2017 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 2017 State of the Market Report presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2017. 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 2017

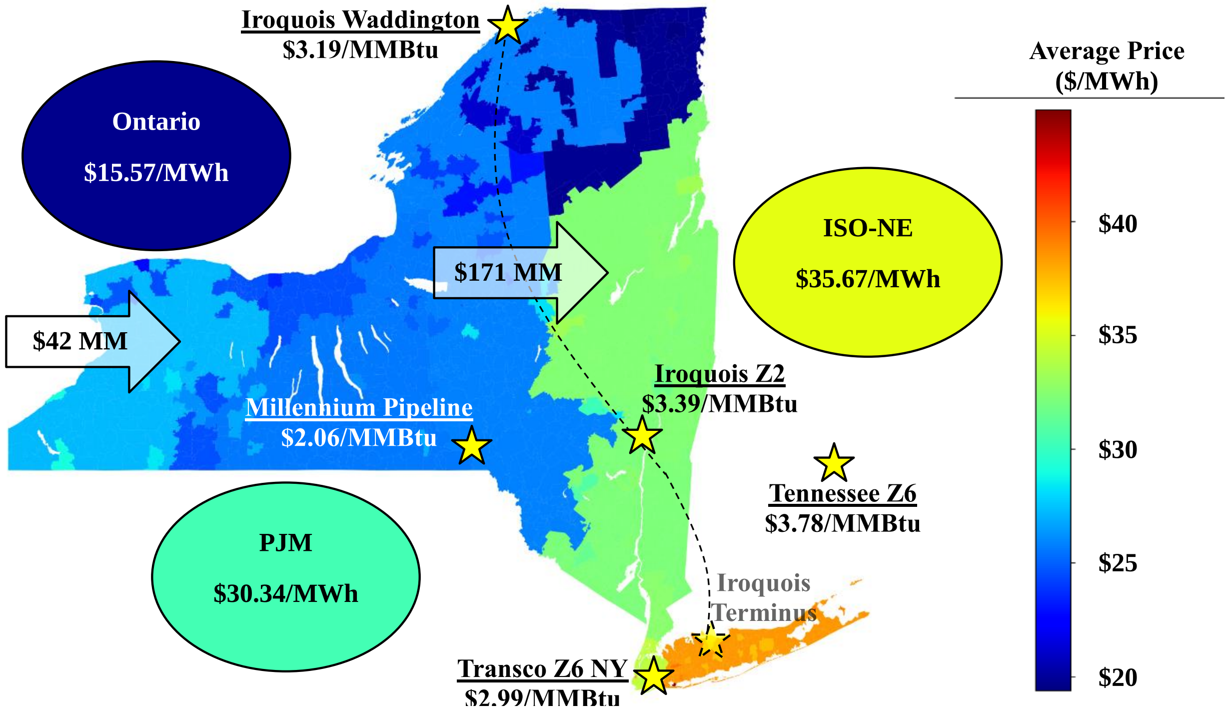
The NYISO markets performed competitively in 2017. The market results in 2017 and market trends are summarized below.

Natural Gas Prices and Load Levels

Load levels were relatively low in 2017. The annual peak load fell 7 percent from 2016 and was lower than 30 GW for only the second time since 2008. Average load fell 2 percent from 2016 and was lower than 18 GW for the first time since 2008. These low levels resulted primarily from very mild weather conditions across the year, particularly in the summer of 2017.

Natural gas prices rose 19 to 42 percent in 2017 across the state from the record-low levels in 2016. There was a general reduction in gas pipeline congestion from west to east, which led to smaller gas spreads between regions. These regional price spreads have been a key contributor to congestion across the state in recent years, so lower gas price spreads helped reduce congestion from western New York to eastern New York.

Day-Ahead Energy, Natural Gas Prices, and Congestion in 2017



Energy Prices and Transmission Congestion

Average energy prices increased 7 to 12 percent in most areas from 2016 to 2017, but fell 3 percent in both the West Zone and Long Island because of reduced congestion in these two areas. The increases in most areas were driven primarily by higher natural gas prices in 2017. 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 nearly $20 per MWh in the North Zone to $39 per MWh in Long Island in 2017. Congestion revenues collected in the day-ahead market fell 5 percent from 2016 to a total of $415 million in 2017. 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 41 percent of total day-ahead congestion revenues in 2017.

Transmission bottlenecks were 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 remote areas of New York toward load centers in the Southeast New York, accounted for 17 percent of day-ahead congestion revenues in 2017. Transmission congestion on the West Zone 230 kV network fell substantially in 2017 because of changes in loop flows, transmission upgrades, and expanded use of the M2M process with PJM. However, congestion on the 115 kV network (currently is managed by out-of-market actions and not reflected in energy prices) became more prevalent.

Installed Capacity Market

Capacity costs to consumers fell 19 percent in New York City and 40 percent in Rest of State from 2016 to 2017, but rose 5 percent in Lower Hudson Valley (i.e., Zones GHI) and 15 percent in Long Island. Changes in the Demand Curve Reference Points were a key driver of price changes in the three Localities. These changes reflected changes in the Net CONE assumptions for the proxy unit from the most recent Demand Curve Reset process. The price reductions in Rest of State were primarily caused by supply increases attributable to higher DMNC test values and increased imports from PJM.

The Local Capacity Requirements ("LCRs") have been relatively volatile in recent years as the LCR for New York City changed from 83.5 percent in 2015 to 80.5 percent in 2016 and to 81.5 percent in 2017. 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. The NYISO plans to implement new rules in 2019 that will result in more stable and efficient capacity requirements. (See Section VII.B for additional details about the new rules.)

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 2017 because of lower energy and capacity net revenues. We summarize below the results for various types of resources:

New Gas Turbines. Our evaluation indicates that there are no areas where investment in a new Frame 7 gas turbine might be economic because of the large capacity margin that currently exists throughout the state.

Existing Steam Turbines. Our evaluation finds that some existing steam turbine units may not be profitable to operate in downstate areas, particularly Long Island. The decisions by owners of individual steam turbine units to retire in the coming years will likely be based on: whether they are under long-term contracts, have high site-specific costs, or face extraordinary repair costs because of forced outages. Ultimately, the retirement of one or more steam turbines would reduce the current capacity margin and increase net revenues for the steam turbines that remain in service.

Existing Nuclear and New Renewables. Investment incentives for existing nuclear units and potential new renewable projects currently depend primarily on state and/or federal subsidies. The cost 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 cap-and-trade carbon market or a carbon tax. Resource-specific subsidies are troubling because they create substantial economic risk for suppliers whose investment and retirement decisions are based on market expectations. At the same time, resource-specific and technology-specific subsidies increase the system-wide costs of achieving emission reduction objectives compared with technology-neutral market mechanisms.

Given the large infusion of intermittent renewables that is expected in the coming years, it is important to evaluate the investment incentives for suppliers to build and maintain resources with flexible characteristics. In this report, we evaluate the financial incentives for investment in various technologies, and we also estimate how the implementation of several of our recommendations to improve real-time performance incentives would affect incentives to build and maintain various technologies. We find that these recommendations would substantially increase net revenues for flexible technologies, while reducing net revenues to existing resources that are inflexible and/or unreliable. (See Section VIII.C and Recommendations #2017-1, #2017-2, #2016-1, and #2016-2 for additional details.)

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 to average real-time energy prices in most areas in 2017. This consistency generally promotes efficient commitment patterns.

The hourly mean absolute differential between day-ahead and real-time prices fell in all regions from 2016 to 2017. The improved convergence resulted from lower real-time price volatility partly because of: a) lower load levels, particularly in the summer; and b) the modification of the Graduated Transmission Demand Curve ("GTDC") in June, which resulted in lower and more predictable congestion prices for most transmission corridors during transmission shortages.

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. Effective arbitrage leads to low average profits for virtual traders. In 2017, the average rate of gross virtual profitability was \$0.16 per MWh, down from \$0.37 per MWh in 2016. This is a general indication that virtual transactions helped achieve better consistency in 2017 between day-ahead and real-time prices.

Competitive Performance of the Markets

As the MMU, we evaluate the competitive performance of the NYISO markets. The energy market performed competitively in 2017 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.

However, this report recommends three modifications to the market power mitigation rules to address shortcomings in the current rules:

- The current rules deter a supplier that over-produces to create transmission congestion only if the congestion leads to high prices downstream of the transmission constraint. However, a supplier with a significant long position in a forward market can benefit from lowering prices in the spot market. We recommend changes to deter uneconomic over-production when it does not result in high prices downstream of the constraint. (See Recommendation #2017-3)

- Gas price volatility and availability issues have increased the need to adjust generation cost estimates used for mitigation to reflect changing market conditions. Generators currently reflect these changing conditions by submitting a "fuel cost adjustment." The current rules do not adequately deter a supplier from submitting inappropriately high fuel cost adjustments to inflate energy prices. We recommend rules to address this deficiency. (See Recommendation #2017-4)

- The NYISO recently revised its tariff to improve the accuracy of forecasts that are used in the buyer-side mitigation exemption tests for the current interconnection class year. However, the tests still employ unrealistic assumptions about the timing of new entry, so we recommend tariff modifications to allow realistic assumptions since these assumptions can greatly affect economic value of a project. (See Recommendation #2013-2d)

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. We evaluated two aspects of how market outcomes were affected by the performance of operating reserve providers.

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

Second, we evaluated how the availability and expected performance of operating reserve providers affected the costs of congestion management in New York City. In some cases, the availability of reserves allow 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, which can lead to inefficient scheduling in the real-time market and inefficient investment incentives for gas turbines that can reduce congestion. We recommend compensation to GTs for this value. (Recommendation #2016-1)

Market Performance under Shortage Conditions

Although shortage conditions occur infrequently, their impact on incentives is substantial. Most shortages are transitory as flexible generation ramp 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, and shortage pricing usually accounts for a significant share of the net revenues that allow a generator to recoup its capital investment costs.

The NYISO was among the first markets to implement robust shortage pricing during operating reserve shortages, and this has supported reliability by attracting imports to New York during peak operating conditions. However, PJM and ISO New England are beginning to phase-in new Pay-for-Performance ("PFP") rules starting in June 2018. The new rules will provide strong incentives to schedule transactions to PJM and ISO New England rather than New York, so we recommend the NYISO consider whether rule changes are needed to help maintain reliability and appropriate incentives during shortage conditions. (See Recommendation #2017-2.)

Transmission shortages occurred in roughly 5 percent of intervals in 2017, accounting for the majority of shortage pricing incentives. The NYISO implemented revised rules for transmission shortage pricing in June 2017. We found that the changes have greatly improved the correlation between the severity and prices during transmission shortages, which has made congestion more transparent and predictable for market participants and reduced real-time price volatility. Nonetheless, we recommend the NYISO develop constraint-specific GTDCs that vary according to the importance, severity, and/or duration of a transmission shortage. (See Recommendation #2015-17)

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 2017 and found the following two categories continued to be 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, frequent flow variations on Phase Angle Regulator ("PAR")-controlled lines (primarily on the A, B, C, J, K, and 5018 lines between New York and New Jersey) because of unrealistic assumptions used in the modeling of PARs, 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 discuss potential solutions and recommend improvements to these issues. (See Recommendations #2012-13 and #2014-9)

Performance 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. While the CTS process is capable of providing significant benefits under current conditions, the benefits of having flexible price-responsive interchange between markets will increase as intermittent resources are added to New York and neighboring systems.

We have found that overall performance of CTS improved significantly from 2016 to 2017. The estimated realized savings (relative to hourly schedules) increased from $2 million in 2016 to over $5 million in 2017 from the CTS processes with PJM and ISO New England. The improvement resulted partly from better price forecasting and partly from an increase in the quantity of price-sensitive bids at both interfaces. Notwithstanding these improvements, CTS is still limited to relatively small (300 MW maximum) adjustments in net interchange every 15 minutes, and it has significantly greater potential to help the three markets balance short-term variations in supply.

The participation in CTS was still much stronger at the New England interface than at the PJM interface. In 2017, an average of 245 MW of price-sensitive transaction bids were offered at the PJM border, compared to 675 MW in the same price range at the New England 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. We found that firms scheduling at the PJM interface require much larger price spreads between markets before they will schedule power to flow across the interface. These results demonstrate that 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 other parties to eliminate these charges at the border. (See Recommendation #2015-9)

We performed an evaluation of factors that contribute to forecast errors by RTC, which is used to schedule CTS transactions and other external transactions and fast-start units. We identify factors that contribute to divergence between RTC and RTD, concluding that they are primarily the same factors that we have identified as contributors to transient price volatility. Hence, the evaluation provides additional support for the recommendations cited above to address transient price volatility. (See Recommendation #2012-13 and #2014-9)

Operations of PAR-Controlled Lines between New York City and Long Island

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 the 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"). The operation of these lines (in accordance with the wheeling agreements) increased production costs by an estimated $13 million 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.)

Operations of PAR-Controlled Lines between New York and PJM

The PARs associated with the old ConEd-PSEG wheeling agreement (which was terminated at the end of April 2017) are now incorporated into the NY-PJM AC interface for interchange scheduling and the M2M process. We found that these changes have led to more efficient utilization of some of these PAR-controlled lines. However, opportunities for improved utilization remain as they were generally operated well below their operational limits. (See Section IX.E)

Out-of-Market Actions and Guarantee Payment Uplift

Guarantee payments to generators fell by 12 percent to $38 million in 2017. Most of the decrease occurred in Western New York, which fell by 49 percent from 2016. This was due primarily to substantially lower reliability commitments and out-of-market ("OOM") dispatch in the Central Zone, both of which fell more than 40 percent from 2016 levels because of transmission upgrades. These upgrades reduced the needs for OOM actions to manage the 115 kV network security in the Central Zone and allowed the Milliken Reliability Support Service Agreement ("RSSA") to expire.

Despite this improvement, the NYISO still frequently took other OOM actions to manage congestion on the 115 kV system, including: (a) manual instructions to generators; (b) taking certain lines out of service on the primary PJM-NYISO interface; (c) derating interfaces with Ontario, PJM, and Quebec; (d) using the interzonal interface constraints as a mechanism to manage flows indirectly on 115 kV facilities, and (e) adjusting PAR-controlled lines on the high voltage network in other parts of the state. Consequently, 115 kV congestion had significant effects on the overall market. In 2017, congestion of the 115 kV facilities were managed via OOM actions frequently, including on:

- 226 days for the West Zone;
- 120 days for flows from the North Zone, and
- 83 days in the Capital Zone.

Hence, we continue to recommend that the NYISO model these constraints to allow the market to price and efficiently manage these low-voltage-network constraints. The NYISO has indicated that some of the low-voltage-network constraints will be incorporated in the market software beginning in the second quarter of 2018, while others will not be modeled until sometime after November 2018. (See Recommendation #2014-12)

Unlike in other regions, guarantee payment uplift rose 59 percent from 2016 to 2017 in New York City. This was driven primarily by a 66 percent increase in reliability commitment as units that were often needed for local reliability were economically committed less frequently in 2017 because of lower load levels and higher natural gas prices (relative to other portion of Eastern New York). Most of these commitments were made to satisfy local N-1-1 requirements in New York City. We recommend the NYISO model reserve requirements for N-1-1 constraints in New York City, which should provide a more efficient market mechanism to satisfy local reliability criteria in the load pockets and contribute to better performance incentives. (See Recommendation #2017-1)

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 fully 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)
- The current capacity market design is generally based on the NYISO's planning criteria. However, it will be difficult for the current capacity market design to adapt to changes over the coming decade, including large-scale retirements and new entry, the introduction of new intermittent generation and energy storage, and new transmission. We have recommended the NYISO implement an optimal locational capacity pricing framework that is simpler and based more directly on NYISO's planning criteria. This framework would be easier to administer, more adaptable to changes in system conditions, and would reduce the overall costs for maintaining reliability. (Recommendation #2013-1c)
- New transmission provides resource adequacy benefits and helps satisfy planning criteria, but most transmission projects are not eligible to be compensated for these benefits through the capacity market. We compared the investment incentives for a hypothetical new generator in the Hudson Valley to a recently-built transmission project into Southeast New York and found:
  - The hypothetical new generator would recoup an estimated 77 percent of its investment from the capacity market; while
  - The transmission project could have recouped 64 percent of its investment from the capacity market if efficient capacity payments were available to transmission projects.
  - Hence, we recommend creating a financial capacity transfer right to provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives. (Recommendation #2012-1c)

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 2017 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 2018 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.

Twenty-one recommendations are presented in six categories below. Most of these were made in our 2016 SOM report, but Recommendations #2017-1 to #2017-4 are new in this report. A detailed discussion of each recommendation is provided in Section XI.

Number	Section	Recommendation	Current Effort	High Priority
Energy Market Enhancements - Pricing and Performance Incentives				
2017-1	IX.G	Model local reserve requirements in New York City load pockets.		
2017-2	IX.A	Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules.		✓
2016-1	VIII.C	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		
2016-2	IX.C	Consider means to allow reserve market compensation to reflect actual and/or expected performance.		
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.		
2015-16	IX.A	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	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	✓	
2014-12	V.A	Model 100+ kV transmission constraints in the day-ahead and real-time markets, and develop associated mitigation measures.	✓	✓
Energy Market Enhancements – Market Power Mitigation Measures				
2017-3	IX.A	Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.		

Number	Section	Recommendation	Current Effort	High Priority
2017-4	III.B	Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.		
Energy Market Enhancements - Real-Time Market Operations				
2014-9	VI.D, IX.F	Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.		
2012-8	VI.D, IX.F	Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.		
2012-13	VI.D, IX.F	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.		
Energy Market Enhancements - BPCG Eligibility and Fuel Limitations/Storage				
2014-13	IX.G	Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.		
2013-11	IX.B.2 (2015 SOM)	Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	✓	
Capacity Market Enhancements				
2015-8	VII.C	Modify the capacity market to better account for imports from neighboring control areas to import-constrained capacity zones.		
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
2013-1c	VII.B	Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements.		
2012-1a	VII.F	Establish a dynamic locational framework that reflects potential deliverability, resource adequacy, and transmission security requirements 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.		
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 2017.[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 and existing generation, transmission, and demand response resources (and/or retire uneconomic 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 reliably 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;

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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."

- 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;
- 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. Furthermore, the markets should adapt as the generation fleet shifts from being primarily fossil fuel-based to having higher levels of renewable penetration. Although large-scale changes in the generation fleet result primarily from public policies to reduce pollution and promote cleaner generation, the NYISO markets provide critical incentives for placing new resources where they are likely to be most economical and deliverable to consumers. Hence, Section XI of the report provides a number of recommendations that are intended to achieve these objectives.

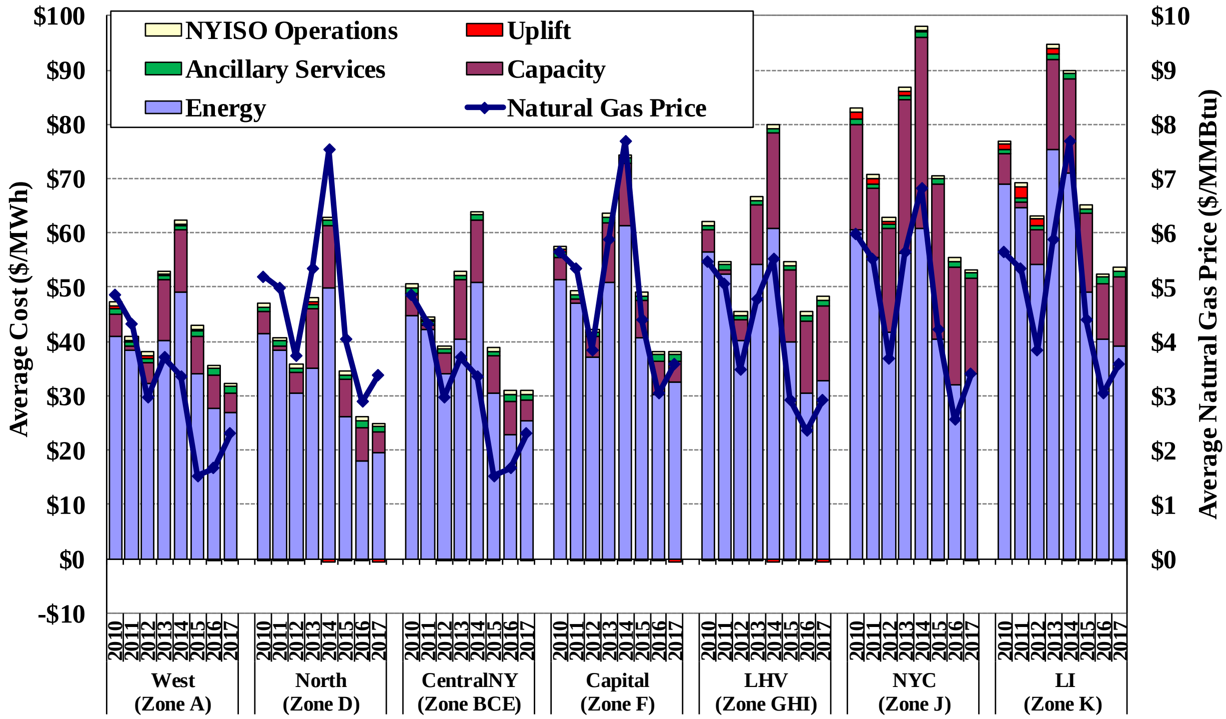
II. OVERVIEW OF MARKET TRENDS AND HIGHLIGHTS

This section discusses significant market trends and highlights in 2017. 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 nine 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 divided by the real-time load in the area.[2]

Figure 1: Average All-In Price by Region
2010-2017



Average all-in prices remained similar to the low levels seen in 2016 across the system, ranging from $25 per MWh in the North Zone to $53 per MWh in Long Island in 2017. Over the nine 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

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

significantly affected the energy prices at some locations. In 2017, energy prices accounted for 64 percent of the all-in price in New York City and 69 to 84 percent of the all-in price in the other regions.

Average energy prices rose 7 to 12 percent in most regions from 2016 to 2017, but fell 3 percent in both the West Zone and Long Island. Most of the year-over-year increases resulted from higher natural gas prices in 2017.[3] However, this was partly offset by lower load levels, particularly in the summer because of mild weather conditions,[4] and higher production from nuclear and hydro units.[5]

Energy prices fell from 2016 levels in the West Zone and Long Island primarily because of greatly reduced congestion in these areas. In Long Island, fewer costly transmission outages was a key driver of the reduction. In the West Zone, congestion on the 230 kV system fell by more than 50 percent from 2016 to 2017 because of several factors that include reduced clockwise loop flows around Lake Erie, transmission upgrades in the West Zone, and the inclusion of these constraints in the M2M process with PJM. Nonetheless, congestion on the 115 kV system in the West Zone became more prevalent and required more frequent out-of-market actions.[6]

Capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs. Average capacity costs rose or fell by various amounts in different regions from 2016 to 2017 as follows:

- 5 percent *increase* in the Lower Hudson Valley (i.e., Zones G, H, and I),
- 19 percent *decrease* in New York City,
- 25 percent *increase* in Long Island, and
- 40 percent *decrease* in Rest of State.

