2011 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit (MMU), our core functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending improvements to the market design. The *2011 State of the Market Report* presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2011. This executive summary provides an overview of key market outcomes and highlights our evaluations and recommendations for the markets.

The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets establish short-term and long-term 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.

A. Market Outcomes and Prices in 2011

Overall, we find that the NYISO markets performed competitively in 2011, producing market outcomes that were generally efficient and consistent with the fundamental supply and demand in New York. However, the report also identifies potential improvements that are summarized at the end of this Executive Summary.

Average electricity prices at the zone level in New York fell 6 to 8 percent from 2010 to 2011, which was primarily due to lower fuel prices and new capacity additions. Natural gas prices fell an average of 8 percent in 2011 as domestic production increased and mild winter temperatures in late 2011 reduced demand. Resources fired by natural gas are frequently the marginal source of supply in New York, so these fuel price changes generally translate into concomitant changes in electricity prices. Additionally, more than one gigawatt of new combined-cycle generating capacity was installed in the Capital Zone (September 2010) and New York City (July 2011).

Load averaged 18.6 GW in 2011, down slightly from 2010. However, New York experienced more hours with extreme high load conditions (i.e., when load exceeded 32 GW) in 2011 than in recent years. Load peaked at 33,865 MW on July 22, 2011, just 70 MW lower than the all-time peak set on August 2, 2006.

The overall amount of congestion was consistent with 2010 as congestion revenues collected in the day-ahead market totaled $407 million in 2011, down 3 percent from 2010. Congestion was less prevalent across the Central-East Interface in 2011, while congestion into Southeast New York and into Long Island became more frequent. Congestion and losses together led average energy prices in 2011 to range from $41 per MWh (West Zone) to $65 per MWh (Long Island).

Ancillary services prices changed significantly in 2011 because of changes in operating requirements and the availability of supply. Regulation prices fell on average from $29 per MWh in 2010 to $12 per MWh in 2011 because new supply entered the market and because the regulation demand curve (which determines prices during regulation shortages) was reduced in May 2011. However, prices for 10-minute spinning and non-spinning reserves rose 19 percent and 70 percent in eastern New York in the day-ahead market as the effective requirement for eastern 10-minute reserves rose from 1,000 MW to 1,200 MW in December 2010.

Finally, capacity market prices fell 35 percent in New York City and 80 percent in other areas from 2010 as new supply entered the market and a lower summer peak load forecast led to lower installed capacity requirements.

Overall, our evaluation indicates that prices in all of the NYISO's markets taken together in 2011 were far below levels that would support investment in new peaking generation anywhere in New York. This is expected because there are large capacity surpluses in New York City, Long Island, and statewide. Therefore, this fact alone raises no significant concerns. However, the report identifies changes in both the energy market and capacity market that will improve the efficiency of the long-term economic signals provided by the NYISO markets.

B. Day-Ahead Market Performance

Convergence between day-ahead and real-time prices is important because the day-ahead market determines which resources are committed each day. Convergence in the energy markets was relatively good in most areas, although large differences occur on some individual days. Virtual trading activity helped align day-ahead prices with real-time prices, particularly when modeling and other differences between the day-ahead and real-time markets would otherwise lead to inconsistent prices.

Convergence at the nodal level was poor at several locations in New York City and Long Island due to inconsistent congestion patterns between day-ahead and real-time. Convergence remained poor for operating reserves, particularly during peak load periods when average real-time operating reserve prices were substantially higher than day-ahead prices on average.

C. Competitive Performance of the Market

As the Market Monitoring Unit, we evaluate the competitive performance of the markets for energy, capacity, and other products on an on-going basis. In the energy market, we found that the market performed competitively as the conduct of suppliers was generally consistent with expectations in a competitive market.

Market power mitigation measures in the energy market were effective in 2011. The instances of mitigation rose considerably in 2011 because of the application of the new reliability mitigation rule in October 2010 and changes in offer patterns by some suppliers in New York City.

In the capacity market, there were several key developments in 2011. Most notably, the supply-side mitigation measures were not fully effective and allowed some New York City capacity to not be sold from October to December 2011, which increased spot prices were as much as $4 per kW-month higher than if all of the capacity had been sold. The report discusses the supply-side mitigation issues and recommends improvements to address them.

D. Real-Time Market Operations

Real-time prices remained relatively volatile in 2011, exhibiting large price variations both statewide and in transmission-constrained areas. Large changes in inflexible resources (e.g., self-scheduled units and external transactions) and unforeseen changes in the flows across PAR-controlled lines were the most significant contributors. Such changes can create brief shortages or over-generation conditions as the output of flexible generation is adjusted to compensate for these changes.

We evaluated market operations during three types of shortage conditions:

- *Operating reserve and regulation shortages* – These occurred in a small share of intervals but had significant real-time price effects, increasing the annual average real-time price in eastern New York by 2 to 3 percent.

- *Transmission shortages* – These were also infrequent, but made significant contributions to real-time prices, including 4 percent of the annual average real-time price in Long Island and 2 percent in New York City.

- *Emergency demand response activations* – These were activated on July 21 to maintain transmission security into Southeast New York and on July 22 to maintain adequate reserves statewide. On July 22, real-time prices were generally consistent with the cost of demand response resources (usually $500/MWh) in the afternoon, but on July 21, real-time prices were far below levels that would reflect the cost of these resources.

Finally, phase angle regulators ("PARs") are used to control power flows over the network, generally to reduce overall production costs. However, some PAR-controlled lines are not operated for this purpose and, thus, sometimes move power in the inefficient direction (i.e., from a high price area to a low price area). The most significant inefficiencies we identified were associated with the two lines that are used to flow almost 300 MW of power from Long Island to New York City in accordance with a wheeling agreement between Consolidated Edison ("ConEd") and Long Island Power Authority ("LIPA") resulting in significant increases in production costs and other market effects in 2011.

E. Supplemental Commitment and Guarantee Payment Uplift

Guarantee payments to generators, which account for a large share of Schedule 1 uplift charges, fell from $211 million in 2010 to $167 million in 2011. Reliability commitment in New York City fell in 2011 by 37 percent as new transmission and a new 550 MW generator entered the market. Reliability commitment in West Upstate also fell in 2011 because there were fewer transmission outages that required the commitment of specific generators. These reductions were partly offset by the increase in uplift on Long Island that resulted from increased reliability commitments and higher oil prices.

More stringent mitigation rules were imposed in October 2010, limiting the amount by which units committed for reliability outside New York City can raise their offers. Improvements in the accuracy of generator reference levels also contributed to overall reduction in uplift in 2011.

F. Recommendations

The NYISO markets generally performed well in 2011. Our evaluation also identifies areas of improvement, so we make recommendations that are summarized in the following table. The table identifies the highest priority recommendations. Because some were recommended in prior reports, we indicate those that NYISO is addressing in the 2012 Project Plan.

Recommendation	In 2012 Project Plan	High Priority/ Benefit
Capacity Market		
1. Better align the local capacity requirements with the Class Year Deliverability Test to allow the market to produce efficient price signals.		✓
2. Use the most economic generating technology to establish the capacity demand curves.		✓
3. Clarify and improve the ICAP qualification requirements and supply-side mitigation measures.		✓
Real-Time Market		
4. Improve coordination of interface scheduling with neighboring markets.	✓	✓
5. Explore options for improving the operation of certain PAR-controlled lines more efficiently.		✓
6. Evaluate criteria for gas turbines to set prices in the real-time market.		
7. Consider using graduated Transmission Shortage Cost (i.e., demand curve).	✓	
8. Modify the real-time market to allow demand response to set prices when appropriate.	✓	
9. Identify and address causes of unnecessary real-time price volatility.		
Day-Ahead Market		
10. Modify mitigation rules for 10-minute reserves in day-ahead market.	✓	
11. Enable virtual trading at a disaggregated level.		

I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2011. The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

- Day-ahead and real-time markets that simultaneously optimize energy, operating reserves and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals that guide decisions to invest in new generation, transmission, and demand response resources (and to 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 a number of areas. The NYISO was the first RTO market to:

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

- Optimize the real-time commitment and scheduling of gas turbines and external transactions based on economics.

- 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 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 other 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.

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. However, it is important to for the markets to continue to evolve to improve alignment between the market design and the reliability needs of the system, to provide efficient incentives to the market participants, and to adequately mitigate market power. Hence, the report provides a number of recommendations that are intended to achieve these objectives.

II. Overview of Market Trends and Highlights

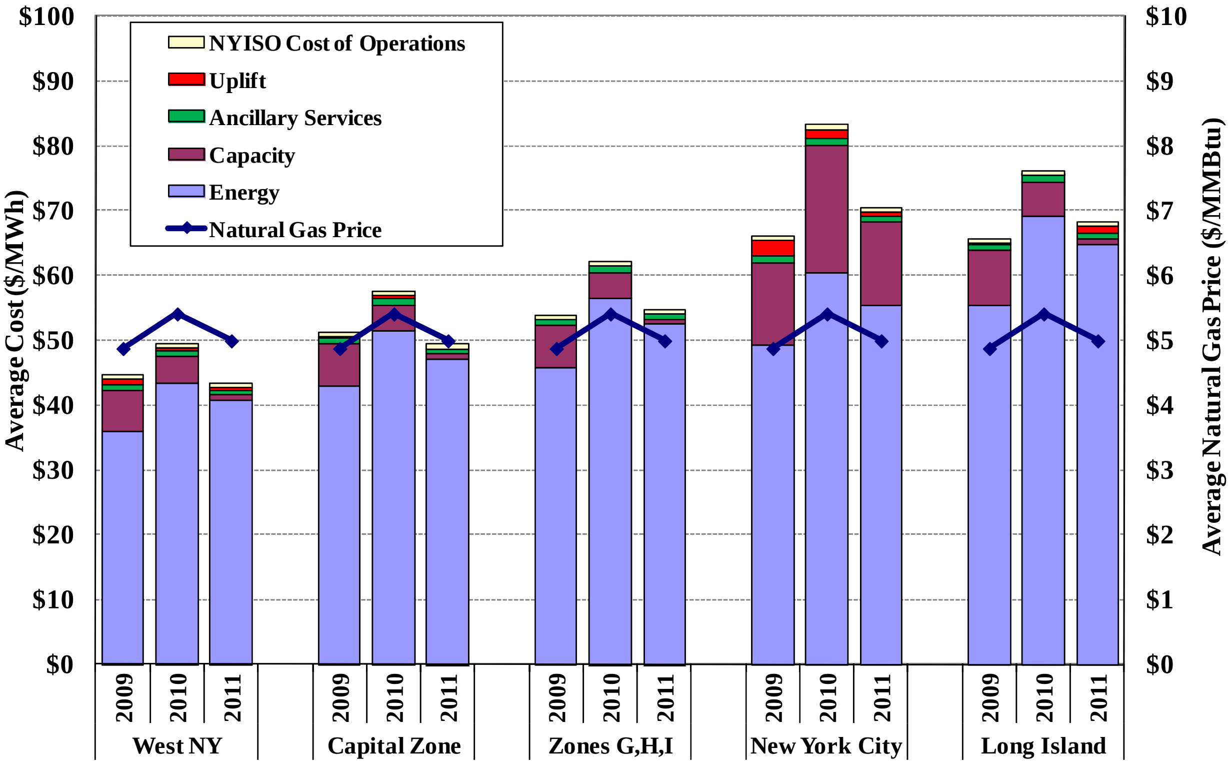
This section provides an overview of key market trends and highlights from 2011.

A. Total Wholesale Market Costs

Figure 1 evaluates wholesale market costs during the past three years by showing the all-in price for electricity, which reflects the average cost of serving load from the NYISO markets. The energy component of this metric is the weighted average real-time energy price, while all other components are the costs in these areas divided by the real-time load. [1]

Figure 1: Average All-In Price by Region

2009-2011



Average all-in prices of electricity ranged from approximately $43 per MWh in West New York to nearly $71 per MWh in New York City in 2011. Energy costs accounted for 79 percent of the all-in price in New York City and 94 to 96 percent of the all-in price in the other four regions.

1 Section I.A of the Appendix provides a detailed description of the all-in price calculation.

Capacity costs accounted for 18 percent of the all-in price in New York City and only 1 to 2 percent of the all-in price in the other four regions, reflecting the large amount of excess installed capacity outside New York City in 2011.

Average electricity prices fell 6 to 8 percent in the five regions of New York State from 2010 to 2011. These decreases were partly due to the change in natural gas prices, which fell 8 percent from 2010 to 2011. The entry of more than 1 GW of new combined-cycle generating capacity in the Capital Zone (September 2010) and New York City (July 2011) also contributed to the reduction in the energy and capacity prices over the period.

Average capacity costs fell 35 percent in New York City and approximately 80 percent in other regions from 2010 to 2011. In 2011, UCAP spot auction clearing prices averaged $5.81 per kW-month in New York City and just $0.29 per kW-month outside New York City. The capacity price reductions were driven primarily by: (i) the entry of more than 1 GW of new capacity in the Capital Zone and New York City; and (ii) reduced installed capacity requirements for New York City and NYCA primarily due to reductions in the summer peak load forecast from the previous year.[2]

The seasonal patterns of electricity prices and natural gas prices were typical in 2010 and 2011 as electricity prices rose in the winter months as a result of tight natural gas supplies and in the summer months as a result of high electricity demand. However, energy prices were unseasonably low in December 2011 due to mild winter weather, which contributed to low electricity demand and low natural gas prices.[3]

2 Figure A-71, Figure A-72, and Figure A-73 in the Appendix summarize capacity market outcomes.

3 Figure A-2 in the Appendix shows seasonal variations in electricity and natural gas prices.

B. Input Fuel Prices

Table 1 summarizes fossil fuel prices, a primary driver of wholesale power prices, on an annual basis from 2008 to 2011.[4] For comparison, the table also shows average electricity prices in eastern and western New York over the same period.

Table 1: Average Fuel Prices and Energy Prices
2008-2011

	2008	2009	2010	2011	Change from Previous Year 2009	2010	2011
Fuel Oil #2 ($/MMBtu)	$20.33	$11.69	$15.13	$20.99	-42%	29%	39%
Fuel Oil #6 ($/MMBtu)	$13.78	$9.36	$12.18	$17.98	-32%	30%	48%
Natural Gas ($/MMBtu)	$10.13	$4.87	$5.41	$4.98	-52%	11%	-8%
Cent. App. Coal ($/MMBtu)	$4.10	$1.99	$2.56	$2.95	-52%	29%	15%
East NY ($/MWh)	$100.06	$48.68	$58.59	$56.33	-51%	20%	-4%
West NY ($/MWh)	$66.56	$35.89	$42.92	$41.10	-46%	20%	-4%

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 source of generation that set market clearing prices, especially in eastern New York. Consequently, electricity prices in eastern and western New York have followed a pattern similar to natural gas prices over the past four years.

In most years, natural gas prices move in the same direction as other fossil fuel prices. In 2011, however, natural gas prices fell while coal and oil prices rose significantly. The narrowing spread between coal prices and natural gas prices combined with the lower delivery costs of natural gas and the better fuel efficiency of most gas-fired units combined to reduce the amount of generation from coal-fired capacity in 2011. Hence, the increase in coal prices partly offset the benefits of lower natural gas prices. The price spreads between fuel oils and natural gas also increased substantially in 2011, leading to higher electricity prices and increased guarantee payments in areas where oil-fired units are sometimes operated for reliability or to manage congestion.

[4] Figure A-6 in the Appendix shows the monthly variation of fuel prices.

C. Demand Levels

Demand is another key driver of wholesale market outcomes. In 2011, load averaged 18.6 GW, down slightly from 2010 and up 3 percent from 2009. New York experienced more hours with extreme high load conditions (i.e., load exceeding 32 GW) in 2011 than in recent years.[5] Load peaked at 33,865 MW on July 22, 2011, just 70 MW lower than the all-time peak set on August 2, 2006. Accordingly, the frequency of real-time operating reserve shortages in Eastern New York rose from 174 intervals in 2010 to 244 intervals in 2011. Due in part to the higher load levels, the NYISO called emergency demand response on two days: July 21 to maintain transmission security into Southeast New York and July 22 to maintain adequate reserves statewide.[6]

D. Transmission Congestion Patterns

Transmission congestion costs were generally consistent from 2010 to 2011. Congestion revenues collected by the NYISO in the day-ahead market (a useful indicator of the overall amount congestion) totaled $407 million in 2011, down slightly from $419 million in 2010.

Although the overall amount of congestion did not change significantly in 2011 from the previous year, there were noteworthy changes in the pattern of congestion due to transmission outages and changes in the availability of supply. Congestion across the Central-East Interface became less prevalent in 2011, while congestion on paths from the Capital Zone to Hudson Valley became more frequent primarily due to the entry of a new combined cycle unit in the Capital Zone, which tends to relieve congestion on the Central-East interface while exacerbating congestion from Capital to Hudson Valley. Congestion into Long Island became more significant in 2011primarily due to several significant outages of the transmission lines that bring imports from Upstate New York and from PJM.

5 Figure A-7 in the Appendix shows the load duration curves from 2009 to 2011.

6 Figure A-65 and Figure A-66 in the Appendix summarize available capacity conditions on these days.

E. Ancillary Services Market

The ancillary services prices changed significantly in 2011 due to changes in operating requirements and the availability of supply. Regulation prices in the day-ahead market fell from an average of $29 per MWh in 2010 to $12 per MWh in 2011. This resulted primarily from new regulation supply offers from both new and existing resources as well as reduced offer prices from existing resources. Regulation prices also fell partly as a result of reductions in the regulation demand curve made on May 19, 2011.[7]

In 2011, day-ahead prices for 10-minute spinning products decreased 24 percent in western New York, while 10-minute spinning and non-spinning reserve products in eastern New York rose 19 and 70 percent, respectively. These changes were partly due to an increase in the effective requirement for eastern 10-minute reserves from 1,000 MW to 1,200 MW in December 2010.

F. 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 by 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.

In the most recent Installed Capacity Demand Curve Reset Process, the levelized CONE for a new peaking unit was estimated at $280 per kW-year in New York City, $250 per kW-year on Long Island, and $120 per kW-year in upstate New York for the 2011/12 Capability Year. The following figure summarizes the estimated net revenues compared to the CONE for a new natural gas combined-cycle unit and a new natural gas combustion turbine in 2010 and 2011.

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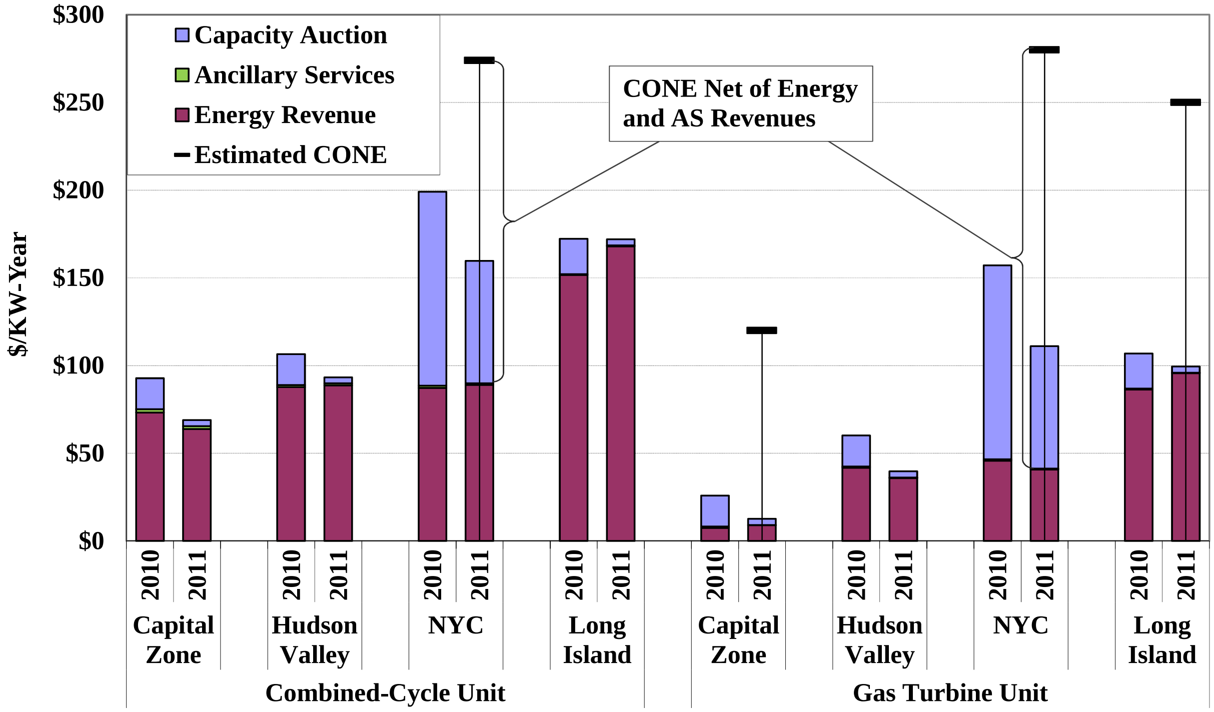
7 The regulation demand curve was reduced from $250 to $80 per MWh for shortages of 25 MW or less, and it was reduced from $300 to $180 per MWh for shortages of 25 to 80 MW. The regulation demand curves was increased from $300 to $400 per MWh for shortages exceeding 80 MW, although such large shortages are relatively infrequent. These changes are discussed further in Section V.F of the Appendix. High real-time regulation prices indirectly affect day-ahead regulation prices by increasing the opportunity cost of being scheduled for regulation in the day-ahead market.

Figure 2: Net Revenue for Combined-Cycles and Combustion Turbines
2010-2011



Estimated net revenues were lower than the estimated levelized CONE in 2011 by 56 percent in New York City, 60 percent on Long Island, and 89 percent in the Capital Zone.[8] Hence, there were no areas of New York where the net revenue levels in 2011 were close to the estimated levelized CONE for a new combustion turbine. These results are not surprising, given the current high levels of surplus capacity in New York City, Long Island, and NYCA.

In most areas of eastern New York, the estimated net revenues for a new combined-cycle unit were $40 to $75 per kW-year higher than those for a new combustion turbine in 2011.[9] CONE estimates for a new combined cycle unit were filed for informational purposes by the NYISO. Using assumptions consistent with those that were used to determine the final levelized CONE value implemented in October 2011 for a new combustion turbine, we estimate the CONE for a

8 See New York Independent System Operator, Inc., *Compliance Filing and Continued Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, Attachment III.

9 See Section I.E of the Appendix for additional information on our net revenue estimates.

combined cycle unit was $278 per kW-year.[10] 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, the NYISO's estimates of Net CONE (i.e., the capacity revenues needed to make new investment profitable under a long-run equilibrium level of surplus) for a new combined cycle unit are 64 percent lower than the Net CONE for a new combustion turbine unit in New York City.[11]

These estimates suggest 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.

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

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[10] This estimated CONE for a new combined cycle unit in New York City assumes property tax abatement comparable to that given to a new combustion turbine unit. It can be derived from the following two files: http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls; and http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/REVISED_WSR_Demand_Curve_Model_09-15-11_NYC.xls.

[11] This assumes an Excess Level of 2.3 percent for both types of unit, although the excess level would likely be higher if a combined cycle unit were used as the demand curve unit. Using a higher Excess Level for the combined cycle unit would increase the estimated Net CONE somewhat, but it would still likely be substantially lower than the estimated Net CONE of a new peaking unit. Similarly, the figure shows that the Net Cone based on actual results from 2011 was substantially lower for a combined cycle unit.

III. Competitive Performance of the Market

We evaluate the competitive performance of the markets for energy, capacity, and other products on an on-going basis. This section discusses the findings of our evaluation of 2011 market outcomes in three areas. First, we evaluate patterns of potential economic and physical withholding at a high load level in eastern New York. Second, we analyze the use of market power mitigation measures in New York City and in other local areas when generation is committed for reliability. Third, we discuss developments in the New York City capacity market and the use of the market power mitigation measures in 2011.

A. Potential Withholding in the Energy Market

In a competitive market, suppliers have strong incentives to offer their supply at prices close to their short-run marginal costs of production. Fuel costs account for the vast majority of short-run marginal costs for most generators, so the close correspondence of electricity prices and fuel prices is a positive indicator for the competitiveness of the NYISO's markets.

The "supply curve" for energy is relatively flat at low and moderate load levels and relatively steep at high load levels. Hence, as demand rises, prices rise gradually until demand approaches peak levels at which point prices can increase quickly, since more costly supply is required to meet load. Hence, prices are generally more sensitive to withholding and other anticompetitive conduct under high load conditions. [12]

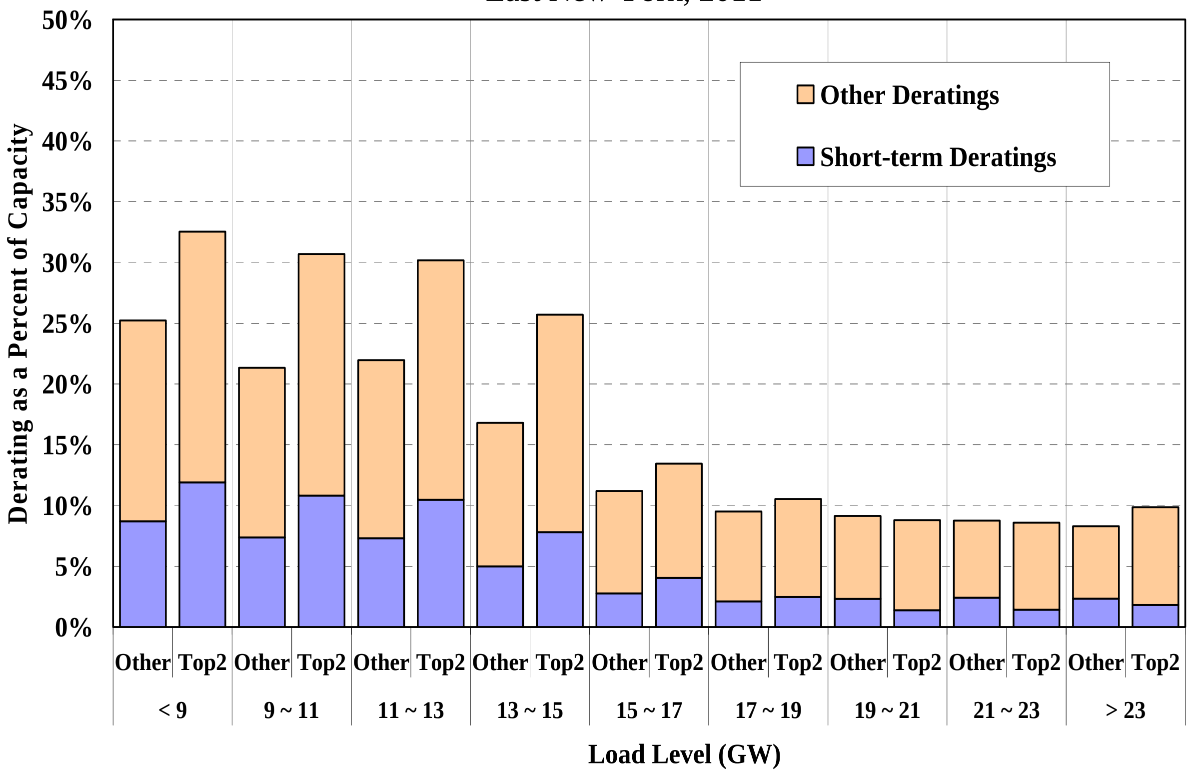
In our competitive assessment of the market, we evaluate potential physical withholding by analyzing generator deratings, and we evaluate potential economic withholding by estimating an

[12] Physical withholding is 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. A supplier with market power can profit from withholding when its losses from selling less output are offset by its gains from increasing LBMPs.

"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. [13]

Figure 3 and Figure 4 evaluate the two withholding measures relative to load levels and participant size. We focus on suppliers in Eastern New York because this area includes roughly two-thirds of the State's load, contains several areas with limited import capability, and is more vulnerable to the exercise of market power than Western New York. [14]

Figure 3: Deratings by Supplier by Load Level
East New York, 2011



13 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. The output gap calculation excludes capacity that is more economic to provide ancillary services. The Mitigation Threshold refers to the threshold used for statewide mitigation, which is the lower of $100 per MWh or 300 percent of the reference level, and the Lower Threshold, which is the lower of $50 per MWh or 100 percent of the reference level.

14 See Sections II.A and II.B in the Appendix for additional analyses of potential physical and economic withholding.

Figure 4: Output Gap by Supplier by Load Level
East New York, 2011

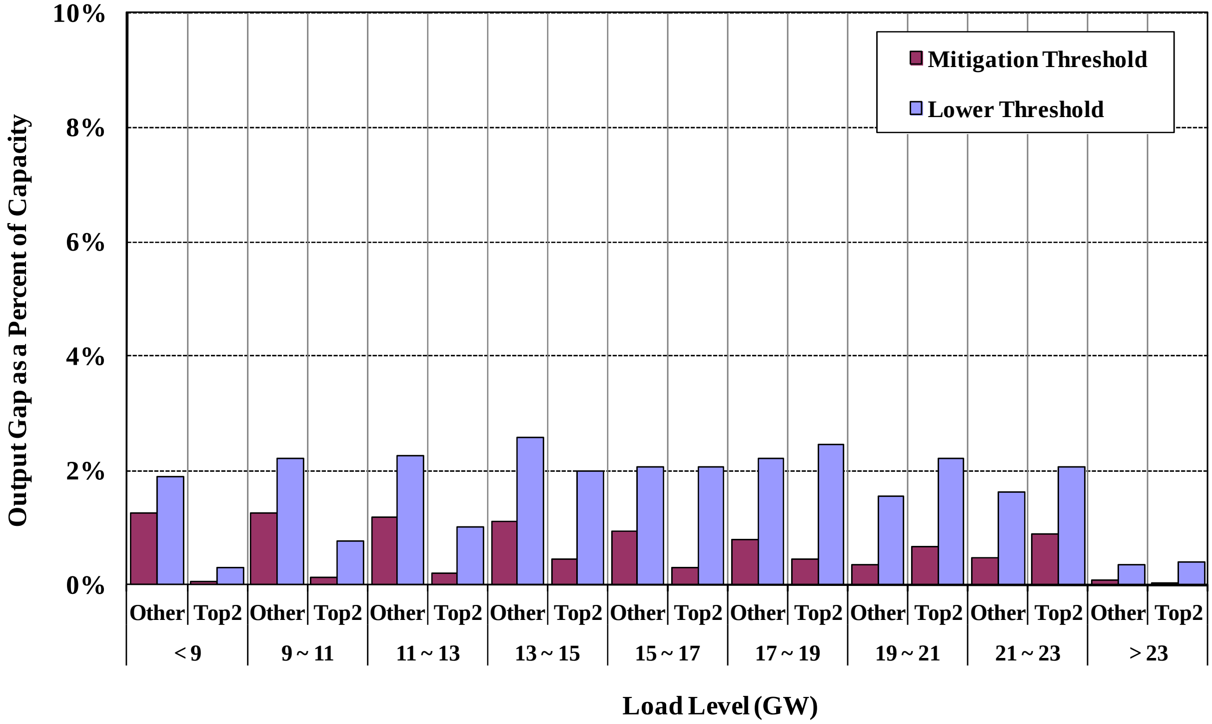


Figure 3 shows that the two largest suppliers and other suppliers increased the availability of their capacity during periods of high load when capacity was most valuable to the market. The majority of deratings were long-term (i.e., greater than 30 days), particularly in the highest load periods. This is a positive indicator given that long-term deratings are less likely to be used by a supplier to withhold profitably. In our review of high load periods, we found that most long-term deratings are associated with generators that are on a forced outage requiring significant repairs and with generators' emergency operating ranges that are only available when specifically requested by the NYISO operators. We found that short-term deratings were generally spread across many large and small suppliers.

Figure 4 shows that the output gap as a percentage of capacity at the statewide mitigation threshold usually averaged less than 1 percent of all capacity for both large and small suppliers. These levels are low and raise very few competitive concerns. It is also a positive indication that the output gap did not rise under high load conditions for either large or small suppliers, since that is when the market is most vulnerable to the exercise of market power.

Overall, the patterns of deratings and output gap were consistent with expectations in a competitive market and did not raise significant concerns regarding potential physical withholding and economic withholding. Additionally, we monitor and investigate potential withholding on a daily basis and found very little conduct that raised substantial competitive concerns. Accordingly, we find that the New York energy market performed competitively in 2011.

B. Mitigation in the Energy Market

In New York City and other transmission-constrained areas, individual suppliers are sometimes needed to relieve congestion and may benefit from withholding supply (i.e., may have local market power). Likewise, when an individual supplier's units must be committed to maintain reliability, the supplier may benefit from raising its offer prices above competitive levels. In these cases, the market power mitigation measures effectively limit the ability of such suppliers to exercise market power. This section evaluates the use of three key mitigation measures.

- Automated Mitigation Procedure ("AMP") in New York City – This is used in the day-ahead and real-time markets to mitigate offer prices of generators that are substantially above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[15]
- Reliability Mitigation in New York City – When a generator is committed for local reliability, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A $0 conduct threshold is used in the day-ahead market and the AMP conduct threshold is used in the real-time market.
- Reliability Mitigation in Other Areas – When a generator is committed for reliability and the generator is pivotal, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A conduct threshold of the higher of $10 per MWh or 10 percent of the reference level is used. This rule was implemented by the NYISO in October 2010 and it replaced much less restrictive thresholds.

In late 2010, it became more common for a generator to be mitigated initially in the day-ahead or real-time market and then to be unmitigated after consultation with the NYISO.[16] The NYISO

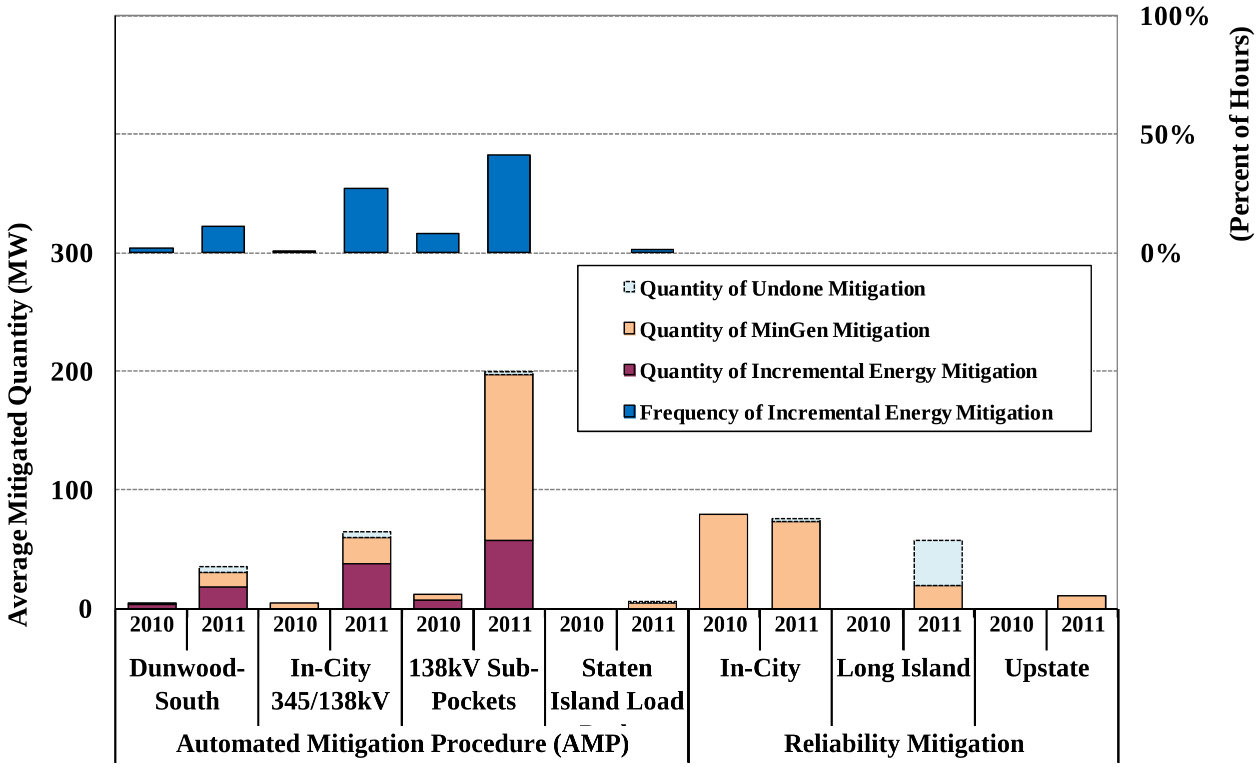
[15] The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

[16] NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation.

may unmitigate a resource for several reasons. First, a generator's reference level on a particular day is lower than the consultative reference level that the NYISO approved for the generator before the generator was mitigated.[17] Second, the generator attempted to inform the NYISO of a fuel price change prior to being scheduled, but the generator was still mitigated.[18] Third, a generator's fuel cost may change by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day. Hence, the generator may be mitigated in one hour of the day-ahead market and then unmitigated once the reference level is corrected.

Figure 5 and Figure 6 summarize the amount of mitigation that occurred in the day-ahead and the real-time markets in 2010 and 2011 as well as the amount of capacity that was unmitigated after consultation with NYISO.[19]

Figure 5: Summary of Day-Ahead Mitigation
January to September, 2010 & 2011



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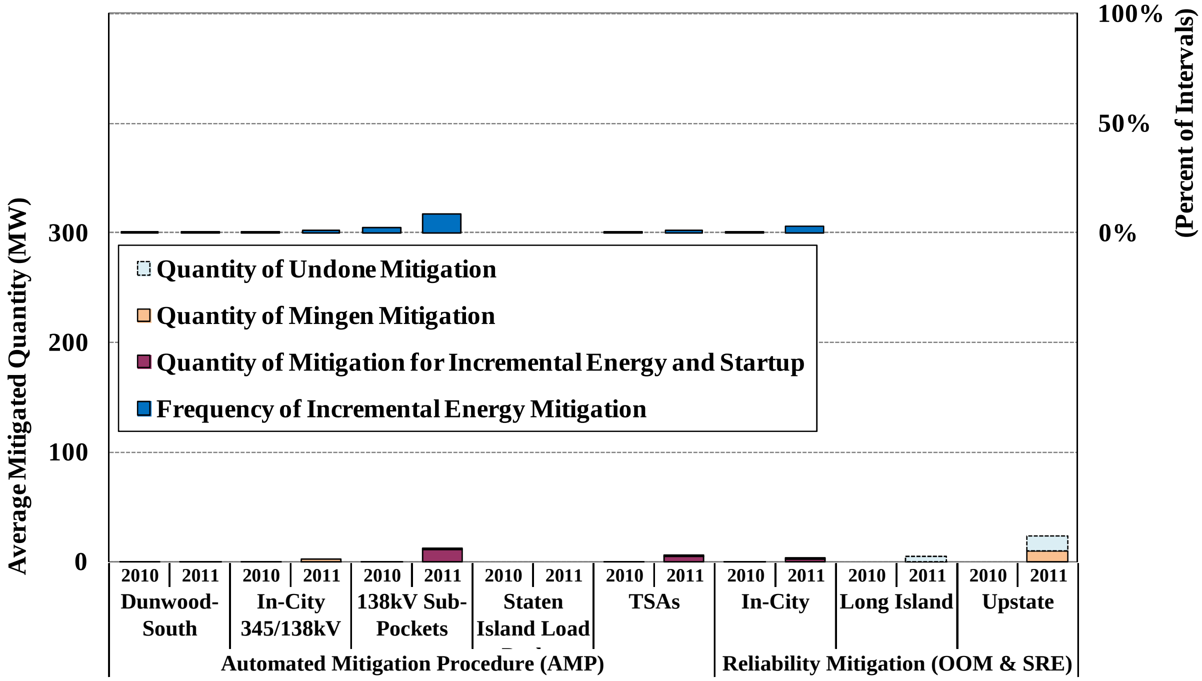
17 This includes when the NYISO approves the consultative reference level submission after the mitigation because the submission was made prior to mitigation.

18 See NYISO Market Services Tariff, Section 23.3.1.4.7.7.

19 See Section II.C in the Appendix for additional description of the figures.

Figure 6: Summary of Real-Time Mitigation
January to September, 2010 & 2011



The figures show that the vast majority of mitigation occurred in the day-ahead market. In 2011, day-ahead mitigation occurred primarily in New York City for the 138kV load pockets, for the 345/138kV interface, and for local reliability commitments. Mitigation increased substantially in Long Island and in Upstate New York from 2010 to 2011 due to the application of the new reliability mitigation rule in October 2010. However, the quantities mitigated were still much smaller than in New York City.

Mitigation increased substantially in New York City from 2010 to 2011, due to changes in offer patterns by some suppliers and improvements in the accuracy of reference levels for some generators. Several units in New York City consistently offered well above marginal cost. Accordingly, these units were mitigated frequently.

NYISO began unmitigating generators more frequently in 2011 for the reasons described above. In the first three quarters of 2011, 76 percent of the capacity that was initially mitigated in Long Island was subsequently unmitigated. Some mitigation consultations are still on-going for the period, so the amount of mitigation may decrease.

With the deployment of its new Reference Level Software ("RLS") in October 2010, the NYISO introduced the capability for generators to update the fuel prices used to calculate their real-time reference levels until 75 minutes ahead of a particular hour. The purpose of this capability, which is known as Increasing Bids in Real-Time ("IBRT"), is to allow generators to reflect their fuel costs more accurately, since this leads to more efficient dispatch and price signals. However, the current limits on fuel-price adjustments prevent generators from reflecting routine intra-day gas balancing charges in their reference levels.[20] Consequently, generators that are not scheduled in the day-ahead market sometimes switch to more expensive fuels or stop offering altogether in real-time, leading energy prices to be higher than if gas balancing charges were properly reflected in the generators' reference levels. We have proposed that the NYISO address this by relaxing the limit on fuel-price adjustments.

C. Competition in the Capacity Market

The capacity market is designed to ensure sufficient capacity is available to meet planning reserve margins and by providing long-term signals for efficient investment in both new and existing generation, transmission, and demand response. Buyer-side mitigation measures were adopted for New York City to prevent entities from artificially depressing prices below competitive levels by subsidizing the entry of uneconomic capacity.[21] Supply-side mitigation measures were adopted in New York City to prevent a large supplier from inflating prices above competitive levels by withholding economic capacity.[22] Given the sensitivity of prices in New York City to both of these actions, we believe that these mitigation measures are essential for ensuring that capacity prices in the City are efficient. This section discusses issues related to the use of the capacity market mitigation measures in 2011.

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20 See NYISO Market Services Tariff, Section 23.3.1.4.7.6.

21 The buyer-side mitigation measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. These are described in NYISO Market Services Tariff, Section 23.4.5.7.

22 The supply-side mitigation measures work by imposing an offer cap on pivotal suppliers in the spot auction and by imposing penalties on capacity otherwise withheld. These are described in NYISO Market Services Tariff, Sections 23.4.5.2 to 23.4.5.6.

1. Buyer-Side Mitigation Measures

The New York Power Authority issued a Request for Proposals in November 2007 for capacity and energy from a new facility. Astoria Energy II LLC was selected in April 2008 to build a 500 MW natural gas generating plant that would supply power under a power purchase agreement with NYPA. [23] The new unit was not mitigated under the buyer-side mitigation rules, although this determination has been challenged by existing New York City suppliers in a Commission proceeding that is on-going.[24] After the new facility entered the market, the New York City capacity price fell by $6 per kW-month in July 2011.[25]

The NYISO is working with stakeholders to adapt the buyer-side mitigation rules to address potential future issues related to existing facilities. In this regard, it is important for the buyer-side mitigation measures to deal appropriately with uprates of existing facilities, repowering of existing sites, and investments made in existing generators to avoid retirement. Accordingly, we support the NYISO's efforts to develop buyer-side mitigation rules for existing facilities.

2. Supply-Side Mitigation Measures

The supply-side mitigation measures were not fully effective in assuring the competitive performance of the capacity market in New York City late in 2011. In October 2011, some installed capacity in New York City began to go unsold, which should not occur under the supply-side mitigation measures unless the capacity is going out of service. The unsold capacity raised the spot auction clearing prices in New York City by as much as $4 per kW-month from October to December 2011. We have concluded that imperfections and ambiguities in the Tariff undermined the effectiveness of the supply-side mitigation measures. Hence, we make several recommendations to improve the efficiency of the outcomes in the capacity market:

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23 See www.nypa.gov/doingbusiness/powerpurchase/rfp5/rfp5.pdf and www.nypa.gov/press/2008/080429d.htm.

24 See Commission Docket EL11-50.

25 New York City capacity market outcomes are shown in Figure A-71 in Section VI of the Appendix.

- Modify the pivotal supplier test in the Tariff to prevent a large supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions), thereby avoiding designation as a pivotal supplier.[26]

- Clarify the existing rules (and modify the Tariff if necessary) related to the requirements a supplier must satisfy to remain qualified to sell installed capacity.[27] The rules should prevent capacity sales from a generator that is out-of-service for an extended period or out-of service and not under-going the steps necessary to come back into service.

- Clarify the existing rules (and modify the Tariff if necessary) related to the calculation of Going-Forward Costs.[28] The rules should specify that Going-Forward Costs include only costs a supplier must incur to remain qualified to sell capacity and can, therefore, only be avoided when it ceases to sell capacity.

Together, these recommendations would ensure that all of the in-service installed capacity that was economic would sell in the New York City capacity market.

[26] See NYISO Market Services Tariff, Section 23.4.5.5.

[27] See NYISO Market Services Tariff, Section 5.12.1.

[28] See NYISO Market Services Tariff, Section 23.4.5.3.

IV. Day-Ahead Market Performance

A. Price Convergence

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.

Table 2 evaluates price convergence at the zonal level by reporting the percentage difference between the average day-ahead price and the average real-time price in select zones, as well as the average absolute value of the difference between hourly day-ahead and real-time prices from 2009 to 2011.[29]

Table 2: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2009 -2011

	Avg. Diff % (DA - RT)			Avg. Absolute Diff %		
Zone	2009	2010	2011	2009	2010	2011
West	-0.1%	-1.0%	1.4%	32.9%	25.0%	24.0%
Central	1.2%	-0.5%	1.1%	31.9%	25.5%	25.7%
Capital	2.4%	1.3%	2.6%	31.9%	28.7%	28.1%
Hudson Valley	-0.5%	-1.5%	0.9%	30.2%	30.1%	30.0%
New York City	0.1%	-2.5%	1.8%	32.4%	32.8%	32.4%
Long Island	-3.7%	-5.8%	0.9%	35.4%	35.5%	35.5%

The table shows that energy price convergence was relatively good in 2011. At the zonal level, average day-ahead prices were higher than average real-time prices by a small margin (roughly 1 to 2.5 percent). The price convergence improved modestly in Southeast New York (i.e., Hudson Valley, New York City, and Long Island) from 2010 to 2011, partly due to improved operations

[29] Figure A-12 and Figure A-13 in the Appendix also show monthly variations of average day-ahead and real-time prices in these zones.

during Thunder Storm Alert ("TSA") events. TSA events are generally difficult to predict and can cause sharp increases in real-time prices.

At certain generator nodes, day-ahead and real-time prices did not converge as well as they did at the zonal level in 2011. For example, the Gowanus and Athens stations exhibited day-ahead price premiums of $6 and $5 per MWh (close to 10 percent of real-time prices) in the summer months. Conversely, the Valley Stream load pocket in Long Island exhibited a real-time price premium of $10 per MWh (more than 15 percent of real-time prices) outside the summer months.[30] At times, the pattern of intrazonal congestion may differ significantly 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. Nonetheless, we have generally found that convergence has been better at the nodal level in recent years than it was before 2009.

We have recommended for a number of years that the NYISO implement virtual trading at a disaggregated level to enable market participants to better arbitrage day-ahead and real-time prices at nodes that exhibit poor convergence. The general improvement in nodal price convergence in recent years reduces the likely benefits from allowing virtual trading, so we have reduced the priority level of this recommendation.

We find that convergence between day-ahead and real-time operating reserve prices remained relatively poor in 2011. 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.[31] 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 to levels that are below their marginal costs.[32] The NYISO is working with market participants on a proposal to modify the mitigation measures

[30] See Figure A-16 in the Appendix for additional results.

[31] Figure A-17 and Figure A-18 in the Appendix show the patterns of 10-minute non-spinning reserve prices in Eastern New York and 10-minute spinning reserve prices in Western New York.

[32] The day-ahead 10-minute spinning reserves offers of New York City units are limited to $0 per MWh by NYISO Market Services Tariff Section 23.5.3.3. The reference levels for day-ahead 10-minute non-spinning reserves offers are limited to $2.52 per MWh by NYISO Market Services Tariff Section 23.3.1.4.5.

for 10-minute reserves to allow suppliers to raise their offers to competitive levels.[33] We recommend the NYISO continue to move forward with changing the mitigation measures, which is also expected to improve consistency between the day-ahead and real-time prices.

B. Day-Ahead Load Scheduling and Virtual Trading

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

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.

The following figure summarizes virtual trading by geographic region. 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 2011. 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 and 2011.

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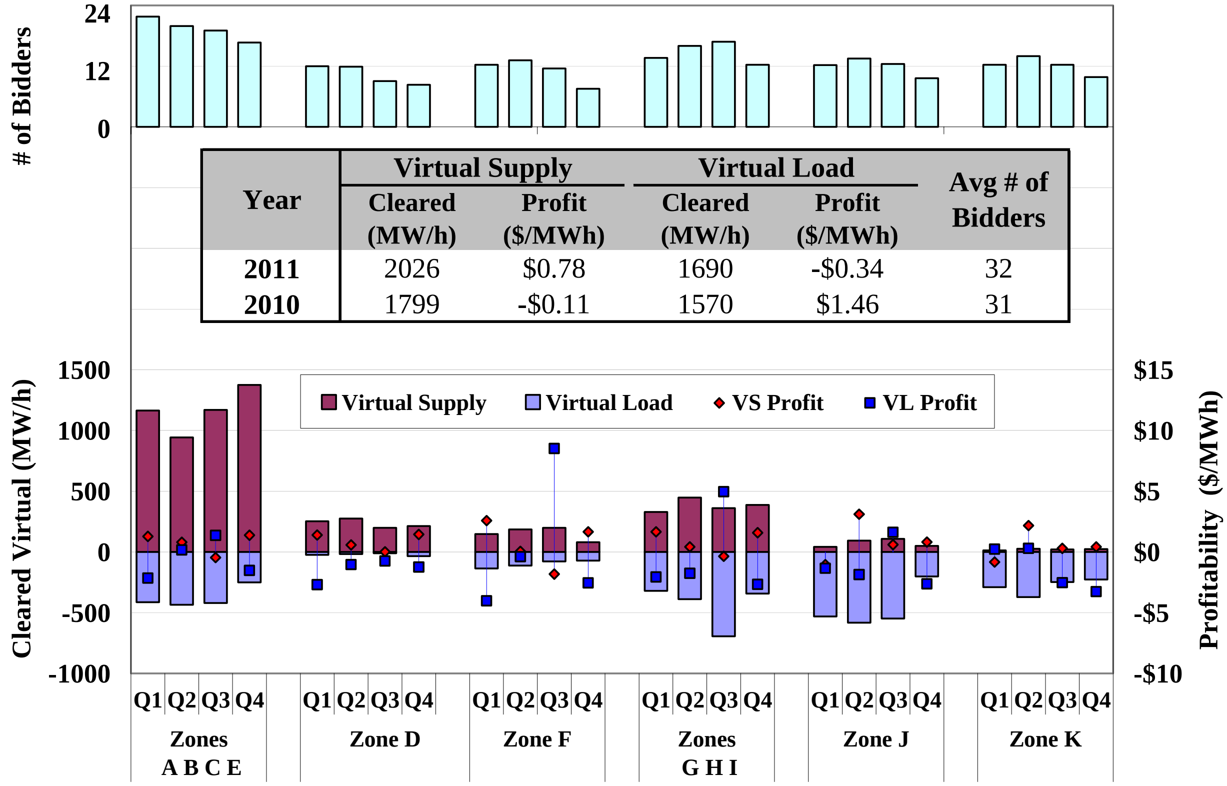
[33] The proposal is described in www.nyiso.com/public/webdocs/committees/mc/meeting_materials/2012-03-28/agenda_05_AS_MitigationPresentationMC_20120328.pdf.

