2016 State of the Market Report For the New York ISO Markets

POTOMAC ECONOMICS

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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. We also evaluate and recommend improvements to the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. The 2016 State of the Market Report presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2016. This executive summary provides an overview of market outcomes and highlights, a list of recommended market enhancements, and a discussion of the highest priority recommendations.

The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These 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. These markets also provide competitive incentives for resources to perform efficiently and reliably.

The energy and ancillary services markets are supplemented by the installed capacity market, which provides incentives to satisfy NYISO's planning reliability criteria over the long-term by facilitating efficient investment in new resources and retirement of older uneconomic resources.

Key Developments and Market Highlights in 2016

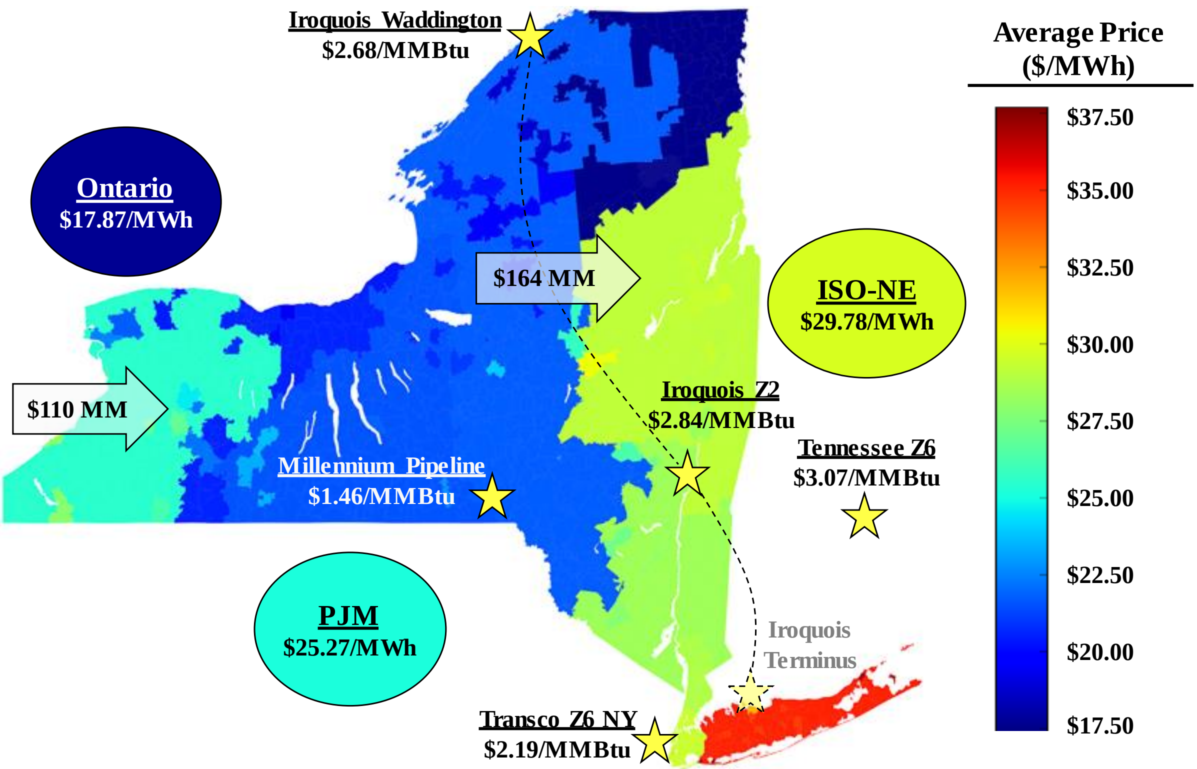
The NYISO markets performed competitively in 2016. These results are summarized below.

Natural Gas Prices and Load Levels

Mild weather during the winter months of 2016 and high levels of production from the Marcellus and Utica shale regions led to record-low natural gas prices across the state in 2016. Natural gas prices fell nearly 20 percent in Western New York and 70 percent in Eastern New York in the first quarter of 2016 relative to the same months in 2015. Natural gas prices recovered slightly after the first quarter, but remained at historically low levels through the end of 2016.

Load averaged 18.3 GW and peaked at 32.1 GW in the summer of 2016. Although the summer peak load level was up 3 percent from 2015, the summer of 2016 was still mild relative to conditions from 2010 to 2013. The winter of 2016 was much milder than the prior winters, with average load in the first quarter being the lowest in the past eight winters.

Day-Ahead Energy, Natural Gas Prices, and Congestion in 2016



Energy Prices and Transmission Congestion

Day-ahead and real-time energy prices fell approximately 20 to 30 percent across the system in 2016 with the largest reduction occurring in the first quarter of 2016. These reductions were largely driven by the decreases in natural gas prices in 2016. A strong relationship between energy and natural gas prices is expected in a well-functioning, competitive market because natural gas-fired resources are the marginal source of supply in most intervals.

Transmission congestion and losses led real-time prices to vary from an average of $18 per MWh in the North Zone to $40 per MWh in Long Island in 2016. Congestion revenues collected in the day-ahead market fell 19 percent in 2016 to total $438 million. A large portion of congestion in the NYISO was associated with congestion on the natural gas pipeline system, which exhibited significant gas price spreads between Eastern and Western New York throughout the year. Consequently, the most significant congestion appeared on the Central-East Interface, which flows power from Western New York to Eastern New York and accounted for 37 percent of total day-ahead congestion revenues in 2016.

Transmission bottlenecks became more significant on flows moving east through the West Zone and on flows moving south out of the North Zone. These transmission corridors, which bring renewable energy from Canada and New York toward load centers in the Southeast New York, accounted for 30 percent of day-ahead congestion revenues in 2016.

Installed Capacity Market

Capacity costs fell substantially from 2015 to 2016, down 29 percent in Long Island, 25 percent in New York City, 2 percent in Lower Hudson Valley (i.e., Zones GHI), and 10 percent in the Rest of State. These reductions were caused primarily by lower load forecasts and reduced installed capacity requirements. On the supply side, the retirement and mothballing of 450 MW of older coal-fired generation was balanced by increased imports of capacity from PJM.

The Local Capacity Requirements ("LCRs") have been relatively volatile in recent years as the LCR for New York City fell to 80.5 percent in the summer of 2016 from 83.5 percent the previous year. The current rules for determining the LCRs and IRM are not optimal, and they produce variations that are difficult to predict, leading to significant market uncertainty. We recommend changes in the rules that will lower the costs of satisfying NYISO's planning requirements and lead to more stability and predictability in the requirements. (See Recommendation #2013-1c.)

Long Run Investment Signals

The economic signals the markets provide that govern participants' long-run decisions (including investment, retirement, and maintenance decisions) can be measured by the net revenues generators receive in excess of their production costs. Net revenues fell for most new and existing generators in 2016 because of lower energy and capacity net revenues. However, net revenues increased significantly for older peaking units because of an increase in operating reserve prices following the implementation of Comprehensive Shortage Pricing.

Our evaluation indicates that the only area where investment in a new Frame 7 gas turbine might be economic is in the West Zone, where its estimated net revenues are similar to its annual levelized cost of new entry ("CONE"). However, this may not be sufficient to attract new investment in the West Zone if developers believe that the elevated net revenue levels will be short-lived given that large transmission upgrades are being considered to relieve these bottlenecks in upstate New York, or that the very low natural gas prices that have been observed in Western New York in recent years may not continue into the future.

Our evaluation finds that some existing steam turbine units may not be profitable to operate in downstate areas, particularly Long Island. The decisions by individual steam turbine units to retire in the coming years will likely be based on factors such as: whether they are under long-term contracts, whether their costs are higher due to site-specific disadvantages, and whether they face extraordinary repair costs because of forced outages.

We also analyze the investment incentives for existing nuclear units and potential new renewable projects. Low natural gas prices have challenged the financial viability of these zero-emission technologies. Based on futures prices, nuclear installations in upstate New York are not expected to recoup their going-forward costs over the next five years from the wholesale market. In this report, we find that the cost per ton of reducing CO_2 emissions varies widely from: a) developing new renewables; b) retaining existing nuclear generation, or c) developing new fuel-efficient gas-fired generation. This underscores the importance of relying on technology-neutral mechanisms to encourage emission reductions such as a tradable rate-based emission credit program, a cap-and-trade carbon market, or a carbon tax. As discussed below, the increasing trend toward resource-specific subsidies is troubling because it creates substantial economic risk for suppliers whose investment and retirement decisions are based on market expectations. At the same time, it likely increases the costs of achieving emission reduction objectives.

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, affecting fuel procurement and other scheduling decisions. Day-ahead energy prices were similar on average to real-time energy prices in most areas in 2016. This consistency generally promotes efficient commitment patterns in the day-ahead market.

Virtual trading helped align day-ahead energy prices with real-time energy prices, particularly when supply offer changes and modeling differences between the day-ahead and real-time markets would otherwise have led to inconsistent prices. Although effective arbitrage led to low average profits for virtual trades, virtual traders earned a net profit of $14 million in 2016. This provides a general indication that virtual transactions improved consistency between day-ahead and real-time prices at the zonal level.

The hourly mean absolute differential between day-ahead and real-time prices increased for most locations from 2015 to 2016, particularly in the West Zone, the North Zone, and Long Island, which also exhibited the highest real-time price volatility. Real-time prices in these areas were most volatile when transmission capability in the affected area was reduced by transmission outages. We found that the implementation of the Graduated Transmission Demand Curve ("GTDC") project led to increased congestion price volatility during transmission shortages beginning in February 2016. (See Recommendation #2015-17.)

In the reserve market, average day-ahead reserve prices were much higher than real-time prices for most products in 2016. Factors leading to high day-ahead reserve prices are discussed below.

Competitive Performance of the Markets

As the MMU, we evaluate the competitive performance of the NYISO markets. The energy market performed competitively in 2016 because the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were generally effective in limiting conduct that would raise energy prices above competitive levels.

In November 2015, the NYISO implemented the Comprehensive Shortage Pricing project, which included a package of energy and ancillary services market design changes. These included an increase in the NYCA 30-minute reserve requirement and a cap on the amount of reserves that could be scheduled on Long Island resources. Although the available supply of 30-minute reserves far exceeds demand in this market, we have found that multiple suppliers consistently offer reserves at levels above their likely marginal costs in the day-ahead market. Although many suppliers who offer reserves in this manner are clearly not attempting to raise prices above competitive levels, inefficiently high offer prices may still lead to inflated day-ahead clearing prices. Given that 30-minute reserve clearing prices were *de minimis* before November 2015, some suppliers may increase sales of this product after gaining additional experience evaluating the costs and risks of providing it. Nevertheless, we find that the current cap on Long Island resources is unnecessarily restrictive, and it reduces the available supply and raises clearing prices. (See Recommendation #2015-16.) We will continue to monitor the performance of this market to determine whether additional rule changes would improve the market's performance.

The NYISO performed Buyer-Side Mitigation evaluations for five Additional CRIS MW projects in Class Year 2015 ("CY15"). All five Additional CRIS MW projects, which involved uprates to existing facilities, were determined to be exempt and will not be subject to Offer Floor mitigation. We carefully reviewed the process and assumptions used by the NYISO to make BSM determinations for each Examined Facility, and we found that they were conducted in accordance with the tariff and that the outcomes were reasonable. Nonetheless, we identify several potential enhancements to the test procedure. (See Recommendation #2013-2d.)

Uneconomic entry and uneconomic retention in the wholesale electricity market raise concerns because they artificially alter the supply and demand balance, undermining long-term investment incentives. We recognize that states have legitimate public policy goals that may entail support for certain types of resources, and we recognize that the current markets do not fully price many externalities of electricity generation, including environmental emissions. Thus, state subsidies that can be justified by the cost/value of the externalities could be legitimate. However, we still have two concerns with such programs. First, state programs to reduce emissions do not compensate resources in an efficient non-discriminatory manner, and this is unlikely to encourage efficient investments for achieving the public policy objectives. Second, while structured similar to longstanding REC programs, the Zero-Emission Credit ("ZEC") program is unprecedented in its magnitude, so it has a larger and more immediate effect on energy and capacity market outcomes. Therefore, we will continue to advocate that states utilize markets to efficiently price and incent investment in new and existing resources to achieve public policy objectives, rather than rely on resource-specific subsidies that can undermine the long-term performance of the wholesale electricity markets. Resource-specific subsidies can lead to artificial supply surpluses will undermine the performance of the market by created sizable risks for market participants. Hence, we encourage NYISO to begin considering provisions that would limit disruptive short-term supply-demand imbalances caused by these public policies.

Real-Time Market Operations and Market Performance

We evaluate several aspects of market operations, focusing on scheduling efficiency and real-time price signals, particularly during tight operating conditions. Efficient prices are important because they reward resources for performing reliably during tight real-time conditions.

Performance of Operating Reserve Providers

Efficient performance incentives encourage investment in resources with flexible operating characteristics in areas where they are most valuable. Over the coming decade, performance incentives will become more critical as the entry of new intermittent renewable generation will require more complementary flexible resources. This section evaluates two aspects of how market outcomes are affected by the performance of operating reserve providers.

First, we analyze the performance of gas turbines in responding to start-up instructions in the real-time market. While there is a wide range in the performance of individual units, their reserve market compensation is unaffected by their performance. Consequently, some gas turbines that almost never perform as instructed still manage to earn most of their revenue from the sale of operating reserves. (See Recommendation #2016-2.)

Second, we evaluate how the availability and expected performance of operating reserve providers affects the costs of congestion management in New York City. In some cases, the availability of reserves allows the operator to increase transmission flows on certain facilities, thereby increasing the utilization of the transmission system. However, operating reserves are not compensated for helping manage congestion. This may lead to inefficient scheduling in the real-time market, and does not provide efficient investment incentives for gas turbines that can perform reliably and provide congestion relief while offline. (See Recommendation #2016-1.)

Drivers of Transient Real-Time Price Volatility

Price volatility can provide efficient incentives for resource flexibility, although unnecessary volatility imposes excessive costs on market participants. Price volatility is an efficient signal when it results from sudden changes in system conditions that cannot be predicted by the NYISO (e.g., a generator or line trips offline). However, unnecessary price volatility can occur when the NYISO's market models do not incorporate an observable factor that affects market conditions significantly. Hence, it is important to identify the causes of volatility. We performed an evaluation of the drivers of real-time price volatility in 2016 and found the following two categories were most significant:

- Resources scheduled by RTC – The RTC model schedules external transactions and gas turbines on a 15-minute basis without considering how large changes in output will affect the market on a 5-minute basis, which can lead to brief shortages of ramp-able capacity.

- Flow changes resulting from non-modeled factors – Includes volatile loop flows and other unforeseen variations in non-modeled flows that lead to acute reductions in the amount of transfer capability that is available to transactions scheduled by the NYISO.

These changes can create brief shortages and over-generation conditions when flexible generators cannot ramp quickly enough to compensate for the change, leading to sharp changes in energy prices and congestion. In this report, we identify modeling improvements by the NYISO that have helped address unnecessary price volatility in Long Island and in western New York, and we discuss potential solutions and recommend further improvements. (See Recommendations #2012-13 and #2014-9.)

Efficiency of Coordinated Transaction Scheduling ("CTS")

CTS enables two neighboring wholesale markets to exchange information about their internal dispatch costs shortly before real-time, and this information is used to assist market participants in scheduling external transactions more efficiently. CTS was implemented with PJM in November 2014 and with ISO-NE in December 2015.

We have found that participation in CTS at the primary PJM interface is still modest after more than two years, while participation at the ISO-NE interface has been stronger. In 2016, an average of 180 MW of price-sensitive transaction bids were offered at the PJM border, compared to 415 MW in the same price range at the ISO-NE border. The large difference in performance of the two CTS processes is likely the result of large fees imposed on and uplift costs allocated to transactions at the PJM interface, while fees are not significant at the ISO-NE interface. Imposing large transaction fees on a low-margin trading activity dramatically reduces liquidity and the overall efficiency of the CTS process. Therefore, we recommend that NYISO work with PJM to eliminate these charges at the border. (See Recommendation #2015-9.)

We estimate nearly $8 million of regional production cost savings was anticipated from the two CTS processes based on information available at the time interchange schedules were determined during 2016. However, only 25 percent of this benefit was actually realized, partly because of inaccurate regional price forecasts. We recommend improvements to better align RTC and RTD (that were discussed above as a remedy for unnecessary price volatility) to address this issue. (See Recommendation #2012-13.)

Market Performance under Shortage Conditions

The impact of shortage conditions was substantial in 2016. Most shortages were brief and relatively small as flexible generation ramped in response to changes in load, external interchange schedules, and other system conditions. Brief shortages provide strong incentives for resources to provide flexibility and perform reliably. Shortage pricing accounted for a large share of the net revenues that a generator could use to recoup capital investment costs, contributing up to $59 per kW-year, depending on the zone and availability of the resource.

Transmission shortages occurred in roughly six percent of intervals in 2016, accounting for the majority of shortage pricing incentives. The implementation of the Graduated Transmission Demand Curve ("GTDC") project in February 2016 led to more volatile congestion pricing during transmission shortages. This was primarily because of changes in the parameters used to "relax" transmission constraints during those shortages when the GTDC was not used in the real-time pricing algorithm. Stakeholders have voted in favor of a NYISO-proposed short-term solution, which we support because it would lead congestion prices to be more consistent with the severity of the shortage. However, we recommend in the long-term the NYISO develop GTDCs that vary according to the importance, severity, and/or duration of the shortage to price all congestion during transmission shortages. (See Recommendation #2015-17.)

Operations of Non-Optimized PAR-Controlled Lines

While most phase angle regulators ("PARs") are operated to reduce production costs, several PARs are used to satisfy bilateral contract flows regardless of whether it is efficient to do so. The most significant inefficiencies we identified were associated with: (a) two lines that normally flow up to 290 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) 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) increased day-ahead production costs by an estimated $15 million in 2016.

The ConEd-PSEG wheeling agreement was terminated at the end of April 2017. PJM and NYISO are implementing a replacement protocol that will incorporate the associated PARs into the NY-PJM AC interface for interchange scheduling and the M2M process. These changes should lead to more efficient utilization of the associated PARs in 2017.

The ConEd-LIPA wheeling agreement continues to use the 901 and 903 lines in a manner that raises production costs inefficiently. Hence, the report recommends that NYISO continue to work with the parties to the ConEd-LIPA wheeling agreement to explore potential changes that would allow the lines to be used more efficiently. (See Recommendation #2012-8.)

Out-of-Market Actions and Guarantee Payment Uplift

Guarantee payments to generators, which account for a large share of Schedule 1 uplift charges, fell by 39 percent to $43 million in 2016. This was due partly to lower natural gas prices across the system, particularly in the first quarter of 2016 because of the mild winter weather. Low gas prices reduced the commitment costs of gas-fired units needed for reliability.

In 2016, reliability commitments and OOM dispatch fell by 32 percent and 29 percent, respectively, which contributed to lower guarantee payment uplift. In New York City, the reduction resulted from: (a) fewer generation and transmission outages that require steam turbines to run for reliability; and (b) more frequent economic commitment of the units often needed for local reliability because of relatively low natural gas prices in New York City. In western New York, recent transmission upgrades that facilitated several unit retirements in western New York in late 2015 and early 2016 resulted in lower local reliability needs.

Despite these improvements, several units were still often scheduled out-of-market to manage flows on 115 kV facilities. These units accounted for more than $15 million of guarantee payment uplift. In addition, the NYISO frequently took other out-of-market actions to manage congestion on the 115 kV system, including: (a) manually instructing the Niagara generator to shift output between the generators at the 115kV station and the generators at the 230kV station; (b) taking certain lines out of service on the primary PJM-NYISO interface; (c) derating interfaces with Ontario, PJM, and Quebec; and (d) using the interzonal Dysinger East, West Central, and Moses South interface constraints as a mechanism to manage flows indirectly on 115 kV facilities. Consequently, 115 kV congestion had significant effects on the overall market. We continue to recommend that the NYISO model these constraints to allow the market to price and efficiently manage these constraints. (See Recommendation #2014-12.)

Capacity Market

The capacity market continues to be an essential element of the NYISO electricity markets, providing 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, although this report identifies several areas for improvement, including the following:

- Because New York is highly constrained, the value of capacity at different locations can vary substantially in satisfying NYISO's planning needs. However, the market cannot reflect this value because it only recognizes four locations. To improve the locational capacity price signals, we recommend a dynamic framework to reflect planning constraints rather than adding capacity zones incrementally over time. (Recommendation #2012-1a.)
- Given a set capacity zones, capacity procurements should be optimized to satisfy planning requirements at the lowest cost, which could be done by setting the IRM and LCRs based on the marginal reliability value of capacity at different locations. This will reduce the overall costs for maintaining reliability, but requires that the NYISO and its stakeholders separately establish equitable capacity costs allocation rules. (Recommendation #2013-1c.)

Finally, to support the competitive performance of the capacity market, we encourage NYISO to consider provisions to limit disruptive supply-demand imbalances caused by public policies that subsidize resources to enter the market or remain in the market when it is economic to retire.

Overview of Recommendations

The NYISO electricity markets generally performed well in 2016 and the NYISO has continued to improve its operation and enhance its market design. Nonetheless, our evaluation identifies a number of areas of potential improvement, so we make recommendations that are summarized in the following table. The table identifies the highest priority recommendations and those that the NYISO is addressing in the 2017 Project Plan or in some other effort. In general, the recommendations that are designated as the highest priority are those that produce the largest economic efficiencies by lower the production costs of satisfying the system's needs or improving the incentives of participants to make efficient long-term decisions.

The table also identifies recommendations as scoping/future if there is significant work is necessary to determine the appropriate solution or establish the priority level, or if the anticipated benefits would be smaller in the short-term than in the long-term. A detailed discussion of each recommendation is provided in Section XI.

Number	Section	Recommendation	Current Effort	High Priority	Scoping/ Future
Energy Market Enhancements - Real-Time Pricing and Performance Incentives					
2016-1	IX.C.2	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.			✓
2016-2	IX.C.1	Consider means allow reserve market compensation to reflect actual and/or expected performance.			✓
2014-10	IX.B	Modify criteria for gas turbines to set prices in the real-time market by incorporating start-up costs.			
2014-12	IX.F.3	Model 100+ kV transmission constraints in the day-ahead and real-time markets, and develop associated mitigation measures.	✓		
2015-16	IX.A.1	Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.			✓
2015-17	IX.A.2	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.			✓
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.			
Energy Market Enhancements - Real-Time Market Operations					
2012-8	IX.D	Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.			
2012-13	VI.D IX.E	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	✓	✓	✓
2014-9	IX.E.4	Consider enhancing modeling of loop flows to reflect the effects of expected variations more accurately.			✓

Number	Section	Recommendation	Current Effort	High Priority	Scoping/ Future
Energy Market Enhancements - BPCG Eligibility and Fuel Limitations/Storage					
2014-13	IX.F.2	Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.			
2013-11	IX.B.2	Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	✓		✓
Capacity Market Enhancements					
2012-1a	VII.F	Establish a dynamic locational capacity framework that reflects potential deliverability constraints to allow prices to fully reflect the locational value of capacity.		✓	✓
2012-1c	VII.D	Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.			✓
2013-1c	VII.C	Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements.	✓	✓	
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.	✓		
2015-8	VII.B	Modify the capacity market and planning process to better account for imports from and exports to neighboring control areas from import-constrained capacity zones.	✓		
Planning Process Enhancements					
2015-7	VII.E	Reform the CARIS process to better identify and fund economically efficient transmission investments.			✓

I. INTRODUCTION

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2016.[1] 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;
- Impose locational requirements in its operating reserve and capacity markets, which play a crucial role in signaling the need for resources in transmission-constrained areas;

1 NYISO MST 30.10.1 states: "The Market Monitoring Unit shall prepare and submit to the Board an annual report on the competitive structure of, market trends in, and performance of, other competitive conditions in or affecting, and the economic efficiency of, the New York Electric Markets. Such report shall include recommendations for the improvement of the New York Electric Markets or of the monitoring, reporting and other functions undertaken pursuant to Attachment O and the Market Mitigation Measures."

- 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 shortages when resources are insufficient to satisfy all of needs of the system;
- 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. Some other RTOs rely on their operators to determine when to start gas turbines and other quick-start units.
- Introduce a market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets.
- Implement a mechanism that allows inflexible gas turbines and demand-response resources to set energy prices when they are needed, which is essential for ensuring that price signals are efficient during peak demand conditions.
- Use a real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one-hour period, allowing the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs.

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, Section XI of the report provides a number of recommendations that are intended to achieve these objectives.

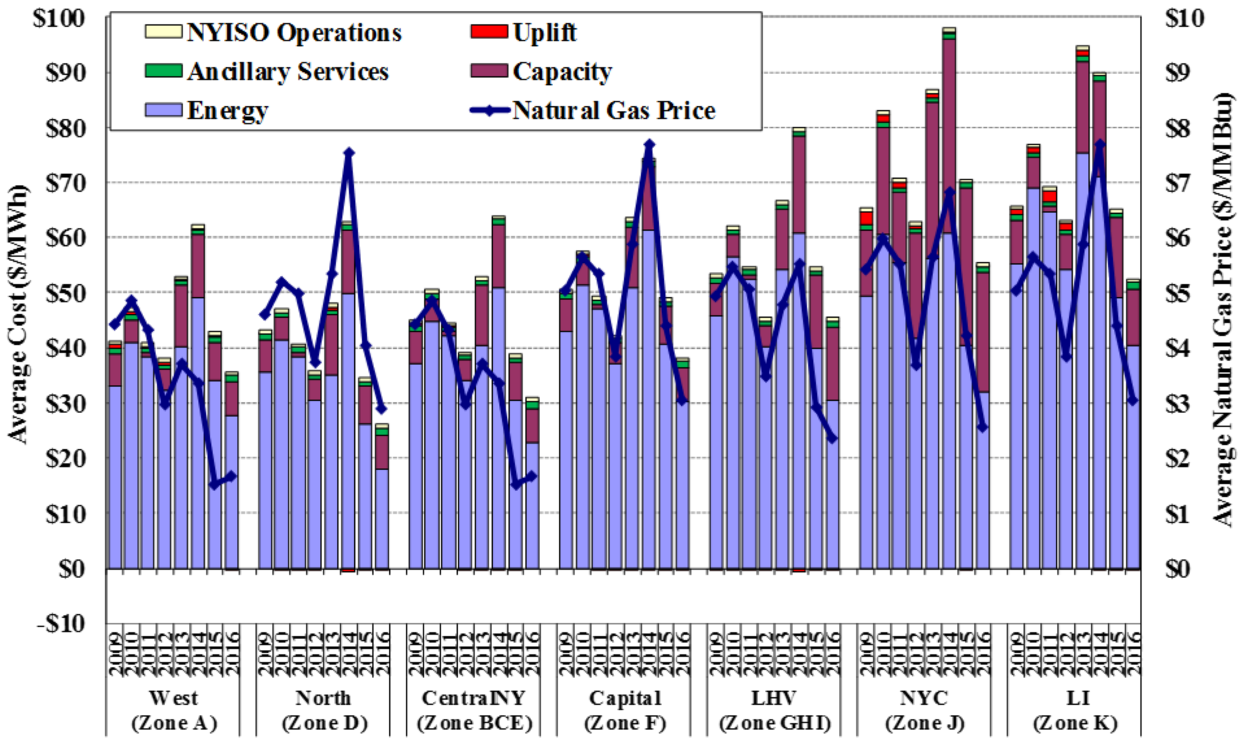
II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2016. It includes evaluations of energy and ancillary service prices, fuel prices, generation and demand patterns, and congestion patterns.

A. Total Wholesale Market Costs

Figure 1 summarizes wholesale market costs over the past eight 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.[2]

Figure 1: Average All-In Price by Region
2009-2016



Average all-in prices fell to the lowest levels seen since 2009 across the system, ranging from $26 per MWh in the North Zone to $55 per MWh in New York City in 2016. Over the eight years shown, variations in natural gas prices have been the primary driver of variations in the energy component of the all-in price, although changes in congestion patterns have also significantly affected the energy prices at some locations. In 2016, energy prices accounted for

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

58 percent of the all-in price in New York City and 68 to 80 percent of the all-in price in the other regions.

Average energy prices fell 18 to 31 percent across different regions from 2015 to 2016. Most of the annual reductions resulted from a mild winter in the first quarter of 2016, which led to much lower natural gas prices and less frequent peaking conditions than in the previous winter.[3,4] Higher production from nuclear and hydro units also contributed to the lower prices in the first quarter of 2016.[5] However, in the other three quarters of 2016, energy prices were slightly higher than in 2015 because of higher summer load levels and multiple lengthy transmission outages that increased congestion on the Central-East interface and in Long Island.[6]

In recent years, increased availability of low-cost imports from Canada and retirements of coal generation in western New York have led to increased congestion west of the Central-East interface. Congestion on west-to-east flows through the West Zone and on flows moving south from the North Zone accounted for 30 percent of all congestion in 2016. [7]

Capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs. Average capacity costs decreased by varying amounts in different areas from 2015 to 2016, falling:

- 2 percent in the Lower Hudson Valley (i.e., Zones G, H, and I),
- 25 percent in New York City,
- 29 percent in Long Island, and
- 10 percent Rest of State.

Capacity prices fell primarily because of the reductions in the ICAP Requirement in each region. The retirements of several units reduced the internal capacity in the state, partially offsetting the capacity price decline. However, increased imports from PJM muted this impact in the Rest of State region.[8]

3 See Section B for discussion of fuel price trends and underlining drivers.

4 See Section I.D of the Appendix for discussion of load patterns.

5 See Section I.B of the Appendix for generation mix by quarter.

6 See Section E for discussion of transmission outages and their impact on congestion.

7 See Section E for more discussion of these congestion patterns.

8 See Section VII.A for additional details.

B. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. This is expected in a competitive market because most of the marginal costs of thermal generators are fuel costs. Table 1 summarizes fossil fuel prices in 2015 and 2016 on an annual basis, and separately for the first quarter and the rest of the year.[9] The table also shows average real-time energy prices in seven regions of New York State over the same time periods. Representative gas price indices are associated with each of the seven regions.

Table 1: Average Fuel Prices and Real-Time Energy Prices
2015-2016

	Annual Average			Q1 Average			Q2 - Q4 Average		
	2015	2016	% Change	2015	2016	% Change	2015	2016	% Change
Fuel Prices ($/MMBtu)									
Ultra Low-Sulfur Kerosene	$14.87	$12.15	-18%	$16.06	$10.09	-37%	$14.47	$12.84	-11%
Ultra Low-Sulfur Diesel Oil	$11.95	$9.69	-19%	$13.23	$7.71	-42%	$11.53	$10.35	-10%
Low-Sulfur Residual Oil	$8.03	$6.59	-18%	$9.40	$4.84	-49%	$7.57	$7.17	-5%
NG - Dominion North	$1.33	$1.47	11%	$1.49	$1.22	-18%	$1.27	$1.55	22%
NG - Millenium East	$1.26	$1.45	15%	$1.50	$1.18	-21%	$1.18	$1.54	30%
NG - Transco Z6 (NY)	$3.84	$2.21	-43%	$8.97	$2.81	-69%	$2.13	$2.01	-6%
NG - Iroquois Z2	$4.26	$2.85	-33%	$9.14	$2.90	-68%	$2.64	$2.83	7%
NG - Tennessee Z6	$4.59	$3.07	-33%	$10.85	$3.24	-70%	$2.51	$3.02	20%
Energy Prices ($/MWh)									
West (Dominion)	$34.12	$27.61	-19%	$46.20	$22.37	-52%	$29.82	$29.36	-2%
North (Waddington)	$26.13	$17.98	-31%	$42.58	$15.06	-65%	$19.46	$19.07	-2%
Central NY (Dominion)	$30.46	$22.80	-25%	$48.28	$17.44	-64%	$23.65	$24.64	4%
Capital Zone (Iroquois)	$40.67	$30.14	-26%	$77.96	$29.32	-62%	$27.24	$30.41	12%
Lw. Hudson(Millen. East/Iroq.)	$39.91	$30.58	-23%	$71.69	$27.30	-62%	$29.07	$31.60	9%
New York City (Transco)	$40.49	$32.00	-21%	$72.48	$28.89	-60%	$30.34	$32.93	9%
Long Island (Iroquois)	$49.23	$40.43	-18%	$86.63	$32.84	-62%	$37.22	$42.65	15%

Although much of the energy 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 clearing prices, especially in Eastern New York. Consequently, energy prices in New York have followed a pattern similar to natural gas prices over the past several years.

In 2016, average natural gas prices fell to record lows across the state since the beginning of the NYISO markets. For the first quarter, gas prices fell nearly 20 percent in Western New York and 70 percent in Eastern New York from 2015 to 2016 primarily because of:

- Milder winter weather conditions that led to lower heating demand for gas and higher quantities of natural gas in storage;

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

- Higher production in the Marcellus and Utica shales; and
- Very low oil prices which also limited the magnitude of increases in natural gas prices.

However, natural gas prices began to rise gradually in late spring partly because of growing demand in the electric power sector and a small drop in natural gas production from the Marcellus and Utica shales.

Consequently, winter-season increases in natural gas prices and gas price spreads between regions (e.g., between Western and Eastern New York) were relatively small in 2016 compared to the last three years. The milder winter had several significant effects in 2016, which included helping reduce energy price spreads between Western and Eastern New York and lowering uplift charges. These and other effects are discussed throughout the report.

C. Generation by Fuel Type

Variations in fossil fuel prices, retirements and mothballing of old generators, and the additions of new gas-fired generation in recent years have led to concomitant changes in the mix of fuels used to generate electricity in New York.

Table 2 summarizes the annual usage of generation by fuel type from 2014 to 2016, 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.[10] The marginal percentages sum to more than 100 percent because more than one type of unit is often marginal, particularly when the system is congested.

Table 2: Fuel Type of Real-Time Generation and Marginal Units in New York
2014-2016

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Nuclear	4.9	5.1	4.7	31%	32%	31%	0%	0%	0%
Hydro	2.8	2.8	2.9	18%	18%	19%	45%	49%	47%
Coal	0.5	0.3	0.2	3%	2%	1%	7%	2%	1%
Natural Gas CC	5.0	5.2	5.1	31%	33%	33%	60%	67%	68%
Natural Gas Other	1.6	1.7	1.7	10%	10%	11%	29%	28%	30%
Fuel Oil	0.2	0.2	0.1	2%	1%	0%	6%	5%	3%
Wind	0.5	0.5	0.5	3%	3%	3%	4%	5%	3%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

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

Gas-fired generation accounted for the largest share of electricity production (41 to 44 percent) from all internal generating resources in each year of 2014 to 2016, driven by lower natural gas prices and higher load levels during the summer.[11]

The small changes in generation from nuclear resources (which accounted for 30 percent of all generation) were driven primarily by variations in the amount of generation deratings and outages. Coal-fired generation continued to fall in 2016 because of mothballing and retirement at the Huntley and Dunkirk stations and low natural gas prices in Western New York throughout the year, making coal production less economic. The continued reduction in oil-fired generation because of mild weather and low natural gas prices in the first quarter of 2016 was partly offset by higher oil-fired output to manage congestion on Long Island in the third quarter of 2016.[12]

Average generation from wind, hydro, and other renewable resources did not vary significantly from 2015 to 2016. Hydro production rose modestly in 2016, particularly in the winter months, reflecting: (a) milder winter weather conditions led to increased supply of water (compared to frequent icy conditions in the prior year); and (b) increased output from the Niagara facility due to less frequent congestion in the West Zone.

Gas-fired and hydro resources were most frequently on the margin in recent years. Most marginal hydro units have storage capacity, leading their offers to include the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by natural gas prices. Other fuel types set prices less frequently. Coal-fired units were rarely on the margin in 2016 because the majority of coal-fired generation resulted from out-of-merit dispatch and commitment for reliability.[13]

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Table 3 shows the following load statistics for NYCA over the past eight years: a) annual summer peak; b) annual winter peak; c) annual average load; and d) number of hours when load exceeded certain levels. The summer peak level rose 3 percent in 2016 because of warmer weather and more frequent peaking conditions. Nonetheless, the summer peak load was still significantly lower than those from 2010 to 2013.

Average load levels fell slightly from 2015 to 2016 because of substantially lower load levels during the first quarter of 2016. Average load fell 8 percent year-over-year in the first quarter of 2016, which exhibited the lowest level of the past eight winters.

11 Figure A-7 in the Appendix shows generation mix by region by quarter in 2015 and 2016.

12 Appendix Section I.C shows generation by fuel type in the Eastern New York on a daily basis in the winter.

13 See Section IX.F.0 for additional information about out-of-merit dispatch.

Table 3: Peak and Average Load Levels for NYCA
2009 – 2016

Year	Load (GW)			Number of Hours >		
	Summer Peak	Winter Peak	Annual Average	32GW	30GW	28GW
2009	30.8	24.3	18.1	0	13	54
2010	33.5	23.9	18.7	13	69	205
2011	33.9	24.3	18.6	17	68	139
2012	32.4	23.9	18.5	6	54	162
2013	34.0	24.7	18.7	33	66	145
2014	29.8	25.7	18.3	0	0	40
2015	31.1	24.6	18.4	0	23	105
2016	32.1	24.2	18.3	1	33	163

E. Transmission Congestion Patterns

Figure 2 shows the value and frequency of congestion along major transmission paths in the day-ahead and real-time markets.[14] Although the vast majority of congestion revenues are collected in the day-ahead market (where most generation is scheduled), congestion in the real-time market is important because it will drive day-ahead congestion in a well-functioning market.[15]

The value of day-ahead congestion fell by 19 percent in 2016, which was largely due to the low natural gas prices in the first quarter of 2016.[16] Day-ahead congestion revenues rose 21 percent in the remaining months of the year because of higher load levels in the summer months, multiple transmission outages on several key transmission paths, and issues with the implementation of the Graduated Transmission Demand Curve ("GTDC") in February 2016.[17]

Congestion across the Central-East interface accounted for the largest share of total congestion value in both 2015 and 2016 – accounting for 37 percent of congestion value in the day-ahead market in 2016. The majority of this congestion occurred in the first quarter and in December as a result of higher natural gas prices and larger gas price spreads between regions. Lengthy transmission outages in early 2016 because of the TOTS projects and the outage of Marcy-New Scotland 345 kV line in December also contributed to higher congestion in these periods.

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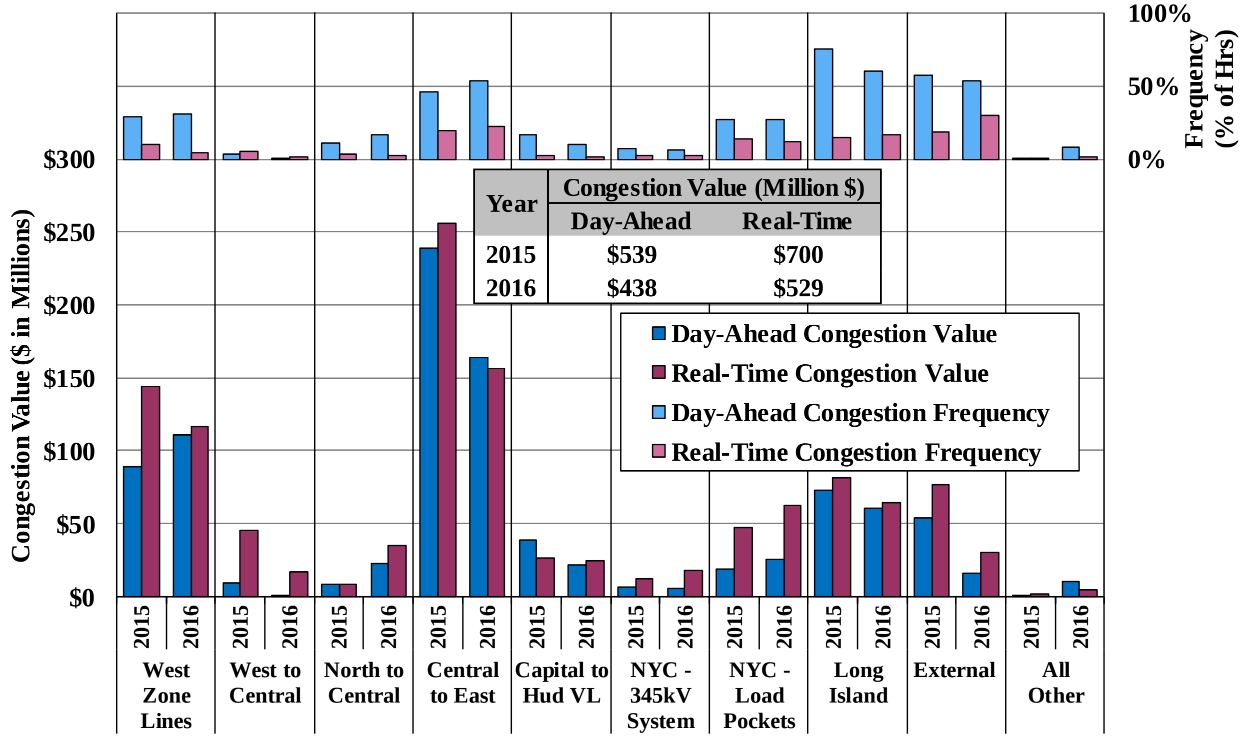
14 Section III.B in the Appendix discusses the congestion patterns in greater detail.

15 Most congestion settlements occur in the day-ahead market. 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.

16 The value of day-ahead congestion and the day-ahead congestion collected by the NYISO may be slightly different because of the settlement for several grandfathered transmission agreements that pre-date NYISO.

17 See Sections V.A for more discussion of factors that affect congestion.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2015-2016



Congestion on 230kV lines in the West Zone has been significant in recent years, accounting for the second largest share (25 percent) of congestion value in the day-ahead market in 2016. West Zone congestion in 2016 has been increased by significant market changes, including: [18]

- The implementation of the GTDC project in February 2016;
- The retirements of coal units in December 2015 and in March 2016 that had previously helped manage congestion; and
- The implementation of the composite shift factor at the Niagara plant in May 2016.

However, the increase in transmission congestion has been limited by:

- Transmission upgrades in May 2016; and
- Two transmission lines between the West Zone and PJM were taken out-of-service to manage 115 kV congestion during most of 2016, but this also helped divert flows away from congested paths on the 230 kV system.

At times, congestion can become severe in the real-time market on these West Zone 230 kV constraints partly because of volatile loop flows moving clockwise around Lake Erie.[19] The

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18 See Appendix Section III.C for more discussion of these factors and their impact on West Zone congestion.

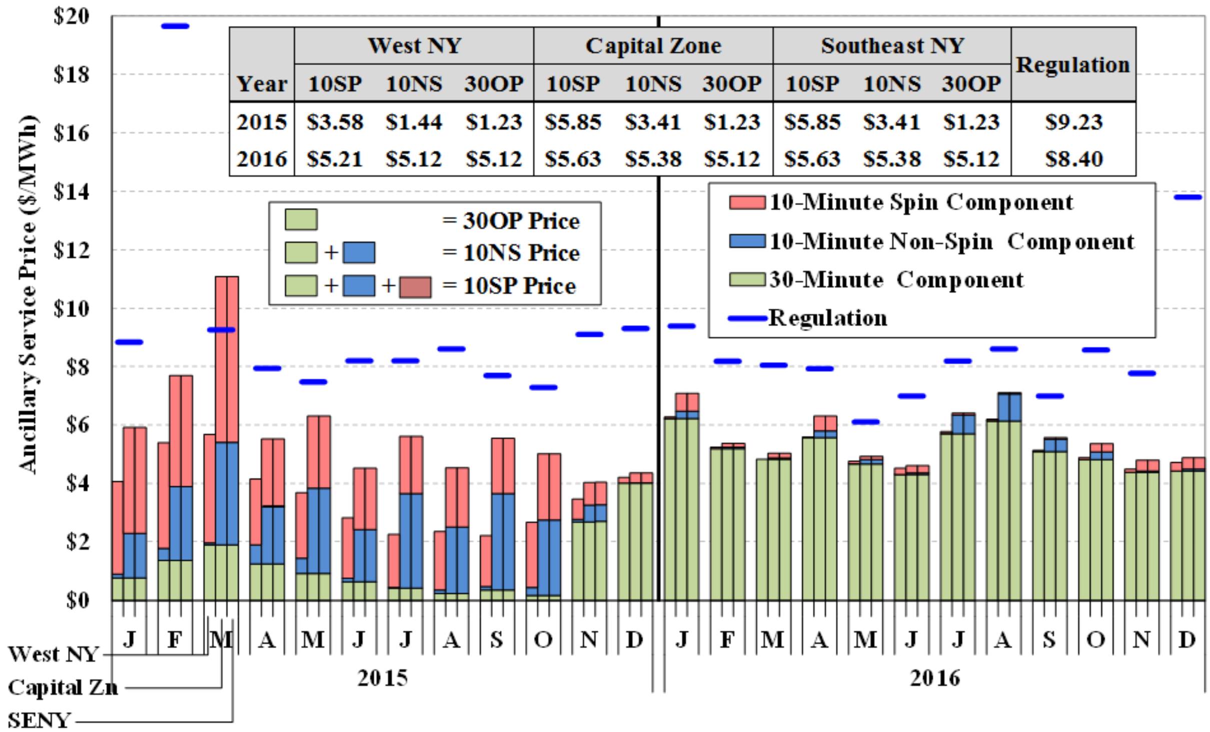
19 See Appendix Section III.D for more discussion of the impact of loop flows on West Zone congestion.

NYISO implemented two modifications at the end of June 2016 to better manage loop flows,[20] which have helped reduce the severity of real-time congestion.

F. Ancillary Services Markets

Ancillary services and energy scheduling is co-optimized. Part of the cost of providing ancillary services is the opportunity cost of not providing energy when it otherwise would be economic to do so. Co-optimization ensures that these opportunity costs is efficiently reflected in LBMPs and reserve clearing prices. The ancillary services markets provide additional revenues to resources that are available during periods when the resources are most economic to provide operating reserves. This additional revenue rewards resources that have high rates of availability in the day-ahead and real-time markets. Figure 3 shows the average prices of the four ancillary services products by location in the day-ahead market in each month of 2015 and 2016.[21]

Figure 3: Average Day-Ahead Ancillary Services Prices
2015-2016



Year	West NY 10SP	West NY 10NS	West NY 30OP	Capital Zone 10SP	Capital Zone 10NS	Capital Zone 30OP	Southeast NY 10SP	Southeast NY 10NS	Southeast NY 30OP	Regulation
2015	$3.58	$1.44	$1.23	$5.85	$3.41	$1.23	$5.85	$3.41	$1.23	$9.23
2016	$5.21	$5.12	$5.12	$5.63	$5.38	$5.12	$5.63	$5.38	$5.12	$8.40

Although reserve price variations are usually correlated with energy price variations, the figure shows that the average prices for most classes of operating reserves rose from 2015 to 2016. In addition, the differential in day-ahead prices between the highest value and lowest value reserve

20 See presentation "Lake Erie Loop Flow Modifications" by Tolu Dina at June 23, 2016 MIWG meeting.

21 See Appendix Sections I.G and I.H for additional information regarding the ancillary services markets and detailed description of this chart.

products became much smaller in 2016 as the price of the NYCA 30-minute reserves rose sharply and accounted for nearly all of the day-ahead market reserve costs in 2016.

The increase in 30-minute operating reserve prices was primarily caused by two key changes in market rules made in November 4, 2015 as part of the Comprehensive Shortage Pricing project:[22]

- The NYCA 30-minute reserve requirement rose from 1,965 MW to 2,620 MW; and
- The 30-minute reserves on Long Island that can be used to satisfy the NYCA reserve requirements is now limited to its 30-minute reserve requirement (normally 270 to 540 MW).

The limitation on Long Island was intended to ensure that reserves scheduled there would be fully deliverable following a large contingency outside Long Island, but the current limitation may be overly restrictive. Long Island frequently imports more than one GW from upstate, making it possible for a comparable amount of reserves to be held on Long Island to satisfy the reserve requirements for the state. Deploying the reserves would involve converting Long Island the reserves to energy which would reduce the imports to Long Island, thereby reducing the amount of power that must be generated outside Long Island after a contingency. Hence, we recommend that the NYISO modify the market software to optimize the upper limit on the amount of reserves that can be held on Long Island.[23]

In addition, the price increase for 30-minute reserves was also partly attributable to increases in reserve offer prices in the day-ahead market in Western New York. These are discussed further in Section IV.A.0.

22 There were other changes made in the ancillary service market on November 4, 2015. See Section IX.A.0 for additional information regarding these changes.

23 See Recommendation #2015-16.

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 2016 market outcomes in three areas. Section A evaluates patterns of potential economic and physical withholding by load level in Eastern New York. Section B analyzes the use of market power mitigation measures in New York City and in other local areas when generation is committed for reliability. Section C discusses developments in the capacity market and the use of the market power mitigation measures in New York City and the G-J Locality in 2016.

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, which causes prices to typically be more sensitive to withholding and other anticompetitive conduct under high load conditions. Prices are also more sensitive to withholding in transmission-constrained areas where fewer suppliers compete to serve the load and manage the congestion into the area. Hence, our assessment focuses on potential withholding in Eastern New York because it contains the most transmission-constrained areas.

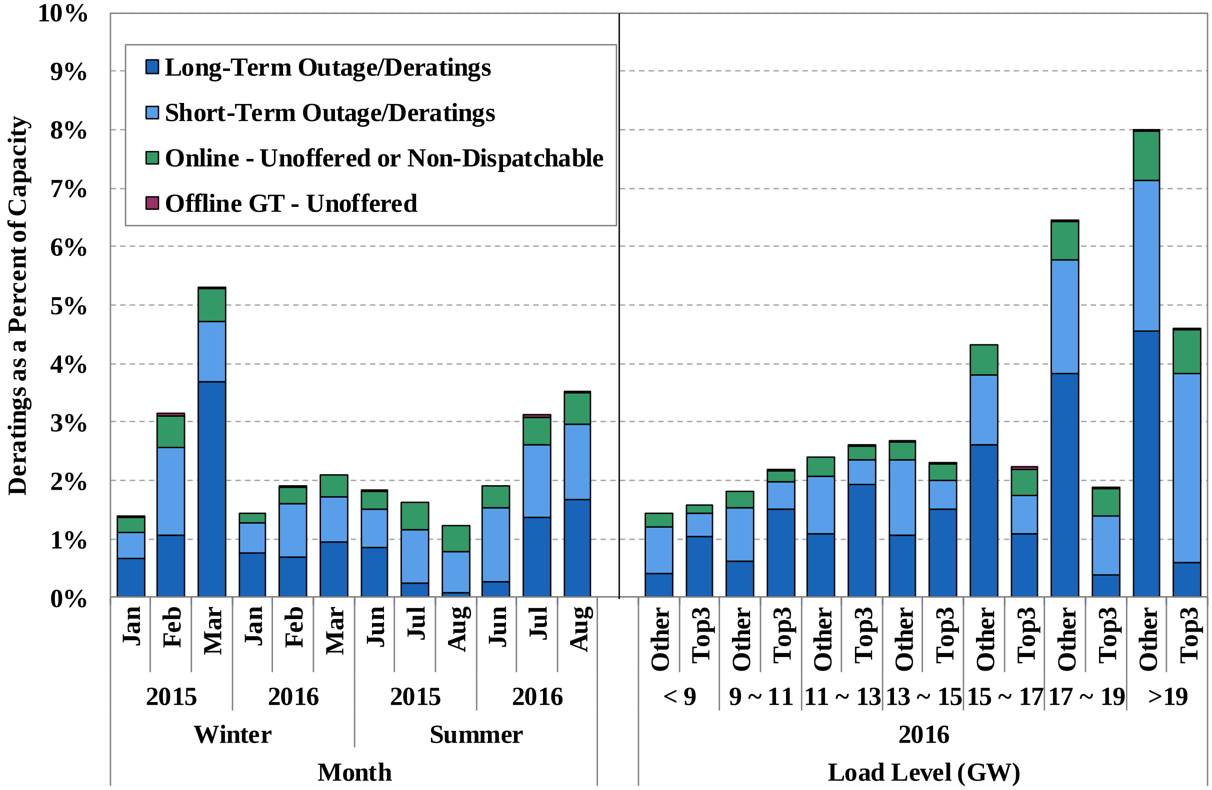
In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap". The output gap is the amount of generation that is economic at the market clearing price, but is not producing output because the supplier's offer parameters (economic or physical parameters) exceed the reference level by a given threshold.[24]

Figure 4 and Figure 5 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[25] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

24 The output gap calculation excludes capacity that is more economic to provide reserves. 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. Lower Threshold 1 is the 25 percent of the reference level, and Lower Threshold 2 is 100 percent of the reference level.

25 Both evaluations exclude capacity from hydro, solar, wind, landfill-gas, and biomass generators. They also exclude nuclear units during maintenance outages, since such outages cannot be schedule during a period when the generator would not be economic. Sections II.A and II.B in the Appendix show detailed analyses of potential physical and economic withholding.

Figure 4: Unoffered Economic Capacity in Eastern New York
2015-2016



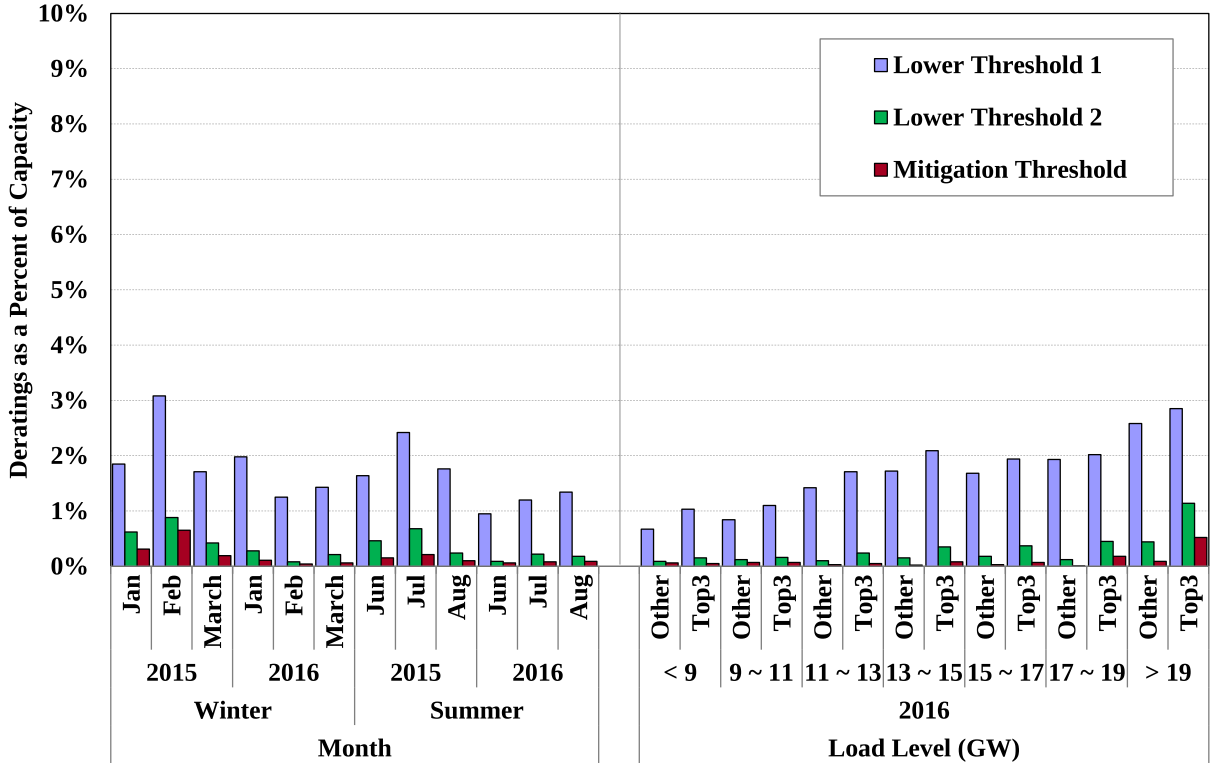
Generator outages and deratings in Eastern New York dropped noticeably in the winter 2016 from the previous winter but increased in the summer 2016 from the prior summer. These trends were driven by:

- Fewer maintenance outages scheduled during high load months; [26]
- Milder temperatures in the Winter 2016 than in the previous winter, reducing the incidence of fuel supply limitations on gas-fired units;
- Tight market conditions in the winter 2015 and the summer 2016 (relative to their counterparts) led more of the unoffered capacity to be economic during these periods; and
- In Southeast New York, one large unit was forced out from early-June to mid-September because of equipment failures.

The amount of output gap in Eastern New York remained very low in 2016, averaging less than 0.1 percent of total capacity at the statewide mitigation threshold and 1.4 percent at the lowest threshold evaluated (i.e., 25 percent above the reference level). These quantities are much smaller than the potential physical withholding shown in Figure 4.

[26] See Figure A-22 for this information by month in 2015 and 2016.

Figure 5: Output Gap in Eastern New York
2015 - 2016



Although output gap increased modestly as load rose, the amount was still relatively small. The output gap increased in high-load hours partly because a larger share of New York's resources tend to be economic at high-load levels. Much of this increase occurred on units that are: (a) co-generation resources that tend to operate inflexibly manner because of the need to divert energy production to non-electric uses; and/or (b) generators with gas supply limitations that are dependent on the consumption of nearby units whose costs are difficult to reflect dynamically in reference levels. In addition, it is generally a positive indicator that the output gap was comparable for top suppliers and other suppliers during high load conditions when the market is most vulnerable to the exercise of market power.

Overall, the patterns of unoffered capacity and output gap were generally consistent with expectations in a competitive market and did not raise significant concerns regarding potential physical or economic withholding under most conditions.

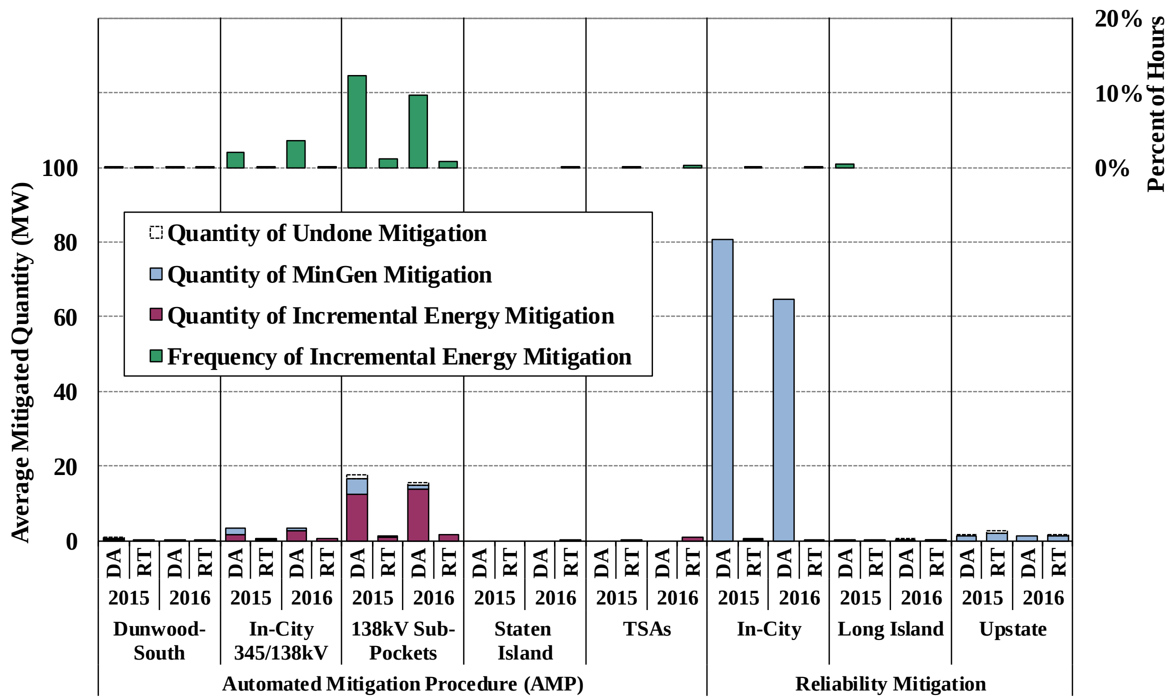
B. Automated Mitigation in the Energy Market

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

- Automated Mitigation Procedure ("AMP") in New York City – This is used in the day-ahead and real-time markets to mitigate offer prices of generators that are substantially above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[27]
- 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.

Figure 6 summarizes the market power mitigation that was imposed in the day-ahead and the real-time markets in 2015 and 2016.

Figure 6: Summary of Day-Ahead and Real-Time Mitigation
2015 - 2016



27 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.

Most mitigation occurs in the day-ahead market where most supply is scheduled. Gas turbines in the Greenwood/Staten Island pocket accounted for the vast majority of AMP mitigation in 2016 because this area had the most frequent congestion and the lowest mitigation threshold in New York City. However, the frequency of AMP mitigation in New York City has decreased in the recent years, falling from over 250 MW in 2011 to 17 MW in 2016, as generation additions and transmission upgrades reduced frequency of congestion (particularly in the 138kV load pockets). In addition, natural gas prices in New York City have fallen relative to other regions of the state, contributing to less frequent congestion in New York City and lower AMP mitigation.

Reliability mitigation accounted for 78 percent of all mitigation in 2016, 98 percent of which occurred in the day-ahead market in 2016. These were primarily for DARU and LRR commitments in New York City, which declined modestly in 2016.[28] Unlike AMP mitigation, these mitigations generally affect guarantee payment uplift, but not energy prices. The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have substantial market power.

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 new and existing generation, transmission, and demand response. Buyer-side mitigation ("BSM") measures are used in New York City and the G-J Locality to prevent entities from artificially depressing prices below competitive levels by subsidizing the entry of uneconomic capacity.[29] Supply-side mitigation measures prevent a large supplier from inflating prices above competitive levels by withholding economic capacity in these areas.[30] Given the sensitivity of prices in these areas to both actions, we believe that these mitigation measures are essential for ensuring that capacity prices in the mitigated capacity zones are efficient. This section discusses issues related to the use and design of capacity market mitigation measures in 2016.

Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests for five Additional CRIS MW projects in Class Year 2015 ("CY15") before they accepted their Project Cost Allocations in January 2017. Additional CRIS MW projects involve uprates to existing facilities and generally require lower investment costs and, in some instances, also improve the operating efficiency of the existing

28 See Section IX.F for more details on reliability commitments in New York City.

29 The buyer-side mitigation measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. See NYISO MST, 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. See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

capacity at the facility. As such, all five Additional CRIS MW projects in CY15 were determined to be exempt and will not be subject to Offer Floor mitigation.

In addition, the NYISO also evaluated the Champlain Hudson Power Express Project ("CHPE Project") for a Competitive Entry Exemption. The NYISO reviewed the project documentation, and confidentially provided a BSM determination to the developer. However, the developer subsequently failed to post the required security and the CHPE Project was removed from CY15. We carefully reviewed the process and assumptions used by the NYISO to make BSM determinations for each Examined Facility, and we found that the test was conducted in accordance with the tariff and that the outcomes were reasonable.[31]

Improvements to the BSM Measures

The NYISO made several modifications to its test methodology before the CY15 BSM evaluation. In particular, the NYISO enhanced its test procedure for the Part A and Part B tests by testing units sequentially from lowest to highest in the order of their presumptive Offer Floors and treating them as price takers. These modifications generally enhanced the alignment of the test procedure with the Tariff and with the underlying intent of the BSM evaluations. Hence, we support continuing the use of the modified test procedure in future BSM evaluations.[32]

It is still important to refine the BSM evaluation methodology, since an incorrect assessment of whether a project is economic could either inefficiently restrict investment or allow uneconomic entry that depresses capacity prices. Our past BSM reports have identified concerns with several assumptions that are used in the BSM evaluations.[33] These mainly relate to the test assumptions regarding forecasted in-service capacity supply and capacity requirements, entry dates of the Examined Facilities, and estimation of interconnection costs. Table 4 provides a list of identified issues and whether we have recommended addressing the issue with a process improvement (indicated by an "I") or with a tariff change (indicated by a "T").[34]

31 The NYISO conducted its BSM evaluation in three rounds. All Additional CRIS MW projects and the CHPE project received BSM determinations in the initial round. After the Caithness II Project (a proposed 750 MW combined cycle unit located in Long Island) dropped out of CY15, all projects received updated BSM determinations in the second round. The CHPE Project was removed from the CY15 after it failed to post the security for its Project Cost Allocation at the end of the second round. The five remaining CY15 Examined Facilities received revised BSM determinations in the final round. See the MMU's *Assessment of the Buyer Side Mitigation Exemption Test for the Class Year 2015 Projects* ("BSM Report for CY15").

32 For additional details, see BSM Report for CY15 Projects at page 50.

33 For example, see BSM Report for CY12 Projects.

34 See Recommendation #2013-2d in Section XI of this report. For details, see BSM Report for CY15.

Table 4: Summary of Recommended Enhancements to the BSM Evaluations

Issue:	Rec:
Interconnection costs may be inflated for some Examined Facilities (Part B test)	T
Starting Capability Period is unrealistic for most Examined Facilities (Part A & B tests)	T
Treatment of units in a Mothball Outage or an ICAP Ineligible Forced Outage or under a retirement notice is unrealistic for some units (Part A & B tests)	T
Treatment of some currently operating units at risk of retiring or mothballing is unrealistic for some units (Part A & B tests)	T
Treatment of Examined Facilities seeking Competitive Entry Exemption may be inconsistent with developers' expectations (Part A & B tests)	T
Treatment of Class Year projects located outside the Mitigated Capacity Zones may be unrealistic (Part A & B tests)	I
Treatment of exempt Prior Class Year Projects in the Interconnection Queue may be unrealistic (Part A & B tests)	I
Estimation of Locational Minimum Installed Capacity Requirements for the Mitigation Study Period needs refinement (Part A & B tests)	I

Potential Expansion of Buyer-Side Mitigation Measures

In response to a complaint by the Independent Power Producers of New York, the Commission recognized that the current buyer-side mitigation measures do not address all potential conduct that may suppress capacity prices.[35] To determine whether the buyer-side mitigation measures should be expanded to address additional types of conduct and capacity zones, the NYISO evaluated the incentives to suppress capacity prices. The NYISO concluded that there are incentives to retain existing capacity resources after they are economic to retire or mothball and submitted a compliance filing proposing a process for monitoring for such activity.[36]

We agree with the NYISO's determination regarding the incentives to retain existing units that should retire. To address this concern, we recommended the Commission require rules that would impose an offer floor on a generator (at its going-forward cost level) if the NYISO determines that the generator would have retired but for an above-market contract.[37]

In January 2017, the Electric Power Supply Association ("EPSA") filed a request for expedited action in the same docket and referred to the evolving "threat" of state-approved subsidies for

35 See the Commission's Order on March 19, 2015: *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, 150 FERC ¶ 61,139.

36 See NYISO filing dated December 16, 2015: *Response to Information Request*, Attachment II – pages 13 to 20, Docket No. EL13-62-002.

37 See MMU's comments filed on January 11, 2016 in Docket No. EL13-62.

retention or repowering of uneconomic units.[38] In particular, EPSA argued that: (a) additional payments to upstate nuclear facilities in the form of ZECs, and (b) the possible resumption of repowering the Dunkirk facility highlight the importance of expanding buyer-side mitigation rules. These initiatives together could retain up to 3.7 GW of capacity in the upstate region, which is unprecedented in magnitude. The largest tranche of new renewable capacity under the CES (Tier 1) will induce nearly 2 GW of UCAP to enter over the next twelve years, while the ZEC program could retain up to 3 GW of UCAP more immediately.[39] Therefore, the ZEC program is likely to have larger and much more immediate price effects.

Uneconomic entry and uneconomic retention in the wholesale electricity market raise serious concerns because they artificially alter the supply and demand balance by causing artificial supply surpluses that create sizable risks for market participants. Ultimately, this undermines the long-term performance of the wholesale markets and raises costs substantially. However, we also recognize that states have public policy goals that may entail support for certain types of resources, and we recognize that the current markets do not fully price many externalities of electricity generation, including environmental emissions. Thus, state subsidies that can be justified by the cost/value of the externalities could be legitimate. To protect the market and balance these competing considerations, we encourage the NYISO to consider provisions that would limit disruptive short-term supply-demand imbalances caused by public policies that subsidize resources to enter the market or remain in the market when it is economic to retire.

Additionally, as discussed in Section VIII.B, the costs of reducing CO_2 emissions varies by technology and location, and state programs to reduce emissions do not compensate resources in an efficient, non-discriminatory manner. For instance, the cost of reducing carbon by building new renewable energy resources is multiples of the cost of other actions. Further, many potential investments that would reduce carbon emissions receive no compensation under the state programs. When payments for the same attribute vary from one technology and/or supplier to another, the payments will not efficiently facilitate decisions to achieve the public policy objective and will undermine the wholesale electric markets.

Hence, the most efficient policies for reducing carbon missions are those that establish a value for carbon emissions that compensates participants in a transparent and non-discriminatory manner, which could include a carbon tax, a tradeable rate-based emission credit program, or a cap-and-trade program. Such programs would allow the market to provide incentives to reduce carbon emissions at the lowest cost.

38 See EPSA's request filed on January 9, 2017 in Docket No. EL13-62.

39 See page 279 of the *Clean Energy Standard White Paper – Cost Study* April 8, 2016. This assumes a constant capacity value for wind and solar units. However, the capacity values of these resources will decrease with increasing penetrations of renewables.

IV. Day-Ahead Market Performance

The day-ahead market enables firms to make forward purchases and sales of power for delivery in real-time the following day. This allows 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 because participants will adjust their purchases and sales to arbitrage such differences. Price convergence is desirable also because it promotes the efficient commitment of generation, procurement of natural gas, and scheduling of external transactions. In this section, we evaluate the convergence of the day-ahead and real-time energy and ancillary services prices and analyze virtual trading and other day-ahead scheduling patterns.

A. Day-Ahead to Real-Time Price Convergence

Convergence of Zonal Energy Prices

The following table 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.[40] These statistics are shown on an annual basis.

Table 5: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2015-2016

	Annual Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff	
Zone	2015	2016	2015	2016
West	-5.6%	-0.5%	52.8%	58.5%
Central	1.3%	0.3%	37.3%	38.4%
North	1.9%	0.6%	44.1%	58.4%
Capital	0.9%	2.1%	33.0%	34.1%
Hudson Valley	2.3%	0.9%	32.8%	33.9%
New York City	1.0%	-1.2%	34.0%	36.6%
Long Island	2.4%	0.5%	41.8%	45.0%

The average absolute difference between day-ahead and real-time prices increased in 2016 in all regions, and was highest in the West Zone, the North Zone, and Long Island because of:

- More transmission outages in the North Zone, Long Island, and near the Central-East interface;
- Increased congestion in the summer of 2016 because of higher load levels; and

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

- The implementation of the GTDC project in February 2016 resulted in higher congestion costs on most transmission constraints during transmission shortages, which increased price volatility, particularly in the West Zone and the North Zone. [41]

The average absolute difference continues to indicate the highest volatility is in Western and Northern New York, which is attributable to relatively low production costs of resources there and the variable effects of congestion from those areas towards the rest of the system. Prices were particularly high and volatile in the West Zone during periods of congestion on 230kV lines downstream of the Niagara plant as discussed below in Part 2.

Day-ahead prices were higher on average than real-time prices by a small margin in most areas in 2016. In general, a small day-ahead premium is expected in a competitive market, since load serving entities and other market participants avoid buying at volatile real-time prices by shifting more of their purchases into the day-ahead market.

Convergence of Nodal Energy Prices

Certain generator nodes exhibited less consistency between average day-ahead and real-time prices than zonal prices did in 2016.[42] This part of the section discusses three locations where price convergence was particularly poor in 2016.

First, at the Niagara 230 kV and 115 kV generator buses in the West Zone, the mean absolute difference between the hourly nodal premium and the hourly zonal premium was significant. This reflects that congestion patterns on the 230kV transmission system were frequently very different between day-ahead and real-time in 2016. This pattern was driven by: a) changes in the amount of supply (offered at a given price level) from Ontario and Niagara after the day-ahead market; b) volatile loop flows around Lake Erie; and c) operating practices that do not fully utilize parallel 115kV transmission lines in order to reduce congestion on the 230kV lines.[43]

Second, the Valley Stream load pocket in Western Long Island was affected by frequent real-time congestion on the East Garden City-to-Valley Stream line that was not well-reflected in the day-ahead market. This was primarily caused by large differences between day-ahead scheduled flows and actual real-time flows across the Jamaica-to-Valley Stream PAR-controlled line (i.e.,

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41 In general, a GTDC is expected to lower congestion price volatility by putting an upper bound on re-dispatch costs, but the GTDC project also included modifications to the pricing and scheduling algorithms that increased volatility in circumstances when the GTDC is not used. See Appendix Section V.F.

42 See Section I.H of the Appendix for detailed results.

43 External transaction bids and offers and generators offers are posted on the NYISO website on a 3-month lagged basis. These factors are discussed in more detail in Sections III.C and III.D of the Appendix.

the “901 Line”), which contributed to real-time price spikes in the load pocket.[44] The agreement under which the 901 Line is used to flow power from the Valley Stream Load Pocket to New York City results in inefficient market outcomes because this load pocket usually has much higher LBMPs. Inconsistencies between day-ahead schedules and real-time flows across the 901 Line also contributed to real-time price volatility and poor convergence between day-ahead and real-time prices (although real-time price volatility became less significant in May 2016 following changes to the modeling of the 901 Line).[45] We recommend the NYISO optimize the scheduling of the 901 Line in the day-ahead and real-time markets as discussed in Section IX.D.

Third, the Greenwood load pocket in New York City exhibited much less congestion in the day-ahead market than in real-time.[46] Day-ahead congestion was understated partly because uneconomic gas turbines were frequently scheduled in the day-ahead market. These schedules are caused by software changes made when the MIP (“Mixed Integer Program”) software was implemented in December 2014. In our 2015 SOM report, we recommended modifying the software to prevent the day-ahead market from over-scheduling gas turbines.[47] Accordingly, the NYISO implemented a software modification to this gas turbine commitment module in December 2016. Now this module does not commit additional gas turbines unless it would lower bid-production costs.[48]

At times, the pattern of intra-zonal 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. Allowing virtual trading at a disaggregated level would enable market participants to better arbitrage day-ahead and real-time prices at nodes that exhibit poor convergence. This would help improve consistency between day-ahead and real-time prices and ensure adequate resources are committed in the day-ahead market in sub-zonal areas.

Convergence of Ancillary Service Prices

As discussed in Section III.F, average day-ahead and real-time reserve prices rose for most reserve products in 2016 despite the decrease in energy prices. Day-ahead and real-time reserve prices did not converge well in 2016 – average day-ahead reserve prices were much higher than average real-time prices.

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44 The volatility of flows across the 901 Line has been a leading cause of transient price volatility in Long Island as shown in Section IX.E and of balancing congestion residual uplift as shown in Section V.A.0.

45 See Section V.D in the Appendix for more discussion of this modeling change.

46 See Section III.B in the Appendix for a discussion of day-ahead and real-time congestion patterns.

47 See Recommendation #21 in our 2015 SOM report.

48 The solution tolerance in the first MIP run is set at a higher level because of runtime considerations. The gas turbine commitment module (the second MIP run) uses a lower solution tolerance.

In addition to increased demand and overly restrictive limitation on scheduling reserves on Long Island, changes in supply offers following the market rule changes also contributed to the elevated day-ahead prices.[49] We have reviewed day-ahead reserve offers and found many units that offer above the standard competitive benchmark (i.e., estimated marginal cost) or do not offer reserves at all. It is likely that many of these suppliers offer in this manner because it is difficult for them to estimate their marginal costs accurately. Hence, day-ahead offer prices may fall as suppliers gain experience with the 30-minute reserve market. We will continue to monitor day-ahead reserve offer patterns, and consider potential rule changes including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the market power mitigation measures.[50]

B. Day-Ahead Load Scheduling and Virtual Trading

Convergence between day-ahead and real-time energy prices continues to be better at the zone level than at the node level partly because physical loads and virtual traders are able to bid at the zonal level in the day-ahead market. Under-scheduling load generally leads to lower day-ahead prices, while 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.

Table 6 shows the day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load on an annual basis in 2015 and 2016 for various regions in New York State.[51] Overall, net scheduled load in the day-ahead market was roughly 95 percent of actual NYCA load during daily peak load hours in 2016, similar to 2015. Day-ahead net load scheduling patterns in each of the sub-regions were generally consistent between 2015 and 2016 as well.

Table 6 indicates that average net load scheduling tends to be higher in locations where volatile real-time congestion is more common. Net load scheduling was generally higher in New York City and Long Island because they were downstream of most congested interfaces. Net load scheduling was the highest in the West Zone in the past two years partly because of high and volatile real-time congestion on the West Zone 230kV system.

49 Appendix Sections I.H and II.D evaluates day-ahead offer patterns and the convergence between day-ahead and real-time prices for: 10-minute spinning reserves in Western New York and in Eastern New York, 10-minute non-spin reserves in Eastern New York, and 30-minute operating reserves in Western New York.

50 See MST 23.3.1.2.1.2.1.

51 Figure A-37 to Figure A-44 in the Appendix also show these quantities on a monthly basis at these locations in New York.

Table 6: Day-Ahead Load Scheduling versus Actual Load
By Region, 2015-2016

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2015	99.5%	0.0%	-4.6%	24.2%			119.1%
	2016	96.7%	0.0%	-4.1%	24.7%			117.3%
Central NY	2015	119.6%	0.0%	33.0%	3.1%			89.7%
	2016	114.0%	0.0%	30.6%	4.0%			87.3%
North	2015	97.7%	0.0%	-51.7%	3.3%			49.3%
	2016	98.8%	0.0%	-55.7%	5.3%			48.4%
Capital	2015	97.8%	0.0%	-21.1%	5.6%			82.2%
	2016	98.3%	0.0%	-17.7%	5.3%			85.9%
Lower Hudson	2015	76.2%	20.8%	-12.1%	6.9%			91.7%
	2016	79.7%	19.5%	-23.9%	8.6%			83.9%
New York City	2015	89.0%	8.1%	-0.5%	4.2%			100.9%
	2016	83.2%	13.6%	-0.6%	6.3%			102.4%
Long Island	2015	100.7%	0.0%	-1.2%	9.3%			108.9%
	2016	99.8%	0.0%	-1.6%	9.8%			108.0%
NYCA	2015	97.1%	5.3%	-11.8%	7.0%	-2.9%	0.4%	95.2%
	2016	94.2%	7.0%	-12.6%	8.3%	-2.5%	1.1%	95.3%

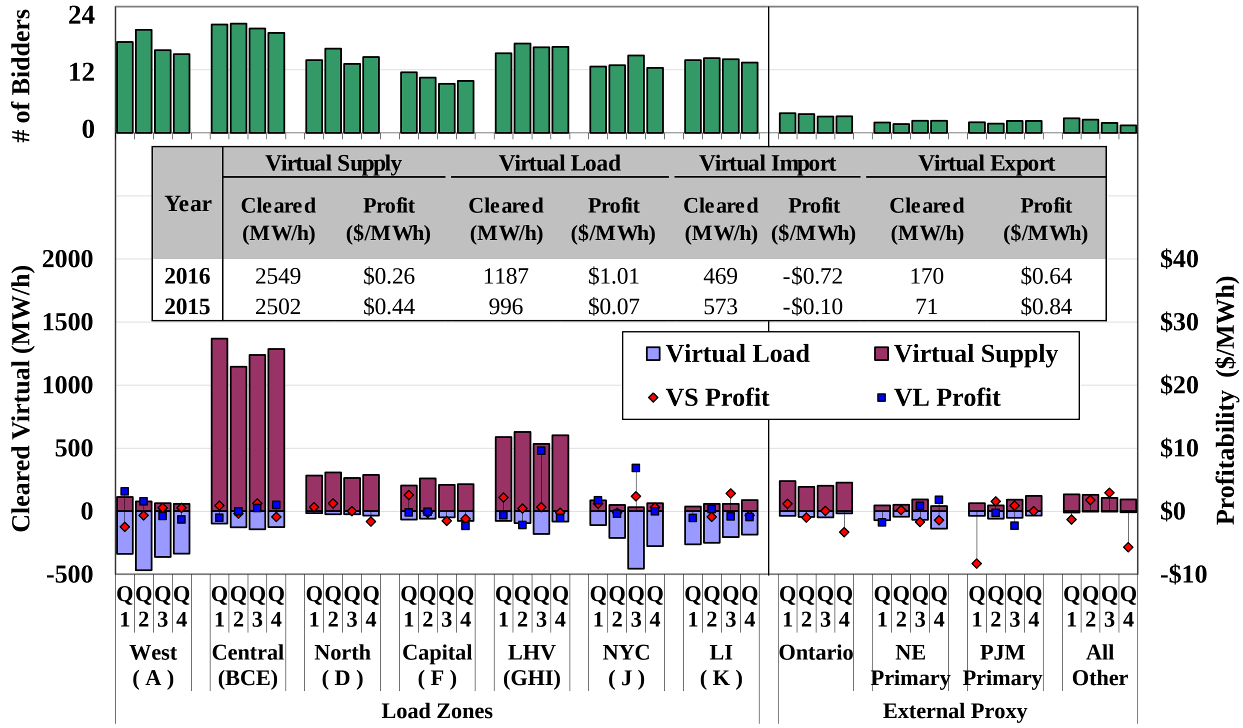
Load was typically under-scheduled in the North Zone by a large margin, primarily in response to the scheduling patterns of wind resources in this area. Wind generators and other renewable generators typically operate in real-time above their day-ahead schedules. In 2016, renewable generators added an average of 521 MW of additional energy supply in real-time, satisfying nearly 7 percent of the average real-time load outside Southeast New York. These increases in physical supply after the day-ahead market provide profit opportunities for virtual traders.

In general, the patterns of day-ahead scheduling were generally consistent with the price premiums exhibited in each of the zones. These patterns helped improve convergence between day-ahead and real-time prices and in doing so, improved the commitment of resources. For example, if constraints in the West Zone are not fully reflected in the day-ahead market, the market will rely heavily on Niagara generation and Ontario imports and commit less generation east of the constraints. Day-ahead scheduling patterns that increase west-to-east congestion in the West Zone increase commitments east of the West Zone in the day-ahead market.

To a large extent, the net day-ahead scheduling patterns are ultimately determined by virtual trading activity. Figure 7 summarizes virtual trading levels by location in 2016, including NYISO's internal zones and external interfaces.[52]

52 See Figure A-46 in the Appendix for a detailed description of the chart.

Figure 7: Virtual Trading Activity
by Region by Quarter, 2016



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)
2016	2549	$0.26	1187	$1.01	469	-$0.72	170	$0.64
2015	2502	$0.44	996	$0.07	573	-$0.10	71	$0.84

The volume of virtual trading did not change significantly in 2016 from the prior year. Virtual traders generally scheduled more virtual load in the West Zone, New York City and Long Island and more virtual supply in other regions. This pattern was consistent with the day-ahead load scheduling patterns discussed earlier and occurred for similar reasons. At the proxy buses, over 70 percent of scheduled virtual transactions were virtual imports. Nearly half of virtual imports were scheduled at the Ontario interface, which exhibited a significant day-ahead premium before 2016 because of higher real-time congestion on the West Zone 230 kV facilities. In 2016, average day-ahead and average real-time prices were more consistent at the Ontario interface.

The profits and losses of virtual load and supply have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices. In aggregate, virtual traders netted approximately $14 million of gross profits in 2016, indicating that they have generally improved convergence between day-ahead and real-time prices. Additionally, the average profit per MWh was relatively low in 2016, indicating that the markets were relatively well-arbitraged and consistent with the good convergence achieved in 2016. Good price convergence, in turn, facilitates an efficient commitment of generating resources.

V. Transmission Congestion and TCC Auctions

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.

A. Day-ahead and Real-time Transmission Congestion

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 day-ahead LBMPs and real-time LBMPs, respectively.[53] 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.

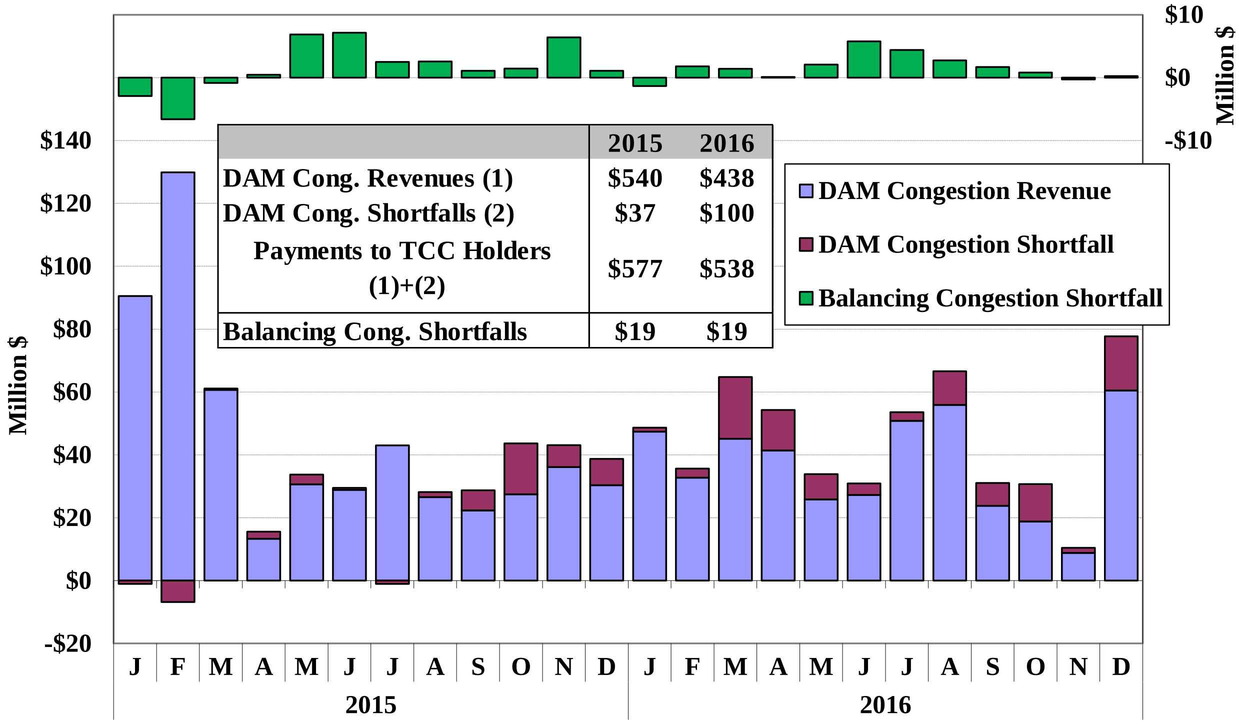
Figure 8 evaluates overall congestion by summarizing:

- 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 – This uplift occurs 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 – This uplift arises when day-ahead scheduled flows over a constraint exceed what can flow over the same constraint in the real-time market.

Congestion revenues collected in the day-ahead market fell by 19 percent from 2015 to $438 million in 2016. However, day-ahead congestion shortfalls rose by 170 percent in 2016 to $100 million, while balancing congestion shortfalls were unchanged. These results are discussed in the subsections below.

53 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). Congestion charges to other purchases and sales are based on the congestion component of the LBMP at the purchasing or selling location.

Figure 8: Congestion Revenues and Shortfalls
2015 – 2016



Day-Ahead Congestion Revenues

Variations in natural gas prices have significant impact on congestion patterns and revenues because they determine the costs of the resources that must be moved to manage transmission flows. In addition, large gas price spreads between regions increase congestion by raising the cost trade-offs of moving units to manage interregional flows. Hence, day-ahead congestion revenues were down 55 percent year-over-year in the first quarter of 2016 as natural gas prices across the state fell 18 to 70 percent. However, day-ahead congestion revenues rose 21 percent in the remaining nine months of 2016 because of:

- Higher load levels in the summer months, which increased flows across the network and resulted in more frequent transmission bottlenecks;
- Costly transmission outages across the Central-East interface, between New Jersey and the Hudson Valley, on Long Island, and from the North Zone to Central New York;[54] and
- The implementation of the GTDC Project in February 2016, which increased the congestion shadow prices on most transmission constraints during transmission shortages, leading to similar increases in the day-ahead market based on expectations.[55]

54 See Section III in the Appendix for more detailed description of these transmission outages.

55 See Section V.F in the Appendix for discussion of the GTDC.

Congestion on 230kV lines in the West Zone has been significant, accounting for the second largest share (25 percent) of day-ahead congestion revenues in 2016. Congestion in the West Zone was affected by offsetting factors in 2016. Factors that increased congestion included:

- The mothball/retirement of the last Dunkirk unit in December 2015 and two Huntley units in March 2016, which had helped relieve West Zone congestion;
- The implementation of a composite shift factor at the Niagara plant in early May 2016; [56]
- Average clockwise loop flows around Lake Erie were higher in 2016.[57]

While the following factors helped reduce congestion in the West Zone:

- Two series reactors on the Packard-Huntley 230 kV lines were added in May 2016, which can divert flows from 230 kV paths to parallel 345 kV and 115 kV paths.
- The S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line were OOS for most of 2016 for 115kV transmission security, reducing flows on congested 230 kV lines.

Day-Ahead Congestion Shortfalls

Day-ahead shortfalls occur when the day-ahead network capability is less than the capability embedded in the TCCs, while day-ahead surpluses (i.e., negative shortfalls) occur when day-ahead schedules across a binding constraint exceed the capability embedded in the TCCs. Table 7 shows total day-ahead congestion shortfalls for selected transmission facility groups.[58]

Table 7: Day-Ahead Congestion Shortfalls in 2016

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**$2**
Other Factors (e.g., Loopflows, Outages)	**$27**
Central to East	
Ramapo, ABC & JK PARs	**$2**
Other Factors	**$32**
North to Central	**$17**
NYC Lines	**$6**
Long Island Lines	
901/903 PARs	**-$2**
Excess GFTCC Allocations	**$4**
Other Factors	**$11**
External	**-$2**
All Other Facilities	**$3**

56 See Section III.C in the Appendix for discussion of the composite shift factor.

57 See Section III.D in the Appendix for discussion of the Lake Erie loop flows.

58 Section III.B in the Appendix also provides detailed description of each transmission facility group and summarizes the day-ahead congestion shortfalls on major transmission facilities.

Day-ahead congestion shortfalls rose substantially from $37 million in 2015 to $100 million in 2016 primarily because of more costly transmission outages. Notable examples include:[59]

- $34 million of shortfalls on the Central-East interface, most of which was attributable to outages from January to May to facilitate the completion of the TOTS project and one 345 kV line outage in December that reduced the interface limit by up to 900 MW;
- $17 million of shortfalls on the transmission paths that typically flow power from North to Central New York, due primarily to outages of 765 kV transmission facilities at the Marcy station in April, May, September and October;
- $11 million of shortfalls on Long Island lines, primarily from the Y49 line outages from late May to early July and from early August to late September; and
- $11 million of shortfalls on West Zone lines because several facilities along the Niagara-Packard-Sawyer-Huntley path were out of service intermittently during the year.

The NYISO allocates day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[60] In 2016, the NYISO allocated 66 percent of the net total day-ahead congestion shortfalls in this manner, down from 103 percent in 2015. Transmission owners can schedule outages in ways that reduce labor and other maintenance costs, but these savings should be balanced against the additional uplift costs from congestion shortfalls. Allocating congestion shortfalls to the responsible transmission owners is a best practice for RTOs because it provides incentives to minimize the overall costs of transmission outages.[61]

Congestion shortfalls that were not allocated to transmission owners typically result from modeling inconsistencies between the TCC and day-ahead markets, which included:

- Different loop flow assumptions between the TCC auction and the day-ahead market. Higher loop flow assumptions in the day-ahead market led to a shortfall of over $10 million in 2016.
- Grandfathered TCCs that exceed the actual transfer capability from Dunwoodie (Zone I) to Long Island.[62] This resulted in a shortfall of $4 million in 2016, comparable to 2015.
- Different scheduling assumptions for the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines). Since flows across these lines are generally uneconomic, reducing the assumed flow from the TCC auction to the day-ahead market led to surplus congestion revenue of $2 million in 2016.

59 Section III.B in the Appendix discusses the transmission outages that are responsible for these shortfalls.

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

61 Transmission outages can also result in uplift from balancing congestion shortfalls and from BPCG payments to generators that must run out-of-merit for reliability due to the outage. The majority of these BPCG payments (which are discussed in Section IX.G) are assigned to the transmission owner.

62 This is categorized as "Excess LI GFTCC Allocations" in the table.

- The difference between the TCC auction and the day-ahead market in the assumed distribution of Niagara generation at its 230 kV and 115 kV buses. The 115 kV Niagara generation generally helps relieve congestion on the 230 kV constraints in the West Zone, while 230 kV Niagara generation exacerbates congestion. In 2016, this led to a shortfall of $2 million, which fell from a $7 million shortfall in 2015 because the NYISO implemented a modeling change on the Niagara Plant on May 4, 2016.[63]

Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in the transmission capability from the day-ahead market to the real-time market, while surpluses (i.e., negative shortfalls) occur when real-time flows on a binding constraint are higher than those in the day-ahead market. Unlike day-ahead shortfalls, balancing congestion shortfalls are generally socialized through Rate Schedule 1 charges.[64] Balancing shortfalls totaled $19 million in 2016 and were comparable to 2015. Table 8 shows total balancing congestion shortfalls by selected transmission facility groups.[65]

Table 8: Balancing Congestion Shortfalls in 2016[66]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**-$0.4**
Ramapo, ABC & JK PARs	**$6**
Other Factors (e.g., Outages, Loopflows)	**$9**
Central to East	
Ramapo, ABC & JK PARs	**-$8**
Other Factors	**$4**
Capital to HVL (TSAs)	**$10**
Long Island Lines	
901/903 PARs	**$3**
Other Factors	**$1**
All Other Facilities	**-$1**

63 See "Niagara Generation Modeling Update" by David Edelson at MIWG, April 5, 2016.

64 The only exception is that some balancing congestion shortfalls from TSA events are allocated to ConEd.

65 Figure A-56 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2015 and 2016 on a monthly basis. Section III.E in the Appendix also provides detailed description for these transmission facility groups and a variety of reasons why their actual flows deviated from their day-ahead flows.

66 The balancing congestion shortfalls estimated in this table differ from actual balancing congestion shortfalls because the estimate: (a) is partly based on real-time schedules rather than metered injections and withdrawals; and (b) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of price corrections and Scarcity Pricing Adjustments.

Similar to 2015, the 230 kV transmission facilities in the West Zone accounted for the largest share of balancing congestion shortfalls in 2016. The primary drivers included transmission outages and un-modeled factors (such as loop flows), which collectively accounted for $9 million of shortfalls. Clockwise loop flows around Lake Erie reduce the transmission capacity available for the NYISO real-time market and increase congestion on transmission paths in Western New York. Hence, congestion shortfalls typically will arise when the actual unscheduled clockwise loop flows is significantly higher than assumed in the day-ahead market. There was a strong correlation between the severity of West Zone congestion and the magnitude and volatility of unscheduled clockwise loop flows.[67]

Thunder Storm Alert ("TSA") constraints accounted for nearly $10 million of shortfalls in 2016, most of which occurred on one day in July and two days in August. During these events, transfer capability into Southeast New York was greatly reduced. TSA-related congestion shortfalls in 2016 were much higher than in the previous two summers partly because of higher load levels during TSA events and less congestion relief from the Ramapo PARs because of outages.

Operation of the Ramapo PARs under the M2M JOA with PJM has provided significant benefits to the NYISO since January 2013, but effects were mixed in 2016. Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed a net of $2 million in estimated surpluses. We estimate that $8 million of *surpluses* primarily from relieving Central-East congestion were offset by $6 million of *shortfalls* from West Zone lines not coordinated under the M2M JOA. To better recognize these competing objectives, the NYISO modified its operating practices in November 2015 to limit use of the Ramapo coordination process to periods when the NYISO does not expect constraints in Western New York to be active.[68]

The operation of the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) contributed to balancing congestion shortfalls of $3 million in 2016 (and $4 million in 2015). These shortfalls arise because of differences in the schedule assumptions for the lines in the day-ahead market and in the real-time market. Average real-time flows on these lines were similar to the average day-ahead assumptions. However, when real-time flows were higher, they often contributed to very high prices in Long Island.[69] For example, real-time flows from Long Island to New York City on the 901 line exceeded the day-ahead assumption by an average of 14 percent during intervals with real-time congestion even though they were consistent on average.

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67 See Subsection III.D in the Appendix for more discussion of loop flows and their effect on congestion.

68 See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

69 The analysis discussed in Section V.D in the Appendix indicates that these lines were the primary cause of price volatility in the Valley Stream load pocket on Long Island until May 2016 when modeling changes were made to improve the forecasted real-time flows across the lines.

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 the Winter 2015/16 and Summer 2016 Capability Periods (i.e., November 2015 to October 2016).