Changes in the Demand Curve Reference Points, which reflected changes to the Net CONE assumptions for the proxy unit from the most recent Demand Curve Reset process, were a key driver of price changes in the three Localities. In the Rest of State, supply increased because of increased DMNC test results and increased imports from PJM.[7]

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 V.A for more discussion of these congestion patterns.

7 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 fuel prices in 2016 and 2017 on an annual basis.[8] The table also shows average real-time energy prices in seven regions of the state for the same years. Representative gas price indices are listed for each of the seven regions.

Table 1: Average Fuel Prices and Real-Time Energy Prices
2016-2017

	Annual Average		
	2016	**2017**	**% Change**
Fuel Prices ($/MMBtu)			
Ultra Low-Sulfur Kerosene	$12.15	$13.53	11%
Ultra Low-Sulfur Diesel Oil	$9.69	$11.92	23%
Low-Sulfur Residual Oil	$6.59	$8.43	28%
NG - Millenium East	$1.45	$2.06	42%
NG - Transco Z6 (NY)	$2.21	$2.99	35%
NG - Iroquois Z2	$2.85	$3.39	19%
NG - Tennessee Z6	$3.07	$3.78	23%
Energy Prices ($/MWh)			
West (Millen. East)	$27.61	$26.81	-3%
North (Waddington)	$17.98	$19.48	8%
Central NY (Millen. East)	$22.80	$25.44	12%
Capital Zone (Iroquois)	$30.14	$32.64	8%
Lw. Hudson(Millen. East/Iroq.)	$30.58	$32.83	7%
New York City (Transco)	$32.00	$34.11	7%
Long Island (Iroquois)	$40.43	$39.19	-3%

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 2017, average natural gas prices rose 19 to 43 percent across the state from 2016 (which had exhibited the lowest annual average gas prices since the beginning of the NYISO markets). There was a general reduction in gas pipeline congestion from west-to-east across the state over the same period, which led to smaller gas price spreads between regions. For example, the Millennium index exhibited an average discount of 39 percent relative to the Iroquois Z2 index

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

in 2017, down from an average discount of 49 percent in 2016. Similarly, the Transco Z6 NY index exhibited an average discount of 12 percent relative to the Iroquois Z2 index in 2017, down from an average discount of 24 percent in 2016. These regional price spreads have been a key contributor to congestion across the New York power system in recent years.[9]

Due to the mild weather in the first quarter of 2017, the 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 2017 compared to the winter months in 2014 and 2015. However, at the end of December 2017 and early January 2018, prolonged cold weather conditions enveloped much of the eastern United States, leading to dramatic increases in gas prices and power prices.[10]

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 2015 to 2017, 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.[11] 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
2015-2017

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2015	2016	2017	2015	2016	2017	2015	2016	2017
Nuclear	5.1	4.7	4.8	32%	31%	33%	0%	0%	0%
Hydro	2.8	2.9	3.2	18%	19%	22%	49%	47%	43%
Coal	0.3	0.2	0.1	2%	1%	0%	2%	1%	1%
Natural Gas CC	5.2	5.1	4.6	33%	33%	31%	67%	68%	77%
Natural Gas Other	1.7	1.7	1.2	10%	11%	8%	28%	30%	33%
Fuel Oil	0.2	0.1	0.1	1%	0%	0%	5%	3%	2%
Wind	0.5	0.4	0.5	3%	3%	3%	5%	3%	5%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

9 See Section III.B of the Appendix for more on this.

10 A detailed review of the cold spell will be included in our Report on the First Quarter of 2018.

11 Section I.o in the Appendix provides regional breakdowns and 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 from all internal generating resources in each year of 2015 to 2017.[12] However, gas-fired generation fell from 44 percent in 2016 to 39 percent in 2017 because of lower load levels, increased generation from nuclear and hydro units, and higher gas prices.

The small changes in generation from nuclear resources (which accounted for slightly more than 30 percent of all generation each year) were driven primarily by variations in the amount of generation deratings and outages. Coal-fired generation continued to fall in 2017 as low gas prices continue to make it relatively uneconomic and transmission upgrades have led the Milliken facility to be no longer needed for local reliability in the Central Zone.[13] Average oil-fired generation fell after 2015 because of mild weather and low natural gas prices in the winter months. However, oil-fired generation rose substantially in the last week of December 2017 because of cold weather.[14]

Hydro production rose in 2017 because of improved water conditions for small facilities across the state because of increased rainfall as well as 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. There was a general decline in the frequency of hydro resources being on the margin from 2015 to 2017, which resulted from less-frequent congestion in the West Zone over this period. Other fuel types set prices much less frequently.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Table 3 shows load statistics for the New York Control Area ("NYCA") since 2009: a) annual summer peak; b) annual winter peak; c) annual average load; and d) number of hours when load exceeded certain levels.

Load levels were relatively low in 2017. The annual peak load level was below 30 GW for only the second time since 2008 and fell sharply (by 7 percent) from 2016 because of very mild weather and fewer peaking conditions in the summer of 2017. Average load levels, which were below 18 GW for the first year since 2008, fell 2 percent from 2016.

12 Figure A-7 in the Appendix shows generation mix by region by quarter in 2016 and in 2017.

13 Appendix Section V.H discusses the scheduling of the Milliken facility for local reliability.

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

Table 3: Peak and Average Load Levels for NYCA
2009 – 2017

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
2017	29.7	24.3	17.9	0	0	43

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.[15] 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 drives day-ahead congestion in a well-functioning market.[16]

The value of day-ahead congestion fell 5 percent to $415 million in 2017, partly because of lower load levels and milder peaking conditions in both the summer and the winter seasons.[17] Additionally, modifications made to the transmission shortage pricing in June 2017 further reduced constraint costs during transmission shortages in most areas, which contributed to the overall decrease in congestion.

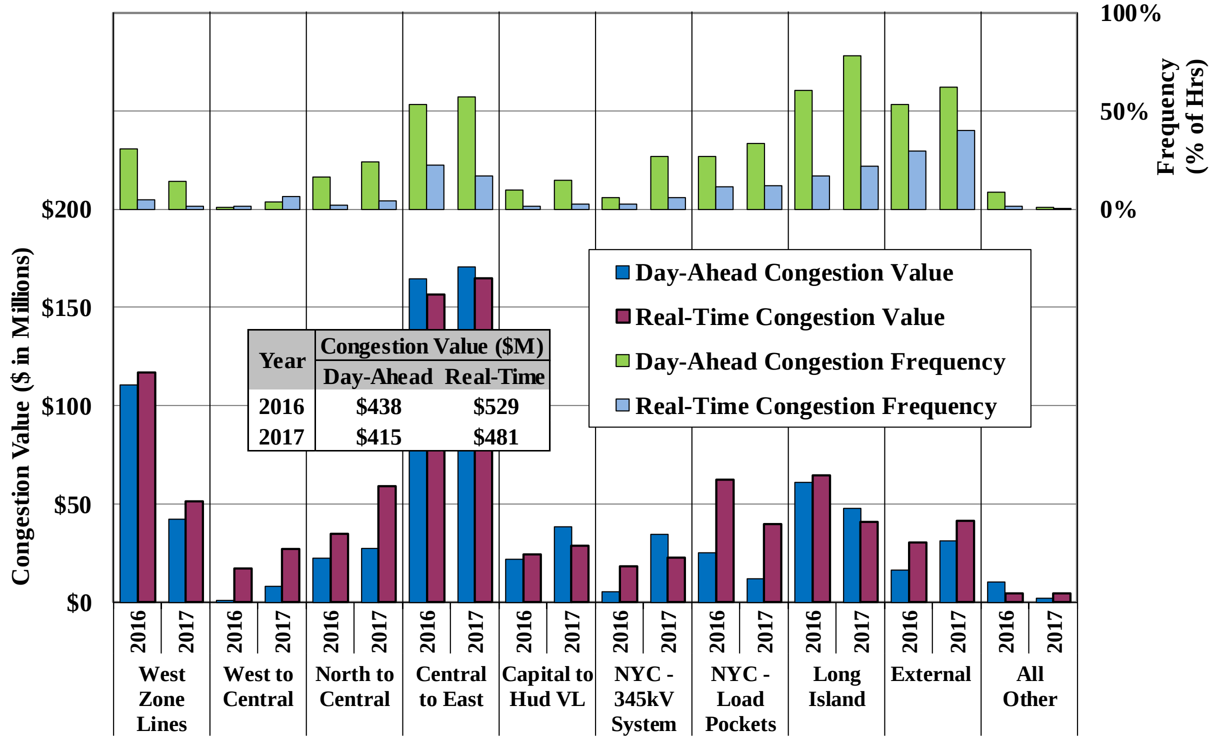
Congestion across the Central-East interface accounted for the largest share of total congestion value in both 2016 and 2017 – accounting for 41 percent of congestion value in the day-ahead market in 2017. The majority of this congestion occurred in the first quarter and in December as a result of higher natural gas prices and larger gas price spreads between regions.

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

16 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.

17 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.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2016-2017



Congestion on 230kV lines in the West Zone fell substantially (by nearly 60 percent) from 2016 levels. The decrease was mainly attributable to: [18]

- Lower and less volatile clockwise loop flows around Lake Erie; [19]
- Transmission upgrades completed in May 2016 that divert a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities, although this has led to increased congestion on the 115 kV network; [20] and
- Expanded use of the M2M process with PJM in May 2017 to help manage congestion in western New York. [21]

Congestion on Long Island fell 21 percent in the day-ahead market and 37 percent in the real-time market. The notable decrease reflected fewer costly transmission outages in 2017.[22]

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

19 See Appendix Section III.E for more discussion.

20 Two new series reactors on the Packard-Huntley 230 kV #77 and #78 lines were installed. See Section III.D for details regarding 115 kV congestion.

21 See Appendix Section V.C for more discussion of the M2M process.

22 A 345 kV line from upstate to Long Island (the Y49 Line) was forced out of service during most of the summer in 2016, but it was in service for most of the year in 2017.

Congestion increased from Capital to Hudson Valley because of more transmission outages affecting transfer capability into Southeast New York. Although the overall amount of congestion from the North Zone to Central New York was similar in the day-ahead market between 2016 and 2017, it increased significantly in the real-time market in 2017 partly because of modifications to the pricing logic during shortages in June 2017 that led to higher constraint costs during transmission shortages.[23]

The 345 kV system of New York City also experienced higher congestion levels in 2017. A few factors in particular contributed to this increase:

- Less imports from PJM across PAR-controlled ABC lines following the expiration of the PSEG/ConEd Wheeling agreement in May 2017;
- More transmission outages into New York City; and
- Smaller gas spreads between New York City and the other portion of Eastern New York, making New York City generators less economic compared to last year.

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 are efficiently reflected in Location Based Marginal Prices ("LBMPs") and reserve 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. Figure 3 shows the average prices of the four ancillary services products by location in the day-ahead market in each month of 2016 and 2017.[24]

Reserve prices have been elevated since the implementation of the Comprehensive Shortage Pricing Project in November 2015, which led to higher reserves prices because it increased the NYCA 30-minute reserve requirement and reduced the amount that could be scheduled on Long Island units. 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 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.

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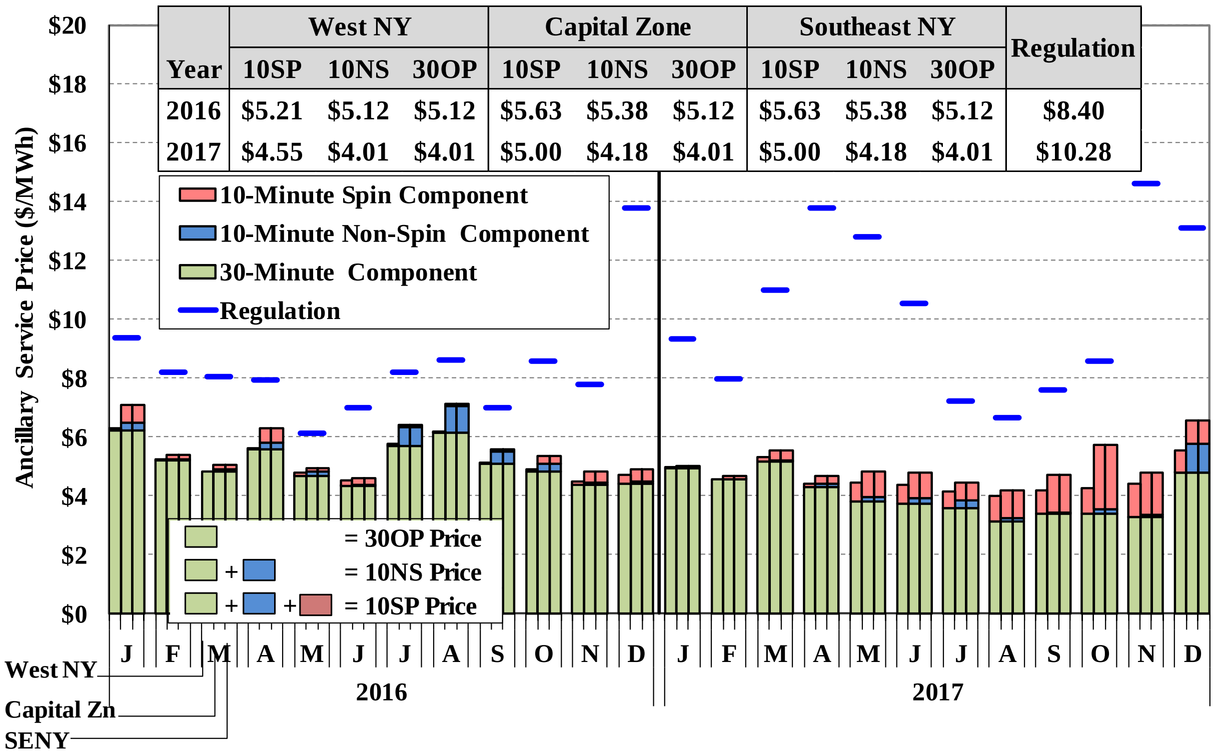
23 See Section V.F in the Appendix for more details on the use of the Graduated Transmission Demand Curve ("GTDC") before and after June 2017.

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

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.[25]

Figure 3: Average Day-Ahead Ancillary Services Prices
2016-2017



	West NY			Capital Zone			Southeast NY			
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	Regulation
2016	$5.21	$5.12	$5.12	$5.63	$5.38	$5.12	$5.63	$5.38	$5.12	$8.40
2017	$4.55	$4.01	$4.01	$5.00	$4.18	$4.01	$5.00	$4.18	$4.01	$10.28

Nonetheless, the average day-ahead prices for all reserve products fell in 2017 despite the increase in energy prices in most areas. The reductions resulted primarily from lower 30-minute reserve prices largely because of lower operating reserve offer prices. As in 2016, the price of the NYCA 30-minute reserves accounted for most of the day-ahead market reserve costs in 2017. The changes in reserve offer prices in the day-ahead market are discussed further in Section II.D in the Appendix.

However, the average regulation prices and the average 10-minute spinning components of reserve prices rose from 2016. Lower load levels in 2017 were a key driver, which generally resulted in committing less generating capacity to meet load and ancillary services requirements. As a result, the available supply for regulation and 10-minute spinning reserves from online resources decreased, driving up prices.

25 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 2017 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. Subsection 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 2017.

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 production costs. 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 steeper 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.

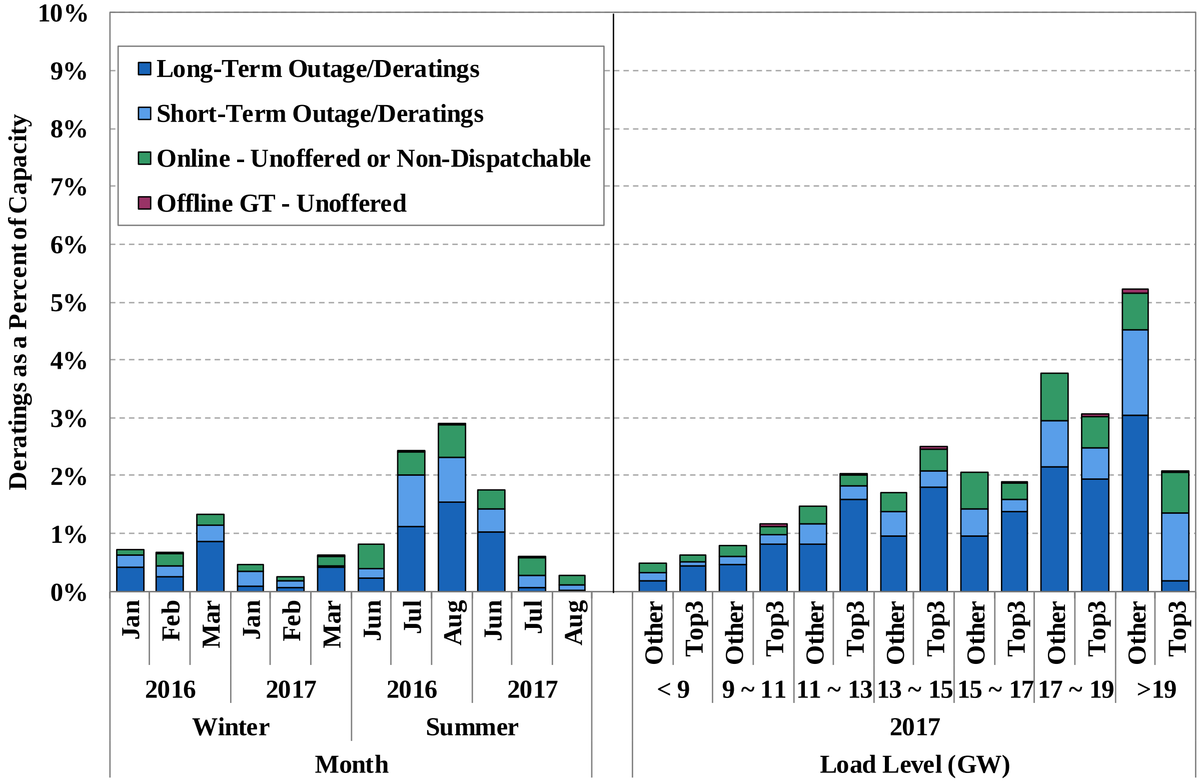
In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap". The output gap is the amount of generation 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.[26]

Figure 4 and Figure 5 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[27] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

26 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.

27 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 scheduled during a period

Figure 4: Unoffered Economic Capacity in Eastern New York
2016-2017



Derated and unoffered economic capacity averaged 1.3 percent of total capacity in NYCA, and 1.5 percent in Eastern New York in 2017, both of which were modestly lower than 2016 levels.

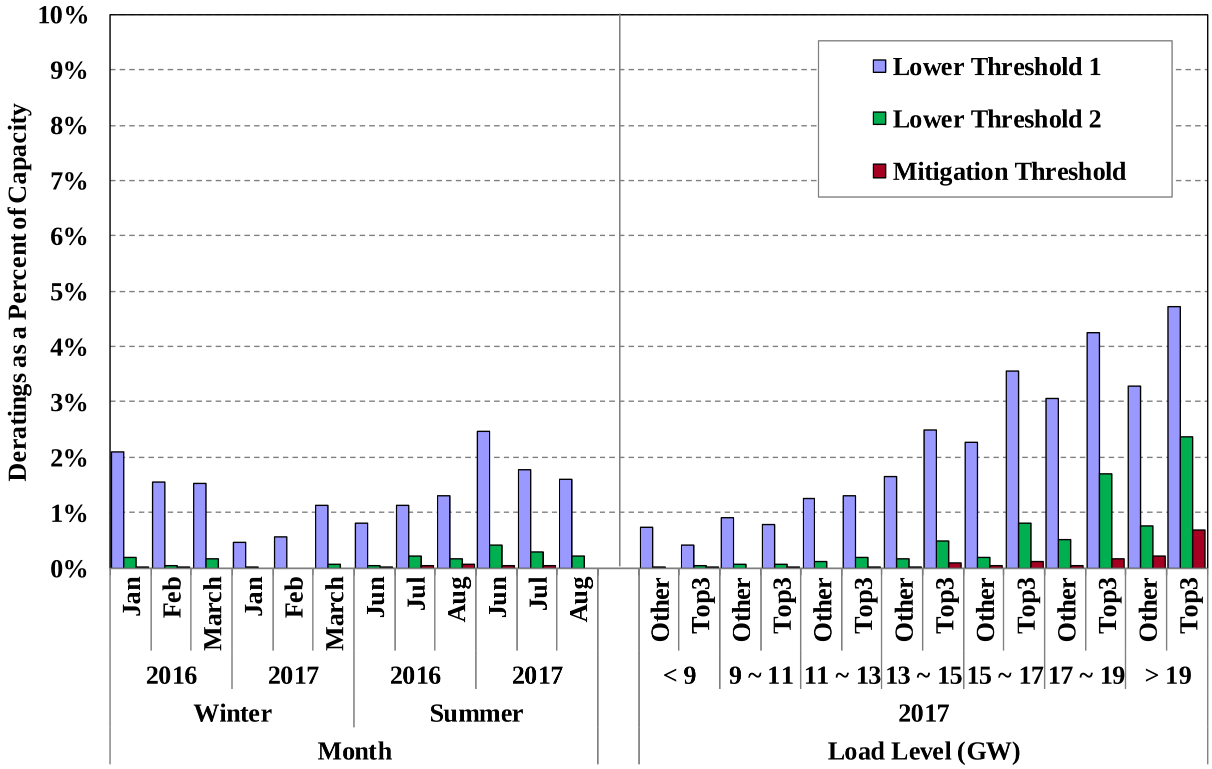
Generator outages and deratings in Eastern New York dropped noticeably in the summer of 2017 from the previous summer. This resulted partly from milder weather conditions (i.e., fewer hot days that require operation of older generators) this summer.[28] In addition, because of lower load levels in 2017, less of the unoffered capacity was economic during the summer months.

The amount of output gap in Eastern New York remained very low in 2017, averaging less than 0.1 percent of total capacity at the statewide mitigation threshold and 1.3 percent at the lowest threshold evaluated (i.e., 25 percent above the reference level).