Figure 7: Virtual Trading Activity
by Region by Quarter, 2011



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2011	2026	$0.78	1690	-$0.34	32
2010	1799	-$0.11	1570	$1.46	31

The figure shows that a large number of market participants regularly submit virtual bids and offers. On average, ten or more participants submitted virtual trades in each region and 32 participants submitted virtual trades somewhere in the state in 2011. However, the average number of market participants fell modestly in the fourth quarter after the implementation of new credit requirements in October 2011, which may have affected the participation of some firms.

The profits and losses of virtual load and supply have varied widely from quarter to quarter, reflecting the difficulty of predicting volatile real-time prices.[34] However, in aggregate, virtual traders netted approximately $9 million of gross profits in 2011. Virtual supply was generally more profitable than virtual load in 2011 and the average quantity of scheduled virtual supply also rose moderately from 1,799 MW in 2010 to 2,026 MW in 2011. This pattern reflects the market response to persistent day-ahead price premiums throughout New York in 2011.

[34] Figure A-39 in the Appendix also shows wide variations in profits and losses on a monthly basis.

There were substantial net virtual load purchases in Southeast New York and net virtual supply sales outside Southeast New York in 2011, consistent with prior years. This pattern of virtual scheduling helps correct some persistent inconsistencies between the day-ahead and real-time markets and improve convergence. For example, TSA events are only called and modeled in the real-time market. During such events, the transfer capability into Southeast New York is greatly reduced for local reliability concerns, which commonly results in high price spikes in real-time. Net virtual load purchases in Southeast New York help ensure that enough physical resources are scheduled in the day-ahead market in preparation for managing real-time congestion in this area during TSA events.

Similarly, outside Southeast New York, virtual supply is scheduled in a manner that helps ensure that physical resources are not over-committed in the day-ahead market. Wind generators, importers from Ontario, and certain generators in western New York tend to schedule substantially more output in the real-time market than in the day-ahead market. If the scheduling patterns of these resources were not offset by the scheduling virtual supply, it would result in large divergences between day-ahead and real-time prices outside Southeast New York.

While we believe there are compelling fundamental reasons that have resulted in net virtual load in Southeast New York, the results in 2011 indicate that these transactions were unprofitable on average. We closely monitor unprofitable virtual transactions as they can potentially raise potential manipulation concerns. In most cases, however, the losses can be attributed to unexpected real-time market outcomes.

Overall, virtual traders 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. The NYISO is also 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.

V. Transmission Congestion and TCC Auctions

A. Day-ahead and Real-time Transmission Congestion

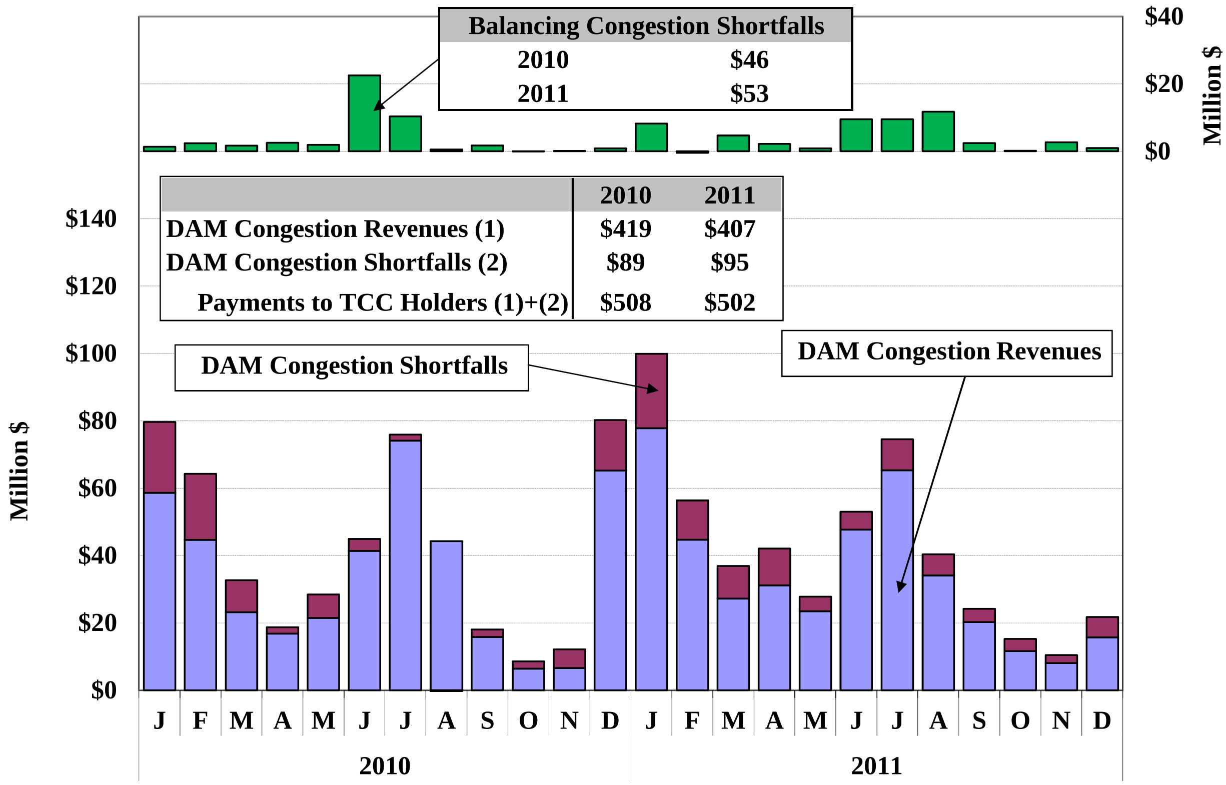
Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy demand. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based 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. 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 NYISO 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. 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 LBMP. There are no TCCs for real-time congestion since most power is scheduled through the day-ahead market.

The next figure evaluates overall congestion by summarizing the following three categories of congestion cost:

- Day-ahead Congestion Revenues – These are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market.
- Day-ahead Congestion Shortfalls – These occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders. This is caused when the amount of TCC sold by the NYISO exceeds the transmission capability of the power system as modeled in the day-ahead market.
- Balancing Congestion Shortfalls – These arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.

Figure 8: Congestion Revenues and Shortfalls
2010 - 2011



The figure shows that the overall congestion revenues and shortfalls were generally consistent from 2010 to 2011. Congestion revenues collected in the day-ahead market fell slightly, while day-ahead and balancing congestion revenue shortfalls both rose moderately.

Day-Ahead Congestion Revenues

Day-ahead congestion revenues are highest in the winter and summer months. In the winter, natural gas prices were higher, causing frequent congestion from western New York to eastern New York (where a larger share of generation is gas-fired). In the summer, higher load levels and frequent TSAs, which limit transfer capability into Southeast New York, led to more frequent congestion into Southeast New York, New York City, and Long Island.

Day-Ahead Congestion Shortfalls

Day-ahead congestion shortfalls are generally highest in the winter and shoulder months when most of the lengthy planned outages of transmission facilities are scheduled. For example, shortfalls on interfaces between the West Zone and Central Zone rose considerably in January primarily because of the planned outages of the Rochester-to-Pannell transmission lines. However, significant shortfalls still occurred during the summer of 2011 that were due to significant forced outages of transmission lines into Long Island from mid-July to mid-August and into Southeast New York in June and July.

The NYISO corrected an inconsistency between the TCC and day-ahead markets, which accounted for 39 percent of the day-ahead shortfalls in 2010. The TCC model had assumed that the PAR-controlled lines between New York and New Jersey imported a fixed quantity of power into New York, while the day-ahead market model assumed that the PAR-controlled lines carried a portion of the scheduled flows across the primary interface between PJM and New York. The inconsistency was addressed in May 2011 by conforming the assumptions of the TCC model to the day-ahead market assumption, after which day-ahead congestion shortfalls across the PAR-controlled lines between New York and New Jersey were virtually eliminated.

The NYISO has a process for allocating the day-ahead congestion shortfalls resulting from transmission outages to specific transmission owners.[35] In 2011, the NYISO allocated 44 percent of day-ahead congestion shortfalls in this manner, up from 37 percent in 2010. Given that a relatively small share of the day-ahead congestion shortfalls are allocated to specific outages, the allocation method may tend to under-allocate shortfalls to specific outages.

Balancing Congestion Shortfalls

Balancing congestion shortfalls occur primarily during the summer months (i.e., June to August). These three months accounted for 73 percent of total balancing congestion shortfalls in 2010 and 59 percent in 2011. A large share of these shortfalls occurred during TSA events when the real-time transfer capability into Southeast New York was reduced below the day-ahead level. The share of balancing congestion shortfalls occurring outside the summer months increased in 2011 primarily due to higher than normal shortfalls in January (mainly related to outages in western New York) and March (mainly related to outages in New York City).

[35] The allocation method is described in NYISO Open Access Transmission Tariff, Section 20.

B. Transmission Congestion Contracts

We evaluate the consistency of TCC auction prices and congestion prices in the day-ahead market. We found that TCC prices reflected reasonable expectations of day-ahead conditions.[36] We did not identify differences between the TCC prices and day-ahead congestion prices that would raise potential concerns with the TCC market's performance.

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2010 to October 2011 earned estimated net profits of $56 million. TCC profits totaled $14 million (25 percent) in the one-year auctions, $34 million (61 percent) in the six-month auctions, and $8 million (14 percent) in the reconfiguration auctions. Profitability (i.e., profit as a percent of TCC payout) averaged nearly 30 percent, although it varied widely from auction to auction and among different types of TCCs (inter-zone vs. intra-zone), reflecting the difficulty of precisely predicting congestion patterns in the forward auctions.

Overall, the TCC auctions under-estimated congestion during the period. In particular, west-to-east congestion in the 2010/11 winter months, which was driven by unusually cold weather and transmission outages, was not well anticipated in the one-year auctions and the six-month auctions for the Winter 2010/11 Capability Period. This difference contributed a substantial share to the $37 million of net profits earned on the TCCs purchased in these auctions.

36 Figure A-46 and Figure A-47 in the Appendix show our analyses regarding TCC auction results and day-ahead congestion.

VI. External Transactions

New York imports a substantial amount of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. 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 1.5 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.

Efficient use of transmission interfaces between regions is beneficial in at least two ways. First, 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. Second, the ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in each control area. Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.

A. Summary of Scheduling Pattern between New York and Adjacent Areas

Table 3 summarizes the net scheduled imports between New York and neighboring control areas in 2010 and 2011 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[37]

Table 3: Average Net Imports from Neighboring Areas
Peak Hours, 2010 - 2011

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	Total
2010	842	231	666	256	288	549	68	147	3,047
2011	1,174	339	677	-59	275	489	122	113	3,130

37 Figure A-48, Figure A-49, and Figure A-50 in the Appendix show more detailed net scheduled interchanges between New York and neighboring areas by month by interface.

The table shows that total net imports from neighboring areas averaged 3,130 MW in 2011 during peak hours, up modestly from 2010. The interchanges over the four controllable interfaces were relatively consistent between years. Most differences arose from transmission outages and facility upgrades affecting these interfaces. 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 2011.

The interchanges across the primary interfaces showed more variation from year to year, reflecting wide variations in system conditions and prices between control areas. Most notably, net imports from Hydro Quebec averaged nearly 1,200 MW in 2011, up almost 40 percent from 2010. The increase was, however, offset by a similar decrease in net imports from New England. New York exported an average of 59 MW to New England in 2011 while it imported an average of 256 MW in 2010.

B. Unscheduled Power Flows

Like interchange, unscheduled power flows ("loop flows") through New York 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 2011, exacerbating west-to-east congestion in New York. Average clockwise loop flows increased 37 percent from 2010 to 2011.[38]

When clockwise loop flows increase, the NYISO uses Transmission Loading Relief ("TLR") procedures to ameliorate their effects on congestion in New York. The number of hours when the NYISO called TLRs increased 25 percent from 2010 to 2011. The TLR process manages congestion much less efficiently than optimized generation dispatch in a nodal market because the TLR process provides less timely system control, it frequently leads to more curtailment than needed, and it does not curtail transactions in economic merit order (i.e., from most expensive to least expensive).

[38] Figure A-51 in the Appendix summarizes the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie.

Additionally, loop flows on paths from Capital to Hudson Valley increased in 2011, which was due in part to a large generating resource in New England that returned to service following an outage during most of 2010. This increased congestion into Southeast New York, particularly during TSA events.

These issues highlight the importance of efforts to manage the congestion created by unscheduled loop flows more efficiently. The NYISO is working with PJM to finalize a procedure to coordinate congestion management between the two markets (i.e., NYISO-PJM Market-to-Market Coordination) and expect to implement this coordination by the end of 2012.[39] The NYISO is also planning to work with ISO New England to coordinate congestion management between the two markets in the future.

There are two additional market developments that may affect the amount of loop flows in 2012. First, phase angle regulators ("PARs") that have been installed to control the flows across three of the four lines that make up the Ontario-to-Michigan interface are expected to begin operating in 2012. These PARs will be used to better conform actual power flows to scheduled power flows at the Ontario/Michigan border. Second, the NYISO introduced Interface Pricing reforms in February 2012 that should improve the accuracy of prices in the day-ahead and real-time market models that are associated with external transactions and generation dispatch. These reforms should better align flows in the NYISO market models with actual power flows.[40]

C. Efficiency of External Scheduling by Market Participants

We evaluate external transaction scheduling between New York and the three adjacent control areas with real-time spot markets (i.e., New England, Ontario, and PJM) in 2011. Like previous years, we find that while external transaction scheduling by market participants provided

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39 See *New York Independent System Operator, Inc.*, 138 FERC ¶ 61,192 (March 15, 2012).

40 See *New York Independent System Operator, Inc.*, 138 FERC ¶ 61,195 (March 15, 2012). The Interface Pricing reforms that were implemented in February 2012 were described in the NYISO's December 22, 2011 filing as "Non-Conforming Mode." The March Order requires the NYISO to make additional modifications to the Interface Pricing reforms.

significant benefits in a large number of hours, the scheduling did not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading.

The following analysis shows that the external transaction scheduling process generally functioned properly and that it tended to improve convergence between markets. Table 4 evaluates the efficiency of inter-market scheduling between New York and Ontario, PJM, and New England during 2011. [41]

Table 4: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2011

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-101	-$2.28	52%
Ontario	378	$5.11	66%
PJM	772	-$1.56	50%
Controllable Ties			
1385 Line	110	$4.46	49%
Cross Sound Cable	252	$6.78	53%
Neptune	493	$5.91	64%
Linden VFT	121	$1.36	61%

The table shows that transactions scheduled by market participants flowed in the efficient direction (i.e., from lower-priced area to higher-priced area) in the majority of hours on most interfaces between New York and neighboring markets during 2011. The share of hours with efficient scheduling ranged from 49 percent on the 1385 Line to 66 percent on the Ontario-New York interface. Nonetheless, there was still a large share of hours when power flowed in the inefficient direction. Furthermore, there were many hours when power flowed in the efficient direction, but additional flows would have been necessary to fully arbitrage between markets.

Although scheduling by market participants tended to improve convergence, significant opportunities remain to improve the interchange between regions. The NYISO has been working on several initiatives to improve the use of the interfaces between ISOs (and RTOs). On July 27,

41 See Section IV.C in the Appendix for a detailed description of this table.

2011, the NYISO activated 15-minute scheduling with Hydro Quebec at the Chateauguay Proxy. The quarter-hour ramp limit was initially set at 25 MW, and was gradually increased to 50 MW on November 2 and 100 MW on December 1. Although it is still too early to quantify the effects of this 15-minute scheduling on the system, market participants have scheduled transactions more flexibly under the new rule, and this should help improve overall market efficiency and reduce unnecessary real-time price volatility. The NYISO's other efforts include:

- Coordinated Transaction Scheduling ("CTS") with New England;[42]
- 15-minute scheduling with PJM (which is expected to be activated in mid-2012);[43]
- Coordinating the interchange with PJM using a solution similar to Tie Optimization or Coordinated Transaction Scheduling; [44] and
- Dispatching the Hydro Quebec interface on a 5-minute basis like a generator.

Given the potential benefits from more efficient coordination with other control areas, we recommend that the NYISO continue to place a high priority on these initiatives.

D. Loss Modeling Issue at the PJM Proxy Bus

On October 11, 2011, the NYISO identified a software anomaly in the calculation of loss factors at the PJM proxy bus. As a result of the anomaly, the marginal losses at the PJM proxy bus did not consistently reflect the expected power flow assumptions from the PAR-controlled lines between PJM and New York.[45] This software anomaly, which had been present since the current scheduling methodology was implemented in June 2007, impacted the first optimization period

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42 www.nyiso.com/public/webdocs/committees/mc/meeting_materials/2012-02-23/Seams_2012-02-23_MC.pdf

43 *Id.*

44 *Id.*

45 The primary PJM interface (which does not include the Neptune or Linden VFT scheduled lines) is used to coordinate transaction scheduling along the border between New York and PJM. It incorporates two groups of transmission lines. First, PAR-controlled lines from New Jersey to Southeast New York (i.e., the 5018, JK, and ABC lines) are assumed to carry 66 percent of the interface flow. Second, free-flowing lines from Pennsylvania to Western New York (i.e., two 345kV lines, two 230kV lines, and several 115kV lines) are assumed to carry the remaining 34 percent of the interface flow.

in each market run (i.e., the first hour or interval in each SCUC, RTC, and RTD run) and the hours when a transmission line status change occurred. Therefore,

- In the day-ahead market, losses *were* modeled correctly in most hours. However, the losses were not modeled correctly in HB 0 and in hours after a change in topology (i.e., a line going in or out of service).
- In the real-time market, losses *were not* modeled correctly in most hours. However, the losses were modeled correctly in some of the hours when the proxy bus price was determined by RTC that was not affected by topology change.

Flows from PJM into Southeast New York tend to reduce transmission losses, while flows from PJM into western New York increase losses. Hence, the scheduling models generally under-valued imports from PJM and under-priced the PJM proxy bus during those hours.

We estimated direct effects of the loss modeling issue on the LBMPs at the PJM proxy bus, as well as Rate Schedule 1 charges for the period from January 1, 2008 to October 10, 2011, and found that: [46]

- In the day-ahead market, losses were incorrectly calculated in approximately 30 percent of hours and the average differential was 1.4 percent of the average PJM proxy bus LBMP (including all hours).
- In the real-time market, losses were incorrectly calculated in approximately 80 percent of hours and the average differential was 5.6 percent of the average PJM proxy bus LBMP (including all hours).
- Loss residual surpluses were reduced by $7 million from $655 million over the evaluation period. The real-time guarantee payments were increased by $1.5 million over the evaluation period.

The modeling issue led the real-time market to under-value power at PJM proxy bus by 5 to 6 percent on average.

These results imply that imports from PJM were systematically under-valued, thereby reducing the quantity of imports from PJM to New York. Consequently, the NYISO scheduled imports from other control areas and generation from internal resources when it would have been slightly

[46] Section IV.D of the Appendix provides additional information on the direct effects of the modeling issue.

less expensive to import power from PJM. We have not performed an estimate of the net impact of loss modeling on LBMPs in New York, but the impact is likely significant given that the modeling issue was present for over four years. Nonetheless, in assessing the market effects of the modeling issue, it is important to consider that the modeling change that was implemented in June 2007 greatly improved the recognition of the value of power at the PJM proxy bus. Previously, the market software did not recognize that a portion of imports from PJM flow into Southeast New York, and instead, it assumed that imports from PJM flowed across the free-flowing lines into Western New York. Hence, the modeling change that was implemented in June 2007, while imperfect, still led to significant improvements in the efficiency of scheduling between PJM and New York.

VII. Capacity Market Results and Design

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. By setting a distinct clearing price in each location, the capacity market facilitates investment in areas where it is most needed.

A. Capacity Market Results in 2011

Seasonal variations resulted in significant changes in clearing prices in spot capacity auctions. Additional capability is typically available in the Winter Capability periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity. This generally contributes to significantly lower prices in the winter than in the summer.

1. New York City Capacity Market Results

In New York City, the spot price averaged $8.36/kW-month in the Summer 2011 Capability period, down 36 percent from the previous Summer Capability period. This reduction was primarily the result of new capacity entering the market, which caused prices to fall from $11.76/kW-month in June to $5.76/kW-month in July.

The spot price averaged $3.74/kW-month in the Winter 2011-12 Capability period (excluding March and April 2012), which is consistent with the average from the previous Winter Capability period. However, the amount of unsold capacity rose significantly in October 2011 and again in December 2011, which is discussed in Section III.C.2.

2. NYCA Capacity Market Results

In NYCA, the spot price averaged $0.29/kW-month in the Summer 2011 Capability period, down 83 percent from the previous Summer Capability period. Likewise, the spot price averaged $0.21/kW-month in the Winter 2011-12 Capability period (excluding March and April 2012), down 40 percent from the previous Winter Capability period. These reductions were due largely to:

- Significant capacity additions that occurred in June 2010, September 2010, and July 2011; and
- The reduction of nearly 1200 MW in the ICAP requirement for NYCA from the 2010/11 capability year to 2011/2012 capability year.

A substantial amount of capacity was not sold in recent months, which was likely due to the relatively large prevailing capacity surplus and the low clearing prices.

Capacity prices in both NYCA and New York City were both significantly affected by the update in the capacity demand curves. The NYISO filed for new capacity demand curves to be in place in May 2011, coinciding with the scheduled expiration of the previous curves (from 2008). However, the Commission did not accept the NYISO's filing until September 2011, so the new curves were not used until the October 2011 spot auction. The new curves were much higher than the previous curves so this delay substantially affected the capacity market results in 2011.

B. Zone Configuration and Deliverability

In recent years, new capacity outside Southeast New York has not been eligible to sell in the capacity market due to limits on deliverability into Southeast New York without funding transmission upgrades.[47] Such limits create several significant efficiency and competitive concerns. First, because the deliverability constraint is not priced, the capacity market cannot provide efficient incentives to invest in supply resources, demand resources, and transmission facilities, or to maintain existing resources in areas that affect the deliverability constraint. Second, the deliverability constraints create substantial barriers 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.[48] Doing

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[47] New resources outside Southeast New York are allowed to sell capacity *if* they pay for significant transmission upgrades into Southeast New York, but the annualized cost of such upgrades are very high relative to the prices of capacity in upstate New York, so new resources outside Southeast New York have generally elected not to sell capacity.

[48] See the 2006, 2007, 2008, 2009, and 2010 *State of the Market Report on the NYISO Electricity Markets* by

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 existing deliverability framework.

Following a lengthy stakeholder process, the NYISO and New York Transmission Owners jointly filed proposed rules for adopting new capacity zones in January 2011. In September 2011, the Commission accepted in part and rejected in part the filing's proposals, directing the NYISO to modify its criterion for determining whether a capacity zone is needed to be consistent with the criterion used in the Class Year Deliverability Test.[49]

The NYISO's November 2011 compliance filing proposed a new criterion to determine whether a capacity zone is needed that is more consistent with the Class Year Deliverability Test criterion.[50] However, the new proposal still includes one critical inconsistency that would preclude the creation of a new capacity zone when needed. Specifically, the proposed criterion for creation of a new zone would exclude new Class Year projects without existing CRIS rights, although such projects are evaluated in the Class Year Deliverability Test.[51] Under this proposal, the NYISO would continue to assign highway deliverability upgrade costs to new entrants, rather than create a new capacity zone so the deliverability constraint can be efficiently priced in the capacity market.[52] Hence, we continue to recommend that the NYISO identify potential improvements to the alignment between the Class Year Deliverability Test and the locational capacity requirements in the Capacity Market. One means to do this would be to pre-define potential deliverability constraints or zones that would be modeled in the NYISO capacity markets. Once defined, the NYISO would cease allocating transmission upgrade charges to resources that affect these constraints. Instead, the capacity market would efficiently limit sales

Potomac Economics.

49 See *New York Independent System Operator, Inc.*, 136 FERC ¶ 61,165 (2011). The Class Year Deliverability Test Methodology is defined in the NYISO OATT Section 25.7.8.

50 The November 2011 compliance filing is pending before the Commission.

51 See *Compliance Filing Proposing Criteria to Govern the Potential Creation of New Locational Capacity Zones*, Docket No. ER12-360-000, dated November 7, 2011.

52 See *Motion to Intervene and Comments of the New York ISO's Market Monitoring Unit*, Docket No. ER12-360-000, dated November 28, 2011.

from these resources by binding in the capacity auction. Upgrade of these deliverability constraints could be governed economically by the resulting locational price differences in the capacity, energy and ancillary services markets. Pre-defining deliverability constraints or capacity zones would also eliminate the cumbersome three year process to implement new individual capacity zones that the NYISO recently described to the Commission.

In recent months, the lack of locational price signals in the capacity market has led to the need for regulated investment to satisfy planning requirements. Specifically, ConEd determined that additional resources are needed to maintain transmission security in the 138kV system in New York City in the summer of 2012. Consequently, ConEd will need to bring a new transmission line into service by the summer of 2012 at a cost that is likely to be quite substantial. Although it may be possible to satisfy the local transmission planning requirements with market-based investment, this cannot occur unless such requirements are represented in the capacity market. Over time, the lack of such locational price signals is likely to result in insufficient investment in some areas areas (e.g., the 138kV system in New York City in this case) and excess investment in other areas (e.g. the 345kV system in New York City). Hence, it would be beneficial to improve the alignment of the local transmission planning requirements and the locational capacity market requirements. This would better enable the capacity market to provide appropriate signals for investment in new and existing resources each local area.

C. 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 for the investments over the long term. To establish a demand curve, the technology of a hypothetical new entrant must be chosen and the current tariff specifies that this is 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 capacity, 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. As discussed in the previous subsection, information filed by the NYISO in the recent Demand Curve Reset Process suggests that Net CONE is substantially higher for peaking resources than for combined cycle units. 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.

VIII. 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 dispatch the available resources efficiently. Clearing prices should be consistent with the costs of dispatching 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.

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.

A. Real-Time Scheduling and Pricing

We evaluate the efficiency of gas turbine ("GT") 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 GT commitment, we found that the majority of capacity committed in 2011 was economic over the initial commitment period and the overall efficiency was consistent from 2010 to 2011.[53] The GT was deemed economic if the as-offered cost was less than the LBMP revenue earned over the initial commitment period (usually one hour). However, this criteria may under-state the share of GT commitments that are efficient for two reasons. First, the efficient commitment of a GT reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer.

[53] See Figure A-56 in the Appendix for details of this analysis.

Second, in some cases, a GT that is committed efficiently may still not set the LBMP due to the manner in which the real-time pricing methodology determines whether a GT is eligible to set the LBMP.[54] We further analyzed GT commitments by RTC and RTD that appeared uneconomic to determine how often the GT's operation displaced output from higher cost resources (i.e., it was efficient). We found:

- The GT was inframarginal or set the LBMP in 42 percent of the intervals.
- The GT did not displace output from higher cost resources and, thus, did not set the LBMP in 37 percent of the intervals.
- The GT displaced output from higher cost resources but was not allowed to set the LBMP in 21 percent of the intervals. These intervals accounted for 180 hours during 2011.

The last category results from the fact that the real-time pricing methodology employs a step where some efficiently committed GTs are deemed ineligible to set the LBMP.[55] Hence, we recommend the NYISO evaluate whether it would be beneficial to modify this step.

In our evaluation of external transaction scheduling, we found that:[56]

- A high portion (81 percent) of price-sensitive import offers and export bids were scheduled consistent with real-time prices at the primary interface with New England in 2011.
- More than 50 percent of scheduling was in the efficient direction (i.e., from the lower-priced region to the higher-priced region).

Although the external transaction scheduling process has functioned reasonably well and scheduling by market participants tends to improve convergence, significant opportunities remain to improve the interchange between New York and adjacent areas. These highlight the importance of the NYISO's efforts to work with neighboring ISOs or RTOs to improve coordination of the interchange between regions.

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[54] See NYISO Market Services Tariff, Section 17.1.2.1.2 for description of real-time dispatch process.

[55] The real-time pricing methodology is discussed further in Section V.A of the Appendix.

[56] See Figure A-57 in the Appendix for detailed of this analysis.

B. Operations of Non-Optimized PAR-Controlled Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows within appropriate levels. However, there are still a significant number of controllable transmission lines that source and/or sink in the New York Control Area ("NYCA"). This includes High Voltage Direct Current ("HVDC") transmission lines, Variable Frequency Transformer ("VFT")–controlled lines, and Phase-Angle Regulator ("PAR")–controlled lines. Controllable transmission lines allow power flows to be channeled along pathways that increase the total transfer capability of the system and that lower the overall cost of generation necessary to satisfy demand. Hence, they have the potential to provide greater benefits than conventional AC transmission lines.

Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways. First, some controllable transmission lines are scheduled as external interfaces using external transaction scheduling procedures.[57] Such lines are evaluated in Section VI, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted in order to avoid generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not necessarily focused on reducing production costs. This part of the section evaluates the use of non-optimized PAR-controlled lines.

The following table evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2011. The evaluation is done for nine PAR-controlled lines between New York and neighboring areas and two between New York City and Long Island.

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[57] This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), and the Linden VFT Scheduled Line.

Table 5: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines [58] [59]
2011

	Average Flow (MW/h)	Avg NYCA Price minus Avg. Price Outside ($/MWh)	Pct of Hours in Efficient Direction	Est. Production Cost Savings (Million $)
PAR Controlled Lines (into NY)				
St. Lawerence (L33/34	21	$7.30	57%	$7
Sand Bar (PV 20)	-80	-$7.59	74%	$6
Waldwick (JK)	-673	-$3.22	44%	$20
Ramapo (5018)	313	-$3.22	57%	$1
Farragut (BC)	528	$0.95	57%	$3
Goethals (A)	346	$2.81	60%	$7
PAR Controlled Lines (LI into NYC)				
Lake Success (903)	145	-$7.31	12%	-$11
Valley Stream (901)	64	-$14.86	11%	-$10

Our analysis shows that power flowed in the efficient direction in the majority of hours on all but one of the PAR-controlled lines between New York and neighboring markets during 2011. The share of hours with efficient scheduling ranged from 44 percent on the Waldwick lines to 74 percent on the PV-20 line. Except for the Ramapo line, the prevailing direction of power flows on each line was from the side that averaged a lower price to the side that averaged a higher-price. The Ramapo line generally flowed power from PJM to NYCA, although the price on the PJM side was higher on average. PJM and the NYISO are working to implement Market-to-Market Coordination in order to improve the scheduling efficiency of the primary interface between them, including the Ramapo line.[60] A total of $44 million in net production cost savings was estimated from the controllable lines between NYCA and adjacent control areas. However, significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

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58 Note, this table reports the estimated production cost savings that actually resulted from the use of these transmission lines in 2011. They do *not* estimate the production cost savings that could have been realized if the lines were used optimally.

59 As discussed further in Section V.C of the Appendix, the methodology used for this evaluation tends to under-estimate the production cost savings from these lines. However, it still provides a useful indicator of the relative scheduling efficiency of individual lines.

60 See Docket No. ER12-718-000.

The scheduling over the PAR-controlled lines from Long Island into New York City was much worse than any of the other PAR-controlled lines. Power flowed in the inefficient direction in nearly 90 percent of hours on the two PAR-controlled lines between Long Island and New York City during 2011. The use of these lines *increased* production costs by an estimated $21 million in 2011 because Long Island typically exhibited higher prices than New York City (particularly the portion of New York City where the 901 and 903 lines connect).[61] In addition to increasing production costs, these transfers (a) depress prices in New York City and (b) can restrict output from generators in the pocket where the lines connect.

These results indicate that significant opportunities remain to improve the operation of these lines, particularly the lines between New York City and Long Island. We recognize that the ability to achieve these improvements and the associated savings may be limited by a wheeling agreement that may specify how the lines are to be operated. However, we are recommending that the NYISO work with the parties to the agreement to explore potential changes to the agreement, or to explore how the agreement may be accommodated within the NYISO markets.

C. 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.[62] 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

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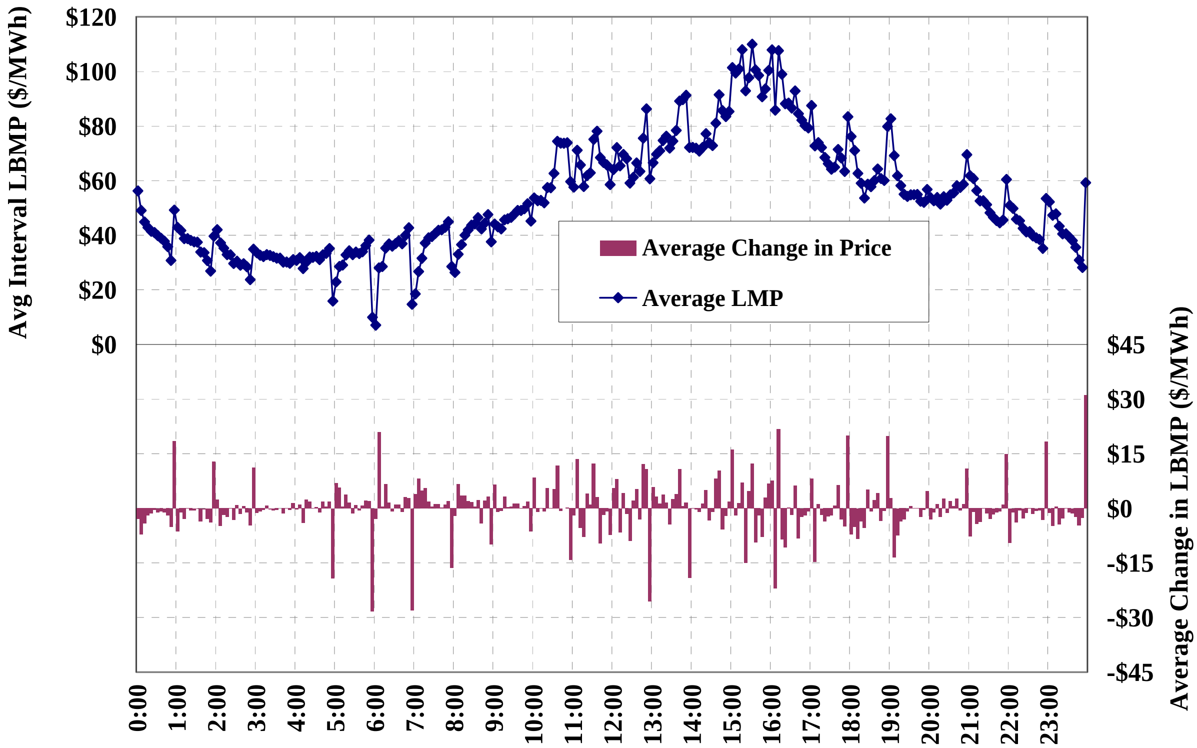
61 These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica "load pocket," an area that is frequently export constrained.

62 See Figure A-59 and Figure A-60 in the Appendix for more details.

making such changes mid-hour. This top of the hour volatility is evident in the following figure, which shows the average 5-minute price for each interval of the day during the summer in 2011.

Figure 9: Statewide Average Five-Minute Prices by Time of Day
June to August 2011



The NYISO's efforts to allow more frequent and efficient scheduling of the external interfaces should help reduce statewide price volatility. In July 2011, the NYISO began to allow small amounts of scheduling every 15 minutes at the primary Quebec to NYISO interface. Although it is too early to evaluate how this will affect statewide price volatility, it should help shift more schedule changes away from the top of the hour, which is likely to result in some improvement.

We also evaluated real-time price volatility in constrained areas during 2011 that was due to congestion.[63] This analysis focused on the "shadow price" of the constraint, which represents the economic value of the constraint. The reflection of individual constraints in LBMPs is a function of the constraint's shadow price times the affect of the location on the constraint (i.e., how energy produced at the location would change the flow on the constraint). Transient shadow

63 See Figure A-61 and Figure A-62 in the Appendix for more details.

price spikes[64] occurred during about 1 percent of all real-time intervals, and they included 32 percent of the intervals when a shadow price exceeded $300 per MWh in 2011. Of the transient shadow price spikes: 31 percent occurred on the East Garden City-to-Valley Stream line in Long Island and 22 percent occurred on lines into the Greenwood/Staten Island load pocket in New York City. Significant numbers of events also occurred on the lines from upstate to Long Island, the Central-East interface, and lines into Southeast New York (e.g., Leeds-to-Pleasant Valley).

Although relatively infrequent, transient price spikes are important because it can be far more costly to manage congestion that is not anticipated. Large quantities of uplift from Balancing Market Congestion Residuals ($10 million) and Day-Ahead Margin Assurance Payments ($4 million) arose from intervals when transient price spikes occurred.

We evaluated factors that contributed to transient shadow price spikes in 2011. Unanticipated changes in flows across non-optimized PAR-controlled lines were the most significant contributing factor for six of the ten facility categories evaluated. This is because RTD and RTC assume the flow across these lines will remain fixed at the most recent telemetered value. However, the flow across these lines is affected by changes in the PAR setting, the settings of other nearby PARs, and changes in the pattern of generation and load.

Another factor contributing to transient price spikes were large changes in external interface schedules, particularly for the Dunwoodie-Shore Road line from upstate New York to Long Island. Long Island can import up to 1.2 GW of generation from PJM and ISO-NE, which accounts for a significant portion of supply serving Long Island load. Hence, large hourly schedule changes across these interfaces often led to price spikes, since available generation in Long Island frequently could not ramp quickly enough to pick up the change.

The NYISO introduced market enhancements in 2011 that addressed 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 Hydro Quebec. The

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64 Shadow price spikes are deemed "transient" if the shadow price > $300 per MWh, the shadow price increased at least 400 percent from the previous real-time interval, and the shadow price is at least 400 percent higher than the last advisory pricing interval.

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. This report recommends that the NYISO also consider other improvements that address other sources of unnecessary real-time price volatility.

D. 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 respond during real-time shortages. Shortage conditions occur most frequently when demand reaches extremely high levels, so the higher peaking conditions in 2011 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;
- Transmission shortages; and
- Emergency demand response activations.

1. Ancillary Services Shortages

The NYISO uses ancillary services demand curves to set efficient prices during operating reserves and regulation shortages. On May 19, 2011, the NYISO updated demand curves for three ancillary services: Regulation, NYCA 10-minute reserves, and Long Island 30-minute reserves.[65] The demand curves for regulation and Long Island 30-minute reserves were reduced, leading to more frequent shortages but much smaller price impacts. The demand curve for NYCA 10-minute reserves was increased, leading to fewer shortages with much larger price impacts. These new demand curves more accurately reflect the economic values of these ancillary services and have led to more efficient dispatch and pricing in Long Island and all of New York, particularly during shortage conditions.

[65] See Section V.F in the Appendix for a description of specific changes.

Several categories of ancillary services shortages had substantial effects on real-time energy prices. The most significant ancillary services shortages were for regulation and eastern 10-minute reserves, which increased the annual average LBMPs in eastern New York by 2 to 3 percent.

2. Transmission Shortages

Transmission shortages occur when power flows (as modeled in the market systems) exceed the limit of a transmission constraint.[66] 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.

Our evaluation of transmission shortages found that: [67]

- The Leeds-to-Pleasant Valley line exhibited the most economically significant transmission shortages in 2011. In 65 intervals, it contributed an average of $940 per MWh to the New York City LBMP, raising the annual average New York City LBMP by roughly 1 percent. Most of these intervals occurred during TSA events.
- The Dunwoodie-to-Shore Road line also exhibited a significant number of shortages in 2011. It raised the annual average Long Island LBMP by 1.2 percent. Many of these shortages occurred as a result of large reductions in imports across the lines between Long Island and Connecticut or New Jersey.
- Overall, downstate areas experienced the most significant price impacts from transmission shortages in 2011. In New York City, the total price impact was $1.16 per MWh averaged over the year. In Long Island, the total price impact was $2.63 per MWh averaged over the year.

In our evaluation, we also 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

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66 Transmission shortages can occur in the following three ways: 1) 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; 2) if the marginal redispatch cost needed to resolve a constraint exceeds the $4,000/MWh Transmission Shortage Cost, RTD foregoes more costly redispatch options; and 3) 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. 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).

67 See Figure A-64 in the Appendix for details.

$4,000 per MWh.[68] This suggests that the reliability value of preventing many transmission shortages is lower than $4,000 per MWh. Therefore, we recommend that the NYISO consider the feasibility of using a graduated Transmission Shortage Cost that would more accurately reflect the severity of the shortage condition.

3. Emergency Demand Response Activation

Emergency demand response resources provide significant economic and reliability benefits to the system. Demand response resources help satisfy a portion of the planning reserve requirements, reducing overall costs in the capacity market. Demand response resources help satisfy demand for energy and operating reserves on very high load days, reducing overall production costs in the real-time market. However, the high cost of emergency demand response resources (usually $500 per MWh) combined with their inflexibility in real-time operations creates at least two significant challenges. First, it is difficult to activate the appropriate amount of demand response resources, since they must be activated with significant lead times and the amount of resources that must be activated to maintain reliability can be difficult to predict. Second, it is difficult to ensure that real-time prices are efficient when emergency demand response is activated, since such resources are typically the system's most costly resources but such resources do not ordinarily set the LBMP (unless special pricing rules are used). Hence, if too much demand response is activated or the demand response resources do not set LBMPs, LBMPs may not accurately reflect the cost of maintaining reliability.

Emergency demand response resources were activated on July 21 and 22. On July 21, the NYISO activated emergency demand response resources in Zones G through K to maintain the security of transmission lines into Southeast New York. An average of 680 MW responded in Southeast New York, while at least 1.8 GW of capacity was available in Southeast New York, leading to relatively modest real-time prices ($126 per MWh on average). The Scarcity Pricing Rules were not invoked on July 21, since they are only applied when the activation of demand response prevents a statewide or eastern reserve shortage.[69] Even if Scarcity Pricing was applied

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[68] 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.

[69] The Scarcity Pricing Rules are defined in NYISO Market Services Tariff, Sections 17.1.2.2 and 17.1.2.3.

when the activation of demand response prevents a shortage in a smaller region such as Southeast New York, it would not have been applied on July 21 because the amount of excess available capacity in Southeast New York exceeded the amount of demand response that was activated by a substantial margin.

Although the NYISO activated demand response on July 21 to secure Southeast New York, the substantial amount of available capacity in real-time highlights that there are differences between (a) the assumptions used in advance to determine that activation is necessary and (b) actual real-time conditions and operations. Differences can arise for many reasons including load forecast error, generation and transmission outages, external transaction curtailments, and wind forecast error. On July 21, the most notable difference was related to the criteria for transmission security. The NYISO activated demand response on July 21 to ensure sufficient capacity would be available to prepare Southeast New York for a contingency after the largest contingency occurs (effectively N-minus-2 criteria). However, the NYISO dispatches generation in real time to secure Southeast New York against the *single* largest contingency. The looser real-time criteria allows more imports into Southeast New York than is assumed for the purpose of activating demand response, contributing to the substantial amount of available capacity in real-time on July 21.

On July 22, the NYISO activated emergency demand response resources in every zone (except Zone D) to maintain adequate reserves statewide. An average of 793 MW responded in eastern New York (Zones F – K) and 624 MW responded in western New York (Zones A, B, C, and E). Real-time prices were near $500 per MWh in eastern New York and near $400 per MWh in western New York for most of the afternoon. These prices were the result of tight supply, as well as the Scarcity Pricing Rules.

The Scarcity Pricing Rules were applied in 34 percent of the 152 intervals when demand response resources were activated on the two days, and there were many intervals when real-time LBMPs were even higher than the levels set by the Scarcity Pricing Rules. However, due to the limited scope of the Scarcity Pricing Rules, there were still circumstances when the costs of demand response resources are not reflected in LBMPs. Hence, we recommend that the NYISO continue to work with stakeholders to develop new pricing provisions that would enable emergency demand response resources to set LBMPs under a wider range of circumstances when appropriate.

E. 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 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.

The following figure summarizes the quarterly quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) in New York City, Long Island, West and East Upstate areas during 2010 and 2011.[70] In addition to showing the total capacity committed in each category, it also shows the minimum generation level of the resources committed for these reasons. We show the minimum generation level because this energy must be accommodated by reducing the dispatch of other units, which is one of the ways that these commitments can affect real-time energy prices.

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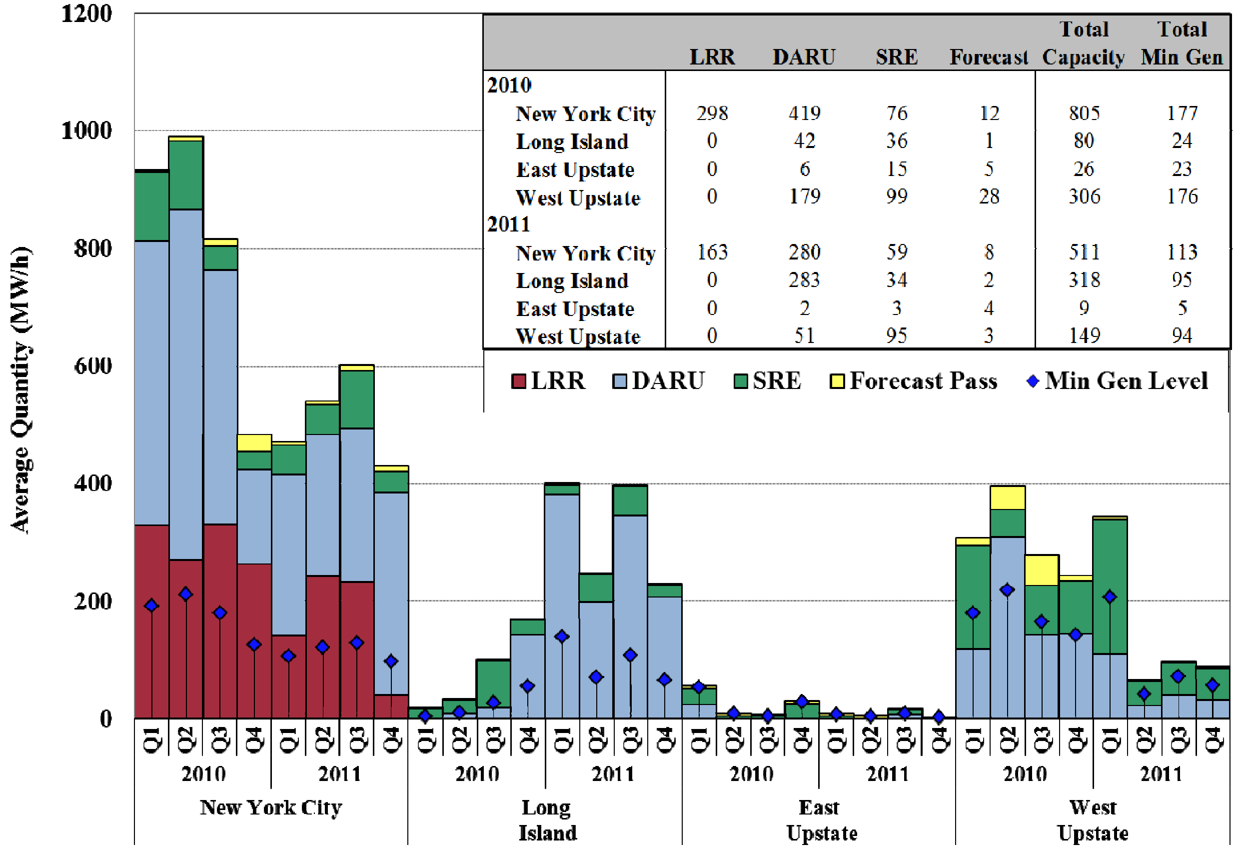
70 The first three types of commitment are primarily for local reliability needs. The last category, Forecast Pass, represents the additional commitment in the forecast pass of SCUC, which occurs after the economic pass. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load.

Figure 10: Supplemental Commitment for Reliability in New York
By Category and Region, 2010 – 2011



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2010						
New York City	298	419	76	12	805	177
Long Island	0	42	36	1	80	24
East Upstate	0	6	15	5	26	23
West Upstate	0	179	99	28	306	176
2011						
New York City	163	280	59	8	511	113
Long Island	0	283	34	2	318	95
East Upstate	0	2	3	4	9	5
West Upstate	0	51	95	3	149	94

The figure shows that nearly 1,000 MW of capacity was committed on average for reliability in 2011, down 19 percent from 2010. Of this total, 52 percent of reliability commitment was in New York City, 32 percent was in Long Island, and 15 percent was in Western New York.

In New York City, reliability commitment decreased substantially from 2010 to 2011. Committed capacity averaged 510 MW in 2011, down 37 percent from 2010. The reduction in local reliability need was partly driven by: (i) increased import capability into the City from the addition of the Dunwoodie-Academy Line; (ii) increased generating supply in the City from the addition of the 550 MW Astoria East II generating facility; and (iii) changes in generator offer patterns and reference levels.

In Long Island, reliability commitments rose substantially from an average of 80 MW in 2010 to an average of 310 MW in 2011, due primarily to the increase in DARU commitment. Many of the units on Long Island needed for reliability often have to burn oil to satisfy their reliability requirements. Oil-fired units were economic less frequently than the prior year as a result of the increased divergence between gas and oil prices during 2011.

In Western New York, reliability commitment decreased substantially in 2011. Capacity committed for reliability averaged 150 MW in 2011, down 51 percent from the previous year. Reliability commitment decreased because in 2010 there were more transmission outages that required generators in Western New York to be committed for local reliability than in 2011.

Most supplemental commitment for reliability occurred in New York City in 2011. We evaluated the reasons for reliability commitments in New York City and found that the following reliability requirements accounted for the most MWhs of capacity in New York City during 2011: [71]

- Astoria West/Queensbridge thermal and voltage requirements, which ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur;
- Sprainbrook/Dunwoodie thermal requirements, which ensure 345 kV facilities in New York City will not be overloaded if the largest two generation or transmission contingencies were to occur; and
- NOX bubble requirements, which require the operation of a steam turbine unit in order to reduce the overall NOX emission rate from a portfolio containing higher-emitting gas turbine units. However, the operation of steam turbine units frequently displaces generation from newer cleaner generation in the city and imports from outside the city.

F. Guarantee Payment Uplift Charges

The NYISO recovers the payments it makes to certain market participants that are not recouped from LBMP and other market revenues through uplift charges. 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.

[71] See Figure A-68 in the Appendix for this analysis.

The following table shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2010 and 2011. [72]

Table 6: BPCG Uplift in New York
By Category, 2010 – 2011

Year	BPCG By Category (Million $)							
	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2011	$55	$29	$2	$7	$31	$29	$12	$167
2010	$89	$34	$2	$12	$25	$31	$18	$211

The table shows that the guarantee payment uplift totaled $167 million in 2011. [73] Local reliability uplift accounted for 56 percent and statewide (i.e., non-local reliability) uplift accounted for the remaining 44 percent. Total uplift fell $44 million (21 percent) from 2010 to 2011 due to large reductions in the local reliability uplift categories.

The following factors contributed to the reduction in uplift charges for guarantee payments:

- The amount of capacity committed for reliability in New York City fell in 2011, partly due to the addition of a new transmission line into the City and the operation of a new 550 MW generating facility in the City.
- The amount of capacity committed for reliability in West New York fell in 2011 because there were fewer transmission issues in Upstate New York that required the commitment of particular generators to manage congestion.
- More stringent mitigation rules were imposed 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.
- The reduction was, however, offset by the increase in uplift on Long Island, which resulted from increased reliability commitment due to higher oil prices.
- Improved generator reference level accuracy contributed to the overall reduction in uplift during 2011.

72 See Figure A-69 in the Appendix for a more detailed description of these seven categories.

73 The NYISO's mitigation consultations are on-going for later periods of 2011, so guarantee payments may increase modestly once these are fully reflected.

IX. 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.

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 all of the 2.2 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 due to difficulties in setting-up communications with the NYISO through the local Transmission Owner. In late 2011, the NYISO released the technical specification to facilitate dispatch of DSASP Resources through Direct Communication with the NYISO rather than through the local Transmission Owner.[74] In 2012, a continuation of the Direct Communication project will develop the market

[74] The presentation of the DSASP Direct Communications Technical Specification is available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2011-11-28/DSASP_Stakeholder_Presentation.pdf

rules and procedures to allow aggregations of small customers to participate in DSASP. Aggregations of small demand resources already participate successfully in the emergency demand response programs.

The fastest growing demand response program operated by the NYISO is the SCR program, whose participation grew to roughly 2 GW in 2011. 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 made improvement to the SCR baseline calculation methodology in 2011. Although these changes contributed to modest (13 percent) reductions in SCR enrollment, they should help ensure that emergency demand response resources perform reliably when needed.

X. List of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2011, although the report finds additional improvements that we recommend be made by the NYISO.

