor under certain circumstances. Day-ahead prices are higher than real-time prices in most hours, but the day-ahead prices are systematically lower than real-time prices during peak conditions when real-time shortages are more likely. This difference should cause suppliers to raise their day-ahead offers in peak hours to arbitrage the difference. However, the mitigation measures limit the day-ahead reserve offers of some suppliers. We recommend the NYISO modify the mitigation measures to ensure suppliers can offer competitively.

E. External Transactions

Efficient use of transmission interfaces between regions allows customers to be served by external resources that are lower-cost than available native resources. New York imports substantial amounts of power from PJM, Quebec, Ontario, and New England, which reduces wholesale power costs for electricity consumers in New York. In 2010, the NYISO imported an average of over 3 GW during peak hours (i.e., Monday through Friday, 6 am to 10 pm).

Our evaluation of external transactions between New York and three adjacent markets indicates that scheduling by market participants did not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading. Improving the efficiency of flows between regions is particularly important during shortages or very high-priced periods when modest adjustments to the physical interchange can reduce prices significantly. We find that the external transaction scheduling process was functioning properly and that scheduling by market participants tended to improve convergence. However, significant opportunities remain to improve the interchange between regions.

To improve interchange, New York ISO and ISO New England commenced a joint effort known as the Inter-Regional Interchange Scheduling project in July 2010 to address the issue of inefficient scheduling between the two markets. We estimated the benefits of optimal scheduling to the benefits that would result from two proposals developed by the RTOs: 1) Tie Optimization; and 2) Coordinated Transaction Scheduling. Our analyses indicate that the potential production cost savings are roughly $17 million per year assuming optimal interchange based on perfect information. The study indicated that a large share of these potential benefits would be captured by either of the two proposed solutions (roughly 70 percent). While the Tie Optimization proposal performed slightly better in our simulations than the Coordinated Transaction Scheduling proposal, the benefits are similar. Therefore, we would support either alternative.

In addition to improving the interface utilization with New England, the NYISO is working on several other initiatives to improve the use of the interfaces between ISOs (and RTOs). These include:

- More frequent scheduling with PJM and Hydro Quebec (every 15 minutes) in the near term (until more comprehensive solutions can be implemented);
- Coordinating the interchange with PJM using a solution similar to Tie Optimization or Coordinated Transaction Scheduling; and
- Dispatching the Hydro Quebec interface on a 5-minute basis like a generator.

Given the benefits of these initiatives, we recommend that the NYISO continue to place a high priority on these initiatives.

In addition to interchange, loop flows through New York caused by external entities can significantly affect the NYISO markets by causing congestion. Loop flows around Lake Erie continued to move in a clockwise direction during a significant portion of time in 2010, which exacerbates west-to-east congestion in New York. However, the average clockwise loop flow fell 65 percent from 2009. When clockwise loop flows increase, the NYISO uses TLR procedures to ameliorate their effects on congestion costs in New York. However, the TLR process manages congestion much less efficiently than optimized generation dispatch through LMP markets because it provides less timely system control and frequently leads to more curtailment than needed. This highlights the importance of efforts to manage the congestion created by unscheduled loop flows more efficiently. The NYISO is working on initiatives to coordinate congestion management with PJM and ISO New England.

F. Market Operations

This section covers several areas related to the operation of the day-ahead and real-time markets, including the market consequences of certain operating procedures and the scheduling actions.

1. Real-Time Scheduling and Pricing

We evaluate the efficiency of gas turbine commitment and external transaction scheduling in the real-time market, which are important because excess commitment and net import scheduling result in depressed real-time prices and higher uplift costs, while under-commitment and inefficiently low net imports lead to unnecessary price spikes. In our evaluation of gas turbine commitment, we find the majority of capacity committed in 2010 was economic and the overall efficiency was consistent from 2009 to 2010. In our evaluation of external transaction scheduling, we found that a high portion (87 percent) of price-sensitive import offers and export bids were scheduled consistent with real-time prices at the primary interface with New England in 2010. Although the external transaction scheduling process has functioned reasonably well, this result highlights the importance of the NYISO's efforts to work with neighboring RTOs to improve coordination of the interchange between regions.

2. Real-Time Price Volatility

Volatile prices can be an efficient signal regarding the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants. Hence, it is important to identify the causes of volatility.

Our first analysis evaluates price volatility at the statewide level and makes several findings. High price volatility during morning and evening ramp periods is largely caused by changes in inflexible supply at the top of each hour. If inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished. Generators who change fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour.

Our second analysis examines factors that contribute to the volatility of real-time transmission constraint shadow prices and finds that:

- Fixed PAR-controlled line flow changes were a significant contributing factor to transient price spikes. The real-time scheduling models assume the flow across a PAR-controlled line will remain constant, even though it is affected by changes in PAR settings, generation, and load. When changes in these factors lead to significant changes in the flow across a PAR-controlled line, it can contribute to transient spikes in congestion.
- External Interface Schedule changes were also a significant contributor to transient price spikes.

We make two recommendations that are intended to address the causes of unnecessary real-time price volatility. These are discussed at the end of this section.

The NYISO is introducing market enhancements in 2011 that should address some of the causes of unnecessary real-time price volatility, including revisions to the ancillary services demand curves and more frequent scheduling (every 15-minutes) of the interface with Quebec. The NYISO is also working to better coordinate the interchange with New England and PJM. Increasing the frequency and efficiency of interchange scheduling with neighboring areas will reduce abrupt schedule changes that often lead to price volatility and will increase the availability of resources to respond to volatile real-time prices.

3. Market Performance during Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Efficient prices also provide suppliers and demand response resources with incentives to help improve the reliability of real-time operations during shortages. Shortage conditions occur most frequently when demand reaches extremely high levels, so the higher demand in 2010 led to more frequent shortages than in previous years. We evaluate the operation of the market and resulting prices when the system was in the following three types of shortage conditions:

- *Operating reserve and regulation shortages* – We found that the most significant ancillary services shortages were for regulation, eastern 10-minute reserves, and Long Island 30-minute reserves. These requirements contributed 3 to 5 percent to the annual average LBMPs in eastern New York.
- *Transmission shortages* – We found that the most significant transmission shortages were for the Leeds-to-Pleasant Valley line, the Central-East Interface, and the Dunwoodie-to-Shore Road line. These requirements contributed 5 to 7 percent to the annual average LBMPs in Southeast New York.
- *Emergency demand response activations* – These resources were only activated in New York City on two days, but these activations may become more significant in the future if supply margins fall.

In the evaluation of transmission shortages, we found many intervals when gas turbines were not dispatched to relieve a constraint even though their marginal cost was lower than the Transmission Shortage Cost of $4,000/MWh.[6] This suggests that the reliability value of preventing many transmission shortages is lower than $4,000/MWh. Therefore, we recommend that the NYISO consider the feasibility and potential impacts on reliability and system security

6 The Transmission Shortage Cost works similar to a "demand curve," indicating the maximum value that the market model will incur to relieve a transmission constraint.

from using a graduated Transmission Shortage Cost that would more accurately reflect the severity of the shortage condition.

Emergency demand response resources in New York City were activated on July 6 and 7, allowing the NYISO to maintain reliability on both days. In some of these hours, the New York City LBMPs were substantially lower than the average cost of activating the demand response resources, which is $500/MWh. If demand response resources were dispatchable at $500/MWh, they would likely have set real-time prices at $500/MWh in at least six hours. Hence, we recommend the NYISO consider how the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.

4. Uplift and Supplemental Commitment for Reliability

Supplemental commitment occurs when a generator is not committed economically in the day-ahead market, but is needed for reliability. It primarily occurs in three ways: (i) Day-Ahead Reliability Units ("DARU") commitment that typically occurs at the request of transmission owners for local reliability prior to the economic commitment in the SCUC; (ii) Day-Ahead Local Reliability Rule ("LRR") commitment that takes place during the economic commitment within the day-ahead market process; and (iii) Supplemental Resource Evaluation ("SRE") commitment, which occurs after the day-ahead market closes.

Generators that are committed for reliability are generally not economic at market prices. They can adversely affect the market by muting price signals and causing uplift charges that are difficult for participants to hedge. Supplemental commitments are largely made to satisfy local reliability requirements, primarily in New York City and result in day-ahead or real-time local reliability uplift.

The average amount of supplemental commitment for reliability exceeded 1,200 MW in 2010, of which 66 percent was in New York City, 25 percent was in Western New York, and 7 percent was in Long Island. The overall amount of supplemental commitment fell 22 percent from 2009 to 2010. As a result, the associated uplift charges for guarantee payments fell from $249 million in 2009 to $205 million in 2010. This reduction was, however, partly offset by increased fuel prices.

The reduction in uplift charges for guarantee payments resulted primarily from the following factors:

- Reliability commitment in New York City fell in February 2010 when the Poletti unit retired, which had frequently been committed by DARU.
- LBMP levels were higher relative to the offers of New York City generators frequently committed for reliability in 2010, resulting in lower guarantee payments to high-cost generators operating for reliability.
- More stringent mitigation rules were imposed in September 2009 and in October 2010 that limited the amount by which generators needed for local reliability outside New York City can raise their offers relative to their operating costs.
- NYISO enhanced procedures for evaluating reliability commitments after they occur, which has reduced the amount of capacity committed for reliability.

5. Uplift Charges

The NYISO recovers its costs through uplift charges when it makes payments to certain market participants that are not recouped from the market. It is important to minimize uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When markets reflect reliability requirements and system conditions, uplift charges should be relatively low. This report evaluates uplift charges resulting from day-ahead congestion revenue shortfalls, balancing congestion revenue shortfalls, and other guarantee payments. The two classes of congestion shortfalls are summarized in sub-section C above.

The final class of uplift costs related to guarantee payments occur when generators are scheduled, but do not recoup their as-offered costs from the day-ahead or real-time markets. Total guarantee payments to generators fell from $249 million in 2009 to $205 million in 2010, of which $135 million was paid for local reliability uplift and $70 million was paid for non-local reliability uplift. The most significant source of the reduction was the decrease in supplemental commitment for reliability in New York City.

G. Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to reliably meet New York's planning reserve margins. This market provides economic signals that supplement the signals provided by the NYISO's energy and operating reserves markets. Currently, the capacity auctions determine clearing prices for three distinct locations: New York City, Long Island, and NYCA. The clearing prices in New York City are generally much higher than those in Long Island and NYCA.

1. Capacity Market Results

We evaluated outcomes in the capacity market and found no significant economic withholding of capacity in 2010. Compared to 2009, average spot prices rose 93 percent in New York City to $9.22 per kW-month in 2010, fell 33 percent to $1.67 per kW-month in Long Island, and fell 34 percent to $1.47 per kW-month in NYCA.[7]

Several changes in the amount of available internal supply affected spot prices in 2010. First, the Poletti unit retired in February 2010, which reduced UCAP supply by nearly 900 MW. This contributed to a $6.13 per kW-month price increase in the spot price in New York City and a $1.64 per kW-month increase in the spot price in NYCA after January. Second, the sales from UDRs increased in Long Island in June 2010, contributing to a $1.40 per kW-month decrease in the spot price after May. Third, several capacity additions increased supply in the state by a total of more than 900 MW in late 2009 and 2010.

There were also significant changes in capacity demand from 2009 to 2010, including the annual escalation of the capacity demand curves, large reductions in the peak load forecasts in each capacity zone, and an increase in the Installed Reserve Margin ("IRM") for NYCA.[8]

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7 The clearing prices in Long Island were equal to the NYCA prices in 10 of the 12 months in 2010 because the local capacity requirement was not binding due to substantial excess capacity in Long Island.

8 The summer peak load forecast fell 325 MW for New York City, 106 MW for Long Island, and 905 MW for NYCA from 2009 to 2010. The IRM rose from 16.5 percent in 2009 to 18 percent 2010.

2. Zone Configuration and Deliverability

The capacity market provides investment signals to help New York state meet its planning reserve margin requirements. Currently, there are three local capacity regions: New York City, Long Island, and NYCA. By setting a distinct clearing price in each capacity region, the capacity market guides investment to areas where it is most valuable.

In recent years, new capacity outside Southeast New York has not been allowed to sell in the capacity market due to limits on deliverability into Southeast New York. Such limits create several significant efficiency and competitive concerns. First, they do not provide efficient incentives to invest in supply resources, demand resources, and transmission facilities, or to maintain existing resources in the constrained area (i.e., Southeast New York). Second, it creates a substantial barrier to entry for competitive new supplies and imports in the unconstrained area, which reduces competition in the market.

We have previously recommended that these inefficiencies be addressed by defining capacity zones that reflect transmission bottlenecks affecting the planning needs of the system.[9] Doing so would provide the market with a mechanism for producing long-term economic signals that accurately and efficiently reflect the supply and demand for capacity in different areas, which is not possible under the current deliverability framework.

The NYISO recently filed proposed criteria with FERC for defining new capacity zones.[10] We did not support the NYISO proposed criteria and filed a protest in that case because the criteria would likely fail to define new capacity zones that are needed to efficiently satisfy the planning requirements of the system.[11] Instead, we recommend NYISO:

- Define new capacity zones whenever deliverability constraints bind on highway transmission facilities, which will ensure consistency between the capacity zones and the results of the deliverability test; or

9 See *2009 State of the Market Report on the NYISO Electricity Markets* by Potomac Economics.

10 See *Compliance Filing Proposing Criteria to Govern the Potential Creation of New Locational Capacity Zones*, Docket No. ER04-449-000, date January 4, 2011.

11 See *Motion to Intervene and Comments of the New York ISO's Market Monitoring Unit*, Docket No. ER04-449-000, dated January 25, 2011.

- Pre-define a full set of capacity zones and inter-zonal limits that address potential deliverability issues.

The latter approach is preferable because it would establish a stable zonal structure that would not require frequent re-definition of the capacity zones over time. It would allow price separation between areas when necessary, but allow areas to clear at the same price when deliverability constraints do not bind between them.

3. Technology of Hypothetical New Unit

The capacity market is designed to ensure that efficient investments recover sufficient revenues that are not recovered through the energy and ancillary services markets. Ideally, the capacity market would efficiently govern investment and retirement decisions such that the NYISO will satisfy planning requirements with a minimum amount of surplus.

To do this, demand curves are established that should allow suppliers to recover the net CONE (i.e., CONE minus net revenues from the energy ancillary services markets) for the investments over the long term. For this process, a technology must be chosen and the tariff specifies a peaking unit. In long-run equilibrium, all types of resources (baseload, intermediate, peaking) should be equally economic, but this may not be the case in the short-run based on the relative levels of energy and ancillary services prices.

There are advantages to choosing a peaking resource as the default technology because the uncertainties regarding the CONE and net energy and ancillary services are lower than for most other technologies. In the short-run, however, the default peaking resource may or may not be the most economic investment. When a demand curve is developed to support investment in a unit that is not the most economic type of unit, investors still have an incentive to invest in the most economic type of unit. As a result, the capacity market may provide incentives to invest when additional investment is not necessary. This can lead to a sustained surplus that will dissipate only when the default peaking resource is among the most economic investments once again. Until this happens, the capacity market may motivate inefficiently large quantities of investment and raise overall market costs. Therefore, it would be preferable for the default resource upon which the capacity demand curves are based to always be among the most economic and realistic investment choices, given regulatory and environmental restrictions.

Given the capacity surpluses that are prevailing and forecasted to continue, and the fact that the most recent investments have not been in the default peaking resources, an examination of the relative economics of alternate technologies is warranted. Recent data produced by NERA and Sargent & Lundy suggests that the Net CONEs are substantially higher for peaking resources than for other resources. The net CONE for a new combined cycle unit is at least 46 percent lower than the net CONE for a new combustion turbine unit in New York City.[12]

These estimated cost differences are consistent with the fact that combined cycle units have been the most common supply investment in recent years. This type of short-term disequilibrium (i.e., when the Net CONE of one technology is substantially higher or lower than another) can result in Demand Curves that lead to inefficient levels of investment and sustained surpluses. Hence, we recommend the NYISO consider modifying its tariff to allow it to select the most economic generating technology to establish the demand curves in the demand curve reset process.

H. Demand Response Programs

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response. In this report, we evaluate the existing demand response programs and discuss the on-going efforts of the NYISO to facilitate more participation.

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[12] See *Compliance Filing and Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, dated March 29, 2011, Attachment IV. Since this filing, it was determined that the demand curve unit would be eligible for property tax abatement in New York City. If a combined-cycle unit were eligible for the same property tax abatement, the percentage difference between the Net CONE of a combustion turbine and a combined cycle would be even larger than 46 percent.

Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, Day-Ahead Demand Response Program ("DADRP") and Demand-Side Ancillary Services Program ("DSASP"), provide a means for economic demand response resources to participate in the day-ahead market and ancillary services markets, respectively. The other three programs, Emergency Demand Response Program ("EDRP"), Special Case Resources ("SCR"), and Targeted Demand Response Program ("TDRP"), are reliability demand response resources that are called when the NYISO or the local Transmission Owner forecasts a shortage. Currently, nearly 90 percent of the 2.8 GW of demand response resources in New York are reliability demand response resources.

The NYISO established the Demand-Side Ancillary Services Program ("DSASP") in 2008 to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. However, no resources have fully qualified as DSASP resources yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner. To expedite the process, the NYISO is developing ways to communicate directly with resources rather than through the local Transmission Owner. NYISO stakeholders have approved a project for 2011 to define the functional requirements for Direct Communication for DSASP. The Direct Communication project will also help the NYISO develop the capability to allow aggregations of small customers to participate in the DSASP (rather than single large customers).

The fastest growing demand response program operated by the NYISO is the SCR program, whose participation grew to over 2.2 GW in 2010. This growth is likely due to the fact that SCRs can sell capacity in the NYISO's capacity market. Given the reliance on Special Case Resources ("SCRs") for satisfying reliability needs, it is important to ensure that SCRs can perform when called. Accordingly, the NYISO revised the baseline methodology, performance measurements, and deficiency calculations for SCRs in time for the Summer 2011 Capability Period. Although these changes have led to modest (10 to 20 percent) reductions in capacity sales by SCRs, they should help ensure that emergency demand response resources perform reliably when needed.

I. List of Recommendations and Recent Enhancements

Our analysis in this report indicates that the NYISO electricity markets performed well in 2010, although the report finds additional improvements that we recommend be made by the NYISO. We believe that the first three recommendations should be given the highest priority.

1. **Adopt one of the following two processes for defining new capacity zone(s) efficiently:**

   - ✓ **Use criteria for creating a new zone that is consistent with the Deliverability Test so a new zone is created whenever deliverability constraints on Highway facilities are binding, and streamline implementation of new zones; or**

   - ✓ **Pre-define a full set of capacity zones that address potential deliverability issues.**

Both of these options will establish efficient capacity prices to govern long-term investment and retirement decisions. However, the second option would achieve these benefits without any implementation delay or costs since the prices between zones will diverge immediately when deliverability constraints bind.

2. **Work with adjacent ISOs to implement rules that will better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange and congestion management.**

The NYISO is working with neighboring control areas on several proposals to improve the efficient use of the interfaces, which should be the highest priority initiatives because they promise the largest economic benefit.

3. **Select the most economic generating technology to establish the demand curves in the next demand curve reset process for the capacity market.**

The use of a new peaking unit in the demand curve reset process is likely to result in a demand curve that is set higher than the level necessary to satisfy New York state's planning criteria in the short run.

4. **We recommend the NYISO conduct an evaluation to determine the causes of and potential solutions for unnecessary real-time price volatility.**

In particular, we recommend the NYISO consider whether additional look ahead assessments in RTC and RTD at intervals-ending :55 and :05 minutes past the hour would lead to more efficient dispatch at the top of each hour.

5. We recommend NYISO modify two mitigation provisions that may limit competitive 10-minute reserves offers in the day-ahead market.

This should improve convergence of day-ahead and real-time reserve prices and suppliers' incentives to provide reserves.

6. We recommend the NYISO consider the feasibility and potential impacts on reliability and system security from using a graduated Transmission Shortage Cost.

RTD uses a "Transmission Shortage Cost" that limits the redispatch costs that may be incurred to $4000 per MWh when managing congestion. However, our analysis suggests that this level may be higher than the true reliability value of certain shortages (typically those that are brief or slight relative to the limit on the constraint). Improving the accuracy of the Transmission Shortage Cost will cause the NYISO markets to take more efficient dispatch and commitment actions, and set more efficient prices.

7. We recommend the NYISO evaluate how the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.

Emergency demand response was only activated in New York City on two days, but these activations may be more common in the future if supply margins fall. Hence, efficient price-setting when demand response resources are needed to satisfy reliability needs market-wide or in a local area will be increasingly important.

8. We recommend enabling market participants to schedule virtual trades at a more disaggregated level.

Currently, virtual trading is allowed at only the zonal level. This change would improve day-ahead to real-time price convergence in New York City load pockets. NYISO has a project underway to expand the set of locations where virtual trading is allowed.

II. Market Prices and Outcomes

The New York ISO operates a multi-settlement wholesale market system consisting of financially-binding day-ahead and real-time markets for energy, operating reserves, and regulation (i.e., automatic generation control). 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.

This section of the report provides a review of market results in 2010 and evaluates the performance of these markets. This evaluation includes an assessment of the long-term economic signals that govern new investment and retirement decisions in New York. Subsequent sections examine individual aspects of the market in greater detail.

A. Summary of Outcomes in 2010

1. Energy Prices

Figure 1 shows monthly average natural gas prices and load-weighted average day-ahead energy prices for Eastern and Western New York in 2009 and 2010. Although much of the electricity used by New York consumers is generated from hydro, nuclear, and coal-fired generators, natural gas units are usually the marginal generation units that set market clearing prices, especially in Eastern New York. This is evident from the strong correlation of electricity prices with natural gas prices shown in the figure.

The figure shows that electricity prices in the day-ahead market rose from 2009 to 2010. In 2010, the electricity prices averaged approximately $43 per MWh and $59 per MWh in Western and Eastern New York, both up roughly 20 percent from 2009. The increase in electricity prices was primarily due to the increases in fuel prices and in load levels. Average natural gas prices rose 11 percent from 2009 to 2010. Likewise, average diesel oil (No.2 oil) prices rose 29 percent and average residual fuel oil (No. 6 oil) prices rose 30 percent from 2009 to 2010. The correlation of electricity prices with natural gas and oil prices is expected, since fuel costs constitute the majority of variable production costs for most generators. In New York, gas units are on the margin in most hours, and oil units are sometimes on the margin during peak operating conditions. The considerable increase in load levels also contributed to the increase in electricity prices. From 2009 to 2010, average load increased by more than 3 percent and peak load rose 9 percent, which led to more frequent dispatch of high-cost peaking resources.

Figure 1: Day-Ahead Energy and Natural Gas Prices
2009 – 2010

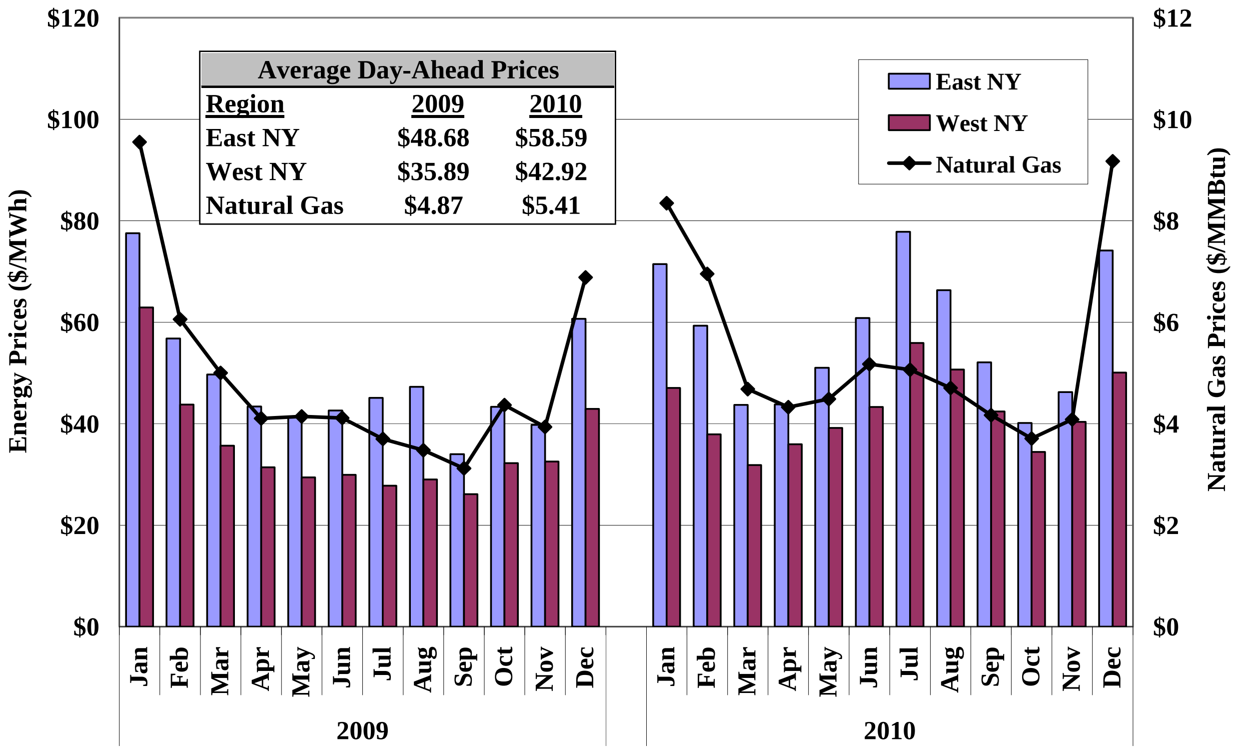


Figure 1 shows that the differences in prices between Eastern and Western New York in 2010 were comparable to the prior year. The average price in Eastern New York was 37 percent higher than the average price in Western New York in 2010, up slightly from the 36 percent in 2009. The small increase in congestion cost and associated price differences from Western New York to Eastern New York was due primarily to the increase in fuel prices, which raised the redispatch costs incurred to manage congestion in 2010. Although congestion costs increased in 2010, west-to-east congestion was less frequent because:

- Imports from neighboring areas into Western New York decreased, which reduced the overall flow from West to East; and

- Clockwise loop flows around Lake Erie that tend to load the west-to-east transmission interfaces in New York decreased notably in 2010.[13]

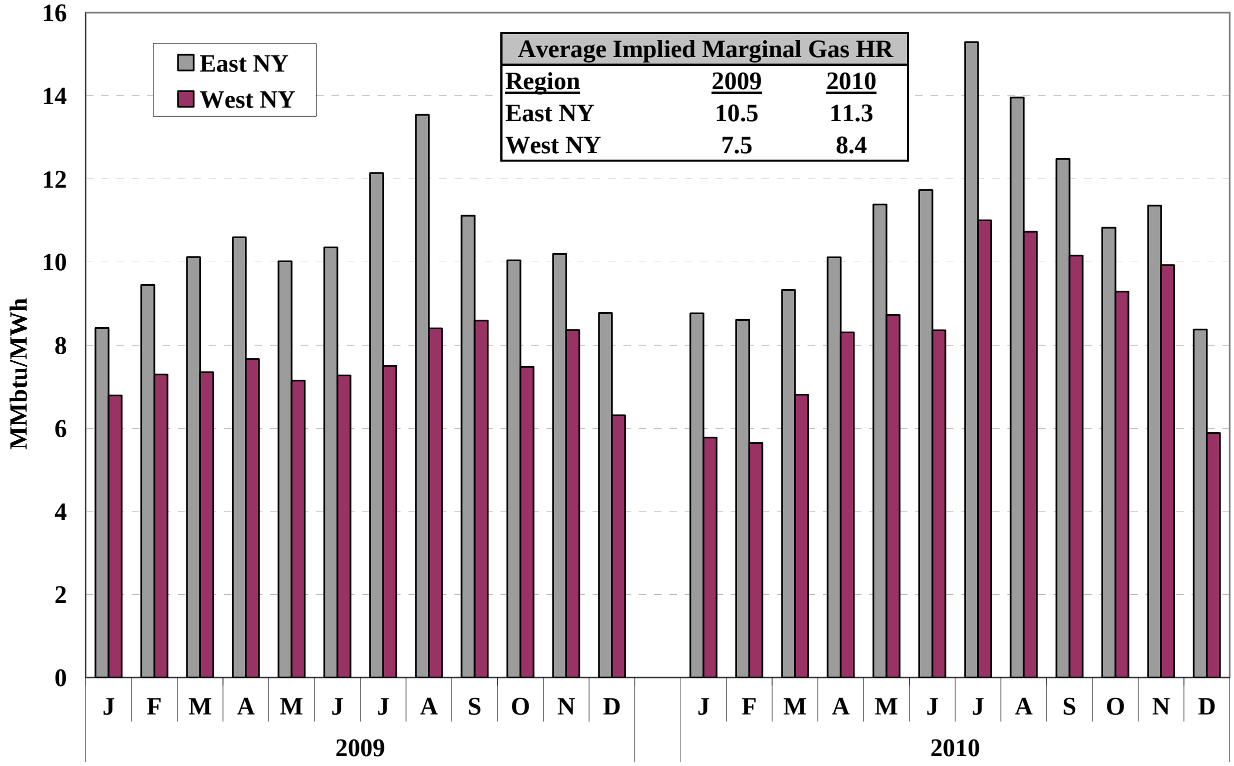
Because loop flows consume a portion of the available west-to-east transmission capability of key interfaces, they reduce the transmission capability available for use by the real-time market. Hence, clockwise loop flows have effects on the real-time market equivalent to a reduction in west-to-east transmission capability. The volume of clockwise loop flows declined notably on average from 2009 to 2010, reducing price separation between Western New York and Eastern New York.

To highlight changes in electricity prices that are not driven by changes in fuel prices, the following figure summarizes the monthly average marginal heat rate that would be implied if natural gas were always on the margin. The *implied marginal heat rate* equals the day-ahead electricity price divided by the natural gas price measured in MMbtu. Thus, if the electricity price is $50 per MWh and the natural gas price is $5 per MMbtu, this would imply that a generator with a 10.0 MMbtu per MWh heat rate is on the margin. Figure 2 shows the load-weighted average implied marginal heat rate for Eastern and Western New York in each month during 2009 and 2010.

By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices. Figure 2 shows that implied marginal heat rates typically rise in the summer as load levels increase. High summer load levels result in elevated electricity prices as high-cost peaking resources are used more frequently to satisfy the system's energy and reserve needs. Furthermore, the supply of generation is reduced because higher ambient temperatures reduce the output capability of thermal units. The months with the highest average implied marginal heat rates were July and August 2010, which were also the months with the highest average loads.

13 Loop flows refer to unscheduled power flows generally resulting from scheduling in other control areas (i.e., loop flow = actual power flow minus scheduled power flow). Clockwise loop flows travel through New York from Ontario to PJM and tend to load the Central East interface.

Figure 2: Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices, 2009 – 2010



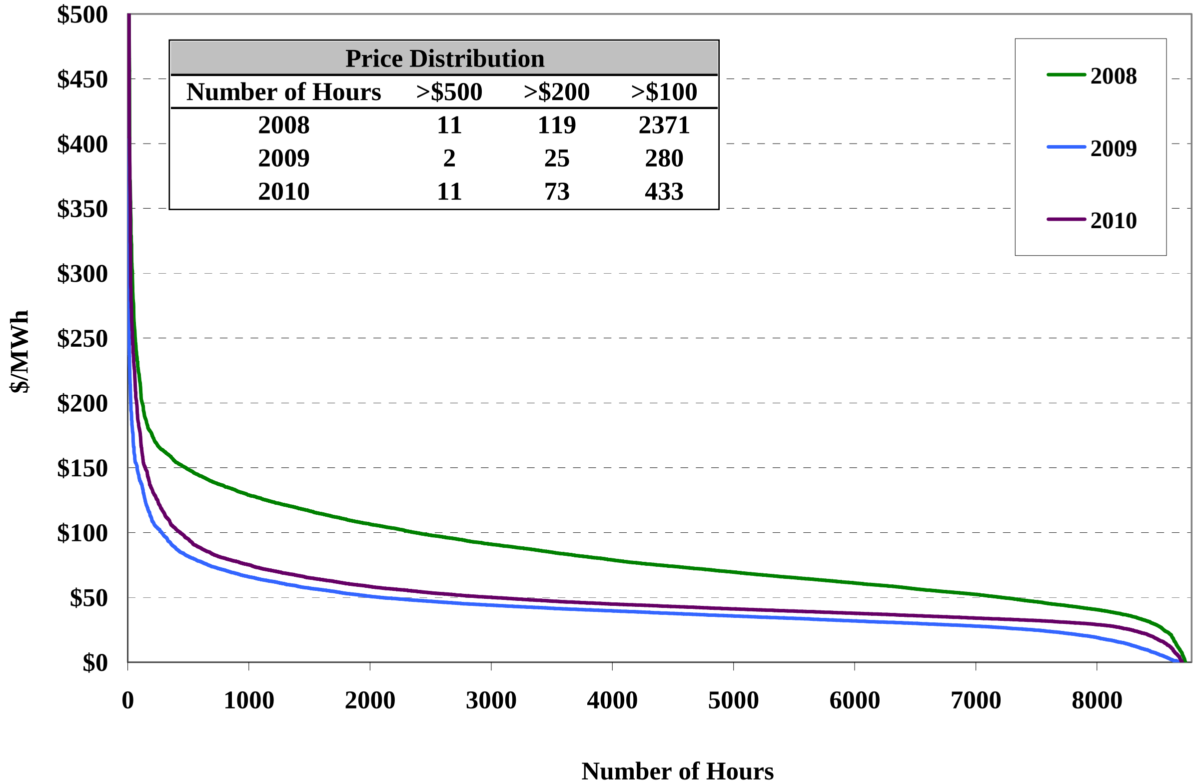
In some of the months shown in Figure 2, the implied marginal heat rate in Western New York declined to levels below the heat rate of the most efficient gas-fired generators. This occurred in months when there were a substantial number of hours when less expensive units were on the margin, such as coal-fired or hydroelectric units.

Overall, the average implied marginal heat rate rose approximately 8 percent in Eastern New York and 12 percent in Western New York from 2009 to 2010. Several factors contributed to the increase in the average implied heat rate:

- Load levels were substantially higher in 2010, particularly in the summer months, resulting in more frequent dispatch of high-cost generation and more shortage conditions;
- The retirement of the Poletti unit reduced supply in New York City, resulting in peaking units being used more frequently during high load conditions;
- Net imports from Hydro Quebec fell 23 percent, contributing to the higher implied heat rates, particularly in Western New York; and
- Production from hydroelectric and nuclear generation also fell by an average of 310 MW, contributing to the higher implied heat rates, particularly in Western New York.

The following two figures illustrate how prices varied across hours in each year. Figure 3 shows three price duration curves, one for each year from 2008 to 2010. Each curve shows the number of hours on the horizontal axis when the load-weighted average real-time price for New York State was greater than the level shown on the vertical axis. This allows us to compare the distribution of prices from year to year.

Figure 3: Real-Time Price Duration Curve
NYCA, 2008 – 2010



The price duration curves show the characteristic distribution of prices in wholesale power markets. Most hours were priced moderately higher. However, a small number of hours exhibited very high prices, which were typically associated with shortages. During periods of shortages, prices can rise to more than ten times the average price level, so a small number of hours with price spikes can have a significant effect on the average price level. The number of extremely high-priced hours (e.g., when price exceeded $500 per MWh) declined from 11 hours in 2008 to 2 hours in 2009, then increased to 11 hours in 2010. These changes were largely due to the change in the number of hours when load reached very high levels (e.g., above 30 GW). We did not find that artificial shortages have resulted from withholding.

Fuel price changes from year to year are revealed by the flatter portion of the price duration curve, since fuel price changes affect power prices in almost all hours. The figure shows that the electricity prices fell substantially from 2008 to 2009 and then rose in 2010, which reflects the changes in fuel prices. The average natural gas price decreased 52 percent from 2008 to 2009 and then increased 11 percent from 2009 to 2010. The change in natural gas prices was also evident from the change in the number of hours when the electricity price exceeded $100 per MWh, which decreased from 2,371 hours in 2008 to 280 hours in 2009 and then rose to 433 hours in 2010.

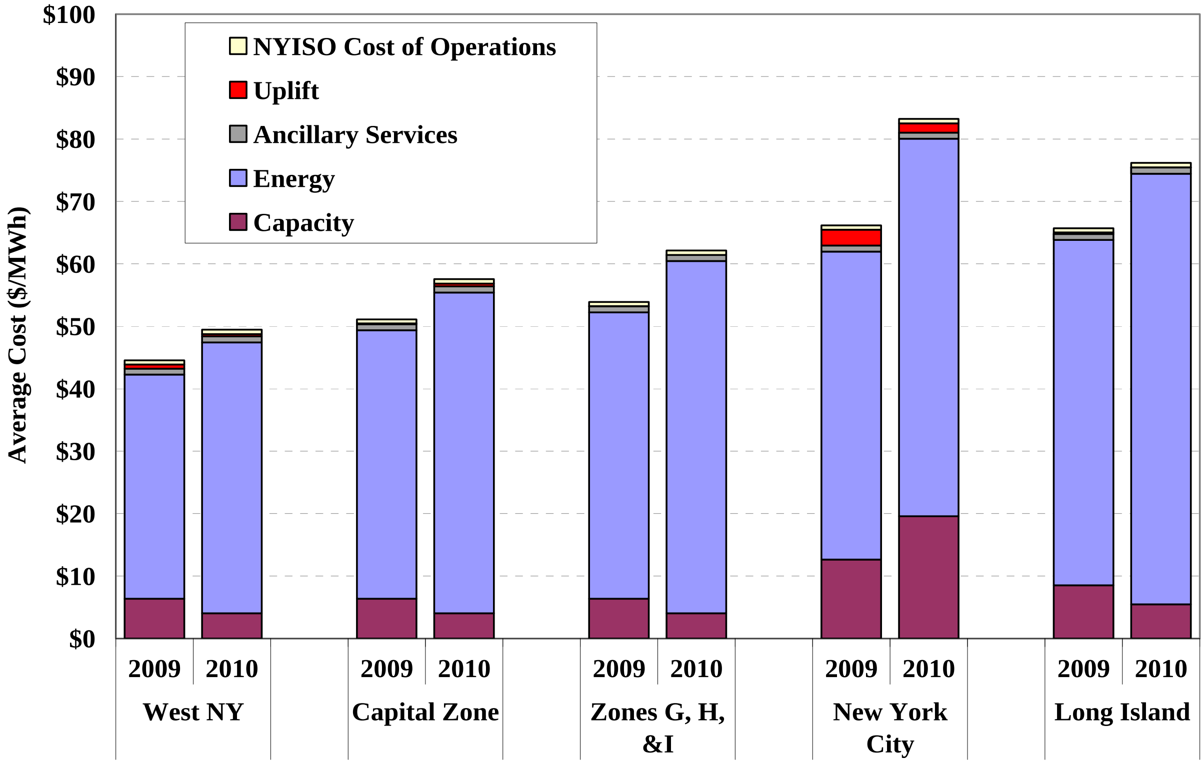
2. Total Market Costs: All-In Price

The next analysis summarizes the energy prices and other wholesale market costs by showing the all-in price for electricity, which reflects the total costs of serving load from the NYISO markets. The all-in price includes the costs of energy, uplift, capacity, ancillary services, and NYISO cost of operations. The all-in price is calculated for various locations in New York State because capacity and energy prices vary substantially by location.

The energy prices in this metric are load-weighted average real-time energy prices. The capacity component is calculated based on clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over the energy consumption in that area. The uplift component is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area. For the purposes of this metric, costs associated with ancillary services are distributed evenly across all locations.

Figure 4 shows the average all-in price at five locations over the past two years. The all-in price increased from 2009 to 2010 in each of the five regions. The largest increase occurred in New York City, where the average all-in price rose 25 percent from 2009 to approximately $83 per MWh in 2010. The smallest increase occurred in Western New York, where the average all-in price increased 11 percent from 2009 to roughly $49 per MWh in 2010.

Figure 4: All-In Prices by Region
2009 – 2010



The increases in all-in prices from 2009 to 2010 were largely due to the increase in energy costs associated with the increases in fuel prices and load levels described in detail later in this section. The larger increases in Eastern New York reflect the higher levels of transmission congestion in 2010.

Capacity costs are also a significant component of the all-in prices. In New York City, capacity costs increased nearly 55 percent in 2010 primarily because of the retirement of the Poletti unit in February 2010. Outside New York City, capacity costs fell in spite of the Poletti retirement, partly offsetting the increase in all-in prices in those areas. The decline in capacity costs outside New York City was due to several capacity additions and a reduction in the statewide capacity requirement, which fell because of a decrease in the peak summer load forecast for 2010.

3. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale power prices because most of the variable production costs of fossil generators are fuel costs. Although much of the electricity generated in New York is from hydroelectric, nuclear, and coal-fired generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices more directly affect wholesale power prices.

Some generators in New York have dual-fuel capability, allowing them to burn either oil or natural gas. These generators usually burn the most economic fuel, although some may burn oil even when it is more expensive if natural gas is difficult to obtain on short notice or if there is uncertainty about its availability. In addition, New York City and Long Island reliability rules (known as Minimum Oil Burn rules) sometimes require that certain units burn oil in order to limit the exposure of the electrical grid to possible disruptions in the supply of natural gas. Since most large steam units can burn residual fuel oil (No.6) or natural gas, the effects of natural gas price spikes on power prices are partly mitigated by generators switching to fuel oil. Figure 5 shows average coal, natural gas, and fuel oil prices by month from 2007 to 2010.

Figure 5: Natural Gas, Oil, and Coal Price Trends
2007 – 2010

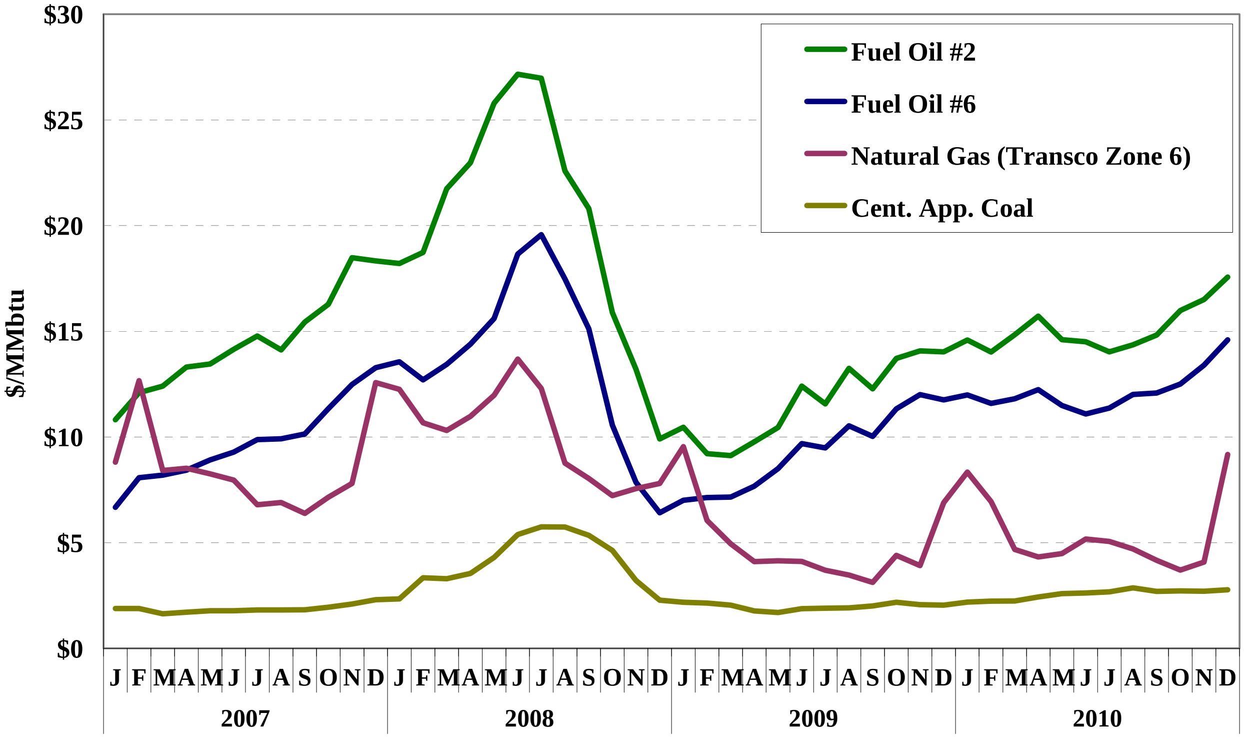


Figure 5 shows that all four fossil fuel prices rose significantly from 2009 to 2010 as economic activity recovered. Natural gas prices averaged $5.41/MMBtu in 2010, up 11 percent from 2009.

Diesel fuel oil (No. 2) prices averaged $15.13/MMBtu in 2010, up 29 percent from 2009. Residual fuel oil (No. 6) prices averaged $12.18/MMBtu in 2010, up 30 percent from 2009. Central Appalachian coal prices averaged $2.56/MMBtu in 2010, up 29 percent from 2009.

The rise in oil prices relative to natural gas prices has decreased the use of oil for electricity production in recent years. Prior to 2006, residual oil was often less expensive than natural gas, allowing oil-fired steam units to be relatively economic compared with gas-fired combined cycle units. However, oil prices have risen such that natural gas was priced lower than fuel oil the vast majority of the time during the past four years. In 2010, natural gas was priced higher than residual fuel oil (No. 6) on just 10 days and higher than diesel fuel oil (No. 2) on only one day. Regardless, the dual-fuel capability of many units in New York moderates the effects on energy prices of transitory spikes in natural gas prices that can occur during the winter months.

Although natural gas prices are usually lower than oil prices, the Minimum Oil Burn rules require some units in New York City and Long Island to burn oil to limit the exposure of the power system to natural gas supply contingencies during high load conditions. Such units are able to choose either: (i) to submit offer prices that reflect the increased fuel cost, or (ii) to submit offer prices that reflect the cost of running on natural gas and participate in the Minimum Oil Burn Compensation (“MOBC”) program. When units submit offer prices that reflect the increased fuel cost, the additional fuel costs are sometimes reflected in market clearing prices and higher guarantee payments to generators.

When units participate in the MOBC program, they receive out-of-market payments to make up the difference between the cost of natural gas and the cost of fuel oil. Accordingly, the additional costs are not reflected in market clearing prices. The uplift from MOBC payments rose from approximately $10 million in 2009 to $12 million in 2010, due primarily to increased residual fuel oil (No. 6) prices and higher load levels. The uplift costs resulting from guarantee payments and MOBC payments are discussed further in Section VI.D.

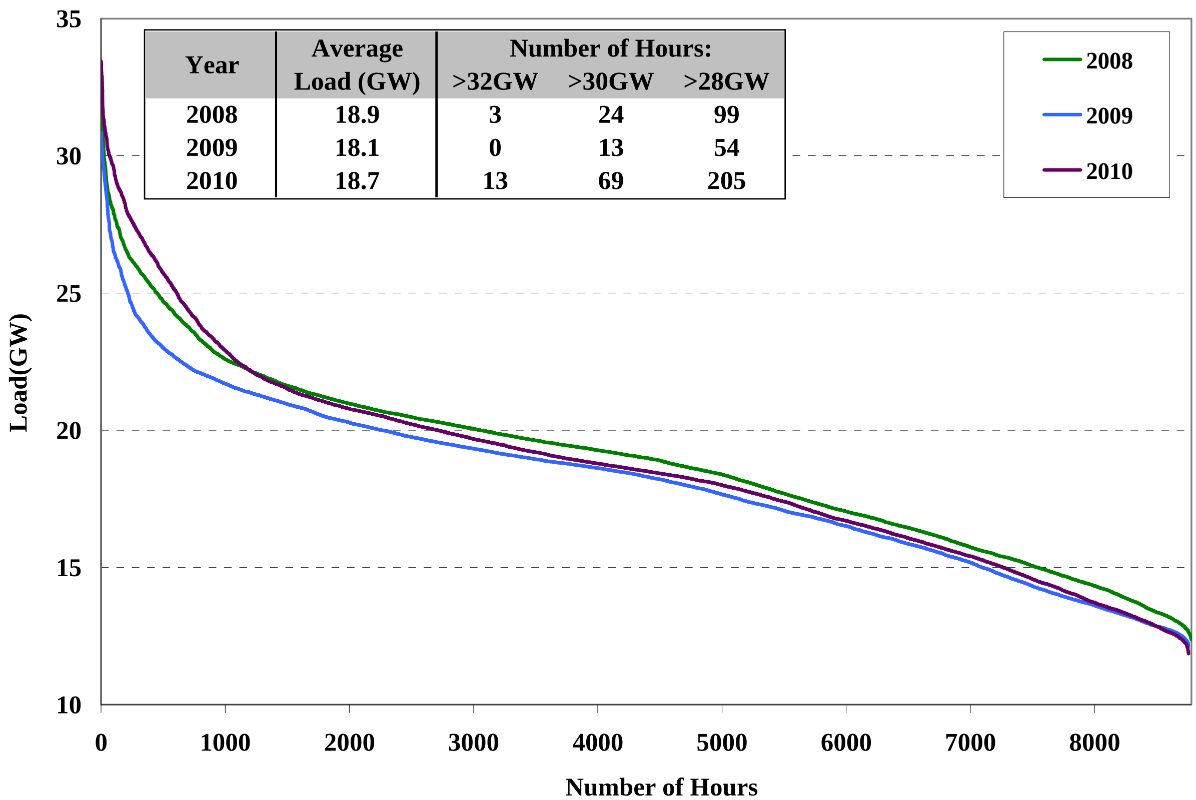
The figure also shows that the difference between natural gas prices and coal prices fell significantly in 2009 and has remained relatively small in 2010. When the natural gas price gets close to the coal price (e.g., April to November 2010), gas-fired combined cycle units become more cost-competitive with coal-fired steam units, reducing the use of coal-fired generation. The retirement of several coal units has also contributed to the reduced use of coal since 2009.