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.

28 One large unit in Southeast New York was forced out of service from early-June to mid-September in 2016 because of equipment failures, contributing to higher unoffered economic capacity in the summer of 2016.

Figure 5: Output Gap in Eastern New York
2016 - 2017



Although output gap increased modestly with load, the amount was still relatively small under all load conditions. The output gap increased in high-load hours partly because our calculation may overstate the amount under such conditions.[29] Much of this increase occurred on units that are: (a) co-generation resources that tend to operate in an inflexible manner; 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.

It is generally a positive indicator that the unoffered economic capacity and the output gap were 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.

29 Our screen methodology 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 have actually been economic to commit.

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.[30]

- 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 (i.e., offer capping) that was imposed in the day-ahead and the real-time markets in 2016 and 2017.

Most mitigation occurs in the day-ahead market where most supply is scheduled. Reliability mitigation accounted for 56 percent of all mitigation in 2017, nearly all of which occurred in the day-ahead market. These were primarily for DARU and LRR commitments in New York City, which rose noticeably in 2017.[31] 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.

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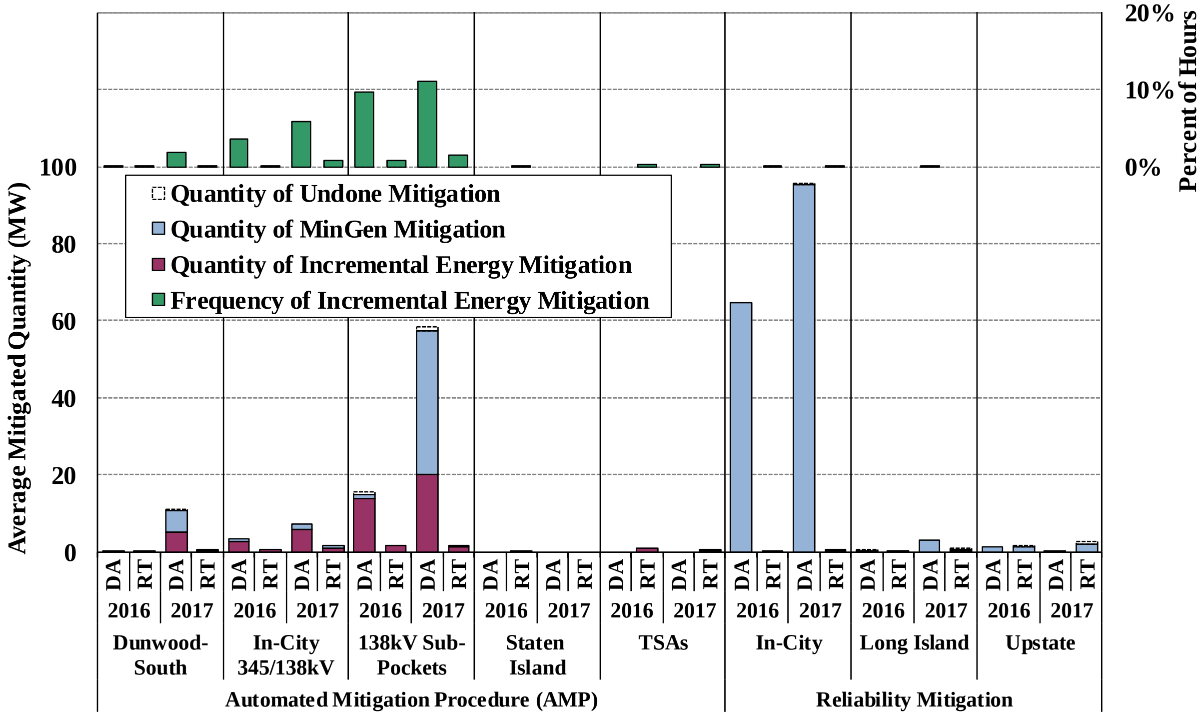
30 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

31 See Section IX.G for more details on higher reliability commitments in New York City.

Figure 6: Summary of Day-Ahead and Real-Time Mitigation
2016 - 2017



AMP mitigation accounted for 44 percent of day-ahead mitigation, up significantly from 2016. The increase resulted from more frequent congestion into the 345 kV system and the 138 kV sub-pockets of New York City because AMP is only invoked when congestion in New York City might lead to conditions where a generator has market power. Increased congestion was primarily driven by higher natural gas prices in New York City (relative to other portions of Eastern New York), lower imports from New Jersey across the PAR-controlled A, B, and C lines as a result of the expiration of the ConEd/PSEG wheeling agreement in May 2017, and more frequent outages of 345 kV circuits into the city. [32]

As natural gas markets have become more volatile in recent years, generators have increasingly utilized the Fuel Cost Adjustment ("FCA") functionality to adjust their reference levels in the day-ahead and real-time markets. The FCA functionality is important because it allows a generator to reflect fuel cost variations closer to when the market clears, and this helps the generator to avoid being mitigated and scheduled when the generator would be uneconomic. While it is important to ensure that generators are not mitigated inappropriately, the FCA functionality provides the opportunity to submit biased FCAs that might allow an economic generator to avoid being mitigated and scheduled. Accordingly, we monitor for biased FCAs and the NYISO administers mitigation measures that impose financial sanctions on generators

32 See Section V.A for more details on increased congestion in New York City.

that submit biased FCAs under certain conditions. However, we've identified circumstances when a supplier could withhold capacity from the market and use a biased FCA to avoid being mitigated and where the mitigation measures are inadequate to deter such conduct. This is because a generator that submits biased FCAs is temporarily barred from using the FCA functionality, but no financial sanction is imposed even if the generator's biased FCAs led to a significant effect on LBMPs. Therefore, we recommend the NYISO modify its tariff so that the market power mitigation measures deter a generator from exercising market power by submitting biased FCAs.[33]

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.[34] Supply-side mitigation measures prevent a supplier with market power from inflating prices above competitive levels by withholding economic capacity in these areas.[35] Given the sensitivity of prices in these areas to both actions, we believe that these market power mitigation measures are essential for ensuring that capacity prices in the mitigated capacity zones are competitive. This section discusses the use and design of capacity market mitigation measures in 2017.

Application of the Supply-Side Mitigation Measures

Two suppliers initiated steps to deactivate capacity by filing notices to retire or deactivate or by beginning to transition into an ICAP Ineligible Forced Outage ("IIFO") in 2017 and 2018. The NYISO's tariff requires that it evaluate whether a proposal to remove capacity from a Mitigated Capacity Zone has a legitimate economic justification. In Zone J, Helix Ravenswood moved eight GTs into an IIFO in November 2017 or April 2018. In addition, Entergy noticed its intent to retire Indian Point 2 by April 30, 2020 and Indian Point 3 by April 30, 2021.

Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests ("METs") and provided BSM determinations for five Class Year 2015 ("CY15") "Additional CRIS MW" projects in January

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33 See Section XI, Recommendation #2017-4.

34 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.

35 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.

2017, which involve investments to uprate an existing resource. All five of these projects were determined to be exempt based on the economics of the projects. In addition, the NYISO also evaluated the 1000MW Champlain Hudson Power Express Project ("CHPE Project") for a Competitive Entry Exemption ("CEE") and confidentially provided a BSM determination to the developer. The five Additional CRIS MW projects accepted their Project Cost Allocations while the CHPE Project was removed from CY15 for failing to post security.

In 2017, the NYISO commenced its evaluation of seven projects that are part of CY17. The NYISO is evaluating two Additional CRIS MW projects, a 230 MW CT and the CHPE Project under the Part B of the MET (in Zone J), and three other projects (two CTs totaling 223 MW in Zone J and a 1020 MW CC in Zone G) for a CEE. The NYISO will provide their BSM determinations in 2018 upon completion of the CY17 Facilities Studies.

Improvements to the BSM Measures

The NYISO made several modifications to its test methodology in the CY15 and CY17 evaluations.[36] These modifications enhanced the alignment of the test procedure with the Tariff and with the underlying intent of the BSM evaluations. Our past BSM reports have identified additional concerns with several assumptions that are used in the BSM evaluations. 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").[37]

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 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

36 See the MMU's BSM Report for CY15 Projects for changes the NYISO made to the test methodology. The NYISO filed additional changes with the Commission and for its CY17 evaluation. See Lorenzo Seirup's May 17, 2017 presentation to the Business Issues Committee on "BSM Forecast Enhancements".

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

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 BSM measures do not address all potential conduct that may suppress capacity prices.[38] To determine whether the BSM 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 their continued operation is uneconomic, and we agree.[39] Uneconomic retention, like uneconomic entry, can undermine long-term performance of the market by distorting short-term prices and creating increased economic risks for suppliers. Hence, we recommended an offer floor be applied to a generator (at its going-forward cost level) if an above-market contract causes an uneconomic generator to remain in operation. In contrast, the NYISO proposed a process for simply monitoring such activity in a compliance filing. The Commission has not issued a ruling.[40]

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.

Recognizing the need to harmonize state policies with its markets, the NYISO created the Integrating Public Policy Task Force ("IPPTF") to work with stakeholders to integrate the cost of carbon into wholesale electricity markets in a technology-neutral, non-discriminatory manner.[41] The costs of reducing CO_2 emissions varies by technology and location.[42] We support the NYISO's approach because it would compensate participants in a transparent and non-discriminatory manner, which should motivate efficient decisions that minimize the costs of satisfying the carbon reduction objective.

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38 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.

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

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

41 See Nathaniel Gilbraith's April 16, 2018 presentation on "The Mechanics of Integrating a Carbon Charge into NYISO Energy Market Operations" for IPPTF's objective and the two approaches the NYISO recently proposed for integrating carbon into the electricity market.

42 See Section VIII.B of the 2016 State of the Market Report.

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, the 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.[43] These statistics are shown on an annual basis.

Table 5: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2016-2017

	Annual Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff	
Zone	2016	2017	2016	2017
West	-0.5%	-1.0%	58.5%	44.4%
Central	0.3%	-0.6%	38.4%	35.8%
North	0.6%	5.5%	58.4%	58.1%
Capital	2.1%	1.2%	34.1%	31.7%
Hudson Valley	0.9%	1.7%	33.9%	30.6%
New York City	-1.2%	2.3%	36.6%	31.6%
Long Island	0.5%	3.2%	45.0%	39.1%

Overall, day-ahead prices were higher on average than real-time prices by a small margin in most areas in 2017. 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.

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

The average absolute difference between day-ahead and real-time prices fell in all regions from 2016 to 2017. The improved convergence resulted from lower real-time price volatility, which was partly attributable to lower load levels, particularly in the summer of 2017. In addition, the modifications to the GTDC in June 2017 resulted in lower and more predictable congestion for most transmission corridors during transmission shortages.[44]

Price convergence improved most in the West Zone. In addition to reasons mentioned above, congestion-price volatility was reduced by lower loop flows around Lake Erie, transmission upgrades, and the inclusion of West Zone constraints in the M2M process with PJM.

The average absolute difference continues to indicate the highest volatility is in Western and Northern New York. These areas have: (a) substantial amounts of intermittent renewable generation, (b) interfaces with Ontario and Quebec that convey large amounts of low-cost imports that are relatively inflexible during real-time operations, and (c) volatile loop flows passing through from neighboring systems. The combination of these factors leads to volatile congestion pricing at several transmission bottlenecks in western and northern New York.

Convergence of Nodal Energy Prices

Although a few generator nodes still exhibited less consistency between average day-ahead and real-time prices than zonal prices did, price convergence generally improved in 2017, particularly at several nodes where poor convergence was common in recent years.[45] Modeling improvements contributed to better price convergence at these locations.

One location where convergence improved is the Greenwood load pocket in New York City.[46] This was partly attributable to the modification of a software module in December 2016. This module had previously caused the day-ahead to frequently commit gas turbines uneconomically in the load pocket, which resulted in understated day-ahead congestion into the pocket. This module now does not commit additional gas turbines unless it would lower bid-production costs.

Nodal congestion may sometimes fail to converge between the day-ahead and the real-time markets even though convergence is good at the zone level. Allowing virtual trading at a nodal level would enable market participants to better arbitrage day-ahead and real-time congestion. 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.

44 See Section V.F in the Appendix for a more detailed analysis on the impact of GTDC changes on prices.

45 See Section I.G of the Appendix for detailed results.

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

Convergence of Ancillary Service Prices

Regulation prices generally converged well between day-ahead and real-time, while day-ahead prices for operating reserves were systematically higher than real-time prices in 2017. This premium for operating reserves in the day-ahead market arises because the day-ahead market schedules operating reserves based on the availability offers of generators and the opportunity costs of not providing other products, while the real-time market schedules reserves based on opportunity costs only (since a generator offering energy in the real-time market does not incur an additional cost to be available to provide reserves). Covergence improved as day-ahead prices fell for all reserve products from 2016, partly because of reduced offer prices from some capacity.[47]

We periodically review day-ahead reserve offers and find many units that offer above the standard competitive benchmark (i.e., estimated marginal cost) or do not offer reserves at all. 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.[48]

B. Day-Ahead Load Scheduling and Virtual Trading

Convergence between day-ahead and real-time energy prices is generally 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 average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2016 and 2017 for several regions.[49] 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 2017. Day-ahead net load scheduling patterns in each of the sub-regions were generally consistent between 2016 and 2017 as well.

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47 Appendix Sections I.H and II evaluate day-ahead offer patterns and the convergence between day-ahead and real-time prices.

48 See MST 23.3.1.2.1.2.1.

49 Figure A-37 to Figure A-44 in the Appendix also show these quantities on a monthly basis.

Table 6 shows that average net load scheduling tends to be higher where volatile real-time congestion often leads to very high (rather than low) real-time prices. 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 highest in the West Zone in recent years because of volatile real-time congestion on the 230kV system there. Over-scheduling generally helped improve the commitment of resources in these areas.

Table 6: Day-Ahead Load Scheduling versus Actual Load
By Region, 2016 - 2017

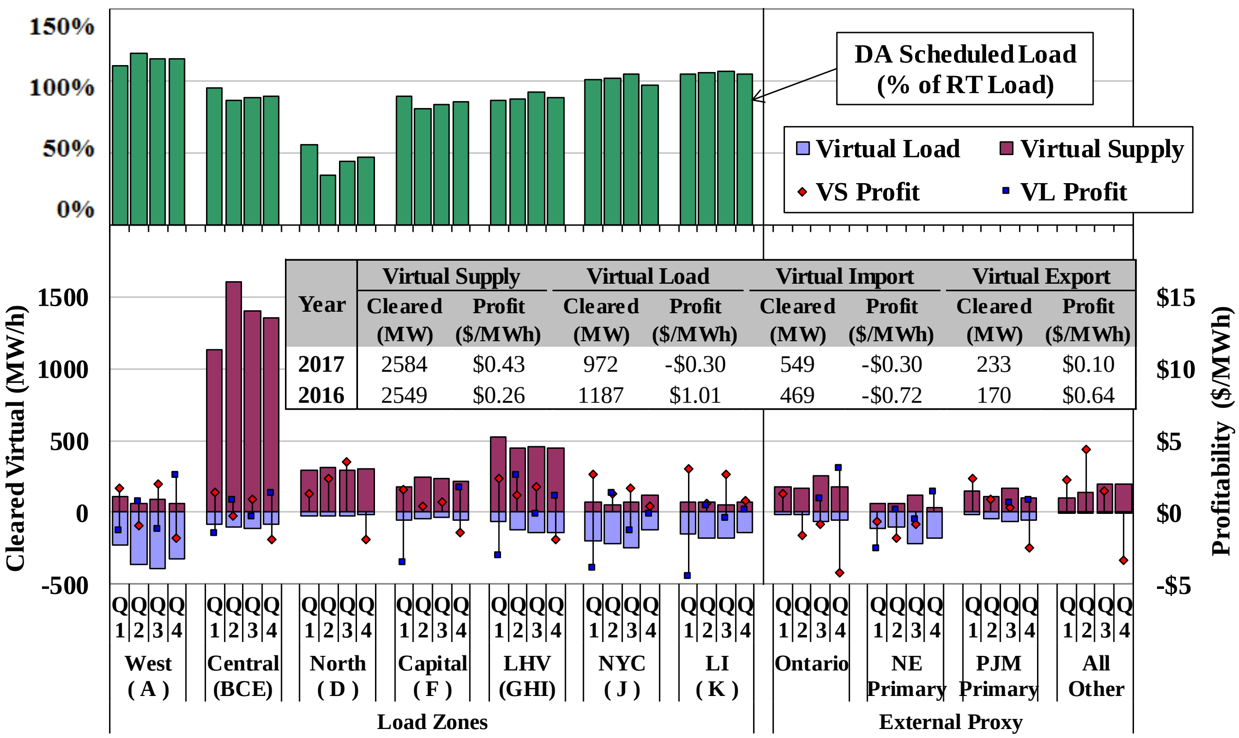
Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2016	96.7%	0.0%	-4.1%	24.7%			117.3%
	2017	97.3%	0.0%	-4.6%	22.4%			115.1%
Central NY	2016	114.0%	0.0%	30.6%	4.0%			87.3%
	2017	120.4%	0.0%	33.8%	3.1%			89.8%
North	2016	98.8%	0.0%	-55.7%	5.3%			48.4%
	2017	99.9%	0.0%	-58.4%	4.4%			45.9%
Capital	2016	98.3%	0.0%	-17.7%	5.3%			85.9%
	2017	97.8%	0.0%	-17.3%	4.5%			84.9%
Lower Hudson	2016	79.7%	19.5%	-23.9%	8.6%			83.9%
	2017	79.8%	20.1%	-19.3%	8.1%			88.7%
New York City	2016	83.2%	13.6%	-0.6%	6.3%			102.4%
	2017	78.8%	18.4%	-1.0%	4.9%			101.2%
Long Island	2016	99.8%	0.0%	-1.6%	9.8%			108.0%
	2017	100.2%	0.0%	-2.0%	7.6%			105.8%
NYCA	2016	94.2%	7.0%	-12.6%	8.3%	-2.5%	1.1%	95.3%
	2017	94.1%	8.7%	-13.0%	6.9%	-3.0%	1.3%	95.0%

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 that increases west-to-east congestion in the West Zone increases day-ahead commitments east of the West Zone. Nonetheless, net load scheduling fell modestly in these three regions in 2017 partly because of less volatile real-time congestion.

Load was under-scheduled most in the North Zone where real-time prices can fall to very low (negative) levels when transmission bottlenecks limit the amount of renewable generation and imports from Ontario and Quebec that can be delivered south towards central New York.

To a large extent, the net day-ahead scheduling patterns are determined by virtual trading activity. Figure 7 summarizes virtual trading levels by location in 2017, including NYISO's internal zones and external interfaces.[50] The pattern of virtual trading did not change significantly in 2017 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.

Figure 7: Virtual Trading Activity
by Region by Quarter, 2017



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)
2017	2584	$0.43	972	-$0.30	549	-$0.30	233	$0.10
2016	2549	$0.26	1187	$1.01	469	-$0.72	170	$0.64

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. Nonetheless, virtual traders netted a gross profit of approximately $6 million in 2017, indicating that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability was $0.16 per MWh in 2017, lower than the $0.37 per MWh in 2016. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market, which facilitates efficient commitment of generating resources. Lower profitability in 2017 was consistent with the better convergence achieved in 2017 as well.

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

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 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 and real-time LBMPs.[51] 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, no TCCs that are sold for real-time congestion since most power is scheduled through the day-ahead market.

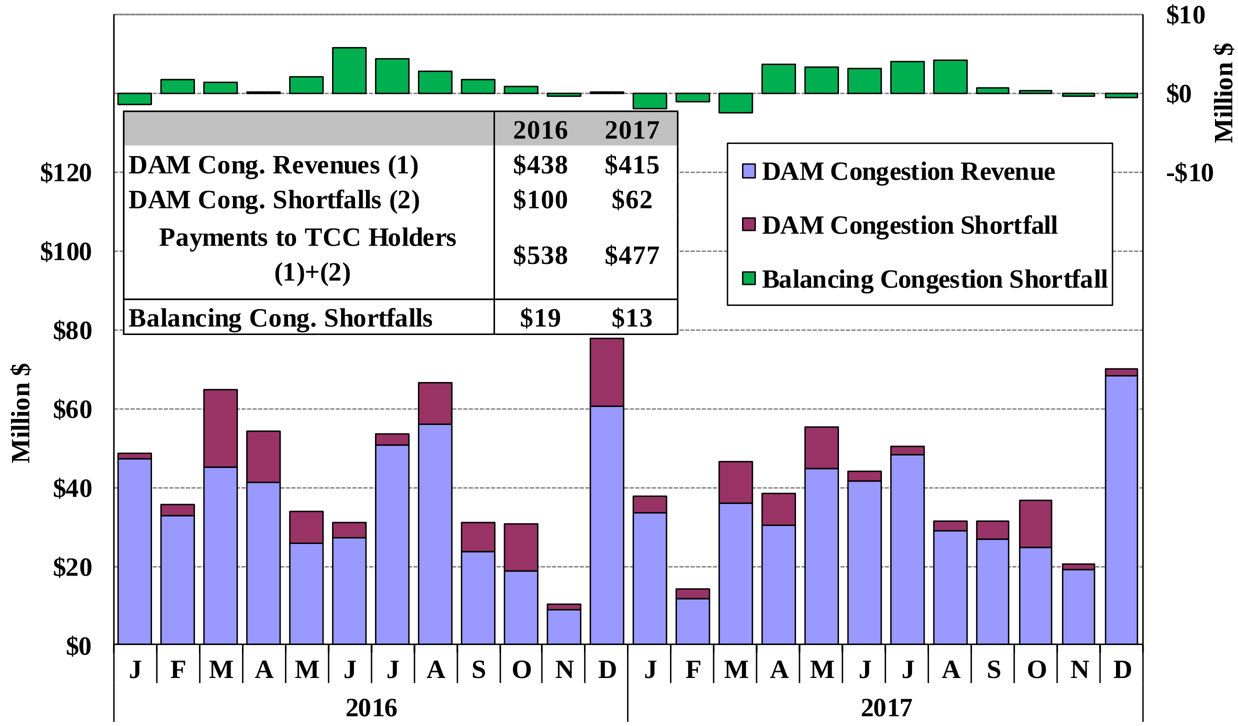
This subsection analyzes congestion that is managed by scheduling resources in the day-ahead and real-time markets to provide relief. This subsection also evaluates transmission constraints on the low voltage network in upstate New York that are managed through out-of-market actions by the operators (since they are not managed as other constraints through the day-ahead and real-time markets). Out-of-market actions have become increasingly common in recent years due to the retirement of generation on the low-voltage network.