Table 9 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[70]

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

Table 9: TCC Cost and Profit
Winter 2015/16 and Summer 2016 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$34	$18	53%
New York City	$10	$3	33%
Long Island	$7	$16	235%
All Other	$14	-$6	-45%
Total	**$65**	**$32**	**49%**
Inter-Zonal TCC			
Other to West Zone	$68	$41	60%
Other to New York City	$16	-$6	-38%
Other to Hud VL	$38	-$17	-44%
Upstate New York to New England	$36	-$19	-51%
All Other	$10	-$7	-70%
Total	**$169**	**-$8**	**-5%**

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2015 to October 2016 netted a total profit of $24 million. Overall, the net profitability for TCC holders in this period was 10 percent (as a weighted percentage of the original TCC prices).

70 Section III.F in the Appendix describes the methodology to break each TCC into inter-zonal and intra-zonal components.

Nearly 45 percent (or $102 million) of TCC purchase costs were spent on inter-zonal and intra-zonal transmission paths sinking at the West Zone, which was substantially higher than the $28 million of purchase costs spent in the prior 12-month period. TCC buyers netted a profit of $59 million on these transmission paths in 2016, consistent with higher-than-anticipated day-ahead market congestion in this area.[71]

TCC buyers also received a $16 million net profit for net purchases of $7 million on Long Island that was primarily due to much higher-than-expected congestion in the third quarter of 2016. This was driven largely by two transmission outages:

- The Y49 line (i.e., the Dunwodie-Shore Rd 345 kV line) was forced out during most of the third quarter, reducing imports from upstate and leading to higher LBMPs on Long Island.
- The 677 line (i.e., the Northport-Pilgrim 138 kV line) was partially derated throughout the quarter, leading to frequent congestion from Northport to other areas of Long Island.

The day-ahead congestion between areas across the Central-East interface was well below the prices in the TCC auctions, particular during the Winter 2015/16 Capability Period. As explained above, natural gas prices and price spreads between areas were much lower than expected, particularly at the time of the one-year and six-month TCC auctions, contributing to lower-than-anticipated west-to-east congestion. This resulted in lower-than-anticipated congestion prices in Eastern New York and at the New England proxy bus as well. Consequently, TCC buyers netted a 46 percent loss (i.e., $42 million in losses on $91 million of purchase) on inter-zonal transmission paths sinking at New York City, Hudson Valley, and New England.

In general, the TCC prices reflected the anticipated level of congestion at the time of auctions. The past results of the TCC auctions generally show that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month auction to the reconfiguration auction. This is expected since more accurate information is available about the state of the transmission system and likely market conditions in the auctions that occur closer to the actual operating period. Since 100 percent of the capability of the transmission system is available for sale in the form of TCCs of six-months or longer, very little revenue is collected from the monthly Reconfiguration Auctions. Hence, selling more of the capability of the transmission system in the monthly Reconfiguration Auctions (by holding back a portion of the capability from the six-month auctions) would likely raise the overall amount of revenue collected from the sale of TCCs.

[71] See Section III.C in the Appendix for discussion of West Zone congestion.

VI. External Transactions

Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas. The latter is beneficial because it allows:

- Low-cost external resources to compete to serve consumers who would otherwise be limited to higher-cost internal resources;
- Low-cost internal resources to compete to serve load in adjacent areas; and
- NYISO to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in each control area.

New York imports and exports substantial amounts of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. In addition, Long Island and New York City connect directly to PJM and New England across eight controllable lines that are collectively able to import nearly 3.5 GW directly to downstate areas.[72,73] The Branchburg-Ramapo line and the J and K lines connect the Hudson Valley to PJM with more than 2 GW of additional transfer capability. Hence, New York's total import capability is substantial relative to its load, making it important to schedule the interfaces efficiently.

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

Table 10 summarizes the net scheduled imports between New York and neighboring control areas in 2015 and 2016 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[74] Total net imports from neighboring areas averaged nearly 2.9 GW during peak hours in 2016, up 13 percent from 2015.

Table 10: Average Net Imports from Neighboring Areas
Peak Hours, 2015 – 2016

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2015	1,149	934	256	-664	186	510	46	61	69	2,548
2016	1,408	778	382	-664	205	590	39	129	11	2,878

72 The controllable lines are: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, the Neptune Cable, and three lines known as the A, B, and C lines.

73 The A, B, and C lines (which interconnect New York City to New Jersey) were used to flow 1,000 MW from upstate New York through New Jersey into NewYork City under the ConEd-PSEG wheeling agreement that terminated May 1, 2017. These lines were scheduled as part of the primary PJM to NYISO interface rather than by participant-submitted transaction, so they are evaluated in Section IX.D.

74 Figure A-58 to Figure A-61 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

Controllable Interfaces

As in prior years, imports from neighboring control areas satisfied roughly 30 percent of the demand on Long Island in 2016. The Neptune line was typically fully scheduled during daily peak hours absent outages/deratings. Net imports over the Cross Sound Cable and the 1385 line varied in a manner similar to the primary New England interface – lower in the winter when natural gas prices in New England were much higher than natural gas prices on Long Island.

Net imports to New York City over the Linden VFT and the HTP interfaces were modest, averaging 140 MW during peak hours in 2016.[75] Net imports across these two controllable interfaces typically rise in the winter months when natural gas prices in New York City are often higher than in New Jersey and fall from May to October when natural gas prices in New York City are lower than in most areas in PJM.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces increased 14 percent from 1,675 MW in 2015 to 1,905 MW in 2016 during the peak hours. Net imports from Hydro Quebec to New York accounted for 74 percent of net imports across the primary interfaces in 2016. Variations in Hydro Quebec imports are normally caused by transmission outages on the interface. Hence, average net imports rose 23 percent in 2016 primarily because of fewer transmission outages.[76]

Average net imports from Ontario fell 17 percent in 2016 as the Ontario interface exhibited more frequent import limitations and lower clearing prices during periods with West Zone congestion. Many of the import limitations were imposed by the NYISO to manage congestion on internal 230 kV and 115 kV constraints in western New York. However, the NYISO has discontinued the practice of imposing such limitations for internal 230 kV constraints because they can be managed more efficiently in the day-ahead and real-time markets' security-constrained commitment and dispatch.[77]

Net imports from PJM and New England across their primary interfaces varied considerably, tracking variations in gas price spreads between these regions. For example, New York normally has higher net imports from PJM and higher net exports to New England in the winter season, consistent with the spreads in natural gas prices between these markets in the winter (i.e., New England > New York > PJM).

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75 The HTP interface has a capability of 660 MW and Linden VFT has a capability of 315 MW.

76 Imports from Hydro Quebec were unusually low in May and October 2015 because of lengthy outages.

77 See *External Total Transfer Capability Interface Limits*, presented by Wes Yeomans to NYISO Operating Committee, February 9, 2017. Curtailment of external transactions to manage internal 115 kV congestion is discussed in Section IX.F.0.

C. Unscheduled Power Flows

The pattern of unscheduled power flows (i.e., 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 generally exacerbate west-to-east congestion in New York, leading to increased congestion costs. Although average clockwise circulation has fallen notably since the IESO-Michigan PARs went into service in April 2012, rapid and large fluctuations in loop flows were still common in 2016.[78,79]

Our analysis shows a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows.[80] During real-time intervals in 2016 with no congestion in the West Zone, the average clockwise loop flows were relatively small. However, West Zone congestion became more prevalent when loop flows were significant in the clockwise direction or when they happened to swing rapidly in the clockwise direction. We found that:

- Congestion value on the West Zone 230 kV constraints exceeded $300,000 in only 0.3 percent of all intervals in 2016. However, these intervals accounted for roughly 60 percent of the total congestion value in the West Zone in 2016.[81]
- During these intervals, unscheduled clockwise loop flows averaged over 160 MW and changes of unscheduled loop flows in the clockwise direction averaged 40 MW.

Section IX.E discusses additional analysis of transient congestion that is caused by unscheduled loop flows and other factors that are not explicitly modeled in the dispatch software. Section V.0 discusses the effects of loop flow on day-ahead and balancing congestion shortfall uplift.

D. 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 2016. As in previous reports, 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.

78 These PARs are generally operated to better conform actual power flows to scheduled power flows across the Ontario-Michigan interface. The PARs are capable of controlling up to 600 MW of loop flows around Lake Erie, although the PARs are generally not adjusted until loop flows exceed 200 MW.

79 Use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

80 See Section III.D in the Appendix for more details.

81 Congestion value is a measure of real-time flow over a constraint times the shadow price of the constraint. The quantity is used to quantify congestion in Section V.0

Table 11 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets during 2016.[82]

Table 11: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2016

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Free-flowing Ties								
New England	-698	$0.56	45%	-$2	52	$1.30	59%	$7
Ontario					871	$7.73	81%	$61
PJM	292	$0.17	69%	$7	5	$0.09	63%	$5
Controllable Ties								
1385 Line	70	$1.14	66%	$2	-31	$0.53	53%	$1
Cross Sound Cable	191	$4.58	73%	$12	-1	$2.83	55%	$0.1
Neptune	568	$7.95	89%	$41	-8	$6.83	59%	$0.5
HTP	7	$3.38	82%	$0.1	2	$3.78	64%	$0.2
Linden VFT	93	$3.56	79%	$6	44	$3.21	67%	$3

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 more than half of the hours on most interfaces between New York and neighboring markets during 2016.

In the day-ahead market, the share of hours with efficient scheduling was generally higher for the five controllable ties than the free-flowing ties, probably because there is generally less uncertainty in predicting price differences across these controllable lines. A total of $61 million in day-ahead production cost savings was achieved in 2016 across the five controllable ties. The Neptune Cable accounted for 67 percent of these savings because the interface was generally fully scheduled and the New York price was nearly $8/MWh higher on average in 2016.

Real-time transactions between Ontario (which lacks a day-ahead market) and New York flowed in the efficient direction in nearly 81 percent of hours. This was partly due to the fact that the price on the New York side was consistently higher by an average of nearly $8/MWh in 2016. As a result, a total of $61 million in production cost savings was achieved across the Ontario interface, despite the congestion on the 230 kV system in the West Zone, the substantial charges that are assessed to export transactions ($3 to $4 per MWh in 2016), and the fact that the NYISO frequently limited imports from Ontario to secure its internal 115 kV transmission facilities.

The right panel in the table evaluates how participants adjusted their transactions in response to real-time prices, indicating that these adjustments were efficient in well over half of the hours. Such adjustments across the PJM and New England primary interfaces resulted in a total of $12

82 See Section IV.B in the Appendix for a detailed description of this table.

million savings in production costs while real-time adjustments across the controllable ties were less frequent. Many of the adjustments resulted from curtailments or checkout failures of a day-ahead transaction, which tended to raise production costs modestly.

Although significant benefits have been achieved in the majority of hours, there was still a large number of hours when power flowed in the inefficient direction on all of the interfaces, or hours when large amounts of additional efficient flows could have been scheduled. These results indicate how uncertainty and other costs and risks interfere with efficient interchange scheduling, which underscores the value of having well-functioning, Coordination Transaction Scheduling.

E. Evaluation of Coordinated Transaction Scheduling

Although scheduling by market participants tends to improve convergence, opportunities remain to improve the interchange between regions. Coordination Transaction Scheduling ("CTS") is a market process whereby two RTOs exchange and use real-time market information to clear market participants' intrahour external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the hourly LBMP-based scheduling system.

- CTS bids are evaluated relative to the neighboring ISO's short-term price forecast, while the previous system required market participants to forecast prices in the adjacent market (more than 75 minutes in advance).
- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established 45 to 105 minutes in advance, while schedules are now determined 15 minutes ahead when more accurate system information is available.
- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

The CTS was first implemented with PJM on November 4, 2014 and with ISO-NE on December 15, 2015. It is important to evaluate the performance of CTS on an on-going basis to identify and implement improvements.

Evaluation of CTS Bidding

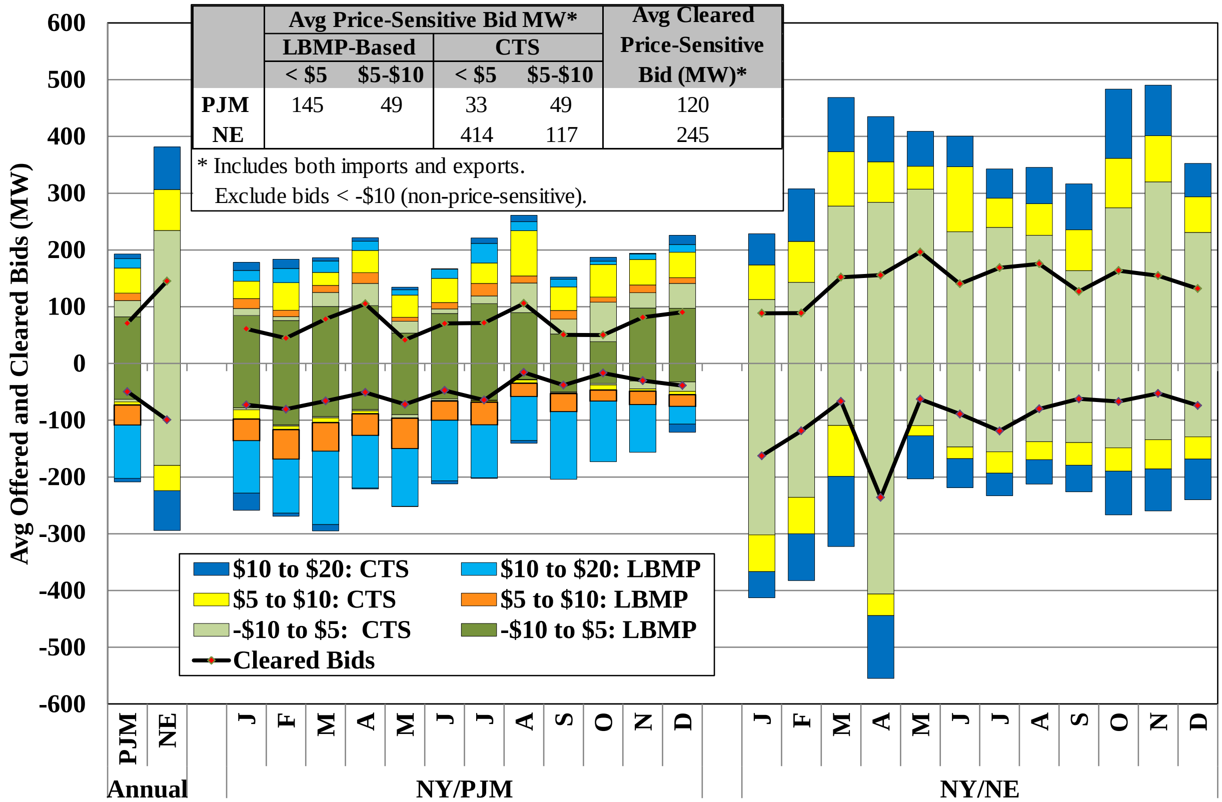
CTS is that it requires traders to submit bids that will be scheduled only when the RTOs' forecasted price spread is greater than the bid price, so the process required a sufficient quantity of price-sensitive bids.[83] Figure 9 evaluates the price-sensitivity of bids at the PJM and ISO-NE interfaces, showing the average amount of bids at each interface during peak hours (i.e., HB 7 to

83 Before adopting CTS, the NYISO and ISO-NE considered an alternative design called "Tie Optimization" which would have scheduled interchange based on the ISO's forecasts without participation by traders. Concurrent with the publication of this report, we published an initial assessment of whether Tie Optimization would likely have performed better than CTS with ISO-NE. For additional details about this study, see *First Year Evaluation of CTS between New England and New York*, presented to Joint ISO-NE/NYISO Stakeholder Meeting on April 20, 2017.

22) by month. Only CTS bids are allowed at the ISO-NE interface, while both CTS bids and LBMP-based bids are allowed at the PJM interface. Thus, the figure shows LBMP-based bids relative to the short-term forecast so that the price-sensitivity of LBMP-based bids can be directly compared to that of CTS bids.[84]

Figure 9: Average CTS Transaction Bids and Offers by Month

PJM and NE Primary Interfaces - 2016



Participation in CTS at the PJM interface is still relatively low after two years. The amount of price-sensitive bids (CTS and LBMP-based together) at the PJM interface was significantly lower than at the New England interface in 2016, and only 30 percent of the price sensitive bids at the PJM interface were CTS bids. An average of 414 MW (including both imports and exports) were offered between -$10 and $5/MWh at the New England interface, more than double the amount offered at the PJM interface. Likewise, the cleared price-sensitive bids at the New England interface were more than double the amount cleared at the PJM interface.

The differences between the two CTS processes are largely attributable to the large fees that are imposed at the PJM interface, while there are no substantial transmission charges or uplift charges on transactions between New York and New England. The NYISO charges physical

84 For example, if the short-term price forecast in PJM is $27, a $5 CTS bid to import would be scheduled if the NYISO price forecast is greater than $32. Likewise, a $32 LBMP-based import offer would be scheduled under the same conditions. Thus, the LBMP-based offer would be shown in the figure as comparable to a $5 CTS import bid. Section IV.C in the Appendix describes this figure in greater detail.

exports to PJM at a rate typically ranging from $4 to $8/MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than $2/MWh. These charges are a significant economic barrier to achieving the potential benefits from the CTS process, since large and uncertain charges deter participants from submitting price-sensitive CTS offers at the PJM border. These results demonstrate that imposing large transaction fees on low-margin trading dramatically reduces trading and liquidity. Hence, we recommend eliminating these charges.[85]

Evaluation of CTS Production Cost Savings

We also performed a more general assessment of the savings produced by the CTS processes at both interfaces, which are primarily affected by the accuracy of the RTOs' price forecasts and the charges assessed to the CTS transactions.[86]

We estimated that $4.5 million and $3.1 million in production cost savings was anticipated based on information available when RTC determined final interchange schedules at the New England and PJM interfaces in 2016.[87] The potential savings were higher at the New England interface because the higher liquidity of bidding at that interface contributes to larger and more frequent intra-hour interchange adjustments. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that:

- Only $2 million of $4.5 million in potential savings were realized at the New England interface; and
- Almost no savings were realized at the PJM interface.

Although projected savings were relatively consistent with actual savings when the forecast errors were moderate, the CTS process produced much more inefficient results when forecast errors were larger. In 2016, nearly 80 percent of projected production cost savings were realized at the New England interface during intervals when forecast errors from both markets were less than $20/MWh. Similarly, nearly 70 percent was realized at the PJM interface in such intervals. However, small or even negative savings were actually realized at both interfaces in a small number of intervals with large forecast errors, undermining the overall efficiency of CTS.

The performance of the price forecast was slightly better at the PJM interface than at the New England interface during 2016. For example, price forecast errors were less than $5/MWh in a

85 See Recommendation #2015-9.

86 Section IV.C in the Appendix describes this analysis in detail.

87 Our evaluation tends to under-estimate the production cost savings, because the hourly schedules that we estimate would have occurred without CTS reflect some of the efficiencies that result from CTS.

higher share of intervals at the PJM interface partly because the price-elasticity of supply in PJM is normally greater because of the larger size of the PJM market.

Based on our evaluation of the NYISO's RTC price forecasts, we identified two significant issues that contribute to its forecast errors:

- During units' shut-down cycles, RTD's "Pricing Pass" (which executes the real-time pricing logic) uses unrealistic ramp assumptions that can cause transient price spikes that increase CTS scheduling risks and undermine scheduling incentives.[88]
- RTC assumes external transactions ramp up to their schedule by the top of the scheduling interval, while RTD assumes that external transactions start to ramp five minutes before the interval and reach their schedule five minutes after the interval (five minutes later than RTC).[89] The price differences between RTC and RTD were much larger when the difference in the assumed imports in the two markets exceeded 200 MW.[90]

Although the intra-hour scheduling through CTS process promises substantial savings, achieving these savings will require:

- Reducing or eliminating the fees charged to transactions between PJM and the NYISO to encourage more efficient utilization of the interfaces between the two regions.
- Improving the accuracy of the forecast assumptions by NYISO and PJM to facilitate more efficient interchange scheduling.[91]

We will continue to monitor the performance of CTS between the NYISO and neighboring markets, and recommend improvements to maximize its effectiveness.

88 See Section IX.E for additional details about this issue.

89 Figure A-66 in Section IV.E in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transaction.

90 See Section IV.C in the Appendix for our evaluation in more detail.

91 See Recommendation #2015-9 to eliminate transaction fees and Recommendation #2012-13 to bring consistency between the ramp assumptions used in RTC versus RTD.

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 to facilitate new investment, retirement decisions, and participation by demand response. The capacity auctions have set clearing prices since their inception for three distinct locations: New York City, Long Island, and NYCA. Beginning with the Summer 2014 Capability Period, the capacity market incorporated an additional capacity Locality for Southeast New York, known as the G-J Locality. By setting a distinct clearing price in each Locality, the capacity market can facilitate investment in areas where it is needed to satisfy the NYISO's planning needs. This section summarizes the capacity market results in 2016, discusses the treatment of exports from import-constrained areas, and proposes new rules to better reflect the value of resources in different locations.

A. Capacity Market Results in 2016

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect capacity clearing prices.[92] Table 12 displays the average spot auction capacity prices for each of the four capacity localities for the 2016/17 Capability Year. The table also shows year-over-year changes in key factors that drove the change in capacity prices from the prior Capability Year.[93]

Table 12: Capacity Spot Prices and Key Drivers by Capacity Zone [94]
2016/17 Capability Year

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2016/17 Yr ($/kW-Month)	$2.28	$7.86	$2.55	$6.36
% Change Yr-Yr	-5%	-26%	-31%	3%
Change in Demand				
Load Forecast (MW)	-209	-136	-60	-31
IRM/LCR	0.5%	-3.0%	-1.0%	-0.5%
ICAP Requirement (MW)	-77	-467	-117	-109
Change in ICAP Supply*				
Generation (MW)	-319	-56	17	42
Import Capacity (MW)	430			

92 Based on the Capacity Demand Curves for the 2016/17 Capability Year (i.e., the 2016 Summer Capability Period and the 2016/17 Winter Capability Period), a 100 MW change in ICAP supply or demand would change the clearing price by: $0.20/kW-month in NYCA, $0.58/kW-month in the G-J Locality, $1.13/kW-month in New York City, and $0.82/kW-month in Long Island.

93 See Sections VI in the Appendix for more information on spot prices and key drivers on a monthly basis.

94 In this table, the MW quantities under "Change in ICAP Supply" are based on ICAP differences between the 2015 Summer Capability Period and the 2016 Summer Capability Period.

While capacity prices increased slightly (3 percent) in the G-J Locality, prices fell by 5 to 31 percent in the other areas in the 2016/17 Capability Year. The year-over-year changes in capacity prices resulted from changes in both supply and demand in each zone. On the supply side, NYCA-wide internal generation fell by 319 MW:

- In Western New York, 450 MW retired or mothballed at the Huntley and Dunkirk plants in the first quarter of 2016; and
- In New York City, small reductions in capacity resulted from the mothballing of multiple Astoria GT and Ravenswood GT units.
- However, these internal capacity reductions were offset by a net increase of over 400 MW in imports during the summer months, some of which persisted in the Winter Capability Period, putting downward pressure on prices.

On the demand side, the ICAP requirement fell in every capacity zone, including:

- 77 MW (or 0.2 percent) in NYCA because of a modest decrease in the peak load forecast that was offset slightly by a 0.5 percent increase in the IRM;
- 109 MW (or 0.7 percent) in the G-J Locality due to a small decrease in the LCR from 90.5 to 90 percent;
- 467 MW (or 4.7 percent) in New York City primarily because of a decrease in the LCR from 83.5 to 80.5 percent, compounded by a decrease in the peak load forecast; and
- 117 MW (or 2 percent) in Long Island primarily because of a decrease in the LCR from 103.5 percent to 102.5 percent.

As observed in the previous year, changes in LCRs continue to be a key driver of the most significant year-over-year capacity price changes in New York. As such, it is important to establish LCRs that will procure capacity in a cost efficient manner. Under the current method for determining LCRs, the G-J Locality LCR tends to rise and fall with the amount of capacity resources in the region. Conversely, the Zone J and Zone K requirement rises when capacity leaves the Lower Hudson Valley and falls when capacity is added to the Lower Hudson Valley. Such variations are inefficient and create significant market uncertainty. The next subsection discusses our recommendation for improving the method for calculating of LCRs.

B. Efficient Locational Requirements Under the Current Zone Configuration

Capacity markets should be designed to facilitate investment in new and existing capacity by providing efficient price signals that reflect the value of additional capacity in each locality. The improved reliability from additional capacity depends on where it is located, so the capacity prices in each location should be proportional to such reliability improvements. This will direct investment to the most valuable locations and reduce the overall cost of maintaining reliability.

To achieve these efficient locational capacity prices, LCRs must be set to minimize the cost of satisfying the resource adequacy criteria. This subsection discusses improvements in the calculation of LCRs that would lead to more efficient price signals and lower capacity costs. Part 0 identifies concerns with the current rules for setting capacity requirements in each area. Part 0 discusses two approaches for implementing a location-based marginal cost pricing mechanism in the capacity market with the NYISO's current zones.

Capacity Prices and Requirements Under the Current Rules

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The current annual process for determining the IRM and LCRs is known as the "Unified Methodology."[95] The Unified Methodology was instituted to define the minimum LCRs for the localities in a manner that provides some balance in the distribution of capacity between upstate and downstate regions. However, the Unified Methodology does not consider economic or efficiency criteria, so the LCRs are not based on where capacity would provide the greatest reliability benefit for the lowest cost. Setting IRM/LCRs such that the capacity demand curves reflect the marginal reliability value of additional capacity in each locality would provide incentives for more efficient investment and lower overall capacity costs.

The following table illustrates the inefficiency that results from the IRM/LCRs for the 2017/18 Capability Year by comparing the marginal reliability value of capacity in each region. It shows that reliability is valued much more highly in some areas than in other areas. The table is based on the system at the long-term equilibrium that is modeled in the demand curve reset process, which assumes each locality has a modest excess (known as its "Excess Level") so that the system is more reliable than the 0.1 LOLE minimum criteria. An Excess Level is assumed so that the demand curve in each area is set sufficiently high to ensure the system never exceeds the 0.1 LOLE criteria. This modest excess results in an LOLE slightly below 0.072.[96]

The table shows two scenarios: (a) the base scenario illustrating the equilibrium in the demand curve reset where each area contains an amount of capacity equal to the Excess Level, and (b) an alternative scenario where small amounts of capacity are shifted in order to reduce costs without increasing the LOLE.

95 See *Locational Minimum Installed Capacity Requirements Study Covering the New York Balancing Authority Area for the 2017 – 2018 Capability Year*.

96 The demand curve reset process is required by tariff to assume that the average level of excess in each capacity region is equal to the size of the demand curve unit in that region. The 2017/2018 demand curve reset assumed proxy units of approximately 220 MW (ICAP) in each area. For the MARS results discussed in this section, the base case was set close to the Excess Level in each area, although the amounts were slightly different. The amount of capacity in Zones J and K was actually a total of 36 MW (UCAP) lower than the Excess Level and the amount of capacity in Zones A, C, and D was 30 MW (UCAP) higher than the Excess Level. These differences should not affect the overall conclusions from the analysis.

For the base scenario, the table shows the following for each area:

- *Net CONE of Demand Curve Unit* – Based on the four demand curves for the 2017/18 Capability Year.
- *NYCA LOLE at Excess Level in Demand Curve Reset* – This is a single value for NYCA that is found by setting the capacity margin in each area to the Excess Level from the last demand curve reset.
- *Change in LOLE from 100 MW UCAP Addition* – The estimated reliability benefit (reduction in LOLE) from placing 100 MW of additional UCAP in the area for the Base scenario.[97]
- *Annual Cost of 0.001 LOLE Improvement* – This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *Change in LOLE from 100 MW UCAP Addition*. This is the annual levelized investment cost necessary for a 0.001 improvement in the LOLE from placing capacity in the area in the Base scenario.[98, 99]

The table also shows how capacity investment costs could be reduced by purchasing more capacity in areas where it is cost-effective (Zone K) and less capacity in areas where capacity is expensive (Zones A-F and Zone J). The alternative scenario illustrates how capacity costs would vary with the following quantities:

- *Adjustment to Installed Capacity* – This shows an example set of additions and subtractions in each area for illustrative purposes.
- *Estimated Change in LOLE* – This shows the LOLE changes that would result from the additions and subtractions in areas that net to a zero change in LOLE overall. We calculate this by multiplying the additions and subtractions in each area by the *Change in LOLE from a 100 MW Addition* for each area.
- *Change in Cost of Capacity* – Shows the resulting annual change in capacity investment cost, which is an efficiency gain rather than a wealth transfer between market parties.

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97 These values were obtained by starting with the system at Excess Level with an LOLE of 0.072 and calculating the change in LOLE from a 220 MW ICAP addition in each area. For each area, the *Change in LOLE from 100 MW UCAP Addition* was approximated based on the change in LOLE from a 220 MW ICAP addition divided by (1 minus the average EFORd for the zone) scaled down.

98 For example, for Zones A-F: \$93/kW-year × 1000kW/MW ÷ (0.003LOLEchange/100MW) × 0.001LOLEchange = \$2.7 million.

99 Note, this value expresses the marginal rate at which LOLE changes from adding capacity when at the Excess Level. However, the actual cost of improving the LOLE by 0.001 might be somewhat higher since the impact of additional capacity tends to fall as more capacity is added at a particular location.

Table 13: Cost of Improving Reliability from Additional Capacity
By Locality, 2017/18 Capability Year

Base Scenario - Equilibrium in Demand Curve Reset		Capacity Area				
		A-F	G-I	J	K	NYCA
Net CONE of Demand Curve Unit ($/kW-yr of UCAP)	(1)	$93	$137	$157	$93	
NYCA LOLE at Excess Level in Demand Curve		0.072				
Change in LOLE from 100 MW UCAP Addition	(2)	-0.003	-0.004	-0.005	-0.005	
Annual Cost of 0.001 LOLE Improvement	(1)/(2)	$2.7M	$3.3M	$3.3M	$1.7M	
Alternate Scenario - Reduced Capacity Cost						
Adjustments to Installed Capacity (UCAP MW)	(3)	-140	0	-65	140	-65
Estimated Change in LOLE	(2)x(3)	0.005	0.000	0.003	-0.008	0.000
Change in Cost of Capacity	(1)x(2)	$-13M	$0M	$-10.2M	$13M	-$10.3M

The table shows large disparities in the annual levelized cost of improving reliability by adding capacity in different locations (see *Annual Cost of 0.001 LOLE Improvement*). The table shows that improving the overall NYCA annual LOLE by 0.001 in the Base Scenario by adding capacity on Long Island would cost $1.7 million, roughly half the cost of achieving the same benefit by adding capacity in New York City or the Lower Hudson Valley, and almost 40 percent less than adding capacity outside of Southeast New York.[100]

The large disparities between areas in the costs of additional reliability (i.e., *Annual Cost of 0.001 LOLE Improvement*) illustrate that the current IRM and LCRs are not determined optimally. These results suggest:

- The statewide IRM and the LCR for Zone J (New York City) exceed the levels that would be necessary to minimize the overall cost of capacity investment; and
- Recognizing the benefits of exports from Zone K (Long Island) to the G-J Locality would likely be necessary to minimize the overall cost of capacity investment.

The alternate scenario illustrates the potential cost savings by removing 205 MW of capacity from Zones A-F and Zone J, and adding 140 MW of capacity to Zone K for export to the G-J Locality. By shifting capacity from high-cost areas to low-cost areas, the NYISO could achieve the same LOLE by purchasing less capacity and saving $10.3 million is annually in this example. These results are illustrative and larger optimal shifts in requirements could achieve much larger cost reductions. Hence, we recommend that these cost-benefit considerations be taken into account in determining the IRM/LCRs for each Locality and in devising rules for the treatment

100 The values in the *Change in LOLE from 100 MW UCAP Addition* row changed considerably in 2016 for the G-I area (from -0.006 in the previous report based on MARS simulations before the TOTS projects to -0.004 in this report). It is likely that the TOTS projects, which increased transfer capability on the UPNY-SENY interface, account for much of this reduction. The marginal value of capacity in the G-I area should fall as a result of new transmission into the area, and ideally, this would be reflected in a reduced LCR. However, the current method of calculating LCRs does not lead to efficient reductions in the LCR.

of exports from export-constrained capacity zones (e.g., Zone K). We describe two approaches in Part 0 of this subsection to implement location-based marginal cost pricing of capacity to achieve these savings that we recommend the NYISO investigate.[101]

Location-Based Marginal Cost Pricing for Capacity

One approach would adjust the LCRs and IRM considering the capacity demand curves in each area with the objective of minimizing overall cost of satisfying the resource adequacy criteria, recognizing the reliability benefits to the G-J Locality from allowing capacity exports from Zone K. A second approach would determine spot capacity prices as a function of the LOLE results for the as-found system in each auction. Both approaches are described briefly below.

Approach 1

Table 13 illustrates how capacity could be shifted to reduce cost while maintaining a target LOLE corresponding to the Excess Level, which is likely to be around 0.07. By iterating between the LOLE model ("MARS") and the demand curve model, it is possible to add and subtract capacity from different locations until reaching an equilibrium point where the *Annual Cost of a 0.001 LOLE Improvement* (see fourth row of Table 13) is the same in all four areas, indicating no further capacity cost reduction is possible. Call this the optimal capacity allocation scenario. The optimal capacity allocation scenario should also satisfy interzonal transmission security criteria. GE has developed software to shift capacity in an iterative fashion as described above, which can be used to identify the optimal capacity allocation.[102]

The LCRs could be determined taking this optimal capacity allocation scenario and proportionately increasing load until the system reaches 0.1 LOLE. However, this would result in an excessively high "requirement" for Zone K just because the net cost of new entry is relatively low there. Thus, it may be appropriate to limit the LCR increase in Zone K (and corresponding decrease in the G-J locality), and instead credit exports from Zone K toward satisfying the G-J Locality LCR.[103] We recommend the NYISO and GE augment its model to treat Zone K (and other export-constrained locations) in this fashion.

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101 See Recommendation #2013-1c.

102 For a discussion of this model, see *Alternative Methods for Determining LCRs*, presented by Zachary Stines to Installed Capacity Working Group, April 4, 2017.

103 This would entail setting: (a) an export limit when additional exports would no longer be fungible with capacity from other zones in Southeast New York, (b) one or more benefit ratios to discount additional exports when the export limit is exceeded and (c) clearing Zone K exports on the G-J Locality demand curve. This concept is discussed further in Section VII.C.3 of *2013 State of The Market Report for the New York ISO Markets* and on slides 15-22 in *2013 State of the Market Report Recommendation to Enhance Locational Pricing in the Capacity Market*, Presented by Market Monitoring Unit to Installed Capacity Working Group, August 20, 2014.

Approach 2

An alternative approach to determining efficient capacity prices at each location would involve calculating the incremental reliability benefit (as measured by the MARS model) of adding capacity to the as-found system in each spot capacity auction. This would require developing a single capacity demand curve or value for the system quantifying the cost of improving LOLE (expressed as dollars per unit change in LOLE). The capacity price at each location would be equal to the product of: (a) the demand value in dollars per unit change in LOLE and (b) the marginal effect on LOLE from additional MW in the zone for the as-cleared system.[104] This approach would require fewer approximations and simplifying assumptions and, thus, would be less resource-intensive prior to the spot capacity auction.

C. Treatment of Export Transactions from Import-Constrained Localities

A generator in the G-J Locality sold 500+ MW of capacity into the ISO-NE Forward Capacity Auctions for the 2018/19 and 2019/20 commitment periods, raising questions about how the NYISO should treat capacity export transactions from an import-constrained zone.[105] When a generator in Rest of State ("ROS") exports capacity, the generator is simply ignored for purposes of clearing the NYCA capacity demand curve. However, it would be inappropriate to simply ignore a generator in an import-constrained locality because it is exporting, since the generator still helps satisfy the need for capacity within the constrained locality.

Until recently, the NYISO did not have rules to account for such transactions efficiently when setting capacity prices. To address this issue, the NYISO filed new rules in November 2016 (which were mostly accepted) while recognizing that some issues may need to be addressed in a subsequent filing ("Phase 2"). While these elements may require significant time to develop fully, it is important that the Phase 2 proposal establishes rules that:

- Set prices for imports from external control areas to the NYISO that are consistent with the basis for the Locality Exchange Factor ("LEF").[106] The NYISO's current rules could set prices for imports that are lower than the value they provide to the NYISO. This could lead the NYISO to forgo imports even when they provide additional reliability value to the NYISO at a lower cost than alternative resources.

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104 See *2013 State of the Market Report Recommendation to Enhance Locational Pricing in the Capacity Market*, presented by Market Monitoring Unit to Installed Capacity Working Group, August 20, 2014, Slides 26 & 27.

105 The Roseton 1 generator sold 511 MW in FCA 9 and 532 MW in FCA 10. Information pertaining to capacity obligations in the FCA 9 and 10 auctions can be found by selecting "Forward Capacity Auction 2018-2019 Obligations" and "2019-2020 Forward Capacity Auction Obligation" from the Documents section at http://www.iso-ne.com/markets-operations/markets/forward-capacity-market/?load.more=1.

106 The LEF represents the share of the exporting resource that could be replaced by capacity outside the import-constrained area.

- Recognize the local reliability value that the exporting generators continue to provide to the import-constrained areas in NYISO. Addressing this issue may involve establishing and pricing a local-reliability product that would include obligations to NYISO for the supplier. This will produce efficient prices and incentives because it brings into alignment: the NYISO's planning needs, its capacity procurements, and the settlements with all of the resources that are contributing to satisfying its needs.
- Make changes to the mitigation thresholds applied to the exporting generator that are coordinated with the rule changes to compensate exporting generators for their local reliability value (see previous bullet). If the exporting generator is not compensated, it will be necessary to have a looser threshold (so that mitigation is not applied to efficient export transactions). If the exporting generator is compensated, a tighter threshold would be appropriate.

In general, efficient market design will lead to prices and corresponding settlements with generators that are consistent with the value and/or cost to the system. Adhering to this principle will provide efficient incentives for participants to engage in cross-border transactions and lower costs. Absent these three elements of a reasonable long-term solution, it will be difficult to expect that the NYISO's proposed solution will produce efficient long-term economic signals and scheduling across the border. Hence, we recommend that the NYISO address these design elements in the second phase of its proposal.

D. Financial Capacity Transfer Rights for Transmission Upgrades

A developer would not have an incentive to build a new generator in New York without being able to earn revenue from the sale of capacity. Likewise, developers will also not have efficient incentives to build new transmission without capacity revenues the reflect their contribution toward satisfying the NYISO's planning needs. Investment in transmission can significantly reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. To provide efficient incentives to invest in transmission, we recommend that transmission developers receive financial capacity transfer rights ("FCTRs") corresponding to the benefits of the upgrade.[107]

The value of the rights should be based on the amount by which installed capacity requirements are reduced by the facility. Thus, efficient compensation equals the product of the following three inputs:

- The effect on the TTC of one or more interfaces from adding the new facility to the as-found system,
- The marginal effect of a change in TTC on the LOLE of the as-found system, and

[107] See Recommendation #2012-1c in Section XI.

- The value of reliability in dollars per unit of LOLE. This demand value is described under Approach 2 in the previous subsection.

To illustrate this concept, suppose a project were to increase TTC for the as-found system on interface A by 200 MW and interface B by 50 MW. Further suppose that the marginal LOLE effect of increasing TTC of interface A by 100 MW is -0.002, and the marginal LOLE effect of increasing TTC of interface B by 100 MW is -0.001. Suppose the value of reliability determined in the demand curve reset was $2 million per -0.001 per year. In this case, the project would receive a FCTR in the first year with a value of $9.0 million = {(200MW x -0.002 per 100MW) + (50MW x -0.001 per 100MW)} x $2 million per -0.001. To ensure revenue adequacy, the effect of the new facility on interface TTC should be recalculated as often as the locational capacity requirements, which currently happens on an annual basis.

Similarly, it would also be appropriate to compensate (or charge) new generation projects for their impact on deliverability constraints through capacity transfer obligations (i.e., negative-value FCTRs). In some cases, it would be more efficient (i.e., cost-effective) for a project developer to accept negative FCTRs than make transmission upgrades (if the value of upgrading the transmission system was lower than the cost of the upgrades). Such compensation would provide incentives to interconnect at points that increase the deliverability of other generators. Such charges would be more efficient than assigning SDU costs, since these can be a barrier to efficient investment if the SDU costs are higher than the value of the upgrade.

E. Incorporating Capacity Market Benefits and Other Reforms to CARIS

The NYISO has an economic transmission planning process known as the Congestion Assessment and Resource Integration Study ("CARIS"). The process was intended to provide cost-of-service compensation through the NYISO tariff when a project is expected to be economic based on a tariff-defined benefit-cost analysis. However, since being established in 2008, no transmission has ever been built and received cost recovery through CARIS. The NYISO is currently evaluating solutions for two transmission needs under the new Public Policy Transmission Need ("PPTN") assessment process in response to NYPSC orders defining a Western New York PPTN and an AC Transmission PPTN.[108] However, the competitive wholesale markets price congestion and should provide incentive to make investments to relieve congestion when it is cost-effective. The use of the PPTN assessment process to reduce congestion in New York highlights deficiencies in the CARIS process, which we discuss below.

We identify several deficiencies in the CARIS process, including: (i) assumptions that systematically undervalue projects, (ii) deficiencies in forecasting models, and (iii) elements that may make an economic project ineligible for funding. We recommend the following changes to

108 Each order is attached to the corresponding project solicitation letter that is posted on the NYISO website at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

address these deficiencies. We recommend changing the following assumptions that systematically undervalue projects:

- *Capacity Market Benefits* – The benefit-cost ratio that is used to identify economic projects ignores capacity market benefits, which undervalues transmission projects that make significant contributions to satisfying the NYISO's planning requirements. These benefits should be quantified using the metric discussed in Subsection D,
- *Retirements and New Entry Assumptions* – CARIS starts with a base case from the Comprehensive Reliability Plan ("CRP"), but the CRP is developed for a different purpose that is not suited to evaluating the economics of new transmission investment. CARIS should recognize that if a new transmission project goes forward, it will likely affect the retirement and/or entry decisions of other resources. [109]

Quality forecasting is essential so we recommend the following enhancements to the models that are used to evaluate projects:

- *Gas System Modeling* – Unprecedented levels of congestion have arisen on the natural gas pipeline system since 2012 that has been the principal driver of congestion in the energy markets. Thus, efficient electricity transmission investments cannot be identified without improvements to the forecasts of future congestion on the gas pipeline system.
- *Electric System Modeling* – The NYISO uses GE MAPS to model the electrical system (a sound platform). However, enhancements are needed to better represent contingencies, other real-time events, and transmission outages that contribute to congestion.

There are elements of the CARIS process that could prevent an economic project from moving forward that we recommend the NYISO modify:

- *80 Percent Voting Requirement* – Before an economic project is funded, the project must garner approval from 80 percent of the beneficiaries. While such a vote may be appropriate to ensure that only projects that are clearly economic move forward, the 80 percent requirement is unreasonably high. This supermajority requirement may enable a small group of participants to block an economic investments.
- *$25 Million Threshold* – To be evaluated in CARIS, a project must cost more than $25 million, which may preclude economic projects or prevent it from being sized optimally.

These recommendations address many of the impediments in the CARIS process to investment in economic transmission projects. We recommend that the NYISO review the CARIS process to identify any additional changes that would be valuable, and make the changes necessary to ensure that the CARIS process will identify and fund economic transmission projects.[110]

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109 This would require the development of a set of new entry conditions based on the costs of hypothetical wind, solar, combined cycle, and simple cycle units. In addition, this would require CARIS to measure the benefit of a project based on the market value of energy and capacity in the scenario with the project rather by comparing the base case scenario to the scenario with the project.

110 See Recommendation #2015-7 in Section XI.

F. Implementing a More Dynamic Locational Capacity Market Framework

Deficiencies in the Current Process for New Zone Creation

The new capacity zone for the G-J Locality in Southeast New York ("SENY") has greatly enhanced the efficiency of the capacity market signals, but took years to create after it was it was first needed. This delay has had several adverse consequences that illustrate the importance of promptly creating new capacity zones when they are needed.

- The capacity in Zones G, H, and I fell by 21 percent from 2006 to 2013, even as the need for resources in SENY interface became more apparent. Some of this capacity may have been economic to remain in service if the G-J Locality had been created sooner.
- Retirements in Zones G and H resulted in higher LCRs for Zones J and K. In the three years prior to the creation of the G-J Locality, the LCR for Zone J rose from 80 percent to 86 percent and led to much higher capacity prices in Zone J.[111]
- For several years prior to creating the G-J Locality, the Highway Deliverability Test prevented some economic capacity suppliers outside SENY from selling their capacity, which increased the capacity prices inefficiently in Zones A to F.

In summary, earlier creation of the G-J Locality would have facilitated more efficient investment and retirement decisions, and lowered overall capacity costs significantly. The NYISO's current NCZ process is destined to produce similar outcomes because it will not create of other new capacity zones in a timely and efficient manner. To understand why, one must recognize that a transmission bottleneck can create two issues from a planning perspective:

1. It can prevent surplus capacity on the unconstrainted side of the bottleneck from being deliverable to load on the constrained side (i.e., deliverability issue).
2. Second, it can require additional capacity to be procured on the constrained side of the bottleneck to meet the reliability needs of the load pocket (i.e., reliability issue).

The first problem with the NCZ process is that it is based on the Highway Deliverability Test criterion. It ignores entirely the reliability issue that would justify the creation of a new capacity zone. Hence, if the NYISO identifies areas where capacity is needed to meet its reliability needs, a new capacity zone will not be created unless there is also a deliverability problem.

The second problem is that the Highway Deliverability Test is performed with only the existing resources with CRIS rights. 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 will not be triggered. This is a case where a new zone is needed to allow the price on the unconstrained side of the bottleneck to fall to reflect the excess capacity, which will help facilitate more efficient capacity trading with external areas and investment decisions.

111 A one percent increase in the LCR equated to a $1.30/kW-month increase in capacity prices given the 2013/14 capacity demand curve for New York City.

Third, the NCZ study process is lengthy and uncertain, occurring just once every four 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, which may needlessly prompt regulated investment.

The Indian Point retirement provides a salient example of the problems that could arise from the issues listed above. If Indian Point retire in 2021, and it leads to resource adequacy violations for Eastern New York or the area south of the UPNY-ConEd interface, the NCZ process would not consider creating an additional zone for any time before 2025. In fact, it would not trigger the creation of a new zone at all if there are no Highway Deliverability constraints.

Because of the issues with the current process for defining additional capacity zones, we recommend the NYISO move to a dynamic framework where potential deliverability and resource adequacy constraints are used to pre-define a set of capacity interfaces and/or zones.[112]

Pre-Defining Capacity Market Interfaces and Zones

To ensure efficient locational pricing of capacity, we recommend that the NYISO pre-define potential capacity interfaces or zones that would be modeled in its capacity auctions. Once defined, the NYISO would cease its deliverability testing of new resources since the capacity market would efficiently limit sales from these resources by binding the relevant constraints in the capacity auction. Upgrade of these constraints would be facilitated by the locational price differences in the capacity, energy, and ancillary services markets. Finally, unexpected retirements that have significant reliability implications in an area 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.

The NYISO has a set of inter-zonal transmission interfaces that are used in the planning process to identify potential future Highway Deliverability issues and deficiencies in the RNA. The capacity market is the primary mechanism for satisfying the NYISO's resource adequacy needs. Hence, it may be appropriate for the capacity market to include some or all of the same eleven inter-zonal interfaces that are modeled in the RNA.[113] Were NYISO to model the seven unmodeled interfaces, some of them could suddenly bind in the future if certain generators retire. Modeling the interfaces will allow the market to immediately begin producing efficient economic signals to facilitate a rapid and efficient response by the market participants.

112 See Recommendation #2012-1a in Section XI.

113 The 2016 RNA modeled the following 11 interface between zones: Dysinger East (A->B), West Central (B->C), Volney East (C->E), Moses South (D->E), Central East + Fraser-Gilboa (E->F), UPNY-SENY (E+F->G), UPNY-CE (G->H), Millwood South (H->I), Dunwoodie South (I->J), Y49/Y50 (I->K), CE-LIPA (J->K).

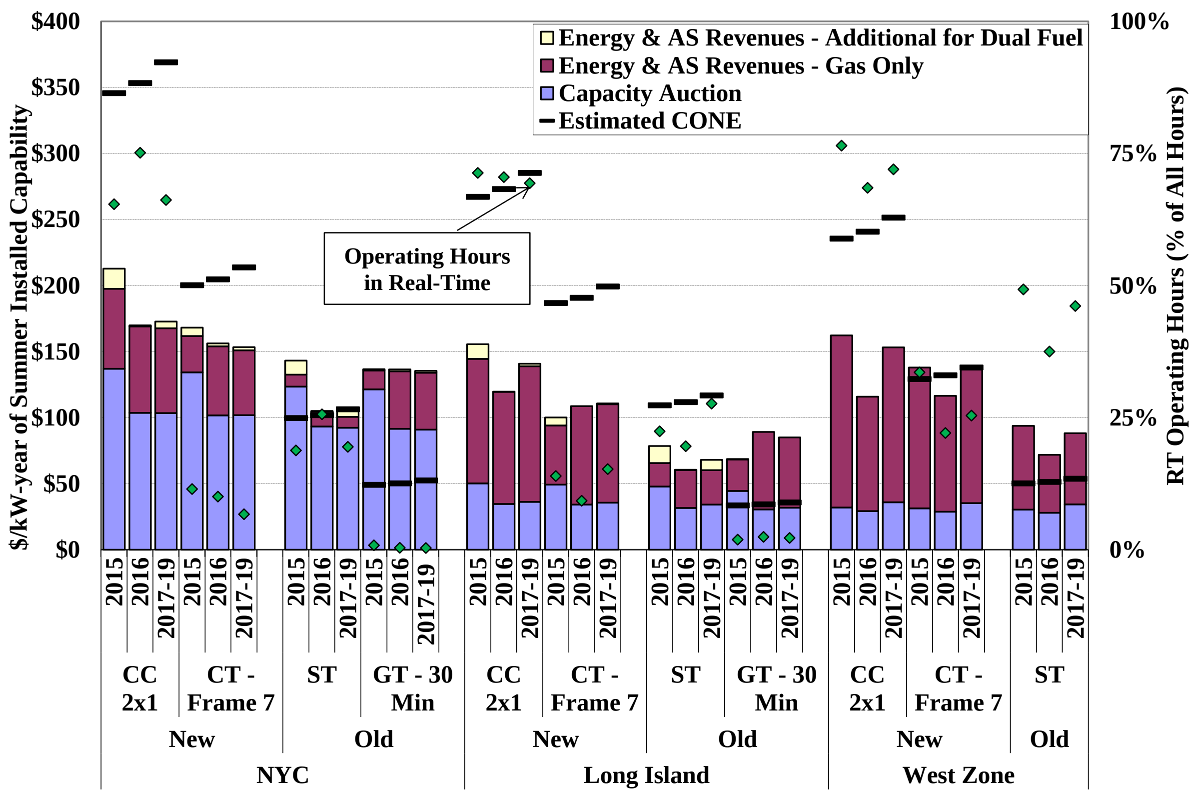
VIII. LONG-TERM INVESTMENT SIGNALS

A well-functioning wholesale market establishes transparent and efficient price signals to guide generation and transmission investment and retirement decisions. We evaluate long-term investment signals by calculating the net revenue that new generators would have received from the NYISO markets and comparing it to the corresponding Cost of New Entry ("CONE") of the generator. We also examine the investment signals for several older existing gas-fired technologies and for several zero-emission technologies. Net revenue is the total revenue that a generator would earn in the New York markets less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units

A. Net Revenues of Gas-Fired and Dual-Fuel Generators

Figure 10 shows the estimated net revenues compared to the CONE or Going Forward Costs ("GFCs") for several types of new and existing gas-fired units from 2015 to 2019. The figure shows the incremental net revenues that would result from dual-fuel capability and the estimated number of running hours as a percent of all hours in the year.[114]

Figure 10: Net Revenue and CONE by Location for Gas-Fired and Dual Fuel Units
2015-2019



114 Section VII.A of the Appendix provides detailed CONE, GFC, and net revenue results for more locations, technologies, and gas price assumptions. Run hours are provided by fuel type for dual-fueled units.

Net Revenue Summary for Gas Units

From 2015 to 2016, net revenues varied depending on the technology and location:

- Capacity net revenues were either relatively flat (in NYCA and G-J Locality) or fell (in Zones J and K) because capacity requirements were reduced.[115]
- The energy and ancillary services ("E&AS") net revenues increased for some technology-location combinations and decreased for others.
  - Energy margins fell because of mild weather during the winter, especially in Western New York, lowering E&AS net revenues of units that rely on energy revenues (e.g. combined-cycle units).
  - Reserve revenues increased because of much higher reserve prices, raising the E&AS net revenues of units that rely on reserve revenues (e.g. peaking units).

Based on forward prices for electricity and natural gas, we estimated higher net revenues in 2017-2019 for most units located outside New York City because of the expected upward trend in energy margins, with a large (25 to 35 percent) year-over-year increase observed in 2017. In New York City, energy margins are expected to fall slightly because natural gas prices there are expected to increase to levels closer to the prices in other areas in Eastern New York.

Implications of Net Revenue Evaluation for Gas and Dual-Fuel Units

The 2016 net revenues estimates for peaking units include substantial reserve revenues because of much higher reserve prices. For instance, the 2016 E&AS net revenues of an older existing GT-10 unit (assumed heat rate of 15000 Btu/kWh) were within 25 percent of the E&AS net revenues of a 2x1 combined cycle unit (assumed heat rate of 6964 Btu/kWh) in most locations, and slightly more than the combined cycle unit in the Capital zone.[116]

The high reserve prices could also impact capacity prices in 2018 and 2019. The ICAP demand curve Reference Point will be adjusted annually based on updates to the gross CONE and the E&AS net revenues of the demand curve unit. For the 2018/19 Capability Year, the updated E&AS net revenues will be based on 2016/17 rather than 2013/14. Therefore, the demand curve unit's E&AS net revenues reflect the high reserve revenues from 2016/17, which will partially offset the unusually high energy margins from the Polar Vortex (in January 2014).

Of the hypothetical new units we evaluated, the most favorable for new investment appears to be a new Frame 7 unit in the West Zone. Although the estimated net revenues for a new Frame 7

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115 Capacity prices and requirements are discussed further in Section VIII.A.

116 However, the capacity that was actually scheduled for reserves during 2016 was considerably less than the total amount of potential supply of reserves in several zones (see Section IV.A.0). Consequently, the reserve net revenues received by many peaking units are likely to be substantially lower than the net revenues shown in this report.

unit were slightly lower than the annual levelized CONE in the West Zone in 2016, this unit's forecasted net revenues are comparable to its CONE from 2017 to 2019. However, these market conditions will not likely induce new investment in the West Zone if developers believe that the elevated net revenue levels will be short-lived. The proposed transmission upgrades in Western New York are likely to reduce the energy prices there.[117] Furthermore, the pattern of unusually low natural gas prices for Western New York in recent years is likely to change since gas production from the Marcellus and Utica shale regions has leveled-off. New investment could still occur at sites with specific advantage, and portions of the 115kV system will see higher energy prices if the NYISO begins to model 115 kV constraints in its energy markets.

Of the existing fossil-fuel technologies we evaluated, steam turbine units in downstate areas are the most challenged economically. Net revenues for steam turbines are substantially lower than the estimated GFC on Long Island and roughly comparable to the estimated GFC in New York City. The decision by individual steam turbine units to retire in the coming years will likely be based on whether: they are under long-term contracts, their GFCs are higher due to site-specific disadvantages, and they face extraordinary repair costs associated with equipment failures.

The additional revenues from dual-fuel capability were *de minimis* in 2016, primarily because of low gas prices and the mild winter. The expected returns over the next three years are not (by themselves) sufficient for some units to maintain the capability and modest inventories of oil.[118] However, dual fuel capabilities provide a hedge against gas curtailment under tight supply conditions and may augment the capacity revenues by reducing fuel-related outages. Thus, investors in new and existing units may still prefer to install and maintain dual fuel capability, particularly as they consider possible changes in market conditions over the long-term.[119]

B. Net Revenues of Nuclear and Renewable Generators

Figure 11 compares the estimated net revenues for existing nuclear units, new onshore and offshore wind units, and new utility scale solar PV plants from 2014 to 2019. For comparison, we show the estimated GFCs for the nuclear units and the CONE estimates for the renewables.

Energy revenues account for 87 percent of the estimated net revenues received by nuclear units in upstate New York over the last three years. Consequently, the retirement decisions for nuclear units are largely driven by expected energy prices, rather than capacity prices. The estimated

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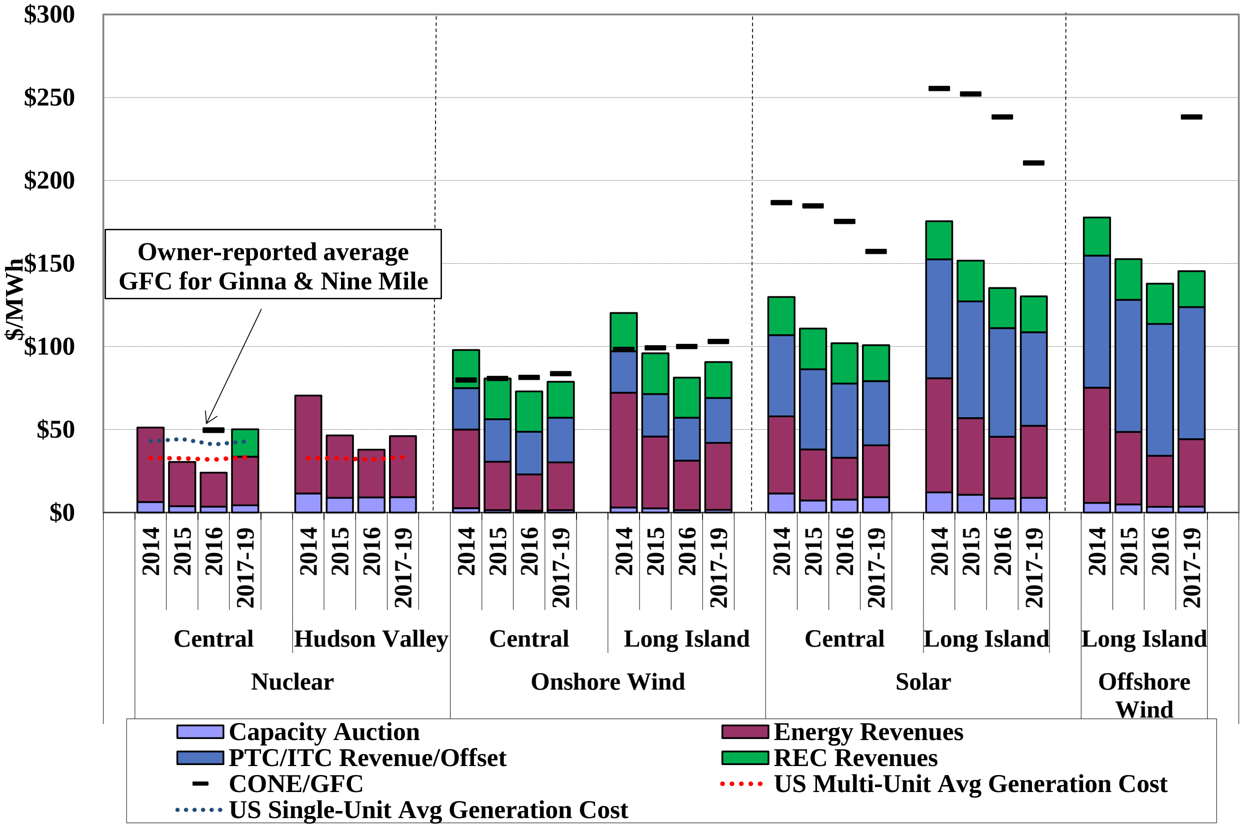
117 The NYISO is currently evaluating proposals for the Western New York Public Policy Transmission Need in response to a New York PSC order.

118 Dual fuel cost and inventory estimates were derived from analysis presented in the Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

119 The additional dual-fuel revenues for CC and ST units in recent years have generally been sufficient to incent dual fuel capability.

nuclear plant net revenues were lower than both the owner-estimated GFCs, and the U.S. average costs for large and small nuclear plants in the Central Zone for the past two years.[120] The nuclear plants in upstate New York will be eligible for payments for the sale of Zero Emissions Credits ("ZECs") beginning in April 2017. Based on recent electricity forward contract prices, ZEC payments appear necessary for single-unit nuclear plants outside Southeast New York to recover their operating costs, as these assets are unlikely to recoup their GFCs costs from the wholesale markets alone through 2019. However, whether ZEC payments are necessary for multi-unit nuclear plants depends on site-specific costs that may differ from the U.S. averages.

Figure 11: Net Revenues of Nuclear and Renewable Units
2014-2019



Renewable resources rely on multiple revenue streams from the NYISO markets and state and federal incentive programs. Wind and solar resources are intermittent, so their capacity value is relatively low. Over half of the net revenues for these resources in 2016 were from federal and state programs, such as Renewable Energy Credits ("RECs") and the Investment or Production Tax Credits.[121] Even with these subsidies, however, the estimated net revenues for offshore wind and solar PV units were well below their CONE levels in every year. The economics of the onshore wind units are considerably better than the solar PV and offshore wind units.

120 See Section VII.C of the Appendix.

121 For more detail on PTCs and ITCs see Section VII.D in the Appendix.

Although new renewable units and existing nuclear units do not appear to be economic, they may have value for achieving public policy goals to reduce carbon emissions. There are several proposals to supplementing the revenues these resources receive from the NYISO markets, which will likely affect the long term economic signals for all generators in New York. For instance, both renewable and nuclear units have very low operating costs, so they tend to lower both energy and capacity prices.

To the extent these proposals satisfy legitimate public policy objectives, it is most economic to structure a mechanism in a technology-neutral manner. Exhibiting an undue preference for certain technologies will ultimately increase the cost of meeting the public policy objectives. To illustrate this, we estimated the cost per-ton of reducing CO_2 emissions using several generic investments (recognizing that the costs of individual projects will vary) and their 2017-19 net revenues. The costs of reducing carbon emission vary substantially by technology and location:

- Efficiency upgrades at existing combined cycle plants could reduce CO_2 emissions at virtually no net cost.[122]
- Retaining existing nuclear capacity at a single unit facility in upstate New York would cost $26 per ton.[123]
- Retaining existing nuclear capacity at a multi-unit facility outside Southeast New York would cost $13 per ton.
- Building a new 2x1 combined cycle unit in Zone G would cost $17 to $144 per ton for a unit with access to gas priced at the Millennium East index and the Iroquois Zone 2 index respectively.[124]
- Using onshore wind, utility-scale solar PV and offshore wind resources on Long Island would cost $48, $175 and $184 per ton, respectively.[125]

The results indicate the value of utilizing a technology-neutral approach in pursing carbon reductions in New York, such as a carbon tax or cap-and-trade market. In fact, the Regional Greenhouse Gas Initiative is a successful cap-and-trade market that has been implemented in the region and could potentially be modified to address New York's clean energy goals. Utilizing markets the provide incentives to achieve New York's public policy goals would likely reduce the costs of achieving the goals, achieve larger reductions more quickly, and minimize adverse effects on the NYISO capacity and energy markets.

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122 For instance, an Advanced Gas Path upgrade at a GE 7F 250 MW unit with a 65 percent capacity factor in New York City that improves the facility's heat rate by 2 percent and the output by 10 MW has been an economic investment based on the NYISO market revenues alone.

123 This assumes that a retiring nuclear unit in Zone C would lead to increased generation with an average carbon intensity 0.45 tons per MWh.

124 This assumes that the new combined cycle units in Hudson Valley would displace generation with an average carbon intensity of 0.55 tons per MWh.

125 This assumes that the new renewable units on Long Island would displace generation with an average carbon intensity of 0.65 tons per MWh.

IX. Market Operations

The purpose 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 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.

This section evaluates the following six aspects of market operations, focusing on the efficiency of scheduling and whether real-time prices provide appropriate incentives, particularly during tight operating conditions:

- Market Performance under Shortage Conditions
- Efficiency of Gas Turbine Commitments
- Performance of Operating Reserve Providers
- Operations of Non-Optimized PAR-Controlled Lines
- Drivers of Transient Real-Time Price Volatility
- Supplemental Commitment & Out of Merit Dispatch for Reliability

The final subsection shows the uplift from Bid Production Cost Guarantee ("BPCG") payments, which are driven primarily by supplemental commitment and out-of-merit dispatch.

A. 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 ancillary services needs of the system while satisfying transmission constraints. Efficient prices also reward suppliers and demand response resources for responding during real-time shortages. Incentives for good performance during shortage conditions have a beneficial effect on the resource mix in the long run because they shifts a portion of net revenues from the capacity market to the energy market, which tends to lower overall costs to consumers.

In this subsection, we evaluate the operation of the market and resulting prices in the real-time market when the system is under the following three types of shortage conditions:

- 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 foregone value of the ancillary service is reflected in LBMPs.
- Transmission shortages – These occur when modeled power flows exceed the limit of a transmission constraint. Clearing prices for energy in the constrained area are set according to several methods during transmission shortages.[126]
- 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.

Operating Reserve and Regulation Shortages

The frequency of shortages for NYCA 30-minute reserves and regulation rose substantially in 2016 while other reserve shortages were very infrequent. Regulation shortages occurred in 4.2 percent of intervals in 2016, up from 1.4 percent in 2015. NYCA 30-minute reserves shortages increased from virtually none in 2015 to 0.4 percent of intervals in 2016. All other reserves shortages occurred in less than 0.1 percent of all intervals in 2015 and 2016. While they are infrequent, shortages of regulation, Eastern 10-minute reserves, and NYCA 30-minute reserves collectively increased annual average LBMPs in Eastern New York by 6 to 8 percent in 2016.[127]

The increase in shortages for regulation and NYCA 30-minute reserves was mostly attributable to several changes made to shortage pricing of ancillary services products in November 2015 as part of the Comprehensive Shortage Pricing project that:

- Increased NYCA 30-minute reserve requirement from 1,965 MW to 2,620 MW,[128] and limited the amount of reserves scheduled on Long Island resources.
- Reduced the lowest demand curve values: (a) from $50 to $25/MWh for NYCA 30-minute reserves, and (b) from $80 to $25/MWh for regulation.[129]

Notwithstanding these market enhancements that better recognize and price ancillary services shortages, we have identified circumstances when the NYISO tends to schedule more operating reserves than necessary. This is because the NYISO relies only on internal resources to satisfy

126 Section V.F in the Appendix describes these methods in greater detail.

127 See Section V.E in the Appendix for this analysis.

128 This was done to reflect the requirement to restore 10-minute reserves to 1,310 MW within 30 minutes following the system's largest supply contingency of 1,310 MW. See *NYSRC Reliability Rules & Compliance Manual*, Version 39, See Section E.1 Operating Reserves: Establishing the Minimum Level of Operating Reserve, Requirement R6.

129 See Section V.E in the Appendix for a complete list of changes in demand curves for ancillary services.

operating reserve requirements. In some cases, this ignores the capability and the economic value of imports for maintaining security in the reserve region. For example, 10-minute operating reserves are held in Eastern New York to ensure that if a large contingency in Eastern New York results in a sudden overload of the Central-East Interface, sufficient reserves can be deployed to reduce flows to maintain security. This need could also be partly met partly more economically by reducing flows across the Central-East interface before the contingency occurs (thereby "holding reserves on the interface").

Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves that should be held in Eastern New York considering that the need can also be met by reducing pre-contingent flows over the Central-East Interface. Likewise, we recommend the NYISO dynamically determine the optimal amount of 30-minute reserves that should be held in SENY considering that the need can also be met by reducing flows over the UPNY-SENY interface.[130]

Transmission Shortages

A transmission shortage occurs when power flows exceed the limit of a transmission constraint in the real-time market. During transmission shortages, the wholesale market should set efficient prices that reflect the severity of shortage and that provide generation and demand response resources incentives to perform reliably. Previous State of the Market Reports have shown a poor relationship between the severity of transmission constraint shortages and the real-time pricings. Specifically, we found that small shortages tended to produce high congestion shadow prices while large shortages tended to produce small congestion shadow prices. In general, this was because transmission shortages were resolved by "relaxing" the limit of a constraint—that is, raising the limit to a level that could be resolved by the market software.[131]

In February 2016, the NYISO implemented the Graduated Transmission Demand Curve ("GTDC") project, which was expected to improve the correlation between the size of a transmission shortage and the corresponding congestion shadow price. The three-step GTDC would limit the marginal cost of re-dispatch for a transmission constraint: at $350/MWh for small shortages, at $2,350/MWh for moderate shortages, and at $4,000/MWh for large shortages.

Figure 12 examines whether constraint shadow prices reflect the severity of operating conditions for four groups of transmission constraints before and after the implementation of the GTDC (by comparing outcomes from 2015 against outcomes from 2016 after the implementation in February). The figure also shows the placement of the three steps of the GTDC.

130 See Recommendation #2015-16 in Section XI.

131 Appendix Section V.F provides additional information about transmission shortages and this analysis.

Figure 12: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2015 – 2016

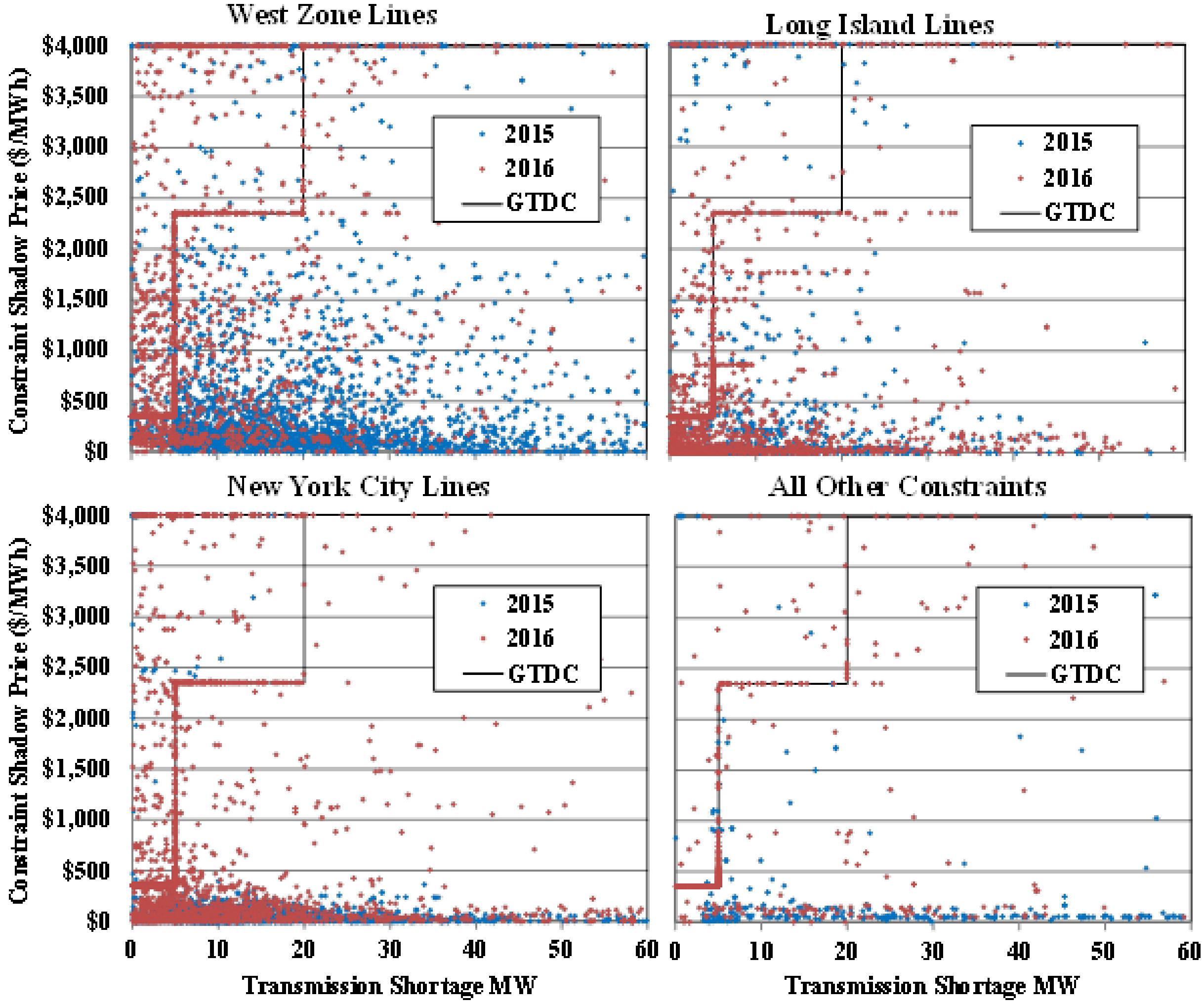


Figure 12 shows that transmission shortage quantities generally decreased in 2016, while the constraint shadow prices during shortages generally increased. In both years, there was a pattern of high shadow prices for very small shortages and lower shadow prices for large shortages. While many of the shadow prices were set by the GTDC in 2016 (which is evident whenever a red dot is set somewhere along the three-step GTDC in the figure), there were many intervals when the shadow prices exceeded the $350 and $2,350 steps of the GTDC.

The pattern of outcomes in Figure 12 reflects how the GTDC Project was implemented. In some intervals, the use of the GTDC limited re-dispatch costs as expected and led to a clear relationship between the size of the shortage and the congestion shadow price of the constraint. However, the market software continued to use the relaxation technique to resolve the majority (61 percent) of transmission constraint shortages after the GTDC was implemented, but the constraint relaxation limit adjustment was reduced from 8 MW to 0.2 MW.[132] The continued use of the relaxation technique combined with the reduced limit adjustment led to higher shadow prices and smaller shortages in most intervals.

Ultimately, the NYISO determined that these pricing outcomes were not consistent with the tariff provisions related to pricing during transmission shortages, and the NYISO filed for a waiver until such time as the market software can be modified.[133] The NYISO recently filed to modify the pricing logic during transmission shortages in two ways.[134] First, the GTDC will be used for the vast majority of constraints, and the relaxation technique will only be used for "Zero-CRM" constraints.[135] Second, the second step of the GTDC will be reduced from $2,350/MWh to $1,175/MWh.

We support the NYISO's proposal as a short-term step towards eliminating unnecessary price volatility and ensuring that there is a logical relationship between the shadow price and the severity of the shortage. This will appropriately limit re-dispatch costs and provide better price signals to market participants. After the short-term proposal is implemented, we recommend that the NYISO replace the single GTDC with constraint-specific GTDCs that can vary according to the importance, severity, and/or duration of a transmission shortage. [136]

Reliability Demand Response Deployment

The NYISO implemented the Comprehensive Scarcity Pricing project in June 2016, which was intended to set LBMPs at appropriate levels during EDRP/SCR deployments. Ideally, the scarcity pricing rules would allow demand response resources to "set price" whenever a reserve shortage would have occurred if the demand response had not been deployed. The previous

132 The constraint relaxation limit adjustment is used with the relaxation technique in the following way. The real-time market model first calculates the minimum feasible flow over the transmission constraint. Then, the model re-solves using a constraint limit equal to the minimum feasible flow plus the relaxation limit adjustment. Thus, the 0.2 MW adjustment imposes a much tighter limit on the final solution, leading to higher shadow prices and smaller violations than the 8 MW adjustment.

133 See *New York Independent System Operator, Inc.*, Docket No. ER17-758, *Request for Tariff Waiver*, (January 6, 2017).

134 See *New York Independent System Operator, Inc.*, Docket No. ER17-1453, *Proposed Tariff Revisions to Clarify and Enhance Transmission Constraint Pricing*, (April 21, 2017).

135 A Constraint Reliability Margin ("CRM") is a small (usually 20 MW) margin that separates: (a) the actual physical limit of a facility and (b) the limit that is used in the market software. A CRM is used to account for differences between physical flows and actual flows that result from loop flows and other un-modeled factors. "Zero-CRM" constraints are constraints for which no CRM is used because there is little or no uncertainty regarding un-modeled factors. A zero-CRM is typically used for facilities that connect generation pockets to the grid because overloads on such facilities can be addressed by small output reductions from the generation facility.

136 Recommendation #2015-17 in Section XI.

shortage pricing rules often set LBMPs at excessively high levels during demand response deployments by allowing them to set price even when a shortage would not have occurred without the deployment. Under the new rule, a more reliable modeling technique is used within the real-time model to determine whether a reserve shortage would have occurred without the demand response deployment.

In 2016, the NYISO activated demand response on only one day, August 12. During this event, an estimated nearly 1 GW of demand response was deployed in all zones for system-wide capacity needs for five afternoon hours.[137] Our evaluation finds that demand response was needed to prevent a capacity deficiency in 18 intervals (1.5 hours) during the 5-hour deployment period and that 30-minute reserves were priced at $500/MWh during all 18 intervals as intended.[138] The improved consistency between real-time price signals and actual system conditions is a significant enhancement. Nonetheless, in retrospect, the actual amount of demand response that was needed to avoid a reserve shortage was only about 350 MW. This implies an over-deployment of demand response by more than 600 MW. Consequently, $1.1 million of guarantee payments was paid to demand response resources.[139] This underscores the benefits of efforts to improve demand forecasting and develop procedures that would allow it to deploy a subset (rather than all) of the demand response resources in a particular zone.

B. Efficiency of Gas Turbine Commitments

We evaluate the efficiency of gas turbine ("GT") commitment in the real-time market, which is important because excess commitment results in depressed real-time prices and higher uplift costs, while under-commitment leads to unnecessary price spikes. We found that 54 percent of the capacity committed by the real-time market model in 2016 was clearly economic over the initial commitment period, consistent with recent years.[140] This evaluation deemed a gas turbine economic if the as-offered cost was less than the LBMP revenue over the initial commitment period of one hour. This likely understates the share of GT commitments that are efficient for two reasons. First, the efficient commitment of a 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 how the real-time pricing methodology determines whether a gas turbine is eligible to set the LBMP.[141]

137 Actual peak load was 31.5 GW. The NYISO estimates that load would have peaked at 32.4 GW without demand response.

138 See Section V.G in the Appendix for this analysis in greater detail.

139 This includes roughly 150 MW of demand response that was activated by utilities from their own demand response programs.

140 See Figure A-69 in the Appendix for details of this analysis.

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

Table 14 evaluates the extent to which gas turbines were economic, but appeared to be uneconomic because they did not set the LBMP for a portion of the initial commitment period.[142]

Table 14: Hybrid Pricing and Efficiency of Gas Turbine Commitment in 2016

	New York City Load Pockets			Long Island
	Greenwood	Other 138 kV	345 kV	
# of Unit Starts	959	1117	148	1999
% of Unit-Intervals that are:				
Uneconomic	32%	42%	50%	40%
Economic - Not Setting Price	10%	12%	8%	11%
Economic - Other	59%	46%	42%	48%
Est. Avg. Annual LBMP Impact If Economic Units Set Price ($/MWh)	**$0.43**	**$0.49**	**$0.10**	**$1.51**

We found that gas turbines that were committed in merit in 2016 were clearly economic in 50 to 68 percent of the five-minute intervals during their initial one-hour commitment period, but they did not set the LBMP in 14 to 20 percent of the intervals when they were economic. We estimated that allowing these economic gas turbines to set prices would have increased the real-time LBMPs by an average of $3.90 to $6.60/MWh for each start in New York City and Long Island. For all of 2016, this would increase LBMPs by an average of $0.40 to $1.50 per MWh, with the largest effect in Long Island. However, the increase in LBMPs would be concentrated during peak conditions when gas turbines are used to satisfy the needs of the system.

Gas turbines are usually started during tight operating conditions when it is particularly important to set efficient real-time price signals that reward available generators that have flexible operating characteristics. Incentives for good performance also improve the resource mix in the long run by shifting net revenues from the capacity market to the energy market.

The NYISO implemented changes to improve upon the price-setting rules for quick start units on February 28, 2017. Specifically, the NYISO eliminated a step in the RTD software that led some units to not set the clearing price even when they were economic.[143] Although this is a significant improvement, the pricing logic still does not reflect the start-up costs of the gas turbine in the price-setting logic, which we continue to recommend that the NYISO incorporate into the price-setting logic.[144] The Commission has also recognized the need for the price-setting logic to consider the start-up and other commitment costs of gas turbines.[145]

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

143 See NYISO filing in Docket ER17-549 to modify pricing logic for Fixed Block Units, December 14, 2016.

144 See Recommendation #2014-10 in Section XI.

145 In Docket RM17-3-000, see the Commission's NOPR on Fast Start Pricing, dated December 15, 2016, and comments of Potomac Economics, dated March 1, 2017.

C. Performance of Operating Reserve Providers

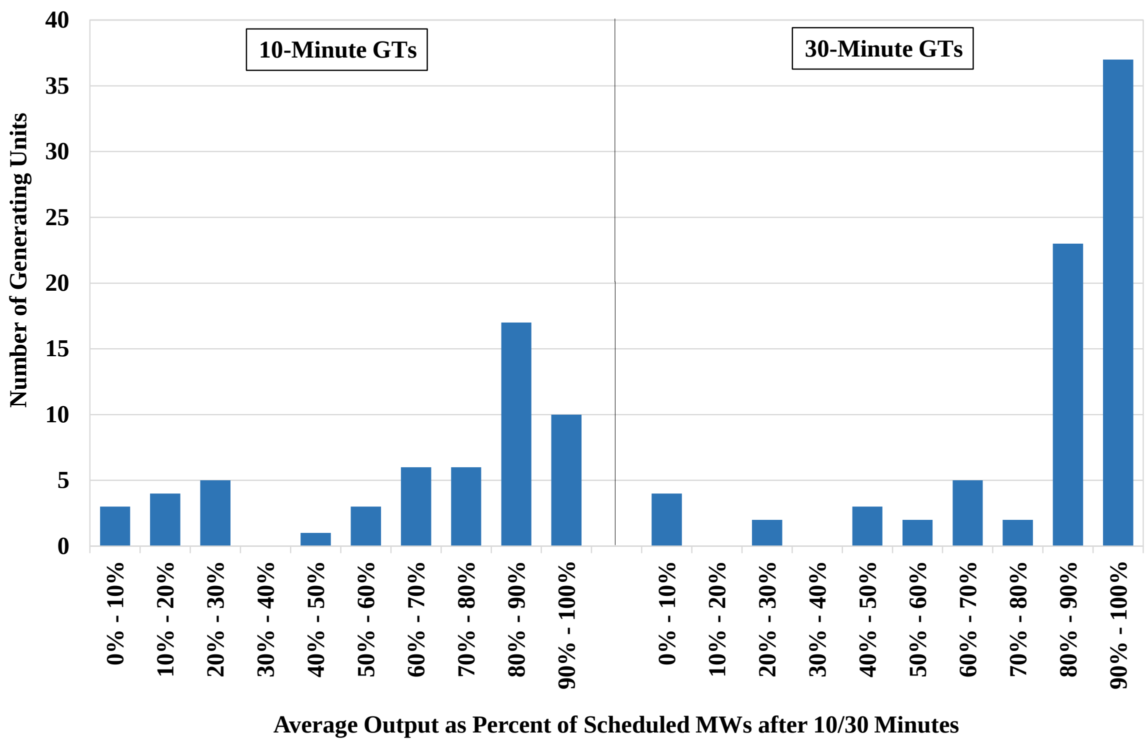
The wholesale market should provide efficient incentives for resources to help the NYISO maintain reliability by compensating resources consistent with the value they provide. Efficient performance incentives encourage participation by demand response and investment in resources with flexible operating characteristics in areas where they are most valuable. Over the coming decade, performance incentives will become more critical as the entry of new intermittent renewable generation will require more complementary flexible resources.

This section analyzes the performance of gas turbines in responding to start-up instructions in the real-time market, evaluates how the availability of and expected performance of operating reserve providers affects the costs of congestion management in New York City, and discusses how the compensation of these resources is affected by their performance.

Performance of Gas Turbines in Responding to Start-up Instructions

Figure 13 summarizes the performance of offline gas turbine units in responding to start-up instructions that result from in-merit commitment by the RTC model. Performance is shown separately for 10-minute gas turbines (units that are qualified to sell Non-Synchronous 10-Minute Reserves) and 30-minute gas turbines (units that are qualified to sell Non-Synchronous 30-Minute Reserves). For each unit in the NYCA, the figure shows the average number of MWs the unit was producing after 10 or 30 minutes as a percentage of the amount it offered in 2016.

Figure 13: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts, 2016



These figures show a wide range of performance by individual units in 2016. For 10-minute units, roughly half of units had an average response of 80 percent or better, while more than three-quarters of the 30-minute units had an average response of 80 percent better.

Units that perform poorly in response to start-up instructions tend to have higher EFORds, which leads to proportional reductions in their capacity payments.[146] Likewise, gas turbines that fail to respond lose the opportunity to sell energy when it would be profitable. However, there is no mechanism for discounting the operating reserve compensation of gas turbines based on their performance. Hence, some gas turbines that almost never perform still earn most of their net revenue from the sale of operating reserves.[147] Hence, operating reserve providers are compensated the same regardless of whether they perform reliably in response to NYISO instructions, so the market does not provide efficient performance incentives to generators scheduled for reserves. To address these concerns, we recommend that the NYISO consider ways to base payments to reserve providers on performance.[148]

Use of Operating Reserves to Manage New York City Congestion

The NYISO is ordinarily required to maintain flows such that if a contingency were to occur, no transmission facility would be loaded above its Long-Term Emergency ("LTE") rating immediately after the contingency. However, in some cases, the NYISO is allowed to operate a facility above LTE if post-contingency actions would be available to reduce flows to LTE quickly after a contingency.[149] Post-contingency actions include the deployment of operating reserves and adjustments to phase-angle regulators. The use of post-contingency actions to help satisfy transmission security criteria is important because it allows the NYISO to increase utilization of the transmission interfaces into load centers and reduce the congestion costs.

The value of rules that allow congestion to be managed with reserve capacity rather than actual generation dispatch becomes apparent when reserve capacity and other post-contingency actions suddenly become unavailable. In such cases, transfer capability is reduced, requiring more generation in the load pocket to manage congestion. In 2016, we found that 92 percent of congestion (as measured by real-time congestion value) on the 345kV system in New York City occurred on just four days when there was a temporary reduction in the availability of reserves downstream of the constraint. These are evaluated in the Table 15, which shows the impact of these reductions on market outcomes on four days in 2016. On these days, the affected facilities were the Dunwoodie-to-Motthaven lines ("71" & "72" lines). For each day, the table shows the constrained facility and the tightest real-time transfer limit that was used based on the available

146 See Appendix Section VI.C for information about the distribution of EFORds for individual gas turbines.

147 See Appendix Section VII.A for more information about the net revenue of gas turbines.

148 Recommendation #2016-2 in Section XI.

149 See *NYISO Transmission and Dispatching Operations Manual*, Section 2.3.2.

post-contingency actions. The table also reports the differential between the real-time limit and the day-ahead limit, which is based on the expected availability of post-contingency actions. Lastly, the table shows the average day-ahead and real-time LBMPs during the event and the amount of balancing congestion shortfall uplift that resulted from the event.

Table 15: Effects of Post-Contingency Actions on Congestion Management in NYC
Four Selected Days in 2016

Date & Hours	Limiting Facility	Minimum RT Limit	Reduction from DA Limit	NYC LBMP DA	NYC LBMP RT	BMCR Uplift
February 12, Hrs 10-21	**71 Line**	**LTE + 100 MW**	**109 MW**	**$35**	**$57**	**$90k**
February 14, Hrs 9-22	**72 Line**	**LTE + 50 MW**	**159 MW**	**$77**	**$103**	**$747k**
December 15, Hrs 9-22	**72 Line**	**LTE + 150 MW**	**54 MW**	**$98**	**$119**	**$305k**
December 16, Hrs 9-10	**71 Line**	**LTE + 150 MW**	**54 MW**	**$128**	**$125**	**$46k**

On the four days shown in the table, one of the Dunwoodie-to-Motthaven 345 kV lines was constrained to a transfer limit that was 54 to 159 MW below the day-ahead limit. These events led to much higher real-time LBMPs on three days, increased production from peaking units in the city, and generated $1.2 million of balancing congestion shortfall uplift. Although these effects were limited to four days in 2016, its significance will increase if congestion becomes more frequent on the constraints into New York City, so it would be beneficial for the NYISO to begin to consider the implications of this issue.

Operating reserve providers are not compensated for helping to manage transmission security requirements, which reduces their incentives to be available in the short term and the incentives to invest in flexible resources in the long term. In addition, when the real-time market dispatches such reserve capacity, it reduces the available reserves and may lead to a reduction in the transfer capability into New York City. In some cases, it would be more efficient to continue scheduling the unit to provide reserves. Hence, we recommend the NYISO evaluate ways to efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria while providing reserves.[150]

D. 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 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

150 Recommendation #2016-1 in Section XI.

flows to be channeled along pathways that lower the overall cost of generation necessary to satisfy demand. Hence, they have the potential to provide greater benefits than conventional AC transmission lines. Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways:

- Some controllable transmission lines are scheduled as external interfaces, evaluated in Section VI.D that assesses external transaction scheduling.[151]
- "Optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted in order to reduce generation redispatch costs (i.e., to minimize production costs) in the day-ahead and real-time markets.
- "Non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not based on reducing production costs, which are evaluated below.

Table 16 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2016. This is done for nine PAR-controlled lines between New York and neighboring areas and two between New York City and Long Island. This is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.

Table 16: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[152, 153]
2016

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					-19	$5.64	52%	$2
New England to NYCA								
Sand Bar	-76	-$11.53	91%	$8	-0.3	-$10.63	51%	$0.4
PJM to NYCA								
Waldwick	-825	$3.62	24%	-$26	130	$3.18	54%	$3
Ramapo	146	$4.05	67%	$11	188	$3.71	55%	$4
Farragut	624	$3.15	73%	$18	-71	$3.38	45%	-$2
Goethals	203	$3.63	76%	$6	73	$3.21	57%	$1
Long Island to NYC								
Lake Success	157	-$5.38	3%	-$8	-2	-$5.81	60%	$0.1
Valley Stream	65	-$7.38	2%	-$5	3	-$10.99	24%	-$2

151 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), the HTP Scheduled Line (an HVDC line), and the Linden VFT Scheduled Line.

152 This table reports the estimated production cost savings from the actual use of these transmission lines. They are *not* the production cost savings that could have been realized by scheduling the lines efficiently.

153 As discussed further in Section V.C of the Appendix, this metric tends to under-estimate the production cost savings from lines that flow from low-priced to high-priced regions. However, it tends to over-estimate the production cost increases from lines that flow from high-priced to low-priced regions. Nonetheless, it is a useful indicator of the relative scheduling efficiency of individual lines.

In the day-ahead market, PAR-controlled lines that were used to support contractual wheeling agreements were scheduled less efficiently than other PAR-controlled lines.

Waldwick and Goethals/Farragut lines. Operated under the ConEd-PSEG wheeling agreement to wheel up to 1000 MW from Hudson Valley to PJM and then on to New York City. Although power flowed in the efficient direction in roughly three quarters of the hours across the Goethals/Farragut lines, power flowed in the efficient direction in only 24 percent of hours across the Waldwick lines. These led to an estimated net increase of $2 million in day-ahead production costs (an increase of $26 million accrued on the Waldwick lines, which was offset by a reduction of $24 million accrued on the Goethals/Farragut lines).

Lake Success and Valley Stream PARs. Operated the 901 & 903 lines under the ConEd-LIPA wheeling agreement to wheel up to 290 MW from upstate to Long Island and then on to New York City. In 2016, power flowed in the *inefficient* direction in 97 percent of hours, much more inefficient than any of the other PAR-controlled lines. The transfers across these lines:

- *Increased* day-ahead production costs by $13 million in 2016 because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect.[154]
- Restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect and at the nearby Astoria Annex. Restrictions on the output of these New York City generators sometimes increases price 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).
- Increase the consumption of gas from the Iroquois pipeline, which normally trades at a significant premium over gas consumed from the Transco pipeline.
- Drive-up generation output from older less-fuel-efficient gas turbines and steam units without Selective Catalytic Reduction capability, leading to increased emissions of CO_2 and NOx pollution in non-attainment areas.

Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since most of these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets. Likewise, real-time production cost savings were low because the operating protocols for most of these lines are not responsive to market conditions. However, the Ramapo line and St. Lawrence line show relatively significant production cost savings in real-time because these lines are operated to flow a share of the external transactions between control areas that are submitted by traders and to manage real-time congestion.

Overall, these results indicate significant opportunities to improve the operation of these lines, particularly the Waldwick and Farragut/Goethals lines and the lines between New York City and

154 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.

Long Island. The ConEd-PSEG wheeling agreement was terminated at the end of April 2017. PJM and NYISO implemented a replacement protocol that includes the Waldwick and Farragut/Goethals lines as part of the NY-PJM AC interface for interchange scheduling and also adds these lines to the M2M coordinated congestion management process.[155,156] The new process will be a significant improvement over the 1,000 MW wheeling agreement and should lead to more efficient scheduling across these lines.

The 901 and 903 lines will still be operated under the ConEd-LIPA wheeling agreement for the foreseeable future.[157] It would be highly beneficial to modify this contract or find other ways under the current contract to operate the lines more efficiently. Although this should benefit both parties in aggregate, it may financially harm one party. Hence, it would be reasonable to create a financial settlement mechanism that would ensure that both parties benefit from the changes.[158] We recommend the NYISO work with the parties to this contract to explore potential changes that would allow the lines to be used more efficiently.[159]

E. Transient 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 scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2016. The effects of transmission constraints are more localized, while the power-balance and reserve constraints affect prices throughout NYCA.

Although transient price spikes occurred in less than 5 percent of all intervals in 2016, these intervals were important because they accounted for a disproportionately large share of the overall market costs. In general, unnecessary price volatility makes it more difficult for market participants, the NYISO, and neighboring system operators to commit quick-start resources and schedule external transactions efficiently. Hence, reducing unnecessary price volatility will lead to more efficient interchange between markets, lower production costs across markets, and less uplift from BPCG and DAMAP payments.

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155 For more information on the new process, see *ConEd/PSEG Wheel Replacement Protocol – Update*, presented by David Edelson to the Market Issues Working Group, April 24, 2017.

156 See Appendix Section V.B for additional information about the M2M process.

157 See NYISO OATT Section 18, Table 1 A - Long Term Transmission Wheeling Agreements, Contract #9 governs the operation of the lines between New York City and Long Island.

158 The proposed financial right is described in Section III.G of the Appendix.

159 See Recommendation #2012-8 in Section XI.

Drivers of Transient Real-Time Price Volatility

Table 17 summarizes the most significant factors that contributed to real-time price volatility in 2016 and shows their contributions to the price spike for the power-balance constraint and the most volatile transmission constraints. Contributions are also shown for: (a) resources that are scheduled by RTC, such as external interchange; and (b) flow changes from un-modeled factors, such as loop flows; and (c) other factors, such as load and generator derates.[160] For each constraint category, the most significant contribution category is highlighted.

Table 17: Drivers of Transient Real-Time Price Volatility
2016

	Power Balance	West Zone 230kV Lines	Central East	Dunwoodie - Shore Rd 345kV	Intra-Long Island Constraints
Average Transfer Limit	**n/a**	**711**	**1721**	**800**	**277**
Number of Price Spikes	**363**	**1101**	**242**	**318**	**965**
Average Constraint Shadow Price	**235**	**1239**	**352**	**373**	**464**
Source of Increased Constraint Cost:	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
Scheduled By RTC/RTD	**63%**	**6%**	**33%**	**66%**	**29%**
External Interchange	32%	6%	14%	37%	7%
RTC Shutdown Resource	24%	0%	11%	24%	14%
Self Scheduled Shutdown/Dispatch	6%	0%	8%	5%	7%
Flow Change from Non-Modeled Factors	**5%**	**78%**	**50%**	**16%**	**64%**
Loop Flows & Other Non-Market	1%	50%	18%	10%	21%
Niagara Generator Distribution	0%	11%	0%	0%	0%
Fixed Schedule PARs (excl. Ramapo)	0%	11%	22%	4%	43%
Ramapo PARs	0%	6%	9%	0%	0%
Redispatch for Other Constraint (OOM)	4%	0%	1%	3%	0%
Load/Wind/Generator Derates	**33%**	**17%**	**18%**	**18%**	**7%**

Note: the *Fixed Schedule PARs* contribution for the Long Island constraints was largely eliminated in May 2016 by an enhancement discussed below.

