2012 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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April 2013

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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 *2012 State of the Market Report* presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2012. 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 2012

Overall, we find that the NYISO markets performed competitively in 2012, 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 fell 16 to 25 percent from 2011 to 2012, which was primarily due to lower natural gas prices. Natural gas prices fell 28 to 35 percent over the same period. Low natural gas prices increased the share of electricity production from natural gas from 38 percent in 2011 to 45 percent in 2012. The correlation between energy and natural gas prices is expected in a well-functioning, competitive market because natural gas-fired resources were the marginal source of supply in 80 percent of the intervals in New York in 2012. Additionally, over 1 GW of new gas-fired generating capacity was installed in New York City (between July 2011 and June 2012), which also contributed to the overall reduction in the energy prices in 2012.

Load averaged 18.5 GW in 2012, down slightly from 2011 and 2010. New York experienced fewer hours with extreme high load conditions (i.e., when load exceeded 32 GW) in 2012 than in recent years, partly due to milder weather in the summer of 2012. Load peaked at 32,439 MW on July 17, 2012, approximately 1,400 MW lower than the 2011 annual peak.

Congestion and losses caused prices to range from an average of $33 per MWh in the West Zone to $41 per MWh in New York City and $54 per MWh in Long Island in 2012. Congestion decreased considerably from 2011 to 2012 as the congestion revenues collected by the NYISO in the day-ahead market fell 26 percent to $301 million in 2012. Lower natural gas prices contributed to the reduction in congestion: a) because lower generator costs reduce the redispatch costs incurred to manage congestion, and b) because eastern New York, where natural gas use is most prevalent, usually imports from other areas. The new capacity in New York City also helped reduce congestion from upstate New York into New York City.

Despite the general reduction in congestion, there were several corridors where congestion increased. First, congestion into Long Island rose following an outage that reduced imports across the Neptune Line beginning in May 2012 and several generator retirements in July 2012. Second, the Central-East interface became more congested in November and December 2012. This was due to reduced transfer capability caused by generation and transmission outages and an increase in natural gas price spreads between western and eastern New York. Third, congestion across the Hydro-Quebec interface rose in the summer months. This pattern reflects a natural response by the market participants to the pattern of very low real-time LBMPs at the interface during TSA events in recent years.

The average prices for most classes of ancillary service were virtually unchanged from 2011 to 2012. The most significant change in operating reserves prices was related to the 10-minute reserve requirement for NYCA. This is the main component of the 10-minute non-spin price in western New York, which increased from $0.10 per MWh in 2011 to $1.05 per MWh in 2012. The higher price levels began in late June of 2012 when the uprate of one Nine Mile Point nuclear unit required the NYISO to increase its operating reserve requirements.

Finally, average capacity costs (per MWh of load) rose 49 percent in New York City and more than 300 percent in other regions from 2011 to 2012. In 2012, UCAP spot auction clearing prices averaged $8.22 per kW-month in New York City, $1.85 per kW-Month in Long Island, and $1.39 per kW-month in Rest of State. The capacity price increases were driven primarily by: a) the retirement or mothballing of 1.3 GW of internal capacity in New York City, Long Island, and western New York; b) higher installed capacity requirements for both New York City (0.2 GW) and NYCA (0.8 GW) ; and c) the implementation of a higher capacity demand curve in New York City. These factors were partly offset by the addition of 1 GW of capacity in New York City between July 2011 and June 2012.

Overall, our evaluation indicates that prices in all of the NYISO's markets taken together in 2012 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 several concerns and recommends 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 in 2012, although large differences occur on some individual days. At the zonal level, average day-ahead prices were higher than average real-time prices by a small margin (roughly 1 percent in most regions). This differential was highest in the Capital zone (nearly 3 percent) where very low real-time prices occur during periods of acute congestion into Southeast New York during TSAs. Convergence at the nodal level was poor at several locations in New York City and Long Island because of inconsistent congestion patterns between the day-ahead and real-time markets.

Virtual trading activity helps 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. Overall, virtual traders were profitable in 2012, indicating that they generally improved convergence between day-ahead and real-time prices, which facilitates an efficient commitment of generating resources.

Convergence remained poor for operating reserves in 2012, particularly during peak load periods when average real-time operating reserve prices were substantially higher than average day-ahead prices. The NYISO took steps to address this in January 2013 by beginning to phase-out the use of two mitigation rules that have inhibited price convergence.

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 and the mitigation measures were generally effective in addressing instances of conduct that would otherwise lead to uncompetitive outcomes.

Market power mitigation measures in the energy market were effective in 2012. The instances of mitigation in New York City fell considerably from 2011 to 2012 as congestion became less frequent with the introduction of new generation and transmission. "Unmitigation" of generators that were initially mitigated by the AMP software became less common in 2012 as the NYISO improved its processes for administering reference levels. This is important because mitigating generators below marginal cost with the AMP software leads to inefficient scheduling and distorted market clearing prices, which cannot be undone when the generator is unmitigated.

In the capacity market, there were several key developments that highlighted the need for changes in market rules to address both supply-side and buyer-side market power more effectively. The report discusses these issues and recommends several improvements to address them.

D. Real-Time Market Operations

Real-time prices remained relatively volatile in 2012. Most of the price volatility occurred consistently at certain times of day or under certain market conditions. As we show in this report, this volatility can be attributed to a limited number of factors, the most significant of which include: large changes in inflexible resources (e.g., self-scheduled units and external transactions), unforeseen changes in the flows across PAR-controlled lines, and the decommitment of gas turbines. Such changes can create brief shortages or over-generation conditions when flexible generators cannot ramp quickly enough to compensate for the change, leading to sharp price increases.

The impact of shortage conditions was substantial in eastern New York in 2012. Shortage conditions accounted for a large share of the average annual real-time LBMP, ranging from 7 percent in most of eastern New York to nearly 10 percent in Long Island. We evaluated market operations during three types of shortages:

- *Operating reserve and regulation shortages* – These occurred in a small share of intervals, but had significant real-time price effects. They increased the annual average real-time price in eastern New York by 2 to 4 percent in 2012.
- *Transmission shortages* – These were also infrequent, but made significant contributions to real-time prices, including 5 percent of the annual average real-time price in Long Island and 2 percent in New York City in 2012.
- *Reliability demand response deployments* – These were deployed on six days (May 29, June 20, 21, 22, and July 17, 18), primarily for maintaining transmission security into Southeast New York and maintaining adequate reserves statewide. Real-time prices were far below levels that would reflect the cost of these resources (usually $500 per MWh) during most of these deployment periods.

Overall, the market performed reasonably well during shortages, although we identify some shortcomings that are addressed in our recommendations.

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: a) two lines that normally flow up to 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”); and b) some lines between New York and New Jersey that are used to wheel up to 1,000 MW in accordance with a wheeling agreement between ConEd and PSEG. The operation of these lines (in accordance with the wheeling agreements) resulted in significant increases in production costs and other market effects in 2012. Hence, the report recommends that NYISO work with these parties to explore opportunities to improve the operation of these lines.

E. Supplemental Commitment and Guarantee Payment Uplift

Guarantee payments to generators, which account for a large share of Schedule 1 uplift charges, fell from the prior year by 19 percent to a total $141 million in 2012. This reduction is consistent with lower natural gas prices, which decreased the costs of gas-fired units needed for reliability.

Uplift costs fell roughly $20 million in both New York City and Long Island in 2012, while uplift costs in western New York rose $7 million in 2012. This was generally in line with the changes in reliability commitments in these regions. Reliability commitment in New York City fell in 2012 as new transmission and over 1 GW of new generation entered the market. Reliability commitments in Long Island also fell in 2012 as units that are frequently needed for local reliability were committed economically by the market more often. This occurred because of the higher LBMPs after the Neptune outage and several generator retirements. Reliability commitment in western New York rose substantially because several coal units frequently needed for reliability were economically committed less often due to lower natural gas prices.

F. Capacity Market

The capacity market continues to be an essential element of the NYISO electricity markets, providing vital economic signals needed to facilitate market-based investment to satisfy the state's planning requirements. The overall market design and rules governing the capacity market are sound, however this report identifies several concerns.

In addition to a number of improvements to the market power mitigation measures that are applicable to this market, we identify improvements needed in the locational aspects of the market. The capacity market has a limited number of local zones (New York City and Long Island) with local requirements that may clear at prices higher than the statewide capacity price.

NYISO is in the process of implementing a new zone for Southeast New York that we have been recommending since the 2006 State of the Market Report. This zone is vitally important for establishing economic signals that accurately reflect the state's capacity needs. We believe that the lengthy delays in defining this zone has resulted in higher capacity prices in other areas and contributed to inefficient investment and retirement decisions. To avoid similar delays in the future, we have recommended a locational framework that would allow the market prices to respond dynamically to changes in local supply and demand conditions.

G. Recommendations

The NYISO markets generally performed well in 2012. Our evaluation identifies a number of areas of improvement, so we make recommendations that are summarized in the following table. The table identifies the highest priority recommendations and those that NYISO is addressing in the 2013 Project Plan or in some other effort.

RECOMMENDATION	CURRENT EFFORT	HIGH PRIORITY/ BENEFIT
Capacity Market		
1. Create a dynamic and efficient framework for reflecting locational planning requirements, including three key aspects: a) Pre-defining interfaces/zones that address potential resource adequacy needs and highway deliverability constraints; b) Model export constraints when additional capacity in a nested zone provides little or no additional reliability benefit; c) Grant internal capacity deliverability rights between zones when private investors upgrade transmission into a local area.		✓
2. Grant a Competitive Entry Exemption from the buyer-side mitigation measures for a purely market-based investment.	✓	✓
3. Reform the Buyer-Side Mitigation Exemption test criteria and the offer floor determination method.	✓	✓
4. Select the most economic generating technology to establish the current capacity demand curves and modify excess level criteria.	✓	
5. Modify the pivotal supplier test to prevent a large supplier from circumventing mitigation by selling capacity in the forward auctions.		
6. Modify the existing rules on the ICAP qualification requirements and the calculation of the Going-Forward Costs (“GFCs”) used in the supply-side mitigation measures for installed capacity suppliers.	✓	

Real-Time Market		
7. 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.	✓	✓
8. Explore options for improving the operation of certain PAR-controlled lines more efficiently.	✓	✓
9. Evaluate criteria for gas turbines to set prices in the real-time market.	✓	
10. Implement a graduated Transmission Demand Curve.	✓	
11. Modify the real-time market to allow demand response to set prices when appropriate.	✓	
12. Raise the demand curve for the NYCA 30-minute operating reserve requirement to $500 per MWh.		
13. Adjust timing of the look-ahead evaluations in RTD and RTC to be more consistent with ramping periods for external transactions.		
14. Modify thresholds used in IBRT software to allow suppliers to reflect intraday fuel cost variations in their real-time offers.	✓	
Day-Ahead Market		
15. Allow suppliers to reflect fuel price variations in their day-ahead offer reference levels prior to the close of the day-ahead bid window.		
16. Enable virtual trading at a disaggregated level.		

I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2012. 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 economic criteria;

- 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;

- Implement operating reserve demand curves, which contribute to efficient prices during shortage conditions when resources are insufficient to satisfy both the energy and operating reserve needs of the system; and

- Use a real-time commitment system (i.e., RTC) that commits quick-start units (that can start within 10 or 30 minutes) and schedules external transactions. RTC runs every 15 minutes, optimizing over a two-and-a-half hour period. Most other RTOs rely on their operators to determine when to start gas turbines and other quick-start units.

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

- A real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one hour period. This allows the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs. RTD can also commit quick-start units (that can start within 10 minutes) based on economic criteria.

- 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.

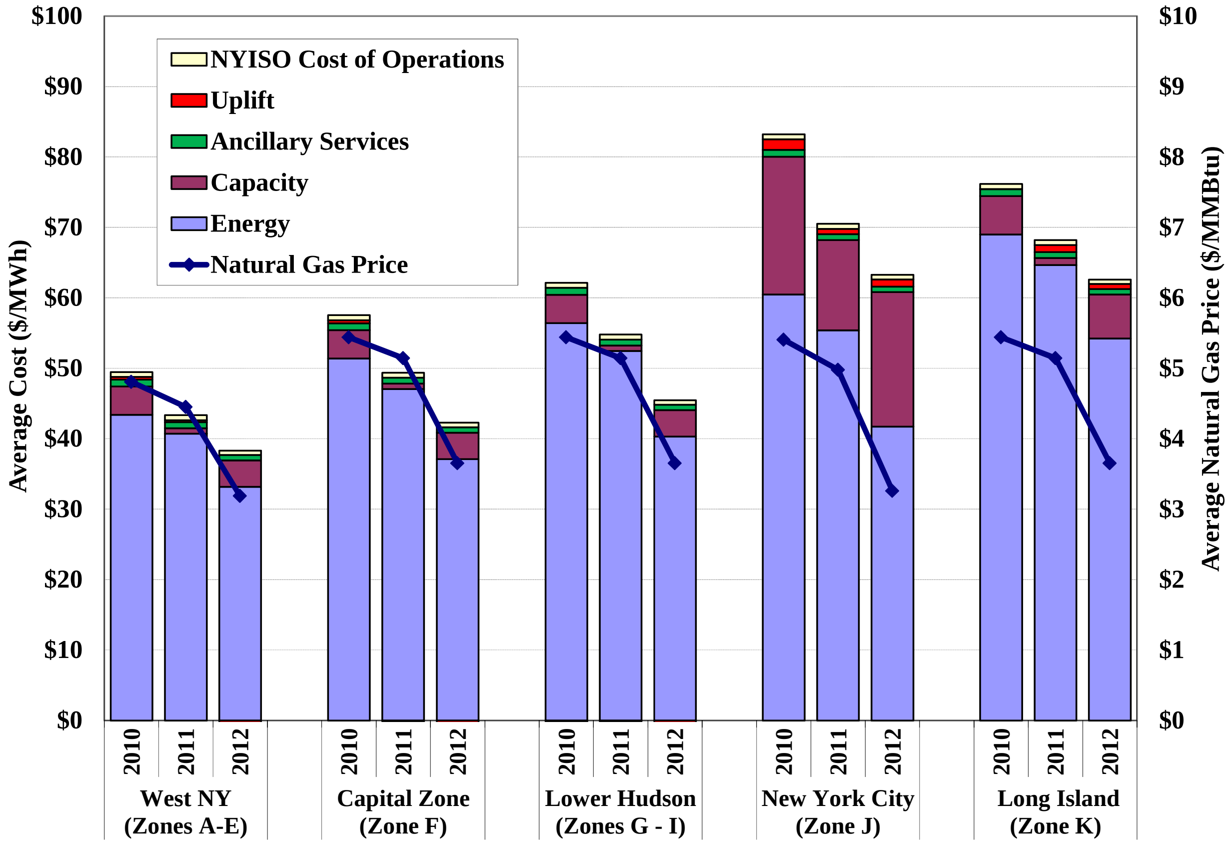
These markets provide substantial benefits to the region by ensuring that the lowest-cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. However, it is important for the markets 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

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 load-weighted average real-time energy price, while all other components are the costs in the areas divided by the real-time load in the area. [1]

Figure 1: Average All-In Price by Region
2010-2012



Average all-in prices of electricity ranged from $38 per MWh in West New York to $63 per MWh in both New York City and Long Island in 2012. Energy was the largest component of the all-in price, ranging from an average of $33 per MWh in West New York to $54 per MWh in

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

Long Island. Energy costs accounted for 66 percent of the all-in price in New York City and 87 to 90 percent of the all-in price in the other four regions. Capacity costs accounted for 30 percent of the all-in price in New York City and 8 to 10 percent of the all-in price in the other four regions. These results reflect the substantial excess installed capacity outside New York City and the much smaller excess in New York City.

Average electricity prices fell substantially from 2011 to 2012, decreasing 20 to 25 percent in most areas. These decreases were consistent with the change in natural gas prices, which fell 28 to 35 percent from 2011 to 2012. The entry of 1 GW of new gas-fired generating capacity in New York City (July 2011 and June 2012) also contributed to the overall reduction in the energy prices over the period. In Long Island, the effects of lower gas prices were offset by the effects of the lengthy Neptune outage, multiple generator retirements, and the effects of uneconomic transfers to New York City.[2, 3, 4]

Average capacity costs rose 49 percent in New York City and more than 300 percent in other regions from 2011 to 2012. In 2012, UCAP spot auction clearing prices averaged $8.22 per kW-month in New York City, $1.85 per kW-Month in Long Island, and $1.39 per kW-month in Rest of State. The increases in capacity prices were driven primarily by: (a) the retirement and mothballing of 1.3 GW of internal capacity in New York City, Long Island, and western New York; (b) higher installed capacity requirements for both New York City (0.2 GW) and NYCA (0.8 GW) ; and (c) the implementation of a higher capacity demand curve in New York City.[5]

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2 The outage of an internal transmission facility has reduced the amount that can flow over the 660 MW Neptune line. The capability to import over Neptune was reduced to 0 MW from May 27 to July 31 and 375 MW for the rest of the year.

3 Glenwood 4 & 5 and Far Rockaway 4, with a total capacity of 330 MW, retired on July 1, 2012. See http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planned_Generation_Retirements/Planned_Retirement_Notices/072811_Glenwood_Far_Rockaway_-_Retirement_Notification.pdf.

4 The 901 and 903 lines are normally used to flow power from Long Island to New York in accordance with contracts that pre-date the NYISO. These flows were usually uneconomic in 2012, since the LBMPs in Long Island were generally higher than LBMPs in New York. This issue is discussed further in Section VIII.B.

5 Section VI of the Appendix summarizes capacity market outcomes in detail.

These factors were partly offset by the addition of 1 GW of capacity in New York City in July 2011 and June 2012.

The seasonal patterns of electricity prices and natural gas prices were typical for most of 2011 and 2012. Electricity prices rose in the summer months as a result of high electricity demand and in the winter months as a result of high natural gas prices, particularly in eastern upstate New York and Long Island.[6]

B. Input Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale electricity prices because most of the marginal costs of thermal generators are fuel costs. Table 1 summarizes fossil fuel prices on an annual basis from 2010 to 2012.[7] The table also shows average real-time electricity prices across New York State over the same period.

Table 1: Average Fuel Prices and Energy Prices
2010-2012

				Change from Prior Year	
	2010	**2011**	**2012**	**2011**	**2012**
Fuel Prices ($/MMBtu)					
Fuel Oil #2	$15.13	$20.99	$21.53	39%	3%
Fuel Oil #6	$12.18	$17.98	$18.09	48%	1%
NG - Transco Z6 (NY)	$5.41	$5.00	$3.26	-8%	-35%
NG - Iroquois Z2	$5.44	$5.15	$3.65	-5%	-29%
NG - Niagara	$4.81	$4.45	$3.19	-7%	-28%
Cent. App. Coal	$2.56	$2.95	$2.39	15%	-19%
Energy Prices ($/MWh)					
West New York	$43.38	$40.71	$33.16	-6%	-19%
Capital Zone	$51.38	$47.04	$37.11	-8%	-21%
Lower Hudson VL	$56.42	$52.45	$40.31	-7%	-23%
New York City	$60.46	$55.39	$41.71	-8%	-25%
Long Island	$69.00	$64.64	$54.24	-6%	-16%

Although much of the electricity used by New York consumers is generated by hydro and nuclear units, natural gas units are usually the marginal source of generation that set market

6 Section I.A in the Appendix shows seasonal variations in electricity and natural gas prices.

7 Section I.B in the Appendix shows the monthly variation of fuel prices.

clearing prices, especially in eastern New York. Consequently, electricity prices in New York have followed a pattern similar to natural gas prices over the past three years.

Natural gas prices are normally consistent between different regions in New York. However, bottlenecks on the natural gas system can lead to temporary variations in prices between locations, especially in the winter when the demand for natural gas is highest. In 2012, the Iroquois Zone 2 price, which is representative of gas prices in Long Island and eastern upstate New York, was 12 to 14 percent higher on average than gas prices in other areas. These locational variations in natural gas prices lead to comparable variations in electricity prices when network congestion occurs.

Natural gas prices have dropped considerably relative to other fuel types in recent years. Natural gas prices fell each year from 2010 to 2012, while oil prices rose significantly and coal prices were relatively flat. The increased price spreads between fuel oil and natural gas led to higher electricity prices and increased guarantee payments in areas where oil-fired units are sometimes operated for reliability or to manage congestion.

C. Generation Fuel Type

The reductions in natural gas prices and the additions of new gas-fired generation have led to considerable changes in the mix of fuels used to generate electricity in New York. Table 2 summarizes the actual usage of fuels by New York generators on an annual basis from 2010 to 2012, including: (a) the average quantities of generation by each fuel type; (b) the share of generation by each fuel type relative to the total generation; and (c) how frequently each fuel type was on the margin and setting real-time energy prices.[8]

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[8] Section I.B in the Appendix the methodology that was used to determine how frequently each type of resource was on the margin (i.e., setting the real-time price).

Table 2: Fuel Type of Real-Time Generation and Marginal Units in New York
2010-2012

	Average Internal Generation						% of Intervals being Marginal		
	GW/hour			% of Total					
Fuel Type	2010	2011	2012	2010	2011	2012	2010	2011	2012
Nuclear	4.8	4.9	4.6	31%	31%	30%	0%	0%	0%
Hydro	2.7	3.0	2.7	18%	19%	17%	41%	42%	39%
Coal	1.6	1.1	0.5	10%	7%	3%	26%	22%	10%
Natural Gas	5.7	6.0	7.0	37%	38%	45%	71%	73%	83%
Fuel Oil	0.1	0.1	0.1	0.9%	0.6%	0.3%	5%	4%	3%
Wind	0.3	0.3	0.3	2%	2%	2%	1%	1%	1%
Other	0.4	0.4	0.3	2%	2%	2%	0%	0%	0%

The share of total electricity production from gas-fired generators rose from 37 percent in 2010 to 45 percent in 2012, while the share from coal-fired resources fell from 10 percent in 2010 to 3 percent in 2012. These changes reflect the narrowing spread between coal prices and natural gas prices, the lower delivery costs of natural gas, and the better fuel efficiency of most gas-fired units. Furthermore, the new entry of more than 1.5 GW of gas-fired generating capacity in the Capital Zone (September 2010) and New York City (July 2011 and June 2012) and the retirement of coal capacity in western New York also contributed to the change in generation pattern.

The combined output from nuclear and hydro generators fell from 50 percent in 2011 to 47 percent in 2012 due to changes in the availability of individual generators and other factors not related to the natural gas market. However, these reductions were primarily replaced by increased production from gas-fired units and additional imports.

Gas-fired resources and hydro resources were on the margin most of time in New York. In 2012, gas-fired resources were on the margin more often (up to 83 percent of the intervals) because of the improvement in the relative production costs of natural gas-fired units. Coal resources were on the margin less than half as often as in 2010 for the same reasons that coal output was down. Other fuel types were rarely on the margin -- nuclear units and wind units are usually base-loaded, and oil units only set the price occasionally during very high-load periods.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. In 2012, load averaged 18.5 GW, down slightly from 2011 and 2010. New York experienced fewer hours with extreme high load conditions (i.e., load exceeding 32 GW) in 2012 than in recent years. This was primarily due to milder weather in the summer of 2012.[9] Load peaked at 32,439 MW on July 17, 2012, approximately 1,400 MW lower than the 2011 annual peak. Accordingly, the frequency of real-time 30-minute operating reserve shortages in New York State fell from 108 intervals in 2011 to 38 intervals in 2012.

E. Transmission Congestion Patterns

Transmission congestion costs decreased considerably from 2011 to 2012. Congestion revenues collected by the NYISO in the day-ahead market (where the vast majority of congestion revenue is collected) totaled $301 million in 2012, down 26 percent from $407 million in 2011. We also calculate the total value of congestion in the real-time market because it indicates where physical constraints occur on the network during the operating day, although most of this congestion does not result in congestion revenues collected by NYISO.[10] In a well-functioning market, the value of congestion in the day-ahead and real-time markets should converge.

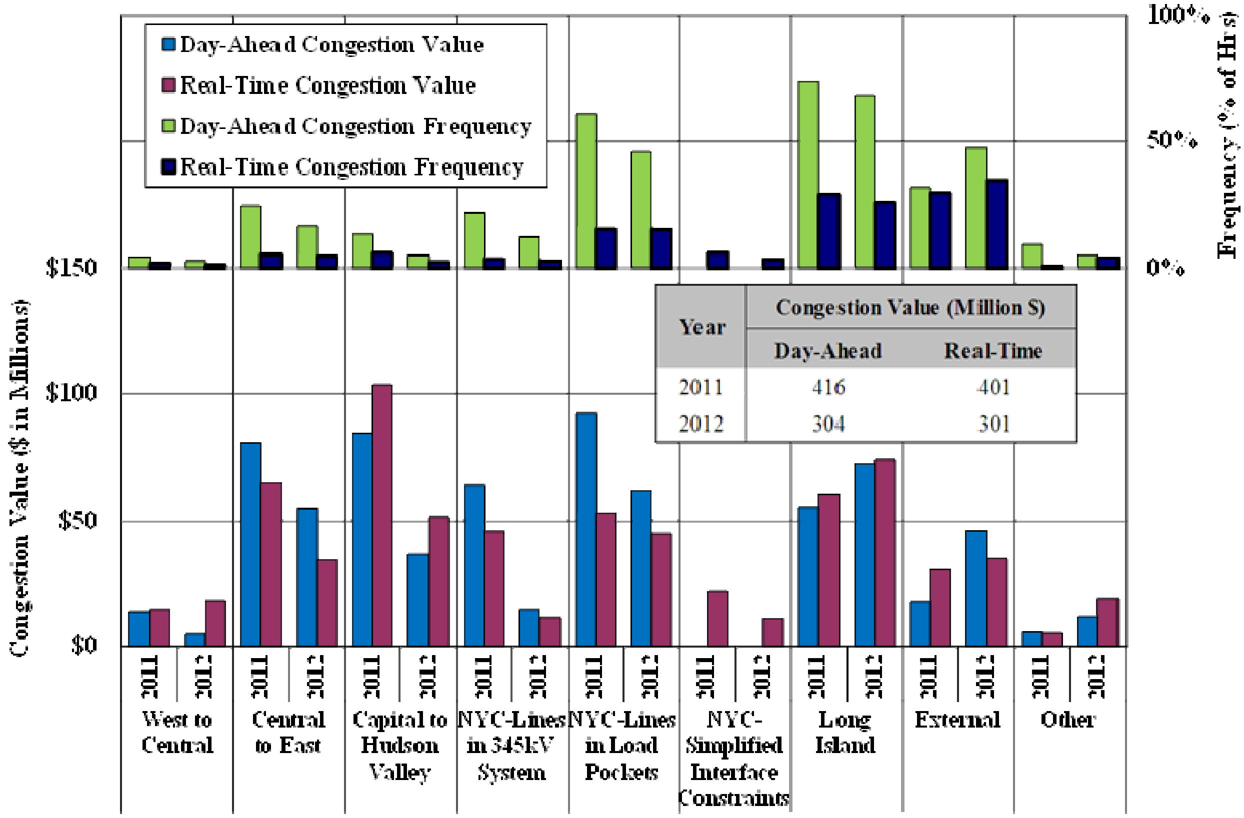
Figure 2 shows the value and frequency of congestion along major transmission lines in the day-ahead and real-time markets in 2011 and 2012. [11]

9 Section I.C in the Appendix shows the load duration curves from 2010 to 2012.

10 Real-time settlements are based on deviations in the quantities scheduled relative to the day-ahead market. For example, if 90 MW is scheduled to flow over an interface in the day-ahead market and 100 MW is scheduled in the real-time market, the first 90 MW settle at day-ahead prices, while the last 10 MW settle at real-time prices.

11 Section V.A discusses the congestion patterns in greater detail.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2011-2012



Both the value and frequency of congestion fell from 2011 to 2012 on most transmission paths because:

- Lower natural gas prices generally reduced redispatch costs for managing congestion;
- 1 GW of new generation entered in New York City between July 2011 and June 2012;
- Eastern New York satisfies a substantial portion of its demand with power from western New York and is more dependent on gas-fired generation. Hence, lower gas prices generally reduced west-to-east congestion; and
- Clockwise loop flows around Lake Erie (i.e., "clockwise Lake Erie circulation") fell, reducing the loadings on interfaces that limit west-to-east power transfers.

However, congestion into Long Island and on external interfaces increased in 2012. Congestion into Long Island increased in the second half of 2012 as transmission outages reduced imports across the Neptune Cable beginning in May and three generators retired in July.

Congestion across the external interfaces also increased in 2012, primarily because of increased day-ahead congestion across the Hydro-Quebec interface in the summer. The increased day-ahead congestion reflects a natural response by the market participants to recent trends in real-time congestion. In recent summers, the Hydro-Quebec interface has frequently become congested in real-time when NYISO Operations reduces the Total Transfer Capability of the interface to manage reliability during TSA events. This has given importers an incentive to schedule more in the day-ahead market until the day-ahead price at the interface is consistent with the expected real-time price.

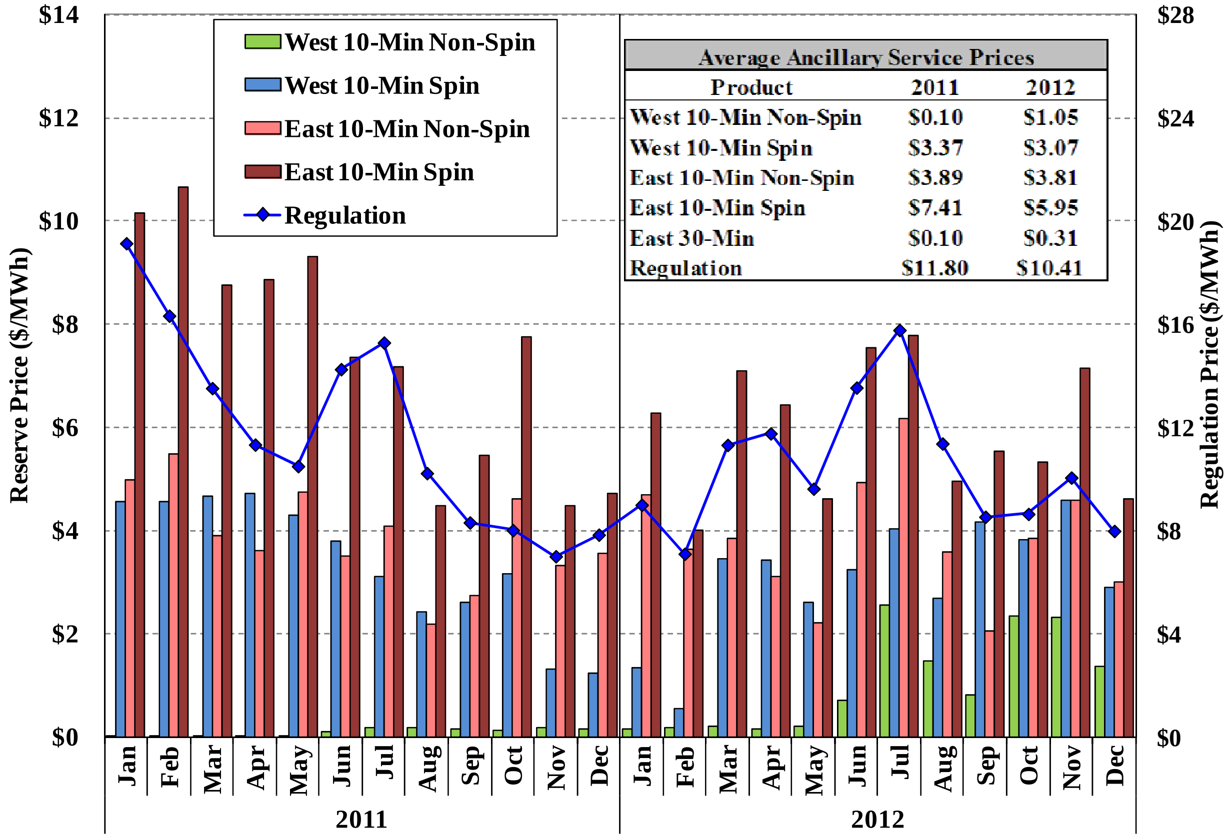
F. Ancillary Services Market

Figure 3 shows the average prices of five key ancillary services products in the day-ahead market in each month of 2011 and 2012. The average prices for most classes of ancillary service were virtually unchanged from 2011 to 2012, although monthly average prices generally tracked changes in fuel prices and load levels, rising and falling with the energy prices. This reflects that a major cost of providing ancillary services for most generators is the opportunity cost of not providing energy when it otherwise would be economic to do so.

The most significant change in operating reserves prices from 2011 to 2012 was related to the 10-minute reserve requirement for NYCA. This is the main component of the 10-minute non-spin price in West New York, which increased from $0.10 per MWh in 2011 to $1.05 per MWh in 2012. The higher price levels began on June 27, 2012 when the uprate of one Nine Mile nuclear unit required the NYISO to increase its operating reserve requirements.[12]

[12] Section I.D in the Appendix describes the increases in the operating reserve requirements in detail.

Figure 3: Average Day-Ahead Ancillary Services Prices
2011-2012



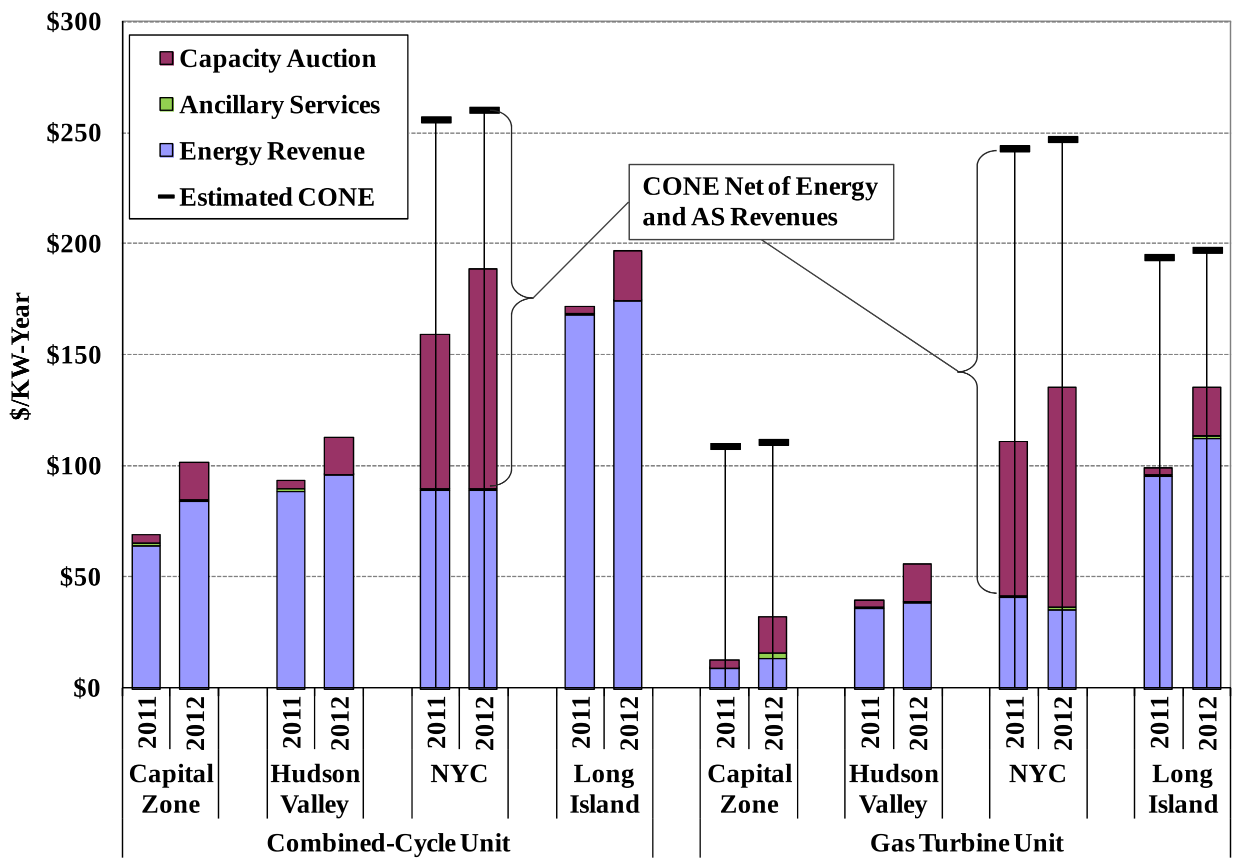
Regulation prices in the day-ahead market have fallen substantially over the last two years from an average of approximately $29 per MWh in 2010 to $10.41 per MWh in 2012. This has resulted primarily from increased regulation supply from new and existing resources, as well as reduced offer prices from existing resources.

G. 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 annual levelized CONE (including the fixed costs of operation) for a new peaking unit was estimated at $247 per kW-year in New York City, $197 per kW-year on Long Island, and $ 111 per kW-year in upstate New York for the 2012/13 Capability Year.[13] 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 2011 and 2012.

Figure 4: Net Revenue for Combined-Cycles and Combustion Turbines
2011-2012



The estimated net revenues in Figure 4 were lower than the estimated annual levelized CONE in 2012 by 45 percent in New York City, 31 percent on Long Island, and 71 percent in the Capital Zone. Hence, there were no areas of New York where the net revenue levels in 2012 were close

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13 These values were estimated from the Annual Revenue Requirement, the Demand Curve Length, and Excess Level in each locality, which may be found at "http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp."

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 $55 to $70 per kW-year higher than those for a new combustion turbine in 2012.[14] 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 combined cycle unit was $260 per kW-year.[15] 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 58 percent lower than the Net CONE for a new combustion turbine unit in New York City.[16]

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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14 See Section I.G of the Appendix for additional information on our net revenue estimates.

15 Property tax abatement is assumed for both the combustion turbine and the combined cycle unit, although the combustion turbine's abatement schedule is based on AB7511 (which allows 15 years of 100 percent abatement), while the combined cycle unit's abatement schedule is based on the ICIP rule (which allowed ten years of 100 percent abatement before phasing out over the subsequent five year period).

16 This assumes an Excess Level of 2.3 percent for the combustion turbine compared to 4.1 percent for a combined cycle unit. A larger value is used for the combined cycle unit, since the Excess Level depends on the size of the demand curve unit relative to the locality requirement.

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 2012 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 2012.

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 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.

For this competitive assessment, we evaluate potential physical withholding by analyzing generator deratings, and potential economic withholding by estimating an "output gap". The output gap is the estimated output that is economic at the clearing price but is not produced because the supplier's offer prices (start-up, minimum generation, and incremental energy) exceed the reference level by a given threshold.[17,18]

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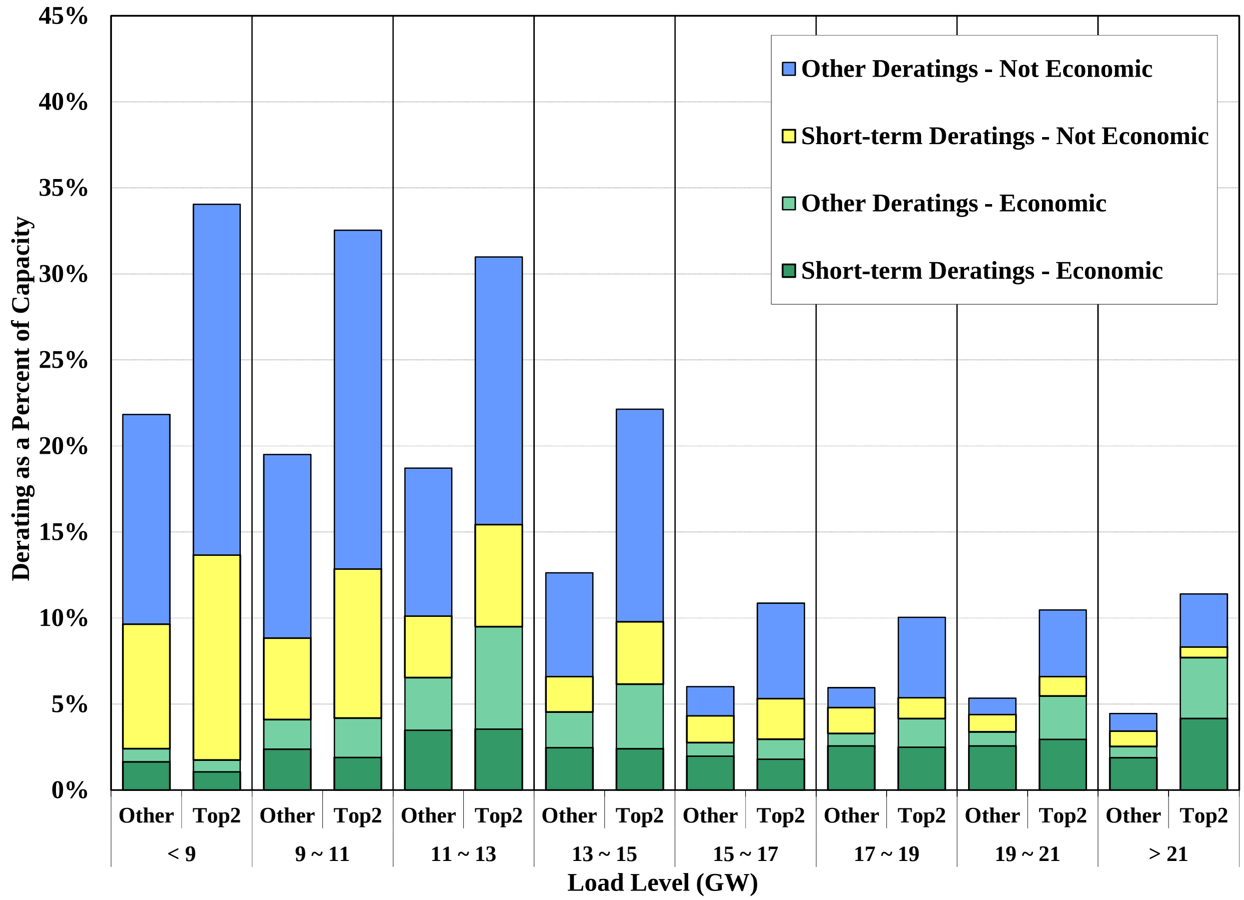
17 Physical withholding is when a resource is derated or not offered into the market when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource). Suppliers may also physically withhold by providing inaccurate information 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

Figure 5 and Figure 6 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. [19] Deratings are shown according to whether they are short-term (i.e., less than 30 days) or long-term and whether the derated capacity would have been economic at day-ahead price levels.

Figure 5: Deratings by Supplier by Load Level

Eastern New York, 2012



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.

18 The output gap calculation excludes capacity that is more economic to provide ancillary services. In this report, 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, the Lower Threshold 1 is the lower of $25 per MWh or 50 percent of the reference level, and Lower Threshold 2 is the lower of $50 per MWh or 100 percent of the reference level.

19 Sections II.A and II.B in the Appendix show the analyses of potential physical and economic withholding.

Figure 5 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, particularly in the highest load periods, which is a positive indicator given that long-term deratings are less likely to be used by a supplier to withhold profitably. Short-term deratings of economic capacity were relatively small (less than 3 percent of total capacity) in Eastern New York, which is reasonable given that low-cost units are economic during some periods when they must undergo a forced or planned outage. Most long-term deratings in the summer were associated with generators' emergency operating ranges, which are only available when specifically requested by the NYISO operators.

The two largest suppliers exhibited higher levels of deratings than other suppliers at all load levels. Both suppliers have portfolios that are primarily made up of older assets whose forced outages rates are not substantially different from that of other suppliers with similar assets. Hence, these deratings did not raise significant competitive concerns.

Figure 6: Output Gap by Supplier by Load Level
Eastern New York, 2012

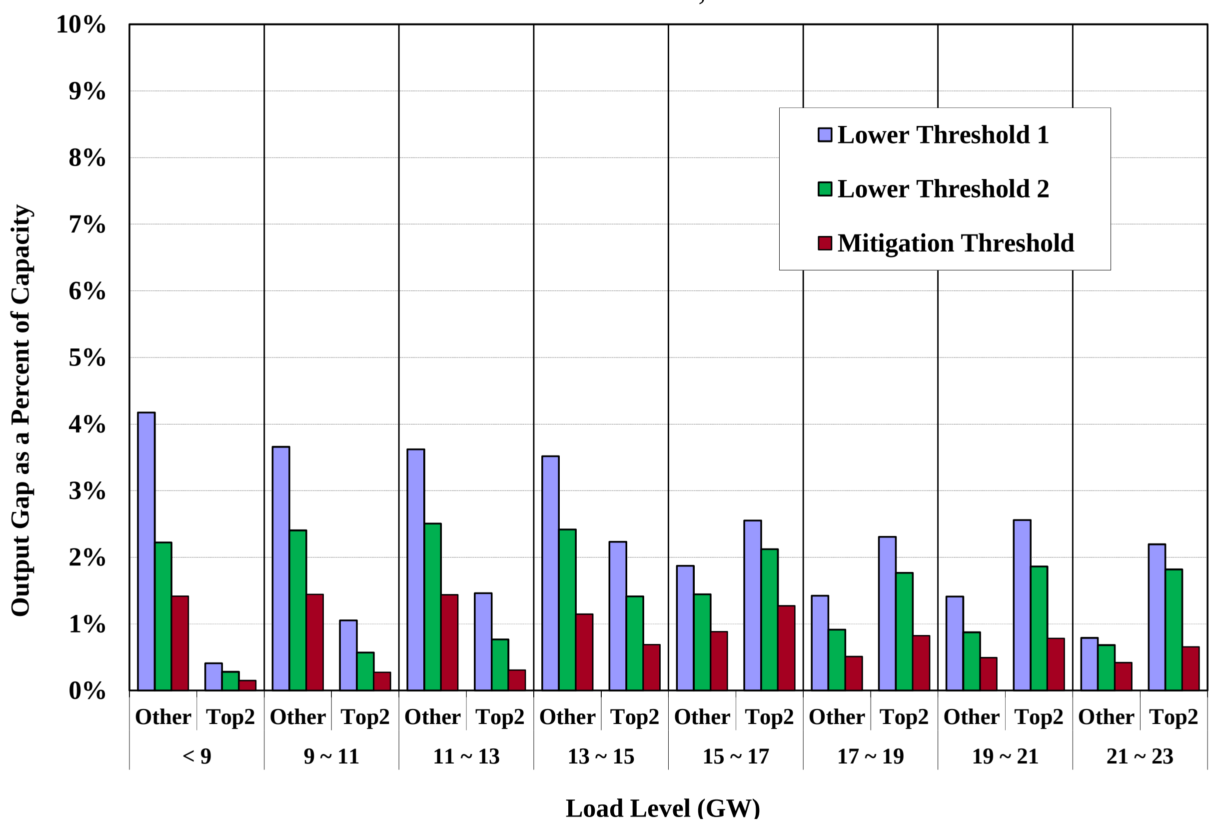


Figure 6 shows that the output gap averaged around 1 percent as a share of total capacity for both large and small suppliers in Eastern New York at the statewide mitigation threshold. At the lowest threshold evaluated (i.e., $25 per MWh or 50 percent above reference), the output gap averaged just 3 percent. These levels are low and raise very few competitive concerns. In general, it is a positive indicator that the output gap declined as load increases for most suppliers and was especially low under high load conditions when the market is most vulnerable to the exercise of market power. Although the output gap for the largest two suppliers generally increased with load in Eastern New York, the pattern was driven primarily by compliance with the IR-5 reliability rule. This rule requires some units to burn a blend of oil and natural gas under higher load conditions.[20]

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 little conduct that raised substantial competitive concerns. Accordingly, we find that the New York energy market performed competitively in 2012.

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

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[20] See *NYISO Transmission and Dispatching Operations Manual*, Table B-4, IR-5 Loss of Generator Gas Supply. The required mix of oil and gas varies by time of day, while the day-ahead market software uses a single reference level for the entire day. So, this tends to produce an output gap in hours when the generator is required to burn some oil.

above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[21]

- 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.

Generators were sometimes mitigated in the day-ahead or real-time market and then subsequently unmitigated after consultation with the NYISO for several reasons.[22] First, a generator's reference level on a particular day was lower than the consultative reference level that the NYISO approved for the generator before the generator was mitigated.[23] Second, the generator attempted to inform the NYISO of a fuel price change prior to being scheduled in the day-ahead or real-time market, but the generator was still mitigated.[24] Third, a generator's fuel cost changed by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day. Fourth, the Reference Level Software ("RLS") had a limited number of fuel price index locations that it could use, causing some generators' reference levels to be based on a fuel price that was inaccurate.[25]

Figure 7 summarizes the amount of mitigation that occurred in the day-ahead and the real-time markets in 2011 and 2012 as well as the amount of capacity that was unmitigated after consultation with NYISO.[26]

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21 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.

22 NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation.

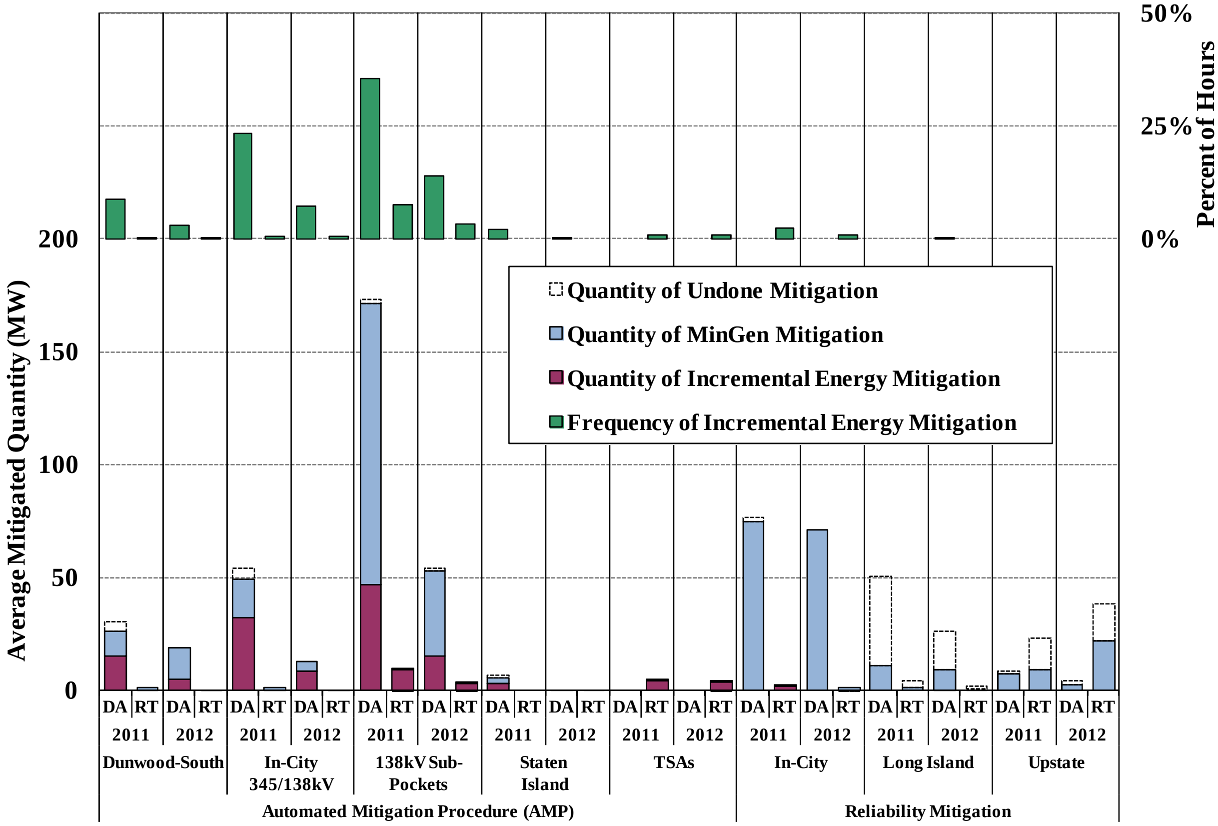
23 This includes when the NYISO approves the consultative reference level submission after the mitigation because the submission was made prior to mitigation.

24 See NYISO Market Services Tariff, Section 23.3.1.4.7.7.

25 The set of fuel price indices was expanded in March 2013.

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

Figure 7: Summary of Day-Ahead and Real-Time Mitigation
2011 & 2012



Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In 2012, 90 percent of AMP mitigation occurred in the day-ahead market, primarily in the 138kV sub-pockets in New York City. Likewise, 84 percent of reliability mitigation occurred in the day-ahead market, primarily for DARU and local reliability (LRR) commitments in New York City.

The frequency of AMP mitigation in New York City decreased substantially from 2011 to 2012 because congestion became less frequent and severe in 2012. However, several units in New York City consistently offered well above marginal cost and were still mitigated relatively frequently. Real-time reliability mitigation increased modestly in the upstate areas in 2012 because of increased SRE commitment.

Unmitigation of generators that were initially mitigated by the AMP software became less common in 2012 as the NYISO improved its processes for administering reference levels. This is important because mitigating generators below marginal cost with the AMP software leads to inefficient scheduling and distorted market clearing prices, which cannot be undone when the generator is unmitigated.[27]

The NYISO introduced the Increasing Bids in Real-Time ("IBRT") capability in October 2010, which allows generators to update the fuel prices used to calculate their real-time reference levels until 75 minutes ahead of a particular hour. This allows generators to reflect their fuel costs more accurately and leads to more efficient dispatch and price signals. However, the current limits on fuel-price adjustments prevent generators from reflecting: (a) the full price of gas on days with intra-day price volatility and (b) routine intra-day gas balancing charges.[28] Consequently, generators that are not scheduled in the day-ahead market sometimes switch to more expensive fuels or stop offering altogether in real-time to avoid being dispatched below cost. Ultimately, this causes more expensive generators to be scheduled in their place. This leads energy prices to be higher than if the full cost of gas were properly reflected in the generators' reference levels. The NYISO plans to introduce a generator-specific IBRT threshold in March 2013, which could be used to allow generators to be scheduled more efficiently.

As gas market conditions lead to increased gas price volatility, the potential for generators to be mitigated in the day-ahead market below their expected marginal costs increases as well. Currently, day-ahead reference levels are based on the price indices for the gas trading day on the day before the day-ahead market runs. For example, the bid window for the day-ahead market for Wednesday closes on Tuesday at 5 am. The RLS software uses the gas price index from the Monday gas trading day for gas that will flow on the Tuesday gas flow day, which can lead to two problems. First, gas market conditions can change significantly from the close of the Monday gas trading day to 5 am the next morning. Second, when the weather is expected to change between Tuesday and Wednesday, natural gas prices may also be expected to change. Hence, using the gas price for the Tuesday flow date will lead to inaccurate reference levels when scheduling generation for Wednesday. For these reasons, we recommend allowing generators to submit fuel price information before the day-ahead market to be used in the

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27 Undoing relability mitigation is much less concerning, since it does not affect schedules or prices. This is because the mitigation takes place after the market runs in the settlement process, although it may be administratively burdensome for the NYISO and some market participants.

28 See NYISO Market Services Tariff, Section 23.3.1.4.7.6.

calculation of reference levels when they have a reasonable basis for expecting fuel prices will be substantially higher than the index that would otherwise be used to calculate reference levels. This will be particularly important during the winter when natural gas prices can be quite volatile and over-scheduling gas-fired generation can further increase gas prices.

C. Competition in the Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to meet planning reserve margins 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.[29] 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.[30] 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 2012.

1. Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests for several projects in 2012, including Astoria Energy II, Bayonne Energy Center, and Hudson Transmission Partners ("HTP").

Astoria Energy II

Astoria Energy II entered into a power purchase agreement with the New York Power Authority ("NYPA") following NYPA's request for proposals in November 2007 for capacity and energy

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29 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.

30 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.

from a new facility.[31] The new unit was not originally mitigated under the buyer-side mitigation rules when it began operations in July 2011 because it passed the NYISO's buyer-side mitigation exemption test, which found that the unit was economic. However, following a complaint by existing New York City suppliers, the Commission ordered the NYISO to re-test the unit with several modifications to key inputs.[32] In the re-test, Astoria Energy II was found to be uneconomic, and the mitigation was commenced by applying an offer floor in the December 2012 spot auction.[33] Following the application of the offer floor, there has been a substantial quantity of unsold capacity and the capacity spot auction price has cleared at $4.91 per kW-month, up from $3.36 per kW-month in November.

Bayonne Energy Center

Bayonne Energy Center was not originally mitigated when it began operations in June 2012 because it passed the NYISO's buyer-side mitigation exemption test. However, in the proceeding where the Commission ordered a re-test of Astoria Energy II, the Commission also ordered the NYISO to re-test Bayonne Energy Center. In the re-test, Bayonne Energy Center was found to be economic and, therefore, retained its exemption from buyer-side mitigation.[34]

Hudson Transmission Partners

HTP entered into a power purchase agreement with NYPA following one of its requests for proposals. HTP was not expected to be in service before 2013. HTP was tested, was found to be uneconomic, and did not receive an exemption from NYISO. After several proceedings before the Commission, the NYISO re-tested HTP and found that the mitigation was still warranted.[35] As required by the Commission, we provided a written assessment of the test, agreeing with the

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

[32] See Commission Docket No. EL11-50.

[33] See http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/In-City_Mitigation_Documents/In-City_Mitigation_Documents/NYISO_Notice_of_BSM_Determinations_Nov_6_2012.pdf

[34] *Id*.

[35] See http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/In-City_Mitigation_Documents/In-City_Mitigation_Documents/HTP_Report_11-6-12_Final.pdf.

overall result while identifying several areas for future improvements. These improvements pertain to the estimation of energy net revenues and the forecasting of capacity prices.[36]

Our written assessment of the HTP exemption test indicated that the project-specific Unit Net CONE for HTP was substantially higher than the non-project-specific Default Net CONE, which is set at 75 percent of the net cost of new entry for the demand curve unit.[37] Consequently, the offer floor that was imposed on HTP was based on the Default Net CONE rather than the actual Unit Net CONE of the project. Following the start of operation for HTP, the use of the Default Net CONE is likely to result in capacity prices that are lower than the net cost of entry for a new unit, indicating that the Buyer Side Mitigation measures may not be sufficiently effective to deter uneconomic entry. This is discussed further in the next part of this section.

2. Improvements to the Buyer-Side Mitigation Measures

Continued efforts to refine the methodology that is used to test new resources for exemption from the buyer-side mitigation offer floor are very important, since an incorrect assessment of whether a project is economic could cause buyer-side mitigation to inefficiently restrict investment or allow uneconomic entry that substantially depresses capacity prices.

Market-Based Investment Exemption

One issue that is particularly difficult to address accurately in future price forecasts is the issue of generation retirements. The recent series of generator retirements highlights the need for the Buyer-Side Mitigation measures to function appropriately when the retirement of existing facilities creates profitable opportunities for new investment. Nearly 2 GW of capacity has been retired or mothballed since the beginning of 2012, and it is uncertain whether the Indian Point nuclear units will be licensed to operate after 2013 and 2015. Additional retirements are expected over the coming decade given the age of many existing generators, but the timing of individual retirements may be hard to predict.[38]

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36 *Id* on page 7-11

37 *Id* on page 15.

38 See *Market Monitoring Unit Review of the NYISO's 2012 Comprehensive Reliability Plan ("CRP")*, March

The Mitigation Exemption Test is conducted three years in advance of the unit entering the market, and it evaluates whether the unit appears uneconomic based on the forecasted conditions at the time of its entry. It is difficult, however, for these forecasts to account for uncertainty regarding unit retirements. Currently, the forecasted capacity prices assume that only suppliers that have submitted a retirement notice (and not just a mothball notice) to the PSC will retire, which is only required to be submitted 6 months from the retirement date. To the extent that other significant retirements are likely, the Buyer-Side Mitigation Exemption test will likely understate the forecasted prices and over-mitigate competitive entry.

To address these concerns, we recommend the NYISO amend the rules to grant exemptions to suppliers engaged in purely private investment. This would allow merchant investors to invest based on their own expectations of whether additional retirements (beyond those that have been noticed to the PSC) were likely to occur. The NYISO is proposing to exempt developers that can establish they will not receive public subsidies or revenues either directly (as a regulated entity or public authority) or indirectly through a contract with another party.[39] Such a rule would help ensure that competitive market-based investments are not precluded by the buyer-side mitigation.

Offer Floors for Mitigated Projects

A new project receives an exemption from Buyer-Side Mitigation when capacity prices are forecasted to be higher than:

- Default Net CONE ("DNC") – a level 25 percent lower than Mitigation Net CONE ("MNC") in the first year of the project's operation, where MNC is intended to equal the annual capacity revenues that the demand curve unit would need to be economic (i.e., the Part A test); or
- Unit Net CONE ("UNC") – a level set at the estimated net CONE of the project over the first three years of the project's operation (i.e., the Part B test).

If a project fails both the Part A and Part B tests, then an offer floor is imposed on the project that is set equal to the lower of DNC and UNC. The use of DNC, which is 25 percent less than

7, 2013.

[39] See ICAP Working Group materials for March 11, 2013, *Competitive Entry Exemption Modified Proposal & Tariff Review*.

the annualized Net CONE of a new resource, is reasonable for purposes of the Part A exemption test because it recognizes that the entry of the new unit will tend to lower the project's net revenues in the initial year. However, its use as an offer floor for projects that have failed both tests significantly weakens the buyer-side mitigation measures because it allows the uneconomic project to lower capacity prices 25 percent below the cost of new entry. To address these issues, we recommend setting the offer floor of mitigated units at the lower of UNC or the 100 percent of the MNC.

3. Supply-Side Mitigation Measures

The supply-side mitigation measures for New York City limit the offers of a pivotal supplier in the spot capacity auction based on the Going Forward Costs of its generators. For the first time since these measures were implemented, a substantial amount of capacity that was qualified to sell in New York City went unsold beginning in October 2011. This lasted until May 2012 when units that were not being sold were mothballed and no longer qualified to sell capacity. These developments led us to make several recommendations in the *2011 State of the Market Report*.[40]

First, we recommended modifying the pivotal supplier test 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.[41] The current definition of a pivotal supplier effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction.

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40 See Section X, Recommendation #3.

41 For the purposes of the capacity mitigation measures, pivotal suppliers are defined in MST Section 23.2.1.

The second and third recommendations were for the NYISO to clarify the rules related to: (a) the requirements an existing supplier must satisfy to remain qualified to sell installed capacity, and (b) the method for calculating Going-Forward Costs ("GFCs"). A GFC should include only costs a supplier must incur to remain qualified to sell capacity, since that is how a competitive supplier would determine whether sell capacity. Hence, effective administration of the supply-side mitigation measures requires that the capacity qualification rules be clear for the GFC calculation method to be accurate.

In response to these recommendations, the NYISO has begun presenting to stakeholders its current practices on the requirements for an existing facility to qualify to sell capacity, including requirements not fully captured in the Tariffs, Manuals, or Tech Bulletins.[42] These presentations will enable the NYISO to receive feedback on its practices and better enable suppliers with older generation to make efficient decisions regarding the maintenance and operation of their assets. However, we have several concerns with the NYISO's current practices on forced outages and mothballed units. Under the NYISO's current practices, a generator in a forced outage with no intention of returning to service could sell capacity for six months. This period could be extended if the unit owner took tangible steps *towards* repairing the unit, although this would still not obligate the owner to return the unit to service eventually. Hence, a unit could potentially sell capacity for up to a year with no affirmative obligation to return.

The NYISO's practices allow an existing generator to be in a forced outage state and continue to sell capacity for an unreasonably long period of time that could easily span an entire summer capability period. Precluding such a unit from selling capacity after a reasonable amount of time would be beneficial because it would provide more accurate and efficient spot capacity signals regarding the current state of the system.. This would improve reliability because the reduction in sales from units on extended forced outages would encourage additional sales from importers, demand response resources, and/or mothballed generators with the ability to return to service on short notice. It would also provide more timely price signals for longer lead time investments in new generation, demand response, and transmission.

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42 See materials from Market Issues Working Group meeting on December 3, 2012, agenda item 6, *Conceptual Approach to Redefining Outage States to Include a Mothball Outage.*

IV. Day-Ahead Market Performance

A. Price Convergence

The day-ahead market enables firms to make forward purchases and sales of power for delivery in 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 diverge systematically. 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.

Convergence of Zonal Energy Prices

Table 3 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 2010 to 2012.[43]

Table 3: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2010-2012

	Avg. Diff % (DA - RT)			Avg. Absolute Diff %		
Zone	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
West	-1.0%	1.4%	0.0%	25.0%	24.0%	26.4%
Central	-0.5%	1.1%	0.6%	25.5%	25.7%	25.5%
Capital	1.3%	2.6%	2.9%	28.7%	28.1%	27.0%
Hudson Valley	-1.5%	0.9%	0.9%	30.1%	30.0%	29.9%
New York City	-2.5%	1.8%	0.8%	32.8%	32.4%	31.4%
Long Island	-5.8%	0.9%	1.7%	35.5%	35.5%	42.1%

Energy price convergence was relatively good in most areas in 2012. At the zonal level, average day-ahead prices were higher than average real-time prices by a small margin (roughly 1 percent in most regions). This differential was highest in the Capital zone where very low real-time prices occur during periods of acute congestion into Southeast New York during TSAs.

43 Section I.G in the Appendix shows monthly variations of average day-ahead and real-time energy prices.

In Long Island, which already exhibited the largest spreads between day-ahead and real-time energy prices, the average spread rose from 35.5 percent in 2011 to 42.1 percent in 2012, reflecting increased real-time price volatility. Real-time prices rise considerably when oil-fired units are dispatched in Long Island during tight operating conditions. This became more frequent in 2012 because of the reduction in imports across the Neptune line and the retirement of 330 MW of steam turbine generation.

Convergence of Nodal Energy Prices

At certain generator nodes, day-ahead and real-time prices did not converge as well as they did at the zonal level in 2012. For example, portions of the Greenwood/Staten Island load pocket in New York City exhibited day-ahead prices that were 15 percent higher on average than real-time prices in the summer, while the Valley Stream load pocket in Long Island exhibited real-time prices in shoulder and winter months that were 15 percent higher on average than day-ahead prices.[44] 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 disaggregated virtual trading, so we have reduced the priority level of this recommendation.

Convergence of Ancillary Service Prices

Figure 8 evaluates the convergence between day-ahead and real-time 10-minute non-spinning reserve prices in Eastern New York, which exhibits a pattern that is characteristic of other reserve products in Eastern and Western New York. Average prices are shown based on the

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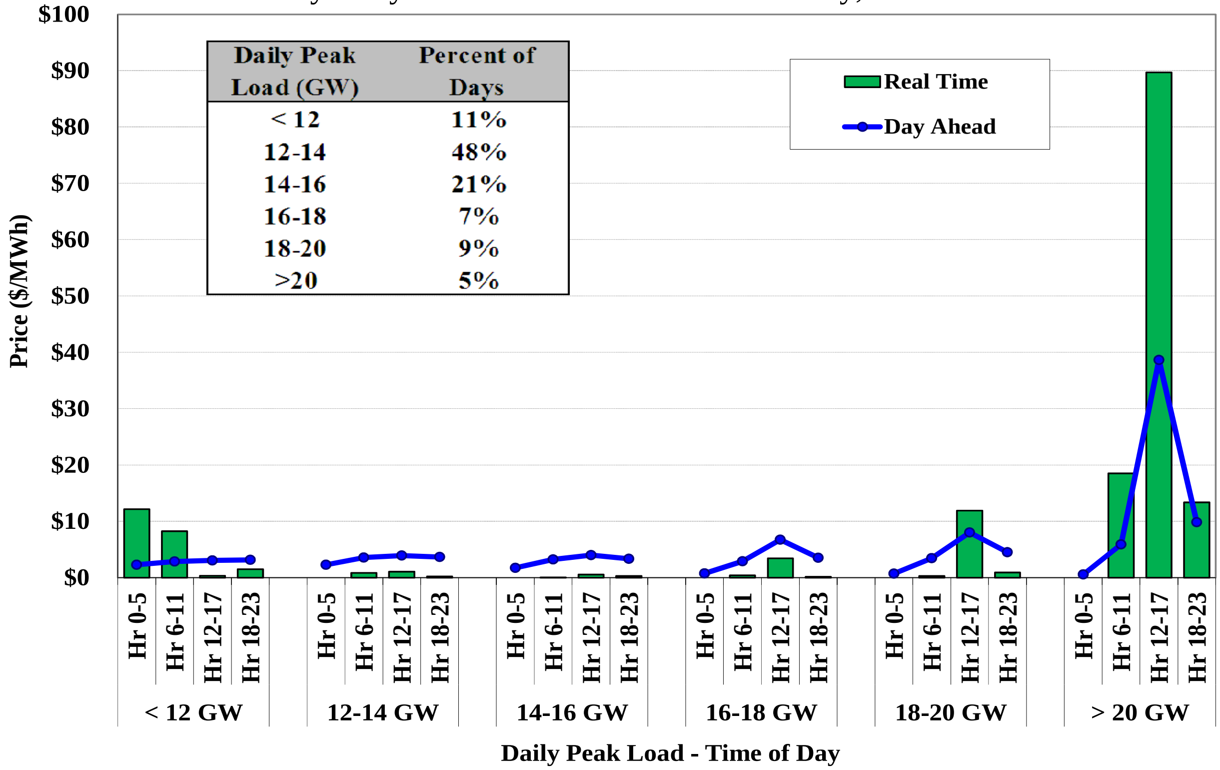
44 See Figure A-20 in the Appendix for additional results.

daily peak load level in Eastern New York and by time of day. The inset table shows the percent of days in each load range.