Capacity Market

1. **Identify improvements to align the Class Year Deliverability Test and the locational capacity requirements in the Capacity Market. (High Priority/Value)**

   The NYISO's application of its proposed criteria to create new capacity zones should result in the creation of a capacity zone for Southeast New York. However, the proposed criteria would likely fail to create new capacity zones when highway deliverability constraints are binding. Failure to achieve consistency between the locational framework in the Capacity Market and the Class Year Deliverability Test will continue to:

   - Serve as an inefficient barrier to new entry and capacity imports,
   - Result in inefficient locational capacity price signals to govern investment in new resources (generation and demand-side) and transmission, and other decisions by existing resource owners and loads.

2. **Select the most economic generating technologies to establish the demand curves in the next demand curve reset process for the capacity market. (High Priority/Value)**

   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. Changing the technology of the demand curve unit would require a corresponding adjustment to the excess level assumption that is used in the demand curve reset process so that the excess level is appropriate for the size of the demand curve unit.

3. **Reform the following rules related to the ICAP qualification requirements and supply-side mitigation measures for installed capacity suppliers. (High Priority/Value)**

   - Modify the pivotal supplier test in the Tariff to prevent a large supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions) to avoid being designated as a pivotal supplier.
   - Clarify the existing rules (and modify the Tariff if necessary) related to the requirements a supplier must satisfy to remain qualified to sell installed capacity. The rules should prevent capacity sales from a generator that is out-of-service for an extended period or out-of service and not under-going the steps necessary to come back into service.

- Clarify the existing rules (and modify the Tariff if necessary) related to the calculation of Going-Forward Costs ("GFCs") to specify that GFCs include only costs a supplier must incur to remain qualified to sell capacity and can, therefore, only be avoided when it ceases to sell capacity.

Real-Time Market

4. Continue to 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. (High Priority/Value)

The NYISO is working with neighboring control areas on several proposals to improve the efficient use of the interfaces of which the most important proposals are: Coordinated Transaction Scheduling ("CTS") with ISO New England and Market-to-Market Congestion Management with PJM. We believe these are high-value improvements, and support extending the CTS to the NYISO's other interfaces with other RTO markets.

2012 Project Plan:

- *ITC Phase III: PJM Intra-hour Transaction Scheduling* – 2012-Q2 Deployment,
- *ITC Phase IV: ISO-NE Inter-Regional Interchange Scheduling (IRIS)*– Design On Schedule,
- *ITC Phase V: PJM Coordinated Transaction Scheduling* – Design On Schedule, and
- *Market-to-Market Coordination: PJM* – 2012-Q4 Deployment.

5. Explore options for improving the operation certain PAR-controlled lines more efficiently. (High Priority/Value)

There may be opportunities to improve the operation of certain PAR-controlled lines, particularly the lines between New York City and Long Island, which were scheduled in the inefficient direction (i.e., from the high-priced area to the low-priced area) nearly 90 percent of the time in 2011. This raises both efficiency and price concerns to the extent that it restricts the output of in-City generation. We are recommending that the NYISO work with the parties to the underlying wheeling agreement to explore potential changes to agreement, or to how the agreement is accommodated within the NYISO markets, to address the inefficient market outcomes.

6. **Evaluate improvements to the real-time pricing methodology to ensure that GTs are eligible to set the LBMP when they are economic (i.e., displacing output from more expensive resources).**

   The real-time pricing methodology (i.e., hybrid pricing) employs a step that causes some efficiently committed GTs are deemed ineligible to set the LBMP. Hence, we recommend the NYISO identify and evaluate potential improvements to this step.

7. **Consider the feasibility and potential impacts on reliability from using a graduated Transmission Shortage Cost (or demand curve).**

   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 value of certain shortages (typically those that are brief or small relative to the limit on the constraint). Improving the accuracy of the Transmission Shortage Cost by representing it as a demand curve may cause the NYISO markets to take more efficient dispatch and commitment actions, and set more efficient prices.

   <u>2012 Project Plan</u>: *Scheduling & Pricing: Graduated Transmission Demand Curve* – 2012-Q4 Deployment.

8. **Modify rules so demand response resources that have been activated are eligible to set LBMPs in the real-time pricing methodology.**

   Emergency demand response was activated twice in 2011, once in southeast New York and once NYCA-wide, except Zone D, 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.

   <u>2012 Project Plan</u>: *Scheduling & Pricing: Enhanced Scarcity Pricing* – Design On Schedule.

9. **Conduct an evaluation to determine the causes of and potential solutions for unnecessary real-time price volatility.**

   The NYISO's initiatives to schedule external transactions with Quebec, PJM, and New England on a 15-minute (rather than hourly) basis should address some of the causes of price volatility. Nonetheless, we recommend the NYISO evaluate whether additional look ahead assessments in RTC and RTD would enable the market to respond more efficiently to changes in external interchange and other top-of-the-hour changes that may cause unnecessary real-time price volatility.

Day-Ahead Market

10. **Modify two mitigation provisions that may limit competitive 10-minute reserves offers in the day-ahead market.**

    The NYISO is working with stakeholders to adopt a proposal for implementing this recommendation by the end of 2012.

    2012 Project Plan: *Ancillary Services Mitigation* – 2012-Q4 Deployment.

11. **Enable 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.

ANALYTIC APPENDIX

2011 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

Appendix – Table of Contents

I. 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. The NYISO also operates markets for installed capacity and transmission congestion contracts.

This section of the appendix summarizes the market results and performance in 2011 in the following areas:

- Wholesale market prices;
- Fuel prices and load levels;
- Ancillary services prices;
- Price corrections; and
- Long-term economic signals governing new investment and retirement decisions.

A. Wholesale Market Prices

Figure A-1: Average All-In Price by Region

The first 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 A-1 shows the average all-in prices along with the average natural gas prices at five locations over the past three years. The West NY location in the figure includes Zones A, B, C, D, and E.

Figure A-1: Average All-In Price by Region
2009-2011

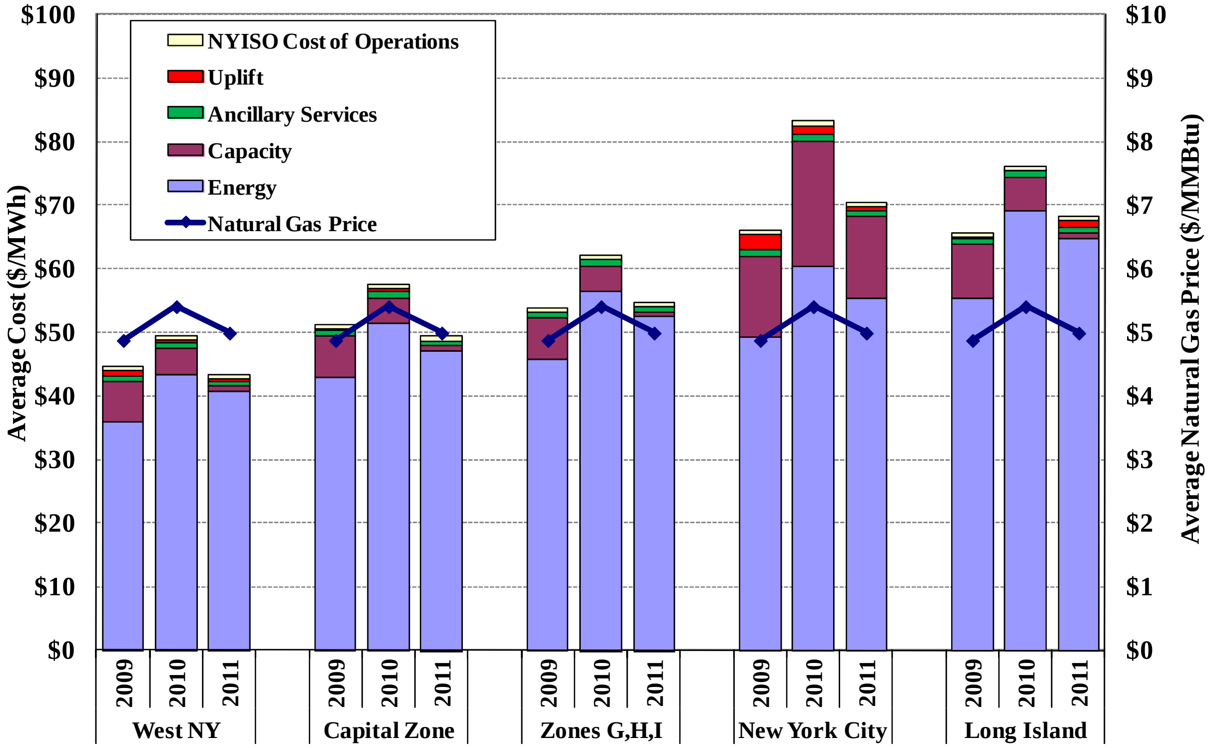


Figure A-2: Day-Ahead Electricity and Natural Gas Prices

Figure A-2 shows average natural gas prices and load-weighted average day-ahead energy prices for Eastern and Western New York in each month of 2010 and 2011. The table in the chart compares the annual averages of these quantities. 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 units that set energy prices, especially in Eastern New York. This is evident from the strong correlation of electricity prices with natural gas prices shown in the figure.

Figure A-2: Day-Ahead Electricity and Natural Gas Prices
2010-2011

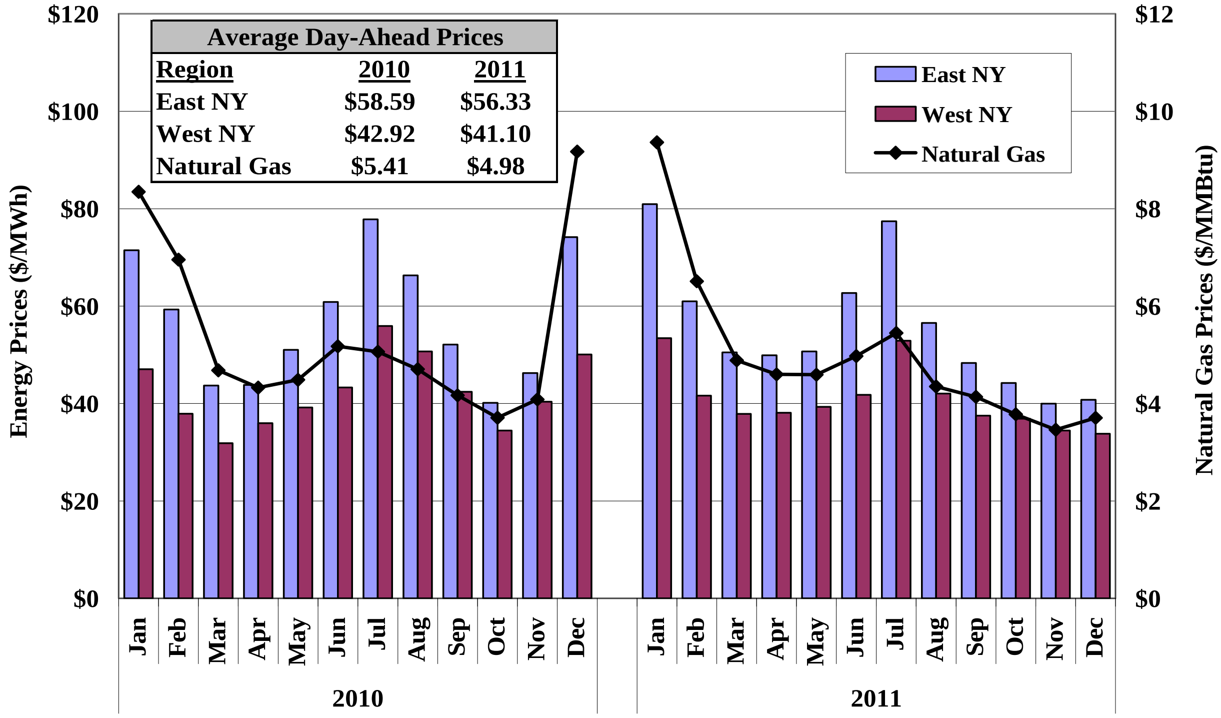


Figure A-3: Average Implied Marginal Heat Rate

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 A-3 shows the load-weighted average implied marginal heat rate for Eastern and Western New York in each month during 2010 and 2011. By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

Figure A-3: Average Monthly Implied Heat Rate
2010-2011

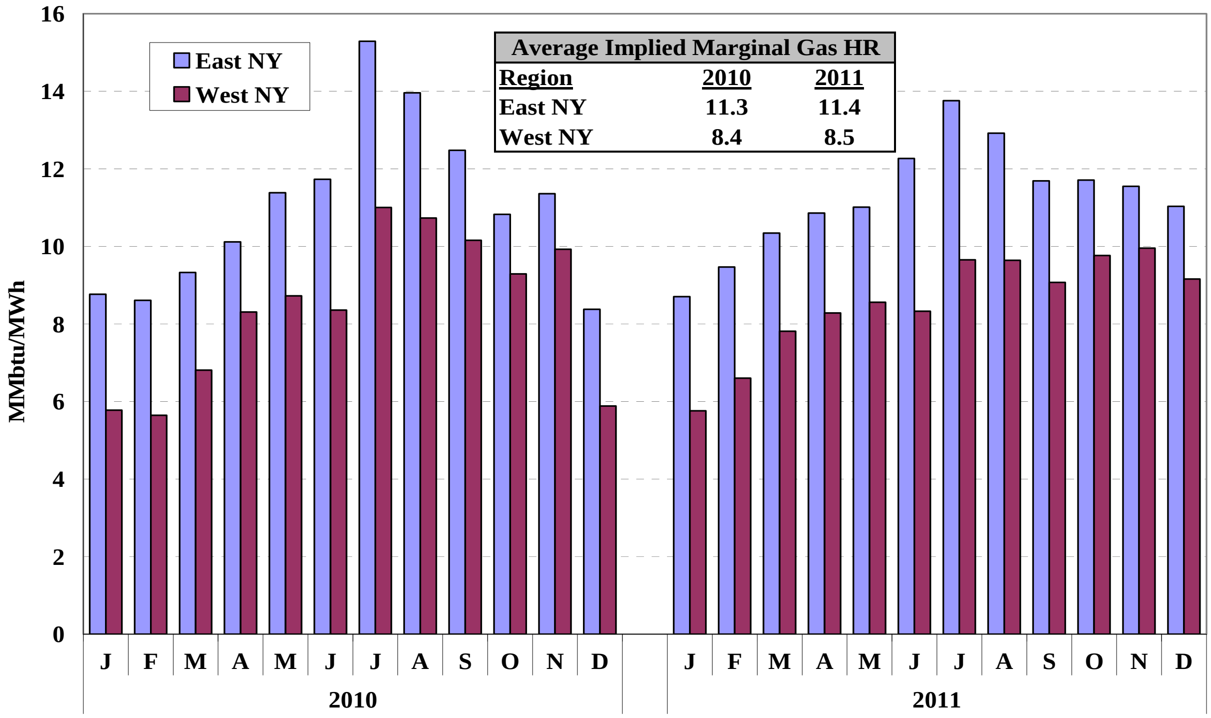


Figure A-4 & Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours in each year. Figure A-4 shows three price duration curves, one for each year from 2009 to 2011. 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. The table shows the number of hours in each year when the real-time prices exceeded \$100, \$200, and \$500 per MWh.

The price duration curves show the characteristic distribution of prices in wholesale power markets, in which a small number of hours exhibited very high prices that are 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. Fuel price changes from year to year can be revealed by the flatter portion of the price duration curve, since fuel price changes affect power prices in almost all hours.

To identify factors affecting power prices other than fuel price changes, Figure A-5 shows three implied heat rate duration curves from 2009 to 2011. Each curve shows the number of hours on the horizontal axis when the implied heat rate for New York State was greater than the level shown on the vertical axis. In this case, the implied marginal heat rate is the state-wide average real-time price divided by the natural gas price. The inset table shows the number of hours in each year when the implied heat rate exceeded 10 and 20 MMbtu per MWh.

Figure A-4: Price Duration Curves
2009-2011

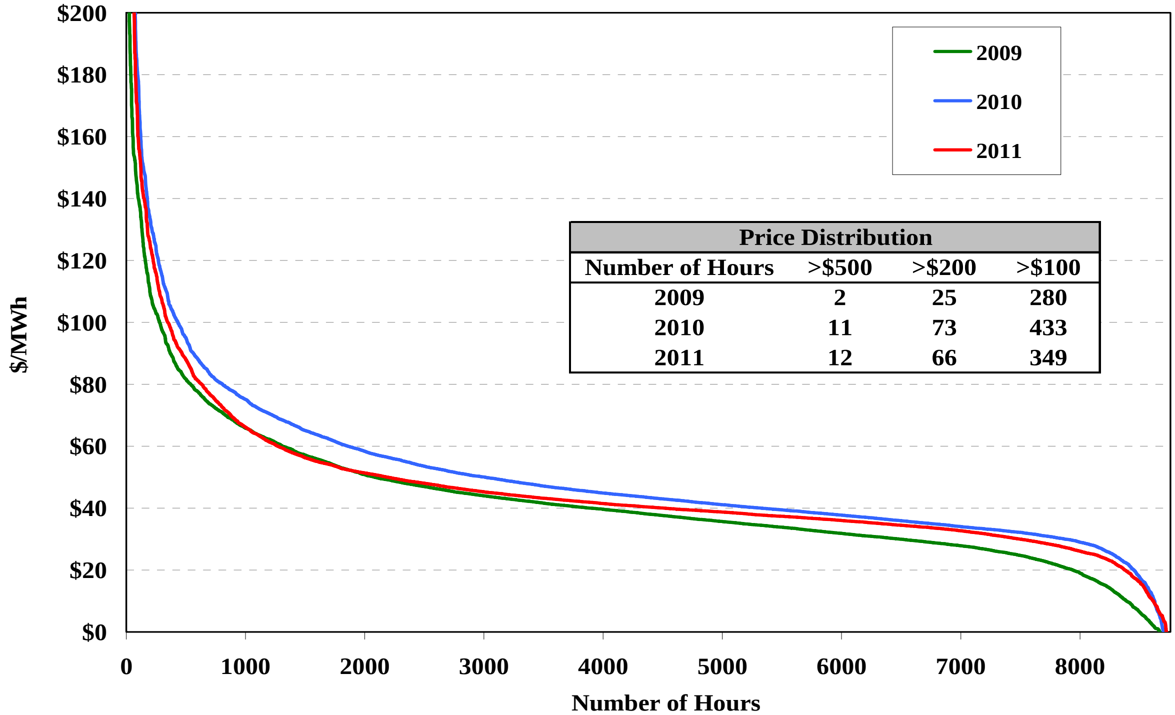
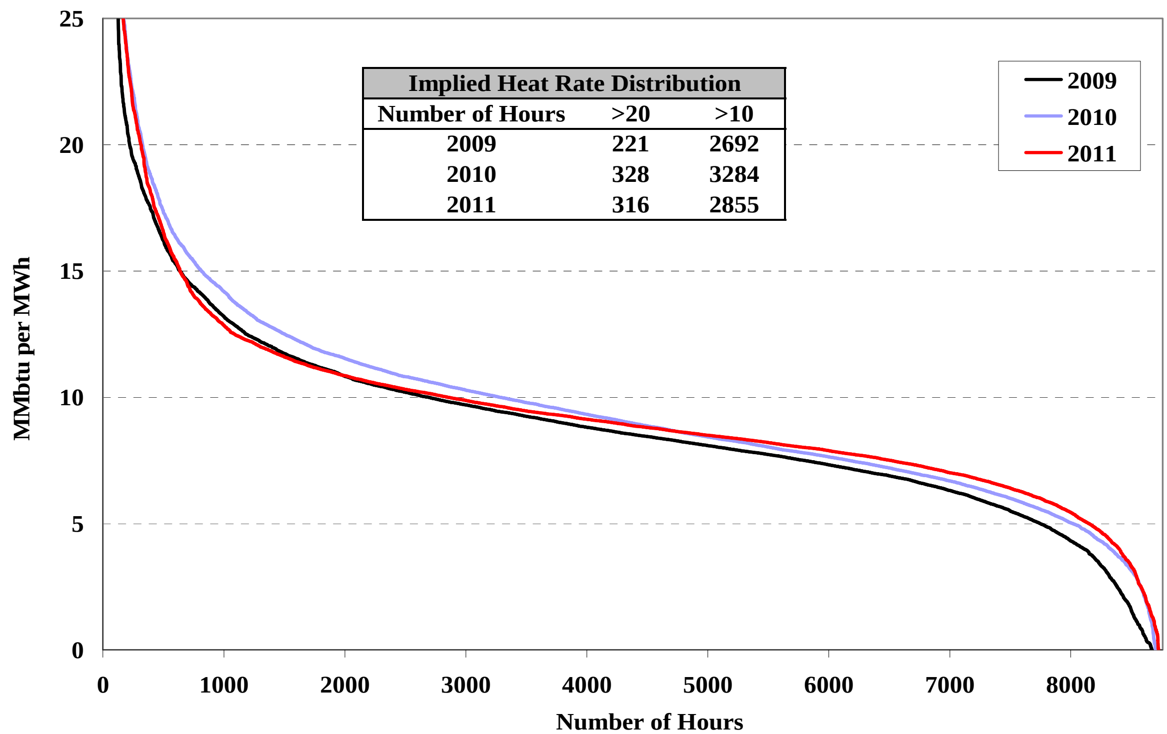


Figure A-5: Implied Heat Rate Duration Curves for New York State
2009-2011



Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from $43 per MWh in West NY to $71 per MWh in New York City in 2011.
  - Energy costs accounted for 79 percent of the all-in price in New York City and 94 to 96 percent of the all-in price in the other four regions.
  - Capacity costs accounted for 18 percent of the all-in price in New York City and 1 to 2 percent of the all-in price in the other four regions, reflecting that there is substantial excess installed capacity outside New York City and that the excess is smaller in New York City.
- Average electricity prices fell 6 to 8 percent in the five regions of New York State from 2010 to 2011. These decreases were consistent with the change in natural gas prices, which fell 8 percent from 2010 to 2011.
- Average capacity costs fell 35 percent in New York City and 80 percent in other regions from 2010 to 2011. These decreases were driven by:
  - The entry of 1 GW of new combined cycle capacity in the Capital Zone and New York City and
  - Reductions in the installed capacity requirements in New York City and for NYCA. The installed capacity requirement fell primarily due to reductions in the summer peak load forecast from the previous year.
- The seasonal patterns of electricity prices and natural gas prices were typical for most of 2010 and 2011 as electricity prices rose in the winter months as a result of tight natural gas supplies and in the summer months as a result of high electricity demand. However, electricity prices were unseasonably low in December 2011 due to mild winter weather, which led to low electricity demand and low natural gas prices.

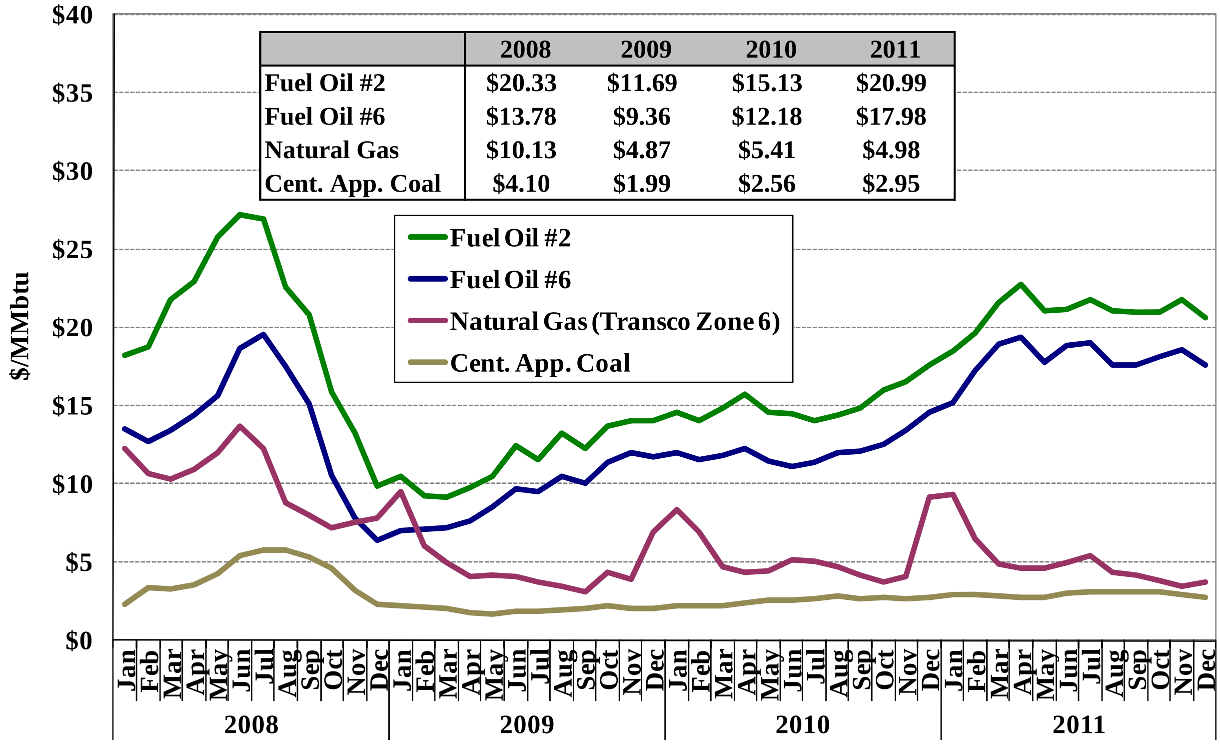
B. Fuel Prices and Load Levels

Figure A-6: Monthly Average Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale power prices because most of the marginal production costs of fossil fuel 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 A-6 shows average coal, natural gas, and fuel oil prices by month from 2008 to 2011. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Prices
2008-2011



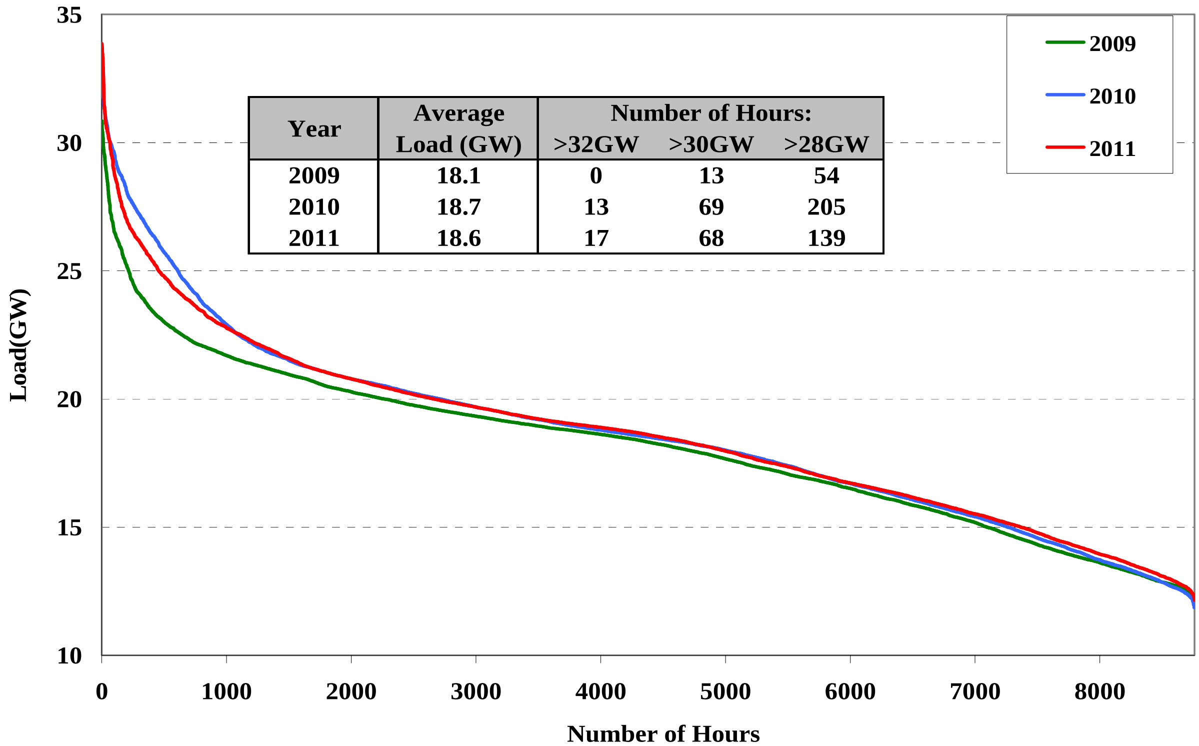
Note: These are index prices that do not include transportation charges.

Figure A-7: Load Duration Curves for New York State

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 A-7 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. The table in the figure shows the average load level on an annual basis for the past three years and also the number of hours in each year when the system was under high load conditions (i.e., load exceeded 28, 30, and 32 GW).

Figure A-7: Load Duration Curves for New York State
2009-2011



Year	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2009	18.1	0	13	54
2010	18.7	13	69	205
2011	18.6	17	68	139

Key Observations: Fuel Prices and Load Levels

- With the exception of natural gas, the prices for fossil fuels rose steadily from 2009 to 2011.
  - Diesel fuel oil (No. 2) prices averaged almost $21/MMBtu in 2011, up 39 percent from 2010;
  - Residual fuel oil (No. 6) prices averaged approximately $18/MMBtu in 2011, up 48 percent from 2010; and
  - Central Appalachian coal prices averaged nearly $3/MMBtu in 2011, up 15 percent from 2010.
  - Natural gas prices, which more directly affected wholesale energy prices, were relatively stable in recent three years, averaging around $5/MMBtu on an annual basis.
- Load averaged 18.6 GW in 2011, down slightly from 2010. However, the system had more hours under extreme high load conditions (i.e., when load exceeded 32 GW) in 2011 because of relatively hot weather in the summer of 2011.
  - Load peaked at 33,865 MW on July 22 during an unexpected heat wave, which is only about 70 MW less than the all-time peak set on August 2, 2006.

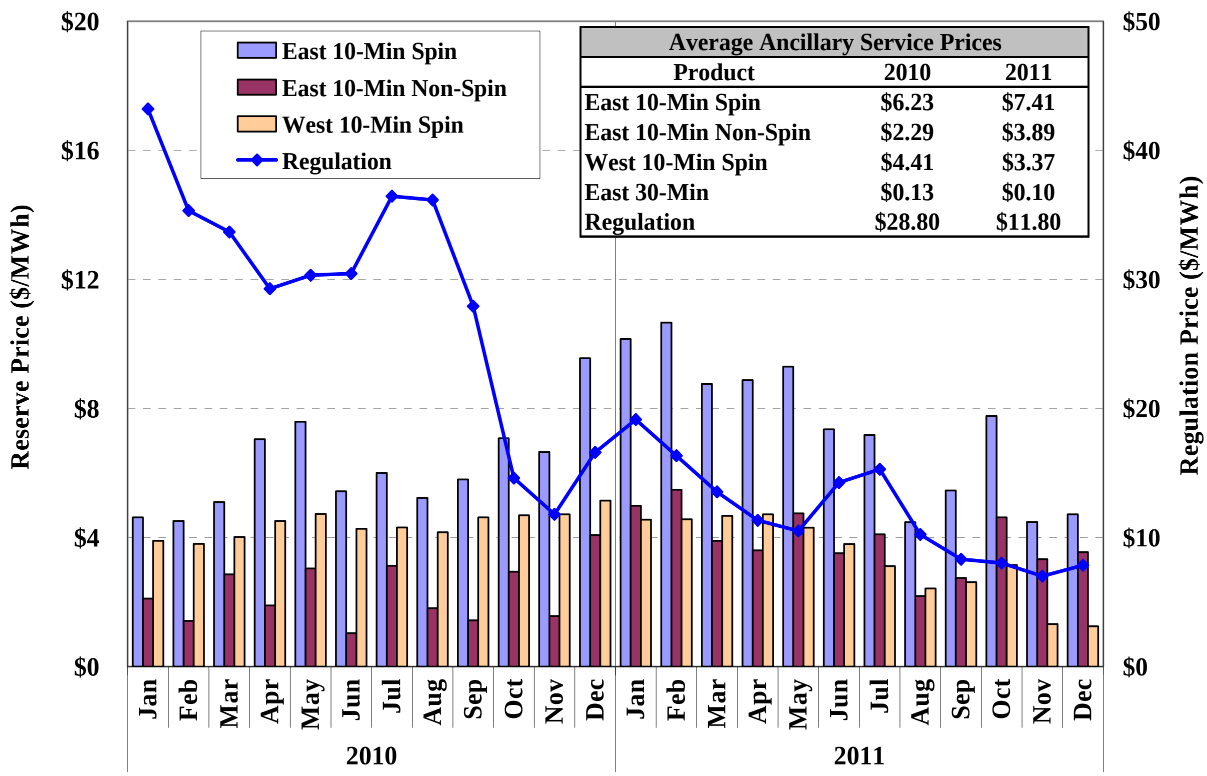
C. Day-ahead Ancillary Services Prices

Figure A-8: Day-Ahead 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 and ancillary services prices both reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. Hence, ancillary services prices generally rise and fall with the price of energy because it influences the level of these opportunity costs.

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 A-8 shows the average prices of the following four key ancillary services products in the day-ahead market in each month of 2010 and 2011: (a) 10-minute spinning reserves in Eastern New York; (b) 10-minute total reserves in Eastern New York; (c) 10-minute spinning reserves in Western New York; and Regulation.

Figure A-8: Day-Ahead Ancillary Services Prices
2010-2011



Key Observations: Day-ahead Ancillary Service Prices

- Eastern 10-minute spinning and non-spinning reserves prices have risen significantly since 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.

- Regulation prices fell considerably from 2010 to 2011. Most of this reduction occurred after September 2010 and was driven by the entry of new regulation-capable capacity and reduced offer prices from existing suppliers.

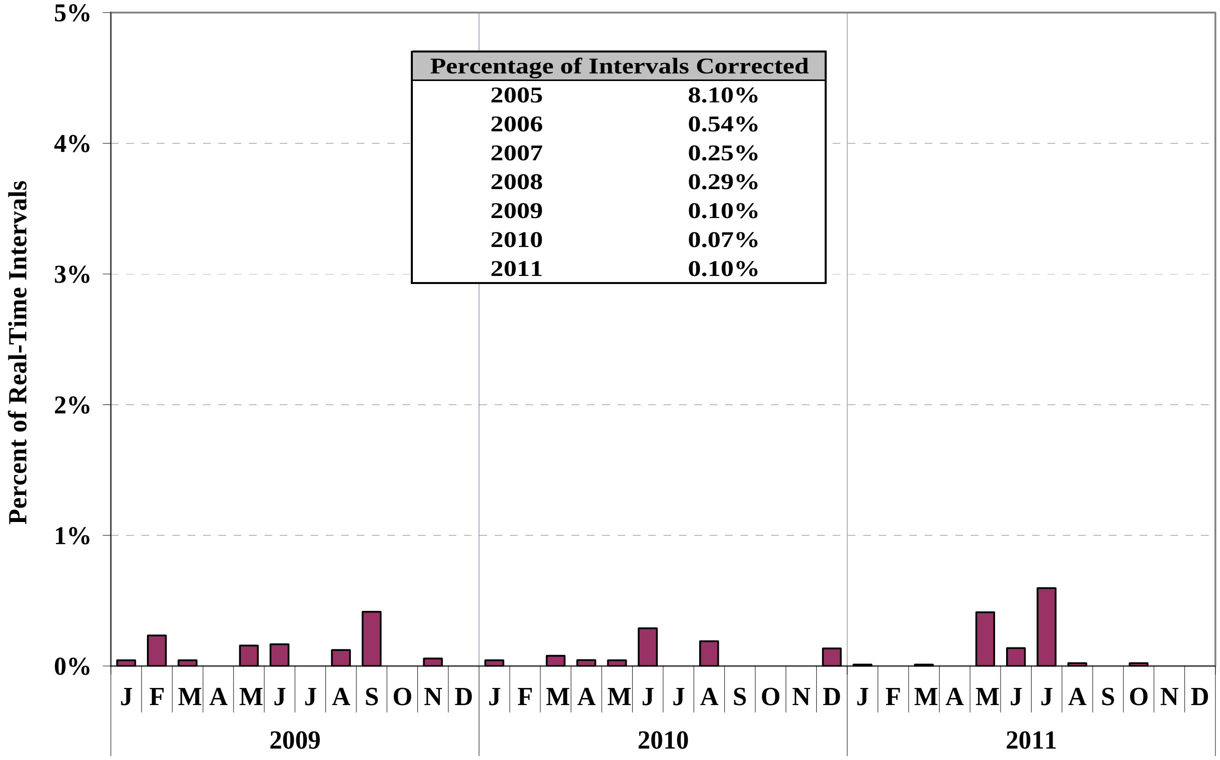
D. Price Corrections

Figure A-9: Frequency of Real-Time 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 A-9 summarizes the frequency of price corrections in the real-time energy market in each month of 2009 and 2011.

The table in the figure indicates the change of the frequency of price corrections over the past several years. Overall, the frequency of corrections and the significance of the corrections have declined to very low levels, less than 0.3 percent of real-time pricing intervals in the past five years.

Figure A-9: Frequency of Real-Time Price Corrections
2009 – 2011



E. 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 exist:

- 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 or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would 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.

We estimate the net revenues the markets would have provided to the two types of new units that have constituted most of the new generation in New York over the past few years:

- A hypothetical combustion turbine unit and
- A hypothetical combined-cycle unit.

Because net revenues can vary substantially by location, we estimate the net revenues that would have been received 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. We utilize the zone-level energy prices for the zonal locations and a representative generator bus for other locations. We also use location-specific capacity prices from the NYISO's spot capacity markets.

The method we use to estimate net revenues is similar to the method that has been adopted by FERC to provide a basis for comparison of net revenues between markets.[75, 76] However, we use several alternate assumptions as well to improve the accuracy of the results.

- 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;[77]
- 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;

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75 FERC uses the following assumptions. First, 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. Second, 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. Third, the hypothetical combustion turbine has a heat rate of 10.5 MMbtu per MWh and a VOM cost of $1 per MWh. Fourth, the hypothetical units are on forced outages five percent of the time.

76 The net revenue estimates produced using FERC's 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.

77 Our 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.

- 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; [78]
- 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.
- We also use the modified operating and cost assumptions listed in the following table:

Table A-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

Figure A-10 & Figure A-11: Net Revenue

The following figures summarize net revenue estimates using our method, and they show the levelized Cost of New Entry ("CONE") estimated in the Installed Capacity Demand Curve Reset Process for comparison. Levelized CONE estimates are not available for some locations and technologies. Figure A-10 shows net revenues for a hypothetical combined-cycle generator, and Figure A-11 shows net revenues for a hypothetical combustion turbine.

78 One 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. Combustion turbines and 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. These issues are not addressed by either method.

Figure A-10: Net Revenue for Combined-Cycle Unit
2007-2011

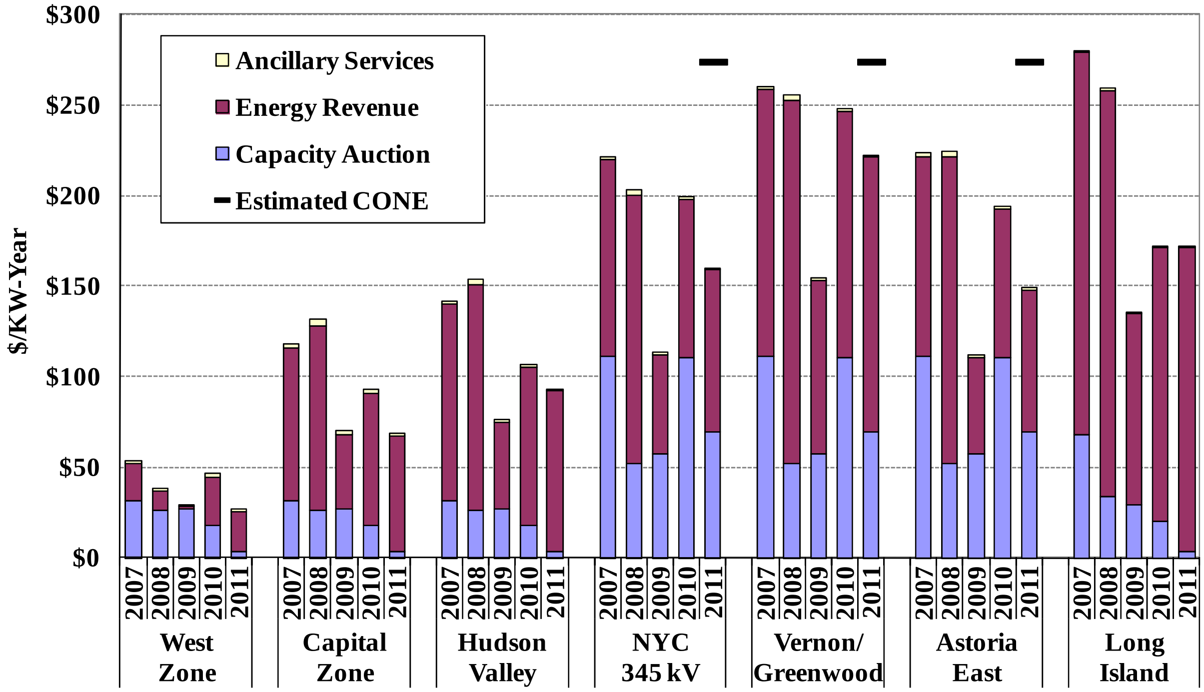
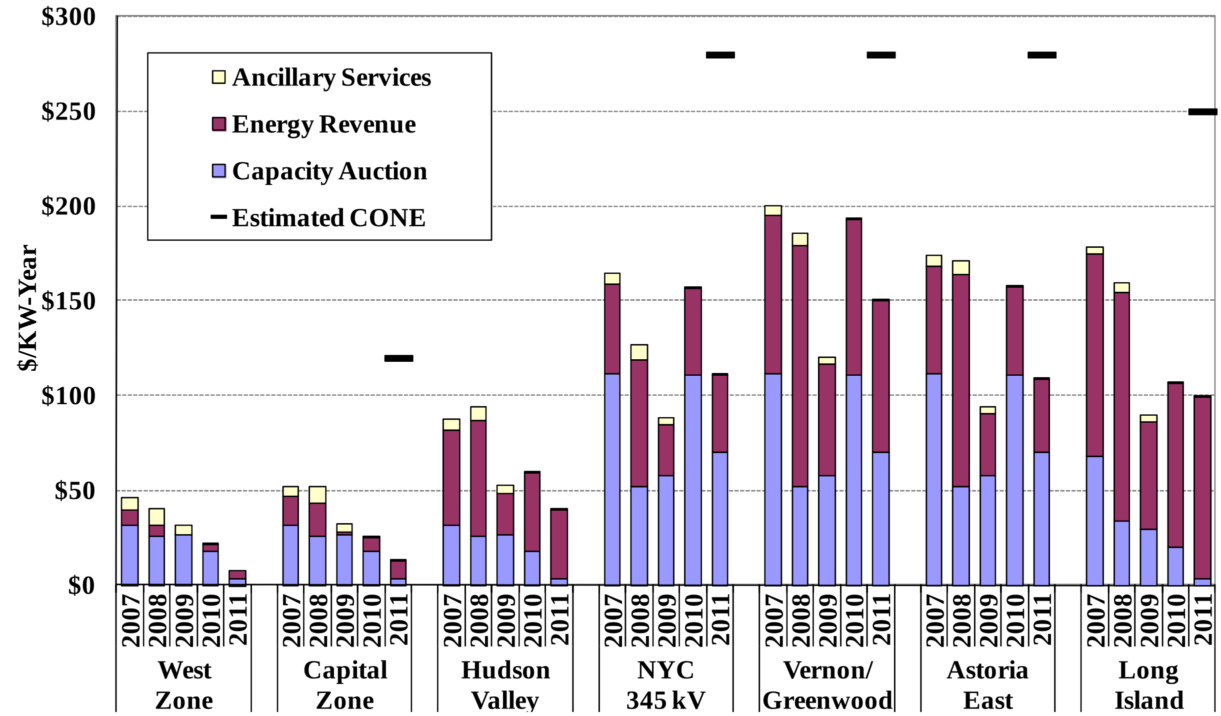


Figure A-11: Net Revenue for Combustion Turbine
2007-2011



Key Observations: Net Revenue

- Both figures show that net revenues declined sharply in 2009 throughout the state, rose substantially in most areas in 2010, and fell again in 2011. These changes were due to a number of factors:
  - Capacity net revenues changed significantly in recent years. Outside New York City, capacity net revenues fell from 2007 to 2011, primarily due to capacity additions around the state and due to unusually low (and sometimes negative) load growth. In New York City, however, capacity net revenues rose in 2010 with the retirement of the Poletti unit and fell in 2011 following the entry of a new combined-cycle generator.
  - Variations in load levels affected energy net revenues over the period. Higher loads lead to more frequent dispatch of high-cost generation and more shortages, resulting in elevated energy net revenues. Accordingly, fluctuations in load levels led net energy revenues fluctuation similarly from 2008 to 2010. Energy net revenues were relatively flat from 2010 to 2011 in most areas.
  - Changes in fuel prices led to concomitant changes in energy net revenues for the combined cycle unit. Energy net revenues and fuel prices are correlated because higher fuel prices increase the spreads between wholesale energy prices and production costs of the combined cycle unit. Accordingly, fuel price changes contributed to the sharp decline in net energy revenues in 2009, the increase in 2010, and flat energy net revenues in 2011.
- Estimated net revenues for a new combined cycle unit declined by roughly 43 percent from 2010 to 2011 in the West Zone, 20 percent in New York City, less than 1 percent in Long Island, and 12 to 26 percent elsewhere. These reductions were primarily due to lower capacity prices throughout New York. Estimated net revenues for a new combustion turbine fell for the same reasons.
  - In Long Island, reduced capacity net revenues were offset by increased energy net revenues, which were driven by increased congestion into Long Island as a result of several significant transmission outages. Hence, lower net revenues would be expected in a year with a more typical number of transmission outages.
- Estimated net revenues were well below the estimated CONE values in 2011 for both combustion turbines and combined cycles at the locations for which such estimates were made.
  - For a new combustion turbine unit, estimated net revenues were lower than the estimated CONE by 89 percent in the capital zone, 46 to 60 percent in New York City, and 60 percent in Long Island.
  - For a new combined cycle unit, estimated net revenues were lower than the estimated CONE by 19 to 45 percent in New York City.

- Hence, a new combined cycle unit appears to be closer to being economic in New York City than a new combustion turbine. However, this is based on CONE estimates that assume New York City property tax abatement.

F. Convergence with the Real-Time Market

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.

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).

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. We expect random variations resulting from unanticipated changes in supply and demand between the two markets on an hour-to-hour basis, but persistent systematic differences between day-ahead and real-time prices would raise potential concerns.

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.

Figure A-12 & Figure A-13: Average Day-Ahead and Real-Time Energy Prices

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. Accordingly, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

Figure A-12 and Figure A-13 compare day-ahead and real-time energy prices in West zone, Central zone, Capital zone, and Hudson Valley, New York City, and Long Island. The figures are 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 2011. 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.

Figure A-12: Average Day-Ahead and Real-Time Energy Prices outside SENY
West, Central, and Capital Zones - 2011

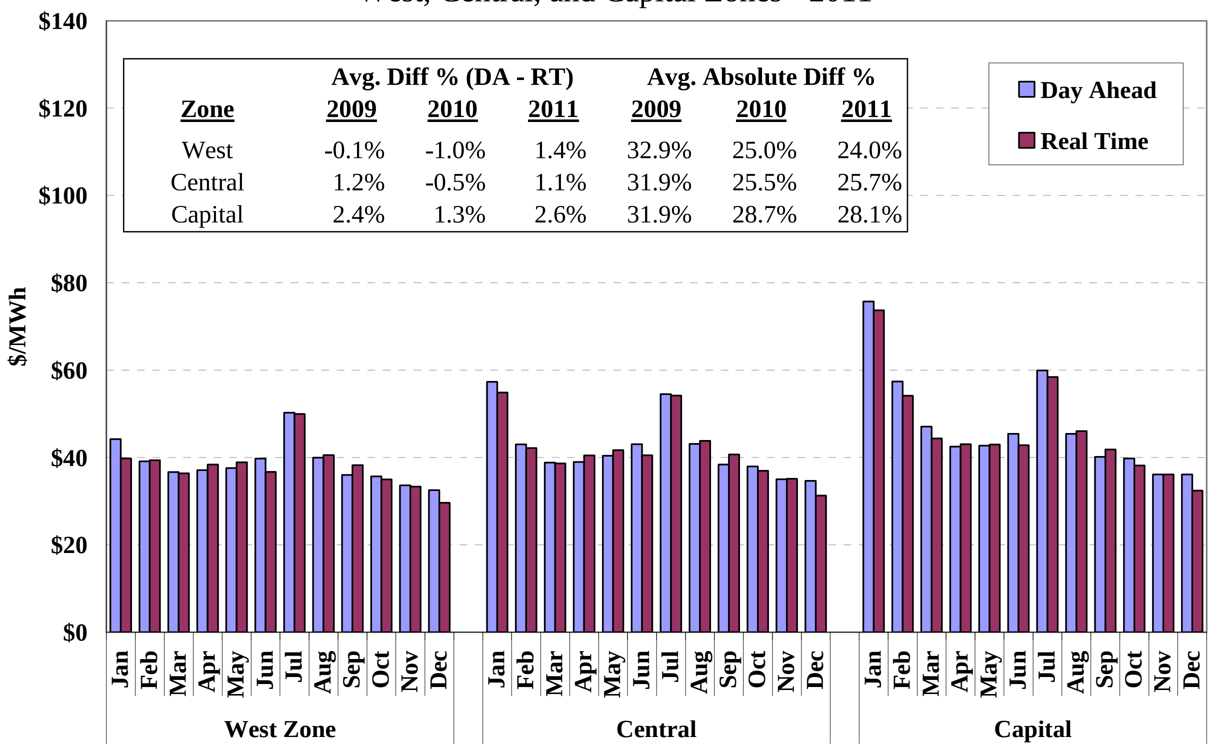


Figure A-13: Average Day-Ahead and Real-Time Energy Prices in SENY
Hudson Valley, New York City, and Long Island - 2011

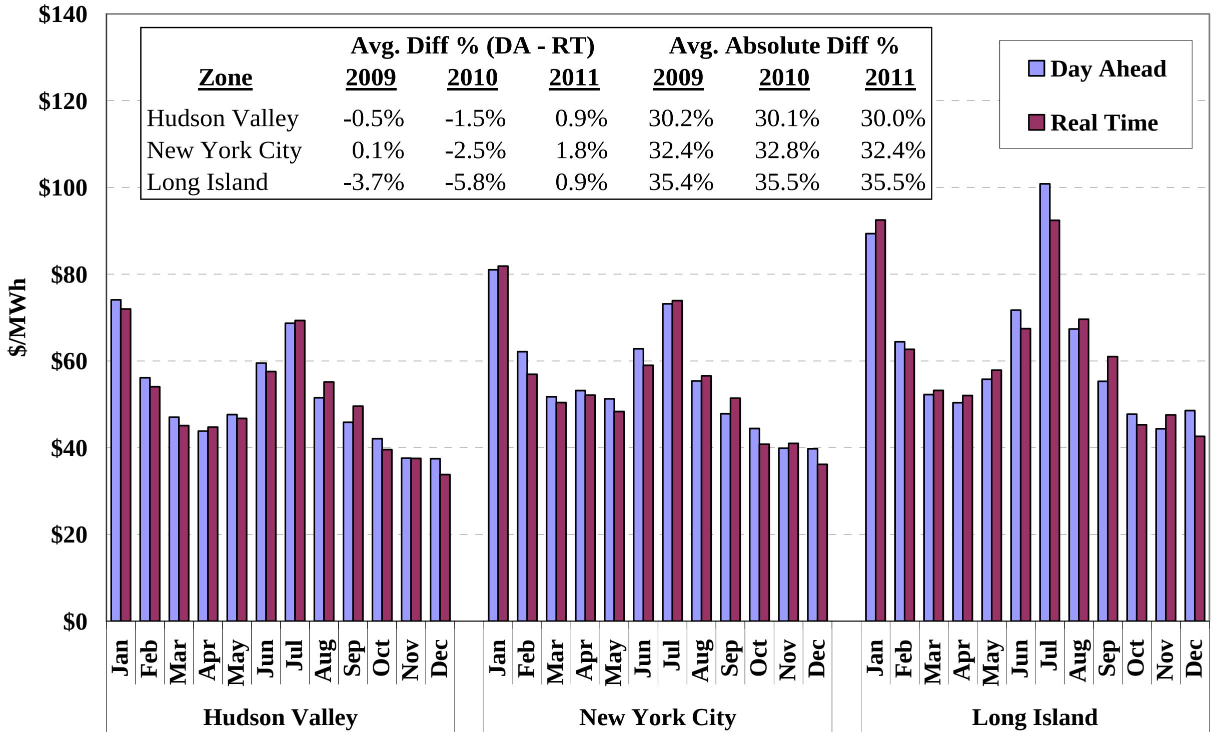
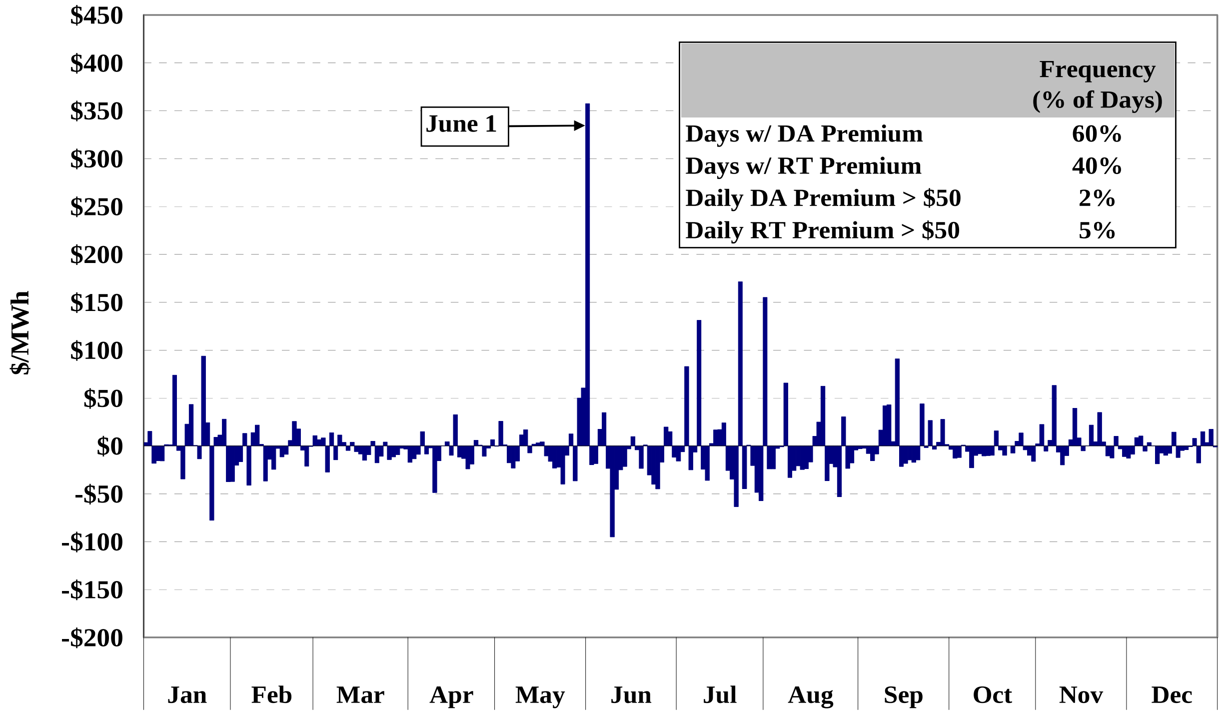


Figure A-14 & Figure A-15: Average Daily Real-Time Price Premium

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. Monthly day-ahead price premiums typically arise when real-time scarcity conditions occur less frequently than market participants anticipate in the day-ahead market.