4. Energy Demand

The interaction between electric supply and consumer demand also drives price movements in New York. The amount of available supply changes slowly from year to year, so fluctuations in electricity demand explain much of the short-term variations in electricity prices. The hours with the highest loads are important because a disproportionately large share of the market costs to consumers and revenues to generators occur in these hours.

Figure 6 illustrates the variation in demand during each of the last three years by showing load duration curves. Load duration curves show the number of hours on the horizontal axis in which the statewide load was greater than or equal to the level shown on the vertical axis.

Figure 6: Load Duration Curves
2008 – 2010



Year	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2008	18.9	3	24	99
2009	18.1	0	13	54
2010	18.7	13	69	205

In general, electricity demand grows slowly over time, tracking population growth and economic activity. However, Figure 6 shows that load declined substantially (4 percent) from 2008 to 2009 and increased considerably (3 percent) from 2009 to 2010. These fluctuations were largely due to the fluctuations in economic activity and changes in weather patterns in these years. Although economic activity has increased, average load levels were still lower in 2010 than in 2008.

The relatively hot summer weather in 2010 increased the frequency of peak load conditions substantially. Load exceeded 28 GW during 205 hours in 2010, up significantly from 54 hours in 2009 and 99 hours in 2008. Likewise, Load exceeded 32 GW in 13 hours during 2010 compared to 0 such hours in 2009 and 3 such hours in 2008. Load peaked at 33.5 GW on July 6th, which was:

- Only 1 percent lower than the all-time peak load hour (33.9 GW on August 2nd, 2006);
- 1 percent higher than the 2010 peak load forecast of 33.0 GW, and
- 9 percent higher than the 2009 peak load hour.

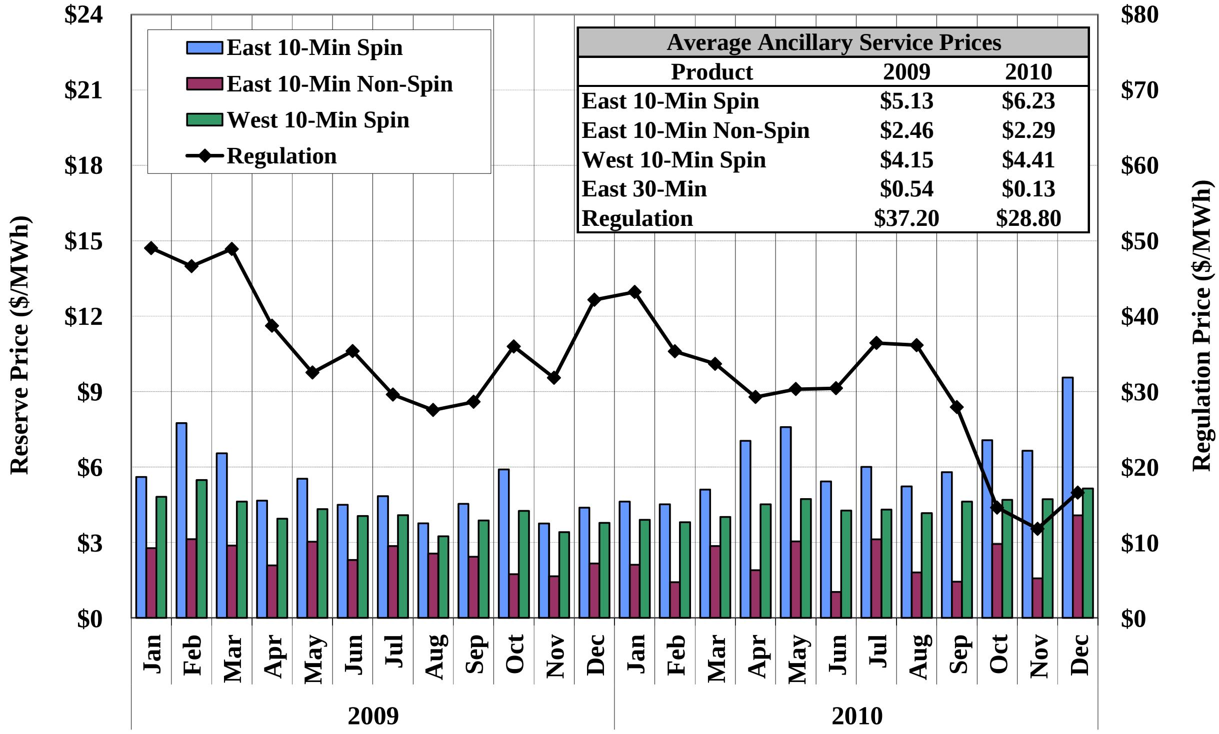
As a result, there were more frequent shortage conditions in 2010, resulting in more real-time price spikes.

5. Ancillary Services Prices

The NYISO schedules resources to provide energy, operating reserves, and regulation service in the day-ahead and real-time markets. The NYISO co-optimizes the scheduling of these products such that the combined cost of all products is minimized. Given that available supplies must satisfy energy demand and ancillary services requirements simultaneously, energy prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy, and vice versa. Hence, ancillary services prices generally rise and fall with the price of energy.

In this part of the section we summarize the prices of several key ancillary services products in the day-ahead market in 2009 and 2010. The NYISO has four ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation. In addition, the NYISO has locational reserve requirements that result in differences between Eastern and Western New York reserve prices. Figure 7 shows the monthly average day-ahead prices of 10-minute spinning reserves and 10-minute total reserves in Eastern New York, 10-minute spinning reserves in Western New York, and regulation.

Figure 7: Day-Ahead Ancillary Services Prices
2009 – 2010



To the extent that ancillary services are scheduled on capacity that would otherwise be economic to produce energy, changes in energy prices lead to corresponding changes in the cost of providing ancillary services. For example, Eastern 10-minute spinning reserves prices increased 21 percent from 2009 to 2010, consistent with the 20 percent increase in energy prices.

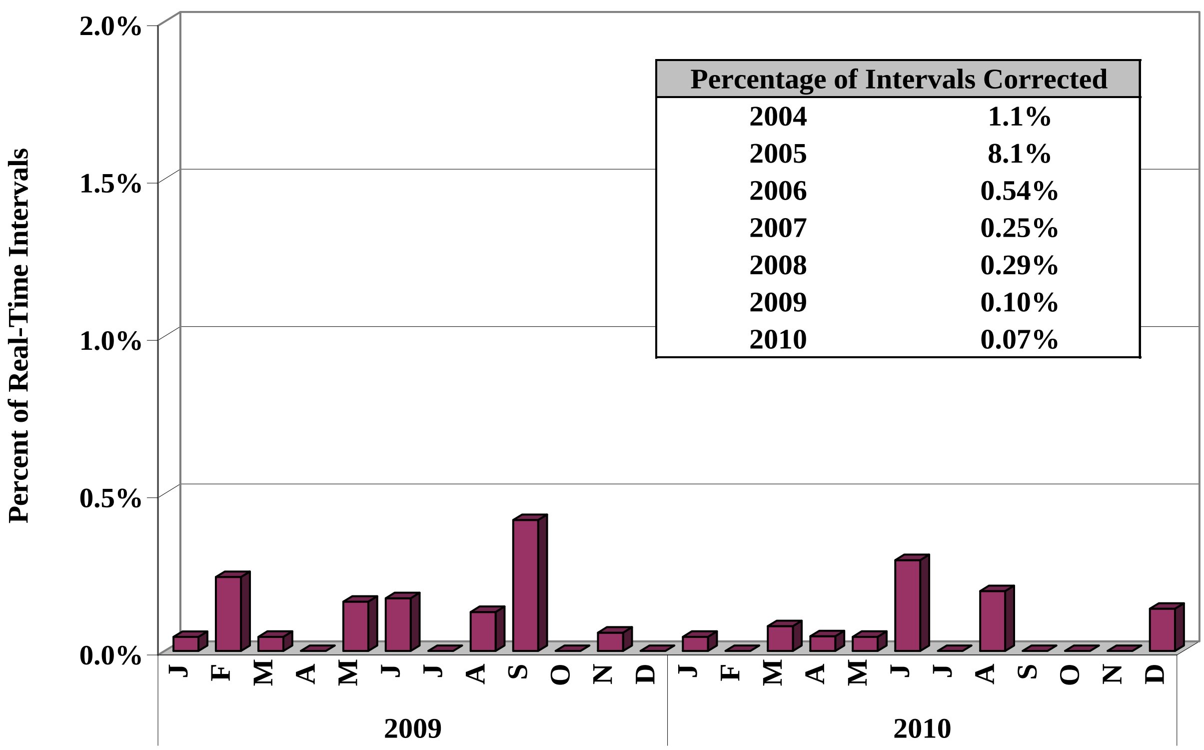
Figure 7 shows that regulation prices declined considerably in 2010, from an average of roughly $37 per MWh in 2009 to $29 per MWh. Most of this reduction occurred after September 2010 and was primarily driven by the entry of new regulation-capable capacity and reduced offer prices from existing suppliers.

Eastern 10-minute spinning and non-spinning reserves prices rose significantly in December 2010. The increase was partly caused by the increase in the eastern 10-minute reserve requirement from 1,000 MW to 1,200 MW on December 1 when the Reserve Sharing Agreement with ISO New England expired.

B. 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. Moreover, price corrections are required when flaws in the market operations software or operating procedures lead prices to be calculated erroneously. Accurate prices are critical for settling market transactions fairly and sending reliable real-time price signals. Less frequent corrections reduce administrative burdens and uncertainty for market participants. Hence, it is important to resolve problems that lead to price corrections quickly to maximize price certainty. Figure 8 summarizes the frequency of price corrections in the real-time energy market in each month of 2009 and 2010.

Figure 8: Percentage of Real-Time Prices Corrected
2009 – 2010



Percentage of Intervals Corrected	
2004	1.1%
2005	8.1%
2006	0.54%
2007	0.25%
2008	0.29%
2009	0.10%
2010	0.07%

The table in Figure 8 indicates that the frequency of price corrections has declined considerably since 2005 when a high frequency of price corrections occurred after extensive changes were made to the real-time scheduling software under SMD 2.0. The frequency of price corrections has been less than 0.3 percent of real-time pricing intervals in the past four years, and was particularly low in 2010 at less than 0.1 percent. Furthermore, the number of pricing locations that were affected has also decreased over years.

In June 2010, the rate of price corrections was somewhat higher than in other months, while still lower than the historical average. This was due to a software issue that only affected proxy buses. Overall, the frequency of corrections and the significance of the corrections have declined to very low levels.

C. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the signals for investment in new generation and retirement of existing generation. The decision to build or retire a generation unit depends on the expected net revenues the unit will receive. Net revenue is defined as the total revenue (including energy, ancillary services, and capacity revenues) that a generator would earn in the New York markets less its variable production costs.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions may be present:

- New capacity is not needed because sufficient generation is already available;
- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- Market rules are causing revenues to be reduced inefficiently.

If a revenue shortfall persists for an extended period without an excess of capacity, this may indicate a potential problem with the market rules or operating procedures. On the other hand, if prices provide excessive revenues in the short-run, it might indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Therefore, the evaluation of the net revenues produced from the NYISO's markets is one of our principal means for assessing whether the markets are designed to provide efficient long-run economic signals.

1. Methodology

In this section, we analyze the net revenues that would have been received by various types of generators at seven different locations: Long Island, the Vernon/Greenwood load pocket in New York City, the Astoria East load pocket in New York City, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone.[14] We estimate the net revenues the markets would have provided to two different types of units at these locations: a hypothetical combustion turbine unit and a hypothetical combined-cycle unit.

We use the following two methods to estimate the net revenues for both types of units:

- *Standard method* – The assumptions have been standardized by FERC and the market monitors of the various markets to provide a basis for comparison of net revenues between markets. It accounts for changes in fuel costs and assumes typical forced outage rates. This method also assumes:
  - That the units sell only at the day-ahead market prices and that net revenues are earned whenever the assumed cost of the unit is less than the day-ahead market clearing price at its location, regardless of the units' physical parameters.
  - The hypothetical combined-cycle unit has a heat rate of 7 MMBtu per MWh and a variable operating and maintenance ("VOM") cost of $3 per MWh; and
  - The hypothetical combustion turbine has a heat rate of 10.5 MMbtu per MWh and a VOM cost of $1 per MWh.
- *Enhanced method* – This method is similar to the standard method, but it assumes:
  - Units are committed based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations;
  - Combined cycles may sell energy, 10-minute spinning reserves and 30-minute reserves; while combustion turbines may sell energy and 30 minute reserves;
  - Offline combustion turbines may be committed and online combined cycles may have their run-time extended based on RTC prices;[15]

[14] For all net revenue analyses: the Long Island calculations are based on prices for Zone K, the Vernon/Greenwood calculations are based on prices at the NYPA/Kent bus, the Astoria East calculations are based on prices at the Astoria GT2/1 bus, the New York City 345 kV area calculations are based on prices at the Poletti bus, the Hudson Valley calculations are based on prices for Zone G, Capital Zone calculations are based on prices for Zone F, and West Zone calculations are based on prices for Zone A.

[15] The enhanced method assumes that such a unit is committed for an additional hour if the average LBMP in RTC at its location is greater than or equal to the applicable minimum generation and/or incremental energy cost of the unit for one hour. This uses the RTC LBMPs posted on the NYISO's website.

- Online units are dispatched in real-time consistent with the hourly integrated real-time price and settle with the ISO on the deviation from their day-ahead schedule;
- Fuel costs assume charges of $0.27/MMbtu on top of the Transco Zone 6 day-ahead index price and a 6.9 percent tax for New York City units;
- For combined cycle units, the average heat rate is higher at the minimum output level (8,100 btu/kWh) than it is at the maximum output level (7,200 btu/kWh);
- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered beginning January 2009.
- The Enhanced Method also uses the modified operating and cost assumptions listed in the following table:

Table 1: Unit Parameters for Enhanced Net Revenue Estimates

Characteristics	CC	Upstate CT	Downstate CT
Size	500 MW	165 MW	100 MW
Startup Cost (Dollars)	$8,000	$11,000	$0
Startup Cost (MMBTUs)	5,000	360	215
Heat Rate (HHV)	8,100 to 7,200	10,700	9,100
Min Run Time / Min Down Time	5 hours	1 hour	1 hour
Variable O+M	$1 / MWh	$1 / MWh	$5 / MWh

Note: For the two unit types, both methods assume a forced outage rate of 5 percent.

The net revenue estimates produced using the standard method may differ from the actual net revenues earned by market participants for several reasons. First, it doesn't consider that combustion turbines have start-up costs, lengthy start-up lead times, and minimum run time requirements that normally exceed one hour. Ignoring these factors tends to over-state net revenues. Second, the standard method uses day-ahead clearing prices exclusively, although online generators can earn additional profits by adjusting their production in the real-time market. Offline combustion turbines can also be economically committed after the day-ahead market by RTC. Ignoring these real-time profits tends to understate net revenues. The enhanced method addresses these limitations of the standard net revenue analysis.[16] Third, the enhanced

[16] Another factor that leads to inaccurate net revenue estimates is that fuel expenses in the analysis are based on day-ahead natural gas price indices, although some generators may incur higher costs to obtain natural gas. Combustion turbines frequently purchase natural gas in the intraday market, which generally trades at a slight premium. Combined-cycle units may also incur additional fuel charges when the amount of fuel they burn in real time differs from the amount of fuel they nominate day-ahead. This issue is not addressed by the enhanced method.

analysis assumes higher fuel costs (e.g., an additional charge of $0.27/MMBtu and 6.9 percent tax for New York City units), which reduce net revenues compared to the standard analysis, particularly for New York City units. Lastly, the different heat rate assumptions in the standard method and in the enhanced method create additional differences in net revenues.

2. Net Revenue Results

The following figures summarize net revenue estimates using the enhanced method, with a marker showing net revenue estimates using the standard method for comparison. Figure 9 shows net revenues for a hypothetical combined-cycle generator, and Figure 10 shows net revenues for a hypothetical combustion turbine. Note that the capacity auction revenues are based on the clearing prices in the spot auctions.

Figure 9: Enhanced Net Revenue: Combined Cycle Unit
2007 – 2010

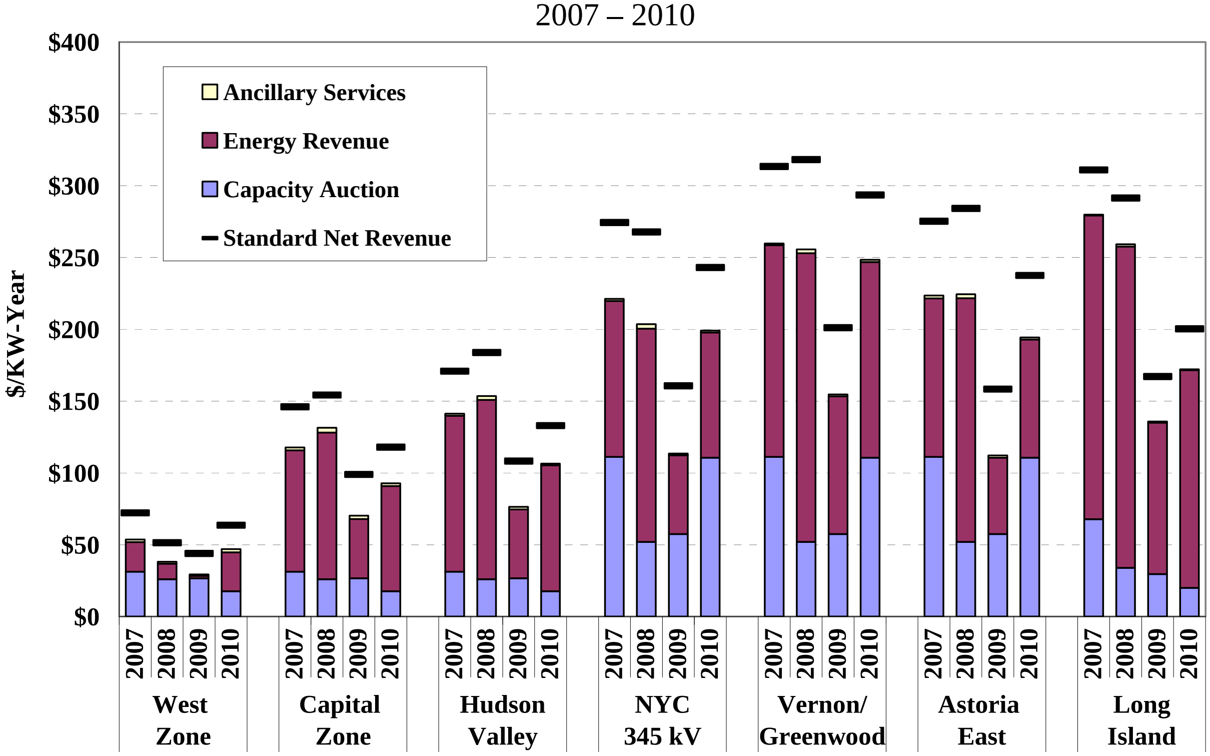
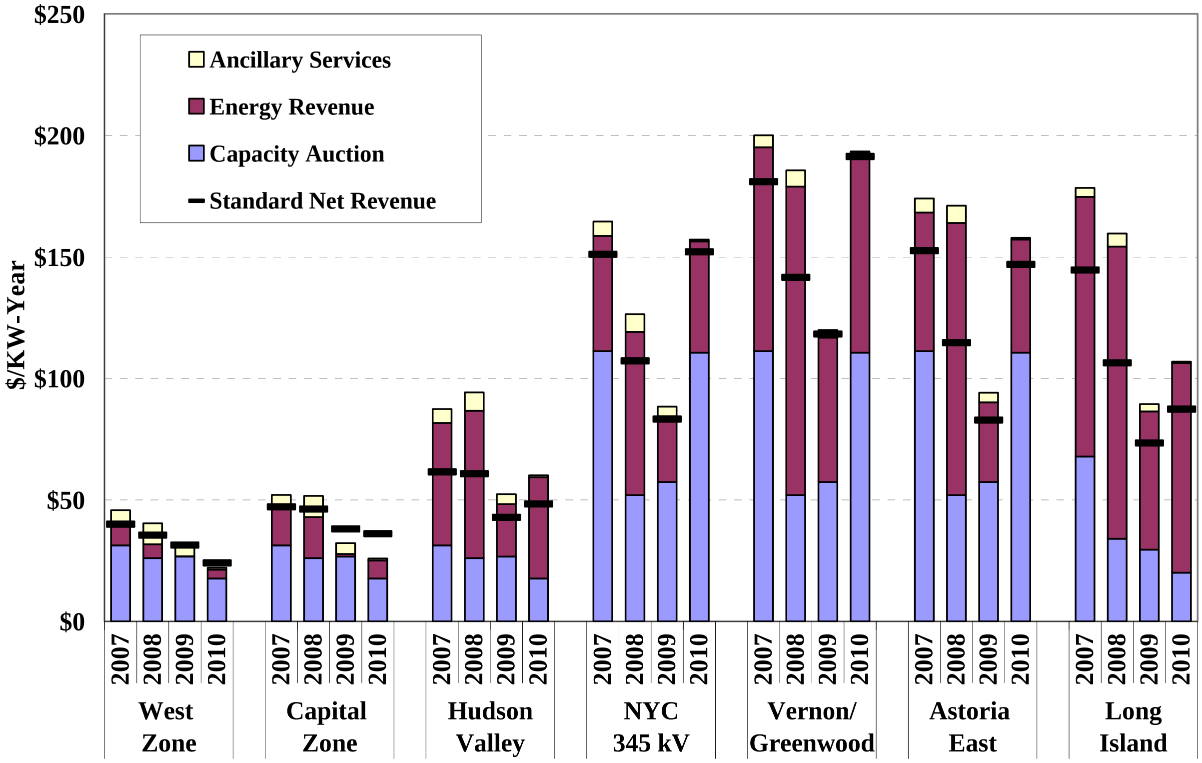


Figure 10: Enhanced Net Revenue: Combustion Turbine Unit
2007 – 2010



Both figures show that net revenues declined sharply in 2009 throughout the state, then rose substantially in most areas in 2010. The changes were due to a number of factors:

- Fluctuations in fuel prices led to proportionate changes in energy net revenues. Energy net revenues and fuel prices are correlated because higher fuel prices increase the spreads between wholesale energy prices and most generators' production costs. Accordingly, fuel price changes contributed to the sharp decline in net energy revenues in 2009 and increase in 2010.
- Capacity net revenues changed significantly in recent years. Outside New York City, capacity net revenues fell from 2007 to 2010, primarily due to capacity additions around the state and due to unusually low load growth. In New York City, however, capacity net revenues rose in 2010 as the Poletti unit retired.
- Variations in load levels affected energy net revenues. Higher loads often lead to more frequent dispatch of high-cost generation and more shortages, resulting in elevated energy prices. Accordingly, the variations in load levels and the frequency of shortages affected the net energy revenues from 2008 to 2010.

In addition, the figures show that the results of the enhanced method differ significantly from the results of the standard method. For a combined-cycle generator, the enhanced net revenue estimates are lower than under the standard method. The differences are primarily due to reductions in net revenue resulting from start-up costs, minimum runtime restrictions, higher fuel costs, and higher heat rates. For a combustion turbine, the enhanced method produces higher net revenue estimates than the standard method. Under the enhanced method, the additional net revenues arise from hours when the generator would be committed after the day-ahead market, although this was partly offset by the inclusion of start-up costs and additional fuel costs in the analysis.

3. Net Revenue Conclusions

Estimated net revenues for a new combined cycle unit increased by roughly 61 percent from 2009 to 2010 in the West Zone, 55 percent in New York City, and 22 to 29 percent in other areas, primarily due to higher energy prices and higher New York City capacity prices. Estimated net revenues for a new combustion turbine rose for the same reasons, but by smaller margins (they actually fell in the West and Capital Zones due to lower capacity prices). To evaluate these net revenue levels, we compare them to the costs of building the new resources in various locations throughout New York.

In the Installed Capacity Demand Curve Reset Process, the levelized Cost of New Entry ("CONE") for a new peaking unit was estimated at $219 per kW-year in New York City, $194 per kW-year on Long Island, and $107 per kW-year in upstate New York for the 2010/11 Capability Period. There were no areas of New York where the net revenue levels in 2010 were close to the estimated CONE for a combustion turbine. This is not surprising because surplus capacity existed in New York City, in Long Island, and in the rest of the state.

In most areas of Eastern New York, the estimated net revenues for a new combined cycle unit were approximately $40 to $70 per kW-year higher than those for a new combustion turbine in 2010. However, recently filed estimates of the CONE for a new combined cycle unit suggests that its costs are similar to the estimated CONE for a new combustion turbine.[17] Because the

[17] See "www.nyiso.com/public/markets_operations/market_data/icap/index.jsp" *Demand Curve Model NYC Revised Tax Abatement*, dated 6/8/2011. The sheet *Reference Tables* shows estimated overnight capital costs in 2011 dollars in New York City of $1,915/ICAP kW for a new combustion turbine installation and $1,897/ICAP kW for a new combined cycle installation.

energy net revenues are substantially higher for a new combined cycle unit, investment in this unit type is more likely to be profitable than investment in a new peaking unit under current market conditions. Accordingly, recently filed estimates of *net* CONE (i.e., the capacity market revenues needed to make new investment profitable) for a new combined cycle unit are 46 percent lower than the net CONE for a new combustion turbine unit.[18]

Net revenues and CONE estimates indicate that a new combined cycle unit is far more economic than a new combustion turbine unit under current conditions. This raises a significant concern regarding the ICAP Demand Curves. If the default unit selected as the basis for the ICAP Demand Curve has a substantially higher net CONE than the net CONE for the most economic new unit, the Demand Curve will provide incentives to over-invest in new resources and maintain an inefficient capacity surplus. Because a new combustion turbine is estimated to have a substantially higher net CONE than a new combined cycle unit, we recommend that the NYISO consider modifying the generator technology used to establish the ICAP Demand Curves. We discuss this in greater detail in Section VII.D.

D. Convergence of Day-Ahead and Real-Time Prices

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real-time. Participants can use the day-ahead market to hedge risks associated with the real-time market, and the system operator uses day-ahead bids and offers to improve the commitment of resources. Loads can insure against price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of starting-up their generators on an unprofitable day since the day-ahead auction market will only accept their offers when they will profit from being committed. In addition to the value it provides individual market participants, perhaps the greatest value of the day-ahead market is that it coordinates the overall commitment of resources to satisfy the next day's needs at least cost.

[18] See *Compliance Filing and Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, dated March 29, 2011, Attachment IV. Since this filing, it was determined that the demand curve unit would be eligible for property tax abatement in New York City. If a combined-cycle unit were eligible for the same property tax abatement, the percentage difference between the Net CONE of a combustion turbine and a combined cycle would be even larger than 46 percent.

In a well-functioning system with day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge from one another. If day-ahead prices were predictably higher than real-time prices, buyers would increase purchases in real-time. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers would increase purchases day-ahead (vice versa for sellers). Historically, average day-ahead prices have been consistent with average real-time prices in New York and other regions with multi-settlement markets, although it has been common for day-ahead prices to carry a slight premium over real-time prices.

Price convergence is desirable because it promotes the efficient commitment of generating resources, procurement of fuel, and scheduling of external transactions. In addition, persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer their resources at marginal cost in the day-ahead market. There are two types inconsistencies between day-ahead and real-time prices: random variations resulting from unanticipated changes in supply and demand between the two markets, versus persistent systematic differences between the average level of day-ahead and the average level of real-time prices. In this section, we evaluate three aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the consistency of average day-ahead and real-time energy prices at individual nodes throughout the state. Third, we compare average day-ahead and real-time ancillary services prices by time of day.

1. Energy Price Convergence

In general, day-ahead prices are based on the expectations of real-time market outcomes and are influenced by several uncertainties. First, demand can be difficult to forecast with precision and the availability of supply may change due to forced outages or numerous other factors. For example, the operators may commit additional generation for reliability after the day-ahead market, increasing the supply available to the real-time market. Second, special operating conditions, such as thunderstorm alerts, may alter the capability of the transmission system in ways that are difficult to arbitrage in day-ahead markets. Finally, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

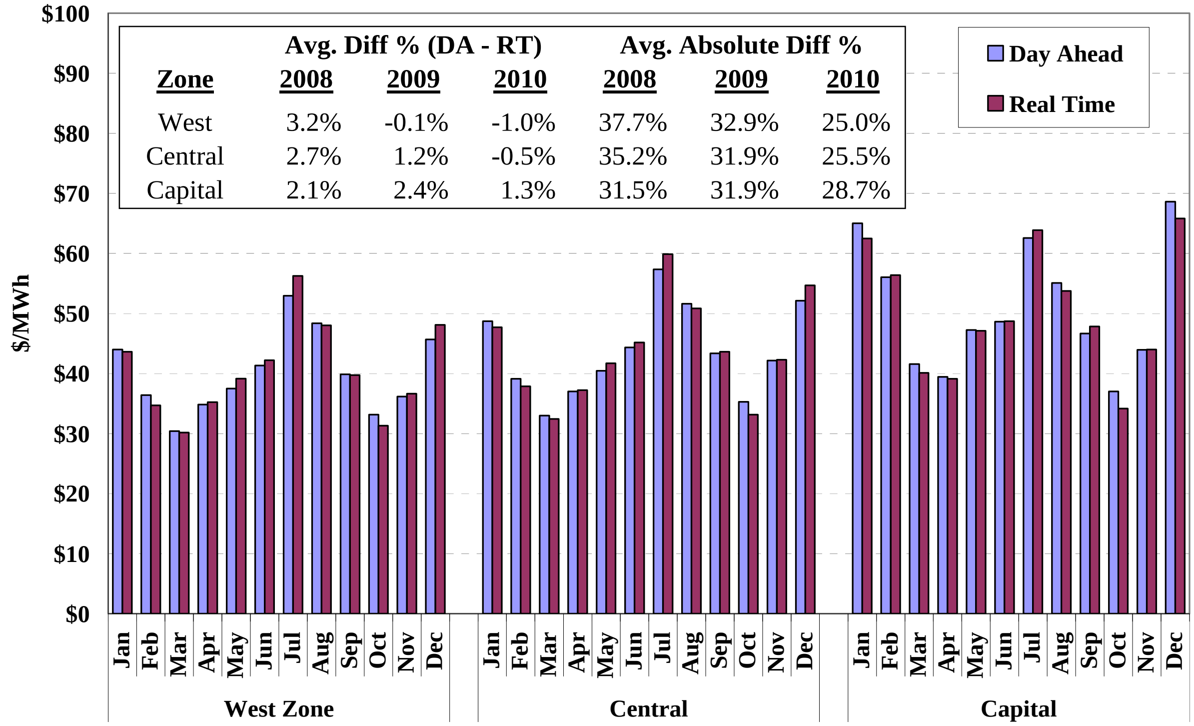
Figure 11 compares day-ahead and real-time energy prices in West zone, Central zone, Capital zone, Hudson Valley, New York City, and Long Island. The figure is intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars compare the average day-ahead and real-time prices in each zone in each month of 2010. The inset tables report the percentage difference between the average day-ahead price and the average real-time price, as well as the average absolute value of the difference between hourly day-ahead and real-time prices in the past three years. The latter metric measures the typical difference between the day-ahead and real-time prices in each hour, regardless of which is higher. This metric is substantially affected by real-time price volatility.

The figure shows that price convergence outside Southeast New York (i.e., West Zone to Capital Zone) improved from 2009 to 2010, which was due to fewer extreme negative price events. Convergence in Southeast New York remained relatively poor. The difference in average prices between the day-ahead and real-time markets was around 1 percent outside Southeast New York and ranged from 2 to 6 percent in Southeast New York. The average absolute difference between day-ahead and real-time prices ranged from 25 to 29 percent outside Southeast New York and from 30 to 36 percent in Southeast New York. These differences reflect the high real-time price volatility, which is typical in wholesale electricity markets, particularly in Southeast New York during the summer when unexpected Thunder Storm Alerts ("TSAs") occurred frequently.[19]

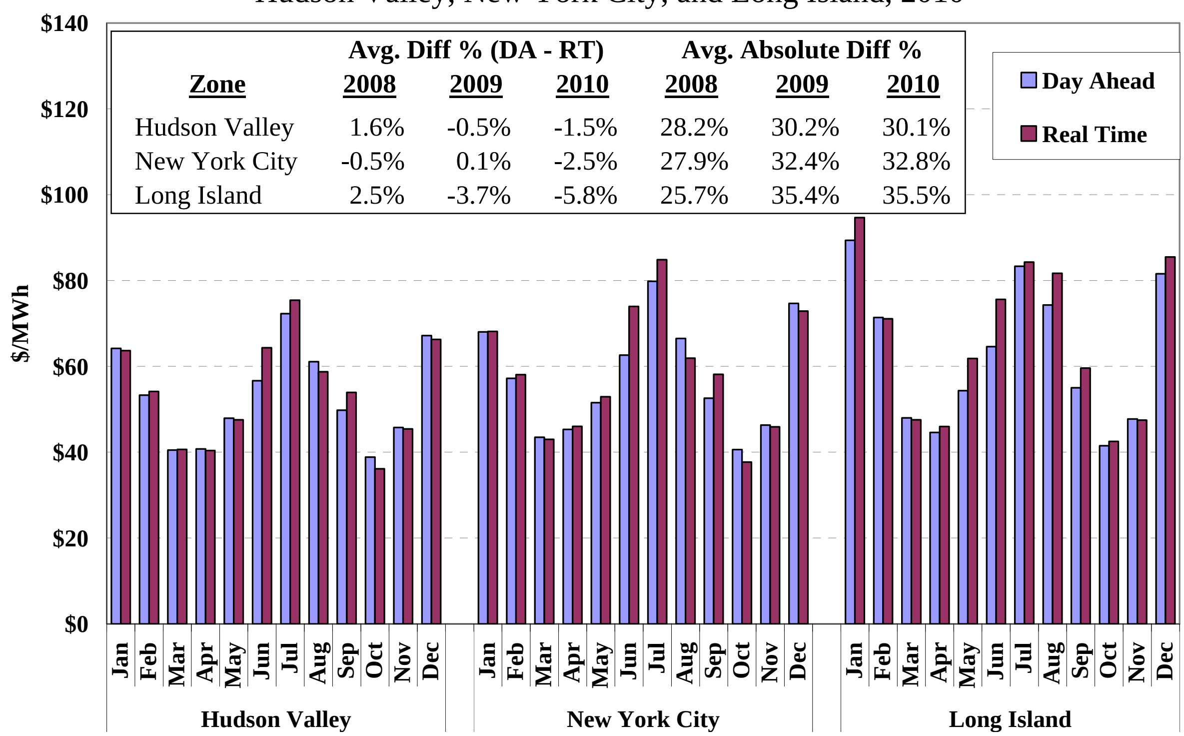
[19] Local Reliability Rule No. 4 requires Con Edison to "operate its system as if the first contingency has already occurred on its northern transmission system when thunderstorms are within one hour of the system or are actually being experienced."

Figure 11: Day-Ahead and Real-Time Energy Price Convergence

West, Central, and Capital Zones, 2010



Hudson Valley, New York City, and Long Island, 2010



The factors that dictate real-time prices on some days are inherently difficult to predict, leading day-ahead and real-time prices to differ significantly from one another on individual days even if prices are converging on average. Substantial day-ahead or real-time price premiums in individual months can occur randomly when real-time prices fluctuate unexpectedly. Large real-time premiums can arise when real-time scarcity is not fully anticipated in the day-ahead market. Transmission forced outages or unforeseen congestion due to TSA events in particular have load to very high real-time locational prices. For instance, extreme real-time congestion occurred into Southeast New York on several days in June 2010 during TSA events, leading to a large real-time premium for the month in Southeast New York. Monthly day-ahead price premiums, such as resulted in October 2010, typically arise when real-time scarcity conditions occur less frequently than market participants anticipate in the day ahead market.

The following two figures show the differences between day-ahead and real-time prices on a daily basis in New York City and Long Island during weekday afternoon hours in 2010. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure 12: Average Daily Real-Time Energy Price Premium in New York City
1 p.m. to 7 p.m., Weekdays, 2010

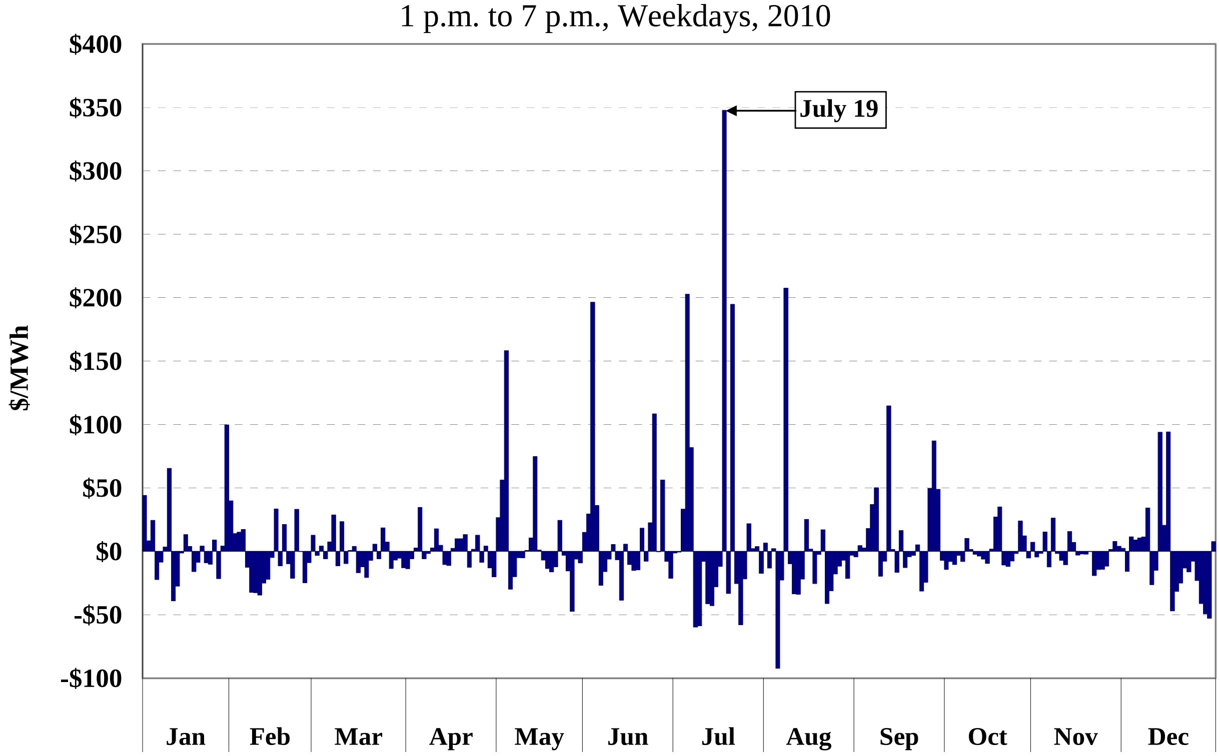
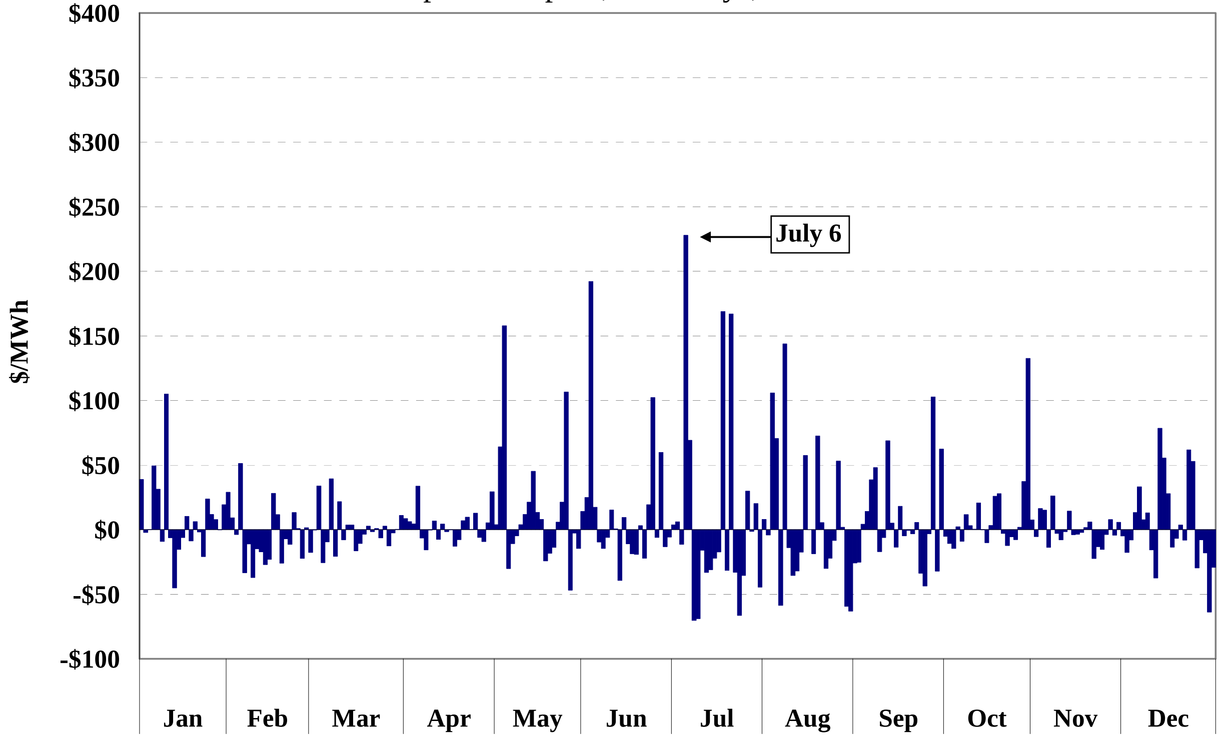


Figure 13: Average Daily Real-Time Energy Price Premium in Long Island
1 p.m. to 7 p.m., Weekdays, 2010



The figures show that even when average day-ahead and real-time prices are consistent in a month, there are substantial differences on individual days. Day-ahead prices were higher than real-time prices on most afternoons (58 percent of the afternoons in New York City and 53 percent of the afternoons in Long Island). However, very high prices were more frequent in the real-time market. The day-ahead price premium never exceeded $100 per MWh in New York City and Long Island, while the real-time price premium exceeded $100 per MWh in 18 afternoons in New York City and and 26 afternoons in Long Island.

A substantial portion of real-time price spikes in New York City and Long Island occurred during TSA events. TSAs require double contingency operation of the ConEd overhead transmission system, which is particularly costly when the TSAs coincide with high load conditions. TSAs require real-time operational changes based on weather conditions as they develop, so they directly affect real-time market outcomes. TSAs also indirectly affect day-ahead market outcomes because market participants can estimate the probability of a TSA and adjust their bids accordingly. However, TSAs alter the real-time capability of the transmission system in ways that are difficult for virtual traders to arbitrage in the day-ahead market. In New

York City, the largest real-time price premium of 2010 occurred on the afternoon of July 19 when the Leeds-to-Pleasant Valley line was severely congested for three hours during a TSA and the average shadow price exceeded $2,000/MWh. In Long Island, the largest real-time price premium occurred on the afternoon of July 6 when load rose to 5.7 GW (and statewide load reached the annual peak at 33.5 GW).

Virtual trading facilitates good price convergence. Virtual transactions allow market participants to offer non-physical generation and load into the day-ahead market and settle those transactions in the real-time market. The resulting additional liquidity in the day-ahead energy market reduces the sensitivity of day-ahead prices to changes in day-ahead purchases and sales by participants with physical supply and load. Improved consistency between day-ahead and real-time prices brings about a more efficient commitment of resources, which lowers the cost of providing power in real-time. Virtual trading is discussed further in Section III.C.

2. Price Convergence at Individual Pricing Nodes

The previous sub-section shows day-ahead prices are generally consistent with real-time prices at the zonal level, although individual nodes may still exhibit significant divergence between day-ahead and real-time prices. Transmission congestion can lead to a wide variation in nodal prices within a particular zone, while the price of each zone is a load-weighted average of the nodal prices in the zone. Hence, the pattern of intrazonal congestion may differ between the day-ahead market and the real-time market, leading to poor convergence at individual nodes even though convergence is good at the zone level.

The pattern of intrazonal congestion may change between the day-ahead market and the real-time market for many reasons. First, generators that are not scheduled in the day-ahead market may change their offers. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead. Second, generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows. Third, there may be differences between the constraint limits used to manage congestion in the day-ahead and real-time markets. Fourth, transmission constraints that are sensitive to the level of demand may become more or less acute after the day-ahead market due to differences between expected load and actual load. Fifth, transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit virtual trades and price sensitive load bids at the load pocket level or more disaggregated level, so good convergence at the zonal level may mask a significant lack of convergence within the zone. The NYISO has proposed to allow virtual trading at a more disaggregated level and this would likely improve convergence between day-ahead and real-time nodal prices. This sub-section examines price statistics for selected nodes in throughout New York State to assess price convergence at the nodal level.

Figure 14 shows average day-ahead prices and real-time price premiums in 2010 for selected locations in New York City, Long Island, and Upstate New York.[20] These are load-weighted averages based on the day-ahead forecasted load. The figure includes nodes in each region that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. For comparison, the figure also shows the average day-ahead LBMP and the average real-time price premium at the zone level. These are shown separately for the summer months (e.g., June to August) and other months because the congestion patterns typically vary by season.

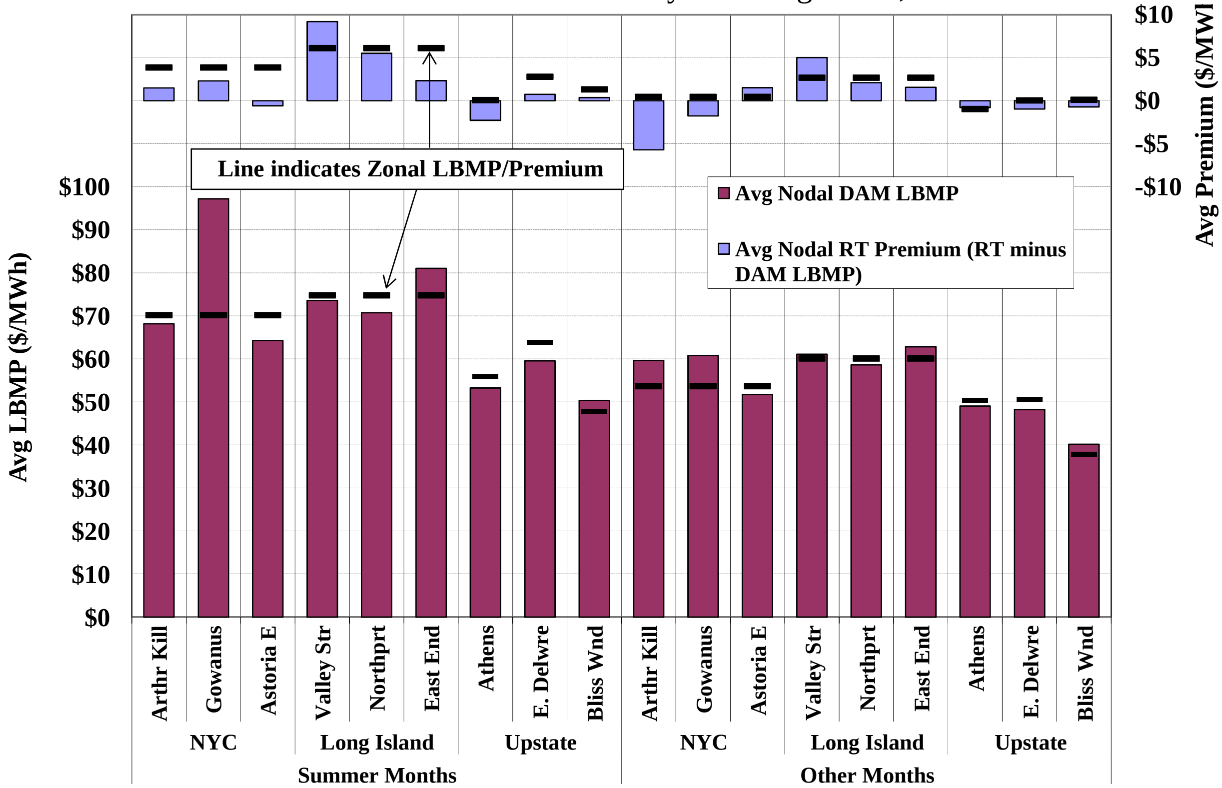
The lower portion of the figure shows the average day-ahead LBMPs at the node compared to the zone in which it is located. For example, Astoria East is sometimes export-constrained, so its average day-ahead LBMP was $5.85/MWh lower than for the New York City zone in the summer. The upper portion of the figure shows the average real-time price premium at the node compared to the zone in which it is located. For example, Astoria East exhibited a real-time price premium that was $4.43/MWh lower than for the New York City zone in the summer. This

20 In New York City, Arthur Kill is the Arthur Kill2 bus and Astoria East is the Astoria GT 2 bus. In Long Island, Valley Stream is the Barrett 1 bus and East End is the Global Greenport GT 1 bus. In Upstate, Athens is in the Capital Zone, E.Delwre is the East Delaware bus in the Hudson Valley Zone, and Bliss Wind is in the West Zone.

implies that the price effects of export-constraints from Astoria East were larger in the real-time market than in the day-ahead market.

Figure 14: Real-Time Price Premiums at Individual Nodes

Selected Nodes in New York City and Long Island, 2010



Outside New York City, several observations can be made regarding the consistency in intrazonal congestion patterns between the day-ahead and real-time markets. The east end of Long Island was import-constrained relative to other areas in Long Island in the day-ahead market, but not in the real-time market. The three nodes shown in upstate areas exhibited better day-ahead to real-time price convergence than the nodes in New York City and Long Island.

In New York City, convergence between day-ahead and real-time prices was relatively good overall at the nodal level in most areas. Several factors helped improve convergence in 2010:

- Supplemental Reliability Evaluation ("SRE") commitments, which increase commitment after day-ahead market, were less frequent in 2010 in New York City. This improves the consistency of committed supply between day-ahead and real-time.
- Simplified interface constraints in New York City, which are never used in the day-ahead market, were used less frequently in real-time to manage congestion.