Figure 8: 10-Minute Non-Spinning Reserve Prices in East NY
by Daily Peak Load Level and Time of Day, 2012



We find that convergence between day-ahead and real-time operating reserve prices remained relatively poor in 2012. Day-ahead prices were higher than real-time prices in most hours. However, the day-ahead prices were systematically lower than real-time prices during peak conditions in 2012, particularly on days when daily peak load exceeded 18 GW in Eastern New York and 28 GW at the system level.[45] For example, Figure 8 shows that from hour 12 to 17 on days when Eastern New York load peaked above 20 GW, the average real-time price was 130 percent higher than the average day-ahead price for 10-minute non-spinning reserves in Eastern New York. These large differentials should cause suppliers to raise their day-ahead offers in peak hours to arbitrage the difference. However, mitigation measures limited the day-ahead reserve offers of some suppliers below their marginal costs, which likely inhibited price

45 Figure A-23 and Figure A-24 in the Appendix show 10-minute spinning reserve prices in Western New York.

convergence during these hours.[46] The NYISO has addressed this problem by phasing-out these mitigation rules starting on January 23, 2013. This should improve convergence going forward.[47]

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. Convergence between day-ahead and real-time energy prices continues to be good at the zone level due, in part, to efficient physical load bidding and scheduling by virtual traders in the day-ahead market.

Physical load can be scheduled in the day-ahead market in the form of physical bilateral contracts, fixed load, and price-capped load. In general, physical loads are willing to buy from the day-ahead market if day-ahead prices are consistent with real-time prices. Under-scheduling load generally leads to lower day-ahead prices. On the other hand, over-scheduling can raise day-ahead prices above real-time prices.

Virtual trading helps align day-ahead prices with real-time prices, which is particularly beneficial when systematic inconsistencies between day-ahead and real-time markets would otherwise cause the prices 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 is profitable when the real-time energy price is higher than the day-ahead price, while virtual supply is 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.

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[46] The day-ahead 10-minute spinning reserves offers of NYC units were 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 were limited to $2.52 per MWh by NYISO Market Services Tariff Section 23.3.1.4.5.

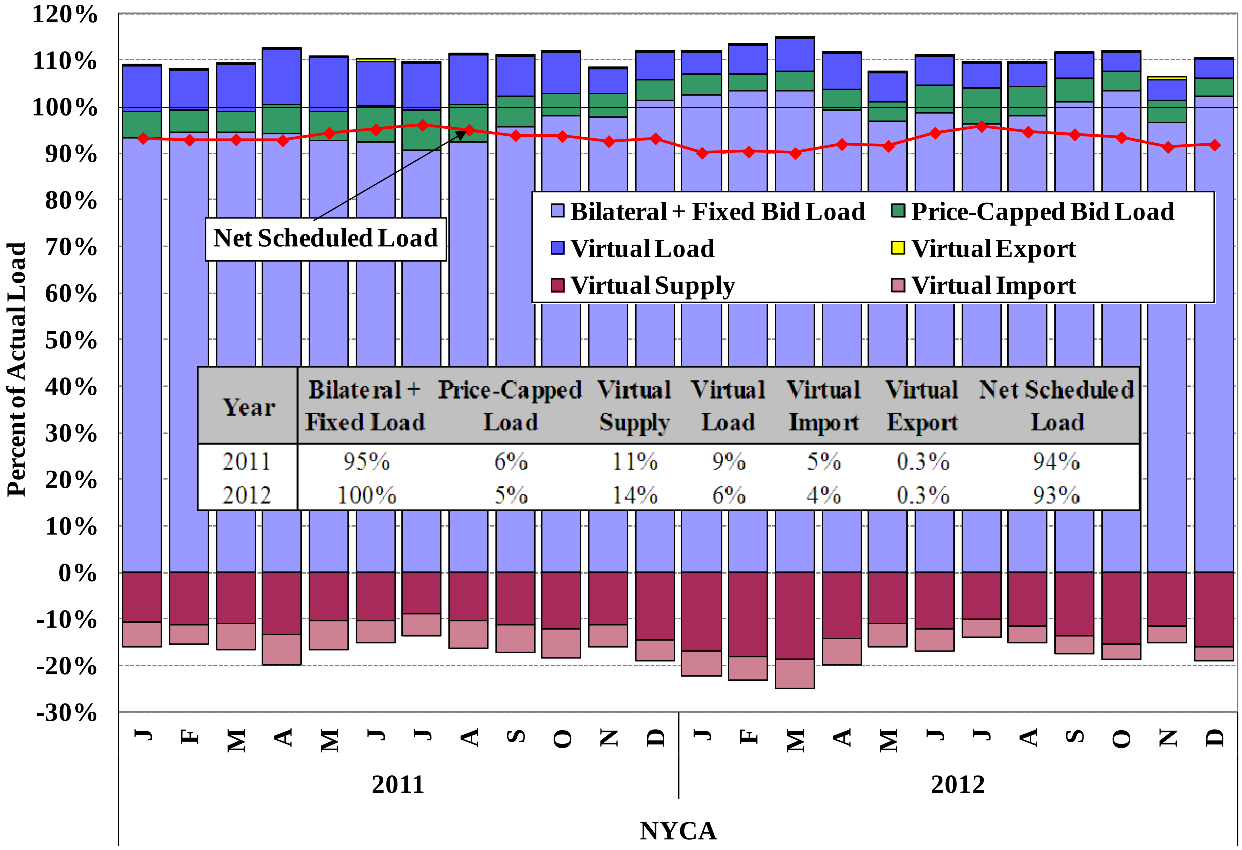
[47] See New York Independent System Operator, Inc., *Proposed Amendments to its Market Power Mitigation Measures revising Mitigation Measures for 10-Minute Non-Synchronized Reserves and New York City Day-Ahead Market Spinning Reserves*, Docket No. ER13-298-000.

This 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.

Virtual Imports and *Exports* are external transactions that are scheduled in the day-ahead market, but are withdrawn or not scheduled in real-time because of their bid/offer price. They are similar to virtual demand and supply, but they are placed at the ten external proxy buses rather than the eleven load zones.

Figure 9 shows the day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load on a monthly basis in 2011 and 2012 for NYCA. [48]

Figure 9: Day-Ahead Load Scheduling versus Actual Load in NYCA
by Month, 2011-2012



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2011	95%	6%	11%	9%	5%	0.3%	94%
2012	100%	5%	14%	6%	4%	0.3%	93%

The figure shows that the overall load in the day-ahead market was scheduled at 93 percent of actual load in NYCA in 2012, down from 94 percent in 2011. This under-scheduling helped

48 Figure A-39 to Figure A-45 in the Appendix also show these quantities at various locations in New York.

moderate the slight day-ahead premium that is shown in Table 3. Physical load scheduling rose from 101 percent in 2011 to 105 percent in 2012, although this was offset by comparable adjustments in virtual trading (i.e., increased scheduled virtual supply and reduced virtual load) over the same period.

The under-scheduling of load shown in the figure is likely a response to inconsistencies between the scheduling of resources in the day-ahead and real-time markets. For instance, wind and hydro resources in upstate New York schedule substantially more output in the real-time market than in the day-ahead. In 2012, this scheduling pattern added an average of 715 MW of additional energy supply in real-time. Hence, this net load scheduling pattern helps ensure that physical resources are not over-committed in the day-ahead market.

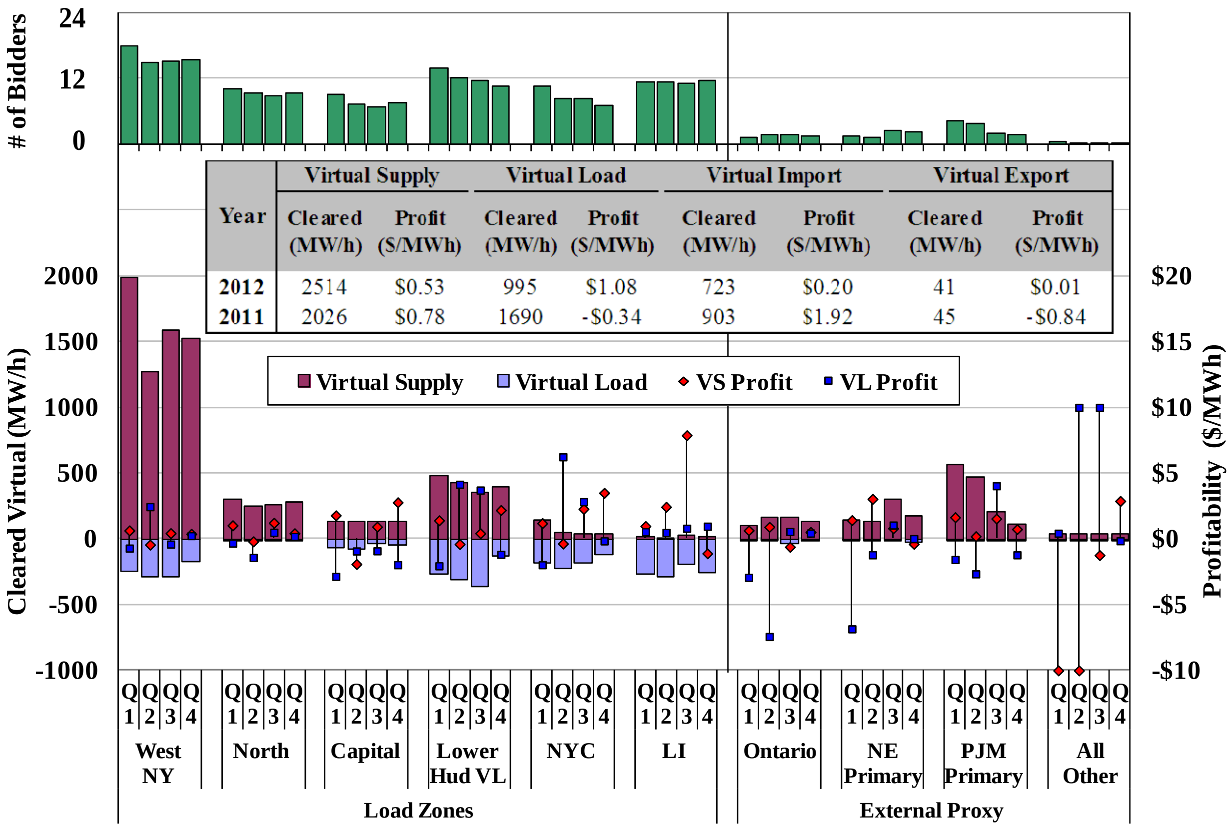
In our evaluation of load scheduling in various regions of New York, we found several notable patterns in 2012. First, load was generally under-scheduled outside Southeast New York (i.e., West Upstate and Capital Zone) and over-scheduled in Southeast New York (i.e., Other East Upstate New York City and Long Island). This pattern has been typical in recent years and is likely in response to real-time congestion across the lines into Southeast New York, New York City, and Long Island. Second, load was generally over-scheduled most in Long Island (108 percent of actual load on average), reflecting the response of market participants to tight operating conditions and high real-time price events.

These patterns of load scheduling help 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 sharp price increases in real-time. Over-scheduling in Southeast New York helps 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.

The overall amount of over-scheduling in Southeast New York fell considerably from 2011 to 2012. The reduction was likely a result of: a) less frequent acute real-time congestion into Southeast New York during TSA events in 2012; b) improved use of PAR-controlled lines between New Jersey and New York to manage congestion into Southeast New York; and c) the addition of new capacity in New York City.

The following figure summarizes virtual activities by geographic region in 2012, which includes virtual trading at the eleven load zones and trading activities related to virtual imports and exports at the ten proxy buses. The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the six regions and four groups of external proxy buses in each quarter of 2012. The upper portion of the figure shows the average number of virtual bidders in each location. The table in the middle compares the overall virtual trading activity in 2011 and 2012.

Figure 10: Virtual Trading Activity
by Region by Quarter, 2012



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2012	2514	$0.53	995	$1.08	723	$0.20	41	$0.01
2011	2026	$0.78	1690	-$0.34	903	$1.92	45	-$0.84

The figure shows that a large number of market participants regularly submit virtual bids and offers. On average, eight or more participants submitted virtual trades in each region and 26 participants submitted virtual trades somewhere in the state in 2012. However, the average number of market participants fell modestly from 2011 to 2012, which was partly due to the new credit requirements implemented in October 2011. The number of market participants that submitted virtual imports and exports at the proxy buses was smaller, averaging six in 2012.

Much of the virtual activity in 2012 was consistent with the day-ahead load scheduling patterns discussed earlier with virtual traders generally scheduling more virtual load in Southeast New York and more virtual supply outside Southeast New York. The reasons for this scheduling pattern are the same as the drivers over the overall net load scheduling described earlier in this section. In addition, scheduled virtual supply rose considerably in Western New York, likely in response to the increase in scheduled bilateral load in this area.

The figure also shows that nearly all of the virtual imports and exports were submitted at three proxy buses, the primary PJM proxy bus, the primary NE proxy bus, and the Ontario proxy bus. 95 percent of all scheduled virtual imports/exports at these interfaces were virtual imports. Since these three proxy buses are primarily interconnected with the regions outside Southeast New York, these virtual imports are consistent with the prevalence of virtual supply scheduled in these regions.

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.[49] However, in aggregate, virtual traders netted approximately $22 million of gross profits in 2012 ($21 million for load zone virtuals and $1 million for virtual imports and exports), which was comparable to the aggregate profits in 2011. 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. Only small quantities of virtual transactions generated substantial losses in 2012, which is significant because they could indicate potential manipulation. We find that most of these losses were caused by real-time price volatility and did not raise significant manipulation concerns.

49 Figure A-46 in the Appendix also shows wide variations in profits and losses on a monthly basis.

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.

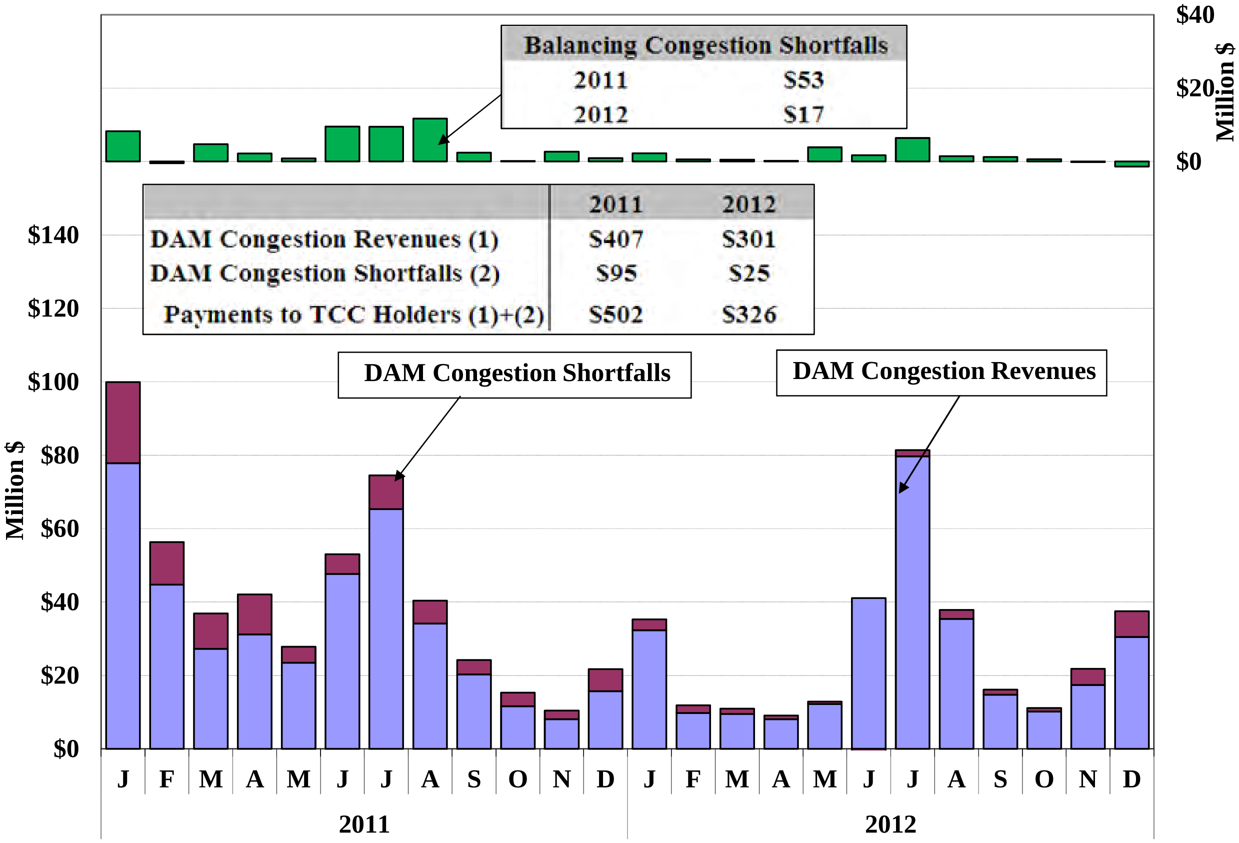
Congestion charges are applied to purchases and sales (including bilateral transactions) in the day-ahead and real-time markets based on the congestion components of the day-ahead LBMPs and the real-time LBMPs, respectively.[50] Market participants can hedge congestion charges in the day-ahead market by owning Transmission Congestion Contracts ("TCCs"), which entitle the holder to payments corresponding to the congestion charges between two locations. However, 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 costs:

- Day-ahead Congestion Revenues – These are collected by the NYISO when power is scheduled to flow across congested transmission lines 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 same constraint in the real-time market.

[50] Congestion charges to bilateral transactions scheduled through the NYISO are based on the difference in congestion component of the LBMP between the two locations (i.e., congestion component at the sink minus congestion component at the source). While congestion charges to other purchases and sales are based on the congestion component of the LBMP at the purchasing or selling location.

Figure 11: Congestion Revenues and Shortfalls
2011 – 2012



The figure shows that the overall congestion revenues and shortfalls decreased significantly from 2011 to 2012. Congestion revenues collected in the day-ahead market fell by 26 percent from 2011 to total $301 million in 2012. Similarly, day-ahead and balancing congestion revenue shortfalls deceased by 72 percent total of $42 million in 2012.

Day-Ahead Congestion Revenues

The decline in day-ahead congestion revenues in 2012 was primarily due to the reduction in natural gas prices. Total congestion revenues in the summer months were comparable between 2011 and 2012 largely because congestion into Long Island rose following the outage that reduced imports across the Neptune Line beginning in May 2012 and several generator retirements in July 2012.

In November and December 2012, congestion rose significantly from the previous year as the Central-East interface became more congested because of several factors. First, outages of generation, voltage regulating equipment, and a major transmission line reduced the transfer limit by up to 900 MW on many days. Second, the spreads in natural gas prices between western and eastern New York rose considerably on many days, averaging $2.40 per MMbtu in November and December and increasing the congestion across the Central-East interface.[51]

Over 70 percent of day-ahead congestion revenues were collected in the winter and summer months of both 2011 and 2012. Congestion is highest at those times for several reasons.. First, load is highest in those months, which increases the demand for transfers into constrained areas in Eastern New York. Second, thunderstorms occurred much more frequently in the summer, causing the NYISO to invoke the Thunderstorm Alert ("TSA") procedures, which substantially reduce the transfer capability into Southeast New York and frequently lead to acute congestion into Southeast New York, New York City, and Long Island. Third, natural gas prices (and sometimes the spreads in natural gas prices between western and eastern New York) tend to be the highest during periods of high demand in the winter. These fuel price patterns lead to higher west-to-east transfers and increase the marginal costs of redispatching the system to manage the congestion.

Day-Ahead Congestion Shortfalls

As described above, day-ahead shortfalls occur when the network capability in the day-ahead market is less than the capability embedded in the TCCs sold by NYISO. Day-ahead congestion shortfalls fell 74 percent from 2011 to 2012, which was due to several factors:

- The overall reduction in day-ahead congestion led to corresponding reductions in day-ahead congestion shortfalls.
- Fewer outages of major transmission lines into Southeast New York and from upstate New York to Long Island contributed to the reduction.
- NYISO corrected a modeling inconsistency between the TCC auctions and the day-ahead market that began to reduce day-ahead congestion shortfalls in May 2011. The day-

[51] Figure A-49 in the Appendix shows the day-ahead and real-time congestion patterns in 2011 and 2012. Figure A-8 shows monthly natural gas prices for several regions in New York.

ahead congestion shortfalls associated with this inconsistency fell from $35 million in 2010 to $16 million in 2011 and $0 in 2012.[52]

Day-ahead congestion shortfalls are generally the highest in the winter and shoulder months when most of the lengthy planned outages of transmission facilities are scheduled. In January and February 2012, shortfalls on New York City lines were primarily caused by transmission outages that were taken to support the installation of new equipment at the Gowanus 345kV substation and a new line into the Astoria East load pocket. In November and December 2012, significant shortfalls accrued on the Central-East interface that were due to the outages described above. [53]

The NYISO has a process for allocating the day-ahead congestion shortfalls resulting from transmission outages to specific transmission owners.[54] In 2012, the NYISO allocated 72 percent of day-ahead congestion shortfalls in this manner, up from 44 percent in 2011. Since issues that led to substantial day-ahead congestion shortfalls, the NYISO is able to allocate a larger share of the remaining shortfalls to the responsible transmission owner, which provides better incentives for transmission owners to minimize the cost of transmission outages.

Balancing Congestion Shortfalls

Like day-ahead congestion shortfalls, balancing congestion shortfalls result from differences in the network capability between markets. In this case, it is the difference between the network capability in the day-ahead and real-time markets. Balancing shortfalls fell sharply in 2012 from $53 million to $17 million. Balancing congestion shortfalls occur primarily during the months from May to September, largely because of TSA events that greatly reduce transfer capability into Southeast New York in real time.[55] In 2012, more than 80 percent of balancing congestion

52 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. TCC modeling assumption was ultimately changed to conform to the day-ahead assumption.

53 Figure A-50 in the Appendix summarizes the day-ahead congestion shortfalls on major transmission facilities for 2011 and 2012 on a monthly basis.

54 The allocation method is described in NYISO Open Access Transmission Tariff, Section 20.

55 Figure A-51 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2011 and 2012 on a monthly basis.

shortfalls accrued during periods when TSAs were frequently called. Lower fuel prices and improvements related to the operation of the PAR-controlled lines described below also contributed to the reduction in balancing congestion shortfalls.

The balancing congestion shortfalls related to the PAR-controlled lines between New Jersey and New York fell from $7 million in 2011 to a $3 million *surplus* in 2012 due to improvements in the real-time operation of the lines. Hence, these improvements accounted for $10 million of the reduction in the shortfalls. These PAR-controlled lines produce significant surpluses when the NYISO is able to adjust flows (relative to the day-ahead scheduled level) across the lines to mitigate real-time congestion.

B. Transmission Congestion Contracts

We evaluate the performance of the TCC market by examining the consistency of TCC auction prices and congestion prices in the day-ahead market. For this report, we perform this assessment for the 12-month period from November 2011 to October 2012. We find that average day-ahead congestion was well below the TCC prices on most inter-zonal paths.[56] These results indicated that the sharp reduction in congestion that occurred from 2011 to 2012 was not anticipated by the participants in the TCC markets. However, the TCC prices fell from the annual auctions (which occurred in August 2011) to the auctions of six-month TCCs (which occurred in September 2011 and March 2012) and fell further in the monthly reconfiguration auctions (which occurred several weeks before each month). This trend indicates that the markets increasingly recognized the decrease in congestion over time.

Because the TCC prices generally exceeded the congestion in the day-ahead market, market participants purchasing TCCs in the auctions covering the 12-month period from November 2011 to October 2012 netted a total loss of $9 million. TCC profits totaled *negative* $8 million in the one-year auctions, *negative* $7 million in the six-month auctions, and $7 million in the reconfiguration auctions, reflecting that the TCCs were particularly over-valued most in the early auctions before the falling congestion levels were fully recognized.

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[56] Section III.D of the Appendix show our analyses regarding TCC auction results and day-ahead congestion.

TCC profits totaled *negative* $32 million for interzonal components of the TCCs and $23 million for intrazonal components of the TCCs. The profitability of interzonal TCCs is highly dependent on factors that increase price differences between regions, such as natural gas prices and load levels. Both of these factors were much lower than anticipated from November 2011 to October 2012.[57] In contrast, intrazonal components of the TCCs were consistently profitable for each TCC auction, indicating that the factors contributing to more localized congestion were generally underestimated by the markets during this period.

57 Section III.D of the Appendix shows additional detail regarding the profitability of TCCs and how TCCs are broken into interzonal and intrazonal components.

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 4 summarizes the net scheduled imports between New York and neighboring control areas in 2011 and 2012 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours. [58]

Table 4: Average Net Imports from Neighboring Areas
Peak Hours, 2011 – 2012

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	Total
2011	1,174	339	677	-59	275	489	122	113	3,130
2012	1,294	666	572	-239	268	267	120	64	3,012

58 Figure A-54, Figure A-55, and Figure A-56 in the Appendix show more detailed net scheduled interchanges between New York and neighboring areas by month by interface.

Average total net imports from neighboring areas did not change significantly from 2011 to 2012, falling roughly 4 percent from 2011 to 2012 during peak hours. However, net imports across individual interfaces varied more substantially over the period.

Controllable Interfaces

The interchange across the four controllable interfaces was relatively consistent from month to month in 2012 with several notable exceptions. First, net imports across the Neptune line fell substantially from the end of May through the end the year due to a transmission outage. Second, net imports over the Cross Sound Cable and the Northport-Norwalk line were significantly lower in November and December 2012 when natural gas prices in New England were significantly higher than natural gas prices in Long Island. Imports from neighboring control areas account for a large share of the supply to Long Island. These factors caused this share to fall from 34 percent of the load in 2011 to 25 percent in 2012.

Primary Interfaces

In contrast to the controllable interfaces, the interchange across the primary interfaces varied more substantially. Net imports from Ontario rose 96 percent (or roughly 330 MW) from 2011 to 2012, partly because fewer transmission outages occurred in 2012 than in 2011 that reduced the transfer capability between the two regions. In addition, changes in the NYISO's interface pricing methodology in February 2012 increased the LBMPs at the Ontario proxy bus slightly and encouraged additional imports from Ontario. [59]

Exports to New England rose considerably during the winter months when the spread in natural gas prices between New England and New York increased sharply. Flows from Hydro Quebec to New York typically rose in the summer months and in periods of high natural gas prices, reflecting the flexibility of their hydroelectric generation to export power to New York when it is most valuable to do so.

59 See NYISO Technical Bulletin 213.

Net imports from PJM fell 15 percent from 2011 to 2012 during peak hours, partly because lower natural gas prices reduce prices in New York relative to PJM. Imports from PJM were also affected by three significant modeling changes listed below. Two of the changes reduced the incentives to import from PJM, while the last one substantially increased the incentives to import from PJM.

- The changes in the NYISO's interface pricing methodology in February 2012 moderately reduced the LBMPs at the PJM proxy bus and encouraged fewer imports from PJM.
- The operation of the PAR-controlled lines between New York and New Jersey was modified in May 2012. This change altered the distribution of flows across the primary PJM interface such that more flows from western Pennsylvania to western New York rather than from New Jersey to New York City and the Hudson Valley.[60] These changes led to corresponding changes in the pricing methodology that reduced the incentive to import from PJM.
- The NYISO corrected a software issue in October 2011 that had reduced the real-time LBMPs at the PJM proxy bus by approximately 5 to 6 percent on average since 2007. By correcting the software issue, the NYISO increased the price paid to importers and provided greater incentives to import from PJM to the NYISO.

Despite the reduction in overall net imports from PJM, average real-time prices were approximately 2 percent higher on the PJM-side of the interface than on the NYISO-side (see Table 5), suggesting that it would have been economic if net imports had dropped even further.

B. Unscheduled Power Flows

Unscheduled power flows (i.e., loop flows) through New York can significantly affect the pattern of congestion. Clockwise loop flows around Lake Erie, which exacerbate west-to-east congestion in New York, decreased substantially from 2011 to 2012. On average, Lake Erie loop flows were 3 MW in the counter-clockwise direction in 2012 compared to 151 MW

60 Before May 1, 2012, the PAR-controlled lines from New Jersey to Southeast New York (i.e., the 5018, JK, and ABC lines) were assumed and operated accordingly to carry 66 percent (40 percent on the 5018, and 13 percent each on the JK and ABC) of the scheduled interchange between NYISO and PJM. Free-flowing tie lines from Pennsylvania to Western New York were assumed to carry the remaining 34 percent of the interface flow. Effective on May 1, 2012, the changes in PAR operations moved the total 26 percent of the interface flow from the JK and ABC lines to the free-flowing western tie lines, which led to corresponding changes in the price calculation at the PJM proxy bus.

clockwise in 2011.[61] Clockwise circulation around Lake Erie has been reduced by multiple factors, including changes in scheduling patterns in the surrounding markets. Low natural gas prices in 2012 increased output from generators in the Northeast and mid-Atlantic areas and reduced the demand for imports from the west, thereby reducing west-to-east flows that contribute to clockwise circulation. Two additional market developments likely contributed to the reduction in the magnitude of clockwise loop flows in 2012:

- Phase angle regulators ("PARs") that have been installed to control the flows across the four lines that make up the Ontario-to-Michigan interface began operating in April 2012. These PARs are generally operated to better conform actual power flows to scheduled power flows across the Ontario-Michigan interface. MISO and IESO have indicated the PARs are capable of controlling up to 600 MW of loop flows around Lake Erie (although the PARs are not adjusted until the loop flows exceed 200 MW).[62]

- The NYISO's new interface pricing methodology has generally improved the accuracy of prices at both the external proxy buses and at internal locations in the day-ahead and real-time market models. The new pricing methodology better accounts for how changes in scheduling of external transactions and internal generators affect power flows across the NYISO-Ontario and NYISO-PJM interfaces and better aligned flows in the market models with actual power flows.[63]

When clockwise loop flows increase, the NYISO may use Transmission Loading Relief ("TLR") procedures to ameliorate their effects on congestion in New York. However, 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). In 2012, the reduction in clockwise loop flows contributed to a substantial reduction in the frequency of TLRs called by the NYISO -- from 23 percent of the hours in 2011 to 8 percent of the hours in 2012. The frequency of TLRs was also reduced by changes in the TLR process that began when the Ontario to Michigan PARs began operating. In particular, there were times when the effectiveness of the TLR process was reduced because the

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[61] Figure A-57 in the Appendix summarizes the pattern of loop flows around Lake Erie for each month of 2011 and 2012.

[62] The use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

[63] See NYISO Technical Bulletin 213.

PARs were deemed to be in "regulate" mode, even though clockwise circulation substantially exceeded 200 MW and contributed to congestion on a NYISO flow gate.

To manage the congestion created by unscheduled loop flows more efficiently, the NYISO and PJM implemented the Market-to-Market coordinated congestion management process on January 16, 2013.[64] Given its very recent implementation, we have not yet evaluated the performance of this process or the benefits it is producing. However, we believe from our ongoing monitoring that it has improved the operation of the Ramapo transmission line.

The NYISO is also planning to work with ISO New England to coordinate congestion management between the two markets in the future. This should improve congestion management on transmission paths from Capital Zone to Hudson Valley Zone that can be affected by unscheduled power flows from New England.

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 2012. Like previous years, we find that while external transaction scheduling by market participants provided 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 5 evaluates the efficiency of inter-market scheduling between New York and Ontario, PJM, and New England during 2012. [65]

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 slightly over half of the hours on most interfaces between New York and neighboring markets during 2012. The share of hours

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64 See Schedule D of Attachment CC to the NYISO OATT.

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

with efficient scheduling ranged from 52 percent on the New England primary interface to 80 percent on the Ontario-New York interface. Nonetheless, there was still a large share of hours when power flowed in the inefficient direction on all of the interfaces. Furthermore, there were many hours when power flowed in the efficient direction, but additional flows would have been necessary to fully arbitrage between markets.

Table 5: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2012

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-237	-$0.59	52%
Ontario	659	$6.70	80%
PJM	629	-$0.95	54%
Controllable Ties			
1385 Line	108	$4.18	57%
Cross Sound Cable	251	$7.74	58%
Neptune	257	$10.49	65%
Linden VFT	72	$2.05	60%

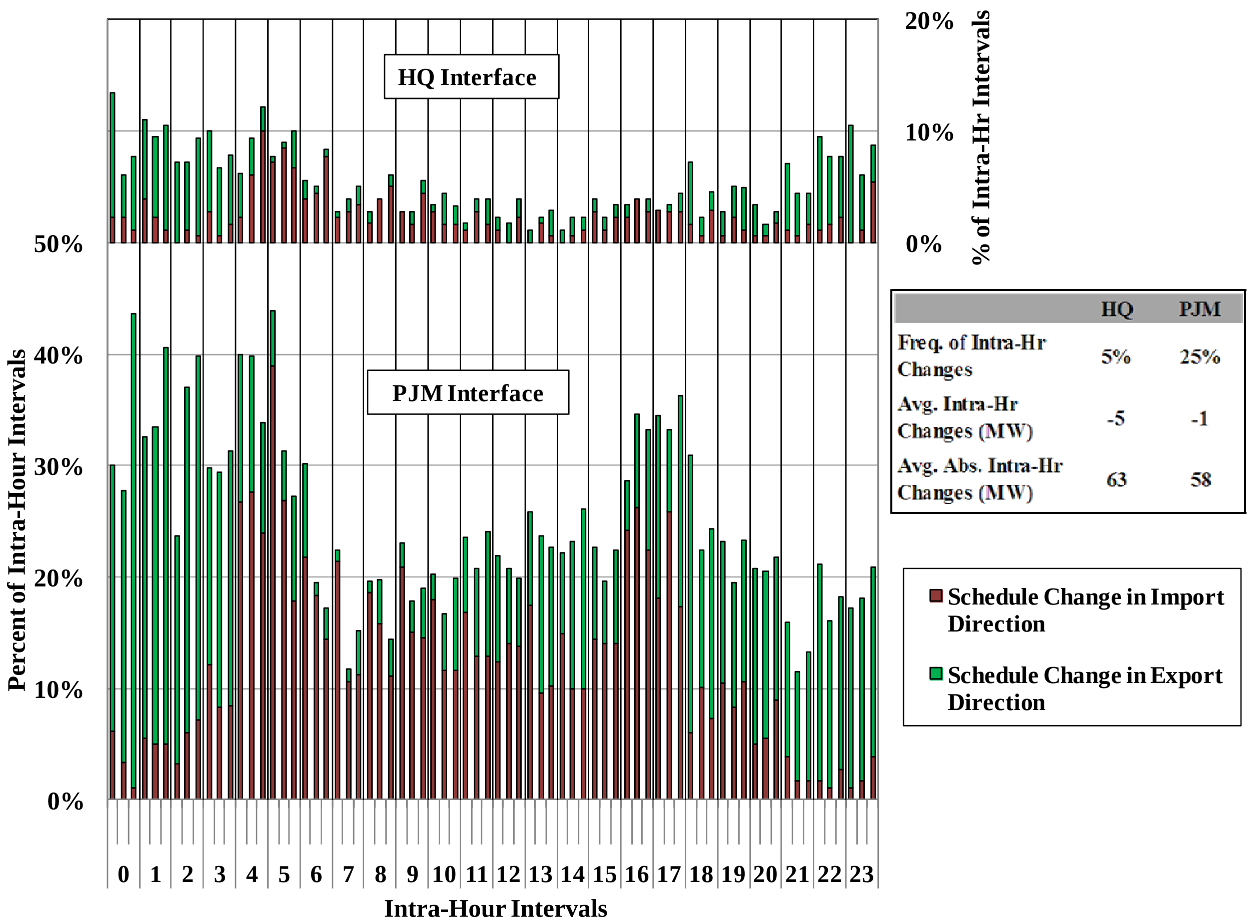
Although scheduling by market participants tended to improve convergence, significant opportunities remain to improve the interchange between regions. The NYISO has been working on several initiatives to improve the utilization of its interfaces with neighboring RTOs, including more frequent scheduling (i.e., 15-minute scheduling) and Coordinated Transaction Scheduling ("CTS"). These market enhancements are being implemented in phases under the Enhanced Interregional Transaction Coordination ("EITC") project. By the end of 2012, 15-minute scheduling (which is discussed in Section D) had been enabled at four interfaces and substantial progress had been made on CTS with PJM and ISO New England. The recent changes in interface scheduling over the primary interfaces are assessed in the next subsection. Ultimately, however, we expect that full implementation of CTS with its adjacent markets is essential for NYISO to capture the economic and reliability benefits of well-utilized external interfaces.

D. Intra-Hour Scheduling with Adjacent Control Areas

On July 27, 2011, the NYISO first activated 15-minute scheduling on the primary interface between New York and Hydro-Quebec. The NYISO and PJM activated 15-minute scheduling on their primary interface on June 27, 2012. 15-minute scheduling was implemented on the Neptune and Linden VFT scheduled line interfaces on October 30 and November 28.

To evaluate the effects of 15-minute intra-hour scheduling, this section assesses the scheduling patterns on the primary interfaces with HQ and PJM in 2012. Figure 12 shows the frequency of quarter-hour schedule changes (not including schedule changes at the top of the hour) by time of day at the primary HQ and PJM interfaces from July to December 2012.

Figure 12: Distribution of Quarter-Hour Schedule Changes by Time of Day
Primary Interfaces with PJM and HQ, July – December 2012



The horizontal axis shows all quarter-hour intervals (i.e., :15, :30, and :45 intervals of each hour) and excludes top of the hour schedule changes to focus on the transactions that were facilitated by the scheduling changes. The vertical axis shows the percent of intervals when the net schedules change from the previous interval in the import direction and the export direction for each interface. The Neptune and Linden VFT interfaces are not included in this evaluation due to the short period of time since the activation of 15-minute schedule at those interfaces.

Figure 12 shows that intra-hour schedule changes occurred during approximately 5 percent of all quarter-hour intervals on the primary HQ interface, much less frequently than the 25 percent of all quarter-hour intervals on the primary PJM interface. Several factors likely account for this difference. First, like the NYISO, PJM runs a real-time spot market that allows market participants to buy and sell from the market and to be more responsive to price changes. In contrast, market participants must find a counter-party in HQ with whom to transact, which may increase the difficulty of responding to arbitrage opportunities. Second, the prices at the PJM proxy bus were generally more volatile than prices at the HQ proxy bus, which increases the incentives to schedule intra-hour. Third, the economic direction in which to flow power changes more frequently between the NYISO and PJM than between the NYISO and HQ.

The figure also shows that intra-hour schedules were typically adjusted in ways that generally reduce price volatility at the top of these hours. In particular, intra-hour schedules are generally adjusted in the export direction during hours when the system is typically ramping-down (e.g., hours-beginning 21 to 23 and hours 0 to 3) and in the import direction during hours when the system is typically ramping-up (e.g., hours-beginning 5 to 10). This is an efficient response to the pattern of real-time prices, which typically move: (a) upward within each ramping-up hour before dropping sharply at the top of the next hour; and (b) downward within each ramping-down hour before rising sharply at the top of the next hour. Hence, these intra-hour transactions tend to moderate real-time price volatility in the ramping hours.

Although intra-hour scheduling has been beneficial, substantial inefficiencies remain in the utilization of the external interfaces between NYISO and the adjacent markets. Given the potential benefits from more efficient coordination of the external interfaces, we recommend that the NYISO continue to place a high priority on the initiatives to improve the utilization of its interfaces with neighboring RTOs.

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 ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response. 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. This section summarizes the capacity market results in 2012, evaluates the process for creating new capacity zones, and discusses the criteria for selecting the technology of the demand curve unit.

A. Capacity Market Results in 2012

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 contributes to significantly lower prices in the winter than in the summer.

The Capacity Demand Curves determine how variations in the supply of capacity or in the capacity requirements (i.e., demand for capacity) affect capacity clearing prices. Based on the Capacity Demand Curves that were in effect in the 2012-13 Capability Year, a one percent change in capacity supply or demand would change the clearing price by: $0.75/kW-month in NYCA, $1.08/kW-month in New York City, and $0.56/kW-month in Long Island.

1. Capacity Market Results: NYCA

In NYCA, the spot price averaged $2.27 per kW-month in the Summer 2012 Capability period and $2.09 per kW-month in the Winter 2012-13 Capability period (excluding March and April 2013), up from less than $0.65 per kW-month in each month during the previous Capability Year. These price increases were due to significant changes in both capacity requirements and the supply of capacity.

On the demand side, the ICAP requirement rose 839 MW (or 2.2 percent) from the May 2011-April 2012 Capability Year to the May 2012-April 2013 Capability Year for two primary reasons. First, the peak load forecast rose 1.8 percent. Second, the Installed Reserve Margin for New York State increased from 15.5 percent to 16 percent.

On the supply side, the following changes increased the statewide capacity prices significantly. First, sales from internal resources fell 1.8 GW (or 4.7 percent) because of the retirement and mothballing of generation, which included: a) 550 MW in New York City in May 2012; b) 330 MW on Long Island in July 2012; c) 370 MW in Western New York in September 2012; and d) 500 MW in Hudson Valley in January 2013.

Second, sales from SCRs fell over 200 MW from the Summer 2011 to the Summer 2012 following recent improvements in the baseline calculation method (i.e., adopting the Average Coincident Load method). However, these factors were partly offset by the entry of new resources in New York City in July 2011 (550 MW) and June 2012 (500 MW).

2. Capacity Market Results: New York City

In New York City, spot prices averaged $11.88 per kW-month in the Summer 2012 Capability period, up 42 percent from the previous summer. Spot prices averaged $4.52 per kW-month in the Winter 2012-13 Capability period (excluding March and April 2013), up modestly from the previous winter. Like the increases statewide, these increases were driven by the following changes in both demand and supply factors.

On the demand side, changes in the local requirement and the underlying demand curve contributed to the capacity price increases in New York City. First, the ICAP requirement rose 219 MW (or 2.3 percent), which was primarily due to an increase in the local capacity requirement from 81 percent to 83 percent. Second, a new demand curve was deployed in October 2011 that increased clearing prices by 20 percent versus the previous demand curve.

On the supply side, there were several offsetting changes. In May 2012, the amount of internal capacity eligible to sell into the spot capacity market fell by more than 500 MW (or 5 percent). In June 2012, this reduction was offset when a 500 MW new resource entered in New York City. In December 2012, buyer-side mitigation was imposed on the 550 MW Astoria Energy II facility. Since mitigation was imposed, the amount of unsold capacity has risen and the clearing price has been $4.91 per kW-month, up from $3.36 per kW-month in November 2012.

3. Capacity Market Results: Long Island

In Long Island, the spot price averaged $3.19 per kW-month in the Summer 2012 Capability period and $2.09 per kW-month in the Winter 2012-13 Capability period (excluding March and April 2013), compared to less than $0.65 per kW-month in each month during the previous Capability Year. Because of the substantial capacity surplus relative to the Long Island locality requirement, these price changes were driven primarily by the rise in NYCA capacity prices.

The local capacity requirement for Long Island was rarely binding during summer and winter Capability Periods in 2012, reflecting that Long Island generally has far more capacity than needed to satisfy its local capacity requirement. The only months when the Long Island clearing price was higher than the NYCA clearing price were July to October 2012. This was because three units on Long Island totaling 330 MW were retired in July 2012, which led the spot price to rise from $1.94 per kW-month in June 2012 to $3.56 per kW-month in July 2012.

B. Capacity Zone Configuration

Capacity price signals should reflect the value of capacity in each area. Currently, capacity clearing prices are set at three distinct locations: New York City, Long Island, and NYCA. In April 2013, the NYISO is expected to file for the creation of a new capacity zone in Southeast New York ("SENY"). This will greatly enhance the efficiency of the capacity market signals, but it is overdue. The delay in creating the SENY capacity zone has had several consequences that illustrate the importance of promptly creating new capacity zones when they are needed.

- The total amount of unforced capacity sold in Zones G, H, and I has fallen by 1 GW (or 21 percent) since the summer of 2006, even as the need for resources to address the UPNY-SENY interface has become more apparent in the NYISO's Comprehensive Reliability Planning Process. Some of this capacity may have been economic to remain in service or been maintained more reliably if the SENY capacity zone had been implemented sooner.

- Because the binding UPNY-SENY interface limits supply resources from reaching Zones G-K, capacity retirement in Zones G and H has resulted in higher Local Capacity Requirements ("LCRs") for Zones J and K. From the 2010/11 Capability Period to the

2013/14 Capability Period, the LCR for Zone J has risen from 80 percent to 86 percent. A one percent increase in the LCR equates to a $1.30/kW-month increase in capacity prices given the current level of the capacity demand curve for New York City (assuming no change in the quantity of supply). Consequently, the delay in modeling a SENY capacity zone has led to higher capacity prices in Zone J.

- Although the capacity market will not recognize the higher reliability benefits of capacity in Zones G, H, and I relative to capacity in Zones A to F until 2014, the Highway Deliverability Test has recognized this for several years. Consequently, some capacity suppliers outside SENY have been prevented from selling at the prevailing price levels, which has increased the capacity prices in Zones A to F.
- Finally, waiting until 2014 to model the SENY capacity zone will likely result in a sharp increase in prices for customers in the SENY capacity zone outside Zone J, rather than a gradual increase that could have been ameliorated with modest changes in consumption behavior or demand response.

In summary, the creation of a SENY capacity zone before 2014 would have facilitated more efficient investment in both new and existing resources where the Reliability Needs Assessment has identified resources are necessary for resource adequacy over the next ten years. Nonetheless, it should remain a high priority for the NYISO to move forward expeditiously to create and price the SENY zone.

It is also important to continue refining the locational signals in the capacity market, since new reliability needs will emerge over time. This section discusses the need for three capacity market design changes that will better enable the market to provide locational signals in the future, and avoid the costly delay that occurred in creating the SENY zone.

1. Pre-defining Interfaces Between Capacity Zones

The NYISO's application of the NCZ study will not lead to the timely creation of other new capacity zones in the future for three reasons. First, the NCZ study methodology is based on the Highway Deliverability Test criterion and does not consider whether additional capacity is needed to satisfy resource adequacy requirements in a particular area. Hence, if the NYISO's Reliability Needs Assessment identifies areas where additional capacity is needed to meet resource adequacy criteria, there is no guarantee that the NCZ study criteria will be triggered.

Second, the NCZ criteria is only triggered if existing CRIS rights result in a binding highway deliverability constraint. Hence, if new resources are entering or imports are being offered that are not deemed deliverable because of a highway constraint, the NCZ study criteria may not be triggered. This is a case were a new zone is needed to allow the price to fall in the zone with the excess capacity, which will help facilitate more efficient capacity trading with external areas and investment decisions.

Third, the NCZ study process is lengthy and uncertain, occurring just once every three years, and leading to the creation of a capacity zone in no less than 13 months from the filing date. This process would be particularly inadequate if the unexpected retirement of large generation resources led to significant unmet reliability needs that were not properly reflected in the capacity market for several years. Consequently, it would be difficult to address the reliability need without regulated investment.

In order to create new capacity zones promptly, we recommend pre-defining 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 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. When private investors make upgrades, they should receive capacity deliverability rights to provide efficient incentives for such investment.

Finally, unexpected retirements that have significant local reliability implications would cause locational capacity prices to move immediately and provide efficient price signals to the market. In some cases, retirements may be avoided altogether by the improved price signals in an area.

2. Modeling Export-Constrained Capacity Zones

Placing additional capacity in a nested capacity zone typically provides reliability benefits to the larger region. As described above, however, the reliability benefits of additional capacity in the nested capacity zone is sometimes limited by inter-zonal transmission limitations when an excess exists. Modeling the export constraints between zones in the capacity market limits how much capacity is sold in the nested capacity zone in order to meet the requirement in the larger region. For example, Long Island might be included in the SENY zone when substantial export capability remains available on the interface between Long Island and upstate New York. However, there is a level of excess capacity on Long Island that would cause additional investment there to produce no incremental reliability benefit in SENY outside of Long Island. Modeling an export constraint in the capacity market would allow the price on Long Island to fall below the rest of SENY when additional Long Island capacity would not relieve resource adequacy needs in the rest of SENY.

In summary, modeling export constraints would ensure that the capacity market provides incentives to invest in new and existing generation, transmission, and demand response that are consistent with the reliability benefits that result from the investment. Hence, we recommend the NYISO incorporate export constraints in its capacity market framework.

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 would 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.

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.

Recent demand curve reset studies have shown that the Net CONE of a new peaking installation is higher than for a combined cycle installation under many circumstances. The most economic choice of technology is the one that renders the lowest demand curve reference point when the excess level of the locality is considered. Although proposals to change the technology of the demand curve unit were recently not approved by stakeholders, we recommend the NYISO continue to pursue changes that would allow using the most economic generating technologies to establish the demand curves in the current demand curve reset process for the capacity market and modify the criteria for setting the excess level as described below.

Changing the technology of the demand curve unit would require a corresponding adjustment to the excess level assumption to make it appropriate for the size of the demand curve unit. The excess level is the assumed equilibrium level of excess capacity that would result if the marginal source of entry were the demand curve unit. Since the efficient scale of investment in new generation is large, new capacity investment is "lumpy". Hence, if capacity investment were to occur in each year when the capacity surplus would otherwise fall below 0 MW, the quantity of excess capacity will vary between 0 MW and the size of a new demand curve resource (averaging 50 percent of the size of the new resource). Because there are other sources of variation in supply, load growth cannot be perfectly predicted years in advance when a project is initiated, the tariff currently specifies a higher level of 100 percent of the size of the new resource is used as the excess level.

This rule works relatively well when the demand curve unit is based on an installation with several small peaking units, but it may not be realistic when the demand curve unit is a larger combined cycle installation. Hence, we recommend modifying the excess level to a level more consistent with the expected equilibrium excess level that would occur if the marginal source of entry were the demand curve resource. One way to accomplish this is to revise the excess level to be equal to 1 percent of the capacity requirement plus, 50 percent of the capacity of the demand curve unit.

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 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.

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.

1. Evaluation of Gas Turbine Scheduling

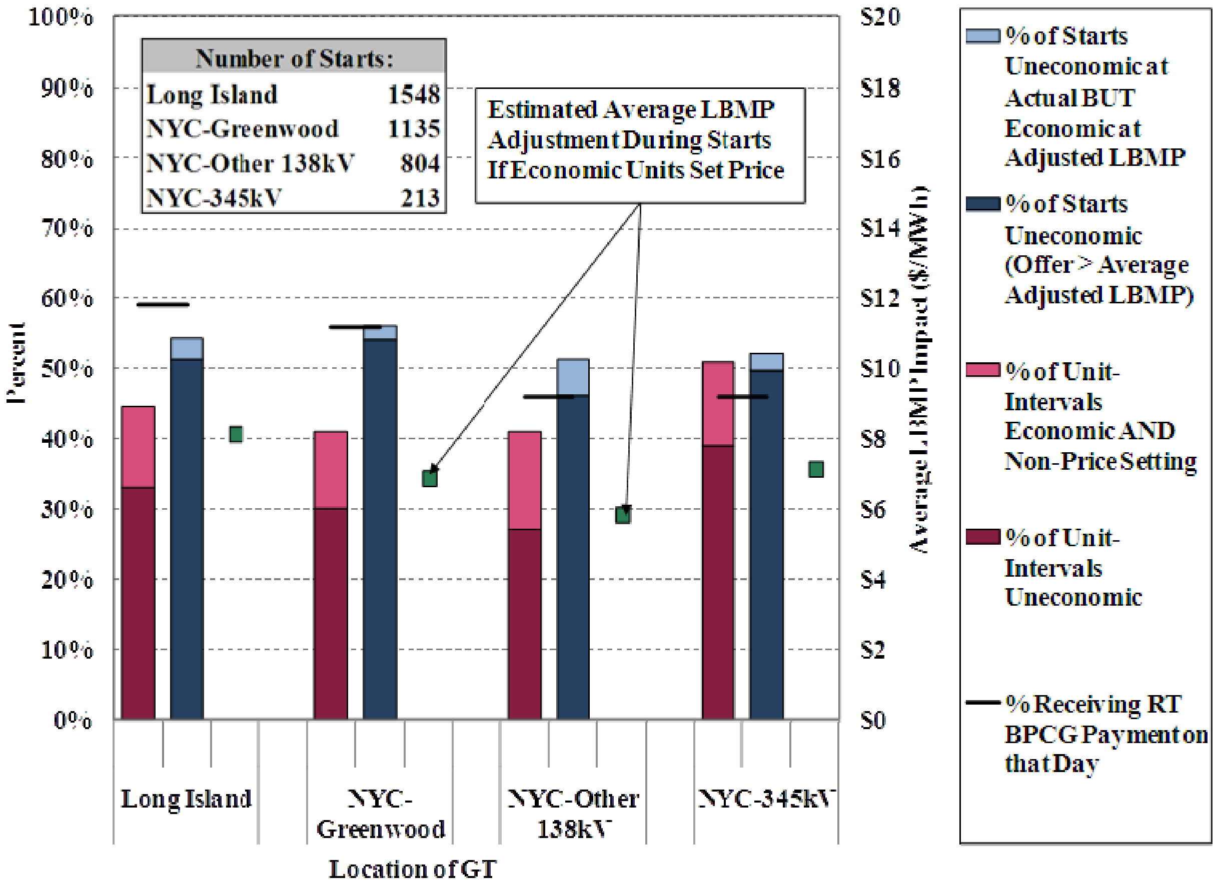
We found that nearly 50 percent of capacity committed (excluding self schedules and local reliability commitments) in 2012 was clearly economic over the initial commitment period and that the overall efficiency was consistent with recent years.[66] The gas turbine was deemed clearly economic if the as-offered cost was less than the LBMP revenue earned over the initial commitment period (usually one hour). However, this criterion likely understates the share of gas turbine commitments that are efficient for two reasons. First, the efficient commitment of a

[66] See Figure A-63 in the Appendix for details of this analysis.

gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer. Second, in some cases, a gas turbine that is committed efficiently may still not set the LBMP due to the manner in which the real-time pricing methodology determines whether a gas turbine is eligible to set the LBMP. [67]

Figure 13 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP in a portion of the initial commitment period. [68]

Figure 13: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2012



We found that gas turbines that were committed in merit order in 2012 were clearly economic in 61 to 73 percent of intervals during their initial commitment period. However, the units did not set the LBMP in 11 to 14 percent of the intervals when they were economic. We estimated that

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

68 See Section V.A in the Appendix for details of this analysis.

allowing these economic gas turbines to set prices would have increased the real-time LBMPs by an average of $6 to $8 per MWh for each start in New York City and Long Island in 2012. These results suggest that the hybrid pricing logic should be evaluated to identify changes that would more effectively allow economic gas turbines to set prices in the real-time markets. Hence, we recommend the NYISO modify the hybrid pricing logic to better allow economic gas turbines to set the LBMP.

2. Evaluation of External Transaction Scheduling

We found that a high portion (93 percent) of price-sensitive import offers and export bids were scheduled consistent with real-time prices at the primary interface with New England in 2012, roughly the same as in 2011. However, only approximately 60 percent of the transactions were scheduled in the efficient direction (i.e., from the lower-priced region to the higher-priced region).[69]

Although the external transaction scheduling process has functioned as well as can be expected and has tended 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 (which are discussed in Section VI.C) to improve coordination of the interchange between regions.

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 lower the overall cost of generation

[69] See Section V.B in the Appendix for detailed descriptions of this analysis.

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.[70] Such lines are evaluated in Section VI.C, 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 2012. The evaluation is done for nine PAR-controlled lines between New York and neighboring areas and two between New York City and Long Island.

70 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 6: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines [71, 72]
2012

	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)	54	$7.21	64%	$7
Sand Bar (PV 20)	-78	-$6.06	66%	$4
Waldwick (JK)	-811	$2.43	42%	-$21
Ramapo (5018)	441	$2.43	60%	$14
Farragut (BC)	567	$1.29	57%	$7
Goethals (A)	317	$2.80	58%	$5
PAR Controlled Lines (LI into NYC)				
Lake Success (903)	123	-$8.00	12%	-$10
Valley Stream (901)	59	-$13.02	10%	-$10

Between New York and neighboring markets, our analysis shows that power flowed in the efficient direction (from the low-priced area to the high-priced area) in the majority of hours on all but one of the PAR-controlled lines in 2012. The Waldwick lines generally flowed power from NYCA to PJM due to the ConEd-PSEG wheeling agreement, although the price on the PJM side was generally lower on average in 2012. [73] We estimated that the controllable lines between NYCA and neighboring control areas achieved a total of $37 million in net production cost savings in 2012, excluding the Waldwick lines. However, the use of the Waldwick lines to support the ConEd-PSEG wheeling agreement *increased* production costs by an estimated $21 million. Hence, significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

71 Note, this table reports the estimated production cost savings that actually resulted from the use of these transmission lines in 2012. They do *not* estimate the production cost savings that could have been realized if the lines were used optimally.

72 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.

73 The Waldwick lines connect New Jersey in the PJM system with the Hudson Valley (Zone G) in the NYISO system. Normally, the ConEd-PSEG wheel agreement requires approximately 1 GW to flow from the NYISO to PJM across the Waldwick lines and then back into New York City across the Farragut and Goethels lines.

Between Long Island and New York City, the scheduling of the PAR-controlled lines was highly inefficient with power flowing in the inefficient direction in nearly 90 percent of hours in 2011 and 2012. The use of these lines *increased* production costs by an estimated $21 million in 2011 and $20 million in 2012 because prices on Long Island were typically higher than those in New York City (particularly the portion of New York City where the 901 and 903 lines connect).[74] In addition to increasing production costs, these transfers: a) depress prices in New York City; and b) can restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect. Restrictions on the output of these generators sometimes adversely affects reliability in a much wider area (e.g., when there is an eastern reserve shortage or during a TSA event with severe congestion into Southeast New York).

These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick lines and 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 the long-standing contracts between scheduling parties that pre-date open access transmission tariffs and the NYISO's markets. However, it would be highly beneficial to modify these contracts or find other ways under the current contracts to operate the lines efficiently. Hence, we are recommending that the NYISO work with the parties to these contracts to explore potential changes.

C. Real-Time Price Volatility

Volatile prices can be an efficient signal of the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants, so it is important to identify the causes of volatility. In this subsection, we evaluate: a) cyclical patterns of price volatility that tend to occur predictably at certain times of day, and b) transient patterns of price volatility that may or may not occur under repetitive conditions.

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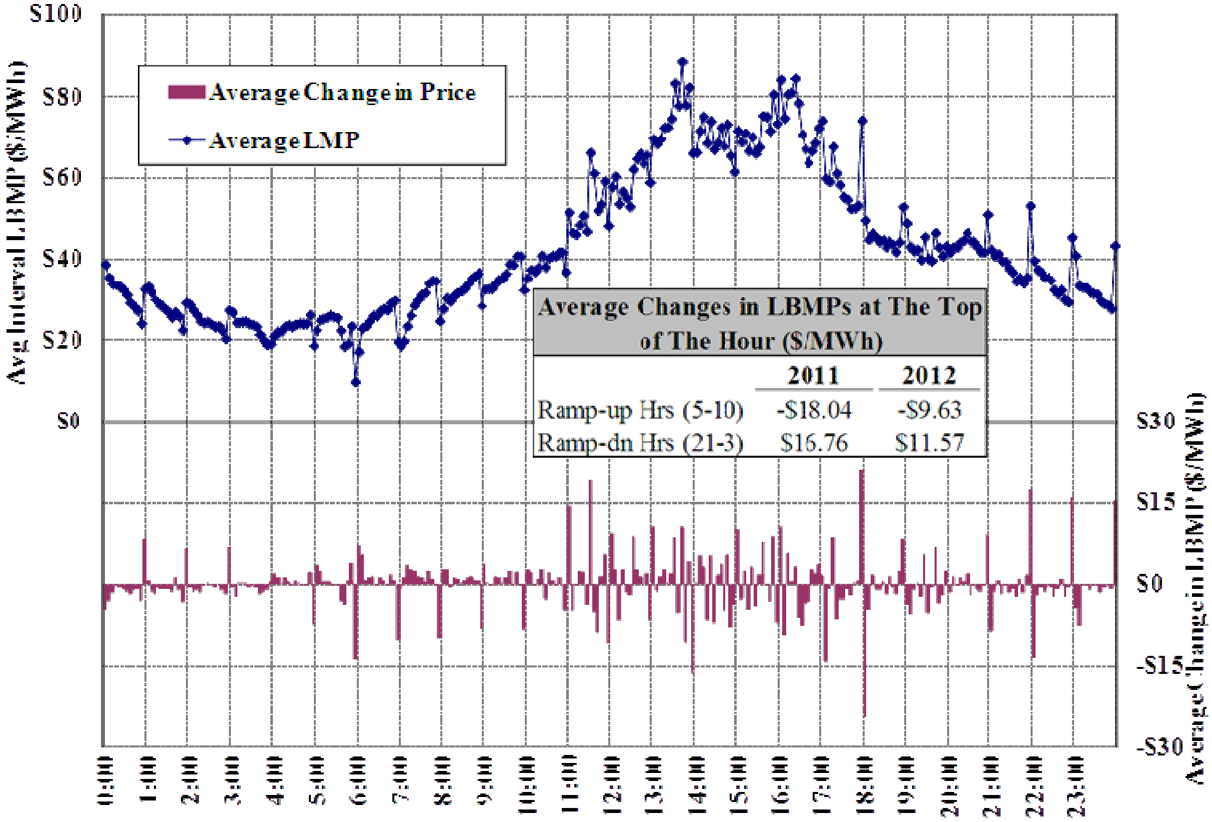
74 These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica "load pocket," an area that is frequently export constrained.

1. Evaluation of Cyclical Price Volatility

Our first analysis evaluates cyclical patterns of price volatility that occur predictably at certain times of day. These typically arise when flexible generators on the system lack the ramp capability to compensate for large changes in external transaction schedules or changes in the output of generators that are self-scheduled, starting-up, or shutting-down. Figure 14 shows the average 5-minute price for each interval of the day in the summer of 2012.

Figure 14: Statewide Average Five-Minute Prices by Time of Day
June to August 2012



Most cyclical real-time price fluctuations occurred predictably near the top of the hour during morning ramp-up (i.e., normally 5:00 to 10:00) and evening ramp-down (i.e., normally 21:00 to 23:00 and 0:00 to 3:00) periods. In the last interval of each hour, clearing prices dropped sharply in morning ramp-up hours and rose sharply in evening ramp-down hours.

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 that change their fixed schedules or that switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour. However, many generators still make their schedule changes at the top of the hour, which increases the need to ramp flexible generators.[75]

Recent changes in external scheduling contributed to reducing price volatility (i.e., the average size of changes in LBMPs) near the top of the hour during ramping periods by roughly 30 to 50 percent from 2011 to 2012. NYISO's introduction of 15-minute scheduling of external transactions, particularly at the primary PJM interface on June 27, 2012, reduced the ramp demand on the system by spreading the changes in external schedules over the hour.[76] This reduces how much internal generation must be ramped in the five-minute dispatch around the top of the hour.

2. Evaluation of Transient Price Volatility

We also evaluated scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the energy-balance constraint (i.e., the requirement that supply equal demand) in 2012.[77] The effects of transient transmission constraints tend to be localized, while transient spikes in the energy-balance constraint affect prices throughout NYCA.

The "shadow price" of a constraint is normally equal to the marginal cost of satisfying the constraint. For a transmission constraint, the effect on each LBMP depends on the proximity of the resource or load to the constrained facility and the shadow price. The energy-balance constraint affects the energy component of the LBMP throughout the system.

Figure 15 summarizes transient shadow price spikes for transmission constraints (i.e., facilities "A" to "H" and "Other") and for the energy-balance constraint (i.e., "Energy") in 2012. [78, 79]

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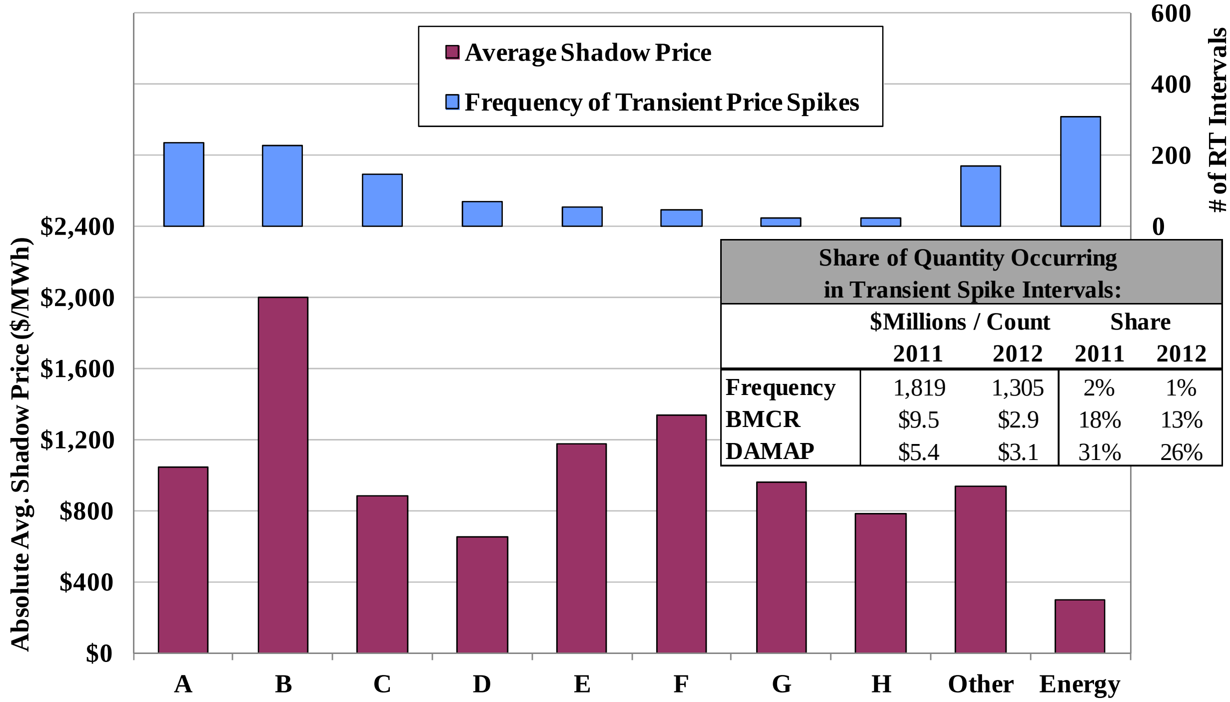
75 See Figure A-68 in the Appendix for more details.

76 See Figure A-62 in the Appendix for more details.

77 See Figure A-69 and Figure A-70 in the Appendix for more details.

78 Transmission constraint shadow price spikes are deemed "transient" if the shadow price is at least $300 per MWh, the shadow price increases 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.

Figure 15: Frequency and Cost of Transient Price Spikes
2012



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

Transient shadow price spikes occurred in about 1 percent of all real-time intervals. Although relatively infrequent, transient price spikes are important because it can be far more costly to manage variations in system conditions that are not anticipated. Disproportionately large quantities of uplift from Balancing Market Congestion Residuals (13 percent of the total in 2012) and Day-Ahead Margin Assurance Payments (26 percent of the total in 2012) arose from intervals when transient price spikes occurred, although both categories of uplift were down significantly from 2011. Transient real-time price spikes can have large effects on average price levels. For example, the two 345 kV lines into Long Island (facilities "C" and "D" in Figure 15)

[79] Energy-balance constraint spikes are considered "transient" if the reference bus price (i.e., the energy component of the LBMP) is at least $150 per MWh and it increases at least 50 percent from the previous real-time interval.

exhibited 212 transient price spikes with an average shadow price of $816 per MWh in 2012, which raised Long Island zone LBMPs by 3 percent over the year.