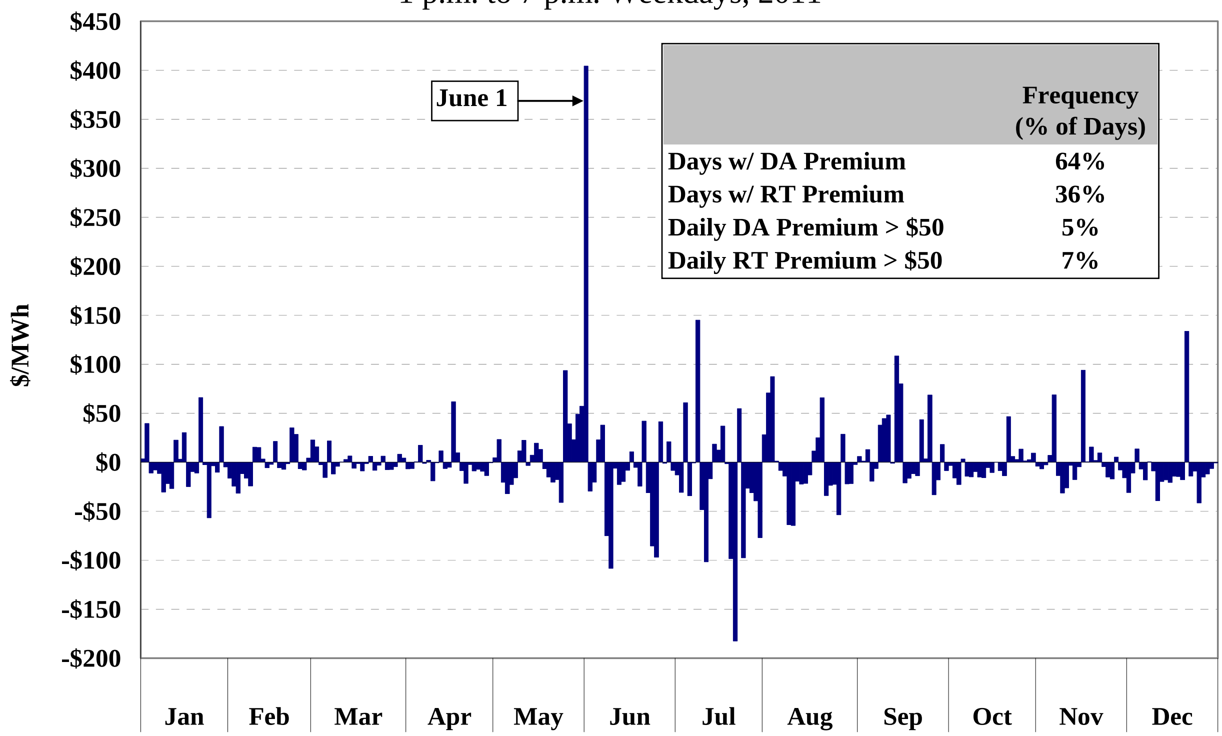
The following two figures show the differences between day-ahead and real-time prices on a daily basis in New York City and Long Island during weekday afternoon hours in 2011. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure A-14: Average Daily Real-Time Price Premium in NYC
1 p.m. to 7 p.m. Weekdays, 2011



	Frequency (% of Days)
Days w/ DA Premium	60%
Days w/ RT Premium	40%
Daily DA Premium > $50	2%
Daily RT Premium > $50	5%

Figure A-15: Average Daily Real-Time Price Premium in Long Island
1 p.m. to 7 p.m. Weekdays, 2011



	Frequency (% of Days)
Days w/ DA Premium	64%
Days w/ RT Premium	36%
Daily DA Premium > $50	5%
Daily RT Premium > $50	7%

Figure A-16: Average Real-Time Price Premium at Select Nodes

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:

- 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.

- Generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows.

- Constraint limits used to manage congestion may change from the day-ahead market to the real-time market.

- 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.

- 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 analysis examines price statistics for selected nodes in throughout New York State to assess price convergence at the nodal level.

Figure A-16 shows average day-ahead prices and real-time price premiums in 2011 for selected locations in New York City, Long Island, and Upstate New York.[79] 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

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[79] 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.

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 (June to August) and other months because the congestion patterns typically vary by season.

Figure A-16: Average Real-Time Price Premium at Select Nodes

2011

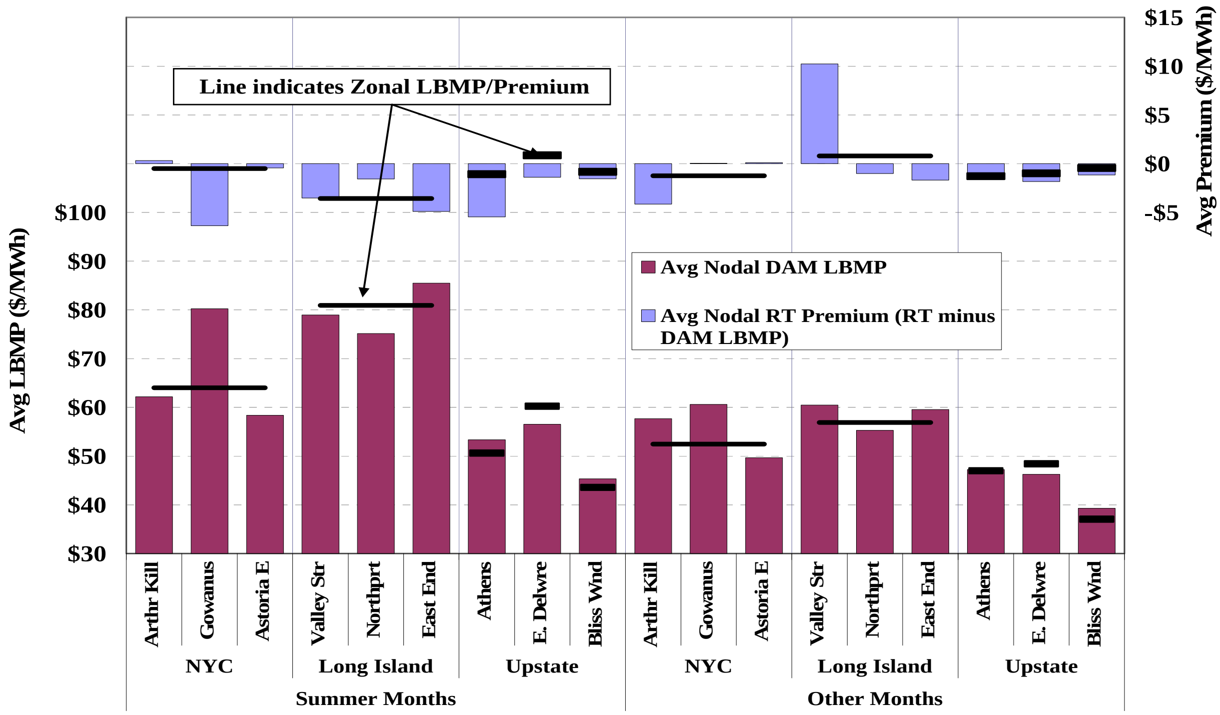


Figure A-17 & Figure A-18: 10-Minute Spinning and Non-Spinning Reserve Prices

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.

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 and 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 two important reserve products in New York.

Figure A-17 shows 10-minute non-spinning reserve prices in Eastern New York, which are primarily based on the requirement to hold 1,200 MW of total 10-minute reserves east of the Central-East Interface. 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. The market uses a "demand curve" that places an economic value of $500 per MW on satisfying this requirement.

Figure A-18 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. Therefore, this represents the base price for spinning reserves in New York before locational premiums for satisfying eastern 10-minutes requirement are added. A demand curve is used that places an economic value of $500 per MW on satisfying this requirement.

In both figures, average prices are shown by season and by hour of day. The inset tables show average differences between day-ahead and real-time prices during afternoon hours (i.e., hour 14 to 20) and other hours.

Figure A-17: 10-Minute Non-Spinning Reserve Prices in East NY

by Season and Hour of Day, 2011

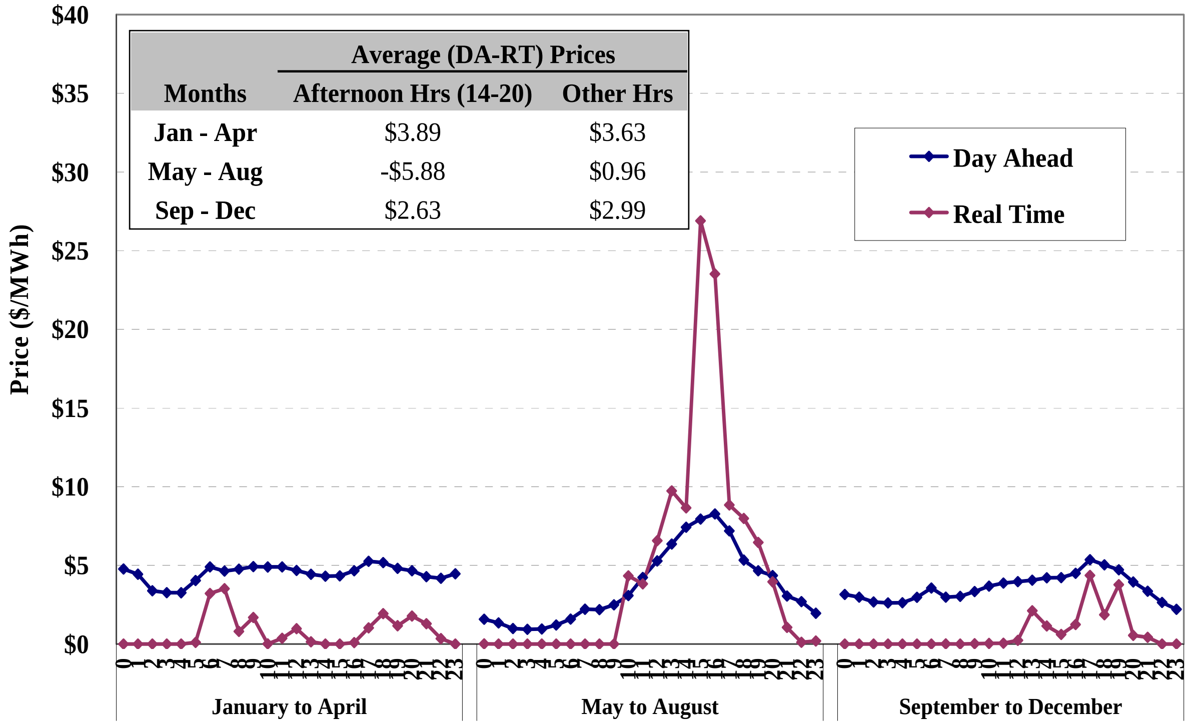
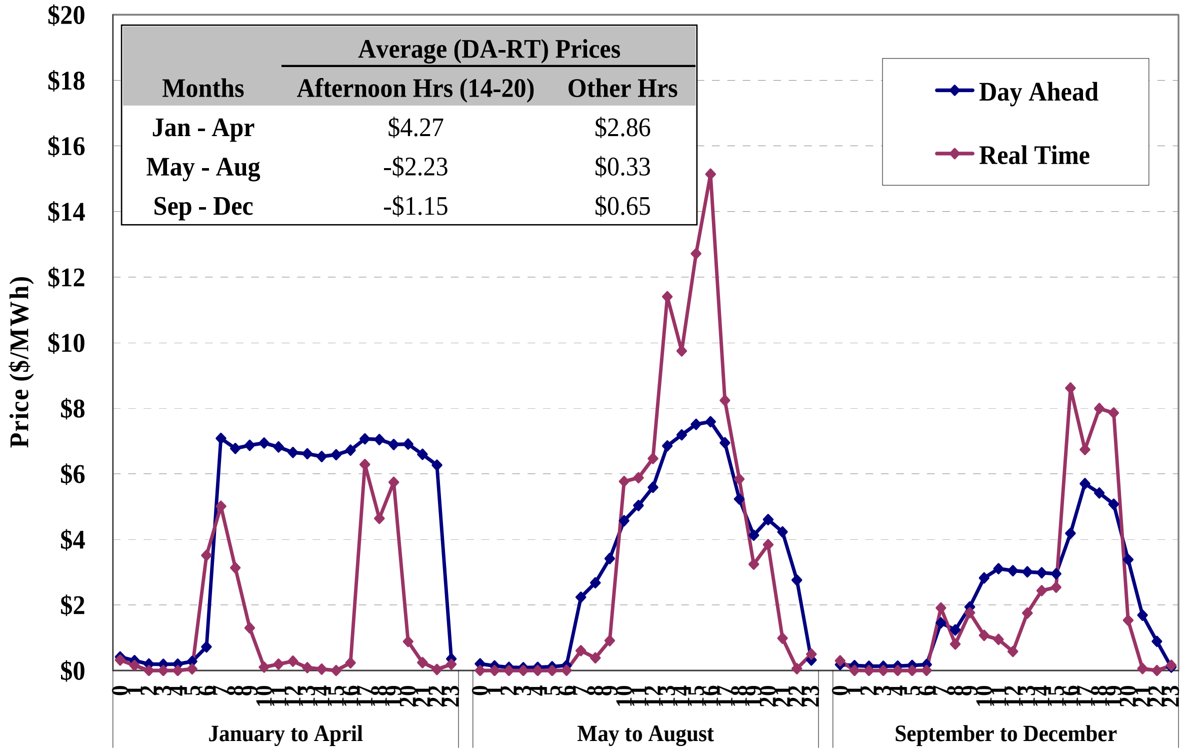


Figure A-18: 10-Minute Spinning Reserve Prices in West NY
by Season and Hour of Day, 2011



Key Observations: Convergence of Day-Ahead and Real-Time Prices

- Energy price convergence was relatively good in 2011.
- At the zonal level, average day-ahead energy prices were higher than average real-time prices by a small margin (1 to 2.5 percent).
  - Although consistent overall, there were substantial differences on individual days as one would expect, particularly in Southeast New York during the summer where unexpected TSAs occurred frequently.
- At the nodal level, a few locations exhibited less consistency between average day-ahead and real-time prices than zonal prices did. These were:
  - The Gowanus and Athens locations, which exhibited day-ahead price premiums of $6 and $5 per MWh in the summer months.
  - The Valley Stream load pocket, which exhibited a real-time price premium of $10 per MWh outside the summer.
  - Allowing disaggregated virtual trading in these areas would address these differences by allowing participants the opportunity to arbitrage them.
- Reserve price convergence was relatively poor in 2011.

- During most conditions, day-ahead reserve prices were higher on average than real-time reserve prices.
- However, average real-time reserves prices were predictably higher than average day-ahead prices during summer afternoon hours.
- The mitigation rules that limit the ancillary services offers of some generators in the day-ahead market may inhibit price convergence during these hours. We have recommended changes in these rules that NYISO is pursuing.

II. 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. This section is divided into the following sub-sections:

- Analysis of energy offers and mitigation patterns, which seeks to identify potential attempts to withhold generating resources to increase prices.
- Evaluate offers to supply regulation and 10-minute operating reserves in the day-ahead market.
- Evaluate load-bidding and virtual trading behavior to determine whether they have been conducted in a manner consistent with competitive expectations.

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, prices rise gradually until demand approaches peak levels, at which point 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 exercise it 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 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.

A. Generator Deratings

Figure A-19 & Figure A-20: Generator Deratings by Month

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). Figure A-19 and Figure A-20 show the broad patterns in outages and deratings in New

York State and Eastern New York in each month of 2010 and 2011. The figures show the quantity of deratings (as a percent of total DMNC from all resources), which measure the difference between the quantity offered in the day-ahead market and the most recent Dependable Maximum Net Capability ("DMNC") test value of each generator. *Short-term Deratings* include capacity that is derated for less than 30 days, and the remaining derates are shown as *Other Deratings.*

We focus particularly on short-term deratings because they are more likely than long-term deratings to reflect attempts to physically withhold, since 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 also focus on suppliers in Eastern New York, since this area includes roughly two-thirds of the State's load, contains several areas with limited import capability, and is more vulnerable to the exercise of market power than Western New York.

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.

Figure A-19: Deratings by Month in NYCA
2010 - 2011

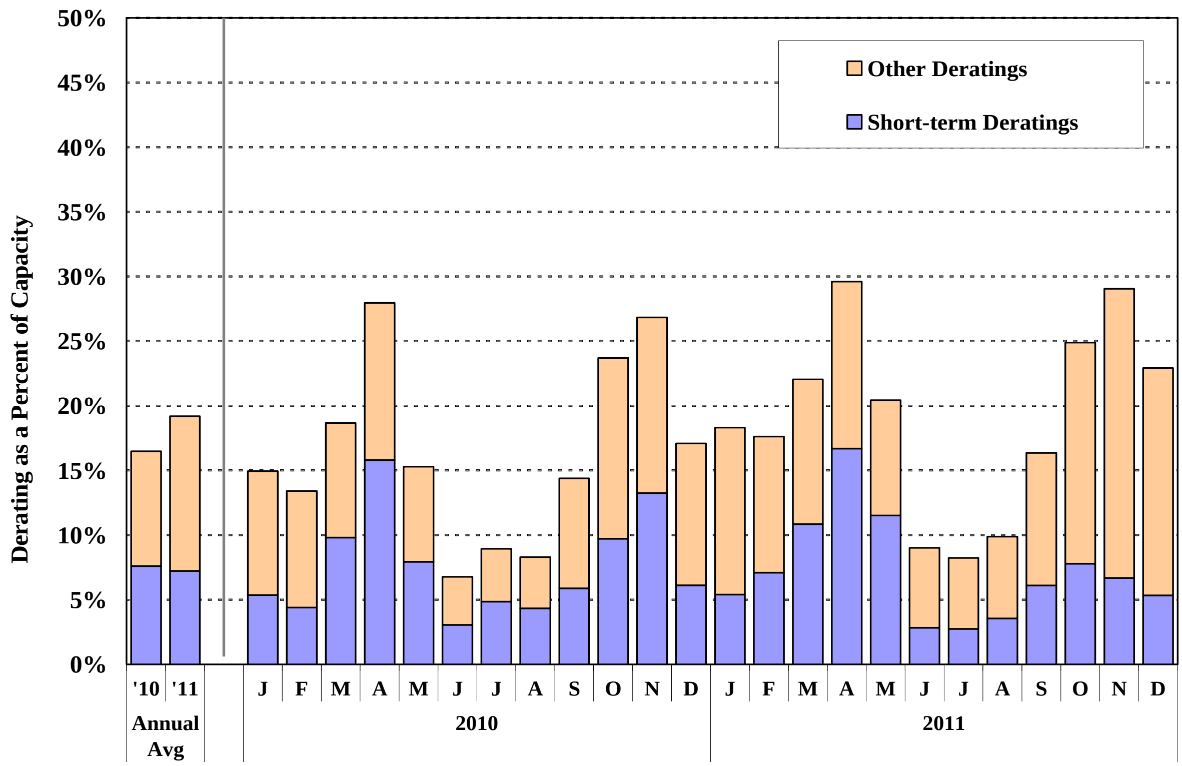


Figure A-20: Deratings by Month in East New York
2010 - 2011

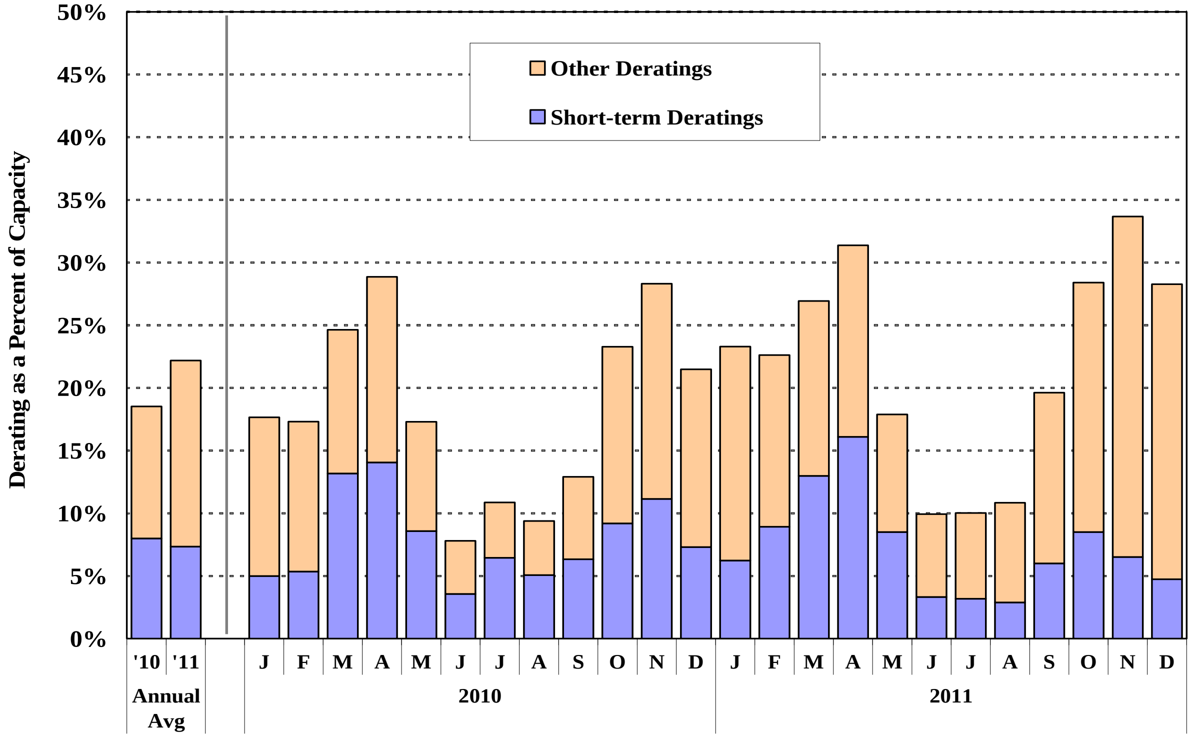


Figure A-21 & Figure A-22: Generator Deratings by Load Level

To distinguish between strategic and competitive conduct, we evaluate potential physical 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.[80] 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, we evaluate the conduct relative to load levels and participant size in Figure A-21 and Figure A-22 to determine whether the conduct of market participants is consistent with workable competition.

80 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.

Figure A-21: Deratings by Supplier by Load Level in New York
2011

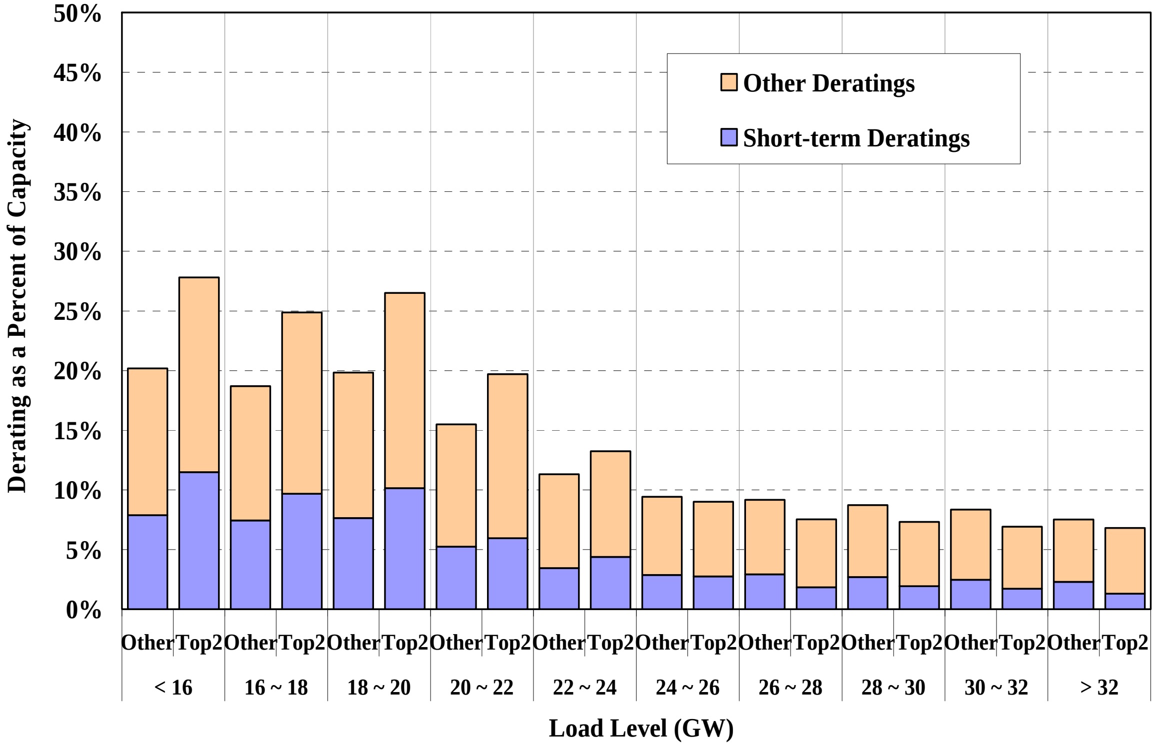
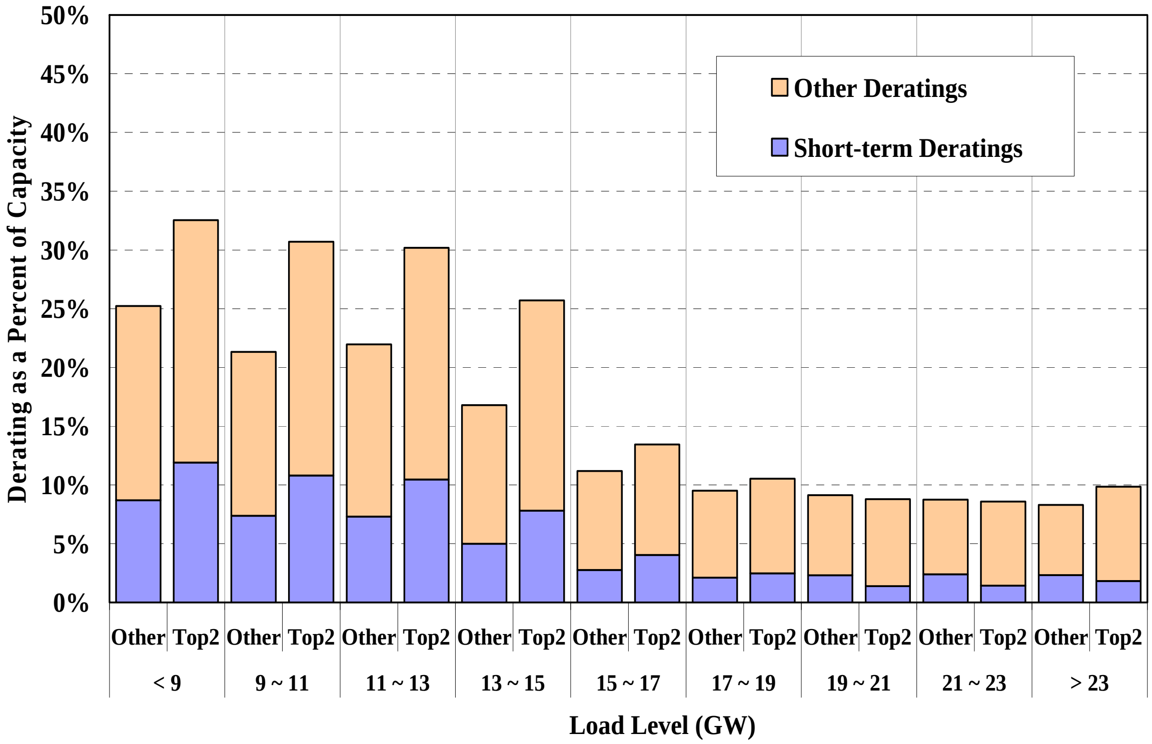


Figure A-22: Deratings by Supplier by Load Level in East New York
2011



<u>Key Observations: Generator Deratings</u>

- Overall, the pattern of deratings was consistent with expectations in a competitive market and did not raise significant concerns regarding potential withholding.
  - Average deratings were lowest during the summer months when average load was the highest. Average deratings also fell during the winter when loads typically increase (to a lesser extent than in the summer).
  - Both top suppliers and other smaller suppliers increased the availability of their capacity during periods of high load when capacity was most valuable to the market.
  - The majority of deratings were long-term (i.e., greater than 30 days), particularly in the highest load periods. This is a positive indication given that long-term deratings are less likely to be used by a supplier to withhold profitably. In the summer months, most of the long-term deratings were associated with:
    - Generators' emergency operating ranges that are not normally available, except at NYISO request; and
    - Generators that have experienced forced outages and may or may not be under-going repairs.

B. Potential Economic Withholding: Output Gap Metric

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.[81] An offer parameter is considered above the competitive level if it exceeds the reference level by a given threshold.

Figure A-23 and Figure A-24: Output Gap by Month

On useful metric for identifying potential economic withholding is the "output gap". 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.[82] We assume that the unit's competitive offer

81 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.

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

price is equal to its reference level. To determine whether a unit is economic, we evaluate whether it would have been economic to commit based on day-ahead prices and whether its incremental energy would have been economic to produce based on real-time prices. Like the prior analysis of deratings, we examine the broad patterns of output gap in New York State and Eastern New York, and also pay special attention to the relationship of the output gap to the market demand level and participant size.

The following four figures show the output gap using two thresholds: 1) 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; and 2) a lower threshold, which is the lower of $50 per MWh or 100 percent of a generator's reference level. The second threshold is included to assess whether there have been attempts to withhold by offering energy at prices inflated by less than the state-wide mitigation threshold.

Figure A-23: Output Gap by Month in New York State
2010 – 2011

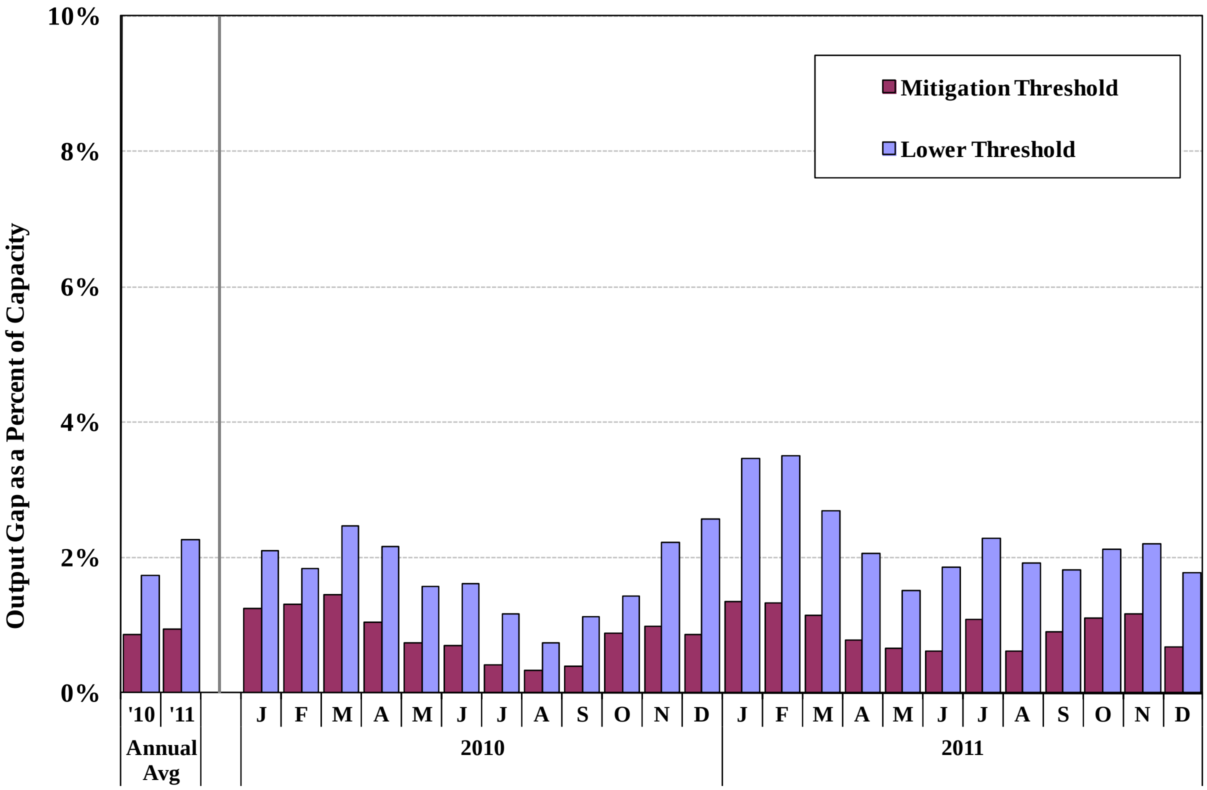


Figure A-24: Output Gap by Month in East New York
2010 - 2011

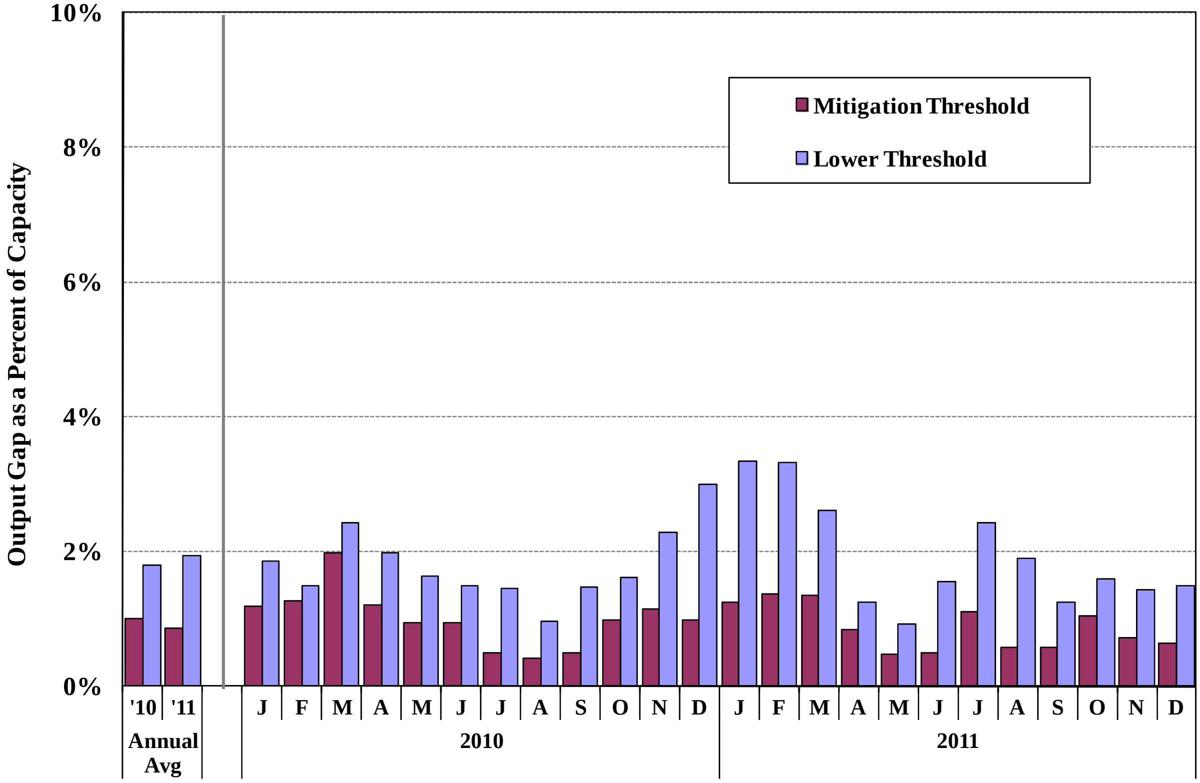


Figure A-25 & Figure A-26: Output Gap by Supplier and Load Level

Like the analysis of deratings in the prior subsection, it is useful to examine the output gap by load level and size of supplier because the incentive to economically withhold resources is likely positively correlated with these factors. Hence, these figures indicate how the output varies as load increase and whether the largest two suppliers exhibit substantially different conduct than other suppliers.

Figure A-25: Output Gap by Supplier by Load Level in New York State
2011

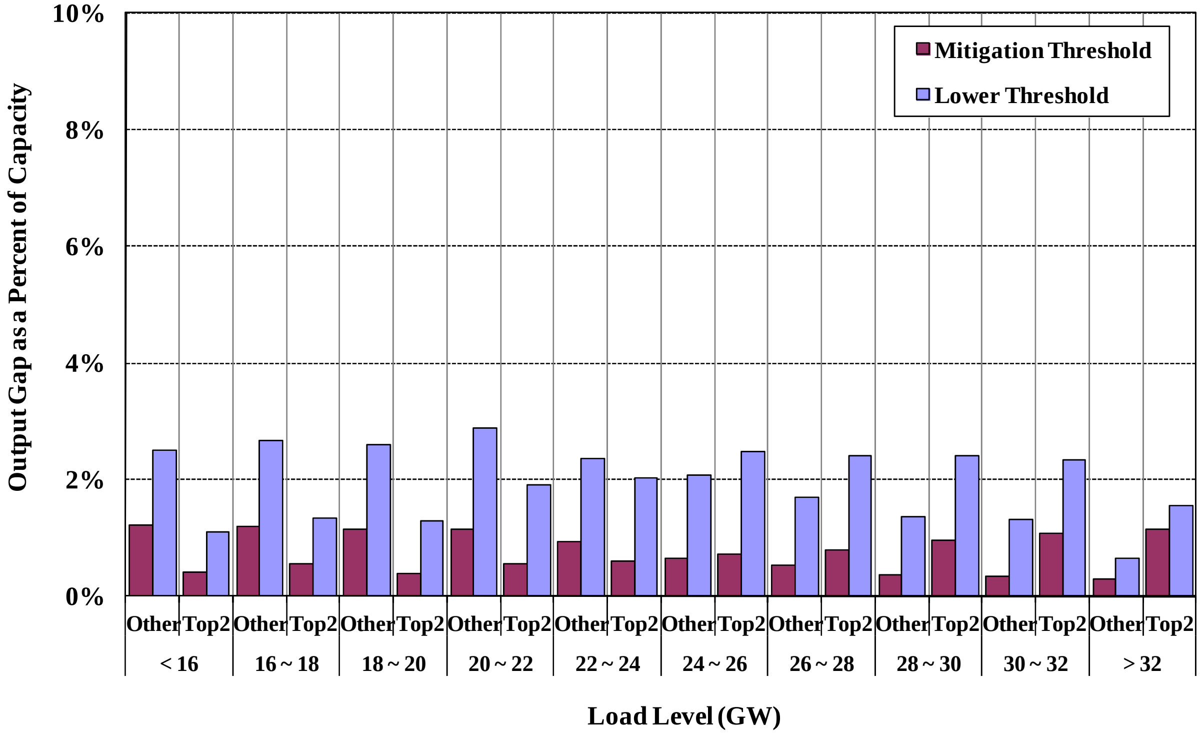
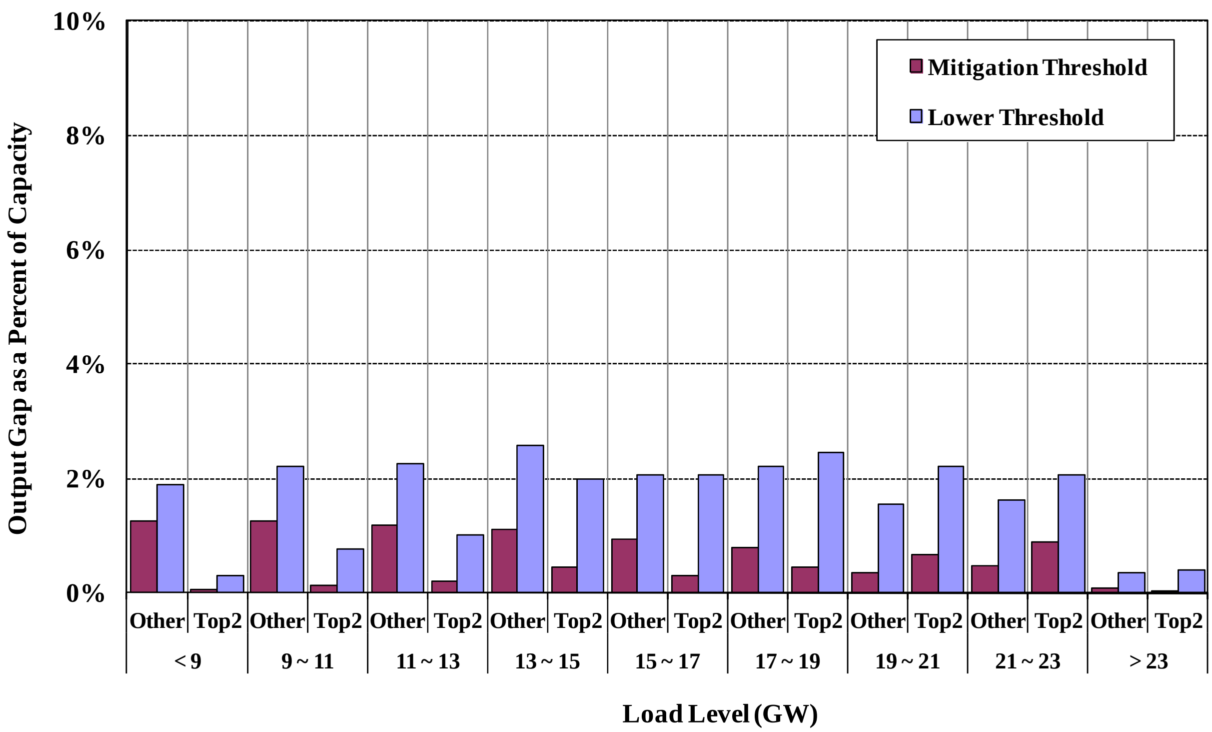


Figure A-26: Output Gap by Supplier by Load Level in East New York
2011



<u>Key Observations: Economic Withholding – Generator Output Gap</u>

- Overall, the pattern of output gap was consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding.
  - The output gap as a percentage of capacity at the mitigation threshold averaged roughly 1 percent in New York State in 2011, ranging from 0.6 percent in June to 1.4 percent in February. These levels are low and raise very few competitive concerns.
  - It is a positive indicator that the output gap did not rise under high load conditions for either top suppliers or smaller suppliers when the market is most vulnerable to the exercise of market power.

C. Day-Ahead and Real-Time 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.[83] 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 the conduct and impact tests and implement the mitigation. 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.[84] 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 the conduct test are tested for price impact by the market software. If their price impact exceeds the threshold, they are mitigated.

[83] See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

[84] 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.

When local reliability criteria necessitates the commitment of additional generation, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the local area. For this reason, the NYISO filed in 2010 to implement more restrictive conduct and impact thresholds when a single supplier is pivotal for satisfying local reliability criteria outside New York City.[85] The Rest-Of-State Reliability conduct and impact thresholds limit the start-up cost and minimum generation cost offers of such units to conduct thresholds of the higher of $10 per MWh or 10 percent of the reference level.[86]

Beginning in late 2010, it became more common for a generator to be mitigated initially in the day-ahead or real-time market and for the generator to be unmitigated after consultation with the NYISO.[87] Reversing a mitigation can occur for several reasons:

- A generator's reference level is inaccurate and the supplier initiated consultation with the NYISO to increase the reference level before the generator was mitigated.
- A generator's reference level on a particular day is lower than the consultative reference level that the NYISO approved for the generator before the generator was mitigated.[88]
- The generator took appropriate steps to inform the NYISO of a fuel price change prior to being scheduled (either through IBRT or some other means), but the generator was still mitigated.
- Fourth, a generator's fuel cost may change significantly by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day, so such a generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

Figure A-27 & Figure A-28: Summary of Day-Ahead and Real-Time Mitigation

Figure A-27 and Figure A-28 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2010 and 2011. The months of October to December are excluded from the figures since mitigation consultations are still on-going for the last quarter of 2011. These figures do not include guarantee payment mitigation that occurs in settlements.

The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower

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[85] More restrictive conduct and impact thresholds already existed for New York City generators when they were committed for local reliability. The start-up cost and minimum generation cost offers of such units are effectively subject to $0 thresholds. See NYISO Market Services Tariff, Section 23.5.2.1.

[86] See NYISO Market Services Tariff, Section 23.3.1.2.3.

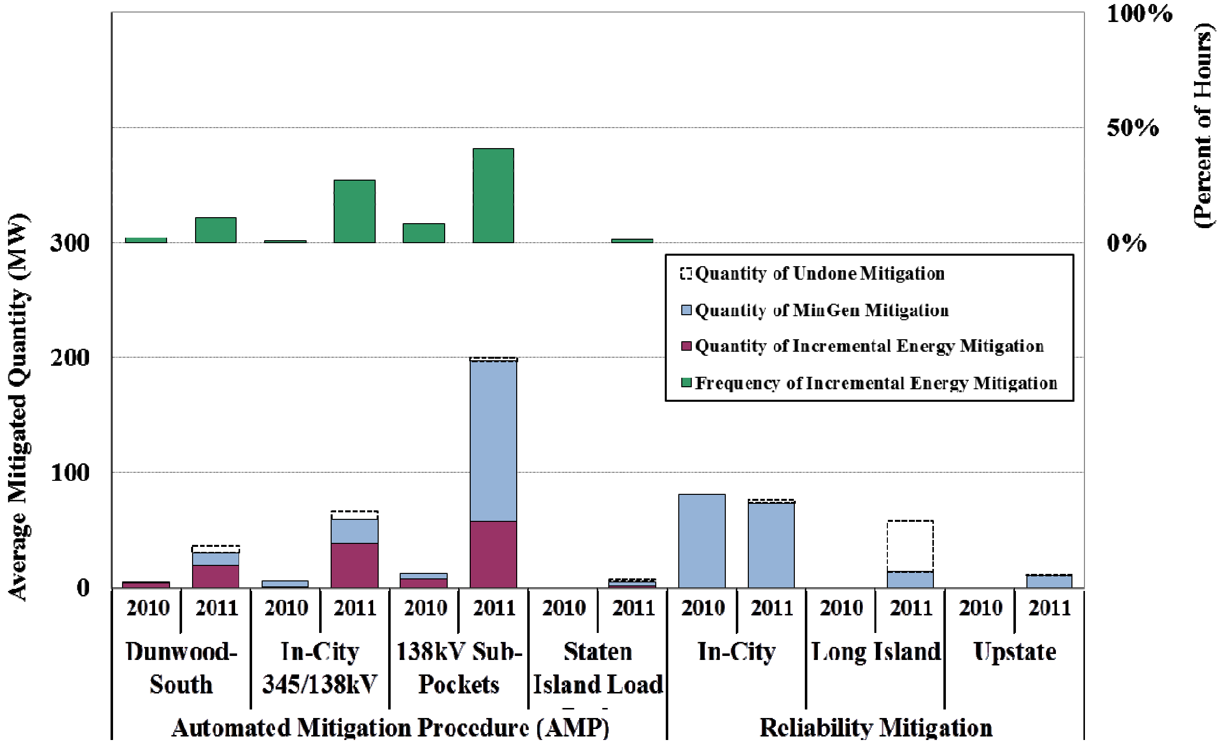
[87] NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation.

[88] The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion that was unmitigated). Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e. MinGen).[89] In each figure, the left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

Figure A-27: Summary of Day-Ahead Mitigation

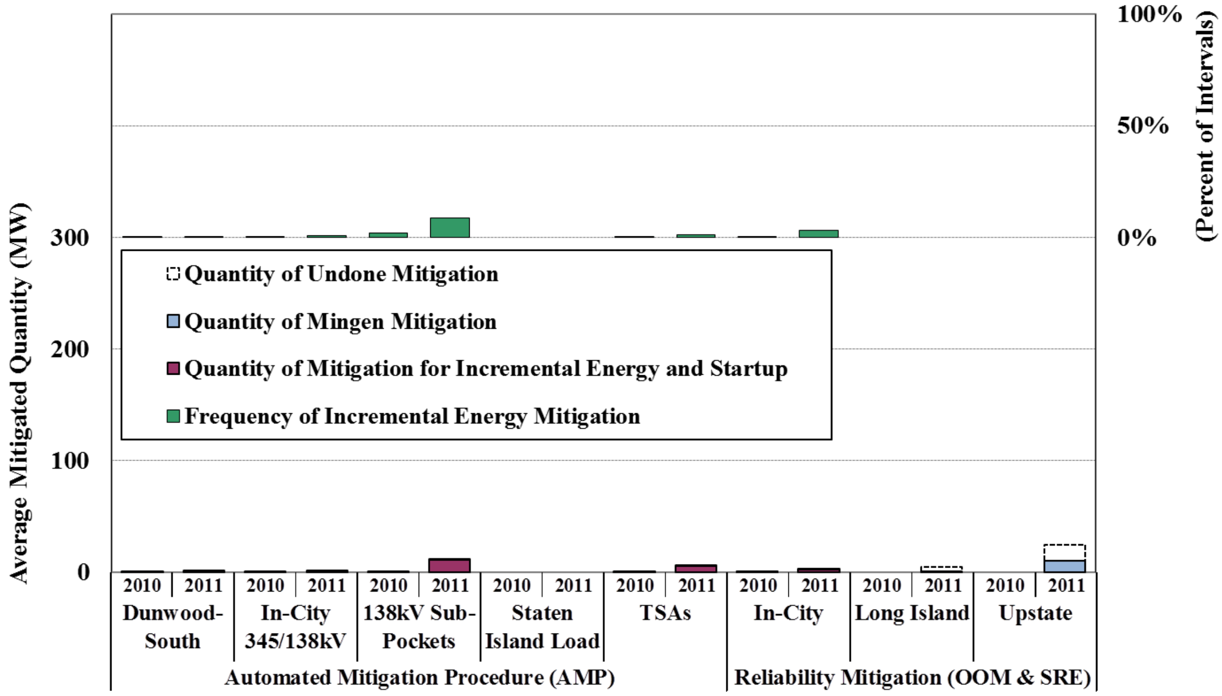
January to September, 2010 & 2011



89 Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Figure A-28: Summary of Real-Time Mitigation

January to September, 2010 & 2011



<u>**Key Observations: Day-ahead and Real-time Mitigation**</u>

- In 2011, mitigation occurred primarily In-City in the day-ahead market for the 138kV load pockets, for the 345 and 138kV areas, and for DARU and LRR commitments.