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 be scheduled to flow in the real-time market.

51 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
2016 – 2017



Congestion revenues and shortfalls fell from 2016 to 2017. In particular:

- Day-ahead congestion revenues fell 5 percent to $415 million;
- Day-ahead congestion shortfalls fell 38 percent to $62 million; and
- Balancing congestion shortfalls fell 31 percent to $13 million.

Day-Ahead Congestion Revenues

Day-ahead congestion revenues fell modestly from 2016 and 2017, reflecting:

- Lower load levels and milder peaking conditions in the summer and winter month. Low, load levels generally decrease flows across the network and lead to fewer severe transmission bottlenecks; and
- The modification of the transmission shortage pricing in June 2017 decreased the congestion shadow prices on most constraints during transmission shortages, leading to similar decreases in the day-ahead market based on expectations.[52]

However, more costly transmission outages contributed to higher congestion from Capital to Hudson Valley and into the 345 kV system of New York City. On the other hand, congestion

52 See Section V.G in the Appendix for discussion of changes to the use of the GTDC.

was reduced in Long Island and in the 138 kV sub-pockets of New York City partly because of fewer costly transmission outages there.

Day-ahead congestion fell most across the 230 kV network in the West Zone, falling 56 percent in the day-ahead market. In addition to drivers mentioned above, the decrease was also attributable to the following:

- Lower and less volatile clockwise loop flows around Lake Erie; [53]
- Transmission upgrades that were completed in May 2016 have diverted a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities in the West Zone. However, this has also led to increased congestion on the 115 kV network (which is discussed below); and
- The inclusion of West Zone constraints in the M2M process with PJM in May 2017.[54]

Transmission Constraints on the Low Voltage Network in Upstate NY

Currently, transmission constraints on 230 kV and above facilities in Upstate New York are generally managed through the day-ahead and real-time market systems. This provides several benefits, including:

- More efficient scheduling of resources that optimally balance the costs of satisfying demand, ancillary services, and transmission security requirements; and
- More efficient price signals for longer lead time decisions such as fuel procurement, generator commitment, external transaction scheduling, and investment in new and existing resources and transmission.

However, transmission constraints on the 115 kV and lower voltage networks in Upstate New York are resolved primarily through out-of-market actions, which usually do not provide the same benefits, including:

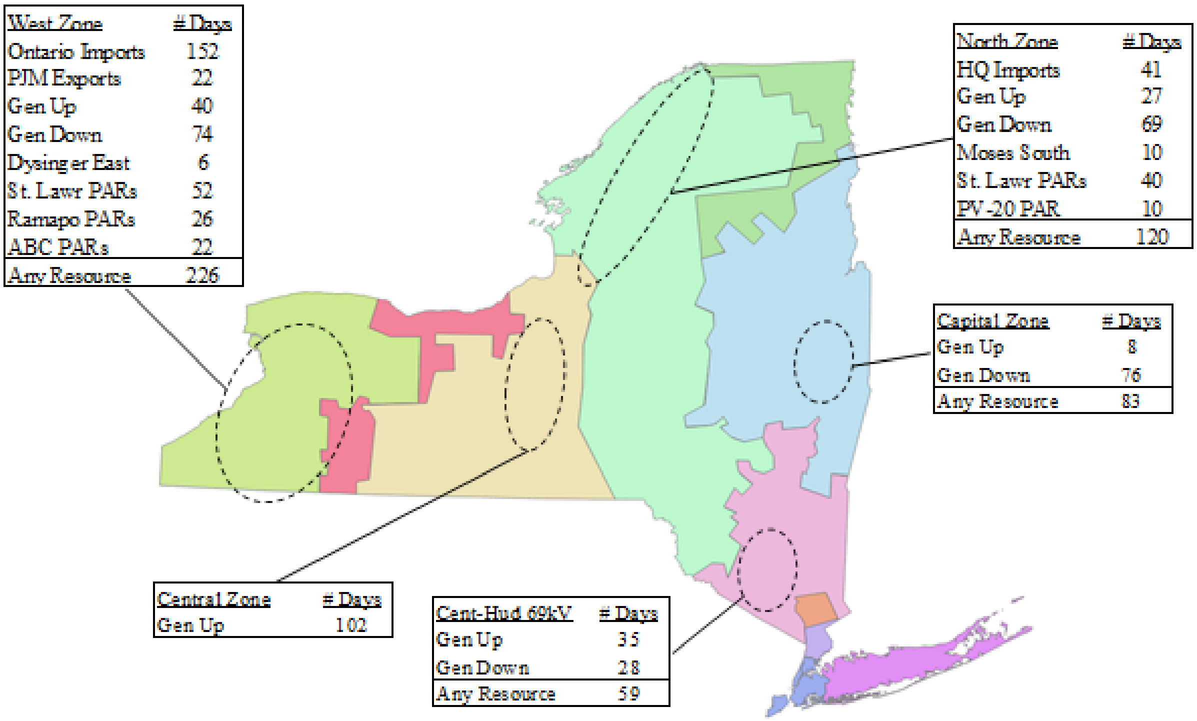
- Out of merit dispatch and supplemental commitment of generation;
- Curtailment of external transactions and limitations on external interface transfer limits;
- Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
- Adjusting PAR-controlled line flows on the high voltage network.

Figure 9 evaluates the frequency of out of market actions to manage constraints on the low voltage network in five areas of Upstate New York: a) West Zone; b) Central Zone; c) Capital Zone; d) North and Mohawk Valley Zones; and e) Hudson Valley Zone. The tables in the figure summarize the number of days in 2017 when various types of resources were used in each area.

53 See Section III.E in the Appendix for discussion of loop flows.

54 See Section V.C in the Appendix for discussion of M2M with PJM.

Figure 9: Constraints on the Low Voltage Network in Upstate NY
2017



The West Zone exhibited the most frequent congestion on the low voltage network among the five areas in 2017. Congestion of the 115 kV facilities in the West Zone has become more prevalent even than congestion on the 230 kV network.[55] In 2017, resources were utilized out of market to manage 115 kV constraints on 226 days, compared to just 158 days of congestion on the 230 kV network in the energy markets. In addition, a 230 kV facility connecting NYISO to PJM (i.e., the "Dunkirk-South Ripley" line, which is not shown in the figure) was taken out of service to manage 115 kV constraints on nearly every day of the year.[56]

The 115 kV facilities that flow power from northern New York towards the central part of the state were constrained on 120 days in 2017 (compared to 166 days of congestion on parallel higher voltage facilities managed through markets), accounting for the second most-frequently-congested low voltage network in these five areas. It is important to manage 115 kV congestion efficiently. Otherwise, inefficient congestion management will:

- Unnecessarily limit low-cost imports from Ontario and Quebec and generation from the Niagara Plant and other renewable generation in western and northern New York; and

55 These constraints have been more prevalent since May 2016 when transmission upgrades were made (to reduce congestion on 230 kV facilities in the West Zone following the retirement of the Huntley plant) that shifted some west-to-east flows onto the 115 kV network.

56 This line was reconnected on just a few days at the request of PJM to facilitate outage work.

- Exacerbate congestion in other areas of the state and raise overall congestion costs. For example, using PARs in the North Zone to relieve constraints in the West Zone often exacerbates constraints going south from the North Zone and across the Central-East interface.[57] When congestion management across multiple regions is not coordinated through the day-ahead and real-time markets, it is difficult to balance the benefits of relieving constraints in one area against the cost of exacerbating congestion in another.

The NYISO has recognized these concerns and is currently evaluating changes that will allow 115 kV constraints to be scheduled and priced in the day-ahead and real-time markets. The NYISO has indicated that some of these low-voltage-network constraints will be incorporated in the market software beginning in the second quarter of 2018, while others will not be modeled until sometime after November 2018.[58]

Enhanced modeling of the Niagara Plant would significantly reduce the costs of managing 115 and 230 kV congestion in the West Zone. The plant consists of 7 generating units on the 115 kV network and 18 generating units on the 230 kV network, and output can be shifted among these generators to manage congestion on both networks and make more of the plant's output deliverable to consumers. However, the NYISO currently represents all 25 units as a single facility in the market models, which prevents the NYISO from shifting generation among these units to manage congestion and increase output from the plant. Instead, the market scheduling systems turn the entire facility up or down without distinguishing between generators that relieve congestion and generators that exacerbate congestion, which increases the costs of congestion management. The NYISO recently recognized this and announced an initiative to improve the modeling of the Niagara generator.[59]

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.[60] Day-

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57 Similarly, using PARs in Southeast New York to relieve West Zone constraints exacerbates constraints across the Central-East interface and into New York City.

58 See *Securing 100+kV Transmission Facilities in the Market Model* presented by Ethan Avallone to the Market Issues Working Group on February 21, 2018.

59 See Section III.C in the Appendix for a discussion of inefficient scheduling of the Niagara Plant. The initiative to improve Niagara modeling is described in *Niagara Generation* Modeling *Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

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

ahead congestion shortfalls fell 38 percent from $100 million in 2016 to $62 million in 2017 primarily because of fewer costly transmission outages.

Table 7: Day-Ahead Congestion Shortfalls in 2017

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	$3.5
Central to East	$26.9
North to Central	$15.5
Capital to Hud VL	$7.6
NYC Lines	$9.3
Long Island Lines	$2.5
External	-$1.8
All Other Facilities	$0.1

West Zone. Shortfalls on West Zone lines fell the most partly because of fewer transmission outages along the most-frequently-congested Niagara-Packard-Sawyer-Huntley path and partly because of reduced loop flows in the clockwise direction around Lake Erie, each accounting for a reduction of roughly $10 million.

Long Island. These lines also accrued noticeably less shortfalls primarily because a 345 kV circuit from upstate to Long Island (the Y49 line) was out of service for much of the summer of 2016 but in service for most of 2017.

Central-East interface. Accounted for the large share of day-ahead congestion shortfalls in 2016 and 2017 primarily because of planned transmission outages in the shoulder months that reduced the interface limit. In addition, a significant portion of shortfalls (i.e., greater than $5 million) resulted from changes in the status of voltage regulating equipment, including nuclear outages and unit commitments of capacity with voltage regulating equipment at the Oswego complex and the status of capacitors and SVCs. These factors affect the voltage collapse limit of the interface.

Capital to Hudson Valley. These paths saw notable increases in shortfalls in 2017 because of more costly transmission outages. New York City lines also accrued more shortfalls as transmission outages were more frequent in 2017 into the 345 kV system of New York City.

The NYISO allocates day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[61] In 2017, the NYISO allocated 81 percent of the net total day-ahead congestion shortfalls in this manner, up from 66 percent in 2016. 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

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

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.[62]

Congestion shortfalls that are not allocated to transmission owners are currently allocated to statewide. These shortfalls typically result from modeling inconsistencies between the TCC and day-ahead markets that do not result from the outage of a NYCA transmission facility. This includes several factors such as the assumed level of loop flows (which has a significant impact on the West Zone lines) and the statuses of generators, capacitors, and SVCs (which affect the Central-East interface).

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.[63] Balancing shortfalls fell 31 percent from 2016, totaling $13 million.

Table 8 shows total balancing congestion shortfalls by selected transmission facility groups.[64] The transmission facilities in the North to Central category accounted for the largest share of balancing congestion shortfalls in 2017. Over 80 percent of these shortfalls occurred on four days because of unexpected events, including transmission forced outages, delayed returns from planned outages, and a Solar Magnetic Event.

The 230 kV transmission facilities in the West Zone accounted for a significant share of balancing shortfalls. The primary drivers included transmission outages and un-modeled factors (such as loop flows), which collectively accounted for $6 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 arise when the actual unscheduled clockwise loop flows are 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

62 Transmission outages can also result in uplift from balancing congestion shortfalls and BPCG payments to generators running out-of-merit for reliability, most of which are assigned to the transmission owner.

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

64 Figure A-56 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2016 and 2017 on a monthly basis. Section III.F 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.

loop flows.[65] Nonetheless, average clockwise loop flows fell from 2016 to 2017, contributing to less congestion and lower resulting shortfalls in the West Zone.

Table 8: Balancing Congestion Shortfalls in 2017[66]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, ABC & JK PARs	**$1.8**
Other Factors (e.g., Outages, Loopflows)	**$6.2**
North to Central	**$10.7**
Central to East	
Ramapo, ABC & JK PARs	**-$7.4**
Other Factors	**$0.8**
Capital to HVL (TSAs)	**$3.0**
Long Island Lines	
901/903 PARs	**$0.1**
Other Factors	**$1.8**
All Other Facilities	**$0.9**

The PAR operations under the M2M JOA with PJM has provided significant benefits to the NYISO in managing congestion on coordinated transmission flow gates. Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $7.4 million of *surpluses* from relieving Central-East congestion, which were partly offset by $1.8 million of *shortfalls* on West Zone lines. However, it is noted that the shortfalls on the West Zone lines fell from the $5.7 million in 2016 partly because West Zone facilities have been included in the list of constraints managed under the M2M JOA since May 2017. Nonetheless, the J and K PAR-controlled lines accrued net shortfalls while the Branchburg-Ramapo and A, B, and C PAR-controlled lines accrued net surpluses, reflecting that the J and K PAR-controlled lines are operated less actively to reduce congestion.

The operation of the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) contributed very little to balancing congestion shortfalls in 2017 (compared to $3 million in 2016 and $4 million in 2015). This is due primarily to a modeling enhancement that was implemented in May 2016 to improve the forecasted real-time flows across the two lines.

65 See Section III.E in the Appendix for more discussion of loop flows and their effect on congestion.

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.

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 2016/17 and Summer 2017 Capability Periods (i.e., November 2016 to October 2017).

Table 9 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[68]

- The *TCC Profit* measures the difference between the *TCC Payment* and the *TCC Cost*.
- 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.

Table 9: TCC Cost and Profit

Winter 2016/17 and Summer 2017 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$30	-$19	-64%
New York City	$10	-$2	-24%
Long Island	$8	-$0.5	-6%
All Other	$11	$1	7%
Total	**$59**	**-$21**	**-37%**
Inter-Zonal TCC			
Other to West Zone	$54	-$33	-61%
Other to New York City	$24	$3	14%
Other to Hud VL	$55	$16	29%
Other to Central New York	$15	$38	255%
All Other	$6	$7	127%
Total	**$153**	**$32**	**21%**

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2016 to October 2017 netted a total profit of $11 million. Overall, the net profitability for TCC holders in this period was 5 percent (as a weighted percentage of the original TCC prices).

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

Nearly 40 percent (or $84 million) of TCC purchase costs were spent on inter-zonal and intra-zonal transmission paths sinking at the West Zone. However, unlike the previous two 12-month reporting periods during which TCC buyers netted a profit of over 50 percent in each period, TCC buyers netted a loss of 62 percent (or $52 million) on these transmission paths in the 12-month period shown above. The losses were largely driven by much lower-than-anticipated congestion in the West Zone on the 230 kV system, while significant profits resulted from higher-than-anticipated congestion from West to Central and North to Central.[69] Consequently, TCC buyers netted a $38 million profit from a net $15 million purchase cost on inter-zonal transmission paths sinking at Central New York (i.e., the Genesee, Central, and Mohawk Valley Zones).

TCC buyers also received $16 million of profit for net purchases of $55 million on inter-zonal transmission paths sinking at the Hudson Valley Zone. This sizable profit resulted partly from:

- Higher-than-expected congestion across the Central-East interface and into South East New York in the second quarter of 2017 because of more transmission outages; and
- Higher-than-anticipated congestion across the Central-East interface in December 2016 on cold days.

In general, the TCC prices reflected the anticipated levels of congestion at the time of auctions. The profits and losses that TCC buyers netted on most transmission paths have been generally consistent with changes in day-ahead congestion patterns from previous like periods. In addition, the past TCC auction results 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 monthly 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 or Balance-of-Period Auctions.[70] Hence, selling more of the capability of the transmission system in the monthly 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.

69 See Section III in the Appendix for discussion of changes in congestion patterns in these areas.

70 The Balance-of-Period Auction started with the September 2017 monthly auction, which replaced the previous Reconfiguration Auction that was conducted only for the next one-month period.

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, which help 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 up to roughly 3.6 GW directly to downstate areas.[71,72] Hence, New York's total import capability is large 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 2016 and 2017 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[73] Total net imports from neighboring areas averaged nearly 3.2 GW during peak hours in 2017, up 10 percent from 2016.

Table 10: Average Net Imports from Neighboring Areas
Peak Hours, 2016 – 2017

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2016	1,408	778	382	-664	205	590	39	129	11	2,878
2017	1,332	863	344	-416	234	563	64	156	33	3,173

71 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.

72 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 New York City under the ConEd-PSEG wheeling agreement prior to May 1, 2017. Currently, these lines are scheduled as part of the primary PJM to NYISO interface and are also operated under M2M JOA with PJM in real-time. The operation of these lines are further evaluated in Sections IX.D and IX.E.

73 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 2017. 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 Variable Frequency Transformer ("VFT") and the HTP interfaces were modest relative to their total transfer capability.[74] In 2017, these net imports averaged 190 MW during peak hours, up 35 percent from 2016. The increase generally reflected higher LBMPs in the 345 kV system of New York City because of increased congestion into that area for reasons discussed in Section V.A. 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 12 percent from 1,905 MW in 2016 to 2,125 MW in 2017 during peak hours. Net imports from Hydro Quebec to New York accounted for 63 percent of net imports across the primary interfaces in 2017. Variations in Hydro Quebec imports are normally caused by transmission outages on the interface, which led to a modest decrease in average net imports in 2017.[75]

Average net imports from Ontario rose 11 percent in 2017, partly because import limitations were imposed less frequently at the Ontario interface. 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 discontinued the practice of imposing such limitations for internal 230 kV constraints in January 2017 because they can be managed more efficiently in the day-ahead and real-time markets' security-constrained commitment and dispatch.[76] In addition, the increase

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

75 For example, net imports from Hydro Quebec averaged below 900 MW in October 2017 primarily because an eight-day-long interface outage.

76 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 V.A.

was also attributable to less frequent congestion on the 230+ kV network in the West Zone in 2017.[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).

B. Unscheduled Power Flows around Lake Erie

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 are still common.[78,79]

Our analysis shows a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows.[80] In general, West Zone congestion became more prevalent when loop flows were moving in the clockwise direction or when they happened to swing rapidly in the clockwise direction. Congestion on the 230 kV network in the West Zone became less prevalent in 2017 partly because of a significant shift in the pattern of loop flows. In 2017, loop flows averaged roughly 20 MW in the *counter-clockwise* direction, compared to an average of 40 MW in the *clockwise* direction in 2016.

West Zone congestion is relatively infrequent, but it tends to be very severe when it does occur. The congestion value on 230 kV constraints exceeded $300,000 in just 0.1 percent of intervals in 2017, although these intervals with severe congestion accounted for nearly 40 percent of the total congestion value in the West Zone in 2017.[81] The NYISO implemented two modifications in June 2016, which have helped reduce the severity of real-time congestion during periods with

77 Ontario imports are upstream of transmission constraints in the West Zone therefore are usually bottlenecked during congested intervals.

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.E 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.A.

highly volatile loop flows.[82] The sporadic but severe pattern of congestion in the West Zone makes it particularly important to manage congestion efficiently.

Subsection D discusses the effects of loop flows on the consistency between RTC and RTD. Section IX.F discusses transient congestion that is caused by unscheduled loop flows and other factors that are not explicitly modeled in the dispatch software. Section V.A discusses the effects of loop flow on day-ahead and balancing congestion shortfall uplift.

C. Efficiency of External Scheduling by Market Participants

We evaluate external transaction scheduling between New York and the three adjacent control areas with real-time spot markets (i.e., New England, Ontario, and PJM) in 2017. 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.

Table 11 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets during 2017.[83] The 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, resulting in a total of $169 million in production cost savings during 2017.

Table 11: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2017

	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	-547	-$0.01	42%	$4	104	$0.35	56%	$3
Ontario	854	$11.22	89%	$88	87	$11.01	61%	$7
PJM	312	-$1.27	63%	$4	-47	-$1.39	66%	$8
Controllable Ties								
1385 Line	80	$1.01	76%	$2	-24	-$0.78	51%	$0
Cross Sound Cable	209	$2.73	80%	$8	-3	$1.97	53%	$0.1
Neptune	528	$6.58	89%	$32	-4	$5.46	54%	$0.0
HTP	22	$2.66	71%	$0.2	8	$1.13	62%	$0.6
Linden VFT	96	$4.06	92%	$6	54	$1.50	64%	$4

82 The modifications are: 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.

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

In the day-ahead market, the share of hours with efficient scheduling was generally high for the five controllable ties because there is a relatively high level of certainty regarding the price differences across these controllable lines. A total of $49 million in day-ahead production cost savings was achieved in 2017 across the five controllable ties. The Neptune Cable accounted for 65 percent of these savings because the interface was generally fully scheduled and the New York price was roughly $6.6 per MWh higher on average in 2017.

Likewise, day-ahead transactions between Ontario and New York flowed in the efficient direction in 89 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 $11 per MWh in 2017.[84] As a result, a total of $88 million in production cost savings was achieved across the Ontario interface in the day-ahead market.

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. Real-time adjustments were more active at the interfaces with CTS ("Coordinated Transaction Scheduling"), particularly the PJM and New England primary interfaces and the Linden VFT interface, resulting in a total of $16 million savings in production costs. However, real-time adjustments across other controllable ties were less frequent, resulting in significantly lower savings in production costs.[85]

The real-time price differences between New York and New England were smaller at the CTS interface (i.e., the primary interface) than at the hourly-scheduling 1385 Line, suggesting that CTS helped improve the utilization of the interfaces. In addition, the table shows that the price differences at the NY/NE CTS interface were smaller than those at the NY/PJM CTS interface, reflecting better performance of CTS with ISO-NE.

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 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 also underscores the value of having a well-functioning CTS process.

84 The price difference is over-stated because the HOEP ("Hourly Ontario Energy Price") used for these calculations understates the Ontario price when there is congestion to the border on the Ontario side.

85 Many of the adjustments resulted from curtailments or checkout failures of a day-ahead transaction, which sometimes raises production costs modestly.

D. Evaluation of Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") is a market process whereby two neighboring RTOs exchange and use real-time market information to clear market participants' intra-hour external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the hourly LBMP-based scheduling system.

- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.
- 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.

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 ensure that the process is working as efficiently as possible.