Resources scheduled by RTC (e.g., external interchange and gas turbine shut-downs) were a key driver of transient price spikes for the Dunwoodie-to-Shore Road 345kV line into Long Island and the power-balance constraint. RTC evaluates resources at 15-minute intervals and may shut-down large amounts of capacity or reduce imports by a large amount without considering whether resources will have sufficient ramp in each 5-minute period to satisfy the energy, reserve, and other operating requirements.

Flow changes resulting from non-modeled factors were a key driver of price spikes for Intra-Long Island constraints. In particular, flow variations on lines making-up the ConEd-LIPA

160 See Section V.D in the Appendix for more details about the evaluation and additional factors that contribute to transient real-time price spikes.

wheel were a key driver of volatility across the East Garden City-to-Valley Stream lines until May 2016 when the NYISO changed the modeling of these fixed-schedule PARs in the real-time market. Prior to May, these PARs contributed to volatility because RTD and RTC inaccurately assumed the flow across these lines would remain fixed at the most recent telemetered value, which was only true if the PAR was perfectly adjusted in response to variations in generation, load, interchange, and other PAR adjustments. In May, the NYISO began forecasting flows on these two lines based on the operating plan of operator of the facilities.[161] This has greatly reduced transient price spikes on Long Island, particularly in the Valley Stream load pocket.

Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines. For example, clockwise circulation around Lake Erie puts a large amount of non-market flows on these lines. Circulation can be highly volatile and difficult to predict since it depends partly on facilities that are scheduled outside the NYISO market.

Inconsistencies Between RTC and RTD

Differences in the ramp assumptions for units that are in the process of shutting-down and changes in external transactions schedules between RTC and RTD are a principal driver the price volatility evaluated above.

- Generators shutting down may reduce output more quickly than RTC recognizes because it assumes it has 15 minutes of ramp capability from one evaluation period to another, leading it to shut down several gas turbines simultaneously and resulting in a transient shortage. RTD runs every five minutes, but RTD is unable to delay the shut-down of a gas turbine for five minutes even if it would be economic to do so.
- The "look ahead" evaluations in RTD and RTC assume transactions ramp in at each quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange schedules actually ramp over 10-minute periods from five minutes before the quarter-hour to five minutes after (i.e., from :55 to :05, from :10 to :20, etc.). This inconsistency frequently causes the system to be short in the interval at the quarter hour (i.e., at intervals-ending :00, :15, :30, and :45) because the external transactions have not finished ramping.

To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:[162]

- Add two near-term look-ahead evaluation periods to RTC and RTD around the quarter-hour to allow them to accurately anticipate the ramp needs for a de-commitment or an interchange adjustment. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

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[161] See *Initialization of Lake Success and Valley Stream PARs*, Presented by David Edelson at the April 5, 2016 Market Issues Working Group.

[162] See Recommendation #2012-13 in Section XI.

- Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
- Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbine generators with the actual demonstrated performance to account for units that often ramp at a rate that is lower than their claimed ramp rate capability.
- Address inconsistencies between the ramp assumptions used in RTD's physical pass and RTD's pricing pass when units are ramping down from a day-ahead schedule.

Potential Solutions to Address Non-Modeled Factors

To reduce unnecessary price volatility from variations in loop flows and other factors not explicitly modeled in the dispatch software, we recommend the NYISO consider developing a mechanism for forecasting additional adjustments from the telemetered value for loop flows that result from factors not scheduled by the NYISO. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude).[163]

F. Supplemental Commitment & Out of Merit Dispatch for Reliability

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

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.

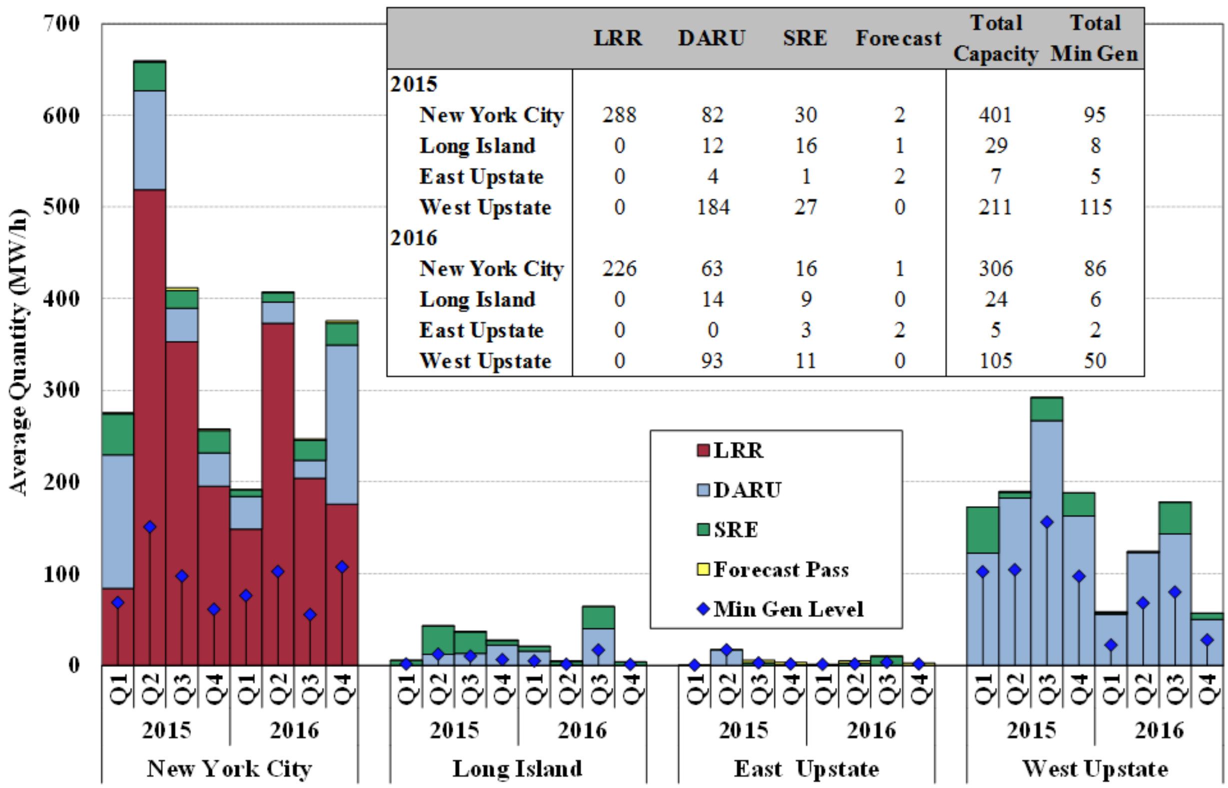
Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is normally uneconomic, which displaces production from economic capacity. Both of these actions tend to depress real-time prices, which undermines incentives for the market to maintain reliability and generates uplift costs. Hence, it is important to minimize supplemental commitment and OOM dispatch.

163 See Recommendation #2014-9 in Section XI.

Supplemental Commitment in New York State

Figure 14 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2015 and 2016. The first three types of commitment are primarily for local reliability needs. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load and reserve requirements. The figure shows the total capacity committed in each category, and it shows the minimum generation level of the resources committed.

Figure 14: Supplemental Commitment for Reliability in New York
By Category and Region, 2015 – 2016



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2015						
New York City	288	82	30	2	401	95
Long Island	0	12	16	1	29	8
East Upstate	0	4	1	2	7	5
West Upstate	0	184	27	0	211	115
2016						
New York City	226	63	16	1	306	86
Long Island	0	14	9	0	24	6
East Upstate	0	0	3	2	5	2
West Upstate	0	93	11	0	105	50

The figure shows that roughly 440 MW of capacity was committed on average for reliability in 2016, down roughly 32 percent from 2015. Similar to 2015, the vast majority of reliability commitment in 2016 occurred in New York City and Western New York, which accounted for 70 and 24 percent, respectively.

Reliability commitments in Western New York fell roughly 50 percent in 2016 to an average of 105 MW. Recent transmission upgrades allowed units previously committed frequently for reliability (at the Huntley and Dunkirk plants) in Western New York to mothball or retire in the first quarter of 2016. Subsequently, the vast majority of DARU commitments were in the Central Zone at the Cayuga (Milliken) plant to maintain reliability on the 115 kV system.

In New York City, reliability commitment fell 24 percent to average 306 MW in 2016, partly because there were fewer costly generation and transmission outages in 2016. This reduced the need to commit additional resources to satisfy the N-1-1 thermal and voltage requirements in the sub-regions on the 138 kV system. Additionally, lower relative gas prices, nuclear outages, and high summer loads caused units that were frequently needed for local reliability to be committed economically more often in 2016, particularly in the second and third quarters.

LRR Commitment in New York City for NOx Bubble Constraints

The NOx bubble constraints were established by the NYISO in the LRR pass of SCUC for three generator portfolios in New York City based on the compliance plans they filed with the Department of Environmental Conservation ("DEC"), The plans rely on "System Averaging" to meet certain emissions limits. These NOx bubble constraints require operation of a steam unit or a combined-cycle unit in order to reduce the overall NOx emission rate from a portfolio containing higher-emitting gas turbine units.[164] Supplemental commitments for these constraints occur only during the five-month ozone season (May to September). They are categorized as for local reliability, so the resulting out-of-market costs are uplifted to local customers.

NOx bubble commitments accounted for 11 percent of all reliability commitment in New York City in 2016. These commitments generally do not reduce output from older gas turbines (as intended). Table 18 summarizes our analysis of the effects of the NOx bubble constraints by load level, showing energy production (as a percent of total production in their bubble) from gas turbines in the NOx bubbles and steam units committed for the NOx bubble constraints.[165]

Table 18: Energy Production from NOx Bubble Generators
2016

Daily Load Levels	Generation Output from GTs in NOx Bubble	Generation Output from STs Committed for NOx
Low	**5%**	**90%**
Medium	**23%**	**10%**
High	**72%**	**0%**
Total	**100%**	**100%**

In 2016, 95 percent of energy production from the gas turbines in the NOx Bubbles occurred on days with medium to high load levels, while 90 percent of the energy production from steam units committed for the NOx constraints occurred on low-load days. Hence, most of the NOx bubble commitments were made on low-load days when older gas turbines rarely operated. In

164 In May 2014, the NYISO updated one of three NOx LRR constraints to reflect that one portfolio can use a combined cycle instead of a steam unit to balance the simple-cycle turbines. See "Ravenswood generating Station Nitrogen Oxide Emission Control Strategy for Compliance with 6 NYCRR Subpart 227-2."

165 See Section V.H in the Appendix for our evaluation of NOx emissions in more detail.

virtually all cases where a steam turbine was running at the same time as a gas turbine, the steam turbine was already committed for economics or another reliability need.

When steam turbine units were committed for the NOx bubble constraints, their output usually displaced output from newer cleaner generation in New York City and/or displaced imports to the city. Our analysis shows that:

- An average of over 1.5 GW of offline capacity from newer and cleaner generators (equipped with SCRs) in New York City was available and unutilized in hours when steam units were committed only for the NOx bubble constraint; and
- The steam units emit approximately 13 times more NOx per MWh than the newer generators with emission-reduction equipment.

Hence, we estimate that these NOx bubble commitments actually *increased* overall NOx emissions in New York City because the commitment of steam turbine units typically crowds-out generation from new fuel efficient generation with Selective Catalytic Reduction ("SCR") capability rather than the older GTs they were intended to displace. These commitments also resulted in uplift that was socialized to other parties and distorted clearing prices from the commitment of out-of-market resources. Owners of generation in NOx bubbles likely have options to comply with RACT that may result in lower emissions at lower cost. Hence, we continue to recommend that the NYISO work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.[166]

Out of Merit Dispatch

Table 19 summarizes the frequency (i.e., the total station-hours) of OOM actions over the past two years 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.[167]

The quantity of OOM actions fell by 29 percent in 2016. Most of the decline occurred in Western New York, which was primarily attributable to transmission upgrades that allowed the mothball of the last Dunkirk unit at the end of 2015 (which was frequently dispatched OOM for local reliability needs). Nonetheless, the largest share of OOM station hours were in Western New York, most of which occurred in the second and third quarters when the Milliken units were frequently dispatched OOM to secure the Elbridge-State Street 115 kV lines. These actions account for a large share of the guarantee payment uplift in 2016 (see Section IX.G).

166 See Recommendation #2014-13 in Section XI.

167 Figure A-80 in the Appendix shows our analysis on a quarterly basis and shows top two stations that had most frequent OOM dispatches in 2016 for each region.

Table 19: Frequency of Out-of-Merit Dispatch
By Region, 2015-2016

Region	OOM Station-Hours		
	2015	2016	% Change
West Upstate	5050	2854	-43%
East Upstate	222	279	26%
New York City	613	312	-49%
Long Island	1621	1849	14%
Total	**7506**	**5294**	**-29%**

The Niagara generator was often manually instructed to shift output between the generators at the 115 kV station and the generators at the 230 kV station to secure certain 115 kV and 230 kV transmission facilities. However, these were not classified as OOM in hours when the NYISO did not adjust the UOL or LOL of the Resource. In 2016, this manual shift was required in about 600 hours to manage 115 kV constraints and in 950 hours to manage 230 or 345 kV constraints. This pattern has continued since the Huntley reactors were activated in May 2016, although a larger share of the manual shifting was done to secure the 115 kV system since the reactors have been in service.

Given that frequent DARU commitments and OOM dispatches were taken to manage congestion on the 115 kV network in the Western New York, and they incurred sizable uplift, we continue to recommend the NYISO model the up-state 115kV transmission constraints in the day-ahead and real-time markets to allow them to be priced and managed efficiently.[168]

OOM dispatch on Long Island rose modestly in 2016. Most of these OOM instructions occurred in the third quarter as higher loads and transmission outages led to increased needs to dispatch peaking generators to manage thermal and voltage constraints on the east end of Long Island.

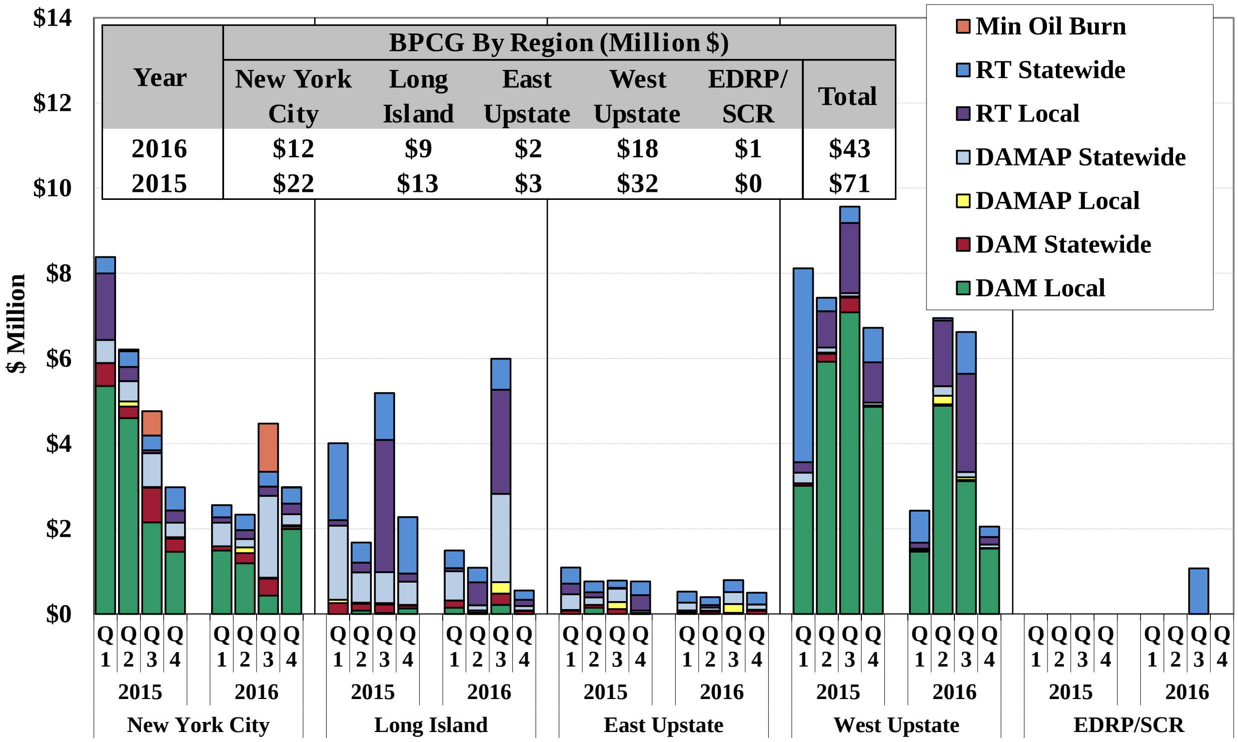
G. Guarantee Payment Uplift Charges

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 2015 and 2016 on a quarterly basis.[169]

168 See Recommendation #2014-12 in Section XI. The NYISO already models the 115kV system in its network security analysis software, but we recommend also modeling constraints for pricing and scheduling purposes that are currently managed with OOM actions that are costly or affect LBMPs.

169 See Figure A-81 and Figure A-82 in the Appendix for a more detailed description of this analysis.

Figure 15: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2015 – 2016



The figure shows that the guarantee payment uplift totaled $43 million in 2016, down 39 percent from 2015.[170] The decline resulted from less reliability commitment and OOM dispatch as discussed in Section F. In addition, lower natural gas prices decreased the commitment costs of gas-fired units, particularly in New York City. However, higher load levels on several days in July and August led to: (a) higher DAMAP payments to New York City and Long Island gas turbines, (b) higher guarantee payments to New York City units for the Minimum Oil Burn requirement, and (c) higher guarantee payments to demand resources for EDRP/SCR activation, partly offsetting the overall decrease in 2016.

Western New York accounted for 42 percent of the total guarantee payment uplift in 2016, which was higher than New York City (29 percent) for the second straight year. More than 85 percent (or $15.5 million) of total guarantee payment uplift in Western New York was local uplift. Nearly all of this local uplift was paid to several units that were committed for reliability and/or dispatched OOM to manage congestion on the 115 kV transmission facilities (which are discussed earlier). This uplift would likely be largely eliminated if these constraints were modeled in NYISO's day-ahead and real-time markets.

170 The 2016 number was based on billing data available at the time of reporting, which may be different from final settlement.

X. 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. This section evaluates existing demand response programs and discusses 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 in the ancillary services markets. 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 94 percent of the 1.3 GW of demand response resources registered in New York are reliability demand response resources.

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,192 MW of resources participating in 2016. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. In the Summer 2016 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- 4.1 percent of the UCAP requirement for New York City;
- 3.2 percent of the UCAP requirement for the G-J Locality;
- 2.1 percent of the UCAP requirement for Long Island; and
- 3.6 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources fell 50 percent from 2010 to 2016 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011. These have improved the accuracy of baselines for some resources, reducing the amount of capacity they are qualified to sell. Business decisions by market participants also contributed to the reduction. This was partly driven by relatively low capacity prices in some areas in recent years and reduced revenues as a result of the enhanced auditing and baseline methodology.

Demand-Side Ancillary Services Program

This program allows demand-side resources to offer operating reserves and regulation service in the wholesale market. When the program was initially set up in 2008, DSASP resources had difficulty setting up communications with the NYISO through the local Transmission Owner. Consequently, no DSASP resources were fully qualified until 2012 when the NYISO enabled resources to communicate directly with the NYISO. Currently, approximately 110 MWs of DSASP resources actively participate in the market, providing considerable value by reducing the cost of ancillary services in the New York market. These resources were capable of providing up to 16 percent of the NYCA 10-minute spinning reserve requirement in 2016.

Day-Ahead Demand Response Program

No resources have participated in this program since 2010. Given that loads may hedge with virtual transactions similar to DADRP schedules, the value of this program is questionable.

Demand Response and Scarcity Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under scarcity conditions. NYISO has special scarcity pricing rules for periods when demand response resources are deployed. In 2016, the NYISO deployed reliability demand response resources on one day (August 12) in all zones from 13:00 to 18:00 for system-wide capacity needs. The new Comprehensive Scarcity Pricing Rule (effective on June 1, 2016) was active during the entire event.[171]

[171] See Section V.G in the report for a detailed evaluation of pricing outcomes for this event.

XI. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2016, although we recommend additional enhancements to improve market performance. Eighteen recommendations are presented in seven categories below. A new numbering system is used in this report whereby each recommendation is identified by the SOM report in which it first appeared and the number used in that report. For example, Recommendation #2015-8 originally appeared in the 2015 SOM Report as Recommendation #8. The majority of these recommendations were made in the 2015 SOM Report, but Recommendations #2016-1 and #2016-2 are new in this report. The following table summarizes our current recommendations.

Number	Section	Recommendation	Current Effort	High Priority	Scoping/ Future
Energy Market Enhancements - Real-Time Pricing and Performance Incentives					
2016-1	IX.C.2	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.			✓
2016-2	IX.C.1	Consider means allow reserve market compensation to reflect actual and/or expected performance.			✓
2014-10	IX.B	Modify criteria for gas turbines to set prices in the real-time market by incorporating start-up costs.			
2014-12	IX.F.3	Model 100+ kV transmission constraints in the day-ahead and real-time markets, and develop associated mitigation measures.	✓		
2015-16	IX.A.1	Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.			✓
2015-17	IX.A.2	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.			✓
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.			
Energy Market Enhancements - Real-Time Market Operations					
2012-8	IX.D	Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.			
2012-13	VI.D IX.E	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	✓	✓	✓
2014-9	IX.E.4	Consider enhancing modeling of loop flows to reflect the effects of expected variations more accurately.			✓

Number	Section	Recommendation	Current Effort	High Priority	Scoping/ Future
Energy Market Enhancements - BPCG Eligibility and Fuel Limitations/Storage					
2014-13	IX.F.2	Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.			
2013-11	IX.B.2	Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	✓		✓
Capacity Market Enhancements					
2012-1a	VII.F	Establish a dynamic locational capacity framework that reflects potential deliverability constraints to allow prices to fully reflect the locational value of capacity.		✓	✓
2012-1c	VII.D	Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.			✓
2013-1c	VII.C	Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements.	✓	✓	
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.	✓		
2015-8	VII.B	Modify the capacity market and planning process to better account for imports from and exports to neighboring control areas from import-constrained capacity zones.	✓		
Planning Process Enhancements					
2015-7	VII.E	Reform the CARIS process to better identify and fund economically efficient transmission investments.			✓

This section describes each recommendation, discusses the benefits that are expected to result from implementation, identifies the section of the report where the recommendation is evaluated in more detail, and indicates whether there is a current NYISO project or stakeholder initiative that might address the recommendation. The criteria for designating a recommendation as "High Priority" are discussed in the next subsection. The last subsection discusses several recommendations that we considered but chose not to include this year.

A recommendation is categorized as "scoping/future" for one or more of the following reasons. First, there is significant uncertainty regarding the scope of the solution that would be necessary to address the underlying issue that motivated the recommendation. Second, some additional work may be necessary to investigate the costs and benefits of potential solutions before deciding on the priority level. Third, the anticipated benefits would be smaller in the short-term than in the long-term, so it is appropriate to take additional time to consider.

A. Criteria for High Priority Designation

As the NYISO MMU, we are responsible for recommending market rule changes to improve market efficiency. In each of our annual state of the market reports, we identify a set of market rule changes that we recommend the NYISO implement or consider. In most cases, a particular recommendation provides high-level specifics, assuming that the NYISO will shape a detailed proposal that will be vetted by stakeholders, culminating in a 205 filing to the FERC or a procedural change. In some cases, we may not recommend a particular solution, but may recommend the NYISO evaluate the costs and benefits of addressing a market issue with a rule change or software change. We make recommendations that have the greatest potential to enhance market efficiency given our sense of the effort level that would be required. In each report, a few recommendations are identified as "High Priority" for reasons discussed below.

When evaluating whether to designate a recommendation as High Priority, we assess how much the recommended change would likely enhance market efficiency. To the extent we are able to quantify the benefits that would result from the enhancement, we do so by estimating the production cost savings and/or investment cost savings that would result because these represent the accurate measures of economic efficiency. In other cases, we quantify the magnitude of the market issue that would be addressed by the recommendation. As the MMU, we focus on economic efficiency because maximizing efficiency will minimize the costs of satisfying the system's needs over the long-term. Other potential measures of benefits that largely capture economic transfers associated with changing prices (e.g., short-term generator revenues or consumer savings) do not measure economic efficiency. Therefore, we do not use such measures when suggesting priorities for our recommendations.

The NYISO operates a $5+ billion per year wholesale market for electricity. With the majority of wholesale market costs attributable to fuel and other inputs, it can be difficult to substantially lower the overall cost of production. Initiatives that reduce production costs often require significant upfront capital costs (e.g., replacement of a less fuel-efficient generator with a new generator). Consequently, market rule changes that reduce costs significantly without requiring an investment in new infrastructure result in large savings relative to the market development costs (i.e., a high benefit-to-cost ratio). Such changes that would produce sustained benefits for at a number of years warrant a high priority designation.

In addition to these considerations, we often consider the feasibility and cost of implementation. Quick, low-cost, non-contentious recommendations generally warrant a higher priority because they consume a smaller portion of the NYISO's market development resources. On the other hand, recommendations that would be difficult to implement or involve benefits that are relatively uncertain receive a lower priority.

B. Discussion of Recommendations

Energy Market Enhancements – Real-Time Pricing and Performance Incentives

2016-12: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief. (Scoping/Future)

The NYISO is required to maintain flows such that if a contingency were to occur, no transmission facility would be loaded above its Long-Term Emergency ("LTE") rating post-contingency. In some cases, the NYISO is allowed to use operating reserves and other post-contingency operating actions to satisfy this requirement. This allows the NYISO to increase utilization of the transmission system into load centers, thereby reducing production costs. Since these operating reserve providers are not compensated for helping manage congestion, the market does not provide efficient signals for investment in new and existing resources with flexible characteristics. Hence, we recommend the NYISO evaluate means to efficiently compensate operating reserves that help manage congestion.

2016-2: Consider means to allow reserve market compensation to reflect actual and/or expected performance. (Scoping/Future)

Operating reserve providers are compensated the same regardless of how they perform when deployed by the NYISO. Consequently, the market does not provide efficient performance incentives to generators that are frequently scheduled for reserves. To address this concern, we recommend the NYISO consider means to base payments for reserves on past performance.

2014-10: Modify criteria for gas turbines to set prices in the real-time market by incorporating start-up costs.

It would be appropriate to amortize start-up costs of gas turbines over the initial commitment period and reflect these costs in the price-setting logic. This will allow the NYISO's real-time energy prices to reflect the full costs of the resources needed to satisfy the system's demands. It will also help ensure that gas turbines that are economic will recover their costs through LBMP revenues rather than through guarantee payments.

2014-12: Model 100+ kV transmission constraints in the day-ahead and real-time markets and develop associated mitigation measures. (Current Effort)

Market incentives for investment in resources on the 115kV system in up-state New York are inadequate, partly because these facilities are not modeled in the NYISO's energy and ancillary services markets. Currently, these constraints are managed primarily through out-of-market actions, which has raised guarantee payments and contributed to the need for cost-of-service contracts to keep older capacity in service. In some cases, these constraints are managed indirectly in the day-ahead and real-time markets by reducing the transfer limits on internal and external interfaces, which is much less efficient than modeling the 115kV facilities in the NYISO markets. We recognize that implementing the processes to manage these constraints in the day-ahead and real-time markets would be a significant effort, since it would require additional coordination with the local Transmission Owner.

Some 115kV transmission constraints raise local market power concerns, which are addressed with mitigation measures that limit suppliers' ability to extract inflated guarantee payments. Once these constraints are modeled and priced, the mitigation measures should be expanded to address the potential exercise of market power in day-ahead or real-time energy markets.

2015-16: Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources. (Scoping/Future)

In some cases, the reserve requirement for a local area can be met more efficiently by importing reserves (i.e., reducing flows into the area and treating the unused interface capability as reserves), rather than scheduling reserves on internal generation. The report identifies two examples where this functionality would provide significant benefits.

- Operating reserves in Zone K are limited in satisfying operating reserve requirements for SENY, Eastern NY, and NYCA can be increased. Long Island frequently imports more than one GW from upstate, allowing larger amount of reserves on Long Island to support the requirements outside of Long Island. Converting Long Island reserves to energy in these cases would be accomplished by simply reducing imports to Long Island, thereby reducing the required generation outside of Long Island.
- The amount of operating reserves that must be held on internal resources can be reduced when there is unused import capability into Eastern New York and SENY. In fact, it is often less costly to reduce flows across Central East or the interface into SENY to hold reserves on these interfaces rather than holding reserves on units in Eastern New York.

Hence, we recommend that the NYISO modify the market software to optimize quantity reserves procured on Long Island and other areas in Eastern New York given the cost of holding reserves on the transmission interfaces into these areas.

2015-17: Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages. (High Priority, Scoping/Future)

Historically, transmission constraints that could not be resolved were "relaxed" (i.e., the limit was raised to a level that would accommodate the flow). However, this does not lead to efficient real-time prices that reflect the reliability consequences of violating the constraint. To address this pricing concern, some organized wholesale market operators have enhanced their shortage pricing by using transmission demand curves that set the constraint shadow prices when a constraint cannot be resolved. The NYISO has begun to use a graduated transmission demand curve to set prices during some transmission shortages. However, the majority of transmission shortages are still resolved by relaxation rather than the use of a demand curve to set prices.

In the short-term, the NYISO has filed a proposal to reform transmission constraint pricing, which we support. In the long-term, we recommend the NYISO replace the single graduated transmission demand curve with ones that can vary according to the importance, severity, and/or duration of the transmission constraint violation.

2015-9: Eliminate transaction fees for CTS transactions at the PJM-NYISO border.

The efficiency benefits of the CTS process with PJM have generally fallen well short of expectations since it was implemented in the fourth quarter of 2014. We have observed far greater utilization of CTS bidding at the ISO-NE interface since it was implemented in 2015. The lower utilization of CTS with PJM can be partly attributed to the relatively large fees that are charged to these CTS transactions, while fees were eliminated between ISO-NE and NYISO. It is unlikely that CTS with PJM will function effectively as long as transaction fees and uplift charges are large relative to the expected value of spreads between markets. Hence, we recommend eliminating transaction fees and uplift charges between the PJM and NYISO.

Energy Market Enhancements – Real-Time Market Operations

2012-8: Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.

Significant efficiency gains may be achieved by improving the operation of the PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines). These lines are scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets. In 2016, these lines were scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 97 percent of the time. Their operation increased production costs by an estimated $13 million, and often restricted production by economic generation in New York City.

We recommend that the NYISO work with the parties to the underlying wheeling agreements to explore potential changes to the agreements or to identify how the agreements can be accommodated within the markets more efficiently. Since more efficient operation would benefit one party financially at the expense of the other, it is reasonable to create a financial settlement mechanism to compensate the party that would be giving up some of the benefits from the current operation. We discuss such a mechanism in Section III.G of the Appendix.

2012-13: Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment. (Current Effort, High Priority, Scoping/Future)

Differences is the ramp assumptions for units that are in the process of shutting-down and changes in external transactions schedules between RTC and RTD are a principal driver the price volatility evaluated above. To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:

- Add two near-term look-ahead evaluation periods to RTC and RTD around the quarter-hour to allow it them to accurately anticipate the ramp needs for a de-commitment or interchange adjustment. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.
- Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
- Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbine generators with the actual demonstrated performance to account for units that often ramp at a rate that is lower than their claimed ramp rate capability.
- Address inconsistencies between the ramp assumptions used in RTD's physical pass and RTD's pricing pass when units are ramping down from a day-ahead schedule.

2014-9: Consider enhancing modeling of loop flows to reflect the effects of expected variations more accurately. (Scoping/Future)

Variations in loop flows were among the leading causes of real-time transient price spikes in 2016. To reduce unnecessary price volatility from variations in loop flows and other factors not explicitly modeled in the dispatch software, we recommend the NYISO consider developing a mechanism for forecasting additional adjustments from the telemetered value for loop flows. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude). Additional scoping is necessary to evaluate the relative complexity, costs, and benefits of these and other potential solutions to this recommendation.

Energy Market Enhancements – BPCG Eligibility and Energy Limitations/Storage

2014-13: Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.

Our analyses continues to indicate that the NOx bubble constraints did not lead to reductions in NOx emissions and actually led to higher overall NOx emissions. These commitments also result in uplift that is socialized to other parties and distort clearing prices. Owners of generation in NOx bubbles likely have options to comply with NOx requirements that will result in lower emissions at lower cost. Hence, we recommend that the NYISO work with generators in NOx bubbles to determine whether they have other available options for NOx RACT compliance that would result in more efficient operation of their units.

2013-11: Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market. (Current Effort, Scoping/Future)

There are at least two types of energy supply constraints that cannot be adequately reflected in the day-ahead generator offers.

- Hydroelectric plants have inventory constraints that may limit their output over a 24-hour period. Likewise, output from oil-fired and dual-fueled generators is often limited by oil inventories or air permit restrictions. It would be beneficial for such generators to conserve their limited inventory for periods when it is most valuable.
- During periods of high gas demand, gas-fired generators may be subject to hourly OFOs that require them to schedule a specific quantity of gas in each hour of a 24-hour period. A supplier that offers a flexible range in the day-ahead market is at risk of being compelled to schedule enough gas to run at its highest single hourly day-ahead schedule level for the entire 24-hour gas day. This subjects the generator to significant financial risks when it is scheduled in the day-ahead market.

Currently, generators with such limitations would likely respond by raising their offer prices, which is imprecise and can lead to uneconomic outcomes for the supplier and the market overall. Hence, allowing generators to submit offers that reflect quantity limitations over the day would facilitate more efficient scheduling and pricing when they are subject to fuel or other production limitations.

Capacity Market Enhancements

2012-1a: Establish a dynamic locational capacity framework that reflects potential deliverability constraints to allow prices to fully reflect the locational value of capacity. (High Priority, Scoping/Future)

The existing rules for creating New Capacity Zones 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, (b) when the NYISO's Class Year Deliverability Test is inefficiently restricting new entry and capacity imports, or (c) when the net cost of new entry varies by a wide margin within a large capacity region that will predictably lead to deliverability and resource adequacy issues.

Establishing a dynamic locational framework by pre-defining interfaces and corresponding zones based on system planning requirements would ensure that locational capacity prices would immediately adjust to reflect changes in market conditions, including the retirement of key units in the state's aging fleet regardless of whether the retirement is anticipated or unexpected. This will, in turn, allow investors to be more confident that the reliability needs will be fully priced and facilitate timely market-based investment.

Under the current rules, when a New Capacity Zone is created, supplier-side and buyer-side market power mitigation rules are automatically applied to the new zone. However, if a comprehensive set of interfaces (and corresponding zones) were pre-defined based on system planning requirements, it would not necessarily be appropriate to apply mitigation rules to every zone. Therefore, we recommend de-coupling the application of market power mitigation from the process of creating a new zone.

This recommendation is identified as a high priority because the current zone configuration is likely to inflate capacity costs in western New York by a substantial margin. We recognize that a process to pre-define capacity zones will be more efficient after the implementation of Recommendation #2013-1c because this would ensure that the resulting LCRs would be set appropriately.

2012-1c: Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate. (Scoping/Future)

This is similar to the NYISO's current rules to provide Transmission Congestion Contracts ("TCCs"). New transmission projects can increase transfer capability over interfaces that bind in the NYISO's capacity market. Hence, transmission projects can provide resource adequacy benefits that are comparable to capacity from resources in constrained areas. Accordingly, transmission should be compensated for the resource adequacy benefits through the capacity market. Creating financial capacity transfer rights will help: (a) provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives, and (b) reduce barriers to entry that sometimes occur under the existing rules when a new generation project is required to make uneconomic transmission upgrades. Additional scoping is necessary to evaluate the extent to which this rule would affect the viability of market-based transmission investments.[172]

2013-1c: Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements. (High Priority, Current Effort)

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The demand curve reset process sets the capacity demand curve for each locality relative to the IRM/LCR without considering whether this results

172 This recommendation would provide more efficient signals for transmission investment regardless of whether Recommendation #2013-1c is adopted. However, capacity prices that overvalue generation (before Recommendation #2013-1c is implemented) could cause generation to preempt efficient transmission investment.

in a consistent relationship between the clearing prices of capacity and the marginal reliability value of capacity in each Locality. The resulting capacity prices do not provide efficient signals for investment, which raises the overall cost of satisfying the capacity needs.

Establishing capacity demand curves that reflect the marginal reliability value of additional capacity in each Locality would lead to capacity prices that will facilitate more efficient investment and retirement, and lower overall capacity costs. We describe two possible approaches in this report for implementing this recommendation, and the NYISO is currently evaluating one approach.

This recommendation is designated as a high priority because it will lead to large investment cost savings, more price stability, and more predictable requirements. Although comprehensive estimates of the potential savings are not yet complete, Section VII.B.0 summarizes an analysis showing that even very limited adjustments in the 2017/18 IRM and LCRs would produce substantial savings, supporting the conclusion that optimizing these requirements would lead to large annual savings under the current zone configuration. Accordingly, we place a high priority on this recommendation.

2013-2d: Enhance Buyer-Side Mitigation Forecast Assumptions. (Current Effort)

The set of generators that is assumed to be in service for the purposes of the exemption test is important because the more capacity that is assumed to be in service, the lower the forecasted capacity revenues of the Examined Facility, thereby increasing the likelihood of mitigating the Facility even if it is economic. The Tariff requires the NYISO to include all existing resources other than Expected Retirements, which leads to the inclusion of mothballed resources that are unlikely to re-enter. This also results in the exclusion of resources that have submitted a retirement notice, but that retain the ability to re-enter the market. These inclusion rules should be reevaluated considering recent changes in other BSM rules, including newly created exemptions for competitive entry, renewables, and self-supply resources. We recommend the NYISO modify the BSM assumptions to allow the forecasted prices and project interconnection costs to be reasonably consistent with expectations.

2015-8: Modify the capacity market and planning process to better account for imports from and exports to neighboring control areas from import-constrained capacity zones. (Current Effort)

The NYISO recently filed tariff provisions that will allow it to recognize the local reliability benefits from capacity that is exported from an import-constrained capacity zone. However, additional refinement is needed to ensure that such resources are properly accounted for in the planning models and to provide efficient incentives to import and export capacity. Hence, we also recommend that the NYISO: a) define a local reliability product provided by such resources and b) set efficient clearing prices at external interfaces that are interconnected with more than one capacity zone. In coordination with these rules, the NYISO should also consider changing the market power mitigation threshold for resources that export. Together, these changes will facilitate efficient utilization of the primary interface with ISO New England and reduce capacity costs in both markets in the coming years.

Enhance Planning Processes

2015-7: Reform the CARIS process to better identify and fund economically efficient transmission investments. (Scoping/Future)

The current economic transmission planning process does not accurately estimate the economic benefits of proposed projects. We identify in this report several key assumptions that lead transmission projects to be systematically under-valued. Additionally, the current requirement for 80 percent of the beneficiaries to vote in favor of a proposed project is likely to prevent economic projects from being funded. We recommend that the NYISO review the CARIS process to identify any additional changes that would be valuable, and make the changes necessary to ensure that the CARIS process will identify and fund economic transmission projects.

C. Discussion of Recommendations Made in Previous SOM Reports

During the development of each State of the Market Report, we review the progress that has been made toward the evaluation and/or implementation of recommendations made in previous reports. Normally, we remove a recommendation from the list if the NYISO has responded to the substance of the recommendation by modifying an operating practice or by filing market rule changes and the Commission has accepted them (or they are largely uncontested). In some cases, we remove a recommendation from the list if it becomes apparent that the cost of implementation would be significantly greater than originally anticipated, there is a material change in the underlying drivers for the recommendation, or there is little prospect for adoption.

Market Developments Since the 2015 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2015 State of the Market Report.

#6 – Modify the pivotal supplier test to prevent a large NYC 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 for NYC. The NYISO implemented this recommendation before the Summer 2017 capacity auction.

#8 – Modify the capacity market and planning process to better account for capacity that is exported to neighboring control areas from import-constrained capacity zones. Although we have repeated this recommendation in this report, the NYISO has made significant progress towards implementing this recommendation since last year. The NYISO filed on November 30, 2016 a package of changes to address the most imminent concerns related to this recommendation, and the NYISO is working with Stakeholders to address remaining issues.[173]

#10 – After the ConEd-PSEG wheeling agreement expires, work with PJM to coordinate scheduling of the associated controllable lines (i.e., the A, B, C, J, and K lines) to minimize production costs across the two regions. The NYISO implemented this recommendation on May 1, 2017.

#13 – Consider enhancing modeling of loop flows and PAR-controlled lines to reflect the effects of expected generation, load, and PAR-controls on line flows more accurately. Although we have repeated this recommendation in this report, the NYISO has made some progress towards implementing this recommendation since last year. In particular, the NYISO made improvements to the modeling of PAR-controlled lines between New York City and Long Island. [174]

#14 – Modify criteria for GTs to set prices in the real-time market by allowing GTs to be eligible to set price in the final pricing pass and incorporating start-up costs. The NYISO partially implemented this recommendation on February 28, 2017 by addressing our concerns with the eligibility of GTs to set price. However, we continue to recommend the NYISO incorporate start-up costs.[175]

#21 – Improve assumptions in the commitment logic of the DAM to avoid scheduling uneconomic gas turbines. The NYISO implemented this recommendation in December 2016.[176]

Other Recommendations Not Included on the List for 2016

This subsection describes recommendations from 2015 and one earlier recommendation that was not resolved, but are not included in this report. The 2015 State of the Market Report recommended expanding the buyer-side mitigation measures to address additional actions such as subsidizing uneconomic existing capacity to suppress capacity prices. We have recommended that the Commission adopt a mitigation measure to address such conduct and this issue is

173 The Commission approved most of these with an order in Docket ER17-446-000, dated January 27, 2017. NYISO discussed the status of remaining issues in *Update on Capacity Exports from Localities* at the April 12, 2017 Business Issues Committee.

174 See Section IX.E.

175 See Recommendation #2014-10.

176 See Section IV.A.0.

pending before the Commission in a complaint proceeding.[177] After the Commission orders on this proposal, we will reassess the adequacy of the buyer-side mitigation measures.

Additionally, the state of the market reports from 2002 to 2012 recommended that the NYISO adopt virtual trading at the sub-zonal level. Since its introduction in November 2001, virtual trading at the zone level has consistently helped improve day-ahead scheduling decisions when systematic differences in modeling and/or behavior between the day-ahead and real-time markets would have otherwise led to under/over-commitment in the day-ahead market.[178] Virtual trading at the subzone level would likely improve the efficiency of day-ahead commitments, fuel procurement decisions, and consistency between day-ahead and real-time prices in areas with persistent differences. Although we continue to see significant persistent differences between day-ahead and real-time prices and associated scheduling inefficiencies that could be ameliorated by virtual trading at the subzone level, we removed the recommendation from the list after the 2012 report because the proposal did not make significant progress in the stakeholder process in the previous eleven years.

177 See discussion in Section III.C.0.

178 Beginning in 2002, each state of the market report has discussed the effects of virtual trading and inconsistencies between day-ahead and real-time market outcomes that would be addressed by virtual trading at the sub-zone level.

Analytic Appendix

2016 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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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 transmission congestion contracts and installed capacity, which are evaluated in Sections III and VI of the Appendix.

This section of the appendix summarizes the market results and performance in 2016 in the following areas:

- Wholesale market prices;
- Fuel prices, generation by fuel type, and load levels;
- Fuel usage under tight gas supply conditions;
- Ancillary services prices;
- Price corrections;
- 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 both 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 2009 to 2016 at the following seven locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and (g) Long Island (i.e., Zone K). The majority of congestion in New York occurs between and within these regions.

Natural gas prices are based on the following gas indices (plus a transportation charge of $0.20 per MMBtu): (a) the Dominion North index for the West Zone and areas in Central New York; (b) the Iroquois Waddington index for North Zone; (c) the Iroquois Zone 2 index for the Capital Zone and Long Island; (d) the average of Iroquois Zone 2 index and the Millennium East index for Lower Hudson Valley [179]; and (e) the Transco Zone 6 (NY) index for New York City. A 6.9 percent tax rate is also reflected in the natural gas prices for New York City.

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

2009-2016

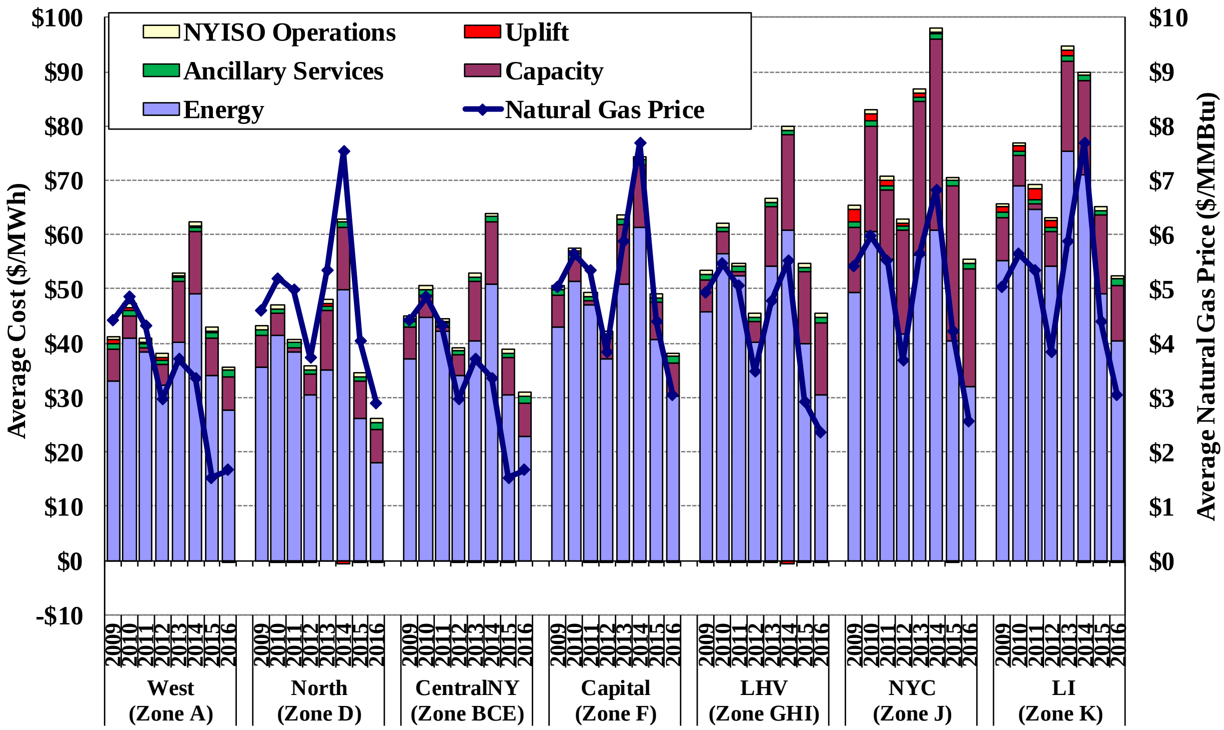


Figure A-2: Day-Ahead Electricity and Natural Gas Costs

Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2016 for the seven locations shown in Figure A-1. The table in the chart shows the annual averages of these quantities for 2015 and 2016. Although much of the electricity used by New York consumers is generated from hydro and nuclear generators, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York. This is evident from the strong positive correlation of electricity prices with natural gas costs shown in the figure.

179 The liquidity at the Millennium index prior to summer 2012 was significantly less than exists today. Days without prices prior to June 2012 at the Millennium index were calculated instead using the Tetco M3 index price.

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2016

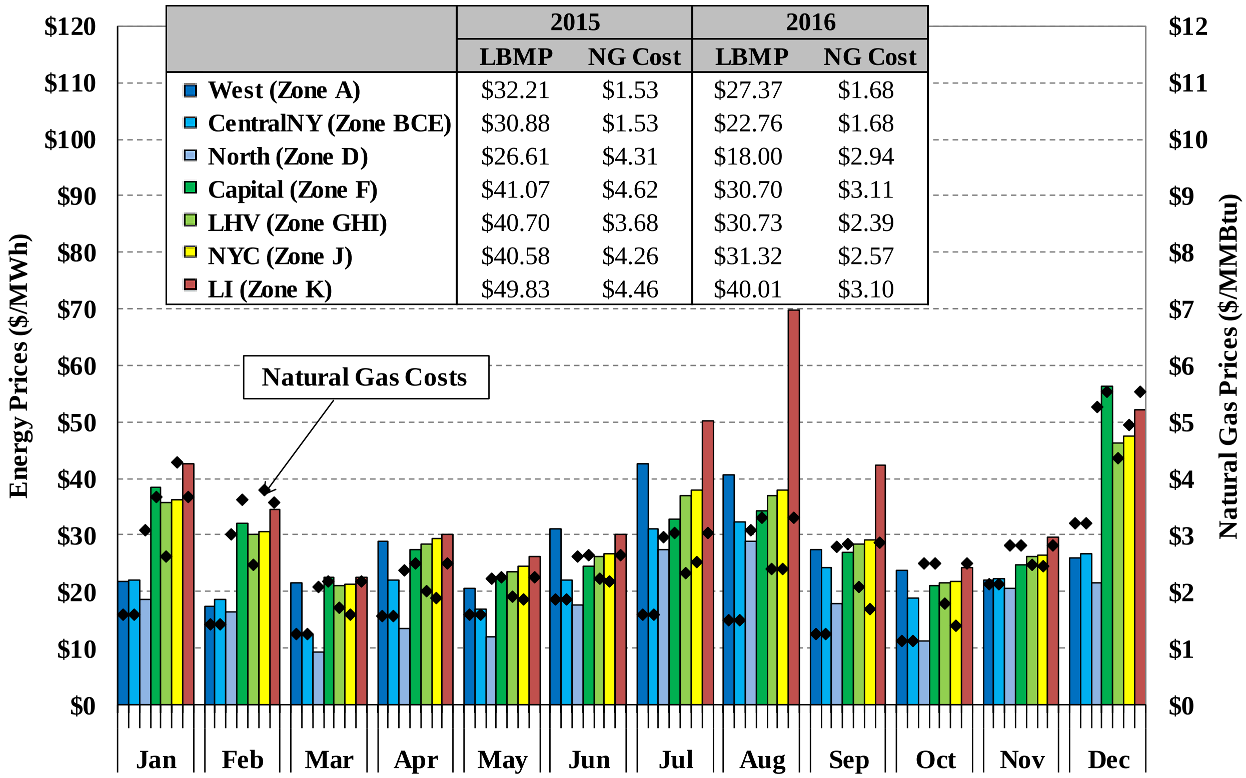


Figure A-3: Average Monthly Implied Marginal Heat Rate

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 minus a generic unit Variable Operations and Maintenance ("VOM") cost then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost).[180] Thus, if the electricity price is $50 per MWh, the VOM cost is $3 per MWh, the natural gas price is $5 per MMBtu, and the RGGI clearing price is $3 per CO_2 allowance, this would imply that a generator with a 9.1 MMBtu per MWh heat rate is on the margin.[181]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2016 for the seven locations shown in Figure A-1 and in Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2015 and in 2016 at these seven locations. By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

180 The generic VOM cost is assumed to be $3 per MWh in this calculation.

181 In this example, the implied marginal heat rate is calculated as ($50/MWh – $3/MWh) / ($5/MMBtu + $3/ton * 0.06 ton/MMBtu emission rate), which equals 9.1 MMBtu per MWh.

Figure A-3: Average Monthly Implied Marginal Heat Rate
Day-Ahead Market, 2016

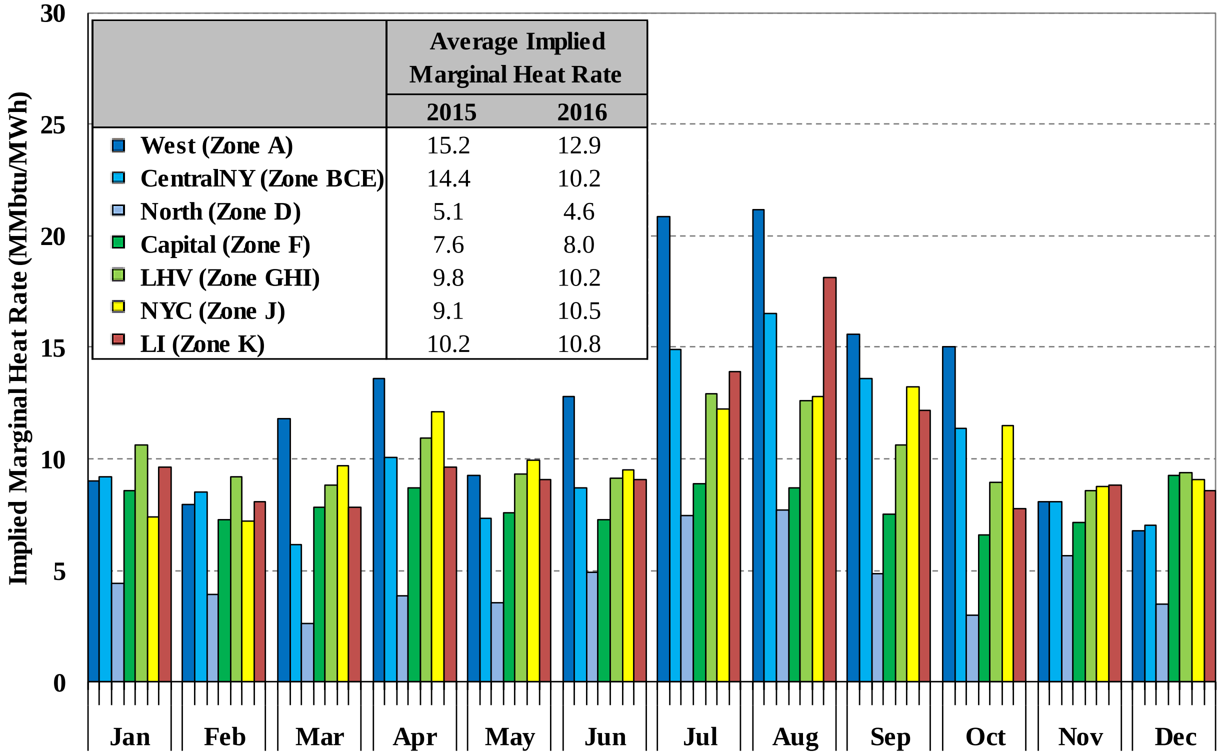
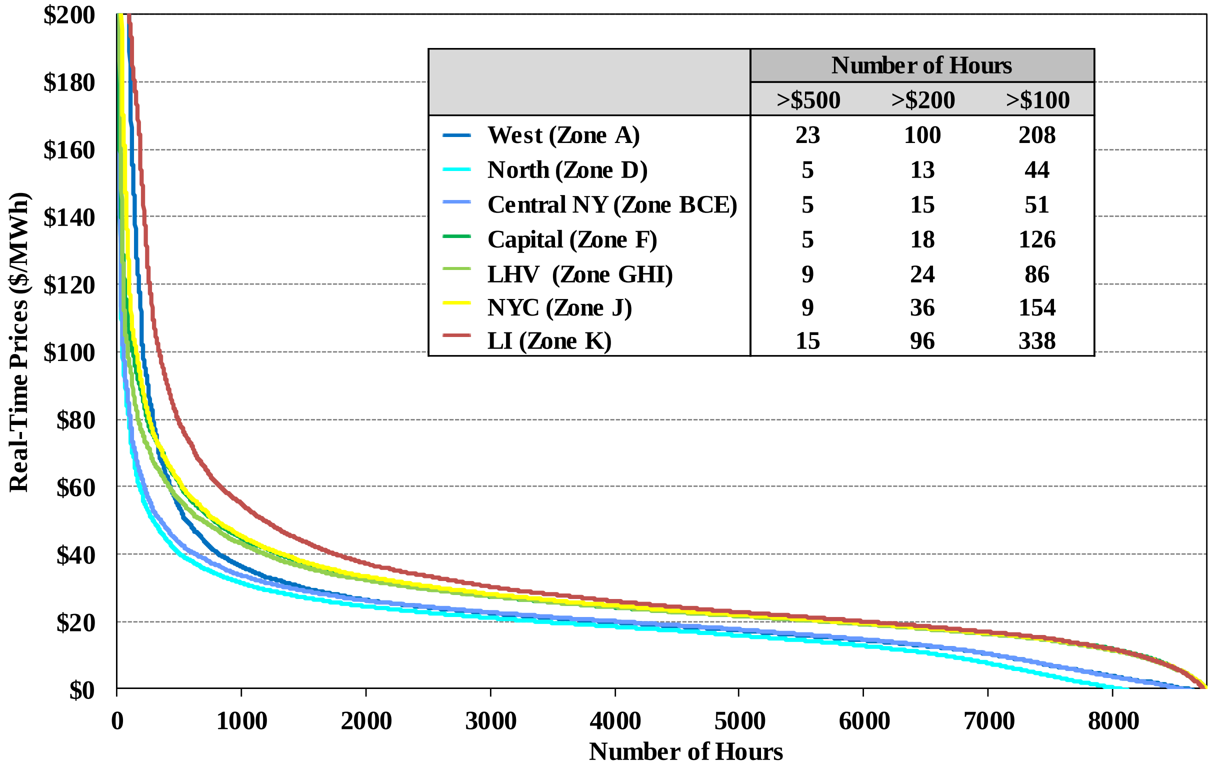


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours in recent years and at different locations. Figure A-4 shows seven price duration curves for 2016, one for each of the following locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and (g) Long Island (i.e., Zone K). Each curve in Figure A-4 shows the number of hours on the horizontal axis when the load-weighted average real-time price for each region was greater than the level shown on the vertical axis. The table in the chart shows the number of hours in 2016 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 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.

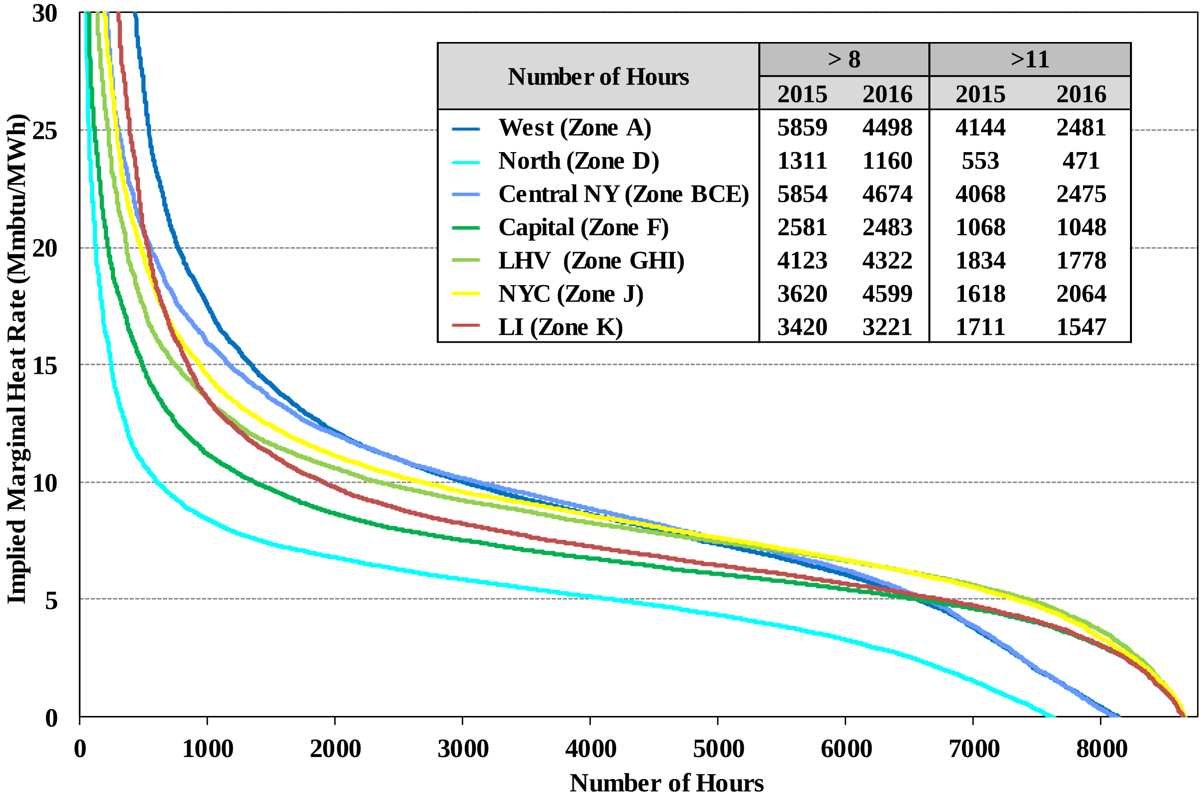
Figure A-4: Real-Time Price Duration Curves by Region
2016



	Number of Hours		
	>$500	>$200	>$100
West (Zone A)	23	100	208
North (Zone D)	5	13	44
Central NY (Zone BCE)	5	15	51
Capital (Zone F)	5	18	126
LHV (Zone GHI)	9	24	86
NYC (Zone J)	9	36	154
LI (Zone K)	15	96	338

To identify factors affecting power prices other than fuel price changes, Figure A-5 shows corresponding implied marginal heat rate duration curves at each location during 2016. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation of the implied marginal heat rate is similar to the one in Figure A-3 except that this is based on real-time prices. The inset table compares the number of hours in each region when the implied heat rate exceeded 8 and 11 MMBtu per MWh between 2015 and 2016.

Figure A-5: Implied Heat Rate Duration Curves by Region
2016



Number of Hours	> 8		>11	
	2015	2016	2015	2016
West (Zone A)	5859	4498	4144	2481
North (Zone D)	1311	1160	553	471
Central NY (Zone BCE)	5854	4674	4068	2475
Capital (Zone F)	2581	2483	1068	1048
LHV (Zone GHI)	4123	4322	1834	1778
NYC (Zone J)	3620	4599	1618	2064
LI (Zone K)	3420	3221	1711	1547

Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from roughly $26/MWh in the North Zone to $55/MWh in New York City in 2016, down 17 to 25 percent from 2015.
  - The decreases were mainly attributable to reductions in prices for both energy and capacity across the state.
  - However, the decrease in energy prices was more pronounced and energy accounted for the majority of the all-in price in all regions.
- Capacity costs accounted for 39 percent of the all-in price in New York City and 16 to 29 percent of the all-in price in the other six regions.
  - Higher capacity costs in New York City reflect that: a) there is generally more excess installed capacity outside New York City than inside New York City; and b) the Reference Point on the capacity demand curve is higher for New York City than for other areas.
- Average energy prices decreased by 18 to 31 percent across all New York regions from 2015 to 2016.
  - Most of the annual reductions occurred in the first quarter of 2016, mainly driven by:

    - Significantly lower natural gas prices (see Subsection B);
    - Higher nuclear and hydro production (see Subsection B); and
    - Lower load levels and less frequent winter peaking conditions (see Subsection D).
  - However, energy prices in the other three quarters of 2016 were slightly higher than levels seen in the same period of 2015, because:
    - Natural gas prices across the state after the first quarter of 2016 were generally similar to prices witnessed in the same period of 2015 (see Subsection B);
    - Load levels were higher in the summer of 2016 (see Subsection D); and
    - Lengthy transmission outages on the Central-East interface and into Long Island led to more frequent congestion in affected regions (see Section III).
- Average capacity costs decreased in all regions from 2015 to 2016, falling by 2 percent in the Lower Hudson Valley (i.e., Zones G, H, and I), 25 percent in New York City, 29 percent in Long Island, and 10 percent in the Rest of State.
  - The primary driver behind the decrease in all zones were reductions in the Local Capacity Requirement ("LCR") in each region which reduces the amount of capacity needed for procurement (see Subsection E).
  - The retirements of several units reduced the internal capacity in the state, partially offsetting the capacity price decline due to the LCR changes mentioned above. However, increased imports from PJM muted this impact in the Rest of State region.
- Similar to 2015, the West Zone exhibited in 2016: a) the highest average energy prices in Western New York (i.e., including Zones A to E); and b) the largest number of hours (i.e., 23 hours) when real-time prices exceeded $500 per MWh in all areas.
  - This was driven by high congestion levels on the 230 kV facilities in the West Zone in 2016 (see Section III).
  - Transmission congestion in the West Zone could not be resolved using available physical resources in slightly less than 2 percent of all intervals in 2016, resulting in transmission shortages and very high congestion costs (with the implementation of GTDC) in this area during these intervals (see Section V).
- The average implied marginal heat rates rose from 2015 to 2016 in Eastern New York but fell in Western New York.
  - The increase in Eastern New York generally reflected higher load levels during the summer months and more frequent congestion across the Central-East interface and into Long Island because of lengthy transmission outages.
  - The decrease in Western New York occurred primarily in the first quarter of 2016.
    - The implied marginal heat rates in most regions of Western New York were higher than in Eastern New York because energy prices in Western New York often rose to the levels in Eastern New York when the Central-East interface was

not fully constrained, while natural gas prices for most of Western New York (indexed to Dominion North trading hub in this report) were still very low.

  - In the first quarter of 2016, the reduction in energy prices in Western New York (because of reductions in Eastern New York) was more pronounced than the reduction of natural gas prices in Western New York.

- The average implied marginal heat rate in the North Zone was substantially lower than in other regions, indicating that gas-fired resources in this area were rarely economic.

B. Fuel Prices and Generation by Fuel Type

Figure A-6 – Figure A-8: 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 and nuclear generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices more directly affect wholesale power prices.

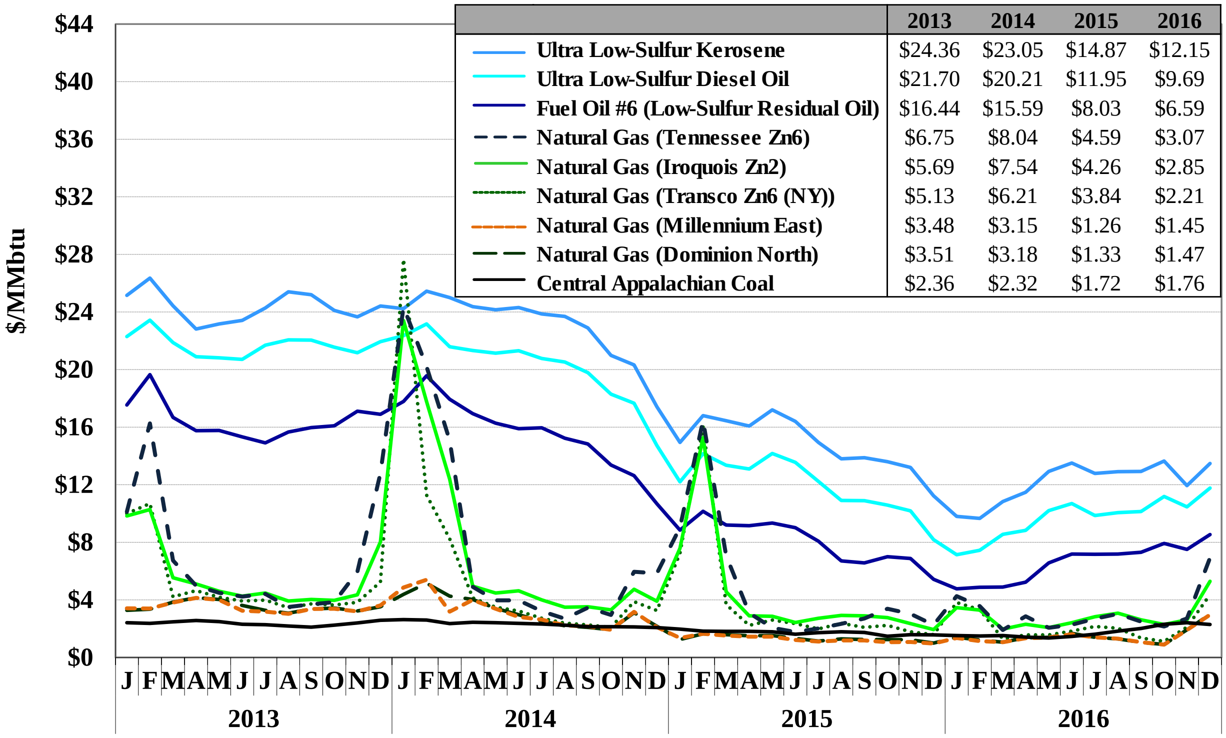
Some generators in New York have dual-fuel capability, allowing them to burn either oil or natural gas. These generators usually burn the most economic fuel, although some may burn oil even when it is more expensive if natural gas is difficult to obtain on short notice or if there is uncertainty about its availability. In addition, New York City and Long Island reliability rules (which are discussed further in Section V.E) 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.

Natural gas price patterns are normally relatively consistent between different regions in New York, with eastern regions typically having a minor premium in price to the western zones. However, bottlenecks on the natural gas system can sometimes lead to significant differences in delivered gas costs by area, which can produce comparable differences in energy prices when network congestion occurs. The natural gas price differences generally emerge by pipeline and zone. We track natural gas prices for the following pipelines/zones, which serve different areas in New York.

- Tennessee Zone 6 prices are representative of gas prices in portions of New England;
- Transco Zone 6 (NY) prices are representative of natural gas prices in New York City;
- Iroquois Zone 2 prices are representative of gas prices in Capital Zone and Long Island;
- Iroquois Zone 2 prices and Millennium East prices are generally representative of natural gas prices in the Lower Hudson Valley; and
- Dominion North prices are representative of prices in portions of Western New York.

Figure A-6 shows average coal, natural gas, and fuel oil prices by month from 2013 to 2016. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices [182]
2013 – 2016



	2013	2014	2015	2016
Ultra Low-Sulfur Kerosene	$24.36	$23.05	$14.87	$12.15
Ultra Low-Sulfur Diesel Oil	$21.70	$20.21	$11.95	$9.69
Fuel Oil #6 (Low-Sulfur Residual Oil)	$16.44	$15.59	$8.03	$6.59
Natural Gas (Tennessee Zn6)	$6.75	$8.04	$4.59	$3.07
Natural Gas (Iroquois Zn2)	$5.69	$7.54	$4.26	$2.85
Natural Gas (Transco Zn6 (NY))	$5.13	$6.21	$3.84	$2.21
Natural Gas (Millennium East)	$3.48	$3.15	$1.26	$1.45
Natural Gas (Dominion North)	$3.51	$3.18	$1.33	$1.47
Central Appalachian Coal	$2.36	$2.32	$1.72	$1.76

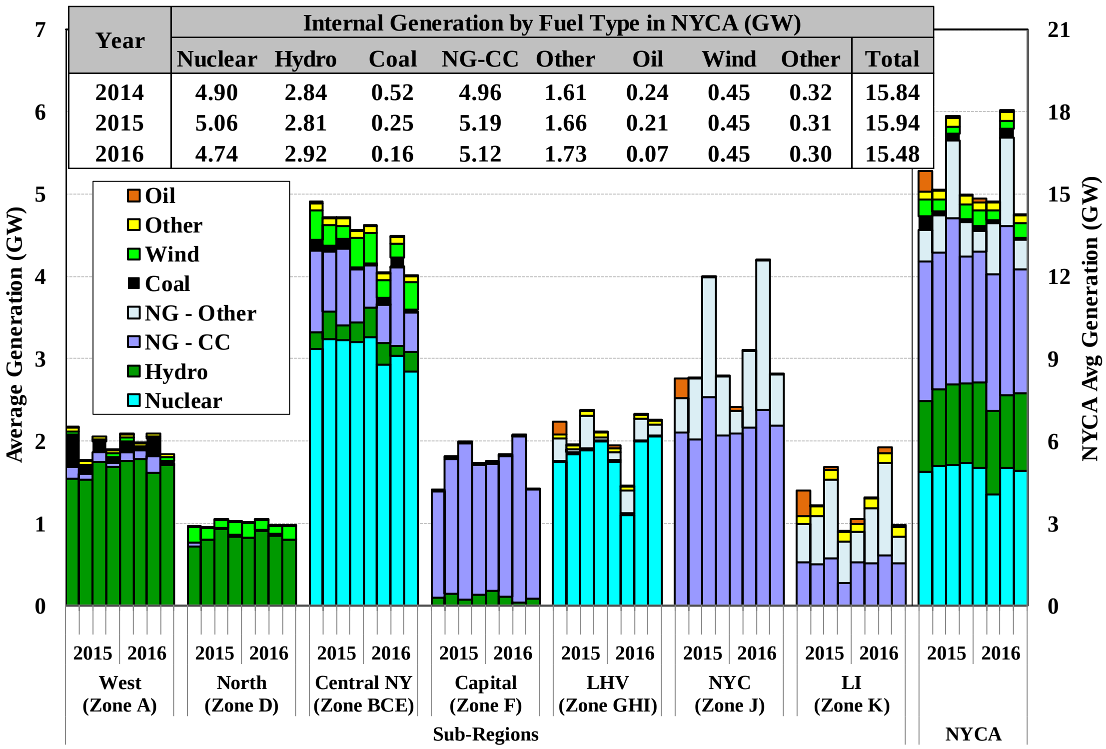
Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2016 as well as for NYCA as a whole. [183] The table in the chart shows annual average generation by fuel type from 2013 to 2016.

Figure A-8 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 2016. 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: (a) generators in other regions in the vast majority of intervals; or (b) shortage pricing of ancillary services or transmission constraints in a small share of intervals. The fuel type for each generator in both charts is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").

182 These are index prices that do not include transportation charges or applicable local taxes.

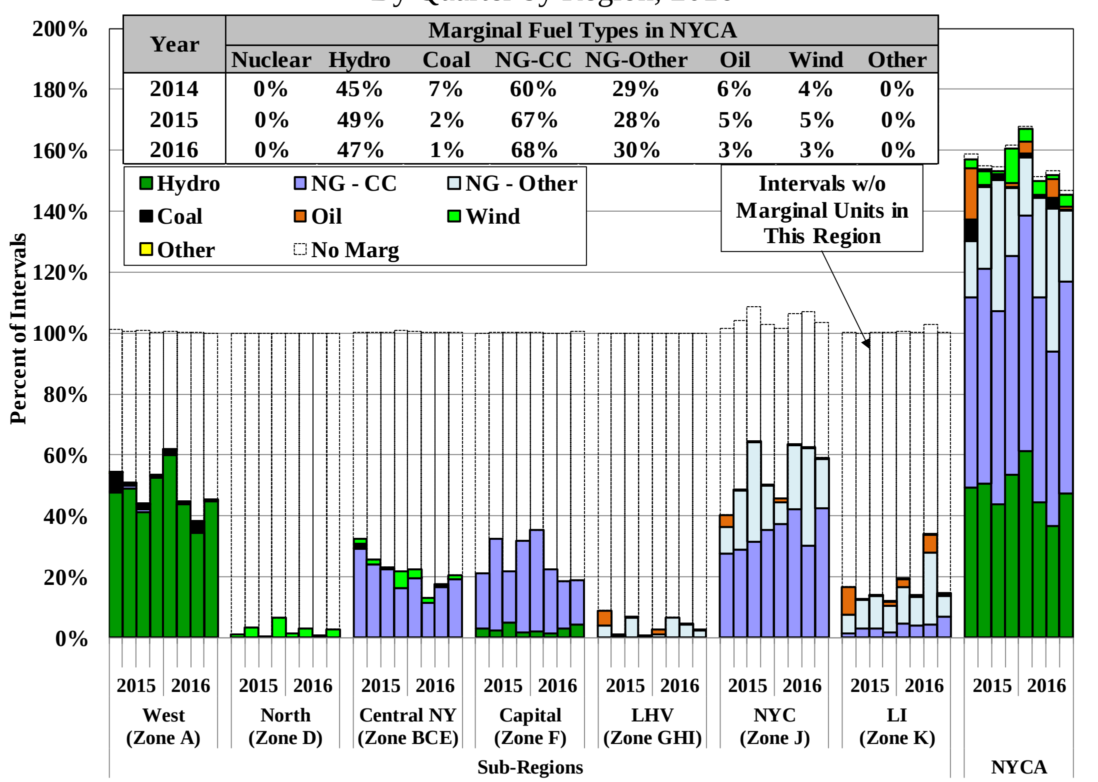
183 Pumped-storage resources in pumping mode are treated as negative generation. The "Other" category includes methane, refuse, solar, and wood.

Figure A-7: Generation by Fuel Type in New York
By Quarter by Region, 2016



Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	Other	Oil	Wind	Other	Total
2014	4.90	2.84	0.52	4.96	1.61	0.24	0.45	0.32	15.84
2015	5.06	2.81	0.25	5.19	1.66	0.21	0.45	0.31	15.94
2016	4.74	2.92	0.16	5.12	1.73	0.07	0.45	0.30	15.48

Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2016



Year	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2014	0%	45%	7%	60%	29%	6%	4%	0%
2015	0%	49%	2%	67%	28%	5%	5%	0%
2016	0%	47%	1%	68%	30%	3%	3%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- On average, reported fuel oil prices fell nearly 20 percent from 2015 to 2016 but bottomed-out in the first quarter of 2016.
  - Lower fuel oil prices helped reduce the severity of natural gas price spikes during winter operations.
- Natural gas prices, which have the strongest effect on wholesale energy prices, exhibited the most variation over time and between regions in recent years.
  - These variations affected generation patterns, import levels, congestion patterns, energy price spreads, and uplift charges, which are discussed throughout the report.
- Natural gas prices and gas spreads between regions (e.g., between Western and Eastern New York) exhibited a typical seasonal pattern.
  - They tended to rise in the winter months as a result of higher demand. However, the magnitude of the increase in 2016 (relative to the rest of the year) was muted significantly compared to the previous several winters.
    - For example, first quarter 2016 prices at Transco Zone 6 NY were roughly 40 percent higher than the average of the remaining months in 2016. In contrast first quarter 2015 prices at this index were more than 420 percent higher than the remaining nine months of that year.
    - Consequently, gas spreads between Western and Eastern New York averaged 231 to 238 percent in the first quarter of 2016, still up notably from an average of 129 to 182 percent in other quarters, but significantly less so than what occurred in previous years.
  - The combined effects of lower heating demand because of milder weather conditions, higher production from the Marcellus shales, and very low oil prices limited the increase in natural gas prices in the 2015/2016 winter.
- Gas-fired (44 percent), nuclear (31 percent), and hydro (19 percent) generation accounted for 94 percent of all internal generation in New York during 2016.
  - Average nuclear generation fell 320 MW from 2015, reflecting increased maintenance and refueling outages at multiple units across the year.
  - Coal-fired generation continued to fall in 2016, reflecting the mothball/retirement of the Huntley and Dunkirk units and low natural gas prices that made coal production uneconomic most of time.
  - Gas-fired steam turbine generators produced considerably more in the third quarter of the year in both New York City and Long Island than in the other quarters.
    - This generally reflected higher load levels and associated higher needs for local reliability in the downstate area during the summer season.

- Average oil-fired generation fell substantially from 2015, primarily because lower natural gas prices in the first quarter of 2016 made oil production less economic. .
  - However, this was partially offset by higher oil production on Long Island in the third quarter of 2016 because of higher load and lower imports from upstate New York (due to transmission outages).
- Average generation from wind, hydro, and other renewable resources did not vary significantly from 2015 to 2016.
  - Nonetheless, hydro production in the West Zone rose modestly in 2016, particularly in the winter months, reflecting: (a) milder winter weather conditions led to increased supply of water (compared to frequent icy conditions in the prior year); and (b) increased output from the Niagara facility due to less frequent congestion in the West Zone.

- Gas-fired resources (68 percent for combined cycle units) and hydro resources (47 percent) were on the margin most frequently during 2016.
  - Most hydro units on the margin have storage capacity, leading them to offer based partly on the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the price levels set by hydro units are also affected by natural gas prices.

C. Fuel Usage Under Tight Gas Supply Conditions

The supply of natural gas is usually tight in the winter season due to increased demand for heating. Extreme weather conditions often lead to high and volatile natural gas prices. A large share of generators in Eastern New York have dual-fuel capability, allowing them to switch to an alternative fuel when natural gas becomes expensive or unavailable. However, the increase of oil-fired generation during such periods may be limited by several factors, including:

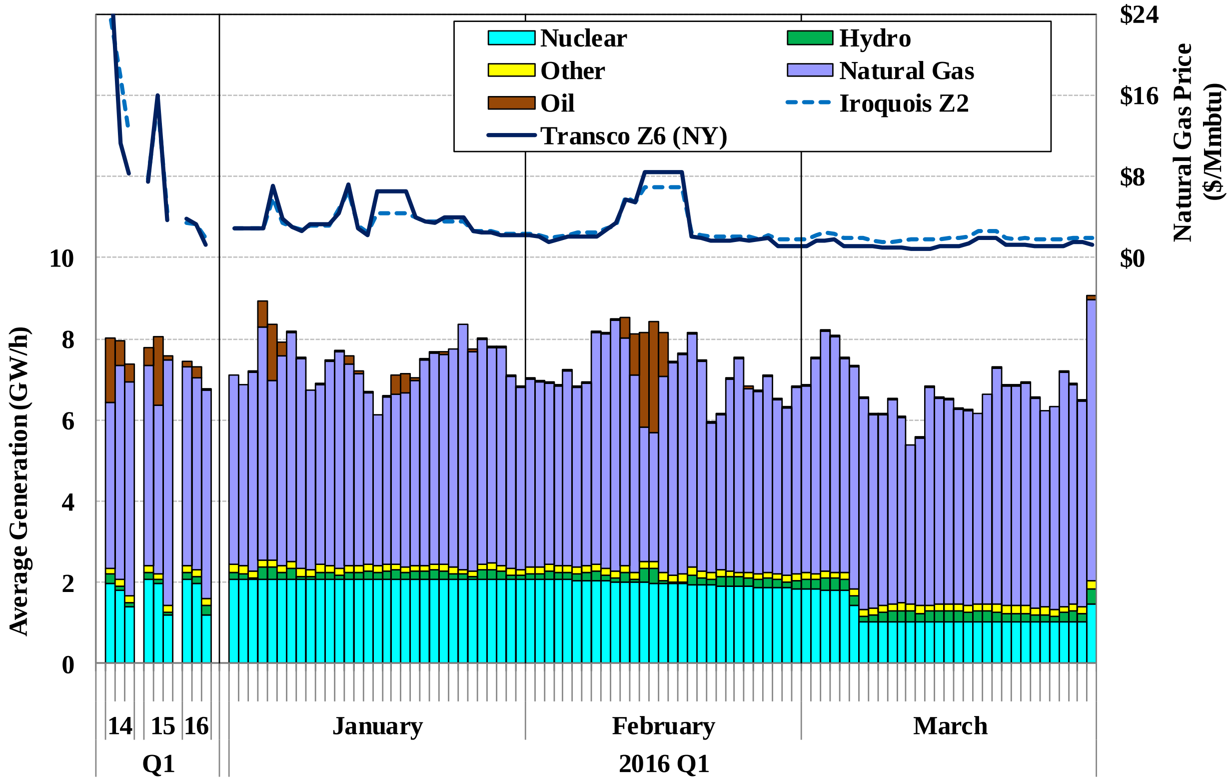
- Not having the necessary air permits;
- Low on-site oil inventory; and
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other.

This sub-section examines actual fuel usage in the winter of 2016, focusing on days when supply of natural gas was very tight. This had a big impact on the system operations, especially in Eastern New York.

Figure A-9: Actual Fuel Use and Natural Gas Prices in the Winter

Figure A-9 summarizes the average hourly generation by actual fuel consumed in Eastern New York on a daily basis during the first quarter of 2016. The figure shows actual generation for the following fuel categories: (a) oil; (b) natural gas; (c) hydro; (d) nuclear; and (e) all other fuel types as a group. In addition, the figure shows the day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY). The figure also compares these quantities by month between the first quarter of 2015 and 2016. Each day in the chart represents a 24-hour gas day, which starts from 10 am on each calendar day and ends at 10 am on the next calendar day.

Figure A-9: Actual Fuel Use and Natural Gas Prices
Eastern New York, First Quarter of 2016



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Oil-fired generation in Eastern New York totaled roughly 300 GWh in the first quarter of 2016, down notably from over 1,500 GWh in the first quarter of both 2014 and 2015.
  - Gas supply constraints were much less frequent and severe than in the previous years (because of factors discussed in subsection B).
  - As a result, gas prices exceeded $8/MMBtu[184] on just five consecutive days in mid-February (while gas prices were over $15/MMBtu on 22 days in 2015 and over $20/MMBtu on 27 days in 2014).
    - This 5-day period accounted for most of oil-fired generation in the quarter.
- The large difference in the amount of oil use between 2015 and 2016 illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.

184 This applies to the Iroquois Zone 2 price only; Transco Z6 NY prices remained below $7 per MMBtu on these days.

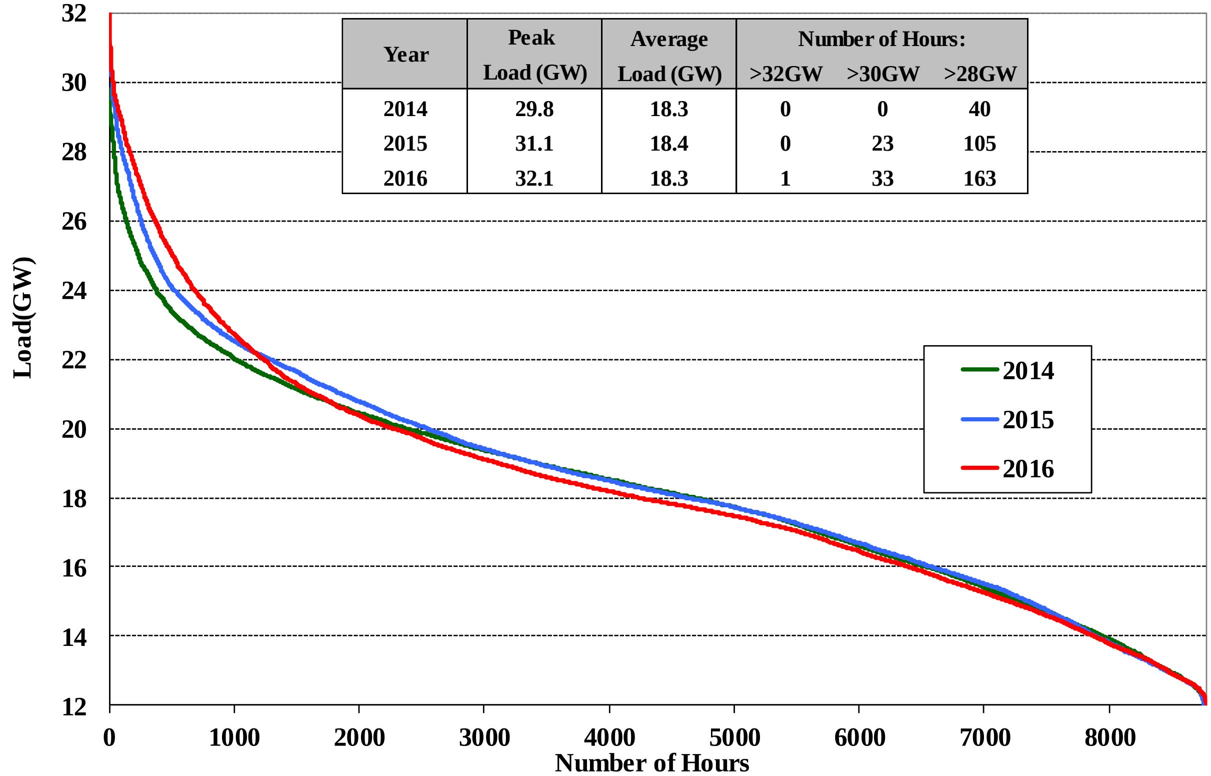
D. Load Levels

Figure A-10: 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-10 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 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-10: Load Duration Curves for New York State
2014 – 2016



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2014	29.8	18.3	0	0	40
2015	31.1	18.4	0	23	105
2016	32.1	18.3	1	33	163

<u>Key Observations: Load Levels</u>

- Annual peak load rose 3 percent from 2015 due primarily to warmer weather conditions in the summer of 2016.

  - Although the peak load level was not the highest, the average load level in the summer was higher than most prior summers (since 2009).

- However, winter weather conditions were milder than in the prior winters, resulting in substantially lower load levels in the winter of 2016.

  - In the first quarter of 2016, average load fell 8 percent and peak load fell 5 percent from a year ago. Both levels were close to the lowest levels over the last ten winters.

E. Day-Ahead Ancillary Services Prices

Figure A-11: 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 Western, Eastern, and Southeast New York reserve prices. Figure A-11 shows the average day-ahead prices for these four ancillary services products in each month of 2015 and 2016. The prices are shown separately for the following three distinct regions: (a) Southeast New York (including Zones G-K); (b) the Capital Zone (Zone F, in Eastern New York but outside Southeast New York); and (c) West New York (including Zones A-E).

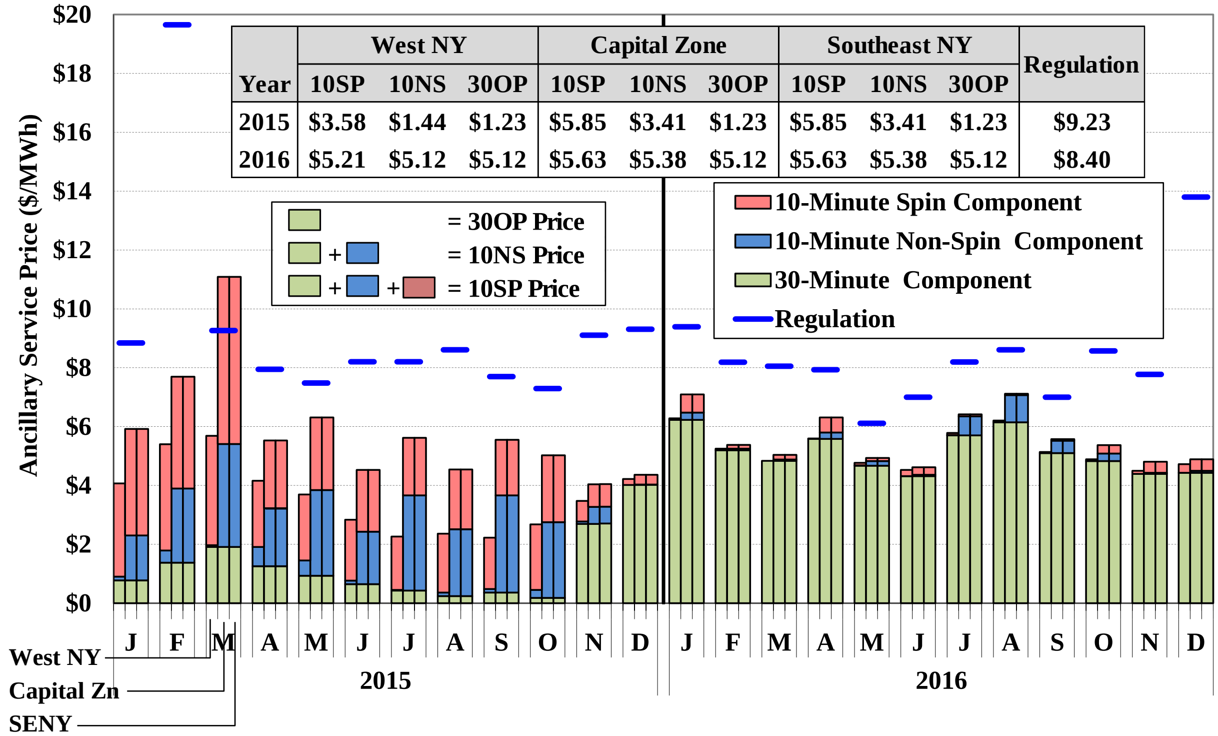
The stacked bars show three price components for each region: the 10-minute spinning component, the 10-minute non-spin component, and the 30-minute component, each representing the cost of meeting applicable underlying reserve requirements. Take Southeast New York as an example,

- The 30-minute component represents the cost to simultaneously meet the 30-minute reserve requirements for Southeast New York, East New York, and NYCA;
- The 10-minute non-spin component represents the cost to simultaneously meet the 10-minute total reserve requirements for East New York and NYCA (Southeast New York does not have a separate 10-minute total reserve requirement); and
- The 10-minute spinning component represents the cost to simultaneously meet the 10-minute spinning reserve requirements for East New York and NYCA (Southeast New York does not have a separate 10-minute spinning reserve requirement).

Therefore, in the figure, the 30-minute reserve price in each region equals its 30-minute component, the 10-minute non-spin reserve price equals the sum of its 30-minute component and 10-minute non-spin component, and the 10-minute spinning reserve price equals the sum of all three price components. The inset table compares average final prices (not the components) in 2015 and 2016 on an annual basis.

Figure A-11: Day-Ahead Ancillary Services Prices

2015- 2016



Key Observations: Day-ahead Ancillary Service Prices

- The average prices for most classes of ancillary services rose from 2015 to 2016 in contrast to the decline in energy prices.
  - The increase was due primarily to the increase of 30-minute operating reserve prices beginning in November 2015, which resulted from changes in market rules and offer patterns (this is evaluated in more detail in Section II.D of the Appendix).
- The differences in day-ahead prices between various reserve products became much smaller in 2016.
  - The largest average difference was only $0.51/MWh (between Southeast New York 10-minute spinning prices and West New York 30-minure reserve prices) in 2016, much lower than the $4.62/MWh in 2015.
  - This indicates that all reserve requirements except the NYCA 30-minute requirement were binding much less frequently in 2016.

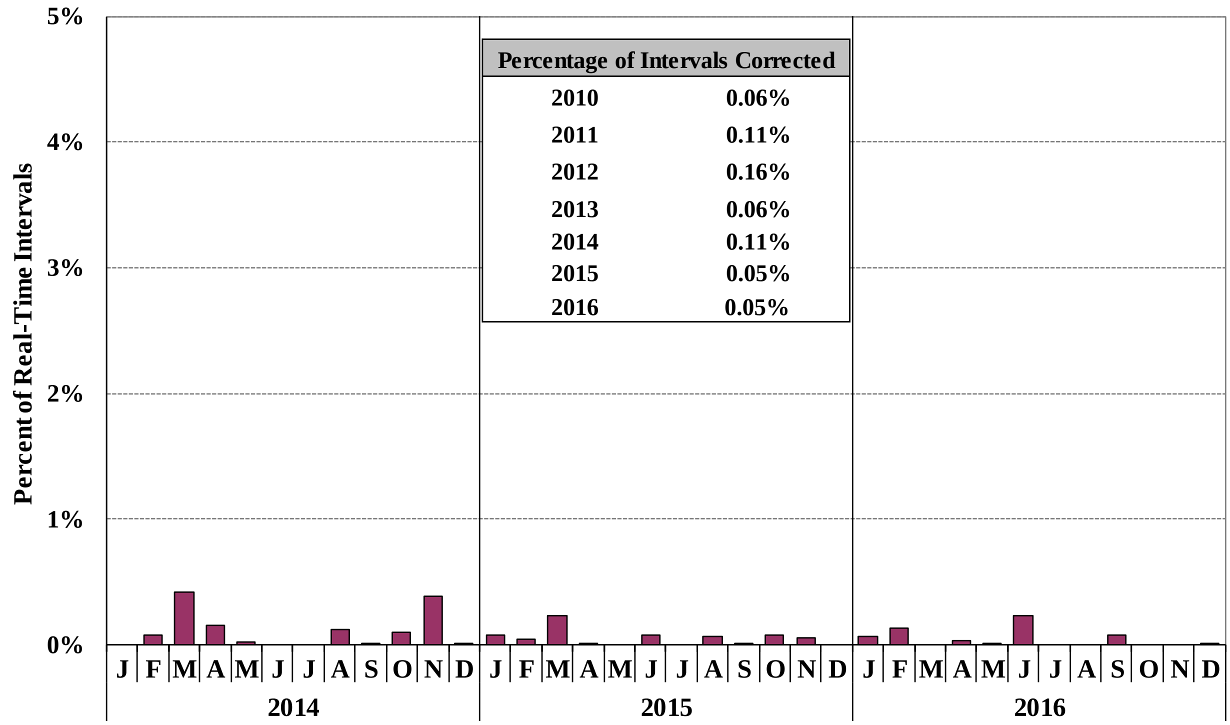
F. Price Corrections

Figure A-12: 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-12 summarizes the frequency of price corrections in the real-time energy market in each month from 2014 to 2016. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-12: Frequency of Real-Time Price Corrections
2014-2016



<u>Key Observations: Price Corrections</u>

- The frequency and significance of corrections have been at very low levels, around 0.1 percent of real-time pricing intervals in each of the past seven years.
  - In 2016, the frequency of price corrections was slightly higher in June because of software errors. However, the effects of these errors on the market outcomes were not substantial.