- Mitigation increased substantially in Long Island and in Upstate New York from 2010 to 2011 due to the application of the Rest-Of-State reliability mitigation rules in October 2010. However, the quantities mitigated were still much smaller than In-City.

- Mitigation increased substantially in In-City from 2010 to 2011 because of changes in offer patterns by some suppliers and improvements in the accuracy of reference levels for some generators.

- Unmitigation of generators became more common in 2011.

  - In the first three quarters of 2011, most of the capacity initially mitigated in Long Island was subsequently unmitigated.

  - Some mitigation consultations are still on-going for the period.

D. 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 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.

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.

Figure A-29 to Figure A-32: Summary of Ancillary Services Offers

The following four figures compare the ancillary services offers for generators in the day-ahead market for 2010 and 2011 on a monthly basis as well as on an annual basis. The quantities offered are shown for the following categories:

- 10-minute spinning reserves in Western New York,
- 10-minute spinning reserves in Eastern New York,
- 10-minute non-spinning reserves in Eastern New York, and
- 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 A-29: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market in 2011

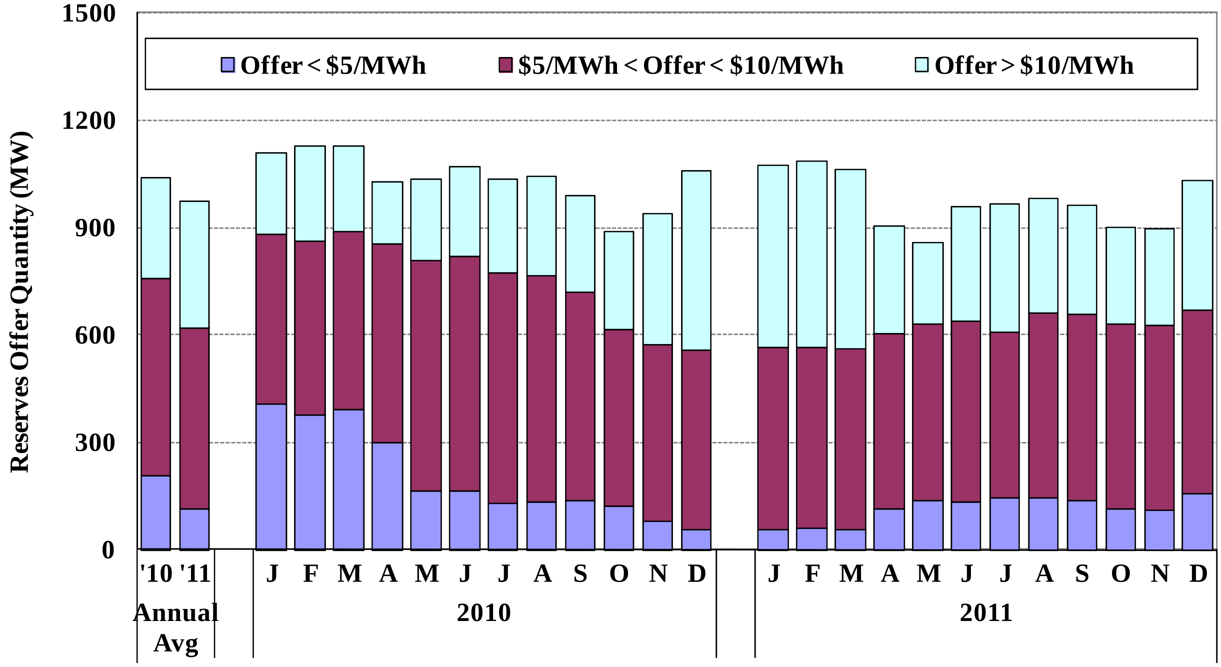


Figure A-30: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market in 2011

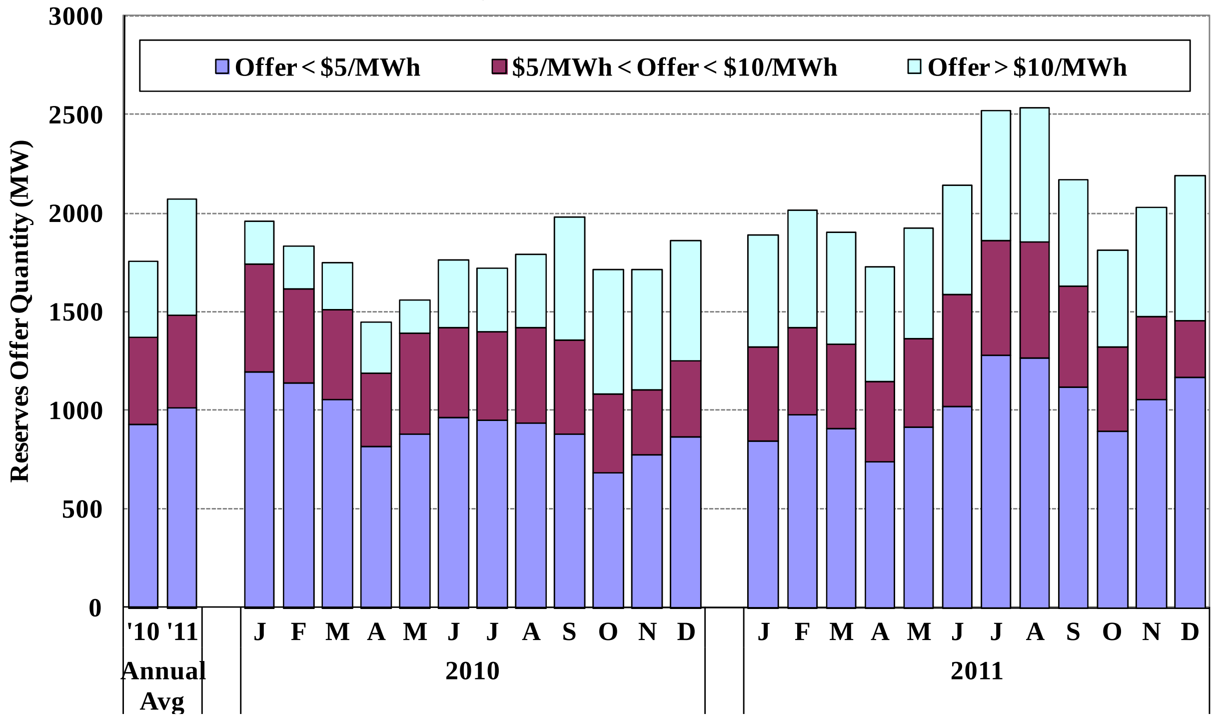


Figure A-31: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market in 2011

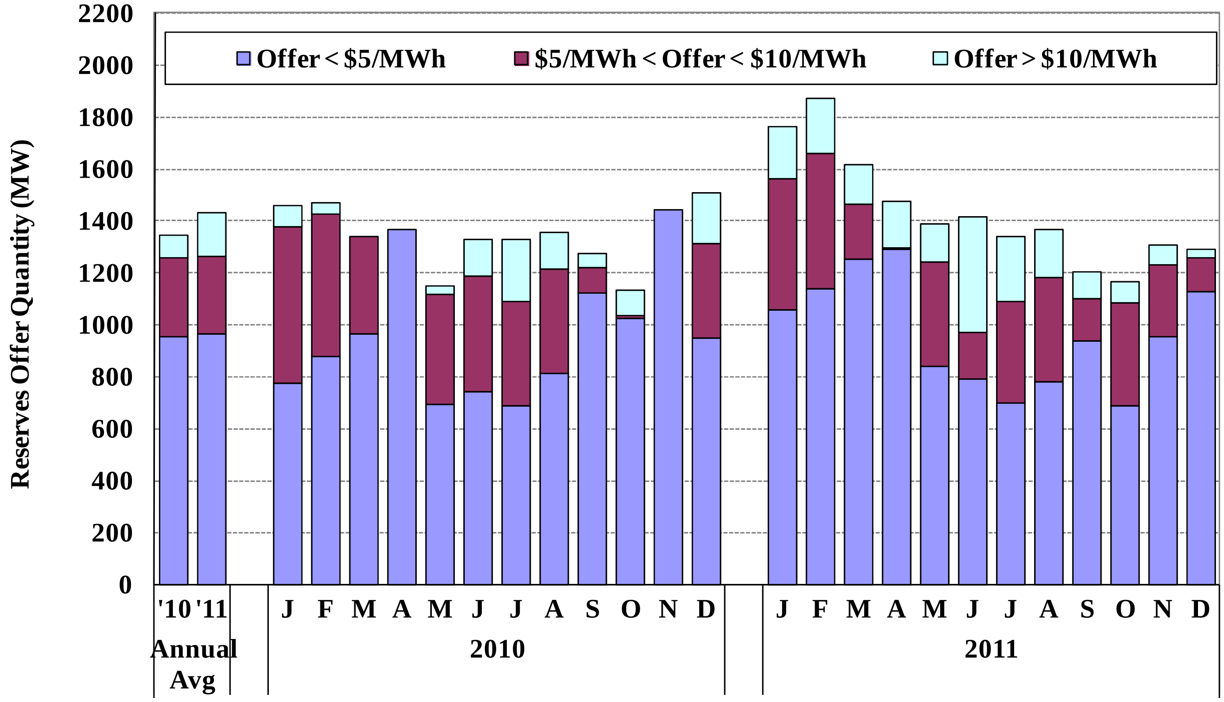
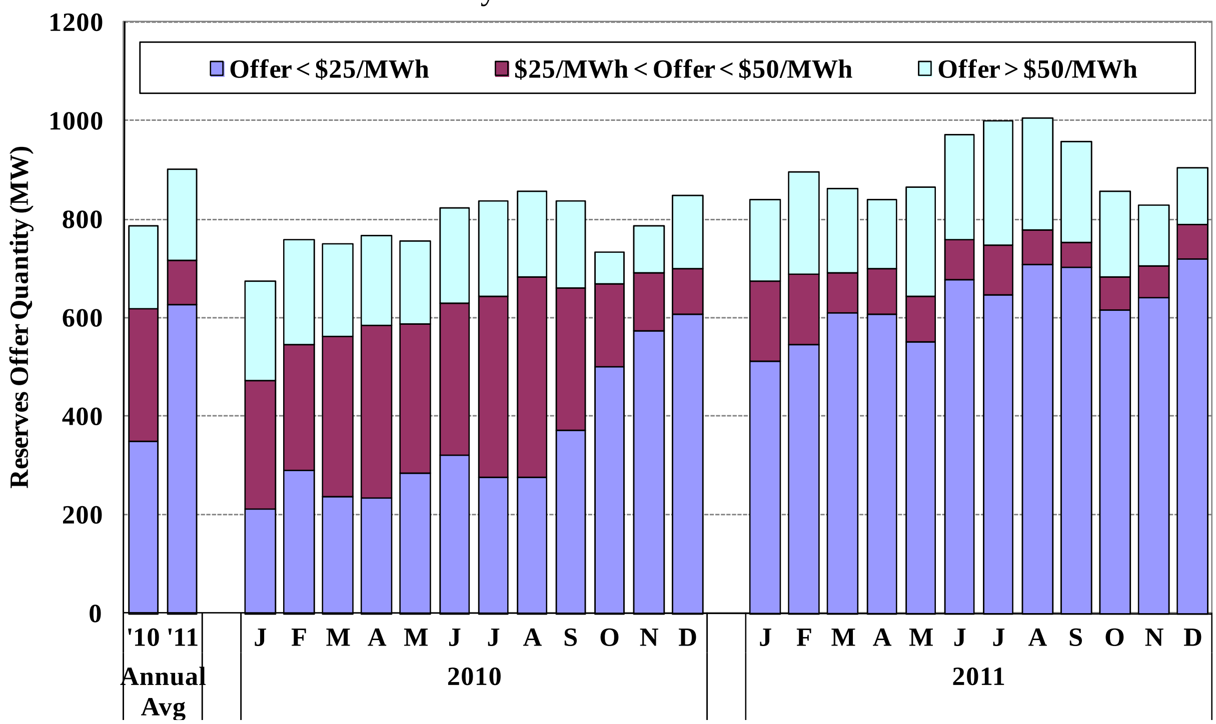


Figure A-32: Summary of Regulation Offers
Day-Ahead Market in 2011



Key Observations: Ancillary Services Offers

- The amount of ancillary services offers from all four categories varied by season.
  - 10-minute spinning reserves and regulation offer quantities were generally lower in the spring and fall than in the summer and winter because most planned outages occur in shoulder months when supply is less valuable.
  - 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
- Low-cost regulation offers increased substantially from 2010 to 2011. The increase in late 2010 and mid 2011 reflected additional supply of regulation from new entry in the Capital Zone and in the New York City, which reduced offer prices from existing suppliers. As a result, regulation prices fell from an average of $29 per MWh in 2010 to $12 per MWh in 2011.
- The amount of 10-minute spinning reserves offered in Eastern New York increased modestly from 2010 to 2011 that was partly due to the installation of new combined cycle capacity in eastern New York.

E. 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 scheduled in one of the following four ways:

- *Physical Bilateral Contracts* – These schedules allow participants to settle transmission charges (i.e., congestion and losses) with the ISO between two points and to settle on the commodity sale privately with their counterparties. It does not represent all of the bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately (e.g., contracts for differences).
- *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.[90]

[90] 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.

- *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 sold back in the real-time market. The virtual buyer earns or pays the difference between the day-ahead and real-time prices. Virtual trading 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, 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-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 purchased back from the real-time market.

Figure A-33 to Figure A-38: Day-Ahead Load Schedules versus Actual Load

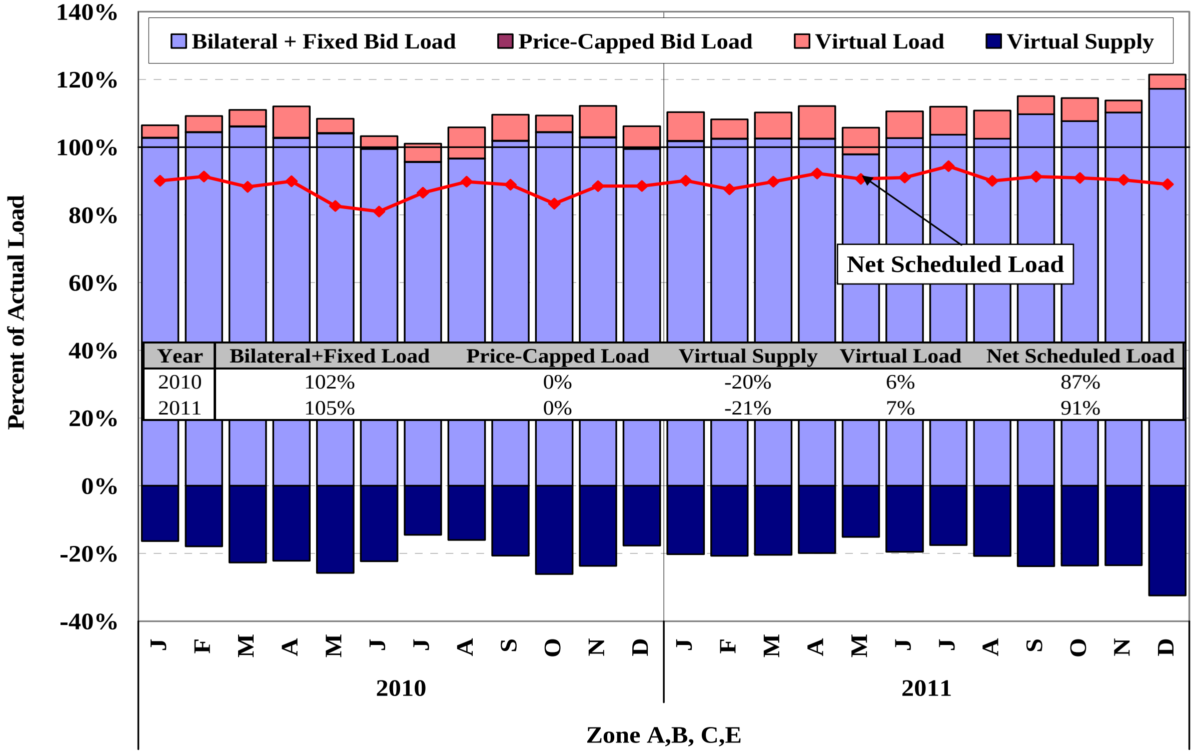
Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when it is 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 following figures help 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 six figures show day-ahead load schedules and bids as a percent of real-time load during 2010 and 2011 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. The inset table shows the overall changes in scheduling pattern from 2010 to 2011.

Figure A-33: Day-Ahead Load Schedules versus Actual Load in West New York

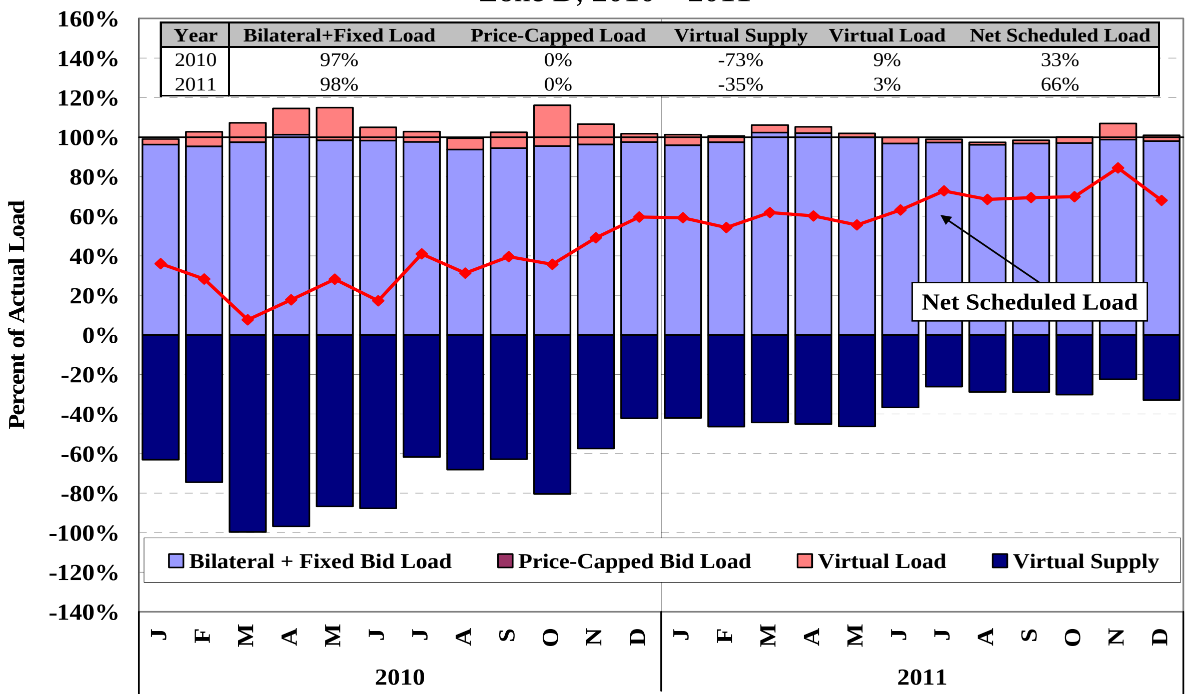
Zones A,B,C, & E, 2010 – 2011



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2010	102%	0%	-20%	6%	87%
2011	105%	0%	-21%	7%	91%

Figure A-34: Day-Ahead Load Schedules versus Actual Load in North Zone

Zone D, 2010 – 2011



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2010	97%	0%	-73%	9%	33%
2011	98%	0%	-35%	3%	66%

Figure A-35: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2010 – 2011

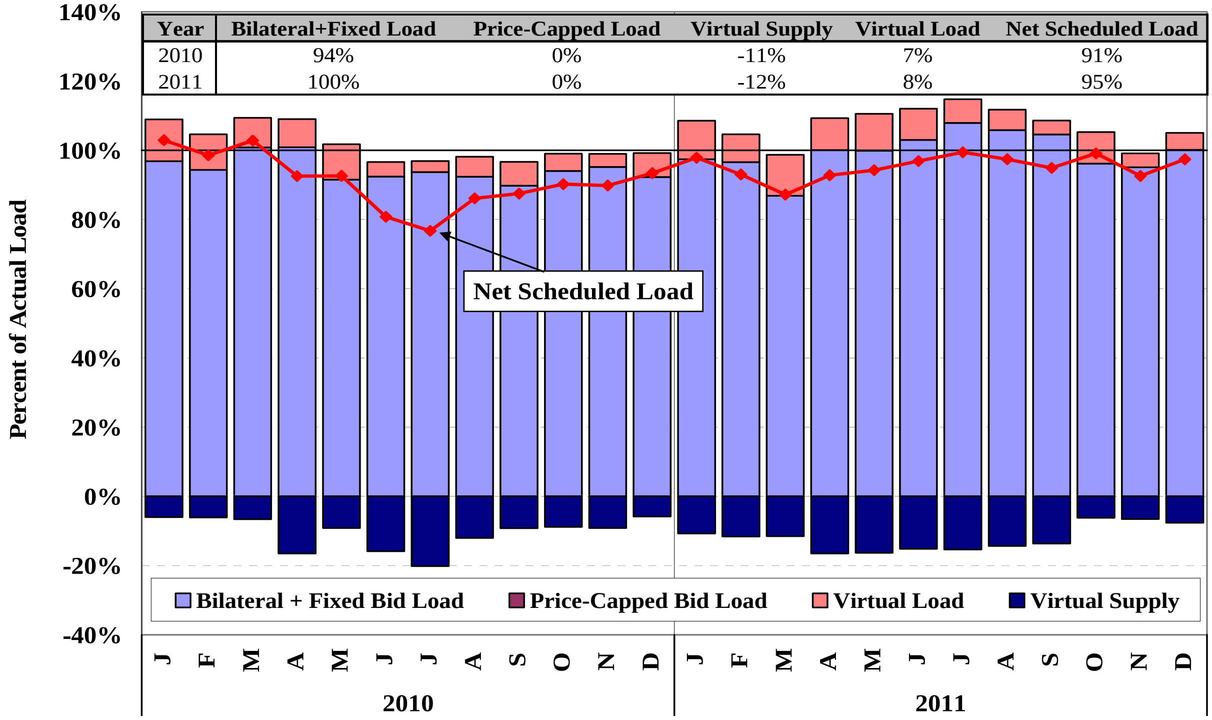


Figure A-36: Day-Ahead Load Schedules versus Actual Load in the Hudson Valley
Zones G, H, & I, 2010 – 2011

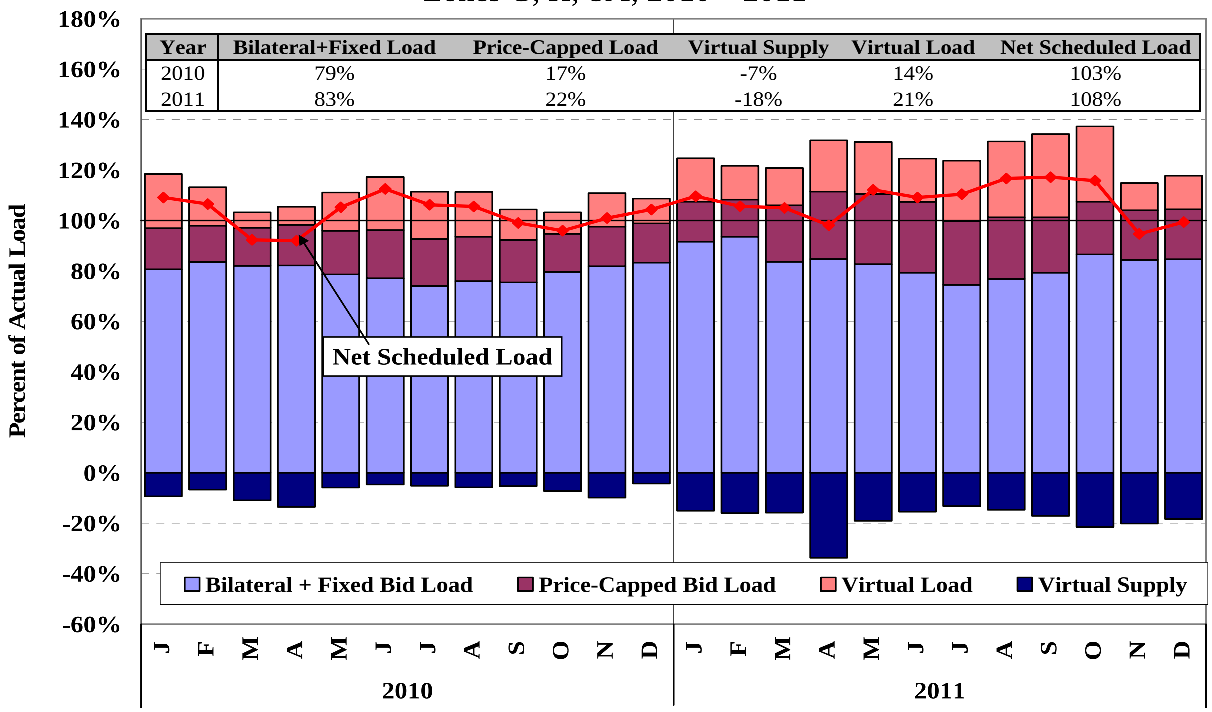
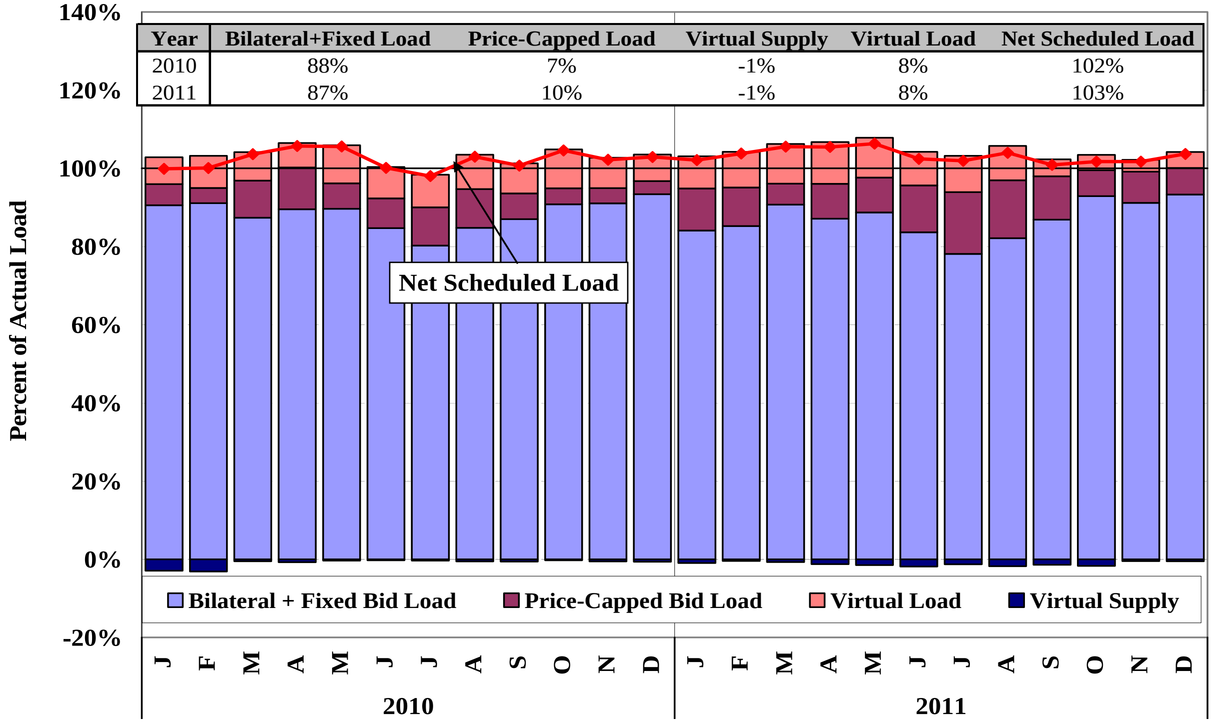
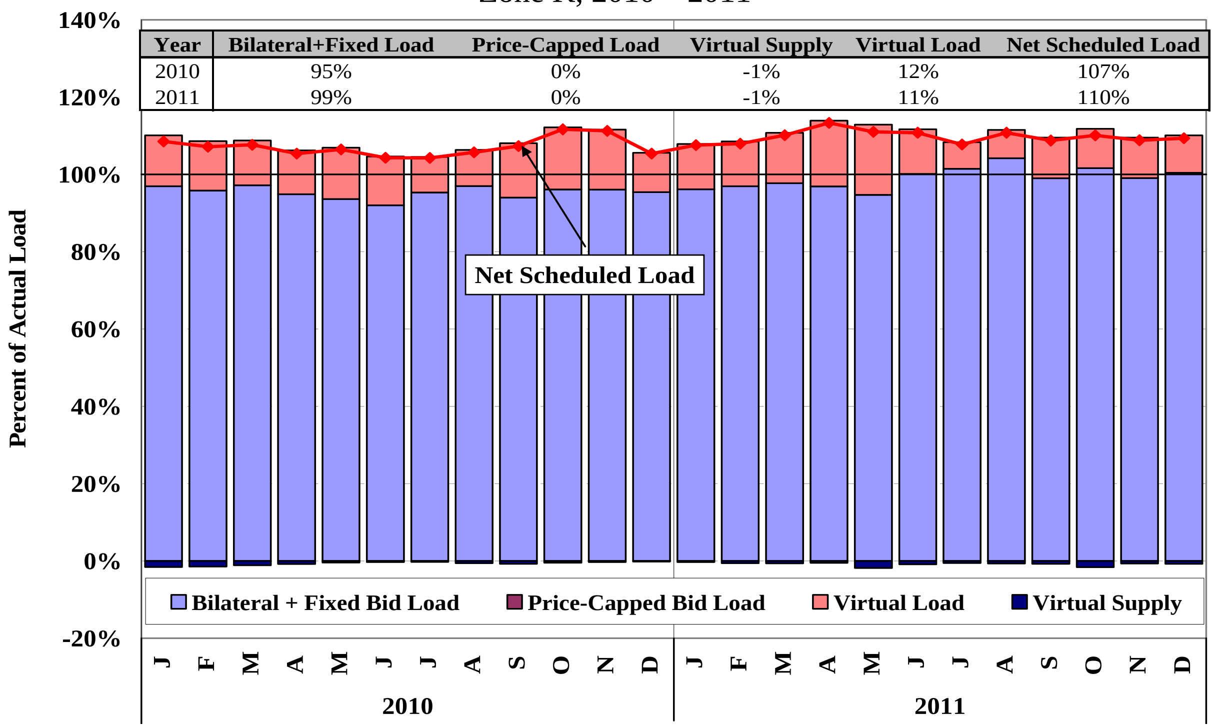


Figure A-37: Day-Ahead Load Schedules versus Actual Load in NYC
Zone J, 2010 – 2011



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2010	88%	7%	-1%	8%	102%
2011	87%	10%	-1%	8%	103%

Figure A-38: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2010 – 2011



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2010	95%	0%	-1%	12%	107%
2011	99%	0%	-1%	11%	110%

Key Observations: Day-ahead Load Scheduling

- Overall, load in the day-ahead market was scheduled at 99 percent of actual load in New York, up from 96 percent in 2010. This increase contributed to the slight day-ahead premium that was shown in Section I.F of the Appendix.

- Load was generally under-scheduled outside Southeast New York (i.e., West Upstate and Capital Zone) and over-scheduled in Southeast New York (i.e., Other East Upstate, New York City and Long Island) in 2011.

  - This pattern is typical and is likely in response to real-time congestion across the lines into Southeast New York, New York City, and Long Island.

  - Despite the pattern of day-ahead under-scheduling, the region outside Southeast New York still exhibited a modest day-ahead premium. This suggests that the under-scheduling helped improve convergence between day-ahead and real-time prices and that further under-scheduling would likely have been profitable.

- The over-scheduling in Southeast New York also generally improved convergence between day-ahead and real-time prices.

  - Although average day-ahead prices were slightly higher than average real-time prices in Southeast New York, they would have been significantly lower if load had not been over-scheduled in Long Island, New York City, and the lower Hudson Valley (i.e., Zones G, H, & I). Without this "over-scheduling" of load, it is likely that less generation would have been committed in the day-ahead market, resulting in more frequent real-time price spikes and shortages.

F. Virtual Trading in New York

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.

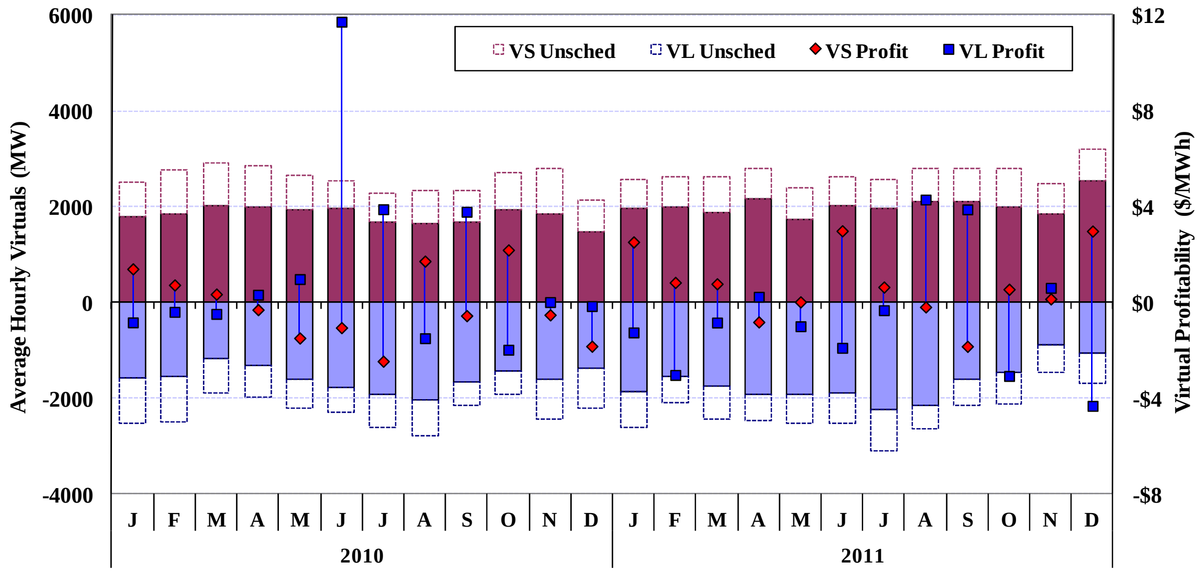
Virtual transactions that are scheduled in the day-ahead market settle against real-time energy prices. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the 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.

Figure A-39: Virtual Trading Volumes and Profitability

Figure A-39 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2010 and 2011. 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.[91]

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 350 MW of virtual transactions (or 9 percent of all virtual transactions) netted profits larger than the 50 percent of their zone prices in June 2011. Large profits may be an indicator of a modeling inconsistency, while a systematic pattern of losses may be an indicator of potential manipulation of the day-ahead market.

Figure A-39: Virtual Trading Volumes and Profitability
January 2010 to December 2011



Profit > 50% of Avg. Zone Price	MW	380	324	240	122	181	285	205	176	162	117	135	221	446	193	161	122	233	350	376	337	186	98	100	208
	%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%	12%	5%	4%	3%	6%	9%	9%	8%	5%	3%	4%	6%
Loss > 50% of Avg. Zone Price	MW	347	284	201	112	211	241	300	205	115	95	131	273	401	244	133	120	277	381	434	334	122	133	120	193
	%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%	11%	7%	4%	3%	8%	10%	10%	8%	3%	4%	4%	5%

Figure A-40: Virtual Trading Activity

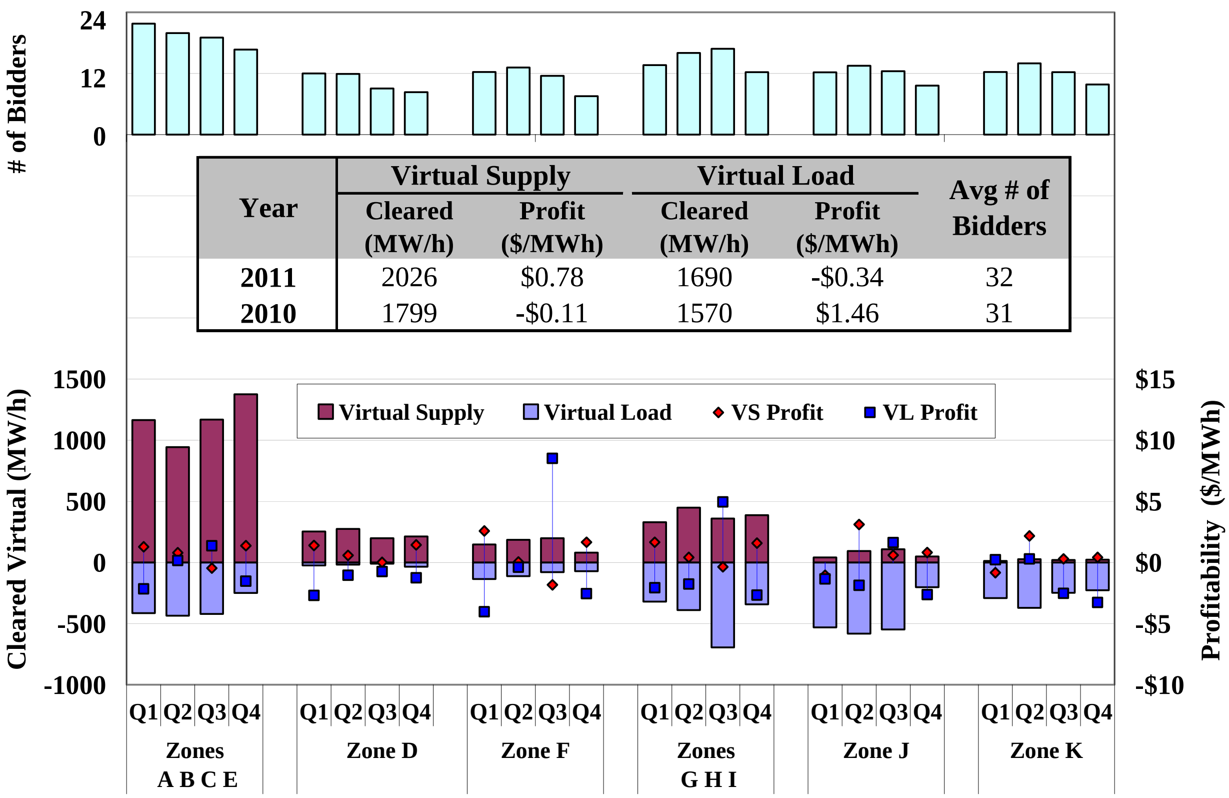
Figure A-40 below summarizes virtual trading by geographic region. The eleven zones in New York are broken into six geographic regions based on typical congestion patterns. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission

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

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.

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 2011. 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 2011 and 2010.

Figure A-40: Virtual Trading Activity
by Region by Quarter, 2011



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2011	2026	$0.78	1690	-$0.34	32
2010	1799	-$0.11	1570	$1.46	31

Key Observations: Analysis Virtual Trading

- 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 32 participants submitted virtual trades somewhere in the state in 2011.
  - The average number of market participants fell modestly in the fourth quarter after the implementation of new credit requirements in October 2011. The new credit requirements may have affected the participation of some firms.
- The average quantity of scheduled virtual supply rose moderately from 1,799 MW in 2010 to 2,026 MW in 2011.

- Much of this activity was related to the west-to-east arbitrage shown in the prior sub-section.
- This arbitrage is exhibited via substantial net virtual purchases in downstate areas and net virtual sales in upstate areas in 2011, which is consistent with prior years.

- In aggregate, virtual traders netted approximately $9 million of gross profits in 2011. However, 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.
  - Virtual supply was generally more profitable than virtual load in 2011, which is consistent with the prevailing day-ahead price premiums throughout New York.
- The quantity of transactions generating substantial profits or losses rose during the third quarter of 2011 because of the price volatility that occurred in the late summer.
  - The transactions with notable profits or losses were primarily associated with real-time price volatility and did not raise manipulation concerns.
- While we believe there are compelling fundamental reasons that have resulted in net virtual load in Southeast New York, the results in 2011 indicate that these transactions were unprofitable on average.
  - We closely monitor unprofitable virtual transactions as they can potentially raise potential manipulation concerns. In most cases, however, the losses can be attributed to unexpected real-time market results.
- 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.

III. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the demands of the system. 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 and real-time markets 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.

Incremental changes in generation and load from the day-ahead market to the real-time market are subject to congestion charges or payments in the real-time market. 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. There are no TCCs for real-time congestion.

This section summarizes 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. Summary of Congestion Revenue and Shortfalls in 2011

In this section, we summarize the congestion revenues and shortfalls that are collected and settled through the NYISO markets. The vast majority of congestion revenues are collected through the day-ahead market, which we refer to as *day-ahead congestion revenues.* These 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.[92]

In addition to day-ahead congestion revenues, the NYISO incurs two types of shortfalls that occur when there are inconsistencies between the transmission capability modeled in the TCC market, the day-ahead market, and the real-time market:

- *Day-ahead Congestion Shortfalls* – These occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders. Shortfalls generally 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.[93] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues. These shortfalls are partly offset by the revenues from selling excess TCCs.

- *Balancing Congestion Shortfalls* – These arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.[94] 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 reduce generation on the export-constrained side of the constraint. These redispatch costs (i.e., the difference between the payments for increased generation and the revenues from reduced generation in the two areas) is the balancing congestion shortfall that is recovered through uplift.

Figure A-41: Congestion Revenue Collections and Shortfalls

Figure A-41 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2010 and 2011. 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.

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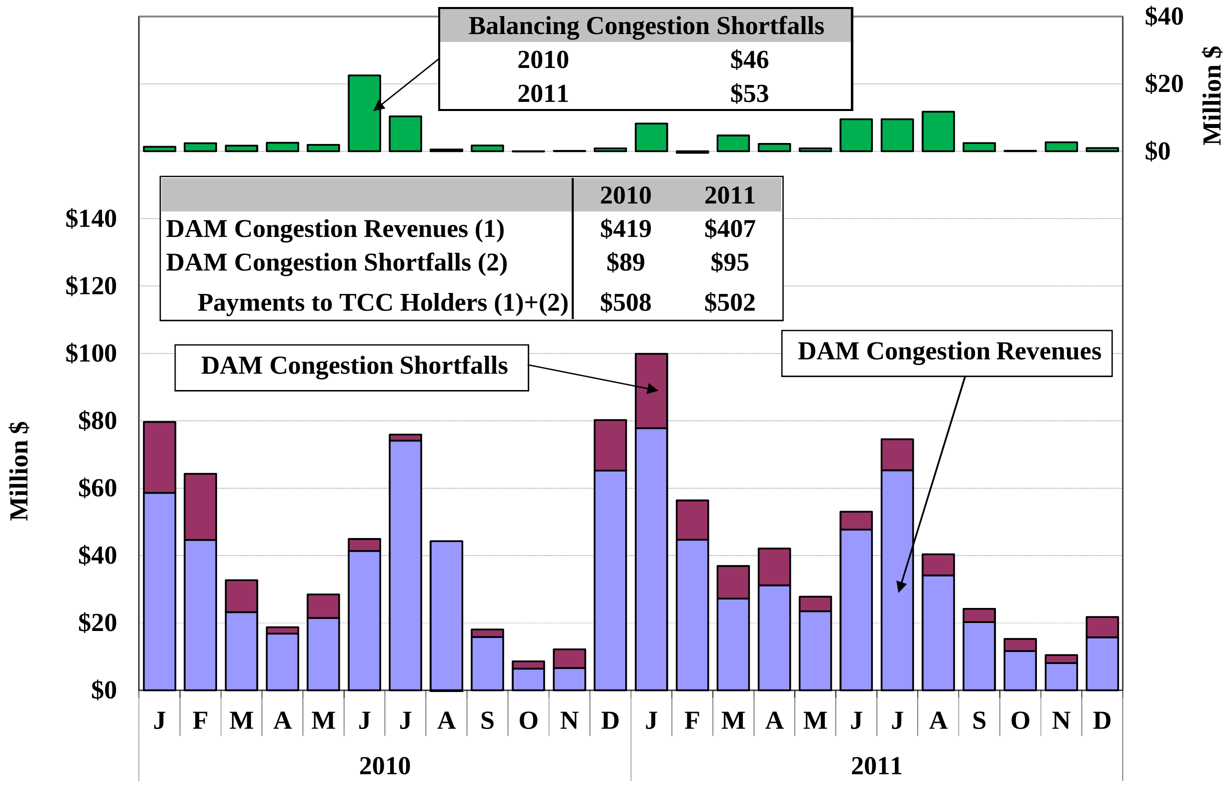
92 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000 in that hour (100 MW * $50/MWh).

93 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).

94 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).

Figure A-41: Congestion Revenue Collections and Shortfalls
2010 - 2011



Key Observations: Day-Ahead Congestion Revenues

- Day-ahead congestion revenues were relatively unchanged from 2010 to 2011.
  - In both years, the largest amounts of congestion revenues were collected in the winter peak and summer peak months.
  - This is expected because the relatively high load in these months often result in higher transmission flows, and storms that cause transmission interfaces to be derated can result in acute congestion.
- Both classes of congestion shortfalls continued to be substantial in 2011, totaling almost $150 million. The locations of these shortfalls are analyzed in the next subsection.

B. Congestion Shortfalls by Path or Constraint

Figure A-42: 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 reflect the expected transfer capability of the system. In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantities of TCCs that are offered by the NYISO.

The NYISO determines the quantities 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 (e.g., assumptions related to PAR schedules and loop flows) 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 A-42 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2011. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths or types of constraints:

- West to Central: Primarily Dysinger East, West-Central, and West Export interfaces.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Primarily the New Scotland-to-Leeds lines.
- New York City Lines: Lines leading into and within New York City
- Long Island Lines: Lines leading into and within Long Island.
- PAR Controlled Lines between NY and NJ: Including two Ramapo lines, three Waldwick lines, two Hudson-Farragut lines, and one Linden-Goethals line.
- All Others: All other types of constraints collectively.

Figure A-42: Day-Ahead Congestion Shortfalls
2011

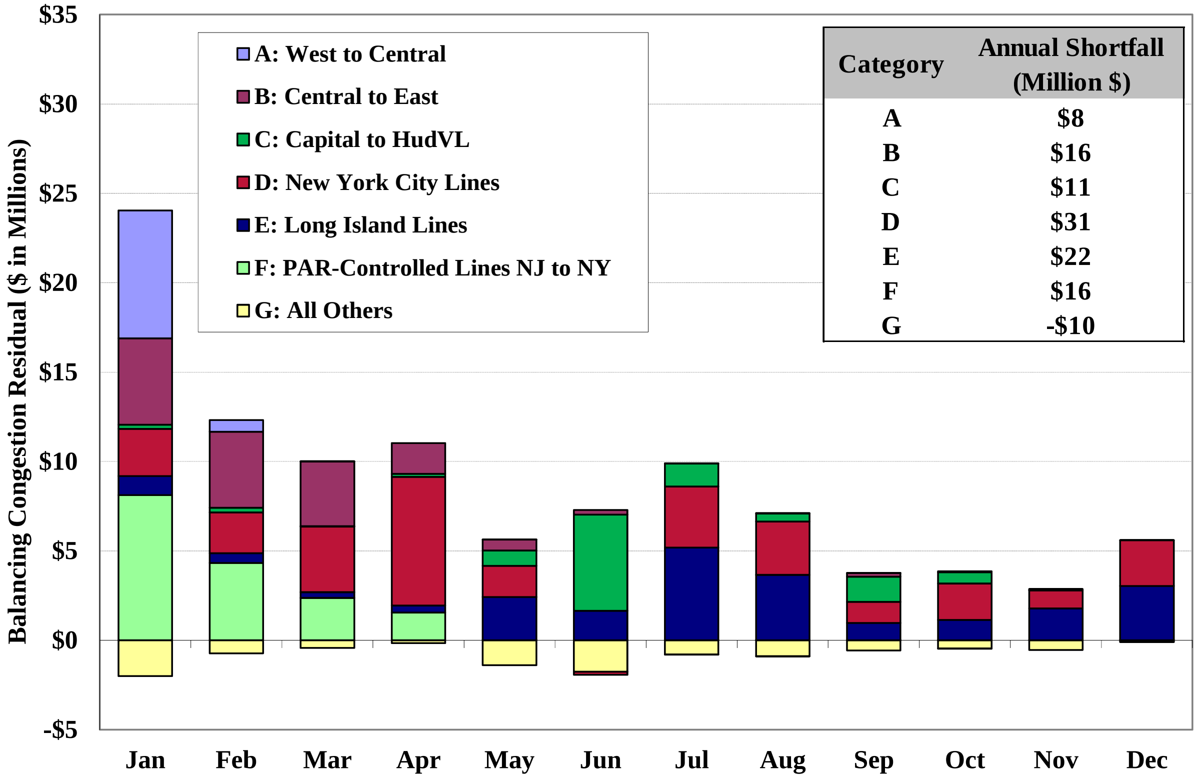


Figure A-43: Balancing Congestion Revenue Shortfalls

Like day-ahead congestion 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 real-time prices are low). The balancing congestion shortfall is the cost of this redispatch. The changes in transfer capability between the day-ahead and real-time markets are most often 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.

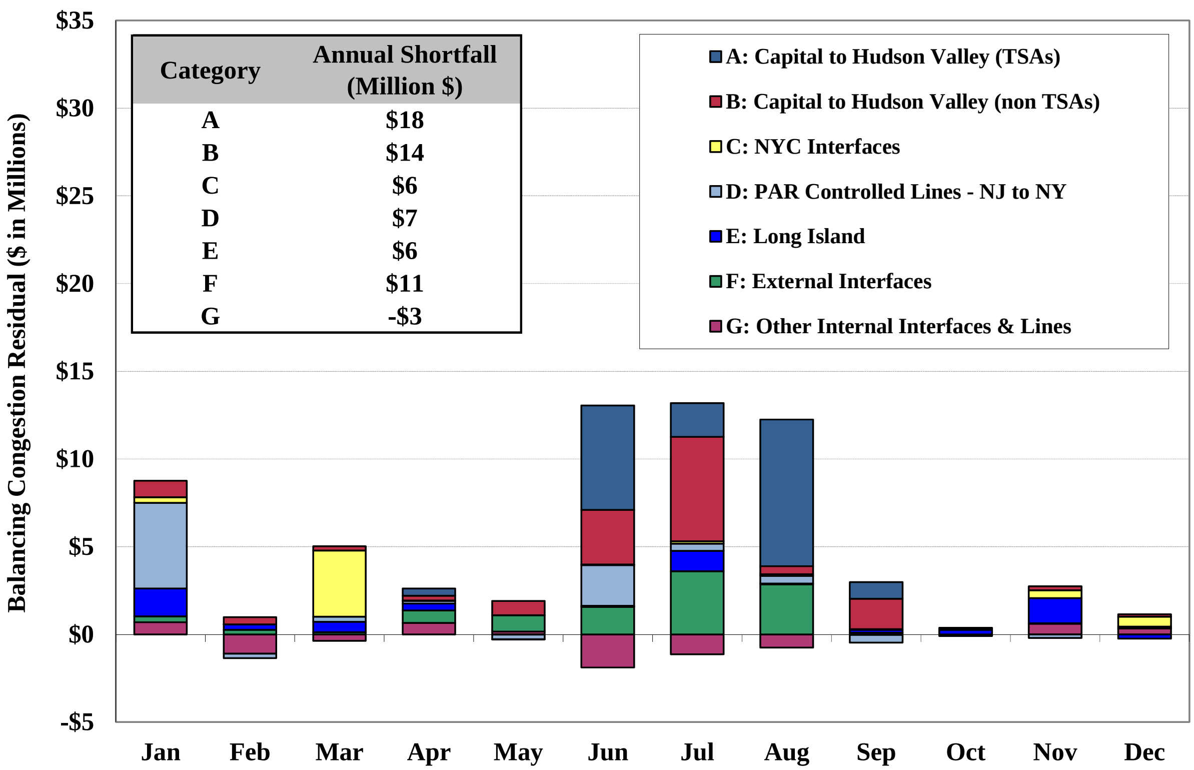
- PAR Controlled Line Flows – the flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces.