Evaluation of CTS Bids and Profits

CTS 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 requires a sufficient quantity of price-sensitive bids.[86] Figure 10 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 22). Only CTS bids are allowed at the ISO-NE interface, while CTS bids and LBMP-based bids are used at the PJM interface. Thus, the figure shows LBMP-based bids relative to the short-term forecast so the price-sensitivity of LBMP-based bids can be directly compared to that of CTS bids.[87]

Use of CTS bids (rather than LBMP-based bids) at the PJM interface increased significantly from 2016 to 2017. Of all price-sensitive bids (CTS and LBMP-based together) submitted in the range of within $10 per MWh of the border price, the share that was from CTS bids increased

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86 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 assessment of whether Tie Optimization would likely have performed better than CTS with ISO-NE. For additional details about this study, see *Second Year Evaluation of CTS between New England and New York*, presented to Market Issues Working Group on April 26, 2018.

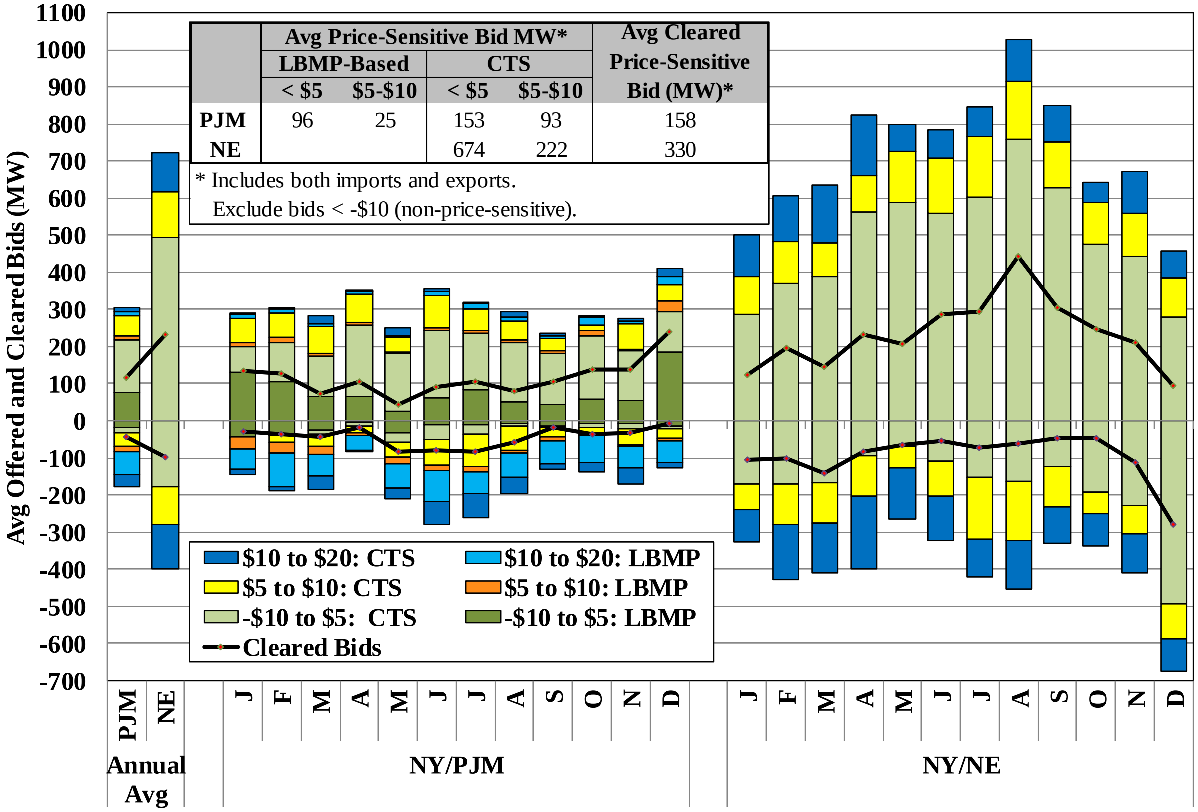
87 For example, if the short-term price forecast in PJM is $27, a $5 CTS bid to import would be scheduled if the NYISO price forecast is greater than $32. Likewise, a $32 LBMP-based import offer would be scheduled under the same conditions. Thus, the LBMP-based offer would be shown in the figure as comparable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

from 30 percent in 2016 to 67 percent in 2017. Furthermore, the average CTS bid quantity (including both imports and exports) rose from 82 MW in 2016 to 245 MW in 2017.

Nonetheless, the average amount of price-sensitive bids at the PJM interface was still significantly lower than at the New England interface. In 2017, an average of 674 MW (including both imports and exports) were offered between -$10 and $5 per 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.

Figure 10: Average CTS Transaction Bids and Offers by Month

PJM and NE Primary Interfaces - 2017



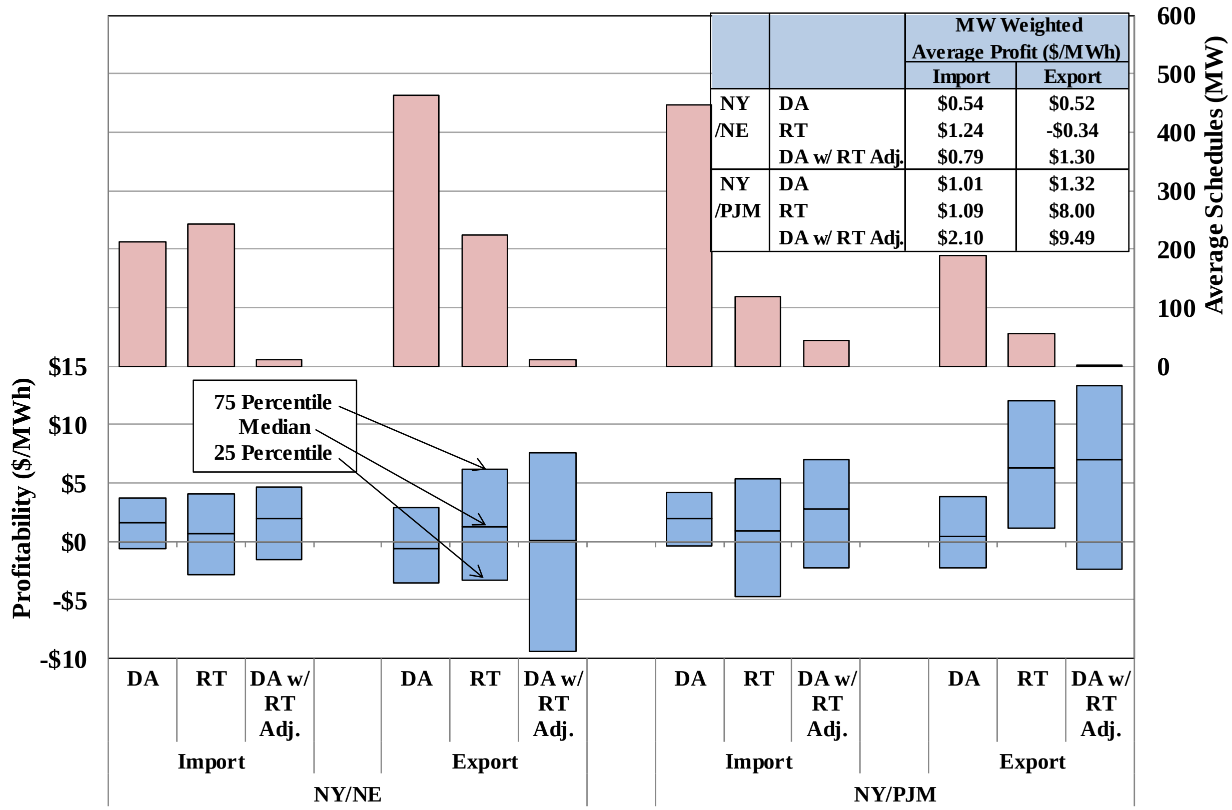
The differences between the two CTS processes are largely attributable to the large fees that are imposed at the PJM interface, while there are no substantial transmission charges or uplift charges on transactions between New York and New England. Typically, the NYISO charges physical exports to PJM at a rate ranging from $4 to $8 per MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than $2 per 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 efficient CTS offers at the PJM border. This is particularly evident from the fact that almost no CTS export bids were offered at less than $5 per MWh at the PJM border.

Figure 11 examines the gross profitability of scheduled transactions (not including fees mentioned above) at the two CTS interfaces in 2017.[88] The gross profitability of scheduled transactions (including both imports and exports) averaged less than $1 per MWh in 2017 at the primary New England interface, indicating this is generally a low-margin trading activity.

At the PJM border, the average gross profitability was modestly higher for scheduled imports (which usually incur fees of less than $2 per MWh) and far higher for scheduled exports (which incur fees ranging up to $8 per MWh). In particular, the average gross profit for real-time exports to PJM was above $8 per MWh in 2017, indicating that participants will only schedule these transactions when they anticipate that the price spread between markets will be large enough for them to recoup the fees that will be imposed on them. We can infer that market participants frequently anticipate smaller price spreads but that they do not arbitrage price differences when they anticipate that the price difference is likely to be smaller than the transaction fee.

Figure 11: Gross Profitability of Scheduled External Transactions

PJM and NE Primary Interfaces – 2017



88 See Section IV.C in the Appendix for a more detailed description of the chart.

Day-ahead exports to PJM exhibited a much lower gross profitability than real-time exports because most of the day-ahead exports were scheduled by participants with long-standing physical contract obligations, making them insensitive to the large export fees.

These results demonstrate that imposing large transaction fees on low-margin trading dramatically reduces trading and liquidity. Hence, we recommend eliminating these charges at the interfaces between New York and PJM.[89]

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 depend primarily on the accuracy of the RTOs' price forecasts and the charges assessed to the CTS transactions.[90]

We estimated that $5.9 million and $3.7 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 2017.[91] The potential savings were higher at the New England interface because the higher liquidity of bids at that interface contribute to larger and more frequent intra-hour interchange adjustments. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that:

- $4.8 million of potential savings were realized at the New England interface; and
- $0.6 million were realized at the PJM interface.

We found that the unrealized savings were much larger in periods when the forecast errors exceeded $20 per MWh, while such reductions were much smaller when the forecast errors were modest. Most of the unrealized savings at the two interfaces occurred in a small number of intervals with large forecast errors.

The overall performance of CTS improved significantly from 2016 to 2017. The estimated realized savings increased from $2.0 million in 2016 to $4.8 million in 2017 at the New England border and from -$0.1 million to $0.6 million at the PJM border. This was partly attributable better price forecasting by NYISO and ISO-NE. During real-time intervals with CTS adjustments, NYISO forecast errors for the New England and PJM borders fell from 29 and 34 percent in 2016 to 25 and 28 percent in 2017, while ISO-NE forecast errors fell from 33 percent in 2016 to 24 percent in 2017. In addition, market participants submitted more price-sensitive

89 See Section XI, Recommendation #2015-9.

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

91 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.

CTS bids at both interfaces (as shown in Figure 10), contributing to more frequent adjustments and improved performance as well.

The efficient performance of the CTS process is greatly dependent on the accuracy of price forecasting. Hence, it is important to evaluate market outcomes to identify sources of forecast error. The remainder of this subsection summarizes our analysis of factors that contribute to forecast errors by the NYISO.

Evaluation of RTC Forecasting Error

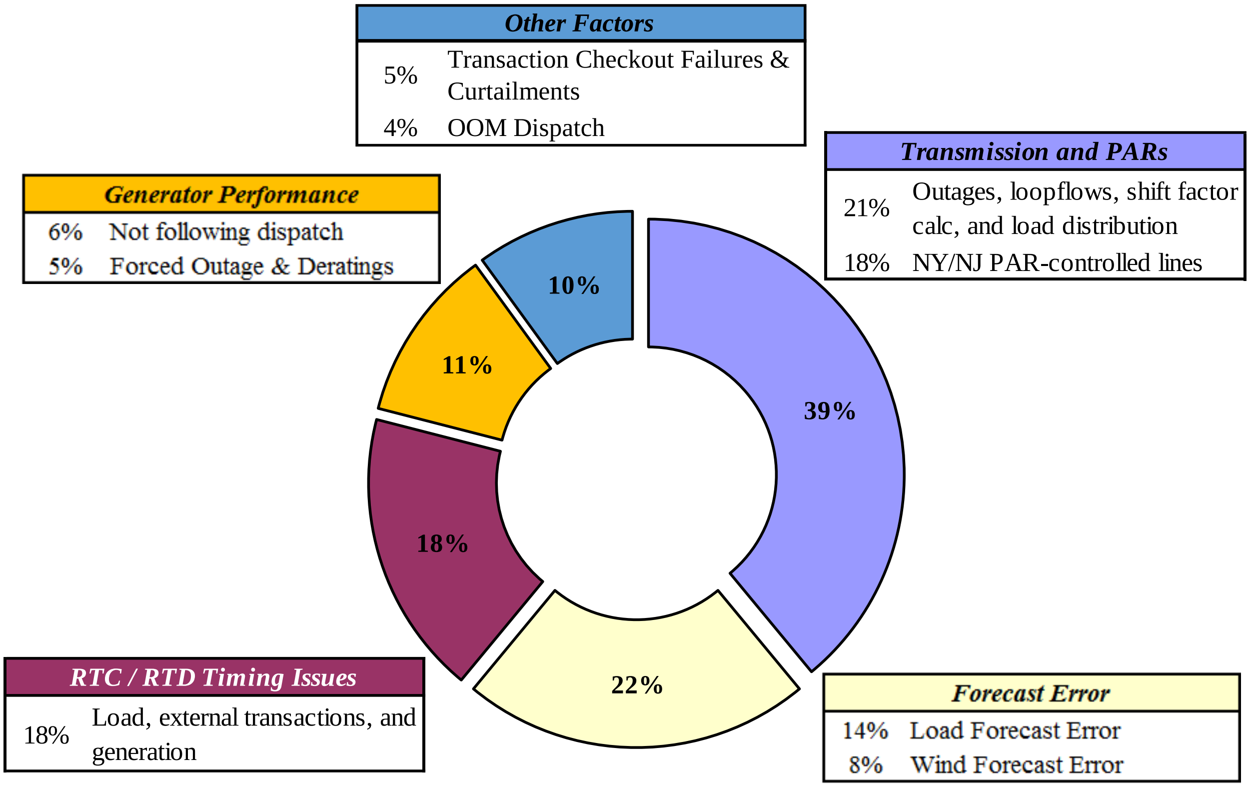
RTC schedules resources (including external transactions and fast-start units) with lead times of 15 minutes to one hour. Inconsistency between RTC and RTD prices is an indicator that some scheduling decisions of RTC may be inefficient. We have performed a systematic evaluation of factors that led to inconsistencies between RTC and RTD prices in 2017. This evaluation measures the contributions of individual factors in each pricing interval to differences between RTC and RTD, and this allows us to compare the relative significance of factors that contribute to forecast errors over time.[92] We expect that this evaluation will be useful as the NYISO and stakeholders prioritize different projects to improve market performance.

Figure 12 summarizes the RTC/RTD divergence metric results for “detrimental” factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2017.[93]

92 See Section IV.D in the Appendix for a detailed description of this metric (illustrated with examples).

93 Section IV.D in the Appendix also shows our evaluation of “beneficial” factors that reduce differences between RTC and RTD prices.

Figure 12: Detrimental Factors Causing Divergence Between RTC and RTD
2017



Our evaluation identified the three primary groups of factors that contributed most to RTC price forecast errors in 2017.[94] First, transmission network modeling issues were the most significant category, accounting for 39 percent of the divergence between RTC and RTD in 2017. In this category, key drivers include:

- Errors in the forecasted flows over PAR-controlled lines between the NYISO and PJM (i.e., the 5018, ABC, and JK lines), which occur primarily because the RTC forecast: (a) does not have a module that predicts variations in loop flows from the eastern portion of PJM across these lines, (b) assumes no PAR tap adjustments will be made to adjust the flows across these lines, and (c) assumes that NYISO generation re-dispatch does not affect the flows across these lines even though it does.
- Variations in the transfer capability that is available to NYISO-scheduled resources resulting from: (a) transmission outages, (b) loop flows around Lake Erie and from New England, (c) inaccuracies in the calculation of shift factors for NYISO resources because of the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch, and (d) variations in the distribution of load within a zone.

94 See Section IV.D in the Appendix for a more detailed list and discussion of "detrimental" and "beneficial" factors.

Second, errors in load forecasting and wind forecasting was another large contributor to price differences between RTC and RTD. Differences in the forecasted load and wind production between RTC and RTD and accounted for 22 percent of the overall divergence between RTC and RTD in 2017.

Third, the next largest category, which accounted for 18 percent of the divergence between RTC and RTD prices, was related to inconsistencies in assumptions related to the timing of the RTC evaluation versus the RTD evaluation. This includes inconsistencies in the ramp profiles assumed for external interchange, load, self-scheduled generators, and dispatchable generators. For example, RTC assumes external transactions ramp to their schedule by the quarter-hour (i.e., at :00, :15, :30, and :45), 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). Figure A-69 in Section IV.D in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transactions.

We have made recommendations to improve the accuracy of the forecast assumptions by RTC to facilitate more efficient interchange scheduling.

- Recommendation #2014-9 is to: (a) enhance the forecast of loop flows such as by introducing a bias into RTC that accounts for the fact that over-estimates of loop flow are less costly on average than under-estimates, and (b) reduce variations in unmodeled flows by modeling the effects of generation redispatch and PAR-control actions on the flows over PAR-controlled lines.
- Recommendation #2012-13 is to bring consistency between the ramp assumptions used in RTC versus RTD. A list of potential changes is listed in Section XI.C.

Addressing sources of inconsistency between RTC and RTD is not only important for improving the performance of CTS with ISO New England and PJM under present market conditions. The performance of RTC is also important because:

- RTC is also responsible for scheduling generators that can start-up in 45 minutes or less;
- The NYISO is exploring the possibility of scheduling the Ontario interface every 15 minutes; and

The resource mix of New York is changing away from fossil-fuel generation towards: (a) intermittent generation that increases uncertainty regarding the amount of flexible resources that are needed to satisfy demand, and (b) new types of peaking generators that must be deployed based on a short-term forecast of system conditions and which are critical for the integration of renewables.

VII. CAPACITY MARKET RESULTS AND DESIGN

The capacity market is designed to ensure that sufficient capacity is available to meet New York's planning reserve margins. This market provides economic signals that supplement the signals provided by the energy and ancillary services markets to facilitate new investment, retirement decisions, and participation by demand response.

The capacity auctions set clearing prices for four locations: New York City, Long Island, a Locality for Southeast New York ("the G-J Locality), and NYCA. By setting a distinct clearing price in each Locality, the capacity market helps facilitate investment in areas where it is most valuable for satisfying the NYISO's planning needs. This section summarizes the capacity market results, discusses the treatment of external transactions to and from import-constrained areas, and proposes new rules to better reflect the value of resources that provide significant planning reliability benefits to New York.

A. Capacity Market Results in 2017

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect capacity clearing prices.[95] Table 12 shows average spot auction capacity prices for each of the four capacity localities for the 2017/18 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.

Table 12: Capacity Spot Prices and Key Drivers by Capacity Zone [96]
2017/18 Capability Year

	NYCA	NYC	Long Island	G-J Locality
Avg. Spot Price				
2017/18 Yr ($/kW-Month)	$1.30	$6.79	$3.70	$6.69
% Change Yr-Yr	-43%	-14%	45%	5%
Change in Demand				
Load Forecast (MW)	-181	-124	-51	-248
IRM/LCR	0.5%	1.0%	1.0%	1.5%
ICAP Requirement (MW)	-47	17	2	18
Change in ICAP Supply*				
Generation (MW)	-272	-226	22	-212
Net Import Capacity (MW)	160			
Change in Demand Curve				
UCAP Based Reference Price @ 100% Req.				
2017 Summer	*$10.01*	*$19.46*	*$13.47*	*$16.01*
2016 Summer	*$10.21*	*$21.41*	*$8.95*	*$13.77*
% Change	**-2%**	**-9%**	**51%**	**16%**

95 Based on the Capacity Demand Curves for the 2017/18 Capability Year, a 100 MW change in ICAP supply or demand would change the clearing price by: $0.19/kW-month in NYCA, $0.68/kW-month in the G-J Locality, $1.09/kW-month in New York City, and $1.26/kW-month in Long Island.

96 See Section VI in the Appendix for more information on spot prices and key drivers on a monthly basis. "Change in ICAP Supply" show ICAP differences between 2016 Summer and 2017 Summer values.

In the 2017/18 Capability Year, capacity prices rose in two of the Localities (i.e., Long Island and G-J Locality) and fell in the other two (i.e., NYCA and NYC). In addition to changes in the supply and demand in each Locality, updates to the demand curve parameters also impacted the 2017 capacity prices. The key factors that influenced year-over-year trends in prices include:

- In Western New York, spot prices fell by 43 percent due primarily to higher net import levels, particularly from PJM resources.
- In New York City, spot prices fell by 14 percent primarily because of a lower demand curve reference price.
- In Long Island, spot prices rose by 45 percent largely because of a 50 percent increase in the demand curve reference point; and
- In the G-J Locality, spot prices rose by 5 percent due mainly to the increase in the demand curve reference point.

Although the load forecasts fell significantly (0.5 to 1.5 percent) in each locality, these reductions were offset by increases in the IRM or LCR for each locality. Hence, the overall installed capacity requirement did not change significantly in any of the localities.

B. Efficient Capacity Requirements and Prices Under the Current Zone Configuration

Capacity markets should be designed to provide efficient price signals that reflect the value of additional capacity in each locality. This will direct investment to the most valuable locations and reduce the overall capital investment cost necessary to maintain reliability.

The first part of this sub-section discusses our concern that the current "Tan 45" method for setting the IRM and LCRs leads to an inefficient allocation of capacity and raises the overall capital investment cost necessary to satisfy the planning reliability requirements. It also discusses enhancements that the NYISO plans to implement for the 2019/20 Capability Year, which will set the LCRs at levels that are designed to minimize the overall capital investment cost necessary to satisfy the "one day in ten year" planning reliability standard.[97]

While the NYISO's enhanced method will be a significant improvement over the current Tan 45 method, in the second part of this sub-section, we propose a superior approach to setting capacity prices at each location that would:

- Provide efficient incentives for investment under a wider range of conditions,
- Improve the adaptability of the capacity market to future changes in transmission network topology and in the resource mix, and

97 The NYISO has presented numerous material on this topic that can be found on its website under the meetings materials for the Business Issues Committee and the Management Committee working groups.

- Reduce the complexity of administering the capacity market as the topology and resource mix evolve.