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-13 & Figure A-14: 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-13 and Figure A-14 compare day-ahead and real-time energy prices in West Zone, Central Zone, North 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 2016. 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-13: Average Day-Ahead and Real-Time Energy Prices in Western New York

West, Central, and North Zones - 2016

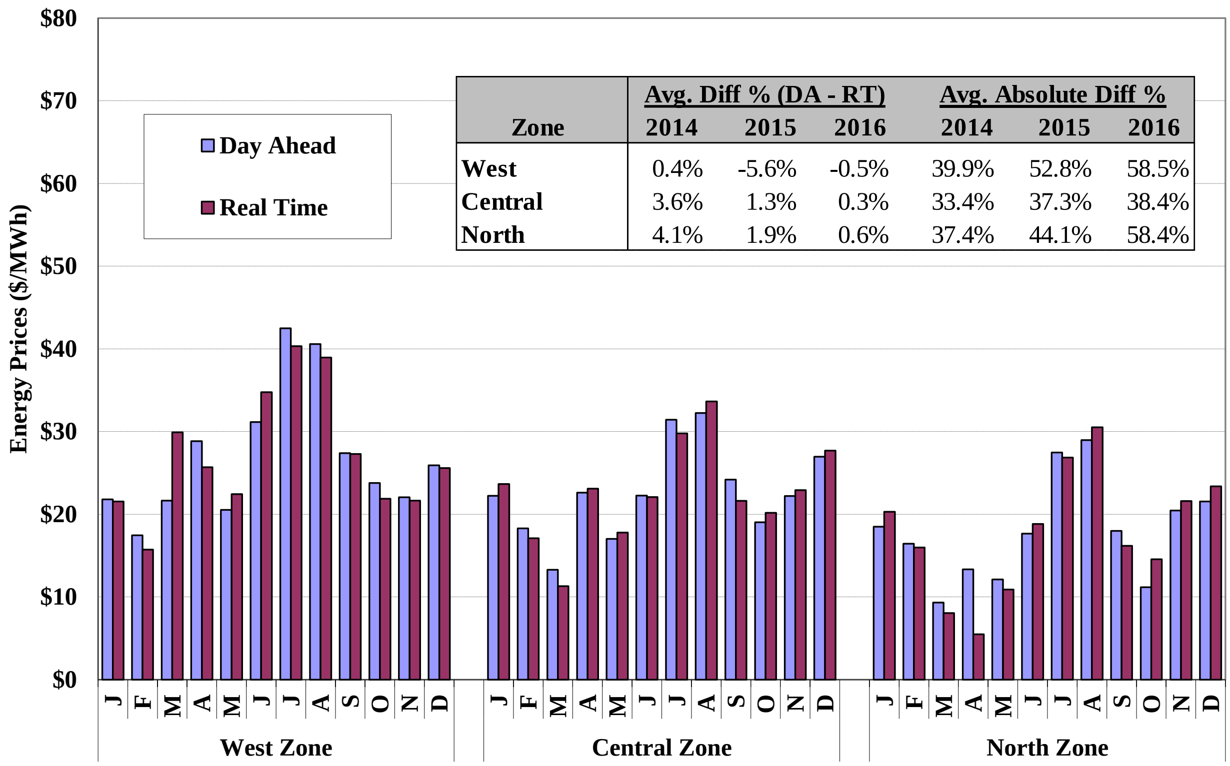


Figure A-14: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2016

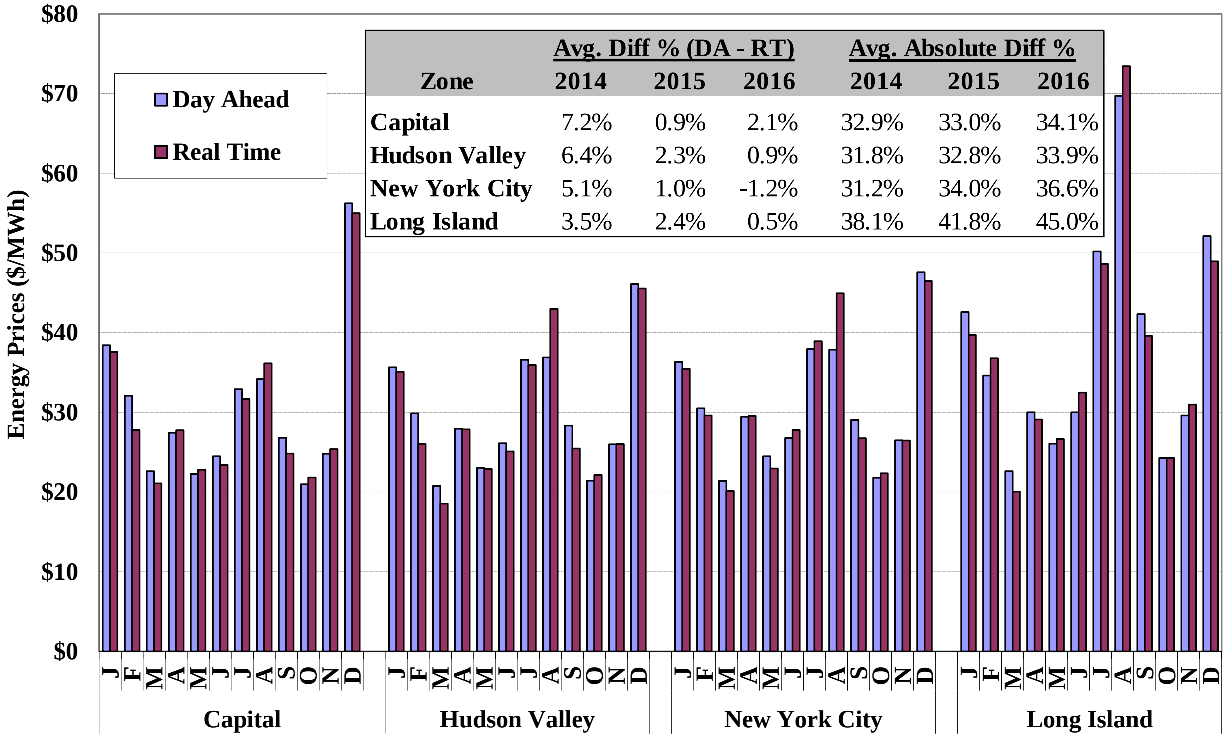


Figure A-15: Average Real-Time Price Premium at Select Nodes

Transmission congestion can lead to a wide variation in nodal prices within a 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.

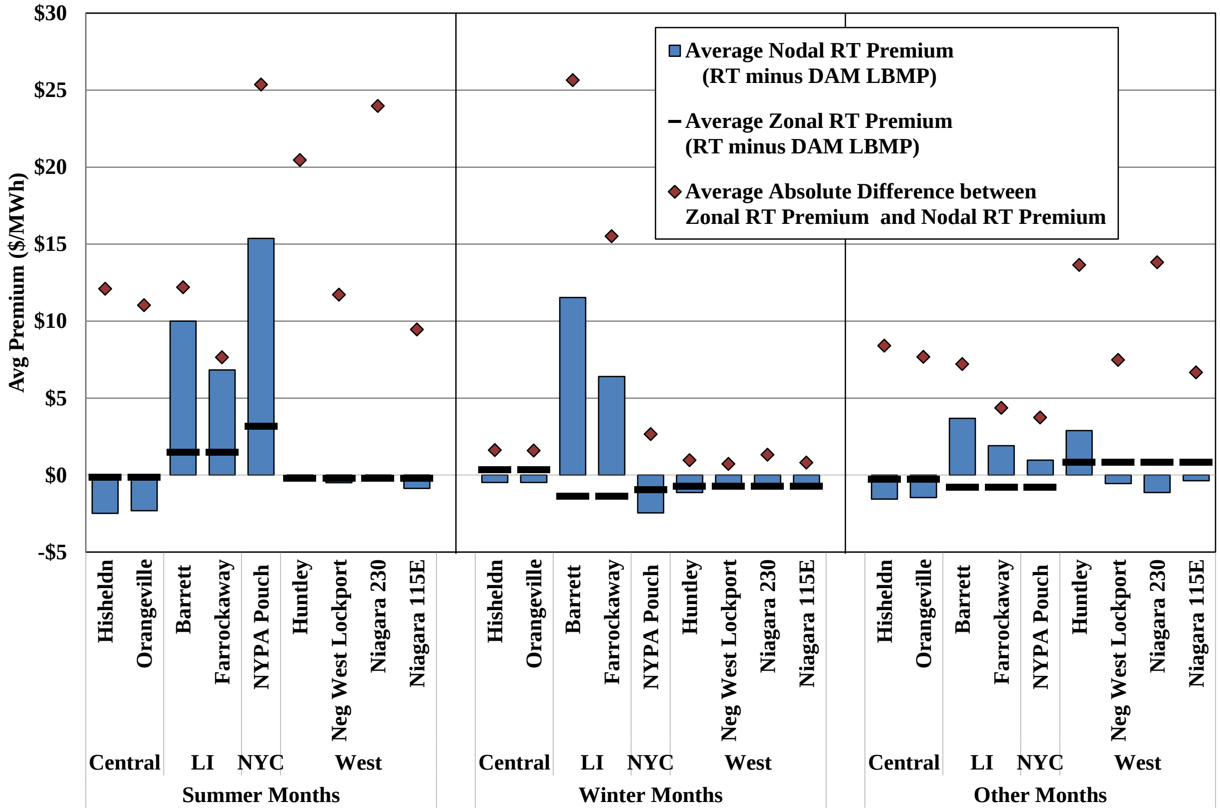
The pattern of intrazonal congestion may change between the day-ahead market and the real-time market for many reasons:

- Generators may change their offers after the day-ahead market. 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 demand may become more or less acute after the day-ahead market due to differences between expected 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. This analysis examines price statistics for selected nodes throughout New York State to assess price convergence at the nodal level.

Figure A-15 shows average day-ahead prices and real-time price premiums in 2016 for selected locations in New York City, Long Island, and Upstate New York.[185] These are load-weighted averages based on the day-ahead forecasted load. The figure includes nodes in several regions that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. These are shown separately for the summer months (June to August), the winter months (December, January, and February), and other months because the congestion patterns typically vary by season.

Figure A-15: Average Real-Time Price Premium at Select Nodes
2016



185 In New York City, NYPA Pouch is the NYPA Pouch GT 1 bus. In Long Island, Barret is the Barrett 1 bus and Farrockaway is Farrockaway ST 4 bus. Orangeville and High Sheldon are two wind turbine locations in the Central Zone, Huntley 67, NEG West Lockport, Niagara 230kV, and Niagara 115kV East represent generator locations in the West Zone.

<u>Key Observations: Convergence of Day-Ahead and Real-Time Energy Prices</u>

- Average day-ahead prices were generally within 1 to 2 percent of average real-time prices in all areas in 2016.
  - Although a small average day-ahead premium was generally desirable in a competitive market, small real-time premiums occurred in some areas because large real-time spikes on a few days (due to unexpected real-time events) outweighed small day-ahead premiums on other days.
- At the zonal level, energy price convergence (as measured by the mean absolute difference between hourly day-ahead and real-time prices for the year) was worse in all regions from 2015 to 2016, due to the following key drivers:
  - More transmission outages in the North Zone, into Long Island, and across the Central-East interface led to increased price volatility in affected areas during outage periods in 2016 (see Section III of the Appendix for more details).
  - Price volatility increased in Southeast New York in the summer of 2016 because of higher congestion levels associated with higher load levels.
  - The implementation of the GTDC in February 2016 resulted in higher congestion costs on most transmission constraints during transmission shortages, which led to higher price volatility in affected areas. (See Section V)
- At the nodal level, a few locations exhibited less consistency between average day-ahead and real-time prices. Most notably:
  - In Long Island, the Valley Stream load pocket (represented by the Barrett and Farrockaway locations) often exhibited a higher real-time price premium than the zonal real-time price premium because of real-time congestion on the East Garden City-Valley Stream line that is not well-reflected in the day-ahead market.
  - In the West Zone, although the average price premiums at select nodes (e.g., the Huntley location, the Niagara 230 kV and 115 kV buses) did not deviate significantly from the zonal average price premiums, the mean absolute difference between nodal premiums and zonal premiums was significant.
  - This reflects that different congestion patterns on the 230kV transmission system frequently occurred between day-ahead and real-time, driven by differences in Ontario imports, Niagara generation, and loop flows around Lake Erie.
  - Allowing disaggregated virtual trading in these areas would address these differences by allowing participants the opportunity to arbitrage them.

H. Day-Ahead Reserve 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.

Figure A-16 – Figure A-19: Distribution of day-ahead price premiums for reserves

To evaluate the performance of the day-ahead ancillary service markets, the following four figures show distributions of day-ahead premiums (i.e., day-ahead prices minus real-time prices) in: (a) Western 30-minute reserve prices; (b) Western 10-minute spinning reserve prices; (c) Eastern 10-minute spinning reserve prices; and (d) Eastern 10-minute non-spin reserve prices.

In each of the four figures, the day-ahead premium is calculated at the hourly level and grouped by ascending dollar range (in $0.25 tranches) shown on the x-axis. The frequency is shown on the y-axis as the percentage of hours in the year. For instance, Figure A-16 shows that the day-ahead Western 30-minute reserve prices were higher than real-time prices by a range of $5/MWh to $5.25/MWh during roughly 35 percent of the hours in 2016.

The figures compare the distributions between 2015 and 2016. The distributions between the 15th percentile and the 85th percentile are also highlighted in shaded areas (light blue for 2015 and light orange for 2016). The inset tables summarize the following annual averages in 2015 and 2016: (a) the average day-ahead price; (b) the average real-time price; (c) the difference between the average day-ahead price and the real-time price; and (d) the average absolute difference between the day-ahead price and the real-time price.

Figure A-16: Day-Ahead Premiums for 30-Minute Reserves in West New York
2015 – 2016

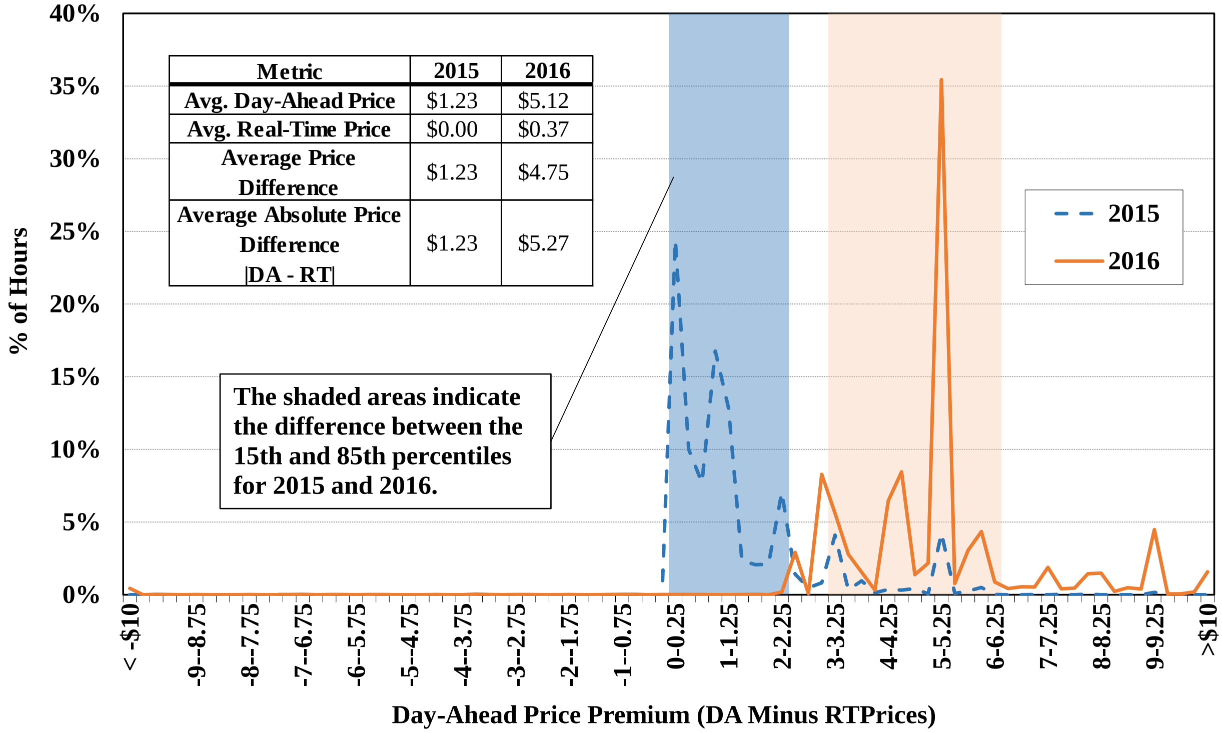


Figure A-17: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2015 - 2016

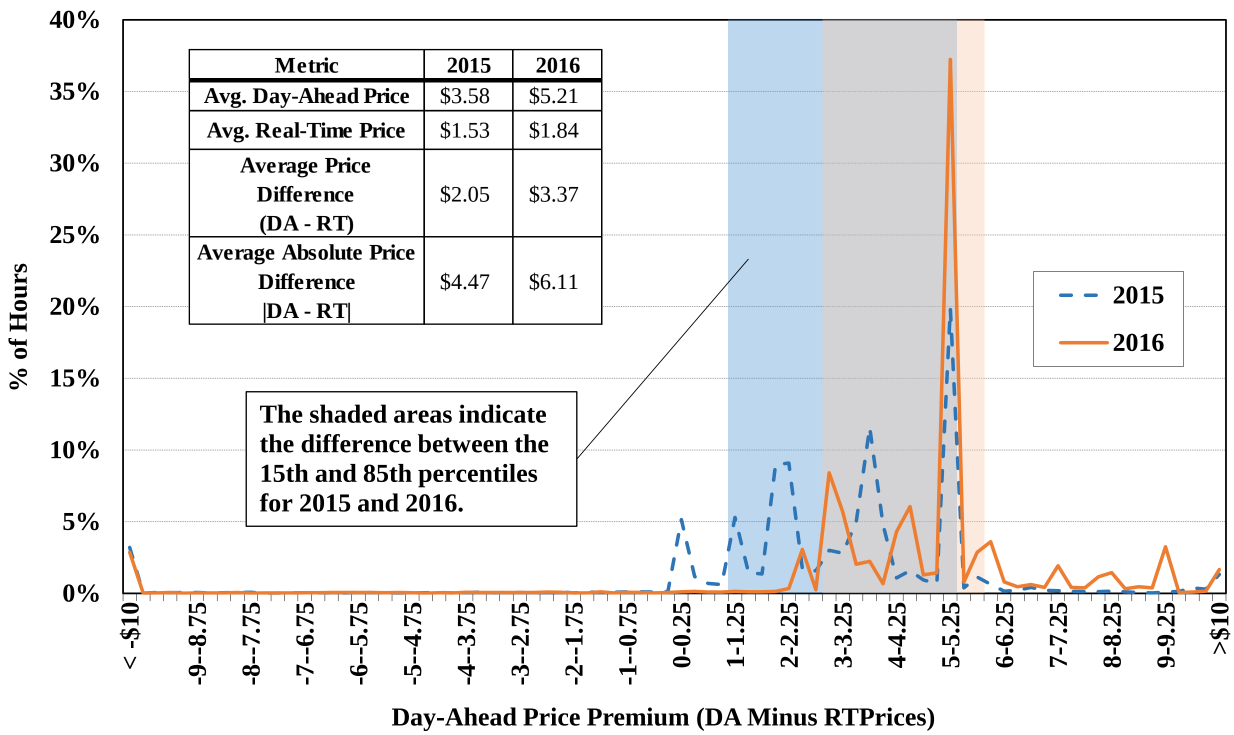
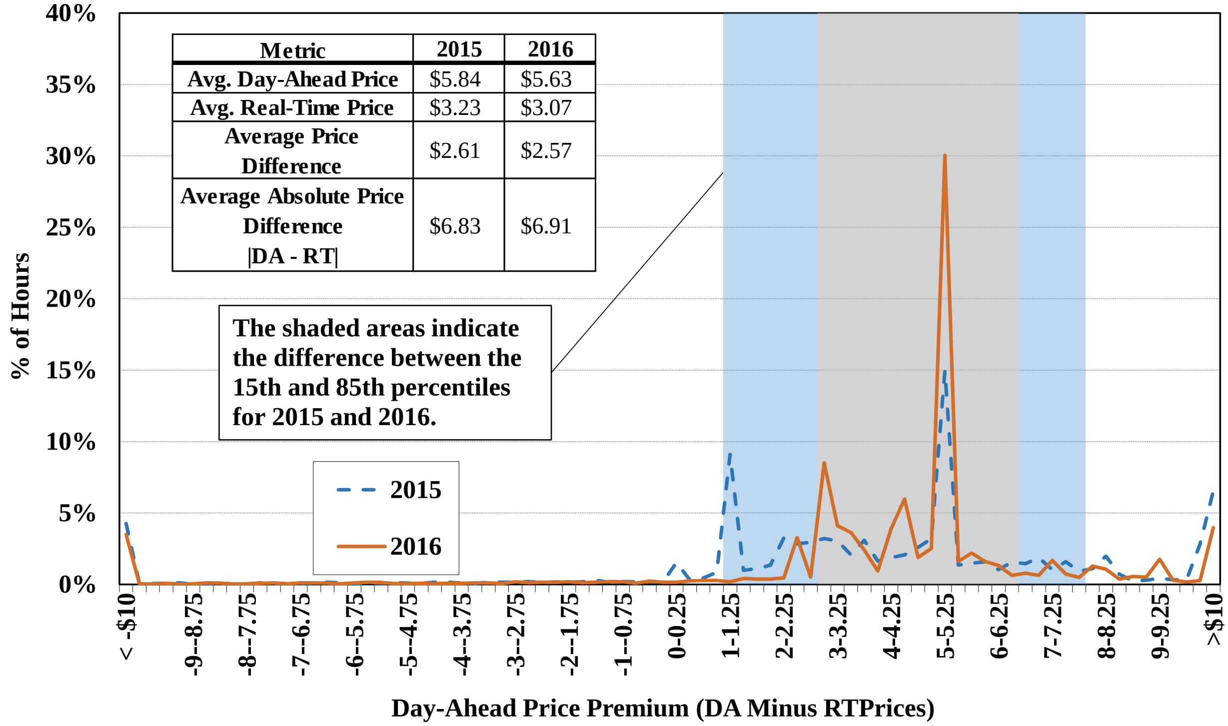
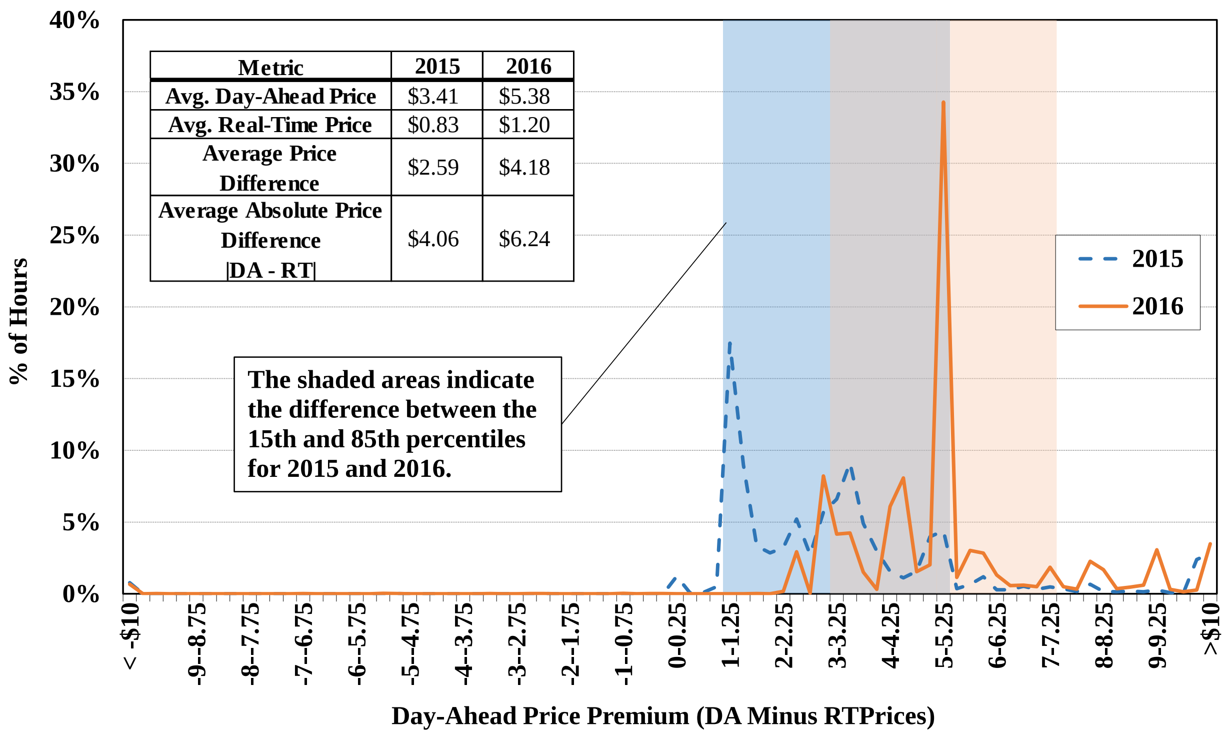


Figure A-18: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2015 – 2016



Metric	2015	2016
Avg. Day-Ahead Price	$5.84	$5.63
Avg. Real-Time Price	$3.23	$3.07
Average Price Difference	$2.61	$2.57
Average Absolute Price Difference |DA - RT|	$6.83	$6.91

Figure A-19: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2015 – 2016



Metric	2015	2016
Avg. Day-Ahead Price	$3.41	$5.38
Avg. Real-Time Price	$0.83	$1.20
Average Price Difference	$2.59	$4.18
Average Absolute Price Difference |DA - RT|	$4.06	$6.24

Key Observations: Day-Ahead Reserve Market Performance

- Reserve prices are relatively consistent from day-to-day in the day-ahead market but are much more volatile in the real-time market.
  - Real-time reserves prices are based on the opportunity cost of not serving energy (because of enforced $0 availability offer in real-time) and are normally very close to $0 due to the excess available reserves in most hours.
    - For example, Western 30-minute reserve prices were zero in more than 98 percent of real-time intervals in 2016.
    - Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
  - While day-ahead reserves prices also depend on opportunity costs, they are also based on suppliers' availability offers, which depend on factors such as the expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
- Although day-ahead price premiums are generally expected in a competitive market without virtual trading, the day-ahead price premiums have been abnormally large since November 2015 when the Comprehensive Shortage Pricing project was implemented.
  - Real-time prices rose modestly for most reserve products from 2015 to 2016, reflecting higher load levels in the summer, higher reserve requirements, and higher demand curve values following the Comprehensive Shortage Pricing project implementation.
  - Day-ahead reserve prices rose notably in 2016, particularly for 30-minute reserves in Western New York because of changes in market rules and supply offers (which are evaluated in more detail in Section II of the Appendix).

I. Regulation Market Performance

Figure A-20 – Regulation Prices and Expenses

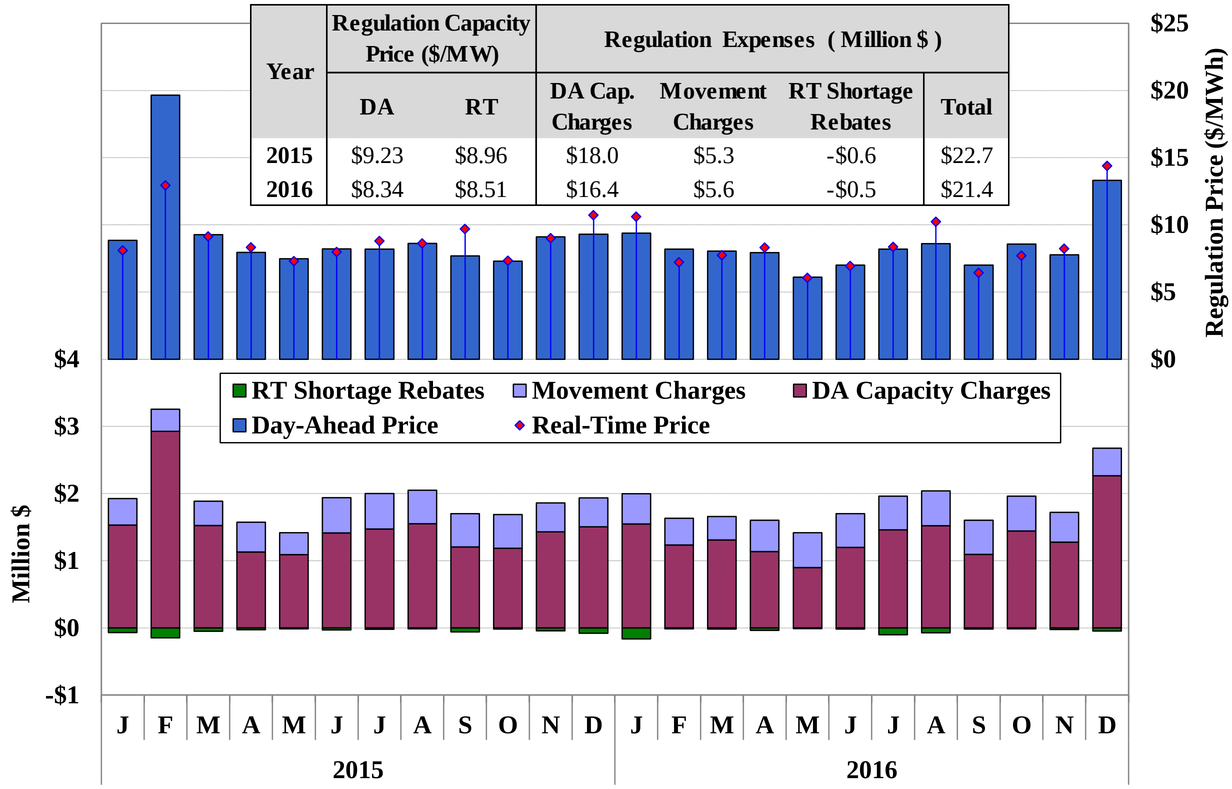
Figure A-20 shows the regulation prices and expenses in each month of 2015 and 2016. The upper portion of the figure compares the regulation capacity prices in the day-ahead and real-time markets. The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.
- Real-Time Shortage Rebate – This arises when a regulation shortage occurs in the real-time market and regulation suppliers must buy back the shortage quantity at the real-time prices.
- Movement Charge – This is the compensation to regulation resources for dispatching up and down to provide regulation service. The payment amount equals the product of: (i)

the real-time regulation movement price; (ii) the instructed regulation movement; and (iii) the performance factor calculated for the regulation service provider.

Figure A-20: Regulation Prices and Expenses

by Month, 2015-2016



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2015	$9.23	$8.96	$18.0	$5.3	-$0.6	$22.7
2016	$8.34	$8.51	$16.4	$5.6	-$0.5	$21.4

<u>Key Observations: Regulation Market Performance</u>

- Monthly average day-ahead regulation capacity prices were generally consistent with real-time capacity prices in 2016.
- From 2015 to 2016, average day-ahead regulation capacity prices fell 10 percent, average real-time capacity prices fell 5 percent, and total regulation costs fell 5 percent.
  - These decreases were generally in line with the reduction in energy prices over the same period, because the opportunity cost of not providing energy or reserves during tight market conditions accounts for a significant portion of the clearing price for regulation capacity.
- However, regulation movement charges rose slightly and did not vary in similar proportion to the natural gas prices and/or load levels.
  - The clearing price for regulation movement is determined by the regulation movement offer price of the marginal resource, so it is not directly affected by the opportunity cost of not providing energy and/or reserves.

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 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 if the uncapped offers would 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 to flexibly shift resources between products and thus increase 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.

This report includes several enhancements to the analysis of potential physical and economic withholding that were shown for periods before 2015. Generally, the enhancements include improvements in the criteria we use to identify capacity that would have been economic to produce energy. These enhancements include:

- Using interval-level real-time prices instead of hourly-integrated prices;
- Considering the effects of ramp-constraints on commitment and dispatch;
- Using RTC forecast prices to determine when gas turbines would have been started-up and shut-down if they had offered differently;
  - The evaluation is done once every 15 minutes: a) for start-up when the quick-start unit is offline; and b) for shut-down after the unit has satisfied its minimum run time. The minimum down time is respected between commitments.
- Accounting for prices of all classes of operating reserves when determining economic dispatch levels for non-quick-start units;

A. Potential Physical Withholding

We evaluate potential physical withholding by analyzing day-ahead and real-time generator deratings of economic capacity as well as economic capacity that is unoffered in real-time. 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, a short-term forced outage, or without any logged outage record. A derating can be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero). Unoffered economic capacity in real-time includes quick-start units that do not offer in real-time and online baseload units that offer less than their full capability. The figures in this section show the quantity of deratings and unoffered real-time capacity as a percent of total Dependable Maximum Net Capability ("DMNC") from all generators in a region based on the most recent DMNC test value of each generator. *Short-term Deratings* include capacity that is derated for seven or fewer days. The remaining deratings are shown as *Long-Term Deratings.* [186]

We focus particularly on short-term deratings and real-time unoffered capacity because they are more likely to reflect attempts to physically withhold than long-term deratings, since it is less

[186] For our analyses of physical and economic withholding, we exclude unoffered capacity from hydro, solar, wind, landfill-gas and biomass generators.

costly to withhold a resource for a short period. 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. Nevertheless, the figures in this section evaluate long-term deratings as well, since they still may be an indication of withholding.

We 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.

We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

The figures in this section show the portion of derated and unoffered capacity that would have been economic based on Reference Levels and market prices (although nuclear units are excluded during planned maintenance outages).[187] This assessment determines economic commitment of baseload units based on day-ahead prices, considering start-up, minimum generation, and incremental costs. Economic dispatch of baseload units is based on RTD prices considering ramp rate limitations.[188] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[189]

Figure A-21 & Figure A-22: Unoffered Economic Capacity by Month

Figure A-21 and Figure A-22 show the broad patterns in deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2015 and 2016.

187 This evaluation also includes a modest threshold, which is described in Subsection B as "Lower Threshold 1."

188 If a baseload unit was committed by the DAM, optimal dispatch and potential physical withholding of incremental energy ranges was evaluated at RTD prices, even if the units DAM reference costs were above the DAM prices.

189 In this paragraph "prices" refers to both energy and reserves prices.

Figure A-21: Unoffered Economic Capacity by Month in NYCA
2015 – 2016

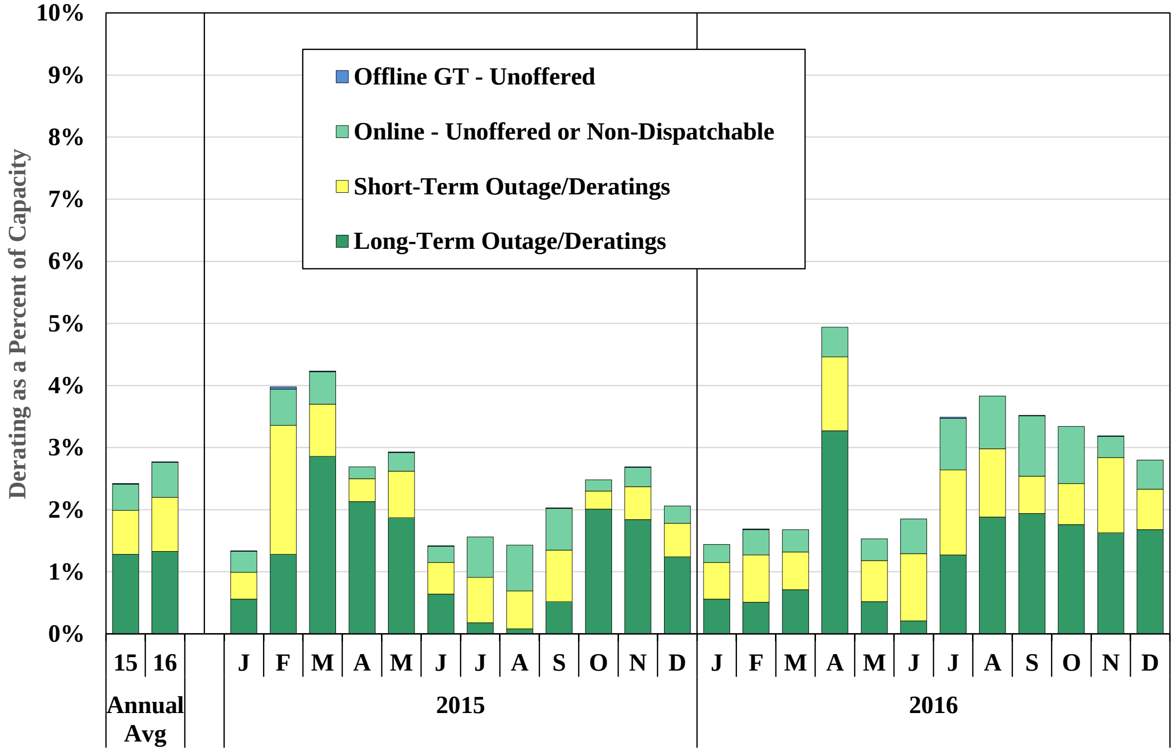


Figure A-22: Unoffered Economic Capacity by Month in East New York
2015 - 2016

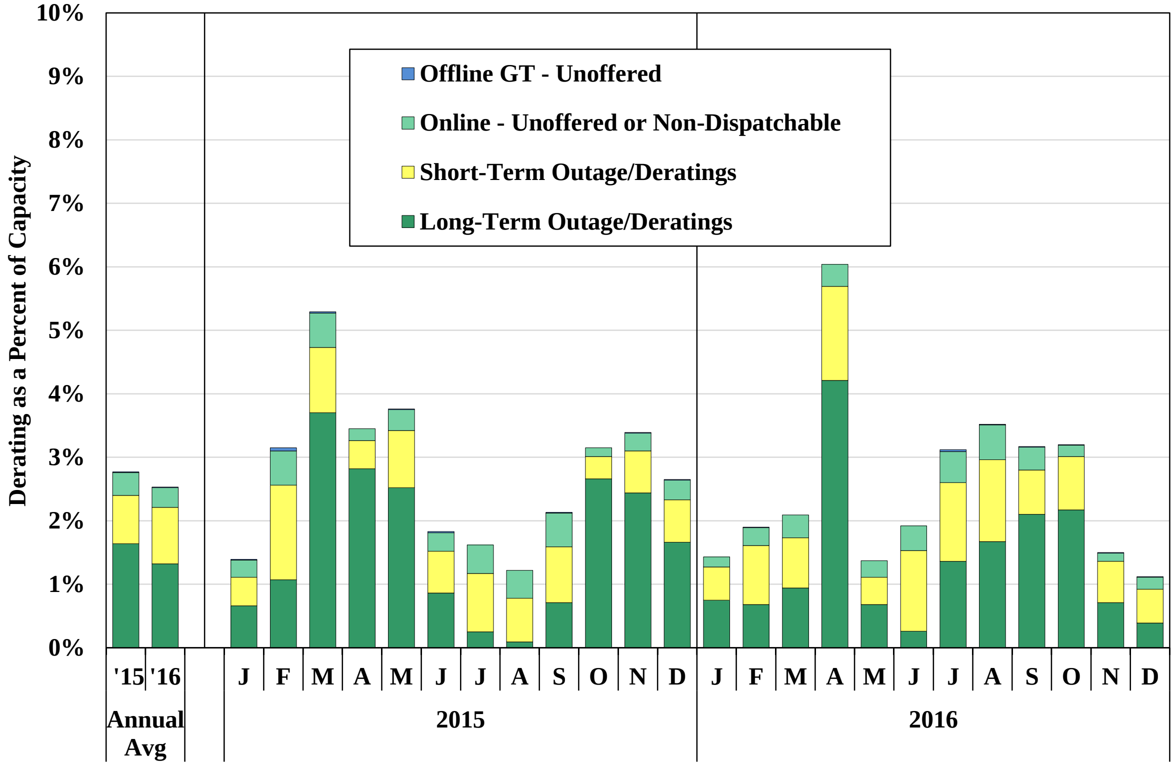


Figure A-23 & Figure A-24: Unoffered Economic Capacity by Load Level & Portfolio Size

Most 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 costlier 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 in broad areas under higher load conditions.

To distinguish between strategic and competitive conduct, we evaluate potential physical withholding considering 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. Thus, we expect competitive suppliers to schedule maintenance outages during low-load periods, whenever possible. 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. Capacity that is on forced outage is more likely to be economic during high-load periods than during low-load periods.

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-23 and Figure A-24 to determine whether the conduct is consistent with workable competition.

Figure A-23: Unoffered Economic Capacity by Supplier by Load Level in New York
2015 – 2016

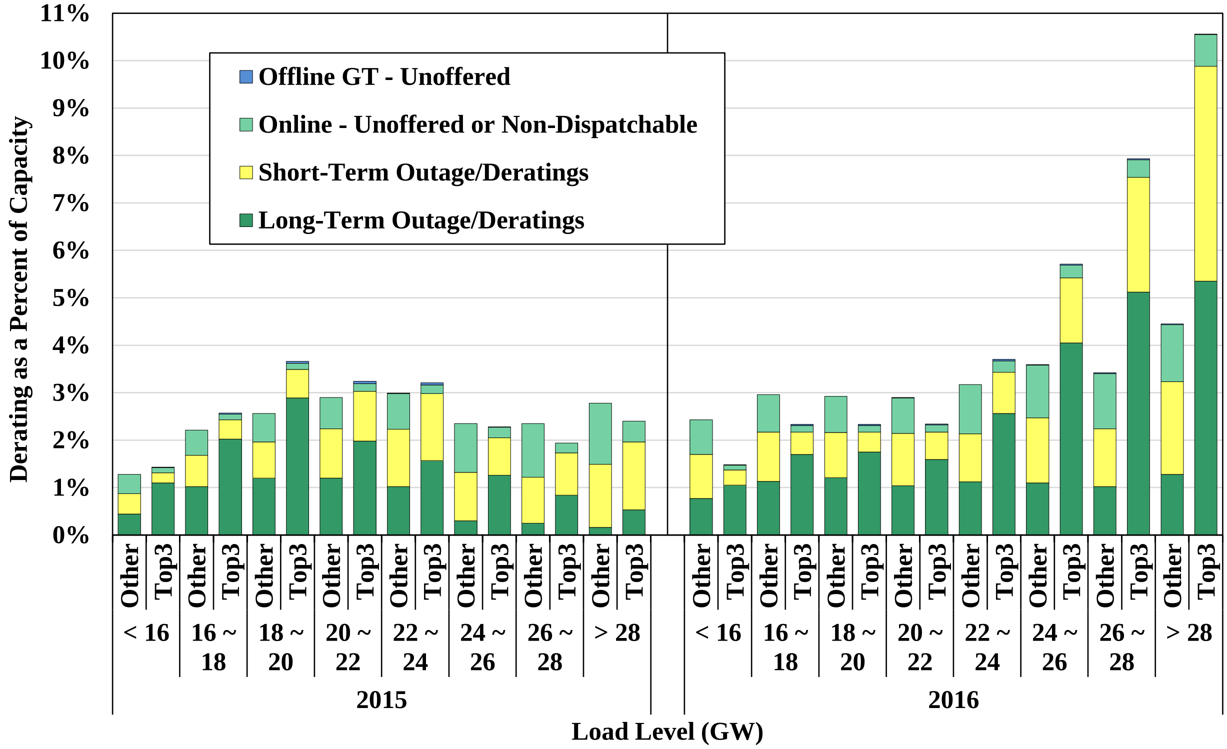
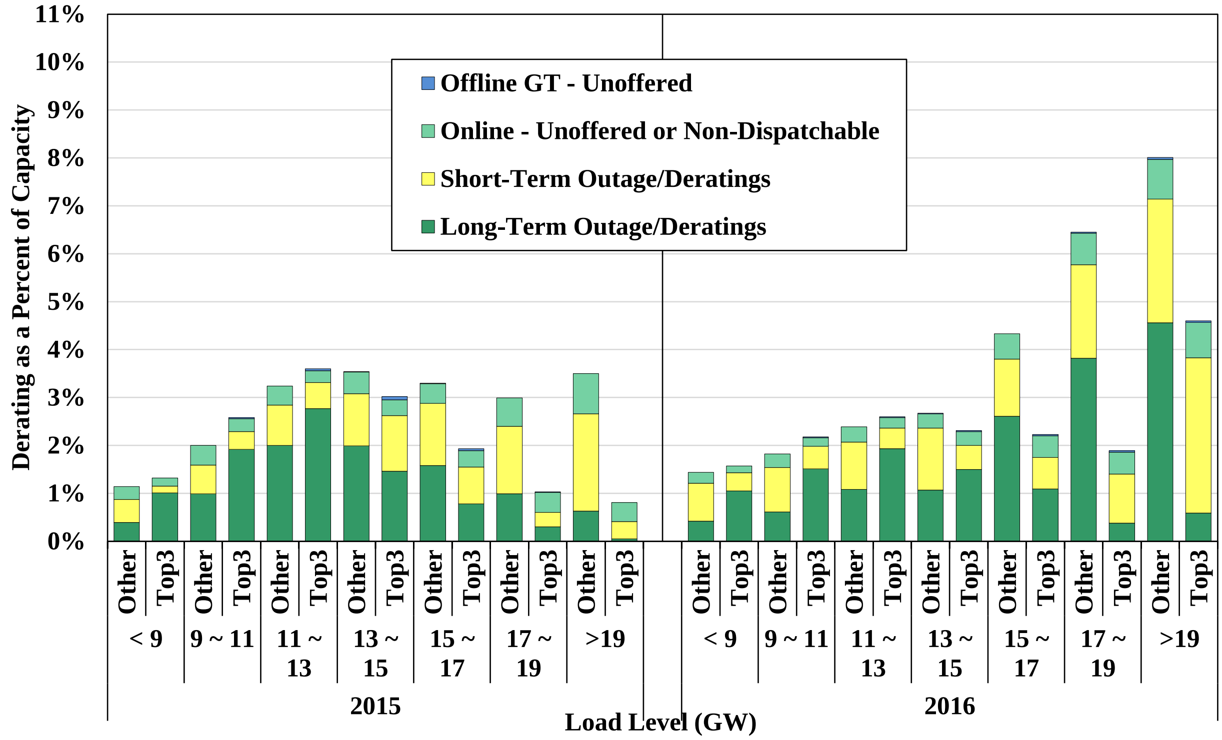


Figure A-24: Unoffered Economic Capacity by Supplier by Load Level in East New York
2015 – 2016



<u>Key Observations: Unoffered Economic Capacity</u>

- The general pattern of deratings was reasonably consistent with expectations for a competitive market in both 2015 and 2016.
  - Derated and unoffered economic capacity averaged 2.8 percent of total DMNC in NYCA, and 2.5 percent in Eastern New York in 2016, comparable to the 2015 levels.
  - Derated and unoffered economic capacity was mostly attributable to long-term maintenance deratings (making up 48 percent of the total derated and unoffered economic capacity in NYCA and 52 percent in Eastern New York in 2016).
  - Most of this economic capacity on long-term maintenance was scheduled during shoulder months (50 percent in NYCA and 56 percent in Eastern New York).
  - Short-term deratings, driven largely by forced outages, were more consistent across load levels than long-term deratings, but they were still highest during the summer months.
  - During the summer months (i.e., June to August) of 2016, total economic deratings and unoffered capacity was about 3 percent of total DMNC in NYCA and Eastern New York, roughly twice as high as the previous year.
  - Long and Short-Term Outage/Deratings primarily drove this increase, with a few large older generators experiencing persistent outages across the summer months.
- In Eastern New York, the short-term economic deratings occurred more frequently in 2016 (17 percent higher than 2015) but still accounted for a similar share of total economic deratings and unoffered capacity as in 2015. The average economic long-term deratings decreased by 20 percent in Eastern New York from 2015 to 2016.
  - Long-term deratings were down especially in the shoulder months.
  - The increase in economic short-term deratings within Eastern New York occurred among many suppliers rather than a small number.
- Although long-term deratings are not likely to reflect withholding, inefficient long-term outage scheduling (i.e., to schedule an outage during a period that the capacity is likely economic for a significant portion of the time if the outage could be scheduled at a better time) raises significant efficiency concerns.
  - The NYISO can require a supplier to re-schedule a planned outage for reliability reasons, but the NYISO cannot require a supplier to re-schedule for economic reasons, and there are no mitigation measures that would address outage scheduling that is not consistent with competitive behavior. It would be beneficial for the NYISO to consider expanding its authority to reject outage requests that would take economic capacity out-of-service during relatively high load conditions. However, any such process would require significant resources for the NYISO to administer effectively.

- However, resources with low marginal costs may have few, if any, time periods when their capacity would not be economic. So, such resources will show up as derated economic capacity, regardless of when they take an outage (except for nuclear units which are excluded during their planned maintenance outages).

B. Potential Economic Withholding: Output Gap Metric

Economic withholding is an attempt by a supplier to inflate its offer price to raise LBMPs above competitive levels. In general, a supplier without market power maximizes profit by offering its resources at marginal cost because inflated offer prices or other offer parameters 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 levels, which is an estimate of marginal cost that is used for market power mitigation.[190, 191] An offer parameter is generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-25 and Figure A-26: 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.[192] 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 are evaluated based on real-time prices. Like the prior analysis of potential physical withholding, we examine the broad patterns of output gap in New York State and Eastern New York, and address the relationship of the output gap to the market demand level and participant size.

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. Lower Threshold 1 is 25 percent of a generator's reference level, and Lower Threshold 2 is 100 percent of a generator's reference level. The two lower thresholds are

190 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 some 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.

191 Due to the Increasing Bids in Real Time (IBRT) functionality, a generator's reference level can now be adjusted directly by a generator for a particular hour or day to account for fuel price changes. The NYISO monitors these generator-set IBRT reference levels and may request documentation substantiating a generator IBRT.

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

included to assess whether there may have been abuse of market power that does not trigger the thresholds specified in the tariff for imposition of mitigation measures by the ISO. However, because there is uncertainty in the estimation of the marginal costs of individual units, results based on lower thresholds are more likely to flag behavior that is actually competitive.

Figure A-25: Output Gap by Month in New York State
2015 – 2016

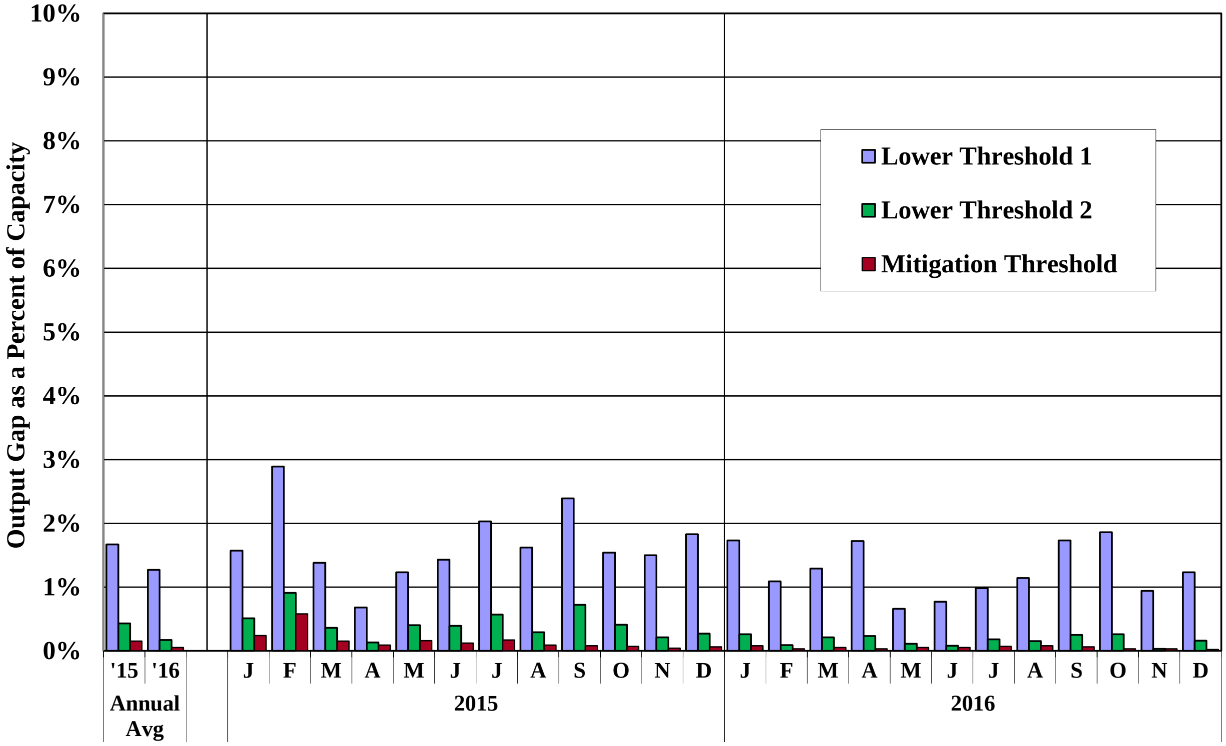


Figure A-26: Output Gap by Month in East New York
2015 - 2016

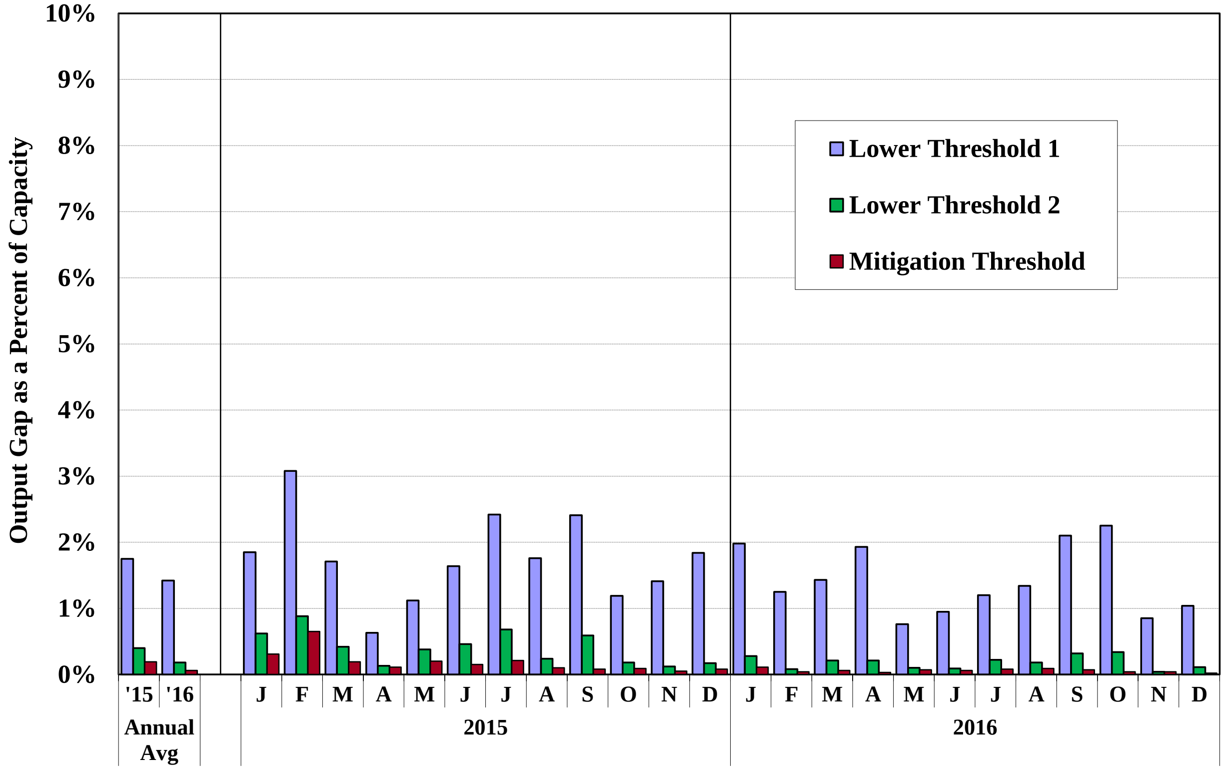


Figure A-27 & Figure A-28: Output Gap by Supplier and Load Level

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 positively correlated with these factors. Hence, these figures indicate how the output varies as load increases and whether the largest three suppliers exhibit substantially different conduct than other suppliers.

Figure A-27: Output Gap by Supplier by Load Level in New York State
2016

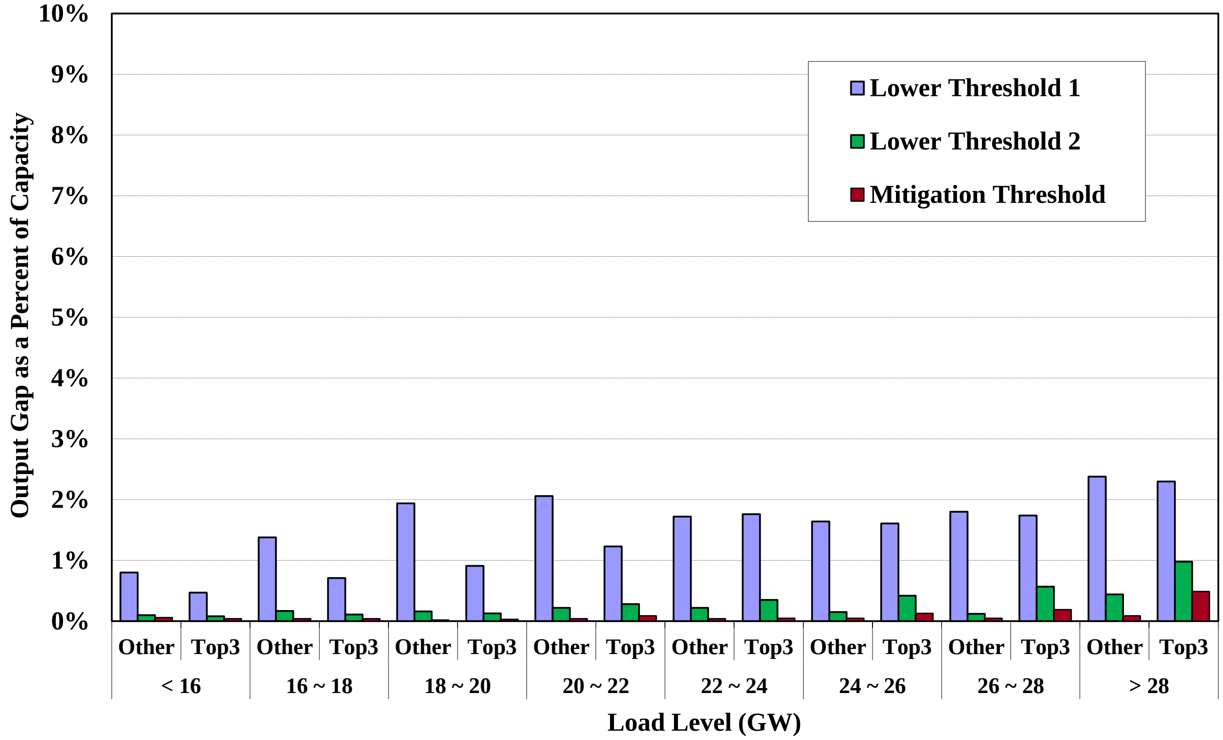
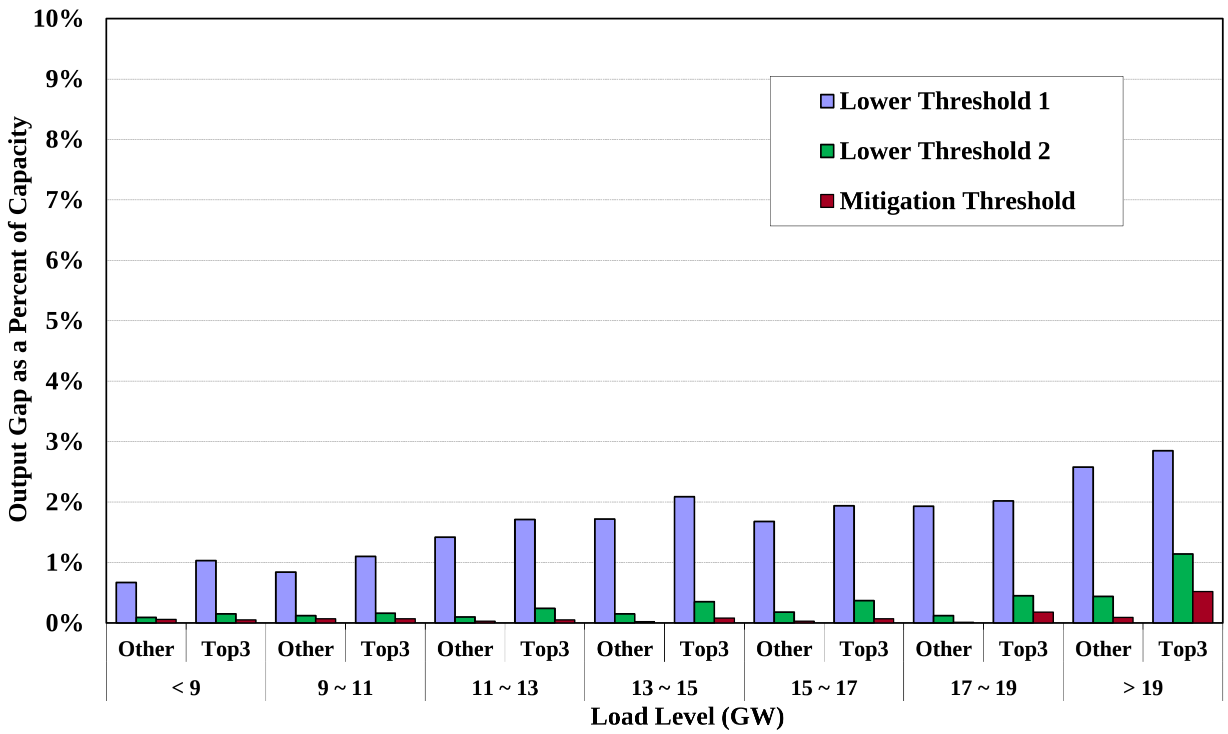


Figure A-28: Output Gap by Supplier by Load Level in East New York
2016



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged about 0.1 percent of total capacity at the mitigation threshold and roughly 1.3 percent at the lowest threshold evaluated (i.e., 25 percent) in 2016 for NYCA.
- Output Gap did rise modestly as load rose. This was due to the following factors:
  - The Output Gap Calculation takes market prices as fixed. However, committing an extra unit would tend to lower Day-Ahead prices, especially during high load periods. Therefore, uncommitted units which show up in our Output Gap calculation may not truly have been economic to commit.
  - Some units, predominantly co-generation resources, consistently offer inflexibly, reducing market commitment and dispatch. This uncommitted capacity appears economic (and shows up as Output Gap) increasingly at high-load periods.
  - Most co-generation resources operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses. Small portfolio owners generally do not have an incentive to withhold supply.
- Overall, the output gap level in 2016 did not raise significant concerns on economic withholding.

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 it 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.[193] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

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

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the

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

preceding twelve-month period.[194] 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 necessitate 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.[195] 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.[196]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[197] 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.[198]
- 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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194 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.

195 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.

196 See NYISO Market Services Tariff, Section 23.3.1.2.3.

197 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.

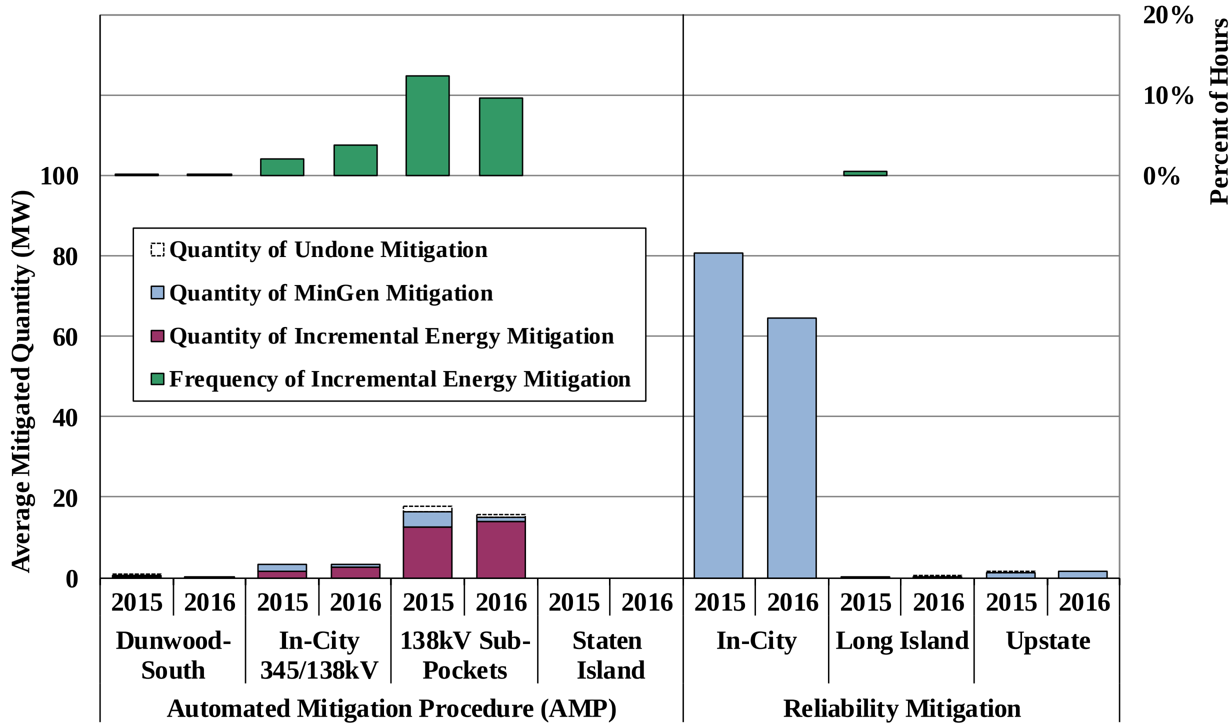
198 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

Figure A-29 & Figure A-30: Summary of Day-Ahead and Real-Time Mitigation

Figure A-29 and Figure A-30 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2015 and 2016. These figures do not include guarantee payment mitigation that occurs in the settlement system.

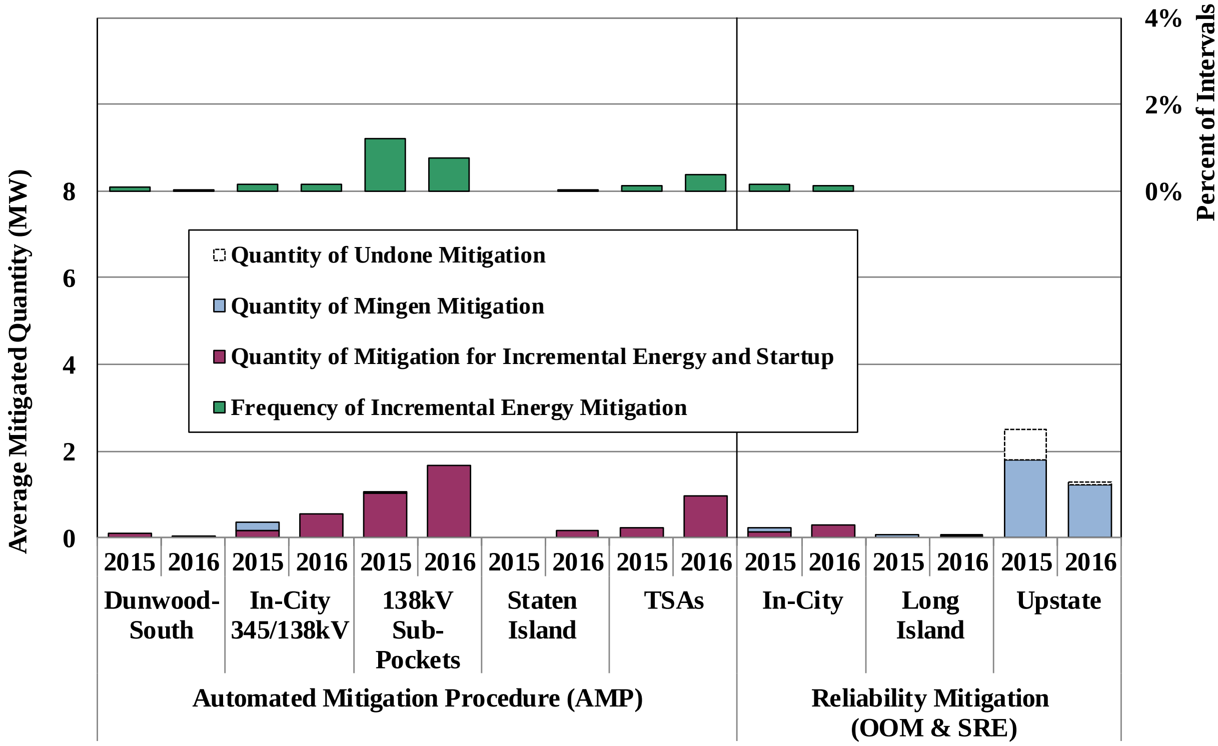
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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).[199] 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-29: Summary of Day-Ahead Mitigation
2015 – 2016



199 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-30: Summary of Real-Time Mitigation
2015 - 2016



Key Observations: Day-ahead and Real-time Mitigation

- Most mitigation occurs in the day-ahead market, since this is where most supply is scheduled.
  - In 2016, nearly all of mitigation occurred in the day-ahead market, of which:
    - Local reliability (i.e., DARU and LRR) units accounted for 78 percent.
      - Most reliability commitment occurs in the day-ahead market, making the instances of reliability commitment mitigation more prevalent in the day-ahead market.
      - These mitigations generally affected guarantee payment uplift but not LBMPs.
    - Gas turbines in the Greenwood/Staten Island load pocket (which had the lowest mitigation threshold and most frequent congestion in New York City) accounted for most of the remaining mitigation.
- The quantity of mitigation declined modestly from 2015 to 2016 primarily because of lower DARU and LRR commitments in New York City (see Section V.H in the Appendix).

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. 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 suppliers that sell reserves in the day-ahead market, since suppliers must forego real-time 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-31 to Figure A-35: Summary of Ancillary Services Offers

The following five figures compare the ancillary services offers for generators in the day-ahead market for 2015 and 2016 on a monthly basis as well as on an annual basis. The quantities offered are shown for the following categories: [200]

- 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,
- 30-minute operating reserves in NYCA, [201] and
- Regulation.

Offer quantities are shown according to offer price level for each category. Offers for the five ancillary services products from all hours and all resources are included in this evaluation.

200 The quantity of 10-minute non-spinning reserve offers in Western New York is very small and is not reported here.

201 This category only includes the reserve capacity that can be used to satisfy the 30-minute reserve requirements but not the 10-minute reserve requirements. That is, the reported quantity in this chart excludes the 10-minute spinning and 10-minute non-spin reserves from the total 30-minute reserve capability.

Figure A-31: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2015-2016

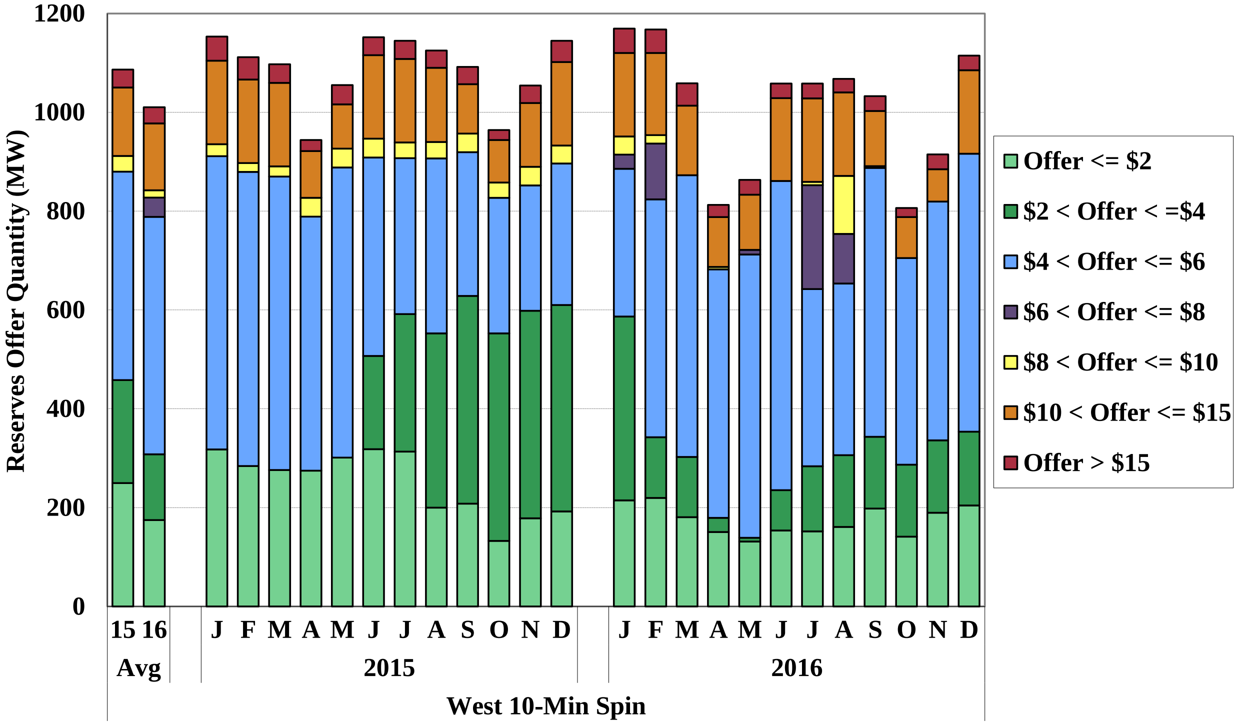


Figure A-32: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2015-2016

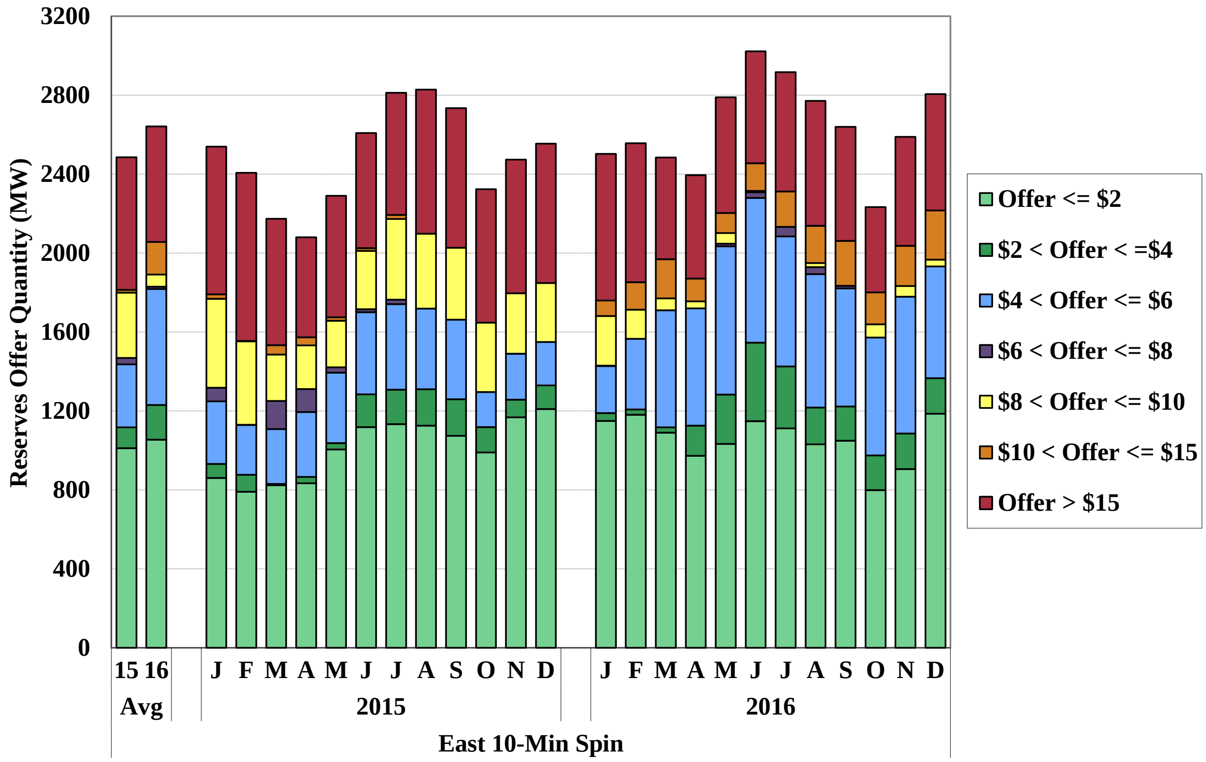


Figure A-33: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2015-2016

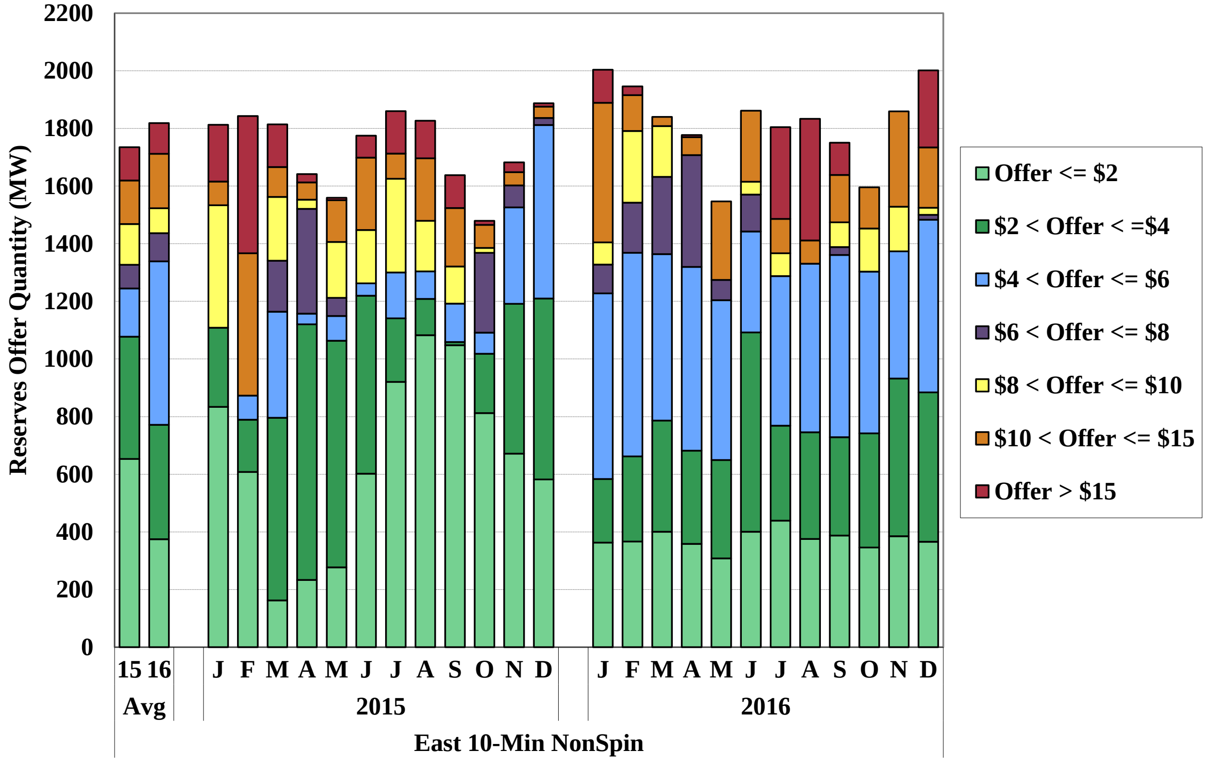


Figure A-34: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2015-2016

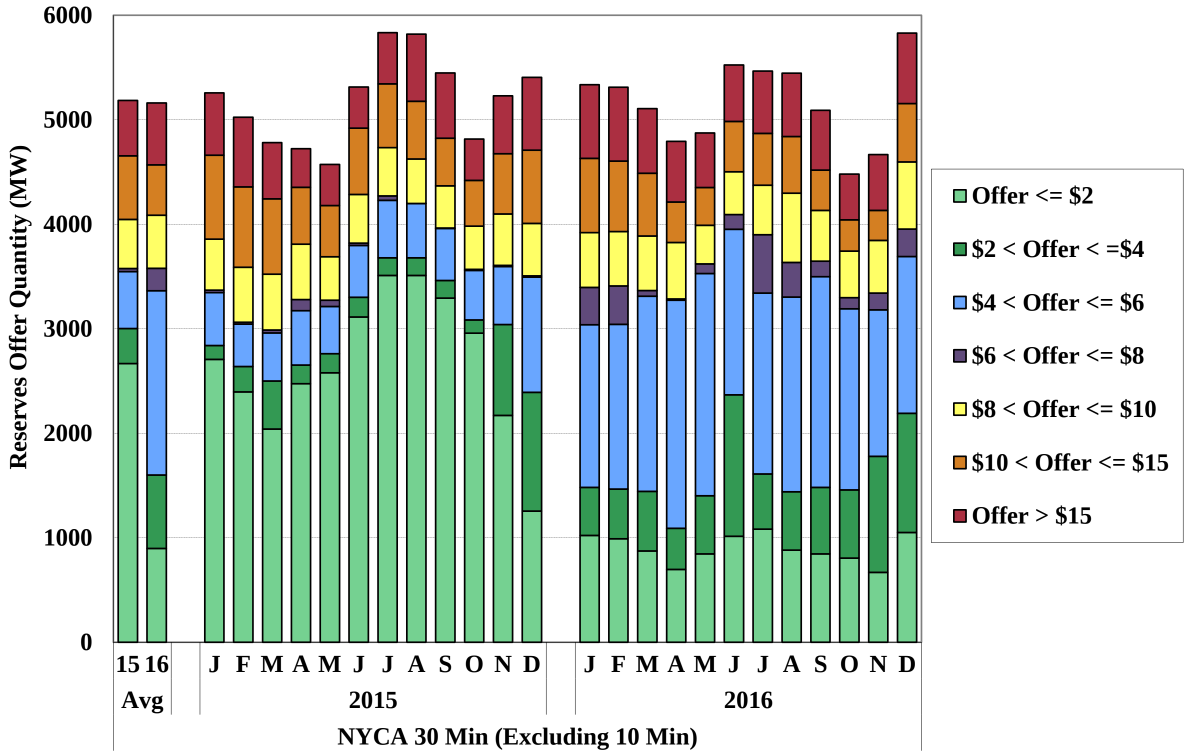


Figure A-35: Summary of Regulation Capacity Offers
Day-Ahead Market, 2015-2016

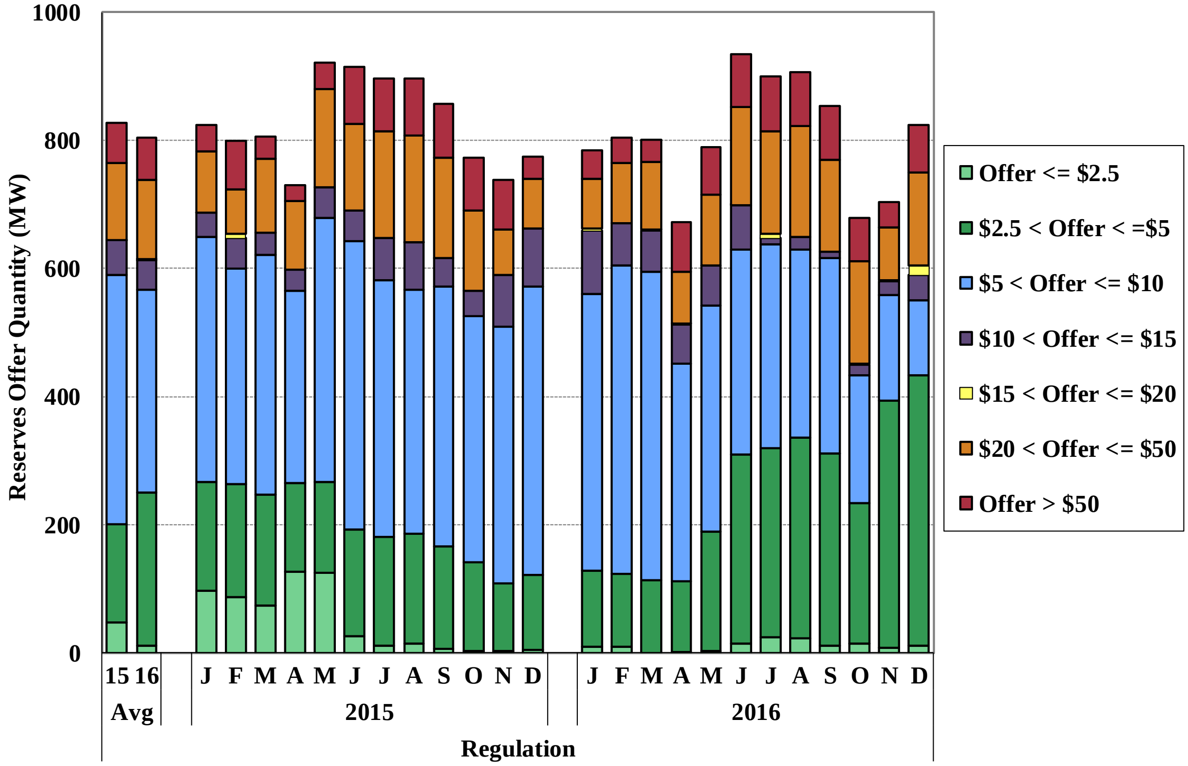


Figure A-36: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

The NYISO implemented the Comprehensive Shortage Pricing Project (CSPP) in early November 2015, which made several market design changes that affect reserve and regulation markets. One notable change in market outcomes was higher 30-minute reserve prices. [202] The next analysis evaluates the drivers of the increase.

Figure A-36 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2015 and 2016. [203] These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers, although they are not shown separately in the figure. Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included in this evaluation, as other resources do not directly affect the reserve prices.

The stacked bars in the figure show the amount of reserve offers in selected price ranges for West NY (Zones A to E), East NY (Zones F to J), and NYCA (excluding Zone K). Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e.,

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202 See Figure A-11 in the Appendix.

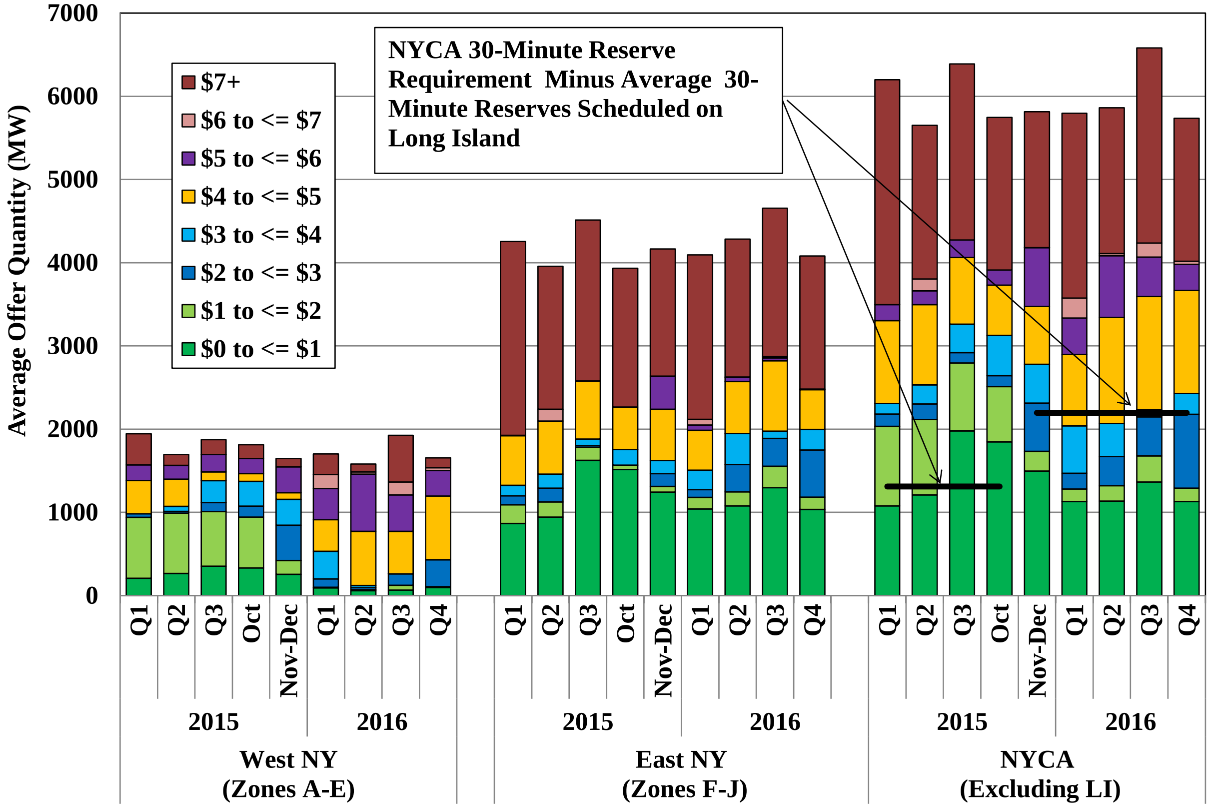
203 The fourth quarter of 2015 is split into "Oct" and "Nov-Dec", representing the two periods before and after the implementation of CSPP.

SENY, East, NYCA). As a result, Long Island reserve offers have little impact on NYCA reserve prices.

The two black bars in the figure represent the equivalent average 30-minute reserve requirements for areas outside Long Island before and after the market rule changes. This is calculated as NYCA 30-minute reserve requirement *minus* 30-minute reserves scheduled on Long Island. Where the lines intersect the bars provides a rough indication of reserve prices, which, however, is generally lower than actual reserve prices because opportunity costs are not reflected in the figure.

Figure A-36: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

Committed and Available Offline Quick-Start Resources, 2015-2016



Key Observations: Ancillary Services Offers

- The quantity of ancillary services offered from all five categories did not change significantly on an annual basis from 2015 to 2016.
  - However, there were monthly variations that exhibited a typical seasonal pattern.
    - Reserves and regulation offer quantities were lower in the spring and fall than in the summer and winter because more planned outages occurred in the shoulder months when supply is less valuable.

- The NYISO implemented the Comprehensive Shortage Pricing project on November 4, 2015, which made several market design changes that affected reserve and regulation market outcomes.
  - Most notably, the NYCA 30-minute reserve prices rose significantly afterwards. (See Appendix Section I.E).
  - The increase was driven partly by:
    - The increase in NYCA 30-min reserve requirement from 1,965 to 2,620 MW; and
    - The limit placed on the amount of reserves scheduled on Long Island resources. An average of 423 MW of 30-minute reserves was scheduled on Long Island in 2016, down 230 MW from 2015.
      - The purpose of this limitation is to ensure that the quantity of reserves scheduled on Long Island does not exceed the capability of the transmission system to deliver them to other zones. However, this limitation is unnecessarily tight and we recommend increasing it to a more reasonable level.[204] For example, when Long Island is importing a net of 900 MW from the rest of NYCA, it should usually be possible to schedule 900 MW of reserves on Long Island so that if a contingency were to occur in another portion of NYCA, net imports to Long Island would fall to 0 MW.
    - Taken together, these two factors increased the demand for 30-minute reserves outside Long Island by 885 MW from the previous year.
  - The price increase was also attributable to increases in reserve offer prices, particularly in Western New York.
    - In Western New York, over 80 percent of the reserve capacity (including both 10-minute and 30-minute) was offered above $4/MWh in 2016, while nearly 55 percent was offered less than $2/MWh in 2015 prior to the rule change.
      - We have reviewed this offer change and found no significant competitive concerns.
    - In Eastern New York, some generators also increased the amount of 30-minute reserves offered at less than $5/MWh.

204 See Recommendation #2015-16.

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 five 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.[205]
- *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 are withdrawn or bid at high price levels in real time. They are similar to virtual load bids, but they are placed at the 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-37 to Figure A-44: 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

205 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.