We evaluated factors that contributed to transient shadow price spikes in 2012 and found that the following three had the most significant impacts. [80]

- External transactions – Particularly for Long Island price spikes (i.e., facilities "C" and "D"), Central-East interface price spikes (i.e., facility "H"), and statewide price spikes (i.e., "Energy"). Large hourly schedule changes across these interfaces often led to price spikes, since available generation in the constrained area could not ramp quickly enough to pick up the change.

- Flow changes on non-optimized PAR-controlled lines – Most significant contributing factor for five of the categories evaluated (includes facilities "A", "E", "F", "H", and "Other"). These occur because RTD and RTC assume the flow across these lines will remain fixed at the most recent telemetered value. In reality, the PAR flows are affected by PAR setting changes, the settings of other nearby PARs, and the dispatch of generation and load. Therefore, the telemetered value may change substantially from one interval to another, resulting in transitory instances of severe congestion.

- Generators ramping-down – Accounted for a large share of statewide price spikes. These occur primarily when generators are in the process of shutting-down and reduce output very quickly. When these decommitments are not staggered, it can cause transitory statewide price spikes.

In many cases, high LBMPs occurred when low-cost capacity was available to relieve the constraint, but the capacity was not utilized because the generator was not instructed to ramp-up soon enough.

3. Real-Time Price Volatility – Conclusions

Both the frequency and magnitude of real-time price volatility has declined in 2012. First, the cyclical price volatility summarized in Figure 14 fell by almost one third from 2011 to 2012 in ramping hours. Second, the frequency of the transient price spikes fell 28 percent from 2011 to 2012. One of the principal causes of these changes was likely the introduction of 15-minute scheduling at the primary PJM interface because it has enabled market participants to avoid large schedule changes at the top of the hour.

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80 See Figure A-70 in the Appendix for details of this analysis.

The largest remaining contributors to real-time price volatility included: a) inflexible scheduling practices by generators; b) unforeseen changes in flows across non-optimized PAR-controlled lines; c) large external transaction schedule changes, particularly at the top of the hour; and d) decommitment of gas turbines. The look ahead evaluations of RTD and RTC help schedule flexible resources to respond to these variations. Hence, the ability of these models to anticipate the ramp demands and schedule the system efficiently has a substantial effect the system's price volatility. These scheduling decisions are particularly important for committing and decommitting gas turbines, and for scheduling external transactions as described below.

Regarding gas turbines, RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut down gas turbines. Since RTC assumes other generation can ramp 15 minutes from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage in a five-minute interval. When RTD solves for each five-minute market interval, it is unable to delay the shut-down of a gas turbine, even if it would be economic to do so.

Regarding external transactions, large adjustments in external transaction schedules in the export direction often led to severe price spikes. The look-ahead evaluations in RTD and RTC evaluate system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45), while external transactions reach their scheduled levels at five minutes past each quarter-hour (i.e., :05, :20, :35, and :50). RTD and RTC do not anticipate well transient shortages that occur in these intervals. Therefore, we recommend: a) modifying the intervals in RTD to always model each five-minute interval in which external transactions are ramping (e.g., intervals :55, :00, and :05); and b) evaluating the cost and feasibility of improvements to RTC that would allow it to better recognize NYISO's ramping demands and be consistent with RTD.

D. Market Performance under Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission constraints. Efficient prices also provide suppliers and demand response resources with incentives to respond during real-time shortages. Three types of shortage conditions can occur in the real-time market:

- Operating reserve and regulation shortages – These occur when the real-time model is unable to schedule the required amount of an ancillary service at a marginal cost less than the "demand curve" for the requirement. Due to the co-optimization of energy and ancillary services, the value of the ancillary service is reflected in LBMPs.

- Transmission shortages – These occur when power flows (as modeled in the market systems) exceed the limit of a transmission constraint. Clearing prices for energy in the constrained area are set according to several methods.[81]

- Reliability demand response deployments – When the NYISO anticipates a reliability or security issue, it can deploy demand response resources for a minimum of four hours, typically at a cost of $500 per MWh.

This section: a) summarizes the three types of shortage pricing outcomes during 2012 and b) evaluates the efficiency of real-time prices during the demand response deployment.

1. Summary of Shortage Pricing in 2012

Table 7 summarizes the frequency of shortage conditions and the resulting pricing outcomes in 2012. Operating reserve requirements that have a demand curve value of $25 per MWh are not included in this evaluation. The table also shows approximately how each type of shortage was reflected in energy LBMPs in West Zone, Capital Zone, Hudson Valley Zone, New York City, and Long Island.

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81 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).

Table 7: Summary of Real-time Shortages and Price Impacts
2012

	Shortage Frequency (# of Intervals)	Avg Shortage Price ($/MWh)	Impact on Zone Prices ($/MWh)				
			West	Capital	Hudson	NYC	LI
Ancillary Services Shortages							
10-Minute East	350	$465		$1.55	$1.55	$1.55	$1.55
Regulation	402	$170	$0.65	$0.65	$0.65	$0.65	$0.65
Other NYCA Requirements	88	$269	$0.22	$0.22	$0.22	$0.22	$0.22
Transmission Shortages							
Dunwoodie - Shore Road	196	$977					$1.82
E. Garden City - Valley Stream	206	$1,310					$0.20
Leeds-Pleasant Valley	63	$2,245		$0.03	$0.44	$0.51	$0.51
Other Facilities	236	$2,251	$0.16	$0.09	$0.09	$0.36	$0.30
Scarcity Pricing During DR Activation							
Rule A	10		$0.04	$0.04	$0.02	$0.02	$0.01
Rule B	24			$0.08	$0.01	$0.01	$0.01
Total			$1.07	$2.66	$2.98	$3.32	$5.27

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 4 percent in 2012. Overall, the price impacts from transmission shortages ranged from $0.12 per MWh in the Capital Zone to $2.83 per MWh in Long Island. Scarcity pricing during demand response deployments, which we evaluate below, was relatively infrequent and raised the average zonal LBMP by up to $0.12 per MWh. In eastern New York, the overall impact of shortage pricing was substantial, accounting for $2.66 to $5.27 per MWh (or 7 to 10 percent) of the average LBMP over the year.

In evaluating the shortages, 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 $4,000 per MWh.[82] 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 Demand Curve that would more accurately reflect the severity of the shortage condition.

82 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.

2. Reliability Demand Response Deployments

Reliability demand response resources provide significant economic and reliability benefits to the system. 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 reliability 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 deploy the appropriate amount of demand response resources, since they must be deployed with significant lead times and the amount of demand response needed can be difficult to predict when there is still considerable uncertainty about the needs of the system. Second, it is difficult to ensure that real-time prices are efficient when reliability demand response is deployed, 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 deployed or the demand response resources do not set LBMPs, LBMPs may not accurately reflect the cost of maintaining reliability. The sub-section evaluates these two aspects of market outcomes on the days when demand response resources were deployed during 2012:

- The amount of demand response that was deployed compared with the amount of resources that were ultimately available in each real-time interval during the event.
- Whether real-time energy prices reflected the costs of deploying demand response to maintain reliability given that most SCR and EDRP resources are paid $500 per MWh to curtail their load.

Reliability demand response resources were deployed by the NYISO on the following six days during 2012:

- On May 29, SCR and EDRP resources were deployed in all zones from 1:00 pm to 6:00 pm (HB 13 – HB 17) for forecasted reserve shortages.
- On June 20, SCR and EDRP resources were deployed from 2:00 pm to 6:00 pm (HB 14 – HB 17) in zones G through J for transmission security in Southeast New York and in zone C for voltage support.
- On June 21, SCR and EDRP resources were deployed in: a) zones G through K for transmission security, and b) zones A through F for Rochester transformer loadings (zone B), voltage support (zone C), and statewide capacity requirements.

- On June 22, SCR and EDRP resources were deployed in zones G through K from 1:00 pm to 6:00 pm (HB 13 – HB 17) for transmission security.
- On July 17, SCR and EDRP resources were deployed in zone B from 2:00 pm to 6:00 pm (HB 14 – HB 17) to reduce Rochester 345/115 kV transformer loadings.
- On July 18, SCR and EDRP resources were deployed in zone J from 1:00 pm to 6:00 pm (HB 13 – HB 17) and zones G, H, I, K from 2:00 pm to 6:00 pm (HB 14 – HB 17) for forecasted reserve shortages and transmission security in Southeast New York.

The following table summarizes system conditions in NYCA during the two deployments on May 29 and June 21 and in Southeast New York during four deployments on June 20, 21, 22 and July 18. The deployment on July 17 was not evaluated because the demand response was called for a unique local issue.[83, 84] Available capacity includes internal capacity above the amounts needed for energy and operating reserve requirements. For NYCA activations, available capacity also includes recallable exports.[85]

Table 8: Real-time Prices and Available Capacity During Reliability DR Deployments
2012

	Reported DR (MW)	Available Capacity (MW)		Avg. LBMP ($/MWh)
		Average	Minimum	
NYCA Activation				
May 29	1081	1402	1214	$99
June 21	1877	3172	2635	$128
SENY Activation				
June 20	669	2132	1974	$111
June 21	650	1979	1414	$235
June 22	677	3371	2055	$101
July 18	676	1307	172	$409

The table shows that, on average, the amount of available capacity exceeded the amount of demand response by a significant margin during the hours when demand response was deployed

83 Figure A-73 to Figure A-75 in the Appendix show more detailed variations of these quantities duration the deployments on an interval basis.

84 The "Reported DR MWs" shown in the table are estimates provided by Responsible Interface Parties ("RIPs") in response to event notification, which are also used as the inputs for the Scarcity Pricing Rule. These numbers are different from the enrolled MWs or the response MWs estimated by the NYISO based on metering information. See Market Issues Working Group meeting presentation for July 19, 2012, *EDRP/SCR Scarcity Pricing Outcomes: May 29th, June 20th, June 21st, June 22nd.*

85 These are exports that could be curtailed to create additional internal operating reserves.

on every day except July 18. As a result, LBMPs were relatively low (e.g., less than $100 per MWh during a significant portion of hours) during most deployment periods and the Scarcity Pricing Rules were not invoked in the vast majority of intervals. They are only applied when the deployment of demand response prevents a statewide or eastern reserve shortage.[86]

The substantial amount of available capacity in real-time highlights that there are significant differences between: a) the assumptions used in advance to determine that deployment 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 June 20, a notable difference was that the NYISO deployed demand response to satisfy an N-1-1 transmission security requirement, but then the NYISO dispatched the system using a less stringent N-1 criteria. The looser real-time criteria allows more imports into Southeast New York than is assumed for the purpose of deploying demand response, contributing to the substantial amount of available capacity in real-time on this day.

In 2012, the Scarcity Pricing Rules were applied in less than 10 percent of the intervals when demand response resources were deployed. There were some intervals when real-time LBMPs were even higher than the levels set by the Scarcity Pricing Rules. However, the costs of demand response resources were not reflected in the real-time LBMPs under most circumstances due in part to the limited scope of the Scarcity Pricing Rules. The NYISO is planning to modify the real-time scarcity pricing methodology to enable reliability demand response resources to set prices under a broader set of circumstances when appropriate. We support this effort and recommend that the NYISO continue to improve the pricing provisions.

E. Supplemental Commitment for Reliability and Out of Merit Dispatch

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

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

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. The "Forecast Pass" of the day-ahead model also commits generation to satisfy forecast load and operating reserve requirements for eastern New York and NYCA.

Similarly, the NYISO and local transmission owners sometimes dispatch generators out of merit order ("OOM") in order to: (i) manage constraints of high voltage transmission facilities that are not fully represented in the market model; or (ii) maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is frequently uneconomic, which displaces production from economic capacity. The costs of both types of out-of-market actions are generally not reflected in real-time market prices and tend to depress real-time prices. This undermines the market incentives for meeting reliability requirements and generates expenses that are uplifted to the market. Hence, it is important to limit supplemental commitment and OOM dispatch as much as possible.

1. Supplemental Commitment

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 2011 and 2012.[87] 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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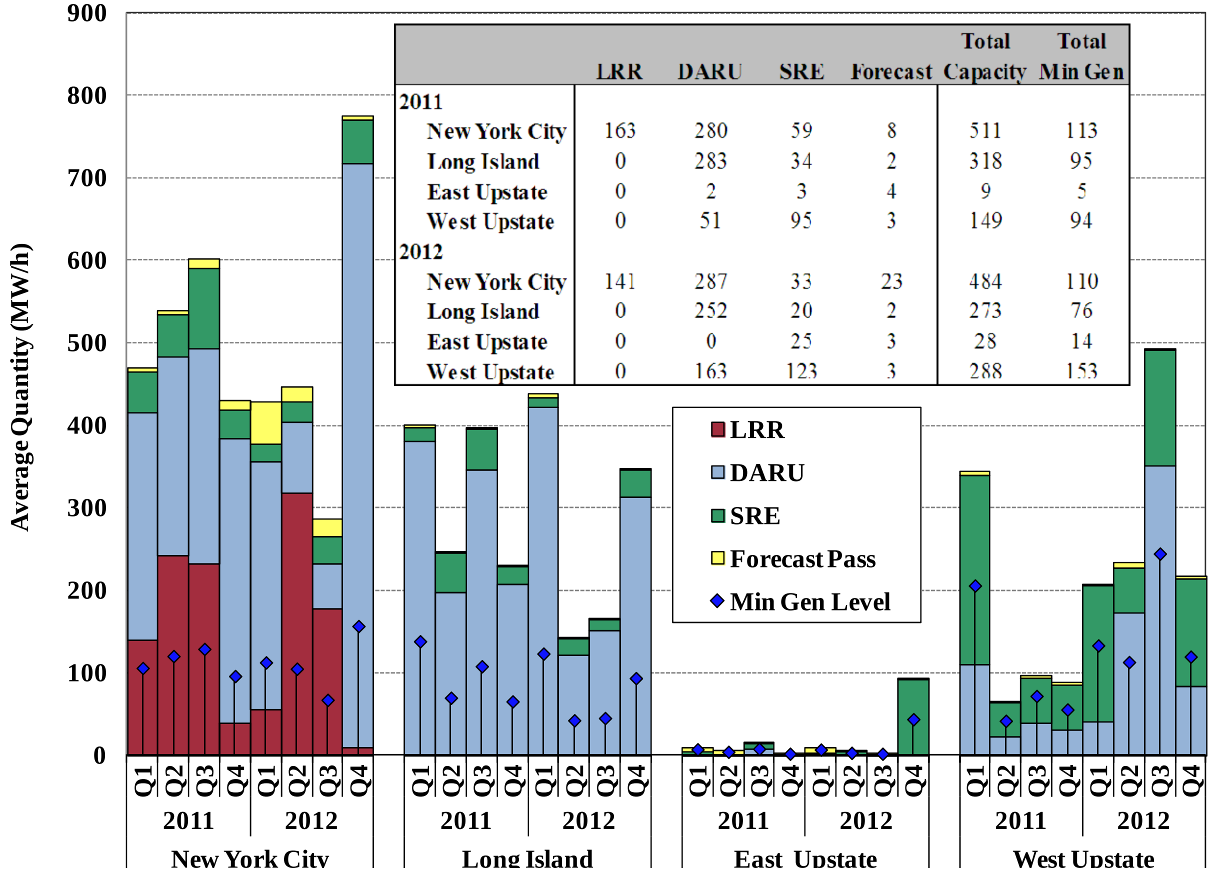
87 The first three types of commitment are primarily for local reliability needs. The last category, Forecast Pass, represents the additional commitment in the forecast pass of SCUC, which occurs after the economic pass. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load.

Figure 16: Supplemental Commitment for Reliability in New York
By Category and Region, 2011 – 2012



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2012						
New York City	141	287	33	23	484	110
Long Island	0	252	20	2	273	76
East Upstate	0	0	25	3	28	14
West Upstate	0	163	123	3	288	153

The figure shows that nearly 1,100 MW of capacity was committed on average for reliability in 2012, up modestly from 2011. Of this total, 45 percent of reliability commitment was in New York City, 25 percent was in Long Island, and 27 percent was in Western New York.

In Western New York, reliability commitment almost doubled in 2012. This was primarily because several coal units that are frequently needed for reliability were economically committed less often due to lower natural gas prices and, therefore, were more frequently committed for reliability.

In Long Island, reliability commitments fell modestly as units frequently needed for local reliability were committed economically more often because of the higher LBMPs after the Neptune outage and several generator retirements.

In New York City, reliability commitment decreased by 5 percent from 2011 to 2012, which was primarily due to new transmission facilities (into Astoria East and at the Gowanus 345 kV substation) and new generation facilities (550 MW Astoria East II unit entering July 2011 and 520 MW Bayonne facility entering in June 2012). However, the reduction in New York City was offset by a substantial increase in DARU commitments in October and November. In October, the amount of DARU capacity rose considerably when a large generator was committed every day for 345 kV transmission security (in case the largest two contingencies were to occur) and/or voltage support. Based on our evaluation of the days before Hurricane Sandy reached New York on the 29th, sufficient capacity should have been available from other committed generators, non-spinning reserve units, and in-service transmission facilities to satisfy the transmission security criteria on all but one day. However, our assessment may not include all of the relevant assumptions since the local TO is not required to provide a detailed description of the assumptions underlying each DARU commitment. In November, supplemental commitments increased due to a large number of transmission and generation outages resulting from Hurricane Sandy.[88]

During the first three quarters of 2012, small amounts of capacity were committed unnecessarily in the Forecast Load Pass under certain conditions when excess capacity was available to satisfy the reliability criteria due to an issue with the optimization. Although these commitments produced little uplift, they moderately depressed day-ahead prices and reduced generator margins in the day-ahead market. The NYISO implemented a modeling enhancement in the fourth quarter that has virtually eliminated commitments in the Forecast Pass.

2. Out of Merit Dispatch

In our evaluation of OOM dispatch, we found that Long Island accounted for the largest share of OOM station-hours in both 2011 (50 percent) and 2012 (40 percent).[89] Most was called to manage local reliability on the East End of Long Island during high load conditions, particularly in the third quarter of each year. Overall, OOM dispatch in Long Island fell roughly 25 percent from 2011 to 2012, since units needed for reliability were more often inframarginal in 2012 due

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88 See Figure A-78 in the Appendix for more detail and analysis regarding supplemental commitments in New York City.

89 See Figure A-79 in the Appendix for this analysis.

to the higher LBMP levels that resulted from the lengthy Neptune outage and multiple generator retirements.

New York City accounted for 35 percent of OOM station-hours in 2012, up from 15 percent in 2011. Units were often dispatched OOM by the local Transmission Owner to secure lines on the 138 kV system typically following significant unit or transmission outages, or to manage NYISO security and reliability on days with high loads and/or during TSA events. OOM actions were less frequent in the first three quarters of 2012 than in 2011, partly due to the addition of new generation and new transmission facilities in New York City. However, in the fourth quarter of 2012, a large number of units were frequently dispatched OOM in the days following Hurricane Sandy, accounting for the overall increase in 2012.

Western New York accounted for 20 percent of OOM station-hours in 2012. Huntley and Niagara units accounted for more than half of all OOM station-hours in Western New York. These units were often dispatched OOM by the NYISO to manage congestion on 230 kV lines in the West Zone. The NYISO introduced constraint modeling of these lines in the day-ahead and real-time markets in May 2012, which substantially reduced OOM dispatch and the related uplift charges.

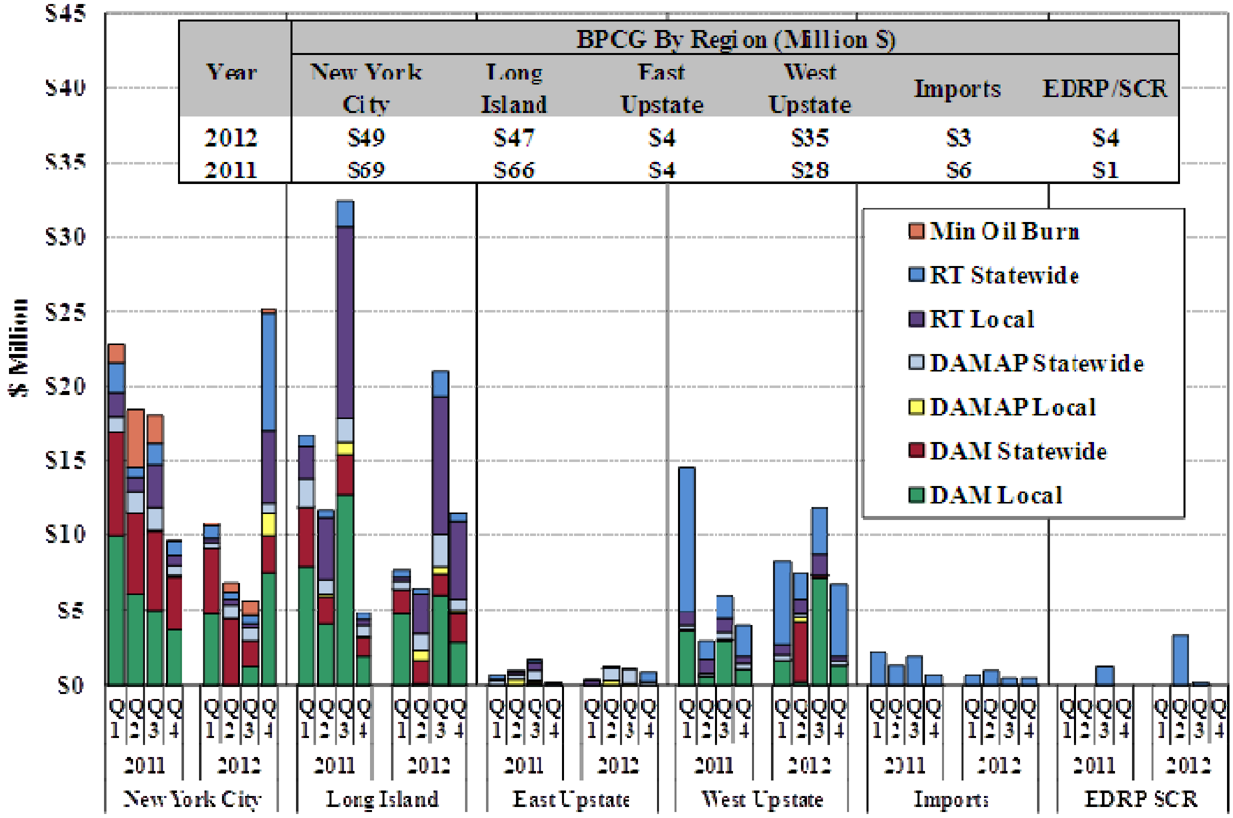
F. Guarantee Payment Uplift Charges

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.

The following figure shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2011 and 2012 on a quarterly basis. [90]

[90] See Figure A-80 and Figure A-81 in the Appendix for a more detailed description of this analysis.

Figure 17: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2011 – 2012



The figure shows that the guarantee payment uplift totaled $141 million in 2012, down 19 percent from 2011.[91] Day-ahead uplift accounted for the majority of the reduction, down $30 million from 2011 to 2012, which was due largely to lower natural gas prices that decreased the commitment costs of gas-fired units needed for reliability. Improved accuracy of generator reference levels also contributed to the overall reduction in uplift.

Uplift costs fell roughly $20 million each in New York City and Long Island in 2012, while uplift costs in Western New York rose $7 million in 2012. The reductions and increases in uplift in these regions were consistent with the changes in reliability commitments and OOM dispatch from 2011 to 2012 discussed in detail in the prior sub-section.

91 The 2012 number was based on billing data available at the time of reporting, which may be different from final settlement.

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, more than 90 percent of the 1.9 GW of demand response resources registered in New York are reliability demand response resources.

The SCR program is the most significant demand response program operated by the NYISO with roughly 1.9 GW of resources participating in 2012. The primary incentive to participate in this program that SCRs can sell capacity in the NYISO's capacity market. In the Summer 2012 Capability Period, SCRs made significant contributions to resource adequacy by satisfying: (i) 4.2 percent of the UCAP requirement for New York City; (ii) 3.0 percent of the UCAP requirement for Long Island; and (iii) 4.6 percent of the UCAP requirement for NYCA.

Given the reliance on SCRs for satisfying reliability needs, it is important to ensure that SCRs can perform when called. Accordingly, the NYISO made improvements in 2011 to the SCR baseline calculation methodology, which is used to estimate the capability of a resource to respond if deployed. The NYISO currently uses the Average Coincident Load ("ACL") methodology, which is based on the resource's load during the 40 highest load hours in the previous like capability period (i.e., Summer 2012 is based on 40 hours from Summer 2011).

Since it is more accurate, the new baseline calculation has reduced the amount of capacity that some SCRs qualify to sell. In addition, the NYISO reviews the baselines of resources after each capability period to identify resources that might have had an "Unreported Change in Status" that would reduce its ability to curtail if deployed. This has resulted in more accurate baselines for some resources, reducing the amount of capacity they are qualified to sell. Although these changes contributed to modest reductions in SCR enrollment in recent years (a 13 percent reduction from 2010 to 2011 and another 13 percent from 2011 to 2012), these changes will ensure that reliability demand response resources perform reliably when needed.

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, DSASP resources have experienced difficulty setting up communications with the NYISO through the local Transmission Owner since the inception of the DSASP program. Consequently, no DSASP resources were fully qualified until 2012 when the NYISO introduced the capability for resources to communicate directly with the NYISO. DSASP resources began to actively participate in the market in December 2012 and the NYISO is making the necessary software changes to allow aggregations of small loads to participate in the program as a single resource by April 1, 2013.[92] This program has the potential to provide considerable value by significantly reducing the cost of ancillary services in the future.

92 See Price-Responsive Load Working Group meeting materials for additional details at: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_prlwg

X. List of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2012, although the report finds additional improvements that we recommend be made by the NYISO.

Capacity Market

1. Create a dynamic and efficient framework for reflecting the NYISO's locational planning requirements in its capacity market, which includes three key aspects. (High Priority/Value)

a. Pre-define a set of interfaces or zones to be modeled in the capacity market that would address potential resource adequacy needs and highway deliverability constraints.

The NYISO's application of the NCZ study methodology should result in the creation of a capacity zone for Southeast New York in 2014, which is extremely important. However, the NCZ creation process will not lead to the timely creation of a new capacity zones in the future when: a) additional capacity is needed to meet resource adequacy criteria in areas that are not currently zones, and b) when the NYISO's Class Year Deliverability Test is inefficiently restricting new entry and capacity imports. Pre-defining interfaces or zones would ensure that locational capacity prices would immediately adjust quickly to reflect changes in market conditions, including the unexpected retirement of key units in the state's aging fleet. This will, in turn, allow investors to be more confident that the reliability needs will be fully priced and facilitate timely market-based investment.

b. The NYISO should model export constraints in the capacity market when additional capacity in a nested capacity zone provides little or no additional reliability benefit to the wider region.

This will ensure that the capacity market provides incentives to invest in new and existing generation, transmission, and demand response that are consistent with the reliability benefits that result from the investment.

c. Grant internal capacity deliverability rights between zones when private investors upgrade the transmission system to expand the capability into a local area.

This is comparable to the NYISO's current provision to provide Transmission Congestion Contracts ("TCCs"). Creating these internal capacity deliverability rights will help provide efficient incentives for economic investment in transmission. Locational capacity market signals are discussed in Section VII.B.

2. Grant a Competitive Entry Exemption from the buyer-side mitigation measures for a purely market based investment. (High Priority/Value)

The Buyer-Side Mitigation Exemption test is conducted three years in advance based on a forecast of conditions at the time of entry. However, it is difficult for such forecasts to account for uncertainty regarding unit retirements and mothballing. To the extent these occur, the Buyer-Side Mitigation Exemption test will likely understate the forecasted prices and over-mitigate competitive entry. Granting an exemption to suppliers engaged in purely private investment would allow merchant investors to make investment decisions based on their own expectations of the increased capacity revenues that would occur if additional retirements occur (beyond those that have been noticed to the PSC). The Competitive Entry Exemption is discussed in Section III.C.2.

Implementation Efforts:

– The NYISO is currently working with stakeholder committees on a proposal.

3. Reform the Buyer-Side Mitigation Exemption test criteria and the offer floor determination method. (High Priority/Value)

A new project receives an exemption when capacity prices are forecasted to be higher than:

- Default Net CONE (“DNC”) – a level 25 percent lower than Mitigation Net CONE (“MNC”), where MNC is intended to equal the annual capacity revenues that the demand curve unit would need to be economic (i.e., the Part A test); or
- Unit Net CONE (“UNC”) – a level set at the estimated net CONE of the project (i.e., the Part B test).

An offer floor is imposed on a project that fails both of the above criteria, which is set at a level equal to the lower of DNC and UNC. The DNC is reasonable for purposes of the exemption test because it recognizes that the entry of the new unit will tend to lower the project’s net revenues in the initial year. However, its use as an offer floor for projects that have failed both tests significantly weakens the buyer-side mitigation measures because it allows the uneconomic project to lower capacity prices 25 percent below the true cost of entry. To address these issues, we recommend setting the offer floor of mitigated units at the lower of UNC or the 100 percent of the MNC. The Buyer-Side Mitigation Exemption tests and offer floors are discussed in Section III.C.2.

4. Select the most economic generating technologies to establish the demand curves in the current demand curve reset process for the capacity market and modify the criteria for setting the excess level.

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. Although proposals to change the technology of the demand curve unit were recently not approved by stakeholders, we recommend the NYISO continue to pursue changes that would allow using the most economic generating technologies to establish the demand curves in the current demand curve reset process for the capacity market and modify the criteria for setting the excess level as described below.

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. The current rules for setting the excess level are based on the assumption that the equilibrium excess level would be approximately equal to the size of the demand curve unit. This rule works relatively well when the demand curve unit is based on an installation with several peaking units, but it is unrealistic when the demand curve unit is a larger combined cycle unit. Hence, we recommend modifying the excess level to a level more consistent with the expected equilibrium excess level (e.g., 1 percent of the capacity requirement plus 50 percent of the capacity of the demand curve unit). The technology of the demand curve unit and the excess level are discussed in Section VII.C.

Implementation Efforts:

- Following the March 27 decision by the NYISO Management Committee not to adopt a similar proposal, the decision has been appealed to the NYISO Board of Directors.

5. 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.

The current definition of a pivotal supplier effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction. The pivotal supplier criteria are discussed in Section III.C.3.

6. Modify the existing rules related to the ICAP qualification requirements and the calculation of the Going-Forward Costs (“GFCs”) used in the supply-side mitigation measures for installed capacity suppliers.

It is important for capacity suppliers to understand the requirements for remaining qualified to sell capacity, and the costs necessary to remain qualified are a key input to the calculation of the GFC. To ensure that the capacity market provides accurate and efficient price signals, the qualification 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. Currently, the existing rules allow an existing generator to be in a forced outage state and continue to sell capacity for an unreasonably long period of time, which can span multiple capability periods. Addressing this issue would improve reliability because the reduction in sales from units on extended forced outages would encourage additional sales from importers, demand response resources, and/or mothballed generators with the ability to return to service on short notice. It would also provide more timely price signals for longer lead time investments in new generation, demand response, and transmission.

In conjunction with this change, the NYISO should modify its tariff to specify that the GFC calculation will only include costs a supplier must incur to remain qualified to sell capacity and can, therefore, only be avoided when it ceases to sell capacity. This change will help ensure that the NYISO administration of the supply-side mitigation in the capacity market is effective. ICAP qualification and GFCs are discussed in Section III.C.3.

Implementation Efforts:

- NYISO has initiated the process of clarifying its existing rules related to the ICAP qualification requirements in December 2012.

Real-Time Market

7. 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. (High Priority/Value)

Utilization of the external interfaces is evaluated in Section VI.C.

Implementation Efforts:

- 2013 Project Plan: *CTS* (includes internal systems that can be used with PJM, ISO-NE, or any other control area) – Functional Requirements by Q4
- 2013 Project Plan: *CTS-PJM* – Market Design Approved by Q4

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

Significant efficiency savings may be achieved by improving the operation the following PAR-controlled lines:

- The 901 and 903 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 2012.
- The J and K lines between New York and New Jersey, which were scheduled in the inefficient direction 58 percent of the time in 2012.
- The A, B, and C lines between New York and New Jersey, which generally flow in the efficient direction but not necessarily at the optimal level.

When these lines flow in the inefficient direction, it leads to inefficient prices between regions and can restrict the production of economic generation. These lines are all scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets. It would be highly beneficial modify these contracts or find other ways under the current contracts to operate the lines efficiently. We are recommending that the NYISO work with the parties to the underlying wheeling agreements to explore potential changes to agreements or to identify how the agreements can be accommodated within the markets more efficiently. Utilization of these PAR-controlled lines is evaluated in Section VIII.B.

Implementation Efforts:

- 2013 Project Plan: Long Island PAR Optimization – Market Design Concept Proposed by Q4

9. Evaluate improvements to the real-time pricing methodology to ensure that GTs 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 GTs to be deemed ineligible to set the LBMP, which lead other GTs to not set the price even though they are economic. Hence, we recommend the NYISO evaluate the benefits of eliminating this step and proceed to eliminate it if it does not find that this step is necessary for efficient pricing. The real-time commitment of and price-setting by gas turbines is discussed in Section VIII.A.1.

Implementation Efforts:

- 2013 Project Plan: *Scheduling & Pricing: Hybrid GT Pricing Improvements* – Market Design Concept Proposed by Q4

10. Implement 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. Transmission shortage pricing is discussed in Section VIII.D.1.

Implementation Efforts:

- 2013 Project Plan: *Graduated Transmission Demand Curve* – Market Design Approved by Q4

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

Reliability demand response was deployed on six days in 2012. Hence, it is becoming more important to set efficient prices when demand response resources are needed to satisfy reliability needs market-wide or in an import-constrained area. Real-time pricing during deployments of demand response for reliability is discussed in Section VIII.D.2.

Implementation Efforts:

- 2013 Project Plan: *Enhanced Scarcity Pricing* – Deployment by Q2

12. Raise the demand curve for the NYCA 30-minute operating reserve requirement to $500 per MWh.

Although the NYISO deployed reliability demand response resources at a cost of $500 per MWh in 2012 to maintain adequate 30-minute reserve levels statewide, the current NYCA 30-minute reserve demand curve ranges from $50 to $200 per MWh . Consequently, the real-time market may forego opportunities to schedule imports and internal generators that would satisfy the 30-minute reserve requirement, thereby increasing the need to deploy demand response resources and commit SRE units to satisfy NYCA reserve requirements. Hence, raising the demand for this product would result in better consistency between pricing and scheduling outcomes when the operators must take actions to satisfy the NYCA 30-minute reserve requirement. Real-time pricing during deployments of demand response to maintain adequate NYCA reserves is discussed in Section VIII.D.2.

13. **Adjusting the timing of the look ahead evaluations of RTD and RTC to be more consistent with the timing of the ramping periods for external transactions.**

The look ahead evaluations of RTD and RTC evaluate the system at each quarter-hour (i.e., :00, :15, :30, and :45), while external transactions reach their scheduled levels at five minutes past each quarter-hour (i.e., :05, :20, :35, and :50). This inconsistency contributes to transient shortage conditions and unnecessary price volatility. We recommend the NYISO:

a. Modify the intervals in RTD to always model each 5 minute interval in which external transactions are ramping (e.g., intervals :55, :00, and :05); and

b. Evaluate the cost and feasibility of improvements to RTC that would allow it to better recognize NYISO's ramping demands and be consistent with RTD.

Contributors to unnecessary real-time price volatility are discussed in Section VIII.C.

14. Modify the thresholds used in the Increasing Bids in Real-Time ("IBRT") software to allow suppliers to reflect intraday fuel cost variations in their real-time offers.

IBRT is intended to allow generators to update the fuel costs used to calculate their real-time reference levels until 75 minutes ahead of a particular hour. This would allow generators to reflect their fuel costs more accurately and leads to more efficient dispatch and price signals. However, the current limits on fuel-price adjustments prevent generators from reflecting: a) the full price of gas on days with intra-day price volatility; and b) routine intra-day gas balancing charges. Consequently, generators that are not scheduled in the day-ahead market sometimes switch to more expensive fuels or stop offering altogether in real-time to avoid being dispatched below cost. This causes more expensive generators to be scheduled inefficiently in their place. The use of IBRT to address intraday fuel cost variations is discussed in Section III.B.

Implementation Efforts:

- Plan to introduce increased generator-specific thresholds in March 2013.

Day-Ahead Market

15. Allow suppliers to reflect fuel price variations in their day-ahead offers prior to the close of the day-ahead bid window.

Currently, day-ahead mitigation is based on the price indices from the gas trading day on the day before the day-ahead market runs, leading to inaccuracies in the reference levels of individual units during periods of high gas price volatility. Allowing suppliers to input another fuel price when appropriate would allow generators to be committed more efficiently in the day-ahead market, which is particularly important during the winter when natural gas prices can be quite volatile and over-scheduling gas-fired generation can further increase gas prices. The use of gas price information during periods of high gas price volatility is discussed in Section III.B.

16. 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. Virtual trading and convergence between day-ahead and real-time prices are discussed in Section IV.

ANALYTIC APPENDIX

2012 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, which are evaluated in Sections V and VII of the Appendix.

This section of the appendix summarizes the market results and performance in 2012 in the following areas:

- Wholesale market prices;
- Fuel prices, generation by fuel type, and load levels;
- Ancillary services prices;
- Price corrections;
- Long-term economic signals governing new investment and retirement decisions;
- Day-ahead energy market performance; and
- Day-ahead ancillary services market performance.

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 from 2010 to 2012 at the following five locations: (a) Western New York, which includes five load zones (i.e., Zones A through E); (b) the Capital Zone (i.e., Zone F); (c) the Lower Hudson Valley region, which includes three load zones (i.e., Zones G, H, and I); (d) New York City (i.e., Zone J); and (e) Long Island (i.e., Zone K). The majority of congestion in New York occurs between these five regions. Natural gas prices are based on: the Niagara index for West NY, Transco Zone 6 (NY) index for New York City, and the Iroquois Zone 2 index for Capital, Lower Hudson Valley, and Long Island.

Figure A-1: Average All-In Price by Region
2010-2012

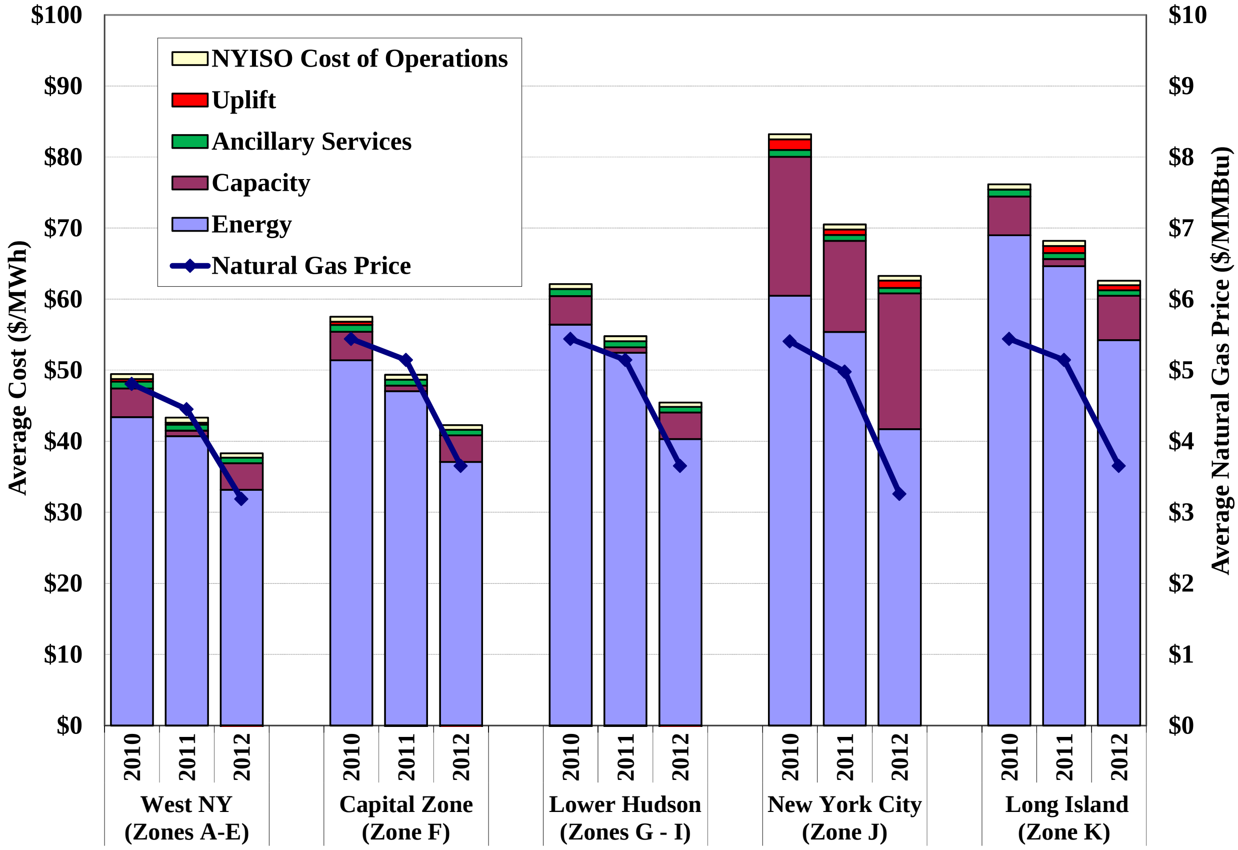


Figure A-2: Day-Ahead Electricity and Natural Gas Prices

Figure A-2 shows average natural gas prices and load-weighted average day-ahead energy prices in each month of 2012 for the five locations shown in Figure A-1. The table in the chart shows the annual averages of these quantities for 2011 and 2012. 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
2012

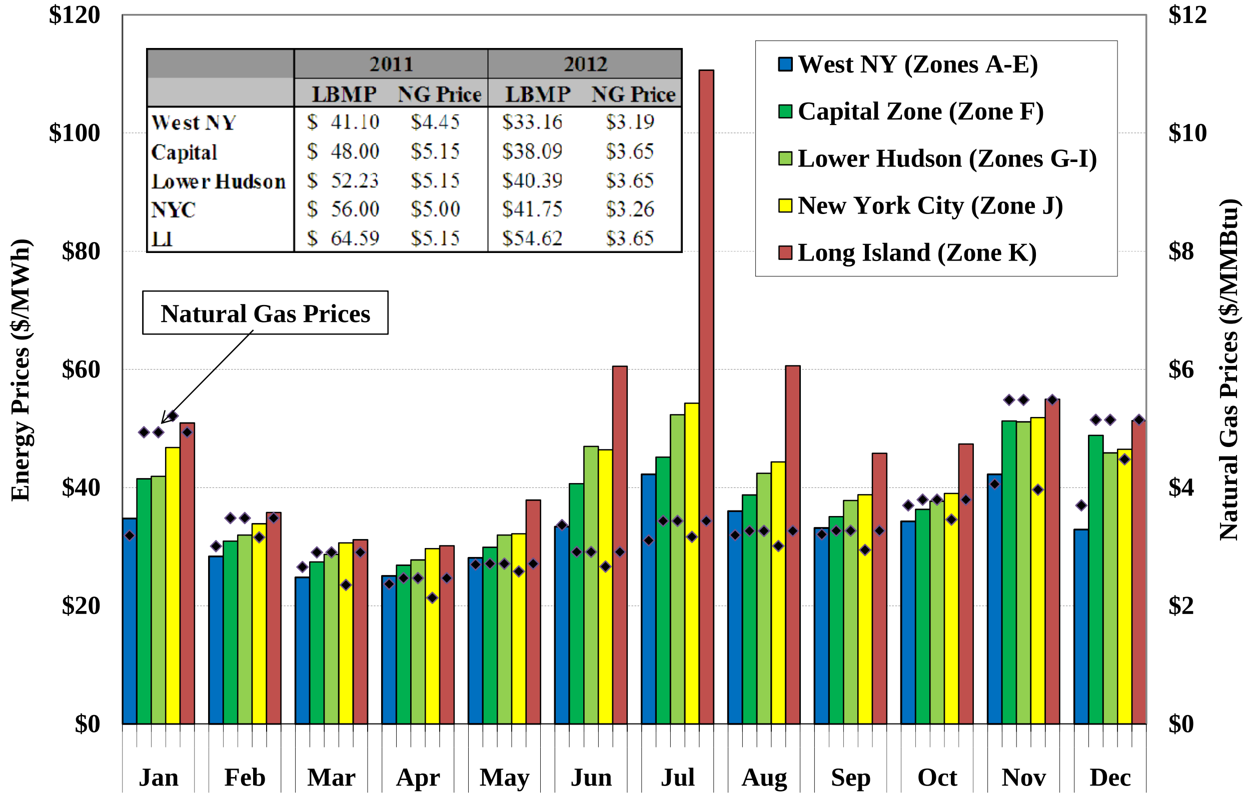


Figure A-3: Average Implied Marginal Heat Rate

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 in each month of 2012 for the five locations shown in Figure A-1 and Figure A-2. The table in the chart shows the annual averages of the implied heat rates in 2011 and 2012 at these five locations. 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
2012

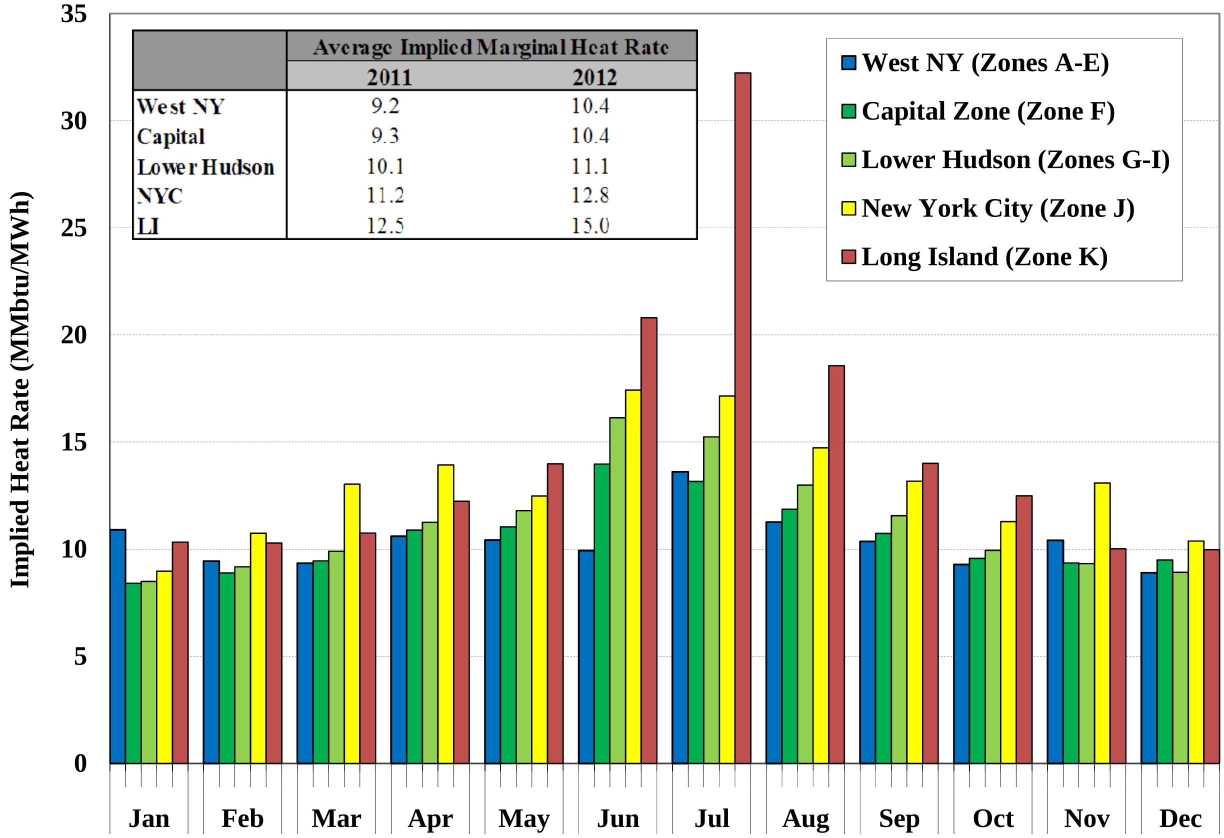


Figure A-4 – Figure A-7: Price Duration Curves and Implied Heat Rate Duration Curves

The following four analyses illustrate how prices varied across hours in recent years and at different locations. Figure A-4 shows three price duration curves, one for each year from 2010 to 2012. Figure A-5 shows five price duration curves for 2012, one for each of the following locations: (a) Western New York, which includes five load zones (i.e., Zones A through E); (b) the Capital Zone (i.e., Zone F); (c) the Lower Hudson Valley region, which includes three load zones (i.e., Zones G, H, and I); (c) New York City (i.e., Zone J); and (e) Long Island (i.e., Zone K). Each curve in Figure A-4 and Figure A-5 shows the number of hours on the horizontal axis when the load-weighted average real-time price for New York State or each sub-region was greater than the level shown on the vertical axis. The table in the chart shows the number of hours in each year or at each location when the real-time price 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-6 and Figure A-7 show corresponding implied heat rate duration curves in each year from 2010 to 2012 and at each location during 2012. Each curve shows the number of hours on the horizontal axis when the implied heat rate for New York State or each sub-region was greater than the level shown on the vertical axis. In this case, the implied marginal heat rate is the region-wide average real-time price divided by the natural gas price. Natural gas prices are based on: the Niagara index for West NY, Transco Zone 6 (NY) index for New York City, and the Iroquois Zone 2 index for Capital, Lower Hudson Valley, and Long Island. The inset table shows the number of hours in each year or in each region when the implied heat rate exceeded 10, 20, and 30 MMbtu per MWh.

Figure A-4: Price Duration Curves for New York State
2010-2012

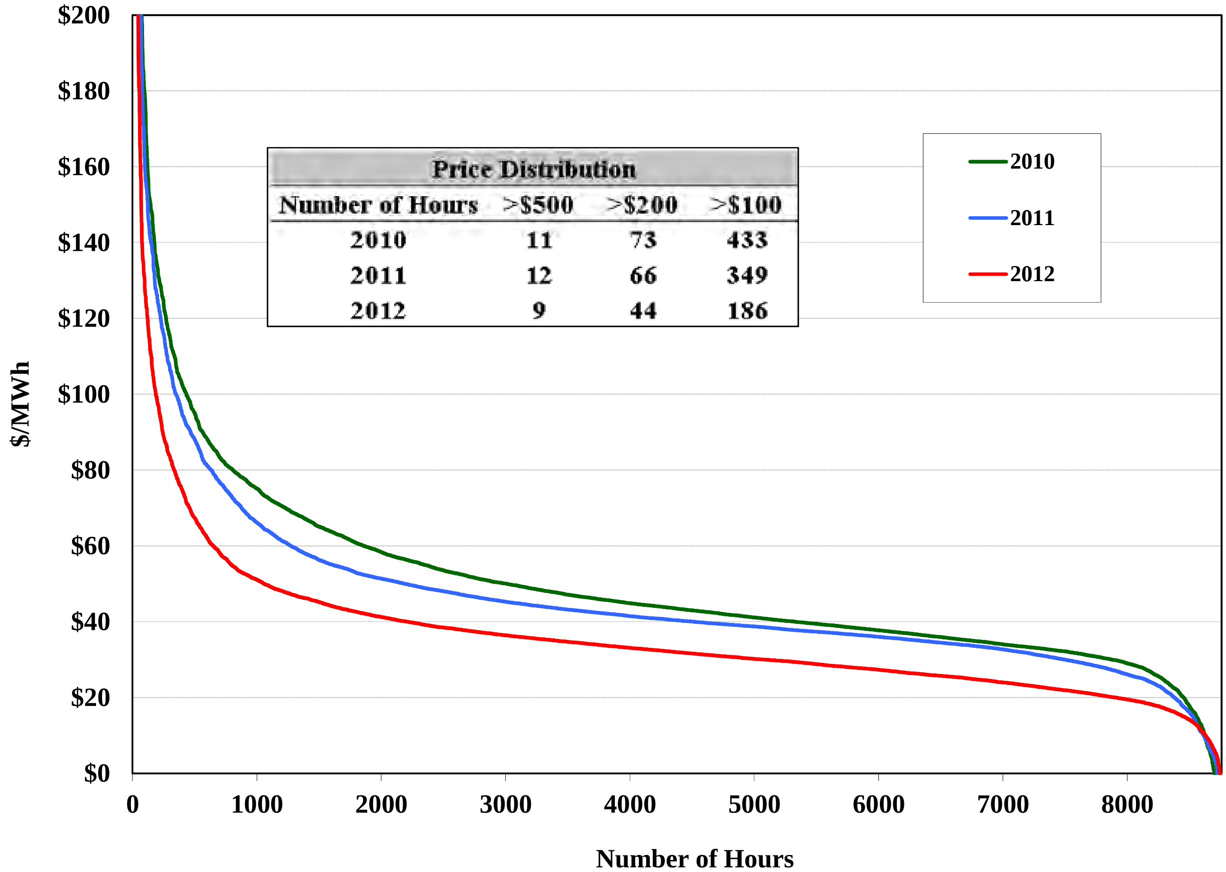


Figure A-5: Price Duration Curves by Region
2012

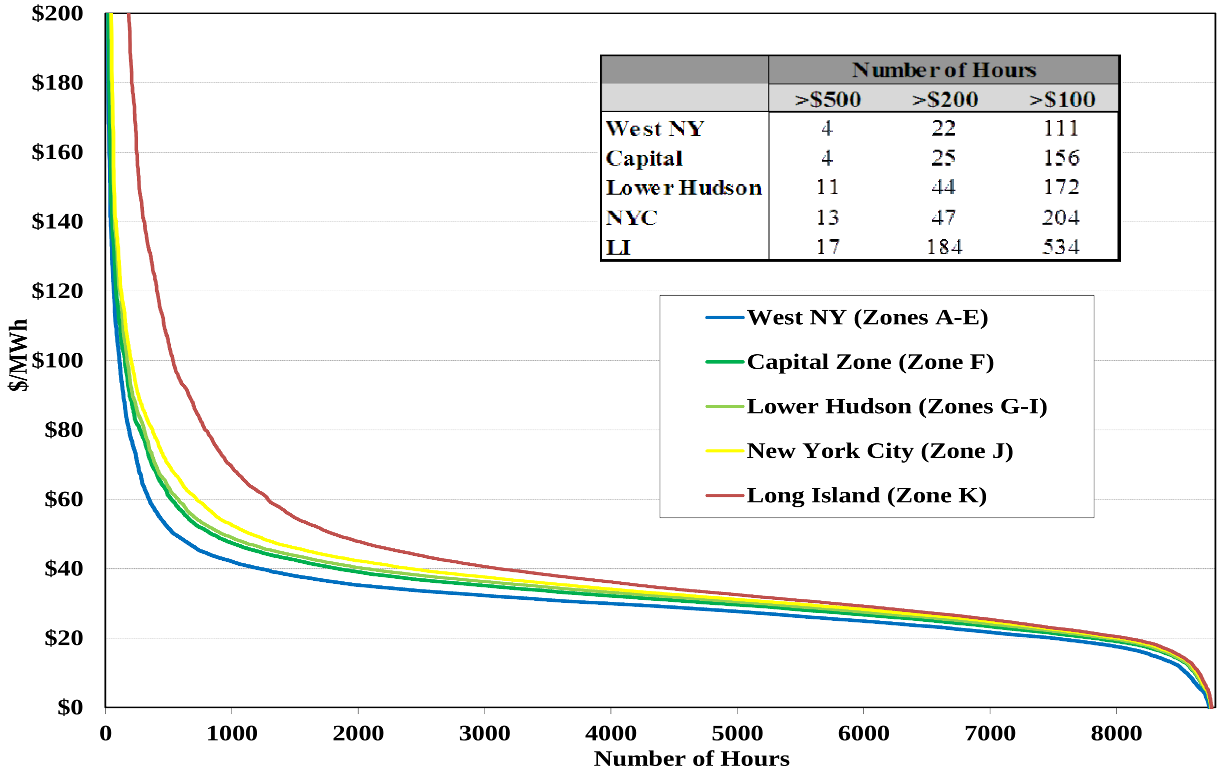


Figure A-6: Implied Heat Rate Duration Curves for New York State
2010-2012

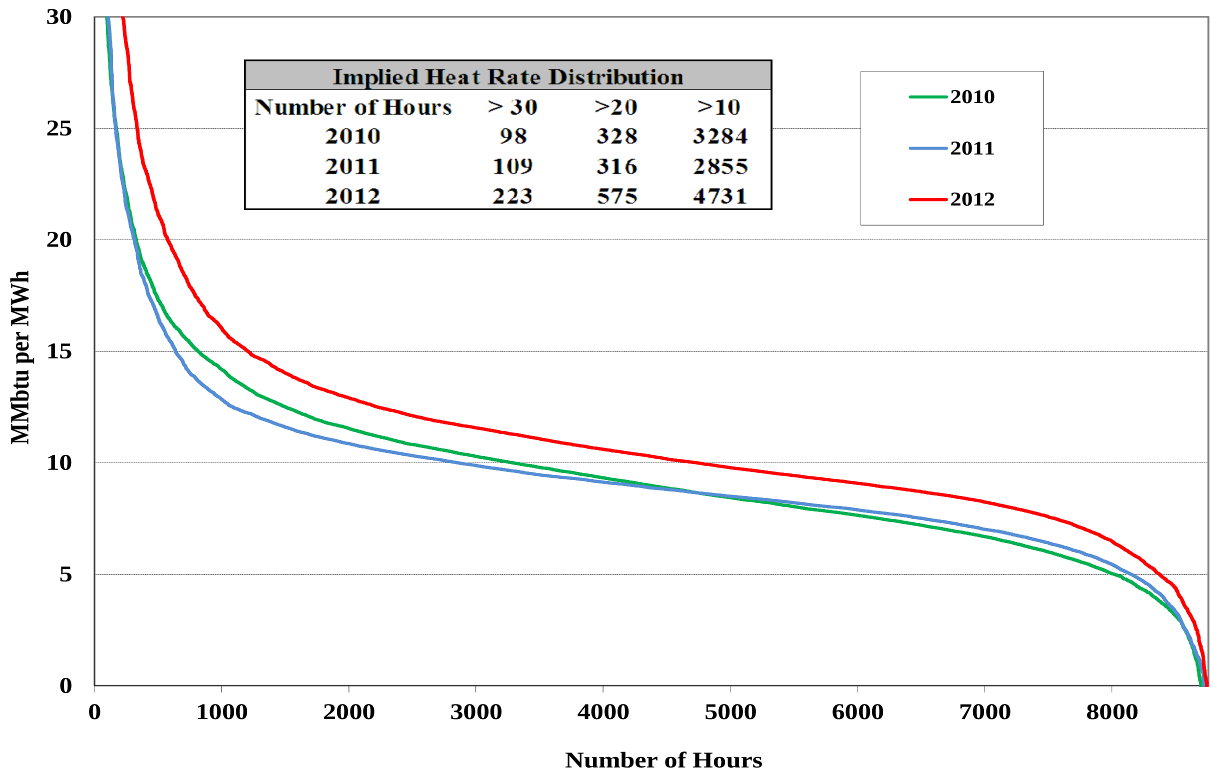
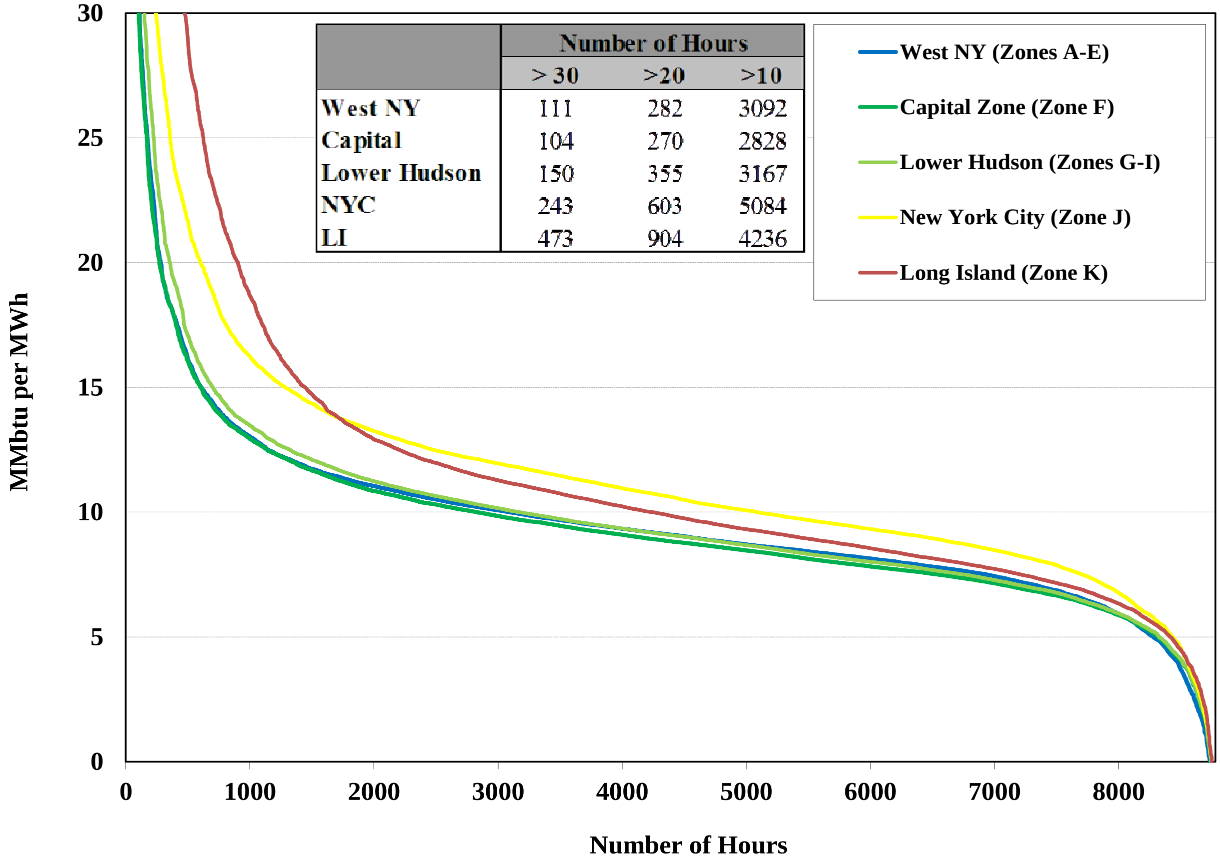


Figure A-7: Implied Heat Rate Duration Curves by Region
2012



Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from approximately $38 per MWh in West NY to $63 per MWh in New York City in 2012.
  - Energy costs accounted for 66 percent of the all-in price in New York City and 87 to 90 percent of the all-in price in the other four regions.
  - Capacity costs accounted for 30 percent of the all-in price in New York City and 8 to 10 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 16 to 25 percent in the five regions of New York State from 2011 to 2012. These decreases were consistent with the change in natural gas prices, which fell 28 to 35 percent from 2011 to 2012.
- Average capacity costs rose substantially from 2011 to 2012, up 49 percent in New York City and more than 300 percent in other regions. These increases were driven primarily by:

- Reduced internal supply of capacity due to multiple retirements in 2012 totaling 1.3 GW; and
- Increases in the installed capacity requirements in New York City and for NYCA. The installed capacity requirement rose due to increases in the summer peak load forecast and the LCR for NYC and the IRM for NYCA from the previous year.

- The seasonal patterns of electricity prices and natural gas prices were typical for most of 2012 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.
  - Electricity prices in Long Island were particularly high in the summer months of 2012, reflecting the lengthy outage of the Neptune Cable (completely out of service from the end of May through July and available up to 375 MW for the rest of the year) and multiple unit retirements (330 MW in total) at the beginning of July.
- Implied heat rates (as calculated in this report) rose from 2011 to 2012 primarily because the significant reduction in natural gas prices caused fuel costs to make up a substantially smaller share of the overall cost of the marginal resource in most hours.[93]

B. Fuel Prices and Generation by Fuel Type

Figure A-8 – Figure A-10: Monthly Average Fuel Prices and Generation by Fuel Type

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.

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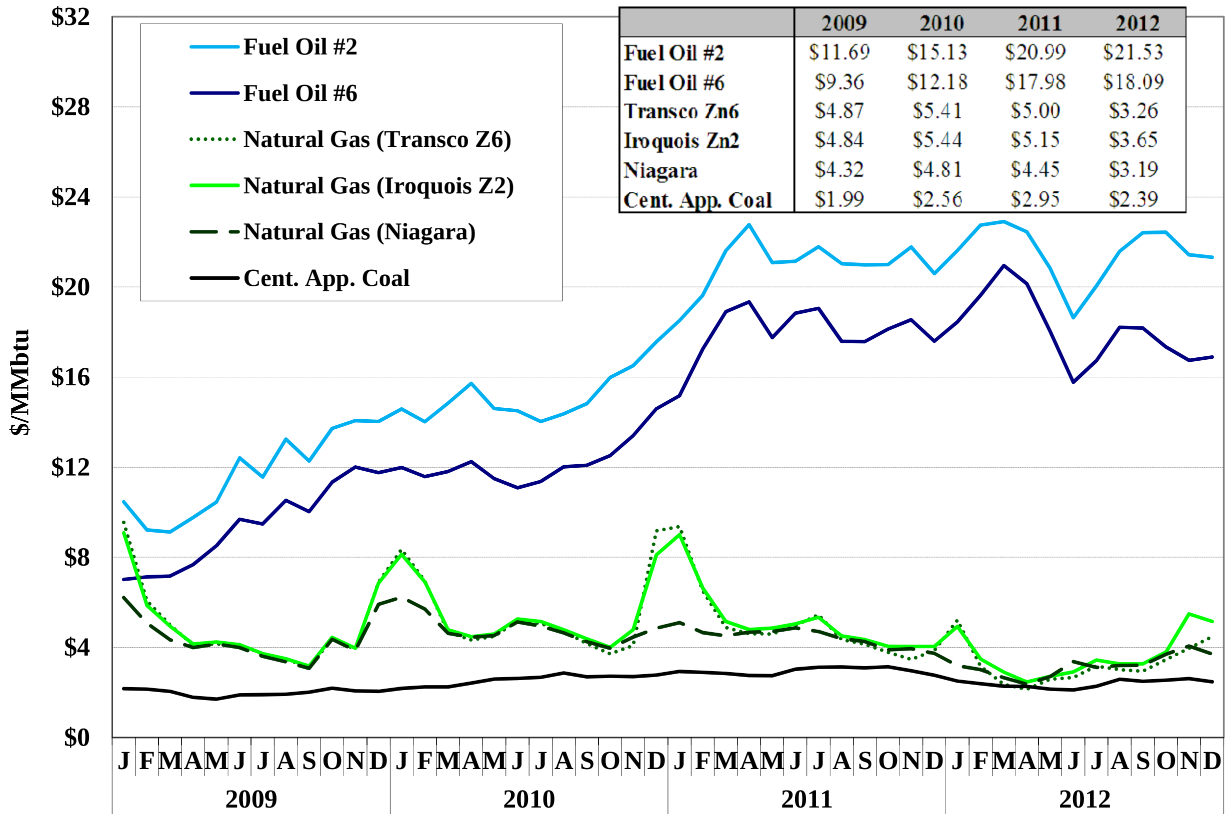
93 The calculation implicitly assumes that fuel costs make up the entirety of the cost of the marginal resource. Since a share of generators' marginal costs are not fuel related, low natural gas prices create the appearance of an increase in implied heat rates. For example, suppose that the marginal generator has a heat rate of 8 MMbtu/MWh and has $4/MWh of other costs. When the natural gas price is $5/MMbtu, the implied heat rate will be calculated as 8.8 MMbtu/MWh. However, when the natural gas price is $3/MMbtu, the implied heat rate will be calculated as 9.3 MMbtu/MWh.

Natural gas prices are normally consistent between different regions in New York. However, bottlenecks on the natural gas system can sometimes lead to significant variations in price according to the location. The Transco Zone 6 (NY) price is generally representative of natural gas prices in New York City; the Iroquois Zone 2 price is generally representative of natural gas prices in Long Island, in the Lower Hudson Valley, and in the Capital Zone; and the Niagara price is generally representative of prices in Western New York. These locational variations in natural gas prices can lead to comparable variations in electricity prices when network congestion occurs.

Figure A-8 shows average coal, natural gas, and fuel oil prices by month from 2009 to 2012. The table compares the annual average fuel prices for these four years.

Figure A-8: Monthly Average Fuel Prices[94]
2009 - 2012



	2009	2010	2011	2012
Fuel Oil #2	$11.69	$15.13	$20.99	$21.53
Fuel Oil #6	$9.36	$12.18	$17.98	$18.09
Transco Zn6	$4.87	$5.41	$5.00	$3.26
Iroquois Zn2	$4.84	$5.44	$5.15	$3.65
Niagara	$4.32	$4.81	$4.45	$3.19
Cent. App. Coal	$1.99	$2.56	$2.95	$2.39

Figure A-9 shows the quantities of generation by fuel type in five regions of New York in each quarter of 2012. The table in the chart shows the annual averages of generation by fuel type from 2010 to 2012.