With regard to the second factor, detailed line constraints allow the market models to manage congestion more efficiently than when the simpler interface constraints are used. The share of binding New York City constraints that were simplified interface constraints (rather than line constraints) decreased from 43 percent in 2009 to 30 percent in 2010. However, these effects were partly offset by increased price volatility in real-time associated with higher load levels, higher fuel costs, and more frequent TSAs.

Currently, virtual trading is allowed at only the zonal level, although the NYISO has developed an approach for allowing virtual trading at a more disaggregated level. If implemented, this would improve convergence at individual nodes by allowing market participants to arbitrage day-ahead to real-time prices at the nodal level.

3. Ancillary Services Price Convergence

The NYISO co-optimizes the scheduling of energy, operating reserves, and regulation service such that the combined production cost of all products is minimized in the day-ahead and real-time markets. The energy and ancillary services markets place demand on the same supply resources, so prices for energy and ancillary services are highly correlated, and scarcity in the energy market is generally accompanied by a scarcity of ancillary services. This sub-section examines ancillary services prices to assess how well day-ahead and real-time prices converge.

In the market for energy, virtual trading improves convergence between day-ahead and real-time prices, which helps the ISO commit an efficient quantity of resources in the day-ahead market. In the ancillary services markets, on the other hand, only ancillary services suppliers participate directly, no virtual trading of ancillary services is allowed. Procurement of ancillary services is managed by the ISO, which obtains the same amounts of ancillary services in the day-ahead and real-time markets, based on reliability criteria and without regard to price. Therefore, when systematic differences arise between day-ahead and real-time ancillary services prices, ancillary services suppliers are the only entities able to arbitrage them and improve convergence.

The following two figures summarize day-ahead and real-time clearing prices for the two most important reserve products in New York. Figure 15 shows 10-minute non-spinning reserve prices in Eastern New York, which are primarily based on the requirement to hold 1,000 MW of

10-minute reserves east of the Central-East Interface. Beginning December 1, 2010, this requirement was 1,200 MW because the reserve sharing agreement with ISO New England expired. This particular requirement is typically the most costly reserve requirement for the ISO to satisfy due to the relative scarcity of capacity in Eastern New York. Figure 16 shows 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 600 MW of 10-minute spinning reserves in New York State. In both figures, average prices are shown by season and by hour of day. The market uses "demand curves" that place an economic value.of $500 per MW on satisfying both reserve needs.

Figure 15: Day-Ahead and Real-Time 10-Minute Non-Spinning Reserves Prices
Eastern New York, 2010

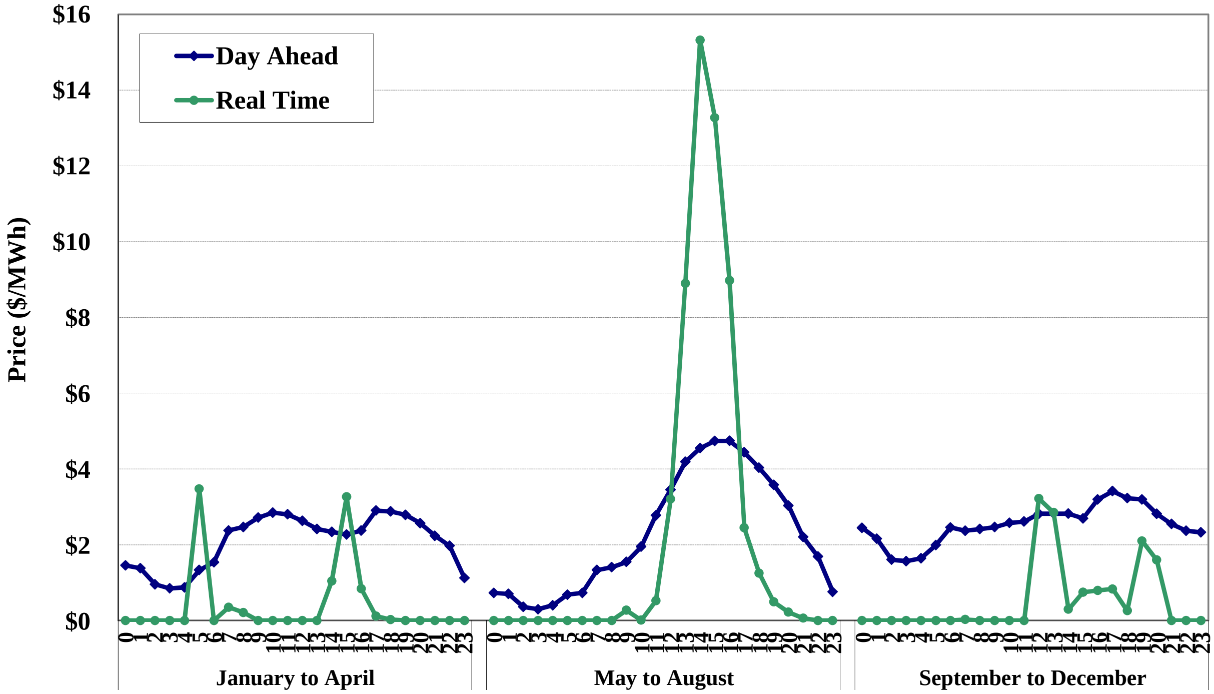
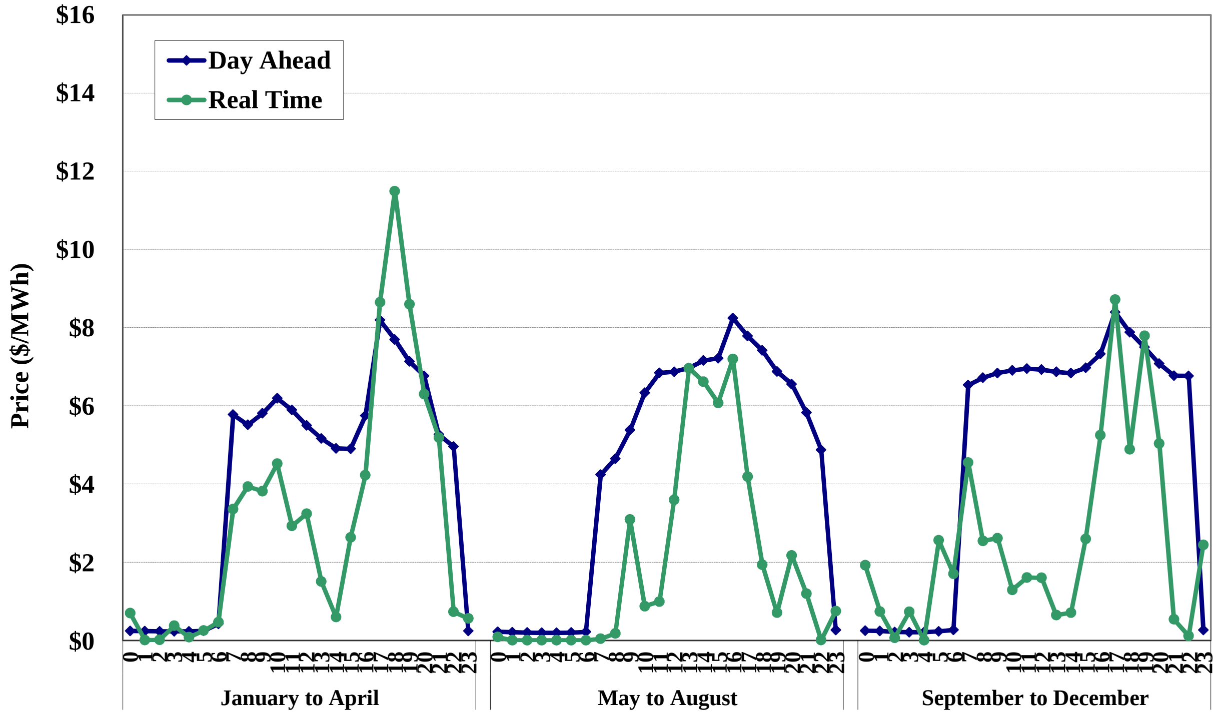


Figure 16: Day-Ahead and Real-Time 10-Minute Spinning Reserves Prices
Western New York, 2010



Both figures show that average day-ahead prices were generally higher than average real-time prices in most hours, while average real-time prices were substantially higher during several afternoon hours, particularly during the summer months. However, these average prices mask the substantial variability in real-time prices. The real-time price is based on the opportunity costs of generators whose energy production is backed-down in order to provide reserves. In most hours, excess reserves are available on on-line units and off-line quick-start units, leading the real-time price of reserves to be $0 per MWh in a substantial share of hours.

In 2010, real-time 10-minute non-spinning reserves prices in Eastern New York were $0 per MWh in more than 99 percent of intervals, but rose significantly in the remaining intervals. Hence, the $15 per MWh average price in hour 14 during the summer in Eastern New York is an average across the many hours in which the price was zero or near zero and a small number of peak pricing events. The real-time prices for 10-minute spinning reserves were less volatile, but still prone to spikes, Day-ahead reserve prices tend to fluctuate based on the expected likelihood of a real-time price spike, although day-ahead reserve prices are also affected by the risks that suppliers face from the high volatility of real-time prices. If a supplier sells reserves in the day-ahead market and the real-time price spikes unexpectedly, the supplier can incur substantial losses or foregone profits. Accordingly, the day-ahead premium during most periods may reflect the risks faced by suppliers. Nevertheless, the fact that day-ahead prices were consistently higher than real-time prices during periods when real-time price spikes are particularly unlikely suggests that participants may be unable to arbitrage the day-ahead prices during these periods under the current market rules.

It may be counterintuitive that Western New York 10-minute spinning reserves prices do not increase during the summer as do most other products. However, Western New York 10-minute spinning reserve prices are driven by the indirect effects of scheduling patterns in Eastern New York. Under tight operating conditions, quick start gas turbines in New York City and Long Island are frequently called on to provide energy. This requires the real-time dispatch model to meet some of the Eastern 10-minute reserves requirement by backing down steam units, which helps relieve state-wide 10-minute synchronous reserves constraints. These actions reduce the amount of 10-minute synchronous reserves that must be held in Western New York.

Market participants can be expected to respond to systematically different day-ahead and real-time prices by bidding up or down the clearing price in the day-ahead market. However, the current market rules do not allow load serving entities and virtual traders to arbitrage day-ahead to real-time price differences by adjusting their ancillary services purchases or by submitting price-sensitive bids. Only generators have the ability to submit price-sensitive offers to the ancillary services markets in the day-ahead market. However, the mitigation rules limit the ancillary services offers of some generators in the day-ahead market, which may inhibit price convergence. This is discussed further in Section III.B.

III. Analysis of Energy and Ancillary Services Bids and Offers

In this section, we examine energy and ancillary services bid and offer patterns to evaluate whether the market is functioning efficiently and whether market participant conduct is consistent with effective competition. In the first sub-section, the analysis reviews energy offers and mitigation patterns, and it seeks to identify potential attempts to withhold generating resources to increase prices. The analysis does not raise concerns that the wholesale market was affected by physical and economic withholding. In the second sub-section, we evaluate offers to supply regulation and 10-minute operating reserves in the day-ahead market. In the last sub-section, we evaluate load-bidding and virtual trading behavior to determine whether they have been conducted in a manner consistent with competitive expectations.

A. Analysis of Energy Supply Offers

The majority of wholesale electricity production comes from base-load and intermediate-load generating resources. Higher-cost resources are used to meet peak loads and constitute a very small portion of the total supply. This causes the market supply curve to be comparatively flat at low and moderate output levels and steeply sloped at high output levels. Therefore, as demand increases from low load levels, (as an almost vertical demand curve shifts along the supply curve) prices remain relatively stable until demand approaches peak levels, where prices can increase quickly as the more costly units are required to meet load. The shape of the market supply curve has implications for evaluating market power.

Suppliers that have market power can exert that power in electricity markets by withholding resources to increase the market clearing price. Physical withholding occurs when a resource is derated or not offered into the market when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource). Suppliers may also physically withhold by providing inaccurate information regarding the operating characteristics of a resource (e.g., ramp rate and minimum down time). Economic withholding occurs when a supplier raises the offer price of a resource in order to reduce its output below competitive levels or otherwise raise the market clearing price.

In the NYISO's Location-Based Marginal Pricing ("LBMP") market design, the competitive offer of a generator is the marginal cost of producing additional output. Absent market power, a supplier maximizes profits by producing output whenever the production cost is less than the LBMP. However, a supplier with market power profits from withholding when its losses from selling less output are offset by its gains from increasing LBMPs.

An analysis of withholding must distinguish between strategic withholding aimed at exercising market power and competitive conduct that could appear to be strategic withholding. Measurement errors and other factors can erroneously identify competitive conduct as market power. For example, a forced outage of a generating unit may be legitimate or it may be an attempt to raise prices by physically withholding the unit.

To distinguish between strategic and competitive conduct, we evaluate 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 maximize profits by increasing their offer quantities during the highest load periods to sell more power at the higher peak prices.[21] Alternatively, a supplier with market power is most likely to profit from withholding during periods when the market supply curve becomes steep (i.e., at high-demand periods) because that is when prices are most sensitive to withholding. Therefore, examining the relationship between potential withholding metrics and demand levels allows us to test whether the conduct of market participants is consistent with workable competition.

1. Potential Physical Withholding

We evaluate potential physical withholding by analyzing generator deratings. A derating occurs when a participant reduces the maximum output available from the plant. This can occur for a planned outage, a long-term forced outage, or a short-term forced outage. A derating can be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero). We evaluate the summer months when demand is highest and market power is most likely. This also minimizes the effects of planned outages that are the least like to reflect

[21] However, more frequent operation of generators during high load periods increases the frequency of forced outages, which can reduce the amount of capacity offered into the market.

physical withholding because they are scheduled in advance, reviewed by the ISO, and typically occur during relatively low load periods.

Figure 17 evaluates the correspondence between deratings and load levels to detect potential physical withholding. This figure shows total derates that measure the difference between the quantity offered and the most recent Dependable Maximum Net Capability ("DMNC") test value of each generator, and short-term derates that capacity derated for more than 30 days. Short-term derates are more likely than long-term derates to reflect attempts to physically withhold because it is less costly to withhold a resource for a short period of time. Taking a long-term forced outage would cause a supplier to forego the opportunity to earn profits during more hours when the supplier does not have market power. We focus on the hours from noon to 6 pm when demand is highest because that is when withholding is more likely to be effective. The figure also focuses on suppliers in Eastern New York, which includes roughly two-thirds of the State's load, has limited import capability, and is more vulnerable to the exercise of market power than Western New York.

Figure 17: Day-Ahead Deratings vs. Actual Load in Eastern New York

12 pm to 6 pm on Weekdays -- June to August, 2010

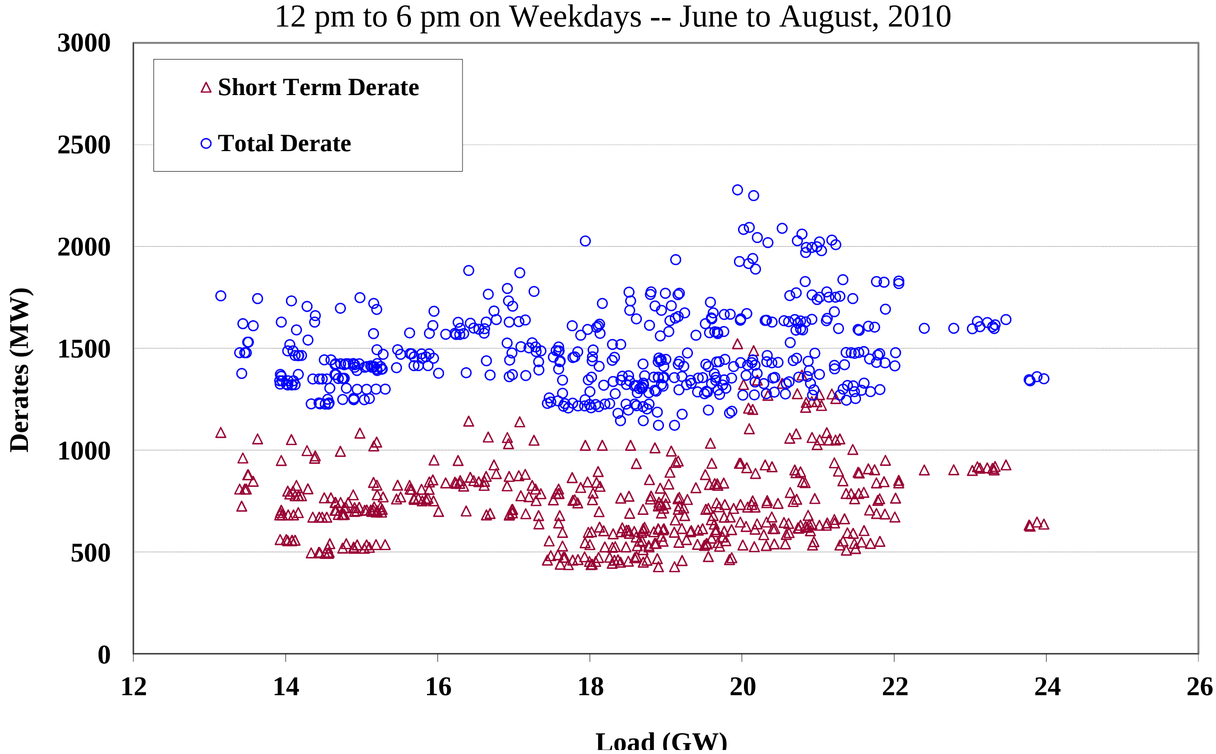


Figure 17 indicates that neither Total Derates nor Short-Term Derates increased substantially during the highest load conditions in 2010. This is consistent with expectations for a competitive market, since the incentive to physically withhold resources generally increases under high load conditions for participants with market power. The pattern of derates is particularly positive when we consider that genuine forced outages are expected to rise under peak load conditions when the NYISO calls on relatively high-cost units that generally do not operate in other hours. In addition, the high ambient temperatures that typically contribute to peak load conditions reduce the capability (i.e., increase the deratings) of many thermal generators. Besides evaluating the overall pattern, we also reviewed individual deratings with significant market effects and found no significant concerns about anti-competitive conduct in 2010.

2. Potential Economic Withholding

Economic withholding is an attempt by a supplier to raise its offer price substantially above competitive levels in order to raise LBMPs above competitive levels. A supplier without market power maximizes profit by offering its resources at marginal cost, because excessive offers lead the unit not to be dispatched when it would have been profitable, and thus, cost the owner lost profits. Hence, we analyze economic withholding by comparing actual supply offers with the generator's reference level, which is an estimate of marginal cost that is used for market power mitigation.[22] An offer parameter is considered above the competitive level if it exceeds the reference level by a given threshold.

We measure potential economic withholding by estimating an "output gap" for units that submit start-up, minimum generation, and incremental energy offer parameters that are above the reference level by a given threshold. The output gap is the amount of generation that is economic at the market clearing price, but is not producing output due to the owner's offer price.[23] We assume that the unit's competitive offer price is equal to its reference level.

22 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 3.1.4. For most generators, the reference levels are based on an average of the generators' accepted bids during competitive periods over the previous 90 days. The theory underlying this approach is that competitive conditions that prevail in most hours provide a strong incentive for suppliers to offer marginal costs. Hence, past accepted offers provide a benchmark for a generator's marginal costs.

23 The output gap calculation excludes capacity that is more economic to provide ancillary services.

Like the prior analysis of derates, we examine the relationship of the output gap to the market demand level. Output gap levels that are relatively large or that rise with load would indicate potential competitive concerns, particularly if this were to occur during periods of congestion. We focus our analysis on Eastern New York where market power is most likely, and on weekday afternoon hours when demand is normally highest. Figure 18 shows the output gap using the state-wide mitigation threshold (i.e., the standard conduct threshold used for mitigation outside New York City), which is the lower of $100 per MWh or 300 percent of a generator's reference level. Figure 19 shows the output gap results using a lower threshold, which is the lower of $50 per MWh or 100 percent of a generator's reference level. The second analysis is included to assess whether there have been attempts to withhold by offering energy just below the state-wide mitigation threshold. Finally, the figures show congested and non-congested hours separately to show whether the output gap increases during periods of congestion when some suppliers are more likely to have market power.

Figure 18: Real-Time Output Gap at Mitigation Threshold vs. Actual Load
Eastern New York, Weekdays, 12 pm to 6 pm, 2010

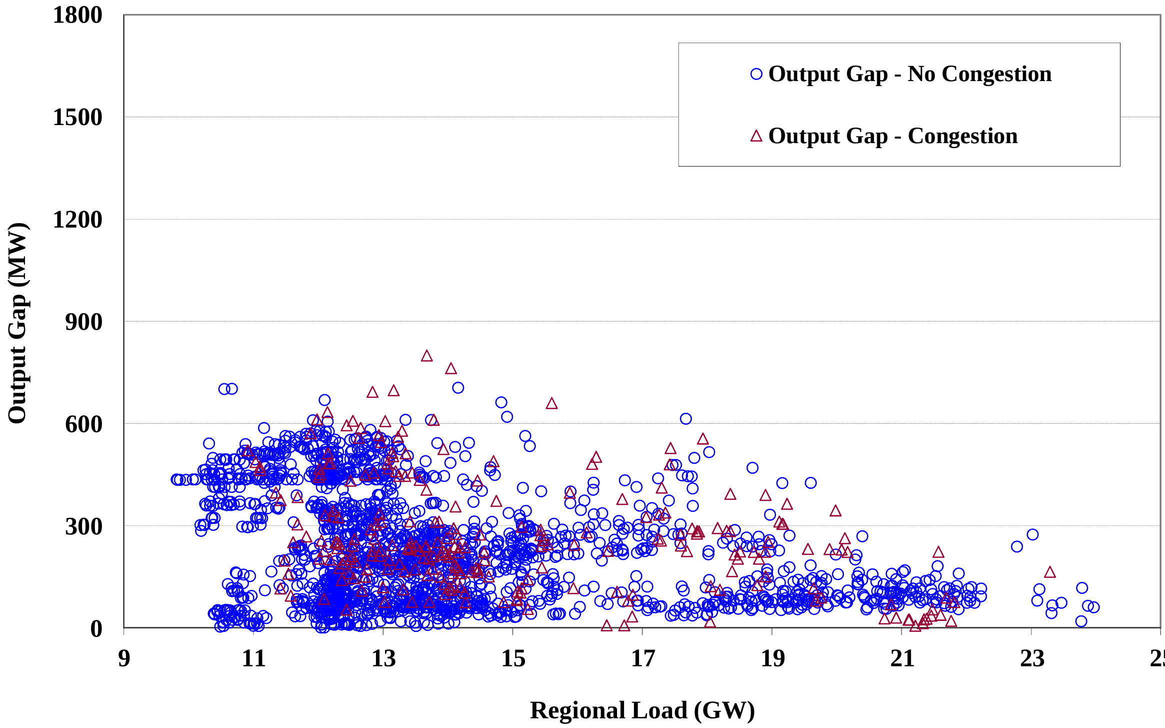
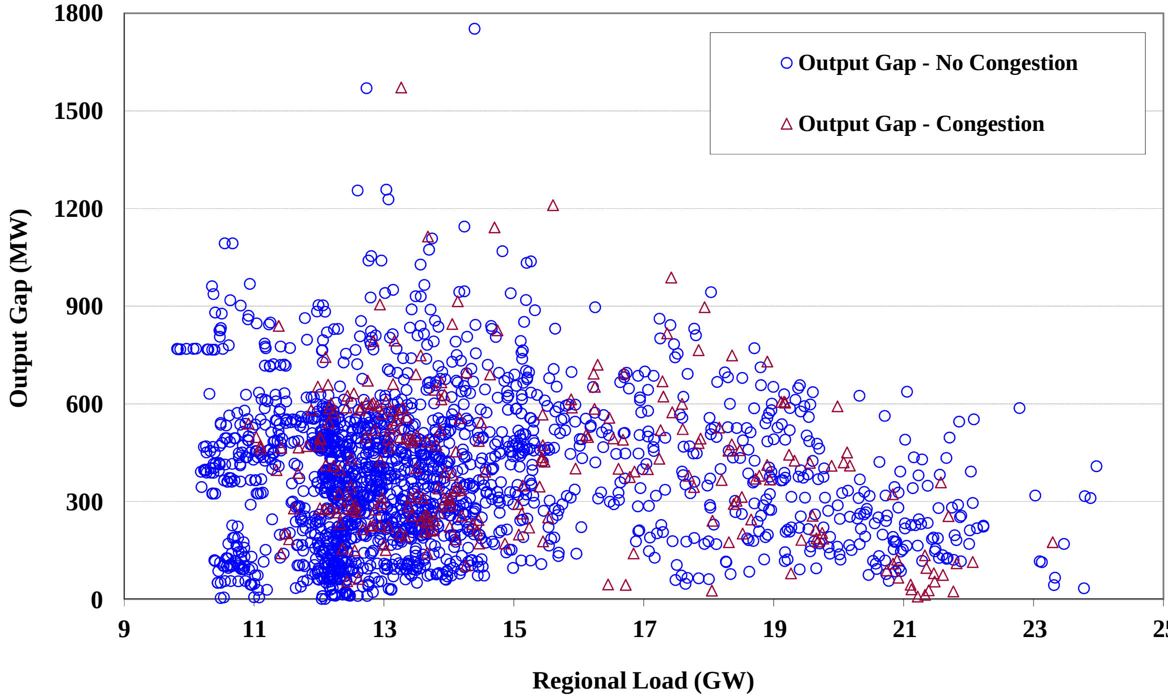


Figure 19: Real-Time Output Gap at Low Threshold vs. Actual Load
Eastern New York, Weekdays, 12 pm to 6 pm, 2010



The figures indicate that the output gap did not rise under high load conditions in 2010. The figures also show that the output gap did not increase substantially during periods of congestion. These are good signs because the market is most vulnerable to the exercise of market power during high load periods and in congested areas. Additionally, the output gap is generally low as a share of the real-time load in Eastern New York. These results are consistent with the expectations for a competitive market and are particularly notable for the lower threshold because such conduct is not subject to mitigation. In addition, we review significant instances of output gap to determine whether they may be an indication of potential withholding and this review raised no significant concerns regarding economic withholding during 2010.

3. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when the market is workably competitive. The NYISO applies a conduct-impact test that can result in mitigation of a participant’s bid parameters (i.e., incremental energy offers, start-up and minimum generation offers, and physical parameters). The mitigation measures are only imposed when suppliers’ conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds.[24] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The day-ahead and real-time market software is automated to perform most mitigation according to the conduct and impact thresholds. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from economic withholding in transmission-constrained areas.

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[25] This approach permits the in-city conduct and impact thresholds to increase as the frequency of congestion decreases, whether due to additional generation or increases in transmission capability. An in-city offer fails the conduct test if it exceeds the reference level by the threshold or more. In-city offers that fail conduct are tested for price impact by the market software, and if their price impact exceeds the threshold, they are mitigated.

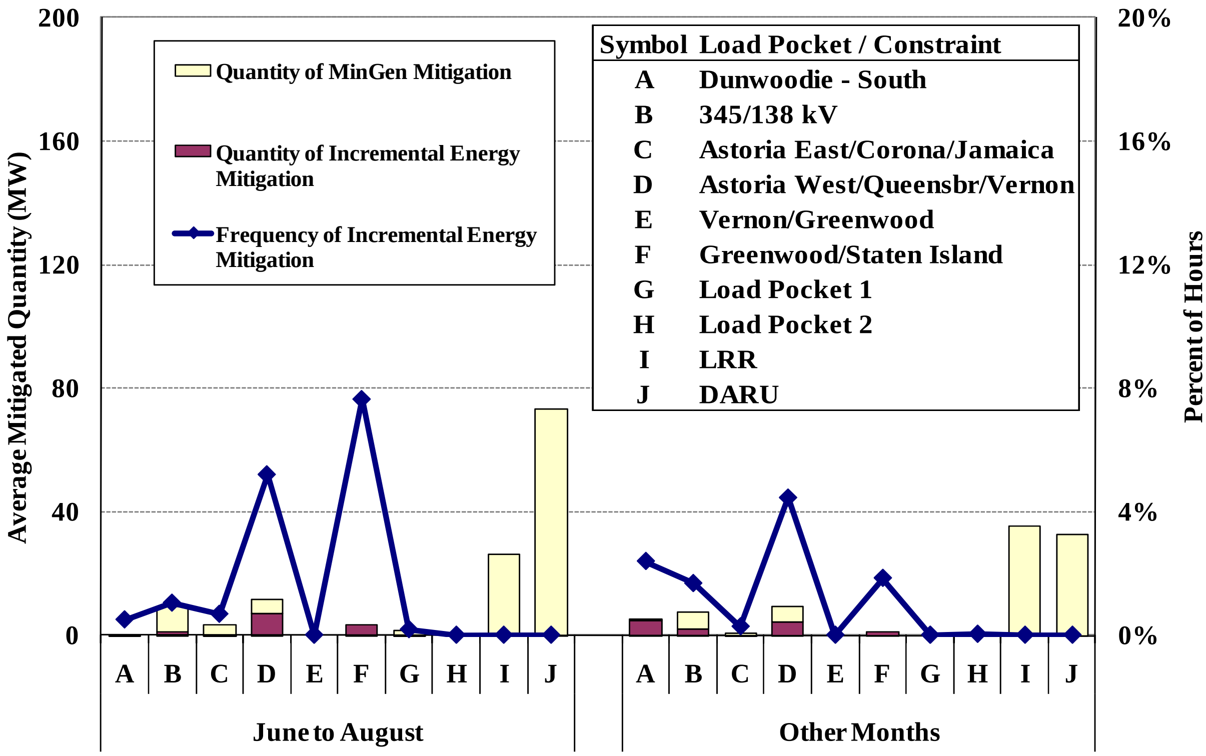
The following two figures summarize the amount of mitigation in New York City that occurred in the day-ahead and the real-time markets in 2010. These figures do not include guarantee payment mitigation that occurs in settlements. In both figures, the line indicates the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars indicate the average amount of capacity mitigated in hours when mitigation occurred. In the day-ahead market, mitigated quantities are shown separately for the

24 See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

25 Threshold = (0.02 * Average Price * 8760) / Constrained Hours. This threshold is defined in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e. MinGen). In the real-time market, mitigated quantities are shown separately for incremental energy and the capacity of gas turbines that is mitigated for startup cost.[26]

Figure 20: Frequency of Day-Ahead Mitigation in the NYC Load Pockets
2010



Note: To avoid providing confidential information, the Astoria West/Queensbridge and Staten Island load pockets are labeled as "Load Pocket 1" and "Load Pocket 2"

Figure 20 indicates that day-ahead mitigation was infrequent in 2010. Overall, the dispatchable portion of energy (i.e., incremental energy) was mitigated during less than 5 percent of all hours. Mitigation was more frequent in the summer months than in other months because withheld resources tend to have larger price impacts under higher load conditions and, therefore, are more prone to fail the impact test.

The figure shows that the majority (roughly 75 percent) of day-ahead mitigation was on generators committed to satisfy Local Reliability Rules ("LRR") or on Day Ahead Reliability

[26] Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer is mitigated, while it is shown in the Startup category when the startup offer is mitigated but the incremental energy offer is not.

Units ("DARU"). The Startup and MinGen offers of LRR and DARU units are mitigated whenever they exceed the reference level.[27] Most (approximately 84 percent) of the incremental energy offer mitigation in the day-ahead market was associated with constraints that bind into three load pockets: the Astoria West/Queensbridge/Vernon load pocket (40 percent of all load pocket congestion); the Dunwoodie South load pocket (29 percent); and the Greenwood/Staten Island load pocket (15 percent).

The majority of capacity mitigated in the day-ahead market during 2010 was associated with the MinGen parameter, while relatively little was for Incremental Energy parameters. This is because generators with long minimum run times are sometimes mitigated for LBMP impact in a small number of hours. For instance, a generator with a 24 hour minimum run time might raise its MinGen bid parameter above the conduct threshold. However, if this conduct causes the generator to not be committed and raises LBMPs more than the applicable impact threshold for one hour, the generator's MinGen parameter would be mitigated for the duration of its minimum run time. Its incremental energy parameter would be mitigated only in the hour with impact.

Figure 21 shows that the mitigation originating in the real-time market occurred much less frequently than in the day-ahead market during 2010 (although day-ahead mitigation is carried forward into the real-time market). Most of the real-time mitigation was associated with constraints that bind into Greenwood/Staten Island load pockets.

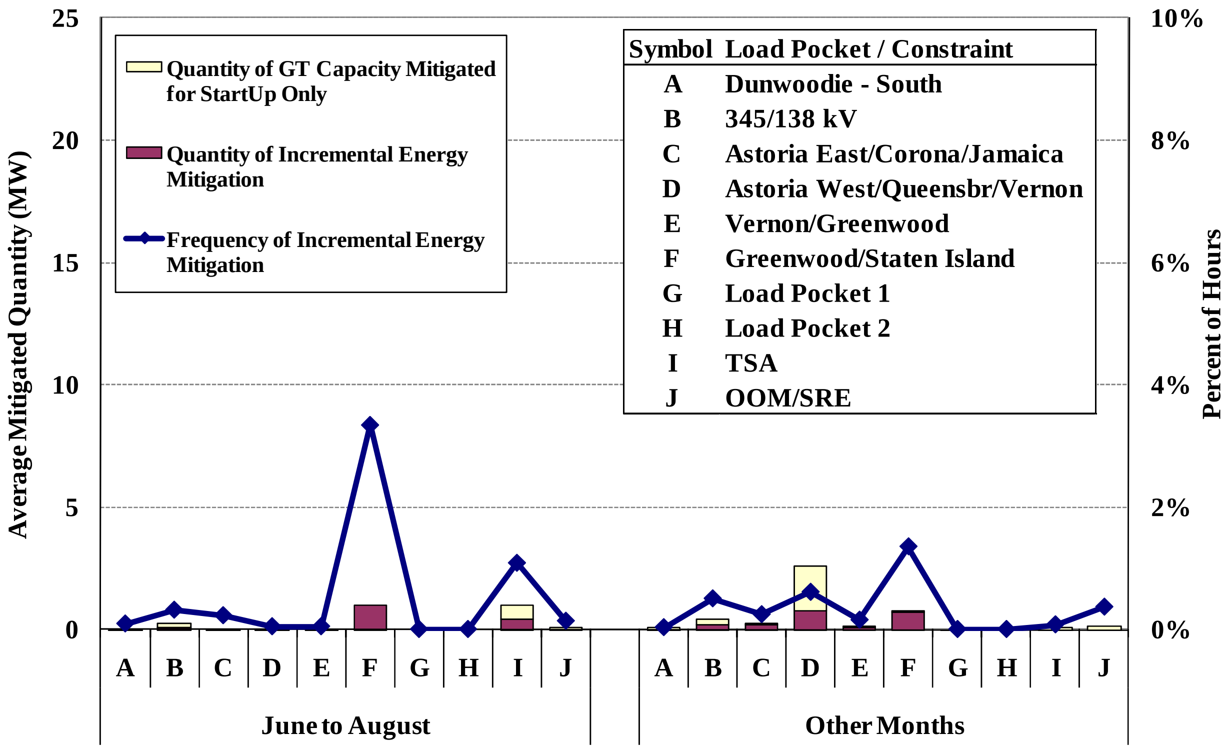
Most mitigation occurs in the day-ahead market rather than the real-time market because:

- The conduct and impact thresholds used in the day-ahead market are generally tighter than in the real-time market because the frequency of congestion is much higher in the day-ahead market.[28]
- Second, most energy is initially scheduled in the day-ahead market, and offers scheduled in the day-ahead market could not be increased in real time for most of the year.[29]

27 LRRs and DARUs are developed by the NYISO to maintain system reliability, particularly in local areas. The day-ahead market commits additional units, which otherwise would not be economic, to meet the reliability requirements. If a unit is committed for this purpose, the mitigation rules require its start-up and minimum generation bids to be set to the lower of the submitted offers and their applicable reference levels.

28 The threshold is inversely related to the frequency of congestion: Threshold = (0.02 * Average Price * 8760) / Constrained Hours.

Figure 21: Frequency of Real-Time Mitigation in the NYC Load Pockets
2010



Note: To avoid providing confidential information, the Astoria West/Queensbridge and Staten Island load pockets are labeled as "Load Pocket 1" and "Load Pocket 2"

Overall, these figures show that mitigation in both markets has been infrequent. Although New York City is highly concentrated, the conduct/impact mitigation framework has been effective in ensuring workably competitive market outcomes without excessive intervention in the market.

B. Ancillary Services Offers

The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time market. This co-optimization causes the prices of both energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.

The ancillary services markets also include ancillary services demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be

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29 This prohibition was removed in October 2010.

satisfied at a cost of less than the demand curve, the system is in a shortage and the reserve demand curve value will be included in both the reserve price and the energy price. This approach is recognized for producing efficient prices during shortages of reserves because it provides a mechanism for reflecting the value of reserves in the price of energy during shortages.

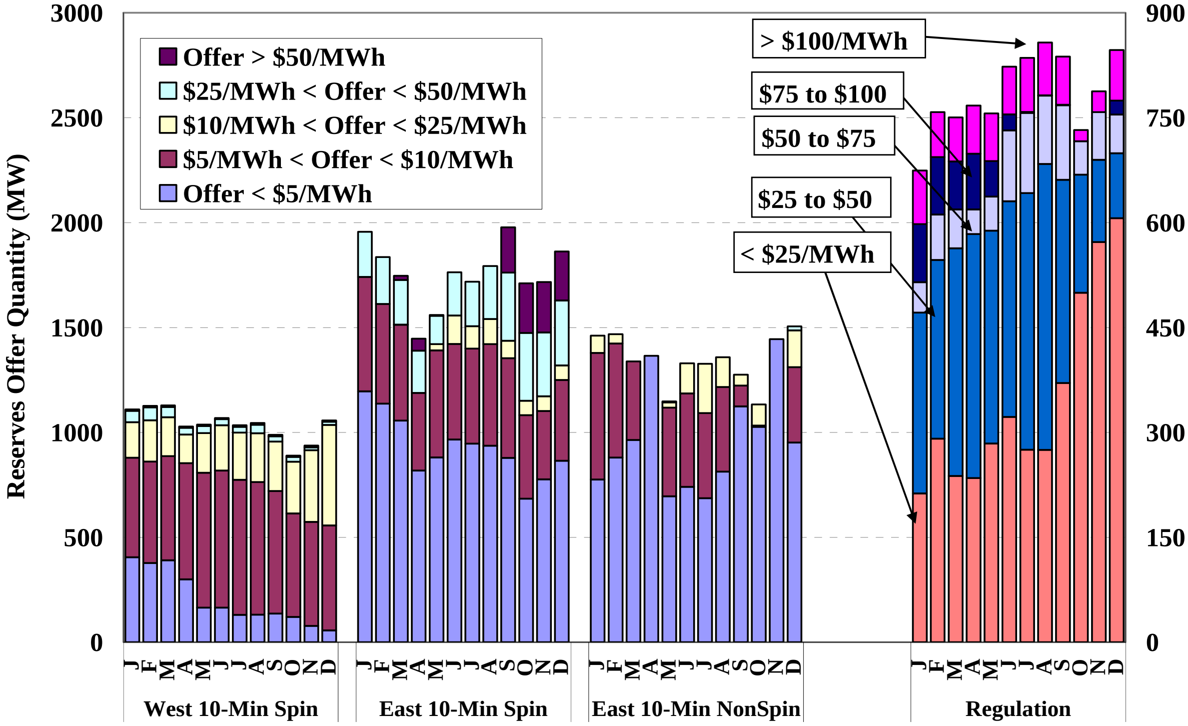
The ancillary services markets are evaluated in several sections of this report. Section II.A.5 summarizes ancillary service prices in the day-ahead market in 2009 and 2010, finding that ancillary services prices have been correlated with energy prices, rising and falling with the price of natural gas. Section II.D.3 evaluates the degree of convergence between day-ahead and real-time ancillary services prices. Although it has improved in recent years, convergence between day-ahead and real-time reserves prices remains poor under some operating conditions. Section VI.C.1 evaluates the efficiency of ancillary services prices during shortage conditions.

This sub-section evaluates the efficiency of ancillary services offer patterns, particularly in light of the relationship between day-ahead and real-time ancillary services markets. Under the current market rules, only generators have the ability to submit ancillary services offers in the day-ahead market. In an efficient market, we expect suppliers to respond to predictable differences between day-ahead and real-time ancillary service prices by raising or lowering their offer prices in the day-ahead market. However, the high volatility of real-time reserves clearing prices makes them difficult for market participants to predict in the day-ahead market. High volatility of real-time prices is a source of risk for generators that sell reserves in the day-ahead market, since generators must forego real-time scarcity revenues if they have already sold reserves in the day-ahead market. Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

1. Summary of Offers

Figure 22 summarizes the ancillary services offers for generators in the day-ahead market in each month of 2010. The quantities offered are shown for the following categories: (i) 10-minute spinning reserves in Western New York, (ii) 10-minute spinning reserves in Eastern New York, (iii) 10-minute non-spinning reserves in Eastern New York, and (iv) Regulation. Offer quantities are shown according to offer price level for each category. Only spinning and non-spinning reserve offers for peak hours are included (from 1 pm to 7 pm), while regulation offers are included for all hours.

Figure 22: Summary of Ancillary Services Offers
Day-Ahead Market, 2010



The amount of ancillary services offers from all four categories shown in Figure 22 varied by season in 2010. 10-minute spinning reserves and regulation offer quantities were lower on average in the spring and fall than in the summer and winter, due primarily to the fact that most planned outages occur in the shoulder months, which reduces the amount of available capacity. In addition, 10-minute spinning reserves offer quantities increased in Eastern New York since September 2010 due to increased participation. 10-minute non-spinning reserves offer quantities were generally lower in the summer than in the winter. This pattern is consistent with the effects of ambient temperature variations on the capability of gas turbines, which provide the majority of non-spinning reserves in Eastern New York.[30]

[30] The capability of thermal generators varies inversely with the ambient temperature, so generating capability is higher in the winter than in the summer.

Figure 22 also shows that 10-minute spinning reserve offer prices increased significantly during 2010 in both Eastern and Western New York. For example, the quantity offered below $10 per MWh fell by 28 percent in Eastern New York and 36 percent in Western New York from January to December. The increased offer prices may reflect changes in suppliers' expectations regarding the relative level of real-time and day-ahead reserve prices.

The offer prices of 10-minute spinning reserves were generally higher in Western New York than in Eastern New York. The primary reason for this is that New York City generators are required to offer 10-minute spinning reserves at $0 per MWh, while there is no offer cap for generators outside New York City. Higher offers for 10-minute spinning reserves tend to increase the clearing prices of 10-minute spinning reserves in the day-ahead market relative to the real-time market.

Figure 22 shows that approximately 200 MW of 10-minute spinning reserves in Eastern New York was offered above $25 per MWh in the first quarter of 2010, while the amount rose to roughly 500 MW by the last quarter of 2010. Suppliers normally submit such high offers when they prefer not to provide 10-minute spinning reserves in the day-ahead market. The volatility of real-time reserves prices makes it risky for a generator to sell reserves in the day-ahead market because if the generator is dispatched to provide energy rather than reserves in the real-time market, it will have to buy back reserves at the real-time clearing price in order to satisfy its obligations from selling day-ahead. Hence, the increase in offer prices may indicate that some suppliers believed that real-time reserve prices had become more volatile by the end of 2010.

To the extent suppliers would prefer to raise their day-ahead offer prices for 10-minute non-spinning reserves (or not offer at all), they are limited by two factors. First, offer prices are limited by the mitigation rules, which cap the reference levels of 10-minute non-spinning reserve units at $2.52 per MWh. Second, decreases in offer quantities are limited by the ICAP rules, which require non-PURPA ICAP units that have 10-minute non-spinning reserve capability to offer it in the day-ahead market. Hence, suppliers that are capable of providing 10-minute non-spinning reserves cannot avoid the mitigation rules simply by not offering in the day-ahead market. These restrictions prevent generators from rationally arbitraging the day-ahead and real-time prices when real-time prices are expected to be higher (or the probability of real-time shortages is non-trivial). Unfortunately, only generators are currently able to arbitrage these prices, so these restrictions may contribute to poor convergence between the day-ahead and real-time markets.

Low-cost regulation offers increased throughout the year, but particularly in the summer and fall. The increase in the summer was likely due to the fact that fewer units are on outage and more regulation-capable units are committed to satisfy the higher load levels. The increase late in the year was due to additional supply of regulation from new entry in the Capital Zone and reduced offer prices from existing suppliers. As a result, regulation prices fell from an average of approximately $34 per MWh in the first eight months of 2010 to an average of $18 per MWh in the last four months of 2010.

2. Ancillary Services Offer Conclusions

In Section II.D.3, we found that convergence between day-ahead and real-time reserves prices has been poor under certain conditions. Day-ahead clearing prices were systematically higher on average than real-time clearing prices in the majority hours. This is generally consistent with the risks suppliers incur by selling reserves in the day-ahead market. It is also possible that some suppliers over-estimated the likelihood of a real-time price spike. However, average real-time prices were frequently higher than average day-ahead prices during afternoon hours under high-load conditions. Systematically lower day-ahead prices in these hours increase the opportunity cost of selling day-ahead reserves. Reserve suppliers should respond by increasing their day-ahead offer prices, which would likely improve convergence between day-ahead and real-time.

However, we find that the mitigation measures likely limit the offers of suppliers below competitive levels under peak demand conditions. Hence, we recommend the NYISO reconsider the following two provisions in the mitigation measures, which may limit competitive offers in the day-ahead market:

- The $2.52 per MWh limit on 10-minute non-spinning reserve reference levels; and
- The requirement for New York City generators to offer 10-minute spinning reserves at $0 per MWh.

C. Analysis of Load Bidding and Virtual Trading

In addition to screening the conduct of suppliers for physical and economic withholding, it is important to evaluate how the behavior of buyers influences energy prices. Therefore, we evaluate whether load bidding is consistent with workable competition. Load can be purchased in one of the following four ways:

- *Physical Bilateral Contracts* – These are schedules that the NYISO allows participants to settle transmission charges (i.e., congestion and losses) with the ISO and to settle on the commodity sale privately with their counterparties. However, it does not represent the entirety of the bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately and generally show up as day-ahead fixed load.
- *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.
- *Price-Capped Load Bids* – This is load bid into the day-ahead market with a bid price indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[31]
- *Virtual Load Bids* – These are bids to purchase energy in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load scheduled in the day-ahead market is automatically sold back to the real-time market. So, the virtual buyer earns the quantity of the purchase in megawatt-hours ("MWh") multiplied by the real-time price minus the day-ahead price. This is currently allowed at the zonal level but not at a more disaggregated level.

These are bids to purchase energy in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load scheduled in the day-ahead market is automatically sold back to the real-time market. So, the virtual buyer earns the quantity of the purchase in megawatt-hours ("MWh") multiplied by the real-time price minus the day-ahead price. This is currently allowed at the zonal level but not at a more disaggregated level.

The categories of load listed above are important because they each tend to increase the amount of physical resources that are scheduled in the day-ahead market. Virtual supply, on the other hand, is also important because it tends to reduce the amount of physical resources that are scheduled in the day-ahead market. Virtual supply is energy that is offered for sale in the day-

[31] For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

ahead market with an offer price indicating the minimum amount the market participant is willing to accept. Virtual supply sold in the day-ahead market is automatically purchased back from the real-time market. So, the virtual seller earns the quantity of the sale in MWh multiplied by the day-ahead price minus the real-time price. This is also currently allowed at the zonal level but not at a more disaggregated level.

1. Day-Ahead Scheduling

Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a way of being committed only when it is economic to do so. These suppliers are willing to sell into the day-ahead market if day-ahead prices are generally consistent with real-time prices. Thus, efficient unit commitment relies on consistency between the day-ahead and the real-time markets. The analyses in this sub-section evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

We expect day-ahead load schedules to be generally consistent with actual load in a well-functioning market. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

The following figures show day-ahead load schedules and bids as a percent of real-time load during 2009 and 2010 at various locations in New York on a monthly average basis. Virtual load scheduling has the same effect on day-ahead prices and resource commitment as physical load scheduling, so they are shown together in this analysis. Conversely, virtual supply has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis. For each period, physical load and virtual load are shown by bars in the positive direction, while virtual supply is shown by bars in the negative direction. Net scheduled load, indicated by the line, is the sum of scheduled physical and virtual load minus scheduled virtual supply.