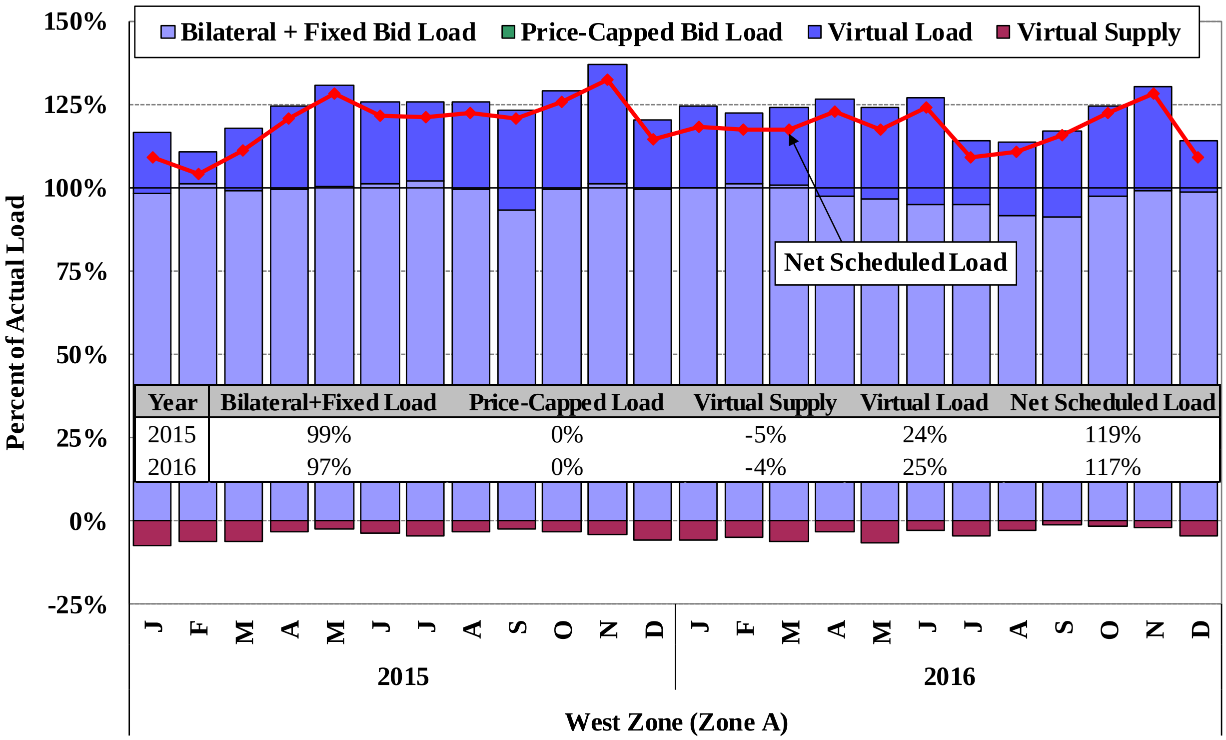
unit commitment relies on consistency between the day-ahead and the real-time markets. The following figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

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

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2015 and 2016 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 2015 to 2016. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

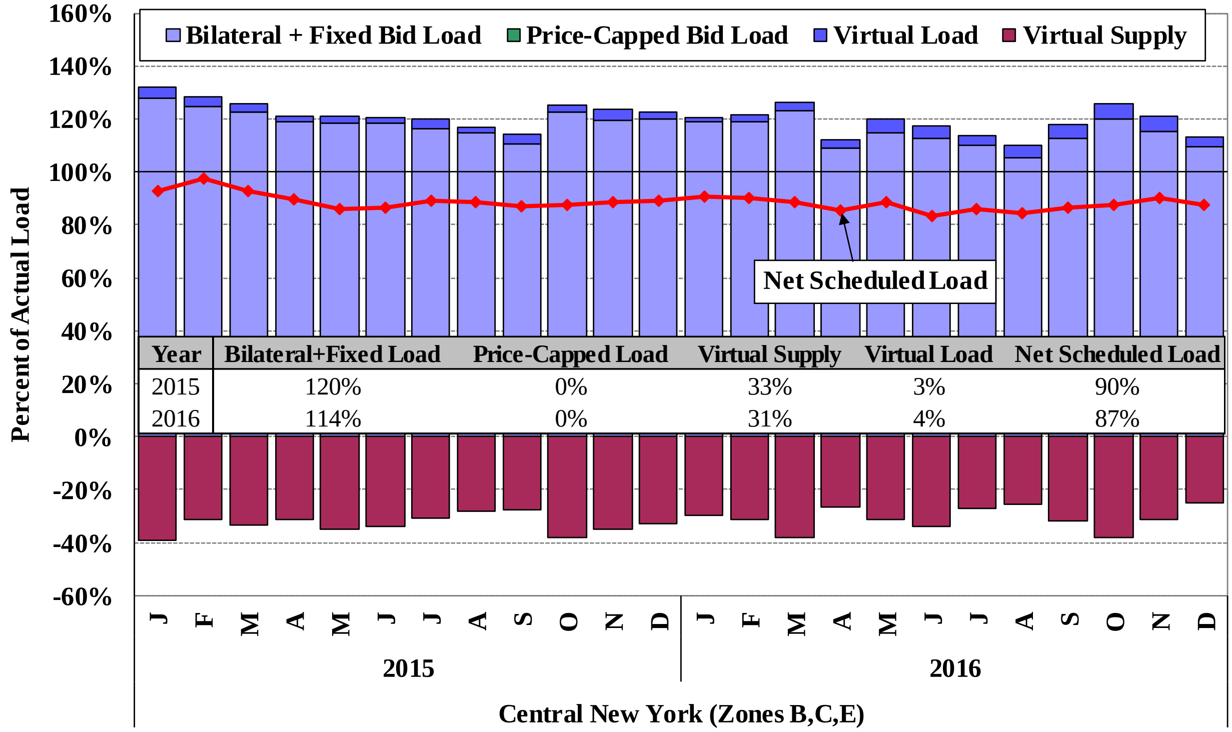
Figure A-37: Day-Ahead Load Schedules versus Actual Load in West Zone

Zone A, 2015 – 2016



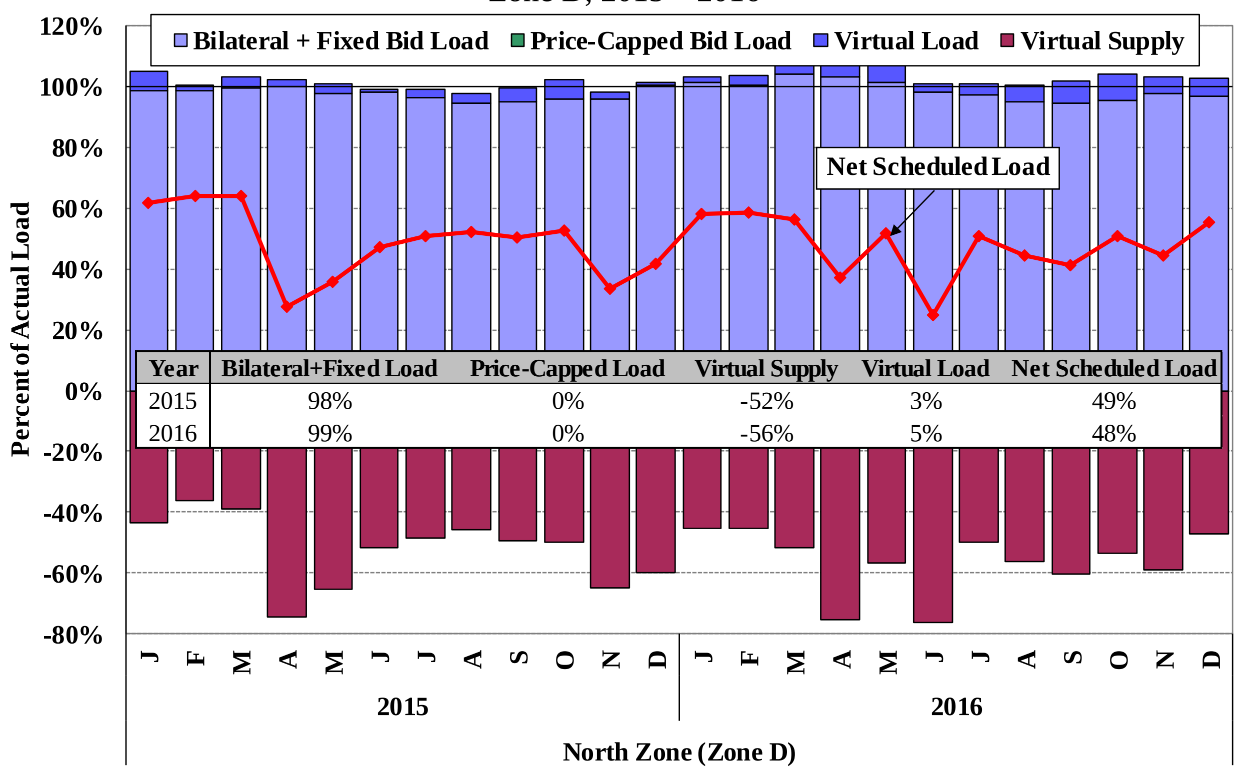
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	99%	0%	-5%	24%	119%
2016	97%	0%	-4%	25%	117%

Figure A-38: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2015 – 2016



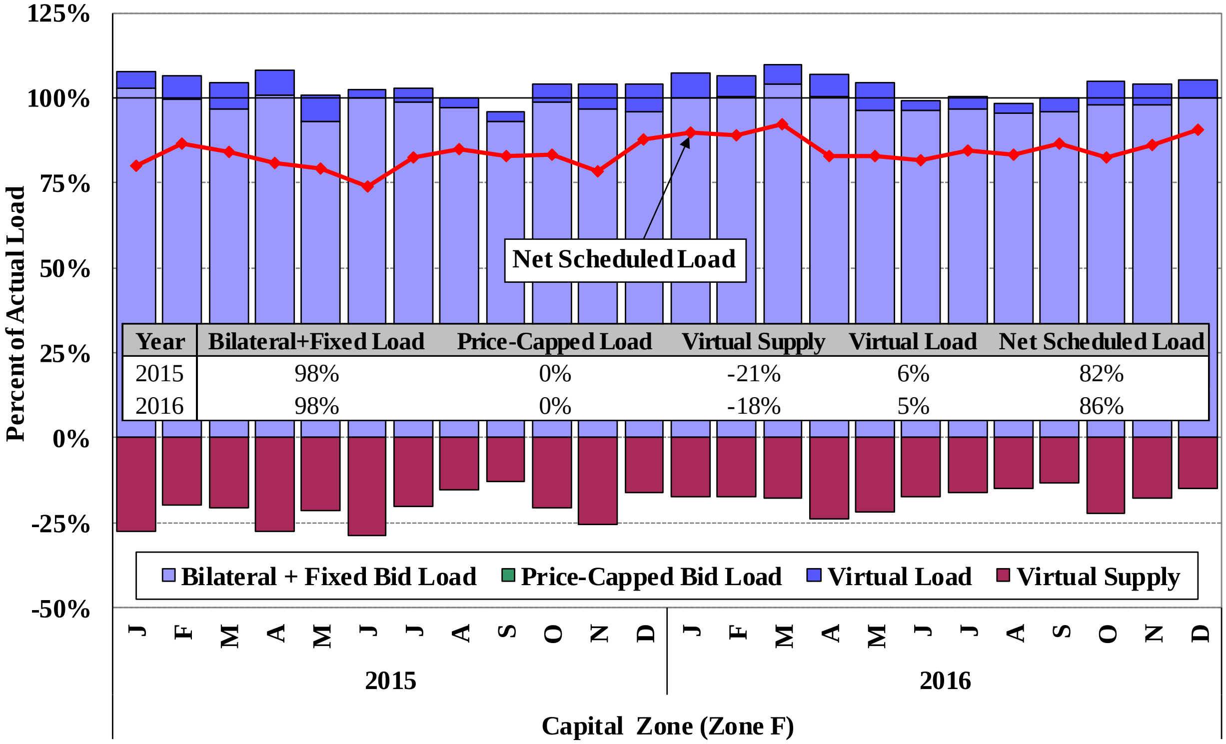
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	120%	0%	33%	3%	90%
2016	114%	0%	31%	4%	87%

Figure A-39: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2015 – 2016



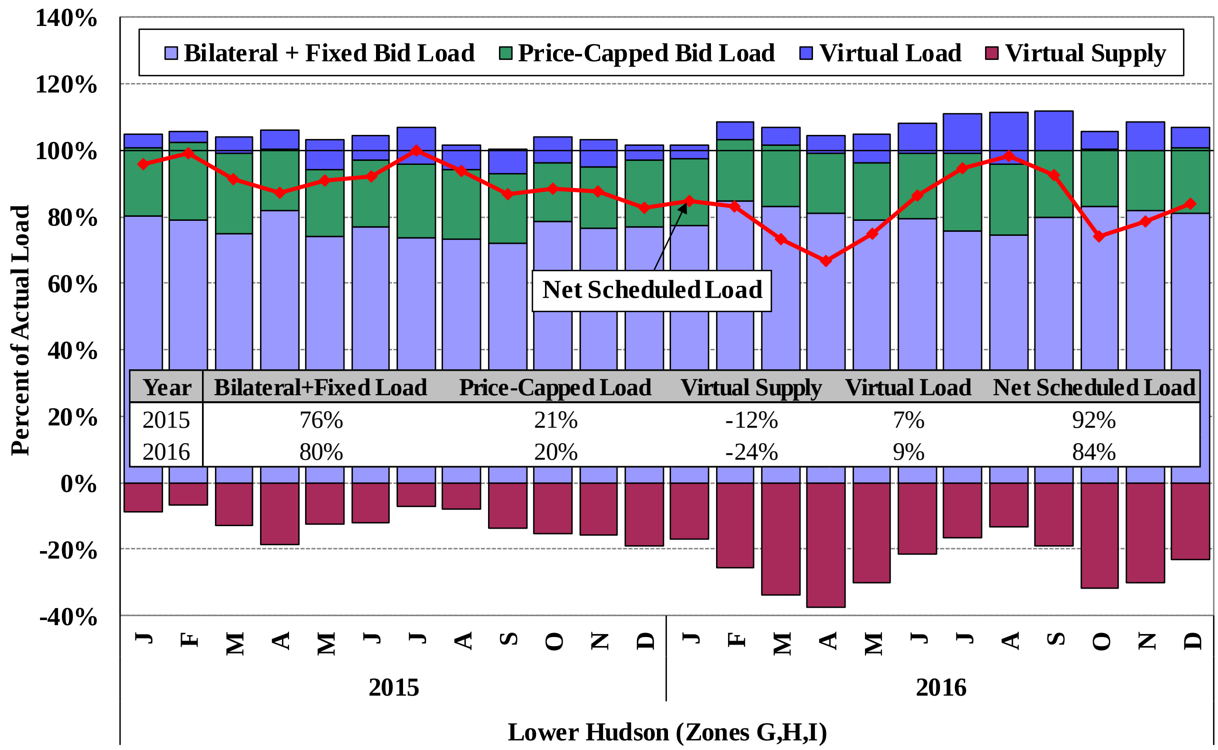
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	98%	0%	-52%	3%	49%
2016	99%	0%	-56%	5%	48%

Figure A-40: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2015 – 2016



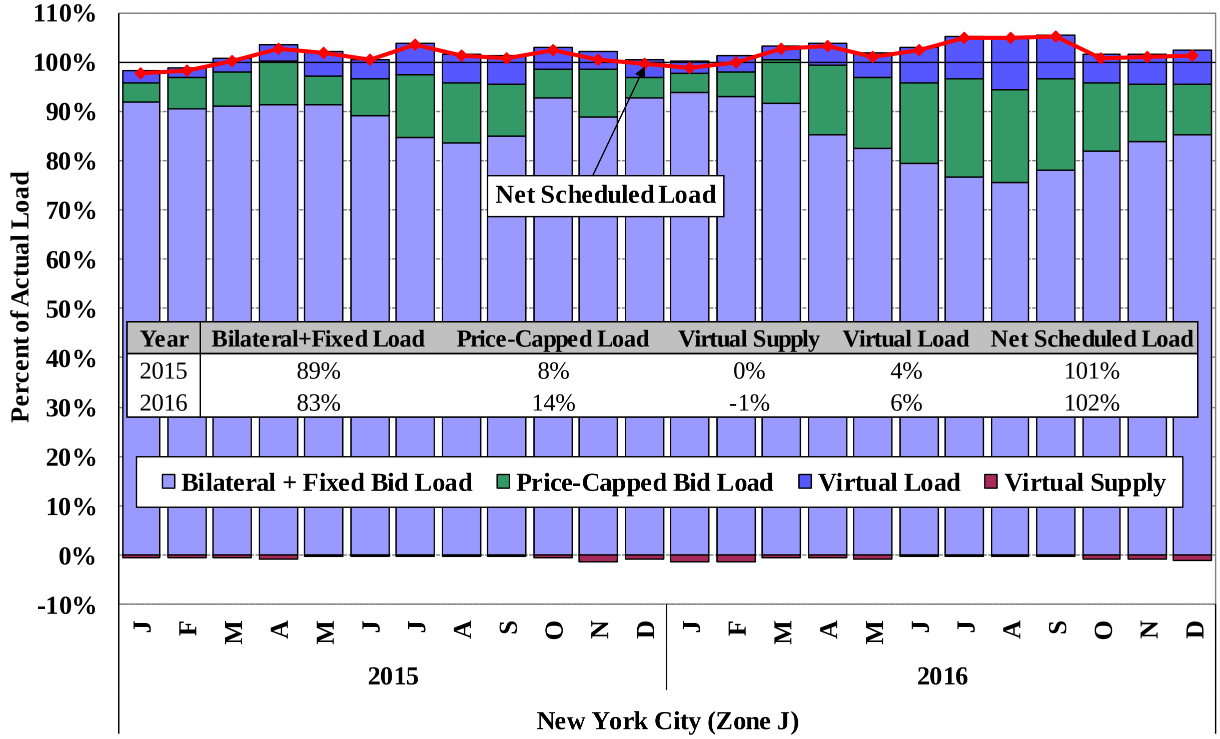
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	98%	0%	-21%	6%	82%
2016	98%	0%	-18%	5%	86%

Figure A-41: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2015 – 2016



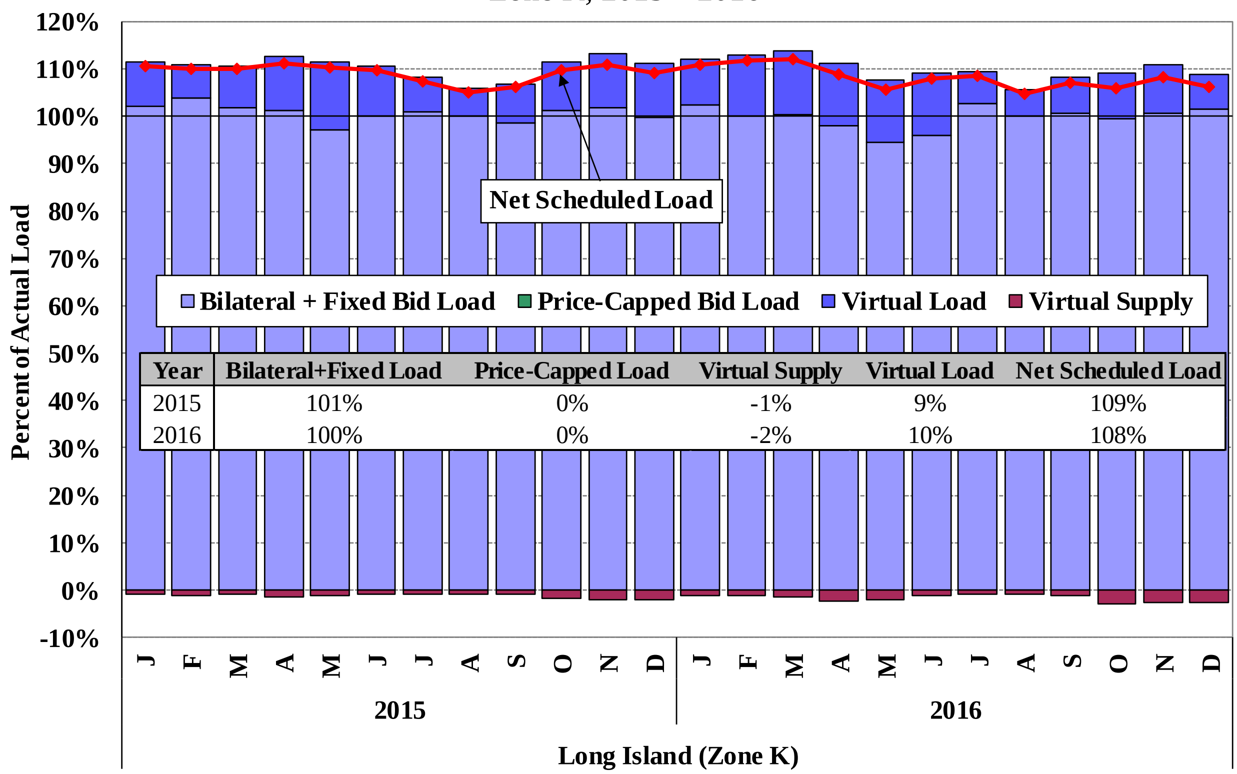
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	76%	21%	-12%	7%	92%
2016	80%	20%	-24%	9%	84%

Figure A-42: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2015 – 2016



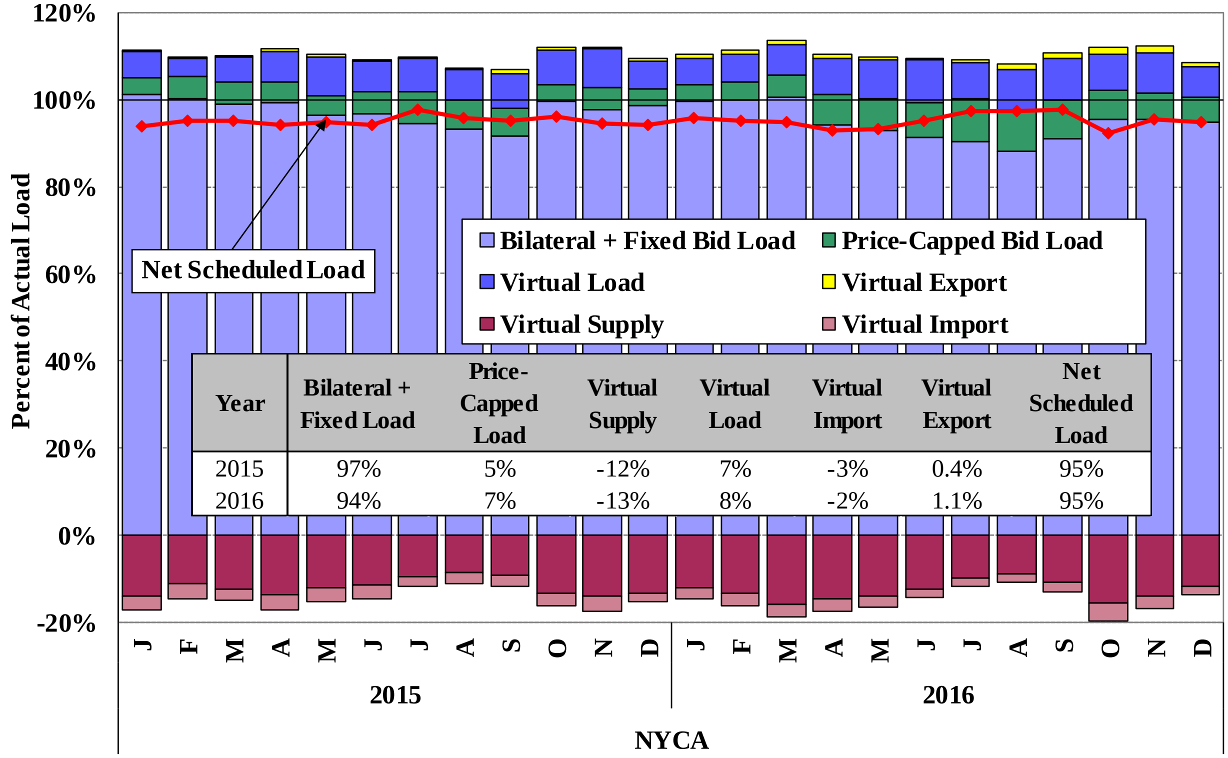
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	89%	8%	0%	4%	101%
2016	83%	14%	-1%	6%	102%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2015 – 2016



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2015	101%	0%	-1%	9%	109%
2016	100%	0%	-2%	10%	108%

Figure A-44: Day-Ahead Load Schedules versus Actual Load in NYCA
2015 – 2016



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2015	97%	5%	-12%	7%	-3%	0.4%	95%
2016	94%	7%	-13%	8%	-2%	1.1%	95%

Key Observations: Day-ahead Load Scheduling

- Overall, load in the day-ahead market was scheduled at roughly 95 percent of actual load in NYCA during daily peak load hours in 2016, similar to 2015 levels.
  - The scheduling pattern in each of the sub-regions was generally consistent between 2015 and 2016 as well.
- Average load scheduling tends to be higher in import-constrained locations and/or at times when acute real-time congestion is more likely.
  - This has led to a seasonal pattern in some regions. For example:
    - Load-scheduling in the Capital Zone typically rose in the winter months because of much higher congestion across the Central-East interface.
    - Load-scheduling in Lower Hudson Valley (i.e., Zone G, H, and I) generally increased in the summer months when acute real-time congestion into Southeast New York was more prevalent (due partly to frequent TSA events).
      - Virtual supply rose in the Lower Hudson Valley in 2016 (particularly in the shoulder months), likely in response to lower congestion levels into this area.
  - This has also resulted in locational differences between regions.

- Average load scheduling was generally higher in New York City, Long Island, and the West Zone than the rest of New York because congestion was typically more prevalent in these areas.
- This was particularly true for the West Zone in recent years because of increased congestion on the 230 kV system. Day-ahead load scheduling was the highest in the West Zone, averaging nearly 120 percent in both 2015 and 2016.

- Under-scheduling was still prevalent in West Upstate outside the West Zone.
  - This is generally consistent with the tendency for renewable generators to increase real-time output above their day-ahead schedules.
  - For example, load was typically under-scheduled in the North Zone by a large margin, primarily in response to the scheduling patterns of wind resources in this area (which typically rose in real-time above their day-ahead schedules).

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.

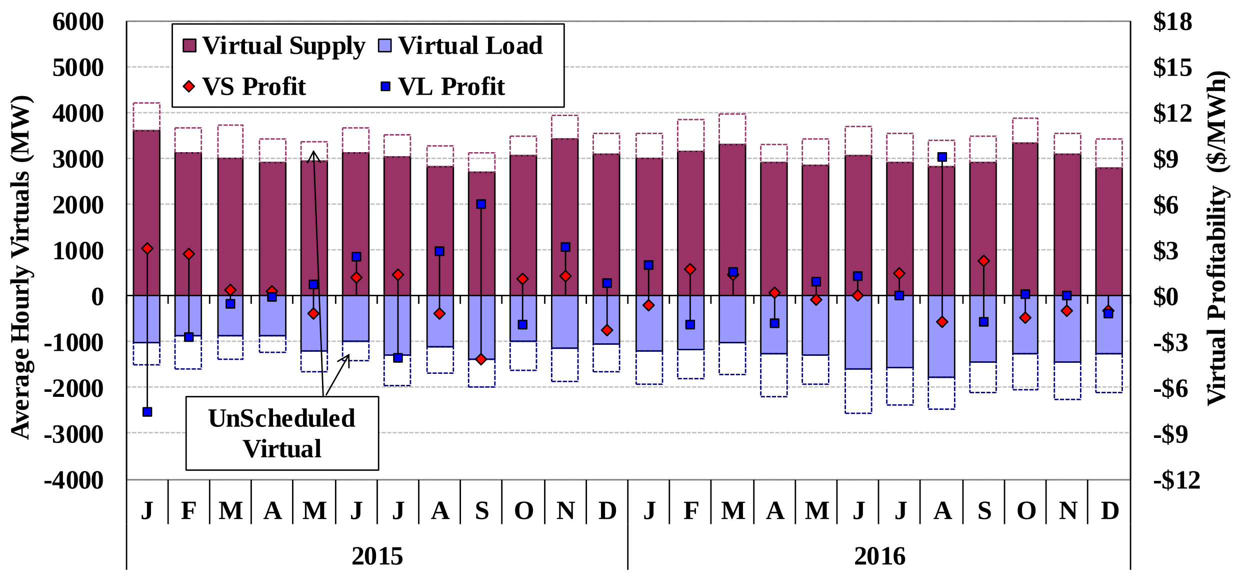
Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as *Virtual Imports* and *Virtual Exports* in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that 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-45: Virtual Trading Volumes and Profitability

Figure A-45 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2015 and 2016. 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.[206, 207]

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 490 MW of virtual transactions (or 12 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2016. 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-45: Virtual Trading Volumes and Profitability
2015 - 2016



Profit > 50% of Avg. Zone Price	MW	537	562	315	296	561	763	471	284	239	375	1078	627	692	638	1003	354	431	460	596	398	360	281	261	490
	%	12%	14%	8%	8%	13%	19%	11%	7%	6%	9%	23%	15%	17%	15%	23%	8%	10%	10%	13%	9%	8%	6%	6%	12%
Loss > 50% of Avg. Zone Price	MW	460	445	373	335	667	680	489	296	336	368	698	752	553	547	680	682	550	528	517	413	411	419	345	587
	%	10%	11%	10%	9%	16%	17%	11%	7%	8%	9%	15%	18%	13%	13%	16%	16%	13%	11%	12%	9%	9%	9%	8%	14%

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

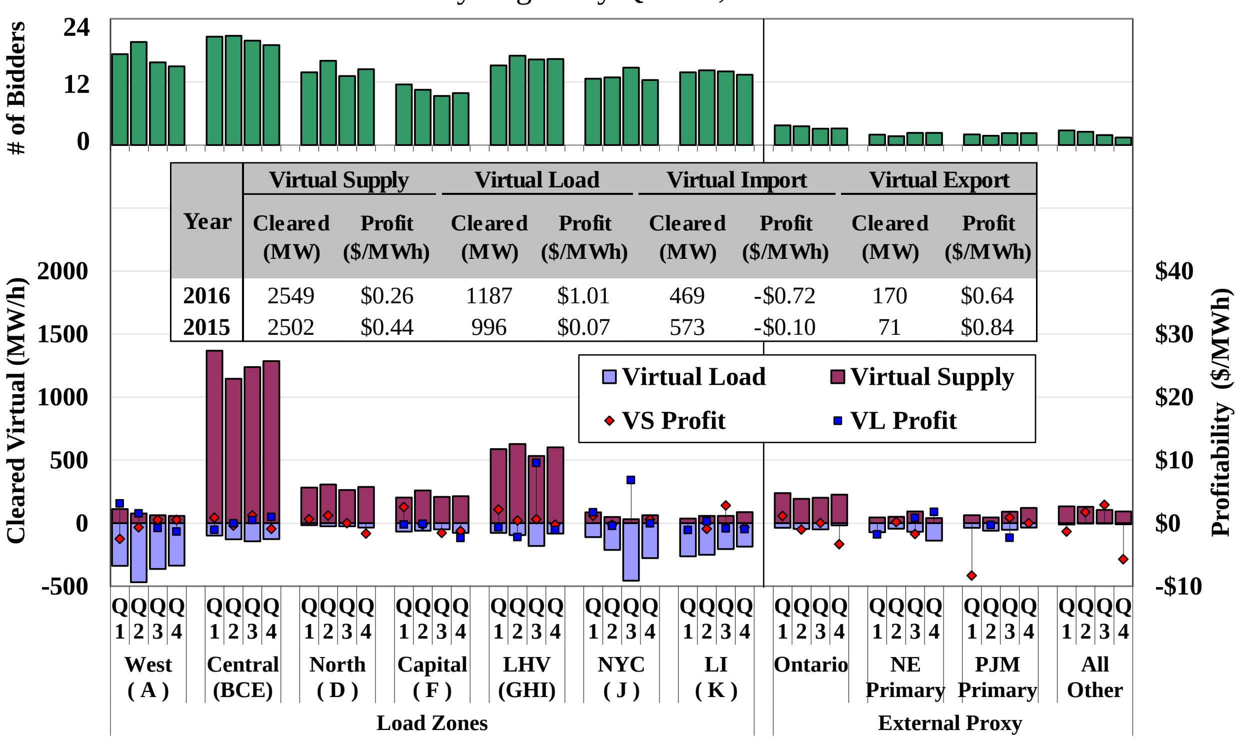
207 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

Figure A-46: Virtual Trading Activity

Figure A-46 summarizes virtual trading by geographic region. The eleven zones in New York are broken into seven geographic regions based on typical congestion patterns. Zone A (the West Zone) is shown separately because of increased congestion on the 230 kV system in recent years. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas. 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 seven regions and four groups of external proxy buses in each quarter of 2016. 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 2015 and 2016.

Figure A-46: Virtual Trading Activity[208]
by Region by Quarter, 2016



Year	Virtual Supply Cleared (MW)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW)	Virtual Export Profit ($/MWh)
2016	2549	$0.26	1187	$1.01	469	-$0.72	170	$0.64
2015	2502	$0.44	996	$0.07	573	-$0.10	71	$0.84

208 Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW.

Key Observations: Analysis of Virtual Trading

- The volume of virtual trading did not change significantly from month to month in 2016, generally consistent with 2015. The pattern of virtual scheduling was similar as well.
  - Virtual traders generally scheduled more virtual load in the West Zone, New York City, and Long Island, while Zones B through I generally scheduled more virtual supply.
  - This was consistent with typical day-ahead load scheduling patterns discussed in subsection E for similar reasons.
- Over 70 percent of scheduled virtual trades at the proxy buses were virtual imports in 2016.
  - Some of the import and export transactions that are classified as “virtual” were actually physical day-ahead transactions that did not flow in real-time because the transmission service was not available in the neighboring market or the transaction was curtailed. Such transactions are not systematically excluded and they account for a portion of the losses accrued on virtual imports and exports.
  - About 46 percent of virtual imports were scheduled at the Ontario proxy bus, which exhibited an average day-ahead premium in 2016 because of higher real-time congestion on the 230 kV transmission facilities in the West Zone from Niagara-to-Packard and Packard-to-Sawyer.
- In aggregate, virtual traders netted approximately $14 million of gross profits in 2016 and $10 million in 2015.
  - Profitable virtual transactions over the period indicate 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.
  - However, profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices.
- The quantities of virtual transactions that generated substantial profits or losses were generally small in 2016, consistent with prior periods.
  - These trades were primarily associated with high real-time price volatility that resulted from unexpected events and did not raise significant manipulation concerns.
  - For example, virtual load netted a profit of $6.4 million on August 12, 2016 because of real-time price spikes that resulted from unexpected system capacity deficiency.

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 2016

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.[209]

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.[210] 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.[211] 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-47: Congestion Revenue Collections and Shortfalls

Figure A-47 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2015 and 2016. The upper portion of the figure shows balancing congestion revenue shortfalls, and the lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month. The tables in the figure report these categories on an annual basis.

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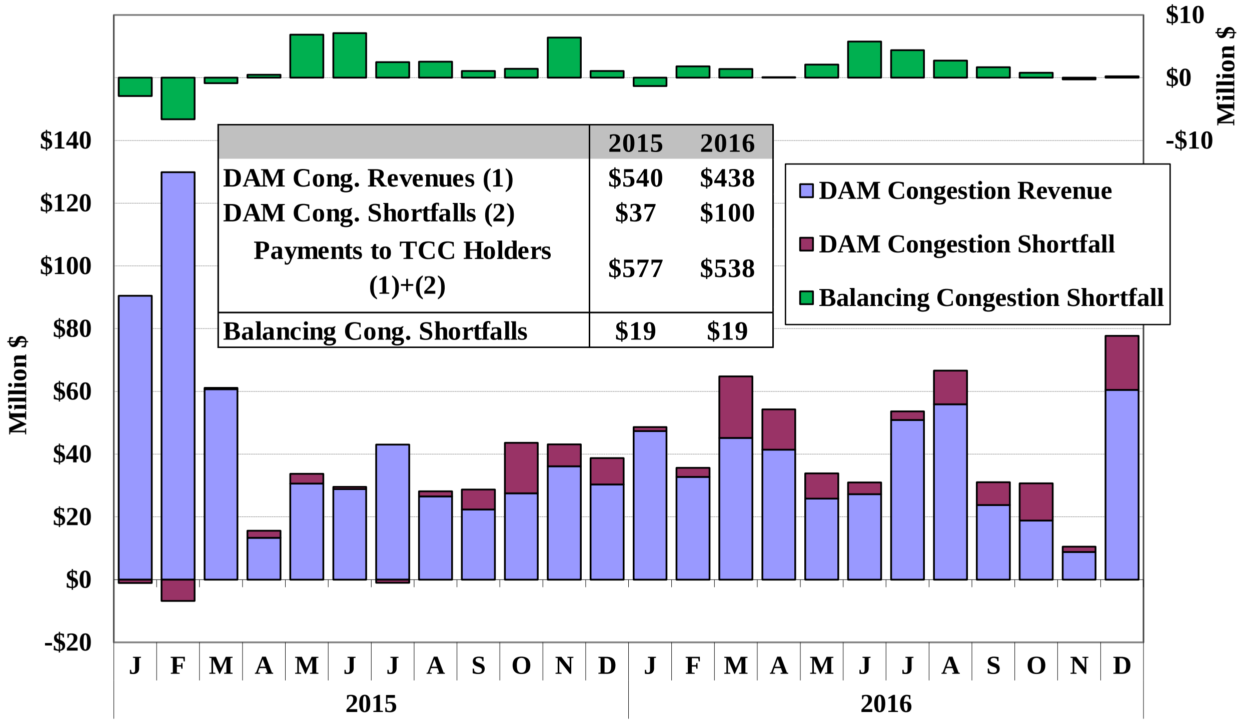
209 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000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

210 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).

211 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-47: Congestion Revenue Collections and Shortfalls
2015-2016



Key Observations: Summary of Congestion Revenues and Shortfalls

- Day-ahead congestion revenues totaled roughly $438 million in 2016, down 19 percent (or $101 million) from 2015.
  - The reduction primarily occurred in the first quarter of 2016, during which day-ahead congestion revenues fell 55 percent (or $156 million) from last year.
    - This was consistent with the 18 to 70 percent reduction in natural gas prices across the state over the same period (see Section I.B)
  - However, day-ahead congestion revenues rose 21 percent (or $54 million) in the remaining months, partly offsetting the overall reduction for the year. Significant drivers of higher congestion costs include:
    - Transmission outages, which are discussed for major transmission facilities in Subsection B;
    - Higher load levels in the summer months (see Section I.D); and
    - The implementation of the GTDC, which is discussed in Section V.F.
- Day-ahead congestion shortfalls rose 170 percent (or $63 million) from 2015 to 2016 primarily because of more transmission outages, while balancing congestion shortfalls were little changed.
  - The locations and causes of these shortfalls 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 day-ahead market, the NYISO schedules generation and load based on the bids and offers submitted by market participants and the assumed transfer capability of the transmission network. 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-48 - Figure A-50: Day-Ahead and Real-Time Congestion by Path

Figure A-48 to Figure A-50 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-48 compares these quantities in 2015 and 2016 on an annual basis, while Figure A-49 and Figure A-50 show the quantities separately for each quarter of 2016.

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.[212]

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 figure groups congestion along the following transmission paths:

- West Zone Lines: Transmission lines in the West Zone on the 230 kV system.

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

- West to Central: Primarily West-to-Central interface, Dysinger East interface, and transmission facilities in the Central Zone.
- North to Central: Primarily transmission facilities within and out of the North Zone.
- Central to East: Primarily the Central-to-East interface.
- Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the New Scotland-to-Leeds Line, the Leeds-to-Pleasant Valley Line).
- NYC Lines in 345 kV system: Lines leading into and within the New York City 345 kV system.
- NYC Lines in Load Pockets: Lines leading into and within New York City load pockets and groups of lines to New York City 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 external interfaces.
- All Other: All of other line constraints and interfaces.

Figure A-48: Day-Ahead and Real-Time Congestion by Transmission Path
2015 – 2016

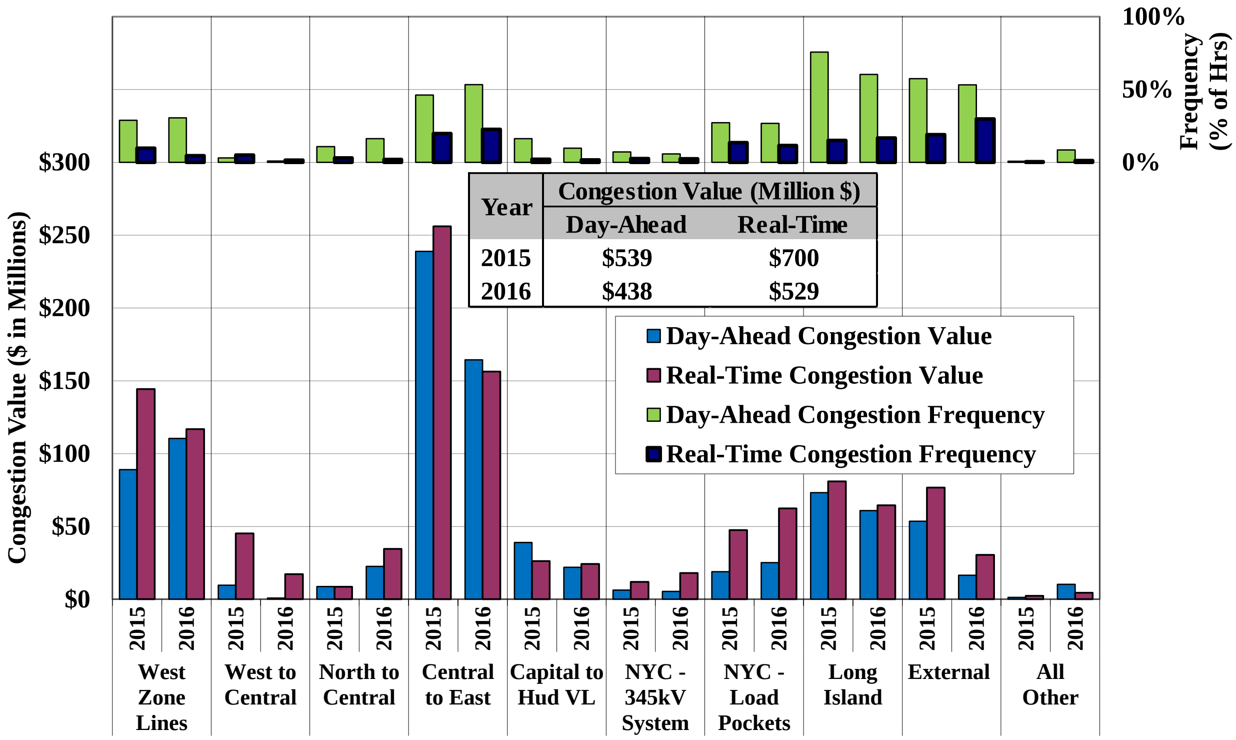


Figure A-49: Day-Ahead Congestion by Transmission Path
By Quarter, 2016

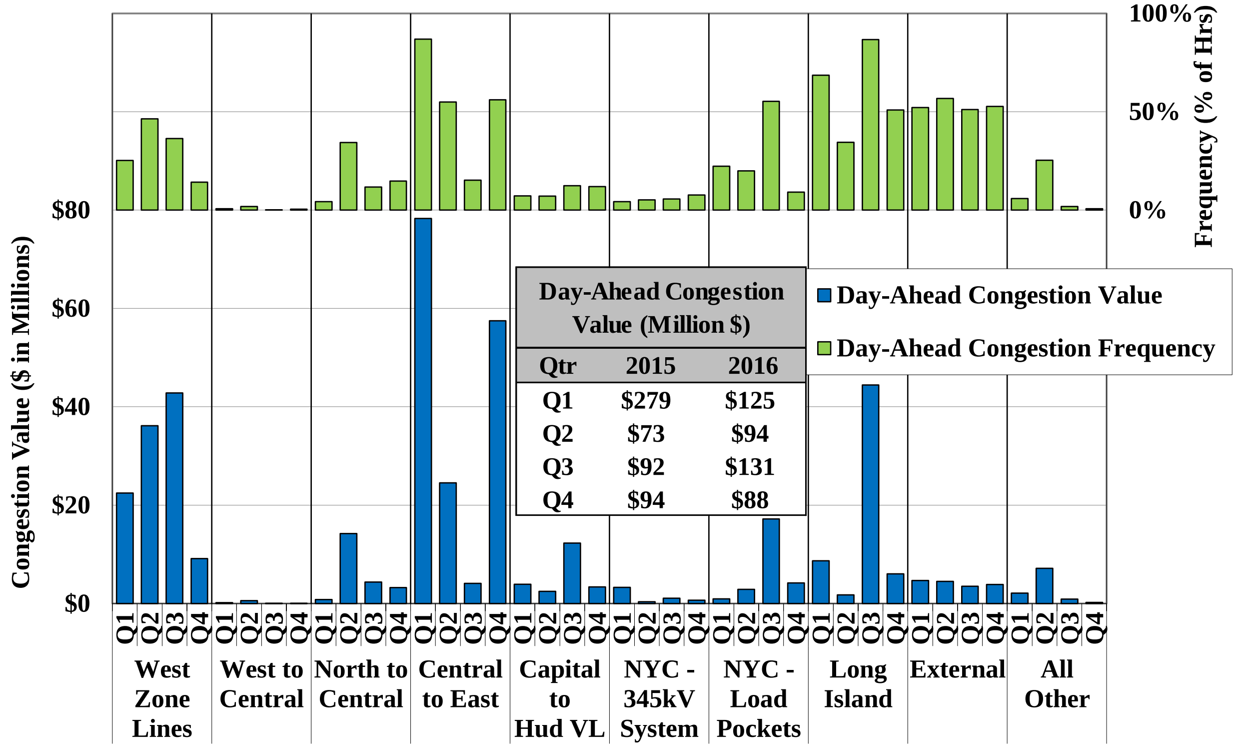
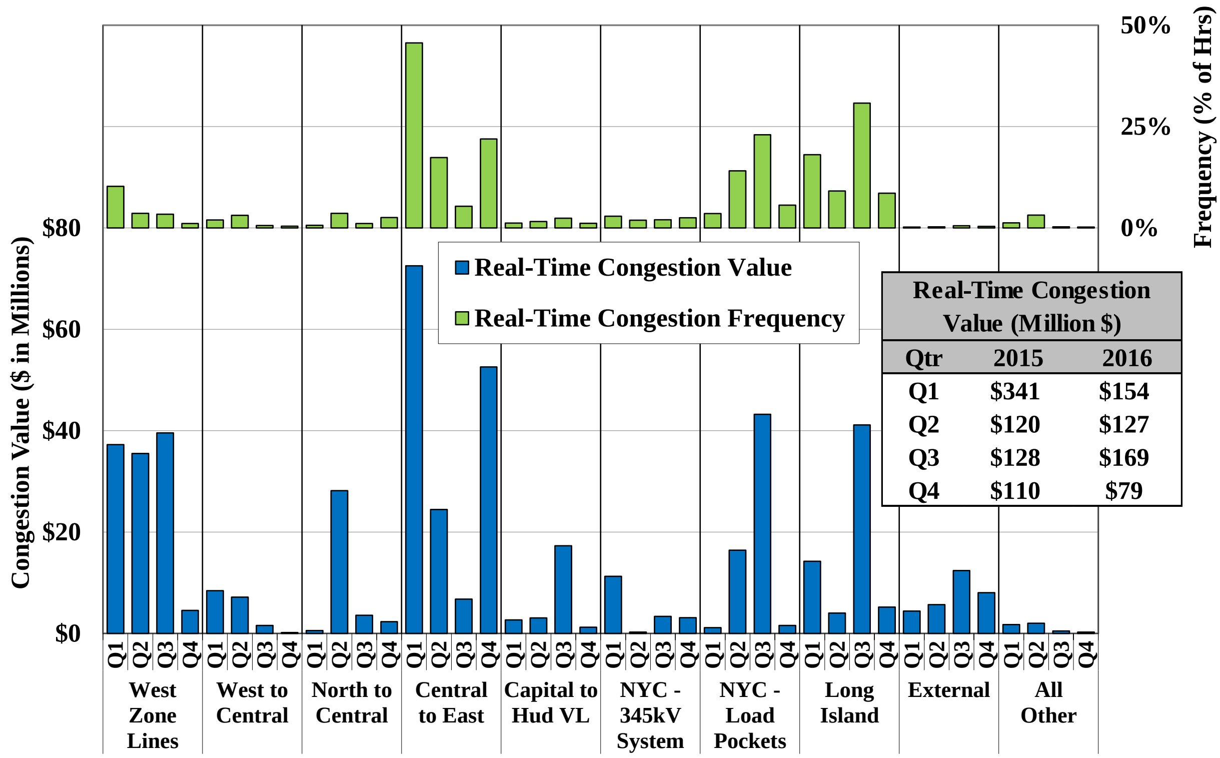


Figure A-50: Real-Time Congestion by Transmission Path
By Quarter, 2016



Key Observations: Congestion Revenues by Path

- Congestion across the Central-East interface accounted for the largest share of congestion value in both day-ahead and real-time markets in 2015 and 2016.
  - In 2016, the Central-East interface accounted for 37 percent of congestion value in the day-ahead market and 29 percent in the real-time market.
    - The majority of this congestion occurred in the first quarter and in December as a result of higher natural gas prices and larger gas price spreads between regions (which are typical in the winter season).
    - Transmission outages in January to May (taken for transmission work for the TOTS projects) and the outage of Marcy-New Scotland 345 kV line in December also contributed to higher congestion in these periods.
- Congestion on 230kV lines in the West Zone rose notably in recent years, accounting for the second largest share of congestion value in 2016.
  - There were notable changes from a year ago in the pattern of West Zone congestion, driven by various factors. The following increased congestion:
    - The implementation of GTDC in February 2016. (see Section V.F)
    - The mothball/retirement of the last Dunkirk unit in December 2015 and two Huntley units in March 2016, which had helped relieve West Zone congestion.
    - The implementation of a composite shift factor at Niagara plant in early May 2016. (see Section III.C)
    - Average clockwise loop flows around Lake Erie were higher in 2016.
  - The following factors helped reduce congestion in the West Zone:
    - The addition of two series reactors on the Packard-Huntley 230 kV #77 and #78 lines in mid-May 2016, which can be used to divert a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities.
    - The S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line were taken OOS during most of 2016 for 115kV transmission security, but these also reduced flows on frequently congested 230 kV lines.
- Transmission outages led to higher congestion in the North Zone in the second quarter and on Long Island in the third quarter (see Section III.E for more details).
  - The Moses-South interface was frequently used to manage congestion on some 115 kV transmission constraints during outage periods.
  - The magnitudes of congestion shadow prices on these constraints were increased by the implementation of GTDC in February 2016. (see Section V.F)

- Congestion was generally more severe in the real-time market than in the day-ahead market on some intra-zonal transmission paths. [213]
  - In the West Zone, congestion on 230kV facilities often rose in real-time because of several factors:
    - Lake Erie circulation, which is highly variable and difficult for the NYISO to predict, has a significant effect on flows across these transmission facilities. When clockwise circulation is higher than assumed in the day-ahead market and/or increases suddenly, it can result in severe real-time congestion that must be resolved with very costly resources. However, when clockwise circulation is lower than assumed, it usually results in no congestion. So, volatile circulation around Lake Erie tends to result in higher real-time congestion costs. The NYISO implemented two modifications at the end of June 2016 to better manage loop flows: a) a cap of 0 MW on the counter-clockwise loop flows in the RTC initialization; and b) a limit of 75 MW on the maximum change of loop flows between successive RTD initializations. [214] These modifications have helped reduce the severity of real-time congestion during periods with highly volatile loop flows.
    - Generation and imports upstream of these constraints is typically offered at much lower prices in the real-time market than in the day-ahead market, increasing congestion in real-time.
    - Redispatch options are often limited by parallel constraints on the 115 kV system, which are currently managed with Out-of-Merit dispatch instructions and by taking certain lines out of service to divert some power flows away from congested facilities (see Figure A-80).
  - In New York City, congestion into the Greenwood load pocket often rose in real-time because of:
    - The tendency for brief small transmission constraint violations to cause very high shadow prices in real-time; and
    - Scheduling of uneconomic gas turbines in the day-ahead market, which resulted from software changes that were made in conjunction with the introduction of the MIP (“Mixed Integer Program”) software in the day-ahead market. The NYISO made software modifications to address this issue in December 2016.
  - In Long Island, acute congestion often occurred in real-time as a result of short-term ramping limitation caused by:

213 The related inconsistencies between day-ahead and real-time LBMPs are evaluated in Appendix Section I.G. Factors that contribute to transient periods of extreme real-time congestion are evaluated in Appendix Section V.D.

214 See presentation “Lake Erie Loop Flow Modifications” by Tolu Dina at June 23, 2016 MIWG meeting.

– Large schedule changes in imports across the Scheduled Lines (i.e., Neptune, Cross Sound Cable, and the 1385 Line);

– Shut-down of gas turbines that would have been economic to remain online; and

– Sudden flow variations on PAR-controlled lines between Long Island and New York City (i.e., the 901 & 903 lines). Previously, the NYISO based its short-term forecast of flows on these lines on the last telemetered flow on the line. Starting in April 2016, the NYISO began to forecast the flows on these lines based on their scheduled flow, which has helped reduce real-time transitory high price spikes on Long Island, particularly in the Valley Stream load pocket.

C. West Zone Congestion and Niagara Generation

Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern New York. Besides many factors discussed above, this subsection discusses issues related to the modeling of the Niagara Power Plant that has had significant effects on congestion management in the West Zone.

The Niagara Power Plant has a total of 13 run-of-river and 12 pump-storage water turbines. Three run-of-river turbines are electrically connected to the 115 kV West Buses, four run-of-river turbines are connected to the 115 kV East Buses, and the rest six run-of-river turbines and twelve pump-storage turbines are connected to the 230 kV Buses. The units at the 115 kV Buses generally help relieve congestion on the most congested 230 kV transmission lines in the West Zone, while units at the 230 kV Buses tend to exacerbate these transmission constraints. However, these impacts are not considered optimally by the optimization engine that schedules generation at the Niagara plant. Instead, these 25 units are currently modeled as one single generator for pricing and dispatch. The marginal congestion impact of the Plant was measured based on: a) the generation shift factor of 230 kV units alone before May 4, 2016; and b) a composite generation shift factor that is based on the most recent telemetered distribution of the Plant output from all 230 kV and 115 kV units since May 4, 2016.[215] Often times, NYISO procedures use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion. These circumstances lead to events when the transmission system in the West Zone is not utilized as efficiently as possible.

Figure A-51 - Figure A-53 : West Zone Congestion and Niagara Generation

Figure A-51 illustrates the above-mentioned inefficiency by showing potential redispatch options for transmission constraints from different modeling of the Niagara Plant. The figure shows the redispatch options on a sample day (September 10, 2016) for the most frequently congested constraints in the West Zone: the Niagara-Packard and Packard-Sawyer 230 kV lines.

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215 Although the individual units are not considered in the pricing and dispatch component of RTD, they are considered in the Network Security Analysis ("NSA") portion of RTD. A presentation was provided by the NYISO on this issue at the April 5, 2016 Market Issues Working Group meeting: see *Niagara Generation Modeling Update*, presented by David Edelson.

The potential flow impact from dispatchable resources is measured based on their upper operating limits. The Import/Export category reflects the potential relief from 1,000 MW adjustments in PJM and Ontario DNI levels. The PAR category reflects the potential relief from making 260 MW adjustments in each of the L33 and L34 PARs, which allow a portion of the imports from Ontario to flow into the North Zone rather than the West Zone. Wind resources, which cannot be dispatched-up in real-time, are also shown in the figure for the purpose of illustrating their typical impact on the constraints (based on their actual output).

Figure A-51: Potential Redispatch Options for West Zone Congestion

September 10, 2016

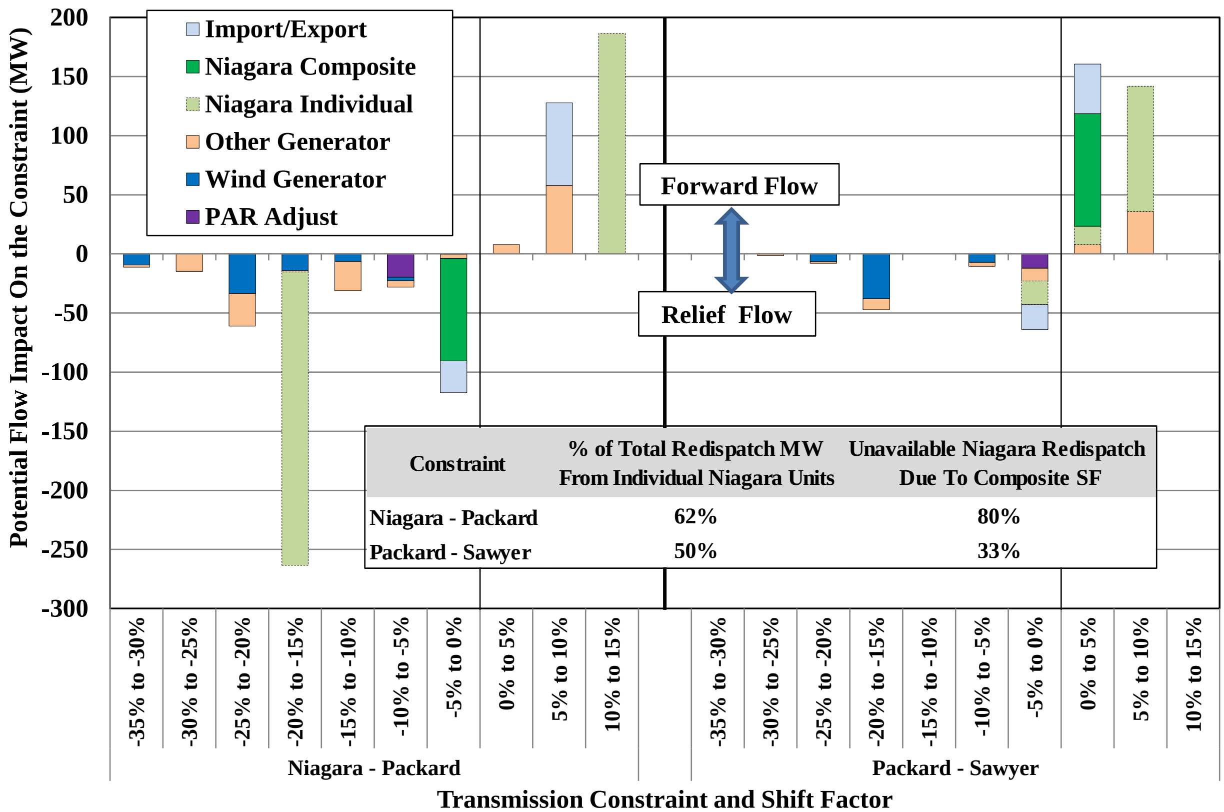


Figure A-52 illustrates how the two modeling assumptions (before and after May 4, 2016) related to the system impacts of the Niagara plant differ from the actual impacts of the plant. The scatter plots show the impact on constrained facilities in the West Zone in 2015 and 2016 (after May 4), where the horizontal axis shows the RTD model's assumed impact and the vertical axis reflects where output was actually increased (or decreased) at the plant (assuming perfect dispatch performance relative to the 5-minute signal). Hence, a point on the diagonal line indicates consistency between modeled impact and actual impact. The table summarizes the average absolute value for both quantities as well as the average differential between the modeled impact and the actual impact.

Figure A-52: Impact of Niagara Generation on West Zone Constraints
Modeled Impact versus Actual Impact, 2015-2016

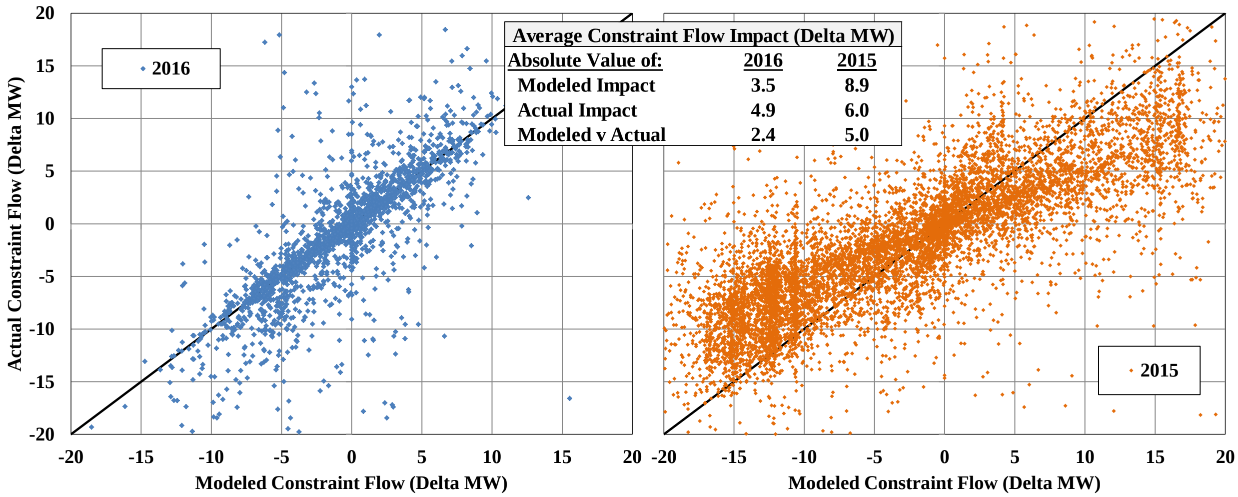
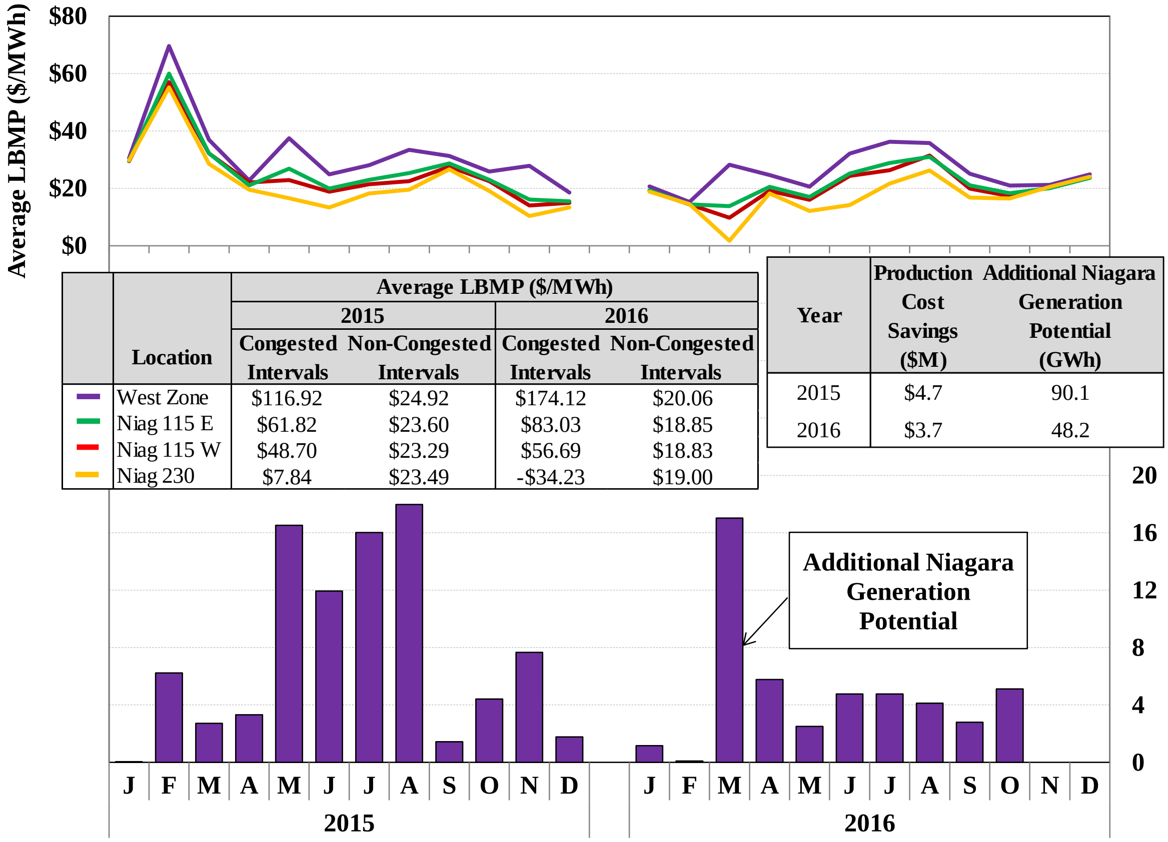


Figure A-53: Niagara LBMPs and Under-Utilization of 115 kV Circuits

Figure A-53 estimates the remaining benefits that might have occurred if the distribution of generation at Niagara was optimized in each month of 2015 and 2016 by showing:

- Production Cost Savings – Estimated savings from reducing congestion by shifting generation from 230kV units to 115kV units that have available head room at the Niagara plant.
- Additional Niagara Generation Potential – Additional Niagara generation (in MWhs) that would be deliverable from the entire plant if output from the 115kV units was maximized.
- Average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus – This illustrates the impact of shifting generation among individual Niagara units.

Figure A-53: Niagara LBMPs and Under-Utilization of 115 kV Circuits
By Month, 2015- 2016



Location	Average LBMP ($/MWh) 2015 Congested Intervals	2015 Non-Congested Intervals	2016 Congested Intervals	2016 Non-Congested Intervals
West Zone	$116.92	$24.92	$174.12	$20.06
Niag 115 E	$61.82	$23.60	$83.03	$18.85
Niag 115 W	$48.70	$23.29	$56.69	$18.83
Niag 230	$7.84	$23.49	-$34.23	$19.00

Year	Production Cost Savings ($M)	Additional Niagara Generation Potential (GWh)
2015	$4.7	90.1
2016	$3.7	48.2

Key Observations: West Zone Congestion and Niagara Generation

- Most potential redispatch (for the two most congested West Zone constraints) is at the Niagara plant, but a large portion is not available as the plant is dispatched as a single unit based either on a shift factor at the 230 kV bus or on a composite shift factor. Figure A-51 illustrates that:
  - If dispatched individually, Niagara units would account for 62 and 50 percent of potential redispatch options for managing congestion on the two key constraints in the West Zone. However, only 20 and 67 percent of these redispatch options are available when the plant is dispatched as a single unit based on a composite shift factor.
  - It is more difficult to manage congestion on the Niagara-Packard constraint due to much larger inconsistences between modeled and actual Niagara redispatch.
    - Operators often lower the Packard-Sawyer limit to prevent overloads on Niagara-Packard because the Packard-Sawyer constraint has more predictable effects on congestion. This further reduces the usable transfer capability in the West Zone.
- Figure A-52 shows that consistency between the modeled and actual impacts was poor for both old and new modeling approaches for the Niagara plant.

   - Although the average differential between modeled and actual impact is large relative to average modeled impact for both modeling approaches (2.4 v 3.5 MW in 2016, 5.0 v 8.9 MW in 2015), the average differential has been smaller under the new modeling approach.
   - In general, RTD over-estimated the impacts from re-dispatching Niagara under the old modeling approach, while RTD under-estimates the impacts under the new modeling approach.
- Although LBMPs at the Niagara 115 kV and 230 kV Buses were very similar when West Zone congestion was not present, LBMP differences were significant during periods of congestion.
   - West Zone 230 kV congestion occurred in roughly 10 and 5 percent of all real-time intervals in 2015 and 2016.
   - On average, LBMPs were $41 to $54/MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals in 2015 and $91 to $117/MWh higher in 2016.
   - Negative LBMPs at the 230 kV bus in 2016 suggest over-utilization of 230kV units at the Niagara plant.
- We estimate that if the 115kV circuits were fully utilized to relieve the 230kV constraints in the West Zone: [216]
   - Production costs would have been reduced by an additional $4.7 million in 2015 and $3.7 million in 2016 (assuming no changes in the constraint shadow costs).
      - However, this does not consider the capital upgrade costs required to fully optimize the resource.
   - An additional 90 and 48 GWh of Niagara generation would have been deliverable in 2015 and 2016.
      - This would have reduced LBMPs in other zones as well, although we have not estimated the effect on statewide average LBMPs.
- Nonetheless, the existing NYISO manual procedures that shift the distribution of generation at the Niagara plant (between 115kV and 230kV units) helped reduce congestion costs on days with congestion in the West Zone.

216 Note, these estimates under-state the true potential increase in deliverable generation and improvement in production costs for two reasons. First, our estimates do not consider the amount of additional water that is used when individual water turbines operate above or below the optimal operating point (i.e., where cubic feet of water per MWh is lowest). This is substantial during uncongested intervals when the 115kV generators are over-utilized by a manual dispatch instruction relative to the optimal operating point of the turbine. Second, our estimates do not consider the increase in production costs that results when the 230kV generators are over-utilized when their LBMP is negative.

D. Lake Erie Circulation and West Zone Congestion

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.

Phase angle regulators ("PARs") were installed at the interface between the MISO and IESO in April 2012 partly to control loop flows around Lake Erie. In general, these PARs are used to maintain loop flows at the MISO-IESO interface to less than 200 MW in either direction. Because of the configuration of surrounding systems, the volume and direction of loop flows at the MISO-IESO interface is comparable to the loop flows at the IESO-NYISO interface. The volume of loop flows has been reduced since the PARs were installed in 2012, but excursions outside the 200 MW band still occur on a daily basis, so loop flows continue to have significant effects on congestion patterns in the NYISO.

Figure A-54: Clockwise Loop Flows and West Zone Congestion

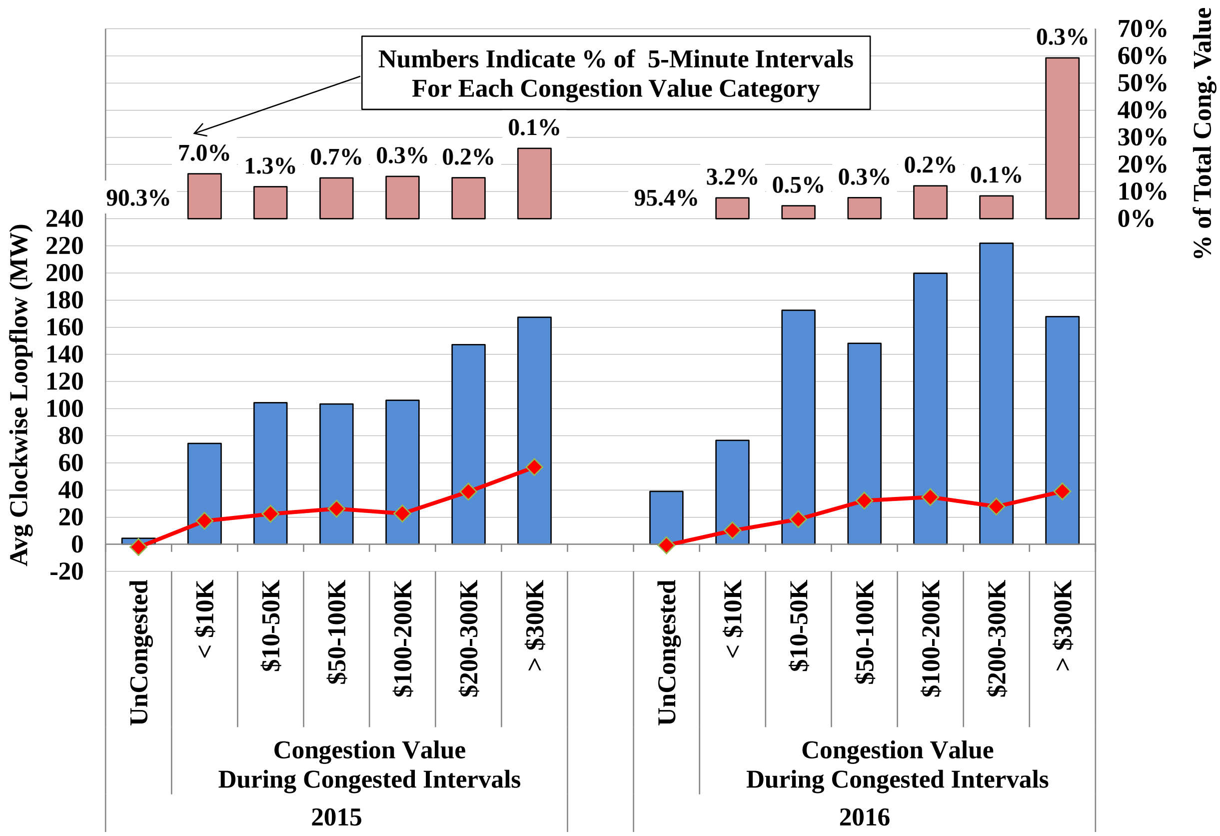
Unscheduled clockwise loop flows are primarily of concern in the congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths in Western New York, particularly in the West Zone.

Figure A-54 illustrates how and to what extent unscheduled loop flows affected congestion on West Zone 230 kV constraints in 2015 and 2016. The bottom portion of the chart shows the average amount of: (a) unscheduled loop flows (the blue bar); and (b) changes in unscheduled loop flows from the prior 5-minute interval (the red line) during the intervals when real-time congestion occurred on the West Zone 230 kV constraints. The congested intervals are grouped based on the following ranges of congestion values: (a) less than \$10,000; (b) between \$10,000 and \$50,000; (c) between \$50,000 and \$100,000; (d) between \$100,000 and \$200,000; (e) between \$200,000 and \$300,000; and (f) more than \$300,000.[217] For a comparison, these numbers are also shown for the intervals with no congestion.

In the top portion of the chart, the bar shows the percent of total congestion values that each congestion value group accounted for in each year of 2015 and 2016, and the number on top of each bar indicates how frequently each congestion value group occurred. For example, the chart shows that the congestion value was more than \$300,000 during 0.3 percent of all intervals in 2016, which accounted for nearly 60 percent of total congestion value in the West Zone.

217 The congestion value for each 230 kV constraint is calculated as (constraint flow × constraint shadow cost × interval duration). Then this is summed up for all binding 230 kV constraints for the same interval. For example, if a 900 MW line binds with a \$300 shadow price and a 700 MW line binds with a \$100 shadow price in a single 5-minute interval, the resulting congestion value is \$28,333 = (900MW × \$300/MWh + 700MW × \$100/MWh) * 0.083 hours.

Figure A-54: Clockwise Lake Erie Circulation and West Zone Congestion
2015 - 2016



Key Observations: Lake Erie Circulation and West Zone Congestion

- West Zone congestion was more prevalent when loop flows were clockwise or happened to swing rapidly in the clockwise direction.
  - A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of unscheduled loop flows and the occurrence of sudden changes from the prior interval.
- A small number of intervals accounted for relatively large share of the total congestion in both 2015 and 2016.
  - This has been accentuated by the implementation of the GTDC project in February 2016, which has resulted in higher congestion shadow prices during congested intervals.
  - In 2016, just 0.3 percent of intervals accounted for 60 percent of the total congestion value in the West Zone. This reinforces the importance of efforts to improve congestion management during periods of extreme congestion.

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

Congestion shortfalls generally occur as a result of inconsistent 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-55: 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.

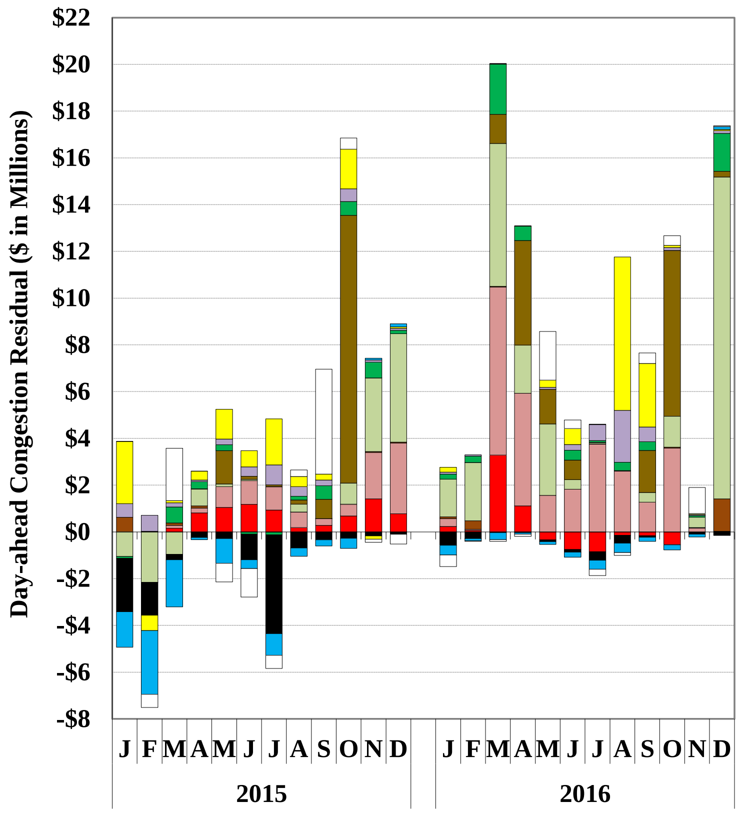
Figure A-55 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2015 and 2016. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- West Zone Lines: Transmission lines in the West Zone.
- North to Central: Transmission lines in the North Zone, the Moses-South Interface, and Marcy 765-Marcy 345 line.
- Central to East: Primarily the Central-East interface.
- New York City Lines: Lines leading into and within New York City.
- Long Island Lines: Lines leading into and within Long Island.
- External: Congestion related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

The figure also shows the shortfalls resulted from some unique factors separately from other reasons for select transmission paths.

- For West Zone lines, the figure shows separately the shortfalls resulted from differences in assumed generation at the Niagara 115 kV Buses between the TCC auction and the day-ahead market (labeled as “Niagara Modeling Assumption”).
- For the Central-East interface, the figure shows separately the shortfalls resulted from differences in assumed flows on the PAR controlled lines between New York and New Jersey (including Ramapo, ABC, and JK PARs) between the TCC auction and the day-ahead market.
- For Long Island lines, the figure shows separately the shortfalls resulted from:
  - Grandfathered TCCs (“GFTCC”) that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K); and
  - Differences in assumed schedules across the two PAR controlled lines between Lake Success and Valley Stream in Long Island and Jamaica in New York City (i.e., 901/903 lines) between the TCC auction and the day-ahead market.

Figure A-55: Day-Ahead Congestion Shortfalls
2015 – 2016



Category	Annual Shortfall ($M) 2015	Annual Shortfall ($M) 2016
West Zone Lines		
Niagara Modeling Assumption	$7.5	$1.8
Other Factors	$9.7	$27.2
Central to East		
Ramapo, ABC & JK PARs	$0.9	$1.9
Other Factors	$5.7	$31.7
North to Central	$14.1	$17.2
NYC Lines	$3.1	$6.2
Long Island Lines		
901/903 PARs	-$11.3	-$2.0
Excess GFTCC Allocations	$4.4	$4.3
Other Factors	$8.7	$10.6
External	-$9.6	-$2.4
All Other Facilities	$3.8	$3.4

Figure A-56: Balancing Congestion Revenue Shortfalls

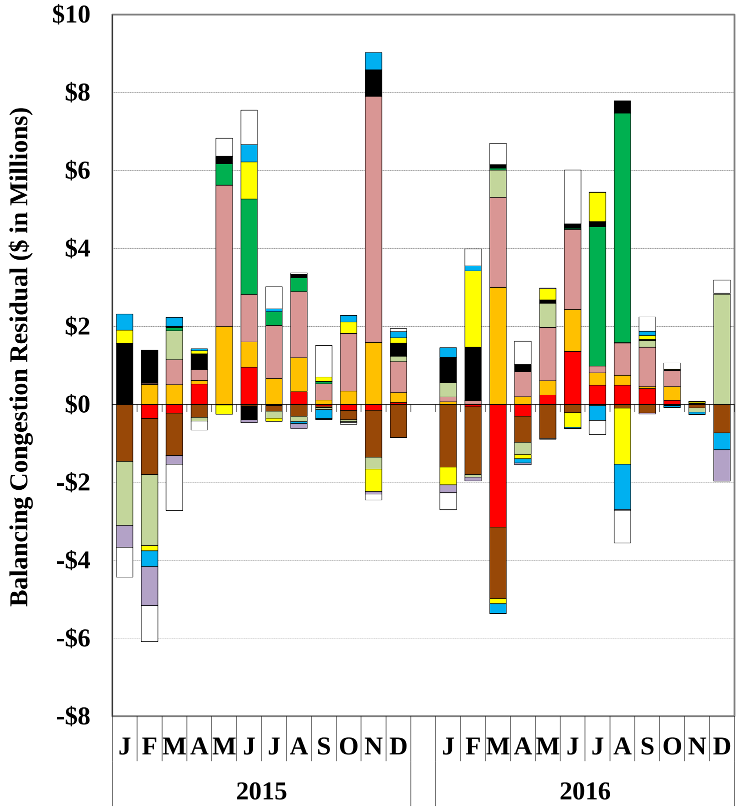
Like day-ahead congestion shortfalls, balancing congestion revenue shortfalls arise when day-ahead scheduled flows across a particular line or interface exceed its real-time transfer capability. When this occurs, the ISO must redispatch in real time by purchasing additional generation in the import-constrained 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. 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 also results in reduced transfer capability between the day-ahead market and real-time operation.
- 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. This includes flow adjustments on PAR-controlled lines that result from the Coordinated Congestion Management ("M2M") process between NYISO and PJM.
- 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.

Similar to Figure A-55, Figure A-56 shows balancing congestion shortfalls by transmission path or facility in each month of 2015 and 2016. For select transmission paths, the figure also shows the shortfalls resulted from some unique factors separately from other reasons. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-56: Balancing Congestion Shortfalls[218]
2015 – 2016



	Category	Annual Shortfall ($M) 2015	2016
	West Zone Lines		
	Niagara Modeling Assumption	$0.9	-$0.4
	Ramapo, ABC & JK PARs	$7.6	$5.7
	Other Factors	$17.9	$9.0
	Central to East		
	Ramapo, ABC & JK PARs	-$7.2	-$8.1
	Other Factors	-$3.4	$4.2
	Capital to HVL (TSAs)	$3.8	$9.5
	Long Island Lines		
	901/903 PARs	$3.8	$3.0
	Other Factors	$0.9	$0.7
	External	$1.3	-$2.0
	PJM M2M Payment	-$2.1	-$1.2
	All Other Facilities	-$0.5	$2.2

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled nearly $100 million in 2016, up 169 percent from 2015 primarily because of more costly transmission outages in 2016.
  - In 2016, roughly $66 million (or 66 percent) were allocated to responsible Transmission Owners for transmission outages.
- Nearly $34 million of shortfalls accrued on the Central-East interface, most of which was attributable to the following transmission outages:

218 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 before April 2014); 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.

- Multiple transmission lines were taken OOS from January to May to facilitate the completion of the TOTS projects, including:
  - a) The Fraser-Coopers 345 line was OOS from early January to early March;
  - b) The Edic-New Scotland 345 line was out of service in most of March;
  - c) The Marcy-Coopers 345 line was OOS in most of April;
  - d) The Edic-Fraser 345 line was OOS from late April to late May; and
  - e) The Ramapo-Rock Tavern 345 line was OOS in most of April and May.
- One Ramapo PAR was OOS from late June throughout the rest of the year.
- The Marcy-New Scotland 345 line was OOS in most of December, which reduced the interface transfer capability by up to 900 MW.

• The West Zone constraints accounted for $29 million of shortfalls in 2016.
  - Several facilities along the Niagara-Packard-Sawyer-Huntley path were out of service intermittently in during the year, accounting for roughly $11 million of shortfalls (mostly in March and April).
  - Inconsistences between the TCC auction and the day-ahead market in the assumed distribution of Niagara generation (230 kV vs. 115 kV) accounted for $2 million of shortfalls. [219]
    - The modeling change of the Niagara Plant on May 4, 2016 led to persistent surpluses (~$3 million), compared to persistent shortfalls before the change (~$5 million).
  - Of the remaining $16 million of shortfalls, a large portion was attributable to different loop flow assumptions between the TCC auction and the day-ahead market.
• Transmission constraints categorized as “North to Central” accounted for $17 million of shortfalls in 2016.
  - Nearly 45 percent of shortfalls accrued on the Moses-South interface on 10 days (including one week in October) during which one 765 kV transmission line was OOS and reduced the interface transfer capability by more than 2,000 MW. The Moses-South interface is typically utilized in order to secure 115kV facilities that are not modeled in the day-ahead and real-time market software.
  - Most of the remaining shortfalls accrued on one of the Marcy 765/345 kV lines when the parallel path was OOS on many days in April, May, September and October.
• Long Island lines accounted for $15 million of shortfalls in 2016.

219 This is categorized as “Niagara Modeling Assumption” under “West Zone Lines” in the figure.

- Most of these shortfalls accrued when the Y49 line was out of service from late May to early July and from early August to late September, which greatly reduced import capacity into Long Island.
- Additional $4 million of shortfalls resulted from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island. [220]
- The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) consistently caused congestion surpluses because of the differences in the schedule assumptions on these two lines between the TCC auction and the day-ahead market. [221]
  - The TCC auctions typically assumed a total of 286 MW flow from Long Island to New York City across the two lines while the day-ahead market assumed lower values—an average of 193 MW in that direction in 2015 and 222 MW in 2016.
  - Since flows from Long Island to New York City across these lines are generally uneconomic and raise production costs, reducing the assumed flow from the TCC auction to the day-ahead market led to significant surplus congestion revenue, which reinforces the notion that scheduling the 901 and 903 lines in an efficient manner would substantially reduce production costs.

Balancing Congestion Shortfalls

- Similar to 2015, the 230 kV transmission facilities in the West Zone accounted for the largest share of balancing congestion shortfalls in 2016.
  - The primary drivers were line deratings and unexpected changes in loop flows, which accounted for $9 million of shortfalls.
- TSA constraints accounted for over $9 million of shortfalls, most of which occurred on one day in July and two days in August.
  - Transfer capability into SENY was greatly reduced during TSA events, contributing to nearly $8 million of shortfalls.
  - Large schedule deviations on the ABC and JK lines on these days also contributed over $1 million of shortfalls.
  - TSA-related congestion shortfalls in 2016 were notably higher than in the prior two summers due in part to:
    - Higher load levels during TSA events this year; and
    - Less congestion relief from Ramapo PARs because of outages.

220 This is categorized as “Excess GFTCC Allocations” under “Long Island Lines” in the figure.

221 This is categorized as “901/903 PARs” under “Long Island Lines” in the figure.

- The operation of Ramapo PAR under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flowgates,
  - Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $8 million of surpluses (primarily from the Ramapo PAR) on the Central-East interface in 2016.
  - This, however, was offset by nearly $6 million of shortfalls on the West Zone lines (currently not under M2M JOA).
    - Nearly $5 million was attributable to large deviations on ABC/JK wheel (particularly under-delivery from NY to PJM on the JK lines).
    - Ramapo PAR accounted for roughly $1 million of shortfalls in 2016, notably lower than the $6 million in 2015. This was partly because the NYISO modified its operating practice in November 2015 to limit use of the Ramapo congestion coordination process to periods when the NYISO does not expect constraints in Western New York to be active. [222]

F. 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 October) or the Winter Capability Period (November to April), as 1-year products for two consecutive capability periods, and as 2-year products for four consecutive Capability Periods. Most transmission capability is auctioned as 6-month products. The Capability Period auctions consist of a series of rounds, in which a portion of the capability is offered, resulting in multiple TCC awards and clearing prices. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in these auctions.
- *Reconfiguration Auctions* – The NYISO conducts a Reconfiguration Auction once every month for the following month for which the TCC will be effective. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Reconfiguration Auction. Each monthly Reconfiguration Auction consists of only one round.

Figure A-57: TCC Cost and Profit by Auction Round and Path Type

Figure A-57 summarizes TCC cost and profit for the Winter 2015/16 and Summer 2016 Capability Periods (i.e., the 12-month period from November 2015 through October 2016). The

222 See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

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*.

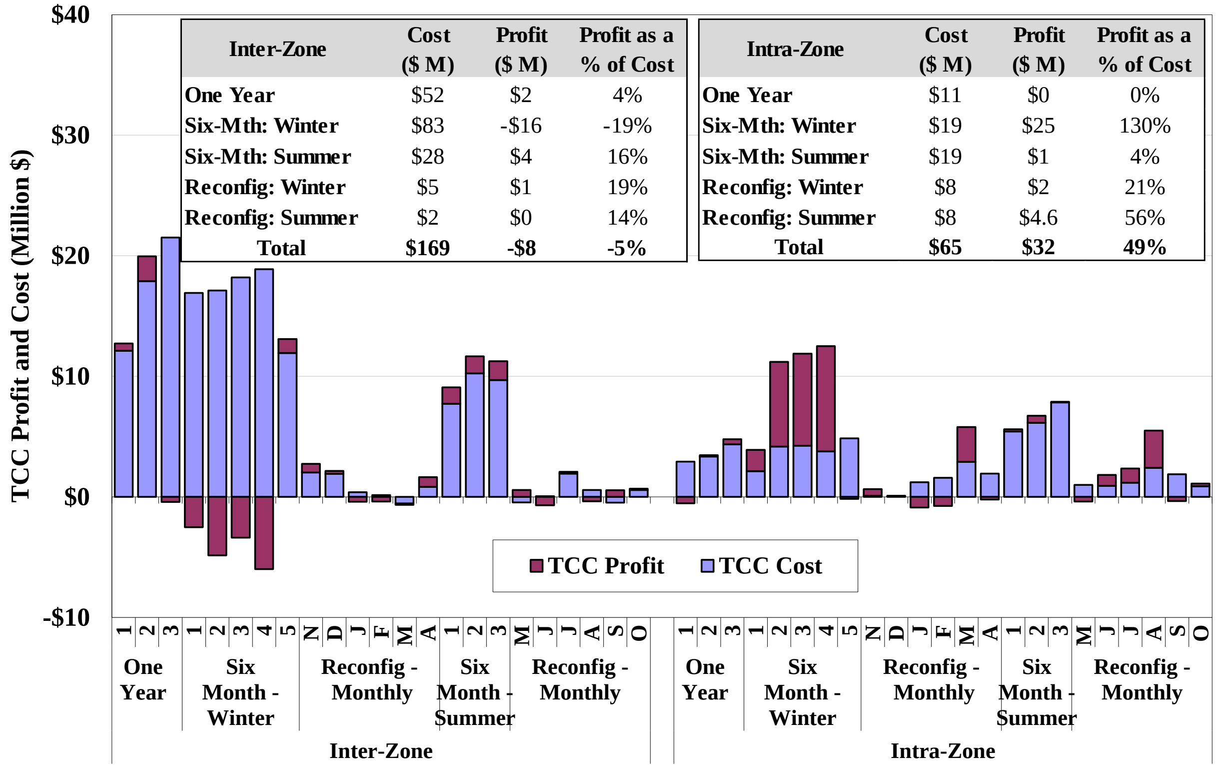
The figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) three rounds of one-year auctions for the exact same 12-month Capability Period; (b) five rounds of six-month auctions for the Winter 2015/16 Capability Period; (c) three rounds of six-month auctions for the Summer 2016 Capability Period; and (d) twelve reconfiguration auctions for each month of the 12-month Capability Period. The figure only evaluates the TCCs that were purchased by Market Participants in these auctions.

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.[223]

The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs. 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. The profitability is measured by the total TCC profit as a percentage of total TCC cost.

223 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 is 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. Components (a) and (c) belong to the intra-zone category and Component (b) belongs to inter-zone category.

Figure A-57: TCC Cost and Profit by Auction Round and Path Type
Winter 2015/16 and Summer 2016 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$52	$2	4%
Six-Mth: Winter	$83	-$16	-19%
Six-Mth: Summer	$28	$4	16%
Reconfig: Winter	$5	$1	19%
Reconfig: Summer	$2	$0	14%
Total	**$169**	**-$8**	**-5%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$11	$0	0%
Six-Mth: Winter	$19	$25	130%
Six-Mth: Summer	$19	$1	4%
Reconfig: Winter	$8	$2	21%
Reconfig: Summer	$8	$4.6	56%
Total	**$65**	**$32**	**49%**

Table A-1 & Table A-2: TCC Cost and Profit by Path

The following two tables compare TCC costs with TCC profits for both intra-zonal paths and inter-zonal paths during the Winter 2015/16 and Summer 2016 Capability Periods (i.e., the 12-month period from November 2015 through October 2016). Each pair of POI and POW represents all paths sourcing from the POI and sinking at the POW. Inter-zonal paths are represented by pairs with different POI and POW, while intra-zonal paths are represented by pairs with the same POI and POW. TCC costs and profits that are higher than $2 million are highlighted with green, while TCC costs and profits that are lower than -$2 million are highlighted with light red.

Table A-1: TCC Cost by Path
Winter 2015/16 and Summer 2016 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$34	-$7	-$11	-$1	$0	$0	$15	$0	$0	$0	$0	-$20	$0	$0	$0	**$10**
GENESE	$4	$0	$2	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	**$7**
CENTRL	$34	-$4	$9	-$1	-$1	$0	$24	$0	$0	$0	$0	$0	$0	$0	$0	**$62**
MHK VL	$16	-$1	$2	-$10	$0	$2	$2	$0	$0	$0	$0	$0	$0	$19	$0	**$29**
NORTH	$4	$1	$5	$15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$25**
CAPITL	$0	$0	$0	$0	$0	$13	-$5	$0	$0	$0	$0	$0	$0	$3	$0	**$11**
HUD VL	-$1	$0	-$1	$0	$0	$9	$1	$1	$1	$14	$0	$0	$0	$14	$0	**$37**
MILLWD	$0	$0	$0	$0	$0	$1	-$1	$0	$0	$1	$0	$0	$0	$0	$0	**$1**
DUNWOD	$0	$0	$0	$0	$0	$1	$0	$0	$0	$3	$1	$0	$0	$0	$0	**$4**
N.Y.C.	$0	$0	$0	$0	-$1	$0	-$2	$0	$0	$10	$1	$0	$0	$0	$0	**$8**
LONGIL	$0	$0	$0	$0	-$2	$0	$0	$0	$0	-$1	$7	$0	$0	$0	$0	**$3**
O H	$10	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$12**
H Q	$0	$0	$1	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$17**
NPX	$0	$0	$0	$0	$0	$0	-$2	$0	$0	$0	$0	$0	$0	$0	$0	**-$2**
PJM	$0	$0	$0	$0	$0	$0	$7	$0	$0	$0	$0	$0	$0	$3	$0	**$10**
Total	**$102**	**-$10**	**$8**	**$19**	**-$4**	**$26**	**$39**	**$1**	**$0**	**$27**	**$10**	**-$21**	**$0**	**$39**	**-$1**	**$235**

Table A-2: TCC Profit by Path
Winter 2015/16 and Summer 2016 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$18	-$12	-$6	-$2	$0	$0	-$12	$0	$0	$0	$0	$0	$0	$0	$0	**-$15**
GENESE	$4	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
CENTRL	$18	$1	-$4	$0	$0	$0	-$6	$0	$0	$0	$0	$0	$0	$0	$0	**$9**
MHK VL	$10	$1	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$7	$0	**$6**
NORTH	$2	$1	$2	$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$11**
CAPITL	$0	$0	$0	$0	$0	-$4	$3	$0	$0	$0	$0	$0	$0	-$3	$0	**-$4**
HUD VL	$2	$0	$0	$0	$0	-$4	-$1	$0	$0	-$5	$0	$0	$0	-$9	-$1	**-$18**
MILLWD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	**-$1**
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3	$0	$0	$0	$0	$0	**$4**
LONGIL	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$16	$0	$0	$0	$0	**$15**
O H	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$6**
H Q	$0	$0	$0	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$9**
NPX	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	**$1**
PJM	$0	$0	$0	$0	$0	$0	-$2	$0	$0	$0	$0	$0	$0	-$1	$0	**-$3**
Total	**$59**	**-$9**	**-$9**	**$15**	**-$1**	**-$8**	**-$18**	**$0**	**$0**	**-$3**	**$17**	**$1**	**$0**	**-$20**	**-$1**	**$24**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a total profit of $24 million in the TCC auctions during the reporting 12-month period (November 2015 to October 2016), resulting in an average profitability (profit as a percent of TCC cost) of 10 percent. [224]
- TCC buyers have netted sizable profit on transmission paths sinking at the West Zone in the recent years because of higher-than-anticipated congestion in this area (for reasons discussed in Section III.B).

224 The reported profits exclude profits and losses from TCC sellers (i.e., firms that initially purchased TCCs and then sold back a portion in a subsequent auction). In addition, purchases in the TCC auctions that include months outside the evaluated 12-month period are not included as well. Therefore, this evaluation does not include any two-year TCC auctions nor the two one-year TCC auctions that were conducted in the Spring of 2015 and 2016. This is because it is not possible to identify the portion of the purchase cost for such a TCC that was based on its expected value during the period from November 2015 to October 2016.

- In 2016, TCC buyers spent $102 million (44 percent of total purchase costs) on these paths and netted a $59 million of profit.
- These were significantly higher than the $28 million of purchase costs and $25 million of profit in the prior 12-month period.

- TCC purchase costs on paths along the transmission corridor from PJM to Hudson Valley Zone to New England fell substantially from $181 in 2015 to $24 million in 2016.
  - This followed the notable loss of $105 million on these paths in 2015 (for the reasons detailed in our 2015 SOM report).
  - TCC buyers netted a $12 million loss in 2016 as well.
    - Day-ahead congestion between areas across the Central-East interface was well below the TCC prices during the winter months as mild winter weather led to much lower natural gas prices and lower load levels (relative to the prior winter).
- TCC buyers netted a $16 million profit on a $7 million purchase on Long Island because of much higher-than-anticipated congestion in the third quarter of 2016.
  - The Y49 line (i.e., Dunwodie-Shore Rd) outage reduced imports from upstate during most of the quarter; and
  - The 677 line (i.e., Northport-Pilgrim) derating led to frequent congestion from Northport to other areas of Long Island throughout the quarter.

G. Potential Design of Financial Transmission Rights for PAR Operation

This subsection describes how a financial right could be created to compensate ConEd if the lines between NYC and Long Island were scheduled efficiently (rather than according to a fixed schedule) in accordance with Recommendation #2012-8. An efficient financial right should compensate ConEd: (a) in accordance with the marginal production cost savings that result from efficient scheduling, and (b) in a manner that is revenue adequate such that the financial right should not result in any uplift for NYISO customers. Note, this new financial transmission right would not alter the TCCs possessed by any market party.

Concept for Financial Transmission Right

An efficient financial right should compensate ConEd for the quantity of congestion relief provided at a price that reflects the marginal cost of relieving congestion on each flow gate in the day-ahead and real-time markets. These are the same principles upon which generators are paid and load customers are charged. Hence, a transmission right holder should be paid:

DAM Payment =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}[-DAM\ SF_{l,c} \times DAM\ SP_c]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}[-RTM\ SF_{l,c} \times RTM\ SP_c]\right)$$

Total Payment = DAM Payment + RTM Payment, where a negative payment would result in a charge to ConEd. To illustrate, suppose there is congestion in the DAM on the interface from upstate to Long Island (Y50 Line), from upstate to NYC (Dunwoodie), and into the Valley Stream load pocket (262 Line) while the 901 Line flows are reduced below the contract amount:

- TCC MW_{901} = 96 MW
- DAM MW_{901} = 60 MW
- DAM SP_{Y50} = \$10/MWh
- DAM $SP_{Dunwoodie}$ = \$5/MWh
- DAM SP_{262} = \$15/MWh
- DAM $SF_{901, Y50}$ = 100%
- DAM $SF_{901, Dunwoodie}$ = -100%
- DAM $SF_{901, 262}$ = 100%
- DAM $Payment_{901}$ = \$720 per hour = (60 MW – 96 MW) x {(-100% x \$10/MWh) + (100% x \$5/MWh) + (-100% x \$15/MWh)}

Since DAM payments are made for deviations from the TCC modeling assumptions, the new financial transmission right would not alter the TCCs possessed by any market party.

Revenue Adequacy

Just as the LBMP compensation to generators is generally revenue adequate, the new financial transmission right would also be revenue adequate. This is illustrated by the following scenarios:

- Basecase Scenario – Provides an example of the current market rules where the NYISO receives revenues from loads that exceed payments to generators, thereby contributing to DAM congestion revenues.
- PAR Relief Scenario – Shows how a PAR-controlled line could be used to reduce congestion, allowing the owner of the line to be compensated without increasing uplift from DAMCRs.
- PAR Loading Scenario – Shows how the owner of the line would be charged if the DAM schedule increased congestion relative to the TCC schedule assumption.

These scenarios use a simplified four node network, including: Upstate, NYC, Valley Stream, and Rest of Long Island. The four nodes are interconnected by four interfaces:

- The Dunwoodie interface from Upstate to NYC,
- The Y50 Line from Upstate to Rest of Long Island,

- The 262 Line from Rest of Long Island to Valley Stream, and
- The PAR-controlled 901 Line from Valley Stream to NYC.

For simplicity, the 901 Line contract amount that is used in the TCC auction is rounded to 100 MW.

The Base Case Scenario shows that a net of $22,500 of DAM congestion revenue is collected from scheduling by generators and loads. The table also shows the amount of DAM congestion revenue that accrues on each constrained facility. In this example, DAMCR equals $0 because the flows on each constrained facility are equal to the capability/assumption in the TCC model. Since the 901 Line contract moves power from a high LBMP area to a low LBMP area, it reduces congestion revenue by $2,000, but it does not cause DAMCR because it is consistent with the TCC auction.

The PAR Relief Scenario shows that if the 901 Line flow is reduced from 100 MW to 10 MW, it reduces the generation needed in Valley Stream and increases generation in NYC, reducing overall production costs by $1,800 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $1,800 of additional congestion revenues are collected. The collection of additional congestion revenues allows the NYISO to compensate ConEd $1,800 for the PAR adjustment, and DAMCR remains at $0.