94 These are index prices that do not include transportation charges.

Figure A-9: Generation by Fuel Type in New York
By Quarter by Region, 2012

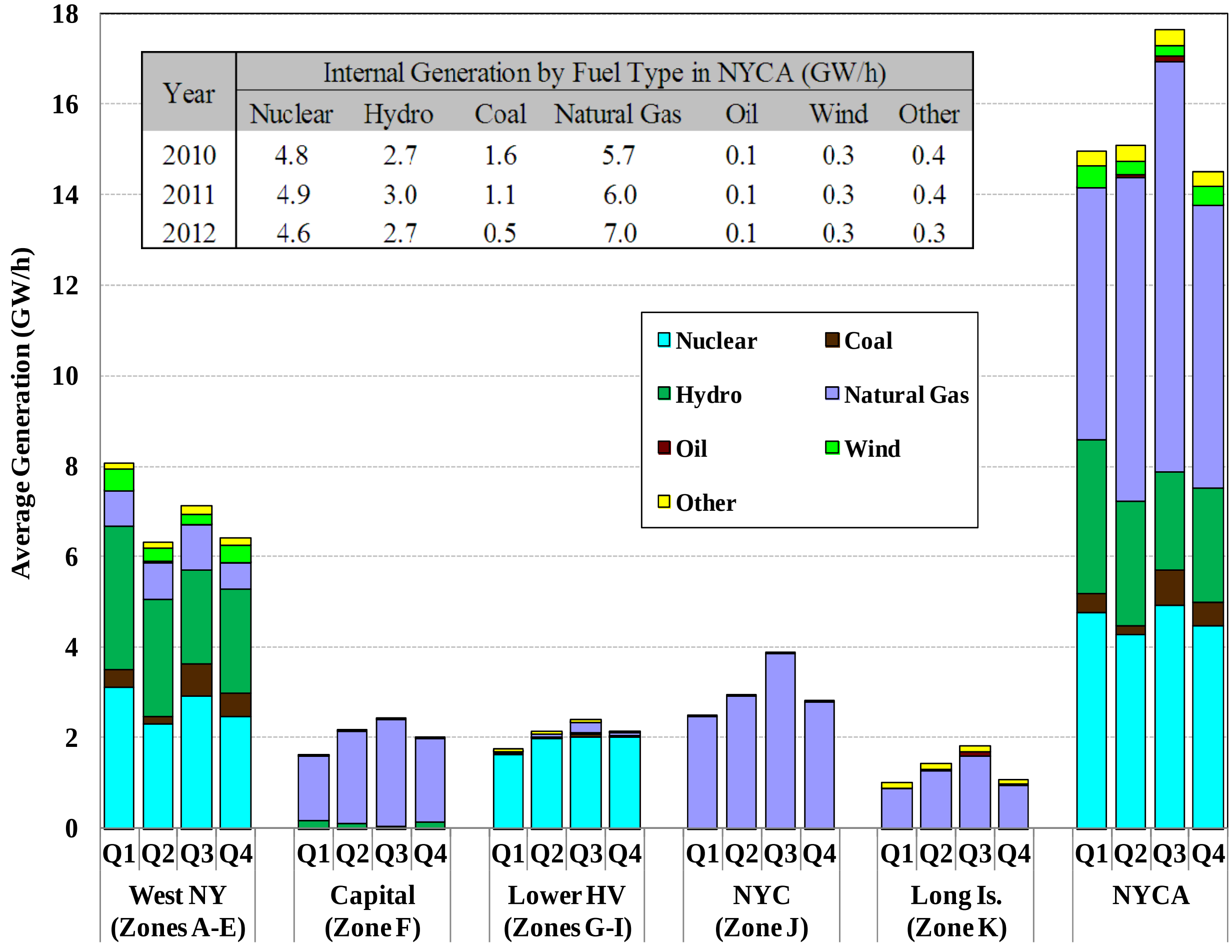
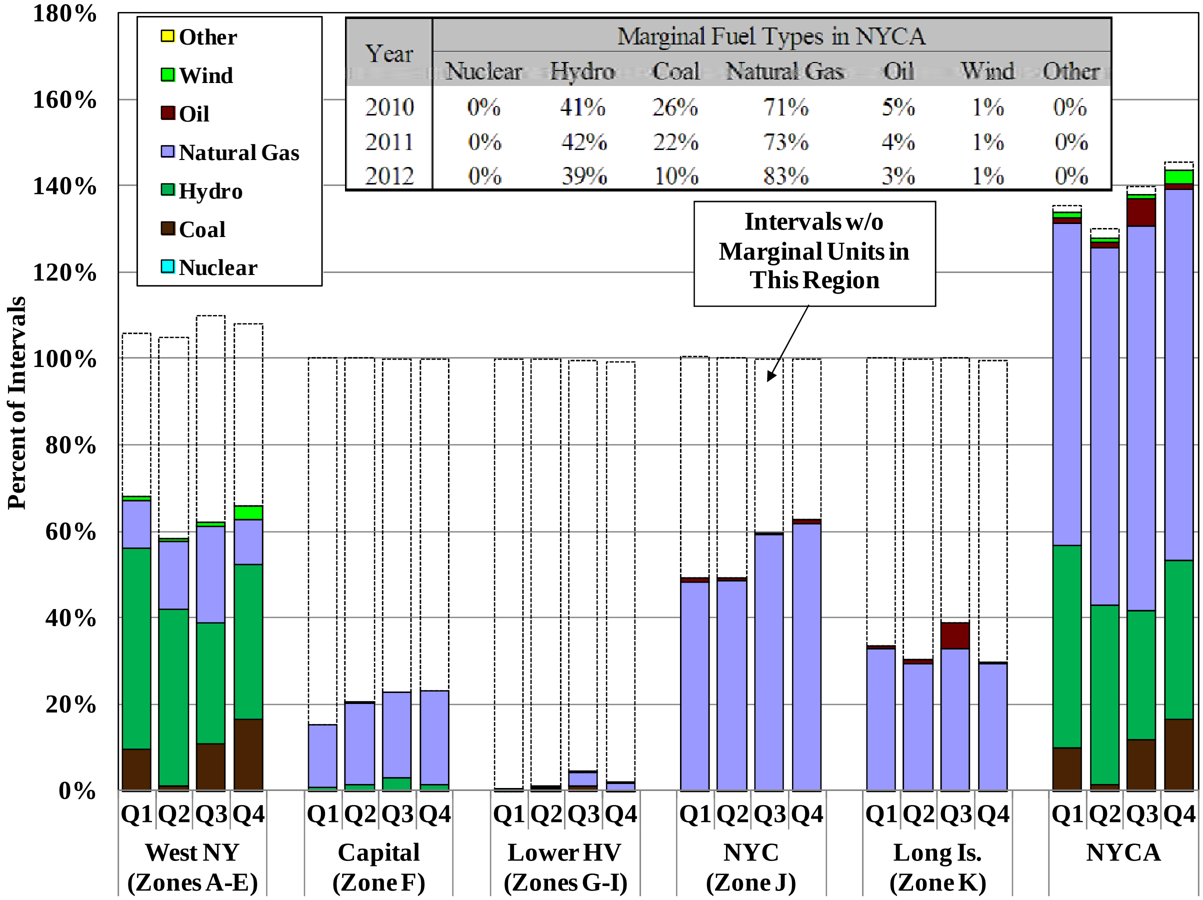


Figure A-10 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2012. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may be marginal in the constrained and unconstrained areas). Hence, the total for all fuel types may be greater than 100 percent. For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent. When no unit is on the margin in a particular region, the LBMPs in the region are set by generators in other regions.

Figure A-10: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2012



Year	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2010	0%	41%	26%	71%	5%	1%	0%
2011	0%	42%	22%	73%	4%	1%	0%
2012	0%	39%	10%	83%	3%	1%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- The prices for fuel oil rose slightly from 2011 to 2012 while coal prices and natural gas prices fell notably over the period.
  - Diesel fuel oil (No. 2) prices averaged \$21.53/MMBtu in 2012, up 3 percent from 2011.
  - Residual fuel oil (No. 6) prices averaged slightly over \$18/MMBtu in 2012, up 1 percent from 2011.
  - Central Appalachian coal prices averaged \$2.39/MMBtu in 2012, down 19 percent from 2011.
  - Natural gas prices, which more directly affected wholesale energy prices, averaged \$3.19 to \$3.65/MMBtu in 2012, down 28 to 35 percent from 2011.
  - The locational spreads between different natural gas price indices increased significantly with Iroquois Zone 2 prices being higher than Transco Zone 6 (NY) prices by an average of 12 percent in 2012, up from 3 percent in 2011.

- Production from gas-fueled generating resources rose considerably from 37 percent in 2010 to 45 percent in 2012 as production from coal units fell from 10 percent to 3 percent over the same period. Natural gas usage has risen due to:
  - The reductions in output from nuclear units and hydroelectric units:
  - The reduction in natural gas prices relative to coal prices; and
  - The entry of new gas-fired capacity in the Capital Zone and New York City and the retirement of coal capacity in Western New York.
- Gas-fired resources and hydro resources were on the margin most of time in NYCA.
  - Gas-fired resources were on the margin in 83 percent of the intervals during 2012 and hydro resources set the prices in 39 percent of the intervals.
  - Coal resources were on the margin in 10 percent of the intervals during 2012, down substantially from 26 percent in 2010 and 22 percent in 2011, driven by lower natural gas prices,
- Other fuel types were rarely on the margin because nuclear units and wind units were usually base-loaded and oil units only set the price occasionally during very high-load periods.

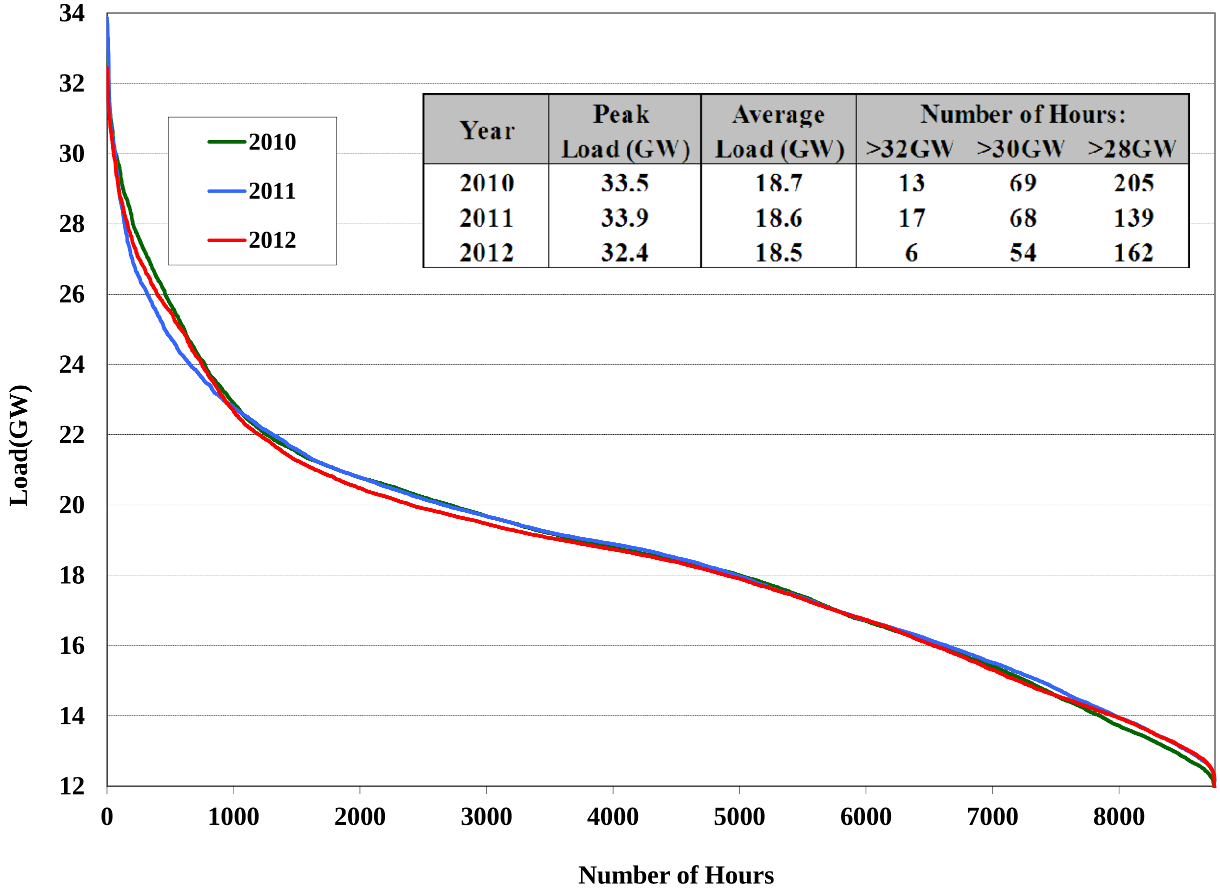
C. Load Levels

Figure A-11: 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-11 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-11: Load Duration Curves for New York State
2010 – 2012



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2010	33.5	18.7	13	69	205
2011	33.9	18.6	17	68	139
2012	32.4	18.5	6	54	162

Key Observations: Load Levels

- Load averaged 18.5 GW in 2012, down slightly from 2011.
- The system had fewer hours with extremely high load conditions (i.e., when load exceeded 32 GW) in 2012 due to the milder weather in the summer of 2012.
  - Load peaked at 32,439 MW on July 17, 2012, approximately 1.4 GW lower than the annual peak from the previous year.

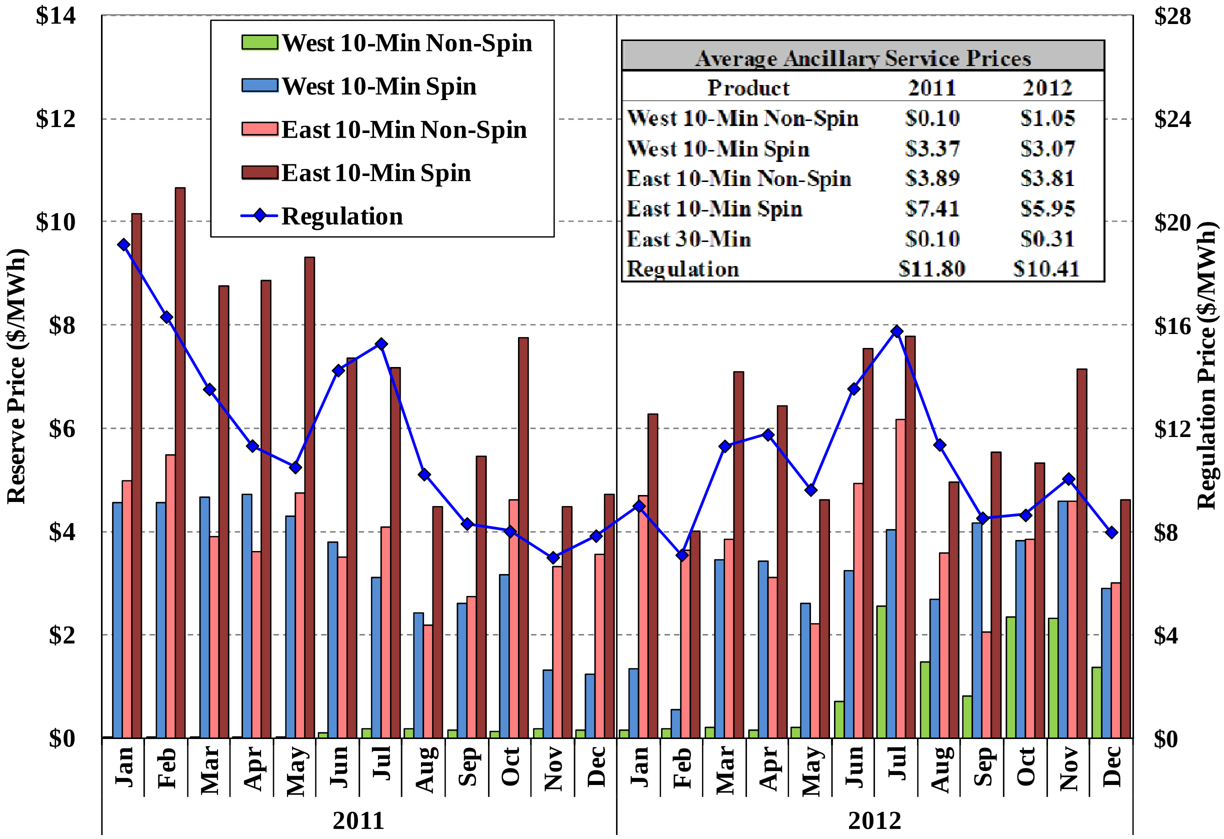
D. Day-ahead Ancillary Services Prices

Figure A-12: 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-12 shows the average prices of the following five key ancillary services products in the day-ahead market in each month of 2011 and 2012: (a) 10-minute total reserves in Western New York; (b) 10-minute spinning reserves in Western New York; (c) 10-minute total reserves in Eastern New York; (d) 10-minute spinning reserves in Eastern New York; and (e) Regulation.

Figure A-12: Day-Ahead Ancillary Services Prices
2011-2012



Key Observations: Day-ahead Ancillary Service Prices

- The average prices for most classes of ancillary services were virtually unchanged from 2011 to 2012.
  - However, monthly average prices generally tracked changes in fuel prices and load levels, peaking in the summer.
- The one class of ancillary services whose price changed significantly in 2012 was statewide 10-minute reserves. This is the primary requirement that is reflected in the

west 10-minute non-spin price, which increased from $0.10 per MWh in 2011 to $1.05 in 2012.

  – This annual increase reflects the substantial rise that began on June 27, 2012 after the increase in the operating reserve requirements described below.

- On June 27, 2012, several reserve requirements increased following an increase in the size of the NYCA system's largest single supply contingency from 1,200 MW to 1,310 MW. The Nine Mile nuclear unit #2 was up-rated to 1,310 MW, thereby increasing the size of the largest single supply contingency. The following requirements increased:

  - 10-minute spinning reserves in Eastern New York from 300 MW to 330 MW;

  - 10-minute spinning reserves in NYCA from 600 MW to 655 MW;

  - 10-minute total reserve requirement in NYCA from 1,200 MW to 1,310 MW; and

  - 30-minute total reserves in NYCA increased from 1,800 MW to 1,965 MW.

- As a result, prices have risen in several reserve products since June 2012, most notably the Western 10-minute non-spinning reserves prices.

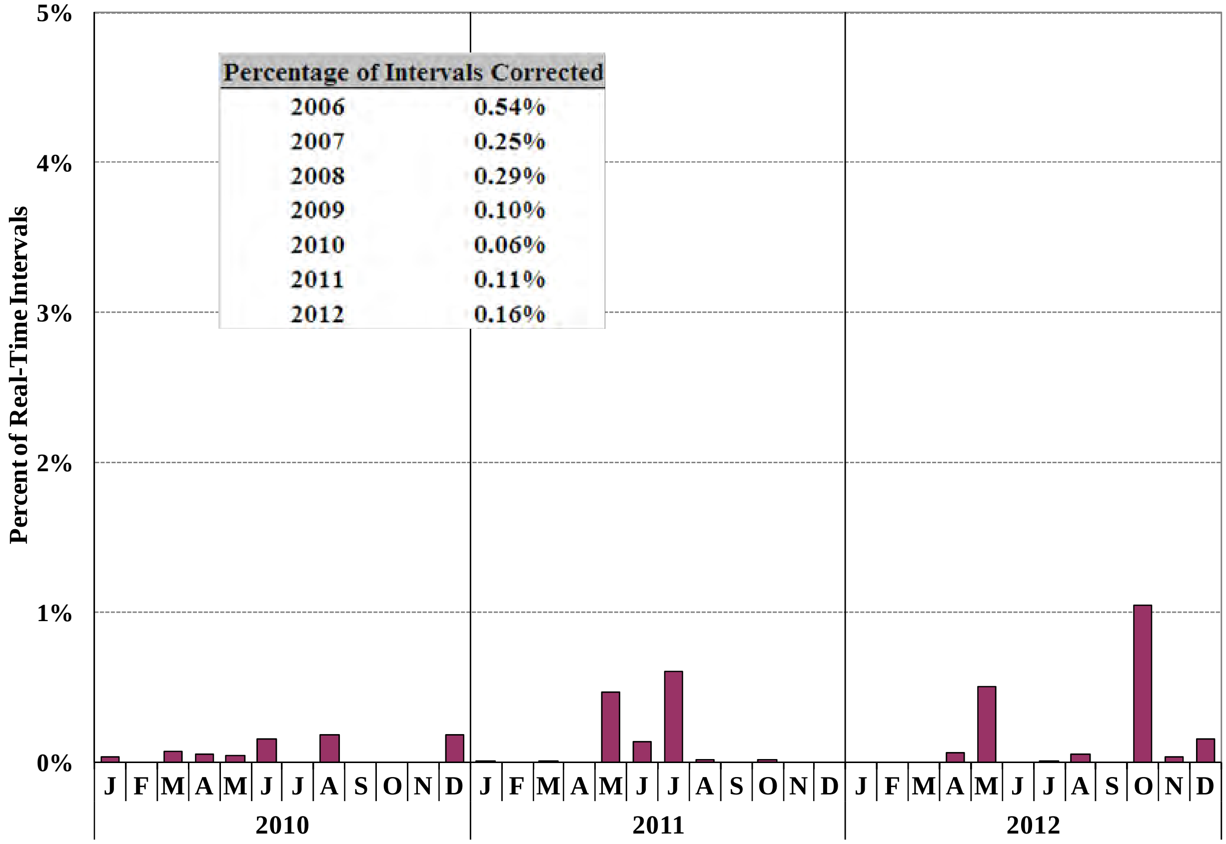
E. Price Corrections

Figure A-13: 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-13 summarizes the frequency of price corrections in the real-time energy market in each month of 2010 and 2012. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-13: Frequency of Real-Time Price Corrections
2010-2012



Key Observations: Price Corrections

- Overall, the frequency of corrections and the significance of the corrections have declined to very low levels, around 0.1 percent of real-time pricing intervals in each of the past four years.
- The frequency of price corrections was slightly higher in October 2012, which was due largely to software errors that only affected prices at the proxy buses on several days. The overall effects of these errors on the market outcomes were not substantial.

F. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the signals for investment in new generation and the 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.[95, 96] 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;

95 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.

96 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 units may 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, it uses day-ahead clearing prices exclusively, although online generators can earn additional profits by adjusting their production in the real-time market. Third, 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.

- 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;[97]
- Online units are dispatched in real-time consistent with the hourly integrated real-time price and settle with the ISO on the deviation from their day-ahead schedule;
- Fuel costs assume charges of $0.27/MMbtu on top of the Transco Zone 6 (NY) day-ahead index price and a 6.9 percent tax for New York City units; [98]
- 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-14 & Figure A-15: 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-14 shows net revenues for a hypothetical combined-cycle generator, and Figure A-15 shows net revenues for a hypothetical combustion turbine.

97 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.

98 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-14: Net Revenue for Combined-Cycle Unit
2008-2012

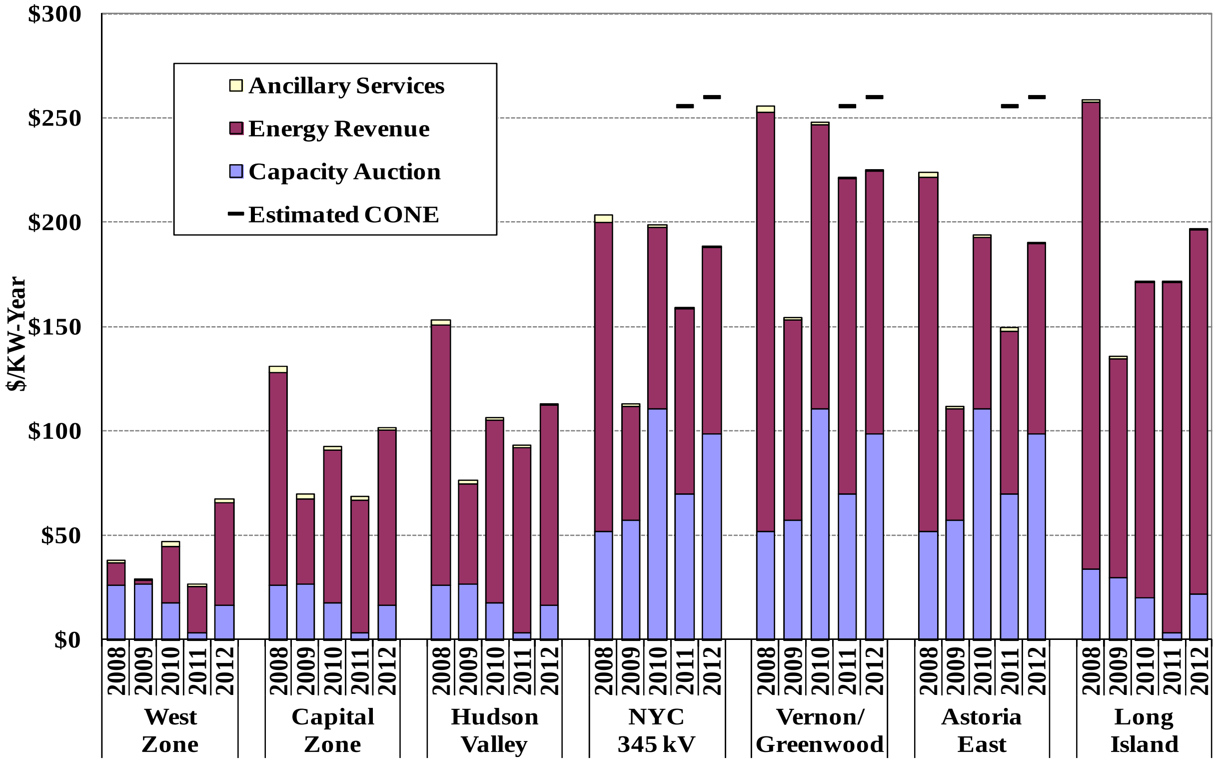
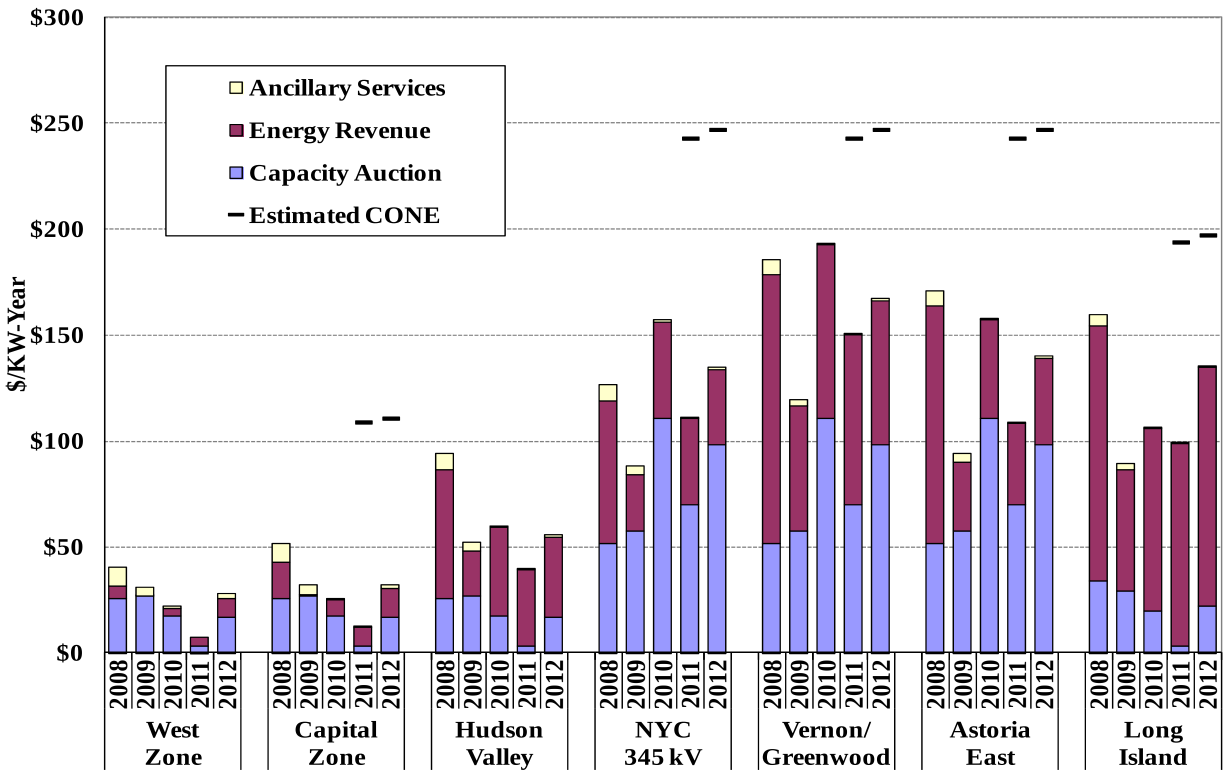


Figure A-15: Net Revenue for Combustion Turbine
2008-2012



Key Observations: Net Revenue

- Both figures show that net revenues varied notably from year to year in most areas. Overall, the net revenues rose in 2012. These changes were due to a number of factors:
  - Outside New York City, capacity net revenues rose notably in 2012 because of multiple retirements and increased capacity requirements. This reversed a trend of falling capacity net revenues from 2007 to 2011 when capacity was added around the state and load was flat (and sometimes falling).
  - In New York City, capacity net revenues rose in 2012 driven largely by the mothballing or retirement of several generators, including two Astoria steam units. Capacity prices are discussed further in Section V of the Appendix.
  - Variations in load levels affected energy net revenues over the period because higher loads lead to more frequent dispatch of high-cost generation and more shortages. However, stability in load levels led to relatively flat energy net revenues from 2010 to 2012 in most areas.
- Estimated net revenues for a new combined cycle unit rose from 2011 to 2012 due to capacity price increases throughout New York.
  - In Eastern New York, capacity net revenues rose by $30 to $40 per kW-year in New York City locations, $25 per kW-year in Long Island, and $20 to $40 per kW-year in Upstate New York. These increases were primarily due to higher capacity prices throughout New York.
  - In Western New York, energy net revenues for a combined cycle generator increased due to the improved economics of gas-fired generation relative to other fuels, which are more prevalent in the west. Estimated net revenues for a new combustion turbine rose for the same reasons.
- Despite these increases, estimated net revenues were well below the estimated CONE values in both 2011 and 2012 for both combustion turbines and combined cycles at the locations for which such estimates were made. In 2012:
  - For a new combustion turbine unit, estimated net revenues were lower than the estimated CONE by 71 percent in the capital zone, 45 percent in New York City, and 31 percent in Long Island.
  - For a new combined cycle unit, estimated net revenues were lower than the estimated CONE by 28 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.

G. Day-Ahead Energy Market Performance

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 two 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.

Figure A-16 & Figure A-17: 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-16 and Figure A-17 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 2012. 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-16: Average Day-Ahead and Real-Time Energy Prices outside SENY

West, Central, and Capital Zones - 2012

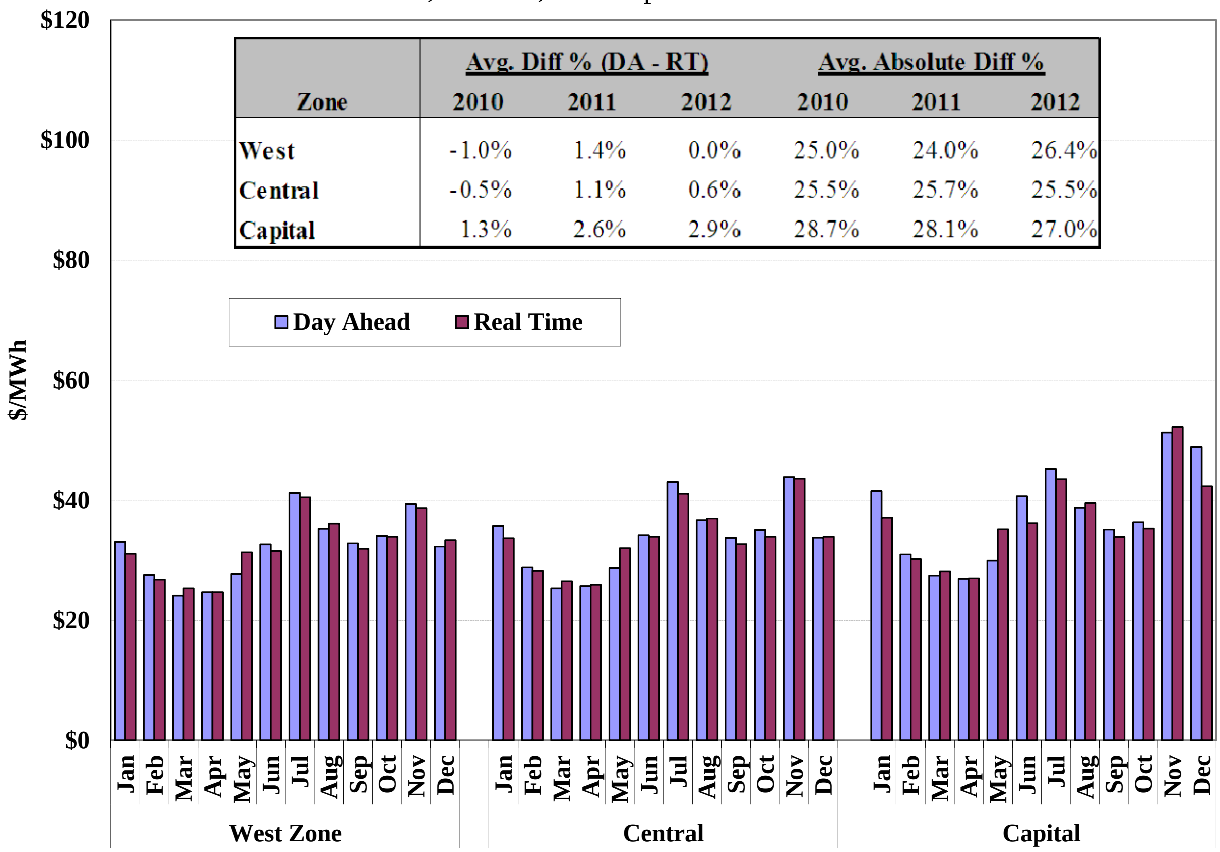
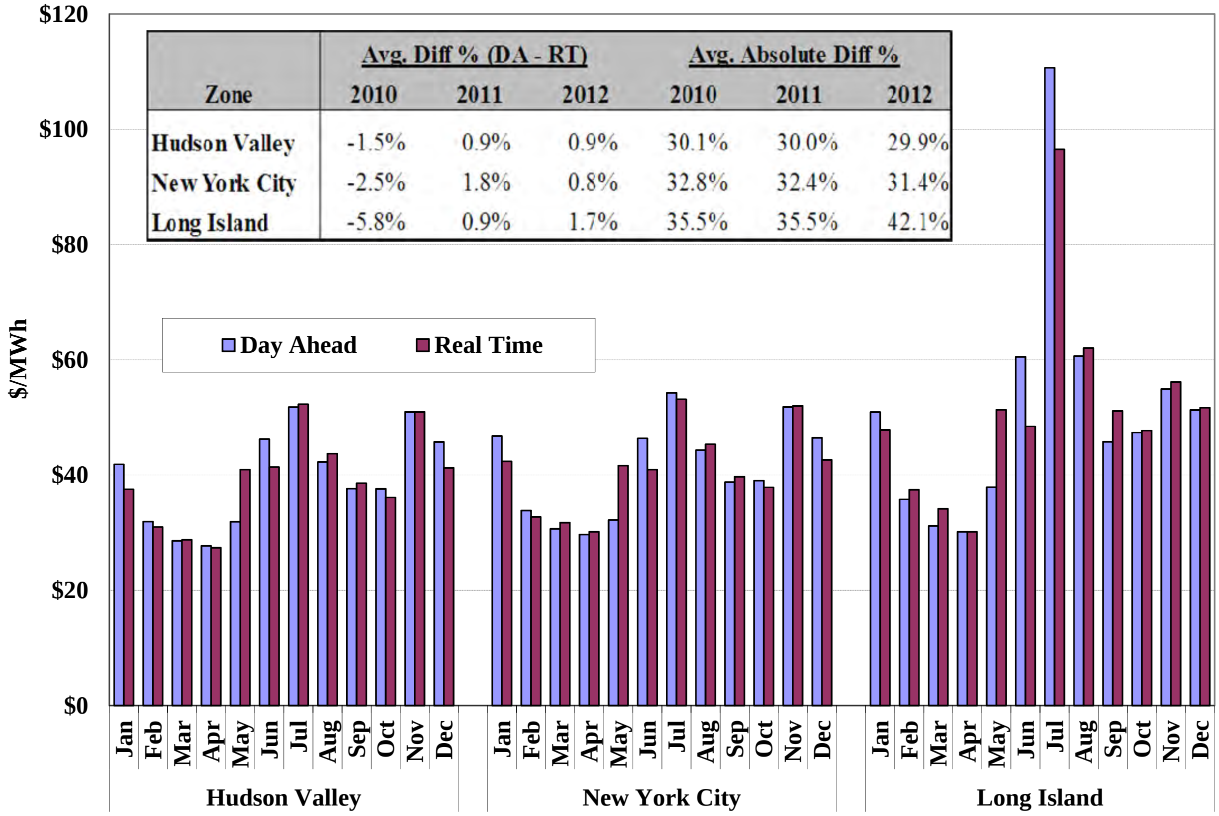


Figure A-17: Average Day-Ahead and Real-Time Energy Prices in SENY
Hudson Valley, New York City, and Long Island - 2012



Zone	Avg. Diff % (DA - RT) 2010	2011	2012	Avg. Absolute Diff % 2010	2011	2012
Hudson Valley	-1.5%	0.9%	0.9%	30.1%	30.0%	29.9%
New York City	-2.5%	1.8%	0.8%	32.8%	32.4%	31.4%
Long Island	-5.8%	0.9%	1.7%	35.5%	35.5%	42.1%

Figure A-18 & Figure A-19: 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 led 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 2012. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure A-18: Average Daily Real-Time Price Premium in NYC
1 p.m. to 7 p.m. Weekdays, 2012

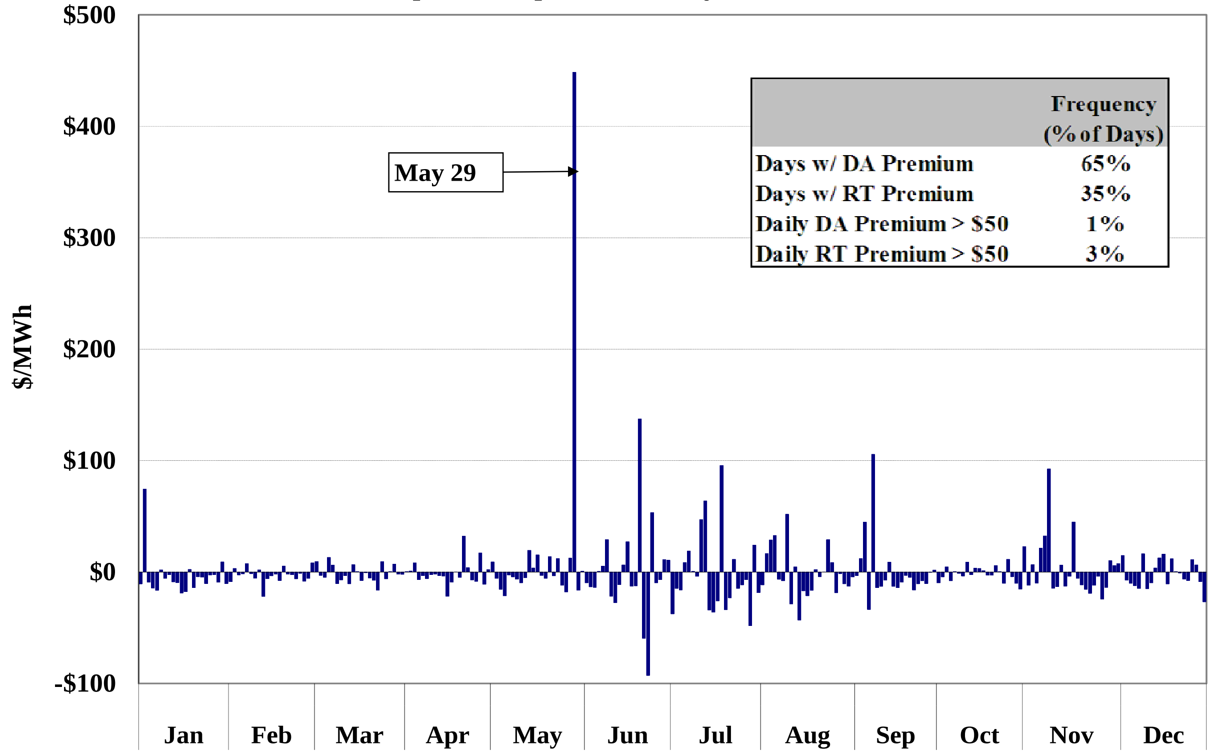


Figure A-19: Average Daily Real-Time Price Premium in Long Island
1 p.m. to 7 p.m. Weekdays, 2012

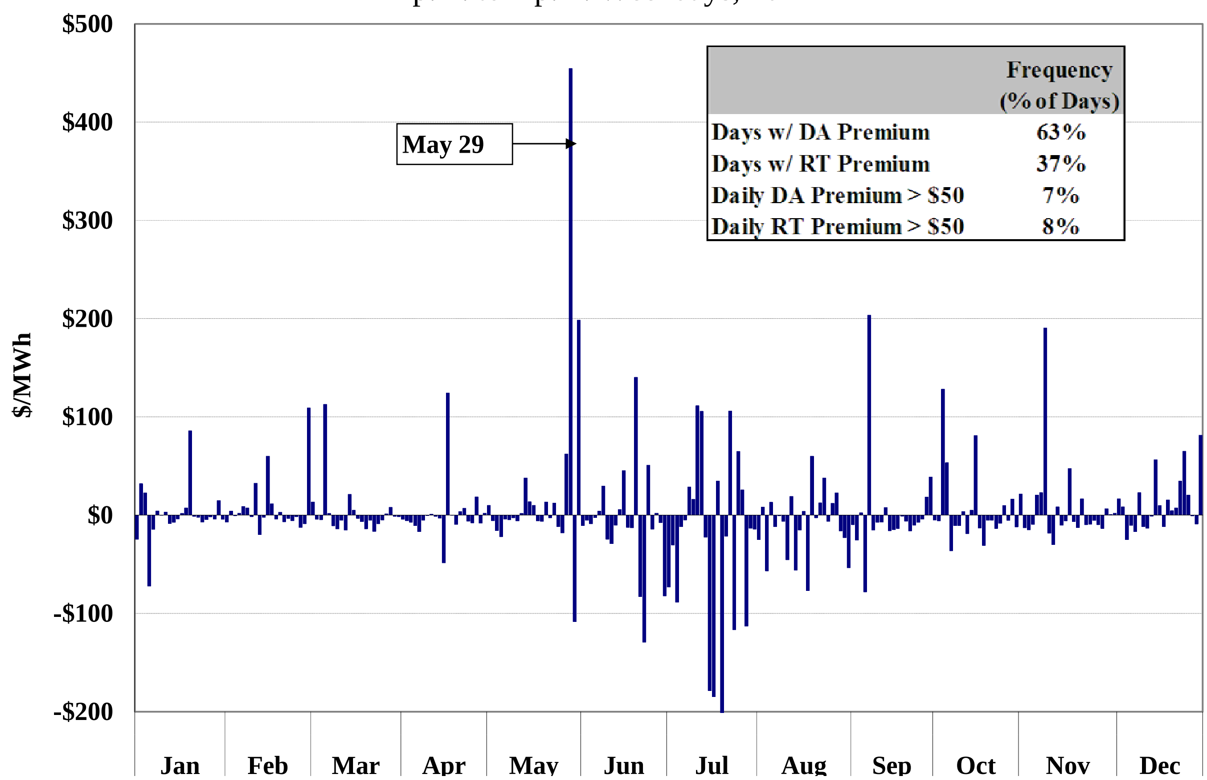


Figure A-20: Average Real-Time Price Premium at Select Nodes

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.

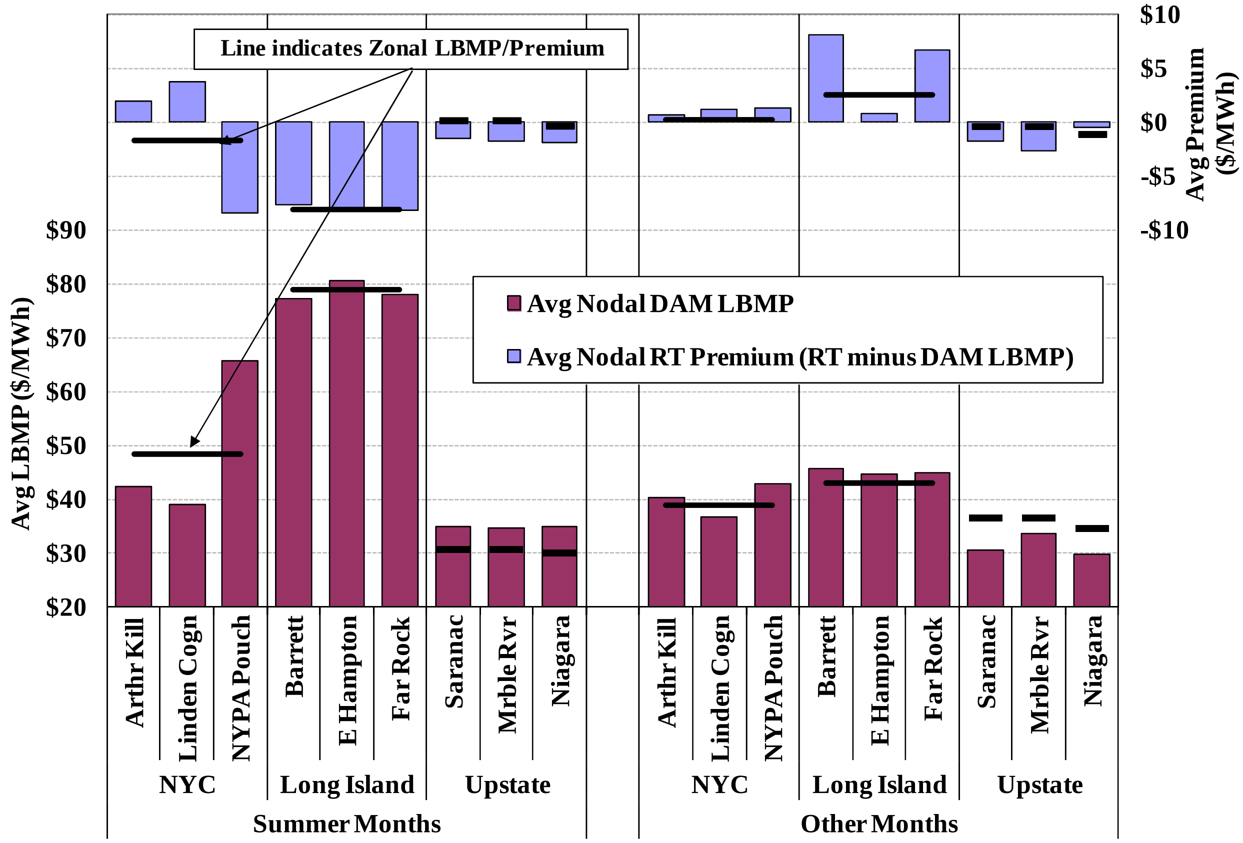
In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit virtual trades and price sensitive load bids at the load pocket level or more 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 throughout New York State to assess price convergence at the nodal level.

Figure A-20 shows average day-ahead prices and real-time price premiums in 2012 for selected locations in New York City, Long Island, and Upstate New York.[99] 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

[99] In New York City, Arthur Kill is the Arthur Kill2 bus and NYPA Pouch is the NYPA Pouch GT 1 bus. In Long Island, Barret is the Barrett 1 bus and Far Rock is FPL Far Rock GT 1 bus. In Upstate, Marble River is the Marble River Wind Generator bus in the North Zone, Saranac is also in the North Zone, and Niagara 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-20: Average Real-Time Price Premium at Select Nodes
2012



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

- Energy price convergence was relatively good in most areas in 2012.
  - However, in Long Island, which already exhibited the largest spreads between day-ahead and real-time energy prices, the average spread rose from 35.5 percent in 2011 to 42.1 percent in 2012. Inconsistencies between day-ahead and real-time prices were increased by increased real-time price volatility. The following factors contributed to the increased real-time price volatility, particularly during the summer: the reduction in imports on the Neptune line, the retirement of 330 MW of steam turbine generation, a greater reliance on oil-fired generators, and inflexible operation by gas-fired generators.
  - On May 29, real-time prices were much higher than day-ahead prices as actual loads ran approximately 10 percent higher than day-ahead forecasted loads. Consequently,

less capacity was committed in the day-ahead market than would have been economic and the NYISO deployed reliability demand response.

- At the zonal level, average day-ahead energy prices were higher than average real-time prices by a small margin (around 1 percent in most regions).
  - 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. [100]
- 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 NYPA Pouch location, which exhibited day-ahead price premiums of $9 per MWh in the summer months.
  - The Valley Stream load pocket, which exhibited a real-time price premium of $8 per MWh outside the summer.
  - Allowing disaggregated virtual trading in these areas would address these differences by allowing participants the opportunity to arbitrage them.

H. Day-Ahead Ancillary Service Market Performance

As in the day-ahead energy market, a well-performing day-ahead ancillary service market will produce prices that converge well with real-time market 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.

To evaluate the performance of the day-ahead ancillary service markets, the following four figures summarize day-ahead and real-time clearing prices for two important reserve products in New York.

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100 For example, SENY exhibited a significant real-time price premium on May 29, 2012 due to the combined effects of a TSA event and actual load running over forecast by more than 3 GW.

Figure A-21 – Figure A-24: 10-Minute Spinning and Non-Spinning Reserve Prices

Figure A-21 and Figure A-22 show 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-23 and Figure A-24 show 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 655 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 Figure A-21 and Figure A-23, 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.

In Figure A-22 and Figure A-24, average prices are shown based on daily peak load levels and different time of day. The inset tables show the percent of days in each load range.

Figure A-21: 10-Minute Non-Spinning Reserve Prices in East NY
by Season and Hour of Day, 2012

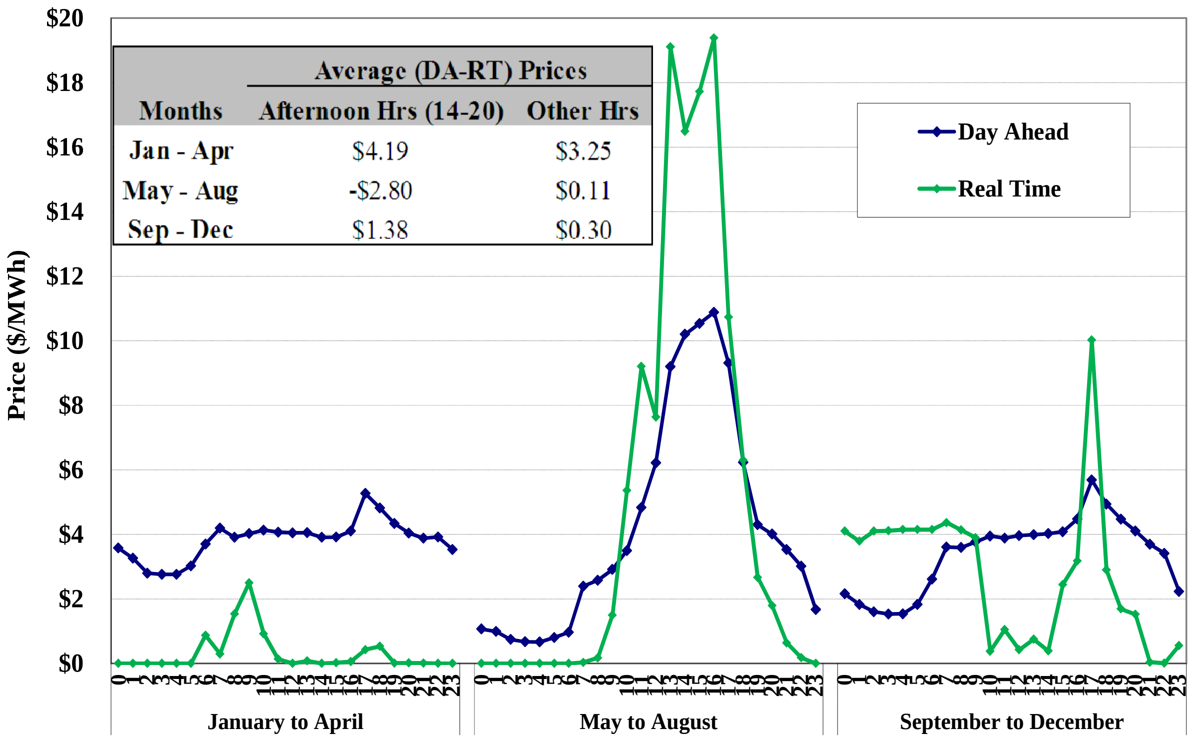


Figure A-22: 10-Minute Non-Spinning Reserve Prices in East NY
by Daily Peak Load Level and Time of Day, 2012

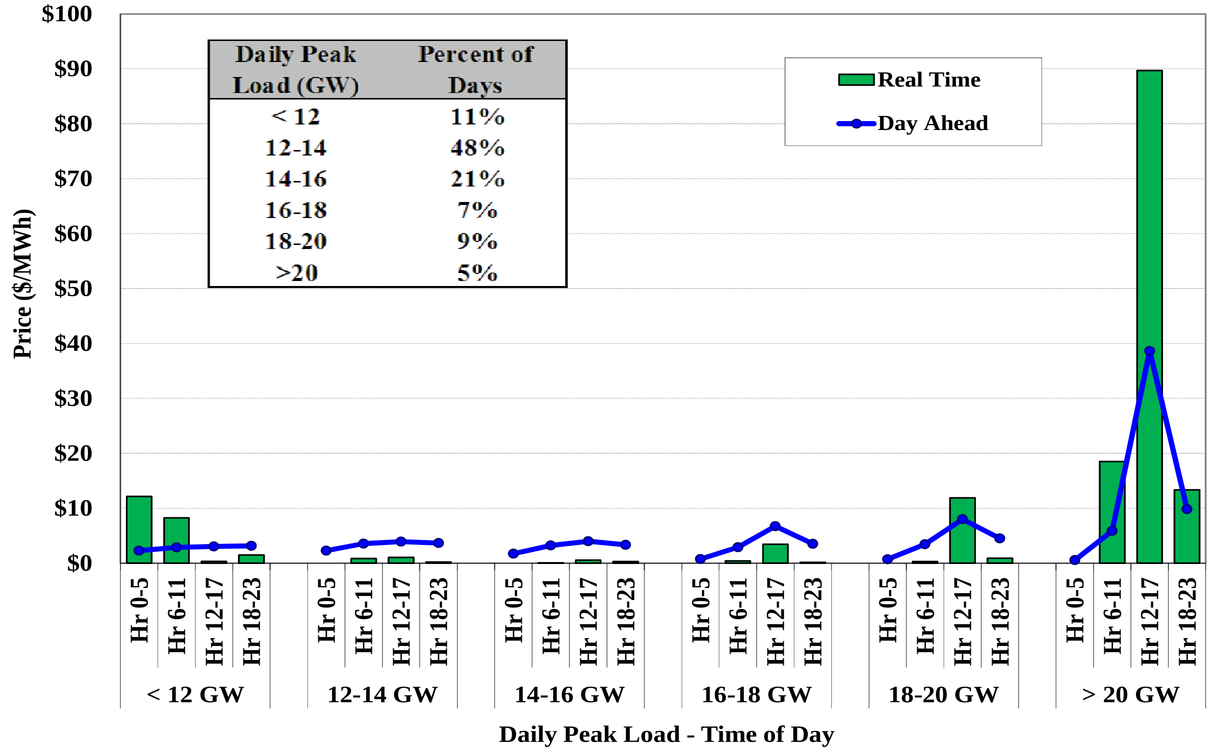


Figure A-23: 10-Minute Spinning Reserve Prices in West NY
by Season and Hour of Day, 2012

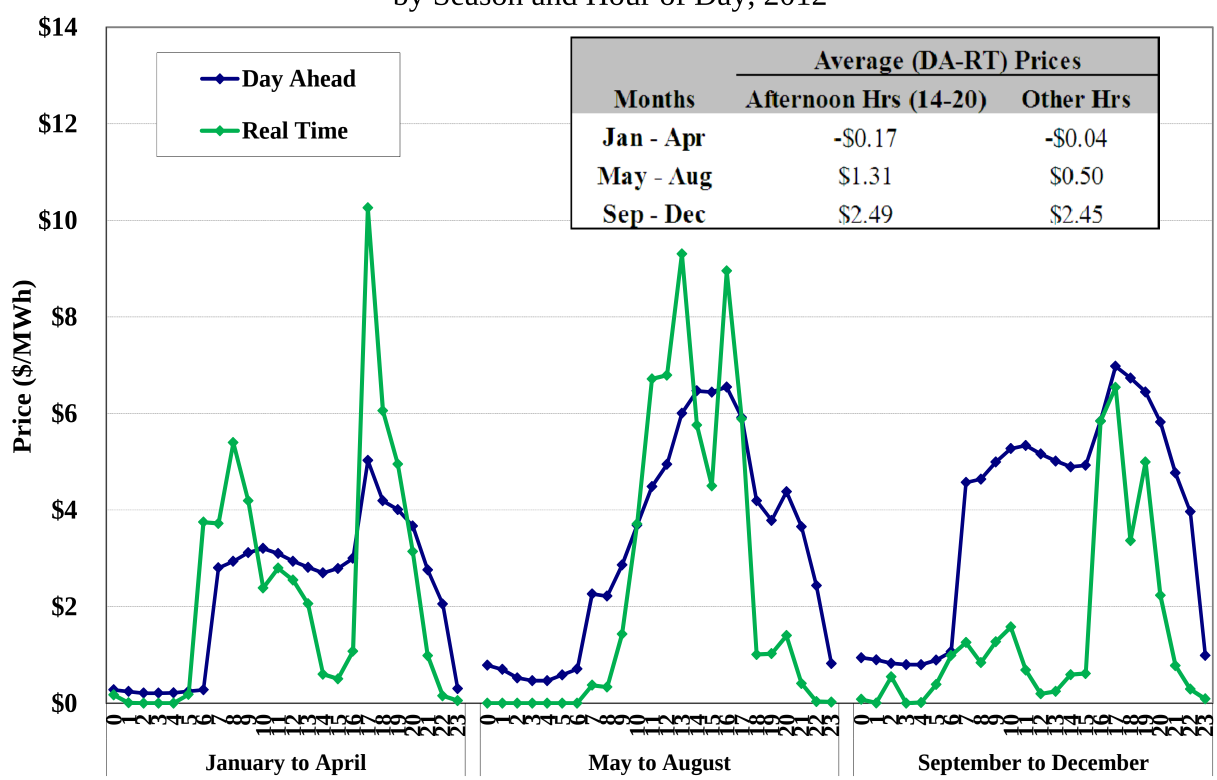
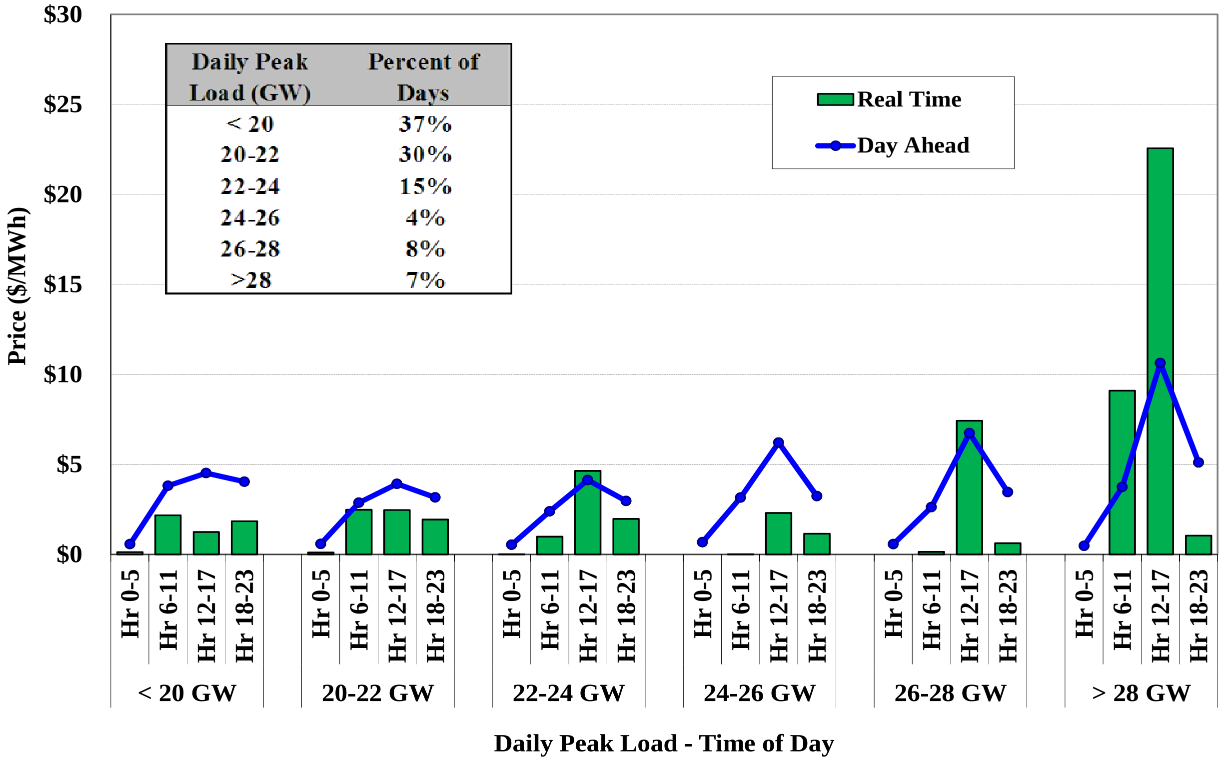


Figure A-24: 10-Minute Spinning Reserve Prices in West NY
by Daily Peak Load Level and Time of Day, 2012



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

- Reserve price convergence was relatively poor in 2012.
- Under 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 when daily peak load in NYCA exceeded 28 GW.
  - The mitigation rules that limit the ancillary services offers of some generators in the day-ahead market likely inhibited price convergence during these hours. To address this problem, the NYISO relaxed the mitigation rules starting on January 23, 2013, which should improve price convergence going forward.[101]

[101] See New York Independent System Operator, Inc., *Proposed Amendments to its Market Power Mitigation Measures revising Mitigation Measures for 10-Minute Non-Synchronized Reserves and New York City Day-Ahead Market Spinning Reserves*, Docket No. ER13-298-000.

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 evaluates the following areas:

- Potential physical withholding;
- Potential economic withholding;
- Market power mitigation;
- Ancillary services offers in the day-ahead market;
- Load-bidding patterns; and
- Virtual trading behavior.

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. Potential physical and economic withholding are evaluated in subsections A and B.

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. Accordingly, the NYISO's market power mitigation measures work by capping suppliers' offers at an estimate of their marginal costs when they offer resources substantially above marginal cost and it would otherwise have a substantial impact on LBMPs. Market power mitigation by the NYISO is evaluated in Section C.

The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. 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. Co-optimization also reduces the potential for suppliers to exercise market power in a particular ancillary service product market because it allows the market the flexibility to shift resources between products and effectively increases the competition to provide each product. Ancillary services offer patterns are evaluated in Section D.

In addition to screening the conduct of suppliers, it is important to evaluate how the behavior of buyers influences energy prices. 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 consistency of day-ahead load scheduling with actual load is evaluated in Section E.

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. When virtual trading is profitable, it generally promotes convergence between day-ahead and real-time prices and tends to improve the efficiency of resource commitment and scheduling. The efficiency of virtual trading is evaluated in Section F.

A. Potential Physical Withholding: Generator Deratings

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). The figures in this section show the quantity of deratings as a percent of total Dependable Maximum Net Capability ("DMNC") from all resources, where deratings measure the difference between the quantity offered in the day-ahead market and the most recent 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 to reflect attempts to physically withhold than long-term deratings, 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.

To identify deratings that might constitute withholding, the figures in this section also show the portion of derated capacity that would have been economic in the day-ahead market. Derating uneconomic capacity would never constitute withholding since it would not affect the market outcomes. This assessment of economic capacity is based on generators' Minimum Generation and Incremental Energy cost reference levels and day-ahead LBMPs, but it does not consider start-up costs. Hence, the figures in this section generally over-estimate the portion of deratings that would be economic in the day-ahead market.

Figure A-25 & Figure A-26: Generator Deratings by Month

Figure A-25 and Figure A-26 show the broad patterns in outages and deratings in New York State and Eastern New York in each month of 2011 and 2012.

Figure A-25: Deratings by Month in NYCA

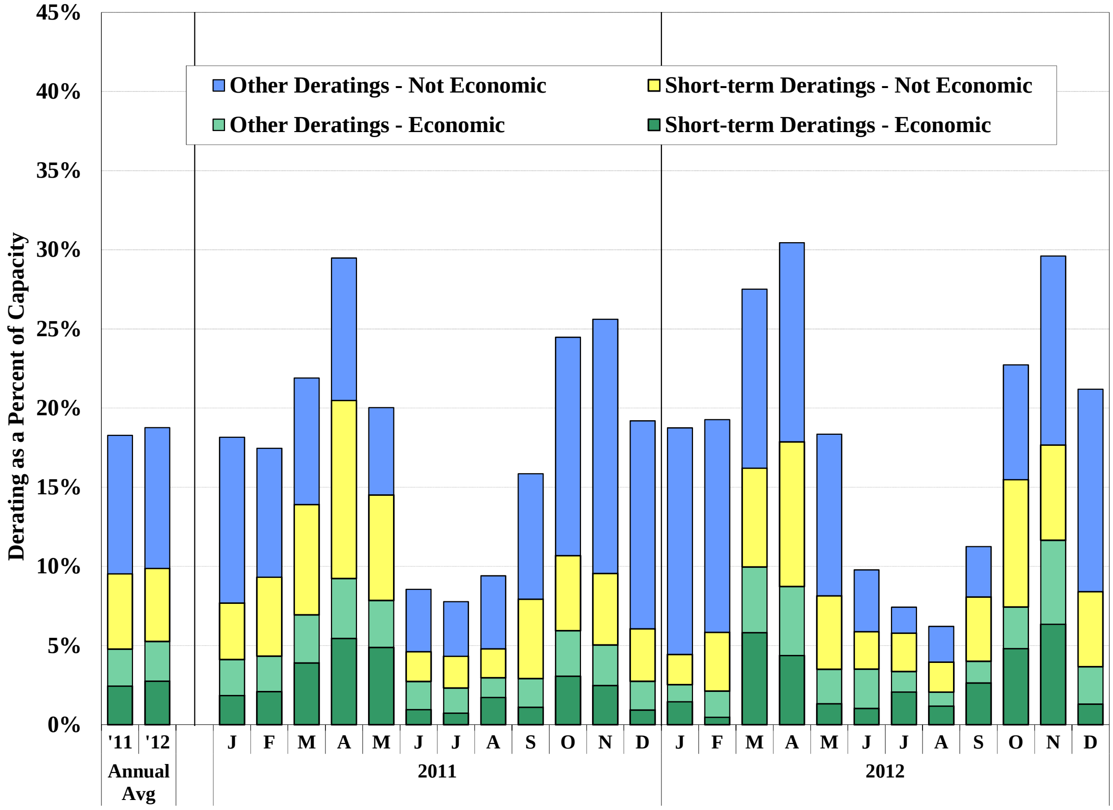


Figure A-26: Deratings by Month in East New York

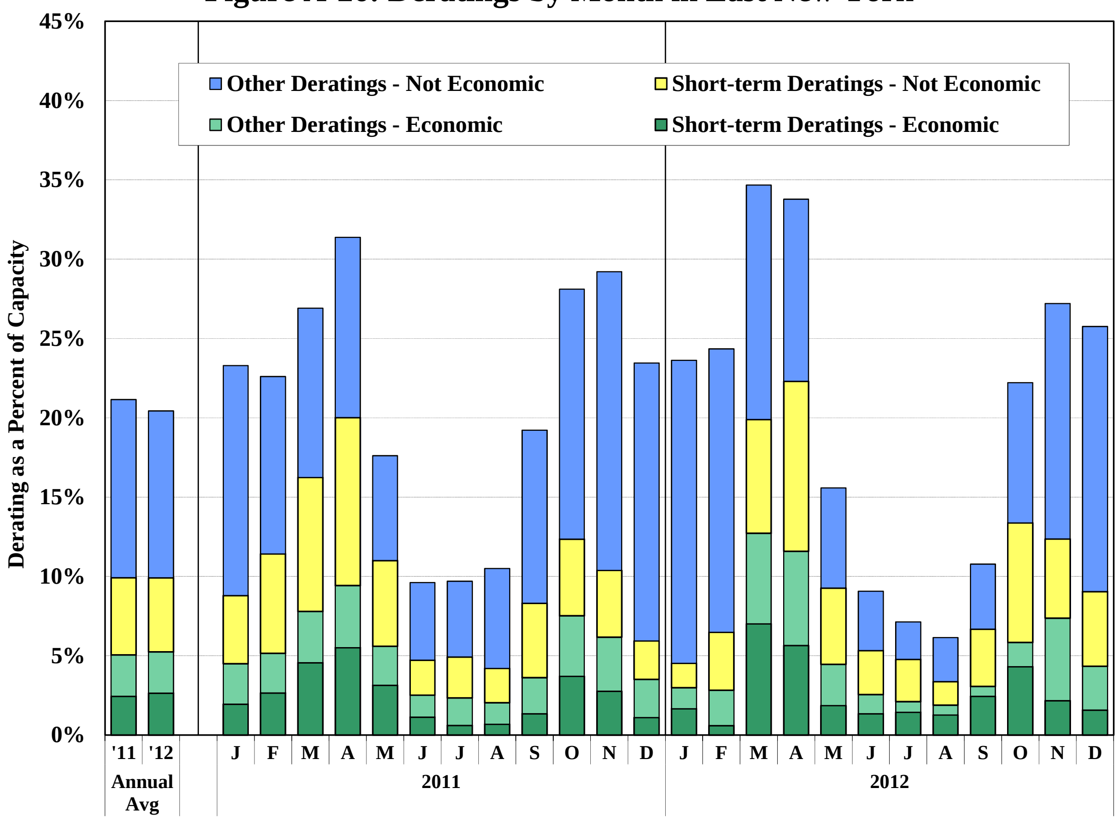


Figure A-27 & Figure A-28: Generator Deratings by Load Level and Portfolio Size

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, namely that suppliers are more likely to have market power under higher load conditions.