Figure 23: Day-Ahead Load Schedules versus Actual Load in Downstate Areas
2009 – 2010

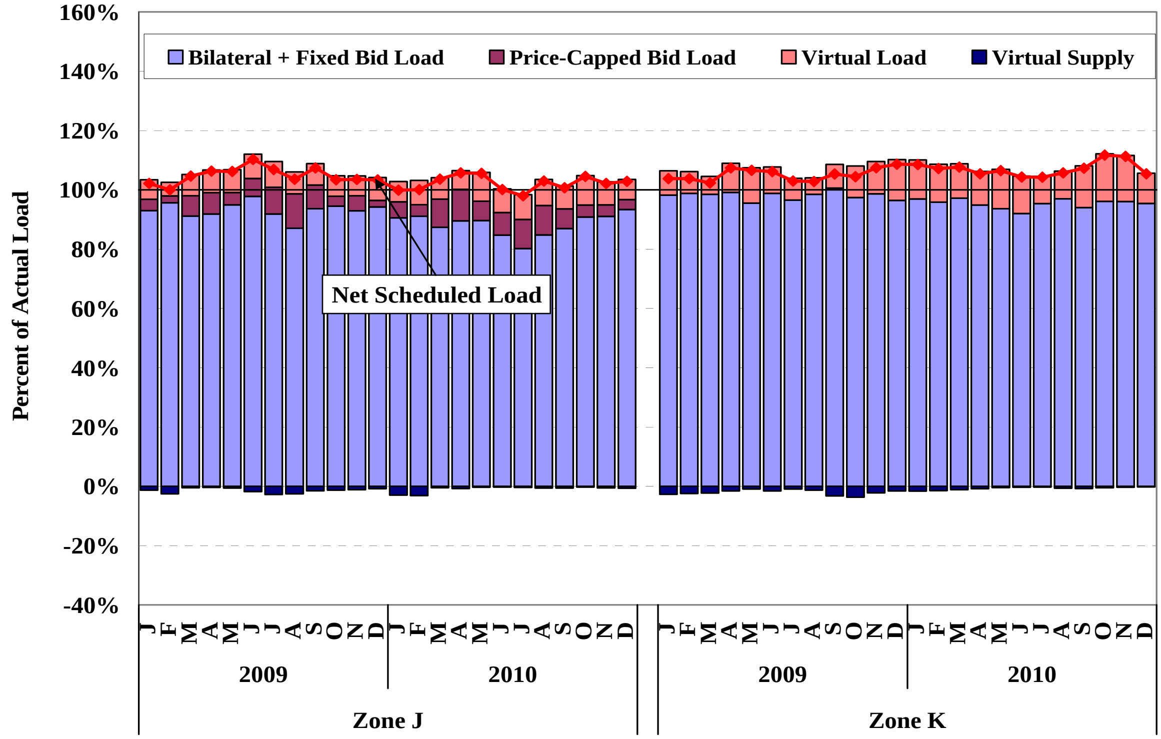


Figure 24: Day-Ahead Load Schedules versus Actual Load in Eastern Upstate Areas
2009 – 2010

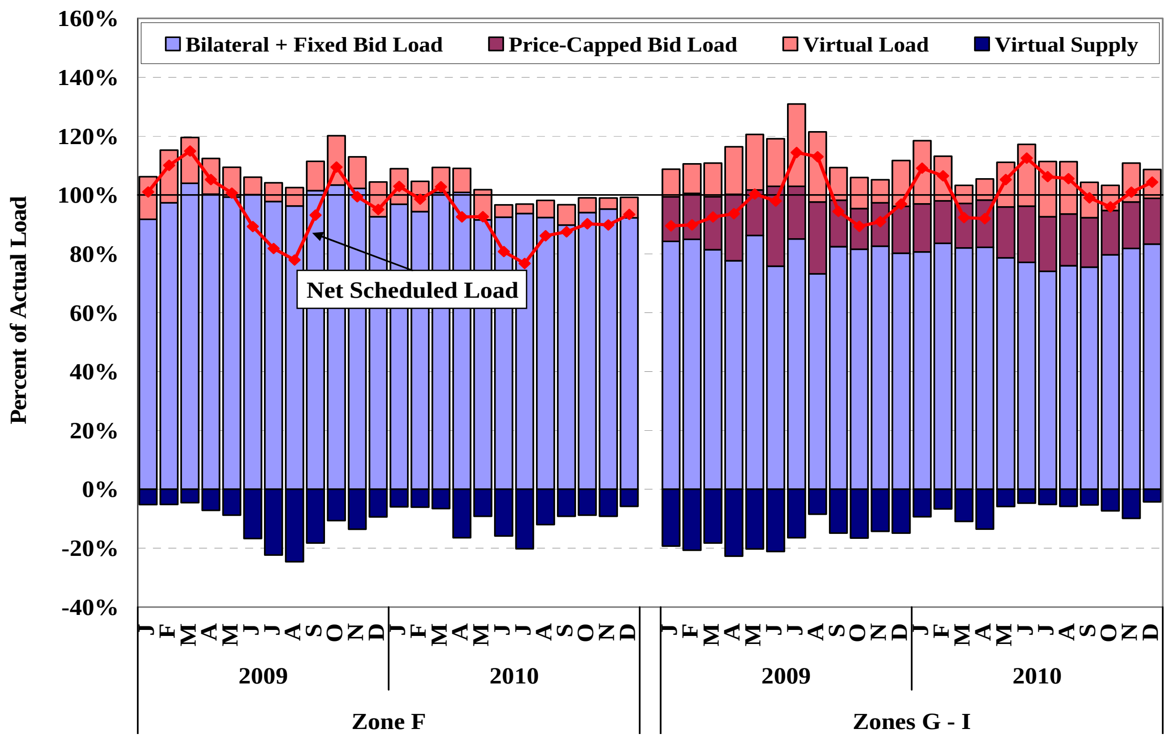
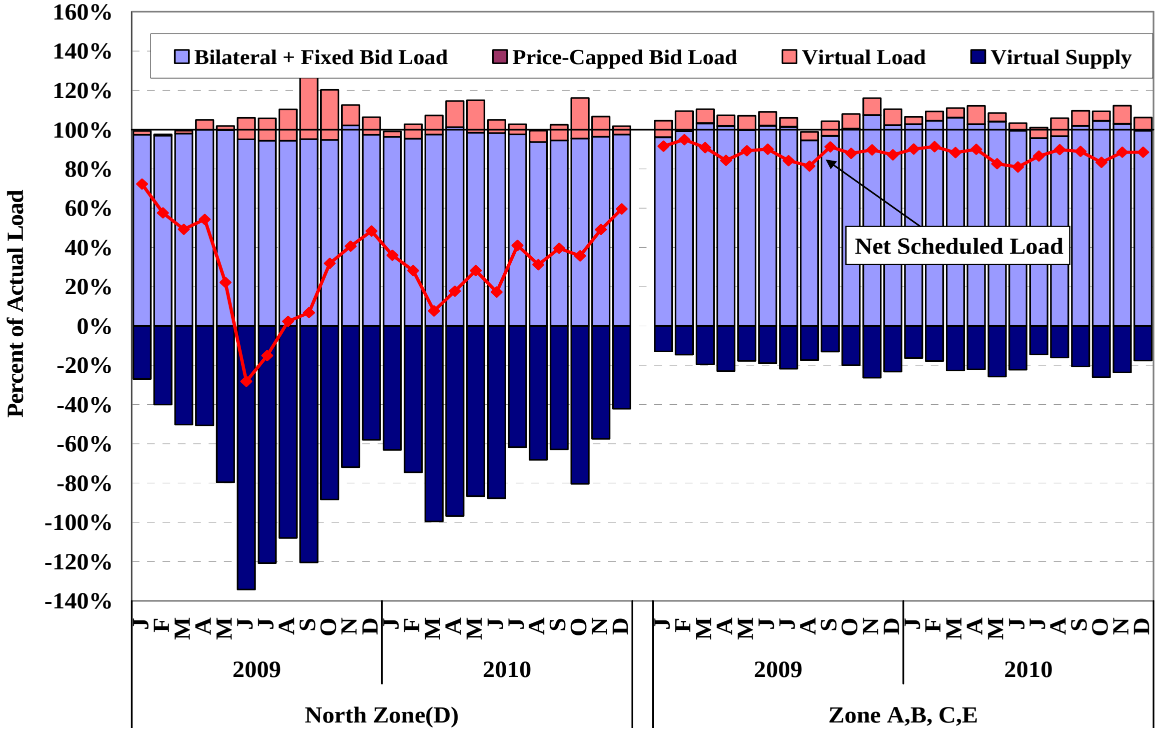


Figure 25: Day-Ahead Load Schedules versus Actual Load in Western Areas
2009 – 2010



On a state-wide basis, the average amount of load scheduled in the day-ahead market was slightly lower than the average amount of real-time load. The ratio of average net load scheduled in the day-ahead market to average real-time load was 96 percent in 2010, comparable to prior years. Since price convergence was relatively good at the zonal level in 2010, we conclude that the slight under-scheduling does not raise efficiency concerns. Rather, the under-scheduling likely reflects that additional supply is sometimes committed or imported after the day-ahead market.

The figures show that there were larger differences between day-ahead scheduling and real-time load in individual regions. In New York City and Long Island, load was consistently over-scheduled, which indicates that the day-ahead market generally scheduled more imports into New York City and Long Island than the real-time market. However, in Western New York, load was consistently under-scheduled, which implies that the day-ahead market typically scheduled more exports from these areas than the real-time market. This was particularly evident in the North Zone (Zone D), where the day-ahead energy schedules of wind and thermal units were typically lower than the real-time energy schedules, creating incentives for other market participants to schedule large quantities of virtual supply.

These figures also show seasonal variations in the day-ahead load scheduling. For example, the average ratio of net scheduled load to actual load was 108 percent in Lower Hudson Valley (Zones G to I) and 81 percent in the Capital zone in the summer months during 2010, and changed to 101 percent in Lower Hudson Valley and 94 percent in the Capital zone in the other months of 2010. These patterns indicate that the market generally responded rationally to differences between the congestion patterns in the day-ahead and real-time markets. Thunderstorm Alerts become more frequent in the summer, which substantially reduce real-time transmission limits from the Capital Zone to the Hudson Valley relative to the day-ahead limits. This provides incentives for market participants to schedule virtual load in Southeast New York (Zones G to K) in anticipation of higher real-time prices, and to schedule virtual supply outside Southeast New York (Zones A to F) in anticipation of lower real-time prices.

These over- and under-scheduling patterns generally helped improve convergence between day-ahead and real-time prices in most areas. Good convergence between day-ahead and real-time prices is important because it helps ensure that the generation committed in the day-ahead market will be economic under real-time operating conditions. Price convergence is evaluated in detail in Section II.D.

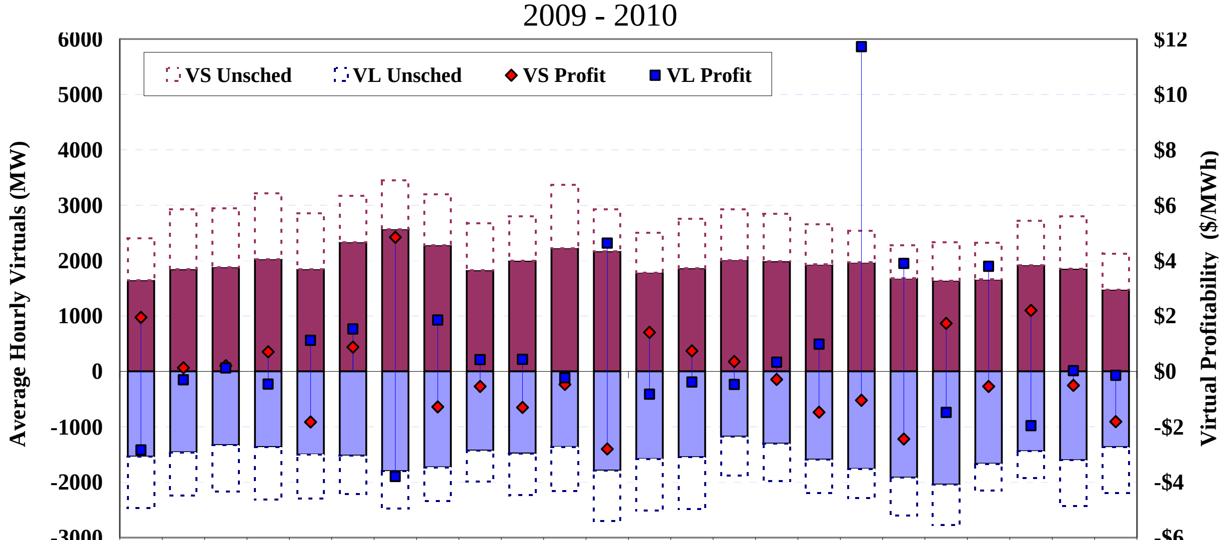
2. Virtual Trading

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual bids and offers provide liquidity to the day-ahead market because they constitute a substantial share of the price-sensitive supply and demand that establish efficient day-ahead prices.

Virtual transactions that are scheduled in the day-ahead market settle against real-time energy prices. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. If prices are lower in the day-ahead market than in the real-time market, a virtual trader may purchase energy in the day-ahead market and sell it back in the real-time market, which will tend to increase day-ahead prices and improve price convergence with the real-time market. Hence, profitable virtual transactions improve the performance of the day-ahead market. The New York ISO currently allows virtual traders to schedule transactions to arbitrage the price differences at the zone level between day-ahead and real-time.

This sub-section evaluates recent virtual trading activity in New York. Figure 26 shows monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2009 and 2010. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market compared to the price at which these positions were covered in the real-time market.[32]

Figure 26: Virtual Trading Volumes and Profitability by Month
2009 - 2010



		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
		2009												2010											
Profit > 50% of Avg. Zone Price	MW	97	105	225	270	271	420	514	293	235	315	239	573	380	324	240	122	181	285	205	176	162	117	135	221
	%	3%	3%	7%	8%	8%	11%	12%	7%	7%	9%	7%	14%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%
Loss > 50% of Avg. Zone Price	MW	108	102	192	249	281	384	611	441	244	369	253	578	347	284	201	112	211	241	300	205	115	95	131	273
	%	3%	3%	6%	7%	8%	10%	14%	11%	7%	11%	7%	15%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%

32 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

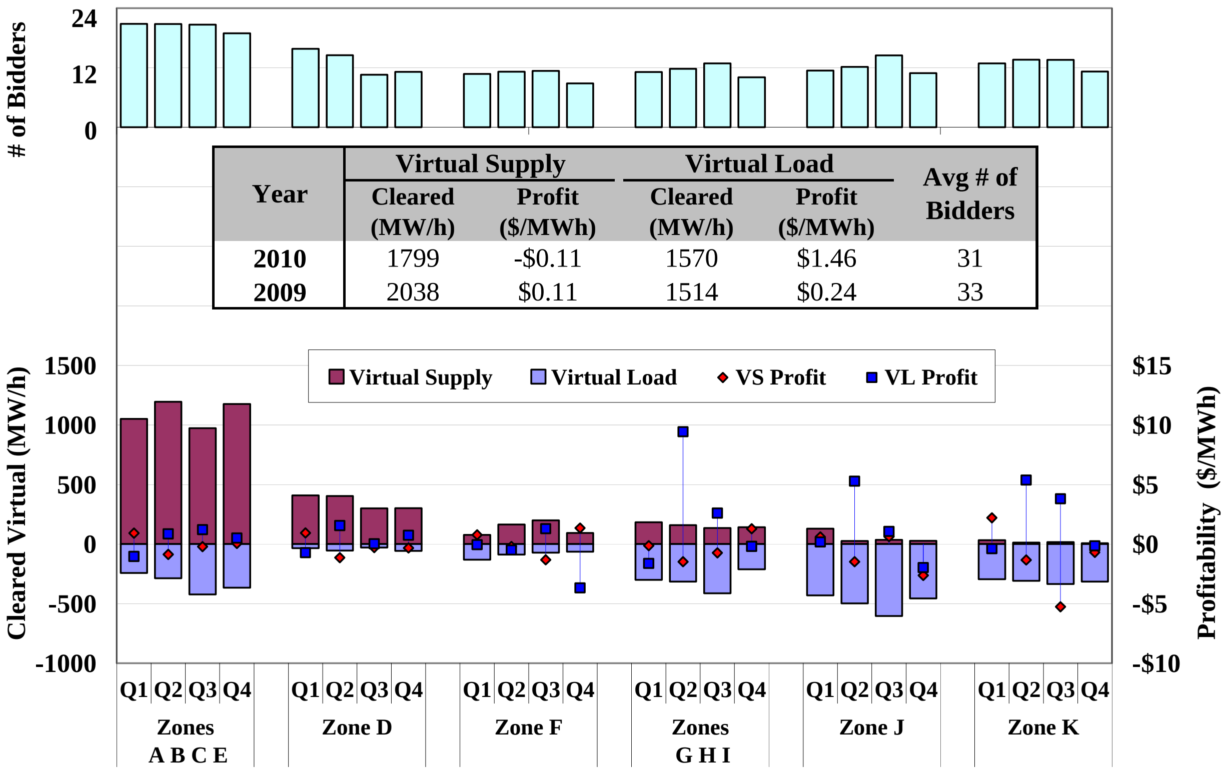
Figure 26 shows that the volume of virtual trading did not change significantly from 2009 to 2010. On a statewide basis, an average of 1.2 to 2.0 GW of virtual load and an average of 1.5 to 2.5 GW of virtual supply have been consistently scheduled in the day-ahead market each hour in each month of 2009 and 2010.

The profits and losses of virtual load and supply have varied widely from month to month, reflecting the difficulty of predicting volatile real-time prices. For example, virtual loads scheduled in Southeast New York earned large profits in June 2010 due to poor price convergence, but they incurred losses in August 2010 due to a reversal in the price differences in New York City.

The table below the figure shows a screen for relatively large profits or losses, which identifies virtual transactions with gross profits (or losses) larger than 50 percent of the average zone price. For example, an average of 285 MW of virtual transactions (or 8 percent of all virtual transactions) netted profits larger than the 50 percent of their zone prices in June 2010. Large profits may be an indicator of a modeling inconsistency, and large losses may be an indicator of potential manipulation of the day-ahead market. These levels were modest in 2010, and our monitoring of these indicators did not raise potential manipulation concerns.

below summarizes virtual trading by geographic region. The eleven zones in New York are broken into six geographic regions based on typical congestion patterns. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.

Figure 27: Virtual Trading Activity
By Region by Quarter, 2010



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2010	1799	-$0.11	1570	$1.46	31
2009	2038	$0.11	1514	$0.24	33

The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the six regions in each quarter of 2010. The upper portion of the figure shows the average number of virtual bidders in each region. The table in the middle compares the overall virtual trading activity in 2010 to 2009. Figure 27 shows:

- A large number of market participants regularly submit virtual bids and offers. On average, 10 or more participants submitted virtual trades in each region and 31 participants submitted virtual trades somewhere in the state in 2010.
- The average quantity of scheduled virtual load increased slightly from 2009 to 2010, while the average quantity of scheduled virtual supply fell notably from 2038 MW in 2009 to 1799 MW in 2010. The change was most likely in response to the increased real-time price premiums in most regions in 2010.
- In aggregate, virtual traders netted approximately $5 million of gross profits in 2009 and $18 million of gross profits in 2010. Virtual load was generally more profitable than virtual supply, reflecting prevailing real-time price premiums in Southeast New York (i.e., Zones G to K), and particularly in 2010.
- There were substantial net virtual load purchases in downstate areas and net virtual supply sales in upstate areas in 2010, consistent with prior years. Virtual load scheduling

in downstate areas in the second and third quarters accounted for 73 percent of total virtual trading profits in 2010. This is not surprising because real-time congestion was not fully reflected in day-ahead prices during these two quarters.

Overall, virtual load and supply have been profitable over the period, indicating that they have generally improved convergence between day-ahead and real-time prices. Good price convergence, in turn, facilitates an efficient commitment of generating resources. Active virtual supply also protects the day-ahead market against market manipulation and market power abuses.

IV. External Transaction Scheduling

This section examines the scheduling of imports and exports between New York and adjacent regions. In both 2009 and 2010, New York was a net importer from each of the four adjacent control areas: New England, PJM, Ontario, and Quebec, although New York exported power to these areas under certain market conditions. In addition to the four primary interfaces with adjacent regions, Long Island and New York City connect directly to PJM and New England across four controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, and the Neptune Cable. The controllable lines are collectively able to import nearly 1.4 GW directly to downstate areas. The total transfer capability between New York and the adjacent regions is substantial relative to the total power consumption in New York, making it important to schedule the interfaces efficiently.

Consumers benefit from the efficient use of external transmission interfaces. The external interfaces allow low-cost external resources to compete to serve consumers who would otherwise be limited to available higher-cost internal resources. Likewise, low-cost internal resources gain the ability to compete to serve consumers in adjacent regions. The ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in the New York system. Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.

This section evaluates the following five aspects of transaction scheduling between New York and adjacent control areas: [33]

- Scheduling patterns between New York and adjacent areas;
- The pattern of loop flows around Lake Erie;
- Convergence of prices between New York and neighboring control areas;
- The efficiency of external interface scheduling by market participants; and
- Potential benefits from market enhancements associated with Inter-Regional Interchange Scheduling (“IRIS”) with New England.

[33] Additionally, Section VI.A evaluates the efficiency of external transaction scheduling by RTC.

The final sub-section summarizes our conclusions and recommends ways to improve scheduling between regions.

A. Summary of Scheduled Imports and Exports

The following three figures summarize the net scheduled interchanges between New York and the adjacent control areas in 2009 and 2010. The net scheduled interchanges do not include unscheduled power flows (i.e., loop flows). For each interface, average scheduled net imports are shown by month for peak (i.e. 6 am to 10 pm on weekdays) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure 28, the primary interfaces with Quebec and New England in Figure 29, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure 30.

Figure 28: Monthly Average Net Imports from Ontario and PJM
2009 – 2010

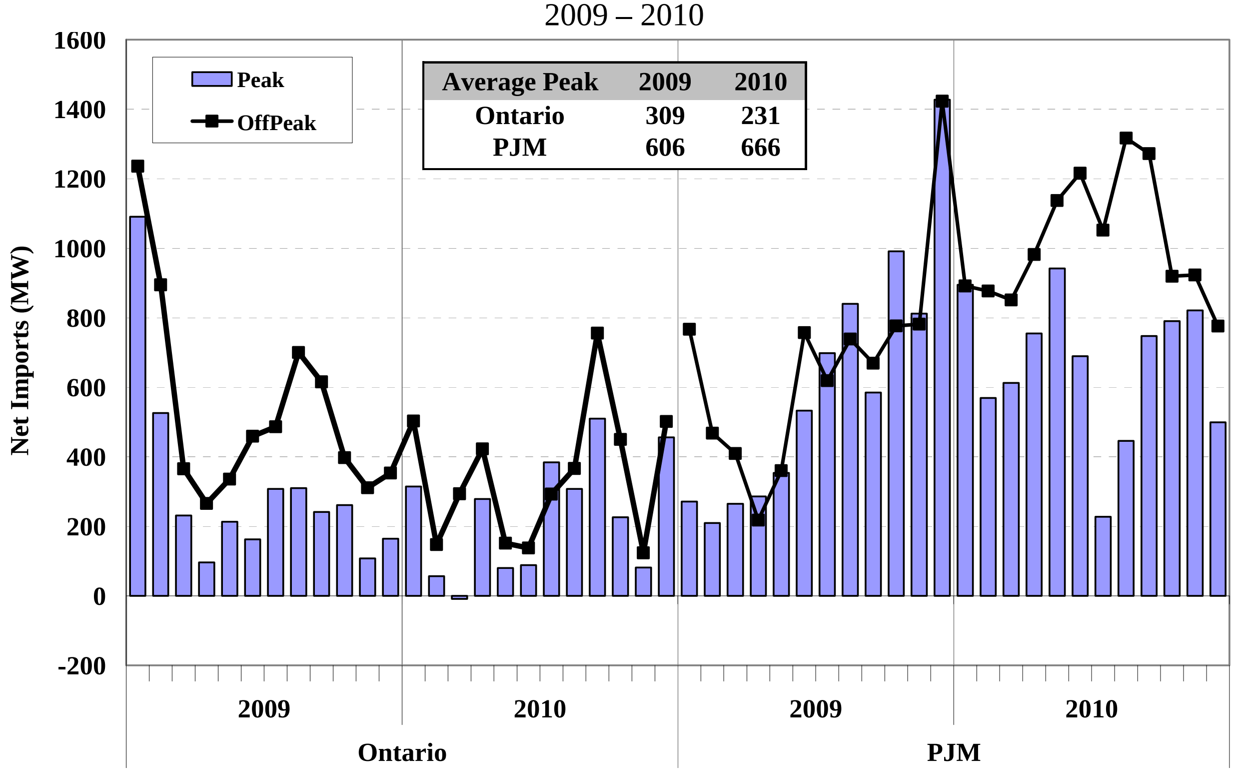
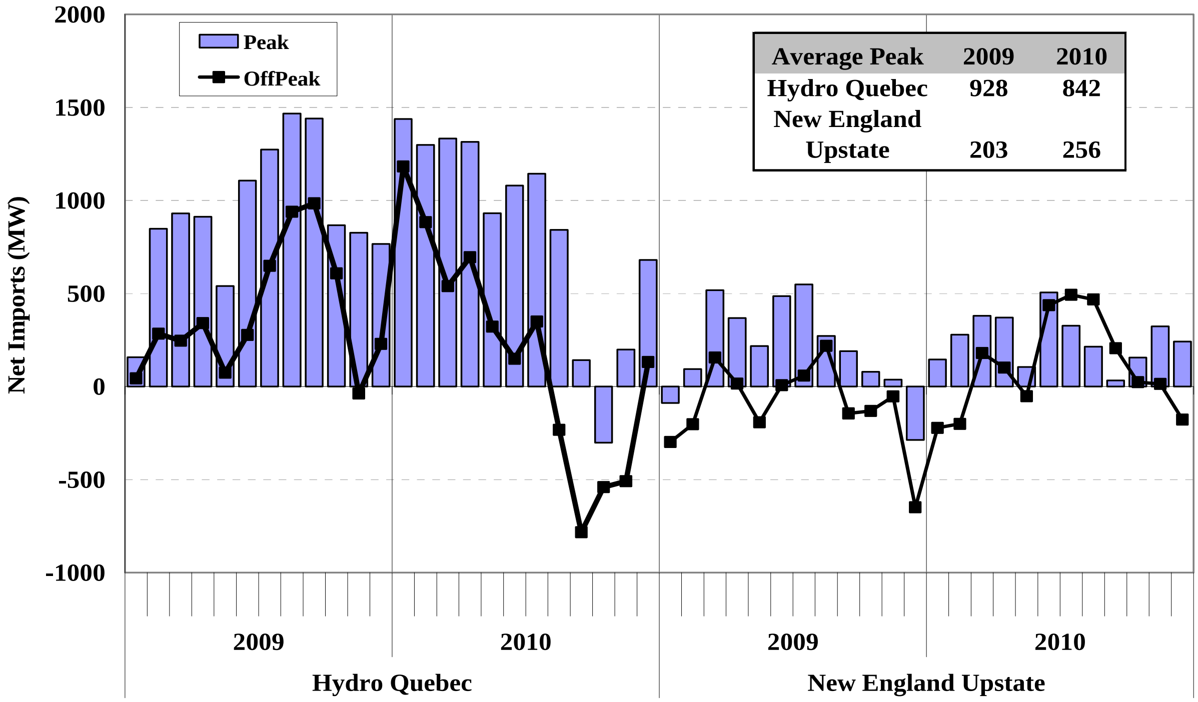


Figure 28 shows that New York generally imported across the interfaces with PJM and Ontario in 2009 and 2010. Average net imports from PJM rose in 2010, increasing 10 percent during peak hours and 53 percent during off-peak hours. The increase was consistent with the increase in price differences between the two markets.

However, average net imports from Ontario fell in 2010, decreasing 36 percent during off-peak hours and 25 percent during peak hours. Scheduling was relatively low on average in several months of 2010 (e.g., February, March, May, June and November), which was partly attributable to transmission and generation outages. For instance, a significant planned generation outage in Ontario occurred in May and June, contributing to a decline in net imports during this period. Several outages of large transmission lines that are part of the interface with Ontario occurred in November, which reduced the transfer capability between New York and Ontario to zero for two weeks in November 2010.

Figure 29: Monthly Average Net Imports from Quebec and New England
2009 – 2010



Average Peak	2009	2010
Hydro Quebec	928	842
New England Upstate	203	256

Figure 29 shows that New York generally imports across the interfaces with Quebec and New England during peak hours. The pattern of scheduling from Quebec reflects the flexibility of their hydroelectric generation, which allows Quebec to export power to New York when it is most valuable to do so. Accordingly, flows from Quebec to New York generally rise in the summer months and in periods of high natural gas prices. Similarly, imports from Quebec decline in the winter and during off-peak periods. Average net imports from Quebec fell 9 percent during peak hours from 2009 to 2010, driven primarily by the sharp reduction from

September to November 2010. This decline reflected increased internal load and reduced reservoir levels in Quebec, and relatively low electricity prices in New York.

Flows from New England to New York also generally rise in the summer months. This is partly because New England is more reliant on natural gas generation, which typically becomes more expensive during the winter months. The pattern of scheduling between New England and New York is also affected by production in Quebec. This is because Quebec schedules a large volume of power to New England during peak hours, which helps support flows from New England to New York.

Figure 30: Monthly Average Net Imports into New York City and Long Island
2009 – 2010

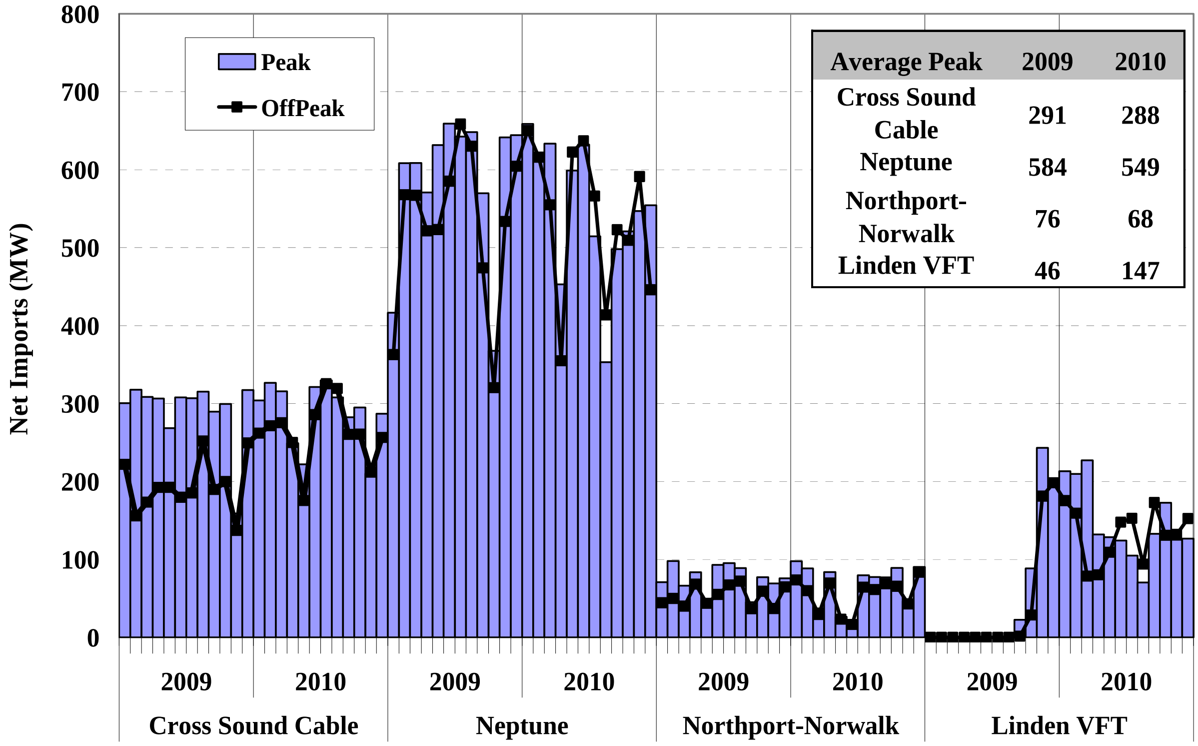


Figure 30 shows that a substantial share of the imports to New York State came directly to New York City and Long Island via four controllable interfaces. The Cross Sound Cable ("CSC"), which connects Long Island to Connecticut, is frequently used to import up to 330 MW to New York. Likewise, the Neptune Cable, which connects Long Island to New Jersey, is frequently used to import up to 660 MW to New York. The Northport-to-Norwalk line ("1385 Line"), which connects Long Island to Connecticut, is frequently used to import up to 100 MW.[34] The Linden VFT Line, which connects New York City to PJM with a transfer capability of 300 MW, began normal operation in November 2009.

Imports from neighboring control areas account for a large share of the supply to Long Island. The Cross Sound Cable, the 1385 line, and the Neptune Cable satisfied approximately 34 percent of the load in Long Island in 2010. Unlike the primary interfaces, the interchange over these direct interfaces was generally relatively consistent from month to month, and was slightly more during peak hours than during off-peak hours.

B. Lake Erie Circulation

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York. Loop flows generally moved around Lake Erie in a counter-clockwise direction in the several years prior to 2008. However, the prevailing direction of loop flows reversed at the beginning of 2008 when the phenomenon of circuitous transaction scheduling around Lake Erie became significant.[35] Although circuitous transaction scheduling was prohibited after July 2008, loop flows usually continue to flow in clockwise direction around Lake Erie due to the scheduling patterns of market participants in the surrounding ISOs.

34 The imports increased across the 1385 Line following an upgrade to the facility from 100 MW to 200 MW in May 2011.

35 Circuitous transactions are transactions that are scheduled from one control area to another along an indirect path when a more direct path exists. Circuitous transactions cause physical power flows that are not consistent with the scheduled path of the transaction. In 2008, the most commonly scheduled circuitous transaction (known as "Path 1 transactions") sourced in New York, wheeled through Ontario and the Midwest ISO, and sank in PJM. Path 1 transactions caused power to move directly from New York to PJM (i.e., in the clockwise direction around Lake Erie), although they financially settled as if they moved through Ontario and the Midwest ISO (i.e., in the counter-clockwise direction around Lake Erie). This inconsistency increased clockwise loop flows around Lake Erie. The NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. This issue was discussed in detail in the 2008 State of the Market report, August 2009, Potomac Economics.

Transmission Loading Relief ("TLR") procedure is used by the NYISO to curtail transactions when loop flows contribute significantly to congestion on its internal flowgates. This NERC Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. When a constraint is binding, the NYISO's real-time scheduling models manage its market flows over the constrained transmission facility by economically redispatching New York generation and by economically scheduling external transactions that source or sink in New York. If total loop flow accounts for a significant portion (i.e., more than 5 percent) of flow on a facility, the NYISO can invoke use the TLR procedure to ensure that external transactions that are not scheduled with the NYISO are curtailed to reduce flow over the constrained facility.

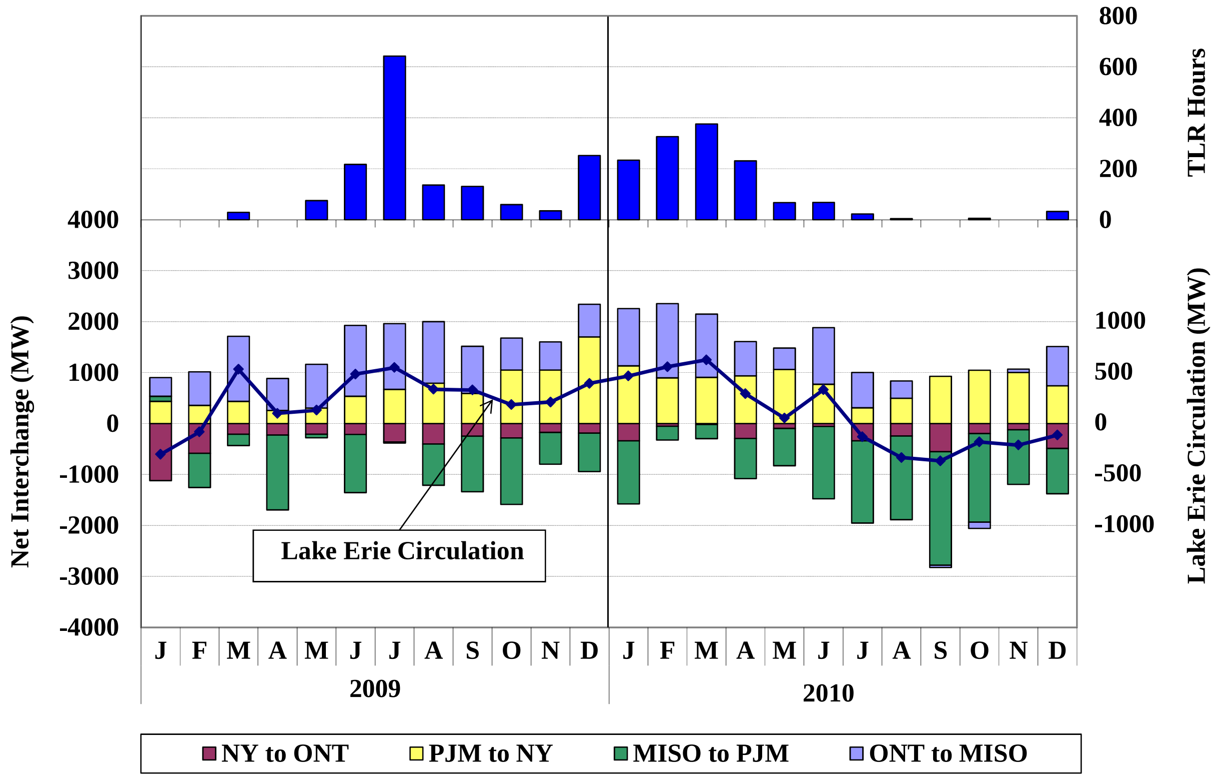
However, the TLR process manages congestion much less efficiently than optimized generation dispatch through LMP markets. The TLR process provides less timely system control and frequently leads to more curtailment than needed. These factors make curtailment of scheduled transactions through the TLR process less reliable than LMP markets for constraint management. Most external transactions that cause loop flows are not scheduled with the NYISO, so the only mechanism the NYISO currently has to address the congestion they cause is theTLR procedures it uses to curtail the transactions.

Figure 31 summarizes the pattern of loop flows around Lake Erie and the net scheduled interchange between the four control areas around the Lake Erie in each month in 2009 and 2010. The lower portion of the figure shows the monthly averages of: (i) actual real-time loop flows in the clockwise (or counter-clockwise, if negative) direction, indicated by the line, and (ii) actual real-time net interchanges between the NYISO, Ontario, PJM, and the MISO, represented by the bars. The upper portion of the figure shows the number of hours in each month when TLRs with Level 3a and above were called by the NYISO.[36]

[36] The following are six TLR levels defined in NERC procedures:

Level 1 – **Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations;
Level 2 – **Hold** transfers at present level to prevent SOL or IROL violation;
Level 3a - **Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority

Figure 31: Lake Erie Circulation
2009 –2010



The figure shows that although circuitous transactions were prohibited in July 2008, loop flows continued to move in a clockwise direction around Lake Erie in most months of 2009 and 2010, due partly to large volumes of transactions that were scheduled from Ontario to PJM via the Midwest ISO ("Ontario-to-MISO-to-PJM transactions"). Ontario-to-MISO-to-PJM transactions are not considered circuitous transactions because they are scheduled along the most direct path available between Ontario and PJM, which is counter-clockwise around Lake Erie. However, nearly half of the physical power flows clockwise around Lake Erie through the NYISO. As a

Transmission Service;
Level 3b - **Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation;
Level 4 - **Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue;
Level 5a - **Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point;
Level 5b - **Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation;
Level 6 – **Emergency Procedures**.

result, these transactions tend to increase congestion and losses through New York without paying congestion and loss charges to the NYISO.

Figure 31 also shows that average clockwise circulation around Lake Erie fell substantially in 2010, down 65 percent from 240 MW in 2009 to 85 MW in 2010. The overall reduction was caused by the decrease in clockwise circulation in the second half of 2010. Clockwise circulation averaged *negative* 222 MW (i.e., counter clockwise), compared to 388 MW (clockwise) in the first six months of 2010. This reduction was driven partly by a change in the scheduling patterns of market participants in the surrounding ISOs, including reduced scheduling from Ontario to MISO and increased scheduling from PJM to MISO.

Since transactions that cause loop flows are not scheduled with the NYISO, the only mechanism the NYISO currently has to address the congestion they cause is its TLR procedure, which allows the NYISO to curtail the transactions. The figure shows that TLRs were used frequently by the NYISO in 2009 and 2010. TLRs (Level 3a and above) occurred in approximately 1,365 hours in 2010, down 13 percent from 2009. The reduction was consistent with the reduction in clockwise circulation from 2009 to 2010. Likewise, 95 percent of TLRs in 2010 occurred in the first six months of the year when circulation around Lake Erie averaged more than 380 MW in the clockwise direction and only 5 percent occurred during the second half of the year when the prevailing direction of loop flows was in the counter clockwise direction.

The NYISO has been working with the other ISOs in the Broader Regional Market ("BRM") initiative to identify additional mechanisms to improve the efficiency of transaction scheduling between control areas around Lake Erie. One mechanism proposed in the BRM initiative (known as the "Buy-Through of Congestion" proposal) would augment the TLR process by allowing non-NYISO transactions (e.g., Ontario-to-MISO-to-PJM transactions) to pay NYISO congestion charges in order to avoid curtailment via the TLR process. We evaluated the potential benefits of this and other mechanisms identified in the BRM initiative in a previous report.[37]

[37] See *2009 State of the Market Report on the NYISO Electricity Markets* by Potomac Economics.

C. Price Convergence between New York and Adjacent Markets

The performance of New York's wholesale electricity markets depends not only on the efficient use of internal resources, but also on the efficient use of transmission interfaces between New York and neighboring control areas. Trading between neighboring markets tends to bring prices together as participants arbitrage price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. For example, when prices are higher in New York than in PJM, imports from PJM should continue until prices have converged or until the interface is fully scheduled. A lack of price convergence indicates that resources are being used inefficiently, as higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region. During peak demand conditions, it is especially important to schedule flows efficiently between control areas, because frequently a small amount of additional supply can substantially reduce prices.

This sub-section evaluates the efficiency of scheduling between New York and the adjacent ISO-run markets across interfaces with open scheduling.[38] ISO-run markets have real-time markets, which allow participants to schedule market-to-market transactions based on transparent price signals in each region. Based on the prevailing prices in each market, we can evaluate whether the interface is scheduled efficiently.

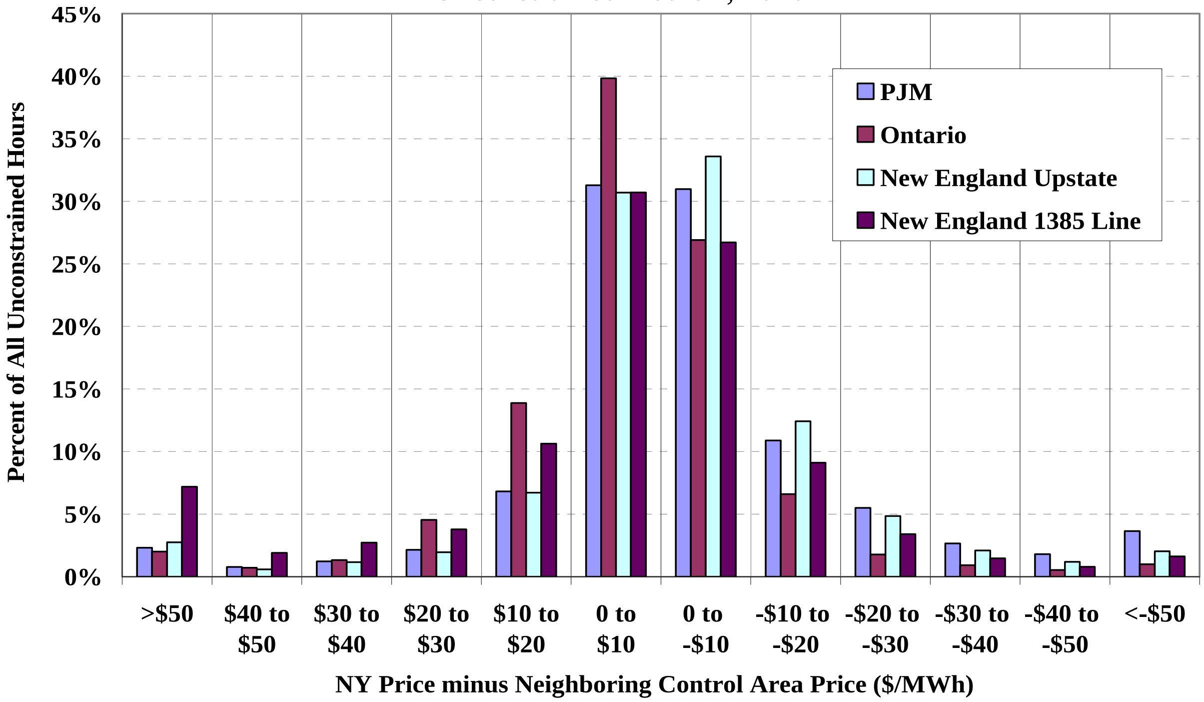
Figure 32 summarizes price differences between New York and adjacent ISOs during unconstrained hours across the four interfaces with open scheduling. The horizontal axis shows the range of price differences between New York and the adjacent control areas at the border. The heights of the bars represent the fraction of hours in each price difference category.

The results shown in the figure indicate that the current process does not maximize the utilization of the interfaces. While the price differences are relatively evenly distributed around $0, a substantial number of hours had price differences exceeding $10 per MWh for every interface. For each interface shown, the price difference between New York and the adjacent control area

[38] The Neptune Cable, the Linden VFT Line, and the Cross Sound Cable are omitted because alternate systems are used to allocate transmission reservations for scheduling on them.

exceeded $10 per MWh in 33 to 43 percent of the unconstrained hours during 2010. The Ontario results were slightly worse than the other interfaces and the price differences were skewed toward higher prices in New York and lower prices in Ontario.

Figure 32: RT Price Convergence Between NY and Adjacent ISO Markets
Unconstrained Hours[39], 2010



The large number of hours with significant price differences between regions indicates that additional efforts are needed to improve real-time interface scheduling between New York and adjacent control areas. Efficient scheduling is particularly important during shortages when flows between regions have the largest economic and reliability consequences. Moreover, efficient scheduling can also alleviate over-generation conditions that can lead to negative price spikes.

Several factors prevent real-time prices from being fully arbitraged. First, market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete

39 In these hours, there were no NYISO constraints that prevented scheduling. However, in some of these hours, there may have been constraints that prevented the other ISO from scheduling transactions or transaction curtailments.

arbitrage will not be possible. Second, differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage. Third, there are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants cannot be expected to schedule additional power between regions unless they anticipate a price difference greater than these costs. Last, the risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small. Given these factors, one cannot expect that trading by market participants alone will optimize the use of the interface.

D. Efficiency of External Interface Scheduling by Market Participants

The prior analyses show that it is difficult to achieve real-time price convergence with adjacent markets through the transaction scheduling of market participants. Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities. Furthermore, transaction costs from uplift allocations and export fees reduce or eliminate the expected profits from arbitrage.

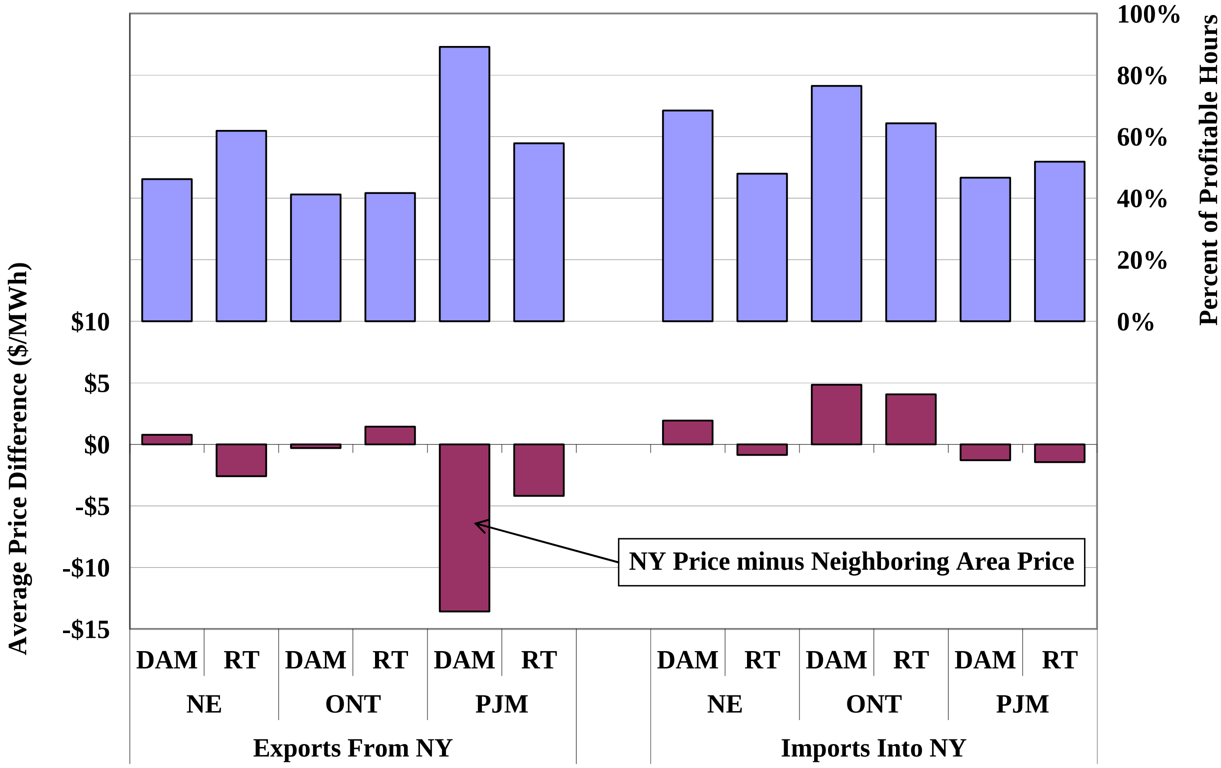
Although scheduling by market participants does not fully exhaust the potential benefits from using the interfaces between regions, Figure 33 and Figure 34 show that scheduling by market participants does improve price convergence between New York and the neighboring markets. Hence, reducing barriers to scheduling by market participants would likely result in more efficient scheduling between regions.

Figure 33 evaluates the consistency of the direction of external transaction scheduling and price differences across the primary interfaces between New York and New England, PJM, and Ontario in 2010. Hours when power was scheduled in the export direction are shown on the left and hours when power was scheduled in the import direction are shown on the right.

The upper portion of the figure reports the share of these hours when power was scheduled in the profitable direction (i.e., from the lower-priced market to the higher-priced market). If more than 50 percent of the hours are profitable, then the market schedules power to flow in the efficient direction in the majority of hours. The lower portion of the figure summarizes price differences between markets during these hours. It is efficient for New York to export in hours when the clearing price in New York is lower than in the adjacent area (i.e., the bar is negative), and to import when the clearing price in New York is higher (i.e., the bar is positive). This analysis separately evaluates: (i) day-ahead schedules and clearing prices (categorized by "DAM" on the horizontal axis), and (ii) incremental changes in schedules in the real-time market relative to the day-ahead schedules (categorized by "RT" on the horizontal axis).