The PAR Relief Scenario shows that if the 901 Line flow is increased from 100 MW to 120 MW, it increases the generation needed in Valley Stream and reduces generation in NYC, increasing overall production costs by $400 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $400 less congestion revenue is collected. The collection of less congestion revenue requires the NYISO to charge ConEd $400 for exceeding the contract amount, and DAMCR remains at $0.

BASECASE SCENARIO

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1900	$120,000	$57,000
	Valley Stream	$50	350	150	$17,500	$7,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,500
	Net (Gen minus Load)			0		$22,500

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	Total			$22,500
	DAMCR (Gen minus Load minus Congestion)			$0

PAR RELIEF SCENARIO (901 Line Flow Reduced from 100 MW to 10 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1990	$120,000	$59,700
	Valley Stream	$50	350	60	$17,500	$3,000
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$450,700
	Net (Gen minus Load)			0		$24,300

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	-90	$1,800
	Total			$24,300
	DAMCR (Gen minus Load minus Congestion)			$0

PAR LOADING SCENARIO (901 Line Flow Increased from 100 MW to 120 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1880	$120,000	$56,400
	Valley Stream	$50	350	170	$17,500	$8,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,900
	Net (Gen minus Load)			0		$22,100

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	20	-$400
	Total			$22,100
	DAMCR (Gen minus Load minus Congestion)			$0

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 five controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, and the Neptune Cable. The controllable lines are collectively able to import nearly 2.2 GW directly to downstate areas.[225,226] 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;
- Convergence of prices between New York and neighboring control areas; and
- The efficiency of Coordinated Transaction Scheduling.

225 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. The Hudson Transmission Project ("HTP Line") connects New York City to New Jersey with a transfer capability of 660 MW, which began its normal operation in June 2013.

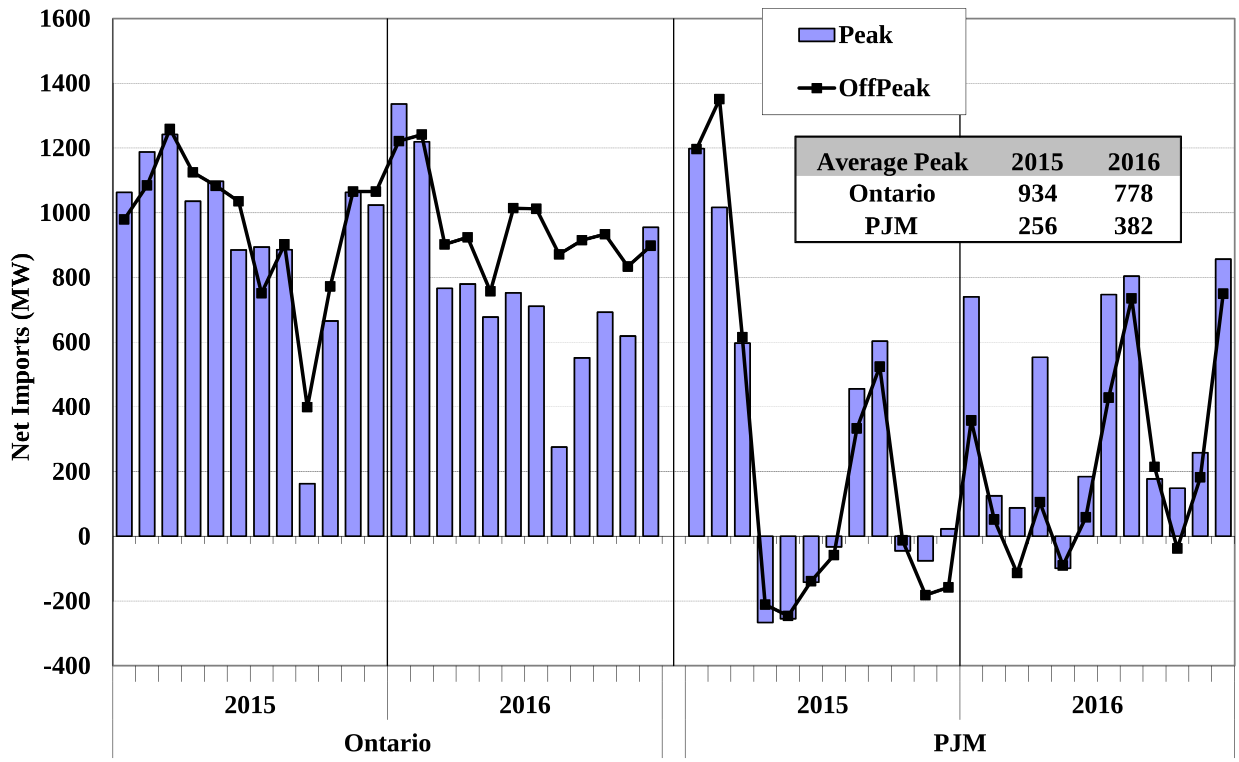
226 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the "Dennison Scheduled Line" and which is scheduled separately from the primary interface between New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

A. Summary of Scheduled Imports and Exports

Figure A-58 to Figure A-61 : Average Net Imports from Ontario, PJM, Quebec, and New England

The following four figures summarize the net scheduled interchanges between New York and neighboring control areas in 2015 and 2016. 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-58, the primary interfaces with Quebec and New England in Figure A-59, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-60 and Figure A-61.

Figure A-58: Monthly Average Net Imports from Ontario and PJM
2015 – 2016



Average Peak	2015	2016
Ontario	934	778
PJM	256	382

Figure A-59: Monthly Average Net Imports from Quebec and New England
2015 – 2016

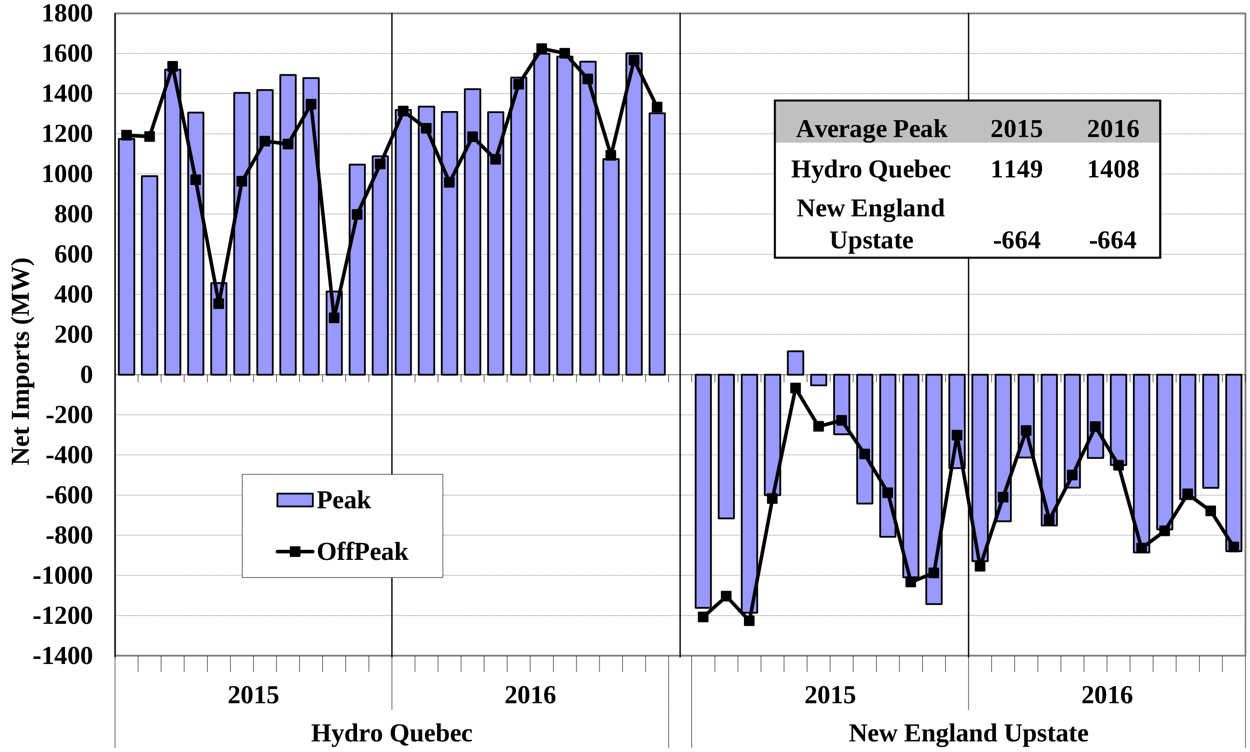


Figure A-60: Monthly Average Net Imports into New York City
2015 – 2016

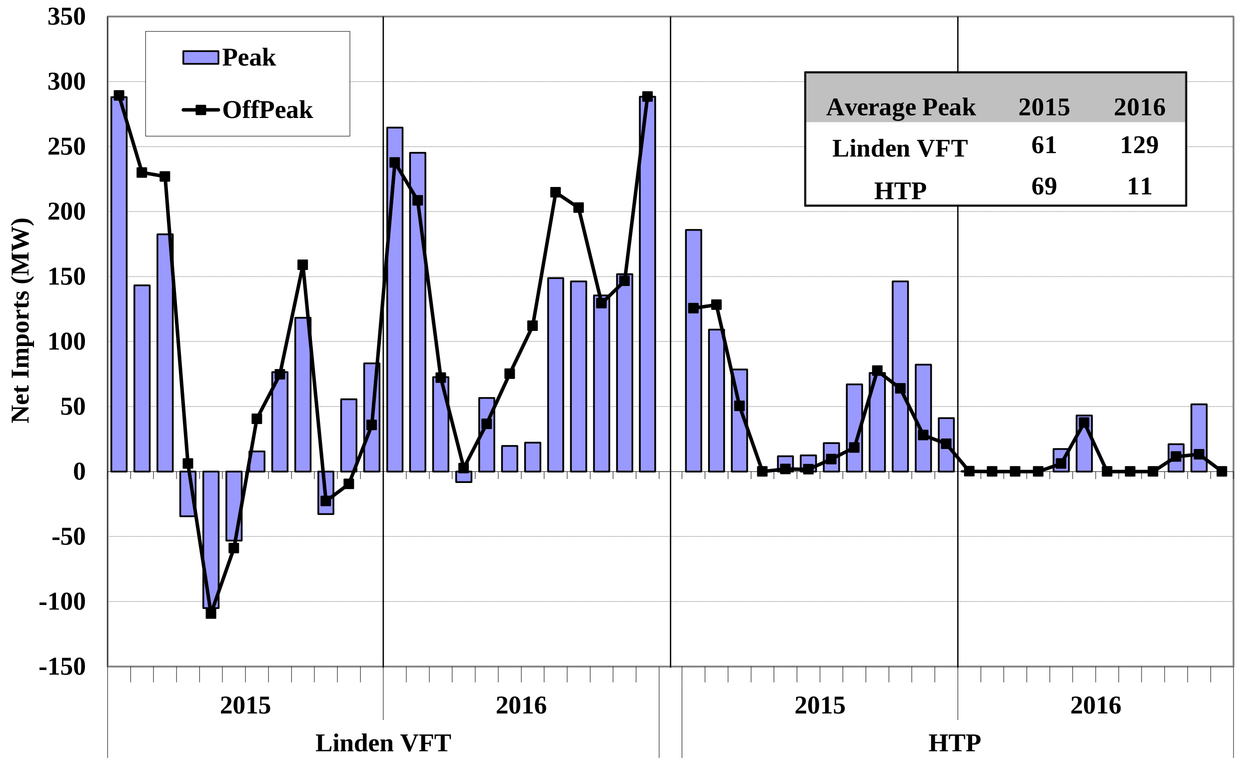
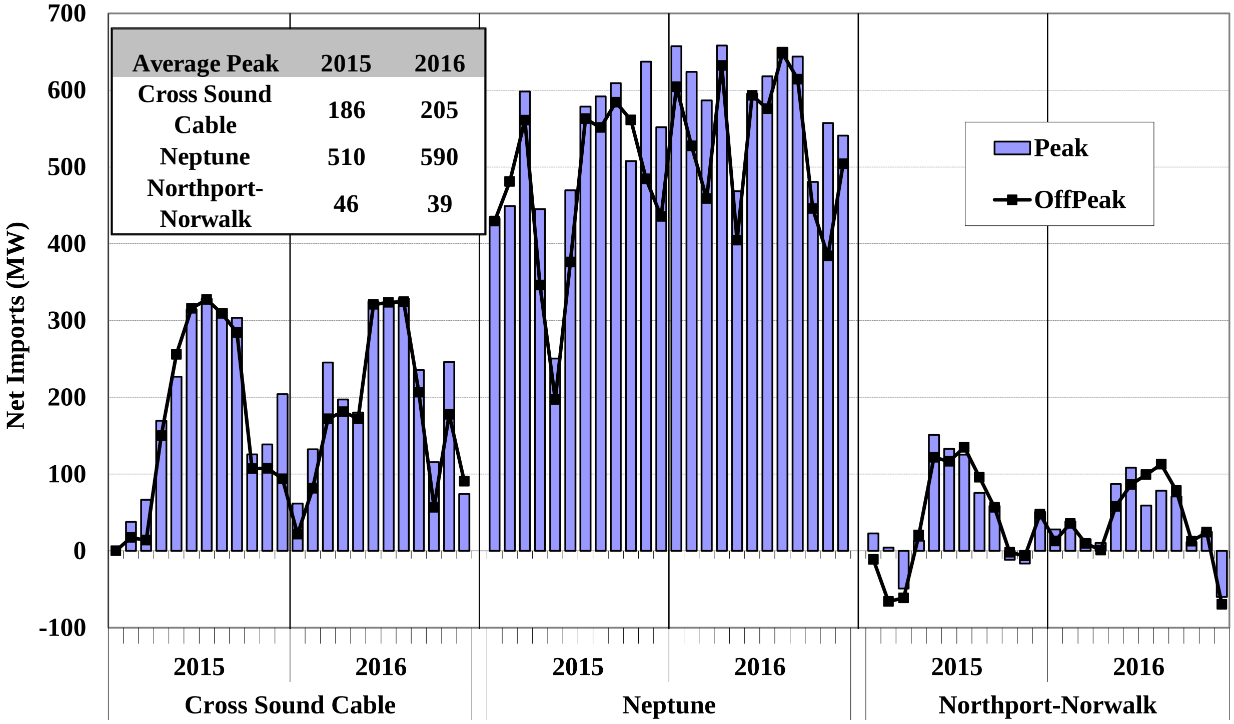


Figure A-61: Monthly Average Net Imports into Long Island
2015 – 2016



Key Observations: Average Net Imports

- Average net imports from neighboring areas across the primary interfaces increased 14 percent from 1,675 MW in 2015 to 1,905 in 2016 during the peak hours.
  - Net imports from HQ averaged roughly 1,410 MW, up 23 percent from 2015 and accounting for 74 percent of net imports across the primary interfaces in 2016.
    - Variations in HQ imports normally reflect transmission outages on the interface.
    - The increase in 2016 was due largely to fewer transmission outages (unusually low imports in May and October 2015 resulted from lengthy interface outages).
  - Average net imports from Ontario fell 17 percent from 2015 to 2016.
    - The reduction reflected import transfer limitations on the interface and West Zone congestion that leads to low clearing prices for Ontario imports (see Section III.C in the Appendix).
  - Net imports from PJM and New England across their primary interfaces varied widely by month. These variations were correlated with variations in gas price spreads between these regions. For example,
    - New York normally has higher net imports from PJM and higher net exports to New England in the winter season, consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged about 835 MW during peak hours in 2016, up 13 percent from 2015.
  - The Neptune Cable was normally fully scheduled. Variations in net imports typically are caused by transmission outages. The increase in 2016 reflected fewer transmission outages.
  - Scheduling pattern across the Cross Sound Cable and the 1385 line varied in a manner similar to the scheduling pattern across the primary New England interface, driven by similar factors.
  - Imports over the three controllable interfaces account for a large share of the supply to Long Island, serving roughly 30 percent of the load in Long Island in both 2015 and 2016.
- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged roughly 140 MW during peak hours in 2016, up modestly from the prior year.
  - Scheduling patterns across the two interfaces were generally consistent with the scheduling pattern across the primary PJM interface, driven by similar factors.

B. Price Convergence and Efficient Scheduling with Adjacent Markets

The performance of New York's wholesale electricity markets depends not only on the efficient use of internal resources, but also on the efficient use of transmission interfaces between New York and neighboring control areas. Trading between neighboring markets tends to bring prices together as participants arbitrage price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. A lack of price convergence indicates that resources are being used inefficiently, as higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region. Efficient scheduling is particularly important during shortages when flows between regions have the largest economic and reliability consequences. Moreover, efficient scheduling can also alleviate over-generation conditions that can lead to negative price spikes.

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

- Market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible.
- Differences in scheduling procedures and market timing 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-62: Price Convergence Between New York and Adjacent Markets

Figure A-62 evaluates scheduling between New York and adjacent RTO markets across interfaces with open scheduling. The Neptune Cable, the Linden VFT Line, the HTP Line, and the Cross Sound Cable are omitted because these are Designated Scheduled Lines and 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-62 summarizes price differences between New York and neighboring markets during unconstrained hours in 2016. 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-62: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2016

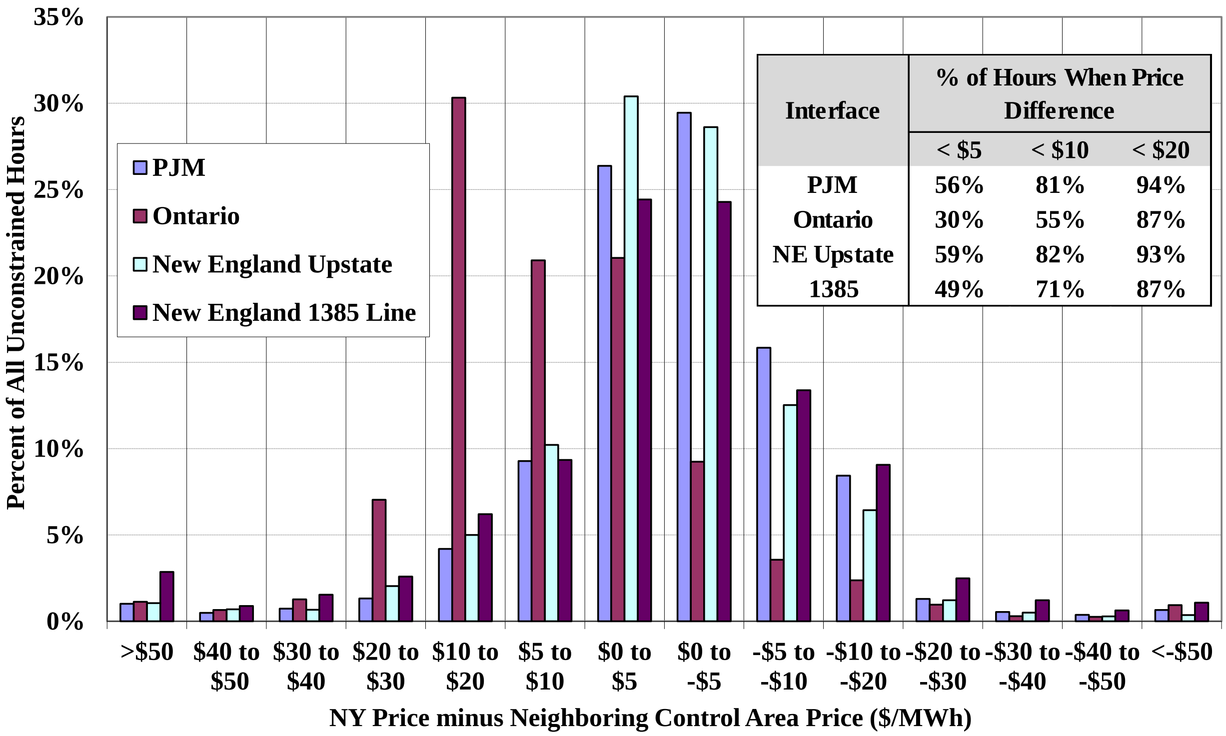


Table A-1: Efficiency of Inter-Market Scheduling

Table A-1 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2016. It evaluates transaction schedules and clearing prices between New York and the three markets across the three primary interfaces and five scheduled lines (i.e., the 1385 Line, the Cross Sound Cable, the Neptune Cable, the HTP Line, and the Linden VFT interface).

The table shows the following quantities:

- Average hourly flows between neighboring markets and New York. A positive number indicates a net import from neighboring areas to New York.
- Average 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.
- 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).
- The estimated production cost savings that result from the flows across each interface. The estimated production cost savings in each hour is based on the price difference across the interface multiplied by the scheduled power flow across the interface. [227]

The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market. So, this analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[228] However, for Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market.

Table A-1 evaluates 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.

227 For example, if 100 MW flows from PJM to New York across its primary interface during one hour, the price in PJM is $50 per MWh, and the price in New York 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 to ramp down and be replaced by a $50 per MWh resource in PJM. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

228 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-1: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2016

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Free-flowing Ties								
New England	-698	$0.56	45%	-$2	52	$1.30	59%	$7
Ontario					871	$7.73	81%	$61
PJM	292	$0.17	69%	$7	5	$0.09	63%	$5
Controllable Ties								
1385 Line	70	$1.14	66%	$2	-31	$0.53	53%	$1
Cross Sound Cable	191	$4.58	73%	$12	-1	$2.83	55%	$0.1
Neptune	568	$7.95	89%	$41	-8	$6.83	59%	$0.5
HTP	7	$3.38	82%	$0.1	2	$3.78	64%	$0.2
Linden VFT	93	$3.56	79%	$6	44	$3.21	67%	$3

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 unconstrained hours (6 to 13 percent) had price differences exceeding $20/MWh for every interface in 2016.
- Transactions scheduled between Ontario and New York flowed in the efficient direction in 81 percent of hours during 2016, significantly higher than on the free-flowing interfaces with PJM and New England.
  - As a result, a total of $61 million in production cost savings was achieved across the Ontario interface in 2016, higher than the combined savings of $17 million over the PJM and New England free-flowing ties.
    - This was partly due to the fact that the price on the New York side was higher by an average of nearly $8/MWh in 2016 (compared to an average of less than $1.3/MWh across the PJM and New England free-flowing interfaces).
  - In many hours, additional Ontario imports were limited by the transfer capability of the Ontario-to-New York interface, the congestion on the 230 kV system in the West Zone, and/or the relatively high charges assessed to export transactions ($3 to $4/MWh in 2016).
- In the day-ahead market, the share of hours scheduled in the efficient direction was higher over the controllable lines than over the free-flowing ties, reflecting generally less uncertainty in predicting price differences across these controllable lines in 2016.
- Real-time adjustments in flows were generally more frequent across the free-flowing ties, since market participants generally responded to real-time price variations by increasing net flows into the higher-prices region across these ties.

- A total of $12 million in real-time production cost savings was achieved in 2016 from the real-time adjustments over the PJM and New England free-flowing interfaces.

- Overall, 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 effective coordination among schedulers, and the other costs and risks that interfere with efficient interchange scheduling.

C. Evaluation of Coordinated Transaction Scheduling

Coordination Transaction Scheduling ("CTS") is a novel market design concept whereby two wholesale market operators exchange information about their internal prices shortly before real-time and this information is used to assist market participants in scheduling external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the hourly LBMP-based scheduling system:

- CTS bids are evaluated relative to the adjacent ISO's short-term forecast of prices, while the previous system required bidders to forecast prices in the adjacent market.
- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established up to 105 minutes in advance, while schedules are now determined less than 30 minutes ahead when more accurate system information is available.
- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

The CTS was first implemented with PJM on November 4, 2014 and then with ISO-NE on December 15, 2015. It is important to evaluate the performance of CTS on an on-going basis so that the process can be made to work as efficiently as possible.

Figure A-63: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

The first analysis examines the trading volumes of CTS transactions in 2016. In particular, Figure A-63 shows the average amount of CTS transactions at the primary PJM and New England interfaces during peak hours (i.e., HB 7 to 22) in each month of 2016. Positive numbers indicate import offers to New York and negative numbers represent export bids to PJM or New England. Stacked bars show the average quantities of price-sensitive CTS bids (bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis) for the following three price ranges: (a) between -$10 and $5/MWh; (b) between $5 and $10/MWh; and (c) between $10 and $20/MWh.[229] The traditional LBMP-based bids still co-

[229] RTC evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the bid price and (b) PJM's or NE's forecast marginal price. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to: (a) PJM's or NE's forecast marginal price less (b) the bid price.

exist with the CTS bids at the PJM interface (unlike the primary New England interface where only CTS bids are allowed). To make a fair comparison between the two primary interfaces, LBMP-based bids at the PJM interface are converted to equivalent CTS bids and are shown in the figure as well. The equivalent CTS bids are constructed as:

- Equivalent CTS bid to import = LBMP-based import offer – PJM Forecast Price
- Equivalent CTS bid to export = PJM Forecast Price – LBMP-based export bid

The two black lines in the chart indicate the average scheduled price-sensitive CTS imports and exports (including LBMP-based bids) in each month. The table in the figure summarizes for the two CTS-enabled interfaces: a) the average amount of price-sensitive CTS bids with low offer prices, which are either less than $5/MWh or between $5 and $10/MWh; and b) the average cleared CTS bids in the months of December 2015 to February 2016. Both imports and exports are included in these numbers, which also include the equivalent CTS transactions that are converted from LBMP-based transactions.

Figure A-63: Price-Sensitive Real-Time Transaction Bids and Offers by Month

PJM and NE Primary Interfaces

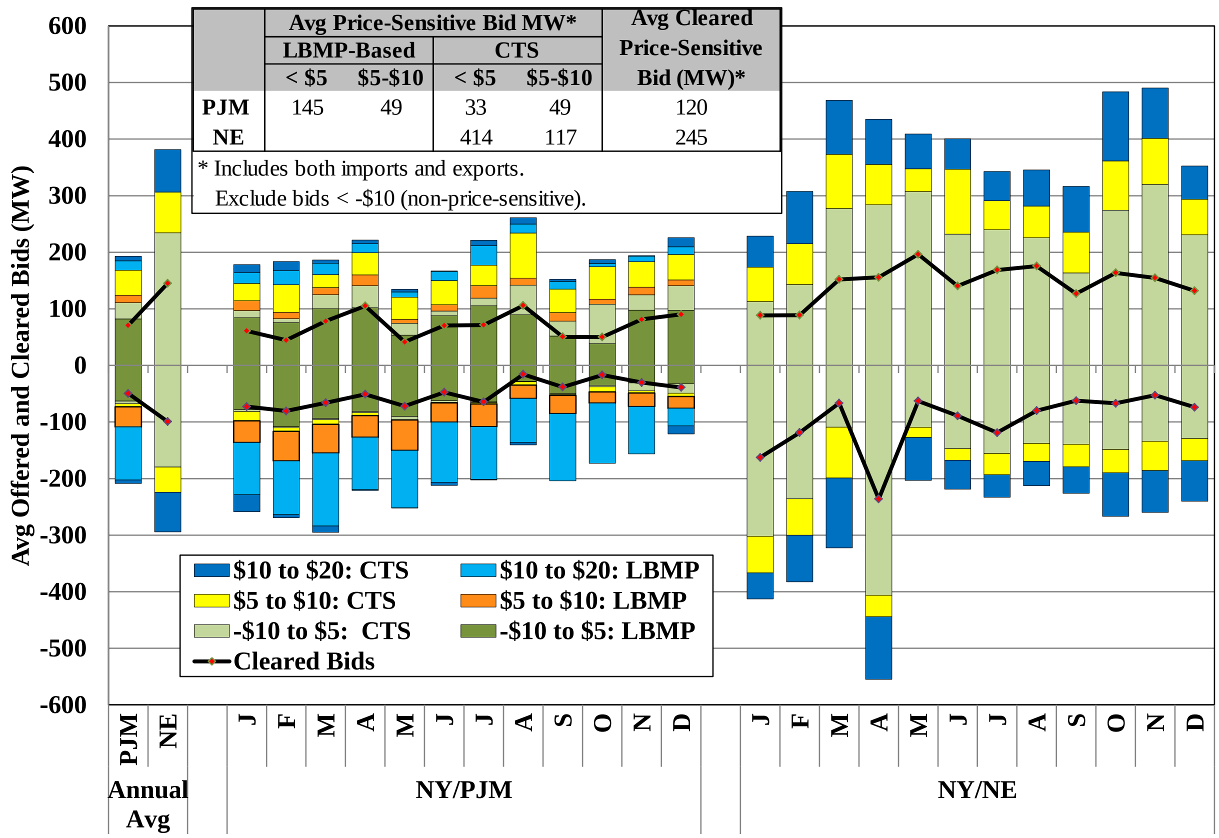


Table A-2: Efficiency of Intra-Hour Scheduling Under CTS

The next analysis evaluates the efficiency of the CTS-enabled intra-hour scheduling process (relative to our estimates of the scheduling outcomes that would have occurred under the previous hourly scheduling process) with PJM and New England.

To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, it is first necessary to estimate a hourly interchange schedule that would have flowed if the intra-hour process was not in place. We estimate the base interchange schedule by calculating the average of the four advisory quarter-hour schedules during the hour for which RTC_{15} determined final schedules at each hourly-scheduling interface. [230]

Table A-2 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2016. The table shows the following quantities:

- % of All Intervals – This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule) in the scheduling RTC interval.
- Average Flow Adjustment – This measures the difference between the estimated hourly schedule and the final schedule. Positive numbers indicate flow adjustments in the import direction (i.e., from PJM or New England to New York) and negative numbers indicate flow adjustments in the export direction (i.e., from New York to PJM or New England).
- Production Cost Savings – This measures the market efficiency gains (and losses) that resulted from the CTS processes.
  - Projected Savings at Scheduling Time – This measures the expected production cost savings at the time when RTC determines the interchange schedule across the two primary interfaces.[231]
  - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled, and/or scheduled in the inefficient direction. This estimates the portion of savings that inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors. [232]
  - Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:

230 RTC_{15} is the RTC run that posts the results by the time 15 minutes past each hour. The first interval of each RTC_{15} is ending at 30 minutes past each hour. For each hourly-scheduling interface, each RTC_{15} makes binding schedules for the second calendar hour in its two-and-a-half optimization period. For example, the first RTC_{15} of each day posts market results by 0:15 am; the first interval of its two-and-a-half optimization period is ending at 0:30 am; and it makes binding transaction schedules for all hourly-scheduling interfaces for the hour beginning at 1:00 am.

231 This is calculated as (final RTC schedule – estimated hourly schedule)*(RTC price at the PJM/NE proxy – PJM/NE forecast price at the NYIS proxy). An adjustment was also made to this estimate, which is described in Footnote 236.

232 This is calculated as: a) (final RTC schedule – estimated hourly schedule)*(RTD price – RTC price) for NYISO forecast error; b) (final RTC schedule – estimated hourly schedule)*(PJM forecast price – PJM RT price) for PJM forecast error; and c) (final RTC schedule – estimated hourly schedule)*(NE forecast price – NE RT price) for NE forecast error.

  - Real-time Curtailment[233] - Some of RTC scheduled transactions may not actually flow in real-time for various reasons (e.g., check-out failures, real-time cuts for security and reliability concerns, etc.). The reduction of flows in the efficient direction reduces market efficiency gains.
  - Interface Ramping[234] - RTD and RTC have different assumptions regarding interface schedule ramping. In RTD, interface flows start to ramp at 5 minutes before each quarter-hour interval and reach the target level at 5 minutes after. RTC assumes that the target flow level is reached at the top of the quarter-hour interval. Therefore, an inherent difference exists between RTD flows and RTC flows at the top of each quarter-hour interval, which will lead a portion of projected savings to be unrealized in real time.
  - Price Curve Approximation – This applies only to the CTS process between New York and New England. CTSPE forecasts a 7-point piecewise linear supply curve and NYISO transfers it into a step-function curve for use in the CTS process (as shown in Figure A-65). This leads to differences between the marginal cost of interchange estimated by ISO-NE and the assumptions used by the NYISO for scheduling.
- Actual Savings[235,236] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.
- Price Forecast Errors – These measure the performance of price forecasting by showing the average difference and the average absolute difference between the actual and forecasted prices on both sides of the interfaces.

233 This is calculated as (final RTD schedule – final RTC schedule with ramping assumption at the top of quarter-hour interval)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy).

234 This is calculated as (final RTC schedule with ramping assumption at the top of quarter-hour interval – final RTC schedule without ramping assumption)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy).

235 This is also calculated as (final RTD schedule – estimated hourly schedule)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy) + an Adjustment (as described below).

236 The marginal cost of production is estimated from LBMPs that result from scheduling a transaction, but the marginal cost of production varies as the interface schedule is adjusted. For example, if 100 MW is scheduled to flow from PJM or NE to NYISO, reducing the price spread between markets from $12/MWh to $5/MWh, our unadjusted production cost savings estimate from the transaction would be $500/hour (= 100 MW x $5/MWh). However, if the change in production costs was linear in this example, the true savings would be $850/hour (= 100 MW x Average of $5 and $12/MWh). We make a similar adjustment to our estimate of marginal cost of production assuming that: a) the supply curve was linear in all three markets; b) at the NY/PJM border, a 100 MW movement in the supply curve changes the marginal cost by 7.5 percent of NY LBMP in the New York market and 2.5 percent of PJM LBMP in the PJM market; and c) at the NY/NE border, a 100 MW movement in the supply curve changes the marginal cost by 15 percent of NY LBMP in the New York market and 5 percent of NE LBMP in the NE market, .

To examine how price forecast errors affected efficiency gains, these numbers are shown separately for the intervals during which forecast errors are less than $20/MWh and the intervals during which forecast errors exceed $20/MWh.

Table A-2: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and New England Interfaces, 2016

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			75%	11%	**87%**	54%	7%	**61%**
Average Flow Adjustment (MW)	Net Imports		-0.3	-2	**-0.5**	13	25	**14**
	Gross		73	101	**76**	59	101	**64**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.4	$2.1	**$4.5**	$0.9	$2.2	**$3.1**
	Net Over-Projection by:	NY Market	-$0.02	-$0.3	**-$0.3**	-$0.1	-$1.7	**-$1.9**
		Neighbor Market	-$0.1	-$1.0	**-$1.1**	-$0.1	-$0.6	**-$0.7**
	Unrealized Savings Due to:	Ramping	-$0.1	-$0.2	**-$0.3**	$0.0	-$0.1	**-$0.2**
		Curtailment	-$0.02	-$0.04	**-$0.1**	-$0.002	-$0.5	**-$0.5**
		Price Curve	-$0.2	-$0.4	**-$0.7**	N/A	N/A	**N/A**
	Actual Savings		$1.9	$0.1	**$2.0**	$0.6	-$0.8	**-$0.1**
Interface Prices ($/MWh)	NY Market	Actual	$24.35	$56.57	**$28.62**	$21.59	$59.12	**$25.87**
		Forecast	$24.76	$45.89	**$27.56**	$21.66	$48.73	**$24.75**
	Neighbor Market	Actual	$25.14	$45.91	**$27.89**	$22.61	$49.41	**$25.66**
		Forecast	$25.00	$41.07	**$27.13**	$23.36	$43.06	**$25.60**
Price Forecast Errors ($/MWh)	NY Market	Fcst. - Act.	$0.41	-$10.68	**-$1.06**	$0.07	-$10.39	**-$1.12**
		Abs. Val.	$3.62	$38.35	**$8.22**	$3.35	$50.54	**$8.73**
	Neighbor Market	Fcst. - Act.	-$0.14	-$4.84	**-$0.76**	$0.75	-$6.35	**-$0.06**
		Abs. Val.	$4.03	$42.15	**$9.08**	$3.02	$35.76	**$6.75**

Figure A-64 - Figure A-65: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-64 shows the cumulative distribution of forecasting errors in 2016. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price.

The figure shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve. Figure A-65 illustrates this by showing example curves from January 5, 2016. The blue squares in the figure show the seven price/quantity pairs that the ISO-NE price forecast engine (CTSPE) provided to the NYISO. The blue line connecting these seven squares represents a piecewise linear supply curve at the New England border. The red step-function curve is generated by the NYISO and is actually used in RTC for scheduling CTS transactions at the New England border.

Figure A-64: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2016

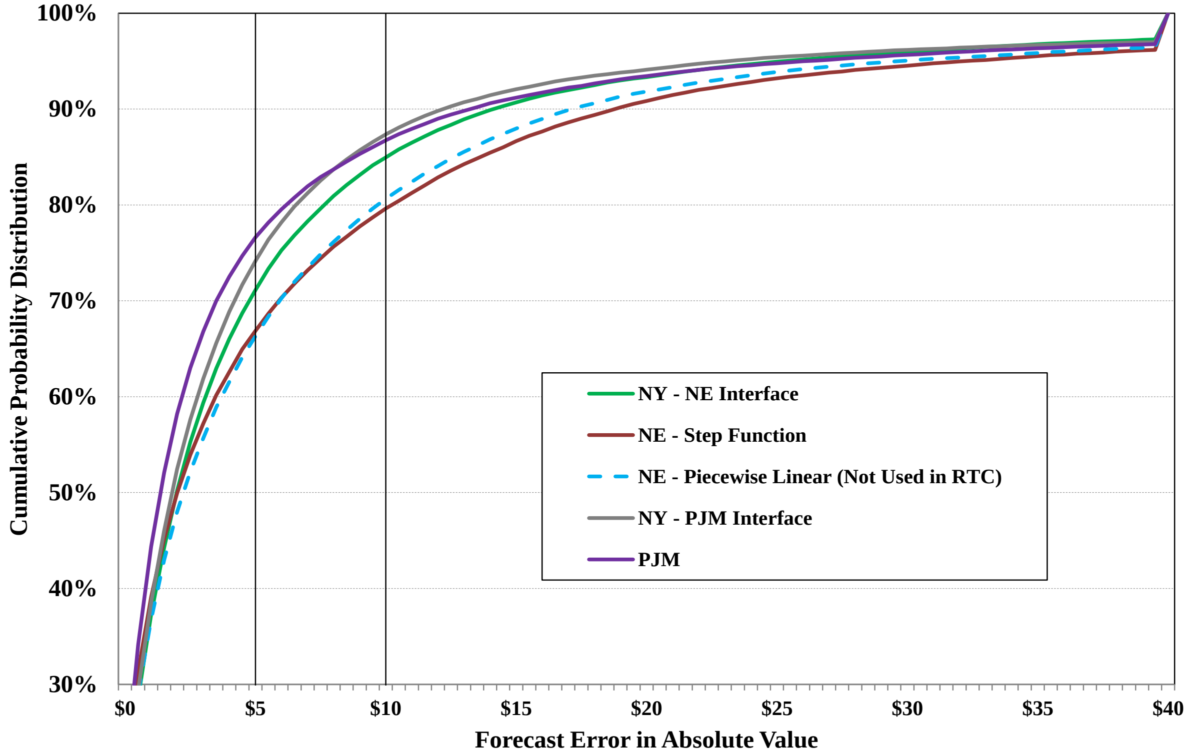


Figure A-65: Example of Supply Curve Produced by ISO-NE and Used by RTC
January 5, 2016

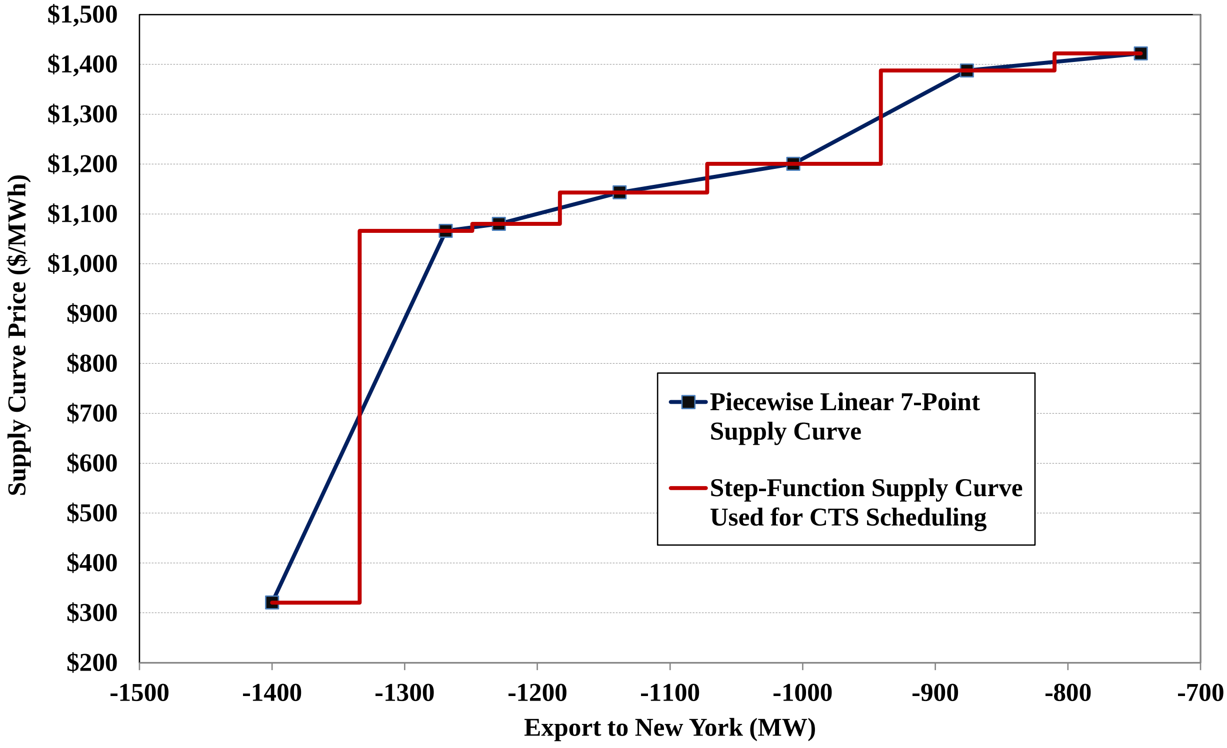


Figure A-66 - Figure A-68: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

RTC schedules gas turbines and external transactions shortly in advance of the 5-minute real-time market, so its assumptions regarding the load profile and the ramp profile of individual resources are important. The following analyses examine how the particular assumptions regarding the ramp profile of external transactions affect the accuracy of RTC's price forecasting. Figure A-66 provides an illustration of the ramp profiles that are assumed by RTC and RTD. The different ramp profiles lead to inconsistencies between RTC and RTD in the level of net imports, which contribute to differences between the RTC price forecast and actual 5-minute RTD clearing prices. These inconsistencies are evaluated in Figure A-67 and Figure A-68

Figure A-66 illustrates the ramp profiles that are assumed by RTC and RTD for external transactions. RTD's assumption is based on the actual scheduled interchange at the end of each 5-minute period. Transactions are assumed to move over a 10-minute period from one scheduling period to the next for both hourly and 15-minute interfaces. The 10-minute period goes from five minutes before the top-of-the-hour or quarter-hour to five minutes after. On the other hand, RTC schedules transactions as if they reach their schedule at the top-of-the-hour or quarter-hour, which is five minutes earlier than RTD. Green arrows are used to show intervals when RTD imports exceed the assumption used in RTC. Red arrows are used to shown intervals when imports assumed in RTC exceed the RTD imports.

Figure A-66: Illustration of External Transaction Ramp Profiles in RTC and RTD

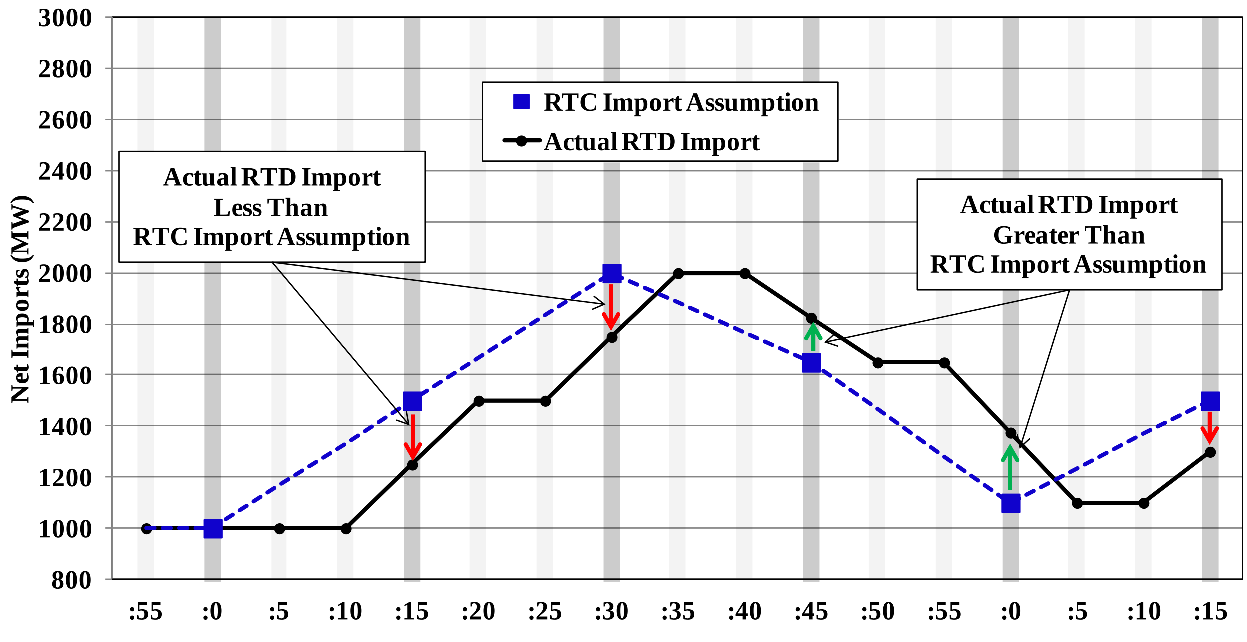


Figure A-67 shows a histogram of the resulting differences in 2016 between (a) the RTC assumed net interchange and (b) the actual net interchange reflected in RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45). For each tranche of the histogram, the figure summarizes the accuracy of the RTC price forecast by showing the average RTC LBMP minus the average RTD LBMP, the median of the RTC LBMP minus the RTD LBMP, and the mean absolute difference between the RTC and RTD LBMPs. LBMPs are shown at the NYISO Reference Bus location at the quarter-hour intervals for both RTC and RTD.

Figure A-67: Histogram of Differences Between RTC and RTD Prices and Schedules
2016

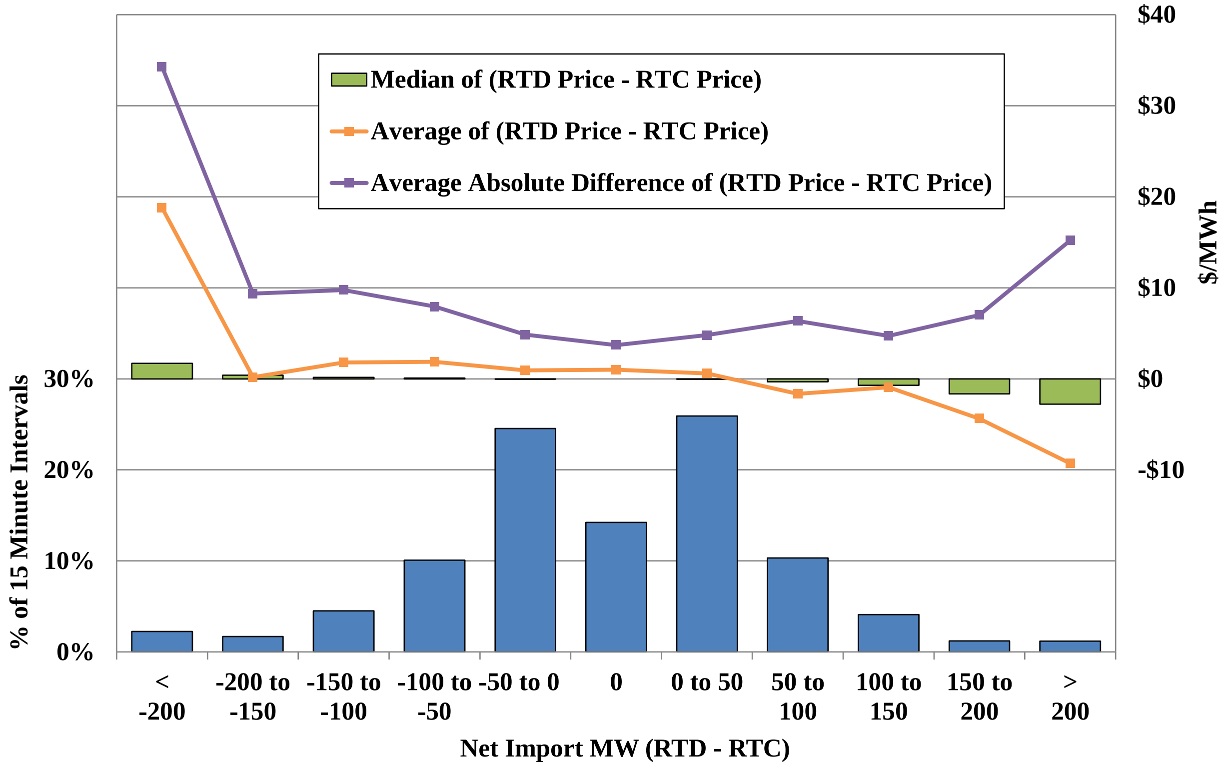
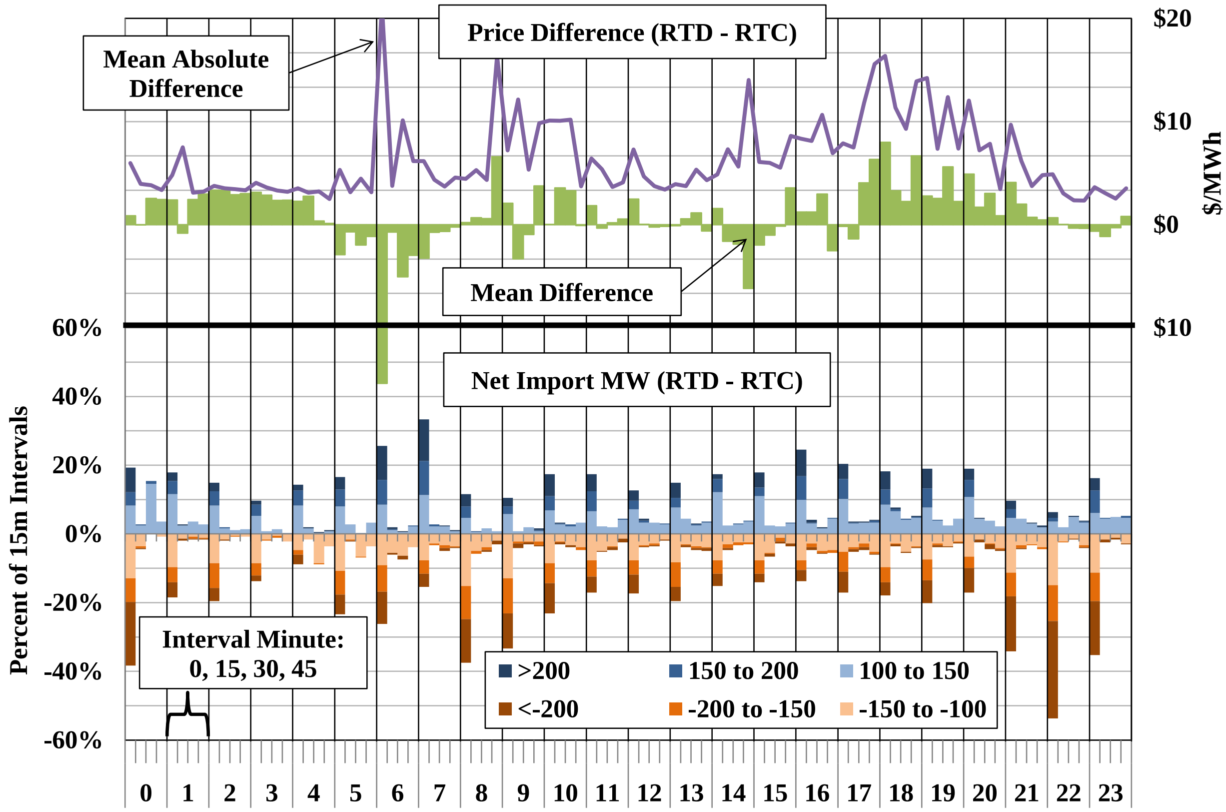


Figure A-68 summarizing these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels that exceed 100 MW by time of day, while the upper portion summarizes the accuracy of the RTC price forecast by showing the average RTD LBMP minus the average RTC LBMP and the mean absolute difference between the RTD and RTC LBMPs by time of day.

Figure A-68: Differences Between RTC and RTD Prices and Schedules by Time of Day
2016



Key Observations: Evaluation of Coordinated Transaction Scheduling

- Participation in CTS at the primary PJM interface was still relatively low after two years of implementation.
  - Of all price-sensitive bids in 2016, CTS bids accounted for roughly 30 percent while LBMP-based bids accounted for the remaining 70 percent.
- The average amount of price-sensitive bids (including both CTS and LBMP-based) submitted at the primary PJM interface was significantly lower than at the primary New England interface.
  - In 2016, an average of 414 MW (including both imports and exports) were offered between -$10 and $5/MWh at the NY/NE interface, while only 178 MW were offered at the primary NY/PJM interface.
  - Likewise, the amount of cleared price-sensitive bids at NY/NE interface doubled the amount cleared at the NY/PJM interface.
  - These results indicate more active participation at the NY/NE interface. As a result, the interchange schedules were adjusted (from our estimated hourly schedule) during 86 percent of all quarter-hour intervals in 2016 at the NY/NE interface, higher than the 61 percent at the NY/PJM interface.

- The differences between the two CTS processes are largely attributable to the large fees that are imposed at the NY/PJM interface, while there are no substantial transmission service charges or uplift charges on transactions at the NY/NE interface.
  - The NYISO charges physical exports to PJM at a rate typically ranging from $4 to $8/MWh, while PJM charges physical imports and exports at a rate less than $2/MWh, and PJM charges “real-time deviations” (which include imports and exports with a real-time schedule that is higher or lower than the day-ahead schedule) at a rate that averages less than $1/MWh.
    - These charges are a significant economic barrier to efficient scheduling through the CTS process, since large and uncertain charges deter participants from submitting price-sensitive CTS bids at the NY/PJM border.
  - Most of the transactions that cleared on the ISO-NE border were offered at less than $5/MWh. Given that the PJM charges are uncertain and can often be expected to exceed $5/MWh, it is not surprising that almost no CTS transactions were offered at prices in this range.
    - This demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquidity of the CTS process.
    - We believe much of this large difference in the performance of the two CTS processes is explained by charges that are imposed on the CTS transactions at the PJM interface and therefore recommend eliminating these charges.
- Our analyses show that $4.5 million and $3.1 million of production cost savings were projected at the time of scheduling at the NY/NE and NY/PJM interfaces in 2016.
  - However, only an estimated of $2 million of savings were realized at the NY/NE interface and nearly no savings were realized at the NY/PJM interface due largely to price forecast errors.
    - We estimated a higher production cost savings at the NY/NE interface because intra-hour interchange adjustments were more frequent and larger.
    - This was due in part to there being more low-priced CTS bids that were available to respond to moderate price differentials between NY and NE.
  - It is important to note that our evaluation may under-estimate both projected and actual savings, because the estimated hourly schedules (by using actual CTS bids and LBMP-based bids) may include some of the efficiencies that result from the CTS process.
  - Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.
- Our analyses show that projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were larger.
  - During intervals when forecast errors from both markets were less than $20/MWh:

   - $1.9 million out of projected $2.4 million of production cost savings were realized at the NY/NE interface; and
   - $0.6 million out of projected $0.9 million were realized at the NY/PJM interface.
  - However, small or even negative savings were actually realized in a small number of intervals with large forecast errors, undermining the overall efficiency of CTS.
  - Therefore, improvements in the CTS process should focus on identifying sources of forecast errors.
- The performance of the price forecast was slightly better at the NY/PJM interface than at the NY/NE interface during 2016. In particular,
  - Price forecast errors were less than $5/MWh in 74 to 77 percent of intervals at the NY/PJM interface, compared to 66 to 71 percent at the NY/NE interface; and
  - Price forecast errors were less than $10/MWh in roughly 87 percent of intervals at the NY/PJM interface, compared to 80 to 85 percent at the NY/NE interface.
  - This is because the price-elasticity of supply is normally greater at the NY/PJM interface than at the NY/NE interface because of the larger size of the PJM market.
- Our evaluation of RTC price forecast error suggests that inconsistencies in the ramp assumptions used in RTC and RTD contribute to forecasting errors on the NYISO side of the interfaces. In 2016, because of inconsistent ramp assumptions:
  - RTC-assumed net imports exceeded RTD net imports by 100 MW or more in 8 percent of the quarter-hours during which the RTD price exceeded the RTC price by an average of $6.00/MWh and the mean absolute difference was $16.20/MWh.
  - RTD net imports exceeded RTC-assumed net imports by 100 MW or more in 6 percent of the quarter-hours during which the RTD price was less than the RTC price by an average of $3.10/MWh and the mean absolute difference was $7.05/MWh.
  - When RTC-assumed net imports were within 100 MW of RTD net imports, the mean absolute difference between RTC and RTD prices was just $5.20/MWh.
  - Hence, RTC price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions, thereby reducing the efficiency gains from CTS.
- The foundation of CTS-enabled intra-hour scheduling is sound, but additional benefits to the market may be realized if enhancements are made to the process.
  - Improving the accuracy of the forecast assumptions by NYISO and PJM would lead to more efficient interchange scheduling.

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 2016:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *M2M Coordination* – This sub-section evaluates real-time flows across the Ramapo PAR-controlled lines under market-to-market coordination ("M2M") between PJM and the NYISO.
- *Operation of Controllable Lines* – This sub-section evaluates the efficiency of real-time flows across controllable lines.
- *Real-Time Transient Price Volatility* – This sub-section evaluates the factors that lead to transient price volatility 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) shortages of operating reserves and regulation, (b) transmission shortages, and (c) reliability demand response deployments.
- *Supplemental Commitment for Reliability* – Supplemental commitments are necessary when the market does not provide incentives for suppliers to satisfy certain reliability requirements. However, supplemental commitments raise concerns because they indicate the market does not provide sufficient incentives, they 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.
- *BPCG Uplift Charges* – This sub-section evaluates BPCG uplift charges resulted primarily from supplemental commitment and out-of-merit dispatch.

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.[237] 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.[238] 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 V.F of the Appendix.

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.

Figure A-69 – Figure A-70: Efficiency of Gas Turbine Commitment

Figure A-69 measures the efficiency of gas turbine commitment by comparing the offer price (energy plus start-up costs amortized over the commitment period) to the real-time LBMP over the unit's initial commitment period. When these decisions are efficient, the offer price components of committed 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

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

238 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

price components to be greater than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

Figure A-69 shows the average quantity of gas turbine capacity started each day in 2016. 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 the following reasons:

- 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;
- 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; and
- Gas turbines that are economic sometimes do not set the LBMP and, thus, appear to be uneconomic (which is evaluated in Figure A-70).

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,[239] 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.

[239] 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-69: Efficiency of Gas Turbine Commitment
2016

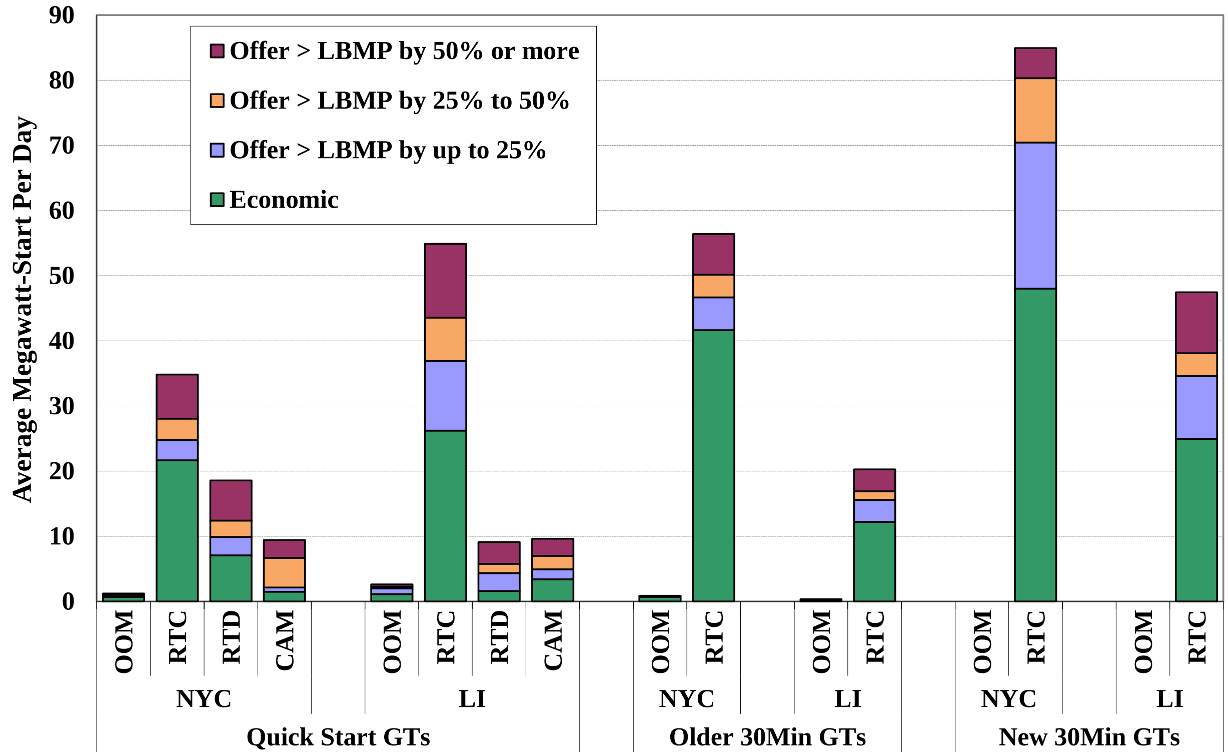


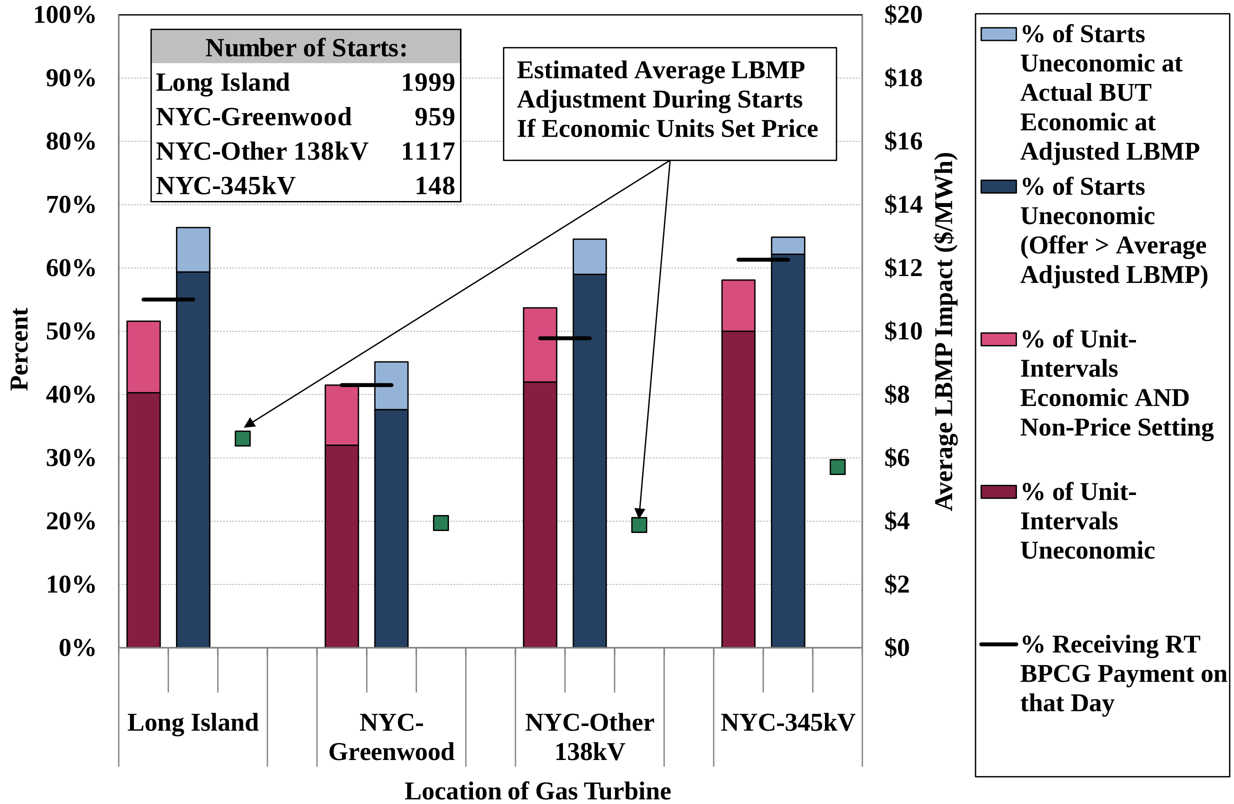
Figure A-70 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP during a portion of the initial commitment period. In particular, we examine every market interval in the initial commitment period of a gas turbine start, which excludes starts via OOM, 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-70: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2016



<u>Key Observations: Efficiency of Gas Turbine Commitment</u>

- Most gas turbine commitments were made by RTC. In 2016, roughly 85 percent was committed by RTC, 8 percent by RTD, 5 percent by RTD-CAM, and less than 2 percent through OOM instructions.
- The NYISO's real-time market models are relatively effective in committing gas turbines efficiently. The overall efficiency of gas turbine commitments has been consistent in the past several years. In 2016,
  - 54 percent of all gas turbine commitments were clearly economic; and

- An additional 18 percent of all gas turbine commitments were cases when the gas turbine offer was within 125 percent of LBMP (a significant portion of these commitments are efficient for the reasons discussed earlier in this subsection).

- Economic gas turbines do not always set the real-time LBMP during their initial commitment period, which is due in part to the effects of NYISO's Hybrid Pricing methodology in the real-time market. In 2016,
  - In 8 to 12 percent of the intervals during the initial commitment period of gas turbines, the gas turbine was economic but did not set the LBMP.
  - We estimate that allowing these economic gas turbines to set prices would have increased the LBMPs by an average of $3.90 to $6.60 per MWh during the first hour after each start in New York City and Long Island. This would increase annual LBMPs by an average of $0.40 to $1.50 per MWh with the largest effect in Long Island. However, the increase in LBMPs would be concentrated during peaking conditions when gas turbines are used to satisfy the needs of the system.
    - The higher LBMPs would be more reflective of the costs of satisfying demand, security, and reliability requirements in the real-time market.
    - Higher LBMPs would increase energy net revenues for resources that are frequently scheduled during relatively tight conditions when gas turbines are needed to serve load and manage congestion. This would reduce dependence on the installed capacity market to retain flexible resources.
    - However, the analysis under-estimates the effects of allowing gas turbines to set the real-time LBMP in intervals when they are economic because it assumes that the real-time LBMP impact is limited to nodes in the same area (out of the four areas shown) that have similar LBMP congestion component. In fact, the LBMPs over a wider area can be affected, depending on congestion patterns.
  - The NYISO implemented changes to the price-setting rules for quick start units in early 2017.[240] These are a significant improvement over the current hybrid pricing rules and result in market clearing prices that are more consistent with the operational needs of the system.
    - However, while the newly implemented changes ensure that a gas turbine will set the clearing price when its output is displacing output from a more expensive resource, these changes do not necessarily reflect the start-up and other commitment costs of the gas turbine in the price-setting logic. We continue to recommend that the NYISO incorporate these costs into the price-setting logic.

240 Specifically, the NYISO proposes to eliminate the Third Pass in the RTD software (which currently produces market clearing prices) and directly use prices from the Second Pass. See NYISO filing of proposed amendments to the Services Tariff to modify the pricing logic used for Fixed Block Unit GTs, filed to FERC on December 14, 2016. This change was implemented on February 28, 2017.

The Commission has also recognized the need for the price-setting logic to consider the start-up and other commitment costs of gas turbines.[241]

B. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") commenced in January 2013. This process allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources when it is less costly for them to do so.[242] M2M includes two types of coordination:

- Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
- Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.

The NYISO and PJM have an established process for identifying constraints that will be on the list of pre-defined flowgates for Re-dispatch Coordination and Ramapo PAR Coordination.[243]

Figure A-71: M2M Coordination with PJM

The use of Re-dispatch Coordination has been infrequent since the inception of M2M, while the use of Ramapo PAR Coordination had far more significant impacts on the market. Hence, the following analyses focus on the operation of Ramapo PARs in 2016.

Figure A-71 compares the actual flows on Ramapo PARs with their M2M operational targets in 2016. The M2M target flow has the following components:

- Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line.[244]
- 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
- ABC & JK Wheel Deviations – The total flow deviations on the ABC and JK PAR-controlled lines from schedules under the ConEd-PSEG Wheeling agreement.[245]

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241 See Recommendation #2015-17. In Docket RM17-3-000, see the Commission's NOPR on Fast Start Pricing, dated December 15, 2016, and comments of Potomac Economics, dated March 1, 2017.

242 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

243 The list of pre-defined flowgates is posted at http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/CoordinatedFlowgatesandEntitlements.mht.

244 This assumed share is 61 percent when both Ramapo PARs are in service and 46 percent when one of the two PARs is out of service.

245 The ConEd-PSEG Wheeling Agreement ordinarily provides for 1,000 MW to be wheeled from NYISO Zone G ("Hudson Valley") across the J & K lines into the PSEG territory in New Jersey and back into

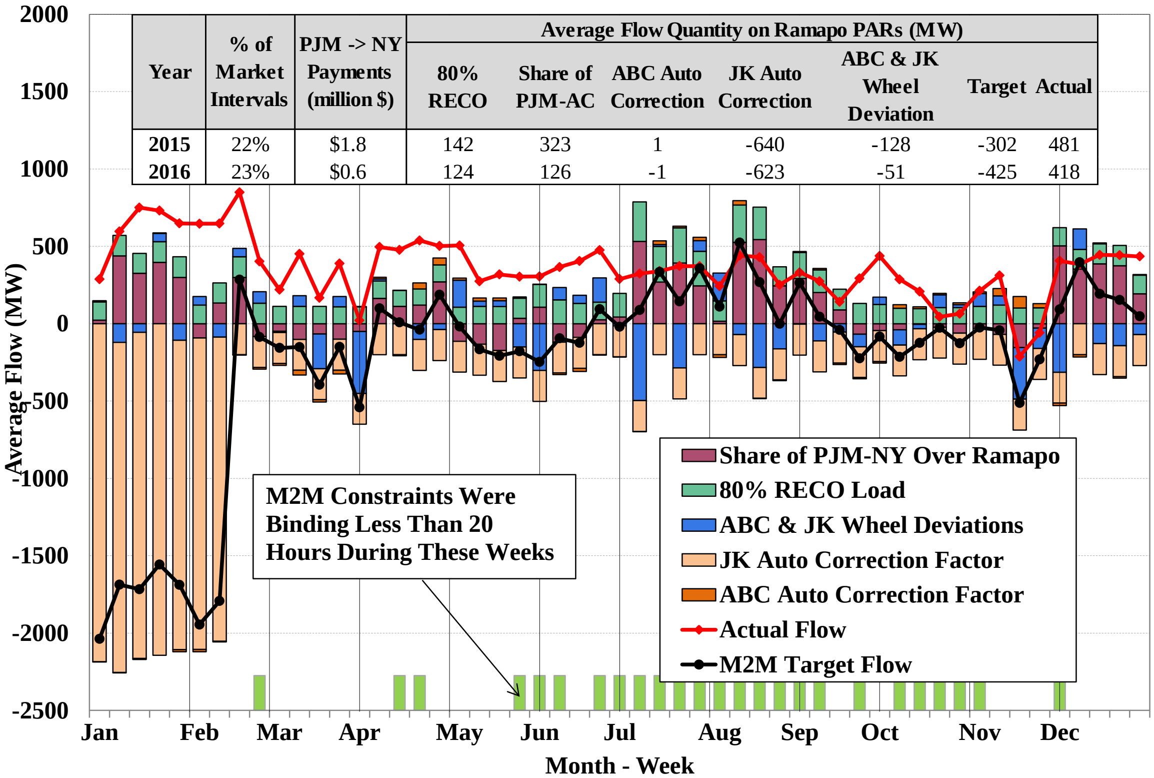
- JK Auto Correction Factor – The JK interface Auto Correction component of the JK interface real-time desired flow. This represents a "pay-back" MW generated from cumulative deviations on the JK interface from previous days. [246]
- ABC Auto Correction Factor - The ABC interface Auto Correction component of the ABC interface real-time desired flow. This represents a "pay-back" MW generated from cumulative deviations on the ABC interface from previous days. [247]

The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a weekly basis. The weeks with less frequent binding M2M constraints (i.e., less than 20 hours) are highlighted.

The table in the figure summarizes the percent of market intervals during which at least one M2M constraint was binding and the total payments from PJM to the NYISO under the M2M agreement in 2015 and 2016. In addition, the table compares the average amount of flows for each component described above for the two years.

Figure A-71: Actual and Target Flows for the Ramapo Line

During the Intervals with Binding M2M Constraints, 2016



Year	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)						
			80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2015	22%	$1.8	142	323	1	-640	-128	-302	481
2016	23%	$0.6	124	126	-1	-623	-51	-425	418

NYISO Zone J ("New York City") across the A, B, & C lines. The operation of the ConEd-PSEG wheel is set forth in NYISO OATT Section 35.22, which is Schedule C to Attachment CC.

246 See NYISO OATT Section 35.22, Attachment CC Schedule C Appendix 3 for detailed description of auto correction factors.

247 See NYISO OATT Section 35.22, Attachment CC Schedule C Appendix 3 for detailed description of auto correction factors.

Key Observations: M2M Coordination with PJM

- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 23 percent of intervals in 2016, comparable to 2015.
  - Average actual flows exceeded the Target Flow by nearly 845 MW, resulting in a small amount of M2M payments (~$0.6 million) from PJM to NY in 2016.
  - The low Target Flow resulted from large cumulative negative deviations on the JK PARs, which were represented by JK auto correction.
    - The cumulative negative deviations on the JK PARs became large since April 2015, reached over 2,000 MW in early 2016, and were capped at 200 MW since mid-February 2016.
- The operation of the Ramapo PARs under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flow gates.
  - Balancing congestion surpluses frequently resulted from this operation on the Central-East interface and transmission paths into Southeast New York (an estimated $8 million of surpluses in 2016, see Section III.E in the Appendix), indicating the Ramapo PARs were used to reduce production costs and congestion in New York.
  - However, these were partly offset by balancing congestion shortfalls (an indication of PAR operations that increase production costs and congestion) on the West Zone lines (see Section III.E in the Appendix), which are currently not coordinated flow gates under the M2M JOA.
    - The NYISO improved its operating practice in November 2015 to limit the use of Ramapo Coordination process to periods when the NYISO does not expect constraints in Western New York to be active. [248]
    - Nonetheless, since the NYISO operators do not have a congestion or production cost forecasting model that can be used in the operating day to help determine the efficient schedule for the Ramapo PARs, it will be difficult to optimize the operation of the Ramapo line without a model to forecast the impacts of PAR tap adjustments in real-time. This deficiency will become more significant starting in May 2017 when the M2M process is also used to schedule flows on the A, B, C, J, and K lines that previously were used to effectuate the ConEd-PSEG Wheeling Agreement.

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

[248] See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

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.[249] Such lines are analyzed in Section IV of the Appendix, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted by the local TO 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-72: 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 2016.

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 2016. The evaluation is done for the following eleven PAR-controlled lines:

- Two between IESO and NYISO: St. Lawrence – Moses PARs (L33 & L34 lines).
- One between ISO-NE and NYISO: Sand Bar – Plattsburgh PAR (PV20 line).
- Six between PJM and NYISO: Two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), two Hudson-Farragut PARs (B & C lines), and one Linden-Goethals PAR (A line).
  - The 5018 line was scheduled in accordance with the M2M coordination agreement, which is discussed in Subsection B.
  - 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.
- Two between Long Island and New York City: Lake Success-Jamaica PAR (903 line) and Valley Stream-Jamaica PAR (901 line).

[249] 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.

- 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 net flows into NYCA or New York City;
- Average price at the interconnection point in the NYCA or New York City minus the average 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.[250]

This analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[251] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market. The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market.

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

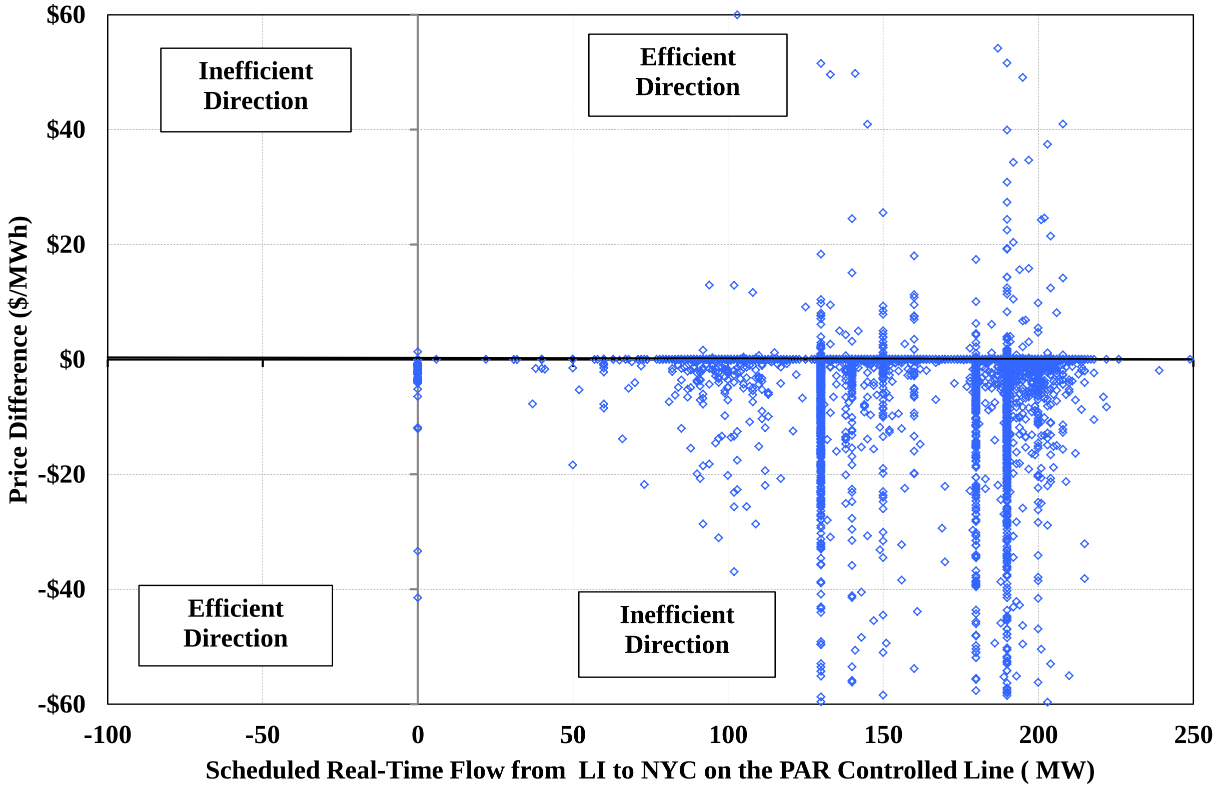
251 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-3: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2016

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					-19	$5.64	52%	$2
New England to NYCA								
Sand Bar	-76	-$11.53	91%	$8	-0.3	-$10.63	51%	$0.4
PJM to NYCA								
Waldwick	-825	$3.62	24%	-$26	130	$3.18	54%	$3
Ramapo	146	$4.05	67%	$11	188	$3.71	55%	$4
Farragut	624	$3.15	73%	$18	-71	$3.38	45%	-$2
Goethals	203	$3.63	76%	$6	73	$3.21	57%	$1
Long Island to NYC								
Lake Success	157	-$5.38	3%	-$8	-2	-$5.81	60%	$0.1
Valley Stream	65	-$7.38	2%	-$5	3	-$10.99	24%	-$2

Figure A-72 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake Success-Jamaica line. The figure shows hourly price differences in the real-time market on the vertical axis versus power flows scheduled in the real-time market on the horizontal axis. Points in the top-right and bottom-left quadrants of the figure are characterized as scheduled in the efficient direction. Power scheduled in the efficient direction flows from the lower-priced market to the higher-priced market. Similarly, points in the top-left and bottom-right quadrants are characterized as scheduled in the inefficient direction, corresponding to power flowing from the higher-priced market to the lower-priced market. Good market performance would be indicated by a large share of hours scheduled in the efficient direction.

Figure A-72: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line –2016



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- In the day-ahead market, the scheduling of PAR-controlled lines that are used to support contractual wheeling agreements was less efficient than other PAR-controlled lines.
  - Under the ConEd-PSEG wheeling agreement, the Waldwick lines are used to wheel power (up to 1000 MW) from Hudson Valley to PJM, and then the Goethals/Farragut lines are used to wheel power back from PJM to New York City. In 2016,
    - Although power flowed in the efficient direction in 73 to 76 percent of hours across the Goethals/Farragut lines, power flowed in the efficient direction in only 24 percent of hours across the Waldwick lines.
    - These led to an estimated net *increase* of $2 million in day-ahead production costs (an increase of $26 million accrued on the Waldwick lines, offset by a reduction of $24 million accrued on the Goethals/Farragut lines).[252]
  - Under the ConEd-LIPA wheeling agreement, the 901/903 lines are used to wheel roughly half of the power flowed on the Y50 line (from upstate to Long Island) back to New York City. In 2016,

252 For the reasons noted in Footnote 227, this method of estimating production cost savings tends to over-estimate the costs from inefficient scheduling.

  - Power flowed in the inefficient direction in 97 percent of hours, much inefficient than any of other PAR-controlled lines.
  - The use of these lines increased day-ahead production costs by an estimated $13 million because prices on Long Island were typically higher than those in New York City (particularly where the 901 and 903 lines connect in the Astoria East/Corona/Jamaica pocket, which is sometimes export-constrained).
  - In addition to increasing production costs, these transfers can restrict output from economic generators in the Astoria East/Corona/Jamaica pocket and at the Astoria Annex. 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).

- Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since most of these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.
  - However, the Ramapo line and St. Lawrence line showed relatively significant production cost savings in real-time because these lines were operated: (a) to flow a share of the external transactions between control areas that are submitted by traders and (b) to manage real-time congestion.
    - Although the Ramapo line is scheduled under the M2M process to minimize congestion across PJM and New York, the process only considers congestion on certain pre-defined interfaces. Table A-3 reports the production cost savings for balancing adjustments considering congestion on all flowgates. This includes balancing adjustments that result from external transaction scheduling and those that result from the M2M process.
- These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick and Goethals/Farragut lines and the lines between New York City and Long Island.
  - These lines are all currently 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.
  - Under the ConEd-LIPA wheeling agreement, ConEd possesses a physical right to receive power across the 901 and 903 lines. To compensate ConEd during periods when it does not receive power across these lines, ConEd should be granted a financial right that would compensate it based on LBMPs when the lines are redispatched to minimize production costs (similar to a generator). [253]

[253] The proposed financial right is described in Section III.G of the Appendix.

- The ConEd-PSEG wheeling agreement was terminated at the end of April 2017. PJM and NYISO are implemented a replacement protocol that: [254]
  - Includes the ABC and JK lines as part of the NY-PJM AC interface for interchange scheduling; and
  - Adds the ABC and JK lines to the M2M process.
  - We support these changes because they will lead to more efficient scheduling across the ABC and JK lines.

D. Transient 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.

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

This sub-section evaluates scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2016. The effects of transient transmission constraints tend to be localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

A spike in the shadow price of a particular transmission constraint is considered *"transient"* if it satisfies both of the following criteria:

- It exceeds $150 per MWh; and
- It increases by at least 100 percent from the previous interval.

A spike in the shadow price of the power-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 $100 per MWh; and

254 For more information on the new process, see *ConEd/PSEG Wheel Replacement Protocol – Update*, presented by David Edelson to the Market Issues Working Group, April 24, 2017.

- It increases by at least 100 percent from the previous interval.

Although the price spikes meeting these criteria account for less than 5 percent of the real-time pricing intervals in 2016, these intervals are important because they account for a disproportionately large share of the overall market costs. Furthermore, analysis of factors that lead to the most sudden and severe real-time price spikes provides insight about factors that contribute to less severe price volatility under a wider range of market conditions. In general, price volatility makes it more difficult for market participants, the NYISO, and neighboring system operators to commit quick-start resources and schedule external transactions efficiently. Hence, reducing unnecessary price volatility will lead to more efficient interchange between markets, lower production costs across markets, and less uplift from BPCG and DAMAP payments.

Table A-4: Transient Real-Time Price Volatility

Table A-4 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2016 for facilities exhibiting the most volatility. The table reports the frequency of transient price spikes, the average shadow price during the spikes, and the average transfer limit during the spikes.

The table also analyzes major factors that contributed to price volatility in these price spike intervals. These factors are grouped into three categories:

- Flows from resources scheduled by RTC
- Flow changes from non-modeled factors
- Other factors

Specifically, the table shows factors that contributed to an increase in flows from the previous five-minute interval. For the power-balance constraint, the table summarizes factors that contributed to an increase in demand and/or reduction in supply. This analysis quantifies contributions from the following factors, which are listed in order of significance:

- External Interchange – This adjusts as often as every 15 minutes, depending on the interface. The interchange at each interface is assumed to “ramp” over a 10-minute period from five minutes before the quarter hour (i.e., :55, :10, :25, :40) to five minutes after the quarter hour (i.e., :05, :20, :35, :50). Interchange schedules are determined before each 5-minute interval, so RTD must schedule internal dispatchable resources up or down to accommodate adjustments in interchange.
- Fixed Schedule PARs – These include PARs that are operated to a fixed schedule (as opposed to optimized PARs, which are operated to relieve congestion). The fixed schedule PARs that are the most significant drivers of price volatility include the A, B, C, J, & K lines (which are used to support the ConEd-PSEG wheeling agreement) and the 901 and 903 lines (which are used to support the ConEd-LIPA wheeling agreement).[255] RTD and RTC assume the flow over these lines will remain fixed in future intervals at

[255] These lines are discussed further in Subsection C.

the most recent telemetered value, but their flow is affected by changes in generation and load and changes in the settings of the fixed schedule PAR or other nearby PARs. Hence, RTD and RTC do not anticipate changes in flows across fixed schedule PARs in future intervals, which can lead to sudden congestion price spikes when RTD recognizes the need to redispatch internal resources in response to unforeseen changes in flows across a fixed schedule PAR.

- RTC Shutdown Peaking Resource – This includes gas turbines and other capacity that is brought offline by RTC based on economic criteria. When RTC shuts-down a significant amount of capacity in a single 5-minute interval, it can lead to a sudden price spike if dispatchable internal generation is ramp-limited.
- Loop Flows & Other Non-Market Scheduled – These include flows that are not accounted for in the pricing logic of the NYISO's real-time market. These result when other system operators schedule internal facilities and external transactions to satisfy their internal load, causing loop flow across the NYISO system. These also result from differences between the shift factors assumed by the NYISO for pricing purposes and the actual flows that result from adjustments in generation, load, interchange, and PAR controls.
- Niagara Generator Distribution – Different units at the Niagara plant have different shift factors, but RTD assumes a single shift factor for the entire plant for pricing and scheduling purposes. When the units that respond to dispatch instructions differ from the assumption used in RTD, it may lead to changes in unscheduled flows over the constraint.
- Self-Scheduled Generator – This includes online generators that are moving in accordance with a self-schedule, resources shut-down in accordance with a self-schedule, and resources that are shut down because they did not submit a RT offer. In some cases, large inconsistencies can arise between the ramp constraints in the physical and pricing passes of RTD for such units.
- Load – This includes the effects of changes in load.
- Generator Trip/Derate/Dragging – Includes adjustments in output when a generator trips, is derated, or is not following its previous base point.
- Wind – This includes the effects of changes in output from wind turbines.
- Redispatch for Other Constraint (OOM) – Includes adjustments in output when a generator is logged as being dispatched out-of-merit order. Typically, this results when a generator is dispatched manually for ACE or to manage a constraint that is not reflected in the real-time market (i.e., in RTD or RTD-CAM).
- Ramapo PARs – The primary determinant of flows across the Ramapo PAR-controlled line is the interchange between PJM and NYISO across the primary interface, 61 percent of which is expected to flow across the Ramapo line when two PARs are in service (46 percent when only one PAR is in service). Under M2M Coordination with PJM, the Ramapo line can carry additional flows in order to manage congestion on M2M flow gates. This category includes the impacts of adjustments in the deviation between the

actual Ramapo flow and the assumed portion of interchange across the primary PJM interface.[256]

- Re-Dispatch for Other Constraint (RTD) – Multiple constraints often bind suddenly at the same time because of some common causal factors. For example, the sudden trip of a generator could lead to a power-balance constraint and a shortage of 10-minute spinning reserves. In such cases, some units are dispatched to provide more energy, while others may be dispatched to provide additional reserves, so the units dispatched to provide additional reserves would be identified in this category. The analysis does not include this category in the total row of Table A-4, since this category includes the responses to a primary cause that is reflected in one of the other rows.

The contributions from each of the factors during transient spikes are shown in MWs and as a percent of the total contributions to the price spike for the facility.[257] For each constraint category, we highlight the category of aggravating factors that most contributed to the transient price spike in green.

Table A-4: Drivers of Transient Real-Time Price Volatility
2016

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints	
Average Transfer Limit	**n/a**		**711**		**1721**		**800**		**277**	
Number of Price Spikes	**363**		**1101**		**242**		**318**		**965**	
Average Constraint Shadow Price	**235**		**1239**		**352**		**373**		**464**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC/RTD	**164**	**63%**	**1**	**6%**	**42**	**33%**	**52**	**66%**	**4**	**29%**
External Interchange	84	32%	1	6%	18	14%	29	37%	1	7%
RTC Shutdown Resource	63	24%	0	0%	14	11%	19	24%	2	14%
Self Scheduled Shutdown/Dispatch	17	6%	0	0%	10	8%	4	5%	1	7%
Flow Change from Non-Modeled Factors	**12**	**5%**	**14**	**78%**	**64**	**50%**	**13**	**16%**	**9**	**64%**
Loop Flows & Other Non-Market	2	1%	9	50%	23	18%	8	10%	3	21%
Niagara Generator Distribution	0	0%	2	11%	0	0%	0	0%	0	0%
Fixed Schedule PARs (excl. Ramapo)	0	0%	2	11%	29	22%	3	4%	6	43%
Ramapo PARs	0	0%	1	6%	11	9%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	10	4%	0	0%	1	1%	2	3%	0	0%
Load/Wind/Generator Derates	**86**	**33%**	**3**	**17%**	**23**	**18%**	**14**	**18%**	**1**	**7%**
Load	48	18%	1	6%	13	10%	6	8%	1	7%
Generator Trip/Derate/Dragging	18	7%	0	0%	9	7%	8	10%	0	0%
Wind	20	8%	2	11%	1	1%	0	0%	0	0%
Total	**262**		**18**		**129**		**79**		**14**	
Redispatch for Other Constraint (RTD)	**85**		**1**		**15**		**7**		**1**	

256 Ramapo M2M coordination is discussed further in Subsection B.

257 The West Zone 230kV Lines category includes the Niagara-to-Packard, Packard-to-Sawyer, Gardenville-to-Stolle Rd, Huntley-to-Sawyer, and Sawyer-to-SUNY Buffalo transmission lines.

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes (as defined in this report) occurred in less than 5 percent of all intervals in 2016.
  - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and increases in load.
  - For the West Zone 230kV Lines, the primary driver was from loop flow and other non-market scheduled factors, but a portion of the non-market scheduled flows results from simplified modeling of the Niagara generator bus in the pricing model of the real-time market and adjustments in fixed schedule PARs between NYISO and PJM.
  - For the Central-East Interface, the primary drivers were from external interchange adjustments and fixed-schedule PAR flow adjustments (particularly from the A, B, C, J, and K lines). Generator shutdowns by RTC and Ramapo PAR flow adjustments were also significant contributors.
  - For the Dunwoodie-to-Shore Road 345kV line from upstate to Long Island (i.e., the "Y50" line), the primary drivers were from external interchange adjustments (especially the Neptune line) and the shutdown of generation by RTC. In previous years, fixed-schedule PAR flow adjustments were also a significant contributor, but these were addressed in May 2016 by modeling changes that are discussed below.
  - For constraints internal to Long Island (the majority of which were for the 138kV East Garden City-to-Valley Stream line), the primary driver was fixed-schedule PAR flow adjustments (particularly from the 901 line). These price spikes became less common in May 2016 as a result of changes to the modeling of fixed-schedule PARs that are discussed below. The shutdown of peaking units by RTC and other non-market factors were also significant contributors.
- External interchange variations were a key driver of transient price spikes for the Central-East Interface, the Dunwoodie-to-Shore Road 345kV line, and the power-balance constraint.
  - Large schedule changes caused price spikes in many intervals when generation was ramp-limited in responding to the adjustment in external interchange.
  - CTS with PJM and ISO-NE provide additional opportunities for market participants to schedule transactions such that it will tend to reduce the size of the adjustment around the top-of-the-hour.
    - However, our assessment of the performance of CTS (see Appendix Section IV.C) indicates that inconsistencies between RTC and RTD related to the assumed external transaction ramp profile likely contributes to price volatility when the total net interchange varies significantly (e.g., >200 MW) from one 15-minute interval to another.

- Fixed-schedule PAR-controlled line flow variations were a key driver of price spikes. The A, B, C, J, and K lines were a key driver for the Central-East Interface, and the 901 line was the primary driver for the East Garden City-to-Valley Stream line until May.
  - Until May, these PARs were modeled as if they fully controlled pre-contingent flow across the PAR-controlled line, so RTD and RTC assumed the flow across these lines would remain fixed at the most recent telemetered values.
    - However, this assumption would have only held true if the PAR was adjusted very frequently in response to variations in generation, load, interchange, and other PAR adjustments. Since the PAR is adjusted less than once per hour on average, the telemetered value can change significantly from one interval to the next, resulting in transitory price spikes. In many cases, severe congestion used to occur when low-cost resources that were available to relieve the constraint were under-utilized because they were not scheduled to ramp-up soon enough.
  - Beginning in May, the NYISO began using a forecast for the lines making-up the ConEd-LIPA wheel based on the operating plan of the transmission owner that operates the facilities.[258] This has greatly reduced the incidence of transient price spikes on Long Island, particularly in the Valley Stream load pocket.
- Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines.
  - Clockwise circulation around Lake Erie puts a large amount of non-market flow on these lines. Circulation can be highly volatile and difficult to predict, since it depends on facilities scheduled outside the NYISO market.
- Generators that are shut down by RTC and/or self-scheduled in a direction that exacerbates a constraint were a significant driver of statewide, Central East, and Long Island price spikes.
  - A large amount of generation may be scheduled to go offline simultaneously, which may not cause ramp constraints in the 15-minute evaluation by RTC but which may cause ramp constraints in the 5-minute evaluation by RTD. Slow-moving generators such as steam turbines are frequently much more ramp-limited in the 5-minute evaluation than in the 15-minute evaluation.

Discussion of Potential Solutions

- 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 or local price spike.
  - 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.

258 See *Initialization of Lake Success and Valley Stream PARs*, Presented by David Edelson at the April 5, 2016 Market Issues Working Group.

- Since RTC assumes a 15-minute ramp capability from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage within the 15-minute period.

- However, when RTD solves each five-minute market interval, it is unable to delay the shut-down of a gas turbine for five minutes even if it would be economic to do so.

• Large adjustments in external interchange from one 15-minute interval to the next may lead to sudden 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 10-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, RTC may schedule resources that require a large amount of ramp in one 5-minute portion of the 10-minute external interchange ramp period, and RTD may not anticipate transient shortages that occur in the second five minutes of each 10-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).

• *Addressing RTC/RTD Inconsistencies* – To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD: [259]

  - Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

  - Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.

  - Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.

  - Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbines generators with the actual demonstrated performance to account for units that often ramp at a rate that is lower than their claimed ramp rate capability.

  - Address inconsistency between the ramp assumptions used in RTD's physical pass and RTD's pricing pass when units are ramping down from a day-ahead schedule.