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. (Nonetheless, 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.) 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. Hence, we evaluate the conduct relative to load and participant size in Figure A-27 and Figure A-28 to determine whether the conduct is consistent with workable competition.

Figure A-27: Deratings by Supplier by Load Level in New York
2012

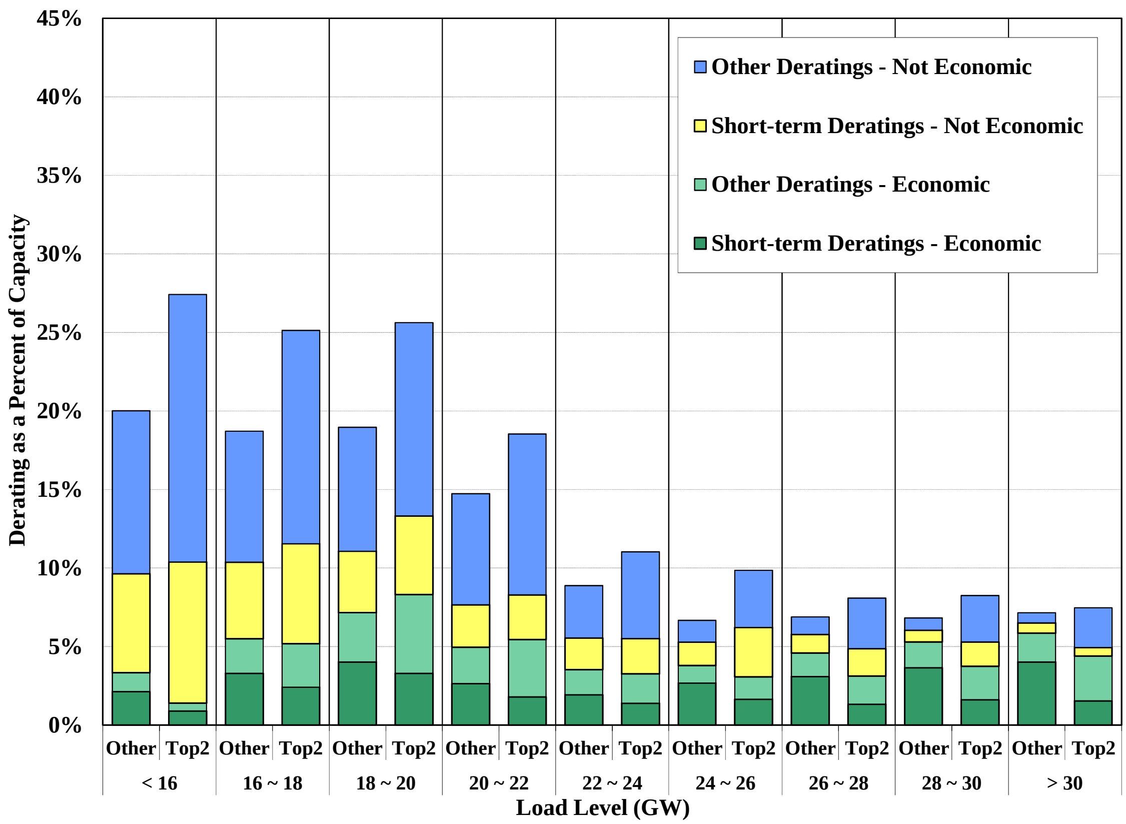
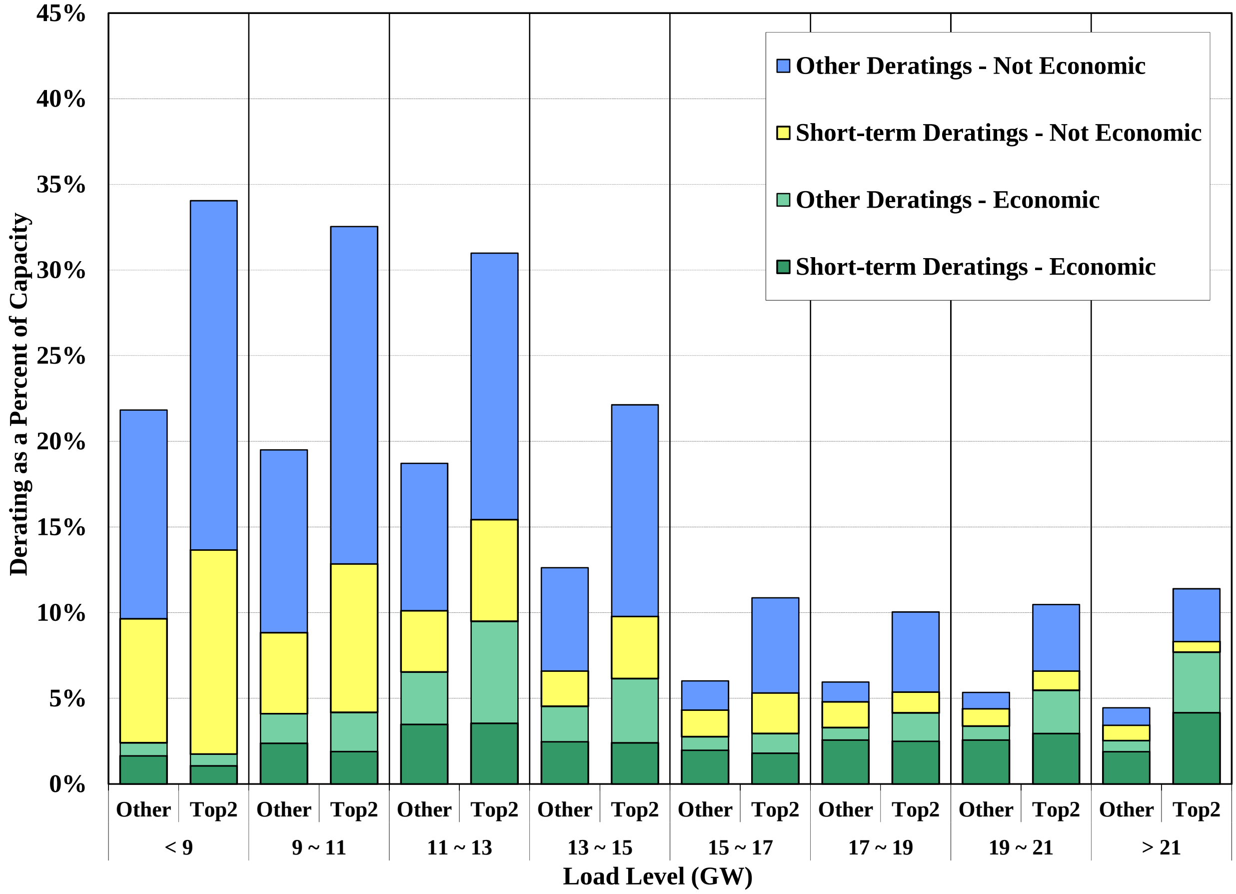


Figure A-28: Deratings by Supplier by Load Level in East New York
2012



Key Observations: Generator Deratings

- The overall pattern of deratings in 2012 was consistent with expectations in a competitive market.
    - Average total deratings were the lowest (typically 5 to 10 percent of total DMNC) during the summer months when average load was the highest. Average total deratings also fell during the winter when loads typically increase (to a lesser extent than in the summer). High levels of deratings outside the summer generally reflect planned outages for maintenance.
    - 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.
    - On average, the short-term deratings (i.e., less than 30 days) that would have been economic accounted for only a small portion of total capacity (less than 3 percent) both in Eastern New York and state wide.
        - This portion was significantly lower during the summer and winter peak seasons than in the shoulder months.

  - This level is reasonable given that low-cost units are bound to be economic during some periods when they have to undergo a forced or planned outage.

- The largest suppliers and other smaller suppliers generally increased the availability of their capacity during periods of high load. However, the largest suppliers exhibited higher levels of deratings than other suppliers, particularly in Eastern New York.

  - In eastern New York, the two largest suppliers exhibited higher levels of long-term deratings than other suppliers at all load levels. Both suppliers have portfolios primarily made up of older assets, and the propensity for these two suppliers to experience forced outages is not substantially different from that of other suppliers with similar assets. Hence, these deratings do not raise significant concerns.

- 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.

B. Potential Economic Withholding: Output Gap Metric

Economic withholding is an attempt by a supplier to inflate its offer price in order to raise LBMPs above competitive levels. A supplier without market power maximizes profit by offering its resources at marginal cost because inflated offer prices prevent the unit from being dispatched when it would have been profitable. 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.[102] An offer parameter is considered above the competitive level if it exceeds the reference level by a given threshold.

Figure A-29 and Figure A-30: Output Gap by Month

One 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.[103] We assume that the unit's competitive offer 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. Since gas turbines can be started in real-time, they evaluated 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.

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102 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. For some generators, the reference level is based on an estimate of its fuel costs, other variable production costs, and any other applicable costs.

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

The following four figures show the output gap using three thresholds: 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 two additional lower thresholds. The first additional threshold is the lower of $50 per MWh or 100 percent of a generator's reference level, and the second additional threshold is the lower of $25 per MWh or 50 percent of a generator's reference level. The two lower thresholds are 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-29: Output Gap by Month in New York State
2011 – 2012

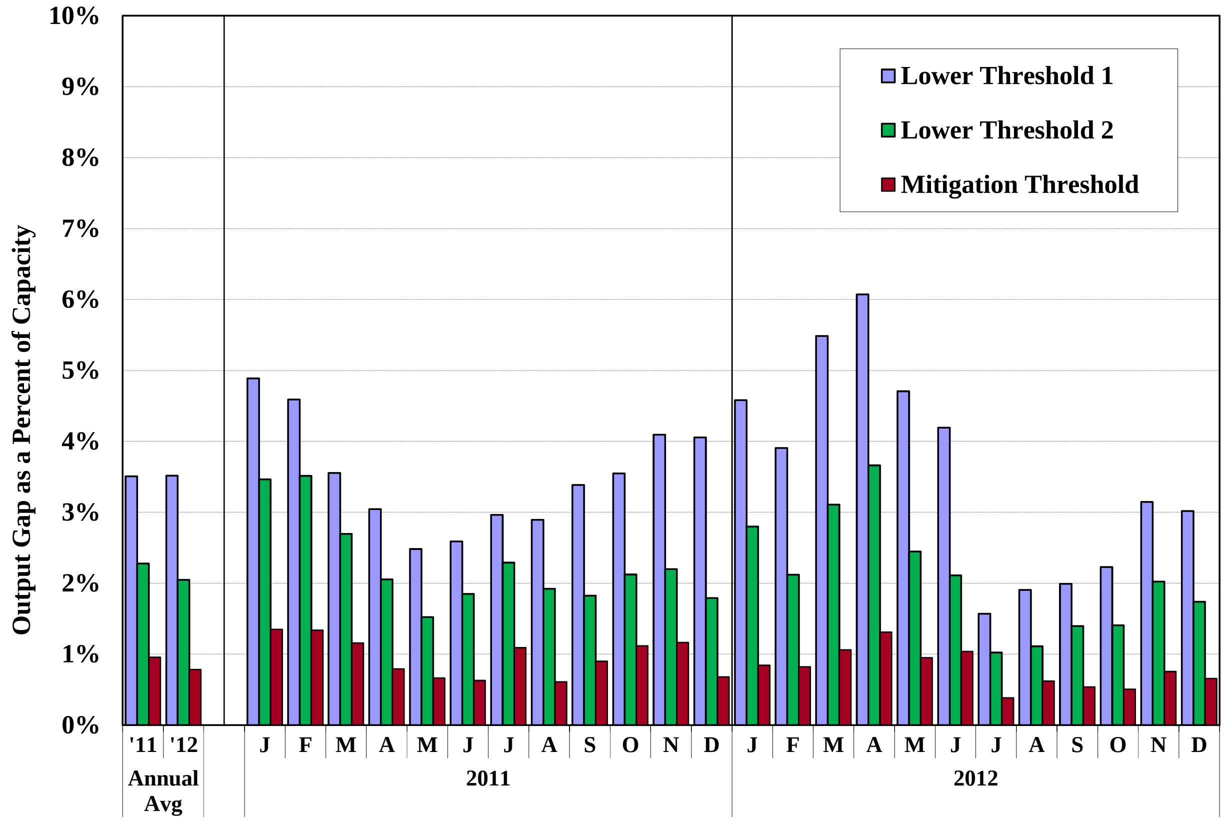


Figure A-30: Output Gap by Month in East New York
2011 - 2012

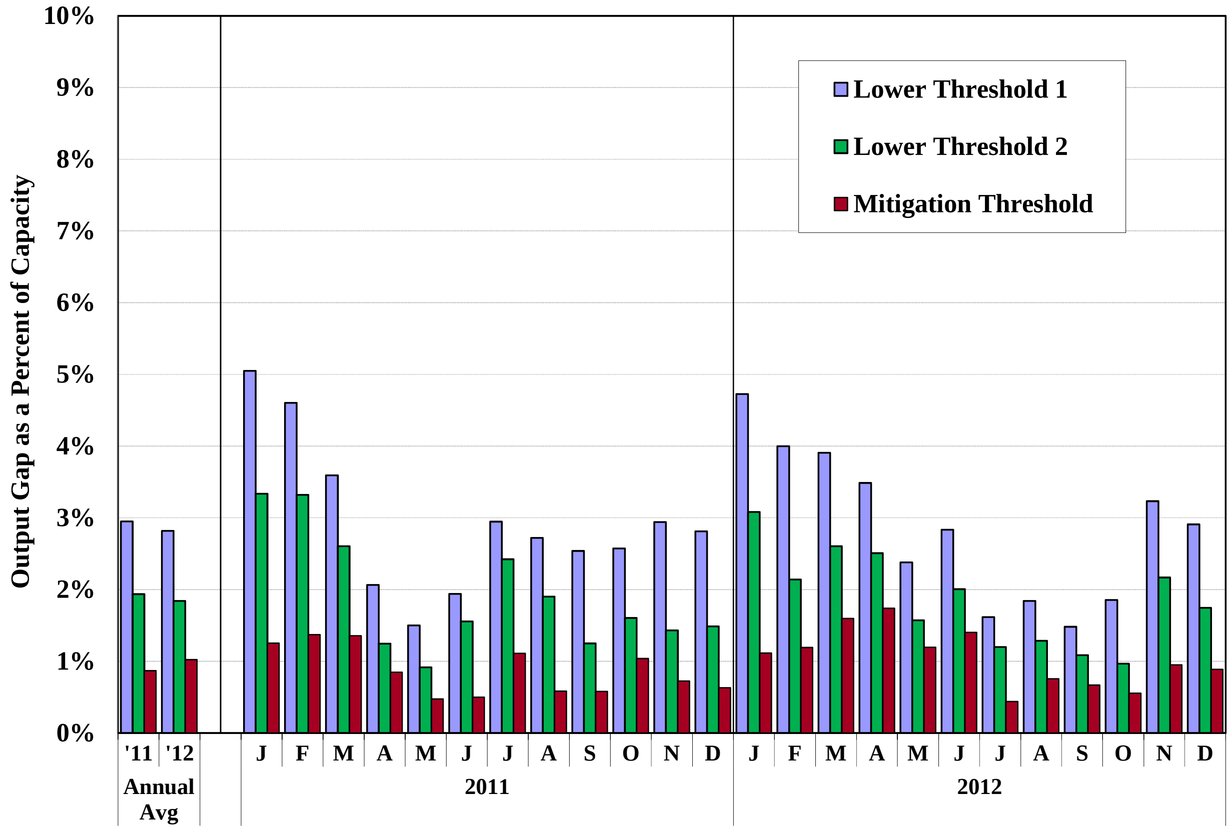


Figure A-31 & Figure A-32: Output Gap by Supplier and Load Level

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-31: Output Gap by Supplier by Load Level in New York State
2012

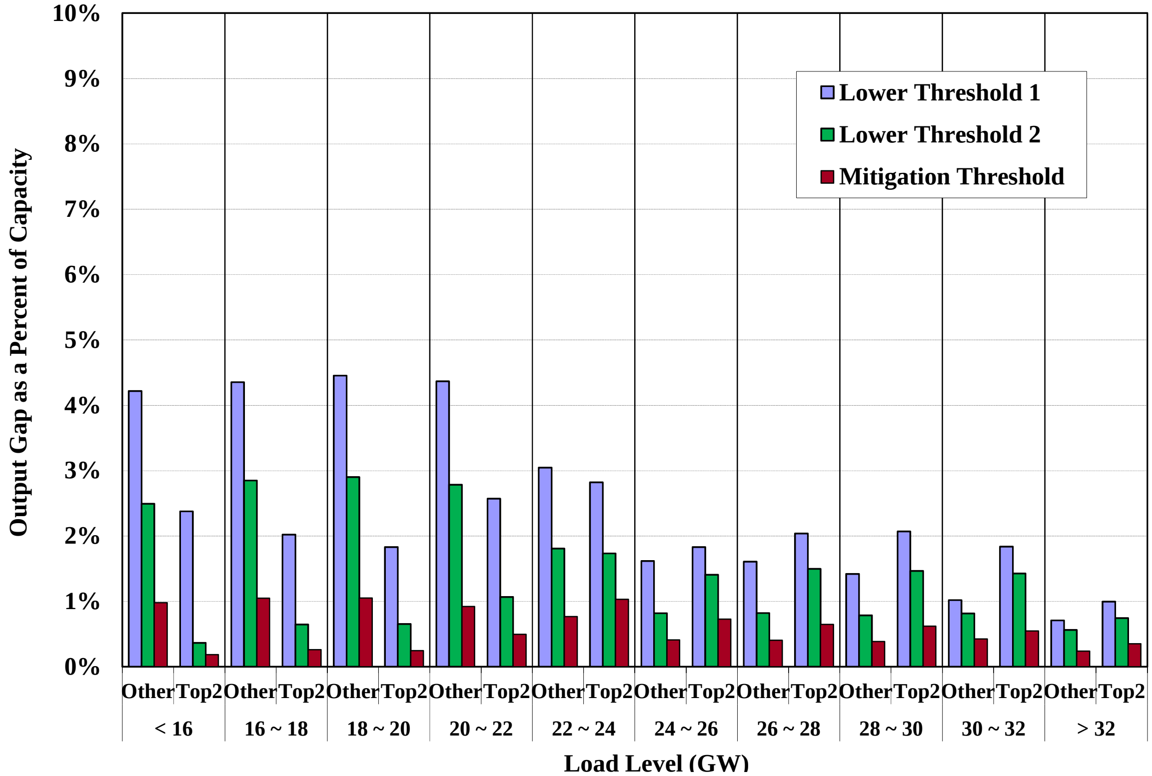
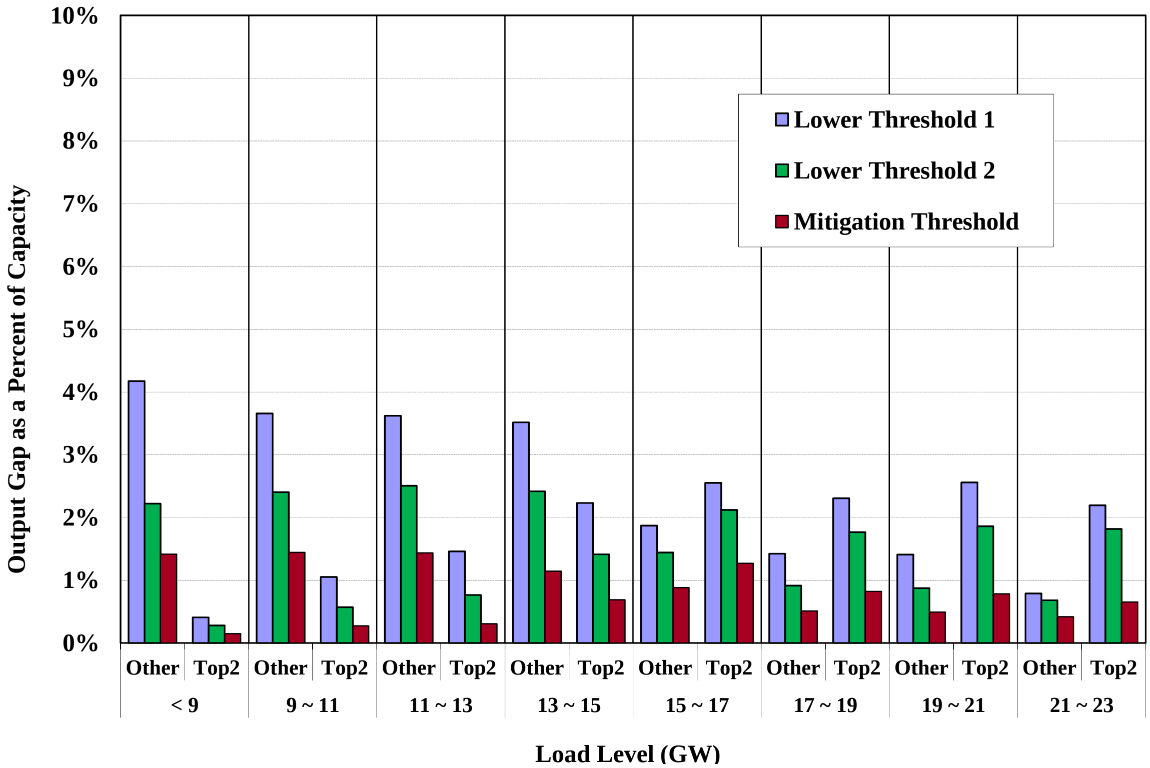


Figure A-32: Output Gap by Supplier by Load Level in East New York
2012



Key Observations: Economic Withholding – Generator Output Gap

- The overall pattern of output gap in 2012 was consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding.
  - The average output gap was low as a percentage of total capacity. At the mitigation threshold, the output gap averaged just 1.0 percent in Eastern New York.
  - At the lowest threshold evaluated (i.e., $25 per MWh or 50 percent), the output gap averaged just 3 percent.
  - In general, it is a positive indicator that the output gap generally declines as load increases for most suppliers and is especially low under high load conditions when the market is most vulnerable to the exercise of market power. However, the output gap for the largest two suppliers tends to increase with load in Eastern New York. In this case, the pattern of increased output gap is driven primarily by the IR-5 reliability rule, which requires some units to burn a blend of oil and natural gas under higher load conditions. Generators that participate in the Minimum Oil Burn Compensation program offer based on the cost of natural gas and receive compensation for the difference between the cost of oil and the cost of natural gas, but generators that do not participate in the program can be expected to offer at the full cost of the blend of oil and natural gas.

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.[104] 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

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

determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[105] 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.

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.[106] 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.[107]

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.[108] 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.[109]
- 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.
- 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.

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[105] 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.

[106] 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.

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

[108] NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation. This occurs after the market date, so any effect of the mitigation on LBMPs is unchanged by unmitigation.

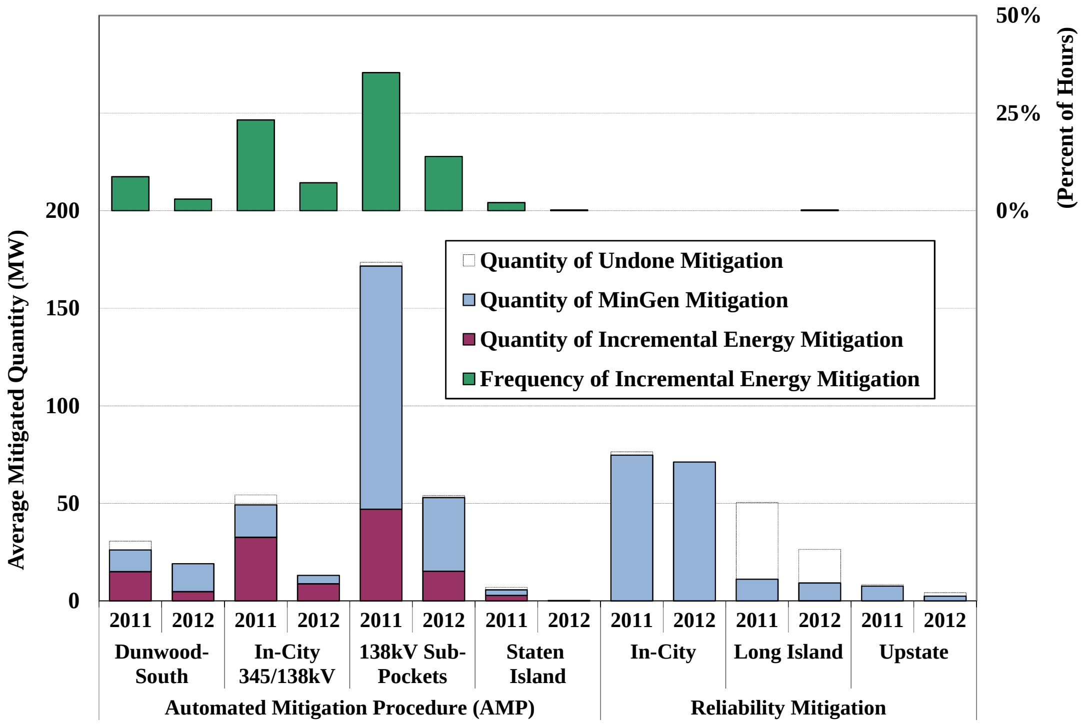
[109] The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

Figure A-33 & Figure A-34: Summary of Day-Ahead and Real-Time Mitigation

Figure A-33 and Figure A-34 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2011 and 2012. These figures do not include guarantee payment mitigation that occurs in the settlement system.

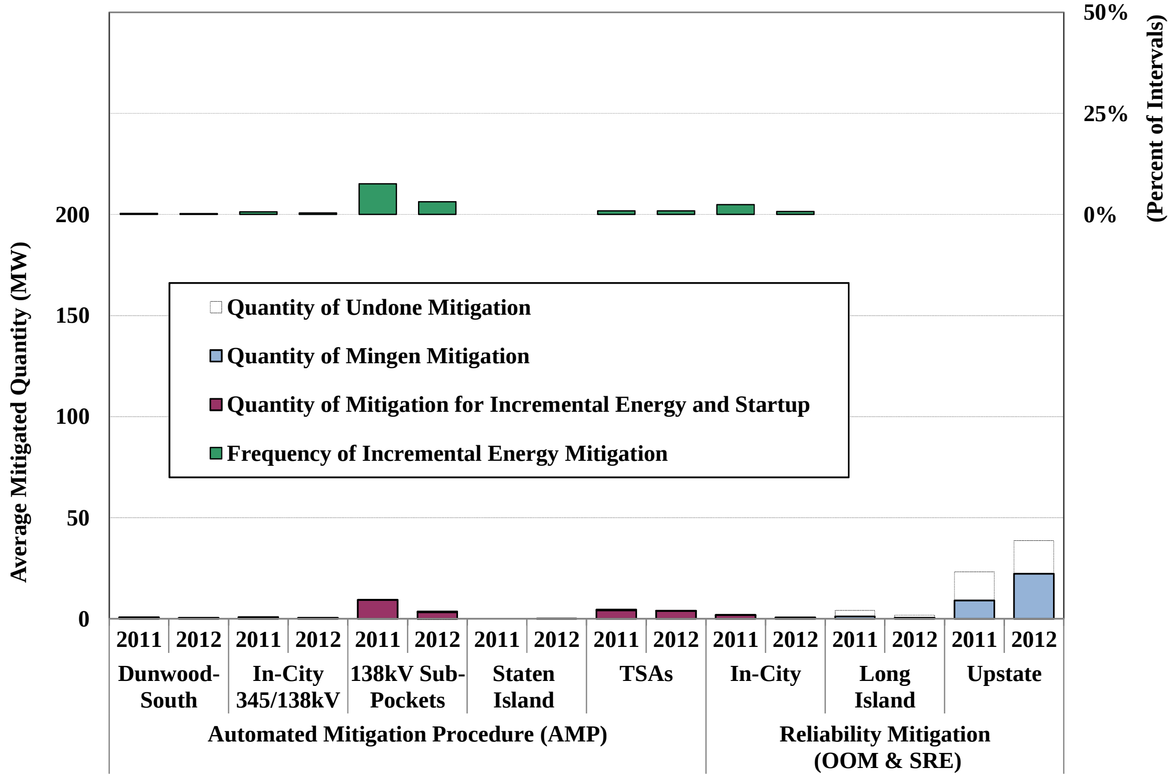
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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).[110] 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-33: Summary of Day-Ahead Mitigation
2011 & 2012



110 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-34: Summary of Real-Time Mitigation
2011 & 2012



Key Observations: Day-ahead and Real-time Mitigation

- The majority of mitigation occurred in the day-ahead market.
  - In 2012, nearly 85 percent of all AMP mitigation occurred in the day-ahead market primarily for generators in the 138kV load pockets.
  - Most reliability commitment occurs in the day-ahead market, making the instances of reliability commitment mitigation more prevalent in the day-ahead market.
- The frequency of AMP mitigation fell substantially from 2011 to 2012, which was primarily due to less frequent and severe transmission congestion in 2012.
- Real-time reliability mitigation increased modestly in the upstate areas in 2012 because of increased SRE commitments.
- Unmitigation of generators became less common in 2012 as the NYISO improved its processes for administering reference levels.

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-35 to Figure A-38: Summary of Ancillary Services Offers

The following four figures compare the ancillary services offers for generators in the day-ahead market for 2011 and 2012 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. Offers for the four ancillary services products from all hours are included in this evaluation.

Figure A-35: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2011-2012

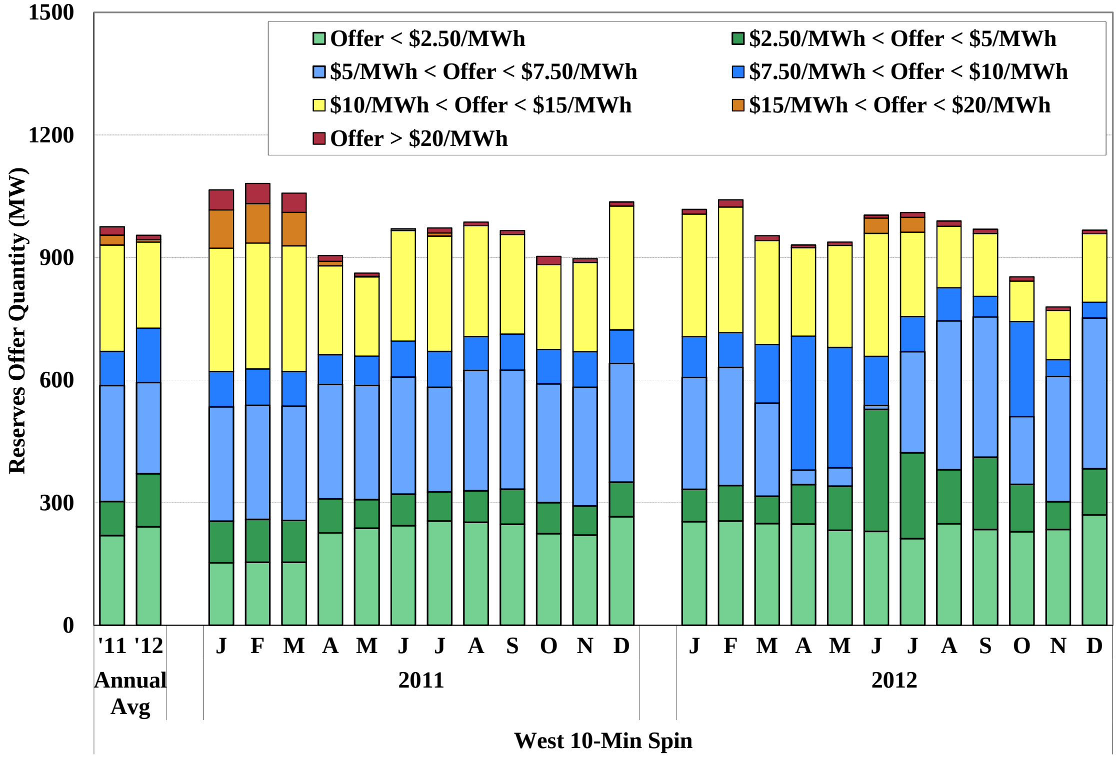


Figure A-36: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2011-2012

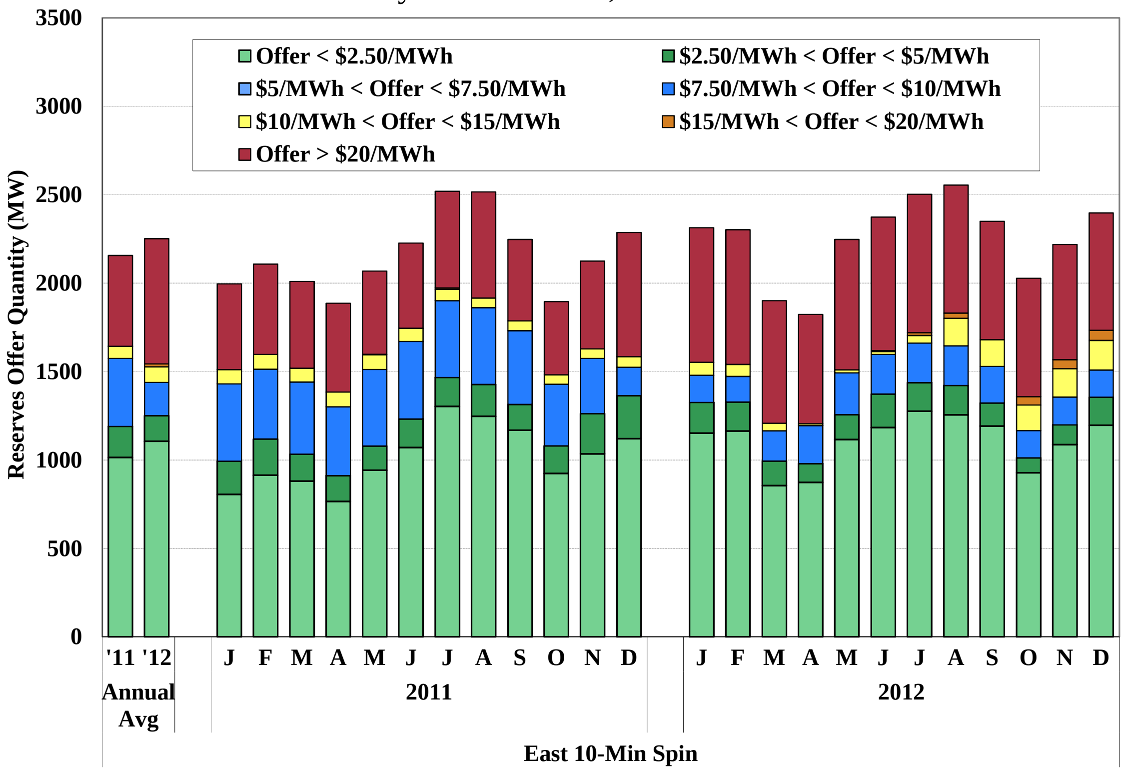


Figure A-37: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2011-2012

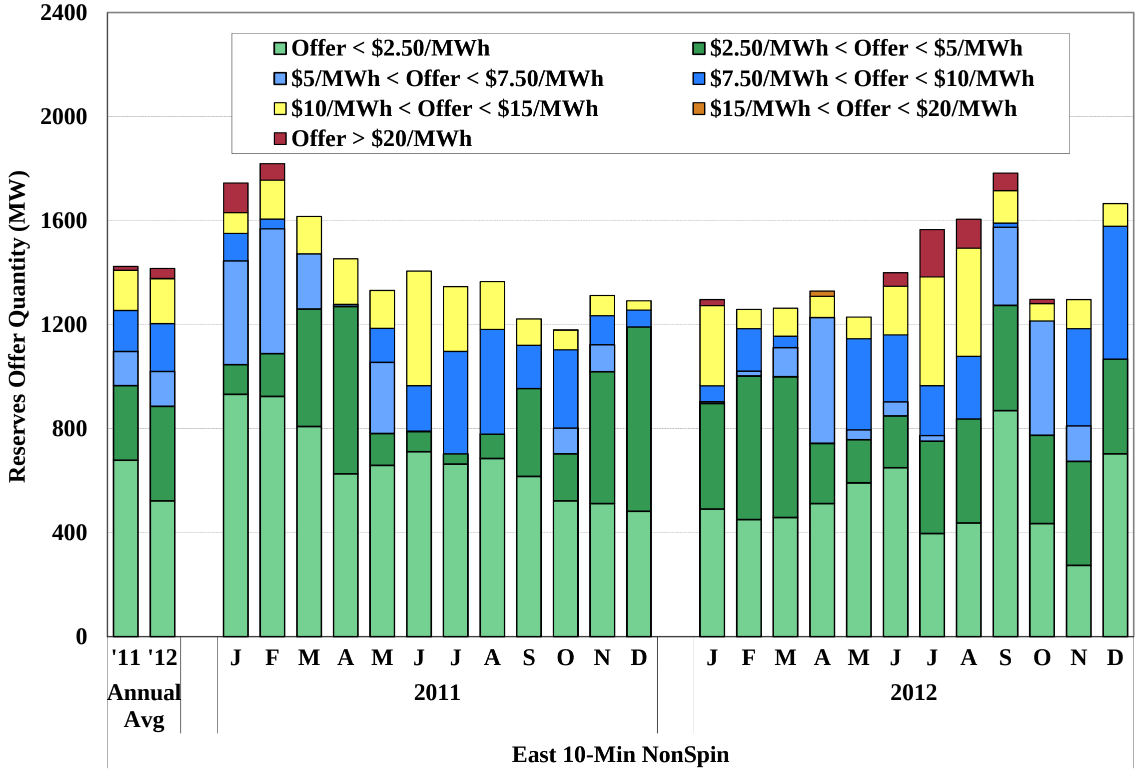
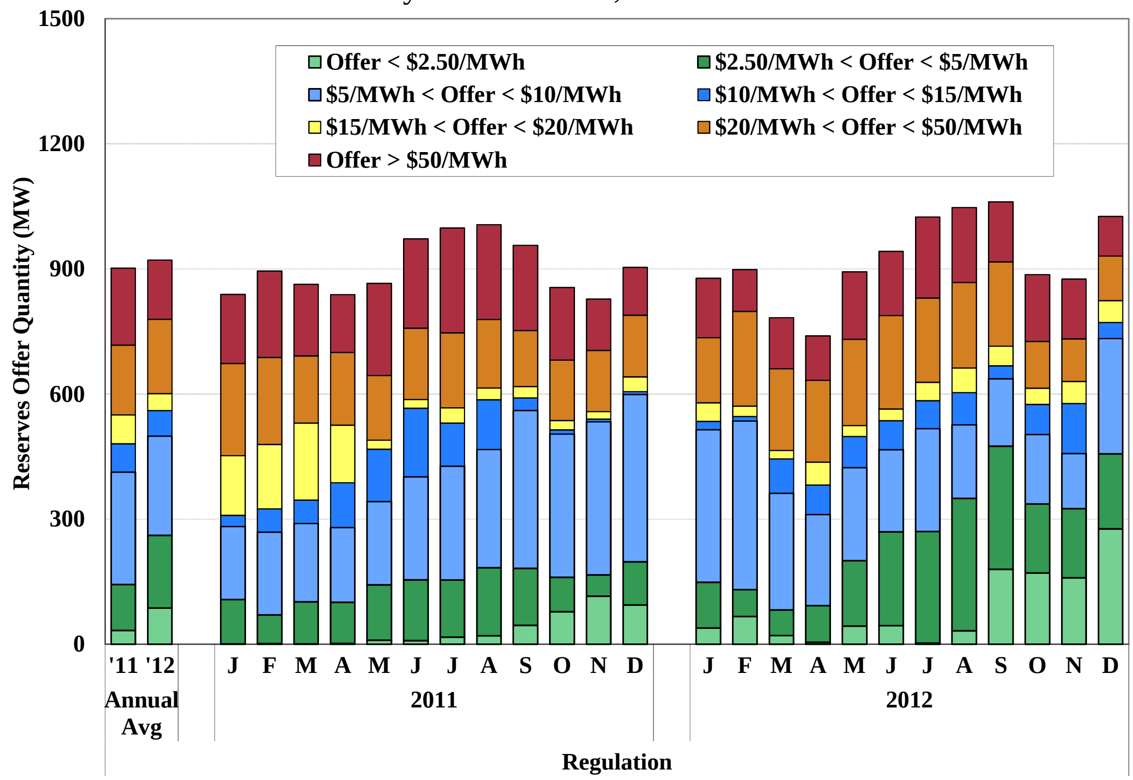


Figure A-38: Summary of Regulation Offers
Day-Ahead Market, 2011-2012



<u>Key Observations: Ancillary Services Offers</u>

- The amount of ancillary services offers from all four categories exhibited typical seasonal variations:
  - 10-minute spinning reserves and regulation offer quantities were 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 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.
- 10-minute spinning reserves offer patterns differ substantially between western New York and eastern New York.
  - This is partly due to the mitigation rule that requires 10-minute spinning reserve units in New York City to offer at $0. Units outside New York City generally do not offer at $0 and are subject only to the ordinary mitigation measures for ancillary services.
  - The mitigation rule for New York City 10-minute spinning reserve units was relaxed on January 22, 2013, allowing units to offer up to $5/MWh.
  - Convergence between day-ahead and real-time prices is worse in eastern New York, providing some generators with incentives to offer at high price levels to avoid being scheduled in the day-ahead market.
- The amount of 10-minute non-spinning reserves offered in Eastern New York increased in mid to late 2012, which was partly due to the installation of new quick-start generating capacity in New York City.
- Regulation offer prices have decreased considerably during 2011 and 2012, reflecting of the effects of inexpensive offers from new regulation-capable capacity.
- The average amount of offers from all four categories of ancillary services were affected by the retirements of generation in New York City, Long Island, and Western New York in 2011 and 2012.

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 NYISO 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.[111]
- *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 load zone level in New York but not at a more disaggregated level.
- *Virtual Exports* – These are external transactions in the export direction that are scheduled in the day-ahead market but withdrawn or bid at high price levels in real time. They are similar to virtual load bids, but they are placed at the nine external proxy buses rather than at the eleven load zones.

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 and virtual imports, on the other hand, tend 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-39 to Figure A-45: 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 them 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

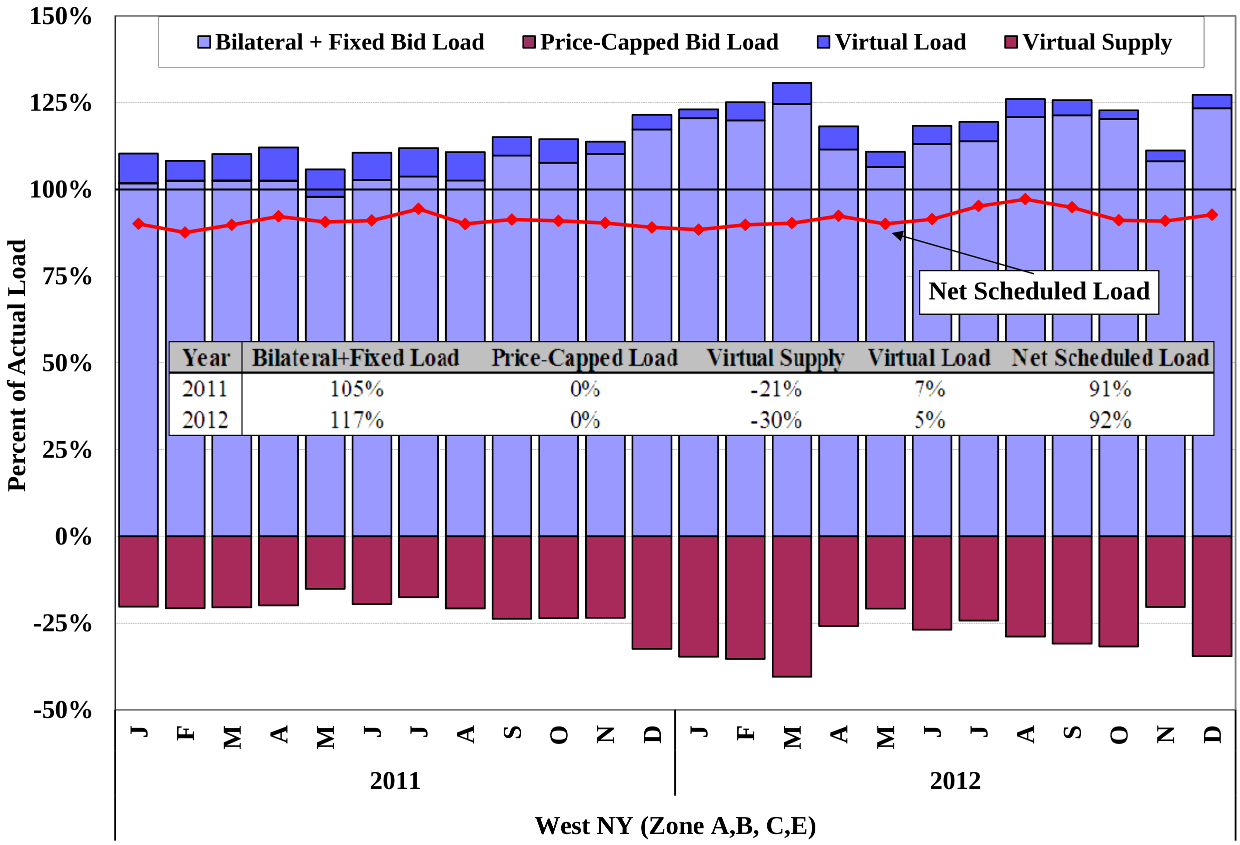
[111] For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

The following seven figures show day-ahead load schedules and bids as a percent of real-time load during 2011 and 2012 at various locations in New York on a monthly average basis. Virtual load (including virtual exports) 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 (including virtual imports) 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 2011 to 2012. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-39: Day-Ahead Load Schedules versus Actual Load in West New York

Zones A,B,C, & E, 2011 – 2012



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2011	105%	0%	-21%	7%	91%
2012	117%	0%	-30%	5%	92%

Figure A-40: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2011 – 2012

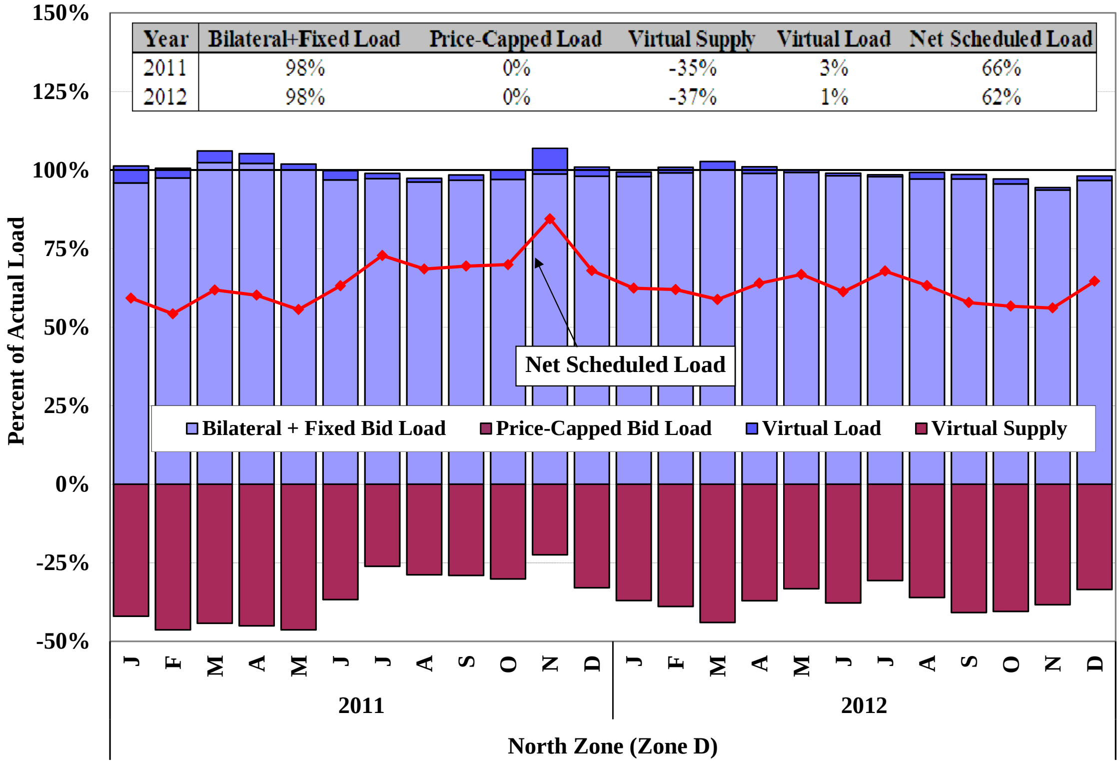


Figure A-41: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2011 – 2012

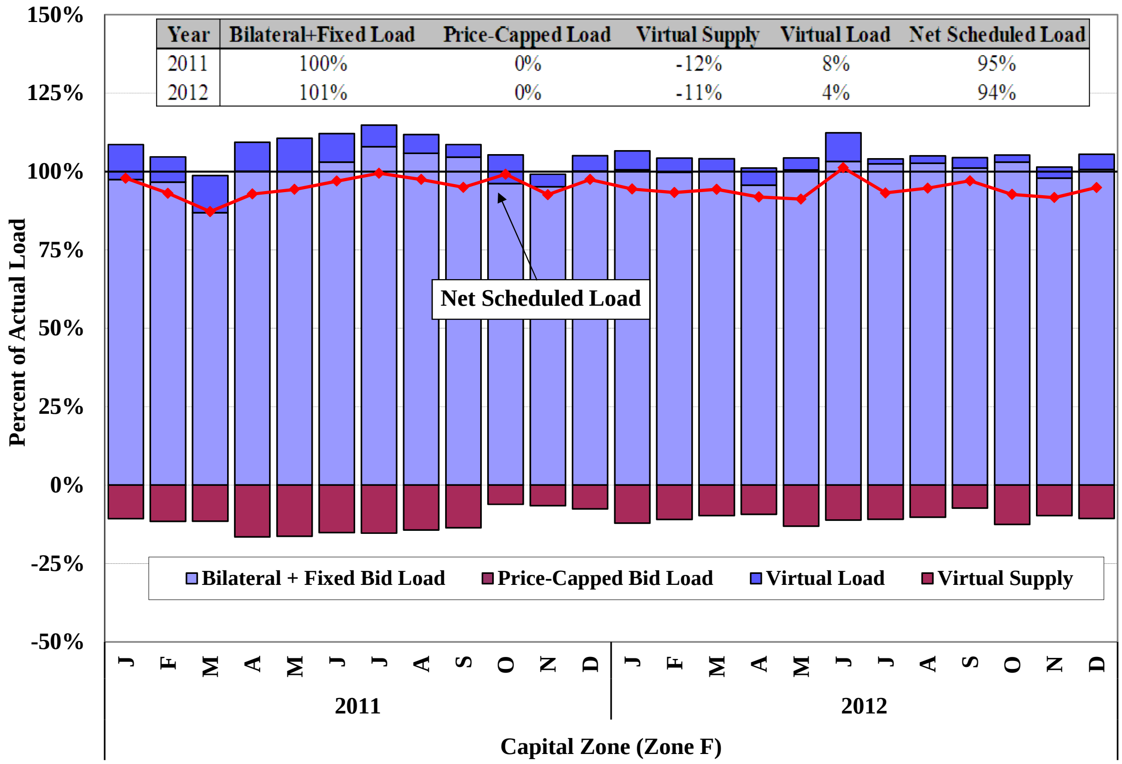
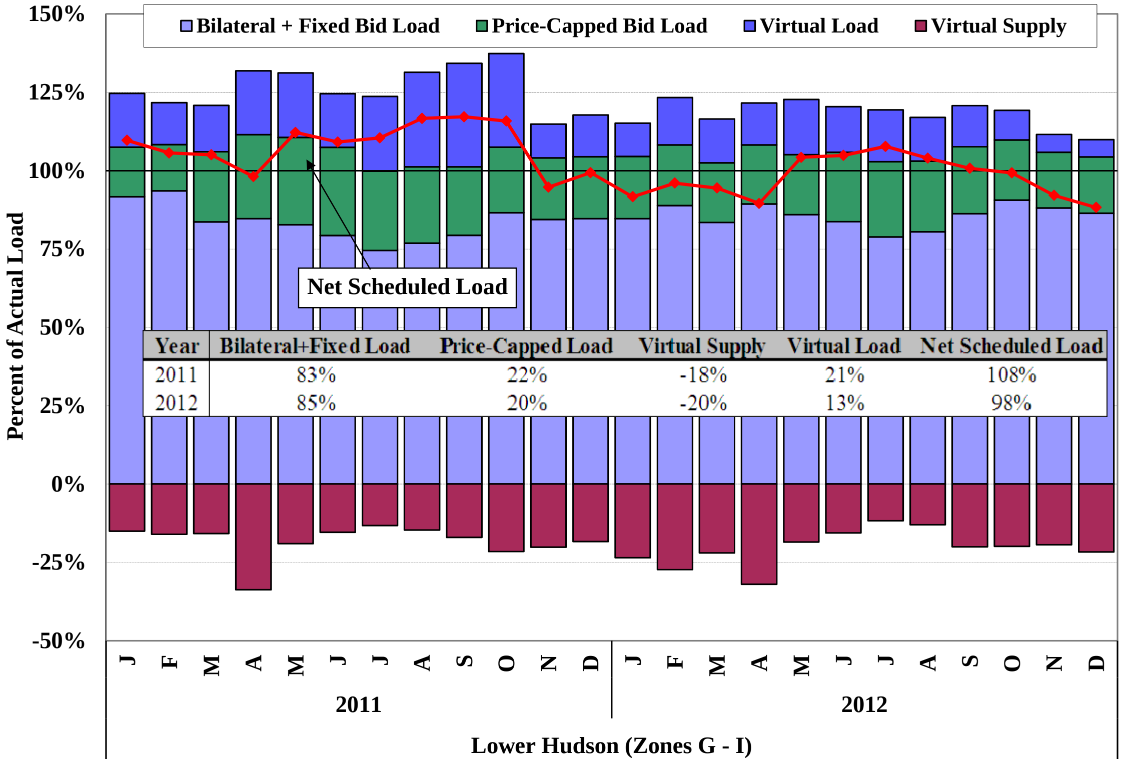
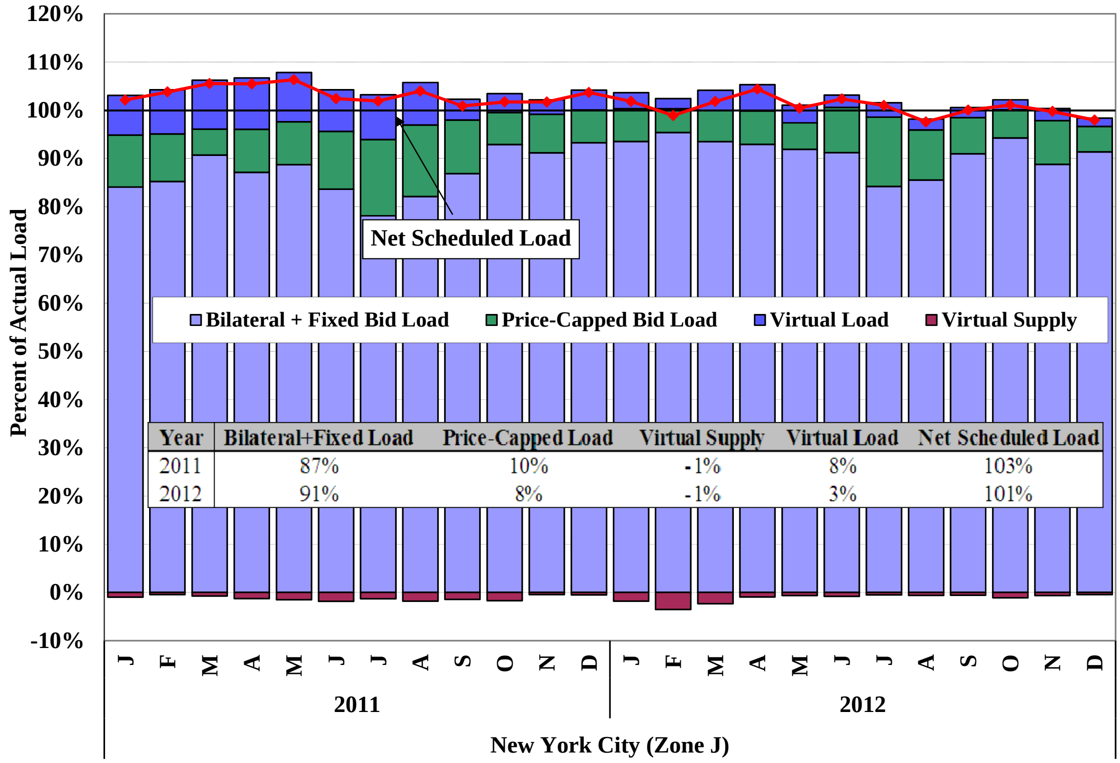


Figure A-42: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2011 – 2012



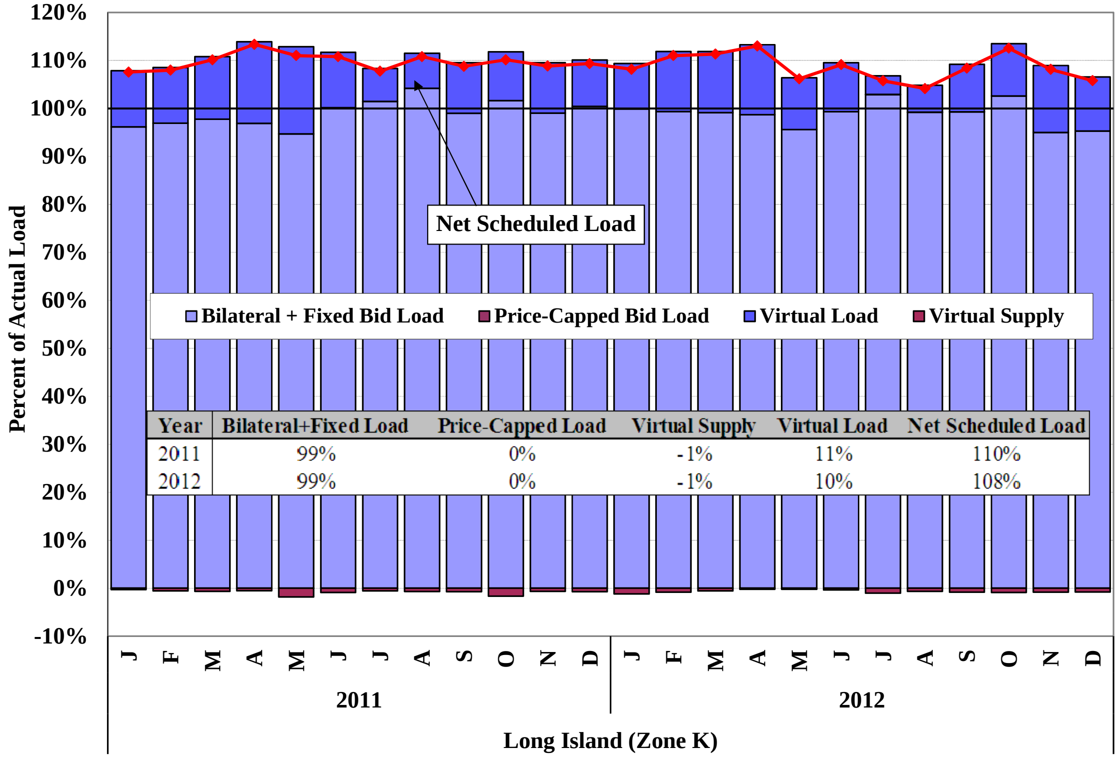
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2011	83%	22%	-18%	21%	108%
2012	85%	20%	-20%	13%	98%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in NYC
Zone J, 2011 – 2012



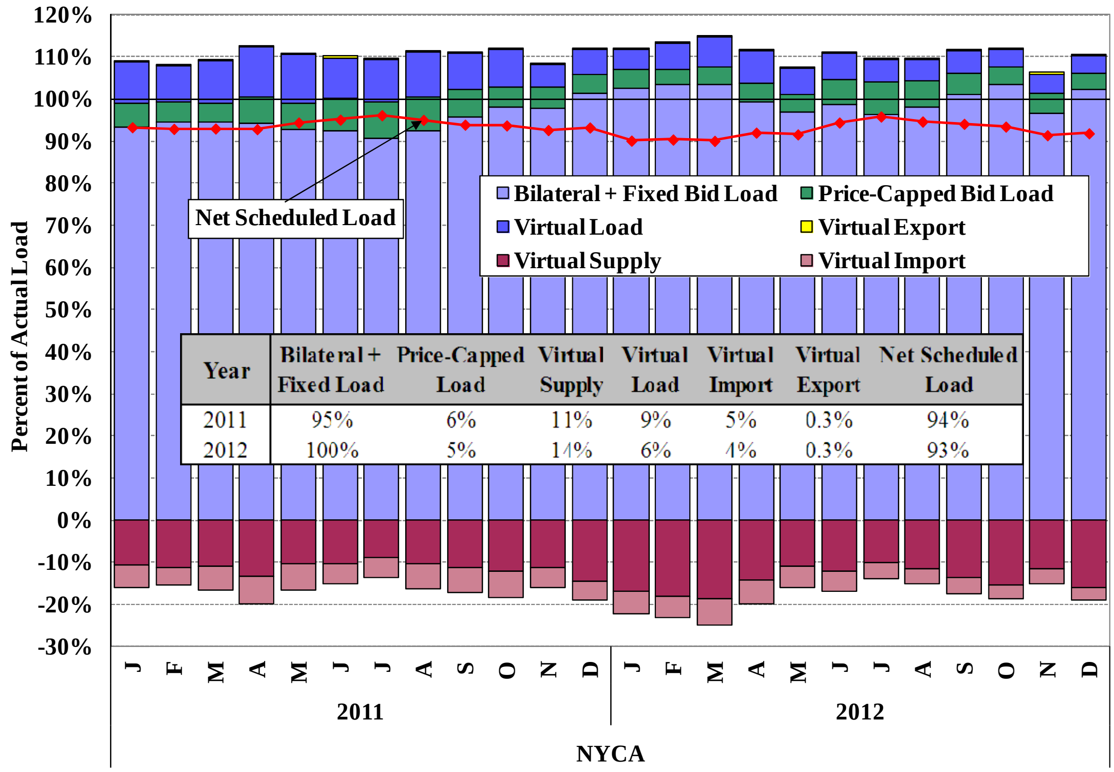
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2011	87%	10%	-1%	8%	103%
2012	91%	8%	-1%	3%	101%

Figure A-44: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2011 – 2012



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2011	99%	0%	-1%	11%	110%
2012	99%	0%	-1%	10%	108%

Figure A-45: Day-Ahead Load Schedules versus Actual Load in NYCA
2011 – 2012



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2011	95%	6%	11%	9%	5%	0.3%	94%
2012	100%	5%	14%	6%	4%	0.3%	93%

<u>Key Observations: Day-ahead Load Scheduling</u>

- Overall, load in the day-ahead market was scheduled at 93 percent of actual load in NYCA in 2012, down from 94 percent in 2011. This under-scheduling helped moderate the slight day-ahead premium that was shown in Section I.G 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 2012.
    - This pattern has been typical in recent years and is likely in response to real-time congestion across the lines into Southeast New York, New York City, and Long Island.
    - However, the overall amount of over-scheduling in Southeast New York fell considerably from 2011 to 2012:
        - From 108 percent to 98 percent in the Lower Hudson Valley,
        - From 103 percent to 101 percent in New York City, and
        - From 110 percent to 108 percent in Long Island).
    - This reduction in over-scheduling in Southeast New York likely resulted from less frequent periods of acute real-time congestion into Southeast New York due to:
        - The more effective use of PAR-controlled lines between New Jersey and New York to manage congestion into Southeast New York; and
        - The addition of new capacity in New York City.
    - Under-scheduling outside Southeast New York occurs partly in response to the following scheduling patterns of individual generators:
        - Hydro and wind resources outside Southeast New York generally increase output in real-time above their day-ahead scheduled level, adding an average of 715 MW of additional energy supply in real-time.
        - The additional real-time output from these resources satisfies 4 percent of average real-time load in the NYCA and 10 percent of the average real-time load outside Southeast New York.
    - Despite the pattern of day-ahead under-scheduling, the regions 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 this area. Without this over-scheduling, 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.
- Scheduled price-insensitive load (i.e., bilateral and fix load bid) rose substantially in Western New York since late 2011. This was offset by comparable increases in scheduled virtual supply over the same period, likely reflecting that some firms that made bilateral load purchases used virtual supply to sell the energy in the day-ahead market.

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 load zone level between day-ahead and real-time.

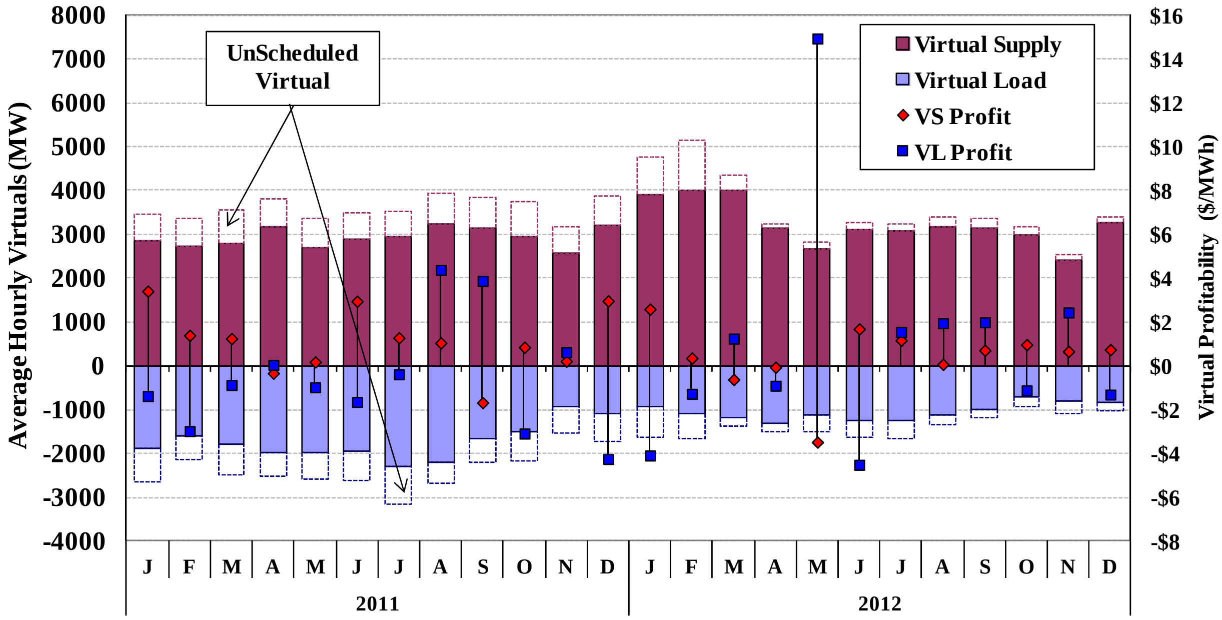
Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as *Virtual Imports* and *Virtual Exports* in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that are scheduled in the day-ahead market do not flow in real-time). Since the virtual imports and exports have a similar effect on scheduling and pricing as virtual load and supply, they are evaluated as part of virtual trading in this section.