Figure 33: Efficiency of Inter-Market Scheduling

Over Primary Interfaces – 2010



The upper portion of Figure 33 shows that power was scheduled in the profitable direction in more than half of all hours for 7 of the 12 categories of transactions shown on the horizontal axis. Although transactions flowed in the profitable (i.e., efficient) direction in the majority of hours, there were still a large share of hours when power flowed inefficiently from the high-priced market to the low-priced market. Individual categories of transactions were unprofitable in 11 percent (for DAM exports to PJM) to 59 percent (for DAM exports to Ontario) of hours.

The lower portion of the figure shows for most of the categories on the horizontal axis that the average clearing price was lower at in New York when exports were scheduled and higher in New York when imports were scheduled. These results indicate that participants generally responded to price differences by increasing net flows scheduled into the higher-priced region, although it is generally difficult to predict the profitable scheduling direction.

To better understand why the prices in adjacent markets were not more effectively arbitraged, we next evaluate the potential effects of the lead time for transaction scheduling. Currently, to schedule external transactions, market participants must submit their offers 75 minutes before the start of an hour, which is 75 to 135 minutes before the power actually flows (since transactions are scheduled in one-hour blocks at the top of the hour). The lead time of as much as 135 minutes may contribute to participants' inability to fully arbitrage the difference in prices between adjacent markets.

The following analysis examines the correlation between the lead times for scheduling transactions and the predictability of price differences between New York and adjacent markets. Figure 34 shows the correlation coefficient between the current five-minute price difference between New York and an adjacent market and the actual differences that occurred up to 90 minutes earlier.

Figure 34: Correlation of Price Differences Between Markets to Lead Time

Primary Interfaces with Adjacent Markets - 2010

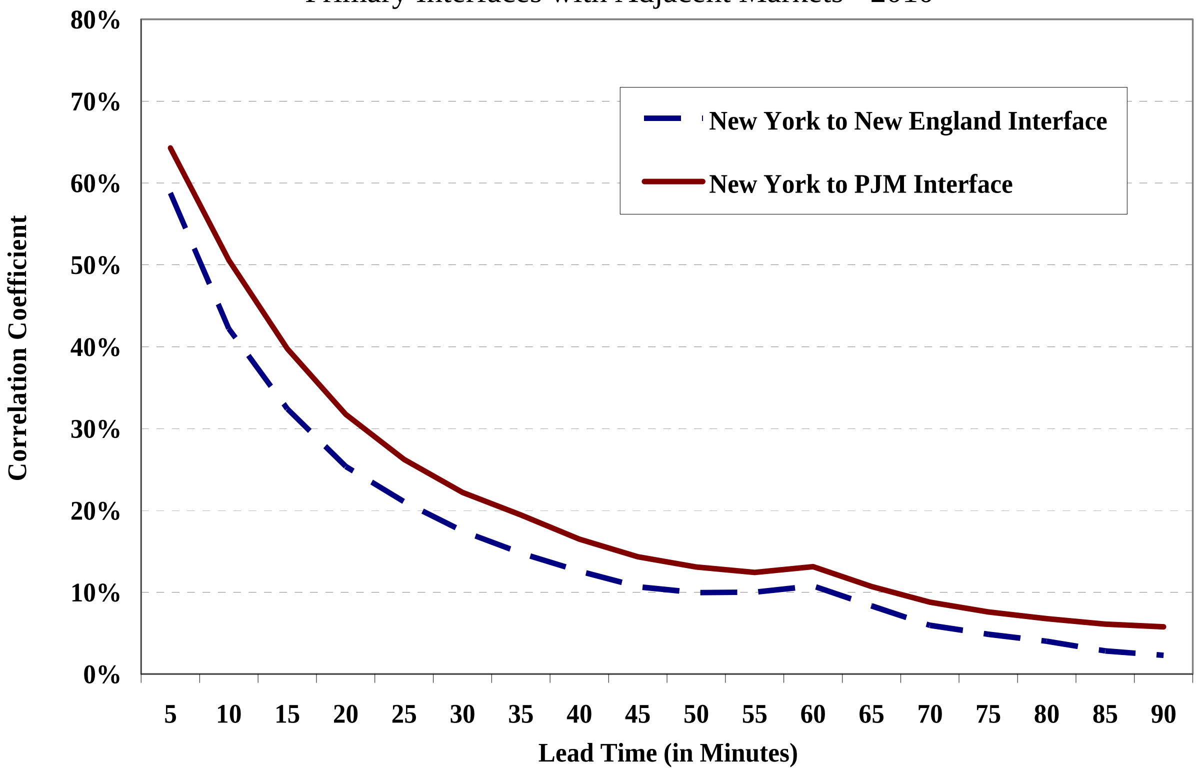


Figure 34 shows that the correlation coefficient increases as lead time is reduced, indicating that actual price differences were more strongly correlated to price differences in periods near in time than to price differences in periods more distant in time. The analysis may underestimate the predictability of price differences between control areas because participants can use more sophisticated techniques for forecasting, as well as make use of the economic evaluation of transactions by RTC.

Nonetheless, the correlation coefficient was still less than 25 percent for a 30 minute lead time at New York's primary interfaces with PJM and New England. Since 30 minutes is the shortest scheduling time used currently by any of the markets, the results of the analysis suggest that shortening lead times for scheduling would likely capture only a modest share of the available benefits from utilizing the external interfaces more efficiently.

The two previous analyses show that scheduling by market participants generally improved the efficiency of power flows between markets by allowing power to flow from the lower-priced region to the higher-priced region, although substantial improvement is possible. Hence, we continue to recommend that the NYISO modify its market design to achieve more efficient interchange with adjacent markets. This can be accomplished by coordinating its interchange with adjacent markets based on the prevailing real-time price in each area (e.g., adjusting the interchange based on a much shorter timeframe to increase the flow from the lower-priced market to the higher-priced market). This and other similar enhancements are being considered and evaluated in the NYISO and its neighboring markets. We evaluate some of the potential benefits from improved interchange in the next sub-section.

E. Coordination of Interchange by the ISOs

Incomplete price convergence between New York and New England suggests that more efficient scheduling of flows between markets would lead to production cost savings and substantial benefits to consumers. Although past efforts to reduce barriers to market participant scheduling between regions have improved the efficiency of flows and additional such efforts would lead to further improvements, uncertainty and risk are inherent in the market participant scheduling process. Hence, even with improvements, one cannot reasonably expect the current process to fully utilize the interface. As is the case for efficient scheduling of the transmission capability within ISO regions, optimal use of transmission capability between ISO regions requires explicit coordination of interchanges between the ISOs.

In July 2010, New York ISO and ISO New England commenced a joint effort known as the Inter-Regional Interchange Scheduling ("IRIS") project to address the issue of inefficient scheduling between the two markets. The RTOs proposed two solution options: 1) Tie Optimization; and 2) Coordinated Transaction Scheduling. The remainder of this sub-section summarizes our assessment of the benefits of two initiatives to improve the efficiency of the interchange between the New York and New England.

1. Benefits Study Approach

The efficiency benefits that would result from these proposals are best measured by their effect on production costs in the two regions, which reveals the true net economic savings of the proposals. Price differences between regions are reduced by scheduling power from the lower-priced market to the higher-priced market. As lower-cost resources in one market displace higher-cost resources in the adjacent market, total production costs are reduced and the savings are equal to the cost difference between the resources in the two markets. In this way, aggregate production costs fall as price convergence improves.

The estimated production cost savings naturally tend to be smaller than estimated consumer net savings resulting from energy price changes in each market. In most cases, a small quantity of lower-cost generators in one area displaces a small quantity of higher-cost generators in the other area, which results in modest production cost savings. Since the consumption of energy far exceeds the quantity of high-cost generation that is displaced by lower-cost generation, the estimated consumer net savings associated with the energy price changes tend to be much larger than the production cost savings.

Our previous assessments have consistently found that coordinating the interchange between ISOs would lead to significant reductions in both production costs and consumer costs.[40] The

[40] See *2009 State of the Market Report on the NYISO Electricity Markets* by Potomac Economics.

previous assessments estimated the benefits that would result from *optimal* scheduling of the interfaces between the markets. However, the share of the potential benefits that are ultimately realized depends on the effectiveness of the market solutions that are implemented by the ISOs. The assessment described in this sub-section builds on prior assessments by estimating the benefits of specific proposals for coordinating the interchange between the ISOs.

The ISOs are currently evaluating specific proposals that will improve, but not perfectly optimize the interchange due to uncertainties present at the time the interchange is determined. The results discussed in this sub-section compare the benefits from optimal scheduling to the benefits that would result from the two proposals put forward by the RTOs under the IRIS project:

- *Tie Optimization* – The ISOs exchange information 15 minutes in advance and optimize the interchange based on a prediction of market conditions. The interchange would be adjusted every 15 minutes.
- *Coordinated Transaction Scheduling ("CTS")* – Identical to Tie Optimization, except the interchange schedule is only adjusted to the extent that market participants submit intra-hour Interface Bids priced below the predicted price difference between markets.

2. Modeling Assumptions

To quantify the share of potential benefits that would be captured by each proposal, we performed the simulations using three sets of assumptions:

- *Ideal Interchange Case* – Assumes the interchange is adjusted to the optimal level based on perfect information. The adjustment in interchange increased toward the higher-priced market until: (i) the interface is fully loaded, (ii) internal constraints prevent additional redispatch, or (iii) the adjustment reaches 500 MW relative to the actual interchange that occurred in real-time.
- *Tie Optimization Case* – Assumes the interchange is adjusted to the forecasted optimal level. The ISOs' forecast may differ from actual conditions, so the resulting interchange may not be optimal. The following forecasts are used for this study:
  - On the NYISO side of the border, the forecast is based on the latest available advisory prices that are produced by its dispatch model ("RTD").
  - On the ISO-NE side of the border, the forecast is based on its hour-ahead forecast model. The forecast errors on the ISO-NE side are larger, which is understandable given that the ISO-NE forecast is performed further in advance than the NYISO forecast. Hence, we assumed the ISO-NE errors would fall by 50 percent to account for the effects of shortening the timeframe.

- *Coordinated Transaction Scheduling Cases* – This is the same as the Tie Optimization Case, except an assumed interface "bid stack" limits redispatch when the marginal bid exceeds the forecasted price difference. We assumed an interface bid stack beginning at zero and rising linearly up to $10 at 500 MW in the first case ("Int Bid1"), and rising linearly to $40 at 500 MW in the second case ("Int Bid2").

Comparing the results of these simulations allows us to evaluate the efficiency of specific proposals compared to ideal interchange scheduling. The simulations discussed in this section differ from the simulations used in previous assessments in the following respects:

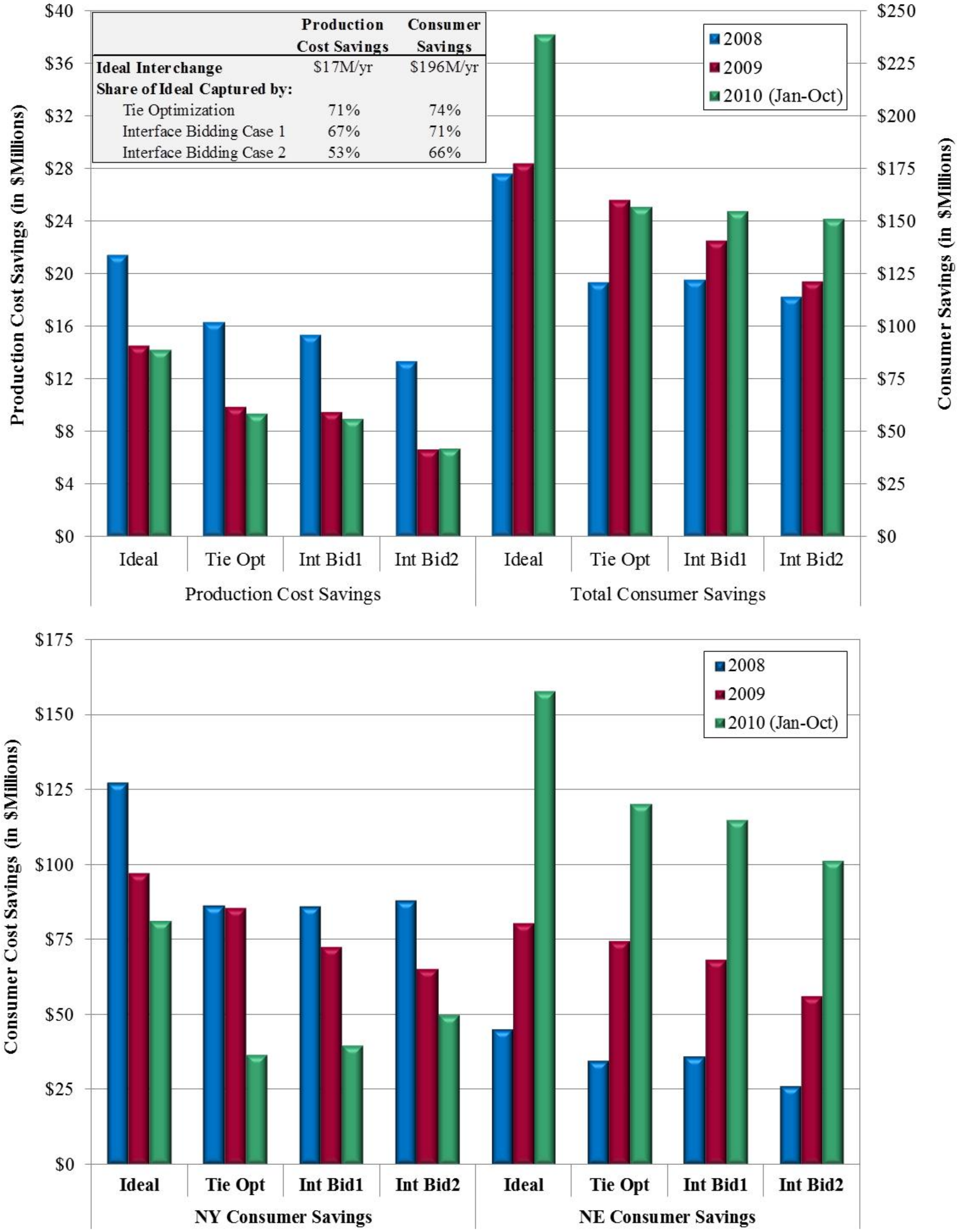
- These simulations use 15-minute interval level data, while previous assessments estimated the optimal interchange using historic hourly-integrated real-time data. Hourly data resulted in conservative estimates because it assumed one interchange value for the hour. It is usually efficient to adjust the interchange throughout the hour.
- These simulations impose a 500 MW limit on the size of the adjustment in the interchange in any interval relative to the actual interchange, while the previous simulations had no limit. We use the 500 MW limit to be conservative because the simulation model does not "see" internal transmission constraints that would bind due to the interchange adjustment.
- We exclude intervals when the NYISO price is negative, since these are likely to become far less prevalent after the NYISO implements several market design changes in 2011.
- These simulations exclude intervals at the top of each hour. These intervals are frequently affected by ramp constraints and other conditions that lead to transient price spikes which our simulation model is not designed to model accurately. Hence, we conservatively estimate $0 production cost savings from these intervals, although it is likely that the interchange would be improved in these intervals.

Both the simulations presented in previous reports and this report use simplified network models that assume interchange adjustments are not possible if they would exacerbate congestion on active transmission constraints. This is conservative because redispatch would be possible in some such cases, and so there may be significant additional savings that we do not capture.

3. Simulation Results

The following figure and table summarize the estimated effects of the two proposals to optimize the interchange between New York and New England. Figure 35 summarizes the production cost savings and consumer savings that would result under each proposal as well as under optimal interchange. The figure also summarizes the distribution of consumer savings between the two ISOs in each of the cases that we analyzed.

Figure 35: Estimated Benefits from Coordinating the Interchange with New York
January 2008 – October 2010



The average production cost savings in the Ideal Interchange Case is roughly $17 million per year, although this is likely conservative as a long-run expectation because: (i) one quarter of the hour is not included; (ii) the supply and demand conditions in both areas were not as tight as they are likely to be in the long run, causing shortages to be relatively infrequent; and (iii) natural gas prices were relatively low for much of this period.

The results indicate that a large share of the potential benefits would be captured by the two proposals for implementation. The Tie Optimization Case captures 71 percent of the efficiency benefits. The CTS Case with lower-priced bids performed nearly as well as the Tie Optimization Case, capturing 67 percent of the potential efficiency benefits. The second CTS case with higher-priced bids captured 53 percent of the efficiency benefits from the Ideal Interchange Case. It is difficult to predict how market participants would bid under CTS, but the bid assumptions used in the simulations are most likely far above the bids that market participants would actually submit, so it is likely that CTS would perform nearly as well as Tie Optimization.

Figure 35 shows that consumer savings in the ideal case average almost $200 million per year, which is conservative for the same reasons as listed above. Nearly three-quarters of the savings are captured by Tie Optimization, which falls only slightly to 71 percent with low-priced interface bids. The figure shows that the consumer savings accrue to both areas, although the relative savings has shifted year-to-year as congestion patterns and supply conditions have changed.

Table 2 provides statistics summarizing the estimated changes in market outcomes in each of the cases that we analyzed. It indicates how frequently flow would be adjusted towards New York and towards New England. It summarizes the average size and the average price impact on each side of the border from these adjustments. This information is provided for the Ideal Interchange, Tie Optimization, and Coordinated Transaction Scheduling Cases.

Table 2: Simulated Effects from Coordinating the Interchange with New York
January 2008 – October 2010

	Ideal Interchange				Tie Opt	Int Bid 1	Int Bid 2
	2008	2009	2010	2008-10	2008-10	2008-10	2008-10
Flow Adjusted Into NY (% of intervals)	42%	46%	44%	44%	43%	43%	43%
Flow Adjusted Into NE (% of intervals)	41%	44%	45%	43%	42%	42%	42%
When Flow Adjusted Into NY:							
Avg. Adjustment (MW)	266	259	265	264	262	186	101
Avg. System LBMP Change in NY ($/MWh)	-$10.63	-$7.19	-$7.07	-$8.30	-$8.24	-$7.11	-$5.64
Avg. System LMP Change in NE ($/MWh)	$7.00	$2.96	$3.39	$4.45	$4.84	$3.95	$2.75
When Flow Adjusted Into NE:							
Avg. Adjusted Interchange (MW)	-226	-220	-237	-228	-210	-153	-89
Avg. System LBMP Change in NY ($/MWh)	$7.96	$4.36	$4.83	$5.72	$6.73	$5.62	$4.14
Avg. System LMP Change in NE ($/MWh)	-$8.21	-$4.93	-$7.43	-$6.86	-$6.88	-$5.87	-$4.39

Table 2 shows that in each year, the adjustments would occur relatively evenly in both directions, contributing to consumer savings in both areas each year. Moreover, the average real-time price effect is larger when flow is adjusted in the import direction than when it is adjusted in the export direction for each ISO. This is why the simulations presented in previous reports and in this report have consistently found that average annual consumer costs would be reduced on both sides of the border. Consumers in both areas would benefit from lower average prices because prices generally decrease more in the high-price area than they rise in the low-price area. This result is due to the nonlinear shape of the supply curve in electricity markets, which causes prices to be more responsive to changes in interchange at higher price levels than at lower prices levels.

4. Conclusions of Benefits Study

The results of the simulations show sizable efficiency and consumer savings in all cases analyzed, which supports the ISOs' initiative to pursue the Inter-Regional Interchange Scheduling project. For the reasons we have discussed, these savings are likely to be conservative and would be larger under tighter supply/demand conditions over the long-run. The estimated savings are large, so this initiative should be a high priority. While the Tie Optimization proposal performed better in our simulations than the Coordinated Transaction Scheduling proposal, the benefits are very similar if participants submit relatively low-cost interface bids. Therefore, we would support either alternative.

F. External Transactions – Conclusions and Recommendations

Efficient use of transmission interfaces between regions allows customers to be served by external resources that are lower-cost than available native resources. New York imports substantial amounts of power from PJM, Quebec, Ontario, and New England, which reduces wholesale power costs for electricity consumers in New York. In 2010, the NYISO imported an average of over 3 GW during peak hours (i.e., Monday through Friday, 6 am to 10 pm).

The pattern of loop flows around Lake Erie has a significant effect on power flows and congestion management in New York. The volume of clockwise loop flows around Lake Erie became significant in recent years, increasing congestion and uplift associated with these loop flows, although these effects were reduced in 2010 as the average net volume of clockwise loop flows around Lake Erie fell from 240 MW in 2009 to 85 MW in 2010. Nonetheless, the rise of clockwise loop flows in recent years has highlighted the importance of efforts to manage the congestion created by unscheduled loop flows more efficiently.

Our evaluation of external transactions between New York and three adjacent ISO-run markets indicates that scheduling by market participants did not fully use the external interfaces or achieve all of the potential benefits available from inter-regional trading. Improving the efficiency of flows between regions is particularly important during shortages or very high-priced periods when modest adjustments to the physical interchange can reduce prices significantly. We find that the external transaction scheduling process was functioning properly and that scheduling by market participants tended to improve convergence, but significant opportunities remain to improve the interchange between regions.

In July 2010, New York ISO and ISO New England commenced a joint effort known as the Inter-Regional Interchange Scheduling project to address the issue of inefficient scheduling between the two markets. We compared the benefits from optimal scheduling to the benefits that would result from the two proposals put forward by the RTOs: 1) Tie Optimization; and 2) Coordinated Transaction Scheduling. Our analyses indicate that the potential production cost savings is roughly $17 million annually when assuming optimal interchange based on perfect information. The study also indicated that a large share of the potential benefits would be captured by either of the two proposed solutions. While the Tie Optimization proposal performed slightly better in our simulations than the Coordinated Transaction Scheduling proposal, the benefits are very similar if participants submit relatively low-cost interface bids. Therefore, we support either alternative.

In addition to improving the interface utilization with New England, the NYISO is working on several other initiatives to improve the use of the interfaces between ISOs (and RTOs). These include:

- More frequent scheduling with PJM and Hydro Quebec (every 15 minutes) in the near term (until more comprehensive solutions can be implemented);
- Coordinating the interchange with PJM using a solution similar to Tie Optimization or Coordinated Transaction Scheduling;
- Dispatching the Hydro Quebec interface on a 5-minute basis like a generator; and
- Coordinating congestion management with PJM and ISO New England.

We recommend that the NYISO continue to place a high priority on these initiatives, particularly the interface utilization initiative because it offers the highest benefit.

V. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the load. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

The day-ahead market is a forward market that facilitates financial transactions among participants. The NYISO allows market participants to schedule transactions in the day-ahead market based on the predicted transmission capacity, resulting in congestion when some bids to purchase and offers to sell are not scheduled in order to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales in the day-ahead market based on the congestion component of the LBMP. Bilateral transactions scheduled through the ISO are charged the difference between the LBMPs of the two locations (i.e. the price at the sink minus the price at the source).

Market participants can hedge congestion charges in the day-ahead market by owning TCCs, which entitle the holder to payments corresponding to the congestion charges between two locations. A TCC consists of a source location, a sink location, and a quantity (MW). For example, if a participant holds 150 MW of TCC rights from point A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and location A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the points.

Transactions not scheduled in the day-ahead market are assessed real-time congestion charges. As in the day-ahead market, charges for bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract. For real-time spot market transactions, the congestion charge is paid by the purchaser through the congestion component of the LMP. There are no TCCs for real-time congestion since most power is scheduled through the day-ahead market.

This section evaluates three aspects of transmission congestion and locational pricing:

- *Congestion Revenue and Shortfalls* – We evaluate the congestion revenues collected by the NYISO from the day-ahead market, as well as the congestion revenue shortfalls in the day-ahead and real-time markets and identify major causes of these shortfalls.
- *Congestion on Major Transmission Paths* – This analysis summarizes the frequency and value of congestion on major transmission paths in the day-ahead and real-time markets.
- *TCC Prices and Day-Ahead Market Congestion* – We review the consistency of TCC prices and day-ahead congestion, which determine payments to TCC holders.

A. Congestion Revenue and Shortfalls

Day-ahead congestion revenues are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market. The revenue collected is equal to the marginal cost of relieving the constraint (i.e., constraint shadow price) in the day-ahead market multiplied by the scheduled flow across the constraint in the day-ahead market.[41, 42]

Day-ahead congestion shortfalls occur when day-ahead congestion revenues collected by the NYISO are less than entitlements of TCC holders. Shortfalls arise when the quantity of TCCs sold on a path exceeds the transfer capability of the path modeled in the day-ahead market when it is congested.[43] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues.

Balancing congestion shortfalls occur when day-ahead scheduled flows over a facility exceed what can flow over the facility in real-time.[44] To reduce flows in real-time below the day-ahead schedule, the ISO must increase generation on the import-constrained side of the constraint and

41 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

42 For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000 in that hour (100 MW * $50/MWh).

43 For example, suppose 120 MW of TCCs are sold across a particular line. If 100 MW is scheduled to flow when the constraint has a shadow price of $50/MWh in an hour in the day-ahead market, the NYISO will have a day-ahead congestion shortfall of $1,000 in that hour ((120 MW – 100 MW) * $50/MWh).

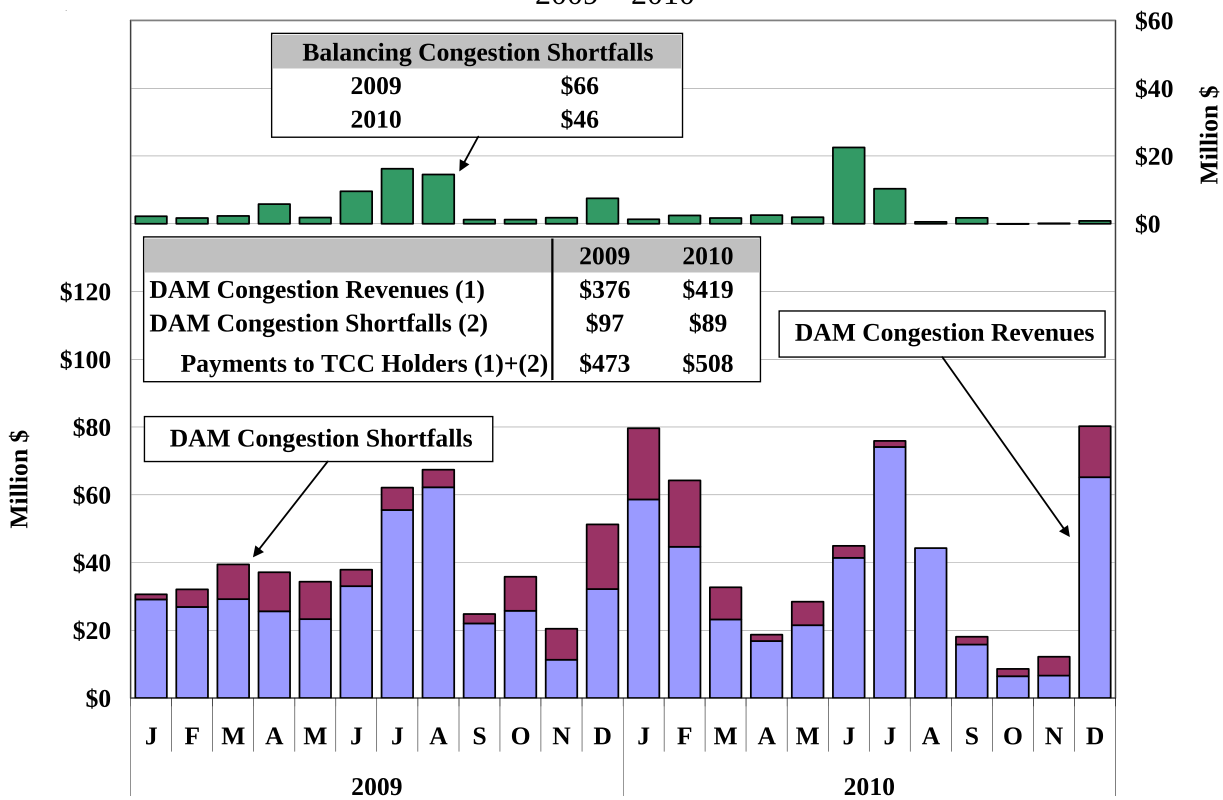
44 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $70/MWh).

reduce generation on the export-constrained side of the constraint. These redispatch costs (i.e., the difference between the LBMPs in the two areas) is the balancing congestion shortfall that is recovered through uplift. This sub-section summarizes and discusses: day-ahead congestion revenues, day-ahead congestion shortfalls, and balancing congestion shortfalls.

1. Summary of Congestion Revenue and Shortfalls

Figure 36 summarizes day-ahead congestion revenue, day-ahead congestion shortfalls, and balancing congestion shortfalls in each month in 2009 and 2010. The upper portion of the figure shows balancing congestion revenue shortfalls. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month. The tables in the figure report these categories on an annual basis.

Figure 36: Congestion Revenue and Shortfalls
2009 – 2010



Balancing congestion shortfalls fell 30 percent from $66 million in 2009 to $46 million in 2010, largely due to lower shortfalls during TSA events. During TSA events, balancing congestion shortfalls fell from $50 million in 2009 to $34 million in 2010, which we attribute primarily to improved operations. In July 2010, the NYISO made operational improvements to better recognize the effects of imports on congestion management in the real-time transaction scheduling process. Other factors contributed to the reduction in shortfalls, including less frequent use of simplified interfaces into New York City load pockets in the real-time market, and reduced circulation around Lake Erie in the clockwise direction.

Figure 36 also shows that day-ahead congestion revenue by the NYISO were $419 million in 2010, up 11 percent from 2009. The increase was due primarily to: a) higher fuel prices that generally increase the redispatch costs to manage west-to-east congestion in New York; and b) higher load levels that generally typically increase transmission flows into import-constrained areas, particularly during the summer months. However, the reduction in clockwise loop flows around Lake Erie helped offset these increases in congestion.

The figure also shows that day-ahead congestion revenue and balancing congestion shortfalls rose during the summer months, reflecting that both categories are affected by the higher summer load levels and more frequent TSAs. TSAs in particular generally lead to higher balancing congestion shortfalls because the NYISO is required to operate the transmission system more conservatively during these events.

Finally, the figure shows that day-ahead congestion shortfalls were lowest in the summer months (i.e., June to August). These months accounted for only 5 percent of the day-ahead congestion shortfall in 2010. This is typical because transmission outages (that are modeled in the day-ahead market but not in the TCC auctions) are less frequent in summer months.

2. Day-Ahead Congestion Revenue Shortfalls

Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion. Similarly, surpluses occur when the quantity of TCCs sold for a path is less than the transfer capability of the path in the day-ahead market during periods of congestion. The NYISO minimizes day-ahead congestion revenue surpluses and shortfalls by offering TCCs in the forward auction that reflects the expected transfer capability of the system.

In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantity of TCCs that are offered by the NYISO.

The NYISO determines the quantity of TCCs to offer in a TCC Auction by modeling the transmission system to ensure that the TCCs sold are simultaneously feasible. The NYISO uses a power flow model that includes an assumed configuration of the transmission system. The simultaneous feasibility condition requires that the TCCs awarded be feasible in a contingency constrained economic dispatch of the NYISO transmission system. If this condition is satisfied, the congestion revenues collected should be sufficient to fully fund awarded TCCs. However, if transmission outages occur that were not modeled in the TCC auction or the assumptions used in the TCC auctions are otherwise not consistent with the assumptions used in the day-ahead market, the congestion revenues collected may be insufficient to meet TCC obligations.

Figure 37 shows the monthly day-ahead congestion revenue shortfalls by transmission path or facility in 2010. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure 37: Day-ahead Congestion Shortfalls by Transmission Path

2010

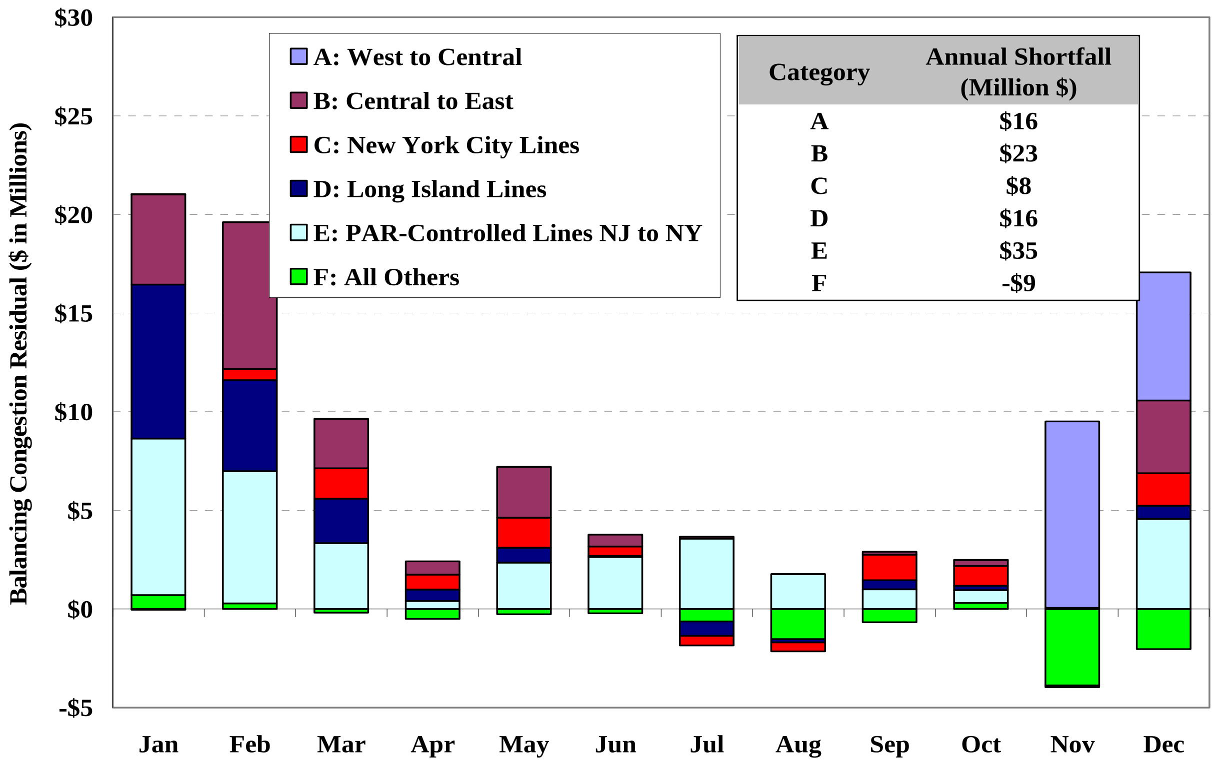


Figure 37 shows that the West to Central and Central to East paths accounted for 43 percent of the total day-ahead congestion revenue shortfalls in 2010. These paths exhibited substantial day-ahead congestion revenue shortfalls in some months (e.g., January, February, November, and December 2010) when the paths were frequently congested. This suggests that the transfer capability between regions in the day-ahead market was consistently lower than the amount of TCCs sold between regions during these months. Two factors led to reduced transfer capability on paths from west-to-east.

First, transmission outages were frequently reflected in the day-ahead market but not in the TCC auctions, reducing transfer capability in the day-ahead market below the assumed capability in the TCC auctions. For example, significant outages on the interface between Ontario and New York occurred in November and December of 2010, which were reflected in the day-ahead market but not in the corresponding TCC auctions. This contributed to the large shortfalls across the paths from West to Central in the two months.[45] The NYISO has a process for attributing day-ahead congestion revenue shortfalls to outages that allow the shortfalls to be allocated to specific transmission owners. Under this process, 37 percent of the day-ahead congestion revenue shortfalls were charged to specific transmission owners in 2010.[46] Transmission owners can avoid allocations of day-ahead congestion revenue shortfalls from specific outages by electing to incorporate them in the TCC auction assumptions. However, planned outages usually last for only a portion of a six-month capability period, so incorporating them in the TCC auction assumptions would lead the NYISO to under-sell TCCs during the portion of the six-month capability period when the facility is in service. Thus, there may be some benefit in selling a portion of the transmission capability in TCC auctions for more granular periods than six months (e.g., one month). This would allow the NYISO to vary the TCC auction assumptions within a six-month capability period to better reflect the effects of outages on the capability of the system.

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45 Outages on the interface between Ontario and New York increase flows across certain transmission lines in the West Zone. Rather than explicitly model these transmission lines in the day-ahead and real-time markets, the NYISO secures them by modeling interface constraints such as the West-Central interface.

46 The portion of day-ahead congestion revenue shortfalls that were charged to specific transmission owners for equipment outages and derates was 43 percent in 2008 and 34 percent in 2009.

Second, there were significant differences in modeling assumptions between the TCC auctions and the day-ahead market regarding the commitment status of individual generators. The commitment status of some generators affects the transfer capability of the transmission system, particularly the Central-East interface. The voltage transfer limit of the Central-East interface is affected by the commitment of generation in the Central Zone, fluctuating by as much as 300 MW depending on the commitment.[47] The relatively large shortfalls on the Central-East interface from January to March were partly driven by these differences.

Flows over PAR-controlled lines can either relieve or exacerbate congestion, so differences in PAR assumptions between the TCC auctions and the day-ahead market can result in day-ahead congestion shortfalls. The figure shows that the differences on PAR-controlled lines between New Jersey and New York (i.e., Waldwick, Ramapo, Farragut, and Linden) accounted for a significant portion (39 percent) of the total shortfalls during 2010. We expect much smaller contributions from the differences in PAR assumptions to the day-ahead congestion shortfalls starting in May 2011. This is because the modeling inconsistencies related to these PAR-controlled lines were addressed in the Spring 2011 TCC auctions.

The figure also shows that Long Island accounted for 18 percent of total day-ahead congestion shortfalls, most of which accrued in January and February. This was primarily due to the outage of the Sprainbrook-to-East Garden City line, one of the two 345kV lines connecting Long Island to Up-State New York. Since the outage was reflected in the assumptions used in the day-ahead market, day-ahead transfer capability was much lower than assumed in the TCC auctions.

3. Balancing Congestion Revenue Shortfalls

Balancing congestion revenue shortfalls arise when day-ahead scheduled flows across a particular line or interface exceed its real-time transfer capability. When this occurs, the ISO must redispatch in real time by purchasing additional generation in the import-constrained area (where real-time prices are high) and selling back energy in the export-constrained area (where

[47] See "http://www.nyiso.com/public/markets_operations/market_data/reports_info/index.jsp" The 300 MW range of variation assumes that all three Fitzpatrick and Nine Mile nuclear units are online. If one of the nuclear units is out-of-service, the Central-East interface limit may fluctuate by as much as 510 MW depending on the commitment of other generators in the Central Zone.

real-time prices are low). The net cost of this redispatch is collected from loads through uplift charges, most of which is allocated to load throughout the state. However, a portion associated with facilities that require special operation during TSA events is charged to Consolidated Edison whose customers benefit most directly from the additional reliability.

This sub-section summarizes balancing congestion revenue shortfalls and identifies significant contributing factors in 2010. Balancing congestion revenue shortfalls occur when the available transfer capability of a line or interface changes between day-ahead and real-time. Such changes can be related to:

- *Deratings and outages of transmission lines* – When these occur after the day-ahead market, they reduce the transfer capability of relevant transmission interfaces or facilities. They may also change the size of the largest contingency relative to a particular transmission interface or the distribution of flows over the transmission system, thereby reducing the available transfer capability of other transmission facilities.

- *Constraints not modeled in the day-ahead market* – Reliability rules require the NYISO to reduce actual flows across certain key interfaces during TSA events. Since TSA events are not modeled in the day-ahead market, they generally result in reduced transfer capability between the day-ahead market and real-time operation. So does the imposition of simplified interface constraints in New York City load pockets in the real-time market that are not modeled comparably in the day-ahead market.

- *Hybrid Pricing* – This methodology treats physically inflexible gas turbines as flexible in the pricing logic of the real-time market model. Differences between the physical dispatch logic and the pricing logic can lead to unutilized transfer capability on interfaces that are congested in real time, leading to balancing congestion revenue shortfalls.

- *PAR Controlled Line Flows* – the flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces.

- *Unscheduled loop flows* – loop flows from other regions use a portion of the transmission capability across many interfaces in New York, reducing the portion of transmission capability available to the NYISO market in the direction of the loop flows. A balancing congestion revenue shortfall occurs when the loop flows assumed in the day-ahead market are lower than the actual loop flows on congested interfaces in real time.

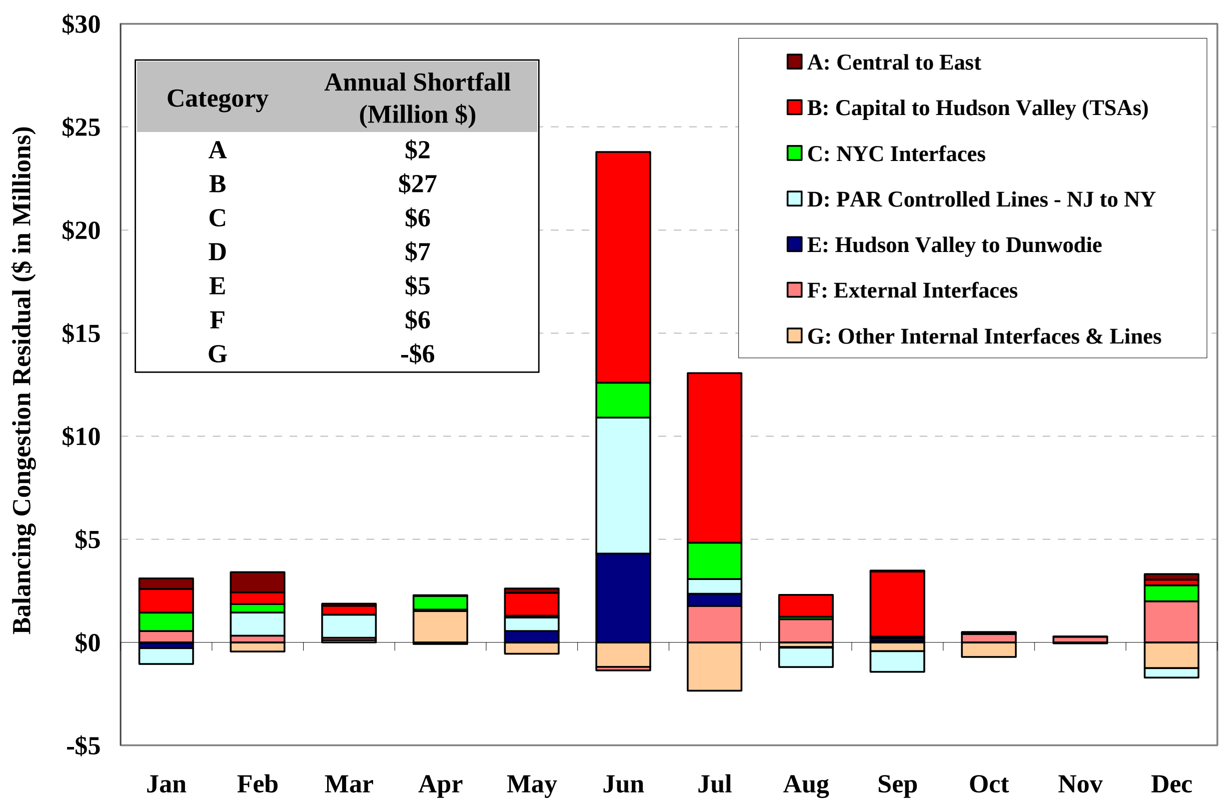
Figure 38 provides monthly detail on significant categories of balancing congestion shortfalls in 2010.[48] Positive values in the figure indicate balancing congestion shortfalls while negative

[48] Note that the actual net balancing congestion revenue shortfalls were $3 million lower than those shown in the figure because the figure excludes the following items (some of which generated balancing congestion

values indicate balancing congestion surpluses. This figure shows the balancing congestion shortfalls for the following paths or types of constraints:

- Central-East interface;
- Lines from Capital to Hudson Valley (primarily during TSA operations);
- Simplified New York City load pocket interfaces;
- PAR-controlled lines between New Jersey and New York, including Waldwick, Ramapo, Farragut, and Linden lines;
- Lines from Hudson Valley to Dunwoodie;
- Other internal interfaces and line constraints; and
- External interfaces.

Figure 38: Balancing Congestion Shortfalls by Transmission Path
2010



Category	Annual Shortfall (Million $)
A	$2
B	$27
C	$6
D	$7
E	$5
F	$6
G	-$6

surpluses in 2010): (i) differences between the generators' base-points (used in our analysis) and their actual output levels (which determine financial settlements) during each interval; (ii) differences between the amount of load scheduled by RTD (used in our analysis) and the amount of actual metered load (which determines financial settlements) during each interval; and (iii) balancing congestion revenue surpluses for certain interfaces that had unused transfer capability in the day-ahead market.

The Capital to Hudson Valley lines accounted for $27 million (or 56 percent) of balancing congestion shortfalls during 2010, the most among all listed categories. This occurred primarily during TSAs events, which require double contingency protection of the Leeds-to-Pleasant Valley line and other facilities into Southeast New York. This effectively reduces the real-time transfer capability into Southeast New York.

The PAR-controlled lines between New Jersey and New York (Waldwick, Ramapo, Farragut, and Linden) accounted for 14 percent of balancing congestion revenue shortfalls, mostly during TSA events. TSAs may suddenly require generators in Southeast New York to increase production before the PAR-settings can be adjusted accordingly. This reduces net flows into NYCA across the PAR-controlled lines, which results in a revenue shortfall. The related shortfalls decreased from previous years, due largely to improved operations during TSA events since late July 2010. NYISO operations now better recognizes the effects of imports on congestion management in the real-time transaction scheduling process, including how imports affect the flows across the PAR-controlled lines. Reduced clockwise circulation around Lake Erie also contributed to the decrease in shortfalls, since clockwise circulation tends to reduce net flows into NYCA across the PAR-controlled lines.

The simplified interface constraints in New York City accounted for $6 million (or 13 percent) of the balancing congestion revenue shortfalls in 2010. Compared with the more detailed transmission modeling in the day-ahead market, using simplified interface constraints in the real-time market generally results in reduced transfer capability in New York City. Congestion across the Greenwood/Staten Island interface constraint accounted for most of the shortfall. The shortfall in this category was substantially reduced relative to previous years partly because the simplified interface constraints were used less frequently. The NYISO should continue to minimize the use of these interfaces.

4. Conclusions

Overall, day-ahead and balancing congestion shortfalls fell substantially in recent years, from $496 million in 2008 to $135 million in 2010. The reduction in balancing congestion shortfalls was particularly notable, which was down from $317 million in 2008 to $46 million in 2010.

The sharp decreases were driven by measures that improved consistency between day-ahead and real-time modeling, including:

- Improved interface scheduling procedures when other control areas declare TLRs;
- Procedures for promptly evaluating the causes of shortfalls and for adjusting market operations accordingly on a timely basis (e.g., more timely updates to the day-ahead assumptions regarding loop flows);
- Less frequent use of simplified interface constraints in New York City over time; and
- Improved operations during TSA to better recognize the effects of imports on congestion management in the real-time transaction scheduling process.

As a result of the reduction in balancing congestion shortfalls, day-ahead congestion shortfalls now account for the majority of the congestion shortfalls. The NYISO has a process for allocating the uplift charges resulting from transmission outages to specific transmission owners, but a relatively small portion of day-ahead congestion shortfalls were charged to specific transmission owners (43 percent in 2008, 34 percent in 2009, and 37 percent in 2010). A modeling inconsistency between the TCC auctions and the day-ahead market was identified that accounted for 39 percent of the day-ahead congestion shortfalls in 2010 (and 62 percent of the day-ahead congestion shortfalls not charged to a specific transmission owner). The NYISO is continuing to identify additional factors that contribute to day-ahead congestion shortfalls.

Additionally, transmission owners rarely choose to model planned transmission outages in the TCC market, even when the outages are scheduled in advance of the capability period. This may be because planned outages usually last for only a portion of a six-month capability period, so incorporating them in the TCC auction assumptions would lead the NYISO to under-sell TCCs during the portion of the six-month capability period when the facility is in service. Thus, there may be some benefit in selling a portion of the transmission capability in TCC auctions for more granular periods than six months (e.g., one month), since this would allow the NYISO to vary the TCC auction assumptions within a six-month capability period to better reflect the effects of outages on the capability of the system.

B. Congestion on Major Transmission Paths

Supply resources in Eastern New York, especially New York City and Long Island, are generally more expensive than those in Western New York. Hence, the transmission lines that move power from the low-cost to high-cost parts of the state provide considerable value. Consequently, transmission bottlenecks arise as power flows from Western New York to Eastern New York, leading to significant price differences between regions. This sub-section examines congestion patterns in the day-ahead and real-time markets in the past two years.

The two analyses in this sub-section measure congestion in two ways. First, they quantify the frequency of binding constraints. Second, they quantify the value of congestion, which is equal to the marginal cost of relieving the constraint (i.e., constraint shadow cost) multiplied by the scheduled flow across the constraint.[49] In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO. In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows settle at day-ahead prices rather than real-time prices. Nonetheless, the real-time congestion value provides a sense of the economic significance of congestion in the real-time market.

1. Day-Ahead Congestion by Transmission Path

In the day-ahead market, the NYISO schedules generation and load based on the bids and offers submitted by market participants. The transmission network allows generation in one area to serve load in another area, so the assumptions that the NYISO makes about the status of each transmission facility determine the amount of trading that can occur between regions in the day-ahead market. When trading between regions reaches the limits of the transmission network, congestion price differences arise between regions in the day-ahead market.