Capacity Requirements Under the Current and Proposed Rules

Capacity markets should provide price signals that reflect: the reliability impact and cost of procuring additional capacity in each location. Specifically, we define two quantities that can be used to quantify the costs and reliability benefits of capacity:

- The Marginal Reliability Impact ("MRI") is the estimated reliability benefit (i.e., reduction in the annual loss of load expectation ("LOLE")) that would result from adding 100 MW of UCAP to an area.
- The Cost of Reliability Improvement ("CRI") is the estimated capital investment cost of adding an amount of capacity to a zone that improves the LOLE by 0.001. This is based on the estimated cost of new investment from the latest demand curve reset study and the MRI of capacity in a particular location.

Under an efficient market design, the CRI should be the same in every zone under long term equilibrium conditions. This is because if the CRI is lower in one zone than in another, it implies that cost savings would result from shifting purchases from a high-cost zone to a low-cost zone.

The current process for determining the IRM and LCRs is known as the "Unified Methodology," which does not consider economic or efficiency criteria.[98] Thus, the IRM and LCRs are not based on where capacity provides the greatest reliability benefit for the lowest cost. NYISO stakeholders recently approved an alternative method for determining the LCRs ("Optimized LCRs Method"), which seeks to minimize capital investment costs: (a) assuming the system is at an LOLE of 0.1 days per year over the long-term, (b) taking the NYSRC-determined IRM as given, and (c) imposing minimum transmission security limits ("TSL") for each locality.

Table 13 shows the estimated MRI and CRI for each locality, which we use to evaluate the efficiency of the requirement for each locality under the current Unified Methodology compared to the requirement that would result from the Optimized LCRs Method.[99]

98 See *Locational Minimum Installed Capacity Requirements Study Covering the New York Balancing Authority Area for the 2018 – 2019 Capability Year*.

99 See VII.F for methodology and assumptions used to estimate the CRI and MRI for each area.

Table 13: Marginal Reliability Impact and Cost of Reliability Improvement by Locality
2018/19 Capability Year

Zone	Unified Methodology		Optimized LCRs Method	
	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*
A - F	0.003	$3.0	0.003	$3.2
G - I	0.004	$3.9	0.004	$3.5
J	0.006	$3.2	0.007	$2.7
K	0.006	$2.2	0.005	$2.9

The table shows large disparities in the CRI across zones under the Unified Methodology. The variation in CRI estimates imply that the ISO could significantly reduce capacity investment costs by increasing capacity purchases in Long Island (Zone K at a cost of $2.2 million per unit of reliability improvement) and reducing capacity purchases in Hudson Valley (Zones G-I for a savings of $3.9 million for an equivalent reduction in reliability). This is not surprising because the current rules for setting the IRM and LCRs do not take cost into consideration.

For the Optimized LCRs Method, the range in CRI values across zones is significantly smaller than the range observed under the Unified Methodology. Nevertheless, the range between the minimum CRI-value location of Zone J (i.e., New York City at $2.7 million per 0.001 events) and the maximum CRI-value location of Zones G-I (i.e., Hudson Valley at $3.5 million per 0.001 events) is still significant. The results suggest:

- The CRI for Zone K (Long Island) is still lower than the CRI for Zones G-I (Hudson Valley), although the difference between the two values is narrowed considerably under the Optimized LCRs Method; and
- Costs would be further reduced by increasing purchases slightly in Zone J (New York City) and reducing purchases slightly in Zones G-I (Hudson Valley).
- Ultimately, these results show that the algorithm that sets the LCRs is not fully optimal. This is because: (a) it is based on a level of reliability (the 0.10 LOLE standard) that is inconsistent with long-term equilibrium level assumed in the demand curve reset study (approximately 0.07 LOLE),[100] and (b) there is an apparent lack of precision in the algorithm itself.

The CRI values for zones within the current configuration of capacity market zones (i.e. Zones G-I and Zones A-F) are similar. However, the MRI and the CRI for each zone depend on several factors that could evolve in the future.[101] Large disparities within a locality usually imply it

100 See *Alternative Methods for Determining LCRs*, presented by Zachary Stines to the Installed Capacity Working Group on August 22, 2017, slides 5 to 16 for discussion of options for the optimization.

101 For instance, the zonal MRIs could change significantly with retirement of a large plant like Indian Point or with increase in the UPNY-SENY transfer capability. Likewise, the CRI could change because of changes in the cost of new entry or changes in the energy and ancillary services revenues.

locality should be broken into multiple localities to ensure that capacity is priced and scheduled efficiently. For example, the last demand curve reset study suggested that the estimated capital investment cost of satisfying the planning requirements with new capacity (i.e., Net CONE) was significantly lower in Zone C than in Zone F. Hence, while the new Optimized LCRs Method will be a significant improvement over the current Unified Method, additional improvements are possible. Accordingly, the next part of this subsection discusses the alternative approach we recommend to improve the efficiency of prices in the capacity market, while making the capacity market simpler to administer and more adaptable to changing system conditions.

Optimal Locational Marginal Cost of Capacity Pricing Approach

Under the Optimized LCRs method, the LCRs depend directly on the Net CONE estimate for each zone, so errors in estimating the Net CONEs could lead to an inefficient allocation of capacity. In addition, the Optimized LCRs method set the LCRs based on the specific scenario where the system is "at criteria" (i.e., an LOLE of 0.10). However, this does not guarantee that capacity prices are efficient under the surplus capacity conditions that actually prevail. Lastly, the both the current Unified Method and the Optimized LCRs Method allocate the cost of capacity based on where the capacity is located rather than to the load customers that benefit from the capacity.

In this part of the subsection, we discuss ~~a~~n optimal locational marginal cost of capacity ("LMCC") pricing approach that would address these shortcomings. The LMCC pricing method would involve the following steps:[102]

- Calculate the optimal level of CRI ("CRI*") in a manner similar to the Optimized LCRs method.[103]
- In each spot auction, estimate the incremental reliability benefit (as measured by the MARS resource adequacy planning model) of (a) adding capacity to the as-found system in each zone z (GenMRI$_z$), (b) increasing the transfer limit of each interface i (TxMRI$_i$),[104] and (c) adding demand in each zone z (LoadMRI$_z$).
- Determine the capacity price for each resource type in each spot auction as the product of CRI* and (a) GenMRI$_z$ for generation resources, (b) TxMRI$_i$ for transmission resources, and (c) LoadMRI$_z$ for load customers.

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102 See Recommendation #2013-1c in Section XI. A more detailed description of the LMCC pricing approach was presented in *Concept for Locational Capacity Pricing Based on Marginal Reliability Impacts and Costs* at the Installed Capacity Working Group meeting on June 22, 2017 and can be read here.

103 Note, that the algorithm should be modified as discussed in the previous part of this sub-section and that CRI* would be calculated while satisfying any applicable TSLs ("Transmission Security Limits")

104 We discuss providing capacity revenues to market-based investment in transmission in subsection D.

This LMCC pricing approach would be less administratively burdensome because it would require fewer approximations and simplifying assumptions than either the current Unified Method or the new Optimized LCRs Method. Furthermore, since this approach relies on CRI* (rather than individual Net CONE values), any biases in the estimation of Net CONE would not bias the distribution of capacity across different localities. Changes in the zonal configuration of the capacity market and changes in transmission network topology that result from new transmission investment and generation additions and retirements would transfer seamlessly from the planning models to the capacity pricing setting mechanism without the NYISO having to make large-scale tariff changes, define additional demand curves, and other administratively burdensome aspects of the current capacity market

In addition, the LMCC pricing approach provides a framework for capacity market compensation that will be simpler to administer as the system adapts to the entry of large amounts of new technologies. New technologies provide significant reliability benefits but also have a range of characteristics that need to be compensated for efficiently, including: (a) intermittency that is correlated with other resources, (b) energy storage limitations that limit the duration of output during peak conditions, and (c) small-size distributed resources that reduce the potential effects of supply contingencies during peak conditions.

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. While these elements may require significant time to develop fully, it is important to establish rules that:

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.

- 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.
- 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.[107]

In addition, the NYISO's current estimate of the LEF was determined based on a deterministic power flow analysis. However, we support the NYISO efforts to develop a probabilistic MARS-based method for quantifying the benefits of export-transactions from an import-constrained zone if this would produce a significantly different result from the deterministic method.

D. Financial Capacity Transfer Rights for Transmission Upgrades

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

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

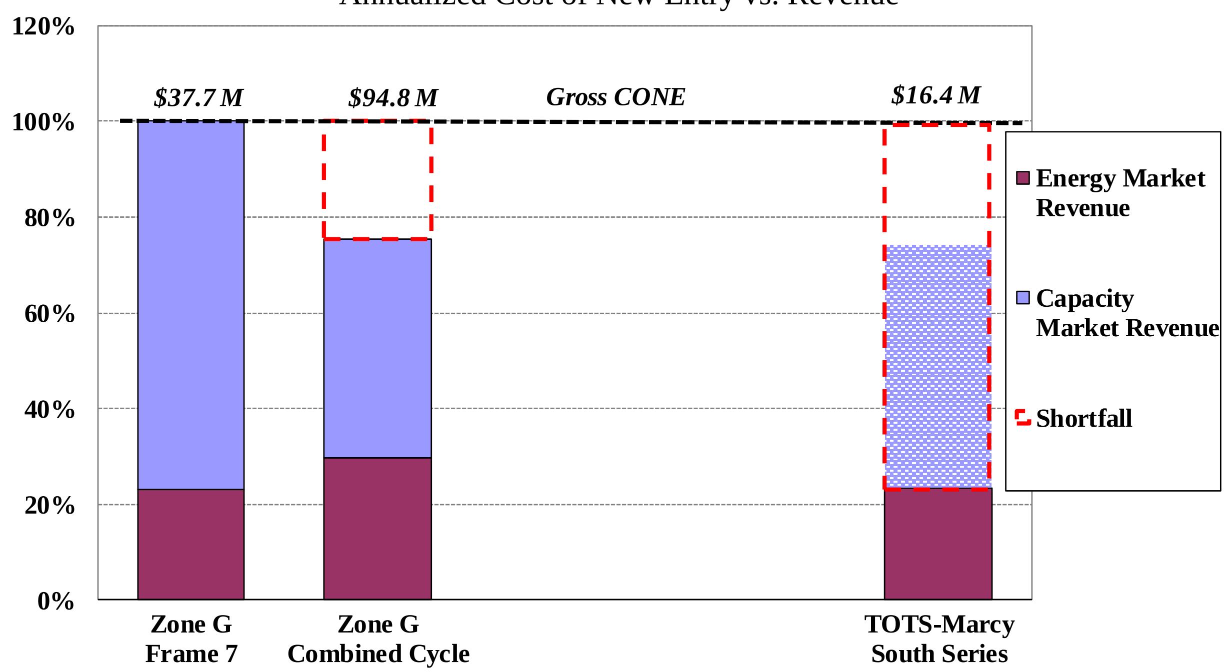
107 See Recommendation #2015-8 in Section XI.

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.[108] The value of the rights should be based on the amount by which installed capacity requirements are reduced by the facility.

Figure 13 shows the contributions from capacity revenues and energy and ancillary services revenues that would be received by the hypothetical demand curve unit in Zone G at demand curve reset conditions (i.e., assuming the G-J Locality was at the Level of Excess ("LOE") modeled in the demand curve reset) compared to the levelized CONE of the project. The table shows the comparable information for the Marcy-South Series Compensation ("MSSC") portion of the TOTS project. For the MSSC project, the table reports the Incremental TCC revenues received by the project under "Energy Market Revenue." Table reports the capacity value (i.e., the revenue that a generator or demand response resource would receive for having the same effect on LOLE) of increased transfer capability in the resource adequacy model under "Capacity Market Revenue."[109] Transmission projects do not receive actual revenue for this capacity value.

Figure 13: Valuation of Generation and Transmission Projects at DCR Conditions

Annualized Cost of New Entry vs. Revenue



108 See Recommendation #2012-1c in Section XI.

109 The basic method for estimating the capacity value of transmission and generation (i.e., "TxMRI" and "GenMRI") is discussed in subsection B. See Appendix Section VI.F for the assumptions and inputs underlying the data shown in the table.

The results illustrate the disadvantages that transmission projects have relative to generation in being compensated for the benefits they provide to the system. Capacity markets provide a critical portion of the incentive (77 percent) for a new generator in Zone G. In the absence of capacity payments to the MSSC project, the project would recoup only 23 percent of its annualized gross CONE. However, granting FCTRs to the project based on its capacity value would have provided an additional 51 percent of the annualized gross CONE. Because of the absence of capacity market compensation for transmission projects, developers lack the critical market incentive necessary for market-based (rather than cost-of-service-based) investment in transmission. Thus, it is unlikely that efficient market-based investments in transmission will occur if transmission developers cannot receive capacity market compensation.

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. Evaluation of Transmission Projects and Reforms to CARIS and the PPTN Process

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.[110] 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

110 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 and Figure 13.
- *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. [111]

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.[112]

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111 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.

112 See Recommendation #2015-7 in Section XI.

Furthermore, most of the recommended changes could also be applied to the PPTN process—only the 80 Percent Voting Requirement and the $25 Million Threshold are not applicable.[113]

F. Implementing a Dynamic Locational Capacity Market Framework

Deficiencies in the Current Process for New Zone Creation

The 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.[114]
- 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:

- 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).
- 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

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113 For a list of recommendations specific to particular PPTN studies, see our report titled *NYISO MMU Evaluation of the Proposed Public Policy Transmission Projects in Western New York*.

114 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.

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.

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 potential retirements in Southeast New York provide a salient example of the problems that could arise from the issues listed above. If the Indian Point plant (which is greater than 2 GW) and all thermal peaking units in New York City and Long Island without back-end pollution controls (which exceed 3 GW) retired in the next five years, and it led 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 until after additional resources were needed to resolve any reliability issues.[115] In fact, the NCZ process would not trigger the creation of a new zone at all if there were 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.[116]

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 could cease its Highway 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,

115 For information on potential retirements, see NYISO PPTN study: *AC Transmission: Preliminary Results*, posted March 30, 2018, slide 35.

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

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 inter-zonal interfaces that are modeled in the RNA.[117] Were NYISO to model the currently 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.

117 The 2018 RNA modeled the following interfaces between zones: Dysinger East (A->B), West Central (B->C), Volney East (C->E), Moses South (D->E), Central East (E->F), Central East Group (E->F+G), Marcy South (E->G), UPNY-SENY interfaces (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. This section evaluates long-term investment signals by calculating the net revenue that generators would have received from the NYISO markets and comparing it to the corresponding capital investment costs of the generator.[118] This section is divided up as follows:

- Subsection A evaluates the net revenue that new generators would have received from the NYISO markets and compares it to the corresponding Cost of New Entry ("CONE") of the generator. It also examines the investment signals for several older existing gas-fired technologies compared to the going-forward costs ("GFCs") of those technologies.
- Subsection B compares the net revenues to the CONE/GFC for several new and existing zero-emission technologies.
- Subsection C analyzes how several of our recommended enhancements to day-ahead and real-time price formation and performance incentives would affect the incentives for investment in various new and existing technologies in New York City.

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

Figure 14 shows the estimated net revenues compared to the CONE or GFCs for several types of new and existing gas-fired units from 2016 to 2020. 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.[119]

Net Revenue Summary for Gas Units

From 2016 to 2017, net revenues of gas-fired resources dropped for all technologies and locations. A common driver of this broad year-over-year decrease is the lower load levels in 2017, which resulted in lower energy margins (despite higher LBMPs and gas prices).

- The decrease in capacity and reserve prices further depressed the net revenues for units located in the upstate and New York City zones. The gas pipeline congestion that depressed 2016 gas prices was alleviated somewhat in 2017. As a result, the decrease in energy margins for West zone units was much larger than the decrease in margins in eastern zones.

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118 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.

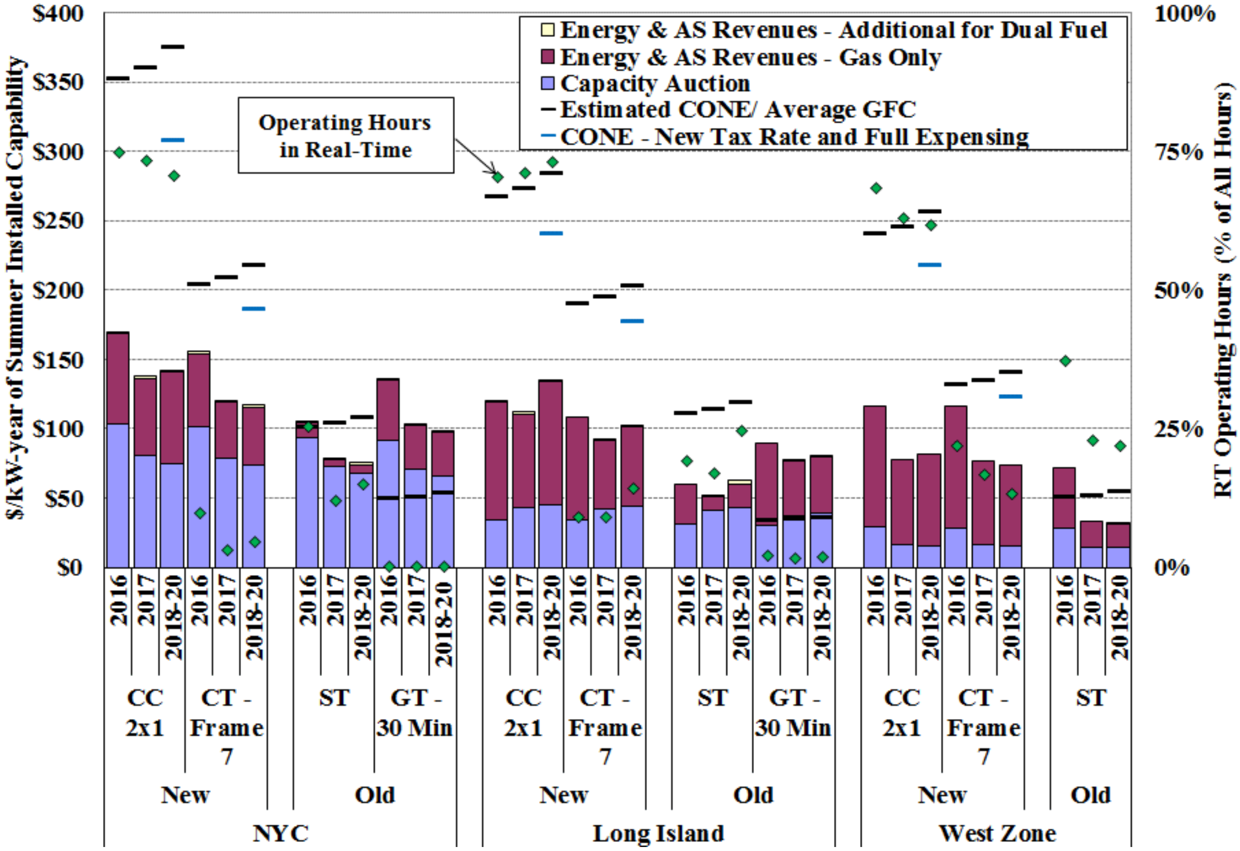
119 Section VII.A of the Appendix provides detailed information about our assumptions as well as CONE, GFC, and net revenue results for more locations, technologies, and gas price assumptions. Run hours are provided by fuel type for dual-fueled units.

- The increase in capacity prices partially offset the drop in E&AS revenues of units located in Long Island. As a result, the year-over-year changes to net revenues of units in Long Island were much smaller compared to units in other locations.

Based on forward prices for electricity and natural gas, we estimated higher net revenues in 2018-2020 for most units than in 2017 because of higher expected energy margins, with the largest year-over-year increase from 2017 to 2018.

Although not shown in the figure below, we calculated the annualized cost of new entry using assumptions that are based on the new tax legislation that was passed at the end of 2017. The recalculated annual CONE values are 15 to 18 percent lower for new CTs and combined cycle units. However, it is important to note that changes in the tax law may have countervailing effects on other factors that go into the calculation of the annual carrying charge rate, thereby reducing the impact of the new tax law on the annual CONE values.[120]

Figure 14: Net Revenue and CONE by Location for Gas-Fired and Dual Fuel Units
2016-2020



120 Section VII.A of the Appendix provides calculations based on the new tax law.

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

New Units. The 2017 net revenues of the hypothetical new units we evaluated were well below the estimated CONE for every case we studied. There continues to be a significant amount of surplus installed capacity which, in conjunction with low demand, led to low net revenues. After several years of congestion-driven high net revenues, the 2017 estimated net revenues of the new Frame 7 unit in the West zone dropped to a level below its CONE. Furthermore, the planned transmission build-out in western New York is expected to further reduce the energy margins for this unit.[121]

Steam Turbines. Of the existing fossil-fuel technologies we evaluated, steam turbine units in downstate areas are the most challenged economically. Average net revenues for steam turbines over the last three years 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/or they face extraordinary repair costs associated with equipment failures.

Gas Turbines. In addition to capacity revenues, the persistence of relatively high reserve prices in 2017 continue to provide strong incentives for operation of existing units. We analyze the impacts of adjusting reserve revenues for the performance of operating reserve providers (as discussed in our recommendation 2016-2) in Subsection C.

New environmental regulations may require GTs and steam turbines in New York City and Long Island to incur significant additional capital expenditures to remain in operation. First, the New York DEC is considering a rule that would require older GTs in New York City and Long Island to install back-end controls (e.g., selective catalytic reduction) for limiting NOx and other pollutants.[122] Second, the City of New York passed an ordinance preventing steam turbine generators from burning residual oil beginning in 2022, so steam turbines will have to install facilities for burning diesel oil in order to remain dual-fueled.[123]

Dual-Fuel. Additional revenues from dual-fuel capability were *de minimis* in 2017, primarily because of the relatively low gas prices throughout the year (except for the last week of 2017). The returns from dual fuel capability in 2016 and 2017 do not exceed the levelized investment

[121] On October 17, 2017, the NYISO Board of Directors approved the NYISO's recommendation to move forward with building a particular transmission project in Western New York.

[122] See NYISO PPTN study: *AC Transmission: Preliminary Results*, posted March 30, 2018, slide 35.

[123] See bill INT 1465-A, *Phasing out the use of residual fuel oil and fuel oil grade no.4 in boilers in in-city power plants*.