Figure A-46: Virtual Trading Volumes and Profitability

Figure A-46 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2011 and 2012. The amount of scheduled virtual supply in the chart includes scheduled virtual supply at the load zones and scheduled virtual imports at the external proxy buses. Likewise, the amount of scheduled virtual load in the chart includes scheduled virtual load at the load zones and scheduled virtual exports at the external proxy buses. 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.[112, 113]

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 (or proxy bus) price. For example, an average of 440 MW of virtual transactions (or 10 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in July 2012. 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-46: Virtual Trading Volumes and Profitability
January 2011 to December 2012



2011		J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	589	237	179	151	286	461	488	481	205	122	116	246
	%	12%	5%	4%	3%	6%	10%	9%	9%	4%	3%	3%	6%
Loss > 50% of Avg. Zone Price	MW	467	280	171	149	346	440	479	393	178	163	146	209
	%	10%	6%	4%	3%	7%	9%	9%	7%	4%	4%	4%	5%

2012		J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	356	117	268	264	150	440	380	255	181	191	278	222
	%	7%	2%	5%	6%	4%	10%	9%	6%	4%	5%	9%	5%
Loss > 50% of Avg. Zone Price	MW	216	158	341	312	169	429	396	261	159	124	216	222
	%	4%	3%	7%	7%	4%	10%	9%	6%	4%	3%	7%	5%

Figure A-47: Virtual Trading Activity

Figure A-47 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

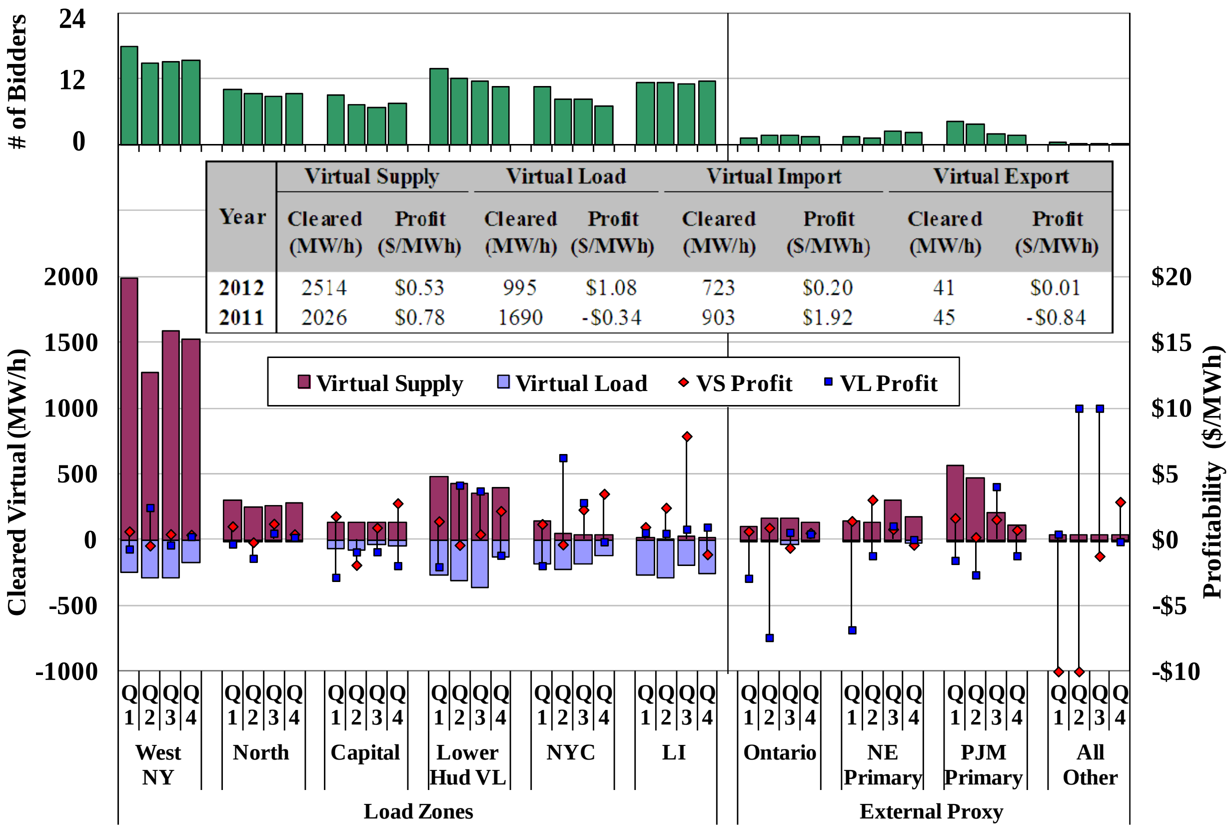
112 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

113 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

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 chart also summarizes trading activities related to virtual imports and exports with neighboring control areas. The Ontario proxy bus, the primary PJM proxy bus (i.e., the Keystone proxy bus), and the primary New England proxy bus (i.e., the Sandy Pond proxy bus) are evaluated separately from all other proxy buses.

The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the six regions and four groups of external proxy buses in each quarter of 2012. The upper portion of the figure shows the average number of virtual bidders in each location. The table in the middle compares the overall virtual trading activity in 2012 and 2011.

Figure A-47: Virtual Trading Activity[114]
by Region by Quarter, 2012



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2012	2514	$0.53	995	$1.08	723	$0.20	41	$0.01
2011	2026	$0.78	1690	-$0.34	903	$1.92	45	-$0.84

114 For "All Other" proxy buses, the profits (or losses) larger than $10 per MWh for virtual imports and exports are shown as $10 per MWh.

Key Observations: Analysis of Virtual Trading

- A large number of market participants regularly submitted virtual bids and offers at the load zone level. On average, eight or more participants submitted virtual trades in each region and 26 participants submitted virtual trades somewhere in the state in 2012.
    - The average number of market participants fell from 2011 to 2012 which was partly due to the new credit requirements implemented in October 2011.
- The number of market participants that regularly submitted virtual imports and exports at the proxy buses was smaller than at the internal load zones, averaging six in 2012.
- Much of the virtual activity was related to the scheduling patterns discussed in Section E. Specifically, virtual traders generally scheduled more virtual load in Southeast New York and more virtual supply outside Southeast New York in 2012, consistent with prior years.
- Overall, the average quantity of scheduled virtual supply rose 24 percent from 2,026 MW in 2011 to 2,514 MW in 2012, while the average quantity of scheduled virtual load fell 41 percent from 1,690 MW in 2011 to 995 MW in 2012.
    - Scheduled virtual supply in Western New York rose considerably, accounting for the majority of the statewide increase. This coincided with increased bilateral load scheduling in Western New York, reflecting that some firms that made bilateral load purchases used virtual supply to sell the energy in the day-ahead market.
    - Scheduled virtual load in Southeast New York (outside Long Island) fell notably, reflecting:
        - Reduced congestion into Southeast New York and in New York City; and
        - More effective use of the PAR-controlled lines between New Jersey and New York for real-time congestion management.
- Nearly all of the virtual imports and exports were submitted at three proxy buses: the primary PJM proxy bus, the primary NE proxy bus, and the Ontario proxy bus.
    - Ninety-five percent of all virtual imports/exports were virtual imports.
    - The three proxy buses where virtual imports are common are primarily interconnected with the regions outside Southeast New York. These virtual imports are consistent with the prevalence of virtual supply scheduled in these regions..
- In aggregate, virtual traders netted approximately $22 million of gross profits in 2012 ($21 million for load zone virtuals and $1 million for virtuals imports and exports), which is comparable to the aggregate profits in 2011.
    - However, the profits and losses of virtual load and supply and virtual imports and exports have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.

- Overall, virtual load and supply and virtual imports and exports 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 efficient day-ahead market outcomes and commitment of generating resources.

- Only small quantities of virtual transactions generated substantial losses in 2012, which is significant because they could indicate potential manipulation, Most of these losses were caused by real-time price volatility and did not raise significant manipulation concerns.

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 zone A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and zone 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 2012

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.[115]

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.[116] 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.[117] 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-48: Congestion Revenue Collections and Shortfalls

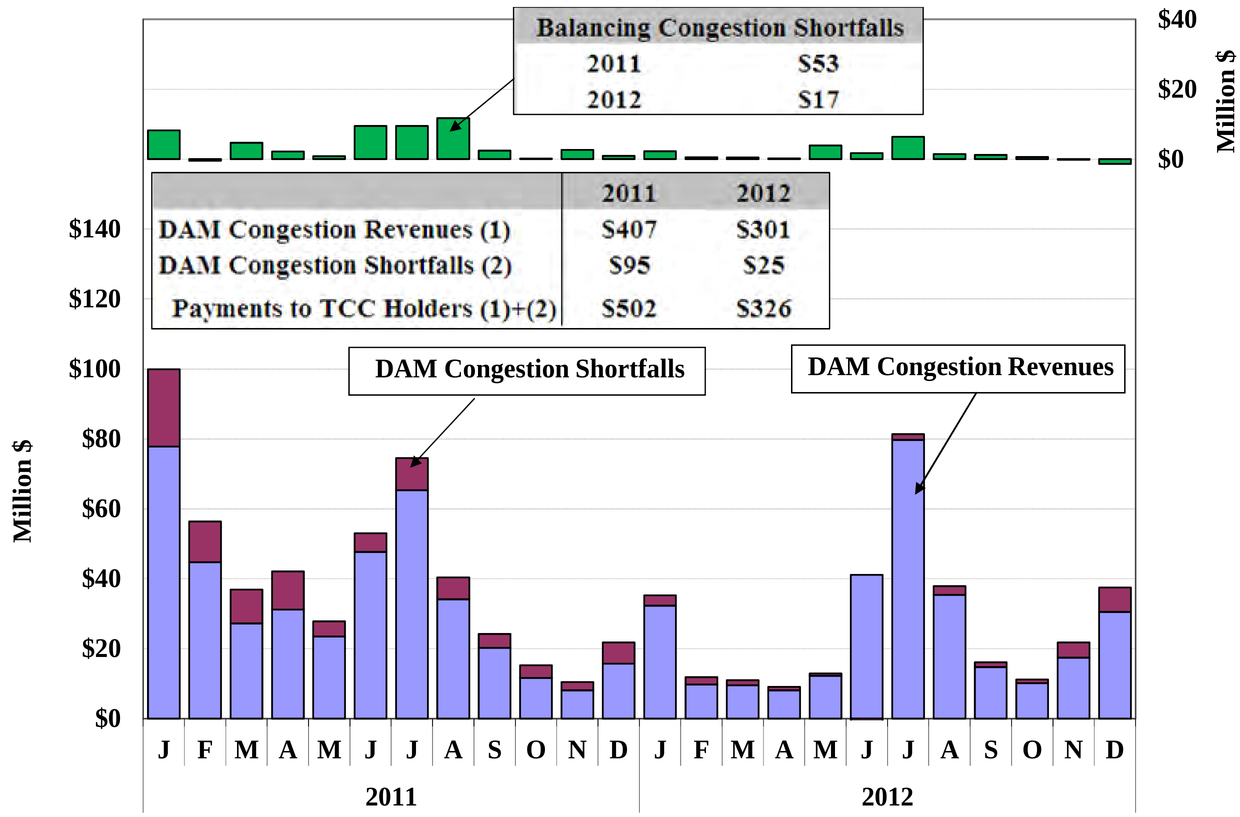
Figure A-48 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2011 and 2012. The upper portion of the figure shows balancing congestion revenue shortfalls. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead 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.

115 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).

116 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).

117 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-48: Congestion Revenue Collections and Shortfalls
2011 - 2012



Key Observations: Day-Ahead Congestion Revenues

- Day-ahead congestion revenues totaled roughly $301 million in 2012, down 26 percent (or $106 million) from 2011.
  - Lower natural gas prices in 2012 were a fundamental driver of the reduction because lower natural gas prices tend to reduce net imports to Eastern New York and also reduce the redispatch costs incurred to manage congestion.
  - Lower load levels (partly due to milder peak conditions) and new generation in New York City also contributed to the decline in congestion.[118]
  - In both years, over 70 percent of congestion revenues were collected in the winter peak and summer peak months. This is expected because: a) the relatively high loads in these months often result in higher transmission flows; b) thunderstorms occur much more frequently during the summer, causing transmission interfaces to be derated and leading to acute congestion; and c) larger spreads in natural gas prices

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118 The Astoria Energy II generator (550 MW) entered the market in July 2011, and the Bayonne generating plant (500 MW) entered the market in June 2012.

between eastern and western New York during periods of high demand (typically in the winter) can lead to increased imports and congestion into eastern New York.

- Day-ahead and balancing congestion shortfalls totaled $42 million, down substantially from $148 million in 2011.
  - In general, these reductions indicate improved consistency between the modeling of the New York system in the TCC market, the day-ahead market, and the real-time market.
  - The locations of these shortfalls and causes of this reduction are analyzed in subsection C.

B. 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-49: Day-Ahead and Real-Time Congestion by Path

Figure A-49 shows 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

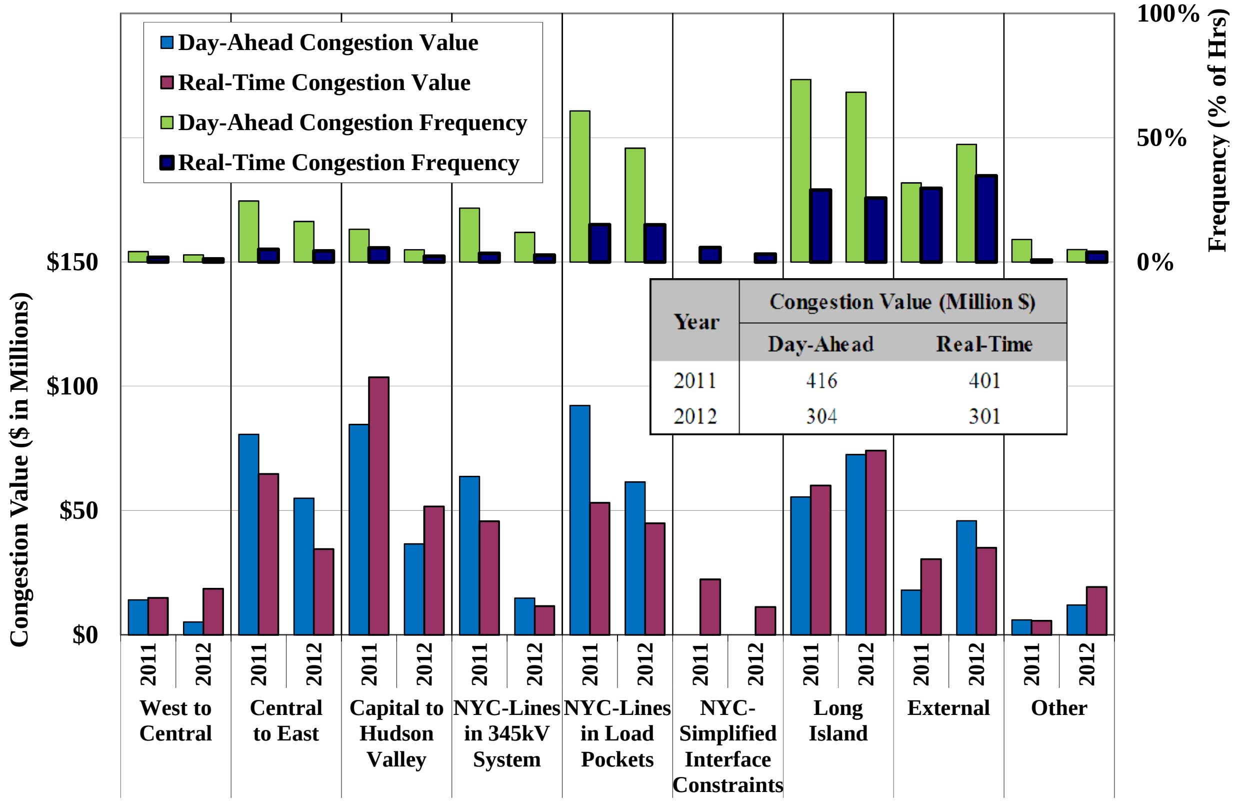
- The value of congestion, which is equal to the marginal cost of relieving the constraint (i.e., constraint shadow cost) multiplied by the scheduled flow across the constraint.[119]

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 and Leeds-to-Pleasant Valley 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 ten external interfaces.

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

Figure A-49: Day-Ahead and Real-Time Congestion by Transmission Path
2011 - 2012



Key Observations: Congestion Revenues by Path

- Congestion occurred less frequently in 2012 than in 2011 on most transmission paths, particularly into and within New York City, primarily due to:
  - Reduced clockwise Lake Erie Circulation;
  - Lower natural gas prices;
  - Lower load levels; and
  - New generation in New York City.
- However, congestion into Long Island and on external interfaces increased in 2012.
  - Most of the increase in congestion into Long Island occurred in the second half of 2012, as outages and deratings of the Neptune Cable began in late May and multiple units retired at the beginning of July.[120]

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120 The Neptune Cable was completely out of service from May 27 through July 31 and partly returned to service (up to 375 MW) for the rest of the year.

   - Congestion across the external interfaces also increased in 2012, primarily due to increased day-ahead congestion across the HQ interface in the summer months. The increased congestion from HQ in the day-market is consistent with real-time congestion patterns. In recent summers, the HQ interface has frequently become congested in real-time when NYISO Operations reduces the TTC of the interface to manage reliability during TSA events. Accordingly, market participants have increasingly fully scheduled the HQ interface in the day-ahead market in anticipation of increased real-time congestion.

- Congestion is more frequent in the day-ahead market than in the real-time market, but the shadow prices of constraints are generally lower in the day-ahead market. This is expected because the day-ahead market reflects an expectation of the value of congestion in the real-time market, which tends to be more episodic.

C. Day-Ahead and Balancing Congestion Shortfalls by Path or Constraint

Congestion Shortfalls generally occur when inconsistencies arise between the modeling of the transmission system between markets. Day-ahead congestion shortfalls indicate inconsistencies between the TCC and day-ahead market, while balancing congestion shortfalls indicate inconsistencies between the day-ahead market and the real-time market. These two classes of shortfalls are evaluated in this subsection.

Figure A-50: Day-Ahead Congestion Revenue Shortfalls

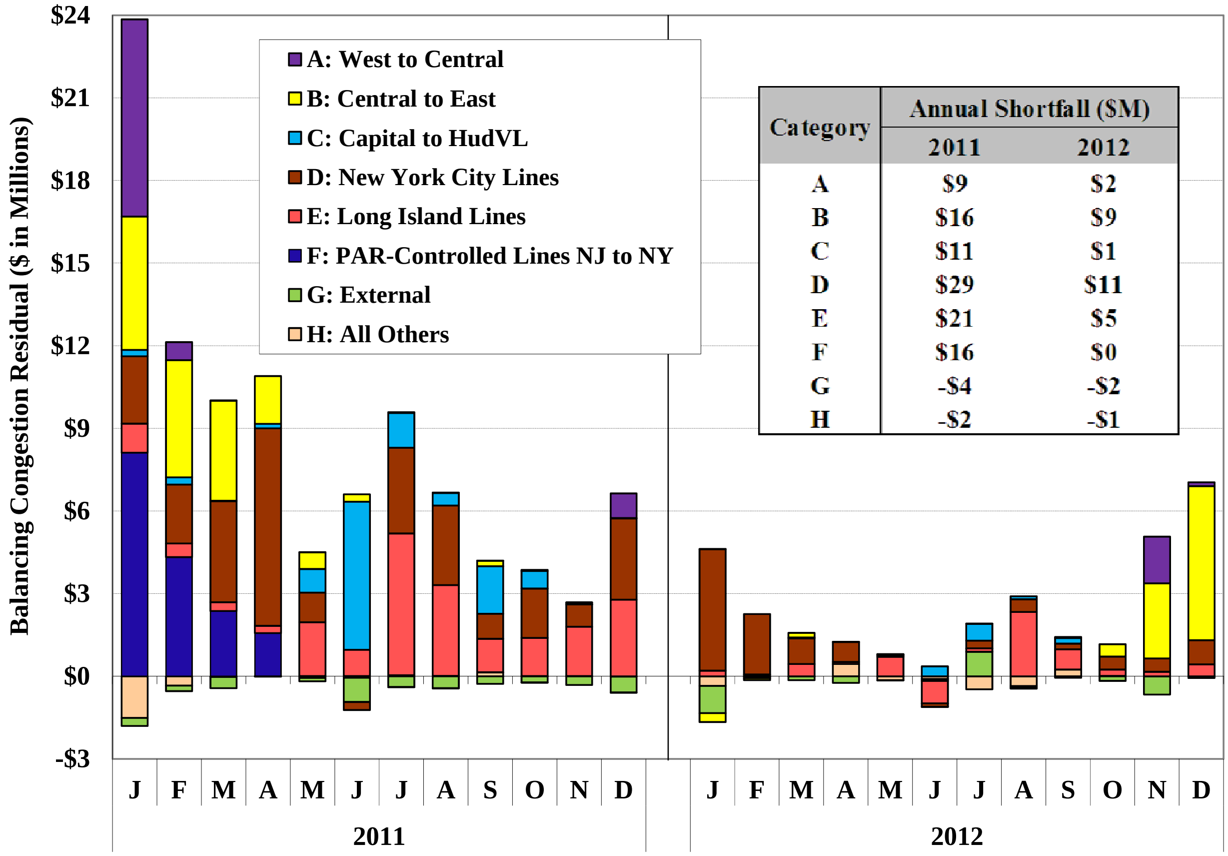
Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion. Similarly, surpluses occur when the quantity of TCCs sold for a path is less than the 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-50 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2011 and 2012. 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 and Leeds-to-Pleasant Valley 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.
- External: Congestion related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

Figure A-50: Day-Ahead Congestion Shortfalls
2011 – 2012



Category	Annual Shortfall ($M)	
	2011	2012
A	$9	$2
B	$16	$9
C	$11	$1
D	$29	$11
E	$21	$5
F	$16	$0
G	-$4	-$2
H	-$2	-$1

Figure A-51: 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.

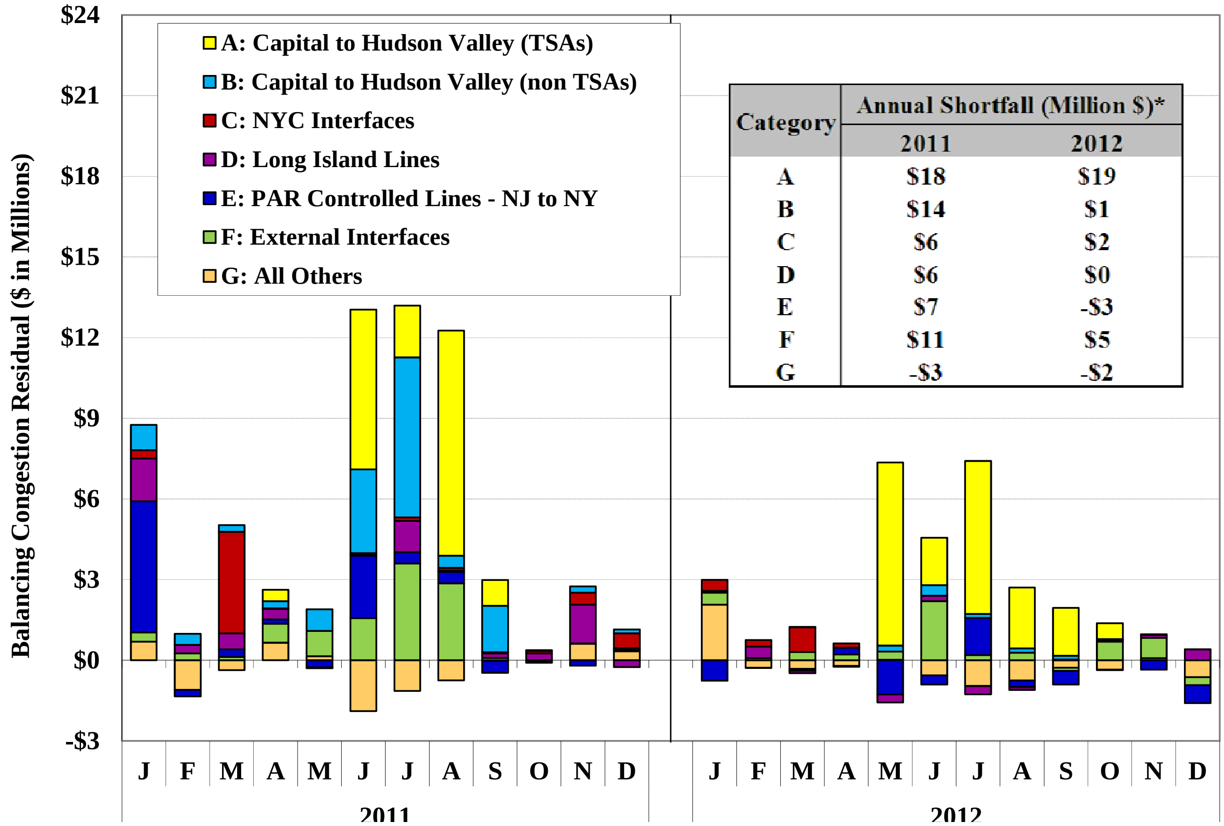
- PAR Controlled Line Flows – the flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces.

- 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-51 shows balancing congestion shortfalls by transmission path or facility in each month of 2011 and 2012. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-51: Balancing Congestion Shortfalls[121]
2011 – 2012



Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Nearly 60 percent of the day-ahead congestion shortfalls in 2012 accrued during the winter season (January, November, December).
  - Transmission outages were taken to support the installation of new equipment at the Gowanus 345kV substation and a new line into the Astoria East load pocket in early 2012, which reduced transfer capability in New York City during this period.
  - The capability of the Central-East interface was significantly reduced in late 2012 that was due to outages of generator equipment (including whole units and the automatic

121 The balancing congestion shortfalls estimated in this figure may differ from actual balancing congestion shortfalls because the figure: (a) is partly based on real-time schedules rather than metered injections and withdrawals; (b) assumes the energy component of the LBMP is the same at all locations including proxy buses (while the actual proxy bus LBMPs are not calculated this way under all circumstances); and (c) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of price corrections and Scarcity Pricing Adjustments (most notably in 2012, the Scarcity Pricing Adjustment on May 29 had the effect of reducing the actual balancing congestion costs by approximately $2 million below what is shown in the figure).

voltage regulating equipment on units otherwise in service) and one major transmission line in late 2012 significantly reduced the transfer capability across the Central-East interface.

- Day-ahead congestion shortfalls associated with Long Island fell from $21 million in 2011 to $5 million in 2012 primarily due to less frequent outages of the transmission lines from upstate New York to Long Island.

- Day-ahead congestion shortfalls related to the PAR-controlled lines between New Jersey and New York were $0 million in 2012 compared to the $16 million in 2011 and the $35 million in 2010.

  - A modeling improvement in the TCC auctions was implemented in May 2011, which virtually eliminated these shortfalls.

Balancing Congestion Shortfalls

- More than 80 percent of the balancing congestion shortfalls in 2012 accrued during the periods when TSAs were frequently called because TSA cause the transfer capability into Southeast New York to be greatly reduced.

- Balancing congestion shortfalls related to the PAR-controlled lines between New Jersey and New York fell from $7 million in 2011 to a $3 million surplus in 2012 due to improvements in real-time market operations.

  - These surpluses arise during periods when the NYISO is able to adjust flows (relative to the day-ahead scheduled level) on the PAR-controlled lines to mitigate real-time congestion.

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.[122] Most transmission capability is auctioned as 6-month products. The

122 2-year TCCs were first sold in the Autumn 2011 auctions for the period from November 2011 to October 2013, which covers a one-year period after the one-year period evaluated in this section of the report.

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-52: TCC Cost and Profit by Path Type

Figure A-52 summarizes TCC cost and profit for the Winter 2011/12 and Summer 2012 Capability Periods (i.e., the 12-month period from November 2011 through October 2012). 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 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 2011/12 Capability Period; (c) Four rounds of six-month auctions for the Summer 2012 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: (a) inter-zone TCCs, which include all unbundled POI Zone to POW Zone TCCs; and (b) intra-zone TCCs, which include POI to POI Zone TCCs and POW Zone to POW TCCs.[123] 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

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123 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 will be unbundled to three components: (a) A 100 MW TCC from Indian Point 2 to Millwood Zone; (b) A 100 MW TCC from Millwood Zone to New York City Zone; and (c) 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.

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.

Figure A-52: TCC Cost and Profit by Path Type
Winter 2011/12 and Summer 2012 Capability Periods

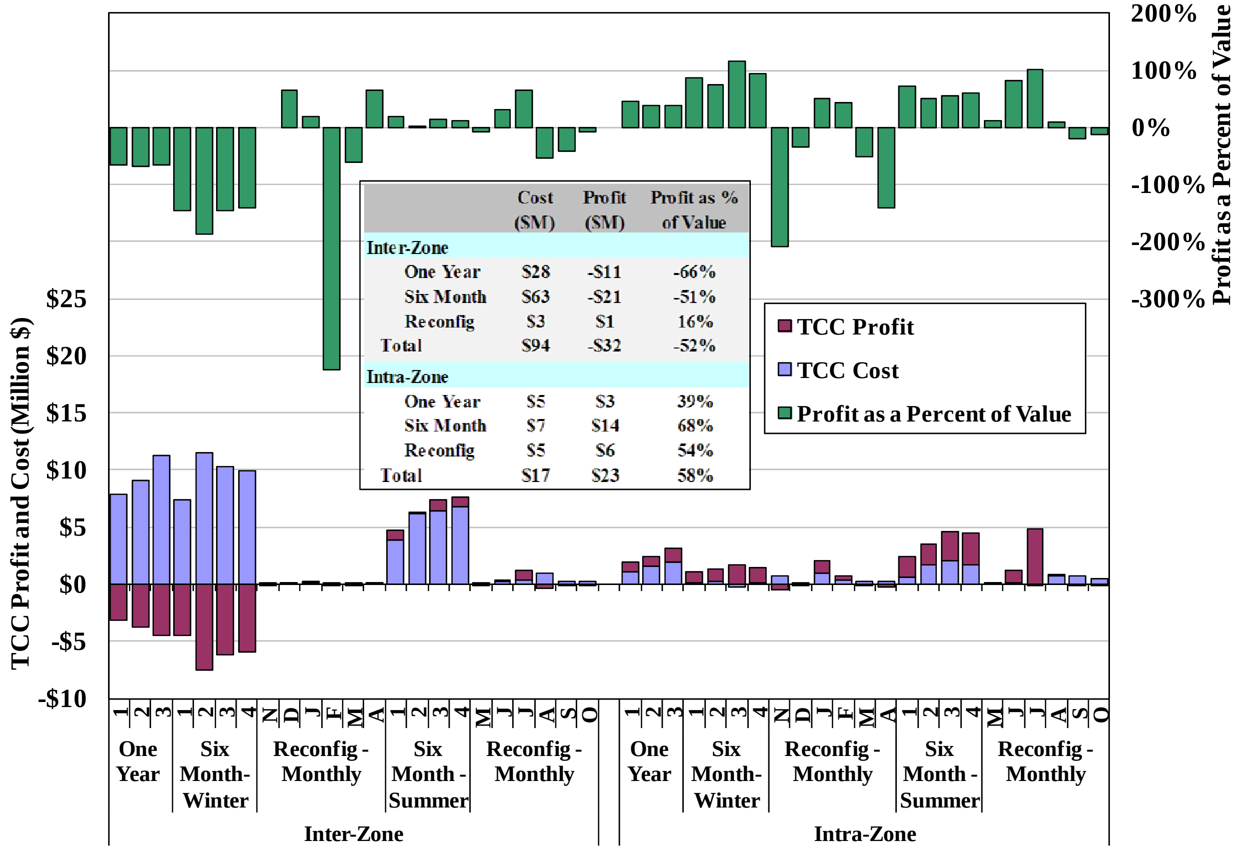


Figure A-53: TCC Prices and Day-ahead Congestion by Zone

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 2012. Figure A-53 compares the TCC prices for the Winter 2011/12 and Summer 2012 Capability Periods (i.e., the 12-month period from November 2011 through October 2012) 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 2011.
- *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.

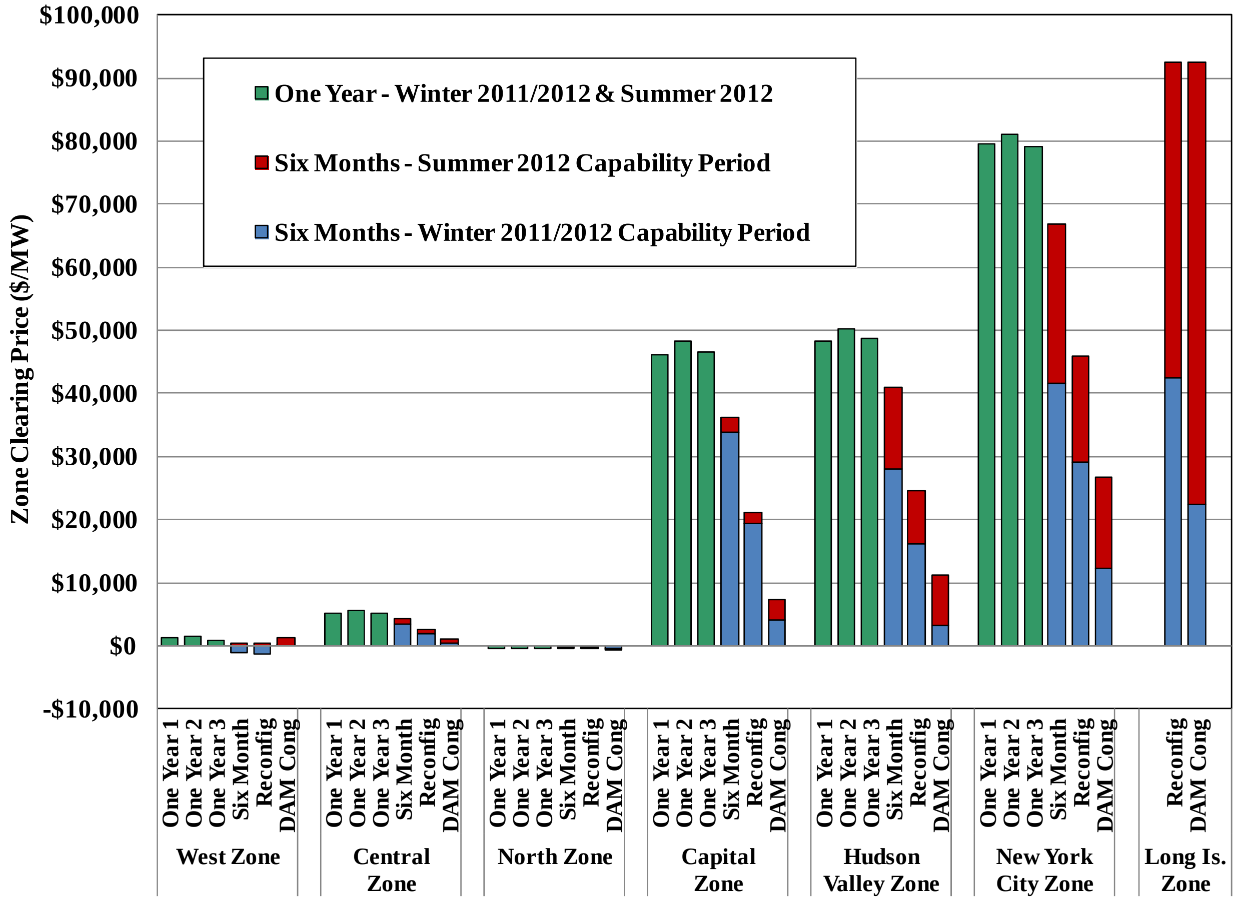
- *Reconfiguration TCC prices* – These are the sum of TCC prices from the six monthly Reconfiguration auctions during the Winter and the Summer Capability Periods

- *Day-ahead congestion prices* – These are the sum of congestion prices in the day-ahead market for the 12-month period.

Figure A-53 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-53: TCC Prices and DAM Congestion by Zone

Winter 2011/12 and Summer 2012 Capability Periods



Key Observations: TCC Prices and Profitability

- Overall, the day-ahead congestion was well below the TCC prices in all of the TCC auctions, which led to substantial losses for the TCC buyers.
  - These results indicate that the sharp reduction in congestion that occurred in 2012 was not anticipated by the participants in the TCC markets.

- As explained above, the decrease in congestion was caused by low natural gas prices and load, reduced loop flows around Lake Erie, and new units in New York City.
- The results of the TCC auctions indicate that these factors were increasingly recognized by the markets as the TCC prices fell from the annual auction to the auction of six-month TCCs, and fell further in the reconfiguration auction.

• Traders netted a loss of $9 million in the TCC auctions during the 12-month period (November 2011 to October 2012):

- TCC profits totaled *negative* $8 million in the one-year auctions, *negative* $7 million in the six-month auctions, and $7 million in the reconfiguration auctions.

• Profitability (profit as a percent of TCC payout) averaged nearly *negative* 9 percent, although it varied widely from auction to auction and among different types of TCCs (inter-zone vs. intra-zone).

- Over the winter 2011/12 capability period, natural gas prices were generally lower than anticipated at the time of the one-year and six-month TCC auctions, contributing to smaller than expected congestion-related inter-zonal LBMP differences.
- Intra-zonal TCC paths were more consistently profitable than inter-zonal TCC paths partly because intra-zonal congestion patterns are less affected by natural gas prices.

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.[124,125] 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
- Scheduling patterns across the interfaces that allow intra-hour schedules (i.e., 15-minute scheduling).

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124 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 capability 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 315 MW (this increased from 300 MW on November 1, 2012), began normal operation in November 2009.

125 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-54 to Figure A-56: 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 2011 and 2012. 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-54, the primary interfaces with Quebec and New England in Figure A-55, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-56.

Figure A-54: Monthly Average Net Imports from Ontario and PJM
2011 – 2012

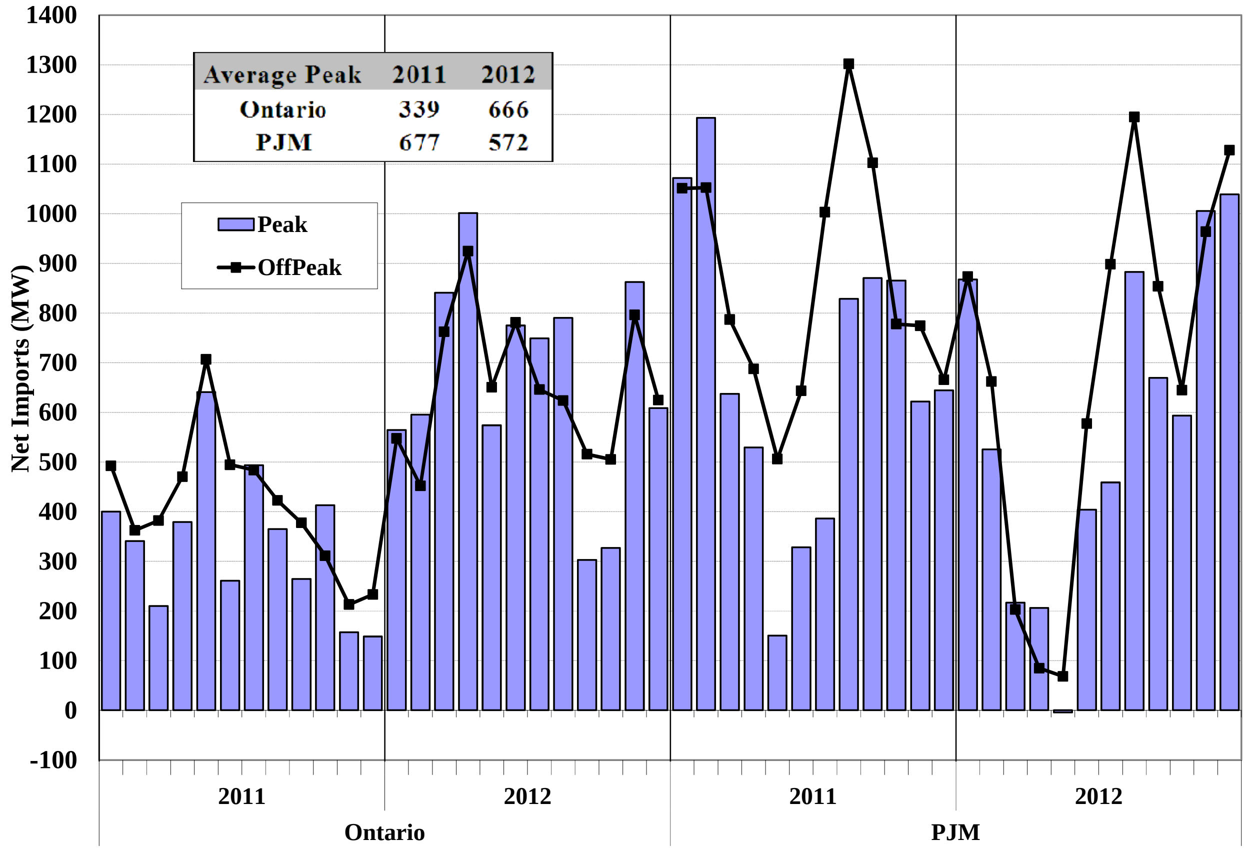


Figure A-55: Monthly Average Net Imports from Quebec and New England
2011 – 2012

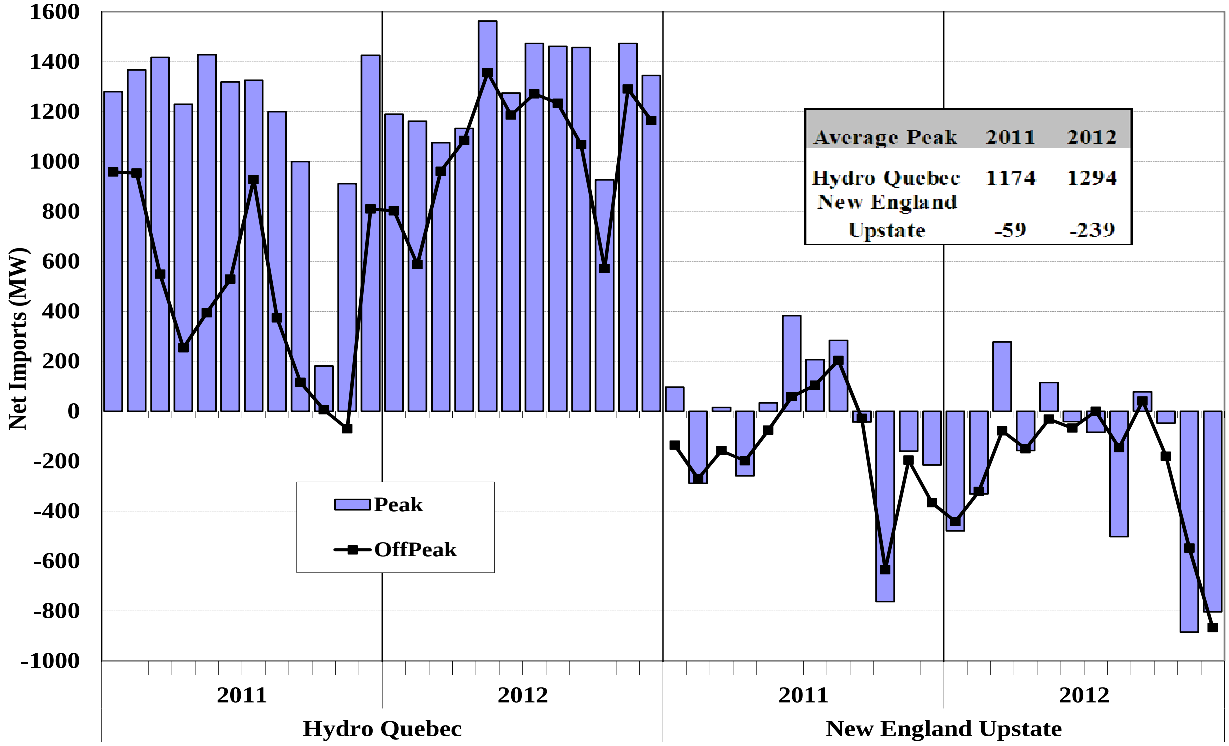
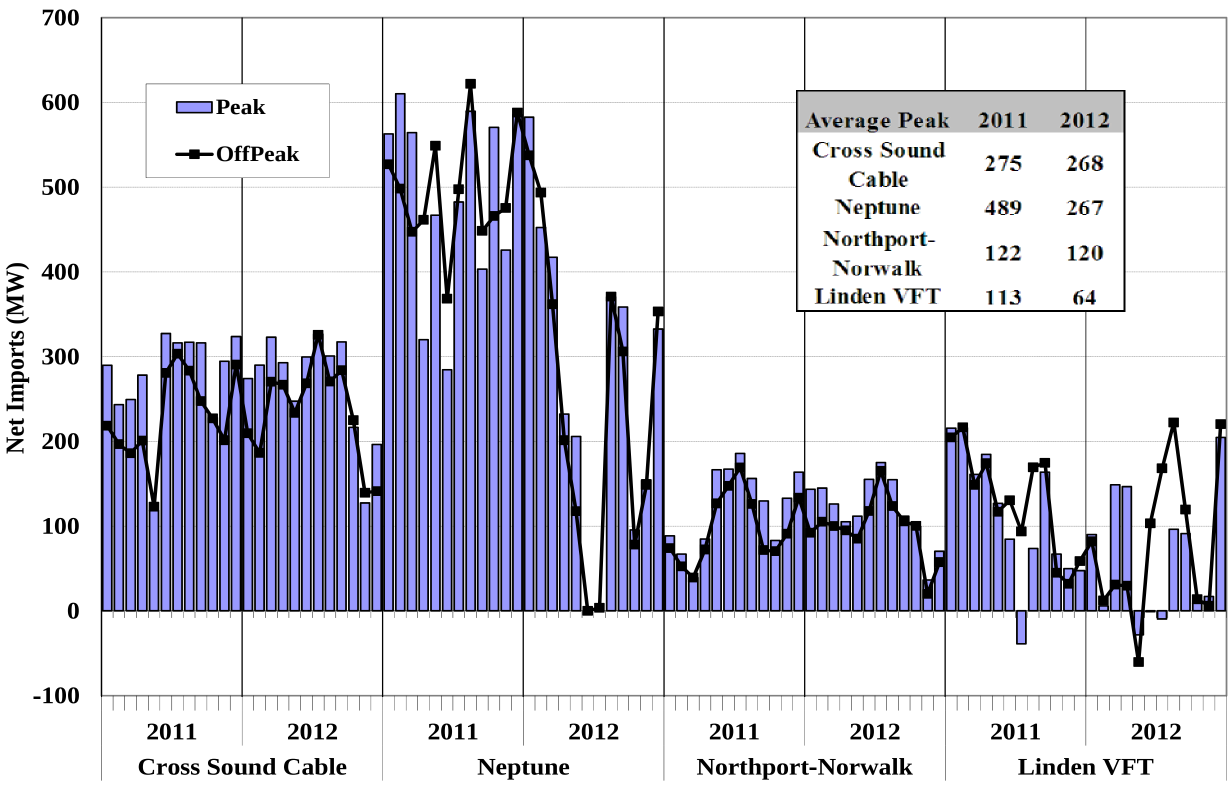


Figure A-56: Monthly Average Net Imports into New York City and Long Island
2011 – 2012



Key Observations: Average Net Imports

- Average net imports from neighboring areas across the primary interfaces increased modestly from 2,130 MW in 2011 to 2,293 MW in 2012 during the peak hours.

- Net imports from Ontario rose in 2012 by 96 percent (or roughly 330 MW) partly because fewer transmission outages occurred in 2012 that reduce the transfer capability between the two regions.

- Net imports from PJM fell 15 percent in 2012 from 2011, averaging roughly 570 MW during peak hours. The decrease was partly due to the less attractive energy prices in New York because of:

  - Lower natural gas prices in 2012; and

  - Changes in the operation of some PAR-controlled lines between New York and New Jersey (i.e., the ABC and JK lines) since May 1, 2012. These changes were intended to shift the distribution of flows across the primary NYISO-PJM interface such that more would flow from western Pennsylvania to western New York rather than from New Jersey to New York City and the Hudson Valley. [126]

  - Nonetheless, even with the reduction in net imports from PJM, average real-time prices were approximately 2 percent higher on the NYISO-side of the interface than on the PJM-side (see Table A-2). This suggests that it would have been economic if net imports had dropped even further from 2011 to 2012.

- Net imports from Hydro Quebec averaged nearly 1,300 MW in 2012 during the peak hours, up 10 percent from 2011.

  - 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..

- Excluding the controllable ties into Long Island, New York was a net exporter to New England in both 2011 and 2012. Average net exports increased from approximately 60 MW in 2011 to 240 MW in 2012.

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126 Before May 1, 2012, the PAR-controlled lines from New Jersey to Southeast New York (i.e., the 5018, JK, and ABC lines) were assumed and operated accordingly to carry 66 percent (40 percent on the 5018, and 13 percent each on the JK and ABC) of the scheduled interchange between NYISO and PJM. Free-flowing tie lines from Pennsylvania to Western New York were assumed to carry the remaining 34 percent of the interface flow. Effective on May 1, 2012, the changes in PAR operations moved the total 26 percent of the interface flow from the JK and ABC lines to the free-flowing western tie lines, which led to corresponding changes in the price calculation at the PJM proxy bus.

    - Exports to New England typically rose during the periods when the spread in natural gas prices between New England and New York was relatively large (e.g., November and December 2012).

- Unlike the primary interfaces, the interchange over the four controllable interfaces shown in Figure A-56 was relatively consistent from month to month. However:

    - Net imports across the Neptune line fell substantially in the second half of 2012 because the line was completely out of service from May 27 through July 31 and partly returned to service (up to 375 MW) for the rest of the year.

    - Net imports over the Cross Sound Cable and the Northport-Norwalk line fell significantly in November and December 2012, when natural gas prices in New England rose significantly above the natural gas prices in Long Island.

    - 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 25 percent of the load in Long Island in 2012, down from the 34 percent in 2011 because of the factors described above.

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.[127] Although circuitous transaction scheduling was prohibited after July 2008, loop flows have still generally moved clockwise around Lake Erie in recent years.

The 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 the TLR procedure to

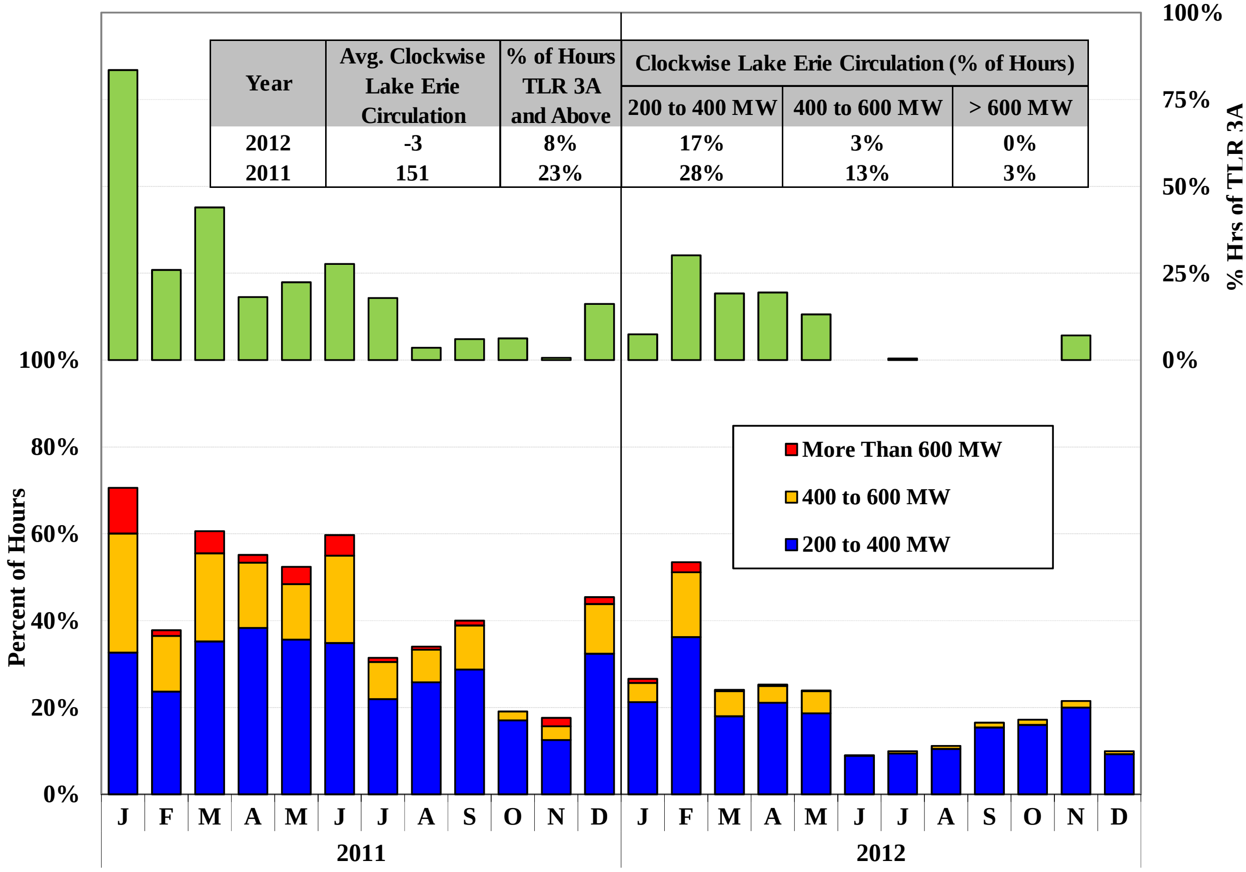
127 Circuitous transactions are transactions that are scheduled from one control area to another along an indirect path when a more direct path exists. Circuitous transactions cause physical power flows that are not consistent with the scheduled path of the transaction. The NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. This issue was discussed in detail in 2008 State of the Market Report, August 2009, Potomac Economics.

ensure that external transactions that are not scheduled with the NYISO are curtailed to reduce flow over the constrained facility.[128]

Figure A-57: Lake Erie Circulation

Figure A-57 summarizes the pattern of loop flows for each month of 2011 and 2012. The lower portion of the figure shows the percent of hours in each month when clockwise loop flows were, on average: (a) between 200 and 400 MW, (b) between 400 and 600 MW, and (c) more than 600 MW. The upper portion of the figure shows the percent of hours in each month when TLRs with Level 3a and above were called by the NYISO. TLR Level 3a allows the NYISO to prevent some Non-Firm Point-to-Point transactions from being scheduled in the subsequent hour. The inset table compares these statistics on an annual basis between 2011 and 2012.

Figure A-57: Lake Erie Circulation
2011 – 2012



Year	Avg. Clockwise Lake Erie Circulation	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation (% of Hours)		
			200 to 400 MW	400 to 600 MW	> 600 MW
2012	-3	8%	17%	3%	0%
2011	151	23%	28%	13%	3%

128 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.

Key Observations: Lake Erie Circulation

- Clockwise loop flows decreased substantially from 2011 to 2012.
  - Average hourly Lake Erie circulation was 3 MW in the counter-clockwise direction in 2012, whereas it was 155 MW in the clockwise direction in 2011.
  - Average hourly clockwise circulation exceeded 400 MW in 3 percent of hours in 2012 versus 16 percent of hours in 2011.
- The reduction in clockwise loop flows around Lake Erie (which contribute to west-to-east congestion on flowgates in upstate New York) led to a substantial reduction in TLRs called by NYISO.
  - TLRs (level 3A and above) were called during only 699 hours (or 8 percent of all hours) in 2012, down significantly from 1,993 hours (or 23 percent of all hours) in 2011.
- IESO-Michigan PARs, which MISO and IESO have stated are capable of controlling up to 600 MW of loop flows around Lake Erie, began operating in April 2012, contributing to the decrease in clockwise loop flows from prior years.[129]
  - The PARs are generally not adjusted until the loop flows exceed or are expected to exceed 200 MW for a substantial period of time.
  - When the NYISO calls a TLR and the PARs are deemed to be in "regulate" mode, transactions scheduled across the IESO-Michigan interface are not subject to the TLR. There were times in 2012 when the clockwise circulation rose above 200 MW for a substantial period, contributing to congestion on a NYISO flow gate, but the NYISO was unable to use the TLR process to manage the congestion or the use of the TLR process was delayed because the PARs were deemed to be in "regulate" mode, further reducing the frequency of TLRs.

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

[129] The use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

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-58: Price Convergence Between New York and Adjacent Markets

Figure A-58 evaluates scheduling between New York and adjacent RTO markets across interfaces with open scheduling. 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. RTOs 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-58 summarizes price differences between New York and neighboring markets during unconstrained hours in 2012. 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 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-58: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2012

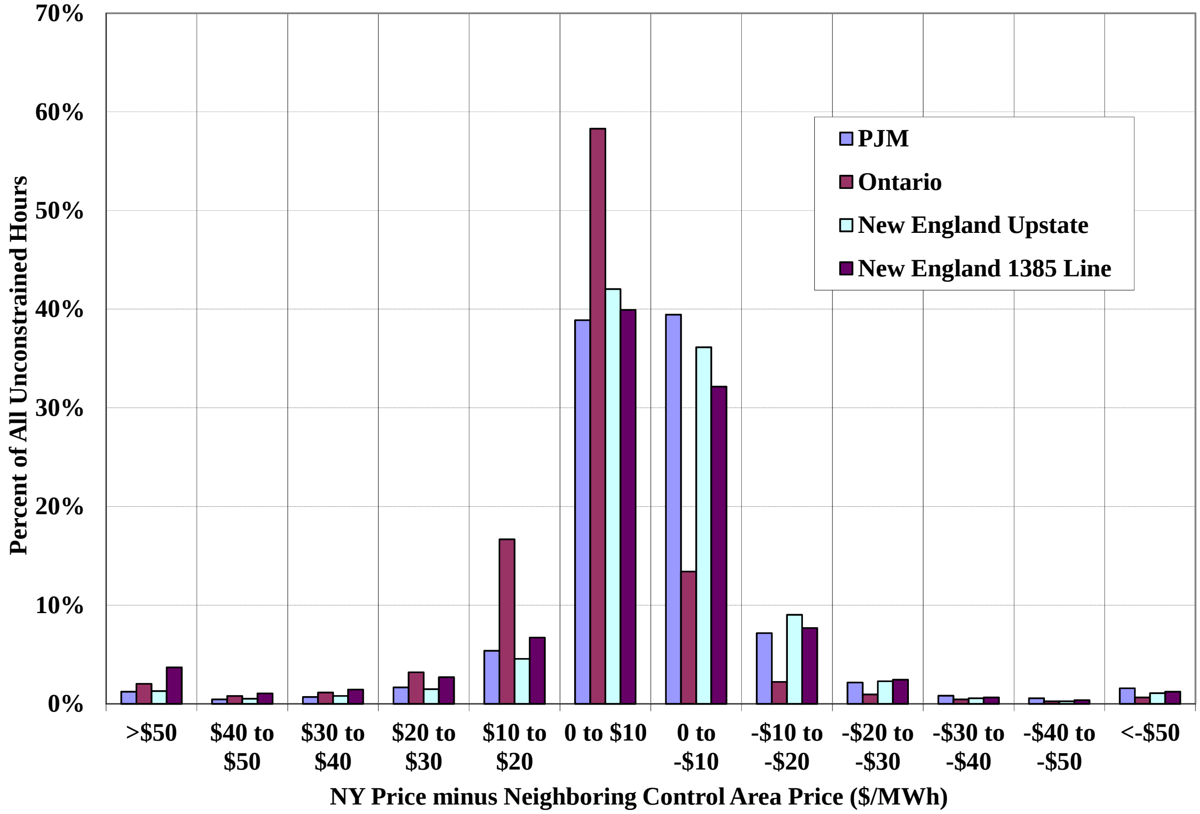


Table A-2 and Figure A-59: Efficiency of Inter-Market Scheduling

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 2012. 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-59 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.

Both Table A-2 and Figure A-59 evaluate the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but this will induce other firms to schedule counterflow transactions, thereby offsetting the effect of the individual transaction. Ultimately, the net scheduled interchange is what determines how much of the generation resources in one control area will be used to satisfy load in another control area, which determines whether the external interface is used efficiently.

Table A-2: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2012

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-237	-$0.59	52%
Ontario	659	$6.70	80%
PJM	629	-$0.95	54%
Controllable Ties			
1385 Line	108	$4.18	57%
Cross Sound Cable	251	$7.74	58%
Neptune	257	$10.49	65%
Linden VFT	72	$2.05	60%

Figure A-59: Efficiency of Inter-Market Scheduling
Over Primary Interface from New England to New York – 2012

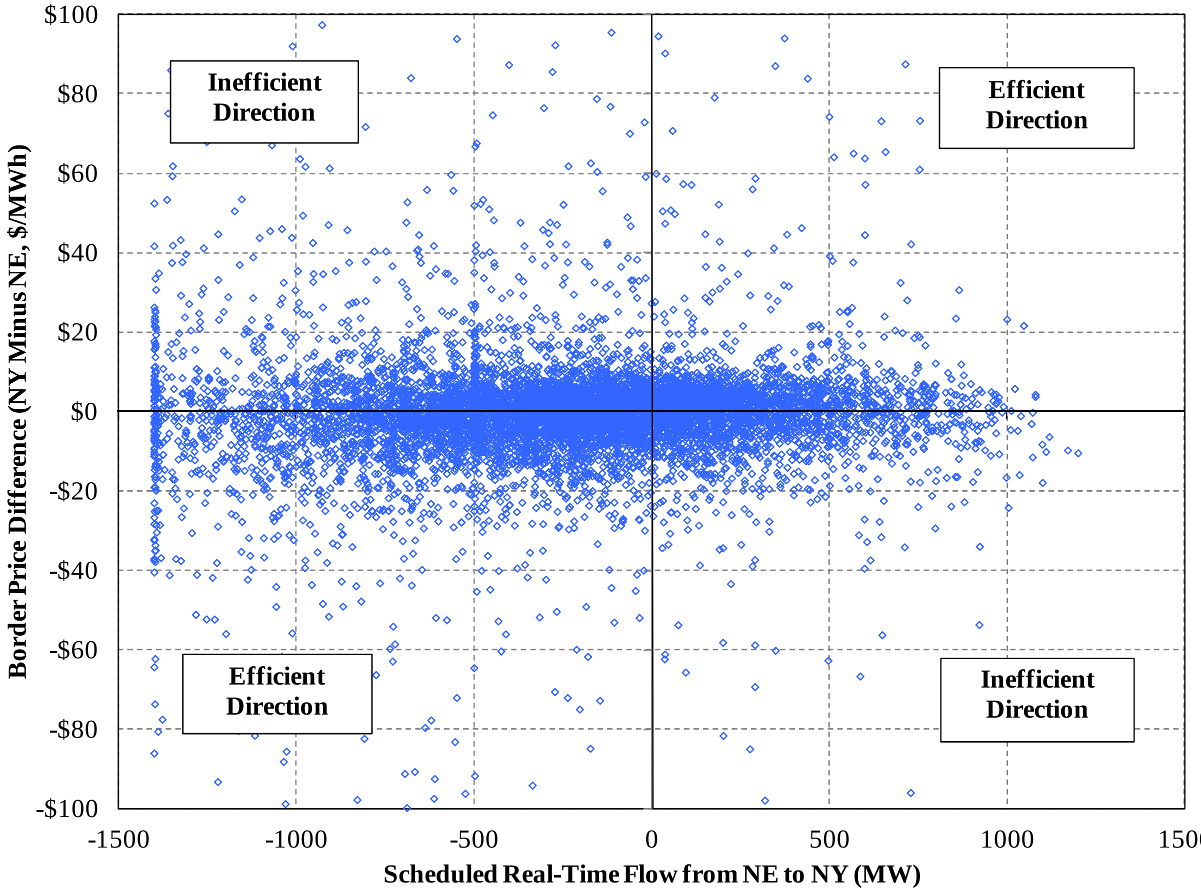
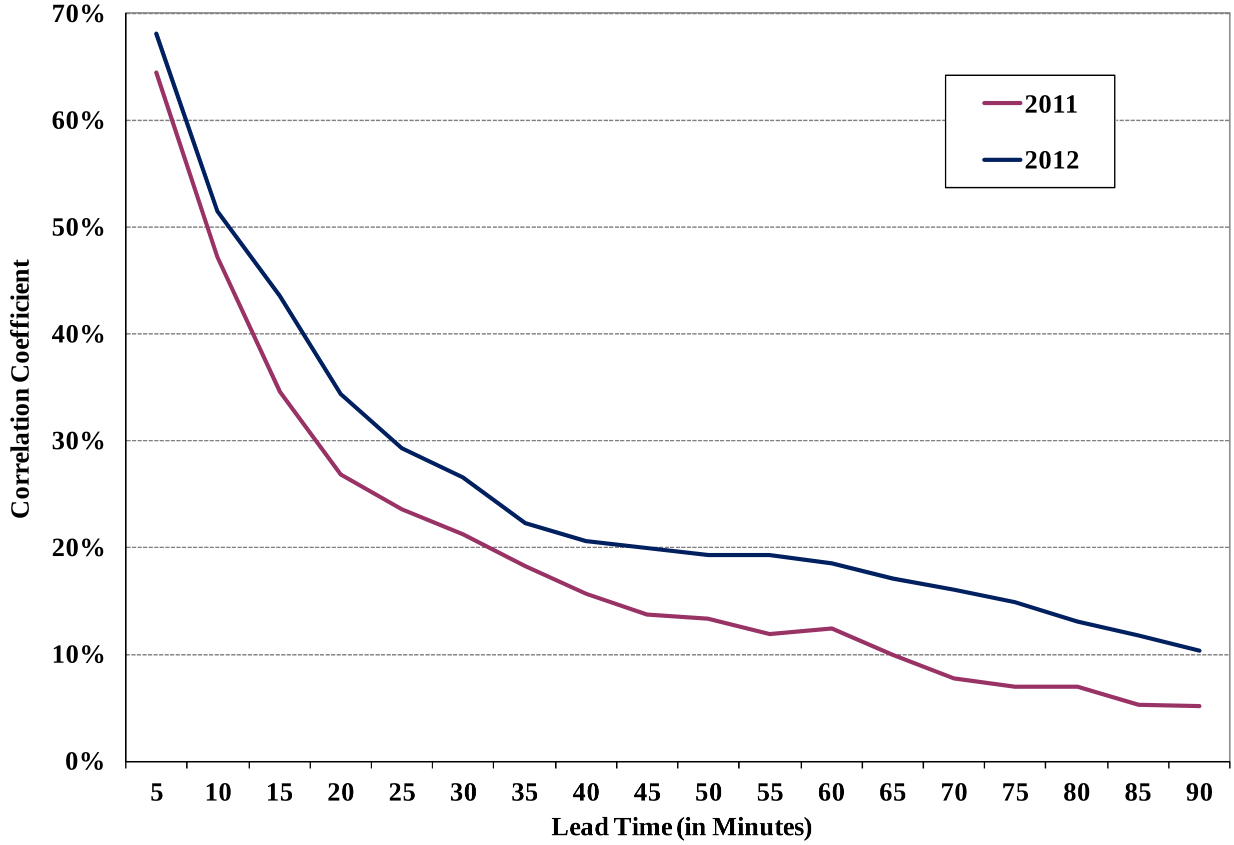


Figure A-60: Correlation of Price Differences and Lead Time

We next evaluate the potential effects of the lead time for transaction scheduling. Currently, to schedule external transactions between NYISO and neighboring areas, 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 most 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 New England across the primary interface. Figure A-60 shows the correlation coefficient between the current five-minute price difference between New York and New England 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-60: Correlation of Price Differences and Lead Time
Primary Interface with New England, 2011- 2012



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 22 to 28 percent of unconstrained hours in 2012, a slight improvement from 2011 when 29 to 36 percent exceeded $10 per MWh.
  - 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 2012.
    - For example, power was scheduled in the profitable direction in 54 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 57 percent on the 1385 Line to 65 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 correlation of price differentials between the NYISO and adjacent markets leading up to real-time rises relatively slowly, suggesting that it would be highly beneficial to reduce the lead times necessary to schedule external transactions.