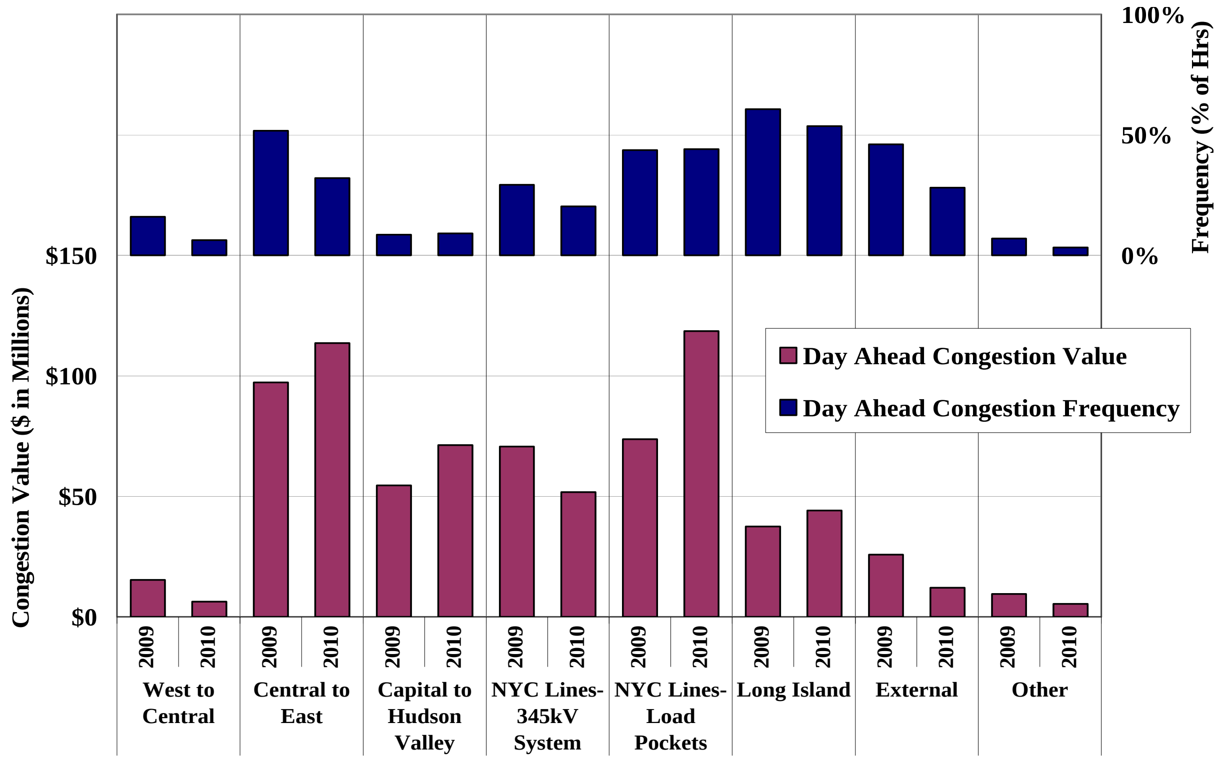
Market participants submit bids and offers in the day-ahead market that reflect their expectations of real-time congestion, so day-ahead congestion prices are generally consistent with real-time congestion prices. To the extent that differences arise between day-ahead and real-time

[49] The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

congestion patterns, it suggests that unexpected operating conditions may have occurred in the real-time market. Consistency between day-ahead and real-time prices is beneficial for market efficiency because it helps ensure that the resources committed each day are the most efficient ones to satisfy the needs of the system in real-time. Therefore, it is important to evaluate the consistency of congestion patterns in the day-ahead and real-time markets.

Figure 39 summarizes the frequency of congestion and the congestion revenues collected by the NYISO in the day-ahead market for eight groups of transmission facilities in 2009 and 2010.

Figure 39: Day-Ahead Congestion by Transmission Path
2009 – 2010



In 2010, the majority of day-ahead congestion revenue was collected on the following paths:

- *In New York City (40 percent)* – The lines into and within New York City are divided into two groups: (a) lines on the 345kV system and (b) lines leading into or within the load pockets (i.e., the 138kV system). The majority of the congestion associated with the load pockets was on the lines into the Greenwood area.
- *From Central to East (27 percent)* – The Central-East Interface limits flows from Western New York to the Capital Zone.

- *From Capital to Hudson Valley (17 percent)* – This was primarily associated with congestion on the Leeds-to-Pleasant Valley line, which carries power from the Capital Zone into Southeast New York.

The general pattern of congestion in 2010 was similar to 2009, although the total congestion revenue in 2010 was 11 percent higher (or $43 million higher) than in 2009. This increase was primarily due to the increases in fuel prices and load levels. Although the cost of congestion increased modestly from 2009, the frequency of congestion actually decreased in 2010. This reduction reflected changes in flow patterns from 2009 to 2010, including decreased clockwise circulation around Lake Erie, decreased net imports from Ontario and Hydro Quebec into Western New York, and increased imports from PJM to New York City via the Linden VFT interface.

The day-ahead congestion patterns summarized in Figure 39 were generally similar to the real-time congestion patterns summarized below in the next subsection. The most notable difference was for the Capital to Hudson Valley path, exhibited less congestion in the day-ahead market than in the real-time market due to the tighter criteria used in the real-time market during TSA events.

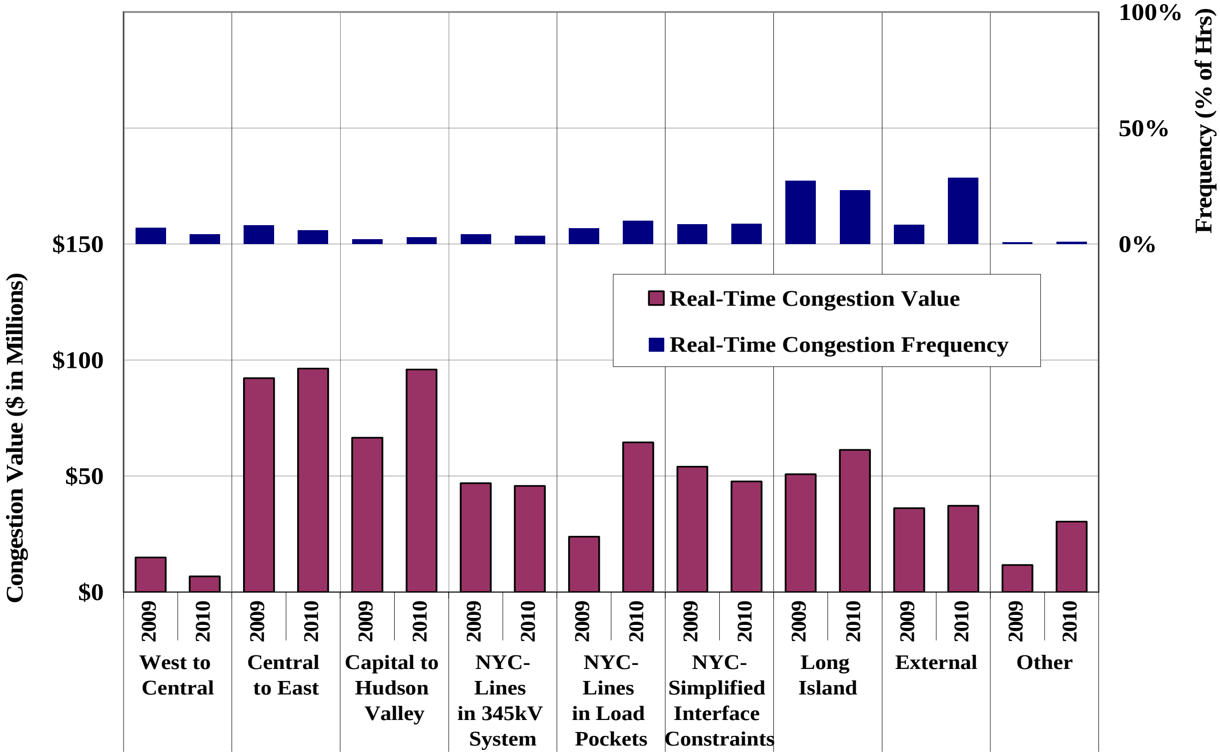
Congestion was typically more frequent in the day-ahead market than in real-time, but shadow prices of constrained interfaces were generally lower in the day-ahead. This is not unexpected because real-time congestion is more uncertain and volatile. For example, if market participants forecast a 20 percent probability of congestion that would lead to a $40 price difference between regions in the real-time market, the expected value of congestion would be $8 (= $40 * 20%). In this case, market participants might be expected to bid up prices in the day-ahead market nearly 100 percent of the time by an amount close to the $8 expected value of congestion.

2. Real-Time Congestion by Transmission Path

This sub-section examines congestion patterns in the real-time market. Figure 40 summarizes the value and frequency of congestion by transmission path in the real-time market for 2009 and 2010. The figure examines the same transmission paths as in the day-ahead market figure above, although New York City congestion is also shown for simplified interface constraints.

Simplified interface constraints are constraints in the real-time market model that represent multiple lines as a single interface with a single transfer limit. Because the simplified interfaces are a much less detailed and accurate representation of the network, use of these interfaces reduces the utilization of the transmission capability. The real-time market uses line constraints and simplified interface constraints, while the day-ahead market only uses line constraints.

Figure 40: Real-Time Congestion by Transmission Path
2009 – 2010



Most real-time congestion (72 percent) occurred on the following transmission paths in 2010:

- *New York City lines and interface constraints (32 percent)* – The use of simplified interface constraints decreased from 2009 to 2010, which reduced the share of the real-time congestion value associated with simplified interface constraints.
- *Central to East (20 percent)* – This was primarily associated with the Central-East Interface.
- *Capital to Hudson Valley (20 percent)* – 59 percent of this occurred during TSA events in the summer. They occurred less frequently than other categories, but they accounted for a relatively large share of the congestion value because they frequently resulted in very high redispatch costs.

In 2010, most real-time congestion occurred during the summer (39 percent) and winter (36 percent) months. In the summer (June to August), congestion was mostly associated with interface from Capital to Hudson Valley and the Greenwood load pocket in New York City, which was primarily associated with higher summer load levels and more frequent TSA events. In the winter (January, February, and December), nearly half of the congestion was related to the Central-East Interface, which was partly driven by increased winter imports from Hydro Quebec.

C. TCC Prices and Day-Ahead Congestion

In this sub-section, we evaluate whether clearing prices in the TCC auctions were consistent with congestion prices in the day-ahead market. TCCs provide an entitlement to the holder for the day-ahead congestion between two points. In a well-functioning market, the price for the TCC should reflect a reasonable expectation of the day-ahead congestion. Perfect convergence cannot be expected because many factors affecting congestion are not known at the time of the auctions, including forced outages of generators and transmission, fuel prices, weather, etc.

There are two types of TCC auctions:

- *Capability Period Auctions* – TCCs are sold in these auctions as 6-month products for the Summer Capability Period (May to Oct.) or the Winter Capability Period (Nov. to Apr.), as 1-year products for two consecutive capability periods, and as 2-year products for four consecutive capability periods.[50] Most transmission capability is auctioned as 6-month products. The capability period auctions consist of a series of rounds, in which a portion of the capability is offered, resulting in multiple TCC awards and clearing prices.
- *Reconfiguration Auctions* – The NYISO conducts a Reconfiguration Auction once in the month that precedes the month for which the TCC will be effective. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Auction. Each monthly Reconfiguration Auction consists of only one round.

The following analyses evaluate whether clearing prices in each type of TCC auction were consistent with the congestion prices in the day-ahead market during 2010. Figure 41 compares the TCC prices for the Winter 2009/10 and Summer 2010 Capability Periods (i.e., the 12-month period from November 2009 through October 2010) to the corresponding congestion prices in the day-ahead market. The figure shows the following values:

50 2-year TCCs were first sold in the Autumn 2010 auctions for the period from November 2010 to October 2012, which is after the period evaluated in this section of the report.

- *One-year TCC prices* – These are shown for the four auction rounds where TCCs were sold for the period, which occurred in August and September 2009.
- *Six-month TCC prices* – These are the average TCC prices for the five rounds in the 6-month Capability Period Auctions.
- *Reconfiguration TCC prices* – These are the sum of TCC prices from the six monthly Reconfiguration auctions during the Winter and the Summer Capability Periods
- *Day-ahead congestion prices* – These are the sum of congestion prices in the day-ahead market for the 12-month period.

Figure 41 shows these values for seven zones across New York state. Each price is shown relative to the reference bus at Marcy. One-year and six-month TCC prices are not shown because the NYISO does not sell TCCs that source or sink in Long Island in those auctions.

Figure 41: TCC Prices and Day-Ahead Congestion by Zone
Winter 2009/10 and Summer 2010 Capability Periods

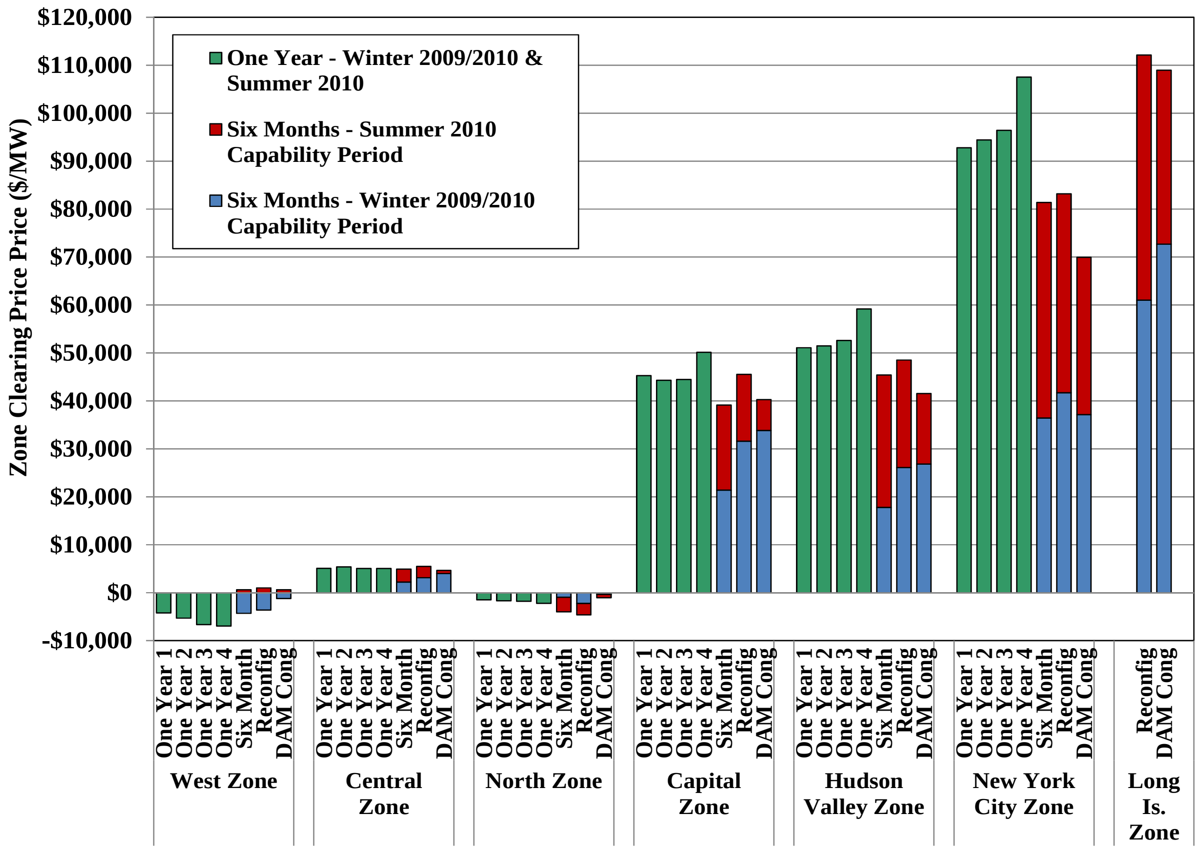


Figure 41 indicates that zone-level TCC prices were relatively consistent with DAM congestion prices. The TCC auctions moderately over-estimated congestion to New York City, although the consistency between TCC prices and day-ahead congestion prices improved from the one-year auctions to the six-month auctions and from the six-month auctions to the reconfiguration auctions. This is consistent with expectations since the monthly reconfiguration auctions occur closer to the actual operating period when more accurate information is available about the state of the transmission system and likely market conditions. Likewise, six-month TCC auctions occur closer to the actual operating period than the one-year TCC auctions.

Figure 42 evaluates congestion patterns within individual zones between the TCC auctions and the day-ahead market for the same 12-month period by showing similar results at six locations. However, this figure differs from the prior figure in that each price is shown relative to the load-weighted average price for its load zone, rather than relative to the reference bus at Marcy. Therefore, it shows the convergence of intrazonal congestion (i.e., congestion between the zone and the location) between the TCC markets and the day-ahead energy market. These six locations we selected to show in this figure exhibited relatively poor convergence of intrazonal congestion (compared to other locations in their respective zones).

Figure 42: TCC Prices and Day-Ahead Congestion at Selected Nodes
Winter 2009/10 and Summer 2010 Capability Periods

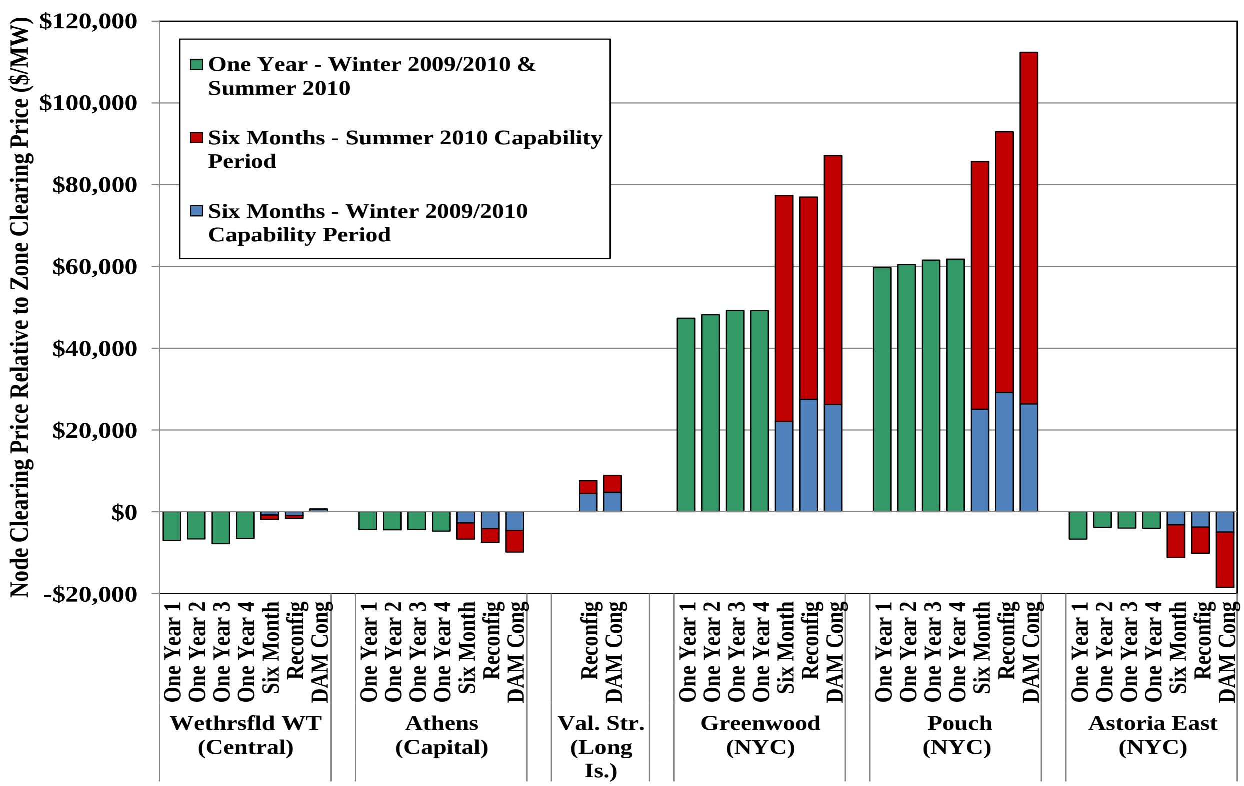


Figure 42 shows that at these locations, the intrazonal congestion exhibited in the TCC prices was generally lower than the intrazonal congestion reflected in the day-ahead market. The lone exception was a wind site (i.e., Wethersfield WT) where the TCC auctions anticipated more intra-zonal congestion to the network than was realized in the day-ahead market. Conversely, the TCC auctions predicted less congestion between export constraint (i.e., Astoria East) and import-constraint areas (i.e., Greenwood/Pouch) in New York City. Since these locations were selected because they exhibited relatively poor convergence of intrazonal congestion, most other locations show better convergence of intrazonal congestion between the TCC auctions and the day-ahead market.

Overall, the figures show TCC prices at the zone level were generally higher than the day-ahead congestion prices, suggesting that participants expected more day-ahead congestion. In New York City, intrazonal TCC prices were generally lower than the day-ahead congestion price differences, suggesting that they expected less day-ahead congestion. However, none of these differences were unusually large or indicative of an issue with the market’s performance.

VI. Market Operations

The objective of the wholesale market is to coordinate resources efficiently to satisfy demand while maintaining reliability. The day-ahead market should commit the lowest-cost resources to meet expected conditions on the following day, and the real-time market should deploy the available resources efficiently. Clearing prices should be consistent with the costs of deploying resources to satisfy demand while maintaining reliability. Under shortage conditions, the real-time market should provide incentives for resources to help the NYISO maintain reliability and set clearing prices that reflect the shortage of resources.

The operation of the real-time market plays a critical role in the efficiency of the market outcomes because changes in operations can have large effects on wholesale market outcomes and costs. Efficient real-time price signals are beneficial because they encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable.

In this section, we evaluate several aspects of wholesale market operations in 2010. This section examines four areas:

- *Real-Time Scheduling and Pricing* – This sub-section evaluates the consistency of real-time pricing with real-time commitment and dispatch decisions.
- *Real-Time Price Volatility* – This sub-section evaluates the factors that lead to transient price spikes in the real-time market.
- *Pricing Under Shortage Conditions* – Efficient operations better enable the existing resources to satisfy demand and maintain reliability under peak demand conditions, and they provide efficient signals for investment. We evaluate three types of shortage conditions: (i) ancillary services shortages, (ii) transmission shortages, and (iii) periods when emergency demand response is activated.
- *Supplemental Commitment for Reliability* – Supplemental commitments are necessary when the market does not provide incentives for suppliers to satisfy local reliability requirements. They raise concerns because they indicate the market does not provide sufficient incentives, tend to dampen market signals, and increase uplift charges.

In these areas, we provide several recommendations to improve wholesale market operations.

A. Real-Time Scheduling and Pricing

The ISO schedules resources to provide energy and ancillary services using two models in real-time. First, the Real Time Dispatch model ("RTD") usually executes every five minutes, deploying resources that are flexible enough to adjust their output every five minutes. RTD also starts quick-start gas turbines ("GTs") when it is economic to do so.[51] RTD models the dispatch across roughly a one-hour time horizon (rather than just the next five minutes), which better enables it to determine when a GT will be economic to start or when a generator should begin ramping in anticipation of a constraint in a future interval.

Second, the Real Time Commitment model ("RTC") executes every 15 minutes, looking across a two-and-a-half hour time horizon. RTC is primarily responsible for scheduling resources that are not flexible enough to be dispatched by RTD. RTC starts-up and shuts-down quick-start GTs and 30-minute GTs when it is economic to do so.[52] RTC also schedules bids and offers for the subsequent hour to export, import, and wheel-through power to and from other control areas.

The scheduling of energy and ancillary services is co-optimized, which is beneficial for several reasons. First, co-optimization reduces production costs by efficiently reallocating resources to provide energy and ancillary services every five minutes. Second, the market models are able to incorporate the costs of maintaining ancillary services into the price of energy by co-optimizing energy and ancillary services. This is important during periods of acute scarcity when the demand for energy and the ancillary services requirements compete for supply. Third, demand curves rationalize the pricing of energy and ancillary services during shortage periods by establishing a limit on the costs that can be incurred to maintain reserves and regulation. This also provides an efficient means of setting prices during shortage conditions. The use of demand curves during shortage conditions is discussed further in sub-section C.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of GTs, and inefficient scheduling of

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51 Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

52 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

external transactions. When RTC commits or schedules excess resources, it leads to depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section includes several analyses that evaluate the efficiency of real-time commitment and scheduling in the following areas:

- Commitment of Gas Turbines; and
- Scheduling of External Transactions.

The following subsections provide our evaluation and discussion in these two areas.

1. Efficiency of Real-Time Commitment of Gas Turbines

The efficient commitment of GTs is important because excess commitment results in depressed real-time prices and increased uplift costs, while under-commitment leads to unnecessary scarcity and price spikes. This is particularly important in New York City and Long Island where GTs account for nearly 30 percent of the installed capability.

The following analysis measures the efficiency of GT commitment by comparing the offer price (energy plus start-up costs amortized over the commitment period) to the real-time LBMP over the unit's initial commitment period. When these decisions are efficient, the offer price components of committed GTs are usually lower than the real-time LBMP. However, when a GT that is committed efficiently is close to the margin, it is possible for the offer price components to be greater than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

Figure 43 shows the average quantity of GT capacity started each day in 2010. These are broken into the following categories according to the sum of the offer price components and the real-time LBMP over the initial commitment period: (a) offer < LBMP (these commitments were clearly economic), (b) offer > LBMP by up to 25 percent, (c) offer > LBMP by 25 to 50 percent, and (d) offer > LBMP by more than 50 percent. Starts are shown separately for quick start GTs, older 30-minute GTs, and new 30-minute GTs. Starts are also shown separately for New York

City and Long Island, and based on whether they were started by RTC, RTD, RTD-CAM,[53] or by an out-of-merit (OOM) instruction.

Figure 43: Efficiency of Gas Turbine Commitment
2010

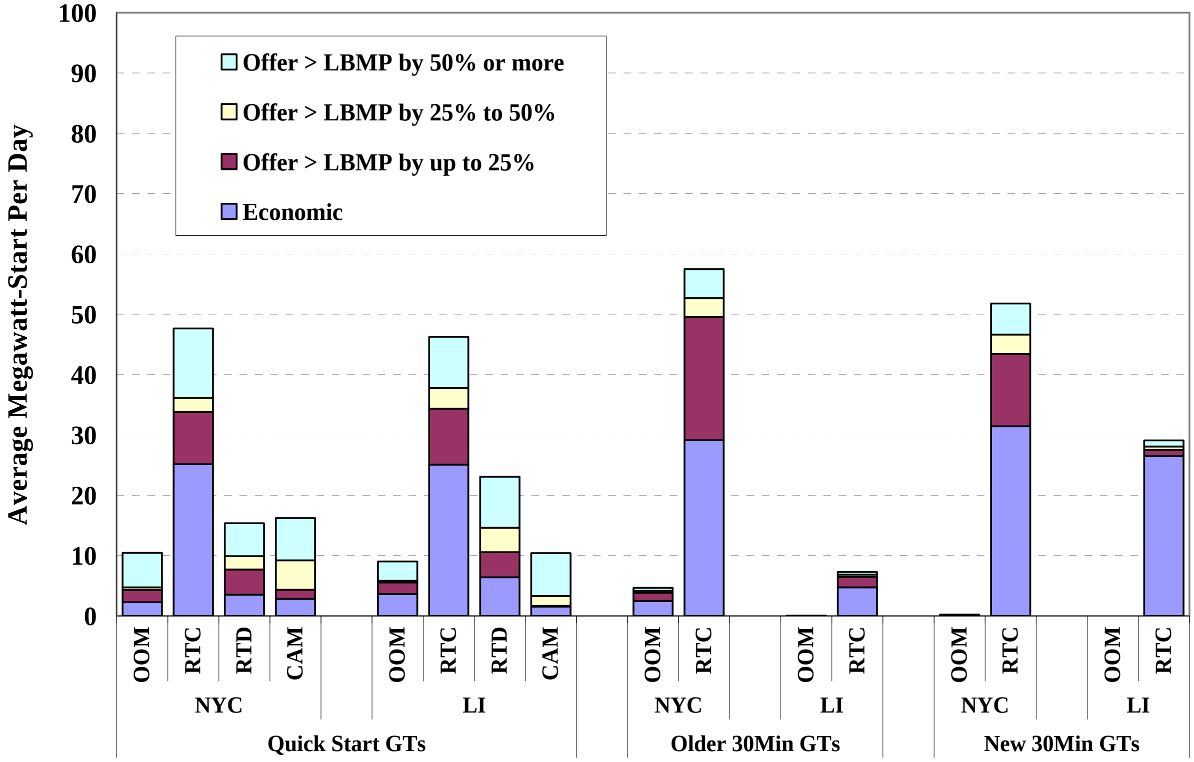


Figure 43 indicates that 73 percent of the GT-capacity started during 2010 was committed by RTC, with an additional 20 percent by RTD and RTD-CAM, and the remaining 7 percent by OOM instructions.

The overall efficiency of gas turbine commitment was consistent from 2009 to 2010. In 2010, 50 percent of all GT commitments were clearly economic, which was similar to 2009. For 71 percent of all GT commitments, the GT offer was within 125 percent of LBMP -- up modestly from the 67 percent in 2009. It is sometimes efficient to start a GT when its offer turns out to be greater than the LBMP for at least two reasons. First, GTs that are started efficiently and set the LBMP at their location do not earn additional revenues needed to recover their start-up offer. Second, GTs that are started efficiently to address a transient shortage (e.g., transmission

53 The Real-Time Dispatch – Corrective Action Mode (RTD-CAM) is version of RTD that NYISO operators can run on-demand to address abnormal or unexpected system conditions.

constraint violation) may lower LBMPs substantially and, as a consequence, appear uneconomic over the commitment period. Another factor that tends to reduce the overall efficiency of GT commitment is the use of simplified interface constraints in New York City load pockets rather than the more detailed model of transmission capability. The more detailed representation of the network allows RTD to redispatch generators more efficiently when constraints are binding. It also enables RTC to better anticipate congestion, leading to more efficient commitment. The use of simplified interface constraints decreased in recent years as a share of the binding real-time constraints in New York City, which helped improve the overall efficiency of GT commitment.

The figure shows that newer 30-minute GTs (those installed after 2000 ran more frequently than older 30-minutes GTs in 2010 because they are generally more fuel efficient than the older GTs. They also tended to be started far more economically. 72 percent of starts of newer GTs were clearly economic as opposed to 52 percent of the older 30-minute GTs. Quick-start GTs appeared more uneconomic in the figure because they often are started to address a transient transmission shortage.

The average amount of GT commitment fell modestly from nearly 370 MW in 2009 to 330 MW in 2010. The decrease was largely due to the 47 percent reduction of GT commitment in Long Island, which was driven by the entry of the Caithness unit in August 2009. This decrease was partially offset by a 53 percent increase in GT commitment in New York City, primarily due to the retirement of the Poletti unit and higher load levels.

2. Efficiency of External Transaction Scheduling

Market participants submit offers to import and bids to export at least 75 minutes ahead of each real-time hour. RTC schedules imports and exports in economic merit order based on their offer/bid prices and a forecast of system conditions. This sub-section evaluates the performance of external transaction scheduling based on two criteria:

- *Consistency* – This refers to whether the transaction was scheduled (or not scheduled) consistent with real-time prices. For example, it is considered "not consistent" when RTC schedules an export but the real-time LBMP is ultimately greater than the export bid price.[54] Likewise, it is considered "not consistent" when RTC does not schedule an export but the real-time LBMP is ultimately less than the export bid price.

- *Profitability* – This refers to whether the transaction would be profitable if scheduled based on the real-time proxy bus LBMPs on either side of the border. Transactions that RTC schedules "consistent" with real-time LBMPs are not always profitable. For example, if a $50/MWh export is scheduled by RTC and the real-time LBMP is ultimately $45/MWh, it would be "consistent." However, if the price on the other side of the border was $40/MWh, the export would be unprofitable.[55]

"Consistent" scheduling indicates that RTC is performing well, accurately forecasting real-time conditions in New York. However, the "profitability" of scheduling indicates whether the scheduling of external transactions is efficient. Transactions are profitable when they flow from the low-priced control area to the high-priced control area.[56]

Figure 44 shows the consistency and profitability of external transaction scheduling across the primary AC interface between New York and New England from 2005 to 2010 using the import/export offer and bid prices and the real-time LBMP at the border.[57] Most imports and exports are not submitted price-sensitively in real-time, although the use of price sensitive offers is becoming more prevalent. The figure evaluates real-time offers submitted in a price-sensitive manner, which excludes transactions with day-ahead priority, exports bid above $300/MWh, and imports offered below -$300/MWh.

Figure 44 shows price-sensitive offers and bids to import and export in four categories of stacked bars:

[54] An export bid expresses a willingness to pay up to the bid price to export power. So, if RTC forecasts a $45/MWh LBMP at the proxy bus and accordingly schedules an export with a $50/MWh bid price, and if the real-time LBMP is ultimately $55/MWh, it is considered "not consistent" because the real-time LBMP exceeds the export bid price (i.e., willingness to pay).

[55] The export would pay $45/MWh for the power in the NYISO and receive $40/MWh for the power in the adjacent control area, losing $5/MWh.

[56] Although this is generally true, there are exceptions due to the way that LBMPs are determined when there is congestion at the interface. For example, if LBMPs within New York are $60/MWh and LMPs within New England are $50/MWh, transactions that export from New England and import to New York are efficient. However, if New York has import congestion and the LBMP on the New York side of the border is set by a $45/MWh import, efficient transactions will be unprofitable.

[57] We analyze the New England interface due to its importance in servicing eastern areas in New York. We would expect similar results for PJM and Ontario.

- *Scheduled and consistent* – RTC schedules these transactions consistent with real-time LBMPs. However, if these transactions are unprofitable, it implies that they cause power to flow inefficiently from the high-priced control area to the low-priced control area.
- *Scheduled and not consistent* – RTC schedules these transactions inconsistent with real-time LBMPs. However, if these transactions are profitable, it implies that they cause power to flow efficiently from the low-priced control area to the high-priced control area.
- *Not scheduled and not consistent* – These transactions are not scheduled by RTC but apparently should have been.
- *Not scheduled and consistent* – These transactions are not scheduled by RTC apparently in accordance with real-time LBMPs. Most bids and offers fall into this category, so they are shown on the secondary y-axis.

Transactions that would be profitable if scheduled based on the real-time proxy bus LBMPs on either side of the border are shown separately from ones that would not be profitable.

Figure 44: Efficiency of External Transaction Scheduling
Primary Interface with New England, 2005 – 2010

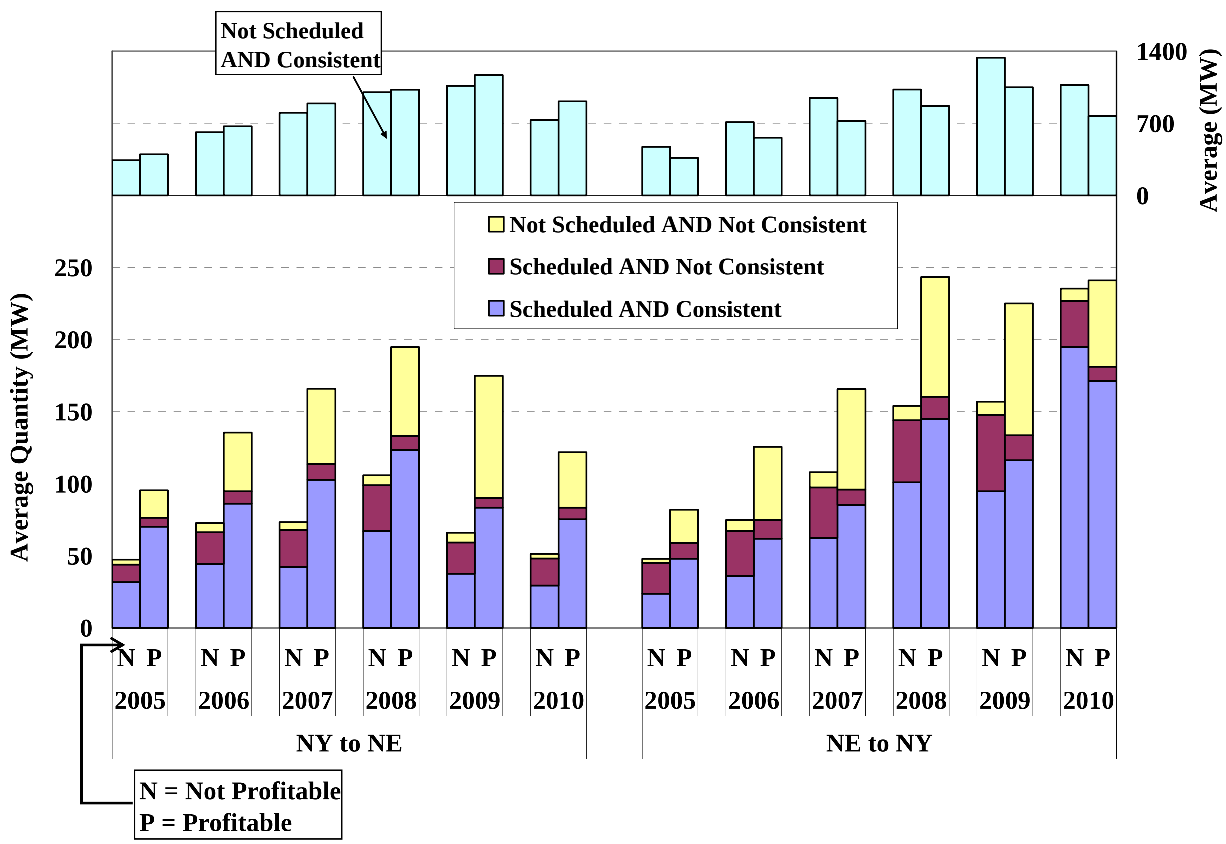


Figure 44 shows that the volume of price-sensitive transactions over the primary interface between New York and New England rose significantly from 2005 to 2010. The average volume of price-sensitive imports increased roughly 139 percent over the past six years, from 970 MW in 2005 to 2,320 MW in 2010. The average volume of price-sensitive exports increased approximately 107 percent, from 880 MW in 2005 to 1,820 MW in 2010. The increases suggest that market participants have increasingly relied on RTC to determine when it will be economic to schedule transactions between adjacent control areas. However, only a small fraction of price-sensitive offers and bids were scheduled, ranging from 8 to 13 percent between 2005 and 2010.

The figure shows that the share of schedules that were consistent rose from prior years. In 2010, 87 percent of scheduled transactions were consistent, up modestly from 75 to 81 percent during 2005 to 2009; 97 percent of offers and bids not scheduled were also consistent, which is comparable the results from 2005 to 2009. These levels are an indication of relatively good performance by RTC.

This analysis also indicates that "consistent" scheduling is not the same as "efficient" scheduling. The figure shows that 52 percent of transactions that were "scheduled and consistent" were also profitable in 2010 and the remaining 48 percent were unprofitable even though RTC performed well by scheduling these transactions in accordance with real-time LBMPs. Alternatively, 26 percent of transactions that were "scheduled and not consistent" were profitable in 2010, even though RTC performed poorly by scheduling these transactions that were not consistent with real-time LBMPs. Similarly, 89 percent of transactions that were "not scheduled and not consistent" would have been profitable if scheduled in 2010, indicating that the remaining 11 percent were not efficient to schedule.

Overall, the analysis suggests that good performance by RTC (i.e., good consistency of RTC with RTD) helps improve the efficiency of external transaction scheduling, but efficient scheduling also depends on the predictability of the differences in real-time prices between New York and neighboring markets. There are several potential means to improve the efficiency of external transaction scheduling by RTC:

- Improve the assumptions that are used in RTC to be more consistent with RTD, including those related to load forecasting and to the ramping of generators and transactions.

- Ensure that market participants have incentives to make sure their transactions pass check-out (i.e., flow in real-time) if scheduled by RTC.
- Reduce unnecessary volatility in RTD prices. RTD price volatility (which is evaluated later in the next sub-section) reduces the efficiency of external transaction scheduling by RTC. Inefficient transaction scheduling may, in turn, contribute to RTD price volatility.

Although we find that the external transaction scheduling process has functioned reasonably well and that scheduling by market participants tends to improve convergence, significant opportunities remain to improve the interchange between New York and adjacent areas. Accordingly, the NYISO is collaborating with ISO-NE, Quebec, and PJM to improve the use of these interfaces. In the longer-run, collaboration with Ontario would yield additional savings. We estimated the potential benefits that could be gained from improving the efficiency of: (i) the net scheduled interchange between control areas, and (ii) congestion management of flowgates that are affected by scheduling in the other ISO footprint. These are summarized in Section IV.E. Given the potential benefits from improved scheduling, we recommend the NYISO continue working with other adjacent control areas to improve the efficiency of the net scheduled interchange and congestion management.

B. Real-Time Price Volatility

The New York ISO usually dispatches the real-time system and updates clearing prices once every five minutes. Real-Time clearing prices can be quite volatile in wholesale electricity markets, even when sufficient supply is online. Generators (and demand response resources) are sometimes unable to adjust quickly enough to rapidly changing system conditions. As a result, wholesale markets experience brief periods of shortage, leading to very high prices; as well as brief periods of excess, leading to very low or even negative prices. This part of the section evaluates patterns of price volatility in the real-time market.

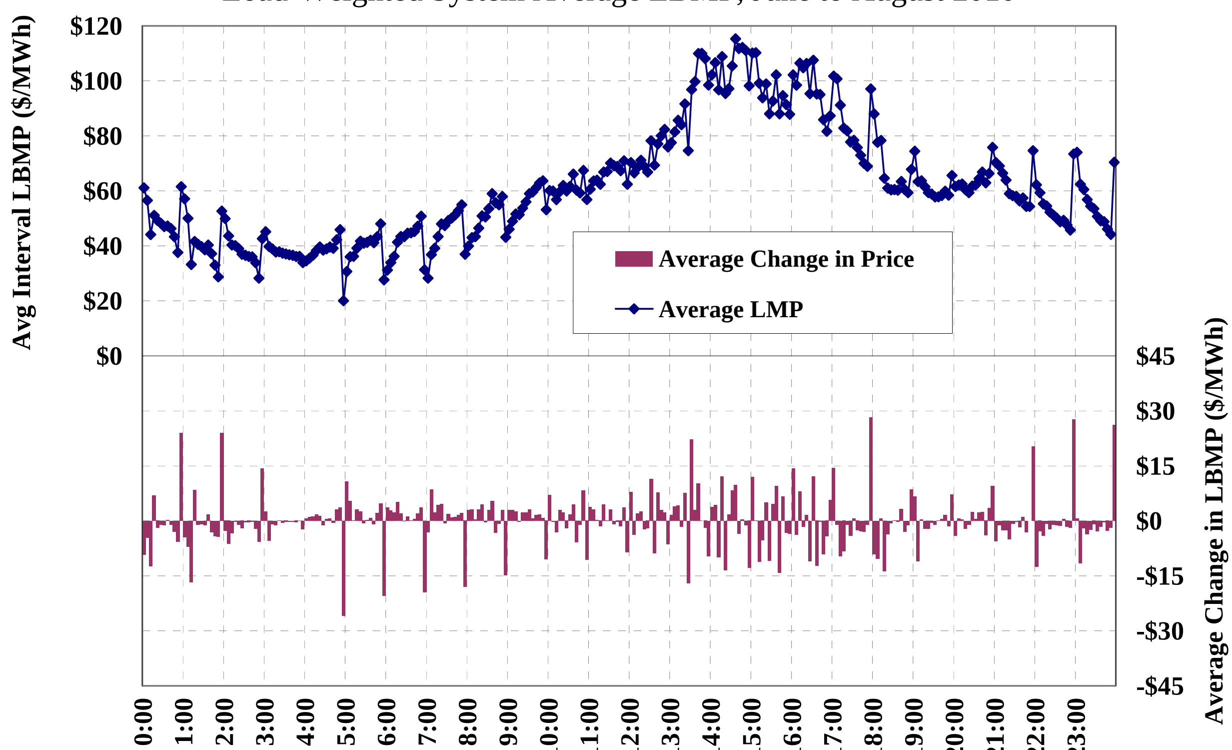
Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient market operations if generators are being cycled unnecessarily. Real-Time price volatility also raises concerns because it increases risks for market participants, although market participants can hedge this risk by buying and selling in the day-ahead market and/or in the bilateral market. Generally, the ISO should seek ways to reduce unnecessary price volatility while maintaining efficient signals for generators to be flexible in real-time.

This sub-section evaluates two types of real-time price volatility: statewide fluctuations in real-time prices, and localized fluctuations that result from transmission congestion. The final part of the sub-section discusses our conclusions and recommendations.

1. Real-Time Price Volatility - Statewide

The first figure shows the volatility of statewide energy prices by time of day. Figure 45 shows the average clearing price in each five-minute interval of the day during the summer months of 2010. The data shows the load-weighted average prices for the entire system, although the results are similar in each individual zone.

Figure 45: Average Five-Minute Price by Time of Day
Load-Weighted System Average LBMP, June to August 2010



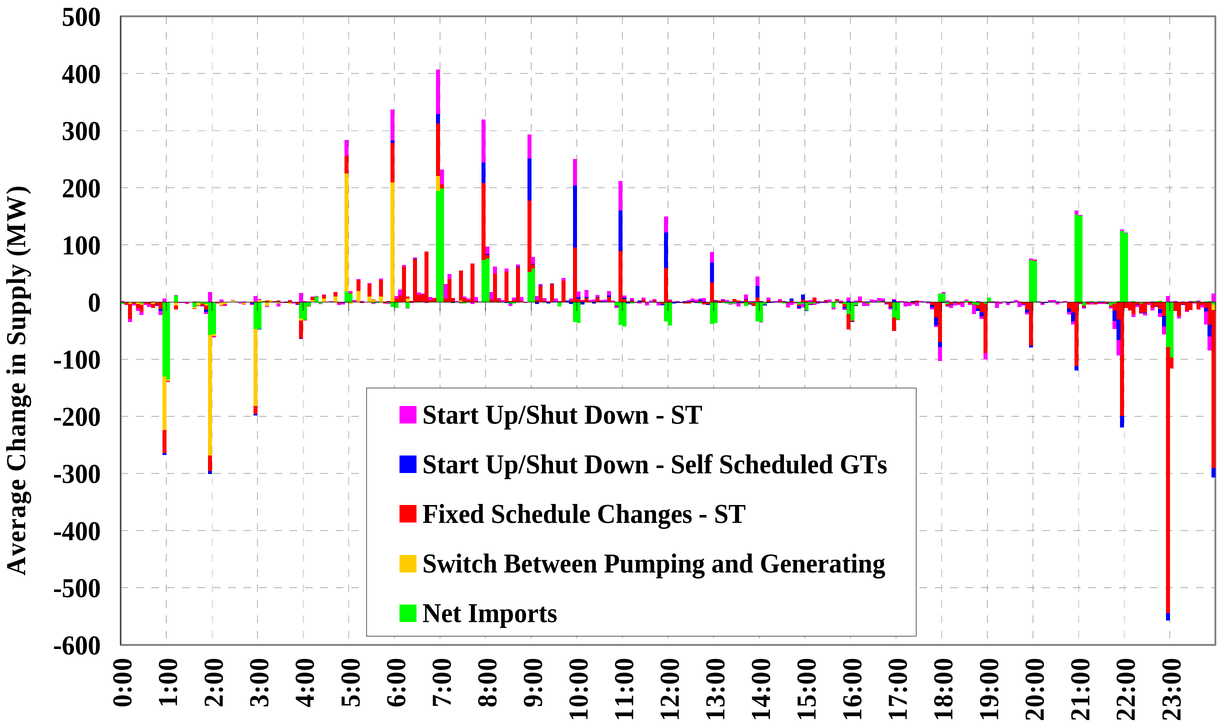
This figure shows that most real-time price fluctuations occurred predictably at specific times of the day, particularly near the top of the hour during ramp-up and ramp-down hours. In the last interval of each hour, clearing prices dropped substantially in ramp-up hours and rose substantially in ramp-down hours. The upward and downward price spikes at the top of the hour ranged from approximately $20/MWh to $30/MWh during ramp-up and ramp-down hours, while most other interval-to-interval price changes were less than $5/MWh. The upward and downward price spikes in these hours frequently occur when sufficient capacity is online. In such cases, ramp rate limitations prevent generators from responding quickly enough to accommodate changes in conditions.

Changes in prices from one interval to the next largely depend on how flexible generators (i.e., generators that can be dispatched by RTD according to their offer) respond to fluctuations in: (i) electricity demand, (ii) net export schedules (which are determined by RTC prior to RTD), (iii) generation schedules of self scheduled and other non-flexible generation, and (iv) transmission congestion patterns. Generally, prices increase as a result of combinations of increased load, increased net exports, decreased non-flexible generation, and increased congestion. Large changes in the clearing prices from one interval to the next are normally an indication of substantial fluctuations in at least one of these factors. The next figure evaluates major factors that may have contributed to the price volatility shown in Figure 46.

Figure 46 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *Net imports* – Net imports normally ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05). They can also change unexpectedly as a result of curtailments and TLRs before and during the hour.
- *Switches between pumping and generating* – This is when pump storage units switch between consuming electricity and producing electricity.
- *Fixed schedule changes for online non-gas-turbine units* – Many generators are not dispatchable by the ISO and produce according to their fixed generation schedule.
- *Start-up and shutdown of self-scheduled gas turbines* – These gas turbines are not dispatchable by the ISO, starting-up and shutting-down according to their fixed schedule.
- *Start-up and shutdown of non-gas-turbine units* – These units are not dispatchable during their start-up and shut-down phases of operation. In addition, the minimum generation level on these units is inflexible supply that must be accommodated.

Figure 46: Factors Contributing to Real-Time Price Volatility
June to August, 2010



The figure shows adjustments in net imports, pumped storage units switching between pumping and generating, and adjustments in fixed generation schedules accounted for the most significant changes in inflexible supply from interval-to-interval in 2010. For example, from 10:55 pm to 11:00 pm, the average net decrease in inflexible supply from imports and fixed scheduled units was more than 545 MW, coinciding with a $28/MWh average increase in real-time clearing prices.

High price volatility during the morning and evening ramp periods is likely exacerbated by large changes in inflexible supply around the top of each hour. If inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished. Market participants who change their fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour. For instance, units starting at 5:00 am sold their output at prices averaging from $20/MWh to $35/MWh in the first 15 minutes of operation. For many units, it would have been more profitable to wait until 5:15 am to start or increase output when prices averaged above $40/MWh.