- 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.

The net cost of the redispatch in real-time due to changes from day-ahead (i.e., balancing congestion shortfalls) 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.

Figure A-43 shows balancing congestion shortfalls by transmission path or facility in each month of 2011. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-43: Balancing Congestion Shortfalls
2011



Category	Annual Shortfall (Million $)
A	$18
B	$14
C	$6
D	$7
E	$6
F	$11
G	-$3

Key Observations: Congestion Shortfalls

- See discussion at the end of Section C.

C. Congestion on Major Transmission Paths

Supply resources in Eastern New York are generally more expensive than those in Western New York, while the majority of the load is located in Eastern 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 congestion-related price differences between regions. This sub-section examines congestion patterns in the day-ahead and real-time markets in the past two years.

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 power that can be scheduled between regions in the day-ahead market. When scheduling 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 prices and 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 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 useful to evaluate the consistency of congestion patterns in the day-ahead and real-time markets.

Figure A-44 & Figure A-45: Day-Ahead and Real-Time Congestion by Path

Figure A-44 and Figure A-45 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. The figures measure congestion in two ways:

- The frequency of binding constraints; and
- 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.[95]

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

In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments. 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 the economic significance of congestion in the real-time market. The two figures group congestion along the following transmission paths:

- West to Central: Primarily Dysinger East, West-Central, and West Export interfaces.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Primarily the New Scotland-to-Leeds lines. NYC Lines – 345 kV system: Lines leading into and within the NYC 345 kV system.
- NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
- NYC Simplified Interface Constraints: Groups of lines to NYC load pockets that are modeled as interface constraints.
- Long Island: Lines leading into and within Long Island.
- External Interface: Congestion related to the total transmission limits or ramp limits of the nine external interfaces.

Figure A-44: Day-Ahead Congestion by Transmission Path
2010 - 2011

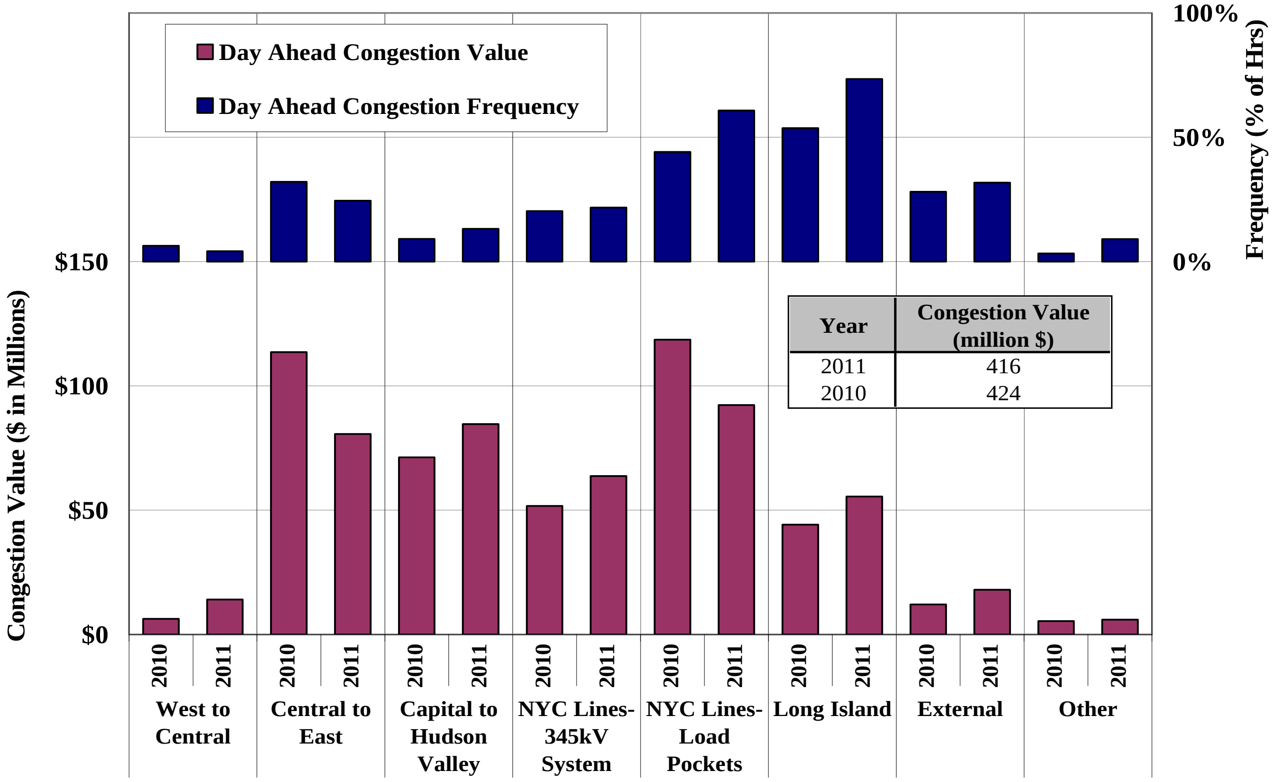
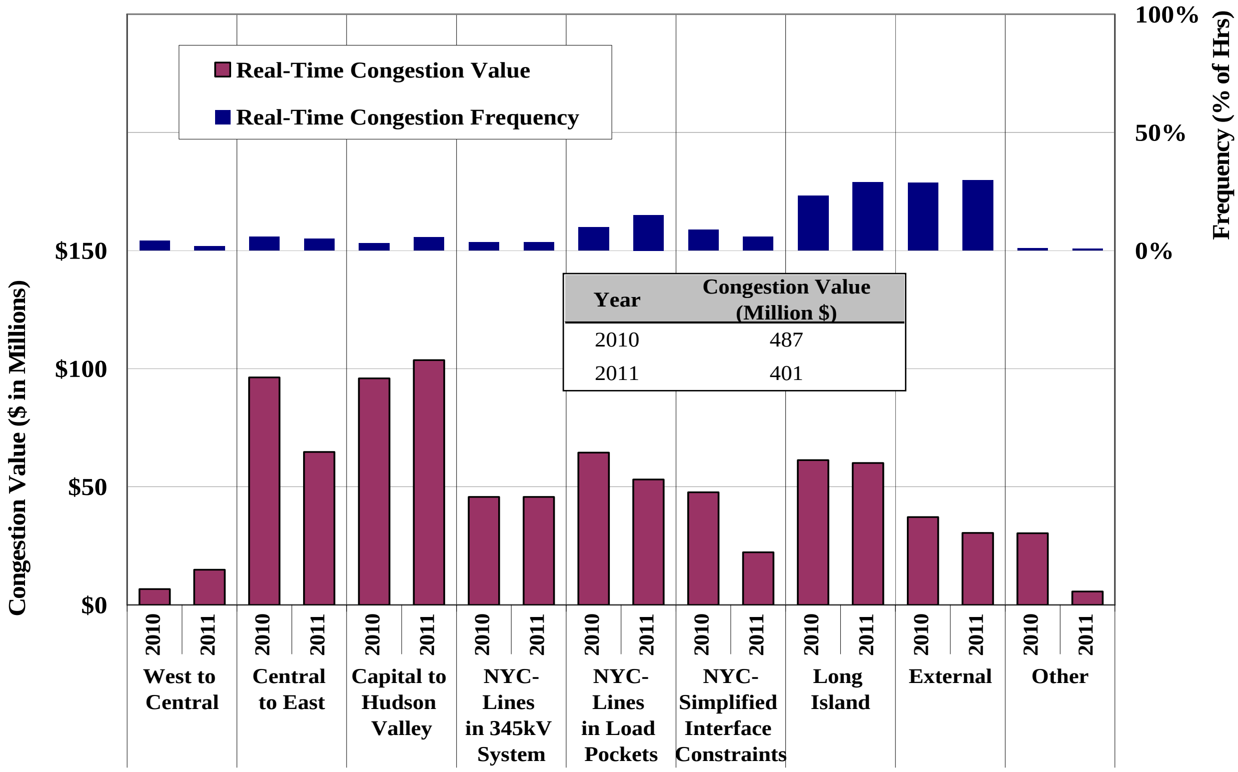


Figure A-45: Real-Time Congestion by Transmission Path
2010 - 2011



Key Observations: Congestion Revenues and Shortfalls

- Compared to 2010, congestion in 2011 occurred more frequently on paths from Capital to Hudson Valley and less frequently on the Central-East interface because:
  - Output from the new Empire plant in the Capital Zone tends to relieve congestion on the Central-East interface while increasing congestion from Capital to Hudson Valley;
  - A large generating resource in New England returned to service following an outage during most of 2010, leading to increased loop flows on paths from Capital to Hudson Valley;
  - Natural gas prices were particularly low in December 2011, leading to more economic commitment of combined-cycle gas units in Eastern New York, thereby reducing West-to-East congestion.
- Transmission outages accounted for more of the congestion costs and total shortfalls in 2011. For example,
  - Congestion from West to Central rose considerably in January that was due primarily to Rochester-to-Pannell transmission outages;

  - Congestion into Long Island rose substantially from mid July to mid August and in the fourth quarter of 2011, which was due largely to the lengthy outage of the Sprainbrook-to-East Garden City line;
  - The NYISO allocated 44 percent of day-ahead congestion shortfalls resulting from transmission outages to specific transmission owners in 2011, up from the 37 percent in 2010.
- PAR-controlled lines between New Jersey and New York accounted for $16 million of day-ahead congestion in 2011, down substantially from the $35 million in 2010.
  - A modeling improvement in the TCC auctions was implemented in May 2011, which virtually eliminated these shortfalls.

D. TCC Prices and DAM 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: Centralized TCC Auctions and Reconfiguration Auctions.

Centralized TCC 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.[96] 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. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Auction.

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.

Figure A-46: TCC Cost and Profit by Path Type

Figure A-46 summarizes TCC cost and profit for the Winter 2010/11 and Summer 2011 Capability Periods (i.e., the 12-month period from November 2010 through October 2011). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC

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[96] 2-year TCCs were first sold in the Autumn 2010 auctions for the period from November 2010 to October 2012, which covers a one-year period after the one-year period evaluated in this section of the report.

price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

The lower portion of the figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) Four rounds of one-year auctions for the 12-month Capability Period; (b) Three rounds of six-month auctions for the Winter 2010/11 Capability Period; (c) Four rounds of six-month auctions for the Summer 2011 Capability Period; and (d) Twelve reconfiguration auctions for each month of the 12-month Capability Period.

For the purposes of the figure, each TCC is broken into inter-zonal and intra-zonal components, making it possible to identify portions of the transmission system that generate the most revenue in the TCC auction and that are most profitable for the buyers of TCCs. Each TCC has a Point-Of-Injection ("POI") and a Point-Of-Withdrawal ("POW"). The POI and POW may be a generator bus, a NYCA Zone, the NYISO Reference Bus, or an external proxy bus. For the purpose of this analysis, all transacted TCCs in the auctions are unbundled into the following standard components: (a) POI to the Zone containing the POI (POI Zone), (b) POI Zone to the Zone containing the POW (POW Zone), and (c) POW Zone to POW. When a TCC is unbundled into standard components for this analysis, the original TCC is replaced by up to three TCCs. The three standard components are further grouped into two categories: (i) inter-zone TCCs, which include all unbundled POI Zone to POW Zone TCCs; and (ii) intra-zone TCCs, which include POI to POI Zone TCCs and POW Zone to POW TCCs.[97] The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs.

The upper portion of the chart shows the profitability for each category, where the total TCC profit is measured as a percentage of total TCC value (i.e., TCC payment), for the intra-zone TCCs and inter-zone TCCs in each round of the auctions. The table in the figure summarizes the TCC cost, profit, and profitability for each type of TCC auction for the two categories of TCC paths.

[97] For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 will be unbundled to three components: (1) A 100 MW TCC from Indian Point 2 to Millwood Zone; (2) A 100 MW TCC from Millwood Zone to New York City Zone; and (3) A 100 MW TCC from New York City Zone to Arthur Kill 2. Component No.1 and No. 3 belong to the intra-zone category and Component No. 2 belongs to inter-zone category.

Figure A-46: TCC Cost and Profit by Path Type
Winter 2010/11 and Summer 2011 Capability Periods

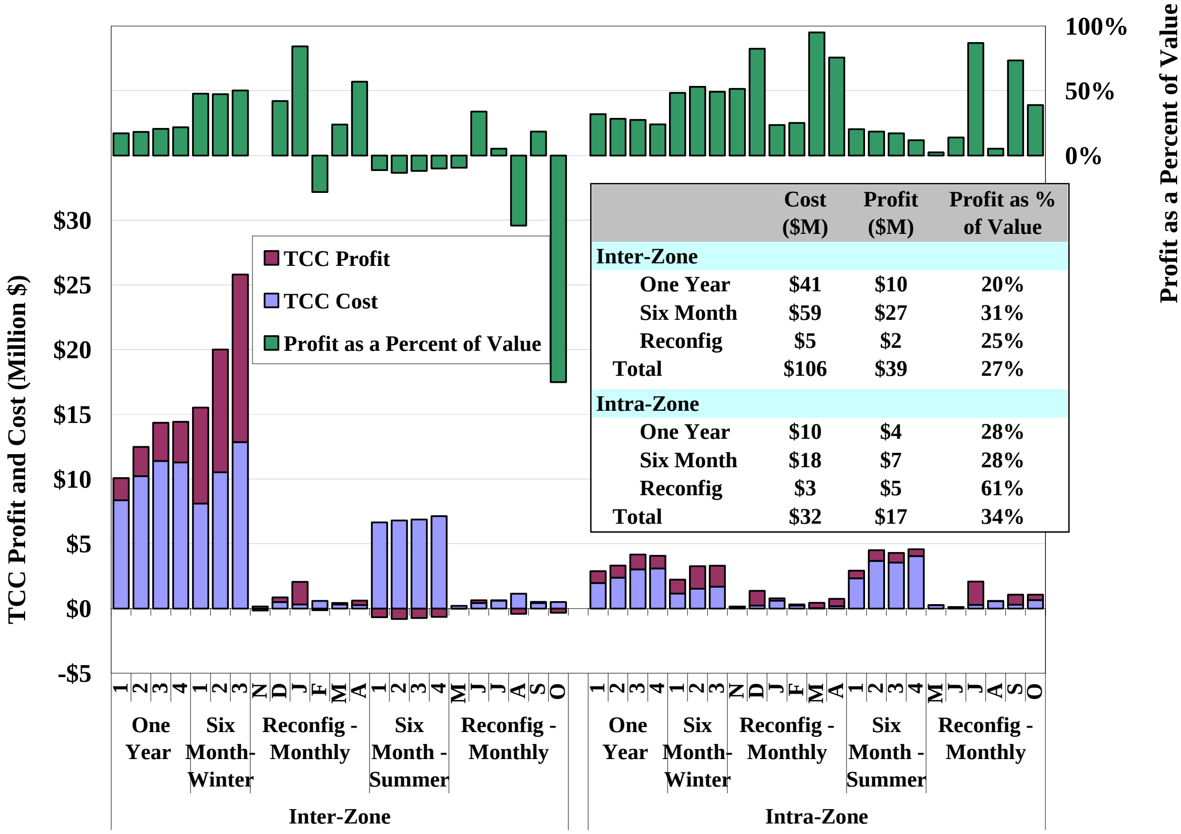


Figure A-47: TCC Prices and Day-ahead Congestion by Zone

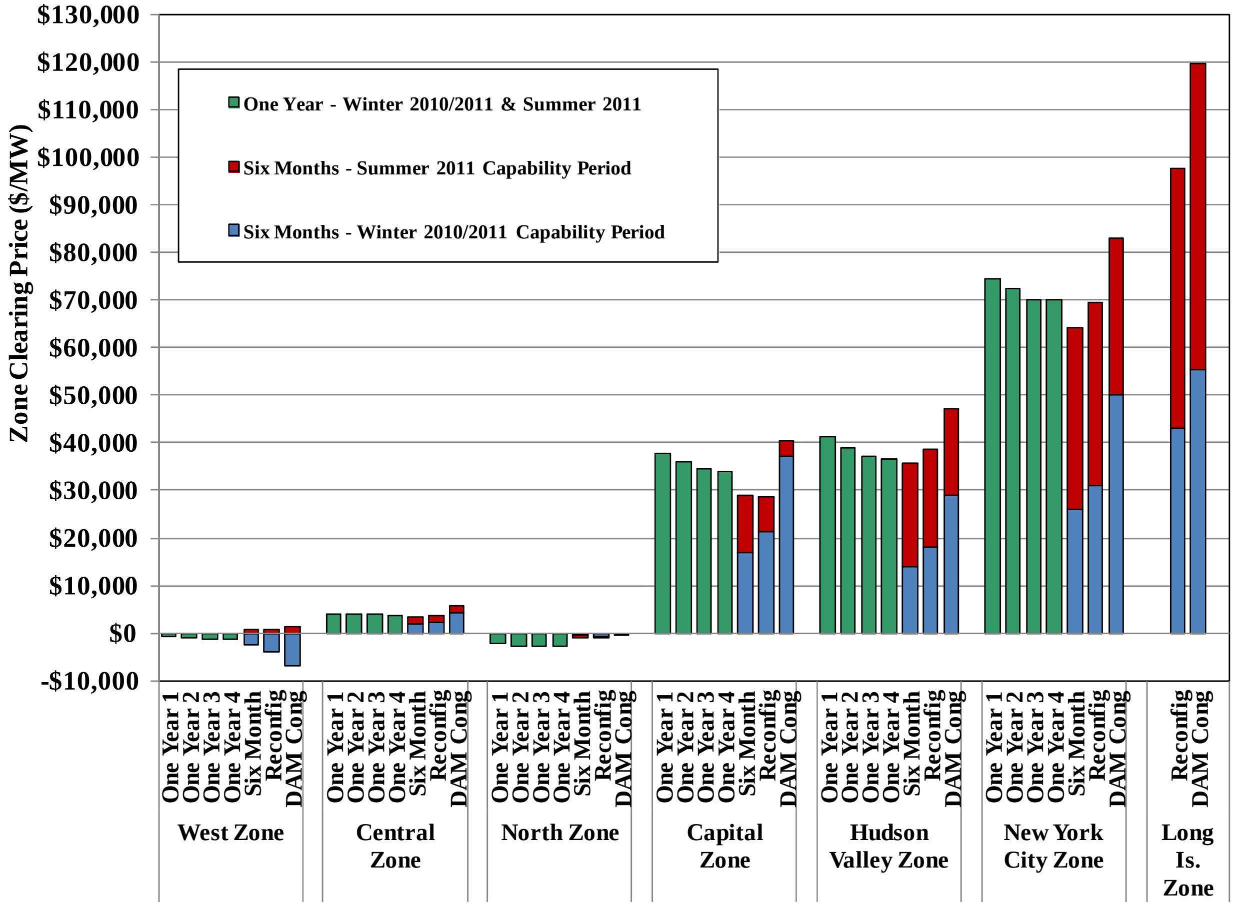
The following analysis evaluates whether clearing prices in each type of TCC auction were consistent with the congestion prices in the day-ahead market at the zonal level during 2011. Figure A-47 compares the TCC prices for the Winter 2010/11 and Summer 2011 Capability Periods (i.e., the 12-month period from November 2010 through October 2011) to the corresponding congestion prices in the day-ahead market. The figure shows the following values:

- *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 2010.
- *Six-month TCC prices* – These are the sum of average TCC prices for the three rounds in the Winter Capability Period Auction and the four rounds in the Summer Capability Period Auction.
- *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 A-47 shows these values for seven zones across New York State. Each price is shown relative to the reference bus at Marcy in the Central Zone. Prices are not shown for Long Island in the one-year and six-month TCC auctions because the NYISO does not sell TCCs that source or sink in Long Island in those auctions.

Figure A-47: TCC Prices and DAM Congestion by Zone

Winter 2010/11 and Summer 2011 Capability Periods



Key Observations: TCC Prices and Profitability

- Traders netted a profit of $56 million in the TCC auctions during the 12-month period (November 2010 to October 2011):
  - TCC profits totaled $14 million in the one-year auctions, $34 million in the six-month auctions, and $8 million in the reconfiguration auctions.
  - Profitability (profit as a percent of TCC payout) averaged nearly 30 percent, although it varied widely from auction to auction and among different types of TCCs (inter-zone vs. intra-zone). This reflected the difficulty of precisely predicting congestion patterns in the forward auctions.
- Overall, the TCC auctions modestly under-estimated congestion.

- West to East congestion in the 2010/11 winter months, which was driven by unusual cold weather combined with transmission outages, was not well anticipated in the one-year auctions and the six-month auctions for the Winter 2010/11 Capability Period. This contributed to the $37 million (66 percent) of net profits in these TCC auctions.

IV. External Interface Scheduling

New York imports a substantial amount of power from four adjacent control areas, New England, PJM, Ontario, and Quebec. 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 1.5 GW directly to downstate areas.[98,99] 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.

Efficient use of transmission interfaces between regions is beneficial in at least two ways. First, the external interfaces allow access to external resources, which lowers the cost of serving load in New York to the extent that lower cost external resources are available. Likewise, lower-cost internal resources gain the ability to compete to serve load in adjacent regions. Second, the ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in each control area. Wholesale markets should 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:

- 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
- An issue with the modeling of transmission losses at the PJM proxy bus that was identified in 2011.

98 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 200 MW (the imports increased from 100 MW to 200 MW in May 2011 following an upgrade to the facility). The Linden VFT Line, which connects New York City to PJM with a transfer capability of 300 MW, began normal operation in November 2009.

99 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the "Dennison Scheduled Line" and which is scheduled separately from the primary interface between New York and Quebec.

A. Summary of Scheduled Imports and Exports

Figure A-48 to Figure A-50: Average Net Imports from Ontario, PJM, Quebec, and New England

The following three figures summarize the net scheduled interchanges between New York and neighboring control areas in 2010 and 2011. The net scheduled interchange does 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, Monday through Friday) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure A-48, the primary interfaces with Quebec and New England in Figure A-49, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-50.

Figure A-48: Monthly Average Net Imports from Ontario and PJM
2010 – 2011

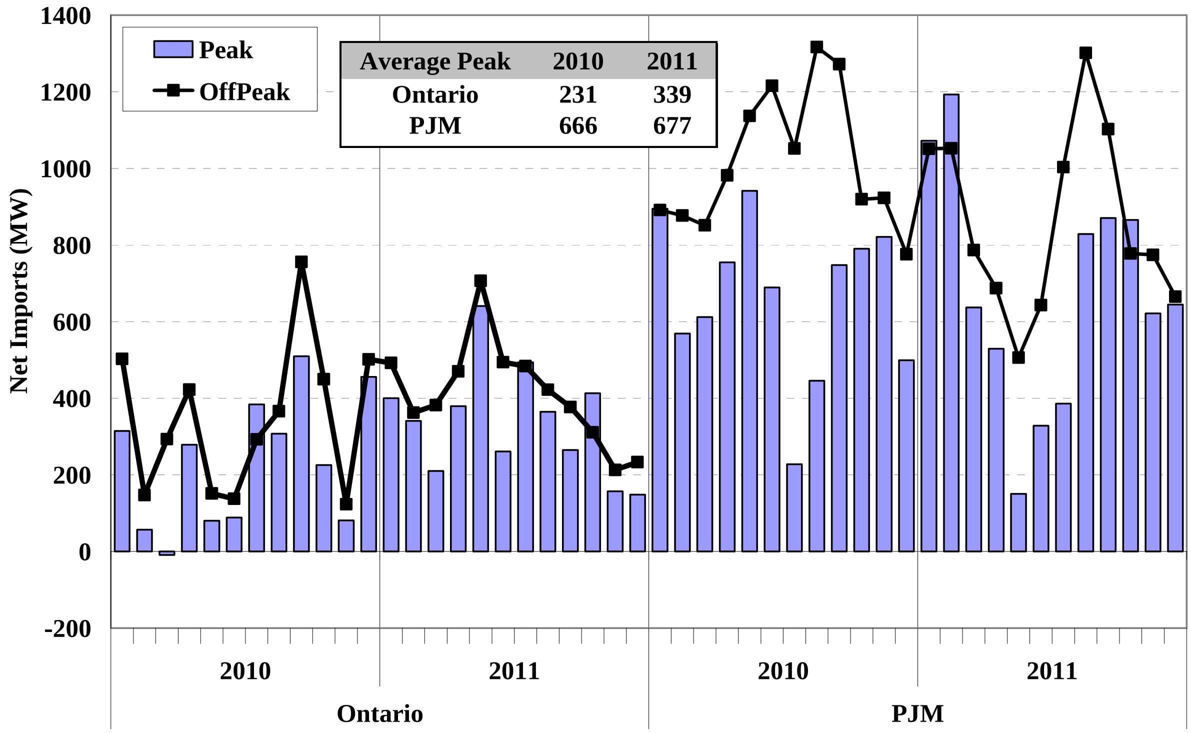
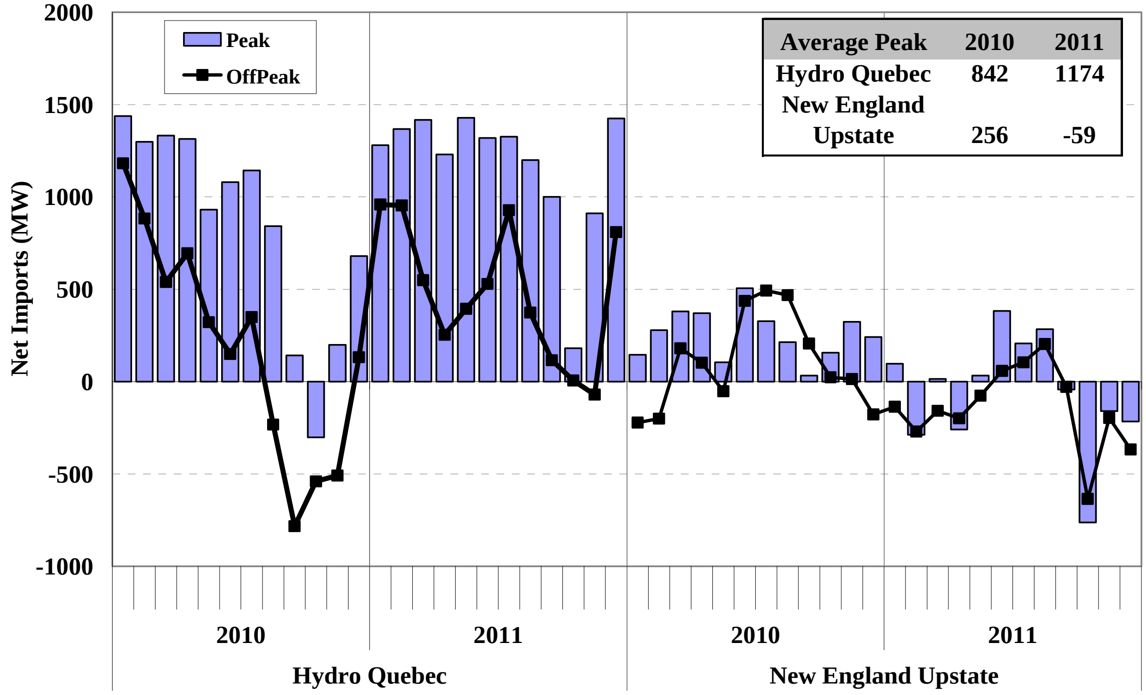
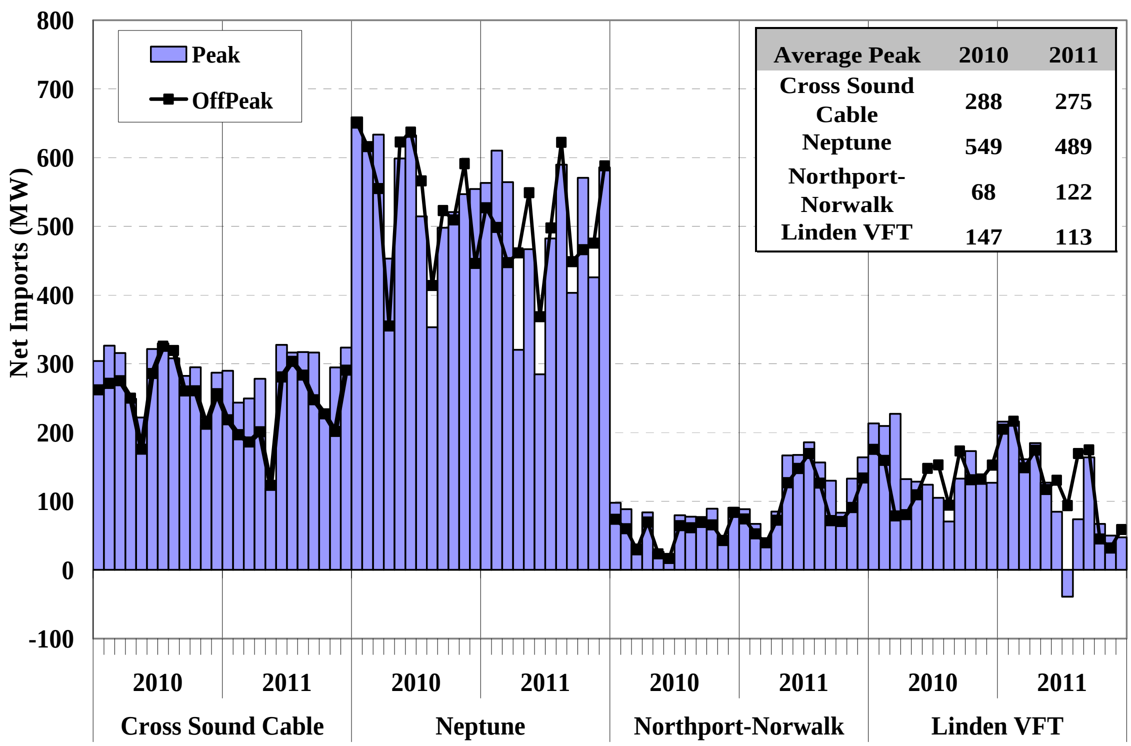


Figure A-49: Monthly Average Net Imports from Quebec and New England
2010 – 2011



Average Peak	2010	2011
Hydro Quebec	842	1174
New England Upstate	256	-59

Figure A-50: Monthly Average Net Imports into New York City and Long Island
2010 – 2011



Average Peak	2010	2011
Cross Sound Cable	288	275
Neptune	549	489
Northport-Norwalk	68	122
Linden VFT	147	113

<u>Key Observations: Average Net Imports</u>

- Average net imports from neighboring areas across the primary interfaces increased modestly from 1,995 MW in 2010 to 2,130 MW in 2011 during the peak hours.

- Net imports from Ontario rose in 2011 by 47 percent (or 110 MW). Generation outages in Ontario and transmission outages on the Ontario-to-New York interface partly accounted for the lower level of imports in 2010.

- More than half of the imports came from Hydro Quebec. 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. Average net imports from Quebec rose nearly 40 percent (or 330 MW) from 2010 to 2011.

- Excluding the controllable ties into Long Island, New York was a net exporter to New England in 2011, but a net importer from New England in 2010.
  - Net imports from New England generally rise in the summer months. This is partly because New England is more reliant on natural gas generation, which is typically less expensive in the summer months.

- Net imports from PJM averaged roughly 680 MW during the peak hours in 2011, which was consistent with 2010.
  - Net imports from PJM generally decline in the summer months as prices in Western New York become relatively less attractive because of: increased west-to-east congestion and the availability
  - This is partly because New York is more reliant on natural gas generation, which typically becomes less expensive during the summer months.

- Unlike the primary interfaces, the interchange over the four controllable interfaces was generally relatively consistent from month to month, and was slightly more during peak hours than during off-peak hours. Most differences arose from transmission outages and facility upgrades that affected the interfaces.
  - 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 2011.

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. Large clockwise loop flows emerged in 2008 when the phenomenon of "circuitous transaction scheduling" around Lake Erie became significant.[100] Although circuitous transaction scheduling was prohibited after July 2008, loop flows still usually occur clockwise around Lake Erie due to the scheduling patterns of market participants in the surrounding ISOs.

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.[101]

Figure A-51: Lake Erie Circulation

Figure A-51 summarizes the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie for each month of 2010 and 2011. 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.[102]

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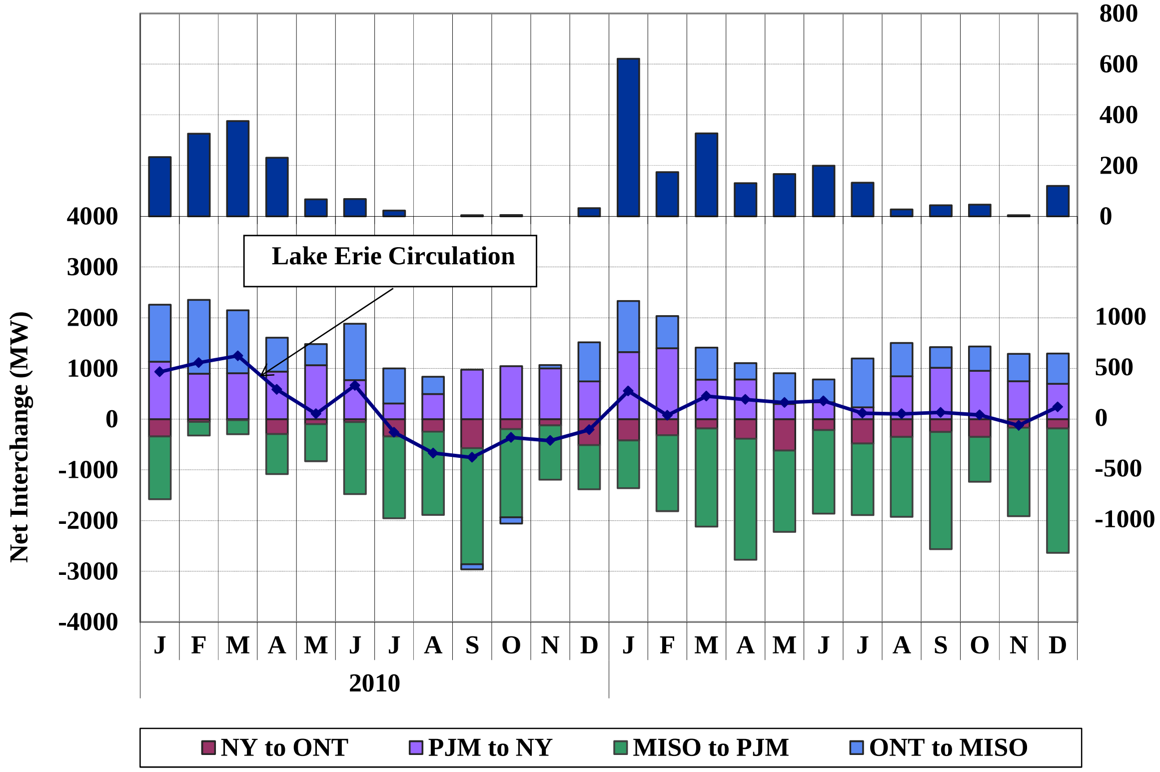
100 Circuitous transactions are transactions that are scheduled from one control area to another along an indirect path when a more direct path exists. Circuitous transactions cause physical power flows that are not consistent with the scheduled path of the transaction. The NYISO filed under exigent 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.

101 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. However, 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 the TLR procedures it uses to curtail the transactions.

102 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 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

Figure A-51: Lake Erie Circulation
2010 – 2011



Key Observations: Lake Erie Circulation

- Loop flows continued to move in a clockwise direction around Lake Erie in most months of 2010 and 2011;
  - Clockwise circulation average roughly 113 MW in 2011, up 37 percent from 2010.
  - The correlation of clockwise circulation and counter-clockwise transactions was relatively weak in 2011, suggesting that dispatch of internal generation by each ISO also significantly affected circulation.
- TLRs (level 3A and above) were called during 1,993 hours in 2011, up 25 percent from 2010, due partly to:
  - Increased clock-wise circulation; and
  - Changes implemented in March 2010 in the NYISO's criteria for calling a TLR.

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**.

C. Price Convergence and Efficient Scheduling with 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. 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. 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.

However, one cannot expect that trading by market participants alone will optimize the use of the interface. Several factors prevent real-time prices from being fully arbitraged.

- 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 arbitrage will not be possible.

- Differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage.

- 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.

- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-52: Price Convergence Between New York and Adjacent Markets

Figure A-52 evaluates the efficiency of scheduling between New York and the adjacent RTO markets across interfaces with open scheduling.[103] RTO 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 A-52 summarizes price differences between New York and neighboring markets during unconstrained hours in 2011. 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 ISOs from scheduling transactions. In the figure, the horizontal axis shows the range of

[103] 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.

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.

Figure A-52: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2011

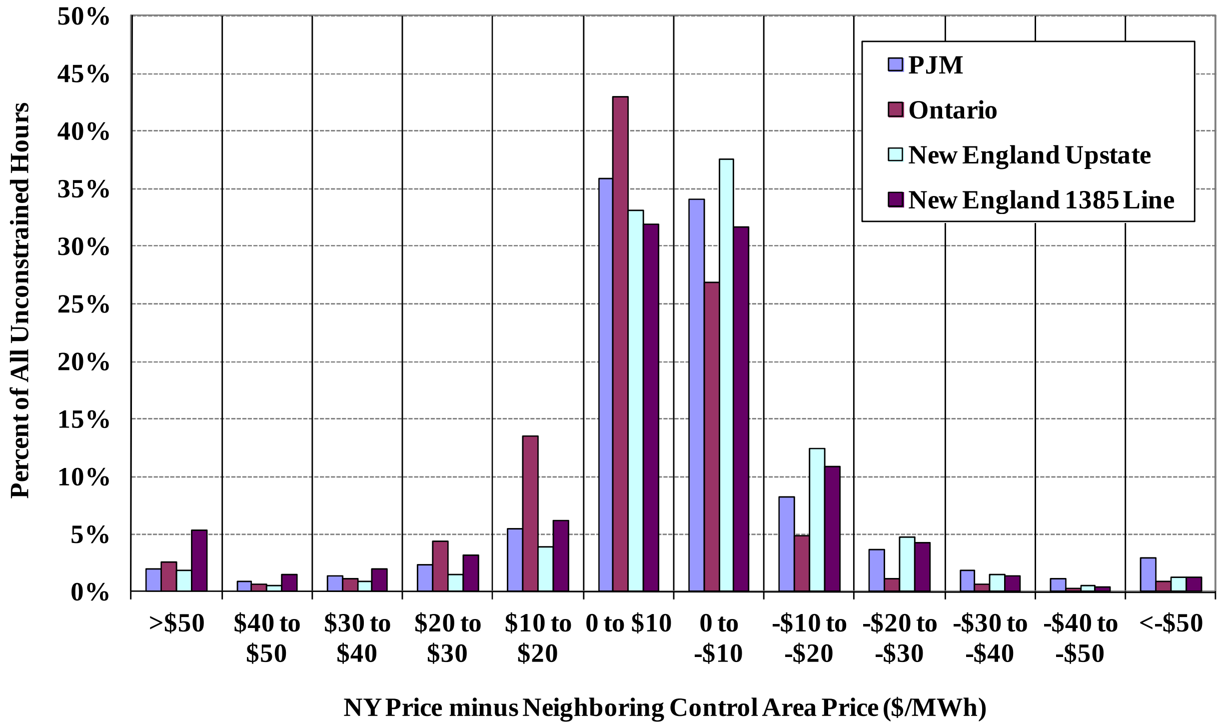


Table A-2 and Figure A-53: Efficiency of Inter-Market Scheduling

Table A-2 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2011. It evaluates real-time schedules and clearing prices between New York and the three markets across the three primary interfaces and four scheduled lines (i.e., the 1385 Line, the Cross Sound Cable, the Neptune Cable, and the Linden VFT interface).

The table shows average hourly real-time flows between neighboring markets and New York. A positive number indicates a net import from neighboring areas to New York. The table also shows the average real-time price differences between markets for each interface. A positive number indicates that the average price was higher on the New York side than the other side of the interface. Additionally, the table reports the share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-priced market).

Figure A-53 shows a scatter plot of net scheduled flows versus price differences between New England and New York across the primary interface. The figure shows hourly price differences in the real-time market on the vertical axis versus net imports scheduled in the real-time market (which include day-ahead schedules) on the horizontal axis. Points in the top-right and bottom-left quadrants of the figure are characterized as scheduled in the efficient direction, that is, power was scheduled in the correct direction from the lower-priced market to the higher-priced market.

Similarly, points in the top-left and bottom-right quadrants are characterized as scheduled in the inefficient direction, that is, power was scheduled in the wrong direction from the higher-priced market to the lower-priced market. Good market performance would be indicated by the predominance of the hours scheduled in the efficient direction.

Table A-2: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2011

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-101	-$2.28	52%
Ontario	378	$5.11	66%
PJM	772	-$1.56	50%
Controllable Ties			
1385 Line	110	$4.46	49%
Cross Sound Cable	252	$6.78	53%
Neptune	493	$5.91	64%
Linden VFT	121	$1.36	61%

Figure A-53: Efficiency of Inter-Market Scheduling
Over Primary Interface From New England to New York – 2011

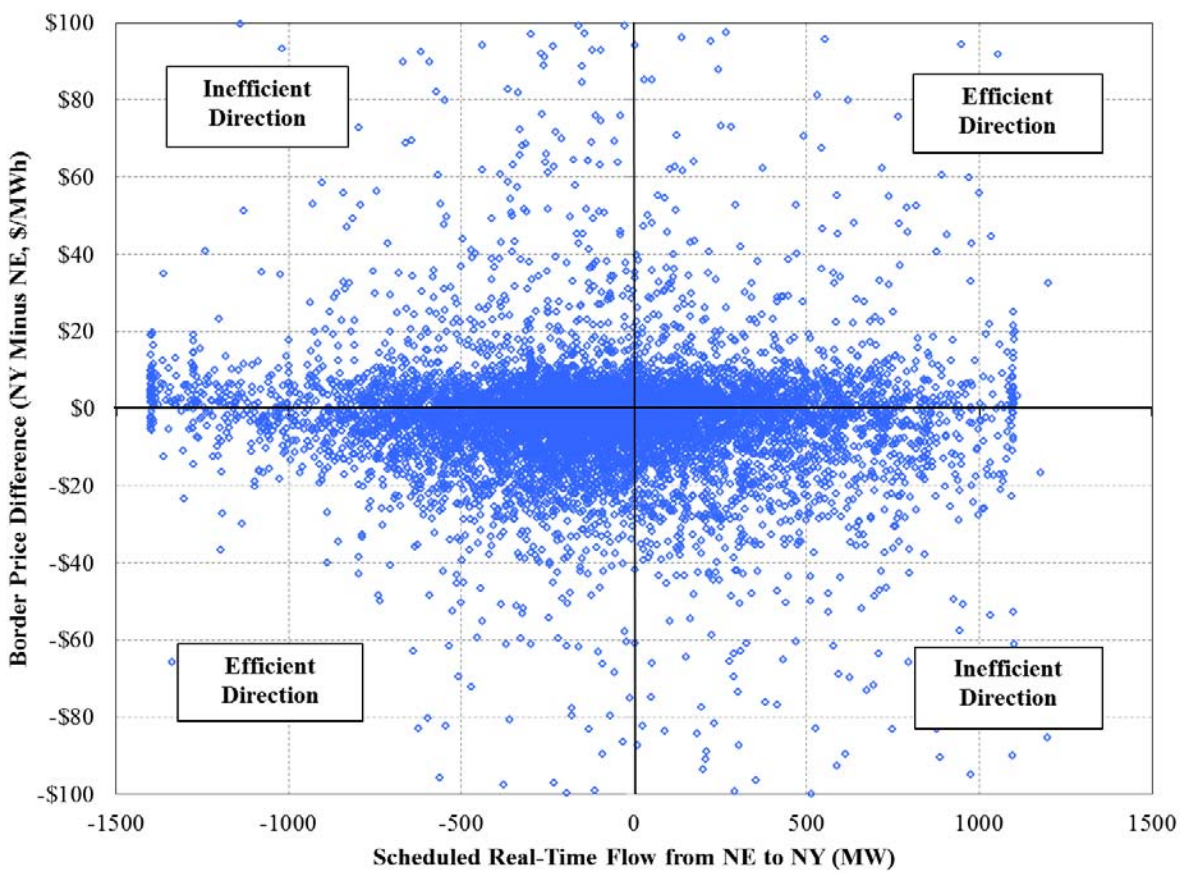


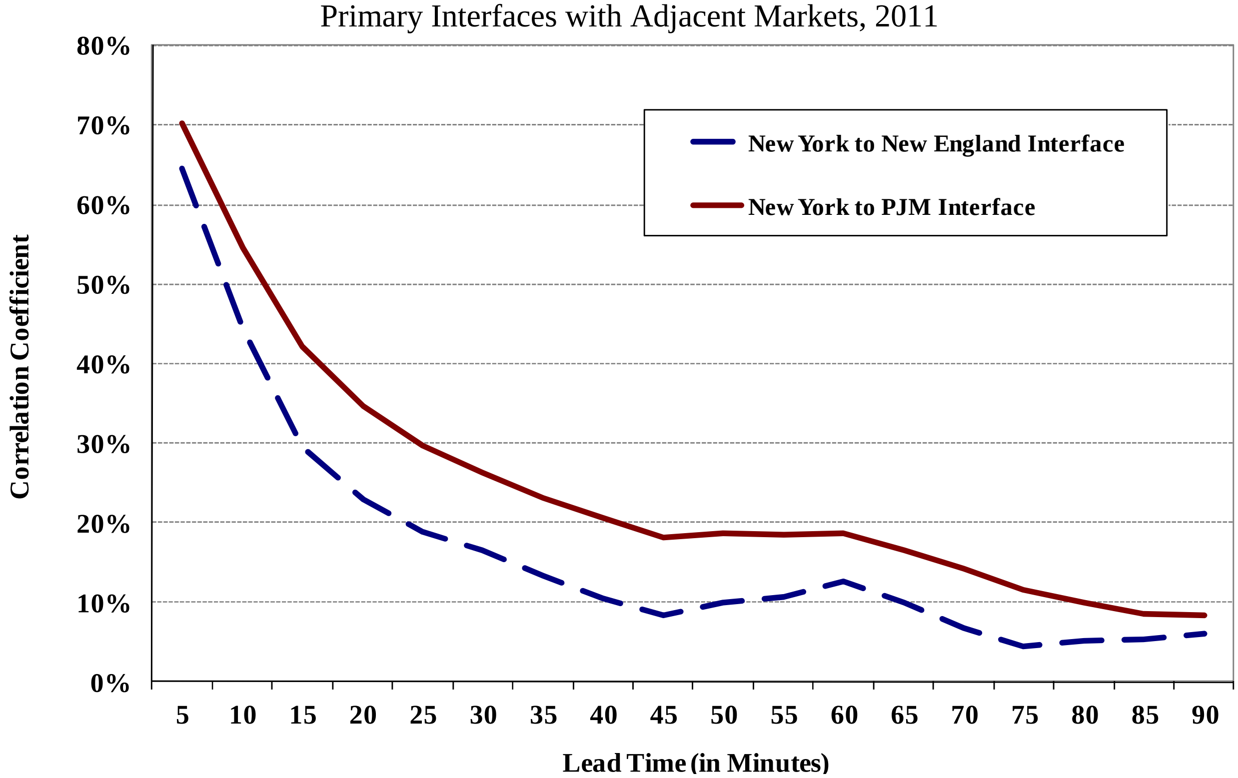
Figure A-54: Correlation of Price Differences and Lead Time

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 A-54 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. This may underestimate the predictability of price differences between control areas because participants can use more sophisticated techniques for forecasting and use the RTC's advisory prices.

Figure A-54: Correlation of Price Differences and Lead Time

Primary Interfaces with Adjacent Markets, 2011



Key Observations: Efficiency of Inter-Market Scheduling

- The distribution of price differences across New York's external interfaces indicates 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 exceeded $10 per MWh in 29 to 36 percent of the unconstrained hours during 2011.
  - Transactions scheduled by market participants flowed in the profitable (i.e., efficient) direction in slightly over half of the hours on most interfaces between New York and neighboring markets during 2011.
    - For example, power was scheduled in the profitable direction in 50 and 52 percent of the hours over the PJM and New England interfaces, respectively.
    - The efficiency of scheduling over the controllable lines exhibited similar scheduling efficiency, ranging from from 49 percent on the 1385 Line to 64 percent on the Neptune Cable.
  - Hence, there was a large share of hours when power flowed inefficiently from the higher-priced market to the lower-priced market. Even in hours when power is flowing in the efficient direction, the interface is rarely fully utilized.
- These scheduling results indicate the difficulty of predicting changes in real-time market conditions, the lack of coordination among schedulers, and the other costs and risks that interfere with efficient interchange scheduling.
- The NYISO is working on several initiatives to improve the utilization of the interfaces between ISOs (and RTOs). These include:
  - Coordinated Transaction Scheduling (“CTS”) with New England;
  - More frequent scheduling with PJM (every 15 minutes) in the near term (15-minute scheduling with Hydro Quebec has been implemented);
  - Coordinating the interchange with PJM using a solution similar CTS; and
  - Coordinating congestion management with PJM and New England.
- We continue to recommend that the NYISO place a high priority on these initiatives, particularly the interface utilization initiative because it offers the highest benefit.

D. Loss Modeling Issue at the PJM Proxy Bus

The primary PJM interface (which does not include the Neptune or Linden VFT scheduled lines) is used to coordinate the bulk of the transactions scheduling between New York and PJM. It incorporates two groups of transmission lines. First, PAR-controlled lines from New Jersey to Southeast New York (i.e., the 5018, JK, and ABC lines) are assumed to carry 66 percent of the interface flow. Second, free-flowing lines from Pennsylvania to Western New York (i.e., two 345kV lines, two 230kV lines, and several 115kV lines) are assumed to carry the remaining 34 percent of the interface flow.

Pricing at the PJM proxy bus should be consistent with these two scheduling assumptions in order to efficiently schedule transactions between the two markets. However, on October 11, 2011, the NYISO identified a software anomaly in the calculation of loss factors at the PJM proxy bus. The anomaly caused the loss factors to fail to consistently reflect the expected power flow assumptions from the PAR-controlled lines between PJM and New York.

The software anomaly was introduced with the current scheduling methodology, which was implemented in June 2007. It affects only the first optimization period in each market run (i.e., the first hour or interval in each SCUC, RTC, and RTD run) and the hours when a transmission line status change occurred. Therefore, the anomaly had different effects in the day-ahead and real-time markets.

- In the day-ahead market, losses *were* modeled correctly in most hours. However, the losses were not modeled correctly in hour beginning 0 and in hours after a change in topology (i.e., a line going in or out of service).

- In the real-time market, losses *were not* modeled correctly in most hours. However, the losses were modeled correctly in some of the hours when the proxy bus price was determined by RTC, which was not affected by topology change.