  - The current scheduling lead times require transactions to be submitted 75 minutes before the hour. Even if market participants were able to schedule closer to real-time, they would still be at risk of scheduling in the efficient direction a quantity that leads to a reversal of the price spread between markets. This is because individual market participants generally have difficulty determining the optimal quantity to schedule.

  - Hence, some explicit coordination by the ISOs will be necessary in order for the external interfaces to be scheduled efficiently.

D. Intra-Hour Scheduling with Adjacent Control Areas

The NYISO has been working on several initiatives to improve the utilization of its interfaces with neighboring RTOs, including more frequent scheduling (i.e., 15-minute scheduling) and Coordinated Transaction Scheduling ("CTS"). These market enhancements are being implemented in phases under the Enhanced Interregional Transaction Coordination ("EITC") project. By the end of 2012, 15-minute scheduling had been enabled at four interfaces and substantial progress had been made on CTS with PJM and ISO New England.

EITC Phase 1 was activated on July 27, 2011, allowing 15-minute scheduling between New York and Hydro-Quebec across its primary interface (i.e., at the HQ-Chateauguay proxy bus). The NYISO initially set the quarter-hour interchange ramp limit to 25 MW and gradually increased it to 200 MW.[130, 131]

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130 The quarter-hour ramp limit at HQ-Chateauguay bus was raised from 25 MW to 50 MW on November 2, 2011, to 100 MW on December 1, 2011, to 150 MW on February 9, 2012, to 175 MW on April 18, 2012, and to 200 MW on May 31, 2012.

131 EITC Phase 2 evaluates the appropriateness of expanding the Interregional Transaction Coordination Concept by scheduling operating reserves and/or regulation service with the HQ control area.

EITC Phase 3 allowed 15-minute transaction scheduling between New York and PJM. The NYISO activated 15-minute scheduling across the primary interface (i.e., at the Keystone proxy bus) on June 27, 2012. The NYISO activated 15-minute scheduling for the Neptune and Linden VFT scheduled line interfaces on October 30 and November 28, 2012. Unlike the primary HQ interface, these three PJM interfaces are not subject to an individual quarter-hour ramp limit, although the NYISO utilizes a NYCA-wide ramp limit of 300 MW to manage the total quarter-hour schedule changes across all 15-minute scheduling interfaces.

EITC Phase 4 and Phase 5 relate to the future deployment of CTS on the interfaces with ISO New England and PJM.

Figure A-61 & Figure A-62: Scheduling Patterns at the 15-minute Scheduling Interfaces

The following analyses examine the pattern of transaction scheduling across the interfaces that allow changes at the quarter-hours (i.e., at :15, :30, and :45 past each hour). Hence, the analyses exclude changes that occur at the top of the hour (i.e., :00). Figure A-61 shows the distribution of the size and direction of schedule changes at the quarter-hours across the primary HQ and PJM interfaces from July to December 2012. The Neptune and Linden VFT interfaces are not included in this evaluation due to the short period of time since the activation of 15-minute schedule at those interfaces.

The bars in the chart show the percent of quarter-hour intervals for each MW-range (i.e., the quarter-hour intervals that do not have a schedule change are not included in the chart). The table in the chart shows the overall frequency and the magnitude of these quarter-hour changes at the two interfaces. Positive numbers indicate schedule changes in the import direction (i.e., more imports into New York or less exports from New York) and negative numbers indicate schedule changes in the export direction (i.e., more exports from New York or less imports into New York).

Figure A-62 shows the frequency of quarter-hour schedule changes at different times of day at the primary HQ and PJM interfaces from July to December 2012. The horizontal axis shows all quarter-hour intervals (i.e., :15, :30, and :45 intervals of each hour) and exclude top of hour schedule changes. The vertical axis shows the percent of intervals when the net schedules change from the previous interval in the import direction and the export direction for each interface.

Figure A-61: Distribution of Quarter-Hour Schedule Changes by Quantity
Primary Interfaces with PJM and HQ, July – December 2012

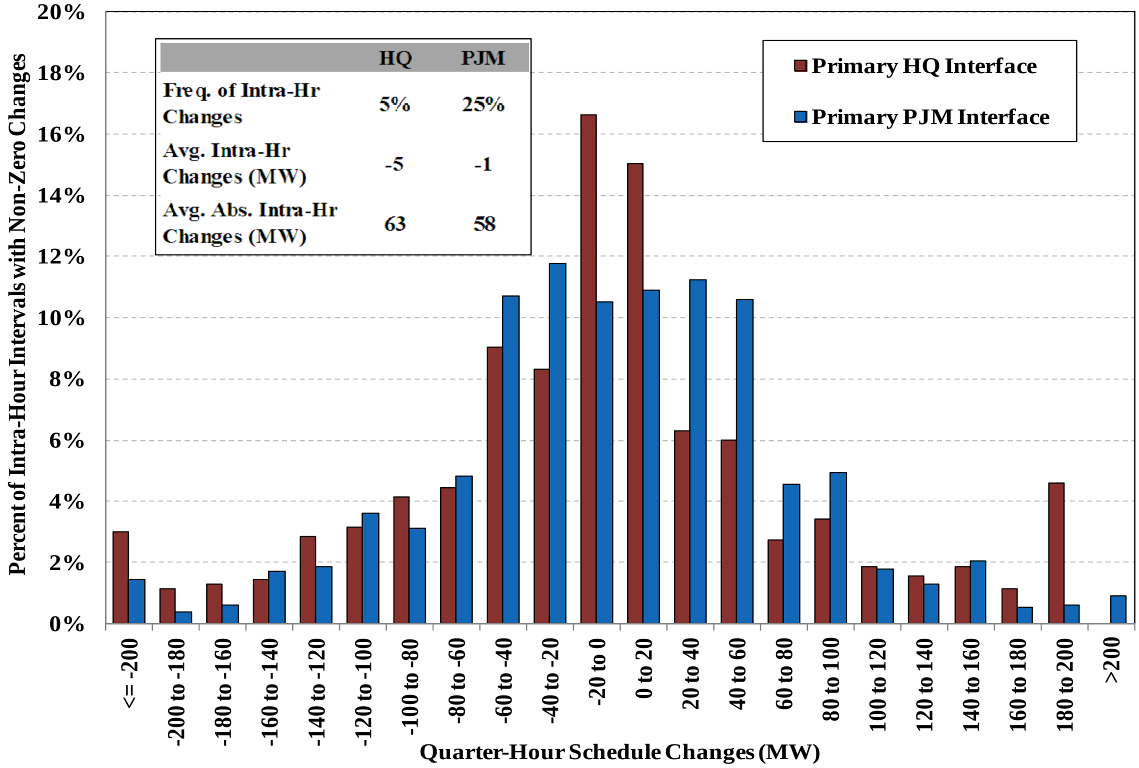
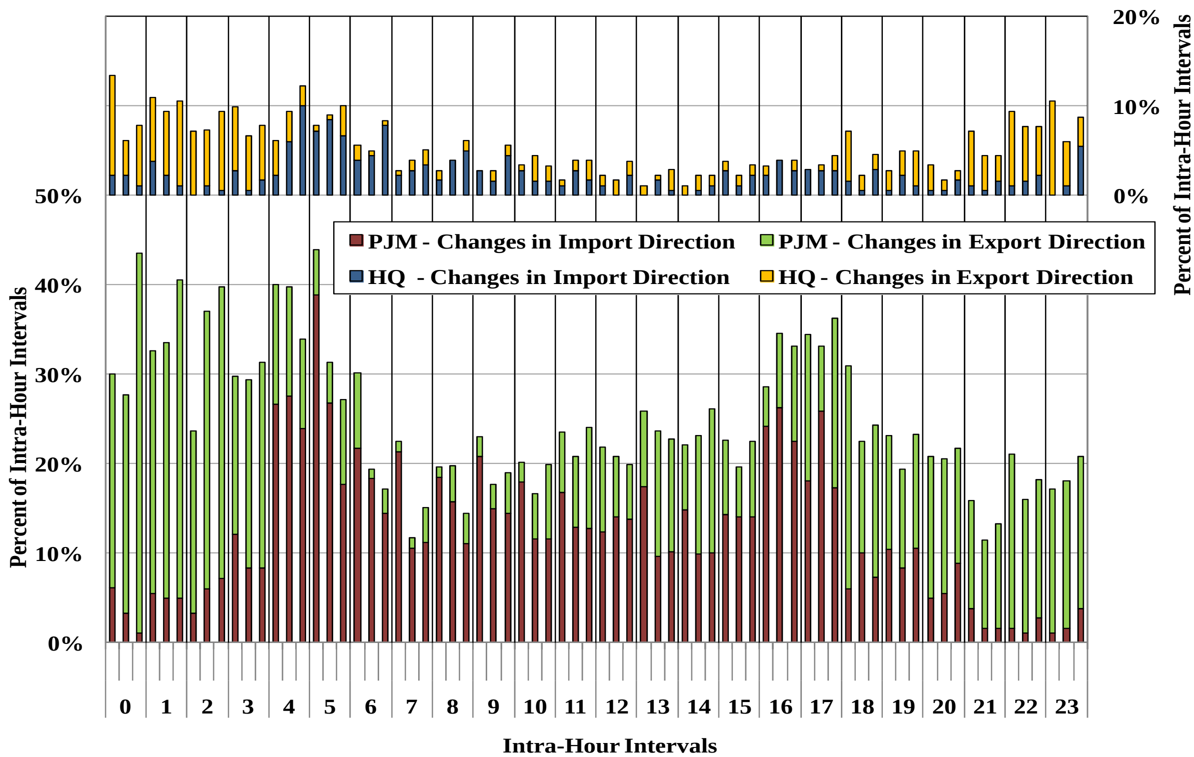


Figure A-62: Distribution of Quarter-Hour Schedule Changes by Time of Day
Primary Interfaces with PJM and HQ, July – December 2012



<u>Key Observations: Intra-Hour Scheduling with Adjacent Control Areas</u>

- Intra-hour schedule changes occurred during approximately 5 percent of all quarter-hour intervals at the primary HQ interface and 25 percent of all quarter-hour intervals at the primary PJM interface, reflecting that:
  - A much larger share of the transactions at the PJM interface are offered price-sensitively than at the HQ interface;
  - Like the NYISO, PJM runs a real-time spot market that allows market participants to buy and sell from the market, which allows them to be more responsive to price changes. In contrast, market participants must find a counterparty in HQ with whom to transact;
  - The prices at the PJM proxy bus are generally more volatile than prices at the HQ proxy bus; and
  - The economic direction in which to flow power changes more frequently between NYISO and PJM than between the NYISO and HQ.
- Intra-hour schedules were typically adjusted in ways that generally reduce price volatility at the top of these hours.
  - Intra-hour schedules generally adjusted in the export direction during hours when the system is typically ramping-down (e.g., hours-beginning 21 to 23 and hours 0 to 3) and in the import direction during hours when the system is typically ramping-up (e.g., hours-beginning 5 to 10).
  - As shown in Figure A-62, the real-time prices typically move:
    - In an upward direction within each ramping-up hour before dropping sharply at the top of each ramping-up hour; and
    - In a downward direction within each ramping-down hour before rising sharply at the top of each ramping-down hour.
  - Hence, scheduling additional imports at the quarter-hour intervals tends to moderate real-time price variations during ramping hours, as do additional exports in ramping-down hours.

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 the following aspects of wholesale market operations in 2012:

- *Real-Time Scheduling and Pricing* – Two sub-sections evaluate 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: (a) ancillary services shortages, (b) transmission shortages, and (c) periods when reliability demand response is deployed.

- *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.

- *Out-of-Merit Dispatch* – Out-of-merit ("OOM") dispatch is necessary to maintain reliability when the real-time market does not provide incentives for suppliers to satisfy certain reliability requirements or constraints. Like supplemental commitment, OOM dispatch may indicate the market does not provide efficient incentives.

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 when it is economic to do so.[132] 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 gas turbine 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 gas turbines and 30-minute gas turbines when it is economic to do so.[133] 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 gas turbines, 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-63 – Figure A-64: Efficiency of Gas Turbine Commitment

Figure A-63 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

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

[133] 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

components of committed gas turbines are usually lower than the real-time LBMP. However, when a gas turbine that is committed efficiently is close to the margin, it is possible for the offer price components to be greater than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

Figure A-63 shows the average quantity of gas turbine capacity started each day in 2012. 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 for several reasons. First, 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. Second, 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. Third, gas turbines that are economic sometimes do not set the LBMP and, thus, appear to be uneconomic, which is evaluated in Figure A-64.

Starts are shown separately for quick start gas turbines, older 30-minute gas turbines, and new 30-minute gas turbines. Starts are also shown separately for New York City and Long Island, and based on whether they were started by RTC, RTD, RTD-CAM,[134] or by an out-of-merit (OOM) instruction.

The real-time market software uses 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, the inflexibility of the gas turbines are modeled accurately with most of these units being "block loaded" at their maximum output levels once turned on. The second pass is a hybrid dispatch pass, which treats gas turbines 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. gas turbines 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. Consequently, when uneconomic gas turbines are forced on in the pricing pass, it may lead some economic gas turbines to not set the LBMP in the pricing pass.

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134 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.

Figure A-63: Efficiency of Gas Turbine Commitment
2012

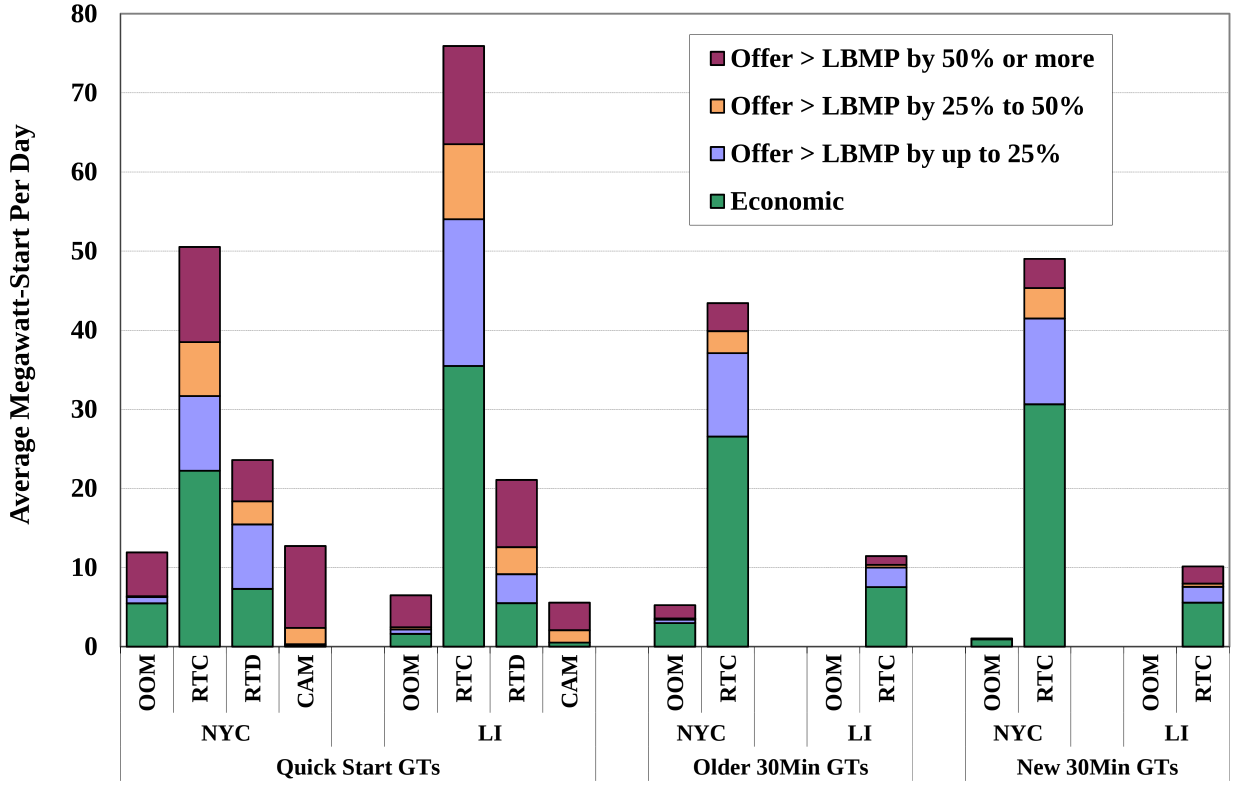


Figure A-64 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP during a portion of the initial commitment period. In particular, we examine every market interval in the initial commitment period of a gas turbine start and report the following seven quantities:

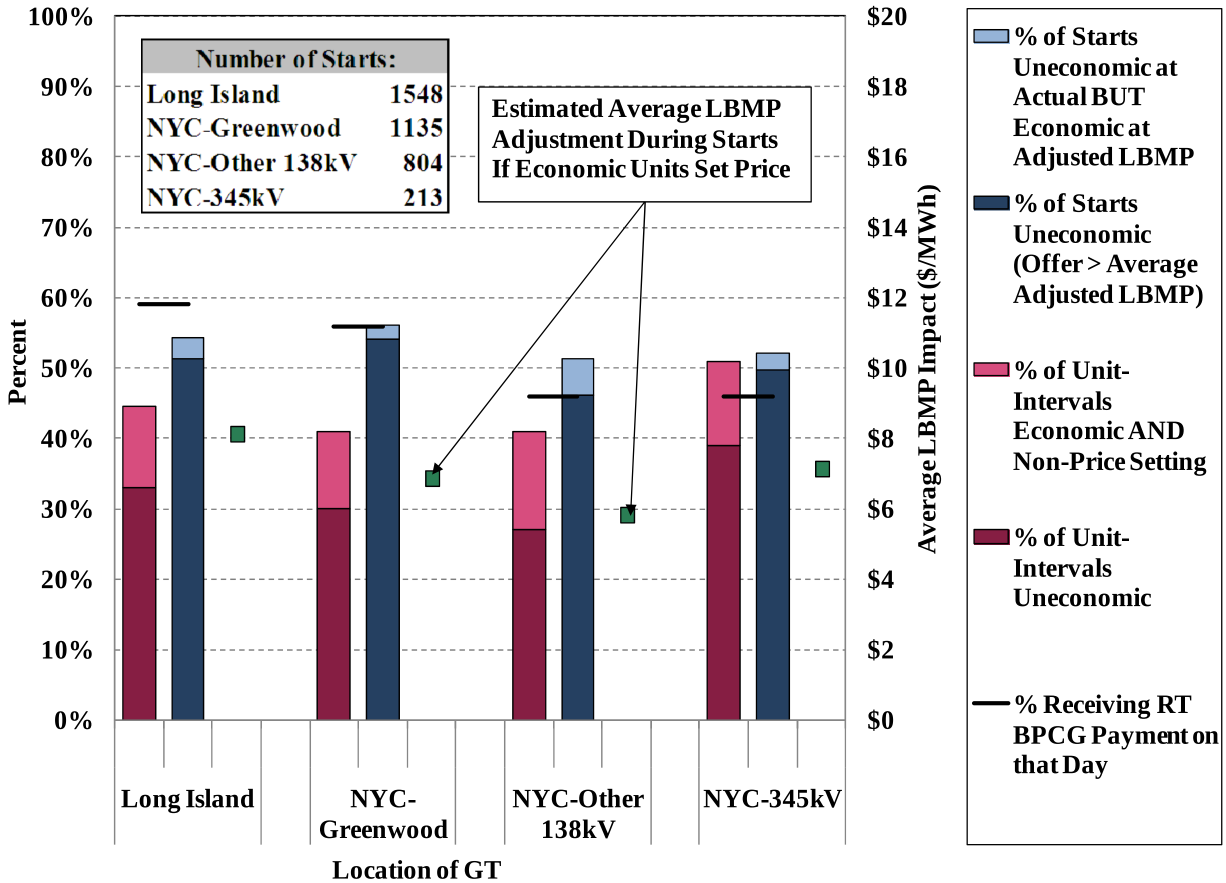
- *Number of Starts* – Excludes self-scheduled and local reliability units.
- *Percent Receiving RT BPCG Payment on that Day* – Share of gas turbine commitments that occurred on days when the unit received a RT BPCG payment for the day.
- *Percent of Unit-Intervals Uneconomic* – Share of intervals during the initial commitment period when the unit was displacing less expensive capacity.
- *Percent of Unit-Intervals Economic AND Non-Price Setting* – Share of intervals during the initial commitment period when the unit was displacing more expensive capacity, but not setting the RT LBMP.
- *Estimated Average LBMP Adjustment During Starts* – Average upward adjustment in LBMPs during starts if economic gas turbines always set the RT LBMP.
- *Percent of Starts Uneconomic (Offer > Average Adjusted LBMP)* – Share of starts when gas turbine's offer was greater than the average "Adjusted LBMP" over the initial

commitment period. (The "Adjusted LBMP" is the price that would have been set if economic gas turbines at the same market location always set the RT LBMP).

- *Percent of Starts Uneconomic at Actual BUT Economic at Adjusted LBMP* – Share of starts when gas turbine's offer was (a) greater than the average actual LBMP but (b) less than the average Adjusted LBMP over the initial commitment period.

These quantities are shown separately for gas turbines in four areas: (a) Long Island, (b) the areas outside the 138kV load pocket in New York City (i.e., the In-City 345kV region), (c) the Greenwood load pocket in New York City (which is part of the In-City 138kV load pocket), and (d) other areas inside the 138kV load pocket in New York City.

Figure A-64: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2012



Key Observations: Efficiency of Gas Turbine Commitment

- 73 percent of the gas turbine capacity that was started during 2012 was committed by RTC, with an additional 19 percent by RTD and RTD-CAM, and the remaining 8 percent through OOM instructions.

- The overall efficiency of gas turbine commitments was consistent with recent years.

- 47 percent of all gas turbine commitments were clearly economic in 2012.
- An additional 20 percent of all gas turbine commitments were cases where the gas turbine offer was within 125 percent of LBMP in 2012.
- Hence, the NYISO's real-time market models are relatively effective in committing gas turbines efficiently.

- Once committed, gas turbines were economic in 61 to 73 percent of their initial commitment period (excluding self schedules and local reliability commitments).
  - However, economic gas turbines do not always set the real-time LBMP (i.e., when their output is economic, they displace output from more expensive resources).
  - In 2012, economic gas turbines did not set LBMP in 11 to 14 percent of intervals during their initial commitment period.
  - We estimate that allowing these economic gas turbines to set prices would have increased the LBMPs by an average of $6 to $8 per MWh for each start in New York City and Long Island in 2012.
  - These results suggest that the hybrid pricing logic should be evaluating to identify changes that would more effectively allow economic gas turbines to set prices in the real-time markets.

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 in the NYISO market. 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.[135] 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

135 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).

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.[136]

"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.[137]

Figure A-65: Efficiency of External Transaction Scheduling

Figure A-65 shows the consistency and profitability of external transaction scheduling across the primary AC interface between New York and New England from 2008 to 2012 using the import/export offer and bid prices and the real-time LBMP at the border.[138] 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.

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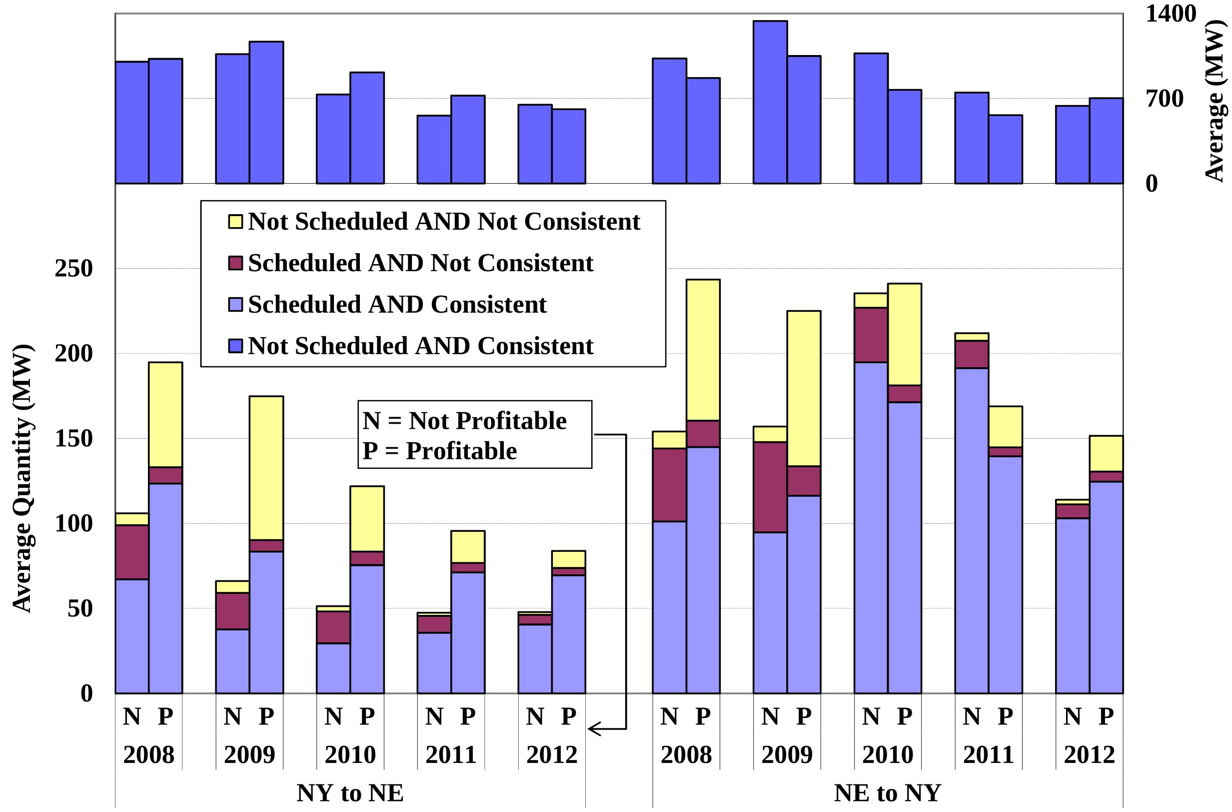
136 The export would pay \$45/MWh for the power in the NYISO and receive \$40/MWh for the power in the adjacent control area, losing \$5/MWh.

137 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.

138 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.

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

Figure A-65: Efficiency of External Transaction Scheduling
Primary NY-NE Interface, 2008 - 2012



Key Observations: Efficiency of External Transaction Scheduling

- The share of schedules that were consistent improved modestly in the past two years.
  - 93 percent of scheduled offers were consistent in 2012 (roughly the same as in 2011), up from 77 to 87 percent during 2008 to 2010.
  - 99 percent of offers and bids not scheduled were also consistent, up slightly from 96 to 98 percent in prior years.
- *Consistent* scheduling is not the same as *Efficient* scheduling (efficient schedules are profitable). Results for 2012 show:
  - Scheduled and consistent – 58 percent of these transactions were profitable.
  - Not scheduled and consistent – 51 percent of these transactions would have been profitable if scheduled.
  - These results indicate that a substantial portion of the time, RTC makes scheduling determinations that are consistent with the bids and offers submitted, but since the

bids and offers are not consistent with real-time prices in the neighboring control area, the final interchange schedule is not efficient.

- Overall, 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.
  - The efforts to improve the efficiency of interchange are discussed in Section IV.D of the Appendix.

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.[139] Such lines are analyzed in Section IV.C 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 primarily focused on reducing production costs in the day-ahead and real-time markets. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-3 and Figure A-66: 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 2012.

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[139] 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 A-3 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2012. 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).
- 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 in 2012.
    - 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.[140]
- 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 wheel of up to 300 MW 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.[141]

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140 Before May 1, 2012, in addition to carrying the 1,000 MW required under the ConEd-PSEG wheeling agreement, 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.

141 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

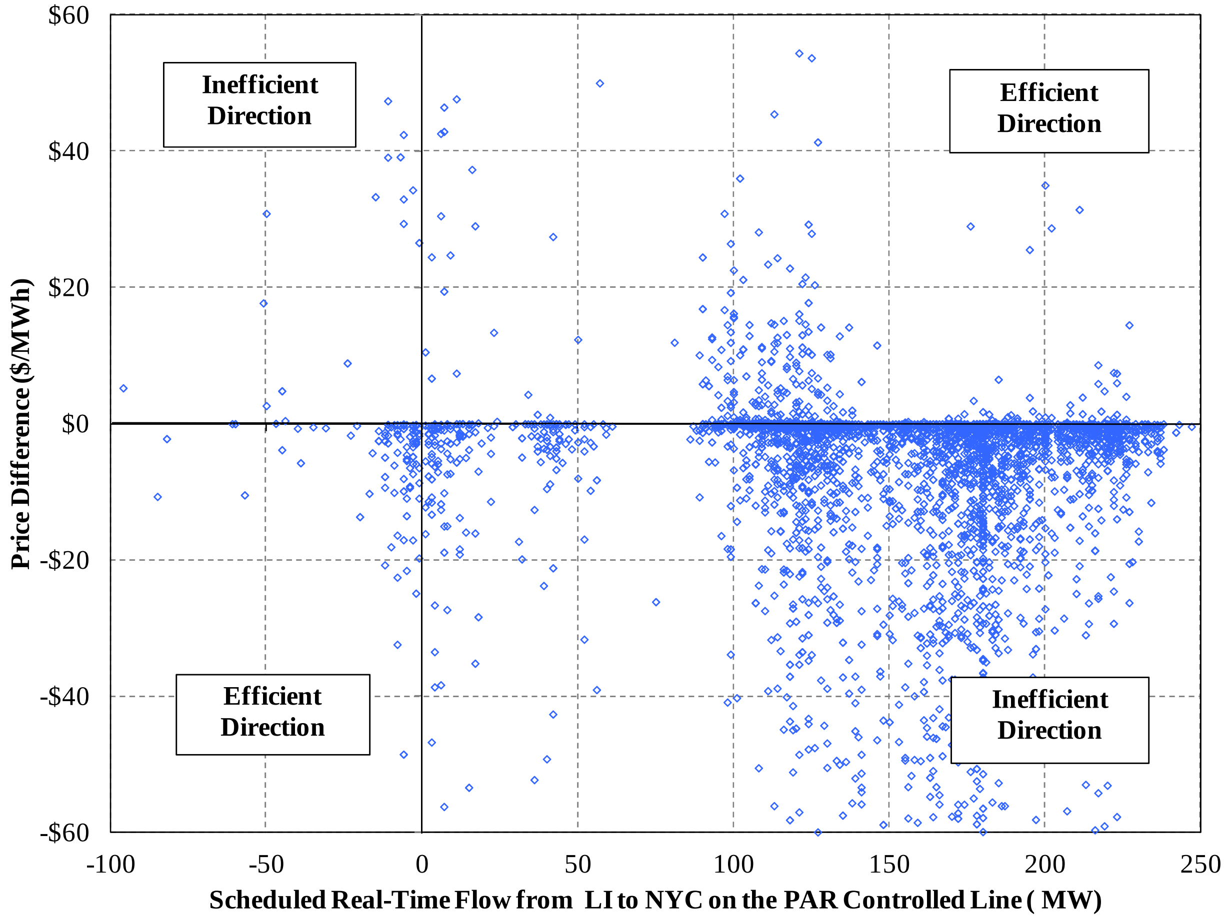
Table A-3: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2012

	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)	54	$7.21	64%	$7
Sand Bar (PV 20)	-78	-$6.06	66%	$4
Waldwick (JK)	-811	$2.43	42%	-$21
Ramapo (5018)	441	$2.43	60%	$14
Farragut (BC)	567	$1.29	57%	$7
Goethals (A)	317	$2.80	58%	$5
PAR Controlled Lines (LI into NYC)				
Lake Success (903)	123	-$8.00	12%	-$10
Valley Stream (901)	59	-$13.02	10%	-$10

Figure A-66 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.

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.

Figure A-66: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2012



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 line between New York and neighboring markets during 2012.
  - The share of hours with power flowing in the efficient direction (from the lower-priced area to the higher-priced area) ranged from 42 percent for the Waldwick lines to 66 percent for the PV-20 line.
    - The Waldwick lines generally flowed power from NYCA to PJM due to the ConEd-PSEG wheeling agreement, although the price on the PJM side was generally lower during 2012.
  - We estimate that the controllable lines between NYCA and adjacent control areas achieved a total of $25 million in net production cost savings, excluding the Waldwick lines.
    - However, the use of the Waldwick lines to support the ConEd-PSEG wheeling agreement *increased* production costs by an estimated $21 million in 2012.

  - Significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

- The scheduling of the PAR-controlled lines from Long Island into New York City was much less efficient 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 2012, which was comparable to the results in 2011.

  - The use of these lines increased production costs by an estimated $20 million in 2012 because prices on Long Island were typically higher than those in New York City (particularly in the Astoria East/Corona/Jamaica pocket where the 901 and 903 lines connect, which is frequently export-constrained).

  - In addition to increasing production costs, these transfers: (a) depress prices in New York City; and (b) can restrict output from economic generators in the Astoria East/Corona/Jamaica pocket. Restrictions on the output of these generators sometimes adversely affects a much wider area (e.g., when there is an eastern reserve shortage or during a TSA event).

- These results indicate that significant opportunities remain to improve the operation of these lines, particularly the ABC and Waldwick lines and the lines between New York City and Long Island.

  - These lines are all scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets. It would be highly beneficial modify these contracts or find other ways under the current contracts to operate the lines efficiently.

D. Cyclical Real-Time Price Volatility

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

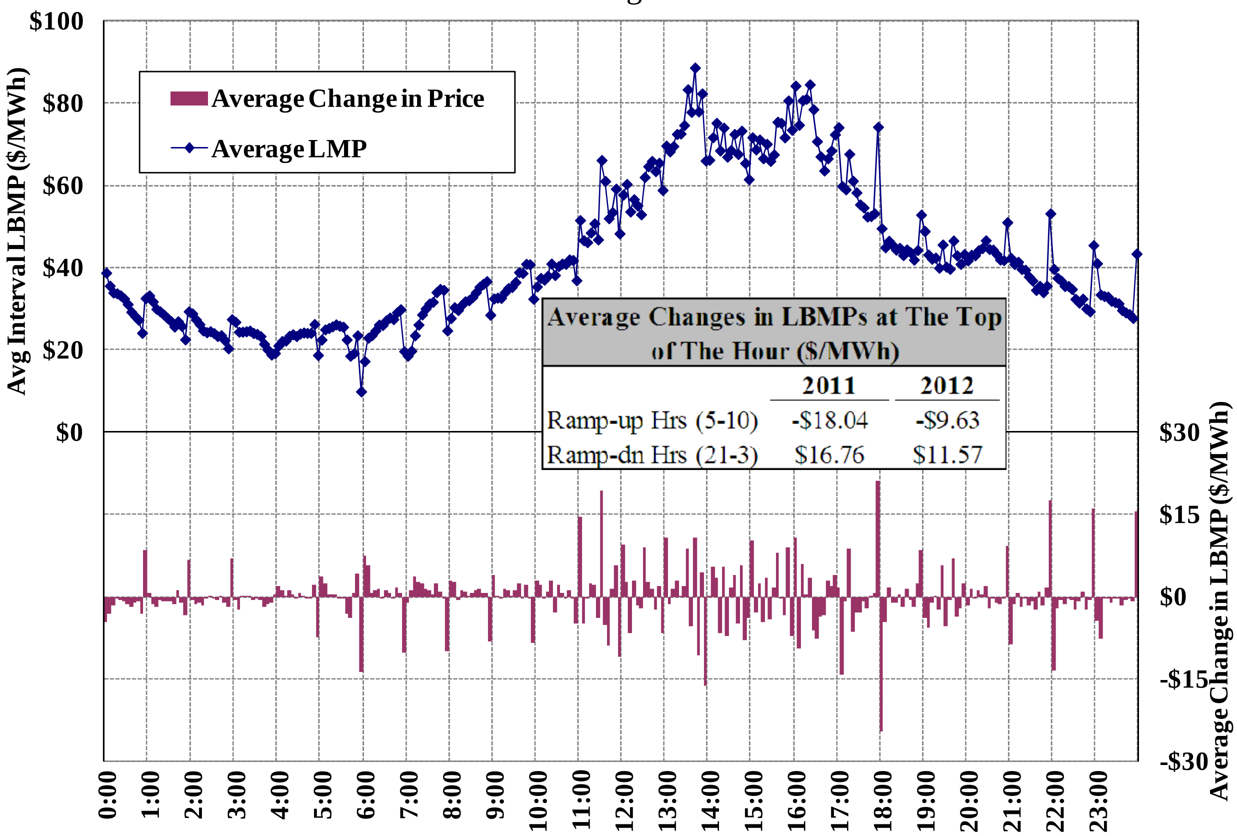
Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient 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 cyclical patterns of price volatility in real time that tend to occur predictably at certain times of day, while the next sub-section focuses on transient patterns of price volatility that may or may not occur under repetitive system conditions.

Figure A-67 & Figure A-68: Cyclical Real-Time Price Volatility

Figure A-67 evaluates cyclical patterns of price volatility that occur predictably at certain times of day, showing the average prices in each five-minute interval of the day in the summer of 2012. The figure shows the load-weighted average prices for all of New York, although the results are similar in each individual zone. The table compares the average size of upward and downward spikes that typically occur at the top of the hour during the ramp-up hours (i.e., hours 5 to 10) and ramp-down hours (i.e., hours 0-3 and hours 21-23) between 2011 and 2012.

Figure A-67: Statewide Average Five-Minute Prices by Time of Day
June to August 2012



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-68 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *Net imports* – Net imports 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). Net imports across the interfaces that allow 15-minute scheduling also ramp from five minutes prior to each quarter-hour interval (i.e., :10, :25, :40) to five minutes after the quarter-hour interval (i.e., :20, :35, :50). In addition, 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.

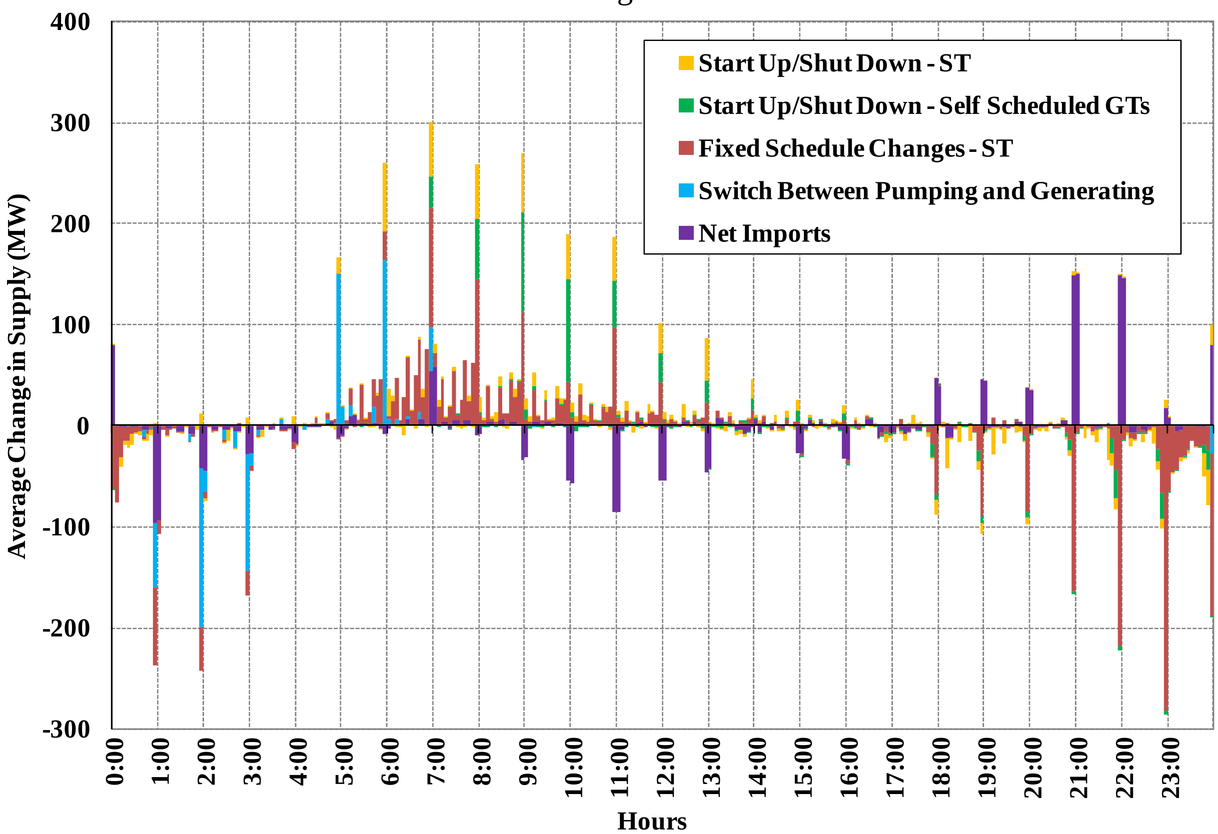
- *Fixed schedule changes for online non-gas-turbine units* – Many units are not dispatchable by the ISO and produce according to their fixed generation schedule.

- *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-68: Factors Contributing to Cyclical Real-Time Price Volatility

June to August 2012



Key Observations: Cyclical Real-Time Price Volatility

- Most cyclical 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 $10 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 2012:
  - Import and export schedules typically adjusted at the top of the hour, although there are many hours in which net imports are adjusted in a direction that tends to help the ISO ramp (e.g., at 22:00, there tends to be a sudden reduction in supply from self scheduled units, which is offset by an increase in net imports);
  - Pumped-storage units typically switch between pumping and generating at the top of 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.
- 15-minute scheduling was introduced for the HQ interface in 2011, the PJM interface in June 2012, and the controllable Neptune and Linden VFT lines in the Fall 2012.
  - The 15-minute scheduling of these interfaces is evaluated in Section IV.D of this Appendix.
  - Allowing external schedule changes throughout the hour, rather than only at the tops of each hour, should reduce the top-of-the-hour price volatility shown in this section. Figure A-62 shows that market participants at the primary PJM interface have used the 15-minute scheduling capability to spread schedule changes more broadly across individual hours.
- This report recommends the NYISO investigate some potential further improvements that would reduce unnecessary price volatility at the top of the hour.

E. Transient Real-Time Price Volatility

This sub-section evaluates scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the energy-balance constraint (i.e., the requirement that supply equal demand) in 2012. The effects of transient transmission constraints tend to be localized, while transient spikes in the energy-balance constraint affect prices throughout NYCA.

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 spike in the shadow price of the energy-balance constraint (known as the "reference bus price") affects prices statewide rather than in a particular area. A statewide price spike is considered "transient" if:

- The price at the reference bus exceeds $150 per MWh; and
- It increases by at least 50 percent from the previous interval.

Figure A-69 & Figure A-70: Transient Real-Time Price Volatility

Figure A-69 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2012. Figure A-70 evaluates major factors that may have contributed to the transient price volatility shown in Figure A-69. Figure A-69 shows the frequency of transient spikes and the average shadow price in transient spikes for each constraint during 2012. In the figure, the top eight transmission facilities (A through H) are ranked in descending order by the frequency of transient spikes and all other facilities are grouped in the "Other" category.

Although relatively infrequent, transient price spikes are important, since it may be far more costly to manage system conditions that are not fully anticipated. The table in Figure A-69 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 price spikes occur.

Figure A-69: Frequency and Cost of Transient Price Spikes
2012

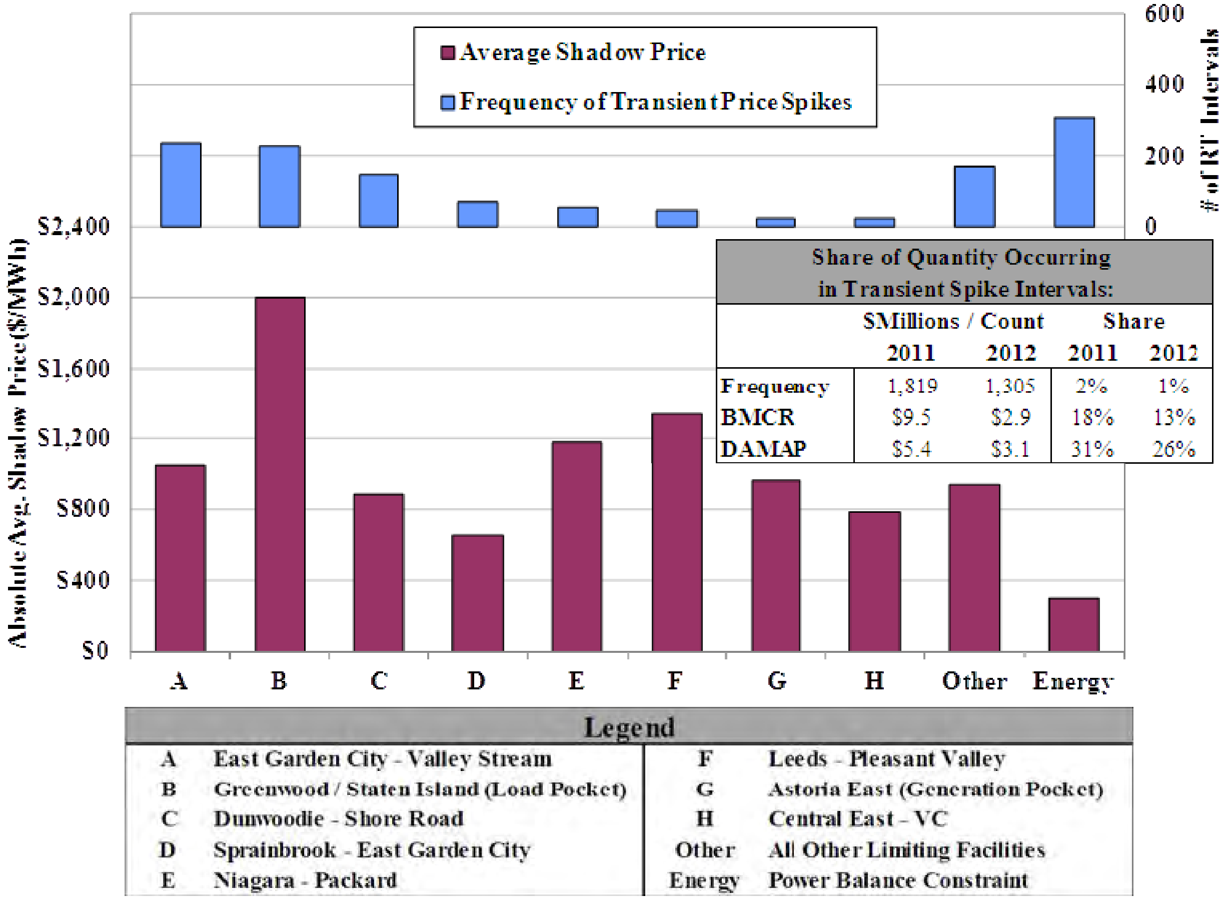


Figure A-70 examines the factors that changed from the previous five-minute interval, contributing to increased flows across the constrained facility or increased net demand statewide. In particular, these factors include:

- 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;

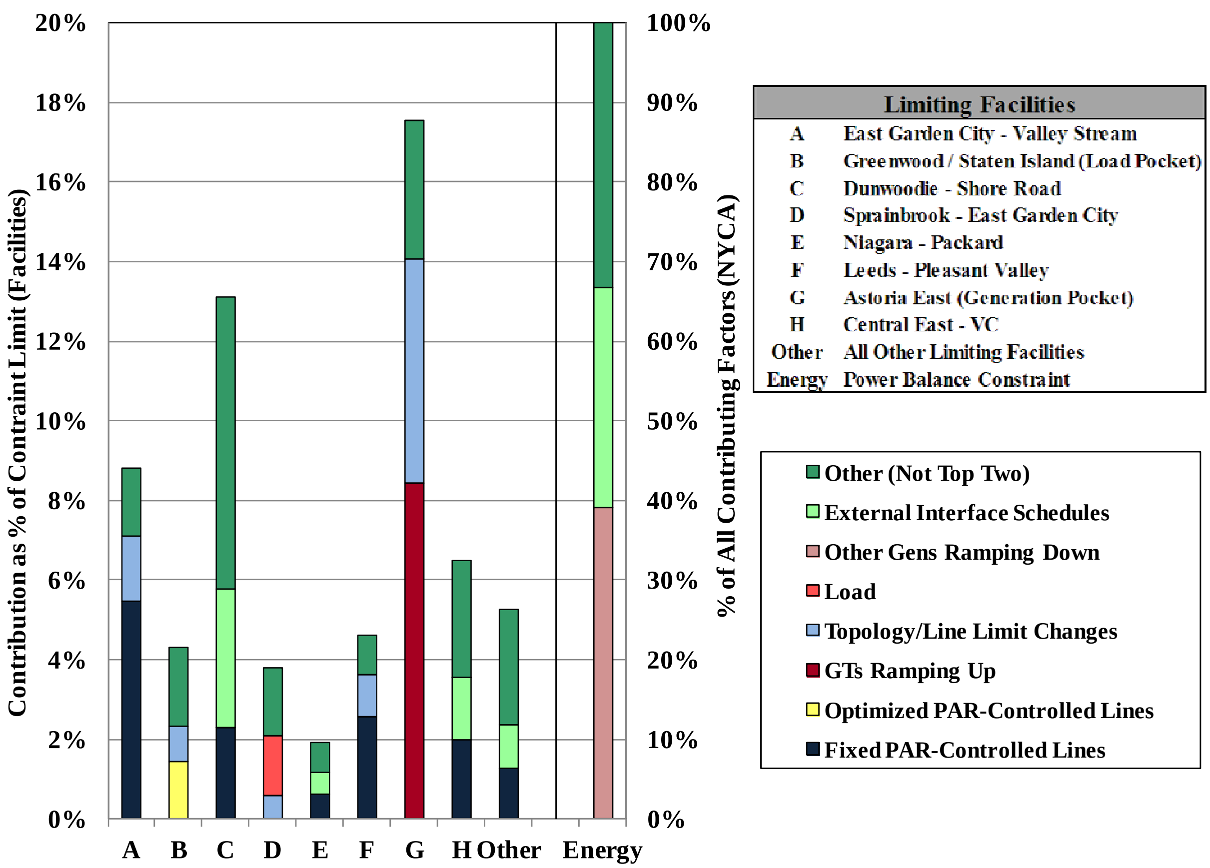
- Gas Turbine Commitment – Most decisions to start-up and shut-down gas turbines are made by RTC;
- Other Generators Ramping Up or Ramping Down – The output of these units is determined by self schedules, dispatch instructions, and/or dragging; and
- Changes in load.

- 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 Two) – This category includes factors that are not among the two most significant factors for a particular facility.

The contributions of these factors for a transient spike on a particular transmission facility are shown as the percent of the facility's transfer limit in the left of the figure. The contributions of these factors for a transient statewide spike are shown as the percent of the total contributions in the right of the figure.

Figure A-70: Factors Contributing to Transient Price Spikes

2012



Key Observations: Transient Real-Time Price Volatility

Transmission Constraint Related Price Spikes

- Transient shadow price spikes occurred in about 1 percent of all intervals, and 36 percent of the intervals when shadow prices exceeded $300/MWh in 2012.
  - More than 45 percent of total transient shadow price spikes occurred in Long Island:
    - The East Garden City-to-Valley Stream line accounted for 24 percent; and
    - Two major transmission lines from upstate New York to Long Island (Dunwoodie-to-Shore Road and Sprainbrook-to-East Garden City) accounted for 22 percent combined.
  - The Greenwood/Staten Island load pocket exhibited the most transient shadow price spikes in New York City, accounting for 23 percent of all transient spikes.
  - In the upstate areas, the Niagara-to-Packard and Leeds-to-Pleasant Valley lines exhibited the most transient spikes, each accounting for 5 percent of all transient spikes.
- Among factors that contribute to transient shadow price spikes for transmission constraints, the Fixed PAR-Controlled Line flow changes were the most significant factor in 2012.
  - This was the top contributing factor for five of the nine 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.
  - In many cases, severe congestion occurs when low-cost capacity is available to relieve the constraint but the low-cost capacity is unutilized because it is not instructed to ramp-up soon enough.
- External schedule changes were the most significant factor contributing to transient price spikes on the Dunwoodie-Shore Road line from the lines 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.
  - 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.

Power Balance Constraint Related (Statewide) Price Spikes

- Changes in generator output and external schedules were the most significant factors contributing to transient statewide price spikes in 2012, accounting for nearly 70 percent of the transient price spikes.
  - When gas turbines and other units are in the process of shutting-down, they may reduce output quickly. When decommitments are not staggered, it sometimes results in a transitory statewide price spikes.
    - RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut-down gas turbines.
    - Since RTC assumes other generation can ramp 15 minutes from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage.
    - However, when RTD solves each five-minute market interval, it is unable to delay the shut-down of a gas turbine even if it would be economic to do so.
    - Hence, it would be beneficial to: (a) adjust the timing of the look ahead evaluation of RTC so that it could anticipate when a de-commitment would lead to a five-minute shortage of ramp and (b) enable RTD to delay the shut-down of a gas turbine when it is economic to remain on-line.
  - Figure A-68 shows that external transaction schedules typically adjust in the real-time market in a direction that reduces the ramp requirements of internal generators, However, large adjustments in external transaction schedules in the export direction suddenly reduce supply and may lead to acute price spikes.
    - The "look ahead" evaluations in RTD and RTC evaluate system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange schedules ramp over ten minute periods from five minutes before the quarter-hour to five minutes after (i.e., from :55 to :05, from :10 to :20, etc.).
    - Hence, RTD and RTC generally perform well in scheduling resources in the first five minutes of each ten-minute external interchange ramp period. However, RTD and RTC do not anticipate transient shortages that occur in the second five minutes of each ten-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).
    - We recommend that the NYISO adjust the timing of the look ahead evaluations of RTD and RTC to be more consistent with the timing of significant operating factors, such as the ramp cycle of external interchange.
- Although relatively infrequent, transient price spikes are important because it can be far more costly to manage variations in system conditions that are unanticipated.
  - 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.

- Roughly 13 percent of total BMCR and 26 percent of total DAMAP accrued during the 1 percent of transient spike intervals in 2012.

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 three 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 uses a transmission demand curve to set real-time clearing prices during transmission shortages. Third, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the deployment 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
- Reliability demand response deployments.

Figure A-71: 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-71 summarizes ancillary services shortages and their effects on real-time prices in 2011 and 2012 for the following six categories:

- 30-minute NYCA – The ISO is required to hold 1,965 MW of 30-minute operating reserves in the state and has a demand curve value 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. [142]

- 10-minute NYCA – The ISO is required to hold 1,310 MW of 10-minute operating reserves in the state and has a demand curve value of $450/MWh. [143]

- 10-Spin NYCA – The ISO is required to hold 655 MW of 10-minute spinning reserves in the state and has a demand curve value of $500/MWh. [144]

- 10-minute East – The ISO is required to hold 1200 MW of 10-minute operating reserves in Eastern New York and has a demand curve value of $500/MWh.

- 30-minute Long Island – The ISO is required to hold typically 270-540 MW of 30-minute operating reserves in Long Island and has a demand curve value of $25/MWh.[145]

- 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.[146]

The top portion of the figure shows the frequency of shortages. The bottom portion shows the average shadow price during shortage intervals and the current demand curve level of the requirement. 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.

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142 The 30-minute NYCA requirement was 1,800 MW before June 27, 2012.

143 The 10-minute NYCA requirement was 1,200 MW before June 27, 2012, and the demand curve value was set to $150/MWh before May 19, 2011.

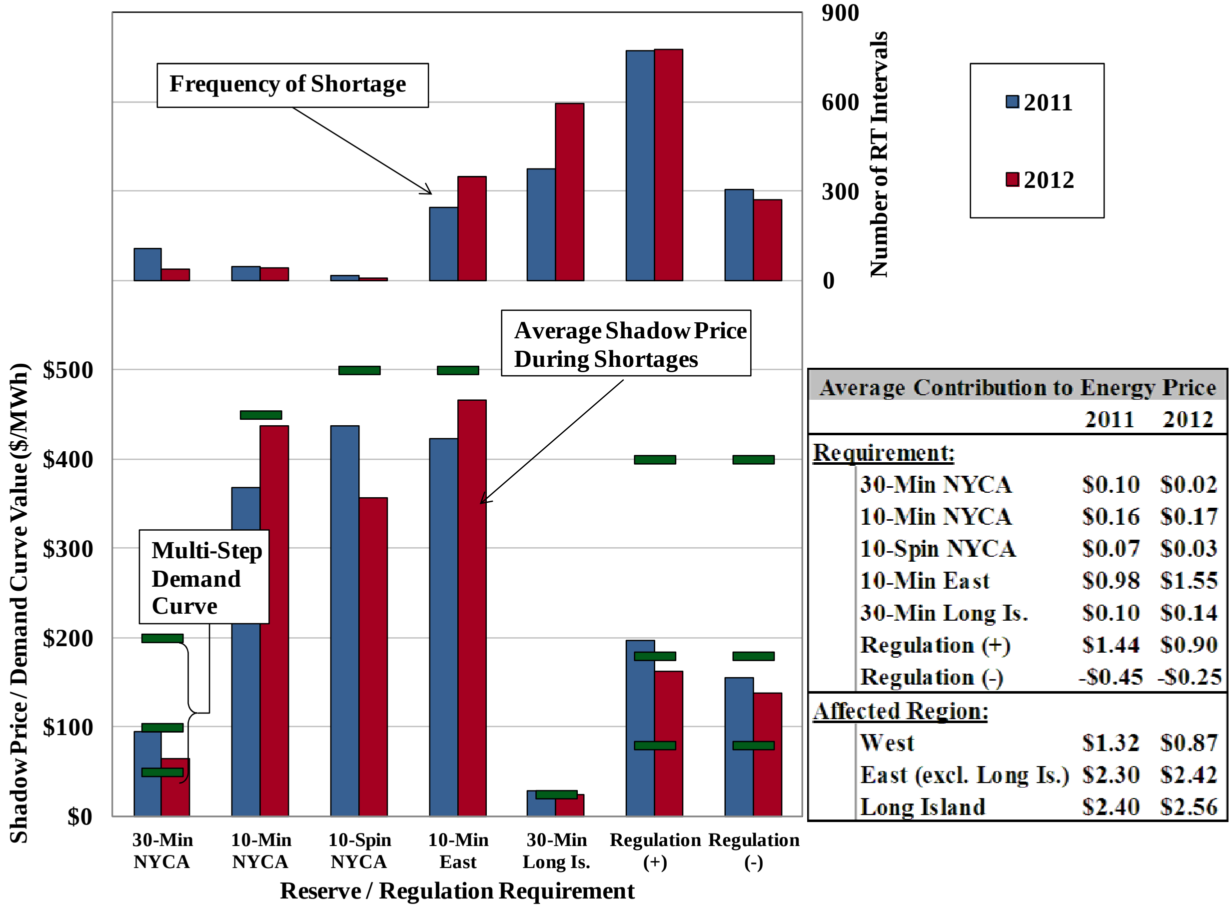
144 The 10-minute spinning NYCA requirement was 600 MW before June 27, 2012,

145 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.

146 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.

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

Figure A-71: Real-Time Prices During Ancillary Services Shortages
2011 - 2012



Average Contribution to Energy Price	2011	2012
Requirement:		
30-Min NYCA	$0.10	$0.02
10-Min NYCA	$0.16	$0.17
10-Spin NYCA	$0.07	$0.03
10-Min East	$0.98	$1.55
30-Min Long Is.	$0.10	$0.14
Regulation (+)	$1.44	$0.90
Regulation (-)	-$0.45	-$0.25
Affected Region:		
West	$1.32	$0.87
East (excl. Long Is.)	$2.30	$2.42
Long Island	$2.40	$2.56

Key Observations: Real-Time Prices During Ancillary Services Shortages

- The incidence of shortage conditions (i.e., the frequency and the average shadow cost of shortages) was comparable between 2011 and 2012 for most reserve products.
- Similar to 2011, ancillary services shortages with the largest effects on real-time prices during 2012 were: (a) 10-minute eastern reserve shortages; and (b) regulation shortages when supply was limited and the opportunity cost of ramp units down to provide regulation was high, leading to energy price spikes in the positive direction;
- Overall, real-time prices generally reflected system conditions accurately.[147]

[147] 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

- 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 equipments. 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 that can be started and brought online within 10 minutes. 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.[148] In such cases, the marginal cost of resources actually dispatched to relieve the constraint are lower than the shadow price set by the offline gas turbine (which is not actually started).

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

optimization is employed so that block loaded generators (i.e., gas turbines) are able to set the clearing price under certain circumstances.

148 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 does not satisfy the start-up requirement (i.e., economic for at least three intervals and scheduled at the full output level for all five intervals), it will not be instructed to start-up after RTD completes execution.

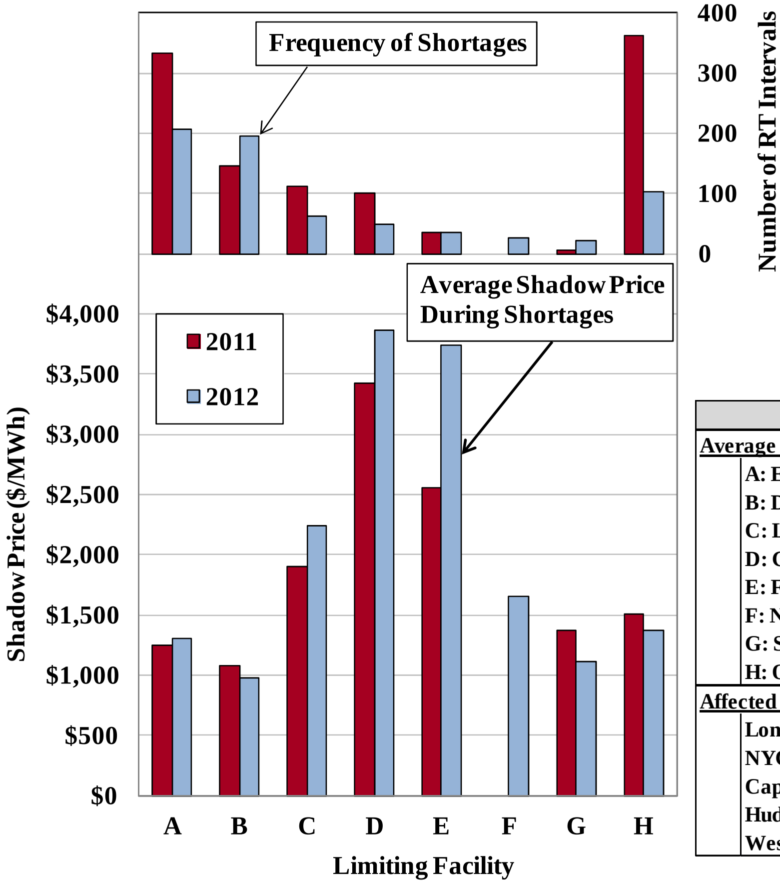
Figure A-72: Real- Time Prices During Transmission Shortages

Figure A-72 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: (a) a transmission constraint shadow price was $4,000 per MWh, or (b) a transmission constraint shadow price was greater than $500 per MWh and an offline GT was marginal and not started.

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.[149] 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-72: Real-Time Prices During Transmission Shortages

2011-2012



Price Set by Offline GT During Transmission Shortages in 2012		
	# of Intervals	Pct of Shortages
A	190	92%
B	196	100%
C	53	84%
D	3	6%
E	4	11%
F	25	93%
G	0	0%
H	96	93%

	2011	2012
Average Shadow Price During All Intervals:		
A: E. Garden City-Valley Stream	$3.94	$2.57
B: Dunwoodie-Shore Road	$1.48	$1.82
C: Leeds-Pleasant Valley	$2.04	$1.35
D: Greenwood-Vernon	$3.26	$1.80
E: Freshkills-Willowbrook	$0.87	$1.24
F: Niagara-Packard	$0.00	$0.43
G: Sprainbrook-E. Garden City	$0.08	$0.23
H: Other	$2.34	$0.17
Affected Zone:		
Long Island	$3.27	$2.83
NYC	$1.93	$0.87
Capital	$0.34	$0.12
Hudson Valley	$1.05	$0.52
West	-$0.07	$0.16

149 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.

Key Observations: Real-Time Prices During Transmission Shortages

- The East Garden City-to-Valley Stream line ("EGVS" line), the Dunwoodie-to-Shore Road transmission line ("DSR" line), and the Leeds-to-Pleasant Valley transmission line ("LPV" line) exhibited the most significant transmission shortages in both 2011 and 2012.
  - Much of the severe congestion on the LPV line occurred during TSAs that substantially reduce available transfer capability on this path and lead to shortages.
  - Severe congestion across the EGVS and DSR lines frequently occurred because of ramping limitations on Long Island. These ramp limitations generally bind when large hourly schedule changes across the interfaces between Long Island and external markets or during the periods when gas turbines were turned off.
  - Much tighter supply conditions on Long Island in 2012 due to the lengthy Neptune Cable outage and multiple retirements contributed to increased transmission shortages across these two lines from 2011 to 2012.
- Overall, downstate areas experienced the most significant price impacts from these likely transmission shortages in 2012.
  - In New York City, the total price impact was \$0.87/MWh on average in 2012, roughly 60 percent of which was caused by the LPV shortages.
  - In Long Island, the total price impact was \$2.83/MWh on average in 2012, nearly 65 percent of which was caused by the DSR shortages.
- An offline gas turbine was scheduled (i.e., counted towards resolving the constraint) and was a marginal resource but was not actually started in 84 percent of all likely transmission shortage intervals in 2012. Hence, the primary mechanism for setting prices during shortage intervals is with offline gas turbines.

H. Real-Time Prices During Reliability Demand Response Deployments

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 reliability demand response resources are deployed.

NYISO deployed demand response (EDRP and SCRs) on six days during 2012:

- On May 29, SCR and EDRP resources were deployed in all zones from 1:00 pm to 6:00 pm (HB 13 – HB 17) for forecasted reserve shortages.

- On June 20, SCR and EDRP resources were deployed from 2:00 pm to 6:00 pm (HB 14 – HB 17) in zones G through J for transmission security in Southeast New York and in zone C for voltage support.

- On June 21, SCR and EDRP resources were deployed in: a) zones G through K for transmission security, and b) zones A through F for Rochester transformer loadings (zone B), voltage support (zone C), and statewide capacity requirements.

- On June 22, SCR and EDRP resources were deployed in zones G through K from 1:00 pm to 6:00 pm (HB 13 – HB 17) for transmission security.

- On July 17, SCR and EDRP resources were deployed in zone B from 2:00 pm to 6:00 pm (HB 14 – HB 17) to reduce Rochester 345/115 kV transformer loadings.

- On July 18, SCR and EDRP resources were deployed in zone J from 1:00 pm to 6:00 pm (HB 13 – HB 17) and zones G, H, I, K from 2:00 pm to 6:00 pm (HB 14 – HB 17) for forecasted reserve shortages and transmission security in Southeast New York.

Figure A-73 – Figure A-75: Evaluation of Reliability Demand Response Deployments

The following analysis evaluates two aspects of market outcomes on the days when demand response resources were deployed:

- The amount of demand response that was deployed compared with the amount of resources that were ultimately available in each real-time interval during the event.

- Whether real-time energy prices reflected the costs of deploying demand response to maintain reliability given that most SCR and EDRP resources are paid $500 per MWh to curtail their load.

Figure A-73 summarizes system conditions in NYCA during the two deployments on May 29 and June 21, 2012. Figure A-74 and Figure A-75 summarize system conditions in Southeast New York during four deployments on June 20, 21, 22 and July 18, 2012. These three figures report the following quantities in each interval during the events for selected regions:

- The Quantity of Demand Response Resources that were reported by RIPs as responding;[150]

- The Available Internal Capacity in real-time, which includes unloaded capacity of online units and the capacity of offline peaking units up to the unit's Upper Operating Limit

150 These are estimates provided by Responsible Interface Parties ("RIPs") in response to event notification, which are also used as the inputs for the Scarcity Pricing Rule. These numbers are different from the enrolled MWs or the response MWs estimated by the NYISO based on metering information. See Market Issues Working Group meeting presentation for July 19, 2012, *EDRP/SCR Scarcity Pricing Outcomes: May 29th, June 20th, June 21st, June 22nd*.