In summary, there are several factors that contribute to large price changes at the top of the hour during ramping hours. First, import and export schedules adjust at the top of the hour. Second, generators are committed and decommitted frequently at the top of the hour during ramping hours. Third, non-dispatchable generators typically adjust their schedules at the top of each hour. Taken together, these factors can create a sizable ramp demand on the system that can sometimes cause the NYISO to temporarily be short of reserves or regulation.

2. Real-Time Price Volatility – Constrained Areas

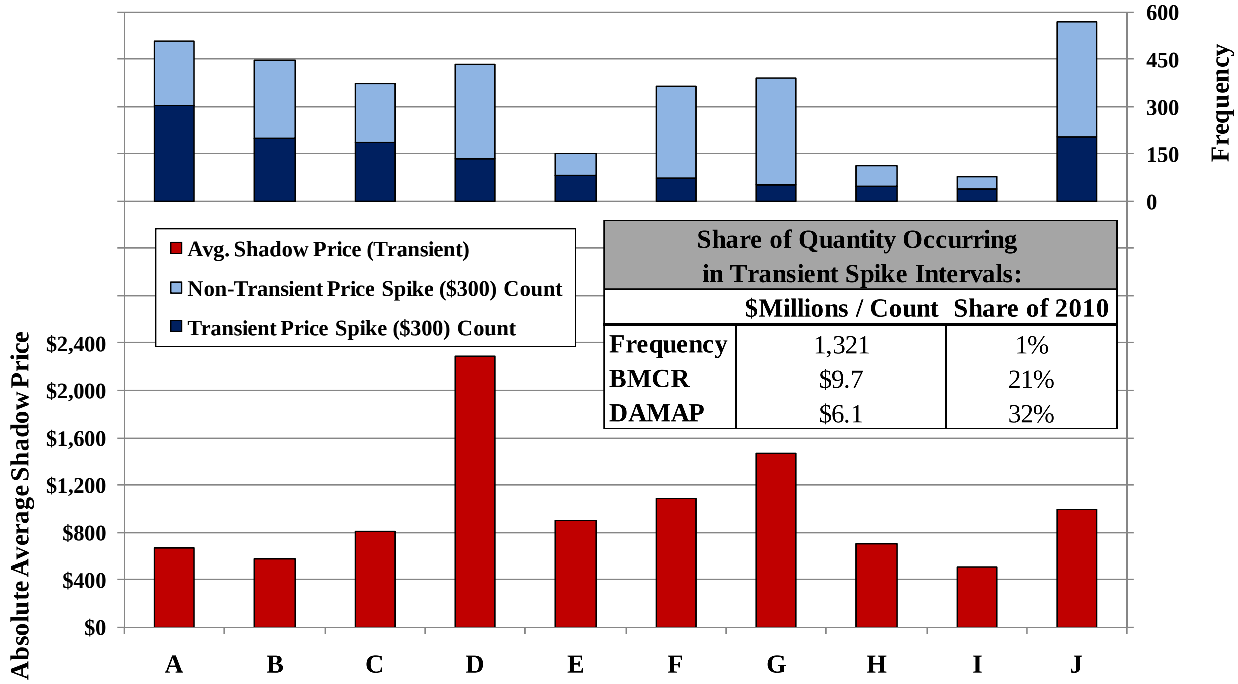
The second analysis in this section examines the real-time price volatility in constrained areas during 2010. Figure 47 summarizes transient congestion price spikes by facility in 2010.[58] For each transmission facility, the figure shows the frequency of transient and non-transient price spikes exceeding $300/MWh.[59] It also shows the average shadow prices during the intervals with transient price spikes. In the figure, the top 9 facilities (A through I) are ranked in descending order by the frequency of transient spikes, and all other facilities are grouped in category J.

Figure 47 shows that most transient shadow price spikes occurred on transmission facilities into and within downstate areas, which are the most congested areas in New York State. In Long Island, approximately 23 percent of total transient shadow price spikes occurred on the transmission line from East Garden City to Valley Stream. Another 18 percent occurred on the two major transmission lines from upstate to Long Island (i.e., Dunwoodie to Shore Road and Sprain Brook to East Garden City). In New York City, the Greenwood/Staten Island load pocket exhibited the most transient shadow price spikes during 2010, accounting for 10 percent of total transient spikes. In the upstate areas, the Central-East interface and the Leeds-to-Pleasant Valley line exhibited most transient spikes, collectively accounting for 18 percent of all transient spikes in 2010.

58 A price spike is considered transient if (a) it exceeds $300 /MWh, (b) it increases by at least 400 percent from the previous interval, and (c) it is at least 400 percent higher than in the most recent RTD "look ahead" interval.

59 A price spike is considered non-transient if it exceeds $300 /MWh but does not satisfy the other criteria for a transient price spike.

Figure 47: Frequency and Cost of Transient Congestion Price Spikes
2010



Legend			
A	East Garden City - Valley Stream	F	Astoria East (Generation Pocket)
B	Dunwoodie - Shore Road	G	Leeds - Pleasant Valley
C	Central East - VC	H	Astoria East (Load Pocket)
D	Greenwood / Staten Island (Load Pocket)	I	Sprainbrook - East Garden City
E	Dunwoodie - Motthaven	J	All Other Limiting Facilities

Figure 47 also shows that transient shadow price spikes occurred during about 1 percent of all intervals in 2010 and 39 percent of the intervals when shadow prices exceeded $300/MWh. Although relatively infrequent, transient price spikes are important because it can be far more costly to manage congestion that is not anticipated. For example, the average shadow price reached nearly $2,300/MWh during transient spikes in the Greenwood/Staten Island load pocket and nearly $1,500/MWh during transient spikes of the Leeds-to-Pleasant Valley line. The table in the figure also indicates that proportionately large quantities of uplift from Balancing Market Congestion Residuals ("BMCR") and Day-Ahead Margin Assurance Payments ("DAMAP") arose from intervals when transient price spikes occurred.[60] In 2010, nearly $10 million of

60 BMCR, also known as balancing congestion revenue shortfalls, are evaluated in Section V.A. DAMAP uplift is evaluated in Sub-section VI.D.2.

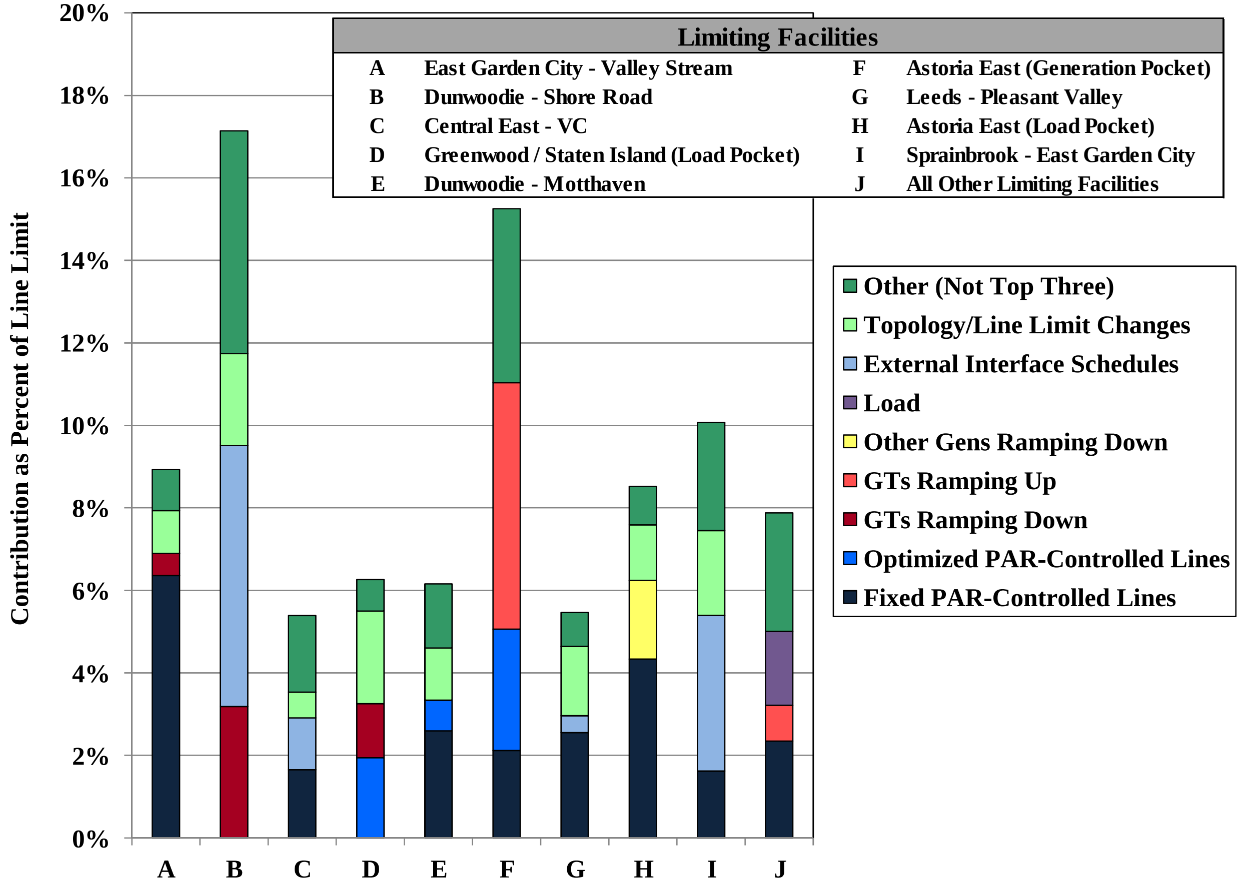
BMCR (or 21 percent of total BMCR) and $6 million of DAMAP (or 32 percent of total DAMAP) accrued during these transient spike intervals.

The next figure evaluates major factors that may have contributed to the price volatility in the constrained areas shown in Figure 47. In particular, the figure shows the factors that changed from the previous interval and that contributed to increased congestion across the constrained facility. These factors include:

- Increases in scheduled flows from the following factors:
  - *Fixed PAR-Controlled Lines* – The flow across these lines is assumed by RTD and RTC to be fixed at the most recent telemetered value, although the flow across these lines is affected by changes in many factors. These factors include the PAR setting, the settings of other nearby PARs, and the pattern of generation and load;
  - *Optimized PAR-Controlled Lines* – The flows across these lines are optimized by RTD and RTC;
  - *External Interface Schedules* – These are normally determined by RTC in the prior hour, although these may be adjusted closer to real-time due to curtailments. This can sometimes create large differences between the look-ahead evaluations of RTC and RTD and the actual real-time dispatch by RTD;
  - *Gas Turbines Ramping Up or Ramping Down* – Most decisions to start-up and shut-down GTs are made by RTC;
  - *Other Generators Ramping Up or Ramping Down* – The output of these generators is determined by self-schedules, dispatch instruction, and/or dragging; and
  - *Load*.
- *Topology/Line Limits* – This includes the reduction in modeled transfers across a facility due to changes in the limit or changes in topology (i.e., shift factors).
- *Other (Excludes Top Three)* – This category includes factors that are not among the three most significant factors for a particular facility.

Figure 48: Factors Contributing to Transient Congestion Price Spikes

2010



The figure shows that Fixed PAR-Controlled Line flow changes were the most significant factor contributing to transient shadow price spikes in 2010. This was the top contributing factor for six of the ten facility categories shown in the figure, including:

(A) East Garden City to Valley Stream;

(C) Central to East;

(E) Dunwoodie to Motthaven;

(G) Leeds to Pleasant Valley;

(H) Astoria East Load Pocket; and

(J) All Other Limiting Facilities.

Both RTC and RTD assume that the flow across these PAR-controlled lines will remain fixed at the level of the most recent telemetered values (plus an adjustment for lines that make up the primary interface between PJM and the NYISO). However, the flow across a PAR-controlled line is affected by changes in many factors, including the setting of the PAR, the settings of other nearby PARs, and the pattern of generation and load. These factors can lead to significant changes in the flow across a PAR-controlled line that are not predicted by RTC and RTD, contributing to transient spikes in the shadow prices of constrained facilities.

The factors that lead to significant changes in the flows across PAR-controlled lines are not generally random or inherently unpredictable. However, RTC and RTD are not provided with information that would allow them to predict such changes. Instead, they are currently designed to assume that the flows across fixed PAR-controlled lines will remain constant. Hence, it would be beneficial to modify the assumptions used by RTC and RTD in a way that would enable them to predict changes in flows across fixed PAR-controlled lines. We recognize that such predictions may not be completely accurate, but they are likely to be more accurate than the current assumption that the flows will remain at the last telemetered value.

External Interface Schedule changes were the most significant factor contributing to transient price spikes on the two lines flowing into Long Island from Upstate New York (i.e., the Dunwoodie to Shore Road line and the Sprainbrook to East Garden City line). Long Island can import up to 1.1 GW of generation from New Jersey (660 MW by the Neptune cable) and Connecticut (330 MW by the Cross Sound Cable and 100 MW by the 1385 Line), which accounts for a significant portion of supply serving Long Island load. Large hourly schedule changes across these interfaces often led to price spikes, typically at the top of the hour, when units were not able to ramp quickly enough to pick up the change.

3. Real-Time Price Volatility – Conclusions

The first part of this section evaluates price volatility at the statewide level and makes several findings. First, high price volatility during morning and evening ramp periods is largely caused by changes in inflexible supply at the top of each hour. Second, if inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished. Third, generators who change fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour.

The second part of this section analyzes factors that contribute to the volatility of real-time transmission constraint shadow prices and finds that:

- Fixed PAR-Controlled Line flow changes were a significant contributing factor to transient price spikes for most of the transmission facilities analyzed.
  - RTC and RTD assume the flow across a PAR-controlled line will remain constant, even though it is affected by changes in PAR settings, generation, or load.
  - When changes in these factors lead to significant changes in the flow across a PAR-controlled line that are not predicted by RTC and RTD, it can contribute to transient spikes in the shadow prices of constrained facilities.
- External Interface Schedule changes were also a significant contributor to transient price spikes.

The NYISO is introducing three market enhancements in 2011 that are expected to help address the causes of unnecessary real-time price volatility. First, Regulation Demand Curve modifications that will prevent small brief shortages of regulation from causing large positive or negative changes in statewide price spikes. Second, 30-Minute Long Island Reserve Demand Curve modifications that will reduce the frequency and severity of transient spikes in the shadow prices of lines from upstate NY to Long Island (i.e., Dunwoodie to Shore Road and Sprainbrook to East Garden City). Third, 15-minute scheduling of the Hydro Quebec interface rather than hourly scheduling. This will increase the flexibility of supply in west NY, reducing the volume of interchange adjustments that occur at the top of the hour. The NYISO is working to ultimately schedule this interface on a 5-minute basis.

The NYISO is also working with both ISO-New England and PJM to improve the real-time coordination of interchange between the markets. This will help reduce real-time price volatility. These enhancements will increase the flexibility of supply in Western and Eastern New York, including New York City and Long Island. These measures should also reduce the volume of interchange adjustments that occur at the top of the hour along with the associated volatility.

Nonetheless, additional work will likely be needed to eliminate unnecessary price volatility. Hence, we recommend that the NYISO conduct an evaluation to determine the causes of and potential solutions for unnecessary real-time price volatility. In particular, we recommend that the NYISO consider two improvements. First, it would be beneficial to evaluate whether fluctuations in the flows across fixed PAR-controlled lines could be predicted more accurately.

Second, we recommend the NYISO consider additional look ahead assessments in RTC and RTD at intervals ending :55 and :05 minutes past the hour to improve the dispatch at the top of each hour. When RTC and RTD accurately forecast that a constraint will bind in a future interval, it is efficient in many cases to start redispatching generation before the constraint binds. So, it is important for RTC and RTD to accurately forecast system conditions. The look ahead assessments of RTC and RTD forecast conditions at :00, :15, :30, and :45 minutes past each hour, although the most volatile pricing intervals include the intervals-ending at :55 and :05 minutes past the hour. Adding look-ahead assessments at :55 and :05 minutes past the hour would address this issue.

C. Market Operations under Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient price signals. In the long-run, prices should signal to market participants where and when new investment in generation, transmission, and demand response would be most valuable to the system. Prices also should provide market participants with incentives to commit sufficient resources in the day-ahead market to satisfy anticipated system conditions the following day. In the short-term, prices should give suppliers and demand response resources incentives to perform well and improve the reliability of the system, particularly during real-time shortages. However, it is also important that shortage pricing only occurs during legitimate shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission security constraints).

The importance of setting efficient real-time price signals during shortages has been well recognized. Currently, there are two provisions in the NYISO’s market design that facilitate shortage pricing. First, the NYISO uses operating reserve demand curves to set real-time clearing prices during operating reserves shortages. Second, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the activation of demand response.

In this section, we evaluate the operation of the market and resulting prices when the system is in the following three types of shortage conditions:

- Shortages of operating reserves and regulation;
- Transmission shortages; and
- Emergency demand response activations.

The final part of the sub-section provides our conclusions and recommendations related to real-time pricing during shortage conditions.

1. Real Time Pricing During Reserve and Regulation Shortages

The NYISO's approach to efficient pricing during operating reserves and regulation shortages is to use ancillary services demand curves. The real-time dispatch model ("RTD") co-optimizes the procurement of energy and ancillary services, efficiently allocating resources to provide energy and ancillary services every five minutes. When RTD cannot satisfy both the energy demand and ancillary services requirements with the available resources, the demand curves for ancillary services rationalize the pricing of energy and ancillary services during shortage periods by causing prices to reflect the value of foregone ancillary services. The demand curves also set limits on the costs that can be incurred to maintain operating reserves and regulation. This sub-section summarizes the effects of ancillary services shortages on market clearing prices.

Figure 49 summarizes ancillary services shortages and their effects on real-time prices in 2009 and 2010 for the following six categories:[61]

- *30-minute NYCA* – The ISO is required to hold 1800 MW of 30-minute operating reserves in the state and has a demand curve value of $100/MWh.
- *10-minute NYCA* – The ISO is required to hold 1200 MW of 10-minute operating reserves in the state and has a demand curve value of $150/MWh.
- *10-Spin NYCA* – The ISO is required to hold 600 MW of 10-minute spinning reserves in the state and has a demand curve value of $500/MWh.

[61] The figure excludes reserve requirements with a demand curve value of $25/MWh, including Eastern 10-minute spinning reserves requirement and Eastern 30-minute reserves requirement.

- *10-minute East* – The ISO is required to hold 1000 MW (1,200 MW beginning December 1, 2010) of 10-minute operating reserves in Eastern New York and has a demand curve value of $500/MWh.
- *30-minute Long Island* – The ISO is required to hold typically 270-540 MW of 30-minute operating reserves in Long Island and has a demand curve value of $300/MWh.[62]
- *Regulation* – The ISO is required to hold 150 to 250 MW of regulation capability in the state and has a demand curve value of $250/MWh if the shortage is less than 25 MW and $300/MWh if the shortage is more than 25 MW.[63]

The top portion of the figure shows the frequency of shortages. The bottom portion shows the average shadow prices during shortage intervals and the demand curve levels of the requirements. The table shows the average shadow prices during shortages multiplied by the frequency of shortages, indicating the overall price impact of the shortages by product and in total in region. In particular, the table shows the cumulative effect of all ancillary services shortages on average real-time energy clearing prices in:

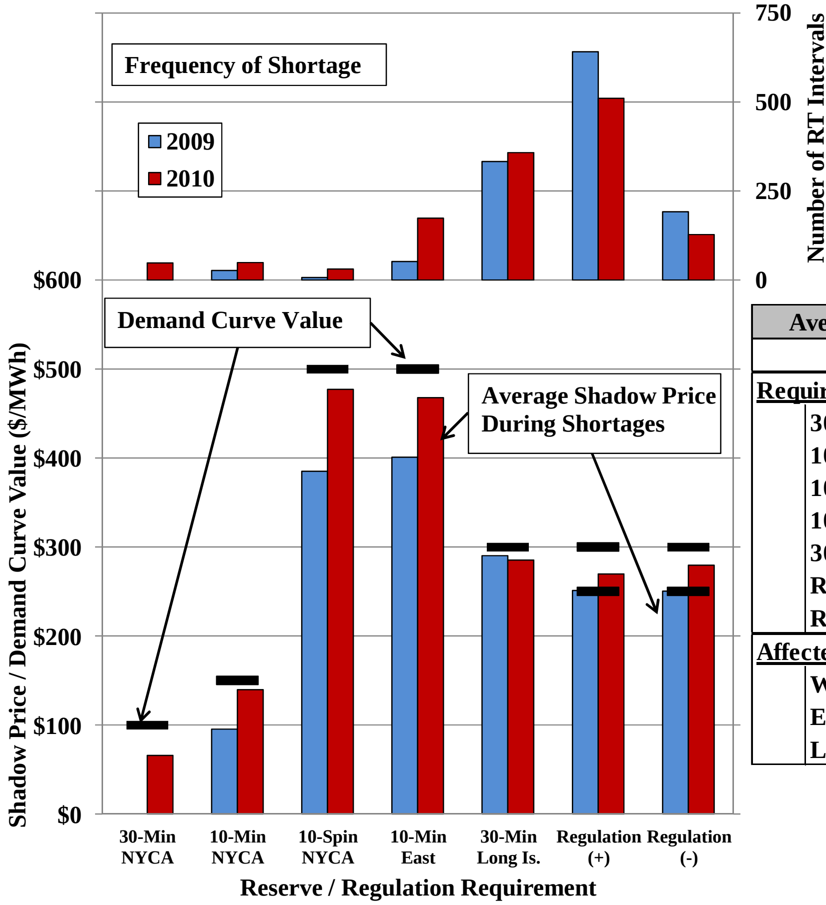
- *Western New York* – This is based on the sum of shadow prices of the NYCA reserve requirements as well as the effects of positive and negative regulation spikes.
- *Eastern New York (exclude Long Island)* – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.
- *Long Island* – This equals the Eastern New York effect plus the sum of shadow prices of Long Island reserve requirements.

Figure 49 indicates that several categories of ancillary services shortages had substantial effects on real-time prices. Regulation shortages occurred when supply was limited and could not ramp down sufficiently to provide regulation, leading to positive energy price spikes. Conversely, regulation shortages also occurred when supply was in excess and could not ramp up sufficiently to provide regulation, leading to negative energy price spikes. 10-minute eastern reserve shortages produced high prices throughout eastern New York, while 30-minute Long Island reserve shortages led to relatively high energy prices in Long Island.

62 This requirement is not reflected in the Long Island reserve clearing prices under the NYISO rules. However, it still affects real-time energy prices since units providing energy usually have an opportunity cost equal to the reserve price. The demand curve value was set to $25/MWh beginning May 2011.

63 The regulation demand curve values were adjusted in May 2011 to $80/MWh when the shortage is less than $25/MWh, $180/MWh when the shortage is between 25 and 80 MW, and $450/MWh when the shortage is more than 80 MW.

Figure 49: Real-Time Prices During Ancillary Services Shortages
2009 - 2010



Average Contribution to Energy Price		
	2009	2010
Requirement:		
30-Min NYCA	$0.00	$0.03
10-Min NYCA	$0.02	$0.07
10-Spin NYCA	$0.03	$0.14
10-Min East	$0.20	$0.77
30-Min Long Is.	$0.92	$0.97
Regulation (+)	$1.27	$1.11
Regulation (-)	-$0.32	-$0.28
Affected Region:		
West	$1.00	$1.06
East (excl. Long Island)	$1.20	$1.84
Long Island	$2.12	$2.81

The average contribution to energy prices from ancillary services shortages increased 6 percent in the West, 53 percent in the East (excluding Long Island) and 33 percent in Long Island from 2009 to 2010. This increase was largely attributable to the greater frequency of and higher shadow prices associated with 10-minute Eastern reserve shortages.

Figure 49 also shows that real-time prices accurately reflected system conditions, especially in 2010. The average shadow price during physical shortages was close to the demand curve level for each class of reserves, and this improved from 2009 to 2010. For example, the average shadow price for 10-minute eastern reserves rose from 80 percent of the demand curve level in 2009 to 94 percent in 2010. The closer correspondence between the shadow price during physical shortages and the demand curve level was likely due to the longer average duration of shortages in 2010. Consistency between the pricing dispatch and the physical dispatch is typically better during shortages of longer duration.[64]

2. Real Time Pricing During Transmission Shortages

Transmission shortages occur when power flows exceed the limit of a transmission constraint. Transmission shortages have widely varying reliability implications. In some cases, they can compel the ISO to shed firm load to maintain system security. However, in many cases, transmission shortages can persist for many hours without damaging transmission equipment. During transmission shortages, it is important for wholesale markets to set efficient prices that appropriately reflect the acuteness of operating conditions. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines. Transmission shortages can occur in the following three ways:

- If the available capacity is not sufficient to resolve a transmission constraint, RTD will relax the constraint by increasing the limit to a level that can be resolved.
- If the marginal redispatch cost needed to resolve a constraint exceeds the $4,000/MWh Transmission Shortage Cost, RTD foregoes more costly redispatch options.
- If the available capacity from an offline quick-start gas turbine is counted towards resolving a transmission constraint, but the gas turbine is not given a startup instruction.[65] In such cases, the marginal costs of the resources actually dispatched are lower than the shadow price set by the offline gas turbine (which is not actually dispatched).

Data is not available regarding the first two types of transmission shortage, so the following analysis focuses on the third type of transmission shortage. This type of shortage is most common because RTD usually finds an available quick-start gas turbine that can be scheduled before it reaches the $4,000/MWh transmission shortage cost limit.

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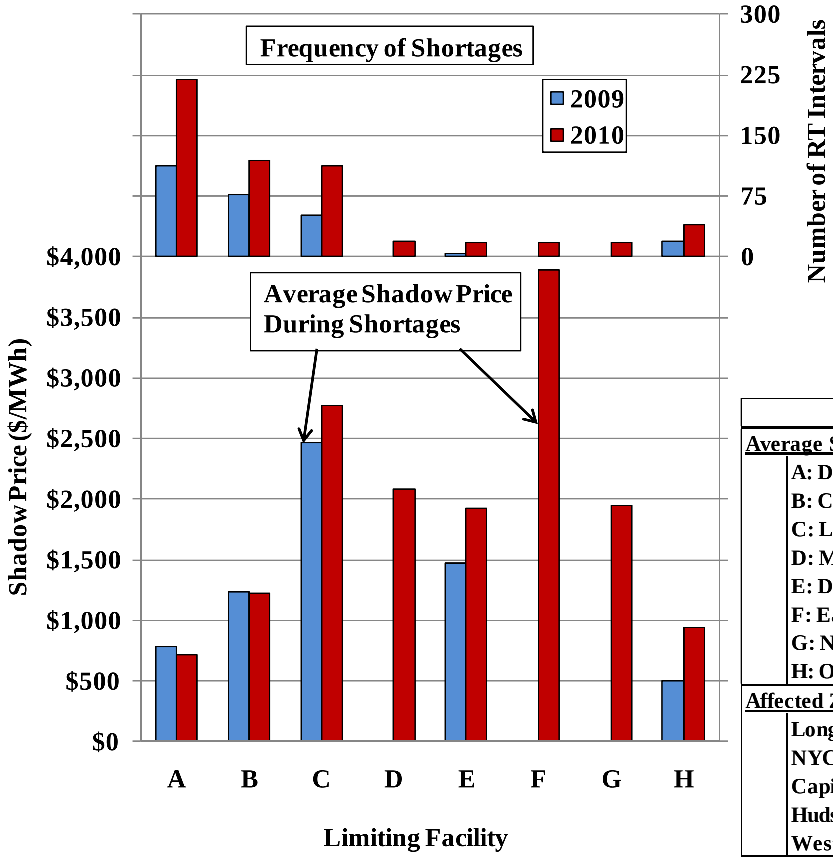
64 Previous assessments found large numbers of instances when real-time prices did not properly reflect shortage conditions. The NYISO made several improvements to the market software in recent years to address these issues. For additional details, see the NYISO State of the Market Reports for 2005 – 2009.

65 Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD but is not economic after the first advisory dispatch interval, it will not be instructed to start-up after RTD completes execution.

Figure 50 analyzes events when a transmission constraint has a very large effect on real-time LBMPs, as this usually coincides with a transmission shortage. Specifically, the figure includes intervals when (i) a transmission constraint accounted for a $500/MWh differential between two zone LBMPs and (ii) one or more zone LBMPs are greater than $500/MWh. The inset upper right table shows the share of these intervals when an offline gas turbine was counted by RTD towards resolving the constraint and marginal (i.e., setting the shadow price), but not actually started.[66] The lower right table shows the average shadow price during likely transmission shortages multiplied by the frequency of shortages over the year, indicating the relative economic significance of the shortages. The lower right table also shows the overall contribution of all likely transmission shortages to the LBMPs in each zone.

Figure 50: Real-Time Prices during Transmission Shortages

2009 - 2010



Price Set by Offline GT That Was Not Started in 2010		
	# of Intervals	Pct of Shortages
A	208	95%
B	101	84%
C	64	57%
D	19	95%
E	17	94%
F	10	59%
G	17	100%
H	33	85%

	2009	2010
Average Shadow Price During All Intervals:		
A: Dunwoodie-Shore Road	$0.84	$1.49
B: Central East	$0.90	$1.40
C: Leeds-Pleasant Valley	$1.20	$2.98
D: Millwood-East View	$0.00	$0.40
E: Dunwoodie-Mott Haven	$0.06	$0.33
F: East Garden City-New Bridge	$0.00	$0.63
G: New Scotland-Leeds	$0.00	$0.31
H: Other	$0.09	$0.35
Affected Zone:		
Long Island	$1.90	$3.78
NYC	$1.01	$2.47
Capital	$0.70	$1.08
Hudson Valley	$0.91	$1.91
West	$0.03	$0.00

[66] The analysis evaluates each interval separately, so a gas turbine that is not started in one interval might then be started in the next interval.

The figure shows that the Leeds-to-Pleasant Valley constraint exhibited the most economically significant transmission shortages in 2010. In the 113 intervals shown, this constraint contributed an average of $1,067/MWh to the New York City LBMP, which is $1.15/MWh averaged over the whole year. This is not surprising because this constraint is the most affected by TSAs that cause its available transfer capability to be reduced and can lead to a shortage.

Other facilities that exhibited economically significant shortages in 2010 were the Central-East Interface and Dunwoodie-to-Shore Road Line, which contributed an average of $1.40/MWh and $1.49/MWh, respectively. The Central-East Interface was often congested when clockwise Lake Erie circulations were significantly higher in real-time than were assumed in the day-ahead market. Severe congestion across the Dunwoodie-to-Shore Road Line frequently occurred during large hourly schedule changes across the interfaces between Long Island and Connecticut and New Jersey.

The lower right table also shows the total contribution from likely transmission shortages to the real-time LBMPs averaged over the year by zone. Downstate areas experienced the most significant price impact from these likely transmission shortages in 2010:

- In New York City, the total price impact was $2.47/MWh averaged over the year with the Leeds-to-Pleasant Valley Line accounting for 46 percent and the Central-East Interface accounting for 31 percent.
- In Long Island, the total price impact was $3.78/MWh averaged over the year with the Dunwoodie-to-Shore Road Line accounting for 39 percent, the Leeds-to-Pleasant Valley Line accounting for 30 percent, and the Central-East Interface accounting for 20 percent.

The upper right table shows that an offline gas turbine was scheduled (i.e., counted towards resolving the constraint) and was a marginal resource but was not actually started in 83 percent of all likely transmission shortage intervals in 2010. In these intervals, the offline gas turbine set the shadow price but was not actually started-up to manage congestion in that interval. In these intervals, small transmission shortages sometimes occur without significantly undermining reliability. The relative frequency of such intervals is an indication that the $4,000/MWh transmission shortage cost is frequently higher than needed to maintain system security.

3. Real Time Pricing During Emergency Demand Response Activation

The NYISO provides demand resources with two programs that compensate them for providing additional flexibility to the energy market. These programs include the Emergency Demand Response Program (EDRP) and the ICAP/SCR program. Resources enrolled in these programs typically earn the higher of $500/MWh or the real-time LBMP when called upon. Given the high costs associated with the programs, it would only be efficient to call upon these resources when all of the cheaper generation has been dispatched. Furthermore, it is important to set real-time prices that reflect the costs of maintaining reliability when emergency demand response resources are activated.

Emergency demand response (i.e., SCR and EDRP) resources were activated in New York City from 1:00 pm to 7:00 pm on July 6 & 7, 2010. The NYISO reported to stakeholders that the activations were necessary to maintain proper voltage at the Sprainbrook 345kV bus. On both days, lines into New York City were not constrained; however voltage constraints limited transfers across the UPNY-ConEd interface. Additionally, there was significant congestion on the Leeds-to-Pleasant Valley Line on July 7.

In the following analysis, we focused on whether real-time energy prices were efficient during the activation, given that most SCR and EDRP resources are paid $500/MWh to curtail their load. Figure 51 summarizes real-time prices and available capacity in several regions of Southeast New York during the activations and the quantities activated. Prices are shown for (i) the Greenwood load pocket, which was import-constrained for a substantial portion of each day, and (ii) the rest of New York City, excluding the export-constrained areas (primarily the Astoria East area). Available capacity is shown for generators in the Greenwood load pocket, the rest of New York City (excluding export-constrained areas) and Long Island. No capacity was available in the import-constrained portion of Upstate New York.

Figure 51: Real-Time Prices and Available Capacity in Demand Response Activations
July 6 & 7, 2010

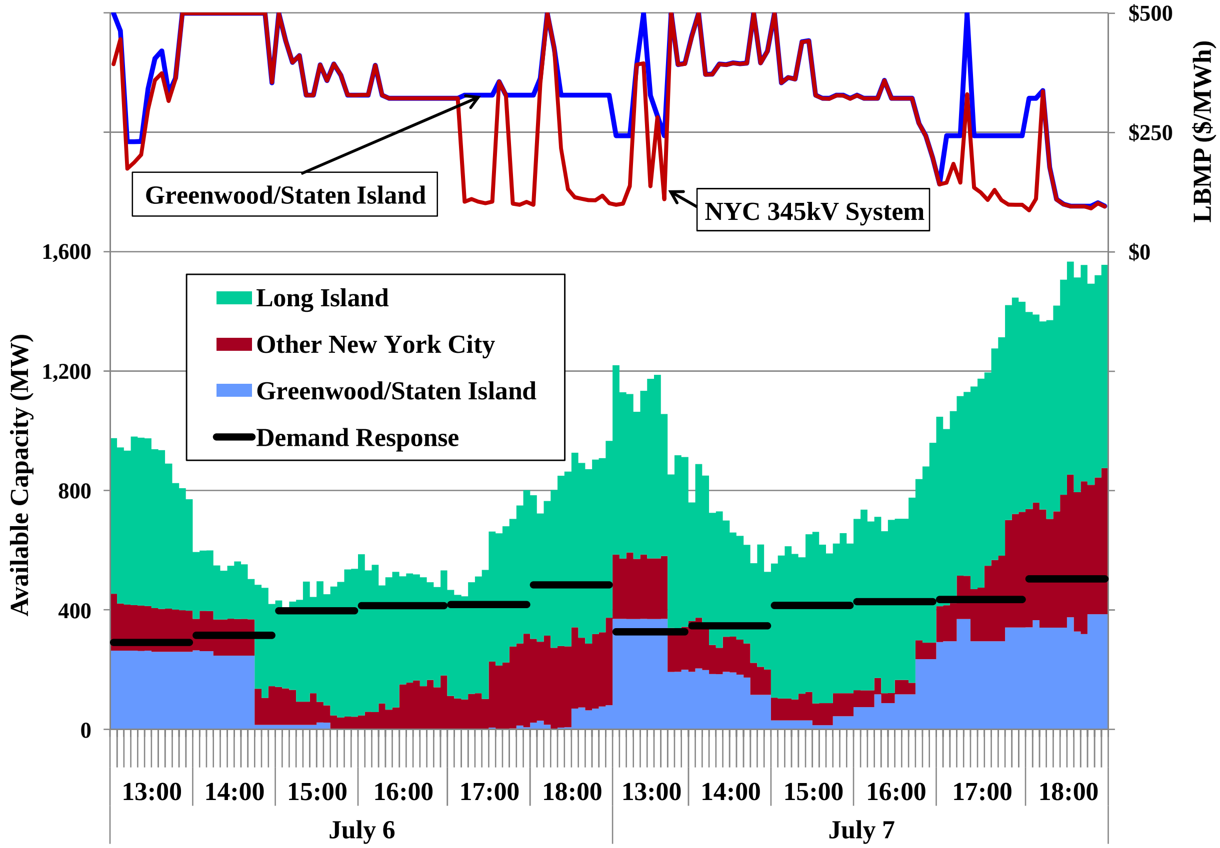


Figure 51 shows that an average of 370 MW of emergency demand response resources responded on July 6 and an average of 390 MW responded on July 7. Available capacity fell under 500 MW in four hours on the July 6 and under 700 MW in two hours on July 7. In these hours, the New York City prices averaged about $456/MWh. Most available capacity was on 30-minute reserve units in Long Island, so many of them would have been scheduled for energy if the demand response had not been activated.[67] Hence, if demand response resources were dispatchable at $500/MWh, they would likely have set real-time prices at $500/MWh in at least six hours.

67 The demand curve value for the Long Island 30-minute reserve requirements was $300/MWh, so Long Island units scheduled for energy would have had an opportunity cost of at least $300/ MWh in addition to their offered cost.

4. Real Time Pricing During Shortage Conditions - Conclusions

Well-functioning markets provide efficient price signals during shortages. The analyses in this section indicate that during 2010:

- The most economically significant ancillary services shortages were for regulation, eastern 10-minute reserves, and Long Island 30-minute reserves, which contributed 3 to 5 percent to the annual average LBMPs in eastern New York.
- The most economically significant transmission shortages were for the Leeds-to-Pleasant Valley line, the Central-East Interface, and the Dunwoodie-to-Shore Road line, which contributed 5 to 7 percent to the annual average LBMPs in Southeast New York.
- Emergency demand response was only activated in New York City on two days, but these activations may become more significant in the future if supply margins fall.

The area with real-time LBMPs most affected by shortages was Long Island, which received a contribution of $2.81/ MWh from ancillary services shortages and $3.78/MWh from likely transmission shortages. The real-time price effect on Long Island from reserve shortages will decrease in May 2011 when the demand curve level for the Long Island 30-minute reserve requirement is reduced from $300/MWh to $25/MWh. The effect from transmission shortages will also fall, since many of the Dunwoodie-to-Shore Road constraints are made more severe by the high opportunity cost of generators not scheduled for reserves during Long Island reserve shortages.

Transmission shortages occur when transmission constraints are not fully resolved by RTD. We performed an analysis of intervals with likely transmission shortages and found that an offline quick start GT was on the margin (i.e., setting the clearing price) but not actually started in 83 percent of these intervals during 2010. In such cases, a transmission shortage occurred since the GT did not actually produce output that would reduce flows over the constrained facility. Accordingly, real-time prices were set at a level that exceeded the actual marginal redispatch cost incurred.

When NYISO does not deem it necessary to start a GT to prevent or reduce a transmission shortage, it suggests that there are some instances when the Transmission Shortage Cost of $4,000/MWh is larger than the reliability value of preventing the shortage. Therefore, we recommend that the NYISO consider the feasibility and potential impacts on reliability and system security of using a graduated Transmission Shortage Cost. This level could be set according to the severity of the shortage condition.

Emergency demand response resources in New York City were activated on July 6 and 7, allowing the NYISO to maintain reliability on both days. In some of these hours, the New York City LBMPs were substantially lower than the average cost of activating the demand response resources, which is $500/MWh. If demand response resources were dispatchable at $500/MWh, they would likely have set real-time prices at $500/MWh in at least six hours. Hence, we recommend the NYISO consider how the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.

D. Uplift and Supplemental Commitment

When the wholesale market does not meet all forecasted load and reliability requirements, the NYISO (or an individual transmission owner) commits additional resources to ensure that sufficient resources will be available in real-time. Such commitments generate expenses that are uplifted to the market and increase the amount of supply available in real-time, depressing real-time market prices and leading to additional uplift. Hence, out-of-market commitment tends to undermine market incentives for meeting reliability requirements, so it is important for supplemental commitments to be as limited as possible.

In this section, we evaluate several aspects of market operations that are related to the ISO's process to ensure that sufficient resources are available to meet the forecasted load and reliability requirements. First, we examine the primary forms of supplemental commitments for reliability. Second, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

1. Supplemental Commitment for Reliability

Supplemental commitment occurs when a generator is not committed economically in the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways:

- *Day-Ahead Reliability Units ("DARU") Commitment* – Typically occurs at the request of transmission owners for local reliability prior to the economic commitment in the SCUC;
- *Day-Ahead Local Reliability Rule ("LRR") Commitment* – Takes place during the economic commitment within the day-ahead market process; and
- *The Supplemental Resource Evaluation ("SRE") Commitment* – Occurs after the day-ahead market closes.

Generators that are committed for reliability are generally not economic at prevailing market prices. They affect the market by: (i) reducing LBMPs from levels that would result from a purely economic dispatch; and (ii) increasing non-local reliability uplift since a portion of the uplift caused by these commitments results from guarantee payments to economically committed generators that do not cover their as-bid costs at the reduced LBMPs. Hence, it is important to commit these units as efficiently as possible.

In February 2009, the NYISO made enhancements to improve the efficiency of reliability commitments, which: (i) allow Transmission Owners to commit units prior to economic commitment of SCUC (i.e., DARU), so that SRE commitments are generally not needed unless there is a change in operating conditions after the day-ahead market; and (ii) commit units for New York City LRR constraints within the economic commitment of SCUC, rather than afterward. To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected without considering factors in the economic evaluation of SCUC.

It is important to evaluate the reliability commitment process because they have significant effects on market clearing prices and efficiency. Figure 52 shows the quarterly quantities of total capacity (in the left panel) and minimum generation (in the right panel) committed for reliability by type of commitment and region in 2009 and 2010. Four types of commitments are shown in the figure: DARU, LRR, SRE, and Forecast Pass. The first three are primarily for local reliability needs. The last category, Forecast Pass, represents the additional commitment in the forecast pass of SCUC, which occurs after the economic pass. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load.

Figure 52: Supplemental Commitment for Reliability
by Category and Region, 2009 – 2010

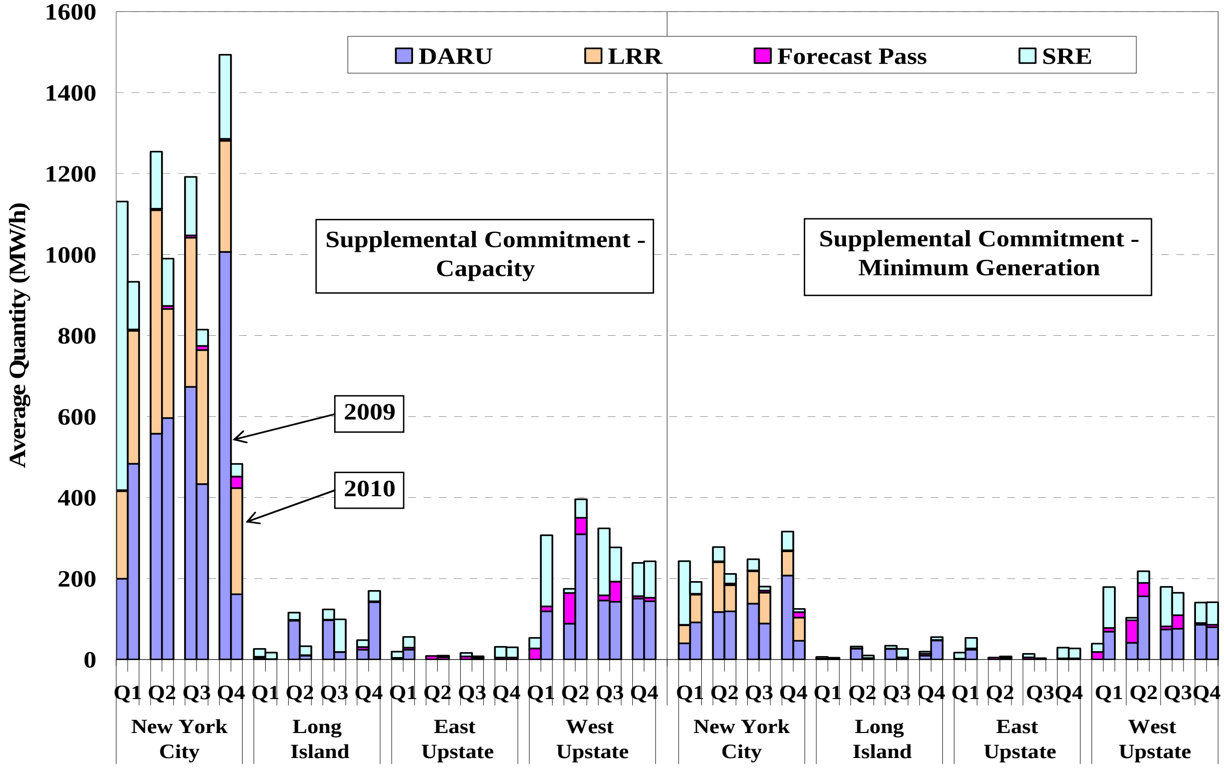


Figure 52 indicates that more than 1,200 MW of capacity was committed on average for reliability in 2010, down 22 percent from 2009. Of this total, 66 percent of reliability commitment was in New York City, 25 percent was in Western New York, and 7 percent was in Long Island.

In New York City, reliability commitment decreased substantially from 2009 to 2010. Committed capacity averaged 810 MW in 2010, down 36 percent from 2009. The minimum generation level of these units averaged 180 MW, down 35 percent from 2009. SRE quantities in particular have fallen significantly beginning in March 2009 when the NYISO began committing resources for local reliability through the day-ahead market (i.e., DARU and LRR).

DARU commitment also fell in 2010 due to at least two factors:

- The Poletti unit retired in February 2010, which had been frequently committed by DARU.
- LBMP levels were higher relative to the offers of generators that were frequently committed for reliability in 2010. As a result, these generators were flagged as economic

more frequently in the day-ahead market, particularly in the third and fourth quarters of 2010.

In Western New York, reliability commitment rose substantially in 2010. Capacity committed for reliability averaged 310 MW in 2010, up 55 percent from the previous year. The minimum generation level of these units averaged 180 MW, up 52 percent from the prior year. Reliability commitment rose considerably in the first quarter of 2010 from the first quarter of 2009 (in the form of increased SRE commitments for bulk power system reliability). DARU commitments increased in the second quarter of 2010 because several coal units were committed more frequently for local reliability.

In Long Island, reliability commitment was comparable to the previous year on average, although the amount varied from quarter to quarter. Committed capacity in Long Island averaged 80 MW in 2010 and the minimum generation level of these units averaged 20 MW. The increase of DARU commitments in the fourth quarter of 2010 from a year ago arose partly because generators needed for voltage support were committed economically more often in the previous year.

2. Uplift Charges from Guarantee Payments

The analysis presented in the following figure shows the magnitude of uplift charges for seven categories of guarantee payments in the past two years. These charges accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. Local reliability uplift charges are allocated to a particular load serving entity, while non-local reliability uplift charges are allocated to loads throughout New York.

There are four categories of local reliability guarantee payment uplift.

- *Day-Ahead Market* – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule ("LRR") or as Day-Ahead Reliability Units ("DARU") for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.

- *Real-Time Market* – Guarantee payments are made to generators committed and redispatched for local reliability reasons after the day-ahead market. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation ("SRE") commitments.
- *Minimum Oil Burn Compensation Program* – Guarantee payments made to generators that cover the spread between oil and gas prices when generators burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.
- *Day-Ahead Margin Assurance Payment* – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

There are three categories of non-local reliability guarantee payment uplift.

- *Day-Ahead Market* – This primarily includes guarantee payments to generators that are economically committed in the day-ahead market. These generators receive payments when day-ahead clearing prices are not high enough to cover the sum of their as-bid costs (includes start-up, minimum generation, and incremental costs).[68]
- *Real-Time Market* – Guarantee payments are made primarily to gas turbines that are committed by RTC and RTD based on economic criteria, but do not receive sufficient revenue to cover start-up and other running costs over their run time. Guarantee payments in the category are also made for: a) SRE commitments and out-of-merit dispatch that are done for bulk power system reliability, and b) imports that are scheduled with an offer price greater than the real-time LBMP.
- *Day-Ahead Margin Assurance* – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules.[69]

These seven categories of uplift costs are shown on a monthly basis in Figure 53 below for 2009 and 2010. The figure shows that guarantee payment uplift typically rises in the summer months (i.e., June to August) when load increases and in the winter months (i.e., January, February, and December) when natural gas prices increase.