• *Addressing Non-Modeled Factors* – The changes to the modeling of the ConEd-LIPA wheel and the cessation of the ConEd-PSEG wheel will reduce the incidence of fixed-schedule PAR flow changes that exacerbate congestion. However, to reduce unnecessary price volatility from variations in loop flows, we recommend the NYISO consider

[259] See Recommendation #2012-13

developing a mechanism for forecasting additional adjustments from the telemetered value for loop flows that result from factors not scheduled by the NYISO. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude).[260]

- Section XI discusses our recommendation for the NYISO to consider modeling 115kV transmission constraints in upstate New York in the day-ahead and real-time markets.[261] This would also reduce unnecessary price volatility on 230kV transmission constraints in the West Zone because it would allow the NYISO real-time market to re-dispatch generation more efficiently to relieve congestion. Currently, any such re-dispatch occurs through less precise out-of-market instructions.[262]

E. 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 a portion of 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 (evaluated in this Subsection);
- Transmission shortages (evaluated in Subsection F); and
- Reliability demand response deployments (evaluated in Subsection G).

260 See Recommendation #2014-9.

261 See Recommendation #2014-12.

262 See Section V.H in the Appendix for more discussion on out-of-merit dispatch for West Zone 115 kV lines.

Figure A-73: Real-Time Prices During Physical 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-73 summarizes physical ancillary services shortages and their effects on real-time prices in 2015 and 2016 for the following five categories:

- 30-minute NYCA – The ISO is required to hold 2,620 MW of 30-minute reserves in the state and has a demand curve value of $25/MWh if the shortage is less than 300 MW, $100/MWh if the shortage is between 300 and 655 MW, $200/MWh if the shortage is between 655 and 955 MW, and $750/MWh if the shortage is more than 955 MW.[263]
- 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 $750/MWh.[264]
- 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 $775/MWh.[265]
- 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 $775/MWh.[266]
- 30-minute SENY – The ISO is required to hold 1300 MW of 30-minute operating reserves in Southeast New York and has a demand curve value of $500/MWh.[267]
- Regulation – The ISO is required to hold 150 to 300 MW of regulation capability in the state and has a demand curve value of $25/MWh if the shortage is less than 25 MW, $400/MWh if the shortage is between 25 and 80 MW, and $775/MWh if the shortage is more than 80 MW.[268]

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263 Prior to November 4, 2015, the ISO was required to hold 1,965 MW of 30-minute operating reserves in the state and had a demand curve value of $50/MWh if the shortage was less than 200 MW, $100/MWh if the shortage was between 200 and 400 MW, and $200/MWh if the shortage was more than 400 MW.

264 Prior to November 4, 2015, this demand curve value was $450/MWh.

265 Prior to November 4, 2015, this demand curve value was $500/MWh.

266 Prior to November 4, 2015, this demand curve value was $500/MWh.

267 This requirement became effective on November 4, 2015. The demand curve value was initially set at $25/MWh and increased to $500/MWh on June 1, 2016 with the implementation of the Comprehensive Scarcity Pricing Project.

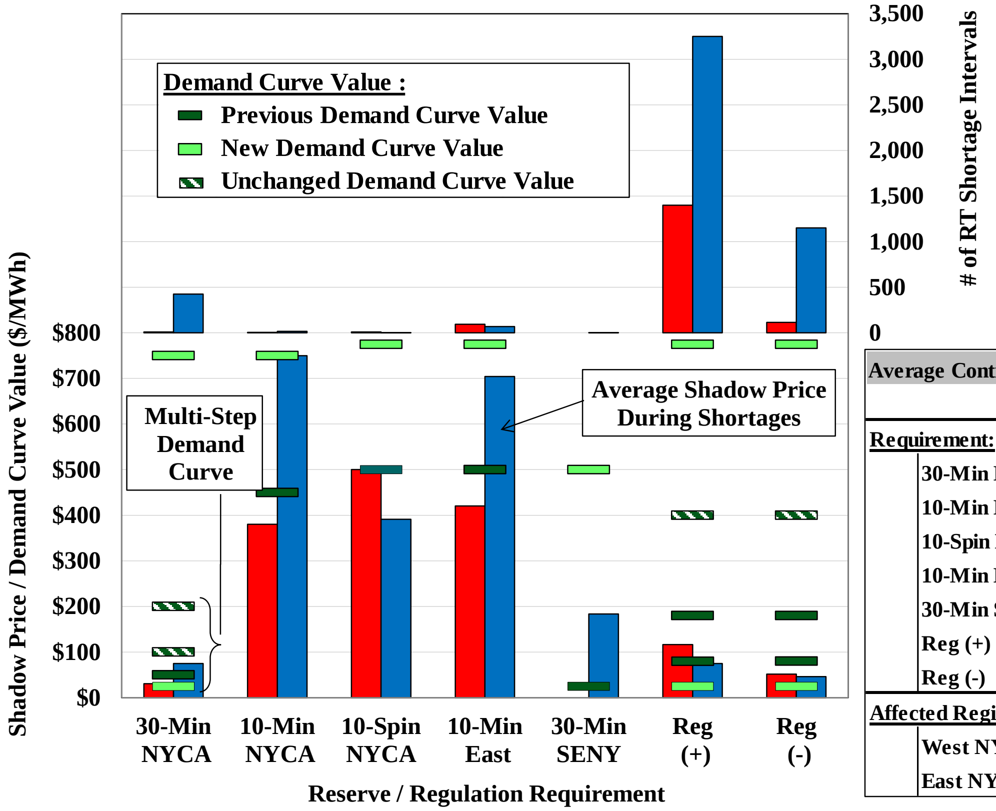
268 Prior to November 4, 2015, this demand curve value was $80/MWh if the shortage was less than 25 MW, $180/MWh if the shortage was between 25 and 80 MW, and $400/MWh if the shortage was more than 80 MW.

The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The changes in the demand curves for these ancillary services products on November 4, 2015 (or June 1, 2016 for SENY 30-minute reserves) are reflected in the chart. The dark green bars represent old demand curve values that are replaced after November 4, 2015 (or June 1, 2016 for SENY 30-minute reserves), the pattern-filled bars represent old demand curve values that are kept in the reset process, and the light green bars represent new demand curve values effective on November 4, 2015 (or June 1, 2016 for SENY 30-minute reserves).

The table shows the average shadow prices during physical 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; and
- Eastern New York – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

Figure A-73: Real-Time Prices During Ancillary Services Shortages
2015 – 2016



Average Contribution to Energy Price		2015	2016
Requirement:			
	30-Min NYCA	$0.00	$0.30
	10-Min NYCA	$0.01	$0.11
	10-Spin NYCA	$0.04	$0.01
	10-Min East	$0.37	$0.46
	30-Min SENY	$0.00	$0.01
	Reg (+)	$1.28	$1.69
	Reg (-)	-$0.03	-$0.28
Affected Region:			
	West NY	$1.31	$1.83
	East NY	$1.68	$2.30

Key Observations: Real-Time Prices During Physical Ancillary Services Shortages

- The frequency of physical shortages for NYCA 30-minute reserves and regulation rose substantially from 2015 to 2016, driven primarily by the following changes (made on November 4, 2015) that:
  - Increased NYCA 30-minute reserve requirement from 1,965 MW to 2,620 MW and limited the amount of reserves scheduled on Long Island resources.
  - Reduced the lowest demand curve value: a) from $50 to $25/MWh for the NYCA 30-minute reserves; and b) from $80 to $25/MWh for regulation.
    - The dispatch model "chose" to be short of 30-minute reserves and regulation when the cost to provide such services exceeded their lowest demand curve values.
- Regulation shortages were most frequent in both years, which occurred in 1.4 percent of all intervals in 2015 and 4.2 percent in 2016, and had the largest effects on real-time prices.
  - All other shortages occurred in less than 0.5 percent of all intervals each year.
- The average shadow price during physical shortages was close to the demand curve level for each class of reserves, indicating that real-time prices generally reflected these shortage conditions accurately in 2015 and 2016.[269]

F. Real-Time Prices During Transmission Shortages

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

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes.

If the available physical 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. This process changed

269 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 (although this has been uncommon since modeling enhancements were implemented in 2009). This can happen because RTD performs a pricing optimization that is distinct from the physical optimization that is used to determine dispatch instructions. The pricing optimization is employed so that block loaded generators (i.e., gas turbines) are able to set the clearing price under certain circumstances.

in November 2015 and February 2016 with the implementation of the Comprehensive Shortage Pricing project: [270]

- Before November 4, 2015: RTD determined the flow level that could be achieved by solving the market using an extremely high transmission constraint penalty cost. If this achievable flow was greater than the original limit, RTD would then set a relaxed limit equal to the achievable flow plus 8.0 MW. Then RTD would re-solve using a Transmission Shortage Cost of $4,000/MWh.
- From November 4, 2015 to February 12, 2016: RTD determined the flow level that could be achieved by solving the market using a transmission constraint penalty cost of $8,000/MWh for "base case" constraints and $4,500/MWh for contingency constraints. If this achievable flow was greater than the original limit, RTD set a relaxed limit equal to the achievable flow plus 0.2 MW. Then RTD would re-solve using a Transmission Shortage Cost of $4,000/MWh.
- After February 12, 2016: RTD continues to relax constraints as from November 4, 2015 to February 12, 2016, but the Graduated Transmission Demand Curve ("GTDC") is now used for some constraints.
  - For constraints where GTDC is used: RTD determines the flow level that can be achieved while treating the first 20 MW of the Graduated Transmission Demand Curve (i.e., $350/MWh for the first 5 MWs and $2,350/MWh for the next 15 MWs) as a resource that can relieve the constraint and set price if on the margin. RTD would still use the Transmission Shortage Cost of $4,000/MWh after exhausting the first 20 MW of the GTDC.
  - Criteria for using the GTDC for a particular transmission constraint in the relaxation procedure of a particular interval:
    - If the limiting facility has a Constraint Reliability Margin ("CRM") of 0 MW; or
    - If the amount of potential relief from rampable output ranges of dispatchable resources (at a cost lower than the applicable transmission constraint penalty cost of $8,000 or $4,500) is not sufficient to reduce flow below the original limit.

A conditions similar to a shortage occurs when 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. [271] In such cases, the marginal cost of resources actually dispatched to relieve the constraint is lower than the shadow price set by the offline gas turbine (which is not actually started). The Commission has recognized that it is not efficient for such units to set the

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270 See *New York Independent System Operator, Inc.*, Docket No. ER17-758, *Request for Tariff Waiver*, (January 6, 2017) for a more complete description of the pricing logic in place since February 12, 2016.

271 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.

clearing price because such a unit: (a) does not reflect the marginal cost of supply that is available to relieve the constraint in that time interval, and (b) does not reflect the marginal value of the constraint that may be violated when it does not generate as assumed in RTD.[272] This category of shortage is not evaluated in this section.

This subsection focuses on evaluating market performance during transmission shortages, particularly comparing the changes in congestion management before and after the GTDC became effective.

Table A-5 - Figure A-75: Real- Time Prices During Transmission Shortages

Table A-5 summarizes the frequency of transmission constraints, average shadow prices, and average amount of transmission shortages (relative to the BMS limit adjusted for the CRM) in the real-time market by constraint group in 2015 and 2016.[273] These quantities are summarized separately for intervals with and without transmission shortages. The quantities reported for 2016 only include periods after February 12, 2016 when the GTDC became effective.

Table A-5: Real-Time Constraint Summary
2015 - 2016

Location of Constrained Facility	Transmission Shortage	# of Constraint-Intervals		Average Transmission Shortage (MW)		Average Constraint Shadow Price ($/MWh)	
		2015	2016	2015	2016	2015	2016
West Zone	N	8,068	3,591			$165	$103
	Y	2,652	1,878	23	11	$668	$1,312
New York City	N	48,689	46,171			$35	$40
	Y	2,522	2,986	14	11	$240	$587
Long Island	N	24,629	26,958			$70	$45
	Y	702	2,226	16	13	$1,183	$624
All Other	N	26,354	25,554			$68	$41
	Y	444	518	45	17	$288	$1,076

Figure A-74 shows this information for individual 5-minute intervals with transmission shortages. In each of the four scatter plots, every point represents a binding transmission constraint during a 5-minute interval, with the amount of transmission shortage showing on the x-axis and the constraint shadow price on the y-axis. The GTDC (the black line) is also plotted to illustrate how constraint shadow costs deviate from this curve in many cases.

272 In Docket RM17-3-000, see the Commission's NOPR on Fast Start Pricing, dated December 15, 2016, and comments of Potomac Economics, dated March 1, 2017.

273 BMS limit is the constraint limit that is used in the market dispatch model. CRM represents Constraint Reliability Margin that is used for most constraints because of various differences between modeled flows and actual flows. For example, if a constraint has a 1000 MW BMS limit and a 20 MW CRM, the shortage quantities reported in this table are measured against a constraint limit of 980 MW.

Figure A-74: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2015- 2016

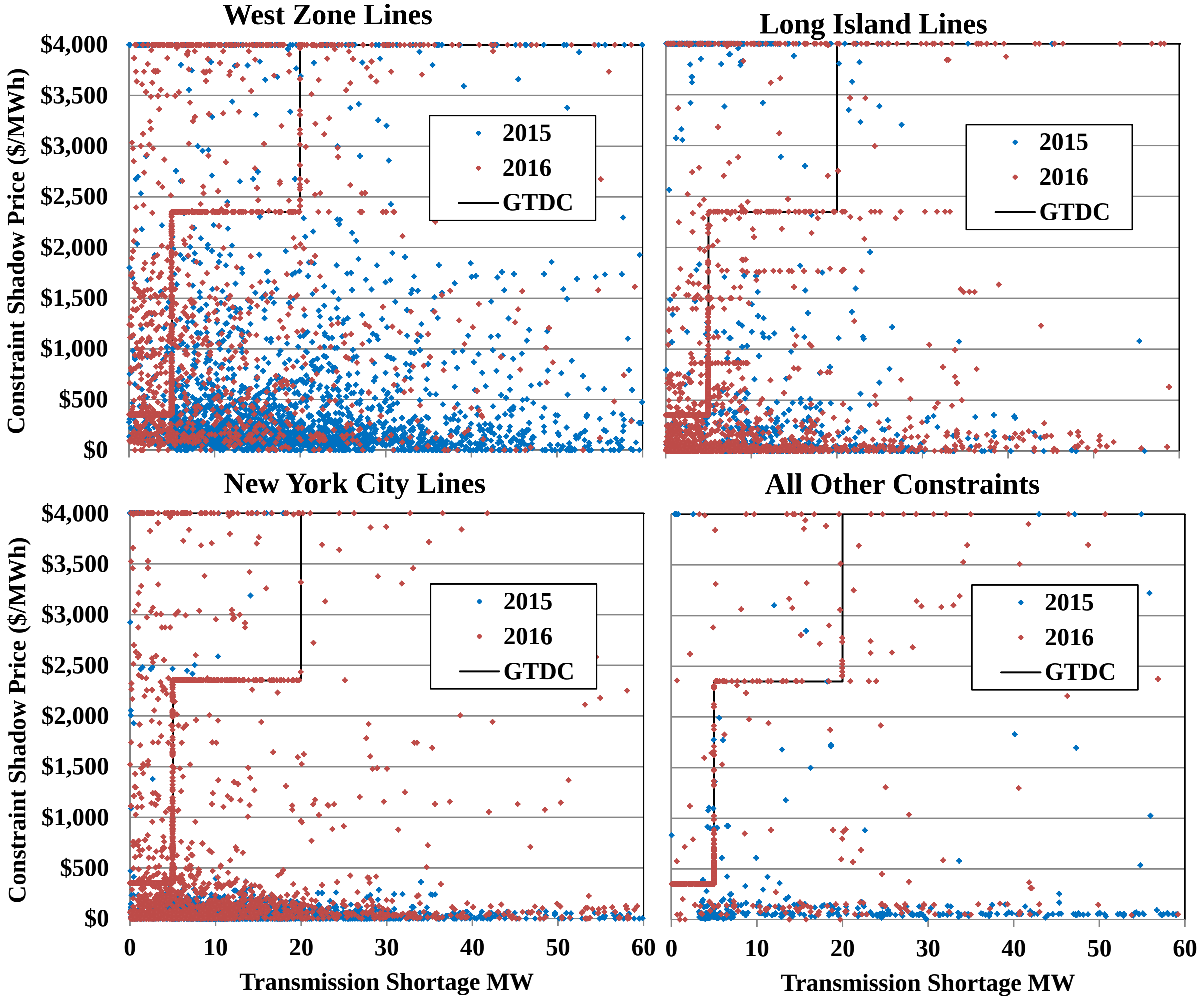
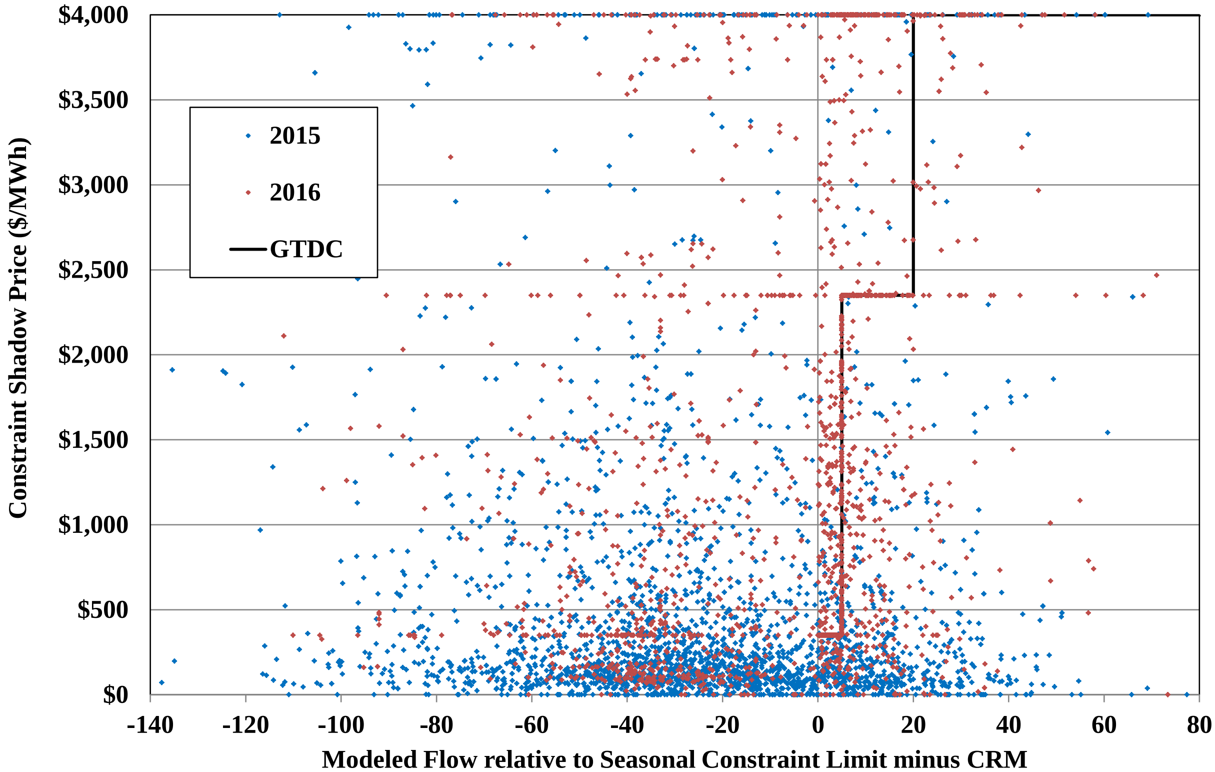


Figure A-75 takes a closer look at the West Zone constraints, which tend to be less predictable and less controllable than other constraints in the system (for the reasons discussed in Sections III.B, III.C, and III.D of the Appendix). Unlike Figure A-74 that shows shortage quantities relative to the BMS limit, this figure shows shortage quantities relative to the seasonal limit (still adjusted for the CRM). Negative numbers on the x-axis indicate that modeled flows are below the seasonal limit (minus the CRM).

Figure A-75: Transmission Shortage Pricing with the GTDC
West Zone Constraints, 2015- 2016



Key Observations: Real-Time Prices During Transmission Shortages

- The NYISO's market software divides constraints into the following three categories: [274]
  - *(1) Zero-CRM constraints* – This category includes facilities that usually lead out of generation pockets, so loop flows and other non-modeled factors are typically smaller. This makes the CRM unnecessary so the CRM is zero.
  - *(2) Feasible Non-Zero-CRM constraints* – The "preliminary screen" evaluates whether there are sufficient physical resources to resolve the constraint. If physical resources are sufficient, constraints are included in this category.
  - *(3) Infeasible Non-Zero CRM constraints* – The "preliminary screen" determines that sufficient physical resources are not available to resolve the constraint.
  - For categories (1) and (3), the economic dispatch runs with a $4,000/MWh price cap for the constraint, and the constraint limit is "relaxed" (i.e., increased) to allow the economic dispatch to find a feasible solution. For category (2), the software operates the same way except that the GTDC is applied.

274 The logic for determining how constraints are broken into the three categories was illustrated by a diagram on slide 4 of the NYISO's December 21 presentation to the MIWG.

- The current process implemented with the GTDC differs from the previous process in the following two ways. First, the previous process did not apply the GTDC, so all three categories were treated the same. Second, when the process relaxes a transmission constraint to find a feasible solution, the NYISO previously raised the constraint limit to the achievable flow level plus a limit adjustment of 8 MW.[275]
  - When it implemented the GTDC project, it reduced this additional relaxation adjustment in the limit from 8 MW to 0.2 MW, resulting in higher congestion shadow prices and smaller transmission shortages.
  - The reduced relaxation adjustment frequently led to shadow prices that were higher than the GTDC (see Figure A-74), which is not consistent with Market Service Tariff 17.1.1 and 17.1.4.[276]
- Of all transmission shortages after the implementation of the GTDC in 2016:
  - 6 percent involved Zero-CRM constraints (Category 1)
  - 39 percent involved Feasible Non-Zero-CRM constraints (Category 2)
  - 55 percent involved Infeasible Non-Zero-CRM constraints (Category 3)
- Table A-5 shows that transmission shortage quantities have fallen since the GTDC was implemented.
  - Higher shadow prices provide stronger incentives for external transactions (and other non-dispatchable resources) to avoid schedules that exacerbate congestion. Efficient prices provide incentives that are neither too strong nor too weak.
  - However, the shortage frequency rose in some areas due partly to less relaxation.
- In the West Zone, volatile loop flows and difficulty managing congestion can lead operators to reduce the BMS limit below the seasonal limit.
  - BMS limits and modeled flows have been much closer to the seasonal limits (i.e., higher) in 2016 in the West Zone partly because the GTDC project has improved the ability of RTS to manage flows.
- Despite better market outcomes under certain system conditions since the implementation of the GTDC, constraint shadow prices still often do not properly reflect the severity of the shortage.
  - This was due primarily to constraint relaxation that led constraint shadow prices to be generally uncorrelated with the shortage amount, the duration of the constraint, or any other measure of the severity of the shortage.

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[275] Effectively, it relaxed the constraint by 8 MW more than necessary to find a feasible solution.

[276] See *New York Independent System Operator, Inc.*, Docket No. ER17-758, *Request for Tariff Waiver*, (January 6, 2017).

- To address issues identified here, the NYISO proposed to: [277]
  - Eliminate Category 3 and instead apply the GTDC to all non-zero CRM constraints (i.e., Category 2); and
  - Reduce the second step of the GTDC from $2,350 to $1,175.
  - We support the proposal for the short-term because this would eliminate the unnecessary price volatility that results from the current process and recommend in the long-term replace current relaxation process with a set of constraint-specific GTDCs because they ensure a clear relationship between the shadow price and the severity of the constraint that is a better signal to market participants. [278]

G. 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. However, the use of demand resources is complicated by scheduling lead times and other inflexibilities. First, the NYISO must determine how much demand response to activate when there is still considerable uncertainty about the needs of the system. Second, the demand response may not be needed for the entire activation period. Hence, there may be substantial surplus capacity during portions of the event. Therefore, it is important to set real-time prices that properly reflect the costs of maintaining reliability when reliability demand response resources are deployed.

Figure A-76: Available Capacity and Real-Time Prices During DR Activation

NYISO deployed demand response (EDRPs and SCRs) on only one day (August 12) in 2016. The activation was in all zones for five hours (from 13:00 to 18:00) for system wide capacity needs. The subsection evaluates during this event: a) whether real-time prices efficiently reflected system conditions; and b) whether demand response deployments were necessary in retrospect to maintain adequate capacity.

In particular, Figure A-76 shows the following quantities in each interval during the period from 12:00 to 19:00 (including one hour before and after the activation period):

- Available capacity (shown as stacked areas in the figure) – Including four categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:

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277 See *New York Independent System Operator, Inc.*, Docket No. ER17-1453, *Proposed Tariff Revisions to Clarify and Enhance Transmission Constraint Pricing*, (April 21, 2017).

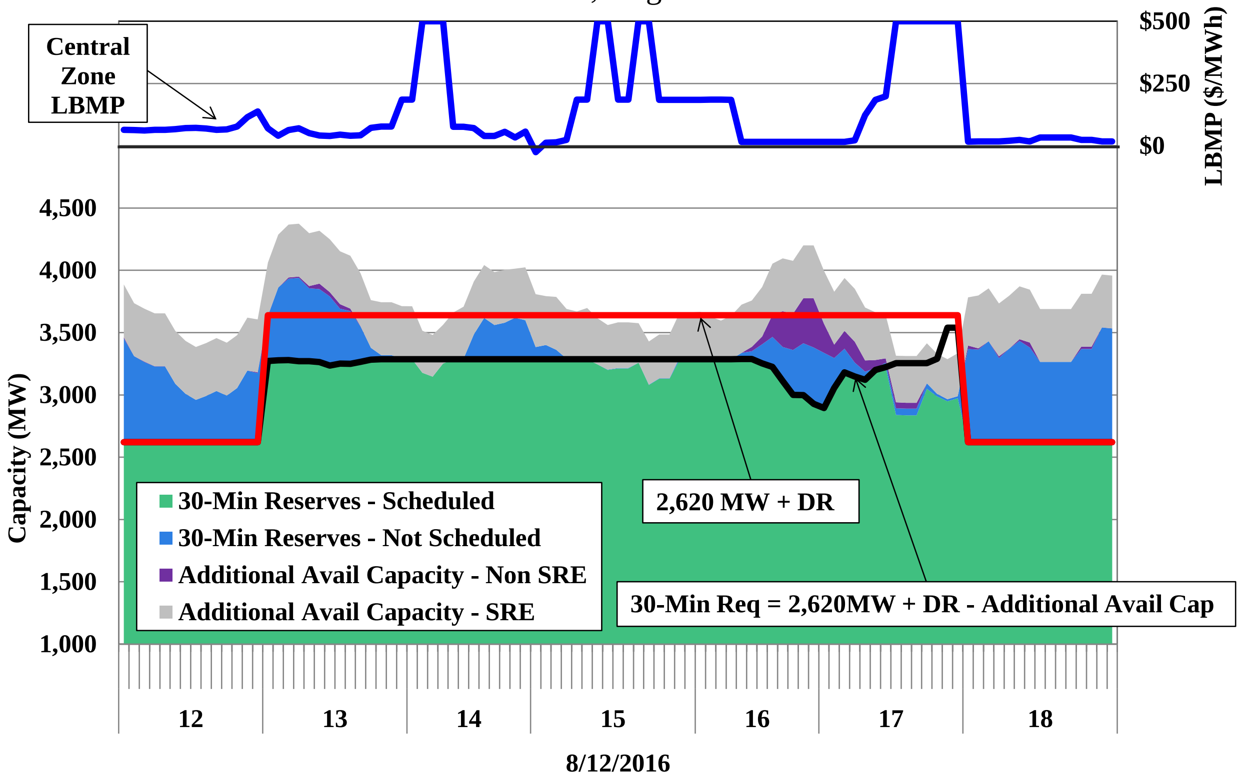
278 Recommendation #2015-17 discusses how the NYISO should further enhance real-time scheduling models during periods of severe congestion.

- Already scheduled 30-minute reserves;
- Unscheduled 30-minute reserves;
- Additional available capacity (beyond 30-minute rampable) from SRE resources; and
- Additional available capacity from non-SRE resources.

- The amount of demand response deployed plus the requirement for NYCA 30-minute reserves (red line).
- Market adjusted requirement (under new pricing rule) for 30-minute reserves (black line).
- LBMP of the least import-constrained zone in NYCA (blue line).

The deployment of demand resources was likely necessary to avoid a capacity deficiency when the amount of demand response deployment plus normal 30-minute reserve needs (which is 2620 MW) exceeds available capacity. This is shown in the figure when the red line is higher than all areas combined.

Figure A-76: Available Capacity and Real-Time Prices During DR Activation
NYCA, August 12



Key Observations: Real-Time Prices During Reliability Demand Response Deployments

- The NYISO activated demand response only on one day (August 12) during 2016. During this event: [279]
  - Demand response was deployed in all zones for system-wide capacity needs for five hours (HB 13-17).
  - Actual peak load was 31.5 GW (estimated peak of 32.4 GW without demand response).
    - An estimated ~1 GW of demand response was activated.
  - NYISO SREed (the day before) four Danskammer units and one Oswego unit.
- Our evaluation finds that:
  - In retrospect, demand response was needed to prevent a capacity deficiency (i.e., red line > height of all areas) in a total of 18 intervals during the 5-hour deployment period.
  - 30-minute reserves were priced at $500/MWh during all 18 intervals. The improved consistency between price signals and actual system needs is a significant enhancement under the new Scarcity Pricing Rule (effective on June 1, 2016).
- Nonetheless, in retrospect, the actual amount of demand response that was needed to avoid a reserve shortage was just ~350 MW (indicated by the largest difference between the red line and the height of all areas).
  - This implies an over-deployment of demand response (by more than 600 MW), which includes roughly 150 MW that was activated by utilities from their own demand response programs.
  - A total of $1.1 million of guarantee payments were made to demand response resources for their deployments (see Figure A-82).

H. 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

[279] See presentation "NYISO Summer 2016 Hot Weather Operations" by Wes Yeomans at 9/28/16 Market Committee Meeting for more details.

displaces economic production. Both types of out-of-market action lead to distorted real-time market prices, which tend to undermine market incentives for meeting 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.

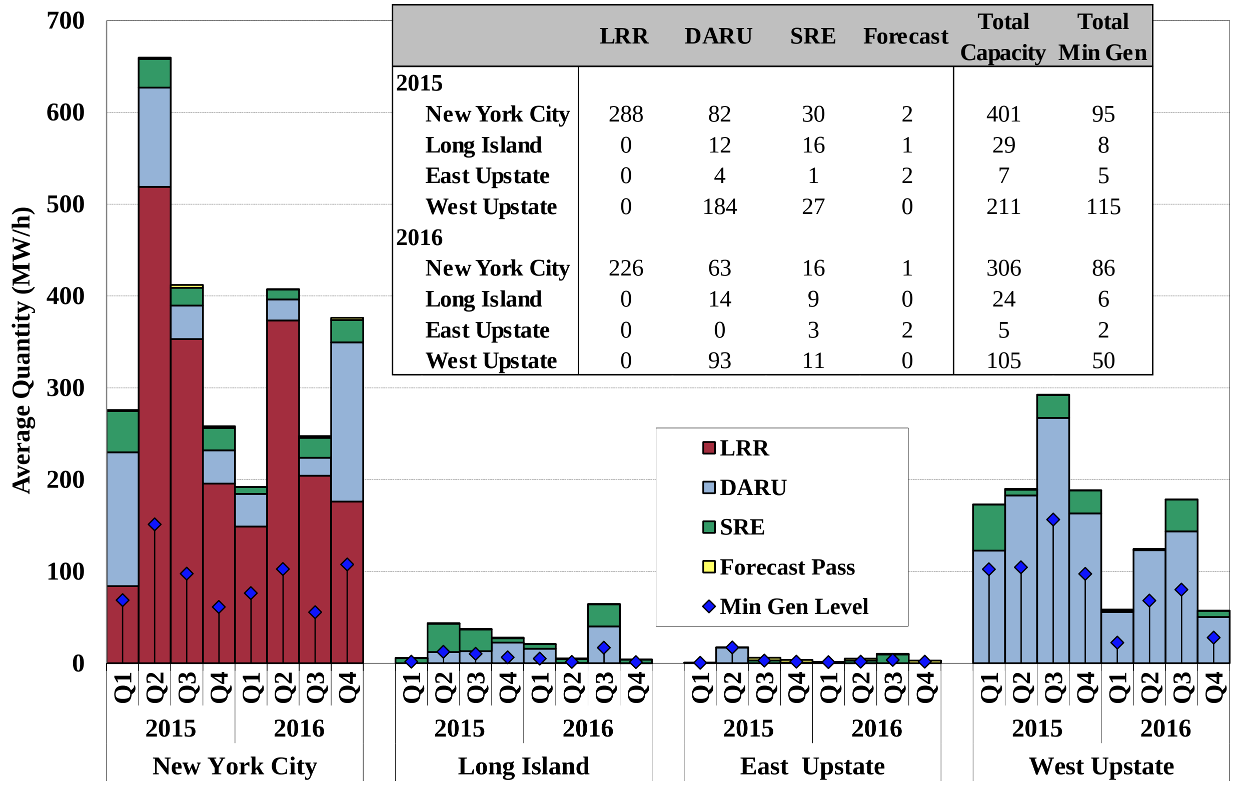
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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 New York City, the local Transmission Owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected 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 2015 and 2016. 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, which 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 2015 and 2016 on an annual basis.

Figure A-77: Supplemental Commitment for Reliability in New York
By Category and Region, 2015 – 2016



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2015						
New York City	288	82	30	2	401	95
Long Island	0	12	16	1	29	8
East Upstate	0	4	1	2	7	5
West Upstate	0	184	27	0	211	115
2016						
New York City	226	63	16	1	306	86
Long Island	0	14	9	0	24	6
East Upstate	0	0	3	2	5	2
West Upstate	0	93	11	0	105	50

Figure A-78: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability typically occurred in New York City. Figure A-78 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-78 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2015 and 2016.

Based on our review of the reliability commitment logs and LRR constraint information, each hour of commitment that was flagged as DARU, LRR, or SRE was categorized as committed for one of the following reliability reasons: [280]

- NOx Only – If needed for NOx bubble and no other reason. [281]

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

281 The New York Department of Environmental Conservation ("NYDEC") promulgates Reasonably Available Control Technology ("RACT") emissions standards for NOx and other pollutants, under the federal Clean Air Act. The NYDEC NOx standards for power plants are defined in the Subpart 227-2.4 in the Chapter III of Regulations : "Reasonably Available Control Technology (RACT) For Major Facilities

- Voltage – If needed for Application of Reliability Rule (“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 to protect NYC against a sudden loss of gas supply and no other reason except NOx. [282]
- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, and Loss of Gas. 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 2016 only.

of Oxides Of Nitrogen (NOx) - Control Requirements”, which is available online at: http://www.dec.ny.gov/regs/4217.html#13915.

282 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

Figure A-78: Supplemental Commitment for Reliability in New York City
By Category and Region, 2015 – 2016

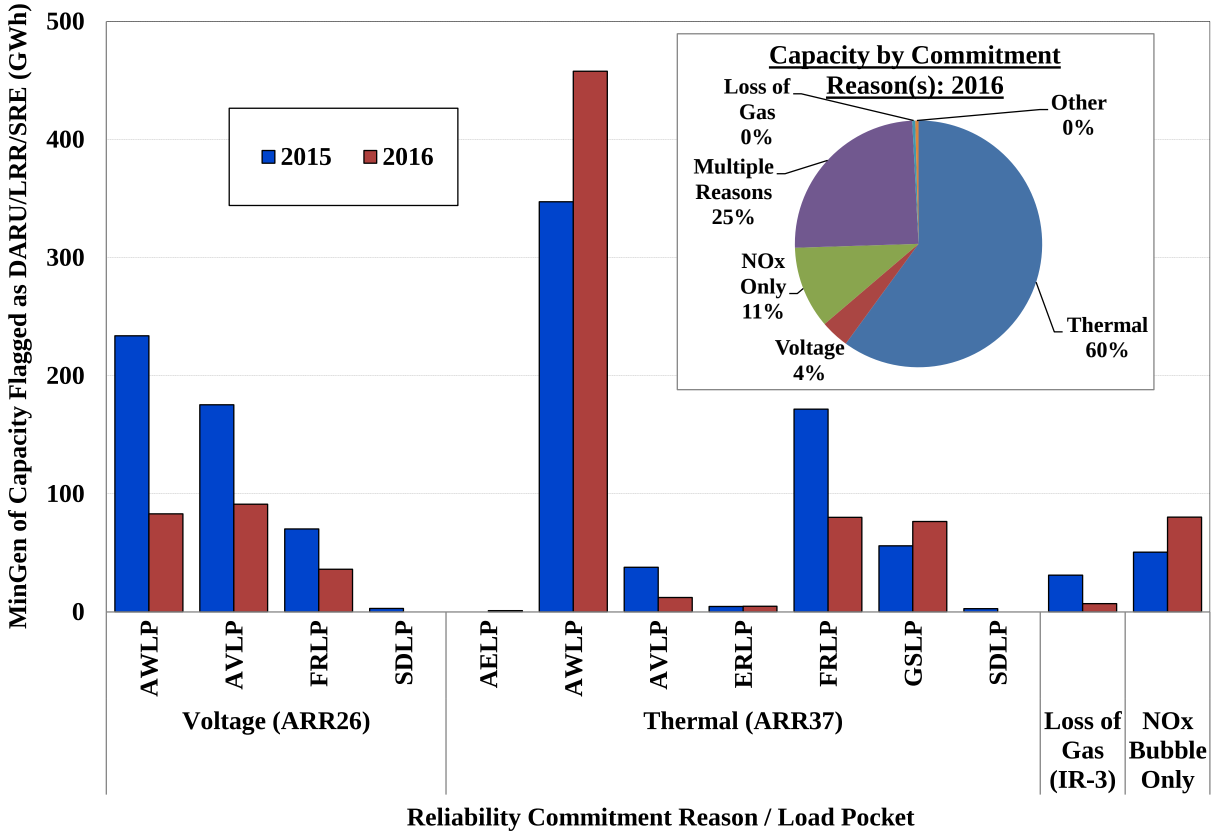


Figure A-79: NOx Emissions from Units in New York City NOx Bubbles

Supplemental commitments for the NOx Bubble constraint occur during the five-month Ozone season (i.e., from May to September) each year. The following analysis evaluates the overall efficiency of such commitments.

Many simple-cycle gas turbines in New York City emit NOx at rates that exceed the presumptive RACT limits.[283] For owners of generators that emit beyond the presumptive RACT limits, they have the following three "compliance options": [284, 285]

- Fuel Switching Option;
- System Averaging Plan – This allows a "weighted average permissible emission rate" across multiple generators; and

283 See 9 NYCRR III , §227-2.4 "Control Requirements" for these presumptive limits.

284 See 9 NYCRR III , §227-2.5(a) - (c) for more details.

285 A fourth compliance option, "shutdown of an emission source," is also listed in 9 NYCRR III , §227-2.5(d).

- Higher source-specific emission limit – This may be allowed if "the applicable presumptive RACT emission limit is not economically or technically feasible." [286, 287]

In "System Averaging Plan", the generation owners request that their steam generators and gas turbines be measured for compliance together. Since the steam units emit below the presumptive RACT limits, having a steam unit online when a gas turbine is operating will result in a lower average NOx rate than if the gas turbines operates alone.

For generation portfolios with approved System Averaging Plans, the NYISO has in turn established an LRR constraint for each generation portfolio. These LRR constraints require that at least one steam unit from each portfolio be committed each day during the five-month Ozone season. [288] This is to ensure that the NOx emission limits won't be violated if gas turbines are committed in real-time. This LRR rule provides uplift payments to the generation owners when the steam commitments are uneconomic at day-ahead LBMPs.

Figure A-79 presents energy production and NOx emissions from different generation types for New York City, by time of day and by load level. The bottom section shows average hourly energy production for NOx Bubble gas turbines and steam units and average hourly offline available capacity from combined cycles and simple cycle turbines with Selective Catalytic Reduction ("SCR") equipment. The top section of the chart shows average hourly NOx emissions for NOx Bubble gas turbines and steam units.

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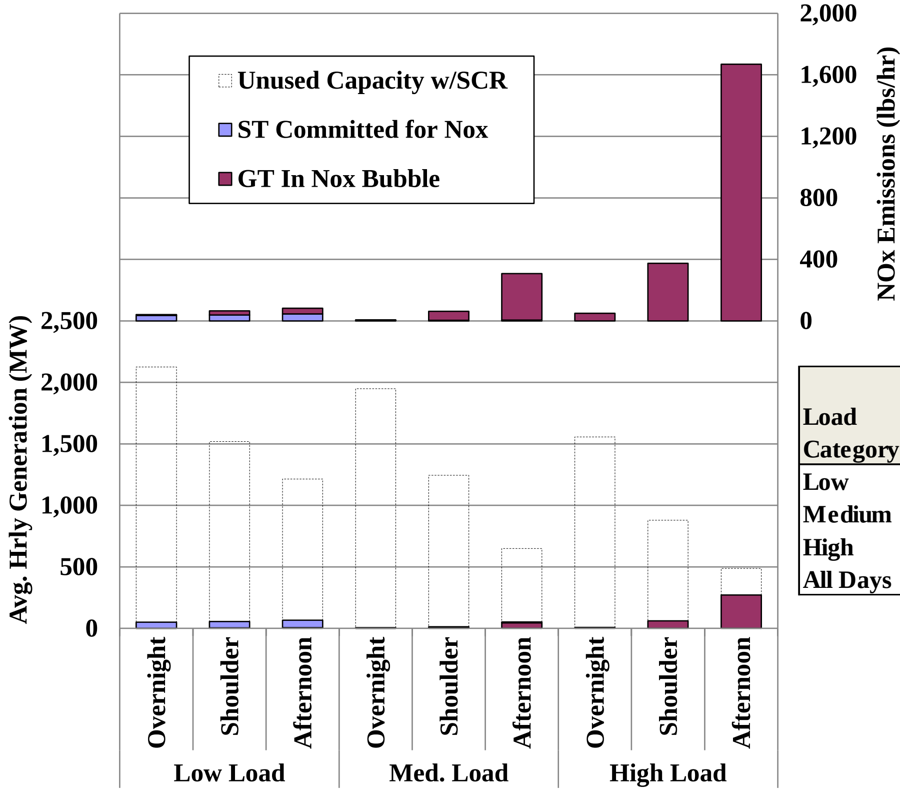
286 The current economic feasibility threshold in the NYDEC regulations is $5,000 per ton of NOx reduced. This threshold was first introduced as $3,000 per ton of NO_x reduced (based on a 1994 finding). The NYDEC elaborates "$3,000.00 dollars in 1994 equates to $4,637.73 dollars in 2012, which is then rounded up to $5,000 by the Department to ensure a level of conservatism." See DAR-20 Economic and Technical Analysis for Reasonably Available Control Technology (RACT).

287 The NYDEC provides a template for calculating the cost of emissions controls per ton of NOx reduced at http://www.dec.ny.gov/docs/air_pdf/dar20table1.pdf.

288 In May 2014, the NYISO updated one of three NOx LRR constraints to reflect that one portfolio could use a combined cycle unit instead of a steam unit to balance the simple-cycle turbines. See "Ravenswood Generating Station Nitrogen Oxide Emission Control Strategy for Compliance with 6 NYCRR Subpart 227-2."

Figure A-79: NOx Emissions and Energy Production from NOx Bubble Generators
By Time of Day, by Load Category, for 2016



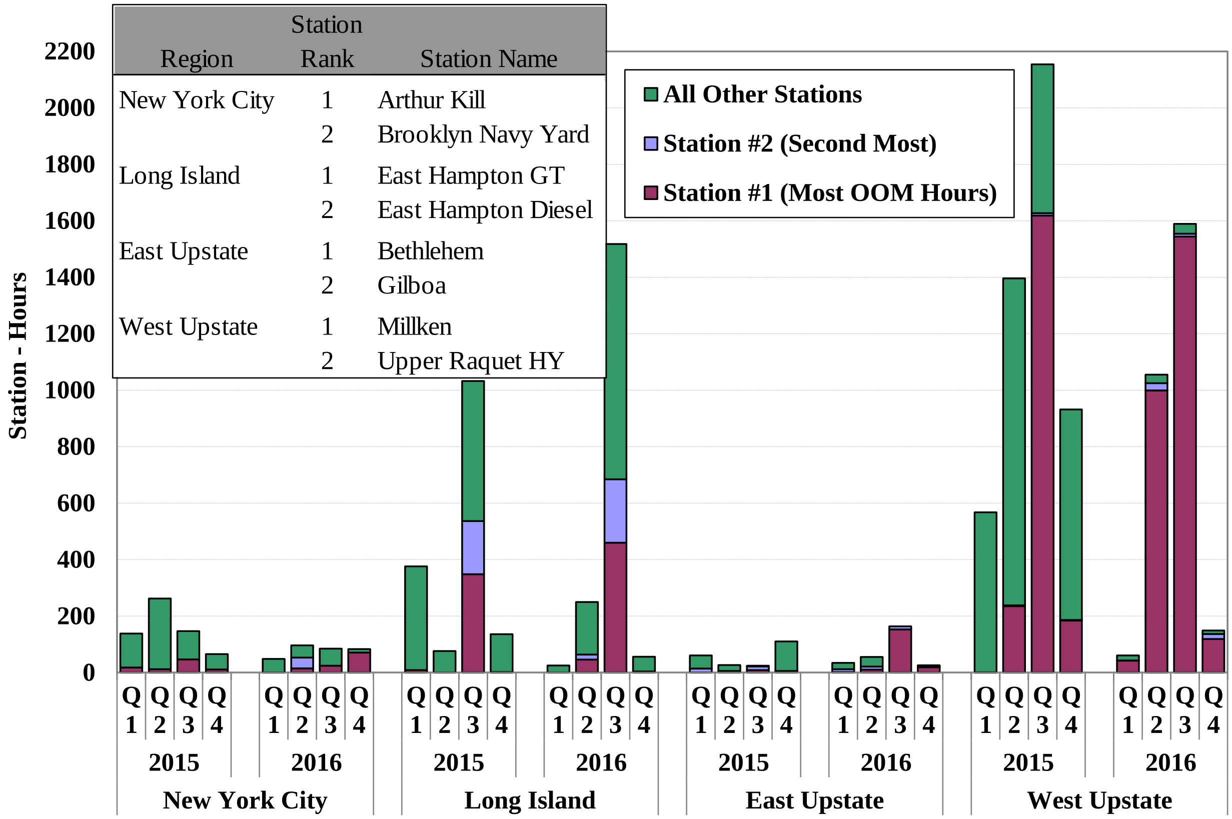
Load Category:	Output from GTs in NOx Bubble	Output from STs Committed for NOx
Low	5%	90%
Medium	23%	10%
High	72%	0%
All Days	100%	100%

Figure A-80: Frequency of Out-of-Merit Dispatch

Figure A-80 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2015 and 2016 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 2016 are shown separately from other stations (i.e., “Station #1” is the station with the highest number of OOM hours in that region during 2016, 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-80: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2015 - 2016



Key Observations: Supplemental Commitment and OOM Dispatch for Reliability

- An average of 440 MW of capacity was committed for reliability in 2016, down 32 percent from 2015.
  - New York City (70 percent) and Western New York (24 percent) accounted for the vast majority of reliability commitment in 2016.
- Reliability commitments in Western New York fell roughly 50 percent from 2015.
  - The reduction was driven partly by reduced local needs because of recent transmission upgrades that facilitated several unit retirements in Western New York. With several coal retirements, the vast majority of DARU commitments have recently occurred in the Central Zone at the Cayuga (Milliken) plant.
  - SRE commitments in the North Zone have occurred much less frequently since March 2014 because of transmission upgrades that greatly reduced local needs. Nonetheless, SRE commitments still occurred in the North Zone when certain transmission outages were present.

- Reliability commitments on Long Island have occurred much less frequently in recent years because of transmission upgrades in early 2014.[289]
  - DARU commitments rose modestly in the third quarter of 2016 because higher load levels and more transmission outages led to increased needs to prevent voltage collapse from inadequate transient voltage recovery.
  - SRE commitments were mainly to keep steam turbines online during overnight hours.
- Reliability commitment in New York City averaged roughly 305 MW in 2016, down 24 percent from 2015. Most of these commitments in 2016 were made to satisfy the N-1-1 thermal and voltage requirements in the Astoria West/Queensbridge load pocket.
  - Reliability commitments in New York City are frequently driven by transmission and generation outages.
    - Fewer transmission and generation outages led to reduced local needs and fewer reliability commitments in 2016.
    - Nonetheless, DARU commitments rose notably in the fourth quarter of 2016 when transmission outages increased the needs in the Freshkills load pocket.
  - The units often needed for local reliability were economically committed more frequently in 2016, particularly in the second and third quarters, reflecting:
    - Larger gas spreads between New York City (on the low side) and the rest of Eastern New York (on the high side);
    - Lengthy nuclear outages in Lower Hudson Valley in the second quarter; and
    - Higher load levels in the summer.
- Similar to prior years, our analysis indicates that in 2016 the NOx bubble constraints did not lead to efficient reductions in NOx emissions and most likely led to higher overall NOx emissions.
  - When steam turbine units were committed for the NOx Bubble constraints, the output from the steam turbine units usually displaced output from newer cleaner generation in New York City and/or displaced imports to the city.
  - On average, over 1.5 GW of offline capacity from newer and cleaner generators (equipped with emission-reducing equipment) were available and unutilized in hours when steam units were committed only for the NOx bubble constraint.
  - The steam units emit approximately 13 times more NOx per MWh produced than the newer generators with emission-reduction equipment.

289 The transmission upgrades included the installation of the West Bus Distributed Reactive Sources ("DRSS") and Wildwood DRSS, which have reduced the need to: a) commit generation for voltage constraints (see ARR 28); and b) burn oil to protect Long Island from a loss of gas contingency (See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.3 Local Area Operation: Loss of Gas Supply – Long Island, Requirement R1).

- Committing steam turbines for the NOx Bubble constraints rarely reduced output from gas turbines with high emissions rates.
  - In 2016, 95 percent of output from the NOx Bubble gas turbines occurred on days with medium to high load levels, while 90 percent of the output from steam units committed for the NOx constraint occurred on low-load days.
  - Hence, the commitment of steam turbines for NOx Bubble constraints rarely coincided with the operation of gas turbines. In virtually all cases where a steam turbine was running at the same time as a gas turbine, the steam turbine was already committed for economics or some other reliability need.

- Generators were dispatched Out-of-Merit ("OOM") for 5,295 station-hours in 2016, down 29 percent from 2015.
  - The decrease primarily occurred in Western New York, where OOM dispatch accounted for 54 percent of all OOM station-hours in 2016 and fell 43 percent from 2015 to 2016.
    - The reduction in Western New York was primarily attributable to transmission upgrades that allowed the mothball of the last Dunkirk unit at the end of 2015, which was frequently OOMed for local reliability needs.
    - Relatively high OOM levels in the second and third quarters were from frequent OOM dispatch of the Milliken units to secure the Elbridge-State Street 115kV lines for various contingencies.
  - OOM dispatch in Long Island accounted for 35 percent of OOM actions in 2016, up modestly from 2015 and offsetting overall reduction in 2016.
    - Most of these OOM instructions were to dispatch peaking generators to manage voltage constraints on the East End of Long Island. Higher load levels and more frequent transmission outages led to increased needs in the third quarter of 2016.
  - Furthermore, the Niagara generator was often manually instructed to shift output between the generators at the 115kV station and the generators at the 230kV station in order to secure certain 115kV and/or 230kV transmission facilities.
    - However, these were not classified as OOM in hours when the NYISO did not adjust the UOL or LOL of the Resource.
    - In 2016, this manual shift was required in about 600 hours to manage 115 kV constraints and in 950 hours to manage 230 or 345 kV constraints.
    - This pattern has continued since the Huntley reactors were activated in May 2016.

I. 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-81 and Figure A-82 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.

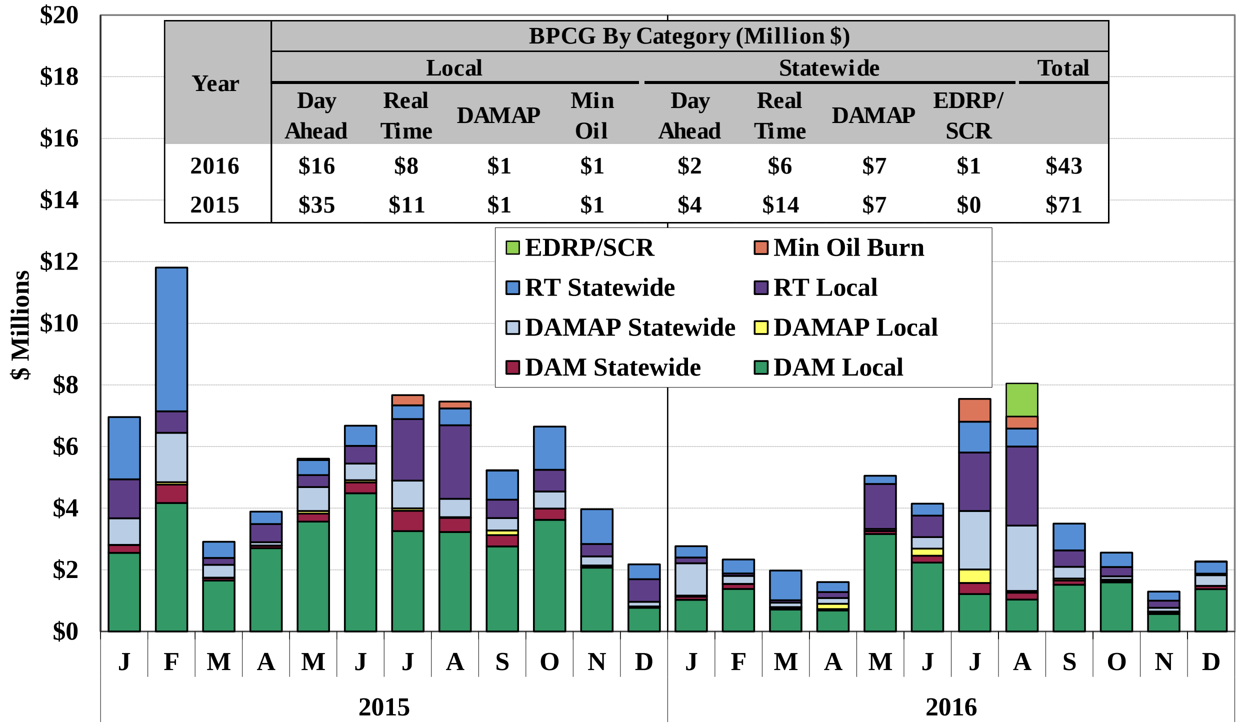
Figure A-81 & Figure A-82: Uplift Costs from Guarantee Payments

Figure A-81 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2015 and 2016. 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-82 shows the seven categories of uplift charges on a quarterly basis in 2015 and 2016 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-81 and Figure A-82 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.

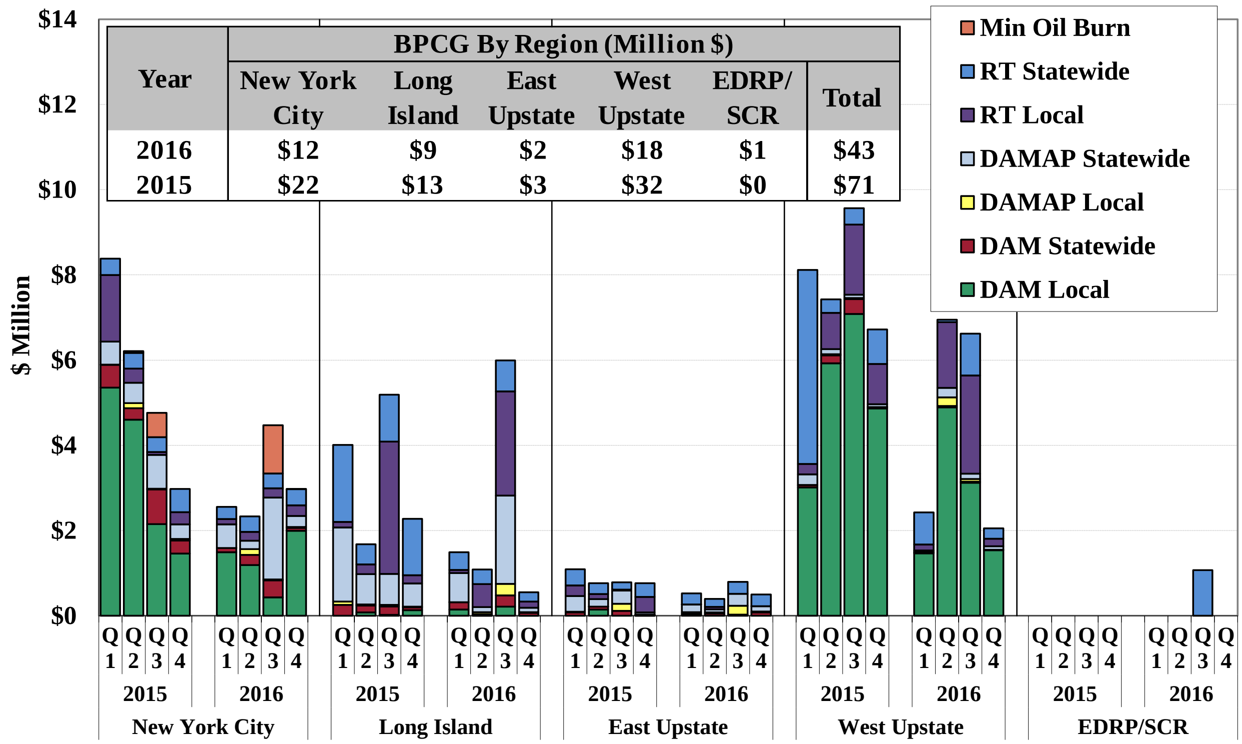
Figure A-81: Uplift Costs from Guarantee Payments by Month

2015 – 2016



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2016	$16	$8	$1	$1	$2	$6	$7	$1	$43
2015	$35	$11	$1	$1	$4	$14	$7	$0	$71

Figure A-82: Uplift Costs from Guarantee Payments by Region
2015 – 2016



Year	BPCG By Region (Million $)					Total
	New York City	Long Island	East Upstate	West Upstate	EDRP/ SCR	
2016	$12	$9	$2	$18	$1	$43
2015	$22	$13	$3	$32	$0	$71

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell 39 percent from $71 million in 2015 to $43 million in 2016. The reduction was consistent with:
  - Decreased supplemental commitment and OOM dispatches for the reasons discussed earlier; and
  - Lower natural gas prices, which decreased the commitment costs of gas-fired units, particularly in New York City.
- Of the total guarantee payment uplift in 2016:
  - Local reliability uplift accounted for 63 percent, while non-local reliability uplift accounted for the remaining 37 percent.
  - Western New York accounted for 42 percent, New York City accounted for 29 percent, and Long Island accounted for 21 percent.
- Local uplift in Western New York totaled more than $15 million, accounting for 36 percent of total guarantee uplift in 2016.
  - Nearly all of the local uplift was paid to several units that were committed for reliability and/or OOMed to manage congestion on the 115 kV transmission facilities.
- Higher load levels on several days in July and August led to:

- Higher DAMAP payments to New York City and Long Island gas turbines. DAMAP payments typically accrued during intervals with real-time price spikes when the units were scheduled for energy in the day-ahead market but not in the real-time market;
- Higher guarantee payments to New York City units for the Minimum Oil Burn requirement; and
- Additional guarantee payments to demand response resources because of EDRP/SCR activation.

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.[290] The NYISO also determines the Minimum Locational Installed Capacity Requirements ("LCRs") for New York City, the G-J Locality, and Long Island, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirement.[291]

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. The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual coincident peak load in each area. LSEs can satisfy their UCAP requirements by purchasing capacity through bilateral contracts, by self-scheduling their own capacity, or by participating in UCAP market auctions run by the NYISO.

The NYISO conducts three UCAP auctions: a forward strip auction where capacity is transacted in six-month blocks for the upcoming capability period, a monthly forward auction where capacity is transacted for the remaining months of the capability period, and a monthly spot auction. The two forward markets are voluntary, but all requirements must be satisfied at the conclusion of the spot market immediately prior to each month. Market participants 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

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290 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 17.5 percent in the most recent Capability Year (i.e., the period from May 2016 to April 2017). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/pdf/Reports/ 2016%20IRM%20Tech%20Study%20Report%20Final%2012-15-15.pdf".

291 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 103.5 percent in the period from May 2015 to April 2016 and 102.5 percent in the period from May 2016 to April 2017. The New York City LCR was 83.5 percent in the period from May 2015 to April 2016 and 80.5 percent in the period from May 2016 to April 2017. The LCR for the newly implemented G-J Locality was set at 90.5 percent in the period from May 2015 to April 2016 and 90 percent in the period from May 2016 to April 2017. Each IRM Report recommends Minimum LCRs for New York City, Long Island, and the G-J Locality, 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".

purchased in each locality in each monthly UCAP spot auction.[292] 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 four years, the NYISO updates the capacity demand curves.[293] 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. Each year starting in 2017, the demand curve is adjusted to account for changes in estimated energy and ancillary services net revenue. The demand curve price equals $0 when the quantity of UCAP procured exceeds the UCAP requirement by 12 percent for NYCA, 15 percent for the G-J Locality, and 18 percent for both New York City and Long Island. The demand curve is defined as a straight line through these two points.[294]

This report evaluates a period when there were four capacity market Localities: G-J Locality (Zones G to J), New York City (Zone J), Long Island (Zone K), and NYCA (Zones A to K).[295] New York City, Long Island and the G-J Locality are each nested within the NYCA Locality. New York City is additionally nested within the G-J Locality. Distinct requirements, demand curves, and clearing prices are set in each individual capacity market Locality, although the clearing price in a nested Locality cannot be lower than the clearing price in the surrounding Locality.

Figure A-83 through Figure A-86 in sub-sections VI.A –VI.C summarize: (a) trends in installed capacity by technology and by location, (b) levels of capacity imports and exports from other control areas, and (c) equivalent forced outage rates (“EFORd”) of gas and oil-fired units.

To evaluate the performance of the capacity market, the figures in the rest of the section show the capacity market results from May 2015 through February 2017. Figure A-87 through Figure A-90 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. Sub-section VI.D evaluates NYCA overall, and sub-section VI.E evaluates the performance in the local capacity zones.

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292 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 participants’ offers and bids.

293 This rule was amended in 2016. Before the 2016 demand curve reset, each reset set the demand curves for three years rather than four.

294 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2013/2014, 2014/2015, 2015/2016, and 2016/2017 Capability Years 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”.

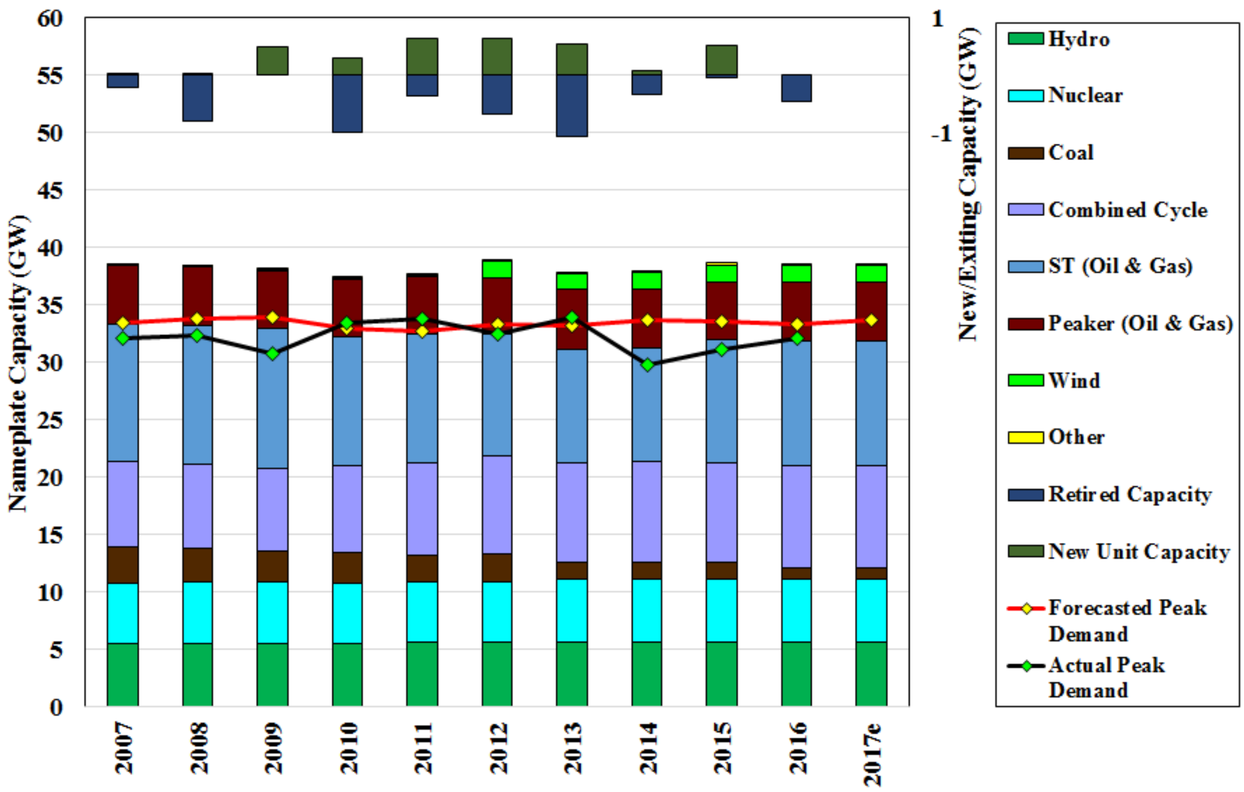
295 The NYISO began to model the “G-J Locality” in May 2014.

A. Installed Capacity of Generators in NYCA

Figure A-83 - Figure A-84: Installed Capacity Nameplate and Forecasted Peak Demand

The bottom panel of Figure A-83 shows the total installed summer capacity of generation (by prime mover) and the forecasted and actual summer peak demands for the New York Control Area for the years 2007 through 2017.[296] The top panel of Figure A-83 shows the amount of capacity that entered or exited the market during each year. Figure A-84 shows a regional distribution of generation resources and the forecasted and actual non-coincident peak demand levels for each region over the same timeframe. The installed capacity shown for each year is based on the summer capacity rating of resources that are operational at the beginning of the Summer Capability Period of that year (i.e., capacity online by May 1 of each given year).

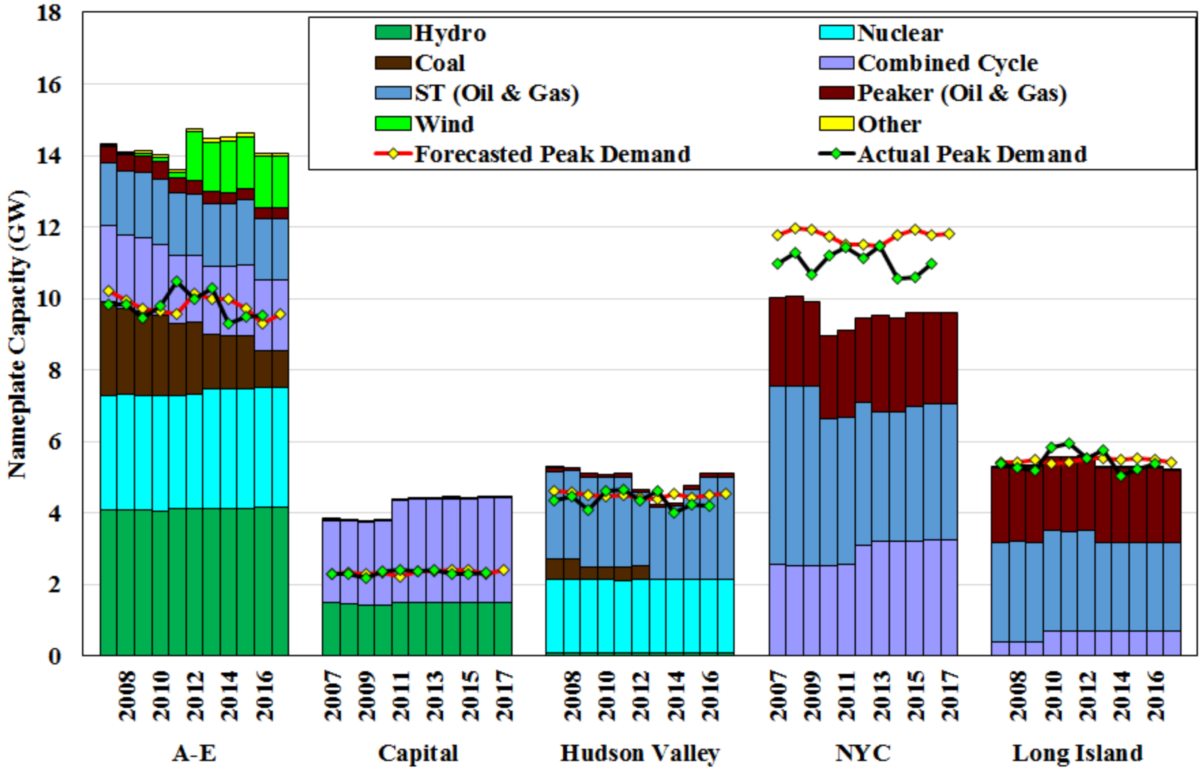
Figure A-83: Installed Capacity Nameplate of Generation by Prime Mover
2007 - 2017[297]



296 The summer peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. The installed capacity shown is based on data from the 2016 NYISO Gold Book. The actual UCAP available is lower than the nameplate ICAP due to the seasonal variations in available capacity and due to various forced or unforced outages that reduce the actual generation capacity.

297 Data for the 2017 calendar year represents the capacity from the 2016 Gold Book updated with information from the Generator Status Update files available at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Figure A-84: Installed Capacity Nameplate of Generation by Region and by Prime Mover
2007 - 2017



Key Observations: Installed Capacity in NYISO

- The total generating capacity in the NYISO remained relatively flat just under 40 GW (summer) between 2007 and 2017.[298] However, since 2007, almost 5 GW of capacity has left the market by retiring or mothballing. In the same timeframe, more than 4 GW of capacity has entered the market in the form of new resources or return of mothballed units. The capacity mix in New York is predominantly gas and oil resources (64 percent) while the remainder is primarily hydro and nuclear (15 and 14 percent, respectively).
  - Reliance on natural gas-fired capacity has increased over the years, increasing from 63 percent of total capacity in 2007 to 65 percent today. This growth is primarily attributable to new combined cycle resources which have increased by almost 2 GW. Major gas-fired unit additions include the Empire (Capital zone), Caithness (Long Island), Astoria Energy II (New York City), and Bayonne (New York City) facilities that commenced commercial operations between 2009 and 2012. In addition, a 680 MW combined cycle facility in Zone G (CPV Valley Energy Center) is at an advanced stage of development and is projected to be operational in 2018.[299]

298 Capacity numbers listed in this section are nameplate values, unless otherwise noted.

299 See NYISO Interconnection Queue at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/NYISO_Interconnection_Queue/NYISO%20Interconnection%20Queue.xls

- On the other hand, a combination of low gas prices and stronger environmental regulations have led to the retirement of the majority of coal-fired generating facilities in New York. The capacity associated with coal units has shrunk from more than 3 GW in 2007 to 1 GW in 2016, a 68 percent decrease.[300] Other notable retirements include Poletti 1 in NYC in 2010. Astoria 4 in NYC in 2012, and the Glenwood 04 and 05 units in Long Island in 2012.[301]
- The implementation of policies favorable to renewable energy helped drive investment in new wind resources, adding roughly 1.4 GW of nameplate capacity to the state resource mix.[302] Most of this capacity is located in zones A-E, with significant amounts of additional wind capacity projected to enter as the procurement of Tier1 Renewable Energy Credits accelerates under the Clean Energy Standard.

- As shown in Figure A-84, a dichotomy exists in the state between the eastern and western regions with the western zones (Zones A-F) possessing greater fuel diversity in the mix of installed capacity resources. This stands in contrast to the eastern zones (Zones G-J) which tend to rely more exclusively on gas and oil-fired resources.
  - Gas and oil-fired generators comprise just under 30 percent of the installed capacity in zones A-E, whereas almost 100 percent of installed capacity in Zones J and K are gas or oil-fired units.[303] The recently announced retirement of the Indian Point nuclear units will exacerbate the downstate fuel diversity situation with almost the entirety of remaining installed capacity in zones G-K being gas or oil-fired.[304]
  - While the fuel diversity in the state exists primarily in the western zones, there has been considerably larger new investments in non-wind resources in the eastern zones where capacity prices tend to be higher.

300 The reduction in coal capacity in the state and the corresponding drop in total installed capacity is not directly one-to-one since four units at the Danskammer station converted from coal to natural gas-fired.

301 The owners of the Fitzpatrick nuclear plant submitted a notice of intent to retire in November 2015. However, the plant owner has subsequently initiated several actions (including those related to refueling and sale of the plant) that indicate the plant will continue to operate. Although the plant owner has not rescinded its notice, there is considerable evidence to suggest the plant will remain in service. Therefore, we did not deem the unit as retired for the purpose of our installed capacity estimate for 2017.

302 See Section I.G of the Appendix for the contribution of federal and state incentives to the net revenues of a hypothetical wind unit in New York.

303 This excludes small contributions from “Other” fuel sources such as solar in Long Island.

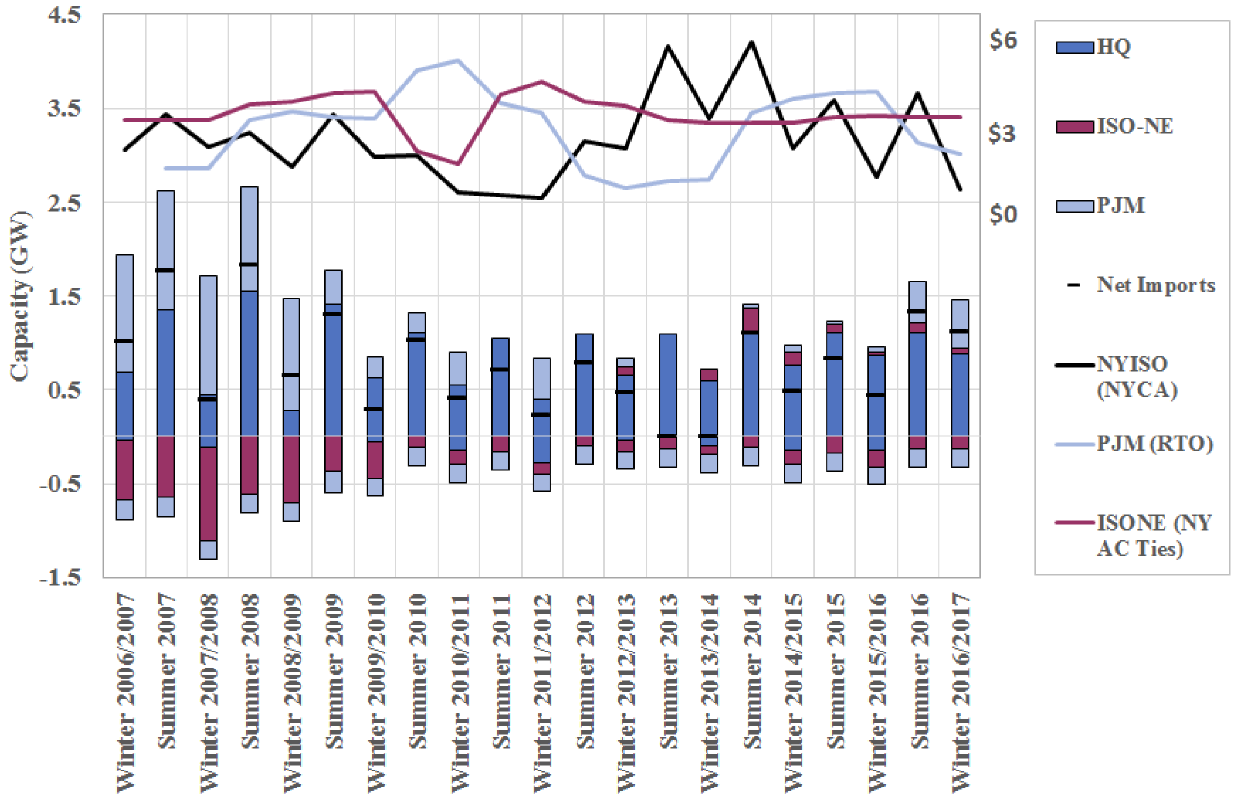
304 Entergy announced on Jan 9, 2017 its intentions to close the Indian Point nuclear units in 2020 and 2021. See: “http://www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/”.

B. Capacity Imports and Exports

Figure A-85: NYISO Capacity Imports and Exports by Interface

Figure A-85 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2006/07 through Winter 2016/17[305] along with capacity prices in the New York Control Area and its neighboring control areas. The capacity imported from each region is shown by the positive value stacked bars, while the capacity exported from the NYCA is shown as negative value bars. The capacity prices shown in the figure are: (a) the NYCA spot auction price for NYISO; (b) the RTO price in the Base Residual Auction for PJM; and (c) the NY AC Ties price in the Forward Capacity Auction for ISO-NE.

Figure A-85: NYISO Capacity Imports and Exports by Interface
Winter 2006/07– Winter 2016/17



Key Observations: Capacity Imports and Exports

- Capacity imports and exports flow between NYISO and three of its neighboring regions: Hydro Quebec, PJM, and ISO-NE. NYISO's capacity imports and exports have fluctuated over the years and have exhibited a seasonality that is a function of several factors, including but not limited to the price differences between control areas.
- HQ is a large exporter of hydro capacity with an internal load profile that peaks in the winter. As such, since the summer 2010 capability period, the imports from HQ have

305 This data shown is the monthly average of capacity imported/ exported over the capability period.

generally been at their maximum CRIS-allocated value, averaging nearly 1.2 GW in summer capability periods. However, imports from HQ during winter months dip substantially with the direction of capacity flows reversing occasionally due to HQ's internal needs.

- Imports from PJM constitute the second largest source of external capacity into the NYISO.
  - Imports from PJM were substantial prior to the summer 2009 capability period, and exceeded 1 GW during several capability periods. However, the level of imports from PJM has remained fairly low since the NYISO Open Access Transmission Tariff ("OATT") was amended to place more stringent deliverability criteria on external capacity sources.[306]
  - This trend reversed in the past two capability periods, with imports from PJM increasing by 400 MW to 500 MW in the summer and winter capability periods. A majority of this capacity has originated from gas units in Pennsylvania and New Jersey which are contracting with suppliers in New York per PJM guidelines to delist and register as capacity resources in New York.[307]
  - Capacity price differences between the NYISO and PJM are not the only driver of capacity imports. There are also major structural differences between the two regions' procurement mechanisms (e.g., particularly PJM's three-year forward procurement relative to New York's monthly spot procurement).
- Capacity located in the NYISO has typically been a net exporter to ISO-NE, although the magnitude of this flow has diminished in the past several years. As is the case with PJM, ISO-NE operates a 3-year Forward Capacity Market ("FCM").
  - Since 2010, between 100 and 200 MW of capacity have steadily exported to ISO-NE, while the imports from ISO-NE have ranged from 0 to 200 MW, primarily from small hydro units.
    - Recent retirements in New England and structural changes to the Forward Capacity Auctions (e.g. sloped demand curves) have yielded much higher capacity prices for future capability periods beginning in the Summer of 2017.

306 NYISO filed tariff revisions to the OATT that redefined the requirements for external generators to acquire and maintain CRIS rights pursuant to Section 25 of Attachment S of the OATT. These filings followed the FERC's decision supporting the measures in 126 FERC 61,046 (January 15, 2009). For more information, refer to: https://www.ferc.gov/whats-new/comm-meet/2009/011509/E-7.pdf.

307 The PJM Capacity Market Manual outlines the guidelines for a resource from its regions to qualify as exporters to neighboring regions such as New York by applying a transmission charge and demonstrating transmission capability. The charge is determined as a function of the price delta between the PJM price the resource would receive and the outside region price, in this case the respective NYISO price. More information on PJM's protocols can be reviewed at https://www.pjm.com/~/media/documents/manuals/m18.ashx.

Consequently, larger amounts of New York capacity will be exported to ISO-NE in the coming years.

- The NYISO signed an MOU with IESO in 2016 regarding import of capacity from Ontario beginning with the Winter 2016-2017 Capability Period. Therefore, the imports into NYISO are likely to be augmented by capacity imports from Ontario which has fulfilled the necessary steps to be granted capacity import rights.[308]

C. Equivalent Forced Outage Rates and Derating Factors

The UCAP of a resource is equal to the installed capability of a resource adjusted to reflect the availability of the resource, as measured by its Equivalent Forced Outage Rate on demand ("EFORd"). A generator with a high frequency of forced outages over the preceding two years (i.e. a unit with a high EFORd) would not be able to sell as much UCAP as a reliable unit (i.e. a unit with a low EFORd) of the same installed capacity. For example, a unit with 100 MW of tested capacity and an EFORd of 7 percent would be able to sell 93 MW of UCAP.[309] This gives suppliers a strong incentive to provide reliable performance.

As discussed previously, the Locality-specific Derating Factors are used to translate ICAP requirements into UCAP requirements for each capacity zone. The NYISO computes the derating factor for each capability period based on the weighted-average EFORd of the capacity resources that are electrically located within the zone. For each Locality, a Derating 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.[310]

Table A-6: Historic Derating Factors by Locality

Table A-6 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2012 onwards.

308 The NYISO Installed Capacity Manual outlines the steps required for capacity outside of the state to qualify as an External Installed Capacity Supplier in sections 4.9.1. See: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

309 The variables and methodology used to calculate EFORd for a resource can be found at http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F%20-%20Equations.pdf

310 The Derating Factor used in each six-month capability period for each Locality may be found at: "http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do".

Table A-6: Derating Factors by Locality
Summer 2012 – Winter 2016/17

Locality	Summer 2016	Summer 2015	Summer 2014	Summer 2013	Summer 2012	Winter 2016/17	Winter 2015/16	Winter 2014/15	Winter 2013/14	Winter 2012/13
G-I	5.00%	3.40%	6.86%	N/A	N/A	6.46%	4.24%	5.72%	N/A	N/A
LI	7.27%	7.83%	7.65%	6.84%	9.31%	6.36%	9.02%	8.28%	7.37%	9.34%
NYC	9.53%	6.92%	5.44%	5.59%	6.79%	5.44%	10.49%	5.06%	6.63%	5.11%
A-F	10.62%	10.21%	10.92%	N/A	N/A	8.12%	9.43%	8.50%	N/A	N/A
NYCA	9.61%	8.54%	9.08%	8.91%	9.18%	7.25%	9.06%	7.32%	8.31%	7.17%

<u>Key Observations: Equivalent Forced Outage Rates</u>

- The NYCA-wide Derating Factor increased from Summer 2015 to Summer 2016 while the Derating Factor for the Winter 2016/17 Capability Period fell relative to the Winter 2015/16 Capability Period.
  - The change in NYCA-wide summer Derating Factor can largely be attributed to the increases in the EFORd of generation located in Zones G-J.
  - The drop in the NYCA-wide winter Derating Factor is due to the significant decrease in EFORds in Zones J and K, and to a lesser extent in Zones A-F.
- The Derating Factor for Zones A-F is generally higher than the values observed in other zones.
  - As shown in Figure A-84, nearly 10 percent of the installed generating facilities located in Zones A-F are intermittent in nature. Consequently, the average EFORd of capacity resources located in Zones A-F is higher than the average EFORd for other zones, where the resources are predominantly gas, oil-fired or nuclear units.
- The Derating Factor for the G-I region increased primarily from long-term derating at a specific generator in the locality.
- The overall mix of capacity resources located in Long Island, as shown in Figure A-84, has a high proportion (84 percent) of older steam and peaking units, when compared to NYC (65 percent). A number of relatively new combined cycle units (over 2.2 GW of capacity that is less than 10 years old) are also located in NYC. As a result, the Derating Factors for Long Island have generally been higher than those for NYC.

Figure A-86: Gas and Oil-Fired EFORds by Technology Type and Region

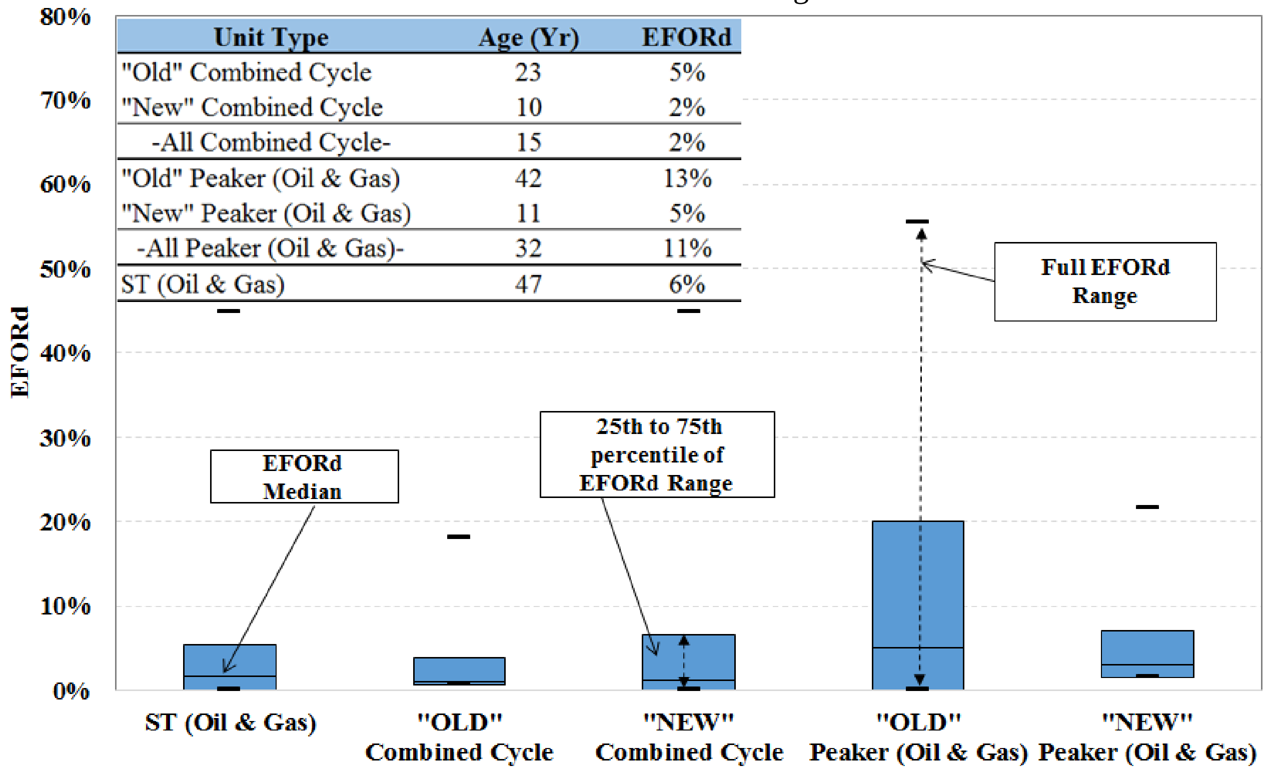
The rest of this sub-section discusses the distribution of the EFORd values for combined cycle gas, steam turbines, and oil and gas-fired peaking units based on a binary age classification.[311]

Figure A-4 depicts several pieces of material pertaining to the EFORd distributions of natural gas and oil-fired units. The EFORd ranges are given based on technology type and age designation (i.e., old or new based on whether the unit is less than or equal to 20 years old). Each column

[311] The age classification is based on the age of the plant. Units that are older than 20 year are tagged as "OLD" while younger units are marked as "NEW."

then is bounded by two dashed lines that denote the full range of observed EFORd values for the given technology. As such, the upper most dash corresponds to the maximum value observed while the lower one is the minimum. Next there are the column bars for each technology-age category that indicate the EFORd spread of the middle two quartiles (i.e. 25 to 75 percentile). The line inside each bar denotes the median value of EFORd for the capacity in the category. The table included in the chart gives the capacity-weighted average age and EFORd of each technology-age category.

Figure A-86: EFORd of Gas and Oil-fired Generation by Age
Summer – Five-Year Average



Unit Type	Age (Yr)	EFORd
"Old" Combined Cycle	23	5%
"New" Combined Cycle	10	2%
-All Combined Cycle-	15	2%
"Old" Peaker (Oil & Gas)	42	13%
"New" Peaker (Oil & Gas)	11	5%
-All Peaker (Oil & Gas)-	32	11%
ST (Oil & Gas)	47	6%

Key Observations: EFORd of Gas and Oil Units

- As shown in Figure A-86, both the prime mover of a unit and the unit age are important drivers of the EFORd distribution.
- Combined cycle units are the youngest gas and oil-fired generators in New York and have lower average EFORd values than steam turbine and peaking units.
- Steam units tend to have a second lowest EFORd despite being the oldest units on average in the state.
  - The methodology for calculating EFORd relies on a number of factors, including the number of hours during which the plant generates power. In situations where two units have similar operating profiles insofar as the outage frequency per start, outage duration, and the number of starts, the EFORd calculation favors the unit that runs for

more hours per start. Consequently, steam units have lower EFORds than peaking units.

- The EFORd values for peaking units tend to be highest on average and also exhibit a greater degree of variance when compared to other types of units.
  - The age of peaking units in New York ranges from five years to fifty years. The reliability (and EFORd) of a unit is likely to be affected by the age of the facility.
  - Peaking units tend to have higher operating costs than other units and are likely to be committed for fewer hours a year. So, the number of sample hours over which the relevant observations (for calculating the EFORd) are made is small. This contributes to the high variance in estimated EFORds across peaking units. Therefore, for units that are equally likely to experience a forced outage, the EFORd calculation methodology is likely to result in a greater variance in EFORds for units with high operating costs, when compared to the variance in EFORds for a group of more efficient units.

D. Capacity Market Results: NYCA

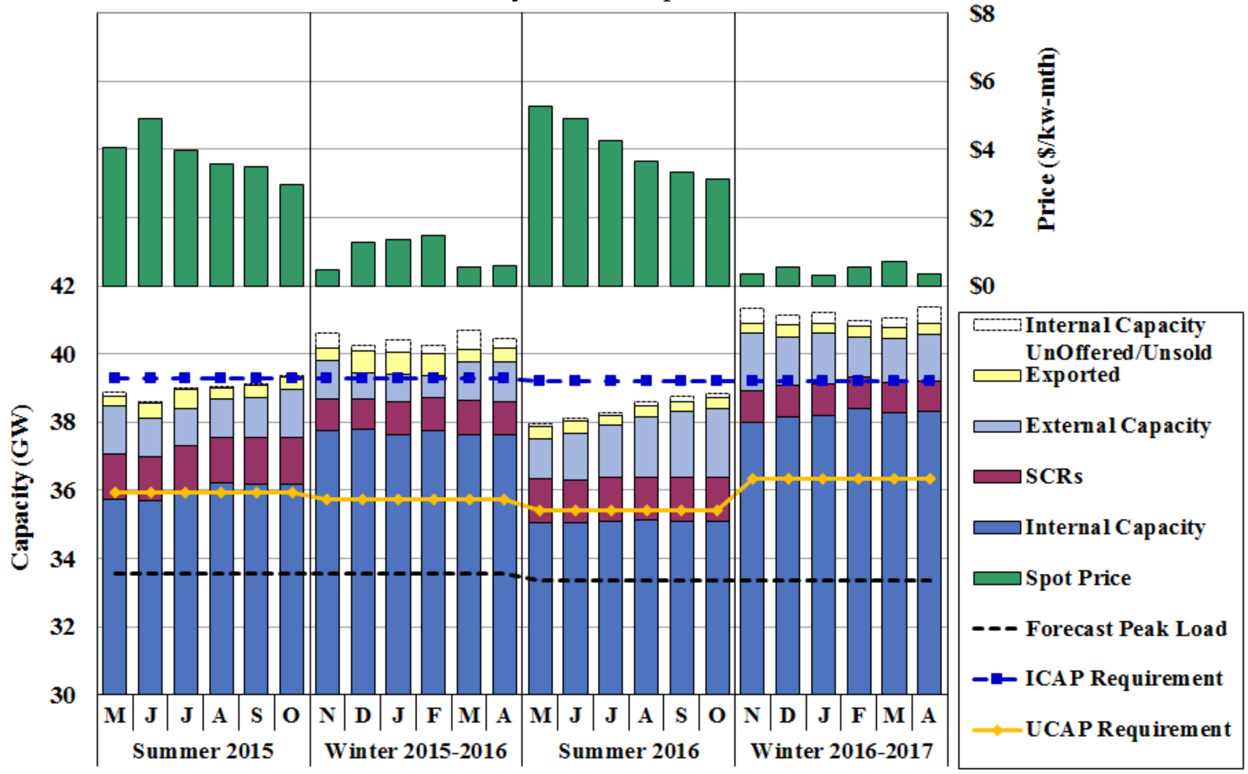
Figure A-87: Capacity Sales and Prices in NYCA

Figure A-87 shows capacity market results in the NYCA for the past four six-month 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.[312] 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 NYCA. Additionally, Figure A-87 shows sales 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-87 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-87 also shows the forecasted peak load and the ICAP requirements.

312 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.

Figure A-87: UCAP Sales and Prices in NYCA
May 2015 to April 2017



Key Observations: UCAP Sales and Prices in New York

- Seasonal variations drive significant changes in clearing prices in spot auctions between winter and summer capability periods.
  - 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.
  - Capacity imports from Quebec typically fall in the coldest winter months (i.e., December through March), since Quebec is a winter peaking region. This reduction partially offsets the decreases in clearing prices during these months.
- UCAP spot prices rose modestly in Rest of State in the 2016 Summer Capability Period relative to the same period during the prior year, while Winter 2016/17 prices fell from the previous year.
  - The spot price averaged $4.08/kW-month in the Summer 2016 Capability Period, which was up 7 percent from the prior summer, and $0.47/kW-month in the Winter 2016/17 Capability Period, which was down 50 percent from the prior winter.

- Summer prices rose as a result of the mothball/retirement of older generators such as Huntley 67 and 68 and Dunkirk 2 with higher imports from external regions, primarily from PJM, offsetting some of the price increase.
- Winter prices fell primarily due to increased imports from external regions (more than 60 percent) and the return to full service of existing generators.
  - On the demand side, the ICAP requirement fell 77 MW (0.2 percent) from the 2015/16 Capability Year because of a modest decrease in the peak load forecast.[313]
- However, the UCAP Requirement fell 490 MW (1.8 percent) in the Summer Capability Period while increasing 640 MW (2.4 percent) in the Winter Capability Period because of the variations in Derating Factor over the period.
  - 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 weighted-average EFORd values of 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.

E. Capacity Market Results: Local Capacity Zones

Figure A-88 - Figure A-90: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-88 to Figure A-90 show capacity market results in New York City, Long Island, and the G-J Locality for the past four six-month Capability Periods. These charts display the same quantities as Figure A-87 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

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.

313 ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2016 Summer and 2016/17 Winter Capability Periods. UCAP Requirements are fixed for a six-month Capability Period, since the Derating Factor for each locality is updated every six months, causing differences in the UCAP requirements during the summer and winter capability periods for the given year. Generally, the directional change in ICAP requirement is positively correlated to the its impact on spot prices.