("UOL") and excludes capacity required for ancillary services in the NYCA (i.e., statewide) figure;

- The recallable External ICAP Energy sales, which is the amount of scheduled exports that are considered as available reserves in the current Scarcity Pricing software;
- The LBMP of the least import-constrained zone in the region that was secured by the demand response deployment (i.e., the West Zone for the statewide deployments and the Millwood Zone for the Southeast New York deployments). LBMPs higher than $500 per MWh are shown as $500 per MWh; and
- Whether the interval was affected by the Scarcity Pricing Rules, which are applied when the DR deployment prevents a statewide or eastern reserve shortage (based on the criteria in Section 17.1.2 of the Market Service Tariff).

Figure A-73: RT Prices and Available Capacity During Reliability DR Deployments
NYCA, May 29 and June 21, 2012

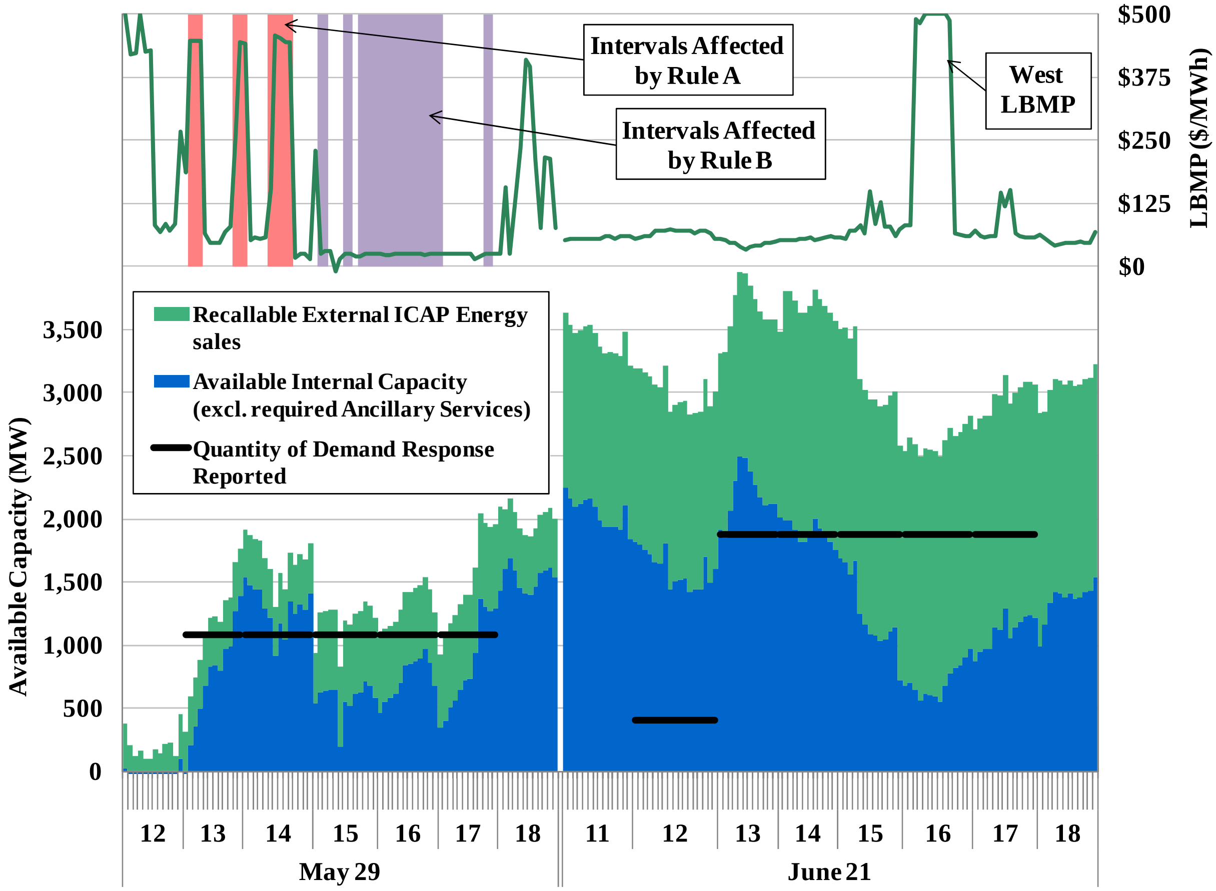


Figure A-74: RT Prices and Available Capacity During Reliability DR Deployments
Southeast New York, June 20-22, 2012

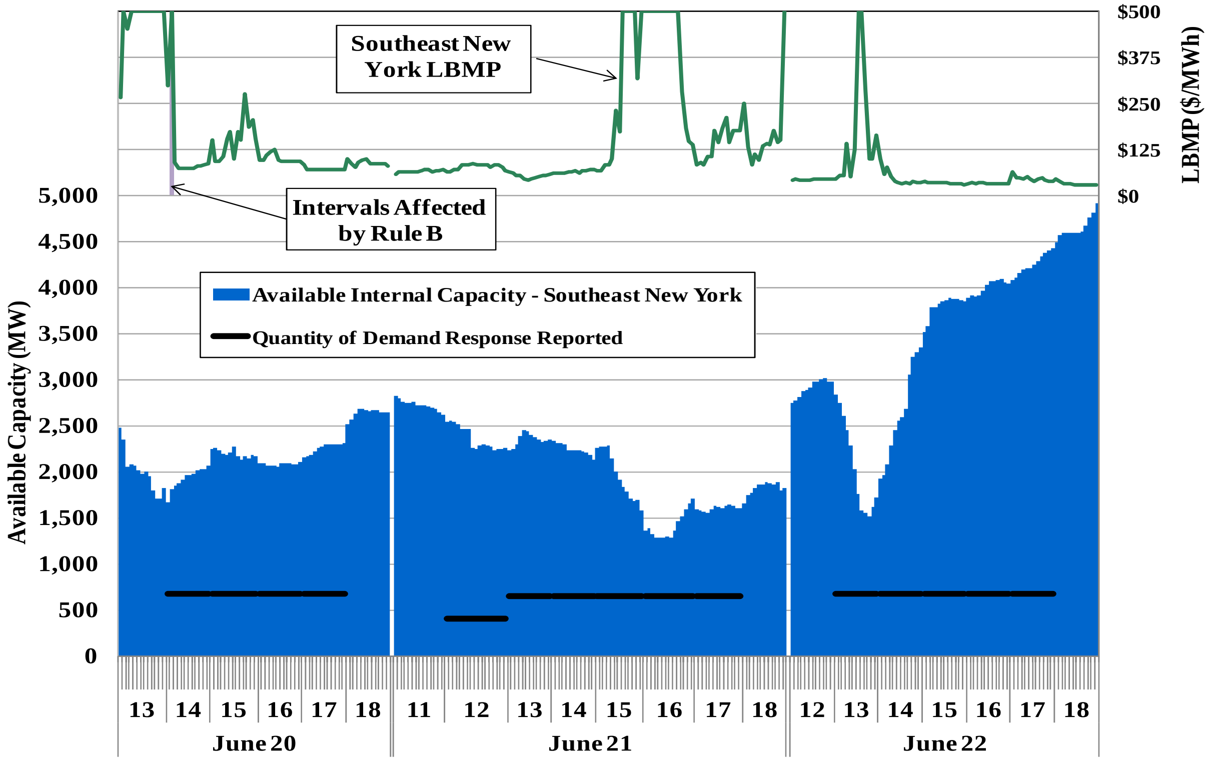


Figure A-75: RT Prices and Available Capacity During Reliability DR Deployments
Southeast New York, July 18, 2012

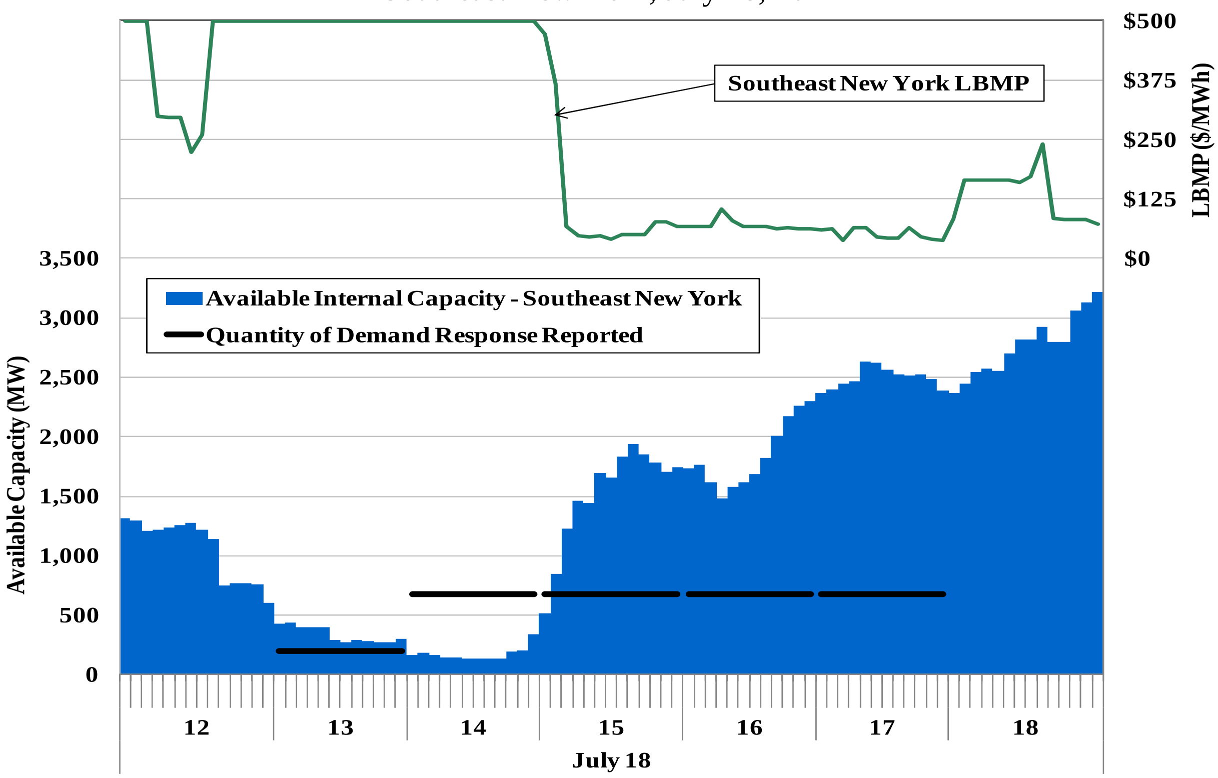


Figure A-76: Variations in Supply and Demand During Reliability DR Deployments

The system often exhibits large variations in the 5-minute real-time LBMPs during reliability demand response deployments. In the real time, most generators respond to 5-minute dispatch instructions, while other supply and demand factors are not dispatchable (e.g., load, net imports, etc.). Hence, large variations in the 5-minute RT LBMPs are usually driven by large changes in load and other inflexible factors.

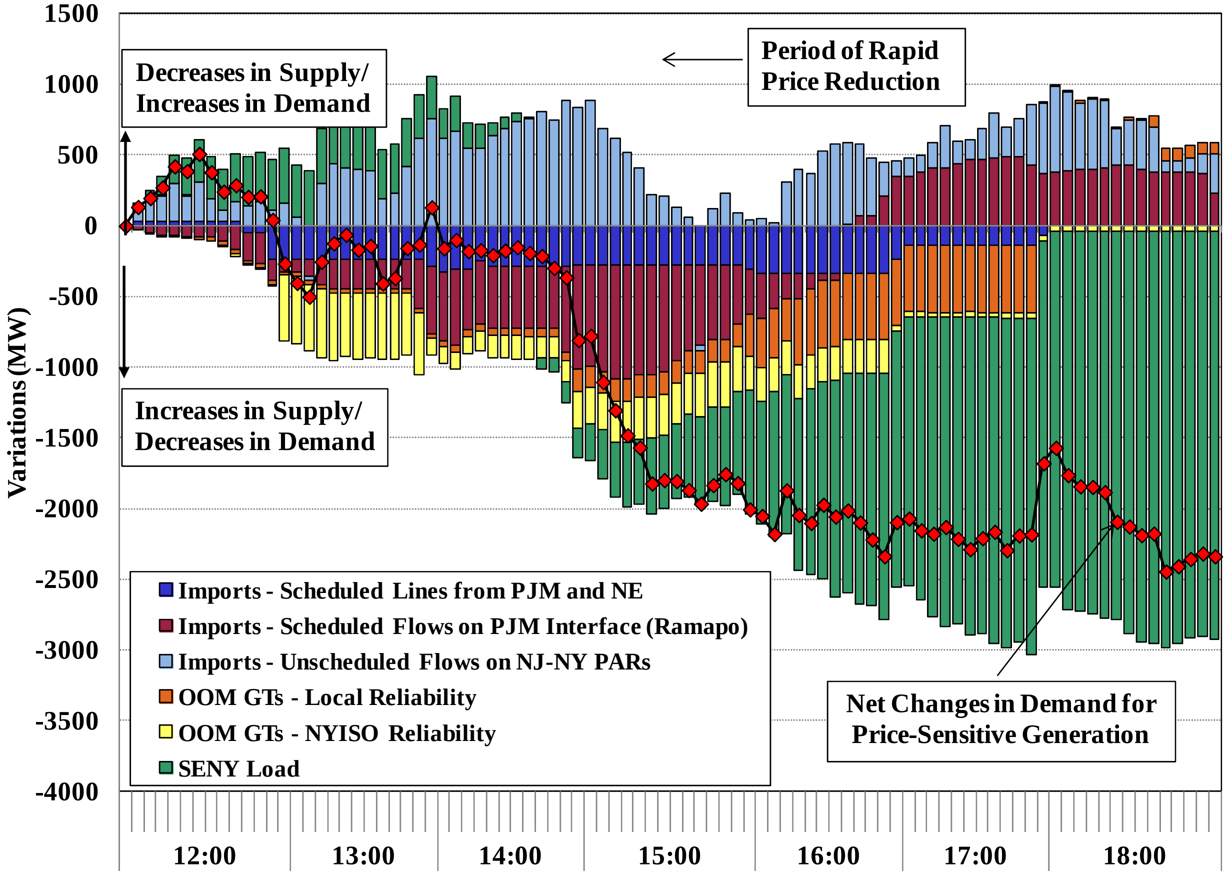
The following analysis examines the factors that contribute to large changes in real-time LBMPs during a demand response deployment. July 18, 2012 was a day when the system was initially in shortage during the demand response deployment but subsequently became relatively unconstrained during the latter portion of the deployment. This day provides a good example of how market conditions can change dramatically in a relatively brief period of time during such events.

Figure A-76 summarizes the changes in supply and demand that contributed the most to price variations during reliability demand response deployments in Southeast New York on July 18, 2012. The figure shows the cumulative impact of these supply and demand variations in each interval relative to start of the examined period at 12:00 pm (noon) by summarizing real-time variations in the following factors:

- Load in Southeast New York – including effects of demand response deployment.
- Net imports across the Scheduled Lines from PJM and ISO-NE – including net imports across the 1385 line, the Cross Sound Cable, and the Linden VFT.
- Scheduled flows across the primary PJM interface into SENY – including the portion of net imports expected to flow into SENY across the Ramapo line.
- Unscheduled flows on the PAR-controlled lines between NJ and NY – The total difference between actual and expected flows into SENY on ABC, JK, & Ramapo.
- GTs committed OOM for local reliability & GTs OOM for NYISO reliability.

In the figure, positive MW values indicate increases in demand or decreases in supply, which tend to contribute to higher LBMPs and negative MW values indicate decreases in demand or increases in supply, which tend to contribute to lower LBMPs. The figure does not show the effect of the TSA, which began at 12:30 and reduced flows into Southeast New York from the rest of Upstate New York.

Figure A-76: Variations in Supply and Demand During Reliability DR Deployments
Southeast New York, July 18, 2012



Key Observations: Reliability Demand Response Deployments

- On May 29 and June 21, the NYISO deployed reliability demand response resources every zone to maintain adequate reserves statewide.
  - Immediately after the deployment of demand response, the amount of available internal capacity rose and LBMPs fell substantially.
  - The amount of demand response deployed exceeded the available internal capacity in nearly all intervals. However, statewide Scarcity Pricing (i.e., Rule A) was not invoked in most of these intervals partly due to the large contribution of "recallable External ICAP Energy sales" on these days.
- On June 20 and 22, the NYISO deployed reliability demand response resources in Zones G through K (Zone K was not called on June 20) to maintain the security of transmission lines into Southeast New York.
  - The available internal capacity in Southeast New York exceeded the amount of demand response by more than 1 GW all afternoon on both days, resulting in relatively low LBMPs in most intervals.

- On June 20, the large margin of available capacity was primarily due to the requirement for NYISO to commit sufficient resources to secure Southeast New York based on N-1-1 (i.e., two contingency) criteria, while less stringent N-1 criteria was required in the real-time dispatch.
- On June 22, the large margin of available capacity was primarily due to an unexpected reduction in load after a change in the weather pattern.

• On July 18, the NYISO deployed reliability demand response resources in Zones G through K for forecasted reserve shortages and to maintain the security of transmission lines into Southeast New York.

- A TSA was in effect from 12:30 to 19:10 on this day. In the initial phase of the TSA (HB 13 & 14), the deployment of demand response allowed the NYISO to maintain sufficient resources in Southeast New York – available capacity was less than the demand response called and LBMPs exceeded $500 per MWh throughout both hours.
- From HB 15 to 17, the amount of available capacity in Southeast New York rose considerably, exceeding the amount of demand response by more than 1 GW during most of the three hours.
- The pattern of load was unusual on this day as Figure A-76 shows that net demand rose by 200 MW between noon and 14:50, but then fell by a total of almost 2000 MW by 15:30, explaining the increase in available capacity shown in Figure A-75.
- Figure A-76 shows that the following factors changed most significantly between 14:50 and 15:30, contributing to the substantial reduction in net demand and LBMPs:
  - Load fell approximately 420 MW due to a sudden change in weather patterns;
  - Scheduled imports across the primary interface with PJM expected to flow into SENY (i.e., expected Ramapo flows) rose approximately 245 MW;
  - Unscheduled across the PAR-controlled lines Jersey approximately 620 MW;
  - 240 MW of GTs were kept online OOM after the decline in LBMPs.

• LBMPs were relatively low (less than $100 per MWh) during most hours when demand response was deployed on these days, well below the marginal cost of maintaining reliability since most demand response resources are paid $500 per MWh to curtail.

- As illustrated for the event on July 18, a) changes in load levels due to a sudden change in weather patterns, b) changes in unscheduled flows from New York across the PAR-controlled lines into New Jersey, and c) kept-on OOM capacity led to a rapid increase in excess supply and a corresponding drop in LBMPs.

• The use of demand response resources is limited by scheduling lead times and other inflexibilities.

  - The NYISO must determine how much demand response to deploy when there is still considerable uncertainty about the needs of the system, and the demand response may not be needed for the entire duration of the deployment period.
  - Hence, the inflexibility of DR resources can lead NYISO to deploy an amount of DR that results in substantial excess capacity during a portion of the event.
  - Moderating the quantities of DR that are deployed would help ensure that LBMPs better reflect the cost of maintaining reliability and that uplift charges are minimized. This might be possible by:
    - Market design changes that enable some DR resources to be scheduled more flexibly (i.e., with shortened lead times and/or shut-down periods); and
    - Staggering the timing of the deployment of DR resources (to the extent possible).
- The NYISO is planning to modify the real-time scarcity pricing methodology to allow reliability demand response resources to set prices at $500/MWh under a broader set of circumstances.
  - Real-time prices are set at $500/MWh when the deployment of reliability demand response prevents a statewide 30-minute reserve shortage or an eastern 10-minute reserve shortage.
  - The proposed changes would allow demand response to set prices in any area of the bulk power system where their deployment enables the NYISO to avoid a shortage of energy or reserves.[151]

I. Supplemental Commitment and Out of Merit Dispatch

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. Similarly, the NYISO and local transmission owners sometimes dispatch generators out of merit order ("OOM") in order to: (a) manage constraints of high voltage transmission facilities that are not fully represented in the market model; or (b) maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is frequently uneconomic, which displaces production from economic capacity. Both types of out-of-market action lead to distorted real-time market prices, which tend to undermine market incentives for meeting

151 http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2012-12-18/agenda_07_Enhanced%20Scarcity%20Pricing.pdf, Dec. 18, 2012 Management Committee materials.

reliability requirements and generate expenses that are uplifted to the market. Hence, it is important for supplemental commitments and OOM dispatches 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: (a) supplemental commitment for reliability and focus particularly on New York City where most reliability commitments occur; and (b) the patterns of OOM dispatch in several areas of New York. 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-77: Supplemental Commitment for Reliability in New York

Supplemental commitment occurs when a generator is not committed by the economic pass of the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways: (a) Day-Ahead Reliability Units ("DARU") Commitment – typically occurs at the request of local Transmission Owner prior to the economic commitment in SCUC; (b) Day-Ahead Local Reliability ("LRR") Commitment – takes place during the economic commitment pass in SCUC to secure reliability in New York City; and (c) 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: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) 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 NYC, 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 outside 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-77 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 2011 and 2012. 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 Forecast Pass, represents the additional commitment in the forecast pass of SCUC 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: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The table in the figure summarizes these values for 2011 and 2012 on an annual basis.

Figure A-77: Supplemental Commitment for Reliability in New York
By Category and Region, 2011 – 2012

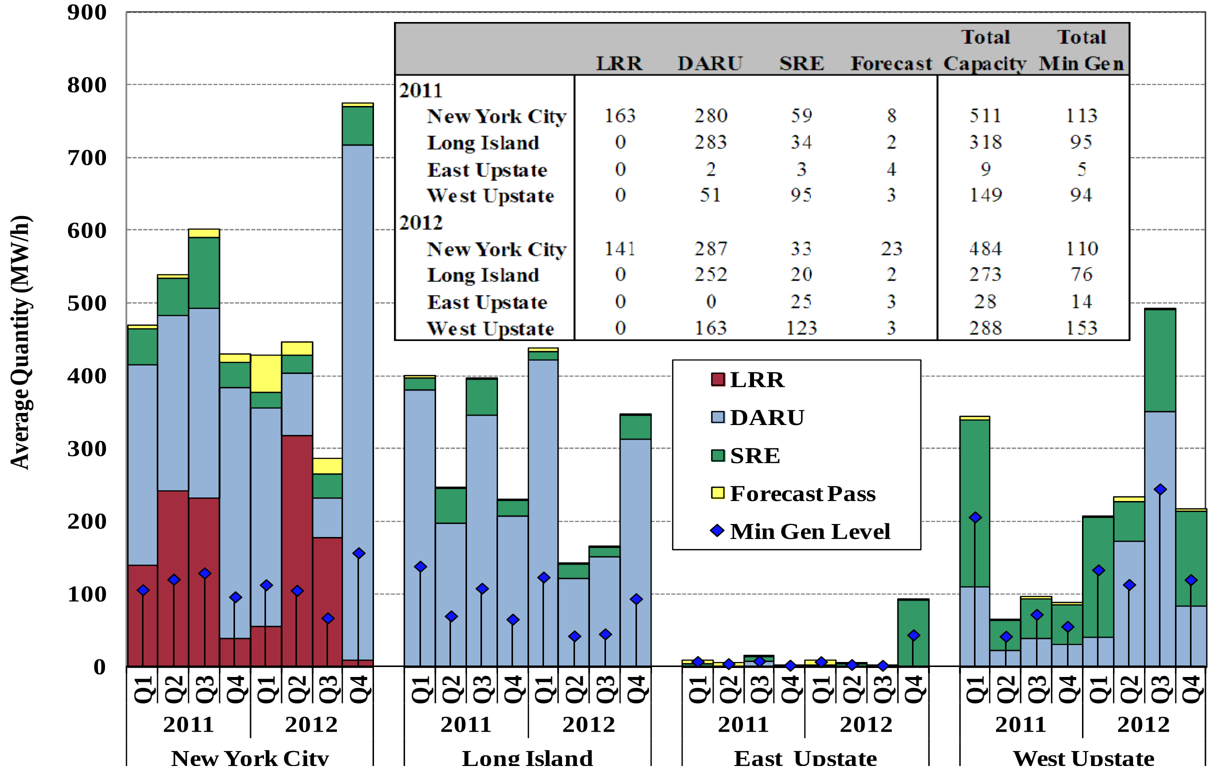


Figure A-78: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City in 2011 and 2012. The next analysis identifies the causes for the reliability commitments in this area. Figure A-78 shows the minimum generation committed for reliability by commitment reason and by location in New York City during 2011 and 2012.

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 as committed for one of the following reliability reasons: [152]

- 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.

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

- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, and 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 for 2012 only.

Figure A-78: Supplemental Commitment for Reliability in New York City
By Category and Region, 2011 - 2012

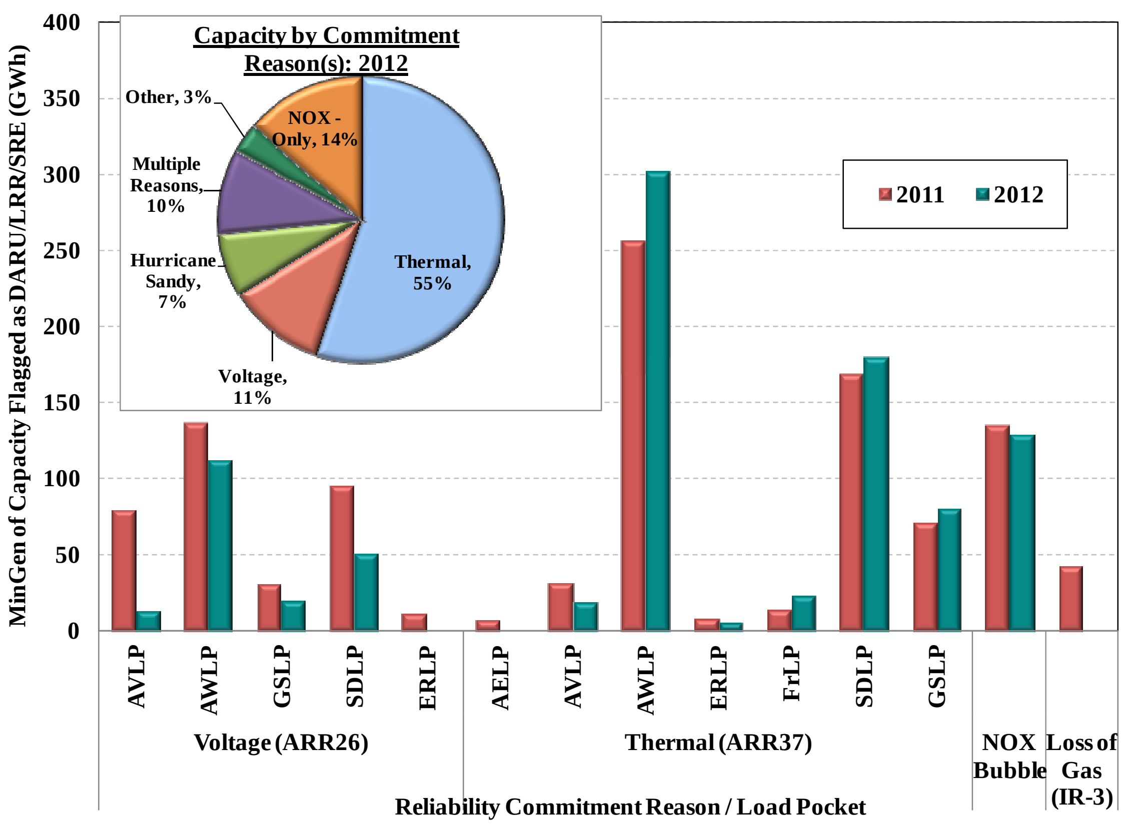
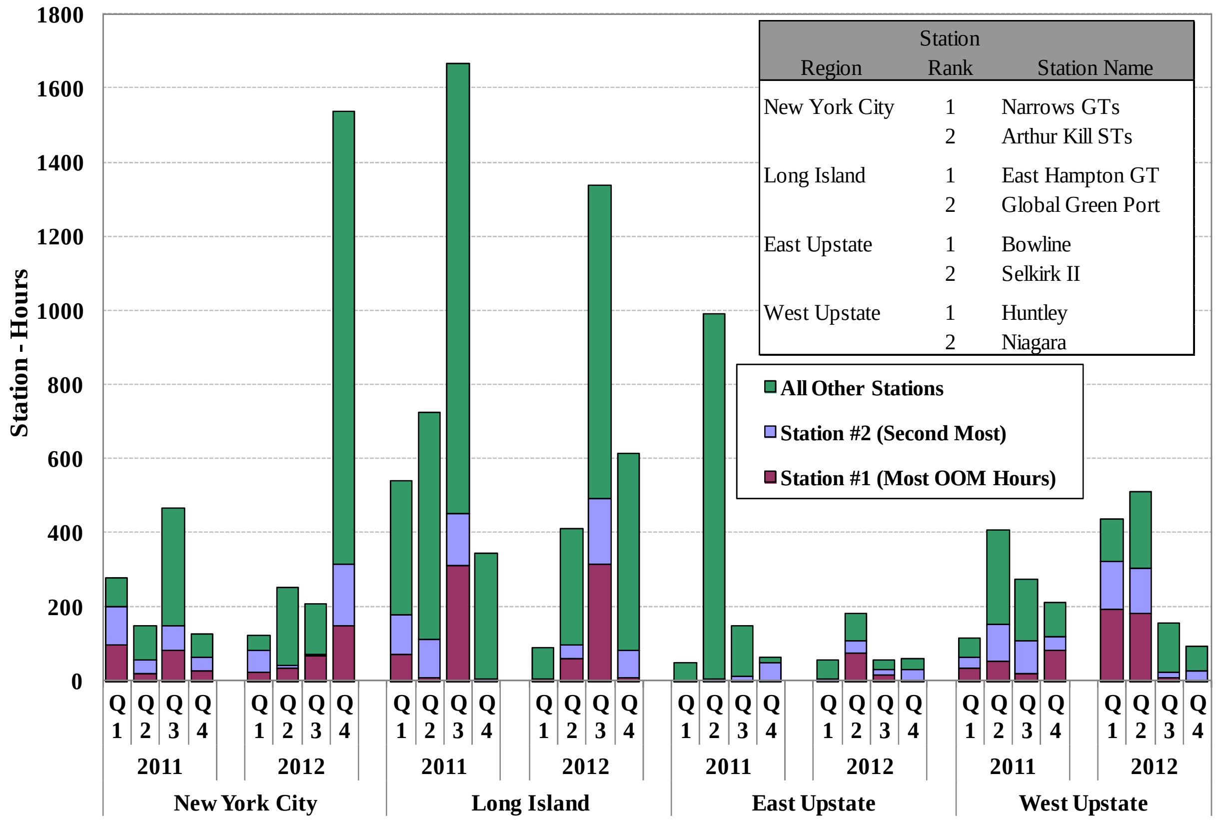


Figure A-79: Frequency of Out-of-Merit Dispatch

Figure A-79 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2011 and 2012 for the following four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K.

In each region, the two stations with the highest number of OOM dispatch hours during 2012 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2012, and "Station #2" is the station with the second-highest number of OOM hours). The figure also excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.

Figure A-79: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2011-2012



Key Observations: Supplemental Commitment and OOM Dispatch for Reliability

- Nearly 1,100 MW of capacity was committed on average for reliability in 2012, up modestly from 2011. Of this total, 45 percent of reliability commitment was in New York City, 25 percent was in Long Island, and 27 percent was in Western New York.

- Reliability commitment in Western New York averaged 290 MW in 2012, up 93 percent from 2011 because several coal units that are frequently needed for reliability were economically committed less often due to lower natural gas prices.

- Reliability commitment in Long Island fell modestly from an average of 320 MW in 2011 to an average of 275 MW in 2012.
  - Units that are frequently needed for local reliability were committed economically more often because of the higher LBMPs after the Neptune outage and several generator retirements.
- Reliability commitment in New York City averaged 485 MW in 2012, down slightly from 2011. The reduction in local reliability need was driven by: (a) increased generating supply in the City (550 MW Astoria Energy II generating facility in July 2011 and 520 MW Bayonne facility in June 2012); (b) new transmission facilities into Astoria East and at the Gowanus 345kV sub-station; and (c) changes in generator offer patterns and reference levels.
  - However, the reduction was offset by the notable increase in DARU commitments in the fourth quarter.
    - In October, the amount of DARU capacity rose considerably when a large generator was committed by the TO for 345 kV transmission security (in case the largest two contingencies were to occur) on every day before Hurricane Sandy reached New York on the 29th.
      - We performed an evaluation of whether sufficient capacity would have been available from other DAM-committed generators, non-spinning reserve units, and in-service transmission facilities to satisfy the N-1-1 criteria, and found that sufficient capacity would have been available on every day except October 6. However, our assessment may not include all of the relevant assumptions since the local TO is not required to provide a detailed description of the assumptions underlying each DARU commitment.
      - The TO also indicated specifically that the generator was needed for 345kV voltage support on October 6, 7, & 8 during transmission outage conditions, although the generator was likely needed for voltage support on other days during the period as well.
    - In November, supplemental commitments increased due to a large number of transmission and generation outages resulting from Hurricane Sandy.
  - Slow-start units were committed unnecessarily in the Forecast Load Pass at times when offline fast-start units were available, although these commitments produced little uplift. The NYISO implemented a modeling enhancement in the fourth quarter to help reduce such unnecessary commitments.
- The reliability requirements that accounted for the most MWhs of capacity in New York City during 2012 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. Although these were reduced by the addition of new capacity in the 345kV system, the overall amount of capacity committed for this reason did not fall from 2011 to 2012 due to the increased supplemental commitment in the fourth quarter of 2012.
  - 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 sometimes displaces generation from newer cleaner generation in the city and from imports to the city.
- Long Island accounted for the largest share of OOM station-hours in both 2011 (50 percent) and 2012 (40 percent).
  - Most was called to manage local reliability on the East End of Long Island during high load conditions, particularly in the third quarter.
  - Overall, OOM dispatch fell roughly 25 percent from 2011 to 2012, since units needed for reliability were more often inframarginal in 2012 due to the higher LBMP levels that resulted from the lengthy Neptune outage and multiple generator retirements.
- New York City accounted for 35 percent of OOM station-hours in 2012, up from 15 percent in 2011.
  - Units were often OOMed by the local Transmission Owner to secure lines on the 138 kV system typically following significant unit or transmission outages, or to manage NYISO security and reliability on days with high loads and/or during TSA events.
  - OOM actions were less frequent in the first three quarters of 2012, partly due to the addition of new generation and new transmission facilities in the city.
  - However, in the fourth quarter of 2012, units were frequently dispatched OOM in the days following Hurricane Sandy, accounting for the overall increase in 2012.
- Western New York accounted for 20 percent of OOM station-hours in 2012.
  - Huntley and Niagara units, which were often dispatched OOM by the NYISO to manage congestion on 230 kV lines in the West Zone, accounted for more than half of all OOM station-hours in Western New York.
  - The NYISO implement improved constraint modeling of these lines in the day-ahead and real-time markets in May 2012, which substantially reduced OOM dispatch and the related uplift charges.

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-80 and Figure A-81 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 total of their as-bid costs (includes start-up, minimum generation, and incremental costs). 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.

- 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; b) imports that are scheduled with an offer price greater than the real-time LBMP; and c) demand response resources (i.e., EDRP/SCRs) that are deployed for system reliability.

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

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-80 & Figure A-81: Uplift Costs from Guarantee Payments

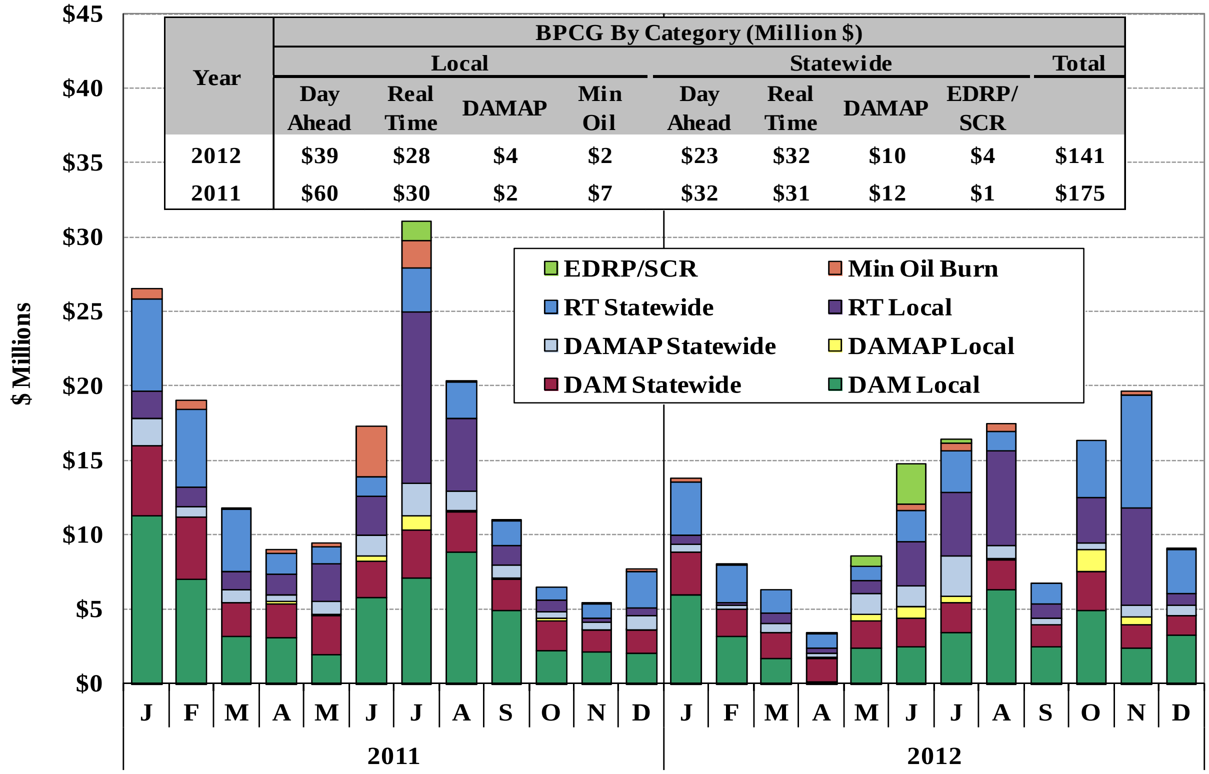
Figure A-80 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2011 and 2012. The uplift costs associated with the EDRP/SCR resources are shown separately from other real-time statewide uplift costs. The table summarizes the total uplift costs under each category on an annual basis for these two years.

Figure A-81 shows the seven categories of uplift charges on a quarterly basis in 2011 and 2012 for four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The uplift costs paid to import transactions from neighboring control areas and EDRP/SCR resources are shown separately from the generation resources in these four regions in the chart. The table summarizes the total uplift costs in each region on an annual basis for these two years.

It is also noted that Figure A-80 and Figure A-81 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.

Figure A-80: Uplift Costs from Guarantee Payments by Month

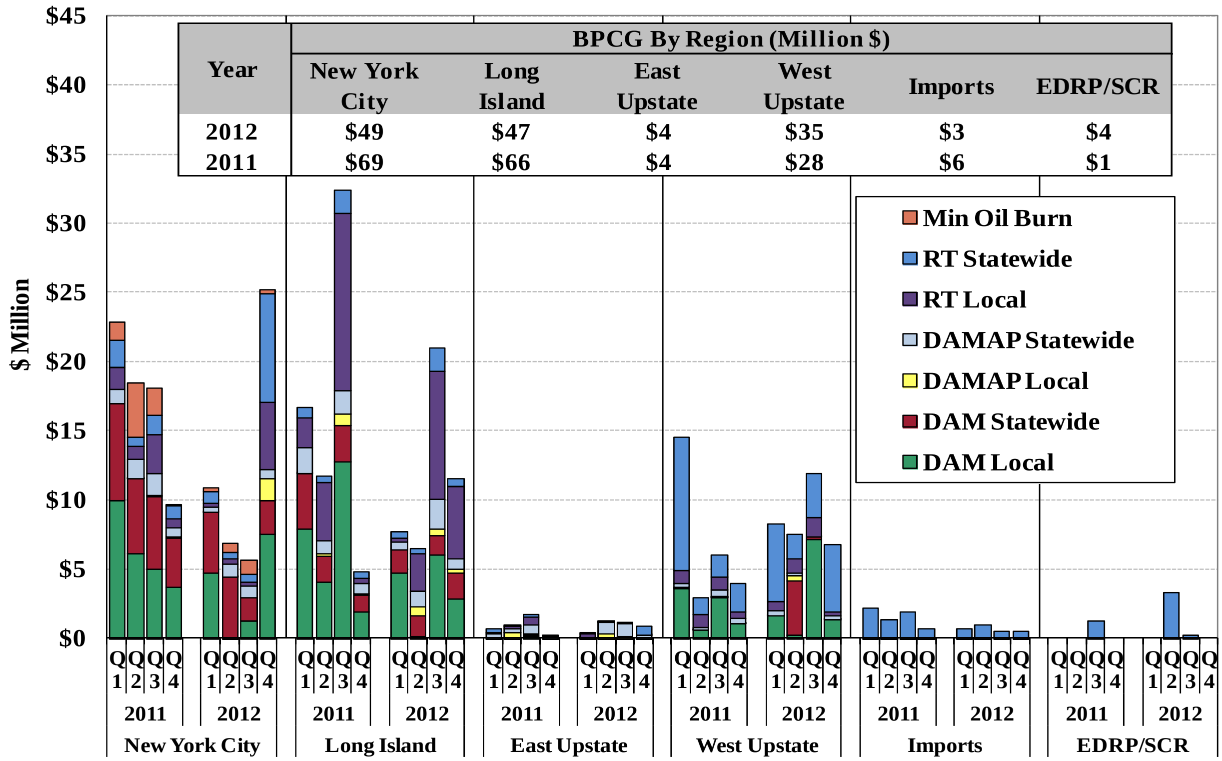
2011 – 2012



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2012	$39	$28	$4	$2	$23	$32	$10	$4	$141
2011	$60	$30	$2	$7	$32	$31	$12	$1	$175

Figure A-81: Uplift Costs from Guarantee Payments by Region

2011 – 2012



Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/SCR
2012	$49	$47	$4	$35	$3	$4
2011	$69	$66	$4	$28	$6	$1

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell 19 percent, from $175 million in 2011 to $141 million in 2012. Day-ahead uplift fell $30 million, accounting for the majority of the overall reduction.
  - Lower natural gas prices decreased the commitment costs of gas-fired units that were needed for reliability.
  - Improved accuracy of generator reference levels also contributed to the overall reduction in uplift.
- Of the total guarantee payment uplift in 2012:
  - Local reliability uplift accounted for 52 percent, while non-local reliability uplift accounted for the remaining 48 percent.
  - New York City accounted for 35 percent, Long Island accounted for 33 percent, and Western New York accounted for 25 percent.
- Uplift costs fell roughly $20 million each in New York City and Long Island in 2012, while uplift costs in Western New York rose $7 million in 2012. .
  - The reductions and increases in uplift in these regions were consistent with the changes in reliability commitments and OOM dispatches from 2011 to 2012, which were discussed in detail in the prior sub-section.
- Long Island accounted for approximately 65 percent of real-time local reliability uplift in both 2011 and 2012.
  - 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.

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.[153] 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.[154]

Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates known as Derating Factors.[155] 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

153 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM increased from 15.5 percent in the period from May 2011 to April 2012 to 16 percent in the period from May 2012 to April 2013. NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp".

154 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 101.5 percent in the period from May 2011 to April 2012 and 99 percent in the period from May 2012 to April 2013. The New York City LCR was 81 percent in the period from May 2011 to April 2012 and 83 percent in the period from May 2012 to April 2013. Each IRM Report recommends Minimum LCRs for New York City and Long Island, which the NYISO considers before issuing recommended LCRs in its annual Locational Minimum Installed Capacity Requirements Study, which may be found at "http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp".

155 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 ("EFORd") of 7 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. For each locality, a Derate Factor is calculated from the six most recent 12-month rolling average EFORd values of resources in the locality in accordance with Sections 2.5 and 2.7 of the NYISO's Installed Capacity Manual.

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 locality in each monthly UCAP spot auction.[156] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction may purchase more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

Every three years, the NYISO updates the capacity demand curves. The demand curves are set so that the demand curve price equals the levelized cost of a new peaking unit (net of estimated energy and ancillary services revenue) when the quantity of UCAP procured exceeds the UCAP requirement by a small margin. The demand curve price equals $0 when the quantity of UCAP procured exceeds the UCAP requirement by 12 percent for NYCA and 18 percent for New York City and Long Island. The demand curve is defined as a straight line through these two points.[157]

To evaluate the performance of the capacity market, the figures in this section show capacity market results from May 2011 through February 2013. The figures summarize the categories of capacity supply and the quantities purchased in each month in UCAP terms as well as the clearing prices in the monthly spot auctions. The first sub-section evaluates NYCA overall, and the second sub-section evaluates the performance in the local capacity zones.

A. Capacity Market Results: NYCA

Figure A-82: Capacity Sales and Prices in NYCA

Figure A-82 show capacity market results in the 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.[158] 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-82 shows sales

156 The capacity demand curves are not used in the forward strip auction and the forward monthly auction. The clearing prices in these two forward auctions are determined based on market participants' offers and bids.

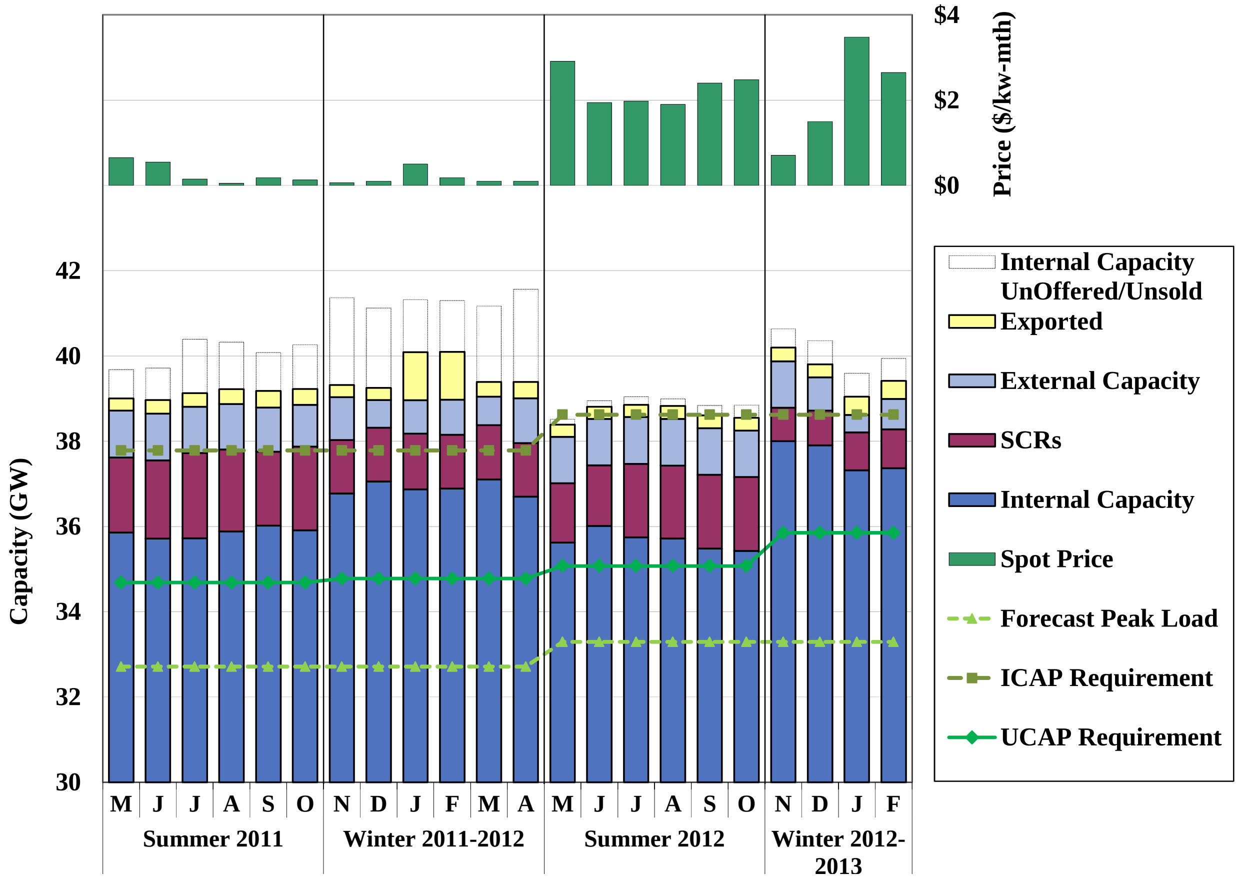
157 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the period from May 2011 to April 2014 may be found in NYISO MST 5.14.1.2. The demand curves are defined as a function of the UCAP requirements in each locality, which may be found at "http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do".

158 Special Case Resources ("SCRs") are Demand Side Resources whose Load is capable of being interrupted upon demand, and/or Demand Side Resources that have a Local Generator , which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the NYISO.

from external capacity resources into NYCA and exports of internal capacity to other control areas. The upper portion of the figure shows clearing prices in the monthly spot auctions for NYCA (i.e., the Rest of State).

The capacity sales and requirements in Figure A-82 are shown in the UCAP terms, which reflect the amount of resources available to sell capacity. The changes in the UCAP requirements are affected by changes in the forecasted peak load, the minimum capacity requirement, and the Derating Factors. To better illustrate these changes over the examined period, Figure A-82 also shows the forecasted peak load and the ICAP requirements.

Figure A-82: UCAP Sales and Prices in NYCA
May 2011 to February 2013



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.
- The spot price rose sharply in 2012, averaging $2.27/kW-month in the Summer 2012 Capability period and $2.09/kW-month in the Winter 2012-13 Capability period

(excluding March and April 2013), compared to less than $0.65/kW-month in each month during the previous Capability Year.

- These price increases were due to significant changes in both capacity requirements and the supply of capacity. The following changes in requirements affected statewide capacity prices in 2012:[159]
  - The ICAP Requirement rose 839 MW (2.2 percent), which was due to:
    - a 1.8 percent increase in the peak load forecast; and
    - an increase in the IRM from 15.5 percent to 16 percent.
  - However, the UCAP Requirement rose just 392 MW (1.1 percent) because the Derating Factor for NYCA rose by 1.0 percent.
  - In the short-term, spot capacity prices are affected most by the ICAP Requirement in each locality (as opposed to the UCAP Requirement), since variations in the Derating Factor closely track variations in the EFORd values of the resources.
    - However, in the long-term, higher Derating Factors tend to increase the IRM and the LCRs because the IRM Report incorporates EFORd values on a five-year rolling average basis.
- The following changes in supply also affected the statewide capacity market results:
  - Sales from internal resources fell 1.8 GW because of the retirement and mothballing of generation, including:
    - 550 MW in New York City in May 2012,
    - 330 MW on Long Island in July 2012,
    - 370 MW in Western New York in September 2012, and
    - 500 MW in Hudson Valley in January 2013.
  - Sales from SCRs fell over 200 MW from the Summer 2011 to the Summer 2012 following recent changes in the baseline calculation method (i.e., adopting the Average Coincident Load method).
  - These factors were partly offset by the entry of new resources in New York City in July 2011(550 MW) and June 2012 (500 MW).

159 ICAP Requirements are fixed for an entire capability year, so the same requirements were used in the 2011/12 and 2012/13 Capability Periods. UCAP Requirements are fixed for a six-month capability period, since the Derating Factor for each locality is updated every six months.

B. Capacity Market Results: Local Capacity Zones

Figure A-83 & Figure A-84: Capacity Sales and Prices in NYC and Long Island

Figure A-83 and Figure A-84 show capacity market results in New York City and Long Island for the past four capability periods. It shows the same quantities as Figure A-82 does for the NYCA region. In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-83: UCAP Sales and Prices in New York City
May 2011 to February 2013

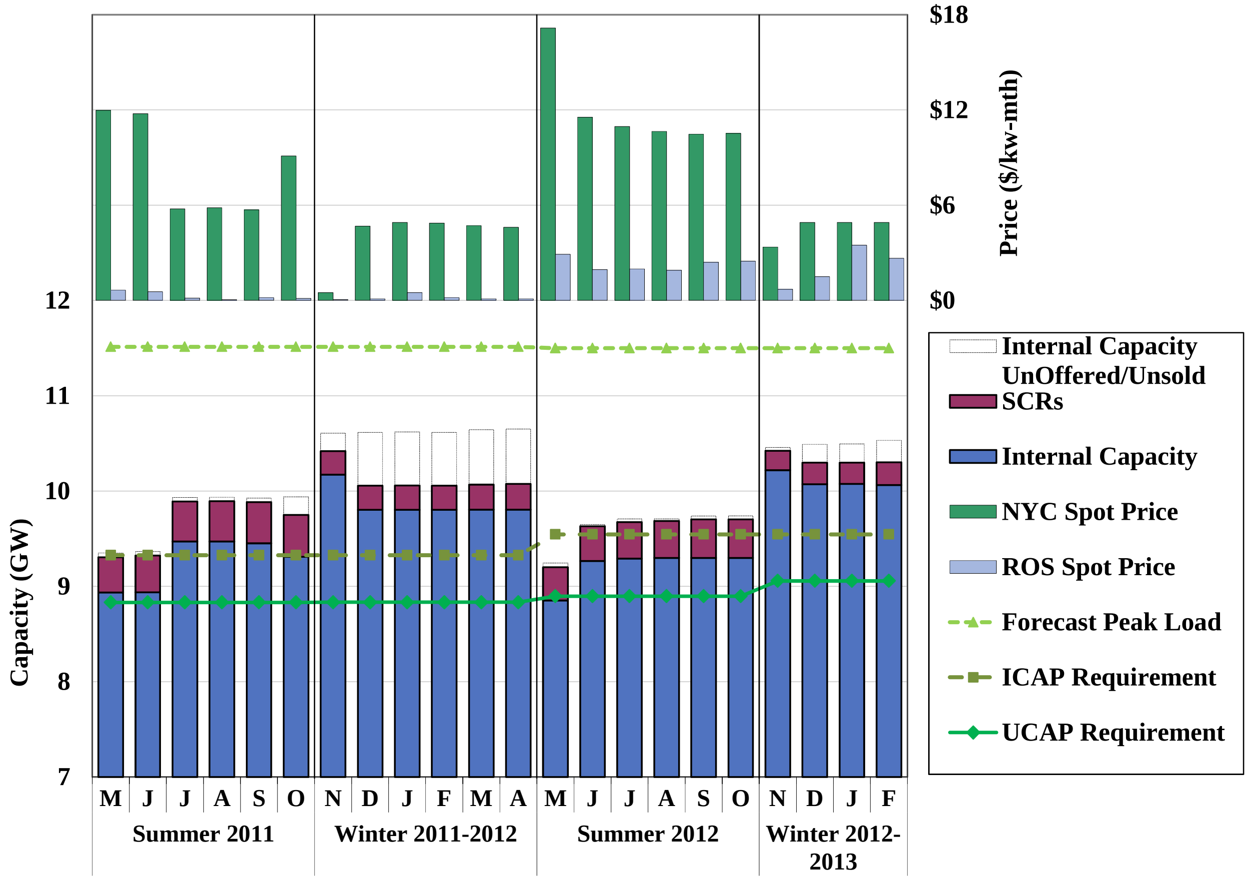
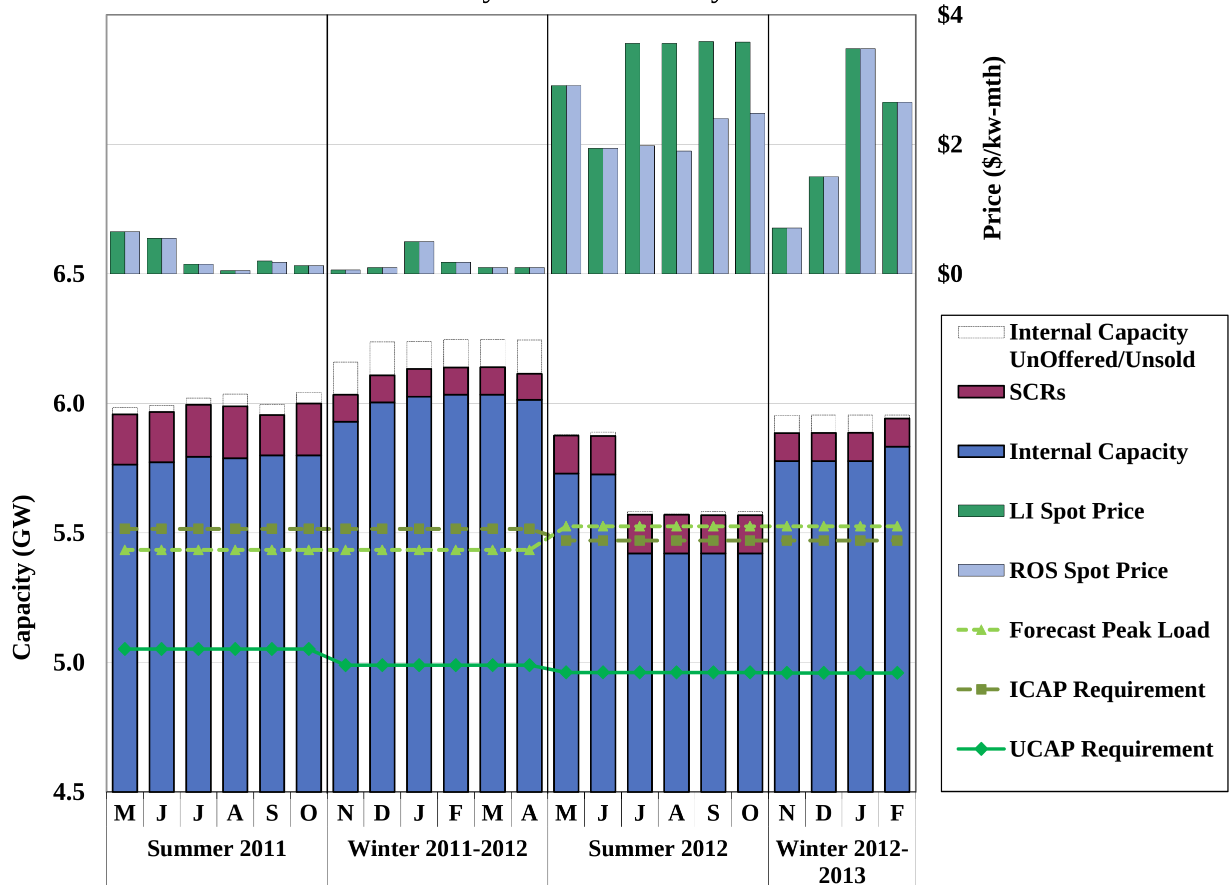


Figure A-84: UCAP Sales and Prices in Long Island
May 2011 to February 2013



Key Observations: UCAP Sales and Prices in Local Capacity Zones

- As in the statewide market, seasonal variations substantially affect the market outcomes in the local capacity zones.
- In New York City, spot capacity prices increased in both capability periods due to changes in both supply and demand factors.
  - The spot price averaged $11.88/kW-month in the Summer 2012 Capability period, up 42 percent from the previous summer.
  - Prices also rose modestly to $4.52/kW-month in the Winter 2012-13 Capability period (excluding March and April).
  - On the demand side, both the changes in the requirements and the underlying demand curve contributed to the capacity price increases in New York City.

    - The ICAP Requirement rose 219 MW (2.3 percent), which was primarily due to an increase in the LCR from 81 percent to 83 percent. [160]
    - In October 2011, a higher new demand curve was deployed, which was approximately 24 percent (or $4/kW-month at the 100 percent of the UCAP requirement) higher than the previous demand curve.
  - Supply-side changes were even more significant in New York City.
    - In May 2012, the amount of internal capacity eligible to sell into the spot capacity market fell by more than 500 MW.
    - This reduction was offset in June 2012 when a 500 MW new resource entered in New York City, which led the spot price to fall from $17.16/kW-month in May 2012 to $11.54/kW-month in June 2012.
  - In December 2012, buyer-side mitigation was imposed on the 550 MW AEII facility. Since mitigation was imposed, the amount of unsold capacity has risen and the clearing price has been $4.91/kW-month.
- In Long Island, capacity prices rose substantially driven in part by the increase in rest-of-state capacity prices.
  - The local capacity requirement for Long Island was rarely binding during summer and winter Capability Periods in 2012, reflecting that Long Island generally has far more capacity than needed to satisfy its LCR.
  - The only months when the Long Island clearing price was higher than the NYCA clearing price were July to October 2012.
    - Prices on Long Island increased after three units totaling 330 MW were retired in July 2012. The spot price rose from $1.94 per kW-month in June 2012 to $3.56 per kW-month in July 2012.
  - The Long Island ICAP Requirement fell 45 MW (0.8 percent) as a 1.7 percent increase in the peak load forecast was offset by a decrease in the LCR from 101.5 percent to 99 percent.

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160 The UCAP Requirement rose just 65 MW (0.7 percent) due to a 1.5 percent increase in the Derating Factor for New York City. However, since UCAP supply was discounted by a comparable amount, the change in the ICAP Requirement had more impact on the Spot Auction clearing price.

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.[161]

- Installed Capacity/Special Case Resource ("ICAP/SCR") Program – These resources are paid the higher of their strike price (which can be up to $500/MWh) or the real-time clearing price. These resources sell capacity in the capacity market in exchange for the obligation to respond when deployed.[162]

- 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 real-time 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.

- Demand Side Ancillary Services Program ("DSASP") – This program allows resources to offer regulation and operating reserves in the day-ahead and real-time markets.

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

162 Special Case Resources participate through Responsible Interface Parties ("RIPs"), which 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.

Despite these programs, significant barriers to participation in the wholesale market by loads remain. The most significant 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 three areas: (a) the reliability demand response programs, (b) the economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions.

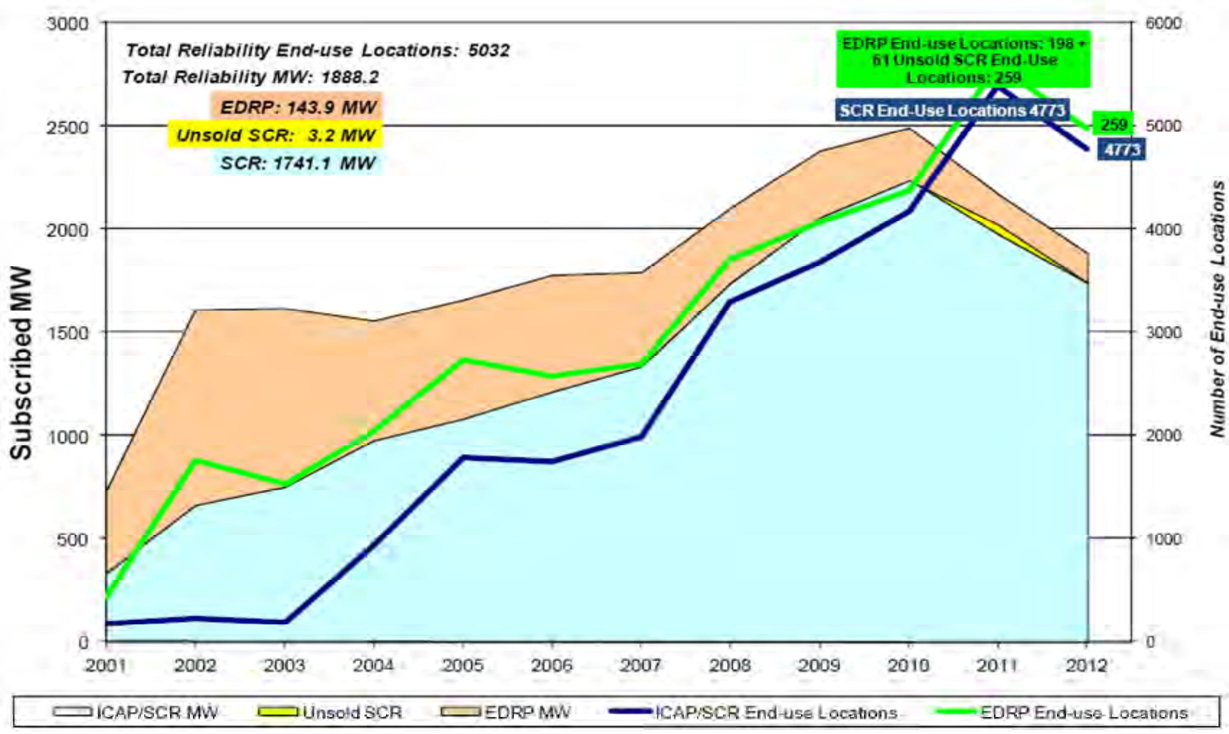
A. Reliability Demand Response Programs

Demand response programs provide incentives for retail loads to participate in the wholesale market. The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when it forecasts a reliability issue.

Figure A-85: Registration in NYISO Demand Response Reliability Programs

Figure A-85 summarizes registration in two of the reliability programs on an annual basis at the end of each summer from 2001 to 2012 as reported in the NYISO's annual report to FERC. Since EDRP and SCR resources in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

Figure A-85: Registration in NYISO Demand Response Reliability Programs
2001 – 2012



Key Observations: NYISO Demand Response Reliability Programs

- Since 2001, SCR program registration has grown considerably, 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 2012, total registration in the EDRP and SCR programs included 5,032 end-use locations enrolled, providing a total of 1,888 MW of demand response capability. SCR resources accounted for 95 percent of the total reliability program enrollments and 92 percent of the enrolled MWs.
- In the Summer 2012 Capability Period, SCRs made significant contributions to resource adequacy by satisfying:
  - 4.2 percent of the UCAP requirement for New York City;
  - 3.0 percent of the UCAP requirement for Long Island; and
  - 4.6 percent of the UCAP requirement for NYCA.
- The registered quantity of reliability program resources fell 13 percent from 2010 to 2011 and an additional 13 percent from 2011 to 2012. These reductions occurred because:
  - Capacity prices outside New York City have fallen in recent years, falling more than 60 percent from 2010 to 2011 in both Long Island and NYCA. This has likely reduced the incentives for demand response to sell capacity.
  - The NYISO modified the baseline calculation method for SCRs in 2011 to estimate more accurately the capability of the resource to respond if deployed. The NYISO uses the Average Coincident Load ("ACL") methodology, which is based on the resource's load during the 40 highest load hours in the previous like capability period (i.e., Summer 2012 will be based on 40 hours from Summer 2011). Since it is more accurate, the new baseline calculation has reduced the amount of capacity that some SCRs qualify to sell.
  - The NYISO audits the baselines of resources after each capability period to identify resources that might have had an "Unreported Change in Status" that would reduce its ability to curtail if deployed. This has resulted in more accurate baselines for some resources, reducing the amount of capacity they are qualified to sell.

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

- No resources participated in the DADRP program during the twelve months from September 2011 to August 2012.
  - 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.
- DSASP resources have experienced difficulty setting up communications with the NYISO through the local Transmission Owner since the inception of the DSASP program in 2008. Consequently, no DSASP resources were fully qualified until 2012 when the NYISO introduced the capability for resources to communicate directly with the NYISO.
  - Since the capability was introduced, some DSASP resources have begun to actively participate in the market.
  - The NYISO is making the necessary software changes to allow aggregations of small loads to participate in the program as a single resource by April 1, 2013.[163]
- Approximately 7 GW of retail load customers are under the MHP program.

163 See Price-Responsive Load Working Group meeting materials for additional details at: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_prlwg

- 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 deployed.

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 deployment of demand response, real-time clearing prices are set to $500/MWh within the region (unless they already exceed that level). This rule helps reflect the cost of maintaining adequate reserve levels in real-time clearing prices and improves the efficiency of real-time prices during shortage conditions. Since demand response resources are frequently deployed to secure an area other than NYCA or the entire eastern New York area (e.g., Southeast New York), the NYISO is planning to implement the Enhanced Scarcity Pricing project. This will allow demand response resources to set real-time clearing prices at $500/MWh within any transmission-constrained area.[164]

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 deployed that provided no reliability benefit, depressed real-time prices, and increased uplift.

The NYISO deployed reliability demand response resources on six days in 2012: May 29, June 20, 21, 22, and July 17, 18. The real-time pricing during these events is evaluated in Section V.H of the Appendix.

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164 See http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2012-12-18/agenda_07_Enhanced%20Scarcity%20Pricing.pdf in the December 18, 2012 Management Committee materials.