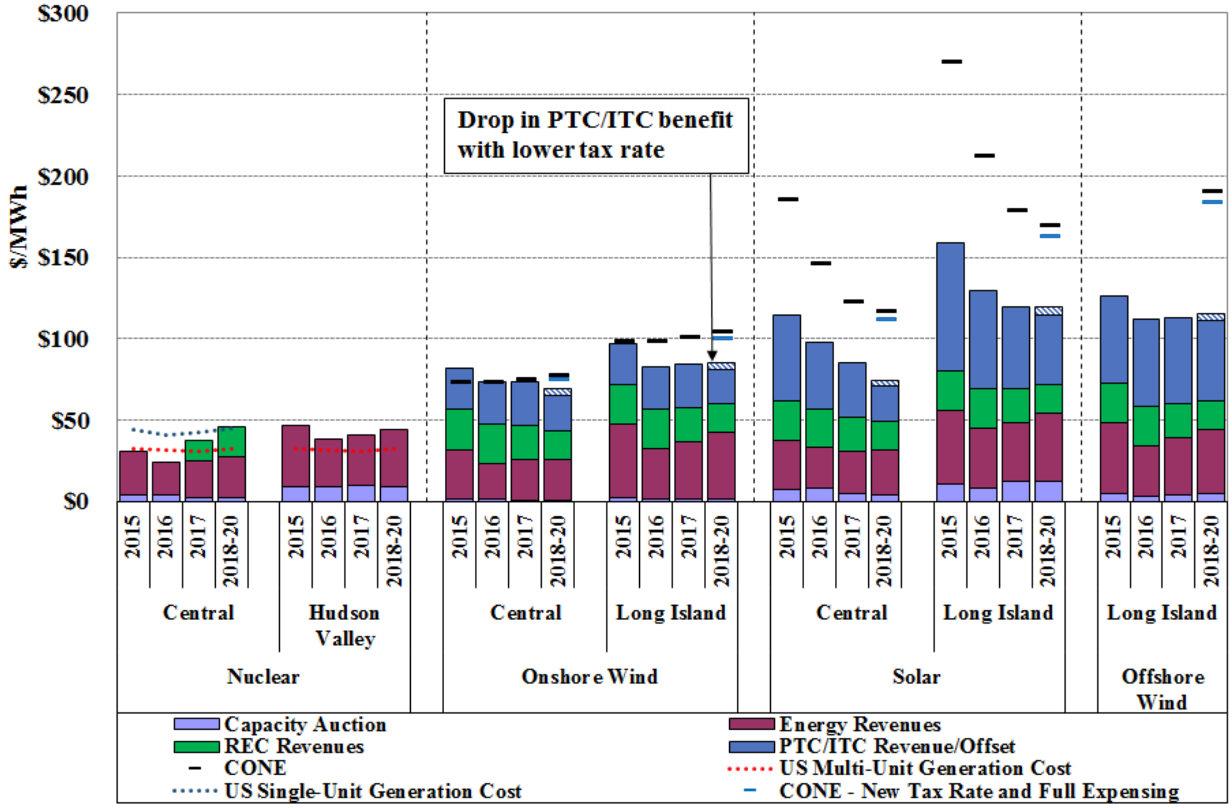
cost of installing and maintaining dual-fuel capability.[124] However, dual fuel capability protects against the risk of gas curtailment under tight supply conditions (such as the cold snap in early 2018) and may hedge capacity revenues by reducing fuel-related outages. Thus, investors in new and existing units may still prefer to install and maintain dual fuel capability, particularly as they consider possible changes in market conditions over the long-term.[125]

B. Net Revenues of Nuclear and Renewable Generators

Figure 15 compares the estimated net revenues for existing nuclear units, new onshore and offshore wind units, and new utility scale solar PV plants from 2015 to 2020. For comparison, we show estimated operating costs for nuclear units and CONE estimates for the renewables.[126]

Figure 15: Net Revenues of Nuclear and Renewable Units

2015-2020



124 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".

125 Additional dual-fuel revenues for CC and ST units in some recent years have been sufficient to incent dual fuel capability.

126 See Section VII.C of the Appendix for details about the assumptions used in this analysis.

Energy revenues account for 88 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 generally driven by expected energy prices, rather than capacity prices. In upstate zones, although the energy revenues have declined in recent years, the estimated 2017-2020 net revenues of single-unit nuclear plants are above the US average of nuclear generation costs, due in large part to the sale of Zero Emissions Credits (“ZECs”).

Nuclear operating and decommissioning costs are highly plant-specific, and the GFCs of the nuclear plants in New York may differ significantly from the US average operating costs. Hence, the difference between the net revenues and GFCs may be smaller than implied by Figure 15, and as a result, the nuclear plants in upstate New York (particularly single-unit) and Hudson Valley may be less economic if the generation costs do not decline in the coming years.[127]

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.[128] Even with these subsidies, however, the estimated net revenues for generic 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. However, the economics of individual renewable projects in New York depend on a number of additional site-specific or project-specific factors which drive new entry decisions. Such factors include differences in returns required by investors, resource potential at individual sites, curtailment risk, REC prices/ procurement targets, and future cost reductions.[129]

C. Impacts of Real Time Pricing Enhancements on Net Revenue

Section XI.B of the report discusses several recommendations that are aimed at enhancing the efficiency of pricing and performance incentives in the real time markets. These recommended market reforms would also increase the financial returns to resources with attributes that are valuable to the power system such as low operating costs, reliability, availability, and flexibility. By rewarding valuable attributes efficiently, the market provides better incentives for suppliers to make cost-effective investments in new and existing resources. In this subsection, we estimate

127 For instance, nuclear units located in New York may be subject to higher labor costs and property taxes. Publicly available estimates for property taxes range from $2 to $3 per MWh.

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

129 The contracts for RECs are fixed and could be up to 20 years long. In addition, the benefits to renewable units from federal incentives are less volatile than the NYISO-market revenues. Therefore, the overall risk profile of the revenues of renewable units in New York is very different from that of a merchant generator.

the impacts of several recommendations on the long-term investment incentives for several new and existing technologies.

Under long-term equilibrium conditions, an increase in energy and ancillary services revenues to the demand curve unit (i.e. the Frame unit) allows for a reduction in capacity prices (since higher energy and ancillary services margins reduce the "missing money" that is needed to satisfy planning reliability criteria).[130] Hence, adopting these recommendations would shift some net revenues from the capacity market to the energy and ancillary services markets. Accordingly, this shift would tend to increase the financial returns for resources that perform flexibly and reliably, while reducing the financial returns to poor-performing resources.

Figure 16 summarizes the estimated impact of recommended enhancements on energy and capacity revenues compared to the corresponding CONE/GFC for resources in NYC.[131] The "Base" category shows the estimated net revenues that would be received by each type of unit under the current market rules if the NYC reserve margin was at the Level of Excess, while the "wRecs" category shows our estimates if the following four recommendations were adopted: [132]

- 2017-1: Model local reserve requirements in New York City load pockets.
- 2017-2: Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules.
- 2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.
- 2016-2: Consider means to allow reserve market compensation to reflect actual and/or expected performance.

Our simulation results indicate that the E&AS revenues of a new Frame 7 unit would increase by $37 per kW-year (60 percent) if the above recommendations were implemented. Consequently, the Reference Point for the ICAP demand curve and the capacity payments to all resources would decline by 22 percent. Overall net revenues to a new Frame 7 unit would not change, but the recommendations would shift a large portion from the capacity market to the E&AS markets.

These recommended enhancements would increase net revenues to other new flexible technologies:

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[130] The "missing money" refers to the revenues over and above those earned from selling energy and ancillary services that are needed to provide market incentives for maintaining sufficient capacity margins to satisfy planning reliability criteria such as the "one-day-in-ten-year" reliability standard.

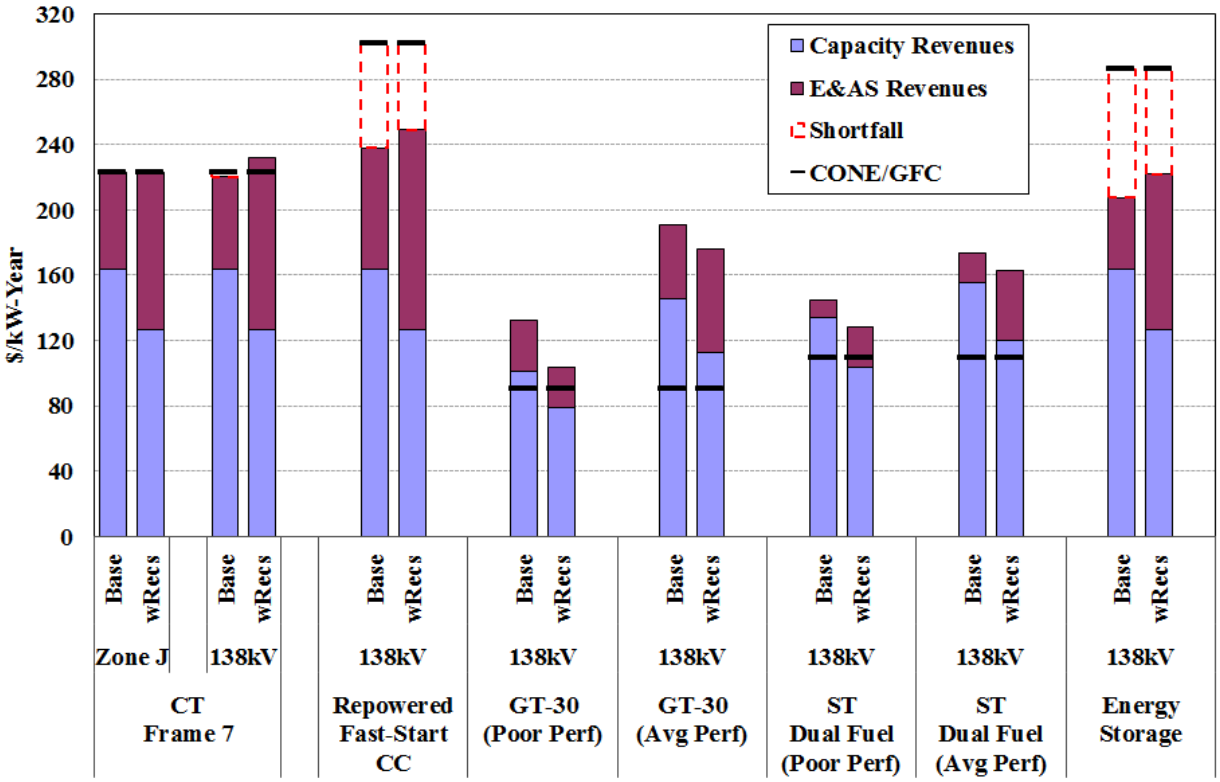
[131] See Section VII.E in the Appendix for details about the assumptions used in this analysis.

[132] See Section XI for more details regarding these recommendations.

- A fast-start combined cycle unit with 10-minute start capability would receive 64 percent more E&AS net revenue, while
- A flexible energy storage unit would receive 115 percent more E&AS revenue.

For new flexible technologies, the increase in energy and reserve revenues would outweigh the decrease in capacity revenues, so their overall net revenues would increase.

Figure 16: Net Revenue Impact from Enhancements in NYC and 138 kV Load Pockets
At Level of Excess Conditions



In contrast, the economics of older existing generators with less flexible and reliable characteristics would become less attractive. For average-performing 30-minute GTs and steam turbines, overall net revenues would fall by an estimated 8 and 6 percent primarily because of the reduced capacity demand curve. However, the net revenues to poor-performing 30-minute GTs and steam turbines would fall by an estimated 22 and 11 percent because of the reduced capacity demand curve and reduced E&AS net revenues.

For older GT-30 units, reserve revenues would drop if units were compensated in accordance with their performance as proposed in Recommendation 2016-2. GTs that perform worse than average would see a larger drop. The high operating costs and lack of flexibility of steam turbines limits their ability to capture additional energy revenues from the enhancements. Consequently, the drop in their capacity revenues outweighs any increase in energy and reserve market revenues.

Although the recommended enhancements would increase net revenues of units that are reliable and flexible, the net increase in revenue would be moderate after considering the reduction in capacity prices. Similarly, the net revenue effects for most older units would not be large enough to push their net revenues below the GFCs under long-term equilibrium conditions. However, under as-found conditions, these enhancements could influence investment decisions to build new resources, retire existing ones, or expend funds on technologies that provide greater operational flexibility. In the future, high levels of renewable penetration are expected to reduce energy prices while requiring increased procurement of ancillary services, so the recommended enhancements are likely to have larger effects on investment incentives after additional renewables are added to the grid.

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. Prices should be consistent with the costs of satisfying demand while maintaining reliability. Efficient real-time prices encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable. During shortages, the real-time prices should reflect the value of the shortage and incent suppliers to help maintain reliability. In addition, the operation of system is critical because it can have large effects on wholesale market outcomes and costs.

This section evaluates the following seven 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
- Uplift from Bid Production Cost Guarantee (“BPCG”) payments

This section discusses several recommendations that we have made to enhance pricing and performance incentives in the day-ahead and real-time markets, while Section XI provides a comprehensive list of our recommendations.

A. Market Performance under Shortage Conditions

Prices during shortages are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the system’s energy and ancillary services needs. Efficient shortage prices reward suppliers and demand response resources for responding to shortages. This ultimately improves the resource mix by shifting revenues from the capacity market into the energy market in a manner the reflects the resources’ performance. 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 two types of shortage conditions:[133]

133 Our previous reports also evaluated market operations during DR deployments. In 2017, the NYISO did not deploy reliability DR resources, so the operation under this type of shortage is not evaluated in this report.

- *Operating reserve and regulation shortages* – These occur when the real-time model is schedules less than the required amount of ancillary services. Co-optimization of energy and reserves causes the foregone value of the ancillary service to be reflected in LBMPs.
- *Transmission shortages* – These occur when modeled power flows exceed the limit of a transmission constraint. LBMPs at affected locations are set by the Graduated Transmission Demand Curve ("GTDC") in most cases during transmission shortages.

Operating Reserve and Regulation Shortages

Regulation shortages were the most frequent, occurring in 9.4 percent of intervals in 2017 (up from 4.2 percent in 2016). The market is designed to "go short" of a small amount of regulation when the price rises to $25/MWh, freeing up additional capacity to provide energy. Most of the increase in 2017 occurred in low load periods when less capacity was online (and capable of providing regulation), and regulating generators had to be dispatched up from their Minimum Generation levels to maintain sufficient capacity for down regulation.

The most frequent reserve shortages were of NYCA 30-minute reserves, occurring in 0.3 percent of intervals in 2017, slightly down from 2016 because of very low demand and fewer summer peaking conditions. All other reserves shortages occurred in less than 0.05 percent of intervals in 2017. While infrequent, the shortages of regulation, eastern 10-minute reserves, and NYCA 30-minute reserves collectively increased average LBMPs in Eastern New York by 6 to 8 percent in 2017.[134] Therefore, efficient price signals during ancillary services shortages are very important.

Although the Comprehensive Shortage Pricing and Comprehensive Scarcity Pricing projects have allowed prices to better recognize ancillary services shortages, we have identified several issues. First, the NYISO tends to schedule more operating reserves than necessary because it relies only on internal resources. In some cases, this ignores the value of import-capability for maintaining security in the reserve region. For example, 10-minute reserves are held in Eastern New York to ensure that a large contingency in Eastern New York will not cause a sudden overload of the Central-East Interface. This need could also be met by reducing flows over the Central-East interface before the contingency (thereby "holding reserves on the interface").

Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves to hold given economic import capability, reducing reserves in:[135]

- Eastern New York by reducing pre-contingent flows over the Central-East Interface;
- Southeast New York by reducing flows over the UPNY-SENY interface;

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

135 See Recommendation #2015-16 in Section XI.

- NYCA by considering that additional imports across the High Voltage Direct Current ("HVDC") connection with Quebec could be increased after a contingency); and
- New York City load pockets (if the NYISO also implements Recommendation #2017-1) by considering unused import capability into load pocket.

Second, the operating reserve demand curves in New York are relatively low considering market design changes in neighboring markets. Since first implementing shortage pricing in 2003, the NYISO has generally benefited from significant net imports during reserve shortages. However, ISO New England and PJM will be phasing-in the implementation of Pay For Performance ("PFP") rules from 2018 to 2022, which provide incentives similar to extreme shortage pricing.

- In ISO-NE, the Performance Payment Rate levels will rise from $2,000 per MWh beginning in June 2018 to $5,455 in May 2024.[136] These payments are in addition to the shortage pricing, which starts at $1,000 per MWh, resulting in total incremental compensation during reserve shortages ranging from $3,000 to $8,000 per MWh.
- In PJM, similar rules are being implemented in June 2018 with an initial Performance Rate between $2,000 and $3,000 per MWh in addition to real-time shortage pricing levels of $350 to $850 per MWh. The rate is expected to rise in subsequent years.[137]

Consequently, the market incentives to import power into New York under tight conditions will change substantially and may result in inefficient transactions that reduce the available supply to New York. Hence, we recommend that the NYISO evaluate consider modifying its operating reserve demand curves to provide efficient import and export incentives during shortage conditions. This recommendation includes establishing multiple steps for each operating reserve demand curve so that clearing prices rise efficiently with the severity of the shortage.[138]

Transmission Shortages

During transmission shortages, when power flows exceed the transmission limit, the market should set efficient prices that reflect the severity of shortage. Previous State of the Market Reports have shown a poor relationship between the severity of transmission shortages and real-time prices. We found that small shortages tended to produce high congestion shadow prices while large shortages tended to produce small shadow prices. In general, this was because

136 See ISO New England Tariff Section III.13.7.2 with an effective date of June 1, 2018 as filed on March 29, 2018 in Docket ER18-1223-000.

137 The initial rate = Net CONE * Balancing Ratio (the share of capacity resources that perform during shortage events) divided by expected Performance Assessment Hours. PJM is proposing to modify its hour counts. See presentation by Patrick Bruno to the Markets Implementation Committee, April 4, 2018.

138 See Recommendation #2017-2 in Section XI.

transmission shortages were resolved by "relaxing" the limit of a constraint—that is, raising the limit of the constraint to a level that could be resolved by the market software.[139]

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. However, the continued use of relaxation in most shortage intervals led prices in these intervals to be inconsistent with the tariff. Consequently, the NYISO revised this pricing process in June 2017, including: [140]

- Modifying the second step of the GTDC from $2,350 to $1,175/MWh; and
- Removing the "feasibility screen" and applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM").[141]

Figure 17 examines whether constraint shadow prices reflect the severity of transmission shortages for four groups of constraints before and after the GTDC enhancements. The figure also shows the placement of the three steps of the GTDC before and after the revision by comparing the period from July to December in 2016 and 2017.

This analysis shows that in most intervals shown in 2017, 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 constraint's shadow price. However, the market software continued to use the relaxation technique to resolve a small portion of transmission shortages (indicated by red points in the figure that are not on the GTDC curve).

Overall, Figure 17 shows that transmission shortage quantities were much better correlated with the constraint shadow prices after the changes in June 2017 because they led to much less frequent constraint relaxation. Only 7 percent of all transmission shortages were relaxed after the changes in 2017, significantly lower than the 59 percent in the same period of 2016. This is desirable because constraint relaxation as it makes congestion less transparent and predictable. In addition, average constraint shadow prices during transmission shortages fell modestly from 2016 in most areas, partly because the GTDC's second step changed from $2,350 to $1,175.[142]

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139 See Section V.F in the Appendix of our 2016 State of the Market report for more information.

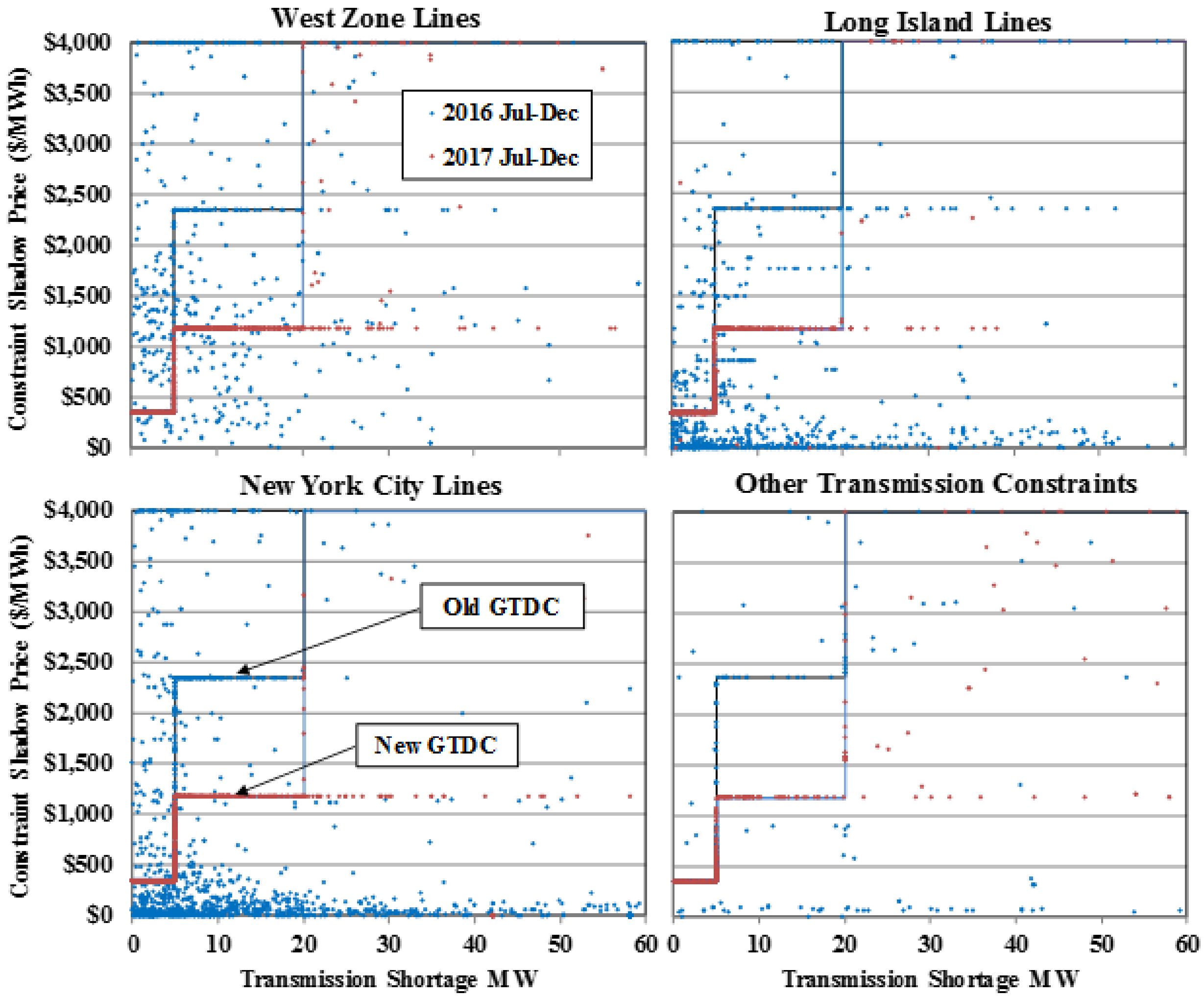
140 See Docket No. ER17-1453, *Proposed Tariff Revisions to Clarify and Enhance Transmission Constraint Pricing*, (April 21, 2017).