Flows from PJM into Southeast New York tend to reduce transmission losses, while flows from PJM into western New York increase losses. Hence, the scheduling models generally under-valued imports from PJM and under-priced the PJM proxy bus during those hours. In this sub-section, we estimated direct effects of the loss modeling issue on the LBMPs at the PJM proxy bus, as well as Rate Schedule 1 charges which include:

- Loss Residual Surpluses – These were reduced by export scheduling (and increased by import scheduling) when the marginal losses were incorrect in the day-ahead and real-time markets; and

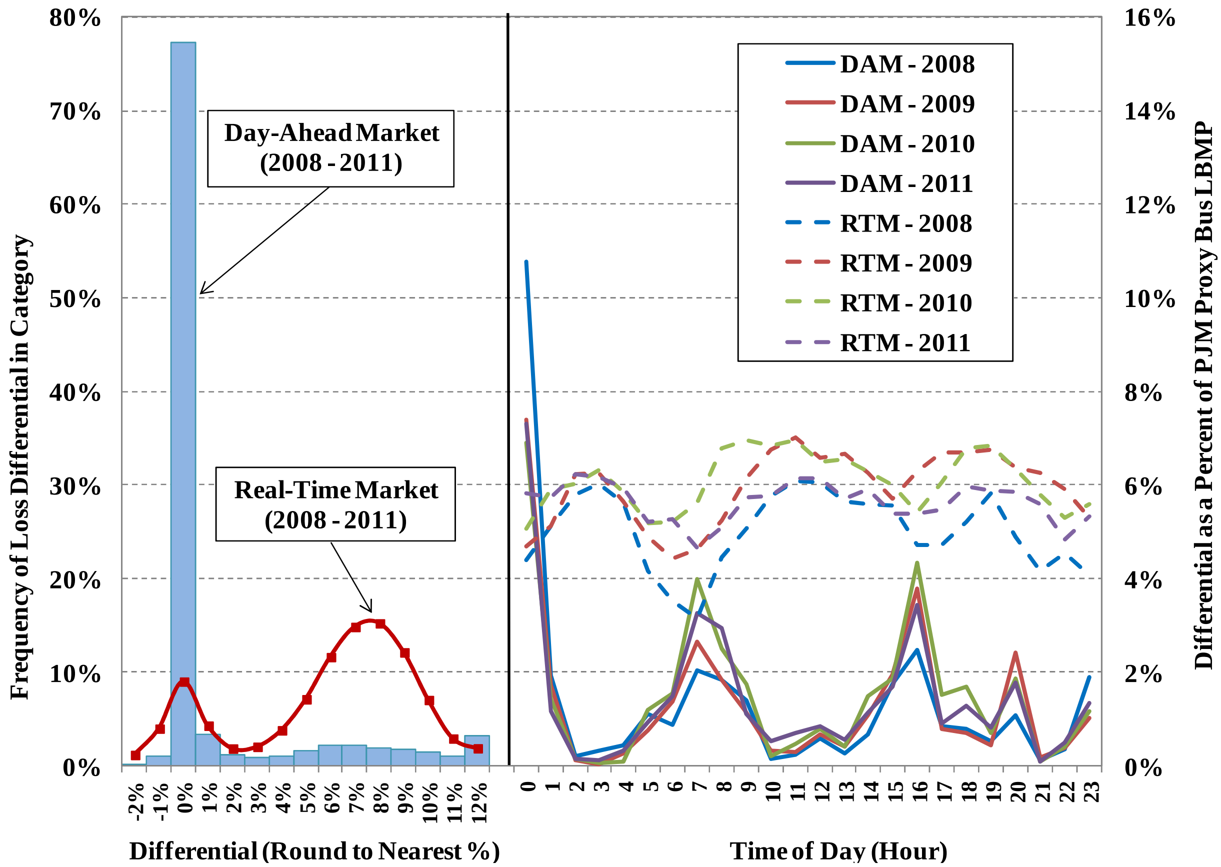
- Real-Time Guarantee Payments – These were increased in some hours when an import was scheduled by RTC based on the correct marginal loss calculation, but the real-time LBMP was incorrect.

Figure A-55: Estimated Difference Between Actual and Correctly-Calculated Loss Factors

The following figure summarizes the differential between the actual loss component of the LBMP and the correctly calculated loss component. The left panel shows the distribution of the differential in individual hours of the day-ahead and real-time markets. The right panel shows the average differential in each year by hour of day in the day-ahead and real-time markets. We studied the period from the beginning of 2008 through October 11, 2011 when the issue was addressed. [104]

[104] Similar effects would likely be observed from June to December 2007, although the necessary data was not readily accessible.

Figure A-55: Estimated Differential Between Actual and Correctly Calculated Loss Factors
PJM Proxy Bus, 2008 - 2011



Key Observations: Market Effects of Loss Modeling Issue at the PJM Proxy Bus

- In the day-ahead market, losses were incorrectly calculated in approximately 30 percent of hours and the average differential was 1.4 percent of the average PJM proxy bus LBMP (including all hours).
- In the real-time market, losses were incorrectly calculated in approximately 80 percent of hours and the average differential was 5.6 percent of the average PJM proxy bus LBMP (including all hours).
- Loss residual surpluses were reduced by $7.0 million from $655 million (a reduction of 1 percent) over the evaluation period. On an annual basis, they were:
  - Increased by $1.0 million ($3K/day) from $259 million in 2008,
  - Reduced by $3.0 million ($8K/day) from $135 million in 2009,
  - Reduced by $1.5 million ($4K/day) from $145 million in 2010, and
  - Reduced by $3.5 million ($12K/day) from $116 million in 2011.

- The real-time guarantee payments were increased by $1.5 million over the evaluation period.

- The day-ahead and real-time LBMPs that were established at the PJM proxy bus, even those established for the intervals impacted by the software anomaly, were consistent with the established schedules and do not warrant correction.

- The modeling issue led the real-time market to under-value power at PJM proxy bus, which likely had the following secondary effects.

  - Net imports from PJM were likely lower because power to/from PJM was systematically under-valued.

  - NYISO would therefore have dispatched higher-cost internal generation or scheduled imports from other control areas when imports from PJM would have been slightly less expensive. We have not estimated the secondary LBMP effects of this issue.

- Although the modeling change introduced in June 2007 included this loss factor anomaly, it is important to consider that modeling change itself greatly improved the recognition of the value of power at the PJM proxy bus. Previously, the market software did not recognize that a portion of imports from PJM flow into Southeast New York, and instead, but rather assumed imports from PJM only flowed across the free-flowing lines into Western New York.

V. 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 2011 in the following five areas:

- *Real-Time Scheduling and Pricing* – These sub-sections evaluates the consistency of real-time pricing with real-time commitment, dispatch, and scheduling decisions.

- *Operation of Controllable Lines* – This sub-section evaluates the efficiency of real-time flows across controllable lines.

- *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. However, supplemental commitments raise concerns because they indicate the market does not provide sufficient incentives, they tend to dampen market signals, and they lead to uplift charges.

A. Efficiency of Gas Turbine Commitments

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.[105] 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.[106] 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 Section F.

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 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 evaluates the efficiency of real-time commitment and scheduling of gas turbines and the next sub-section contains a similar evaluation of external transactions.

Figure A-56: Efficiency of Gas Turbine Commitment

Figure A-56 measures the efficiency of gas turbine 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.

[105] Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

[106] 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

The figure shows the average quantity of GT capacity started each day in 2011. 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:

- Offer < LBMP (these commitments were clearly economic);
- Offer > LBMP by up to 25 percent;
- Offer > LBMP by 25 to 50 percent; and
- Offer > LBMP by more than 50 percent.

Gas turbines with offers greater than the LBMP can be economic, since gas turbines that are started efficiently and that set the LBMP at their location do not earn additional revenues needed to recover their start-up offer. Also, gas turbines that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period.

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,[107] or by an out-of-merit (OOM) instruction. The table in the chart also shows our evaluation of uneconomic starts (i.e., the three categories of Offer > LBMP over the initial commitment period) by RTC and RTD. We focus on the effects of the hybrid pricing logic on the overall GT commitment efficiency.[108] In particular, we examine every market interval in the initial commitment period for an uneconomic GT start by RTD or RTC and summarize these intervals into the following categories:

- GT is Economic – this indicates that the GT is economic in both the hybrid pass and the pricing pass (i.e., its offer is less than or equal to its LBMP);
- GT is Uneconomic – this indicates that the GT is not economic in both the hybrid pass and the pricing pass (i.e., its offer is higher than its LBMP) but it is blocked on the pricing pass to satisfy its minimum run time; and

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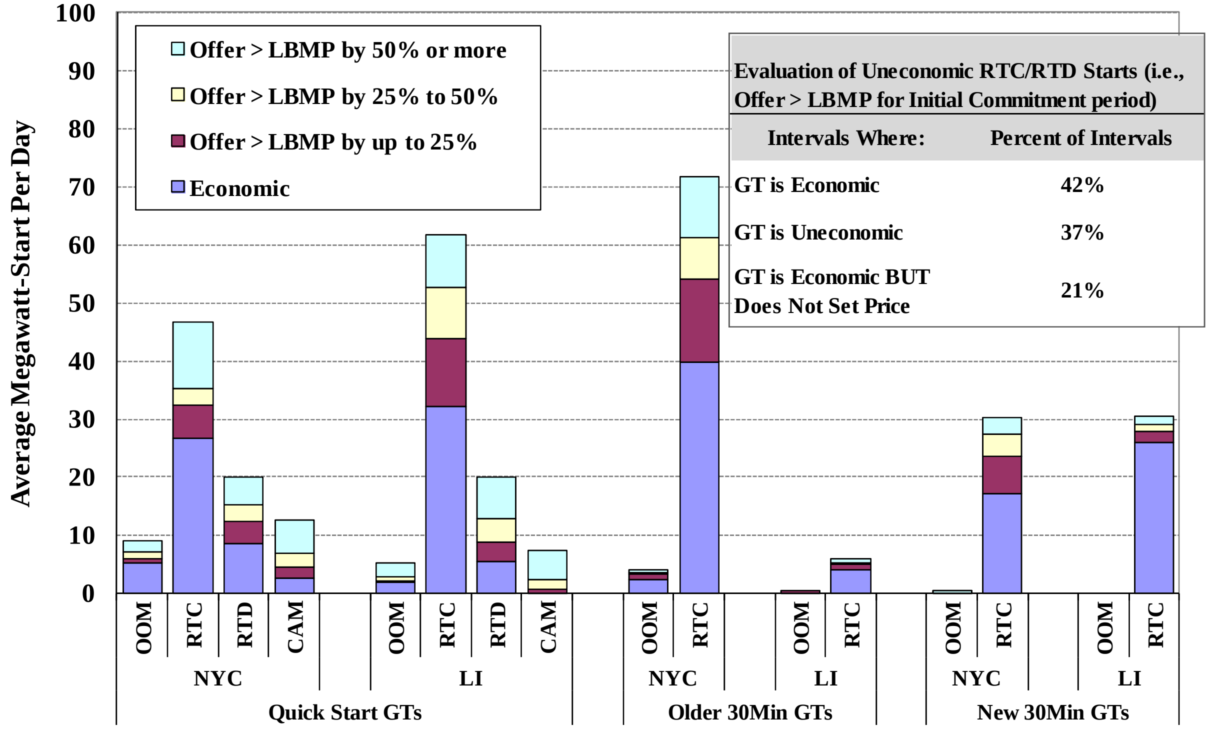
107 The Real-Time Dispatch – Corrective Action Mode (RTD-CAM) is version of RTD that NYISO operators can run on-demand to address abnormal or unexpected system conditions.

108 The market software adopts a three-pass mechanism for the purpose of dispatching and pricing. The first pass is a physical dispatch pass, which produces physically feasible base points that are sent to all resources. In this pass, GTs are treated as inflexible resources and are dispatched at their maximum output levels once turned on. The second pass is a hybrid dispatch pass, which treats GTs as flexible resources that can be dispatched between zero and the maximum output level. The third pass is a pricing pass, which produces LBMPs for the market interval. GTs that are not economic (i.e., dispatched at zero) in the hybrid pass but are still within their minimum run times are forced on and dispatched at the maximum output level in the pricing pass.

- GT is Economic BUT Does Not Set Price – this indicates that the GT is economic in the hybrid pass but does not set price in the pricing pass (i.e., its offer is higher than its LBMP and the GT is dispatched at zero).

Figure A-56: Efficiency of Gas Turbine Commitment
2011



Key Observations: Efficiency of Gas Turbine Commitment

- 76 percent of the GT-capacity started during 2011 was committed by RTC, with an additional 18 percent by RTD and RTD-CAM, and the remaining 6 percent through OOM instructions.
- The overall efficiency of gas turbine commitment was consistent in recent years.
  - 53 percent of all GT commitments were clearly economic in 2011.
  - 69 percent of all GT commitments were cases where the GT offer was within 125 percent of LBMP in 2011.
- Among all GT commitments by RTD and RTC:
  - GT capacity was economic in 42 percent of the intervals over the initial commitment period;
  - GT capacity was not economic in 37 percent of the intervals over the initial commitment period, which largely resulted from inconsistencies between RTC and

RTD, and between RTD and advisory RTD. Reducing these inconsistencies will likely reduce the share in this category;

- GT capacity was economic but did not set prices in 21 percent of the intervals over the initial commitment period, which accounted for roughly 180 hours in 2011. These results suggest that there may be potential improvements possible in the hybrid pricing logic.

B. 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.[109] 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.[110]

"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.[111]

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[109] 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).

[110] 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.

[111] 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.

Figure A-57: Efficiency of External Transaction Scheduling

Figure A-57 shows the consistency and profitability of external transaction scheduling across the primary AC interface between New York and New England from 2005 to 2011 using the import/export offer and bid prices and the real-time LBMP at the border.[112] 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.

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

- *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.

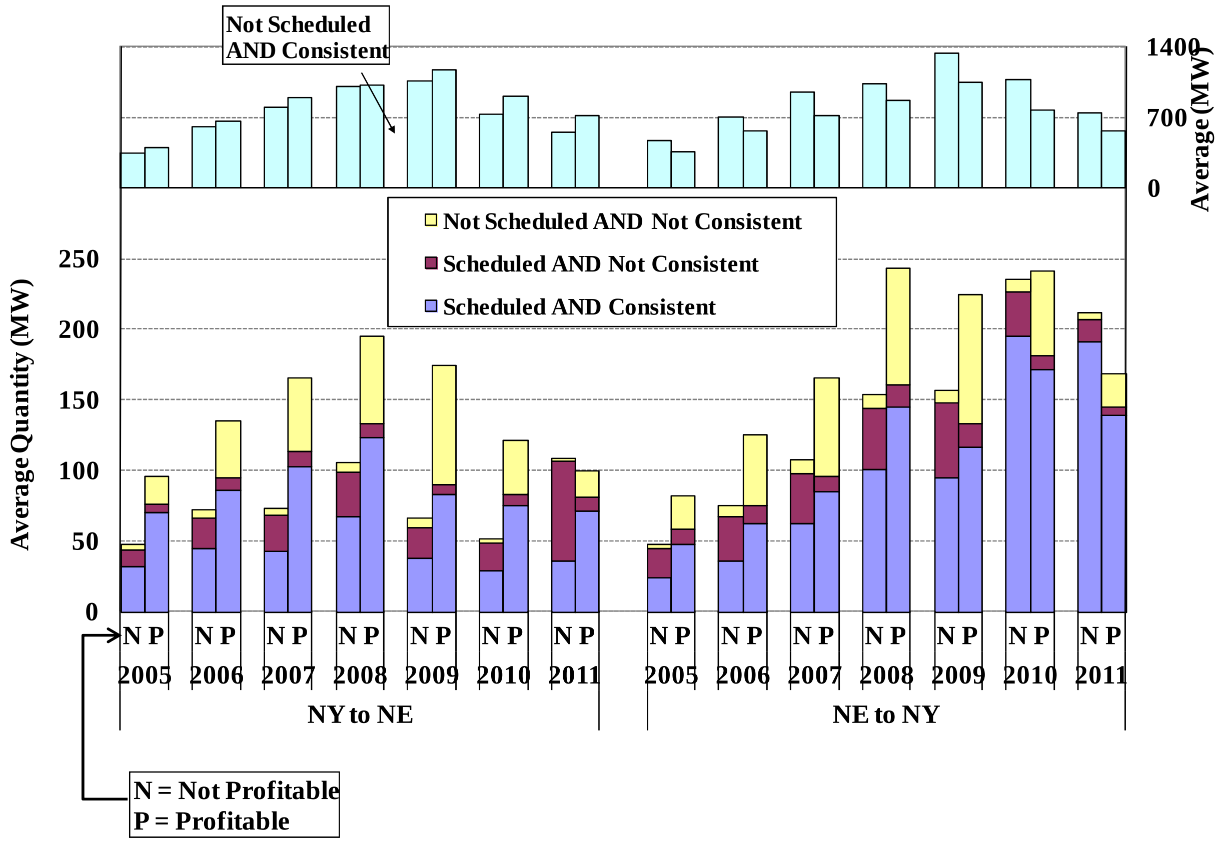
- *Not scheduled and not consistent* – These transactions are not scheduled by RTC but apparently should have been.

- *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.

[112] 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.

Figure A-57: Efficiency of External Transaction Scheduling
2011



Key Observations: Efficiency of External Transaction Scheduling

- The share of schedules that were consistent was similar to prior years.
  - 81 percent of scheduled offers were consistent in 2011, comparable to the averages from 2005 to 2010, which ranged from 75 to 87 percent.
  - 98 percent of offers and bids not scheduled were also consistent, up slightly from prior years.
- *Consistent* scheduling is not the same as *Efficient* scheduling (efficient schedules are all profitable). Results for 2011 show:
  - Scheduled and consistent – 49 percent of these transactions were profitable.
  - Scheduled and not consistent – 29 percent of these were still profitable.
  - Not scheduled and not consistent – 87 percent of these transactions would have been profitable if scheduled.
- The external transaction scheduling process has functioned reasonably well and scheduling by market participants tends to improve convergence. However, significant opportunities remain to improve the interchange between New York and adjacent areas.

- We strongly support NYISO is collaborating with ISO-NE, Quebec, and PJM to improve the use of their interfaces by making intra-hour interchange adjustments.

C. Operation of Controllable Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows below applicable limits. However, there are still a significant number of controllable transmission lines that source and/or sink in New York. This includes High Voltage Direct Current ("HVDC") transmission lines, Phase-Angle Regulator ("PAR") –controlled lines, and Variable Frequency Transformer ("VFT") –controlled lines. Controllable transmission lines allow power flows to be channeled along paths that lower the overall cost of satisfying the system's needs. Hence, they can provide greater benefits than conventional AC transmission lines.

Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways. First, some controllable transmission lines are scheduled as external interfaces using external transaction scheduling procedures.[113] Such lines are analyzed in Section IV of the Appendix, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted in order to reduce generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not focused on reducing production costs. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-3 and Figure A-58: Scheduling of Non-Optimized PAR-Controlled Lines

PARs are commonly used to control line flows on the bulk power system. Through control of tap positions, power flows on a PAR-controlled line can be changed in order to facilitate power transfer between regions or to manage congestion within and between control areas. This sub-section evaluates efficiency of PAR operations during 2011.

Table A-3 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2011. The evaluation is done for the following eleven PAR-controlled lines:

- Two between IESO and NYISO- St. Lawerence – Moses PARs (L33 and L34).
- One between ISO-NE and NYISO - Sand Bar – Plattsburgh PAR (PV20).

[113] This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), and the Linden VFT Scheduled Line.

- Six between PJM and NYISO - two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), two Hudson-Farragut PARs (B & C lines), and one Linden-Goethals PAR (A line).
  - The 5018 line was ordinarily scheduled to carry 40 percent of the total interface schedule of the primary PJM-NYCA interface.
  - The A, B, C, J, & K lines support the operation of the ConEd-PSEG wheeling agreement whereby 1,000 MW is ordinarily scheduled to flow out of NYCA on the J & K lines and 1,000 MW is scheduled to flow into New York City on the A, B, & C lines. In addition, the A, B, & C lines were scheduled to carry 13 percent of the total interface schedule of the primary PJM-NYCA interface, and the J & K lines were scheduled to carry another 13 percent.
- Two between Long Island and New York City - Lake Success-Jamaica PAR (903) and Valley Stream-Jamaica PAR (901).
  - The 901 & 903 lines were ordinarily scheduled to support a 300 MW wheel from upstate New York through Long Island and into New York City.

For each group of PAR-controlled lines, Table A-3 shows:

- Average hourly real-time net flows into NYCA or New York City;
- Average real-time price at the interconnection point in the NYCA or New York City minus the average real-time price at the interconnection point in the adjacent area (the external control area or Long Island);
- The share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-price market); and
- The estimated production cost savings that result from the flows across each line. The estimated production cost savings in each hour is based on the price difference across the line multiplied by the scheduled power flow across the line.[114]

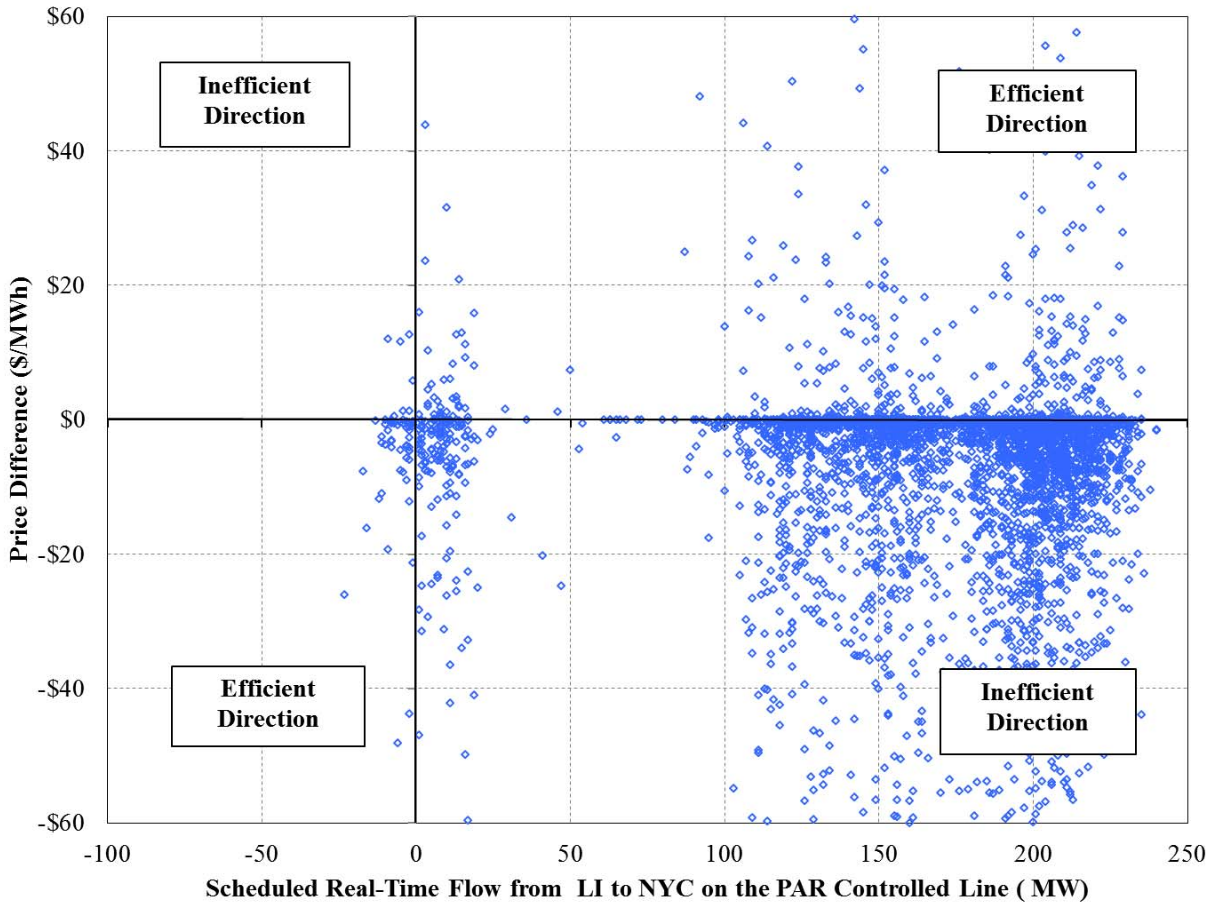
[114] For example, if 100 MW flows from Lake Success to Jamaica during one hour, the price at Lake Success is $50 per MWh, and the price at Jamaica is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10). This is because each MW of flow saves $10 by allowing a $60 per MWh resource in New York City to ramp down and be replaced by a $50 per MWh resource in Long Island. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

Table A-3: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2011

	Average Flow (MW/h)	Avg NYCA Price minus Avg. Price Outside ($/MWh)	Pct of Hours in Efficient Direction	Est. Production Cost Savings (Million $)
PAR Controlled Lines (into NY)				
St. Lawerence (L33/34	21	$7.30	57%	$7
Sand Bar (PV 20)	-80	-$7.59	74%	$6
Waldwick (JK)	-673	-$3.22	44%	$20
Ramapo (5018)	313	-$3.22	57%	$1
Farragut (BC)	528	$0.95	57%	$3
Goethals (A)	346	$2.81	60%	$7
PAR Controlled Lines (LI into NYC)				
Lake Success (903)	145	-$7.31	12%	-$11
Valley Stream (901)	64	-$14.86	11%	-$10

Figure A-58 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake Success-Jamaica line. The figure shows hourly price differences in the real-time market on the vertical axis versus power flows scheduled in the real-time market on the horizontal axis. Points in the top-right and bottom-left quadrants of the figure are characterized as scheduled in the efficient direction. Power scheduled in the efficient direction flows from the lower-priced market to the higher-priced market. Similarly, points in the top-left and bottom-right quadrants are characterized as scheduled in the inefficient direction, corresponding to power flowing from the higher-priced market to the lower-priced market. Good market performance would be indicated by a large share of hours scheduled in the efficient direction.

Figure A-58: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2011



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- Power flowed in the efficient direction in the majority of hours on all but one PAR-controlled lines between New York and neighboring markets during 2011.
  - The share of hours with efficient scheduling ranged from 44 percent on the Waldwick lines to 74 percent on the PV-20 line.
  - Except for the Ramapo line, the prevailing direction of power flows on each line was from the side that averaged a lower price to the side that averaged a higher-price. The Ramapo line generally flowed power from PJM to NYCA, although the price on the PJM side was higher on average. PJM and the NYISO are working to implement Market-to-Market Coordination in order to improve the scheduling efficiency of the primary interface between them, including the Ramapo line.[115]

[115] See Docket No. ER12-718-000.

- A total of $44 million in net production cost savings was estimated from the controllable lines between NYCA and adjacent control areas. However, significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

- The scheduling results over the PAR-controlled lines from Long Island into New York City was much worse than any of the other PAR-controlled lines.
  - Power flowed in the inefficient direction in nearly 90 percent of hours on the two PAR-controlled lines between Long Island and New York City during 2011.
  - The use of these lines increased production costs by an estimated $21 million in 2011 because Long Island typically exhibited higher prices than New York City (particularly the portion of New York City where the 901 and 903 lines connect). These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica "load pocket," an area that is frequently export constrained.
  - In addition to increasing production costs, these transfers a) depress prices in NYC and B) can restrict output from generators in the Astoria East/Corona, Jamaica pocket. The latter effect can reduce reliability in eastern New York, particularly when the system is in an eastern reserve shortage (which occurs during some TSAs).
- These results indicate that significant opportunities remain to improve the operation of these lines, particularly the lines between New York City and Long Island. However, we recognize that the ability to achieve these improvements and the associated savings may be limited by contracts that specify how the lines are to be operated.

D. Real-Time State-wide 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 sub-section evaluates patterns of price volatility in the real-time market.

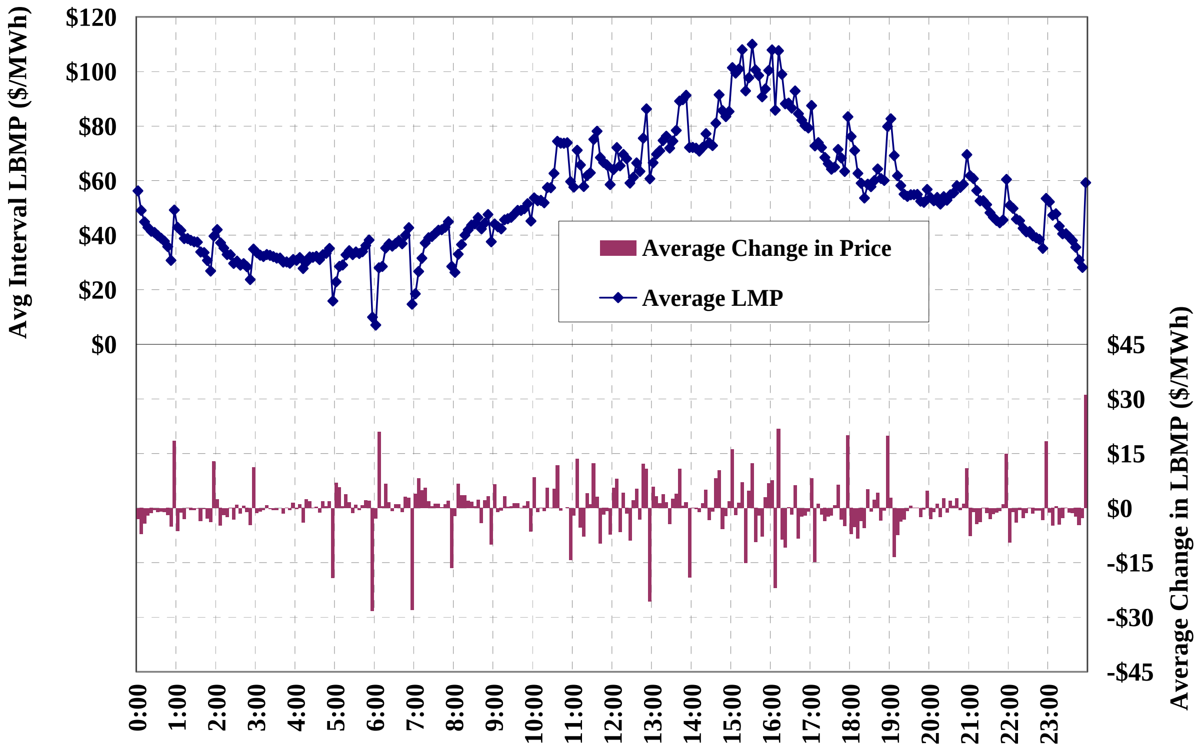
Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient 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 analyzes statewide fluctuations in real-time prices, while the next sub-section focuses on localized fluctuations that result from transmission congestion.

Figure A-59 & Figure A-60: Statewide Real-Time Price Volatility

Figure A-59 examines the volatility of statewide energy prices by time of day, showing the average prices in each five-minute interval of the day in the summer of 2011. The figure shows the load-weighted average prices for all of New York, although the results are similar in each individual zone.

Figure A-59: Statewide Average Five-Minute Prices by Time of Day
June to August 2011



Changes in LBMPs from one interval to the next depend on how much dispatch flexibility the system has to respond to fluctuations in the following factors: electricity demand, net export schedules (which are determined prior to RTD by RTC or by transaction curtailments), generation schedules of self-scheduled and other non-flexible generation, and transmission congestion patterns.

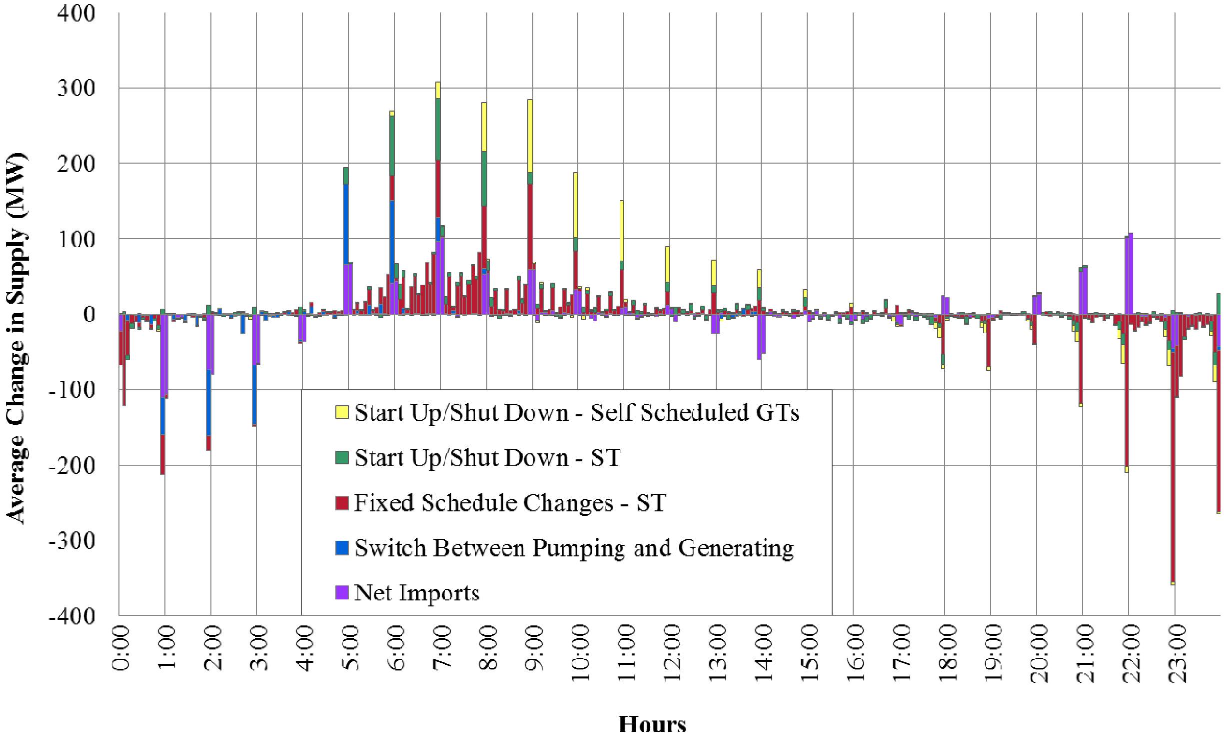
Figure A-60 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *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 change unexpectedly due to curtailments and TLRs before or 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 units 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 much be accommodated.

Figure A-60: Factors Contributing to Real-Time Price Volatility
June to August 2011



Key Observations: Statewide Real-Time Price Volatility

- Most real-time price fluctuations occurred predictably 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 ranged from roughly \$15 to \$30/MWh, while most other interval-to-interval price changes were less than \$5/MWh.
- Several factors contributed to large price changes at the top of the hour during ramping hours in 2011:
  - Import and export schedules typically adjusted at the top of the hour;

- Generators were committed and decommitted frequently at the top of the hour during ramping hours; and
- Non-dispatchable generators typically adjusted 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.

- This report recommends the NYISO investigate some potential further improvements that would reduce unnecessary price volatility at the top of the hour.

E. Real-Time Price Volatility in Constrained Areas

This sub-section examines the real-time price volatility in constrained areas during 2011. We differentiate two types of price spikes: *transient* and *non-transient.* A spike in the shadow price of a particular transmission constraint is considered *"transient"* if it satisfies all of the following three criteria:

- It exceeds $300 per MWh;
- It increases by at least 400 percent from the previous interval; and
- It is at least 400 percent higher than in the most recent RTD "look ahead" interval.

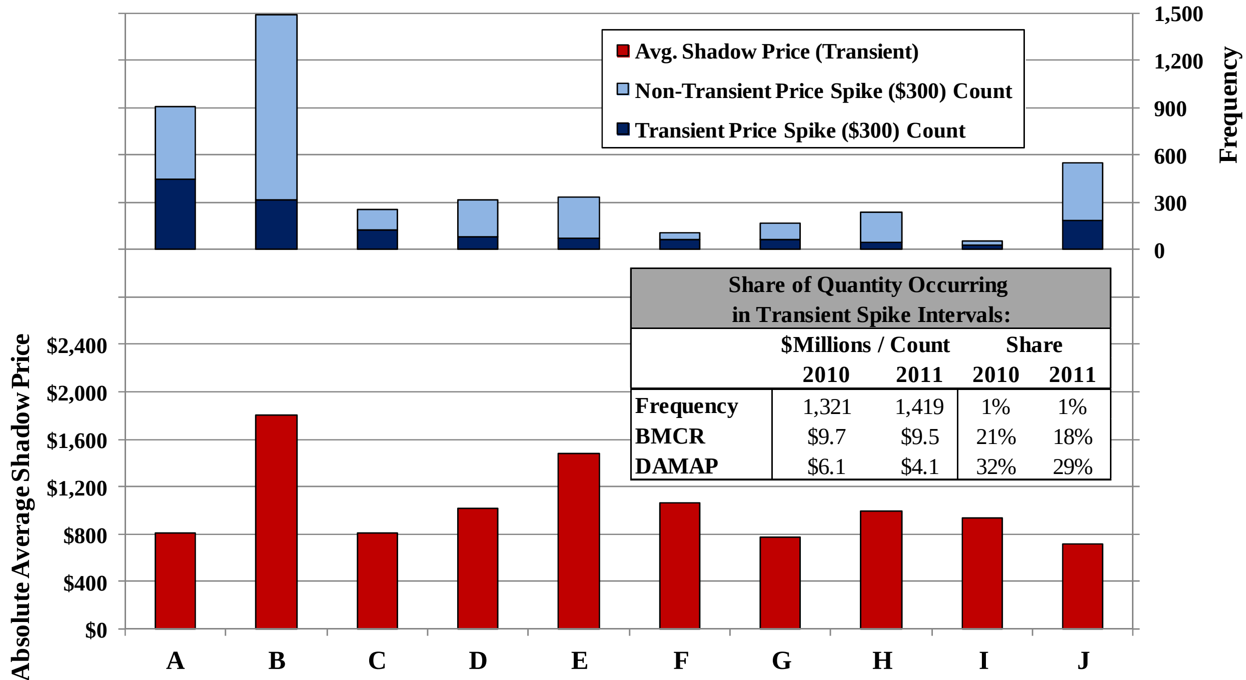
A price spike is considered *"non-transient"* if it exceeds $300 per MWh but does not satisfy either of the other two criteria for a *transient* price spike.

Figure A-61 & Figure A-62: Real-Time Price Volatility – Constrained Areas

Figure A-61 summarizes transient congestion price spikes by facility in 2011. Figure A-62 evaluates major factors that may have contributed to the price volatility in the constrained areas shown in Figure A-61. Figure A-61 shows the frequency of transient and non-transient spikes and the average shadow price in transient spikes for each transmission facility during 2011. In the figure, the top nine facilities (A through I) are ranked in descending order by the frequency of transient spikes and all other facilities are grouped in category J.

Although relatively infrequent, transient shadow price spikes are important, since it may be far more costly to manage congestion that is not fully anticipated. The table in Figure A-61 shows that proportionately large quantities of uplift from Balancing Market Congestion Revenue ("BMCR") and Day-Ahead Margin Assurance Payment ("DAMAP") arise from intervals when transient spikes occur.

Figure A-61: Frequency and Cost of Transient Congestion Price Spikes
2011



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

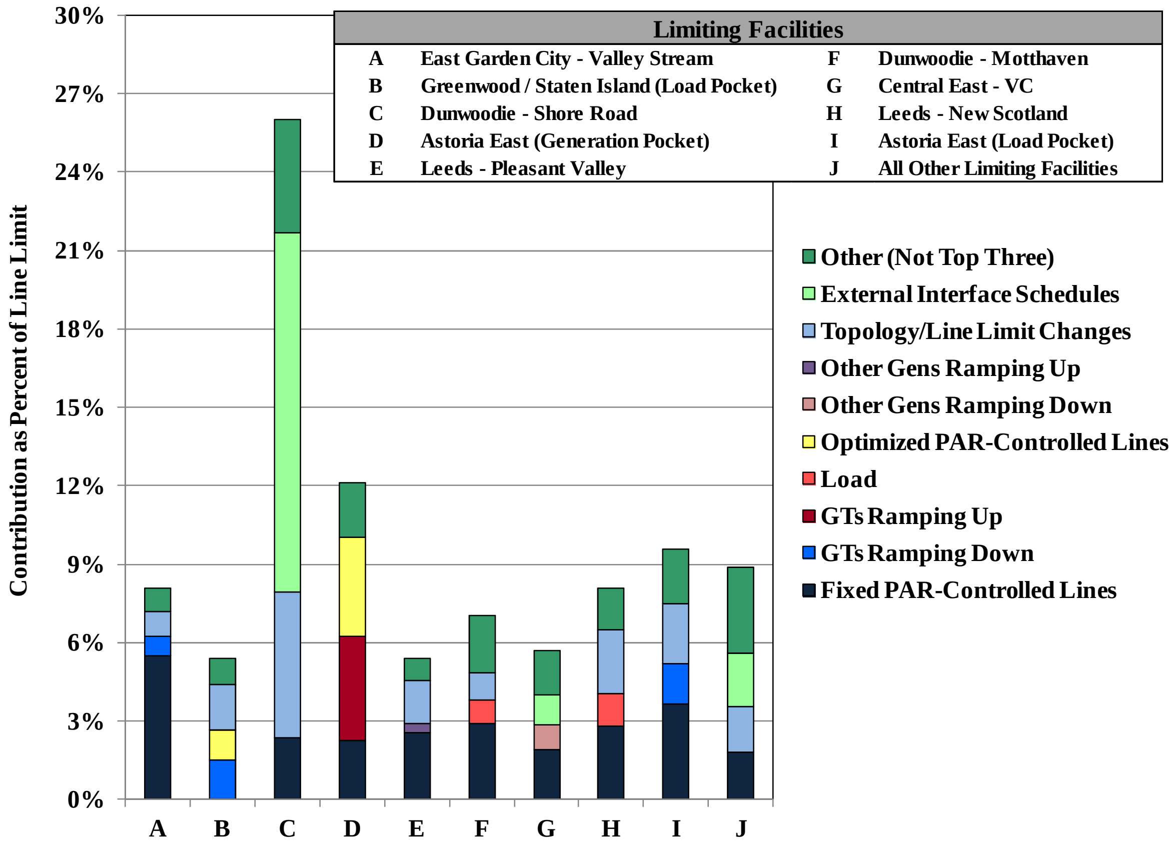
Figure A-62 examines the factors that changed from the previous five-minute interval, contributing to increased flows across the constrained facility. In particular, these factors include:

- Increases in scheduled flows from the following factors:
  - Fixed PAR-Controlled Lines – RTD and RTC assumes the flow will remain fixed in future intervals at the most recent telemetered value for these lines, but their flow is affected by changes in generation and load and changes in the settings of the PAR or other nearby PARs. Hence, RTD and RTC to not anticipate changes in flows across these lines in future intervals;
  - Optimized PAR-Controlled Lines – The flows across these lines are optimized by RTD and RTC;
  - External Schedules – These are normally determined by RTC, although these may be subsequently changed 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 Turbine Commitment – Most decisions to start-up and shut-down gas turbines are made by RTC;

- Other Generators Ramping Up or Ramping Down – The output of these units is determined by self schedules, dispatch instructions, and/or dragging; and
- Changes in 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 A-62: Factors Contributing to Transient Congestion Price Spikes
2011



Key Observations: Real-Time Price Volatility – Constrained Areas

- Transient shadow price spikes occurred during about 1 percent of all intervals and 32 percent of the intervals when shadow prices exceeded $300/MWh in 2011.
  - Approximately 31 percent of total transient shadow price spikes occurred on the transmission line from East Garden City to Valley Stream in Long Island.
  - The Greenwood/Staten Island load pocket exhibited the most transient shadow price spikes in New York City, accounting for 22 percent of total transient spikes.

  - In the upstate areas, the Central-East interface and paths from Capital to Hudson Valley (the Leeds-Pleasant Valley line and the New Scotland-Leeds line) exhibited most transient spikes, collectively accounting for 13 percent of all transient spikes.

- Although relatively infrequent, transient price spikes are important because it can be far more costly to manage congestion that is not anticipated.
  - Disproportionately 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.
  - Similar to 2010, nearly $10 million of BMCR (or 18 percent of total BMCR) and $4 million of DAMAP (or 29 percent of total DAMAP) accrued during these transient spike intervals during 2011.
- Among many factors that contribute to transient shadow price spikes, the Fixed PAR-Controlled Line flow changes were the most significant factor in 2011.
  - This was the top contributing factor for six of the ten facility categories shown.
  - RTD and RTC assume the flow across these lines will remain fixed at the most recent telemetered value (rather than forecasted). Therefore, when the telemetered value changes substantially, it can result in transitory instances of severe congestion.
- External schedule changes were the most significant factor contributing to transient price spikes on the Dunwoodie-Shore Road line from upstate into Long Island.
  - Long Island can import up to 1.2 GW of generation from PJM and ISO-NE, 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 account for the change.

F. Market Operations under Shortage Conditions

Prices that occur under shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission security constraints) 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. In the short-run, prices should provide market participants with incentives to commit sufficient resources in the day-ahead market to satisfy anticipated system conditions the following day, and 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 rather than as the result of anticompetitive behavior or inefficient market operations.

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.

Figure A-63: Real-Time Prices During Ancillary Services 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.

Figure A-63 summarizes ancillary services shortages and their effects on real-time prices in 2010 and 2011 for the following six categories:

- 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 of $50/MWh if the shortage is less than 200 MW, $100/MWh if the shortage is between 200 and 400 MW, and $200/MWh if the shortage is more than 400 MW.
- 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 $450/MWh.[116]
- 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.
- 10-minute East – The ISO is required to hold 1200 MW (1,000 MW before December 1, 2010) of 10-minute operating reserves in Eastern New York and has a demand curve value of $500/MWh.

[116] The demand curve value was set to $150/MWh before May 19, 2011.

- 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 $25/MWh.117

- Regulation – The ISO is required to hold 150 to 250 MW of regulation capability in the state and has a demand curve value of $80/MWh if the shortage is less than 25 MW, $180/MWh if the shortage is between 25 and 80 MW, and $400/MWh if the shortage is more than 80 MW.[118]

The top portion of the figure shows the frequency of shortages. The bottom portion shows the average shadow price during shortage intervals and the demand curve level of the requirement. The reset in the demand curves for some ancillary services products on May 19, 2011 is reflected in the chart. 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 by region. The table also 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.

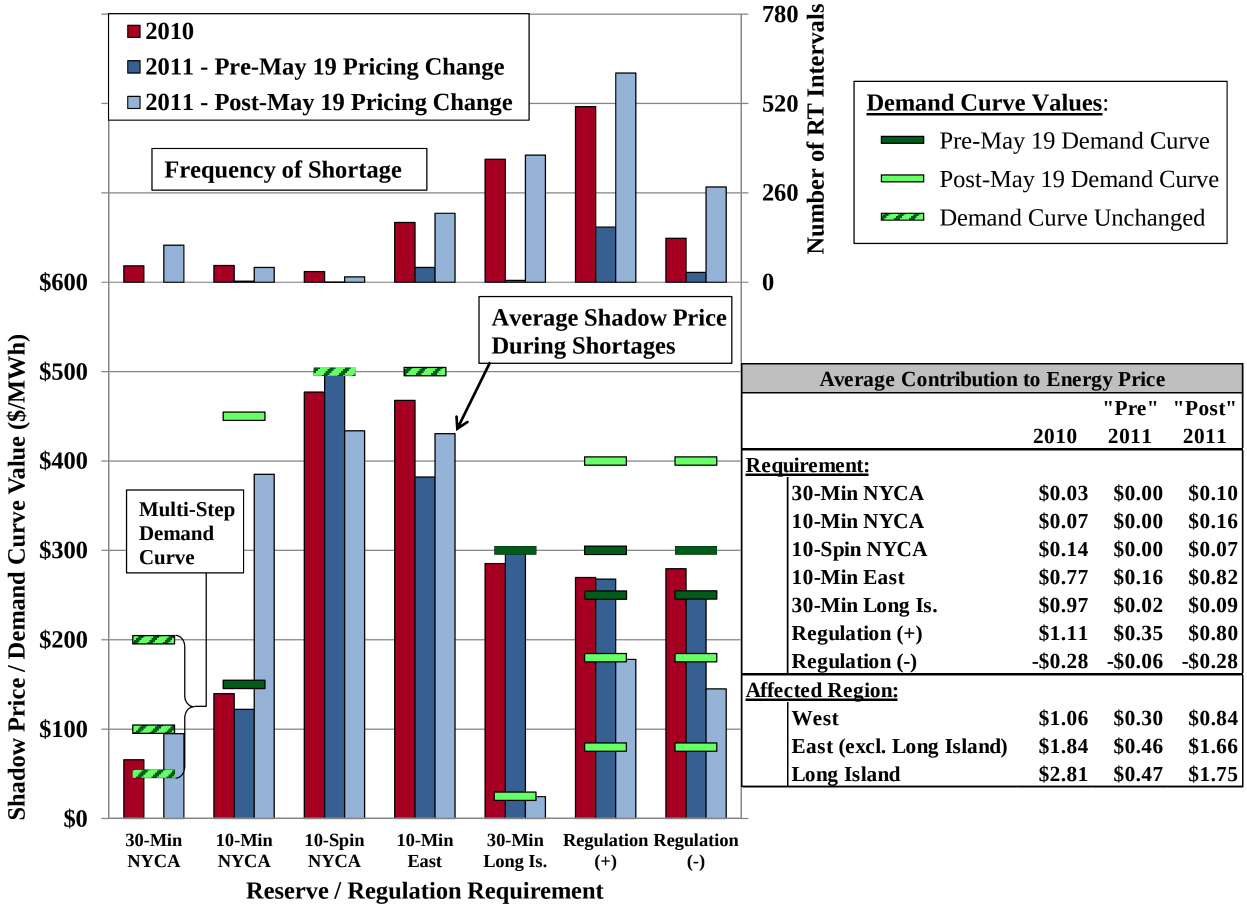
- Eastern New York (excluding Long Island) – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

- Long Island – This equals the Eastern New York effect plus the sum of shadow prices of Long Island reserve requirements.

[117] 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 $300/MWh before May 19, 2011.

[118] The regulation demand curve values before May 19, 2011 were set to $250/MWh when the shortage is less than 25 MW and $300/MWh when the shortage exceeds 25 MW.

Figure A-63: Real-Time Prices During Ancillary Services Shortages
2010 – 2011



Average Contribution to Energy Price	2010	"Pre" 2011	"Post" 2011
Requirement:			
30-Min NYCA	$0.03	$0.00	$0.10
10-Min NYCA	$0.07	$0.00	$0.16
10-Spin NYCA	$0.14	$0.00	$0.07
10-Min East	$0.77	$0.16	$0.82
30-Min Long Is.	$0.97	$0.02	$0.09
Regulation (+)	$1.11	$0.35	$0.80
Regulation (-)	-$0.28	-$0.06	-$0.28
Affected Region:			
West	$1.06	$0.30	$0.84
East (excl. Long Island)	$1.84	$0.46	$1.66
Long Island	$2.81	$0.47	$1.75

Key Observations: Real-Time Prices During Ancillary Services Shortages

- Ancillary services shortages with the largest effects on real-time prices during 2011 were:
  - Regulation shortages when supply was limited and could not ramp down sufficiently to provide regulation, leading to positive energy price spikes;
  - 10-minute eastern reserve shortages; and
  - Regulation shortages when supply was in excess and could not ramp up to provide regulation, leading to negative energy price spikes.
- Changes in the ancillary services demand curves on May 19 noticeable affected the frequency of shortages and reserve prices during those shortages.
  - Regulation shortages occurred more frequently, but with smaller price impacts.
  - NYCA 10-minute reserve shortages occurred less frequently, but generated much larger price impacts.

  - The frequency of Long Island 30-minute reserve shortages was relatively consistent, but the price impacts decreased dramatically.

- Overall, real-time prices generally reflected system conditions accurately, as reflected in the ancillary services demand curves.[119]

  - The average shadow price during physical shortages was close to the demand curve level for each class of reserves.

G. Real- Time Prices 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.[120] 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 started).

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

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[119] In previous state of the market reports, we have identified periods when real-time prices did not reflect that the system was in a physical shortage. This can happen because RTD performs a pricing optimization that is distinct from the physical optimization that is used to determine dispatch instructions. The pricing optimization is employed so that block loaded generators (i.e., gas turbines) are able to set the clearing price under certain circumstances.

[120] 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.