Figure A-88: UCAP Sales and Prices in New York City
May 2015 to April 2017

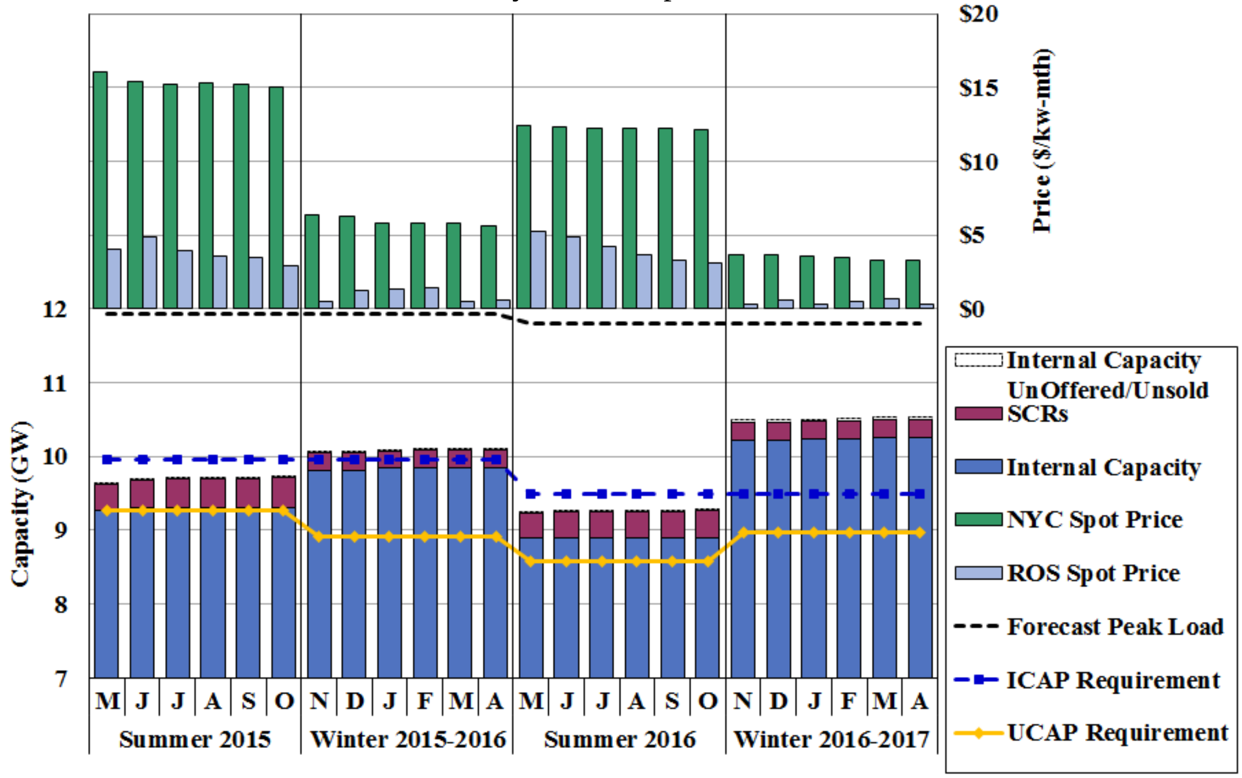


Figure A-89: UCAP Sales and Prices in Long Island
May 2015 to April 2017

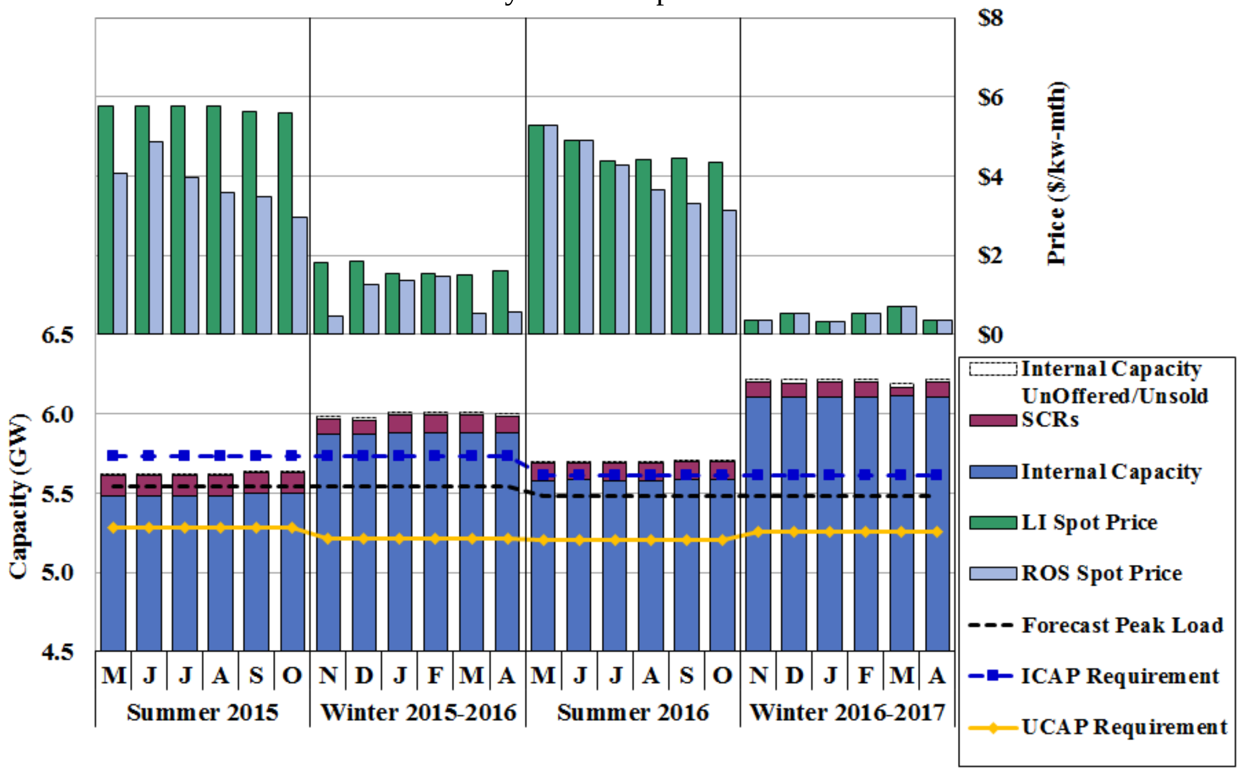
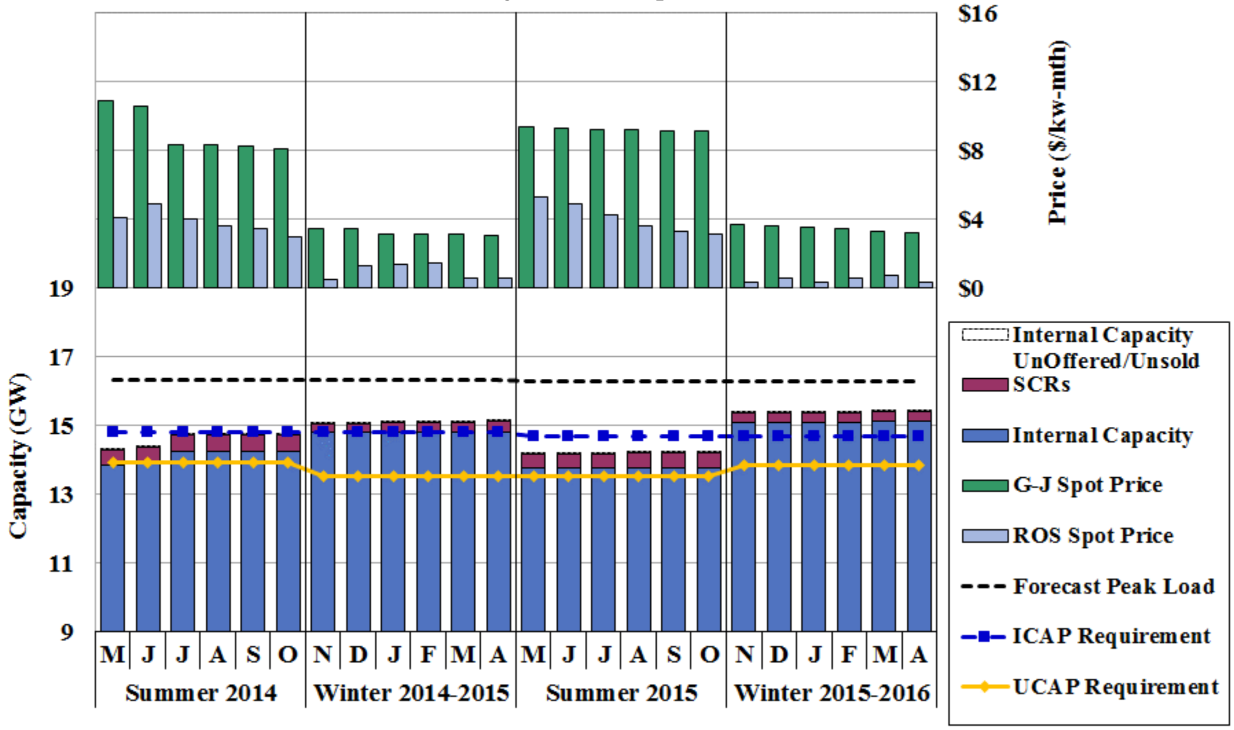


Figure A-90: UCAP Sales and Prices in the G-J Locality
May 2015 to April 2017



Key Observations: UCAP Sales and Prices in Local Capacity Zones

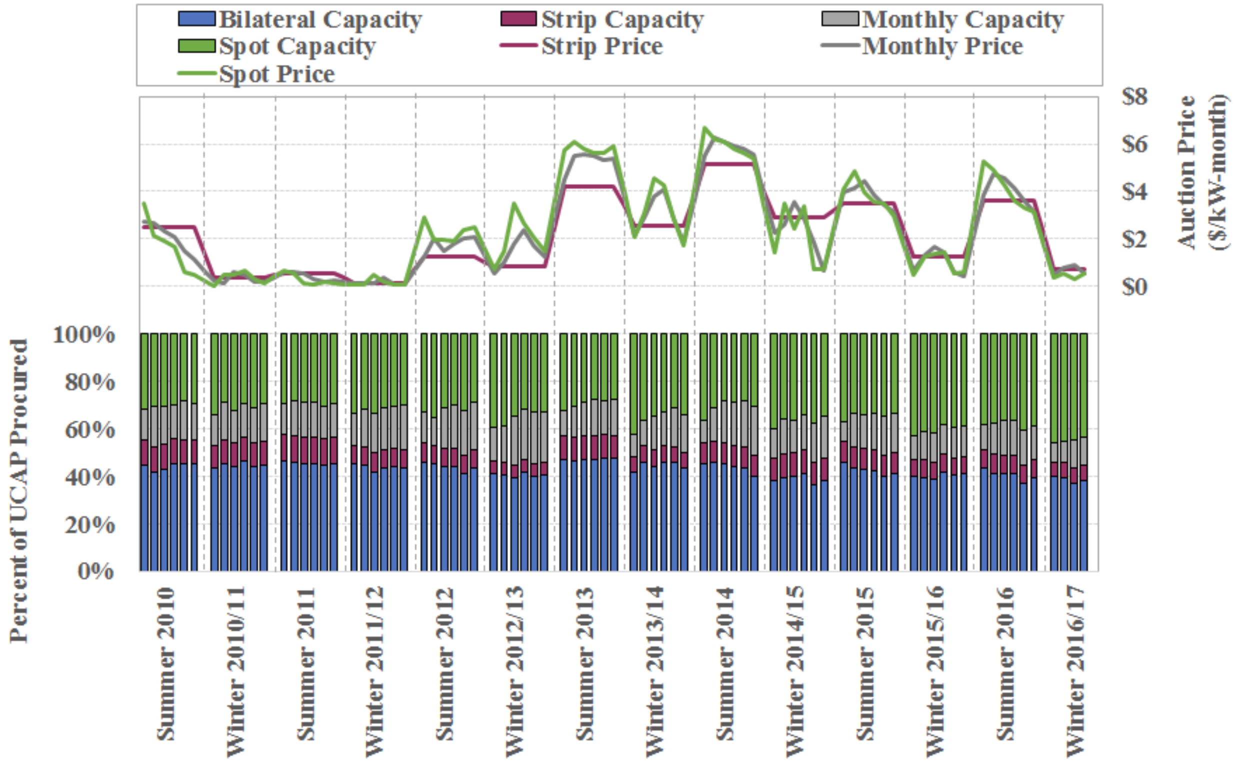
- As in the statewide market, seasonal variations substantially affect the market outcomes in the local capacity zones.
- UCAP spot prices fell in the New York City and the Long Island capacity zones in the 2016/17 Capability Year from the prior Capability Year, but rose slightly in the G-J Locality year over year. Specifically,
  - New York City spot prices fell: (a) 20 percent to an average of $12.24/kW-month in the Summer 2016 Capability Period; and (b) 42 percent to an average of $3.48/kW-month in the Winter 2016/17 Capability Period.
  - Long Island spot prices fell: (a) 19 percent to an average of $4.63/kW-month in the Summer 2016 Capability Period; and (b) 71 percent to an average of $0.47/kW-month in the Winter 2016/17 Capability Period.
  - The G-J Locality spot prices increased: (a) 1.6 percent to an average of $9.24/kW-month in the 2016 Summer Capability Period; and (b) 7 percent to an average of $3.48/kW-month in the Winter 2016/17 Capability Period.
- The spot prices in New York City fell largely because:
  - The ICAP requirement fell by 467 MW (or 4.7 percent) from the 2015/16 Capability Year to the 2016/17 Capability Year, which was primarily due to a decrease in the LCR requirement from 83.5 to 80.5 percent.

  - Furthermore, the decrease in the LCR was compounded by a 136 MW (or 1.2 percent) decrease in the peak load forecast.
  - The mothballing of a subset of Astoria and Ravenswood GTs offset some of the decrease in UCAP prices in Zone J.
- The spot prices fell in Long Island primarily because the ICAP requirement fell by 117 MW (or 2 percent) in the 2016/17 Capability Year because of a decrease in the LCR from 103.5 percent to 102.5 percent.
  - Long Island spot prices cleared above the Rest-of-State prices in a subset of the summer months; otherwise, prices in Long Island cleared at Rest-of-State levels.
  - UCAP sales from generation located in Long Island rose during the Winter 2016/17 capability period as a result of minor improvements in EFORd across several generators.
- The spot prices in the G-J Locality increased slightly because:
  - The decrease in the amount of capacity supply was larger than the decrease in capacity requirement that fell by 109 MW. This was primarily due to a substantially worse EFORd of a large ICAP supplier.
- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2016.

Figure A-91: Capacity Procurement by Type and Auction Price Differentials

Figure A-91 describes the breakdown of capacity procured by mechanism (bilateral markets, strip auctions, monthly auctions and spot auctions) and the resulting prices for various auctions over the last twelve capability periods. Bilateral price information is not reported to the NYISO and therefore not included in this image from a pricing perspective. The stacked columns correspond to the left vertical axis and indicate the percentage of total capacity procured via the four procurement methods for each month in a given capability period. The top panel of the chart (corresponding to the left vertical axis) shows the monthly prices for each of the spot, monthly and strip auctions since the Summer 2010 capability period on a dollar-per-kilowatt-month basis.

Figure A-91: Auction Procurement and Price Differentials
May 2010 – February 2017



<u>Key Observations: Capacity Procurement and Price Comparison</u>

- Almost 80 percent of the total UCAP in NYCA is procured via bilateral transactions (41 percent in Summer 2016) or in the spot market (38 percent in Summer 2016). The remaining capacity is procured through the strip (8 percent in Summer 2016) and monthly (14 percent in Summer 2016) auctions.
  - The proportions of capacity procured through the four different mechanisms has remained in a relatively narrow range over the past twelve capability periods, with the procurement in the spot market increasing slightly at the expense of the other three mechanisms.
- Since Summer 2011, monthly and the spot auction prices have frequently been set at a premium to the strip price during the summer capability periods.

VII. 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: (a) new and existing gas-fired units, (b) new utility-scale solar PV units, (c) new onshore wind units, and (d) existing nuclear plants. Net revenues vary substantially by location, so we estimate the net revenues that each unit would have received at a number of locations across New York.

A. Gas-Fired and Dual Fuel Units Net Revenues

We estimate the net revenues the markets would have provided to three types of older existing gas-fired units and to the three types of new gas-fired units that have constituted most of the new generation in New York:

- *Hypothetical new units*: (a) a 2x1 Combined Cycle ("CC 2x1") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.

We estimate the historical net energy and ancillary services revenues for gas-fired units based on prices at two locations in Long Island, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone. We also use location-specific capacity prices from the NYISO's spot capacity markets. Future years' net energy and ancillary services and capacity revenues are based on zonal price futures for each individual zones. Energy and ancillary services revenues for units in the Capital Zone and West Zone, energy prices are based on average zonal LBMPs. For Long Island, results are shown for the Caithness CC1 generator bus, which is representative of most areas of Long Island, and for the Barrett 1 generator bus, which is representative of the Valley Stream load pocket. For New York City, results are shown for the Ravenswood GT3/1 generator bus, which is representative of most areas of the 345kV system in New York City. For the Hudson Valley zone, results are shown for the average of LBMPs at the Roseton 1 and Bowline 1 generator buses, since these are representative of areas in the Hudson Valley zone that are downstream of the UPNY-SENY interface.

Table A-7 to Table A-10: Assumptions for Net Revenues of Fossil Fuel Units

Our methodology for estimating net revenues for gas-fired units is based on the following assumptions:

- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves.
- Combustion turbines (including older gas turbines) are committed in real-time based on RTC prices.[314] Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule. To the extent that these combustion turbines are committed uneconomically by RTC, they may receive DAMAP and/or Real-Time BPCG payments. Consistent with the NYISO tariffs, DAMAP payments are calculated hourly, while Real-Time BPCG payments are calculated over the operating day.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, for the ST unit, a limitation on its ramp capability is assumed to keep the unit within a certain margin of the day-ahead schedule. The margin is assumed to be 25 percent of the maximum capability.
- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability.
  - Combined-cycle units and new combustion turbines are assumed to use diesel oil, older gas turbines are assumed to use ultra-low sulfur diesel oil, and steam turbines are assumed to use low-sulfur residual oil.

314 Our method assumes that such a unit is committed for an hour if the average LBMP in RTC at its location is greater than or equal to the applicable start-up and incremental energy cost of the unit for one hour. This uses the RTC LBMPs posted on the NYISO's website.

- During hourly OFOs in New York City and Long Island, generators are assumed to be able to operate in real-time above their day-ahead schedule on oil (but not on natural gas). Dual-fueled steam turbines are assumed to be able to run on a mix of oil and gas, while dual-fueled combined-cycle units and combustion turbines are assumed to run on one fuel at a time.
- During hourly OFOs in New York City and Long Island, generators are assumed to offer in the day-ahead market as follows:

Table A-7: Day-ahead Fuel Assumptions During Hourly OFOs[315]

Technology	Gas-fired	Dual Fuel
Combined Cycle	Min Gen only	Oil
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- Fuel costs include a 6.9 percent natural gas excise tax for New York City units, a one percent gas excise tax for Long Island units, and transportation and other charges on top of the day-ahead index price as shown in the table below. Intraday gas purchases are assumed to be at a premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a discount for these reasons. The analysis assumes a premium/discount as shown in the table.

Table A-8: Gas and Oil Price Indices and Other Charges by Region

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West	Dominion North	$0.27	$2.00	$1.50	10%
Central	Dominion North	$0.27	$2.00	$1.50	10%
Capital	Iroquois Zn2	$0.27	$2.00	$1.50	10%
Hudson Valley	50% Iroquois Zn2, 50% Millenium E	$0.27	$1.50	$1.00	10%
New York City	Transco Zn6	$0.20	$1.50	$1.00	20%
Long Island	Iroquois Zn 2	$0.25	$1.50	$1.00	30%

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered for all years. However, the older GT-30 unit is assumed not to have RGGI compliance costs because the RGGI program does not cover units below 25 MW.
- The minimum generation level is 454 MW for the CC 2x1 unit and 90 MW for the ST unit. At this level, the heat rate is 7453 btu/kWh for the CC 2x1 unit and 13,000 btu/kWh for ST unit. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.

315 **Dual-fuel STs are assumed to offer Min Gen on the least expensive fuel and to offer incremental energy on residual oil in the DAM.

- We also use the operating and cost assumptions listed in the following tables:

Table A-9: New Gas-fired Unit Parameters for Net Revenue Estimates[316]

Characteristics	CC 2x1	LMS	Frame 7 with SCR	Frame 7 no SCR
Summer Capacity (MW)	668	202	230	230
Winter Capacity (MW)	704	218	230	230
Summer Heat Rate (Btu/kWh)	7028	9153	10193	10187
Winter Heat Rate (Btu/kWh)	6900	8993	10040	10020
Min Run Time (hrs)	4	1	1	1
Variable O&M - Gas (2016$/MWh)	$2.4	$5.6	$0.8	$0.2
Variable O&M - Oil (2016$/MWh)	$2.8	$9.6	$2.7	$1.5
Startup Cost (2016$)	$0	$0	$10,816	$10,560
Startup Cost (MMBTU)	3700	61	350	350
EFORd	2.50%	2.17%	2.17%	2.17%

Table A-10: Existing Gas-fired Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M (2016$/MWh)	$8.2	$4.6	$5.6
Startup Cost (2016$)	$6,132	$1,226	$530
Startup Cost (MMBTU)	2000	50	60
EFORd	5.14%	10.46%	19.73%

Figure A-92 and Figure A-93: Forward Prices and Implied Heat Rate Trends

We estimate the net revenues from 2017 to 2019 using forward prices for power, fuel and capacity.[317] We developed the hourly day ahead power price forecast for each zone by adjusting the 2016 LBMPs using the ratio of monthly forward prices and the observed monthly average prices in 2016.[318] We held the reserve prices for future years at their 2016 levels. Figure A-92 shows the variation in the forward prices and implied marginal heat rates for Zone A and Zone G over a six month (July-Dec, 2016) trading period. In general, there is considerable volatility in power and gas forward prices during the last two quarters of 2016. The zonal forward prices in

316 These parameters are based on technologies studied as part of the 2017 ICAP Demand Curve reset. The CC2x1 unit parameters are based on the Cost of New Entry Estimates for Combined Cycle Plants in PJM. The CONE estimate for gas-fired units in West Zone are based on data from Zone C in the 2017 ICAP Demand Curve reset study.

317 We used average monthly capacity forwards pricing data over the period of October 2016 through December 2016 for the NYCA and New York City zones. In the years or Localities for which capacity forward data were not available, we assumed the latest observed or forward capacity prices for the purpose of our net revenue analysis.

318 Our net revenue estimates for the 2017-19 time period are based on zonal and not nodal prices.

Zone G have ranged from $34 to $41 while Zone A forward prices were in the $29 to $35 range. Therefore, we used the trailing 90-day average of the forward prices as of January 1st 2017. In contrast, the implied marginal heat rates (and the spark spreads) have been reasonably stable over the last six months in all zones except for the West zone. Consequently, the estimated net revenues of gas-fired units in most locations are less volatile than the net revenues of non-gas-fired (i.e., nuclear and renewable) units.

Figure A-93 shows the assumed monthly forward power and gas prices for the 2017-2019 period along with the observed monthly average prices during the 2014-2016 period. The power forward prices for 2017 are considerably higher than the 2016 prices, but are significantly lower than 2014 and 2015 levels. The forward prices for 2018 and 2019 delivery of power and gas are only slightly lower than the 2017 prices. The year-over-year change in pricing of gas and power forward prices are generally consistent with each other in all locations except for New York City, where gas prices are expected to rise by 83 percent while power prices are expected to rise by 35 percent. This indicates that the higher implied marginal heat rate observed in 2016 for New York City (see Section I.E of the Appendix) is expected to diminish and revert to the level observed in 2015.

Figure A-92: Forward Prices and Implied Marginal Heat Rates by Transaction Date
2017, 2018, & 2019 Strip Prices from July to December 2016

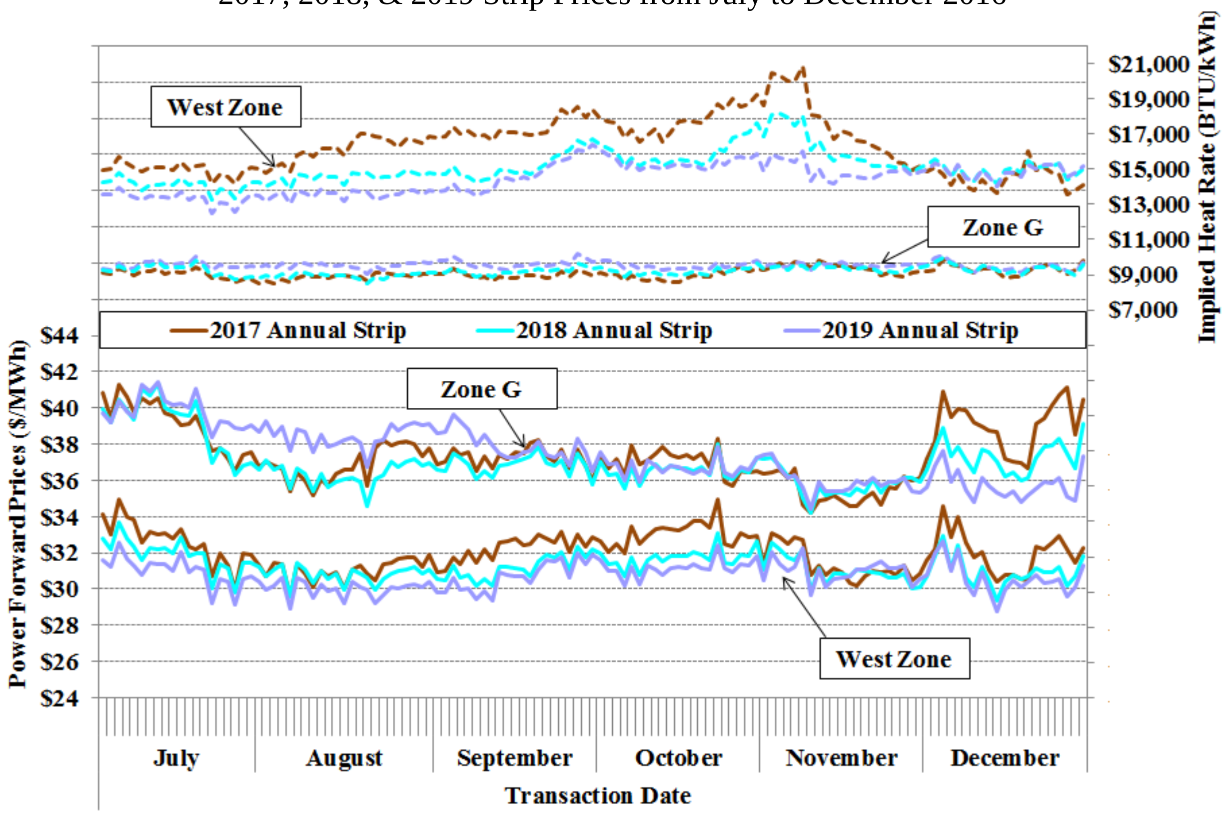


Figure A-93: Past and Forward Price Trends of Monthly Power and Gas Prices
2014 – 2019

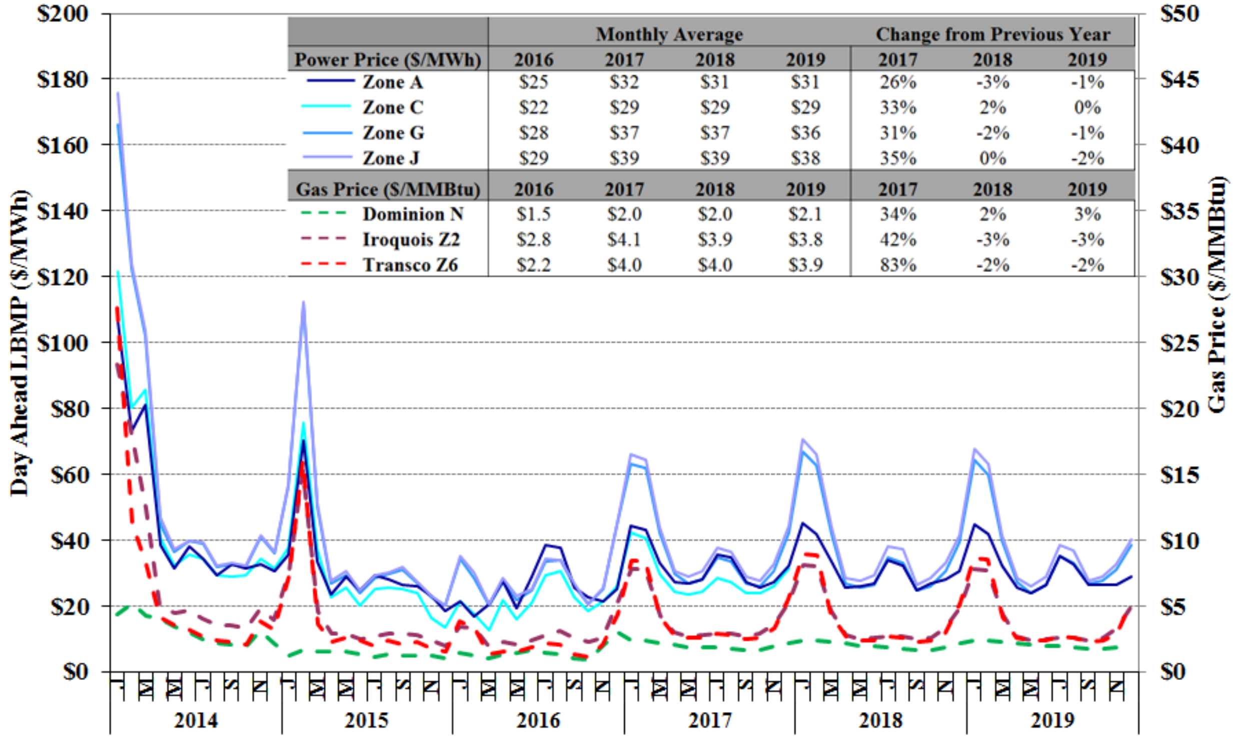


Figure A-94 to Table A-12: Net Revenues Estimates for Fossil Fuel Units

The following six figures summarize our net revenue and run hour estimates for gas-fired units in various locations across New York. They also indicate the levelized Cost of New Entry ("CONE") estimated in the Installed Capacity Demand Curve Reset Process for comparison.[319] Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-11 shows our estimates of net revenues and run hours for all the locations and gas unit types in 2015. Table A-12 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2016.

319 The CONE for the CC 2x1 units are based on publicly available cost information for the latest of the proposed large-scale CC projects in Long Island (Caithness II) and LHV (Cricket Valley Energy Center). For the CC2x1 unit in NYC, we show the cost of the CC 1x1 unit from the latest Demand Curve Reset study. We limit the capacity factor of the unit to 75% and assume that the unit will secure a property tax exemption. The CC 2x1 CONE shown for upstate zones is based on the CONE assumed for LHV.

Figure A-94: Net Revenue & Cost for Fossil Units in West Zone
2014-2019

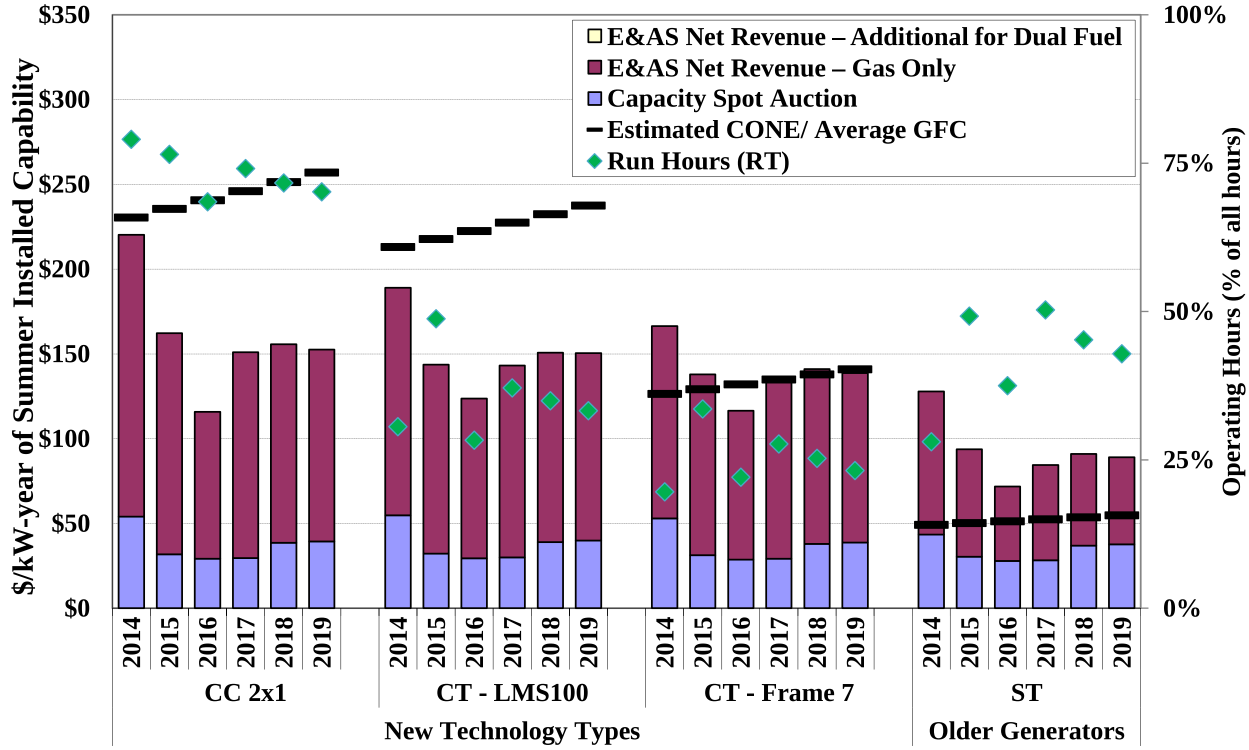


Figure A-95: Net Revenue & Cost for Fossil Units in Central Zone
2014-2019

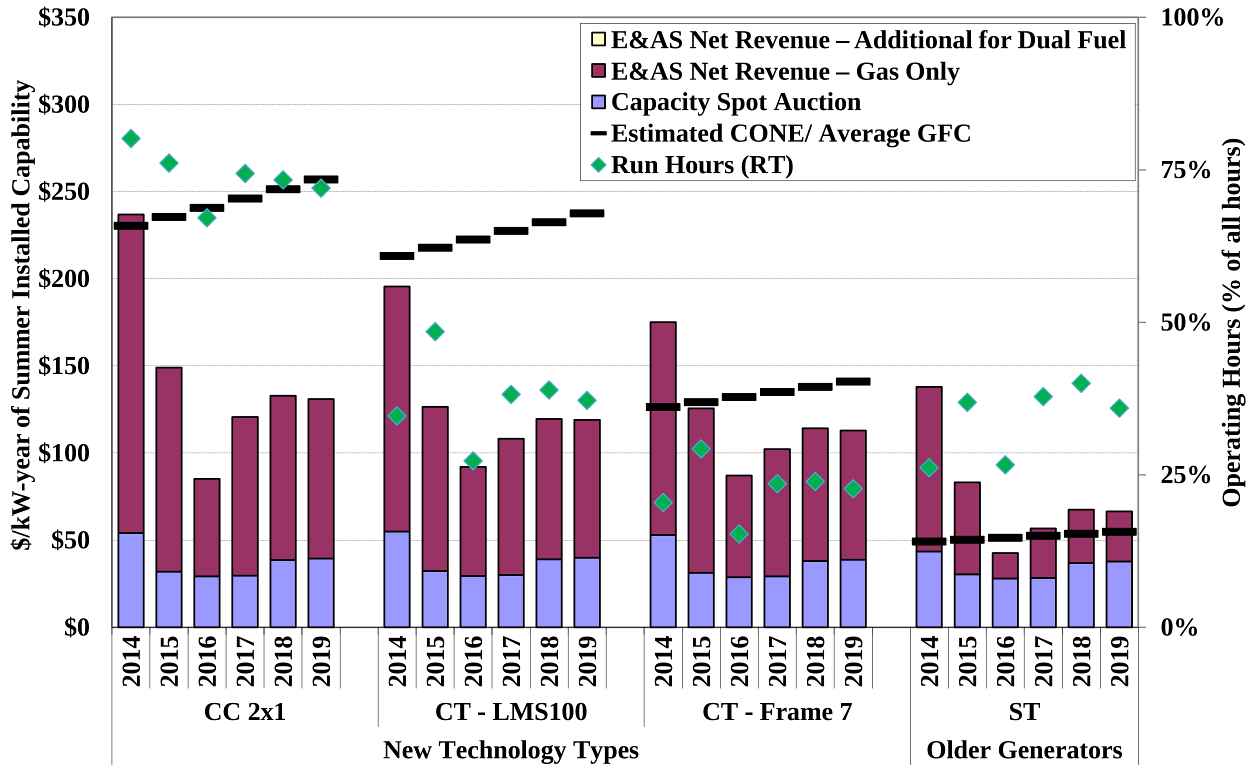


Figure A-96: Net Revenue & Cost for Fossil Units in Capital Zone
2014-2019

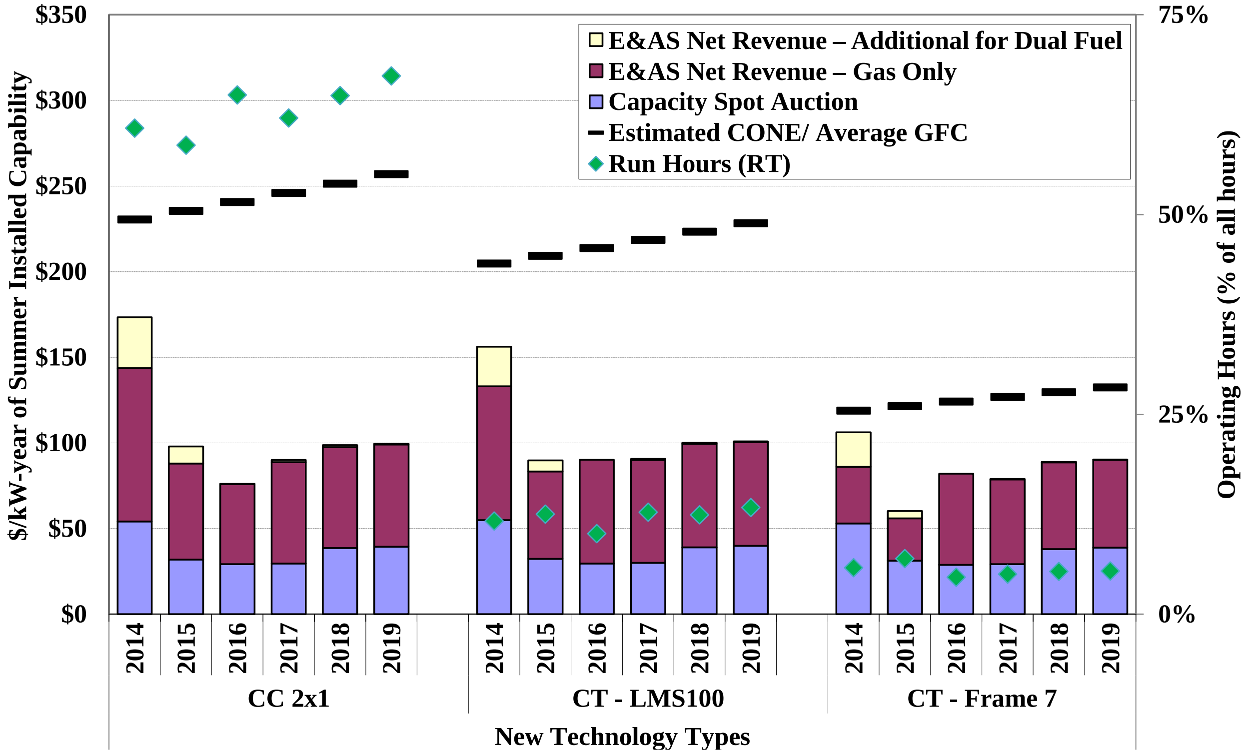


Figure A-97: Net Revenue & Cost for Fossil Units in Hudson Valley
2014-2019

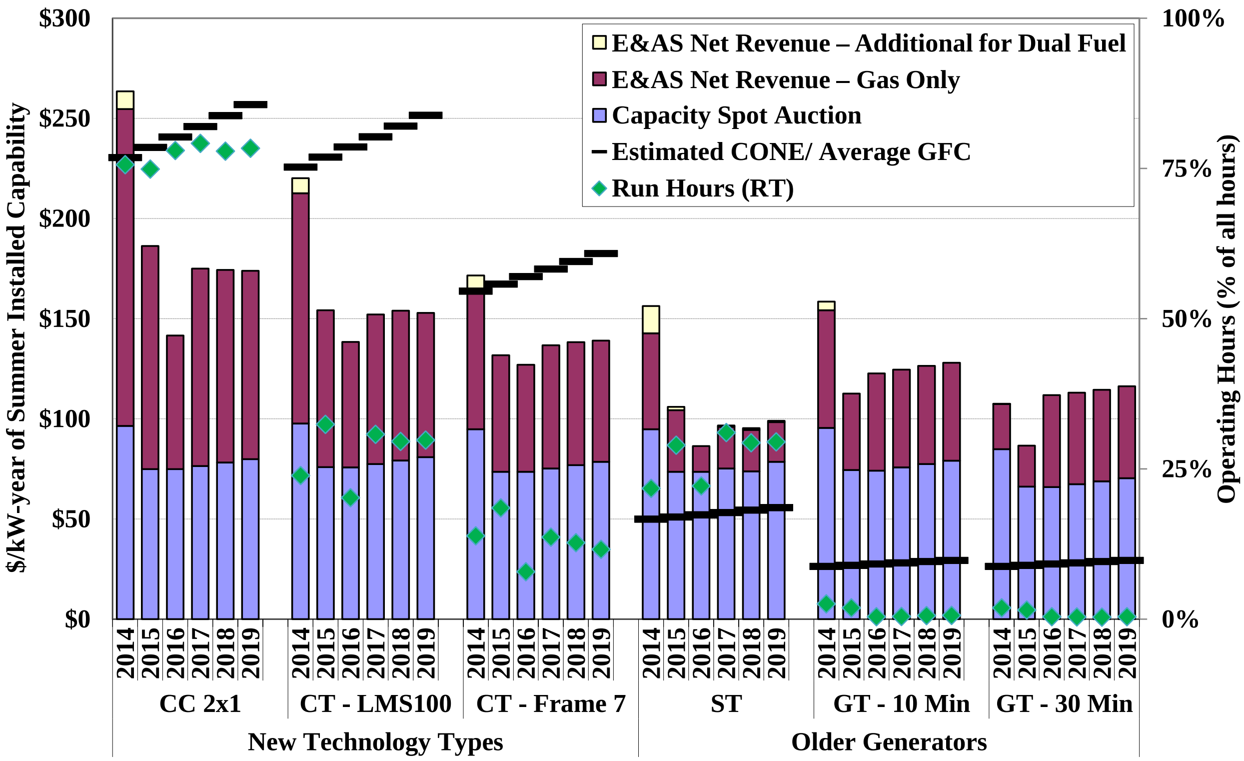


Figure A-98: Net Revenue & Cost for Fossil Units in New York City
2014-2019

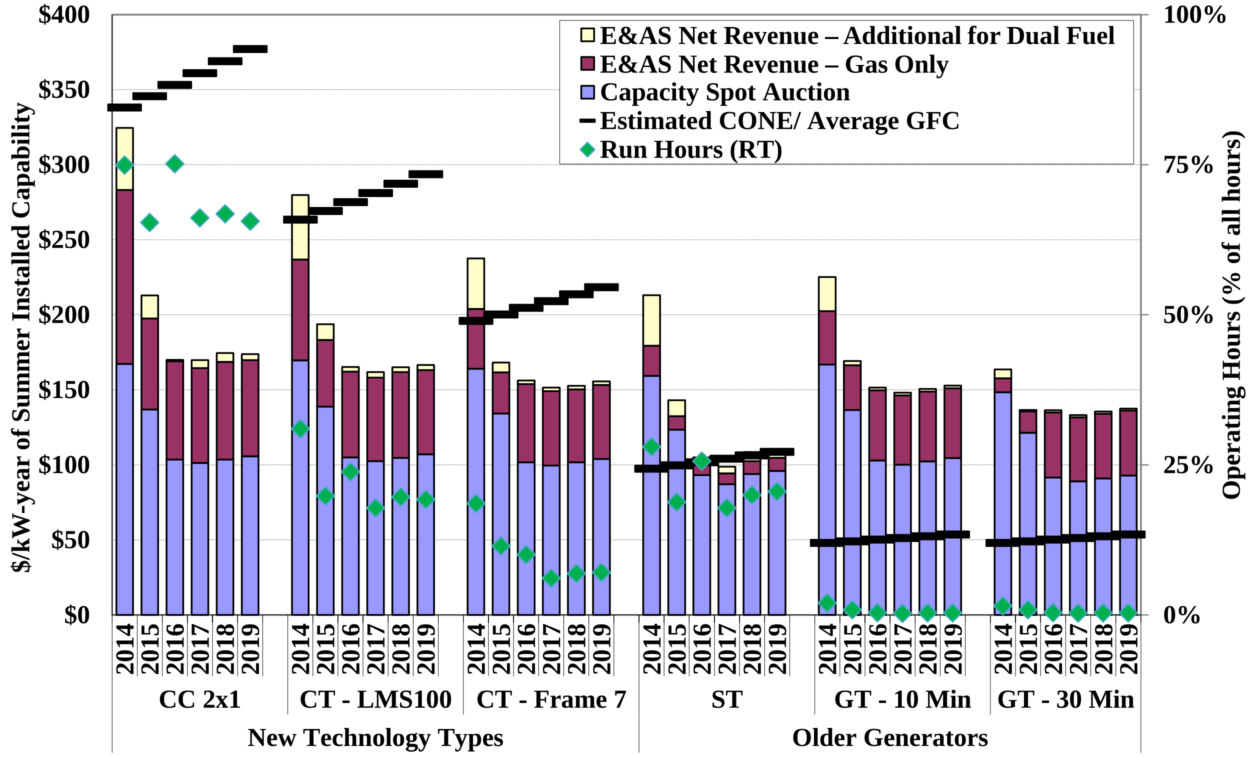


Figure A-99: Net Revenue & Cost for Fossil Units in Long Island
2014-2019

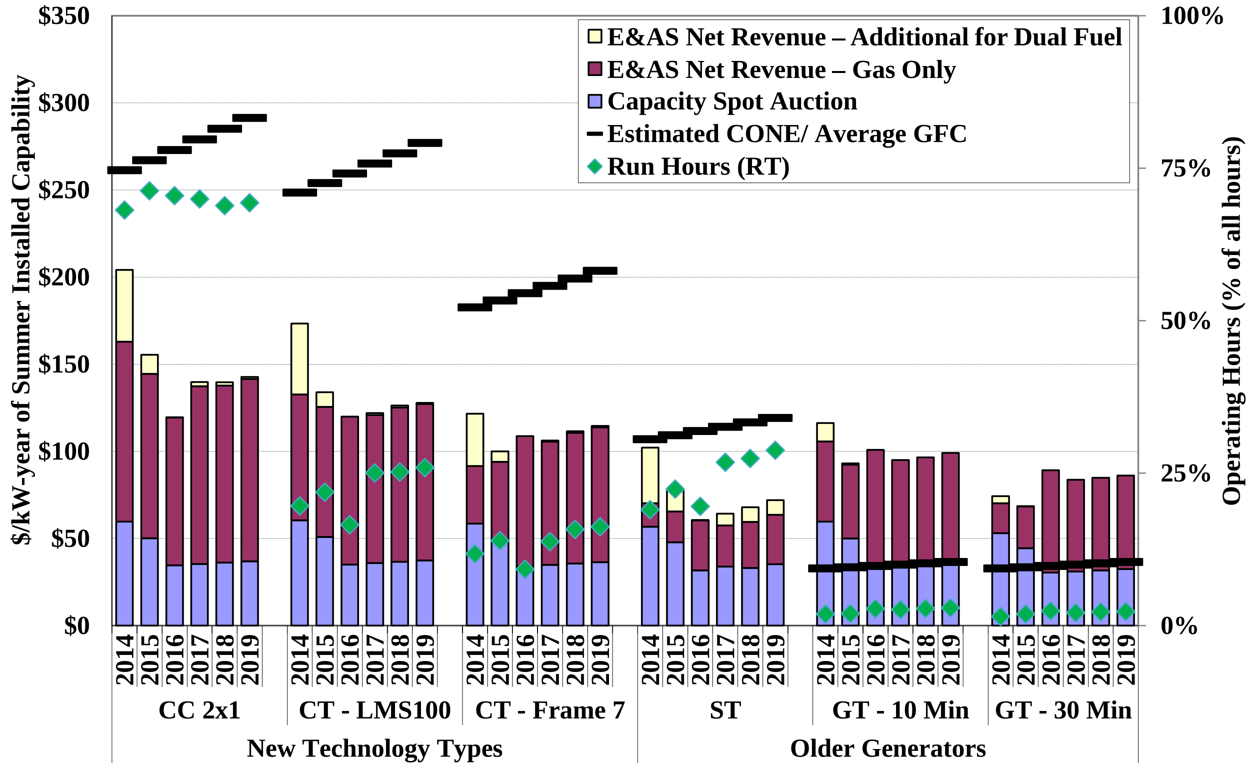


Table A-11: Net Revenue for Gas-Fired & Dual Fuel Units
2016

Location	Unit Type	Capacity	2016 Net Revenue ($/kW-yr)			Real Time Run Hours			
			Gas Only	Dual Fuel Additional	Dual Fuel Total	Gas Only Unit	DF Unit on Gas	DF Unit on Oil	DF Unit Total
Capital Zone	CC 2x1	$29	$47	$0	$76	5692	5668	23	5692
	CT - Frame 7	$29	$53	$0	$82	405	405	0	405
	GT - 10 Min	$29	$48	$0	$77	33	33	0	33
	GT - 30 Min	$26	$42	$0	$68	15	15	0	15
	CT - LMS100	$30	$61	$0	$90	881	881	0	881
	ST	$26	$4	$0	$30	723	721	19	740
Central Zone	CC 2x1	$29	$56	$0	$85	5882	5882	0	5882
	CT - Frame 7	$29	$58	$0	$87	1339	1339	0	1339
	GT - 10 Min	$29	$49	$0	$78	80	80	0	80
	GT - 30 Min	$26	$45	$0	$70	66	66	0	66
	CT - LMS100	$30	$63	$0	$92	2390	2390	0	2390
	ST	$28	$15	$0	$43	2331	2331	0	2331
West Zone	CC 2x1	$29	$87	$0	$116	5999	5999	0	5999
	CT - Frame 7	$29	$88	$0	$117	1934	1934	0	1934
	GT - 10 Min	$29	$79	$0	$108	422	422	0	422
	GT - 30 Min	$26	$71	$0	$97	390	390	0	390
	CT - LMS100	$30	$94	$0	$124	2480	2480	0	2480
	ST	$28	$44	$0	$72	3286	3286	0	3286
Hudson Valley (Iroquois-Zn2 Gas)	CC 2x1	$75	$40	$0	$115	5160	5156	16	5172
	CT - Frame 7	$74	$50	$0	$123	246	246	0	246
	GT - 10 Min	$74	$48	$0	$122	24	24	0	24
	GT - 30 Min	$66	$44	$0	$110	27	27	0	27
	CT - LMS100	$76	$56	$0	$132	722	722	0	722
	ST	$59	$4	$0	$63	613	613	0	613
Hudson Valley	CC 2x1	$75	$67	$0	$142	6834	6834	0	6834
	CT - Frame 7	$74	$53	$0	$127	694	694	0	694
	GT - 10 Min	$74	$49	$0	$123	36	36	0	36
	GT - 30 Min	$66	$46	$0	$112	37	37	0	37
	CT - LMS100	$76	$63	$0	$138	1771	1771	0	1771
	ST	$74	$13	$0	$86	1942	1942	0	1942
Hudson Valley (Millenium E Gas)	CC 2x1	$75	$102	$0	$176	7653	7653	0	7653
	CT - Frame 7	$74	$79	$0	$152	2140	2140	0	2140
	GT - 10 Min	$74	$53	$0	$127	200	200	0	200
	GT - 30 Min	$66	$49	$0	$115	178	178	0	178
	CT - LMS100	$76	$82	$0	$158	3969	3969	0	3969
	ST	$74	$36	$0	$109	4552	4552	0	4552
Long Island	CC 2x1	$35	$85	$0	$120	6175	6159	18	6177
	CT - Frame 7	$34	$75	$0	$109	811	811	0	811
	GT - 10 Min	$34	$67	$0	$101	243	243	0	243
	GT - 30 Min	$30	$59	$0	$89	213	213	0	213
	CT - LMS100	$35	$85	$0	$120	1450	1450	0	1450
	ST	$32	$29	$0	$61	1699	1688	26	1714
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$35	$115	$0	$150	6408	6384	23	6408
	CT - Frame 7	$34	$110	$0	$145	1666	1663	3	1666
	GT - 10 Min	$34	$109	$0	$143	550	550	0	550
	GT - 30 Min	$30	$95	$0	$126	462	462	0	462
	CT - LMS100	$35	$125	$0	$161	2013	2008	2	2010
	ST	$33	$48	$2	$83	2679	2556	130	2687
NYC	CC 2x1	$104	$65	$1	$170	6578	6514	68	6583
	CT - Frame 7	$102	$52	$2	$156	865	865	15	879
	GT - 10 Min	$103	$47	$2	$151	29	29	3	32
	GT - 30 Min	$92	$43	$1	$136	30	30	2	32
	CT - LMS100	$105	$57	$3	$165	2059	2059	28	2088
	ST	$93	$11	$0	$105	2167	2180	63	2243

Table A-12: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units

2016

Location	Unit Type	Gas-Only Units								Dual Fuel Units			
		E&AS Revenue ($/kW-yr)				Real Time Run Hours				E&AS Revenue ($/kW-yr)		Real Time Run Hours	
		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 4	Qtr 1	Qtr 4
Capital Zone	CC 2x1	$12	$7	$14	$14	1654	1350	1346	1343	$12	$14	1654	1343
	CT - Frame 7	$14	$11	$14	$14	73	55	117	159	$14	$14	73	159
	GT - 10 Min	$13	$11	$13	$11	0	1	13	20	$13	$11	0	20
	GT - 30 Min	$12	$9	$11	$9	2	1	10	2	$12	$9	2	2
	CT - LMS100	$15	$13	$16	$16	167	163	273	278	$15	$16	167	278
	ST	$1	$0	$2	$1	107	46	384	186	$1	$1	107	203
Central Zone	CC 2x1	$10	$9	$28	$9	1463	1188	2079	1153	$10	$9	1463	1153
	CT - Frame 7	$13	$12	$22	$11	131	207	835	165	$13	$11	131	165
	GT - 10 Min	$15	$11	$13	$11	7	7	55	11	$15	$11	7	11
	GT - 30 Min	$14	$10	$12	$9	6	6	50	2	$14	$9	6	2
	CT - LMS100	$0	$0	$0	$0	0	0	0	0	$0	$0	0	0
	ST	$1	$1	$11	$2	244	418	1366	303	$1	$2	244	303
West Zone	CC 2x1	$16	$18	$42	$10	1485	1288	2079	1148	$16	$10	1485	1148
	CT - Frame 7	$16	$22	$36	$14	262	391	1020	260	$16	$14	262	260
	GT - 10 Min	$19	$21	$27	$12	71	73	252	26	$19	$12	71	26
	GT - 30 Min	$17	$19	$25	$10	66	66	232	26	$17	$10	66	26
	CT - LMS100	$21	$23	$35	$15	438	501	1059	481	$21	$15	438	481
	ST	$6	$9	$24	$4	568	929	1388	401	$6	$4	568	401
Hudson Valley (Iroquois-Zone2 Gas)	CC 2x1	$9	$7	$16	$7	1406	1244	1417	1094	$9	$7	1406	1105
	CT - Frame 7	$13	$11	$15	$10	24	42	151	28	$13	$10	24	28
	GT - 10 Min	$13	$11	$13	$11	0	1	23	0	$13	$11	0	0
	GT - 30 Min	$12	$9	$13	$9	2	1	25	0	$12	$9	2	0
	CT - LMS100	$14	$13	$17	$12	86	181	325	130	$14	$12	86	130
	ST	$0	$0	$3	$0	47	106	445	15	$0	$0	47	15
Hudson Valley	CC 2x1	$18	$11	$24	$14	1824	1593	1930	1487	$18	$14	1824	1487
	CT - Frame 7	$14	$11	$18	$11	113	128	356	97	$14	$11	113	97
	GT - 10 Min	$13	$11	$14	$11	6	1	29	0	$13	$11	6	0
	GT - 30 Min	$13	$9	$14	$9	6	1	30	0	$13	$9	6	0
	CT - LMS100	$17	$13	$19	$13	368	377	682	344	$17	$13	368	344
	ST	$3	$1	$8	$1	430	356	996	159	$3	$1	430	159
Hudson Valley (Millenium E Gas)	CC 2x1	$30	$15	$35	$22	2095	1721	2130	1706	$30	$22	2095	1706
	CT - Frame 7	$22	$13	$27	$16	464	310	1015	350	$22	$16	464	350
	GT - 10 Min	$15	$11	$15	$12	72	2	82	44	$15	$12	72	44
	GT - 30 Min	$16	$9	$14	$10	70	2	82	25	$16	$10	70	25
	CT - LMS100	$23	$15	$25	$18	907	786	1324	953	$23	$18	907	953
	ST	$11	$3	$16	$6	1176	902	1642	833	$11	$6	1176	833
Long Island	CC 2x1	$14	$11	$47	$13	1633	1447	1805	1290	$14	$13	1633	1292
	CT - Frame 7	$12	$13	$37	$12	56	106	507	143	$12	$12	56	143
	GT - 10 Min	$13	$13	$29	$11	5	17	202	19	$13	$11	5	19
	GT - 30 Min	$13	$11	$25	$10	6	14	177	15	$13	$10	6	15
	CT - LMS100	$14	$15	$41	$14	184	289	644	334	$14	$14	184	334
	ST	$1	$1	$26	$1	158	263	1093	184	$1	$1	173	184
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$32	$12	$53	$18	1726	1462	1879	1341	$32	$18	1726	1341
	CT - Frame 7	$38	$14	$45	$14	485	190	755	236	$38	$14	485	236
	GT - 10 Min	$42	$15	$40	$12	158	44	319	29	$42	$12	158	29
	GT - 30 Min	$37	$13	$35	$10	133	37	272	20	$37	$10	133	20
	CT - LMS100	$42	$17	$49	$18	556	317	773	368	$42	$18	556	365
	ST	$11	$2	$31	$4	760	385	1221	314	$13	$4	760	321
NYC	CC 2x1	$11	$14	$27	$14	1496	1584	2040	1459	$12	$14	1469	1495
	CT - Frame 7	$13	$12	$18	$10	22	211	487	145	$14	$11	36	145
	GT - 10 Min	$12	$11	$14	$10	0	1	28	0	$13	$11	3	0
	GT - 30 Min	$11	$9	$14	$9	2	1	26	0	$13	$9	5	0
	CT - LMS100	$12	$14	$19	$12	143	561	858	498	$15	$13	165	504
	ST	$0	$2	$8	$1	107	581	1188	291	$1	$1	161	314

Key Observations: Net Revenues of Gas-fired and Dual Fuel Units

- *Year-Over-Year Changes* – The results indicate that the year-over-year changes in net revenues for gas-fired units varied significantly by technology type and location. The primary drivers of year-over-year changes in net revenues for gas-fired units are: (a) the decrease in energy margins (because of the lower gas prices in 2016), and (b) the increase in reserve prices (due to the higher 30-minute reserve requirements in NYCA and withholding from certain generators; see Section II.D of the Appendix).
  - In New York City, the 2016 net revenues for all units fell as a result of the decrease in capacity prices as well as energy prices. The resulting decrease was sufficient to offset the higher reserve revenues that new or existing peaking plants would earn.
  - For units located in Capital, Hudson Valley and Long Island zones, capacity prices were relatively flat or decreased, energy prices decreased, and reserve prices rose substantially. Consequently, the total net revenues of combined cycle and steam units decreased while those of the Frame and existing gas turbines increased.
  - As was the case in 2015, the congestion between western and eastern zones in the gas system was greater than the electric system congestion, which resulted in continued prevalence of high energy margins in western New York in 2016. As such, the net revenues of units in the West and Central zones continued to be driven by the energy prices rather than the reserve prices. Therefore, the net revenues of gas-fired units in West zone decreased by 14 to 29 percent from 2015 to 2016.
- *Potential Reserve Market Revenues for Gas Turbines in 2016* – The 2016 results for new and existing gas turbines include large revenues from the sale of reserves.
  - For instance, 30-minute reserve sales in Hudson Valley would have provided a typical GT-30 (average age of 42 years and 33 run hours in 2016) with 87 percent of its total E&AS revenues of $46/kW-year. The GT-30 total E&AS revenue is only 24 percent lower than the E&AS revenues for a new 2x1 combined cycle (6674 predicted run hours in 2016).
  - However, the actual reserves revenues received by gas turbines were considerably lower than our estimates for all firms. For instance, in New York City, over 50 percent of the 10-minute and 30-minute capable supply was scheduled for less than 20 percent of the hours for energy or reserves in 2016. However, the results of our analysis indicate that similarly situated GT-10 and GT-30 units would have been scheduled for reserves during almost all of the hours in 2016.[320] Consequently, the actual reserve revenues of most peaking units were substantially lower than the simulated net revenues reported in this section.
- *Estimated Future Net Revenues* - Given the current pricing of forward contracts, the net revenues of most units in the 2017 to 2019 timeframe appear to be higher than 2016 due

[320] The operating reserve offer prices are discussed in Section II.D of the Appendix.

to the upward trend in energy margins, with the largest year-over-year increase seen in 2017.[321] However, these estimates are uncertain because they depend on volatile power and gas forward prices and it is unclear whether operating reserve prices will remain at the current high levels. Retirements or new generation, additional transmission capability, clean energy mandates or new gas pipeline development can all drive significant changes in the forward prices. For instance, Zone G forward power prices for 2017 delivery increased by $4/MWh in early May 2016 after the Constitution pipeline permit was rejected.[322] Thus, actual net revenues could be significantly different from the results reported in this section.

- *<u>Implications for Annual Update of ICAP Demand Curve</u>* - The Commission accepted the NYISO's proposal to update the reference point of its ICAP demand curves on an annual basis using the Frame unit CONE and net revenues over the three most recent capability years.[323] For the next annual update (i.e. for the 2018/19 capability year), the net E&AS revenue offset will be calculated by replacing the net revenues earned by a Frame unit during May 2013 through April 2014 with the net revenues from May 2016 through April 2017. Given the current levels of energy and gas futures pricing, the updates to the ICAP demand curve reference points are likely to be affected by the following two offsetting factors:
  - The unusually high net revenues from the Polar Vortex of 2014 will pass out of the most recent three-year period, so the updated net revenues of the Frame unit will decrease.
  - If elevated reserve clearing prices persist, this will tend to increase net revenues going forward.
  - Based on our results, the overall decrease in net revenues of the demand curve unit would range from $0.65 to $6.30 per kW-year (depending on the location) if we do not consider any adjustments for the level of excess capacity.[324]

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321 Our estimates of net revenues for 2017-19 are based on zonal and not nodal LBMPs.

322 The Constitution pipeline was proposed to bring up to 650,000 Dth/day from Pennsylvania to an interconnection with the Iroquois and Tennessee pipelines near the New York/Massachusetts border. This would have helped increase the supply of natural gas to New York.

323 See the Commission's Order on July 18, 2016: New York Independent System Operator, Inc., 156 FERC ¶ 61,039.

324 The net revenue estimates of the demand curve unit that are reported in this section cannot directly be applied to quantify the actual updates to the ICAP demand curves due to three factors. First, the estimated E&AS revenue offsets in the demand curve reset study and in the annual updates are based on the LBMPs and reserve prices that are adjusted to reflect the tariff-prescribed level of capacity excess. Second, the model utilized by the NYISO to estimate the E&AS offsets includes a cost associated with providing reserves, while our model does not consider any such costs. Third, the updates to the ICAP demand curves will be subject to limits (12 percent increase and 8 percent decrease) on the changes from the values for the 2017/18 capability year.

- *Incentives for New Units* - The 2016 net revenues for all the technology-location combinations were well below the CONE estimates.

  - Surplus installed capacity has led to net revenues being lower than the CONE for most hypothetical units. Figure A-19 illustrates the relationship between net revenues and the size of the installed capacity surplus.

  - Estimated net revenues are higher than the CONE for Frame units in the West zone in 2014, 2015, and 2017 to 2019. However, investment decisions are based on projected net revenues over the economic life of the unit. Estimated net revenues for a Frame 7 unit at this location would not have been sufficient to cover its CONE from 2011 through 2013.[325] Additionally, the proposed transmission build out in the western New York would reduce electric system congestion and lower West Zone energy prices in the future.[326] The implied marginal heat rate for the West zone from 2017 to 2019 has been more volatile than that of other zones during the same timeframe. So, it is uncertain whether a Frame 7 unit in the West zone would earn sufficient net revenue to be economic over the long-term.

- *Estimated Net Revenues for Existing Units* - For older existing gas-fired units, the estimated net revenues were higher than the estimated “going-forward costs” for most location-technology combinations, but estimated GFCs were much higher for steam turbines in Long Island and comparable for steam turbines in New York City.

  - High reserve clearing prices in 2016 provide strong incentives for continued operation of existing gas turbines. Among older technologies, the estimated net revenues were highest for a GT-10 unit.

  - Steam turbine net E&AS revenues, unlike older GTs’ revenues, are driven primarily by energy and not reserve prices. Consequently, the net revenues of steam turbines dropped in 2016 more than other technologies. Simulation results for 2017-2019 suggest continued pressure for some steam turbines to retire because of low capacity prices and gas prices. However, retirement decisions are also impacted by other factors including individual unit GFCs, the owner’s market expectations, existence of self-supply or bilateral contracts, etc.

- *Incentive for Dual Fuel Units* - Our results indicate that the additional returns from dual fuel capability were de minimis in 2016 across all regions in New York because of the low gas prices. Such returns are much lower than the levels observed during 2014 and

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325 See Section I.G of the Appendix of 2013 State of the Market Report for the New York ISO Markets.

326 The New York Public Service Commission’s order addressing the Western New York Public Transmission Need can be found at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Public_Policy_Documents/Public_Policy_Transmission_Needs/2015_07_20_PSC_Order_NYISO_Pblc_Plcy_Trnsmssn_Nds_14-E-0454.pdf. The NYISO’s solicitation and baseline results for the related study can be found at: at:http://www.nyiso.com/public/markets_operations/services/planning/ planning_studies/index.jsp.

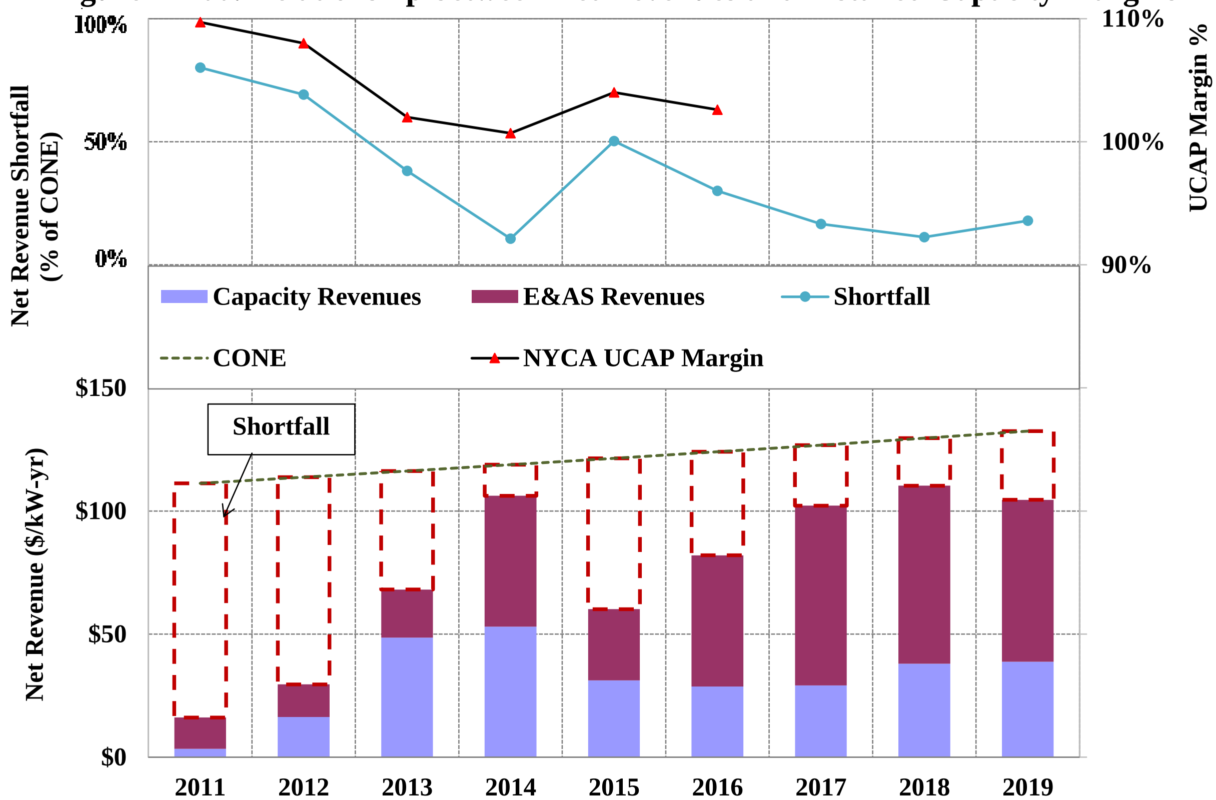
2015. Although current returns from dual fuel capability do not exceed the levelized investment cost of installing and maintaining dual-fuel capability, it provides a hedge against gas curtailment under tight supply conditions and reduces potential for fuel-related outages. Moreover, the additional revenues for CC and ST units in recent years have generally been sufficient to incent dual fuel capability.[327] Thus, most unit owners will continue to have incentives for installing and maintaining dual fuel capability.

B. Net Revenues and Capacity Margins

Figure A-100: Relationship between Net Revenues and Installed Capacity Margins

The bottom panel of Figure A-100 shows the shortfall in the net revenues of a Zone F Frame unit relative to its CONE from 2011 through 2019. The top panel of Figure A-100 shows the shortfall in yearly net revenues of the Zone F unit as a percentage of its CONE and the average capacity (summer UCAP) sold in NYCA as a percentage of the UCAP requirement.

Figure A-100: Relationship between Net Revenues and Installed Capacity Margins



327 See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

Key Observations: Relationship between Net Revenues and Capacity Margins

- The average shortfall in net revenues is about 40 percent of the CONE during the 2011-2019 time period, suggesting a prolonged period of unfavorable conditions for new entry in Zone F. Overall, the shortfall in net revenues received by the hypothetical new entrant has been consistent with the trends in NYCA capacity margins. During the years 2011 through 2014, as the amount of capacity in excess of the IRM decreased, the revenue shortfall for the demand curve unit also decreased.
- Capacity revenues are the primary source of revenue for the demand curve unit and existing fossil fuel units. For instance, the average share of capacity revenues for older generators in Hudson Valley during 2014-2015 was 73 percent, while it was 52 percent for new generators in the same zone. The market has been fairly responsive to net revenues, particularly capacity revenues. Several units exited the market following the very low capacity prices in 2011, while high capacity prices from 2013 to 2014 were followed by the entry of units.

C. Nuclear Unit Net Revenues

We estimate the net revenues the markets provide to the nuclear plants in the Genesee, Central, and Hudson Valley Zones. The estimates are based on LBMPs at the Ginna bus (for Genesee), the Fitzpatrick and Nine Mile Unit 1 buses (for Central), and the Indian Point 2 bus (for the Hudson Valley Zone). For future years, bus prices are estimated based on differences between historic zone prices and zone prices for which forward prices are available.

Figure A-101: Net Revenues for Nuclear Plants

Figure A-101 shows the net revenues and the US-average operating costs for the nuclear units from 2014 to 2019. Estimated net revenues are based on the following assumptions:

- Nuclear plants are scheduled day-ahead and only sell energy and capacity.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two percent, and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[328]
- The costs of generation (including O&M, fuel, and capex) for nuclear plants are highly plant-specific and vary significantly based on several factors that include number of units at the plant, technology, age and location. Our assumptions for operating costs for

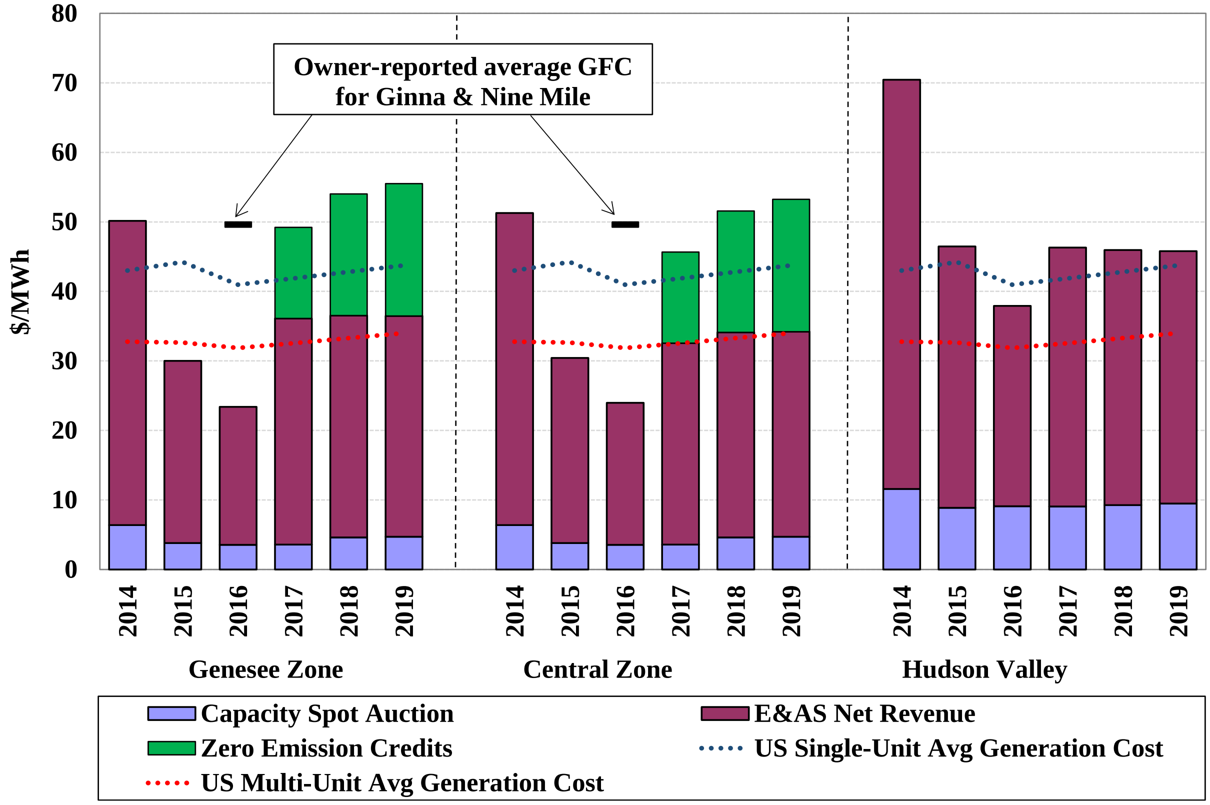
[328] The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year to enable a year over year comparison of net revenues.

single-unit and larger nuclear plants are based on observed average costs of nuclear plants in US from 2012 through 2015.[329]

- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[330] The ZEC price for Tranche 1 (April 2017 to March 2019) is $17.48/MWh. For the subsequent tranche (April 2019 to March 2021), the DPS-estimated ZEC price is $19.59/MWh.

Figure A-101: Net Revenue of Existing Nuclear Units

2014-2019



329 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings and http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/statusandoutlook.pdf?ext=.pdf. The weighted average GFC for Nine mile and Ginna was reported by the plant owners as part of the petition of Constellation energy nuclear group to initiate a proceeding to establish the facility costs for Ginna and Nine Mile Point nuclear power plants. See page 140 of the Clean Energy Standard Order issued on August 1, 2016 at https://www.nyserda.ny.gov/Clean-Energy-Standard.

330 See State of New York PSC's "Order adopting a clean energy standard", issued on August 1, 2016 at page 130. The price of ZECs is determined by 1) starting with the U.S. government's estimate of the social cost of carbon; 2) subtracting fixed baseline portion of this cost already captured in current wholesale power prices through the forecast RGGI prices embedded in the CARIS phase 1 report; and 3) converting the value from $/ton to $/MWh, using a measure of the New York system's carbon emissions per MWh. These prices are subject to reduction by any increase in the Zone A forward prices above a threshold of $39/MWh.

Key Observations: Net Revenues of Existing Nuclear Units

- *Year-Over-Year Changes* – The estimated net revenues for nuclear units indicate a significant decrease from 2015 to 2016 in all the three locations we studied. This result is in line with the overall drop in energy and capacity prices. Energy revenues constitute the majority of the revenue received by nuclear plants and accounted for 87 percent of the estimated net revenue over the last three years for the Central zone, much higher than the levels of renewable and gas-fired units. Consequently, the decision to retire or to continue to operate a nuclear unit is generally driven by the expected LBMPs more than expected capacity prices.
- *Incentives for Existing Nuclear Plants* – The results indicate that the 2016 estimated net revenues of all nuclear plants in the upstate zones were well below the US average of nuclear generation costs. In Hudson Valley, the estimated net revenues from the NYISO markets are greater than the average generation costs of multi-unit nuclear plants in 2016.
- *Estimated Future Net Revenues* – The energy and capacity futures prices suggest that the net revenue of nuclear plants from the NYISO-administered markets is expected to increase from 2016 levels by 36 to 43 percent over the next three years. However, the nuclear units located in upstate New York are unlikely to be economic without receiving additional payments for the sale of ZECs.[331] Multi-unit nuclear plants located in the Hudson Valley zone appear to be economic over the next three years based on the average generation costs.

D. Renewable Units Net Revenues

We estimate the net revenues the markets would have provided to utility-scale solar PV and onshore wind plants in the Central, North, and Long Island zones, and to offshore wind plants interconnecting in the New York City and Long Island zones. For onshore wind units in Central and North zones, we calculated the net E&AS revenues using the capacity-weighted average of LBMPs at major wind installations in the zones.[332] For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

331 Nuclear unit costs are highly unit-specific and the actual GFCs of the nuclear plants in New York may differ significantly from the average operating costs shown. However, the difference between the upstate nuclear plant revenues and costs may be smaller than the value implied in Figure A-101. First, the costs of nuclear units located in New York may be higher than the corresponding operating costs shown due to higher labor costs and property taxes. Publicly available estimates for property taxes range from $2 to $3 per MWh. Second, our future net revenue estimates are based on zonal and not nodal LBMPs. On an average, the nodal LBMPs at the upstate nuclear unit locations were $2 per MWh lower than the zonal LBMPs in recent years. These two factors in conjunction with the volatility of futures prices may render the single-unit nuclear plants in upstate New York to be only marginally economic if the generation costs do not decline during the 2017-19 period.

332 We considered only the wind units whose nameplate capacity is larger than 100 MW.

Table A-13: Cost and Performance Parameters of Renewable Units

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and onshore wind units is based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- Energy production is estimated using technology and location-specific hourly capacity factors for each month. The capacity factors are based on location-specific resource availability and technology performance data.[333]
- The capacity revenues for solar PV, onshore wind, and offshore wind units are calculated using prices from the spot capacity market. The capacity values of renewable resources are based on the factors (30, 2, and 38 percent for Winter Capability Periods and 10, 46, and 38 percent for Summer Capability Periods for onshore wind, solar PV, and offshore wind, respectively) specified in the February 2017 NYISO Installed Capacity Manual.[334]
- We estimated the value of Renewable Energy Credits ("RECs") produced by utility-scale solar PV, onshore wind, and offshore wind units using the weighted-average prices of RECs from the NYSERDA's last four Main Tier program procurements. Future REC prices are derived by inflating the 2017 REC price.[335]
- Solar PV, offshore wind, and onshore wind plants are eligible for the Investment Tax Credit ("ITC") or the Production Tax Credit ("PTC"), which are federal programs to encourage renewable generation. The ITC reduces the federal income tax of the investors by an amount equal to 30 percent of a unit's eligible investment costs and is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.[336] We incorporate

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333 The data sources for assumed capacity factors are as following:
a) Onshore wind: EIA AEO, 2016 and NREL Annual Technology Baseline
b) Offshore wind: CES Cost Study, 2016 (see page 151 of the Clean Energy Standard White Paper – Cost Study April 8, 2016)
c) Solar PV: CES Cost Study, 2016 (see page 166 of the study)

334 The factors are available in Section 4.5.b of the ICAP Manual in the tables labeled Unforced Capacity Percentage – Wind and Unforced Capacity Percentage – Solar. See http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf.

335 For more information on the recent Main Tier procurements, see http://www.nyserda.ny.gov/All-Programs/Programs/Main-Tier/Main-Tier-Solicitations. The 2017 REC price of $21.16/MWh is based on the Dec, 2016 agreement for the sale of the RECs between NYSERDA and the LSEs.

336 The ITC is 30% of the total eligible investment costs for projects that commence construction by end of 2019. It will step down to 26% for projects starting construction in 2020 and 22% for projects starting construction in 2021. The Production Tax Credit is also scheduled to be phased out through 2019 and only wind facilities that commence construction prior to December 31, 2019 are eligible for this credit. The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC.

the value of these federal incentives as an additional revenue stream for solar PV and wind units.[337]

The cost of developing new renewable units, especially solar PV plants, has dropped rapidly over the last few years. As such, the estimated investment cost for solar PV technologies varies significantly based on the study methodology and study period. Table A-13 shows cost estimates for solar PV, onshore wind and offshore wind units. The data shown are based on our review of studies published in 2016.338 The table also presents the operating and cost assumptions we used for calculating net revenues for these renewable units. The CONE for solar PV and onshore wind units was calculated using the financing parameters and tax rates specified in the most recent ICAP demand curve reset study.

337 In addition to these federal programs, renewable power projects may qualify for several other state or local-level incentives (e.g., property tax exemptions) in New York. However, our analysis does not consider any other renewables-specific revenue streams or cost offsets beyond the revenues from sale of Renewable Energy Credits and the PTC or the ITC. We assumed that these units will be subject to the property tax treatment that is specified in the most recent ICAP demand curve reset study.

338 The studies reviewed for developing the range for utility-scale solar PV, onshore wind and offshore wind costs are: (a) NREL, 2016, *Annual Technology Baseline and Standard Scenarios*, See http://www.nrel.gov/analysis/data_tech_baseline.html; (b) Lazard, 2016, *Lazard's levelized cost of energy analysis —version 10.0*, See https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf; (c) CES Cost Study: Clean Energy Standard White Paper – Cost Study April 8, 2016; and (d) EIA's report on "Capital Cost Estimates for Utility Scale Electricity Generating Plants" – https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

The assumed investment costs and fixed O&M costs for solar PV are based on the CES Cost Study (See pages 157 and 160) while the onshore and offshore wind costs were developed based on the 2016 NREL ATB (Mid) values for TRG 6. The DC investment cost for solar PV was converted to AC basis based on the assumed PV system characteristics as outlined in the CES Cost Study (see page 166 of the CES Cost Study). For each renewable technology, US average investment costs were adjusted to New York conditions using technology-specific regional cost regional multipliers used in the EIA's AEO and the CES Cost Study. See "Capital Cost Estimates for Utility Scale Electricity Generating Plants", available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. A labor cost adjustment factor of 1.1, intended to represent regional labor cost differences (based on the CES Cost Study), was applied to the Fixed O&M costs. In addition, the assumed investment cost trajectory over the years was assumed to follow the technology-specific CapEx trajectory specified in the 2016 NREL ATB.

The assumed investment cost estimates do not include interconnection costs. Interconnections costs for wind and solar units can vary significantly from project to project. The SUFs allocated to the most recent onshore wind-based entrant would have added $9/kW-yr (or $2.80/MWh) to the net CONE of the project. We assume construction lead time (i.e. time taken by a unit from commencement of its construction to reaching commercial operation) of 1 year for solar PV plant, 2 years for onshore wind plant and 3 years for offshore wind plant.

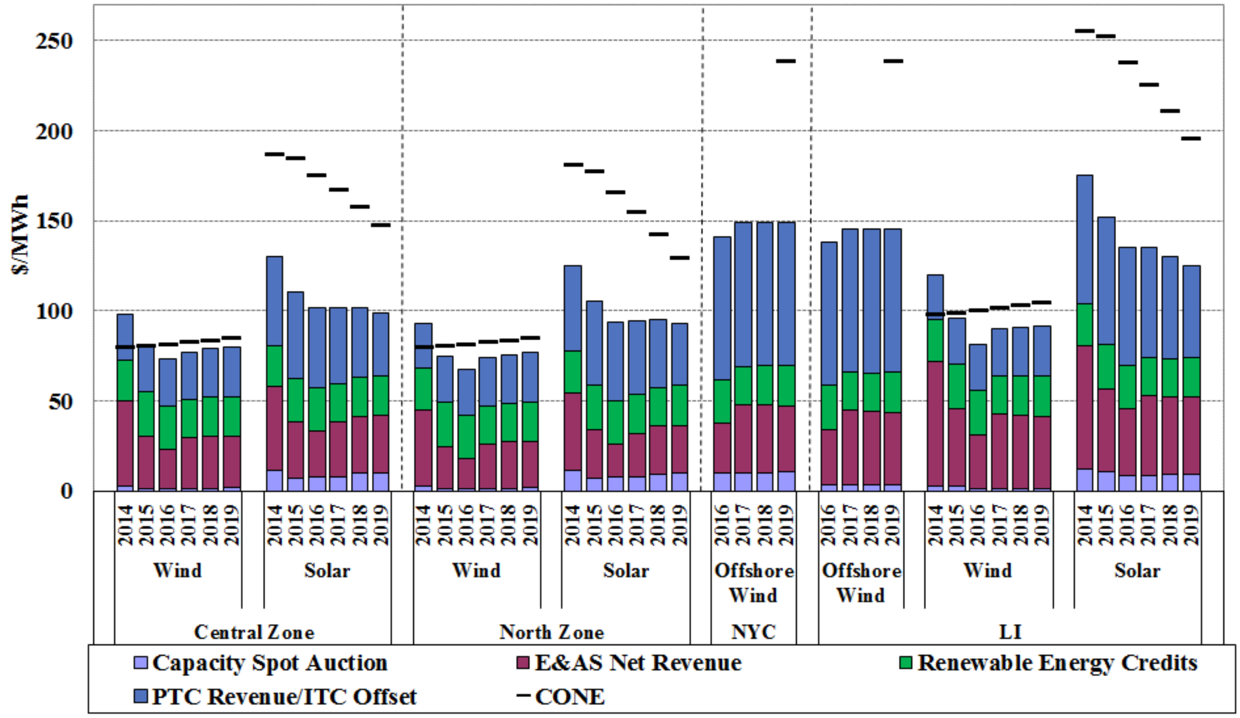
Table A-13: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2016$/kW AC basis)	*Upstate NY*: $2110 ($1774 low to $2857 high) *Long Island*: $3187 ($2680 low to $4315 high)	*Upstate NY*: $2035 ($1667 low to $2035 high) *Long Island*: $2624 ($2151 low to $2624 high)	*Long Island/NYC*: $7671
Fixed O&M (2016$/kW-yr)	$38 ($23 low to $38 high)	$59 ($52 low to $64 high)	$75
Federal Incentives	ITC (30%)	PTC ($23/MWh)	ITC (30%)
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	Central: 17.0% North: 17.3% LI: 17.6%	Upstate NY: 38.1% LI: 38.0%	LI/ NYC: 45%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 10% Winter: 30%	Summer: 38% Winter: 38%
Renewable Energy Credits (Nominal $/MWh)	***2017*** - $21.16 ***2016*** - $24.24 ***2015*** - $24.57 ***2014*** - $22.96		

Figure A-102: Net Revenues of Solar, Onshore Wind and Offshore Wind Units

Assuming the operating and cost parameters shown in the table above, Figure A-102 shows the net revenues and the estimated CONE for each of the units during years 2014-2019.

Figure A-102: Net Revenues of Solar, Onshore Wind and Offshore Wind Units[339]
2014-2019



Key Observations: Net Revenues of New Utility-Scale Solar PV, Onshore Wind, and Offshore Wind Plants

- *Net Revenues from NYISO Markets* – Given the relatively low capacity value of solar PV, onshore, and offshore wind units, energy market revenues constitute a large majority of the revenues these units receive from the NYISO markets. Consequently, the results indicate a drop in the estimated net revenues of solar PV and wind units from 2014 to 2016 in all the four locations we studied because of the sharp reduction in energy prices. In addition, given the current expectations for future power prices, the total revenues for renewable units from the NYISO markets are likely to increase over the next three years.
- *Role of State and Federal Incentives* – Renewable energy projects in New York receive a significant portion of their net revenues from state and federal programs in addition to revenues from the markets administered by the NYISO. The results indicate that a new solar PV project would have earned 67 percent to 72 percent of its 2016 net revenues from RECs and ITC, depending on the location. Similarly, onshore wind units would have received 61 percent to 74 percent of their 2016 net revenues from state and federal

339 The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.

programs. The value of these incentives shows only a modest change across years due to the relatively small drop in the average REC prices.

- *Incentives for Utility-scale Solar PV Units* – The results for 2016 indicate that the net revenues of solar PV units would be insufficient to meet their estimated CONE in all the locations studied. The investment costs for solar PV units are expected to drop significantly (30+ percent by 2019) in the near future. Therefore, the spread between the net revenues received by the utility-scale solar PV units and their CONE is likely to decrease. However, the step-down of ITC starting in 2020 will reduce the profitability of utility-scale solar PV. Overall, our results indicate that the generic utility-scale solar PV unit we studied is unlikely to be economic through 2019.
- *Incentives for Onshore Wind Units* – In 2016, the estimated net revenues of the generic onshore wind units, driven by the low energy prices, were likely to be insufficient to meet their CONE in all the locations we studied. The economics of the onshore wind units appear to be improving in the near term with the shortfall in net revenues (after considering the impact of state and federal incentive) likely to be small or de minimis depending on individual site conditions. However, onshore wind units are particularly exposed to curtailment risks and energy market value deflation (at high levels of penetration). Therefore, the actual revenues realized might be lower than the estimated revenues shown in Figure A-102.
- *Incentives for Offshore Wind Units* – Offshore wind plants have relatively high capacity factors and capacity value. Consequently, the net revenues of these units are the highest on a $/kW-year basis among all the renewable units we studied. However, our results indicate that the estimated net revenues (based on the revenue streams considered for our analysis) of offshore wind units are considerably lower (32 to 34 percent lower in 2019) than most estimates of the CONE in Long Island and New York City.

VIII. DEMAND RESPONSE PROGRAMS

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

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

- Emergency Demand Response Program ("EDRP") – These resources are paid the higher of $500/MWh or the real-time clearing price. There are no consequences for enrolled EDRP resources that fail to curtail.[340]
- 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.[341]
- 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, currently only 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.

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

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

341 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.

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.

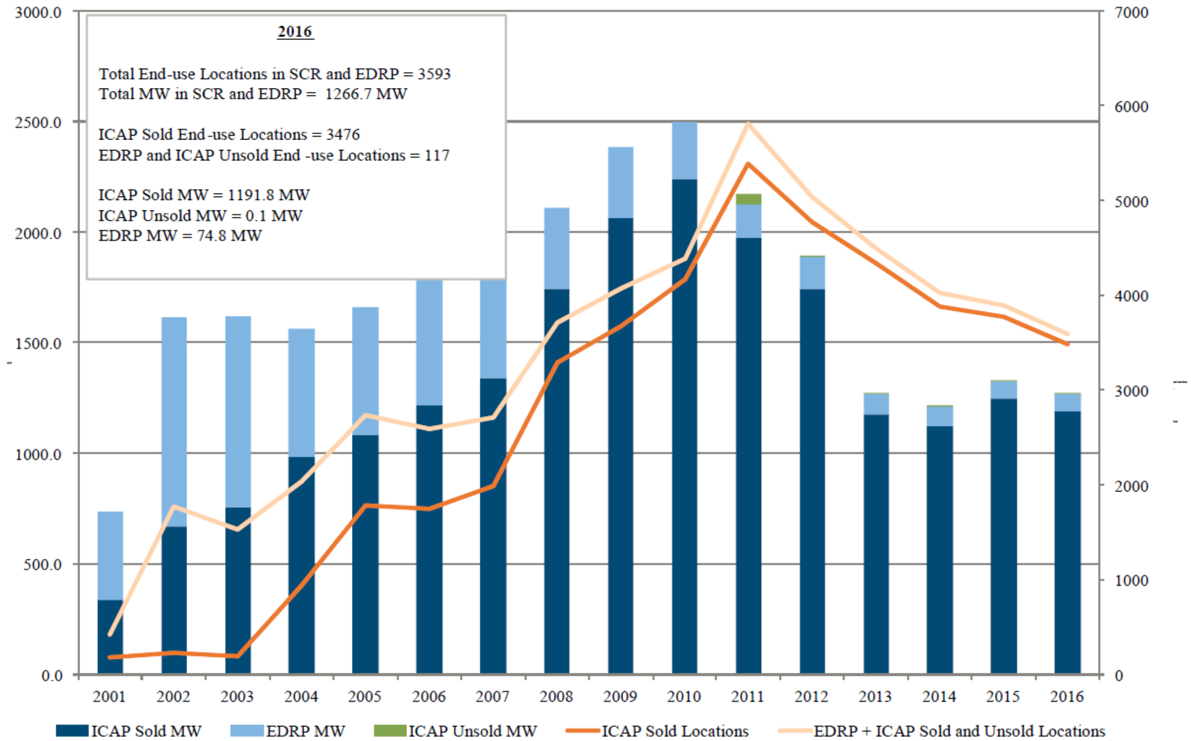
A. Reliability Demand Response Programs

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-103: Registration in NYISO Demand Response Reliability Programs

Figure A-103 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2016 as reported in the NYISO's annual demand response report to FERC. The stacked bar chart plots enrolled MW by year for each program. The lines plot the number of end-use locations by year for each program. 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-103: Registration in NYISO Demand Response Reliability Programs [342]
2001 – 2016



342 This figure is excerpted from the compliance filing report to FERC: *NYISO 2016 Annual Report on Demand Response Programs*, January 13, 2017.

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 2016, total registration in the EDRP and SCR programs included 3,593 end-use locations enrolled, providing a total of 1,267 MW of demand response capability. SCR resources accounted for 94 percent of the total enrolled MWs in the reliability-based program.
- In the Summer 2016 Capability Period, SCRs contributed to resource adequacy by satisfying:
  - 4.1 percent of the UCAP requirement for New York City;
  - 3.2 percent of the UCAP requirement for the G-J Locality;
  - 2.1 percent of the UCAP requirement for Long Island; and
  - 3.6 percent of the UCAP requirement for NYCA.
- The registered quantity of reliability program resources has fallen considerably since 2010, down nearly 50 percent from 2010 to 2016.
  - The reduction occurred primarily as a result of the enhanced auditing and baseline methodology for SCRs in 2011. These have resulted in more accurate baselines for some resources, reducing the amount of capacity they are qualified to sell.
  - The reduction was also partly due to business decisions that have been driven by low capacity prices in some areas in recent years and reduced revenues as a result of lower qualified capacity.

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, currently 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, which enhances competition, reduces costs, and improves 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 in the real-time, they settle the energy consumption with their load serving entity rather than with the NYISO. But they are eligible for a Day-Ahead Margin Assurance Payment (“DAMAP”) to make up for any balancing differences between their day-ahead operating reserves or regulation service schedule and real-time dispatch, subject to their performance for the scheduled service.

The Mandatory Hourly Pricing (“MHP”) program encourages loads to respond to wholesale market prices, which intends to shift customer load to less expensive off-peak periods and reduce electric system peak demand. The MHP program is administered at the retail load level, 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.

<u>Key Observations: Economic Demand Response Programs</u>

- No resources participated in the DADRP program since December 2010.
  - Given that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is doubtful.
- DSASP resources in Upstate New York (with a combined capability of nearly 110 MW) actively participated in the market in 2016 as providers of operating reserves.
  - These resources were capable of providing up to 16 percent of the NYCA 10-minute spinning reserve requirement in 2016.

C. Demand Response and Scarcity Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under scarcity 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 scarcity pricing rules for periods when demand response resources are deployed. Generally, when a shortage of 30-minute reserves is prevented by the deployment of demand response in certain regions (e.g., state-wide, Eastern New York, or Southeastern New York), real-time energy prices will be set to $500/MWh or higher within the region. 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 scarcity conditions. Prior to June 22, 2016, the real-time LBMPs during EDRP/SCR activations were set in an *ex-post* fashion, which tended to cause inconsistencies between resource schedules and pricing outcomes and result in potential uplift costs. The NYISO implemented a Comprehensive Scarcity Pricing on June 22 to address this issue. Under this new rule, the 30-minute reserve requirement in the applicable region is increased to reflect the expected EDRP/SCR deployment in the pricing logic, setting the LBMPs in the applicable region at a proper level in an *ex-ante* fashion.

Second, to minimize the price-effects of "out-of-merit" demand response resources, NYISO implemented the TDRP in 2007. This program is currently available in New York City, 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.

Key Observations: Scarcity Pricing

- In 2016, the NYISO activated reliability demand response resources on just one day, August 12, when EDRP and SCR resources in all zones were deployed from HB13 to HB17 for system-wide capacity needs.
  - Response from SCRs in this event was mandatory and the Scarcity Pricing Rule was active during the entire event.
  - See Section V.G in the Appendix for a detailed evaluation of pricing outcomes for this event.
- TDRP was activated six times on four days (July 25 & August 13-15) in 2016.
  - Response from SCRs and EDRPs to these events was voluntary and Scarcity Pricing Rule was not applicable during these events.