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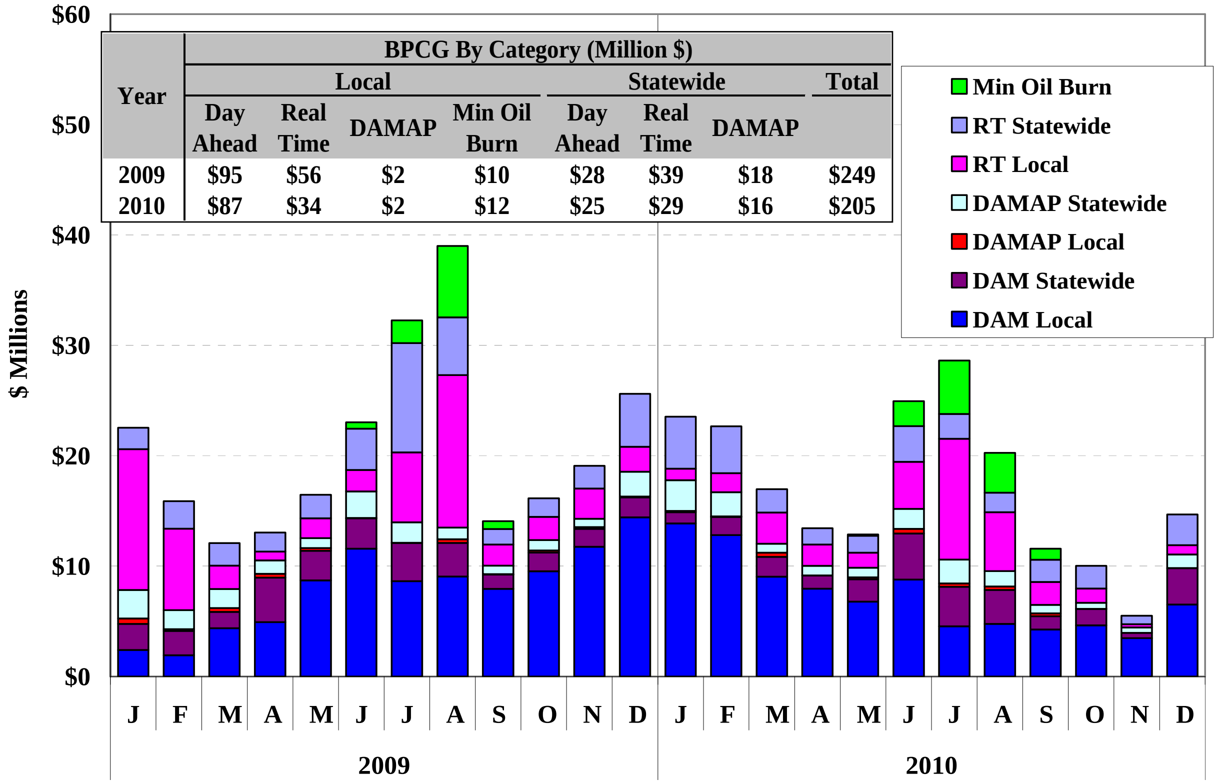
68 When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.

69 When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

Figure 53: Uplift Expenses from Guarantee Payments by Month 2009 – 2010



Year	BPCG By Category (Million $)							
	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2009	$95	$56	$2	$10	$28	$39	$18	$249
2010	$87	$34	$2	$12	$25	$29	$16	$205

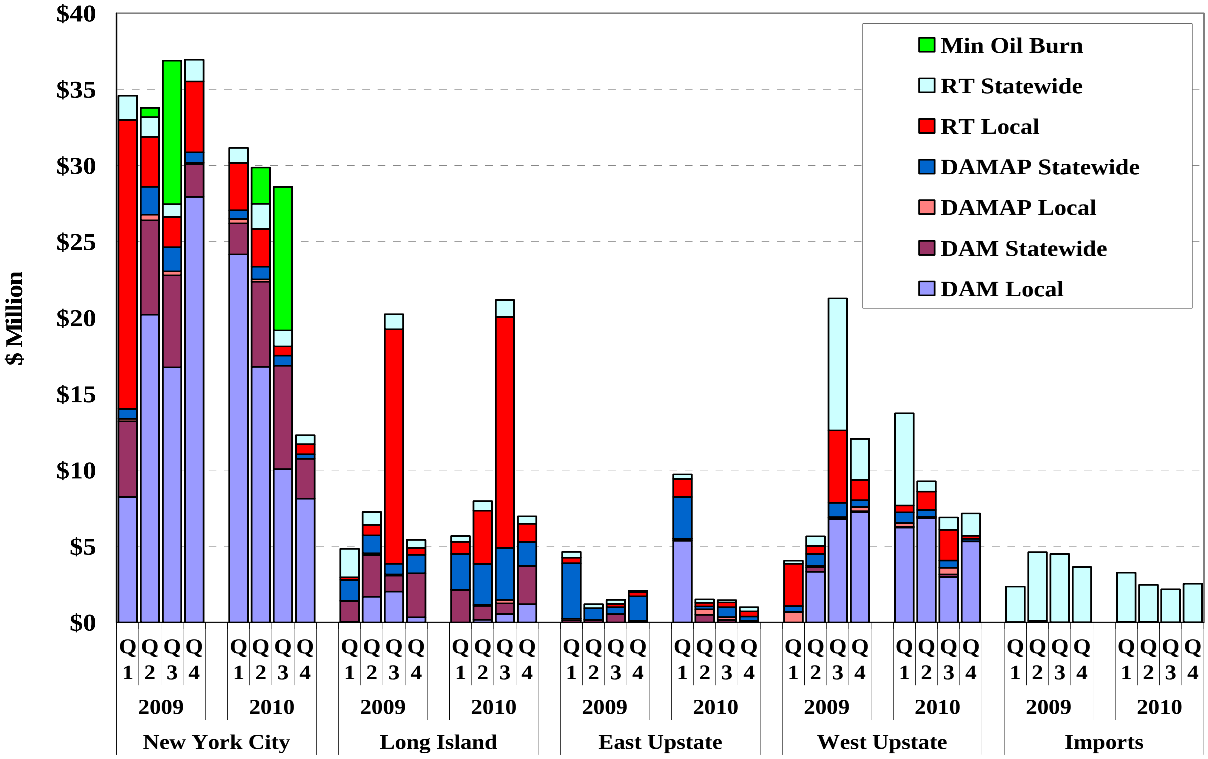
The figure also shows that total guarantee payment uplift fell 18 percent, from $249 million in 2009 to $205 million in 2010. Local reliability uplift categories fell $28 million, while statewide uplift categories fell $16 Million. These reductions were comprised of the following changes:

- Real-time local reliability uplift fell 39 percent (or $22 million) from 2009 primarily due to the large reductions in SRE commitment in New York City during 2010.
- Real-time statewide uplift fell 26 percent (or $10 million) from 2009. Guarantee payments to import transactions were lower in 2010, due mostly to less frequent negative price events in real-time. In addition, mitigation measures that were implemented in the fall of 2009 reduced the uplift charges from SRE commitments for bulk power system reliability.
- Day-ahead local reliability uplift fell 9 percent (or $8 million) from 2009. This was driven primarily by the reduction in DARU commitments in New York City, as generators that were needed for local reliability were flagged as economic more frequently in 2010 due to higher LBMPs relative to their offers.

Nonetheless, the overall reduction in guarantee payment uplift was partly offset by increased fuel prices in 2010.

The next figure shows the same seven categories of uplift on a quarterly basis by region for 2009 and 2010. The figure shows that New York City accounted for the vast majority of the reduction in total guarantee payment uplift from 2009 to 2010 (91 percent or $40 million). Guarantee payment uplift in Western New York fell by $6 million and guarantee payments to imports declined by $5 million from 2009 to 2010. These reductions were offset by the modest increases in Long Island and East Upstate regions.

Figure 54: Uplift Expenses from Guarantee Payments by Region
2009 – 2010



Most of the real-time statewide guarantee payments in 2010 were received by imports and generators in Western New York. Import transactions are scheduled by RTC based on anticipated market conditions and receive guarantee payments when the real-time clearing prices are lower than their offer prices. In 2010, 36 percent of real-time statewide uplift was paid to such import transactions. Another 21 percent was paid to several generators in Western New York in the first quarter of 2010 when they were committed more frequently for local reliability due partly to transmission outages and changes in commitment patterns. Regarding the different classes of uplift, the figure shows:

- *DAMAP* – Relatively slow-ramping steam units in Southeast New York accounted for a large portion of DAMAP statewide uplift, which typically accrued when a unit was operating below its day-ahead schedule in the intervals immediately after the onset of a price spike.[70] In Long Island, this occurred more often in the summer when generators were dispatched frequently out-of-merit below their day-ahead schedules to manage transmission facilities on the East End.

- *Day-Ahead Local Reliability* – New York City and Western New York accounted for the majority of day-ahead local reliability uplift (i.e., for DARU and LRR commitments) in 2010. Sixty-eight percent of the total was paid to generators in New York City and another 25 percent was paid to generators in Western New York. The total uplift fell from 2009 primarily due to reduced DARU commitment in New York City in 2010.

- *Day-Ahead Market* – New York City accounted for the largest share (68 percent) of day-ahead statewide uplift. Eighty-one percent of this category of uplift in New York City accrued in hours when the generator was needed for local reliability but was ultimately flagged as economic.[71] Another 25 percent of the uplift was paid to Long Island generators.

- *Real-Time Local Reliability* – Long Island accounted for the largest share (62 percent) of real-time local reliability uplift in 2010. The third quarter alone in Long Island accounted for 45 percent, primarily to manage transmission facilities on the East End that are secured by out-of-merit dispatch by the local Transmission Owner (rather than by the security-constrained economic dispatch performed by RTD).

E. Market Operations – Conclusions and Recommendations

The NYISO is tasked with operating day-ahead and real-time markets while maintaining the reliability of the system. The NYISO's markets are designed to give market participants efficient incentives to take actions that help satisfy the reliability needs of the system, particularly under shortage conditions. Overall, we conclude that the NYISO markets performed well in 2010, in part because the NYISO's systems are among the most advanced of any of the RTOs. For example, most RTOs lack the look-ahead commitment and dispatch capabilities of the NYISO's RTC and RTD models.

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70 This happens typically when these units are dispatched below their day-ahead schedules and then an unanticipated price spike occurs. The generator cannot ramp fast enough to its economic dispatch level indicated by the LBMP and needs to buy out of the difference between its day-ahead and real-time schedules at the elevated real-time LBMP.

71 If SCUC commits a resource to minimize production costs even when the local reliability rules are removed from the evaluation, it is deemed economic.

Nonetheless, we have identified a number of changes that will reduce price volatility and improve pricing during shortage conditions. To this end, we recommend that NYISO consider:

- Whether fluctuations in the flows across fixed PAR-controlled lines can be predicted and utilized by RTC and RTD.
- Whether additional look ahead assessments in RTC and RTD at intervals ending at :55 and :05 minutes past the hour would lead to more efficient dispatch at the top of each hour.
- The feasibility and potential impacts on reliability and system security of using a graduated Transmission Shortage Cost (i.e., demand curve).
- How the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.

VII. Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to satisfy New York's planning reserve margin requirements. The capacity market provides economic signals that supplement the signals provided by the NYISO's energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response. In this section, we evaluate the performance of the capacity market, and we discuss the merits of two market design changes that would improve the efficiency of the market.

A. Background

The New York State Reliability Council ("NYSRC") determines the Installed Reserve Margin ("IRM") for NYCA, which is the amount of planning reserves necessary to meet the reliability standards for New York State. The NYISO uses the IRM in conjunction with the annual peak load forecast to calculate the Installed Capacity ("ICAP") requirement for NYCA.[72] The NYISO also determines the Minimum Locational Installed Capacity Requirements ("LCRs") for New York City and Long Island, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirement.[73] Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates.[74] The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual peak load in each area.

72 The ICAP requirement = (1 + IRM) * Load Forecast. For the period from May 2009 to April 2010, the IRM was set to 16.5 percent. For the period from May 2010 to April 2011, the IRM was increased to 18 percent.

73 The locational ICAP requirement = LCR * Load Forecast for the location. The Long Island LCR was 97.5 percent for the period from May 2009 to April 2010, and rose to 102 percent in May 2010 and 104.5 percent for the period from June 2010 to April 2011. The New York City LCR was set to 80 percent for all periods from May 2009 to April 2011.

74 Capacity payments are made for UCAP, which is equal to the installed capability of a resource adjusted to reflect the availability of the resource. Thus, a generator with a high frequency of forced outages over the preceding two years would not be able to sell as much UCAP as a reliable unit of the same installed capacity. For example, a unit with 100 MW of tested capacity and an equivalent forced outage rate of seven percent would be able to sell 93 MW of UCAP. This gives suppliers a strong incentive to provide reliable performance. Renewable generators availability rates are based on their performance during peak

LSEs can satisfy their UCAP requirements by purchasing capacity through bilateral contracts, by self-scheduling their own capacity, or by participating in UCAP market auctions run by the NYISO. The NYISO conducts three UCAP auctions: a forward strip auction where capacity is transacted in six-month blocks for the upcoming capability period, a monthly forward auction where capacity is transacted for the remaining months of the capability period, and a monthly spot auction. The two forward markets are voluntary, but all requirements must be satisfied at the conclusion of the spot market immediately prior to each month. LSEs that have purchased more than their obligation prior to the spot auction may sell the excess into the spot auction.

The capacity demand curves are used to determine the clearing prices and quantities purchased in each location in each monthly UCAP spot auction. The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction may purchase more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

Every three years, the NYISO updates the capacity demand curves. The demand curves are set so that the demand curve price equals the levelized cost of a new peaking unit (net of estimated energy and ancillary services revenue) when the quantity of UCAP procured exceeds the UCAP requirement by a small margin. The demand curve price equals $0 when the quantity of UCAP procured exceeds the UCAP requirement by 12 percent for NYCA and 18 percent for New York City and Long Island. The demand curve is defined as a straight line through these two points.[75]

B. Capacity Market Results

To evaluate the performance of the capacity market, the following three figures show capacity market results from May 2009 through February 2011. This includes four six-month capability periods from the Summer 2009 Capability period through the Winter 2010-11 Capability period (excluding March and April 2011). These figures show the sources of UCAP supply and the

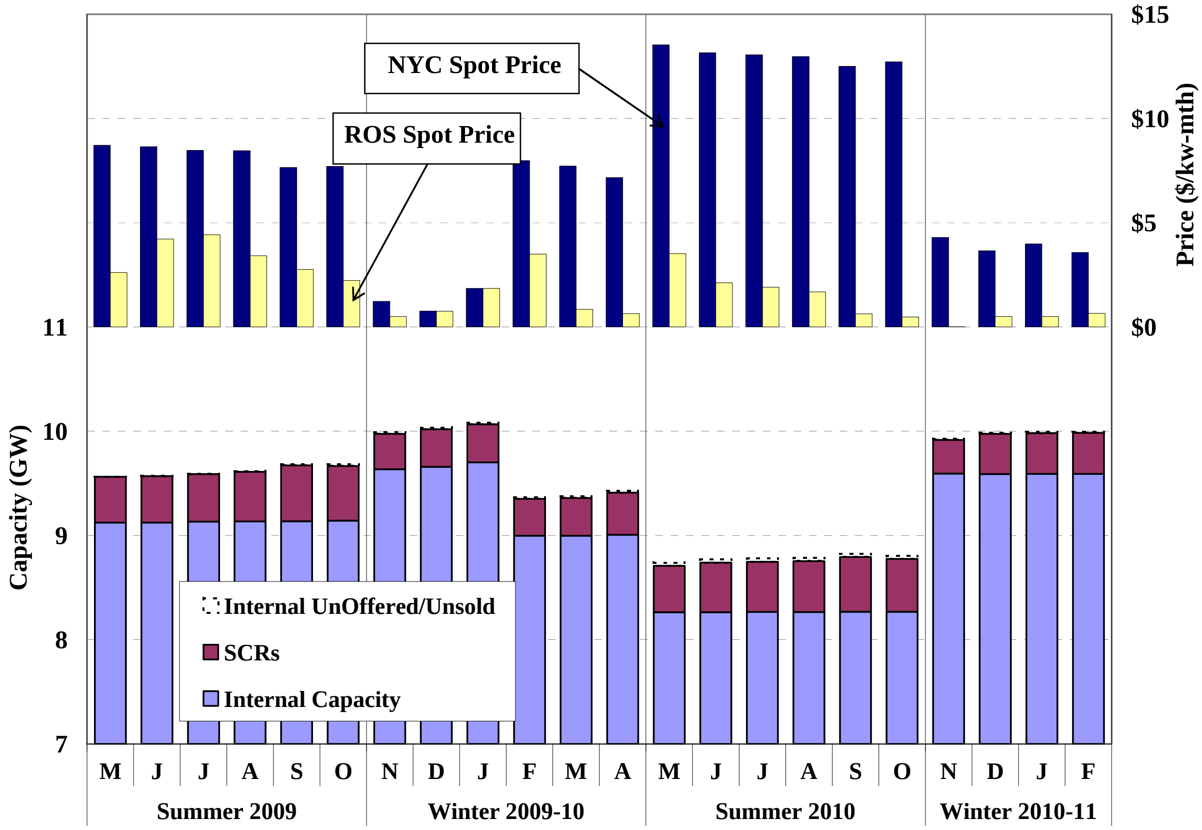
load hours, and SCR's availability rates are based on the performance during tests and events.

[75] The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement.

quantities purchased in each month. They also summarize the clearing prices in the monthly spot auctions.

Figure 55 shows the amount of resources in New York City available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the spot auctions for New York City and for Rest of State ("ROS").

Figure 55: Capacity Market Results for New York City
May 2009 to February 2011



Note: Sales related to Unforced Deliverability Rights ("UDRs") are shown as "Internal Capacity."

Figure 55 shows that virtually all internal capacity (as determined in DMNC tests) has been sold in each month, so economic withholding of supply has not been a significant concern in New York City in recent years. In early 2008, the NYISO implemented the supply-side market power mitigation measures for New York City that addresses both economic and physical withholding. This figure is evidence that these measures have been effective.

The figure also shows that the most significant changes in the clearing prices resulted from seasonal variations, which occurs for two reasons. First, additional capability is typically available in the Winter Capability periods due to lower ambient temperatures that increase certain resources' capability to produce electricity. This increase in capability contributes to significantly lower prices in the winter than in the summer. Second, the capacity demand curves are set at lower levels in the winter than in the summer, leading to correspondingly lower prices in the winter.[76]

New York City clearing prices in the spot auctions rose significantly from an average of $8.27 per kW-month in the Summer 2009 Capability period to an average of $12.99 per kW-month in the Summer 2010 Capability Period. This was primarily due to:

- The scheduled escalation of the NYC capacity demand curve; and
- The retirement of the Poletti unit in February 2010, which reduced supply in New York City by nearly 900 MW.

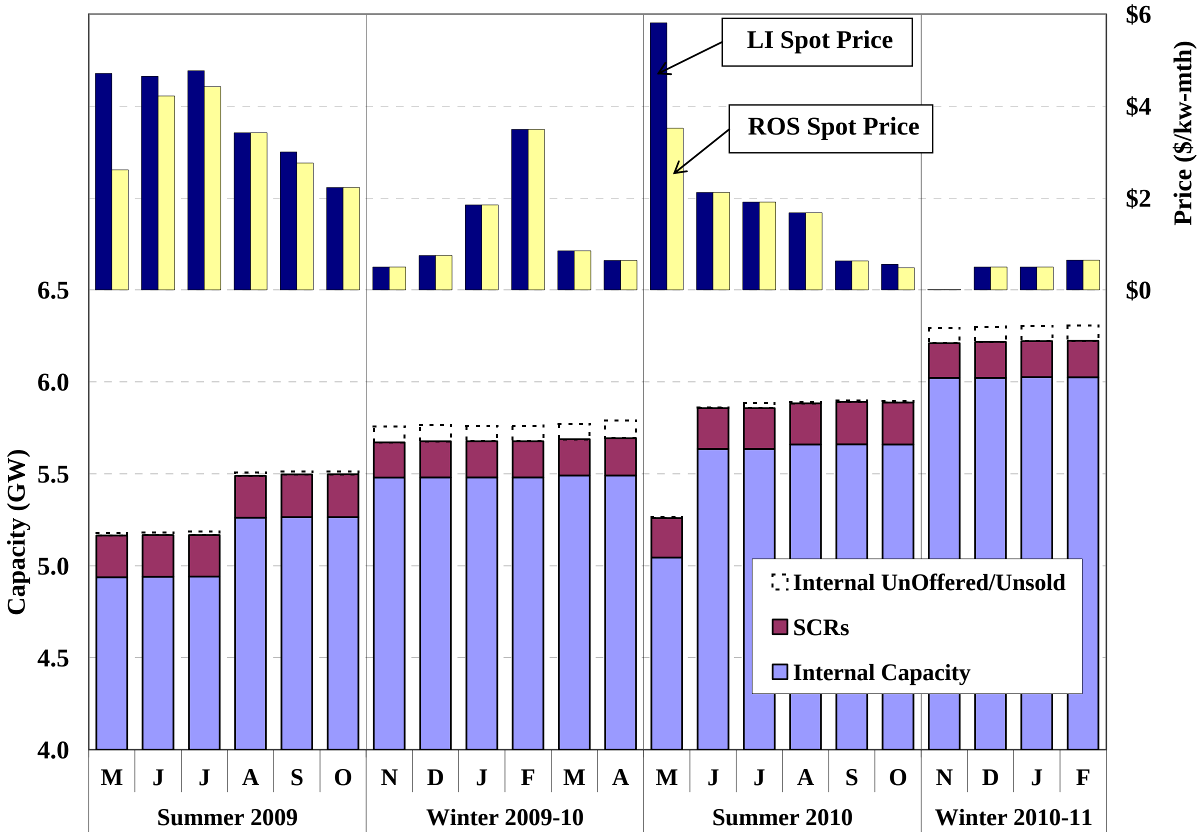
These increases were partly offset by a 325 MW reduction in the summer peak load forecast for New York City and capacity sales from new resources.

The figure also shows that UCAP sales rose significantly from the end of the Winter 2009/10 Capability Period to the Winter 2010/11 Capability Period. This was primarily due to an improvement in forced outage rates that led to increased UCAP supply in the Winter 2010/11 Capability Period. However, this did not significantly reduce prices because an improvement in forced outage rates automatically translates to an increase in the UCAP requirement.

Figure 56 shows the amount of resources in Long Island that are available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the monthly spot auctions for Long Island and for Rest of State ("ROS").

[76] In the winter months, the demand curve reference point is set to a level that is typically around 45 percent of the level used in the summer months.

Figure 56: Capacity Market Results for Long Island
May 2009 to February 2011



Note: Sales related to Unforced Deliverability Rights ("UDRs") are shown as "Internal Capacity."

The local capacity requirement for Long Island was not binding during most of the period, so the Long Island clearing price was equivalent to the ROS clearing price in 16 of the 22 months shown. This reflects that Long Island generally has more capacity than needed to satisfy the local capacity requirement.[77]

The capacity surplus in Long Island generally increased during the period shown in the figure for three reasons.

- In August 2009, the capacity level increased approximately 300 MW following the entry of the Caithness combined-cycle generation plant. This contributed to a $1.35 per kW-month decrease in Long Island spot price from July 2009 to August 2009.

[77] Long Island has approximately 17 percent more capacity than the amount needed to satisfy the local summer capacity requirement.

- The summer peak load forecast for Long Island fell 106 MW (or roughly 2 percent) from 2009 to 2010, which increased the capacity margin.
- The sales of internal capacity from UDRs changed considerably in the summer of 2010, rising 600 MW from May to June. As a result, the spot price fell from $5.81 per kW-month in May to $2.12 per kW-month in June.

However, the price impacts of these factors were partly offset by the increase in the LCR from 97.5 percent to 102 percent in May 2010 and 104.5 percent in June 2010.

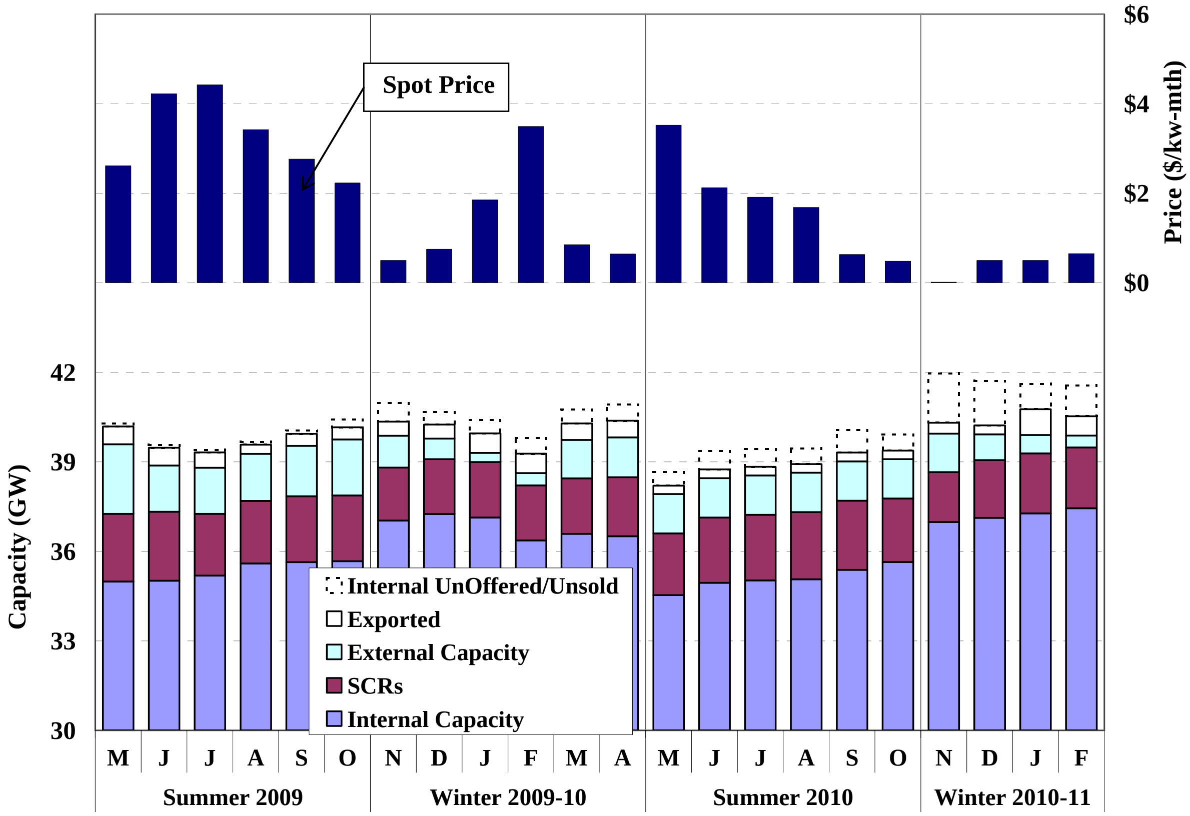
Figure 57 shows the resources available to provide UCAP to New York State and the amounts actually scheduled for the past four Capability Periods. The bars show the quantities of internal capacity sales, sales from SCRs,[78] sales from external capacity resources into New York, and exports of internal capacity to other control areas. The hollow portion of each bar represents the In-State capacity not sold (including capacity not offered) in New York or in any adjacent market. The figure also shows UCAP spot clearing prices in NYCA (i.e., the price applicable to capacity outside New York City and Long Island).

The figure shows most capacity was supplied by internal generation, although external suppliers and SCRs each provided significant amounts of capacity. Like the local areas, seasonal changes in internal capability between the summer and winter capability periods typically resulted in higher prices in the summer than in the winter.

NYCA clearing prices were primarily affected by changes in the amount of available internal supply during the examined period. First, Poletti's retirement in February 2010 reduced UCAP supply nearly 900 MW, contributing to a $1.64 per kW-month increase in the NYCA clearing price after January. Second, the sales of new capacity in New York City, Long Island, and upstate New York contributed to reducing capacity prices during the period. Significant capacity additions occurred in August 2009, November 2009, June 2010, and September 2010.

[78] Special Case Resources ("SCRs") are end-use loads capable of being interrupted upon demand, and distributed generators, both of which must be rated 100 kW or higher and are invisible to the ISO's Market Information System.

Figure 57: Capacity Market Results for NYCA
May 2009 to February 2011



Note: Sales related to Unforced Deliverability Rights ("UDRs") are shown as "Internal Capacity."

Substantial changes in imports and exports in response to changes in capacity prices in New York and neighboring markets also affected prices. For example, imports rose sharply in March 2010 following the retirement of Poletti. Likewise, imports fell and exports increased after the market cleared at close to zero in November 2010.

NYCA spot prices during the period were also affected by the reduction in the capacity requirement, driven by the 905 MW decrease in the NYCA summer peak load forecast from 2009 to 2010. This was, however, partly offset by an increase in the installed capacity requirement from 116.5 percent to 118 percent over the same period.

C. Capacity Market Design – Zone Configuration and Deliverability

The capacity market provides economic signals to facilitate investment sufficient to allow New York State to meet its planning reserve margin requirements. Transmission constraints limit the ability of the system to deliver supplies from upstate New York to New York City and Long Island, so these areas have local planning requirements. Accordingly, three regions are represented as separate zones in the capacity market: New York City (Zone J), Long Island (Zone K), and Rest-of-State (Zones A to I). By setting a distinct clearing price in each capacity region, the capacity market provides incentives to invest in areas where it is needed.

The Deliverability Test determines when resources in one location cannot be fully delivered to another location in the same capacity zone. The deliverability test has indicated issues related to transmission constraints within the Rest-of-State zone that prevent capacity outside Southeast New York from serving load in Southeast New York. In order to be able to sell capacity in the market, new resources or imports that are deemed undeliverable must either pay to upgrade the transmission network so that they can be fully delivered or acquire deliverability rights from another market participant.[79] Resources may be undeliverable because excess supply on the unconstrained side of a constraint cannot all be transferred across the constraint, even if such transfers would not likely occur in reality and the constraint would not likely bind.

The new deliverability test creates several significant efficiency and competitive concerns. First, it does not provide efficient incentives in constrained areas to invest in supply resources, demand resources, and transmission facilities, or to maintain existing resources. Second, it creates a substantial barrier to entry for competitive new supplies and imports in unconstrained areas, reducing competition in the market. These issues are exacerbated by the fact that the deliverability test is unrealistic and can raise deliverability concerns when transmission capability is sufficient to allow "undeliverable" resources to contribute to satisfying reliability needs statewide. Lastly, it will likely raise capacity costs inefficiently for New York consumers.

We have previously recommended that these inefficiencies be addressed by defining capacity zones that reflect transmission bottlenecks affecting the planning needs of the system. Doing so would provide the market with a mechanism for producing long-term economic signals that

[79] The Deliverability Test found that projects outside Southeast New York were deemed undeliverable, beginning with Class Year 2008 projects (i.e., projects that requested interconnection in 2008) and including all future class years. To sell capacity, these suppliers would have had to pay to upgrade transmission into the Hudson Valley at a cost of over $170 per kW or acquire rights from existing suppliers.

accurately and efficiently reflect the supply and demand for capacity in different areas, which is not possible under the current deliverability framework. Our prior State of the Market Reports provided illustrative examples to show why this is the case. These examples also explain why the current method of defining a single zone in the ROS area and applying transmission costs to new entrants under the current deliverability test will hinder efficient investment and will not likely provide efficient incentives to invest in areas where capacity is needed.[80]

The transmission bottleneck that has raised deliverability issues most recently is an interface into Southeast New York. Defining a new capacity zone in Southeast New York would be beneficial because it would:

- Allow the capacity market to signal where new capacity would be most beneficial. This may be particularly important in Southeast New York where the cost of new entry is likely higher than in other areas.
- Enable more suppliers to sell capacity outside the new zone(s), thereby lowering capacity costs for New York consumers in those areas.

Some have argued that applying the deliverability tests and rules as currently envisioned will encourage transmission investment. However, creating new zones should not reduce the likelihood that investments will be made to upgrade the transmission system when it is economically efficient. If those that invest in new transmission capability between capacity zones have access to the economic property right corresponding to the difference in the capacity prices between the zones, then creating new zones will provide investors in transmission with clear economic signals and incentives to invest efficiently in transmission.

The NYISO recently filed proposed criteria with FERC for defining new capacity zones.[81] We did not support the NYISO proposed criteria and filed a protest in that case because the criteria would likely fail to define new capacity zones that are needed to efficiently satisfy the planning requirements of the system.[82]

80 See *2009 State of the Market Report on the NYISO Electricity Markets* by Potomac Economics.

81 See *Compliance Filing Proposing Criteria to Govern the Potential Creation of New Locational Capacity Zones*, Docket No. ER04-449-000, date January 4, 2011.

82 See *Motion to Intervene and Comments of the New York ISO's Market Monitoring Unit*, Docket No. ER04-449-000, dated January 25, 2011.

Instead, we recommend one of two following alternative approaches for defining new capacity zones. The objectives described in this section can be achieved if NYISO either:

- Defines new capacity zones whenever deliverability constraints bind on highway transmission facilities, which will ensure consistency between the capacity zones and the results of the deliverability test; or
- Pre-defines a full set of capacity zones and inter-zonal limits that address potential deliverability issues.

The latter approach is preferable because it would establish a stable zonal structure that would not require frequent re-definition of the capacity zones over time. It would allow price separation between areas when necessary, but allow areas to clear at the same price when deliverability constraints do not bind between them.

D. Capacity Market Design – Technology of Hypothetical New Unit

The capacity demand curves are set to ensure that a sufficient amount of investment in new resources (and maintenance of existing resources) occurs to satisfy the NYISO's planning reserve requirements efficiently. Such investors must cover their entry costs from the energy, ancillary services, and capacity markets. Ideally, these markets efficiently govern investment and retirement decisions such that the NYISO would satisfy planning requirements with a minimum amount of surplus.

The capacity market is designed to ensure that efficient investments recover necessary revenues that are not recovered through the energy and ancillary services markets. To do this, demand curves are established that should allow suppliers to recover the Net CONE (i.e., CONE minus net revenues from the energy ancillary services markets) for the investments over the long term. For this process, a technology must be chosen and the tariff specifies a peaking unit. In long-run equilibrium, all types of resources (baseload, intermediate, peaking) should be equally economic. As one type of resource becomes more profitable, increased investment in that type should reduce its profitability and increase the profitability of others by shifting the net revenues in the energy and ancillary services market. However, this may not be the case in the short-run based on the relative levels of energy and ancillary services prices.

There are advantages to choosing a peaking resource as the default technology because the uncertainties regarding the CONE and net energy and ancillary services are lower than for most other technologies. In the short-run, however, the default peaking resource may or may not be the most economic investment. When a demand curve is developed to support investment in a unit that is not the most economic type of unit, investors still have an incentive to invest in the most economic type of unit. As a result, the capacity market may provide incentives to invest when additional investment is not necessary. This can lead to a sustained surplus that will dissipate only when the default peaking resource is among the most economic investments once again. Until this happens, the capacity market may motivate inefficiently large quantities of investment and raise overall market costs. Therefore, it would be preferable for the default resource upon which the capacity demand curves are based to always be among the most economic and realistic investment choices, given regulatory and environmental restrictions.

Given the capacity surpluses that are prevailing and forecasted to continue, and the fact that the most recent investments have not been in the default peaking resources, an examination of the relative economics of alternate technologies is warranted. Recent data produced by NERA and Sargent & Lundy suggests that the Net CONEs are substantially higher for peaking resources than for other resources. For example, the Net CONE for the default peaking resource in New York City is 46 percent higher than the Net CONE for a combined cycle unit.[83]

These estimated cost differences are consistent with the fact that combined cycle units have been the most common supply investment in recent years. This type of short-term disequilibrium (i.e., when the Net CONE of one technology is substantially higher or lower than another) can result in Demand Curves that lead to inefficient levels of investment and sustained surpluses. Hence, we recommend the NYISO consider modifying its tariff to allow it to select the most economic generating technology to establish the demand curves in the demand curve reset process.

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[83] See *Compliance Filing and Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, dated March 29, 2011, Attachment IV. Since this filing, it was determined that the demand curve unit would be eligible for property tax abatement in New York City. If a combined-cycle unit were eligible for the same property tax abatement, the percentage difference between the Net CONE of a combustion turbine and a combined cycle would be even larger than 46 percent.

VIII. Demand Response Programs

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response.

The New York ISO operates five demand response programs that allow retail loads to participate in NYISO wholesale electricity markets. Three of the programs allow NYISO to curtail loads in real-time for reliability reasons:

- *Emergency Demand Response Program ("EDRP")* – These resources are paid the higher of $500/MWh or the real-time clearing price. There are no consequences for enrolled EDRP resources that fail to curtail.[84]
- *Installed Capacity/Special Case Resource ("ICAP/SCR") Program* – These resources are paid the higher of their strike price (which can be up to $500/MWh) or the real-time clearing price. These resources sell capacity in the capacity market and accept an obligation to respond when called in exchange.[85]
- *Targeted Demand Response Program ("TDRP")* – This program curtails EDRP and SCR resources when called by local Transmission Owner for reliability reasons at the sub-zone level in New York City. EDRP resources are paid the higher of $500/MWh or the real-time clearing price. SCRs are paid the higher of their strike price or the real-time clearing price. These resources are not required to respond.

Two additional programs allow demand response resources to participate in the day-ahead energy market or in the ancillary services markets:

[84] Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

[85] Special Case Resources participate through Responsible Interface Parties ("RIPs"), which serve as the interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two hour notice, provided that the resource is informed on the previous day of the possibility of such a call.

- *Day-Ahead Demand Response Program ("DADRP")* – This program allows curtailable loads to offer into the day-ahead market (with a floor price of $75/MWh) like any supply resource. If the offer clears in the day-ahead market, the resource is paid the day-ahead clearing price and must curtail its load in real-time accordingly.[86]
- *Demand Side Ancillary Services Program ("DSASP")* – This program allows resources to offer regulation and operating reserves in the day-ahead and real-time markets.

Despite these programs, significant barriers to participation in the wholesale market by loads remain. The most significant of these barrier is that most retail loads have no incentive to respond to real-time prices even when they exceed their marginal value of consumption. Hence, developing programs to facilitate participation by loads in the real-time market could be beneficial, although it is important that such a program provide efficient incentives to demand response resources.

In this section, we evaluate the demand response programs in New York. In particular, this section discusses the following three areas:

- Participation in the existing demand response programs;
- Pricing during shortage conditions; and
- Future enhancements to demand response programs.

A. Demand Response Programs in 2010

Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, DADRP and DSASP provide a means for economic demand response resources to participate in the day-ahead energy market and ancillary services markets (day-ahead and real-time), respectively. The other three programs, EDRP, SCR, and TDRP, are emergency demand response resources that are called when the NYISO forecasts a reliability issue. Currently, nearly 90 percent of the demand response resources in New York State are reliability demand response resources.

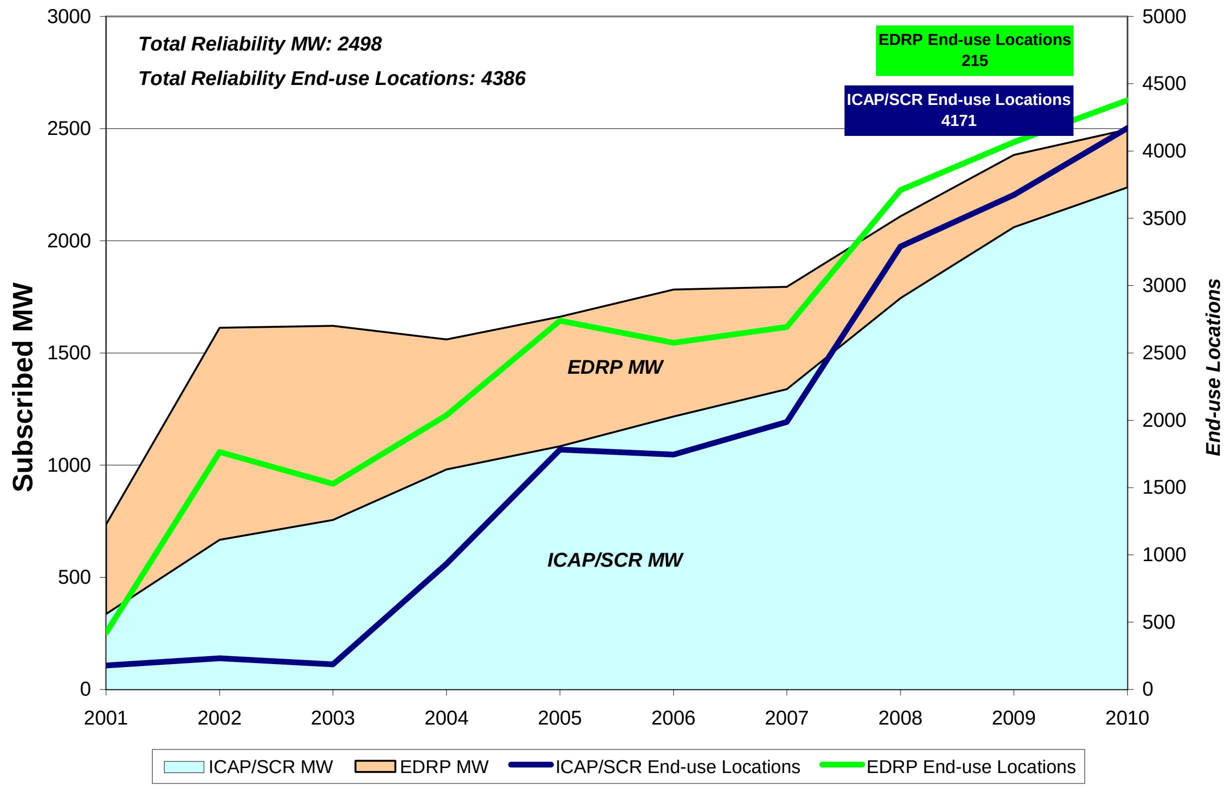
86 Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead or real-time LBMPs.

This sub-section discusses participation in each of the NYISO's five demand response programs. The first part summarizes participation in the reliability demand response programs, while the second part discusses participation in the economic demand response programs.

1. Reliability Demand Response Programs

The following figure summarizes registration in two of the reliability programs on an annual basis from 2001 to 2010. Since EDRP and SCR resources in New York City participate in the TDRP program on a voluntary basis and TDRP resources are not shown separately.

Figure 58: Registration in NYISO Demand Response Reliability Programs
2001 – 2010



Note: Figure reproduced from the NYISO's January 25, 2011 filing to FERC related to the Demand Response Compliance Report.

Figure 58 shows SCR program registration has grown consistently in each year since 2001, while EDRP program registration has gradually declined since 2002. These trends reflect that many resources have switched from the EDRP program to the SCR program in order to earn revenue from the capacity market.

In 2010, total registration in the EDRP and SCR programs included 4,386 end-use locations enrolled, providing a total of 2,498 MW of demand response capability, which represents a 4.5 percent increase from 2009. SCR resources accounted for 95 percent of the total reliability program enrollments and 90 percent of the enrolled MWs. EDRP and SCR resources in New York City are automatically registered in the TDRP program.

When EDRP resources are activated under the reliability programs (SCR, EDRP, and TDRP), they are paid the higher of $500/MWh or the LBMP for the amount of the load reduction.[87] When SCR resources are activated under the reliability programs, they are paid the higher of their strike price or the LBMP for the amount of the load reduction. This is greater than the marginal value of consumption for many loads during peak periods. Such loads have an incentive to respond, even though they are served under regulated or otherwise fixed rates that cause them not to pay the wholesale price of electricity.[88] However, to the extent that some resources have a marginal value of consumption exceeding $500/MWh, they would be more likely to participate in demand response programs if they were allowed to submit strike prices exceeding $500/MWh.

In addition to receiving payments for curtailing in real-time, SCR resources can sell their curtailable load in the capacity market in exchange for an obligation to respond when called. Accordingly, these resources are counted towards meeting the planning reserve margin requirement for NYCA, as well as for New York City and Long Island. These resources provide substantial benefits by reducing the overall cost of meeting the planning requirements since the requirements would otherwise need to be met by building more costly generation resources and/or transmission facilities. In 2010, total SCR registration reached approximately 547 MW in New York City, 176 MW in Long Island, and 1,517 MW in Upstate areas. These resources

87 SCR resources receive the higher of their strike price or the LBMP, although more than 90 percent submit strike prices at or very close to the maximum level of $500/MWh. In 2010, nearly 98 percent of the SCR strike prices were at or above $490/MWh.

88 While the average regulated rate paid by load is much lower than $500/MWh, the value of power at peak times is typically much higher than the average. Hence, if the NYISO did not pay for load reductions, the interrupted loads would save only the regulated rate, which does not reflect the marginal system cost of serving the load as reflected in the wholesale LBMPs.

increase the competitiveness of the capacity market, particularly in New York City and Long Island where ownership of generation is relatively concentrated.

Given the growing reliance on SCR resources to meet New York's capacity needs, it is increasingly important to ensure that SCR resources can perform when called. The current SCR baseline methodology is based on the resource's monthly peak loads from the prior year, which may not accurately indicate the ability of the SCR resources to respond if called in the current year. The NYISO made revisions to the baseline methodology, aggregation performance, and deficiency calculation, effective for the Summer 2011 Capability Period.

2. Economic Demand Response Programs

The DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to generation supply offers, subject to a bid floor price of $75/MWh.[89] Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. DADRP participants are also eligible for bid production cost guarantee payments to make up for any difference between the market price received and their block bid price across the day. Load reductions scheduled in the day-ahead market obligate the resource to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead and the real-time price of energy.

During the twelve months from September 2009 to August 2010, market participants submitted DADRP offers in Zone F (Capital) and Zone K (Long Island). An average of 2.3 MW of DADRP resources was offered each hour in the day-ahead market and an average of 1.1 MW was scheduled in 134 hours during the period Hence, the quantities scheduled under the DADRP program were extremely small. Given that such resources may submit virtual transactions that are very similar to DADRP schedules, the value of this program is dubious.

89 Prior to November 1, 2004, the offer price had to be $50/MWh or higher. As of November 1, 2004, the offer floor price for DADRP has been set at $75/MWh.

The NYISO established the DSASP program in June 2008 to enable demand response resources to provide ancillary services. This program has the potential to increase the amount of resources that provide operating reserves and regulation services, enhancing competition, reducing costs, and improving reliability. Under this program, resources must qualify to provide operating reserves or regulation under the same requirements as generators. To the extent that DSASP resources increase or decrease consumption when deployed for regulation or reserves, they settle the energy consumption with their load serving entity rather than with the NYISO.

However, no resources have fully qualified as DSASP resources yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner. To expedite the process, NYISO is developing ways to communicate directly with DSASP resources rather than through the local Transmission Owner.

In addition to the opportunities that loads have under the five demand response programs administered by the NYISO, some loads are also encouraged to respond to wholesale market prices under the New York Public Service Commission’s Mandatory Hourly Pricing (”MHP”) program. Under the MHP program, retail customers as small as 400 kW (depending on their load serving entity) pay for electric supply based on the day-ahead market LBMP in their load zone in each hour. Currently, approximately 6 GW of retail load customers are under this program. This program gives loads strong incentives to moderate their demand during periods when it is most costly to serve them, resulting in lower costs for all customers and more efficient consumption decisions. In the future, some retail customers as small as 100 kW are expected to participate in the MHP program. This change would increase total participation in the MHP program and therefore increase the program’s overall benefits to New York.

B. Demand Response and Shortage Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under shortage conditions. Ordinarily, to be involved with setting prices in the real-time market, resources must be dispatchable by the real-time market model on a five-minute basis. EDRP and SCR resources must be called in advance based on projections of operating conditions, they are not dispatchable by the real-time model.

Hence, there is no guarantee that these resources will be "in-merit" relative to the real-time clearing price, and their deployment can actually lower prices. Prices can be well below $500/MWh after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time. NYISO currently has two market rules that improve the efficiency of real-time prices when demand response resources are activated.

First, NYISO has special shortage pricing rules for periods when demand response resources are deployed. When a shortage of state-wide or eastern reserves is prevented by the activation of demand response, real-time clearing prices are set to $500/MWh within the region (unless they already exceed that level). This rule helps reflect the cost of maintaining adequate reserve levels in real-time clearing prices and improves the efficiency of real-time prices during shortage conditions.

Second, to minimize the price-effects of "out-of-merit" demand response resources, NYISO implemented the TDRP, which enables the local transmission owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. Prior to July 2007, local transmission owners called all of the EDRP and SCR resources in a particular zone to address local issues on the distribution system. As a result, substantial quantities of demand response were activated that provided no reliability benefit, depressed real-time prices, and increased uplift.

In 2010, the NYISO activated emergency demand response resources on four occasions. TDRP resources were activated on June 28 and June 29, and SCR and EDRP resources were activated on July 6 and July 7. We evaluated the real-time pricing during the two July events in greater detail in Section VI.C.3.[90]

C. Enhancements and New Developments

Price-responsive demand has great potential to enhance wholesale market efficiency because modest reductions in consumption by end-users during high-price periods can significantly

[90] We did not evaluate the pricing during the two TDRP events because TDRP resources are activated for reliability issues on the Con Edison distribution system rather than for the bulk power system.

reduce the costs of committing and dispatching generation. Furthermore, price-responsive demand mitigates market power, improves power system reliability, and reduces the need for new investment in generation. The NYISO has several ongoing initiatives to facilitate participation in the wholesale market by loads.

First, the NYISO continues to develop the Demand Response Information System (DRIS), which automates much of NYISO's manual processes that support the participation of demand response. The automated system directly interfaces with other NYISO software systems and performs the core functions of registration processing, event notification, and reporting. It also automates other functions including settlements, performance monitoring, meter data management, and other activities that have historically required significant manual effort. The DRIS is expected to substantially reduce administrative burdens, contribute to an increase in demand response program participation, and reduce costs for both NYISO and program participants. In addition, it will have the flexibility to support new demand response products and evolving market rules. DRIS have been deployed in phases since November 2009.[91]

Second, NYISO is developing the capability to communicate directly (i.e., "Direct Communication") with DSASP resources rather than communicating through the local transmission owner. There have been long delays in some cases related to communicating through the local transmission owners. Working directly with DSASP resources is expected to lead to an increase in participation in the program. NYISO stakeholders have approved a project for 2011 to define the functional requirements for Direct Communication for DSASP.

Third, NYISO is developing the process that would allow smaller demand response resources (e.g., retail customers) to provide ancillary services as DSASP resources. Aggregations of small demand resources are currently able to participate in the reliability-based demand response programs (EDRP, SCR, and TDRP) and the DADRP program. These resources are not able to participate in the DSASP program because they do not satisfy the applicable telemetry and communication requirements. Direct Communication for DSASP is expected to provide a streamlined approach that will facilitate the participation of aggregated small demand resources

[91] The NYISO has deployed four releases of DRIS: November 2009, March 2010, June 2010, and January 2011.

in the NYISO's ancillary services markets. The NYISO presented its market design concept to stakeholders in November 2010 and is working to deploy the ability for aggregated small demand resources to provide operating reserves in late 2011.[92]

[92] The presentation of the Market Design Concept is available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2010-11-30/DSASP_Aggregations_113010_PRLWG.pdf