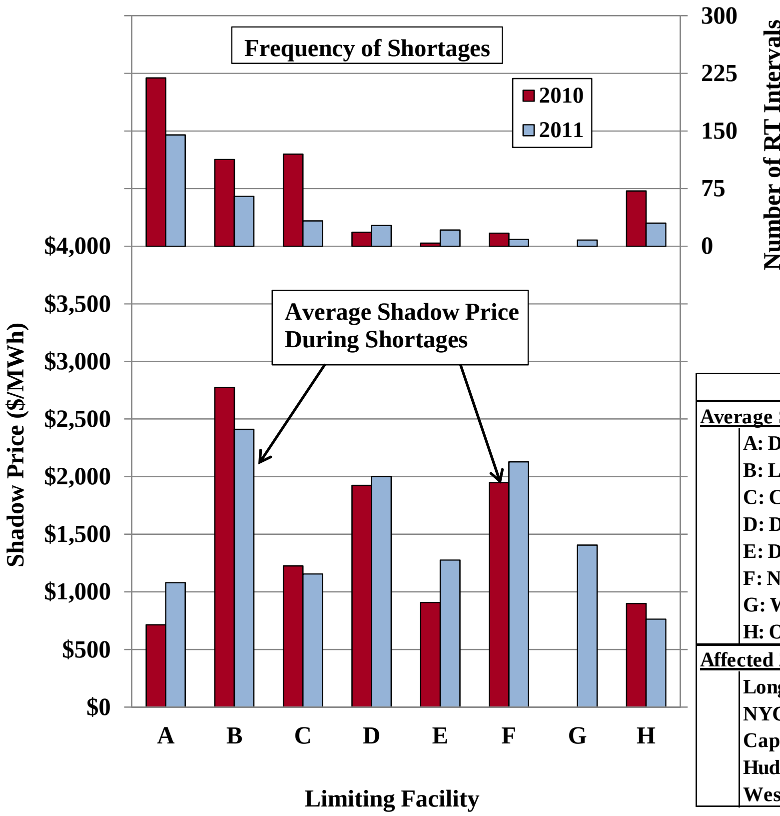
common because RTD usually finds an available quick-start gas turbine that can be scheduled before it reaches the $4,000/MWh transmission shortage cost limit.

Figure A-64: Real- Time Prices During Transmission Shortages

Figure A-64 summarizes events when a transmission constraint has a large effect on real-time LBMPs, since this often coincides with a transmission shortage. Since no data is retained on precisely when transmission shortages occur, the figure shows likely transmission shortages, which we define as 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 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.[121] 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 table also shows the overall contribution of all likely transmission shortages to the energy prices in each zone.

Figure A-64: Real-Time Prices During Transmission Shortages
2010 – 2011



Price Set by Offline GT That Was Not Started in 2011		
	# of Intervals	Pct of Shortages
A	73	50%
B	10	15%
C	18	55%
D	21	78%
E	5	24%
F	5	56%
G	6	75%
H	14	47%

	2010	2011
Average Shadow Price During All Intervals:		
A: Dunwoodie-Shore Road	$1.49	$1.49
B: Leeds-Pleasant Valley	$2.98	$1.49
C: Central East	$1.40	$0.36
D: Dunwoodie-Mott Haven	$0.33	$0.51
E: Dysinger East	$0.03	$0.25
F: New Scotland-Leeds	$0.31	$0.18
G: W49th St-Sprainbrook	$0.00	$0.11
H: Other	$0.62	$0.22
Affected Zone:		
Long Island	$3.78	$2.63
NYC	$2.47	$1.16
Capital	$1.08	$0.32
Hudson Valley	$1.91	$0.76
West	$0.00	$0.00

121 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.

<u>Key Observations: Real-Time Prices During Transmission Shortages</u>

- The Leeds-to-Pleasant Valley transmission line exhibited the most significant transmission shortages in 2011 and in 2010 as well.
  - In the 65 intervals shown during 2011, this constraint contributed an average of $940/MWh to the New York City LBMP, which raised the average New York City LBMP by roughly $0.60/MWh overall in 2011.
  - Much of this severe congestion occurred during TSAs that substantially reduce available transfer capability on this path and lead to shortages.
- Dunwoodie-to-Shore Road line constraint also exhibited significant transmission shortages in 2010 and 2011.
  - This constraint contributed an average of $1.49/MWh to the Long Island LBMP over the year of 2011. Severe congestion across this line frequently occurred during large hourly schedule changes across the interfaces between Long Island and Connecticut and New Jersey.
- Overall, downstate areas experienced the most significant price impacts from these likely transmission shortages in 2011.
  - In New York City, the total price impact was $1.16/MWh on average in 2011.
  - In Long Island, the total price impact was $2.63/MWh on average in 2011.
- An offline gas turbine was scheduled (i.e., counted towards resolving the constraint) and was a marginal resource but was not actually started in 45 percent of all likely transmission shortage intervals in 2011.

H. Real-Time Prices During Emergency Demand Response Activations

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.

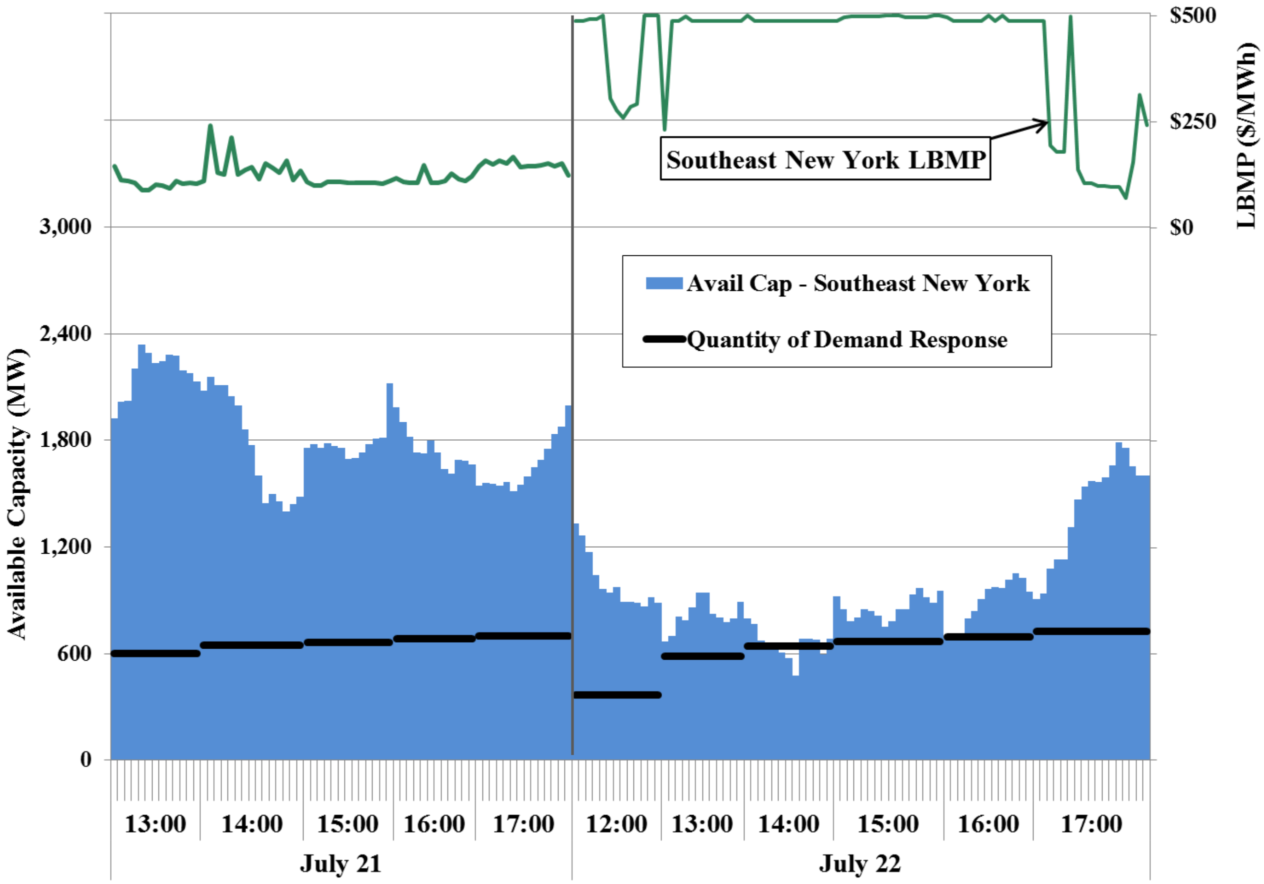
NYISO called for demand response (EDRP and SCRs) on two days during 2011. On July 21, SCR and EDRP resources were deployed in Southeast New York (SENY, including Zones G, H, I, J, and K) from 1:00 pm to 6:00 pm (HB 13 – HB 17). On July 22, SCR and EDRP resources were deployed in Zone J from 12:00 pm to 6:00 pm (HB 12 – HB 17) and in zones A, B, C, E, F, G, H, I, and K from 1:00 pm to 6:00 pm (HB 13 to HB 17). On July 21, demand response was activated to maintain transmission security into Southeast New York. On July 22, demand response was activated to maintain adequate reserves statewide.[122]

Figure A-65 & Figure A-66: Evaluation of Emergency Demand Response Activations

In the following analysis, we focused on whether real-time energy prices reflected the costs of activating demand response to maintain reliability given that most SCR and EDRP resources are paid $500/MWh to curtail their load. Figure A-65 and Figure A-66 summarize system conditions during the two activations on July 21 and 22, 2011. Figure A-65 summarizes LBMPs, the amount of demand response activated, and the amount of available capacity in Southeast New York on both days. Figure A-66 summarizes LBMPs, the amount of demand response activated, and the amount of available capacity on July 22 in eastern New York and in all of New York State.

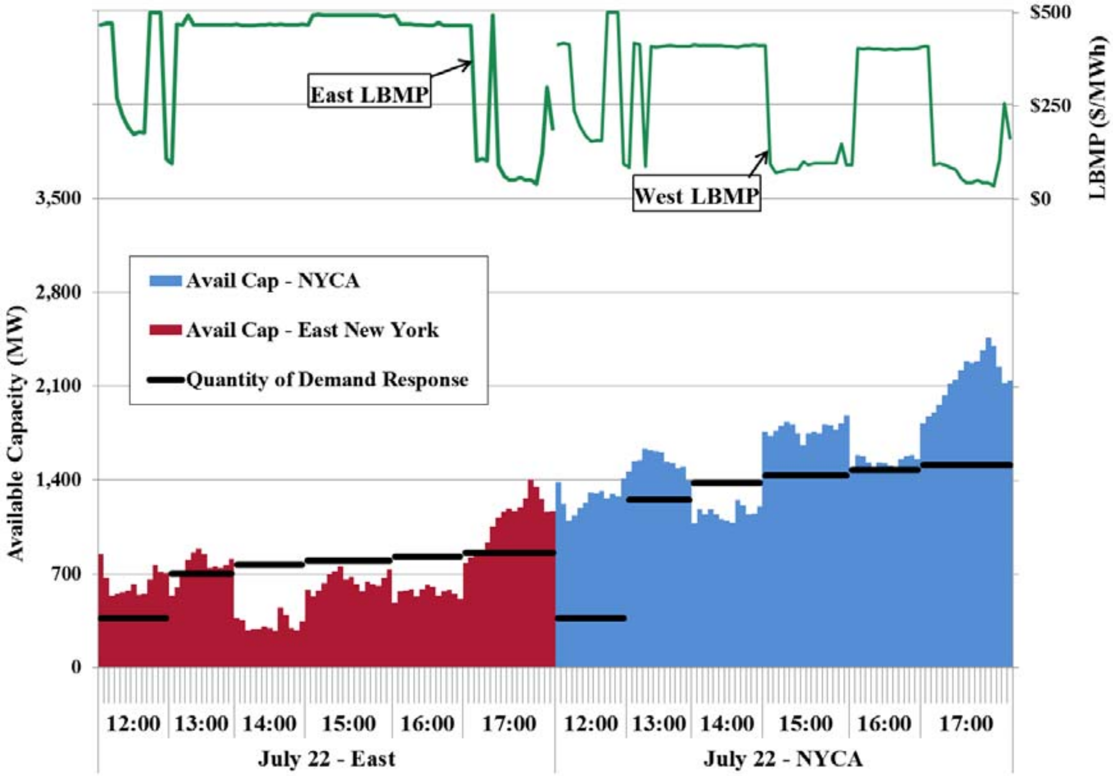
Figure A-65: Real-Time Prices and Available Capacity During Emergency DR Activations

Southeast New York, July 21 and 22, 2011



122 Load peaked on July 22 at 33, 865 MW, only about 70 MW less than the all-time peak set on August 2, 2006. Weather conditions on July 22 were well above peak expectations. The Cumulative Temperature-Humidity Index was in the 93 percentile for expected peak conditions.

Figure A-66: Real-Time Prices and Available Capacity During Emergency DR Activations
NYCA and Eastern NY, July 22, 2011



Key Observations: Emergency Demand Response Activations

- On July 21, the NYISO activated emergency demand response resources in Zones G through K to maintain the security of transmission lines into Southeast New York.
  - An average of 680 MW responded in Southeast New York, while at least 1.8 GW of capacity was available in Southeast New York, leading to relatively modest real-time prices ($126 per MWh on average).
  - The Scarcity Pricing Rules were not invoked on July 21, since they are only applied when the activation of demand response prevents a statewide or eastern reserve shortage.
  - The NYISO activated demand response on July 21 in advance of real-time to ensure sufficient capacity would be available to secure Southeast New York against the two largest contingencies, as required. However, in real-time operations, the NYISO dispatched generation to secure Southeast New York against the single largest contingency, as required. The looser real-time criteria contributed to the available capacity in real-time.
- On July 22, the NYISO activated emergency demand response resources in every zone (except Zone D) to maintain adequate reserves statewide.

- An average of 793 MW responded in eastern New York (Zones F – K) and 624 MW responded in western New York (Zones A, B, C, and E).
- Real-time prices were near $500 per MWh in eastern New York and near $400 per MWh in western New York for most of the afternoon. These prices were the result of tight supply as well as the Scarcity Pricing Rules.

- NYISO is working with stakeholders to develop new pricing provisions that would enable emergency demand response resources to set the clearing price in a manner similar to gas turbines.

I. 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. In this sub-section, we examine the primary forms of supplemental commitments for reliability in local areas and focus particularly on New York City where most reliability commitments occurred. In the next sub-section, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

Figure A-67: Supplemental Commitment for Reliability in New York

Supplemental commitment occurs when a generator is not committed in the economic pass of 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 local Transmission Owner prior to the economic commitment in SCUC.

- *Day-Ahead Local Reliability ("LRR") Commitment* – Takes place during the economic commitment pass in SCUC to secure reliability in New York City.

- The Supplemental Resource Evaluation ("SRE") Commitment – Occurs after the day-ahead market closes.

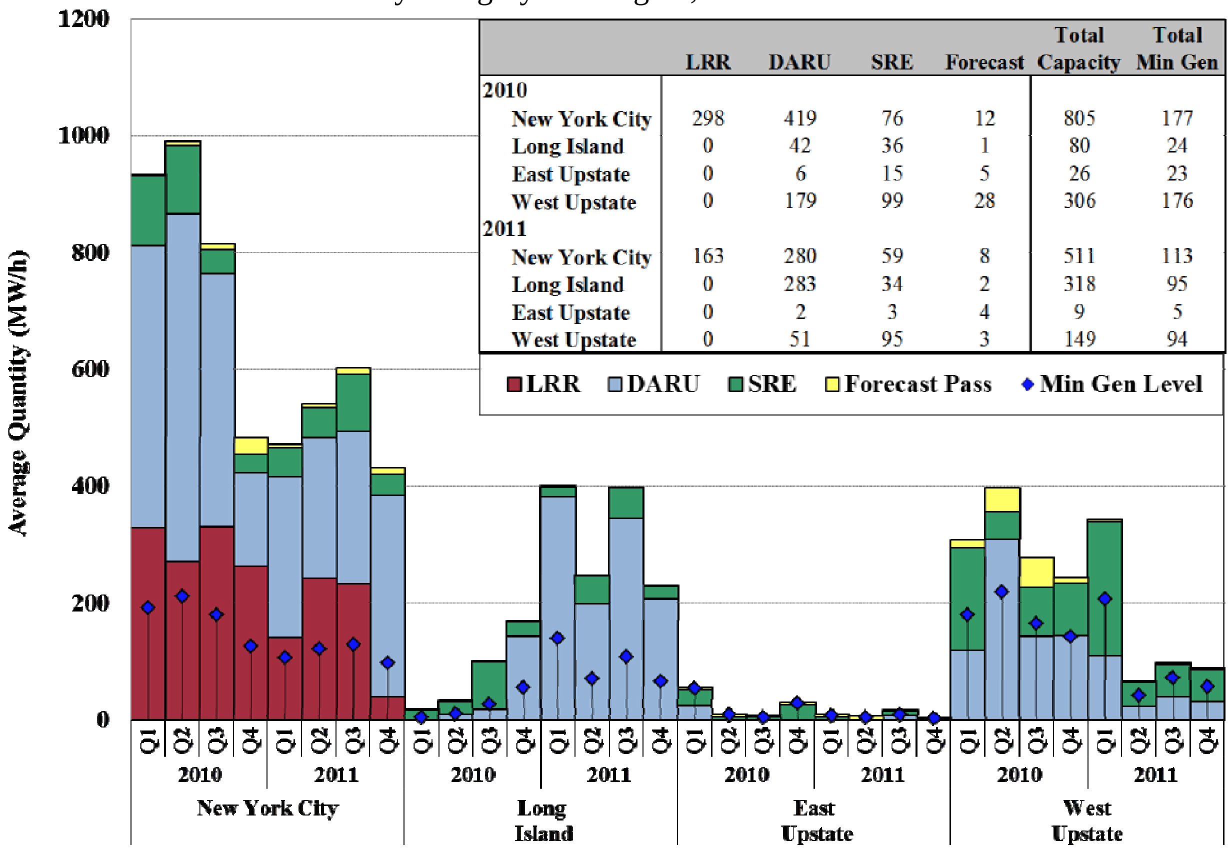
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (i) reducing prices from levels that would otherwise result from a purely economic dispatch; and (ii) increasing non-local reliability uplift since a portion of the uplift 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.

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 coordination through the economic evaluation of SCUC. However, in order to commit units efficiently, SCUC must have accurate assumptions regarding the needs in each local reliability area.

Figure A-67 shows the quarterly quantities of total capacity (the stacked bars) and minimum generation (the markers) committed for reliability by type of commitment and region in 2010 and 2011. 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. The figure shows these supplemental commitments separately for the following four regions: (i) West Upstate, which includes Zones A through E; (ii) East Upstate, which includes Zones F through I; (iii) New York City, which is Zone J; and (iv) Long Island, which Zone K. The table in the figure summarizes these values annually.

Figure A-67: Supplemental Commitment for Reliability in New York

By Category and Region, 2010 – 2011



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2010						
New York City	298	419	76	12	805	177
Long Island	0	42	36	1	80	24
East Upstate	0	6	15	5	26	23
West Upstate	0	179	99	28	306	176
2011						
New York City	163	280	59	8	511	113
Long Island	0	283	34	2	318	95
East Upstate	0	2	3	4	9	5
West Upstate	0	51	95	3	149	94

Figure A-68: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City in 2011. The next analysis identifies the causes for the reliability commitments in this area. Figure A-68 shows the minimum generation committed for reliability by commitment reason and by location in New York City during 2011.

Based on our review of the reliability commitment logs and LRR constraint information, each hour that was flagged as DARU, LRR, or SRE was categorized to one of the following reliability reasons: [123]

- NOX Only – If needed for NOX bubble and no other reason.
- Voltage – If needed for ARR 26 and no other reason except NOX.
- Thermal – If needed for ARR 37 and no other reason except NOX.
- Loss of Gas – If needed for IR-3 and no other reason except NOX.
- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.

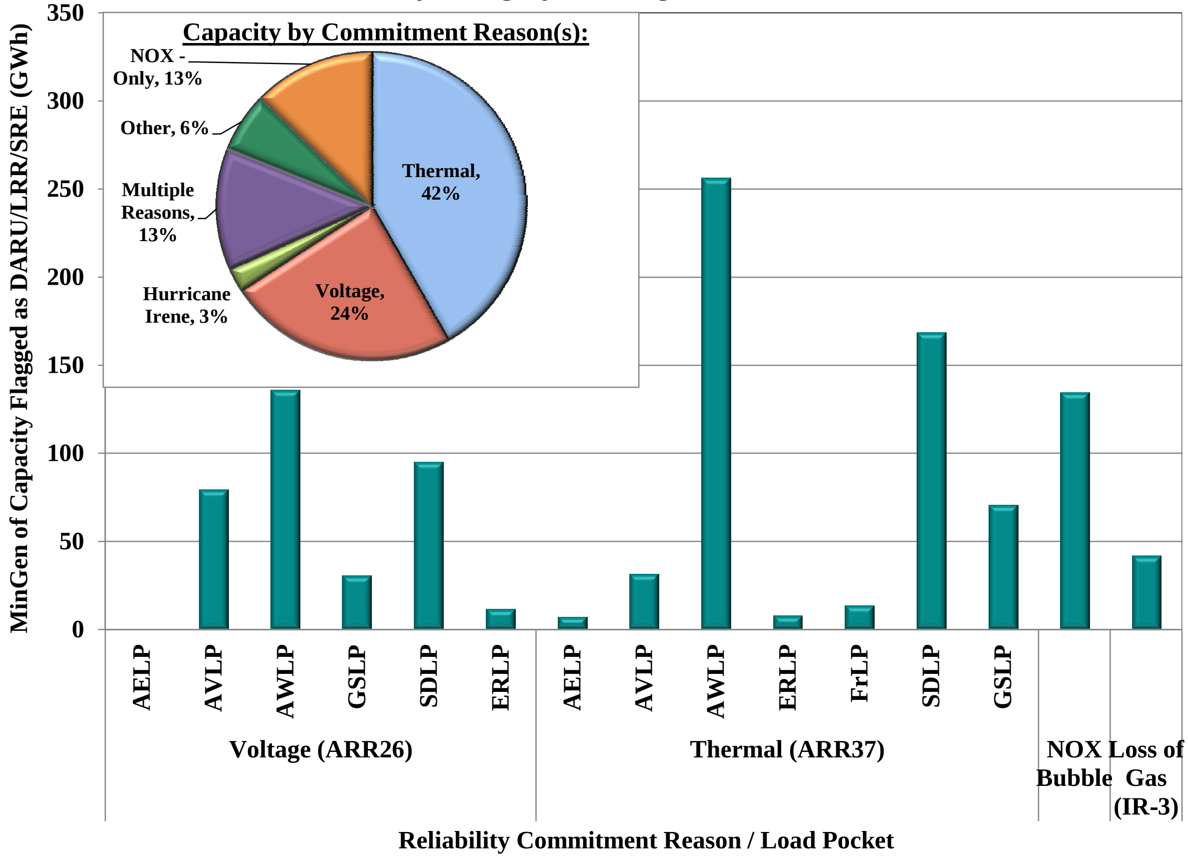
For voltage and thermal constraints, the capacity is shown for the load pocket that was secured, including:

- AELP - Astoria East Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket
- ERLP - East River Load Pocket
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

The pie chart in the figure shows the portion of total capacity committed under different reasons.

[123] A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.

Figure A-68: Supplemental Commitment for Reliability in New York City
By Category and Region, 2011



Key Observations: Supplemental Commitment for Reliability

- Nearly 1,000 MW of capacity was committed on average for reliability in 2011, down 19 percent from 2010. Of this total, 52 percent of reliability commitment was in New York City, 32 percent was in Long Island, and 15 percent was in Western New York.

- Reliability commitment in Western New York averaged 150 MW in 2011, down 51 percent from 2010, due largely to fewer transmission outages in that area.

- Reliability commitment in Long Island rose substantially from an average of 80 MW in 2010 to an average of 310 MW in 2011.

  - DARU commitment increased considerably, partly because units that are required to burn a gas-oil blend for reliability were economic less often as a result of higher oil prices.

- Reliability commitment in New York City averaged slightly more than 500 MW in 2011, down 37 percent from 2010. The reduction in local reliability need was partly driven by:

  - Increased import capability into the City from the addition of the Dunwoodie-Academy Line;

- Increased generating supply in the City from the addition of the 550 MW Astoria East II generating facility; and
- Changes in generator offer patterns and reference levels.

- The reliability requirements that accounted for the most MWhs of capacity in New York City during 2011 were:
  - Astoria West/Queensbridge thermal and voltage requirements, which ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur;
  - Sprainbrook/Dunwoodie thermal requirements, which ensure 345 kV facilities in New York City will not be overloaded if the largest two generation or transmission contingencies were to occur; and
  - NOX bubble requirements, which require the operation of a steam turbine unit in order to reduce the overall NOX emission rate from a portfolio containing higheremitting gas turbine units. However, the operation of steam turbine units sometimes displaces generation from newer cleaner generation in the city and from imports to the city.

J. Uplift Costs from Guarantee Payments

Uplift charges from guarantee payments accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. Figure A-69 and Figure A-70 summarize the three categories of non-local reliability uplift that are allocated to all Load Serving Entities ("LSEs") and the four categories of local reliability that are allocated to the local Transmission Owner.

The three categories of non-local reliability uplift are:

- *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).[124]

- *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.

124 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.

- *Day-Ahead Margin Assurance Payment* – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules.[125]

The four categories of local reliability uplift are:

- *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.

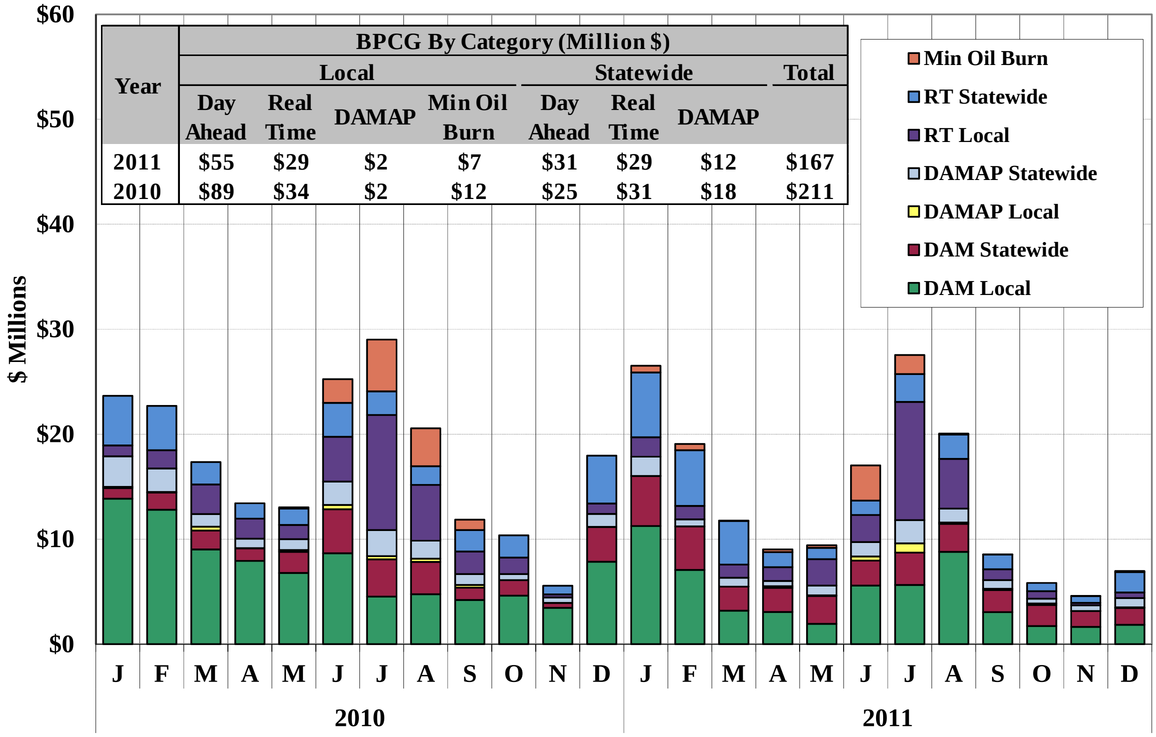
- *Day-Ahead Margin Assurance Payment* – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-69 & Figure A-70: Uplift Costs from Guarantee Payments

Figure A-69 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2010 and 2011. The table summarizes the total uplift costs under each category on an annual basis for these two years. Figure A-70 shows the seven categories of uplift charges on a quarterly basis by region for the 2010 and 2011. Note, Figure A-69 and Figure A-70 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

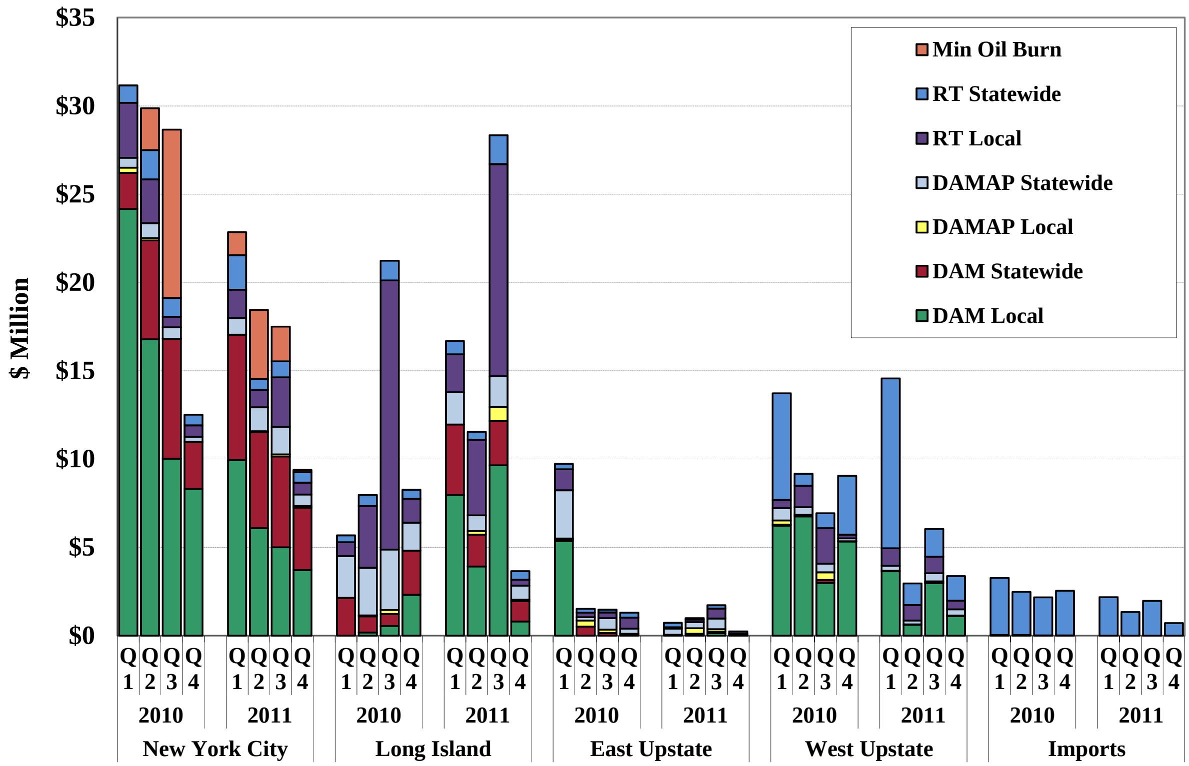
[125] When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

Figure A-69: Uplift Costs from Guarantee Payments by Month
2010 – 2011



Year	BPCG By Category (Million $)							
	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2011	$55	$29	$2	$7	$31	$29	$12	$167
2010	$89	$34	$2	$12	$25	$31	$18	$211

Figure A-70: Uplift Costs from Guarantee Payments by Region
2010 – 2011



Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell 21 percent, from $211 million in 2010 to $167 million in 2011. Local reliability uplift categories fell nearly $44 million, while statewide uplift categories fell $1 million.

- Local reliability uplift accounted for 56 percent of total guarantee payment uplift in 2011, while non-local reliability uplift accounted for the remaining 44 percent.

- Day-ahead local reliability uplift fell 38 percent (or $34 million) from 2010.
  - Uplift in New York City totaled $25 million in 2011, down from $59 million in 2010, driven largely by reduced LRR and DARU commitment.
  - Uplift in Western New York totaled $8 million in 2011, down from $21 million in 2010, due primarily to reduced DARU commitment.
  - The decreases were offset by the increase in the uplift in Long Island, which rose from $3 million in 2010 to $22 million in 2011, due to increased DARU commitment and higher oil prices.

- Long Island accounted for 66 percent of real-time local reliability uplift during 2011.
  - Frequent OOM dispatches were needed, particularly in the third quarter, to manage congestion on the East End of Long Island. Some generators in this area burn oil because they do not have a source of natural gas.

- DAMAP uplift fell $6 million from 2010 to 2011 that was partly due to improved TSA operations and enhanced reserve demand curve settings.

- Improved generator reference level accuracy also contributed to overall reduction in uplift during 2011.
  - NYISO's mitigation consultations are on-going for later periods of 2011, so guarantee payments may increase modestly once these are fully reflected.

VI. 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.

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.[126] 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.[127]

Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates.[128] The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual coincident peak load in each area. 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

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126 The ICAP requirement = (1 + IRM) * Load Forecast. The IRM decreased from 18 percent in the period from May 2010 to April 2011 to 15.5 percent in the period from May 2011 to April 2012.

127 The locational ICAP requirement = LCR * Load Forecast for the location. The Long Island LCR was 102 percent in May 2010, 104.5 percent in the period from June 2010 to April 2011, and 101.5 percent in the period from May 2011 to April 2012. The New York City LCR was 80 percent in the period from May 2010 to April 2011 and 81 percent in the period from May 2011 to April 2012.

128 The UCAP of a resource 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 load hours, and SCR's availability rates are based on the performance during tests and events.

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.[129]

A. Capacity Market Results

To evaluate the performance of the capacity market, the following three figures show capacity market results from May 2010 through February 2012. This includes four six-month capability periods from the Summer 2010 capability period through the Winter 2011-2012 capability period (excluding March and April 2012). The figures show the sources of capacity supply and the quantities purchased in each month in UCAP terms. Each figure also summarizes the clearing prices in the monthly spot auctions.

Figure A-71 to Figure A-73: Capacity Sales and Prices

Figure A-71 through Figure A-73 show capacity market results in New York City, Long Island, and NYCA for the past four capability periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs"), and sales from SCRs.[130] The hollow portion of each bar represents the In-State capacity in each region not sold (including capacity not offered) in New York or in any adjacent market. The line indicates the capacity requirement for each capability period for each region. Additionally, Figure A-73 shows sales from external capacity resources into NYCA and exports of internal capacity to other control areas. The upper portion of each figure shows clearing prices in the monthly spot auctions for New York City, for Long Island, and for NYCA (i.e., the Rest of State), respectively.

The capacity sales and requirements in Figure A-71 through Figure A-73 are shown in the UCAP terms, which reflects the amount of resources available to sell capacity in each region.

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

[130] 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.

Figure A-71: UCAP Sales and Prices in New York City
May 2010 to February 2012

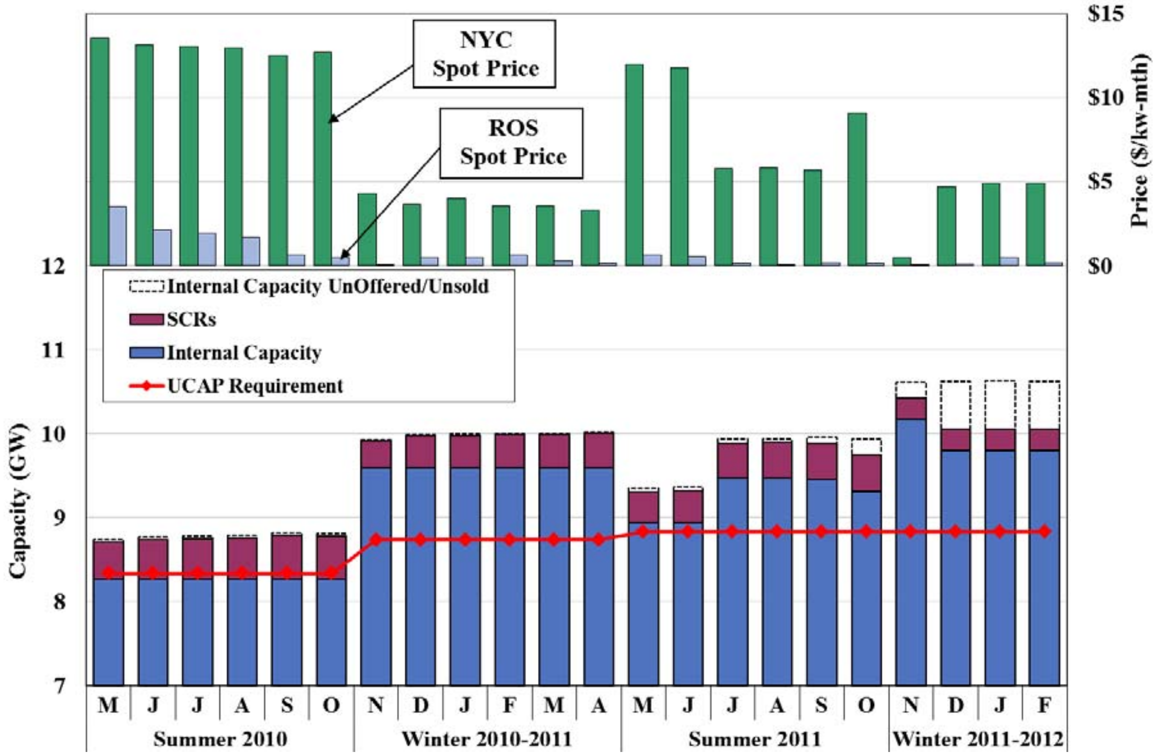


Figure A-72: UCAP Sales and Prices in Long Island
May 2010 to February 2012

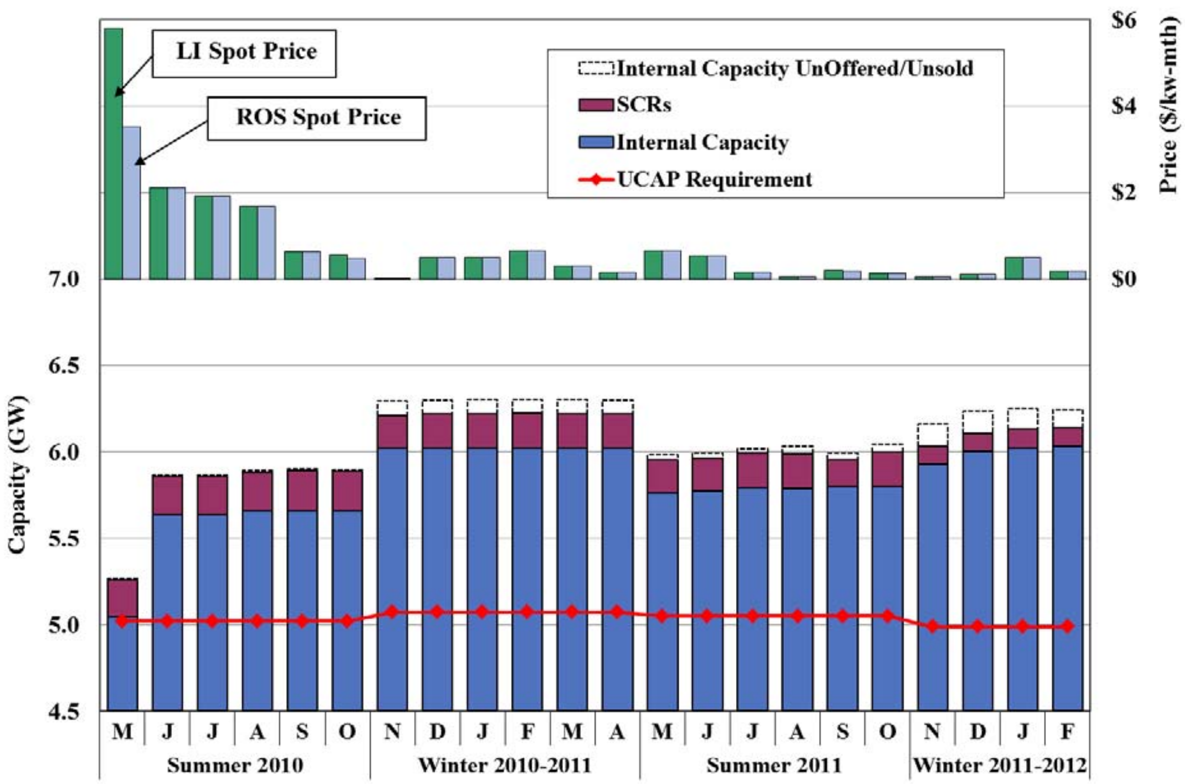
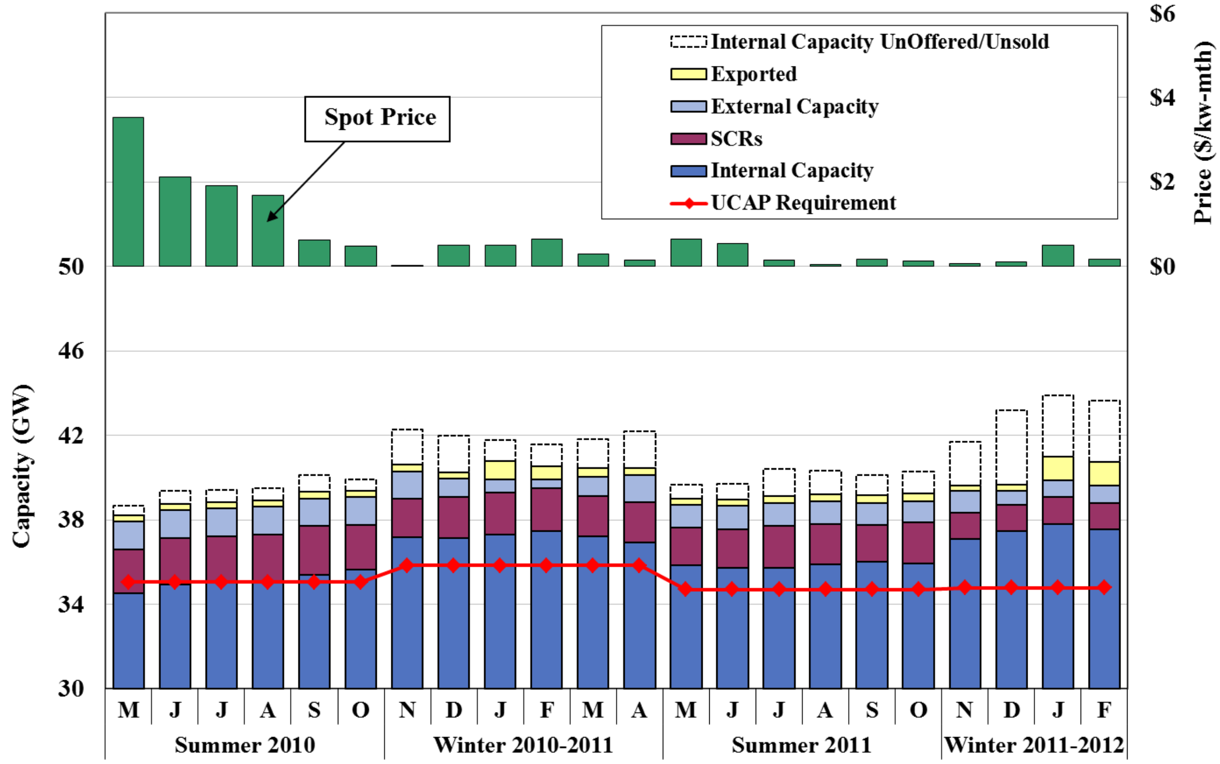


Figure A-73: UCAP Sales and Prices in NYCA
May 2010 to February 2012



Key Observations: UCAP Sales and Prices in New York

- Seasonal variations resulted in significant changes in clearing prices in spot auctions.
  - Additional capability is typically available in the Winter Capability periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity. This generally contributes to significantly lower prices in the winter than in the summer.
- In New York City, the spot price averaged $8.36/kW-month in the Summer 2011 Capability period, down 36 percent from the previous Summer Capability period; the spot price averaged $3.74/kW-month in the Winter 2011-12 Capability period (excluding March and April 2012), consistent with the average from the previous Winter Capability period.
  - The sales of internal capacity rose in July 2011 due primarily to the addition of a 550 MW new facility, leading the spot price to fall from $11.76/kW-month in June to $5.76/kW-month in July.
  - The amount of unsold capacity rose significantly in October 2011 and again in December 2011. In each case, the rise of unsold capacity coincided with an increase in the spot price from the previous month. The capacity was unsold for reasons that are discussed in the main body of this report.

  - The NYISO filed for new capacity demand curves to be in place in May 2011, coinciding with the scheduled expiration of the previous curves, which had been filed in early 2008. However, the Commission did not accept the NYISO's filing until September 2011, so the new curves, which were higher than the previous curves, were not used until the October 2011 spot auction.

- In Long Island, the spot price was equivalent to or slightly higher than the NYCA spot price during 21 of the 22 months shown.

  - The local capacity requirement for Long Island was rarely binding during the period, reflecting that Long Island generally has far more capacity than needed to satisfy the local capacity requirement..

  - May 2010 was the only month when the Long Island price was significantly higher than the NYCA price. The sales of internal capacity from UDRs increased 600 MW from May 2010 to June 2010, leading the spot price to fall from $5.81 per kW-month in May to $2.12 per kW-month in June.

- In NYCA, the spot price the spot price averaged $0.29/kW-month in the Summer 2011 Capability period, down 83 percent from the previous Summer Capability period; the spot price averaged $0.21/kW-month in the Winter 2011-12 Capability period (excluding March and April 2012), down 40 percent from the previous Winter Capability period. The reduction was due largely to:

  - Significant capacity additions that occurred in June 2010, September 2010, and July 2011; and

  - The reduction of nearly 1200 MW in the ICAP requirement for NYCA from the 2010/11 capability year to 2011/2012 capability year.[131]

  - A substantial amount of capacity was not sold in recent months, likely due to the relatively large prevailing capacity surplus and the low clearing prices.

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131 From the 2010/11 capability year to the 2011/12 capability year, the summer peak load forecast for NYCA fell 313 MW, and the installed capacity requirement fell from 118 percent to 115.5 percent.

VII. 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.[132]

- Installed Capacity/Special Case Resource ("ICAP/SCR") Program – These resources arepaid 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.[133]

- Targeted Demand Response Program ("TDRP") – This program curtails EDRP and SCR resources when called by the local Transmission Owner for reliability reasons at the sub-load pocket level in New York City. EDRP resources are paid the higher of $500/MWh or the realtime clearing price. SCRs are paid the higher of their strike price or the real-time clearing price. Response from these resources is voluntary.

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

- 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.[134]

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

[133] 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.

[134] 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.

- 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 the following three areas: (a) participation in the existing demand response programs, (b) pricing during shortage conditions, and (c) future enhancements to demand response programs.

A. Demand Response Programs in 2011

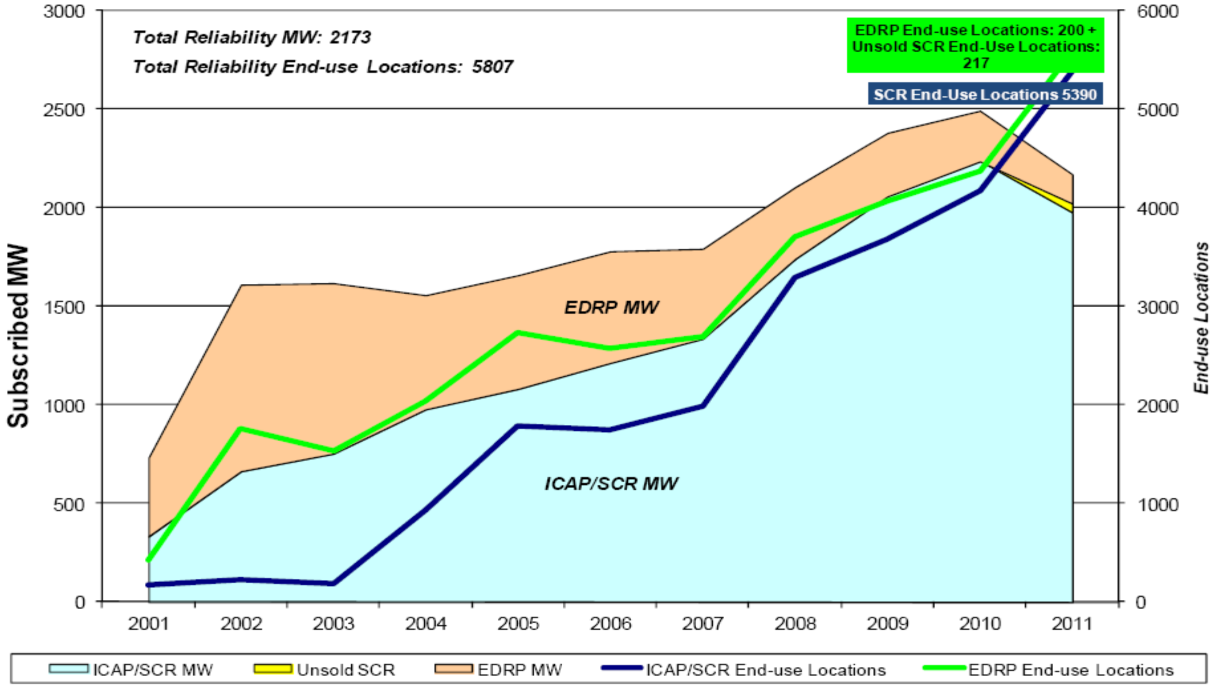
Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, DADRP and DSASP provide a means for economic demand response resources to participate in the day-ahead energy market and ancillary services markets (day-ahead and real-time), respectively.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

Figure A-74: Registration in NYISO Demand Response Reliability Programs

Figure A-74 summarizes registration in two of the reliability programs on an annual basis from 2001 to 2011. 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 A-74: Registration in NYISO Demand Response Reliability Programs[135]
2001 - 2011



Key Observations: NYISO Demand Response Reliability Programs

- SCR program registration has steadily grown 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 2011, total registration in the EDRP and SCR programs included 5,807 end-use locations enrolled, providing a total of 2,173 MW of demand response capability. SCR resources accounted for 97 percent of the total reliability program enrollments and 93 percent of the enrolled MWs.
  - Total enrolled MW in the reliability program fell 13 percent from 2010 to 2011.
  - The NYISO made tariff changes for the SCR baseline from APMD to ACL in mid-year 2011, which accounted for nearly all of the reduction in registered capacity.

135 The figure is reproduced from the NYISO's January 25, 2012 filing to the Commission related to the Demand Response Compliance Report.

B. 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. Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. 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.

The DSASP program was established 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, and they are paid the same market clearing prices as generators for the ancillary service products they provide. 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.

The Mandatory Hourly Pricing (”MHP”) program encourages loads to respond to wholesale market prices. The MHP program is administered at the retail load level, and so it is regulated under the New York Public Service Commission. Under the MHP program, retail customers as small as 200 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. In the future, some retail customers as small as 100 kW are expected to participate in the MHP program.

Key Observations: Economic Demand Response Programs

- One DADRP resource made offers on a single day during the twelve months from September 2010 to August 2011. The resource was scheduled for only 6 MWhs.
  - Given that the scheduled quantities are extremely small and that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is doubtful.
- No DSASP resources have been fully qualified yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner. The NYISO's release of the technical specification for direct communication between the NYISO and DSASP resources in late 2011 has increased interest in the program. Implementation of market rules currently under development to allow participation by aggregators of small demand resources is expected to result in qualified DSASP resources in 2013.
- Approximately 7 GW of retail load customers are under the MHP program.

- The program gives retail 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.

C. 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 nominally 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 2011, the NYISO activated emergency demand response resources on July 21 and 22. The real-time pricing during the two events is evaluated in greater detail in Section V.F of the Appendix.

D. 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 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 has automated many 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, limited meter data management, and other activities that have historically required significant manual effort. The DRIS has already reduced administrative burdens, facilitated enrollment and administration for the market participants that enroll demand resources, and reduced 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 has been deployed in phases since November 2009.[136]

Second, NYISO has released a technical specification to facilitate Direct Communication with DSASP resources rather than communicating through the local transmission owner.[137]

Third, NYISO is developing the market rules and procedures 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 it would be costly for each demand resource to 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 in the NYISO's ancillary services markets. The NYISO began discussions with stakeholders about market rule changes for aggregated small demand resources to provide operating reserves in early 2012.

The NYISO is awaiting a final order on its August 19, 2011 compliance filing on Order 745. In its filing, the NYISO proposed a Net Benefit Test calculation that would replace the current DADRP offer floor on a monthly basis. In addition, the NYISO proposed to expand its cost allocation methodology to accommodate congestion at multiple interfaces. The NYISO also proposed a new baseline that would maintain its relative integrity with the expected increase in scheduling that could result from the lower offer floors produced by the Net Benefit Test calculation.

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[136] The NYISO has deployed six releases of DRIS: November 2009, March 2010, June 2010, January 2011, July 2011 and September 2011.

[137] The presentation of the DSASP Direct Communications Technical Specification is available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2011-11-28/DSASP_Stakeholder_Presentation.pdf.