141 A Constraint Reliability Margin ("CRM") is a small (usually 20 MW) reduction in limit used in the market software from the actual physical limit, which is used to account for loop flows and other un-modeled factors. Some constraints have no CRM because un-modeled flows are low.

142 See Table A-5 in the Appendix for more details.

Figure 17: Real-Time Transmission Shortages with the GTDC

By Transmission Group, July-December of 2016-2017



Although the reduced frequency of constraint relaxation has led to more efficient and transparent congestion prices, it can also increase incentives to exercise market power by over-generating upstream of a transmission constraint to benefit from extremely low LBMPs. For example, if a generator with a day-ahead schedule is the only unit available to reduce output to relieve a transmission constraint following a transmission outage, the generator can lower its offer and be paid excessively to reduce output (by buying back its day-ahead energy at a very low or negative price). Constraint relaxation generally lowered these payments. To address this, we recommend changes to the market power mitigation measure for uneconomic over-production.[144]

Despite overall improved market outcomes, at times constraint shadow prices still did not properly reflect the importance and severity of a transmission shortage. For example, the

144 See Recommendation #2017-3 in Section XI.

NYISO uses a higher CRM for certain facilities such as the Dunwoodie-ShoreRd 345kV line (which has a CRM of 50 MW), leading the GTDC to over-value some constraint violations.[145] Thus, we continue to recommend that the NYISO, in the long-term, replace the current single GTDC with a set of constraint-specific GTDCs that can vary according to the importance, severity, and/or duration of a transmission shortage. This will ensure a clear relationship between the shadow price and the severity of the constraint that is a better signal to market participants.[146]

B. Efficiency of Gas Turbine Commitments

We evaluate the efficiency of gas turbine 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. Gas turbines are usually started during tight operating conditions when it is particularly important to set efficient real-time prices 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.

We found that 51 percent of the capacity committed by the real-time market model in 2017 was clearly economic over the initial commitment period (deemed to be one hour for GTs), consistent with recent years.[147] This likely understates the share of GT commitments that are efficient because the efficient commitment of a gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer.

Nonetheless, there were many commitments in 2017 when the total cost of starting gas turbines exceeded the LBMP by more than 25 percent. There are two primary reasons:

- The divergence between RTC and RTD may lead an economic RTC-committed GT to be uneconomic in RTD.[148]
- The fast-start price-setting rules do not reflect the start-up costs of the gas turbine in the price-setting logic, which we have recommended in the past.[149,150]

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145 Our February 12, 2018 comments in Docket EL18-33-000 discussed that the increased CRM is partly necessitated by the practice of offline gas turbine price-setting whereby offline gas turbines are treated as able to respond to dispatch instructions when they actually cannot, leading to large differences between modeled flows and actual flows for facilities such as the Dunwoodie-ShoreRd 345kV line. We recommended eliminating offline gas turbine price-setting in conjunction with the implementation of constraint-specific GTDCs.

146 Recommendation #2015-17 in Section XI.

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

148 See Section IV.D in the Appendix for analysis of divergence between RTC and RTD.

The Commission and the NYISO have also recently recognized the need for fast-start pricing to include the start-up and other commitment costs of fast-start units.[151] If the proposed changes are accepted by the Commission, it will lead real-time prices to better reflect system conditions and better performance incentives for flexible resources when fast-start units are deployed.

C. Performance of Operating Reserve Providers

The wholesale market should provide efficient incentives for resources to help maintain reliability by compensating resources consistent with the value they provide. Efficient incentives encourage participation by demand response and investment in flexible resources in areas where they are most valuable. Over the coming decade, performance incentives will become even more critical as the entry of intermittent resources 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 18 summarizes the performance of GTs in responding to start-up instructions resulting from economic commitment by the RTC model (not including self-schedules). The figure reports the average performance for GTs that received at least one start instruction in 2017. Units that were not started in-merit by RTC in 2016 or 2017 are shown in "Not Started".[152]

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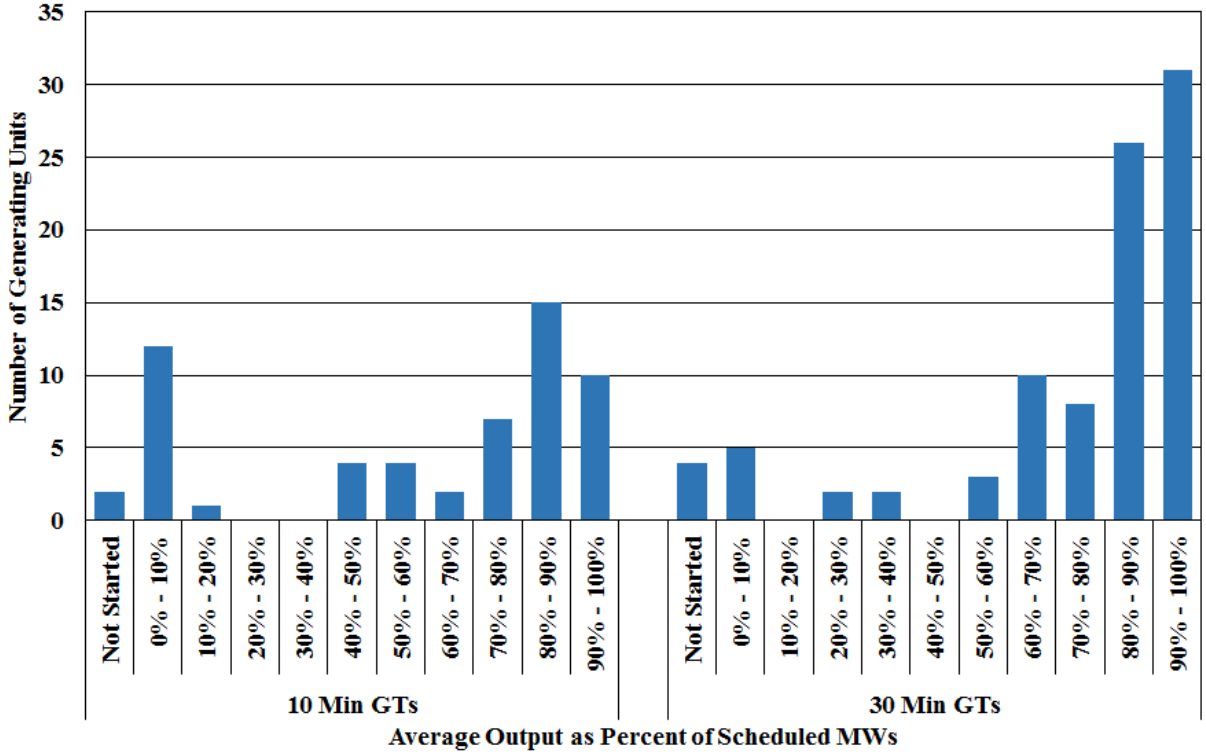
149 The NYISO implemented changes to improve upon the price-setting rules for quick start units on February 28, 2017. Specifically, the NYISO eliminated a step in the RTD software that led some units to not set the clearing price even when they were economic. See NYISO filing in Docket ER17-549 to modify pricing logic for Fixed Block Units, December 14, 2016

150 See Recommendation #2014-10 in Section XI of the 2016 State of the Market Report.

151 In Docket EL18-33-000, see *Order Instituting Section 206 Proceeding and Commencing Paper Hearing Procedures and Establishing Refund Effective Date re New York Independent System Operator, Inc.*, dated December 21, 2017; comments of the New York ISO, dated February 12, 2018; and comments of Potomac Economics, dated February 12 and March 14, 2018.

152 See Section V.B in the Appendix for a description of the figure.

Figure 18: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts



Gas turbines exhibited a wide range of performance in 2017: [153]

- *10-minute units*: only 46 percent of units started economically by RTC had an average response above 80 percent, while the average response of all units was 61 percent.
- *30-minute units*: only 66 percent of units started economically by RTC had an average response of 80 percent better, while the average response of all units was 77 percent.

Units that perform poorly when started tend to have higher EFORds, which reduces their ability to sell capacity.[154] However, this reduction does not accurately reflect the start-up performance of fast-start units. Additionally, gas turbines lose their energy revenues when they fail to start, but there is no mechanism for discounting operating reserve revenues for gas turbines that do not perform well. Hence, some gas turbines that almost never perform when called will still earn most of their net revenue from the sale of operating reserves.[155] Because operating reserve revenues are not sensitive to suppliers' performance, the market does not provide efficient

153 Six gas turbines were not evaluated because they were never started economically by RTC in 2016 or 2017 and the available data does not allow us to accurately evaluate the performance of gas turbines during other types of start-ups.

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

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

performance incentives to reserve providers. To address this concern, we recommend that the NYISO consider ways to allows reserve revenues to reflect suppliers' performance.[156]

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, the NYISO sometimes operates a facility above LTE if post-contingency actions would be available to quickly reduce flows to LTE after a contingency.[157] Post-contingency actions include the deployment of operating reserves and adjustments to phase-angle regulators. The use of post-contingency actions is important because it allows the NYISO to increase flows 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 become unavailable. In such cases, transfer capability is reduced, requiring more generation in the load pocket to manage congestion. In 2017, 68 percent (or $42 million) of real-time congestion occurred on N-1 transmission constraints that would have been loaded above LTE after a single contingency. The additional transfer capability above LTE in New York City averaged from roughly 20 MW for some constraints in the 138 kV load-pockets to over 200 MW for constraints in the 345 kV system during congested hours. Although these increases were largely due to operating reserve providers in the City, they are not compensated for this service. This reduces their incentives to be available in the short term and to invest in flexible resources in the long term. In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability into New York City. In some cases, it would have been more efficient to continue scheduling the resources 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.[158] For similar reasons, the NYISO should also consider market-based compensation for generators that support transmission security by being able to continue to operate (e.g., dual fuel units that can quickly switch from gas to oil) following the loss generation after a natural gas system contingency.

156 Recommendation #2016-2 in Section XI.

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

158 Recommendation #2016-1 in Section XI.

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 NYCA. This includes HVDC transmission lines, VFT-controlled lines, and PAR-controlled lines. Controllable transmission lines allow power 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, which are evaluated in Section VI.A that assesses external transaction scheduling.[159]
- "Optimized" PAR-controlled lines are normally adjusted 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 operating procedures that are not primarily based on reducing production costs, which are evaluated below.

Table 14 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2017. 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.

159 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.

Table 14: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[160, 161]
2017

	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					-35	$7.26	47%	$1
New England to NYCA								
Sand Bar	-75	-$12.72	92%	$7	0.3	-$14.34	52%	$0.1
PJM to NYCA								
Waldwick	-398	$2.11	36%	-$10	45	$1.17	51%	$2
Ramapo	191	$2.76	70%	$11	173	$1.74	52%	$6
Farragut	284	$3.28	73%	$10	34	$1.79	49%	-$0.4
Goethals	156	$4.07	79%	$6	99	$1.49	52%	$1
Long Island to NYC								
Lake Success	115	-$4.19	7%	-$6	-0.2	-$4.13	34%	-$0.03
Valley Stream	82	-$9.12	7%	-$7	2	-$8.29	23%	-$0.04

The Lake Success and Valley Stream PARs are used to control flows over the 901 and 903 lines, which are operated 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 the day-ahead market in 2017, power flowed in the *inefficient* direction in 93 percent of hours, much more inefficient than any of the other PAR-controlled lines. Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets. The transfers across these lines:

- *Increased* day-ahead production costs by **$13 million** in 2017 because prices on Long Island were typically higher than those in New York City where the lines connect.[162]
- Restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect and at the nearby Astoria Annex. Restrictions on these New York City generators sometimes increases price in a much wider area (e.g., during an eastern reserve shortage or 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.

160 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.

161 As discussed further in Section V.D 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.

162 These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica pocket in New York City, an area that is frequently export-constrained.

- 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.

This indicates there are significant opportunities to improve the operation of the 901 and 903 lines under the ConEd-LIPA wheeling agreement.[163] 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.[164] We recommend the NYISO work with the parties to this contract to explore changes that would allow the lines to be used more efficiently.[165]

The Goethals, Farragut, and Waldwick lines[166] were 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 prior to May 1, 2017. Afterwards, these lines have been operated: (a) to flow a share of the external transactions scheduled over the primary interface between New York and PJM); and (b) to manage real-time congestion under M2M with PJM. This change has improved the efficiency of scheduling over these lines, contributing to an estimated reduction in production costs of $9 million in 2017, compared to a net effect of around $0 in 2016. Nonetheless, the scheduling on the Waldwick lines (which *increased* production costs by approximately $8 million in 2017) was still much less efficient than on the Goethals and Farragut lines (which reduced production costs by approximately $17 million). The next sub-section examines the operation of these lines under M2M coordination with PJM.

E. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") 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 to do so.[167] Ramapo PARs have been used for the M2M process since its inception in January 2013, while Farragut, Goethals, and Waldwick PARs (i.e., ABC

163 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.

164 The proposed financial right would compensate ConEd for congestion management consistent with the revenue adequacy principles underlying nodal pricing, so the financial right holder would receive congestion revenues like other wholesale market transactions from the congestion revenue fund and no uplift charges would be necessary. The proposed financial right is described in Section III.H of the Appendix.

165 See Recommendation #2012-8 in Section XI.

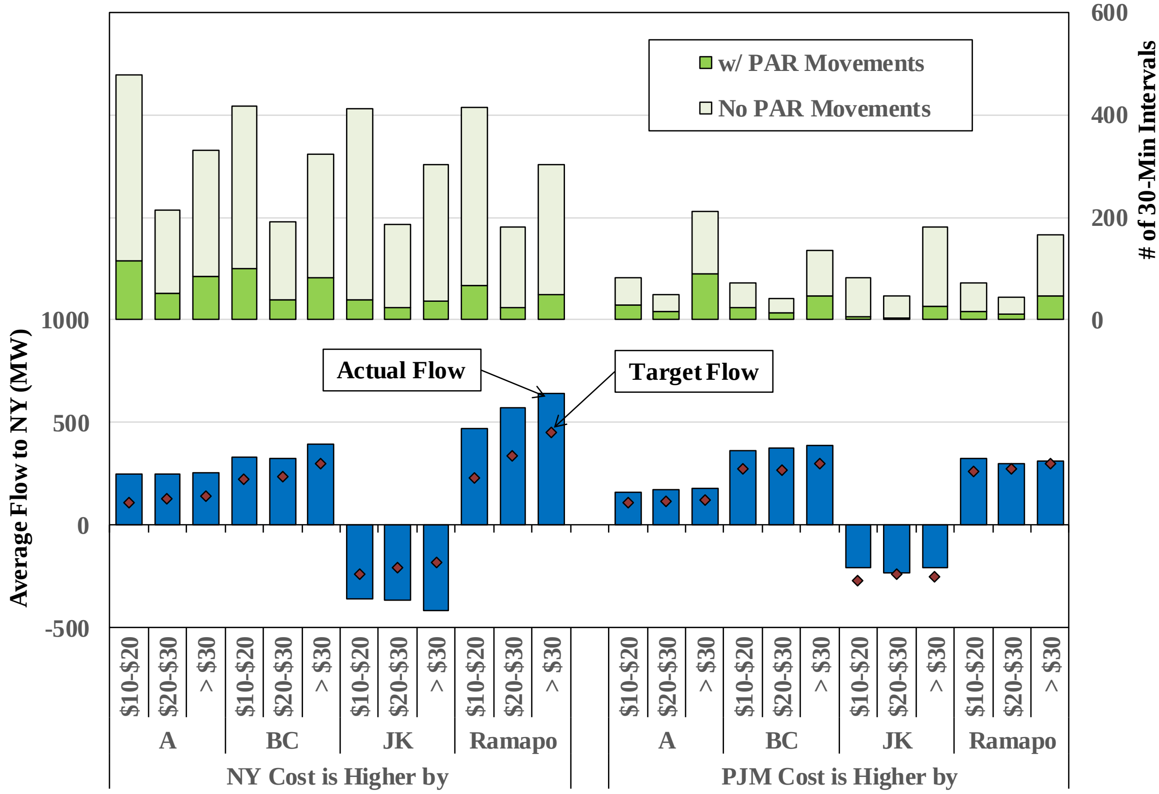
166 The Goethals line is known as the "A" line, the Farragut lines are known as the "B & C" lines, and the Waldwick lines are known as the "J & K lines."

167 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

and JK PARs) were added in May 2017 following the expiration of the ConEd-PSEG Wheel agreement. Figure 19 evaluates operations of these PARs under M2M with PJM from May to December 2017 during periods of significant congestion between New York and PJM. [168]

Figure 19: PAR Operation Under M2M with PJM

Congested Periods, May – December 2017



Overall, the PAR operations under M2M with PJM have provided benefit to the NYISO in managing congestion on coordinated transmission flow gates. We have observed instances of efficient M2M coordination as PARs were moved in the direction to reduce overall congestion costs in a relatively timely manner. Balancing congestion revenue surpluses frequently resulted from this operation on the Central-East interface and transmission paths into Southeast New York (including an estimated $7 million of revenue surpluses in 2017. See Section III.F in the Appendix), indicating that the process reduced production costs and congestion in New York.

Nonetheless, there were instances when PAR adjustments were likely available and that would have reduced congestion, but no adjustments were made. During all of the 30-minute periods when the congestion differential between PJM and NYISO exceeded $10 per MWh across these PAR-controlled lines (which averaged less than five times per day), PAR taps were taken in only

168 See Section V.C in the Appendix for a detailed description of the figure.

21 percent of these periods. Overall, each PAR was adjusted just 1 to 5 times per day on average, which is well below their operational limits of 20 taps per day and 400 taps per month.

Although actual flows across these PAR-controlled lines typically exceeded their M2M targets towards NYISO during these periods, flows were generally well below their seasonal limits (more than 500 MW for each line). In some cases, PAR adjustments were not taken because of:

- Difficulty predicting the effects of PAR movements under uncertain conditions;
- Adjustment would push actual flows or post-contingent flows close to the limit;
- Adjustment was not necessary to maintain flows above the M2M target;
- The transient nature of congestion; and
- Mechanical failures (e.g., stuck PARs).

These results highlight potential opportunities for increased utilization of the M2M PARs. Our evaluation of factors causing divergences between RTC and RTD also identifies the operation of these PARs as a net contributor to price divergence.[169] This is partly because RTC has no information related to potential tap changes. Consequently, RTC may schedule CTS imports to relieve congestion across the Central East interface, but operators may already be taking tap adjustments in response to the congestion. Unfortunately, NYISO operators do not have a congestion or production cost forecasting model that can be used to determine the efficient schedule for these M2M PARs, so it will be difficult to optimize the PAR operation without a model to forecast the impacts of PAR tap adjustments in real time.

F. 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 2017. 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 4 percent of all intervals in 2017, 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, and reduced uplift costs.

169 See Appendix Section IV.D for a more detailed discussion on factors causing RTC and RTD divergence.

Drivers of Transient Real-Time Price Volatility

Table 15 summarizes the most significant factors that contributed to real-time price volatility in 2017 and shows their contributions to the price spike for the power-balance constraint and the most volatile transmission constraints.[170] Contributions are also shown for: (a) resources and external interchange scheduled by RTC; and (b) flow changes from un-modeled factors, such as loop flows; and (c) other factors, such as load and generator derates.[171] For each constraint category, the most significant categories are highlighted in purple and green, respectively.

Resources scheduled by RTC (e.g., external interchange and gas turbine shut-downs) were a key driver of transient price spikes for the power-balance constraint and most transmission constraints shown in the table (except the West Zone 230 kV Lines). 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 evaluation period by RTD to satisfy the energy, reserve, and other operating requirements.

Table 15: Drivers of Transient Real-Time Price Volatility
2017

	Power Balance	West Zone 230kV Lines	Central East	UPNY-SENY
Average Transfer Limit	**n/a**	**689**	**2138**	**1616**
Number of Price Spikes	**525**	**708**	**225**	**88**
Average Constraint Shadow Price	**$217**	**$1,028**	**$355**	**$643**
Source of Increased Constraint Cost:	**(%)**	**(%)**	**(%)**	**(%)**
Scheduled By RTC	**64%**	**8%**	**43%**	**30%**
External Interchange	30%	8%	15%	14%
RTC Shutdown Resource	23%	0%	18%	13%
Self Scheduled Shutdown/Dispatch	11%	0%	10%	4%
Flow Change from Non-Modeled Factors	**5%**	**77%**	**44%**	**62%**
Loop Flows & Other Non-Market	1%	46%	18%	42%
Fixed Schedule PARs	0%	23%	26%	20%
Niagara Generator Distribution	0%	8%	0%	0%
Redispatch for Other Constraint (OOM)	5%	0%	0%	0%
Other Factors	**31%**	**15%**	**13%**	**8%**
Load	17%	8%	6%	5%
Generator Trip/Derate/Dragging	6%	0%	7%	3%
Wind	8%	8%	1%	0%

170 Section V.E in the Appendix also shows constraint into and within Long Island, which were significant in 2016 but became less prevalent in 2017 as a result of fewer significant transmission outages, lower GTDC values, improved modeling of the 901 and 903 PAR-controlled lines.

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

Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines and the UPNY-SENY interface. Clockwise circulation around Lake Erie puts a large amount of non-market flows over lines in the West Zone. Circulation can be highly volatile and difficult to predict since it depends partly on facilities that are scheduled outside the NYISO market. Thunderstorm Alert ("TSA") operations require dramatic reductions in transfer capability across the UPNY-SENY interface, which often led to severe congestion.

Fixed-schedule PAR-controlled line flow variations (over the A, B, C, J, K, and 5018 lines) were a key driver of price spikes for the West Zone 230kV lines, the Central-East Interface, and the UPNY-SENY interface. These PARs are modeled as if they fully control pre-contingent flow across the PAR-controlled lines, which is unrealistic.[172] The PARs are not adjusted frequently in response to variations in generation, load, interchange, and other PAR adjustments.[173] Since each PAR is adjusted less than five times per day on average, the telemetered value can change significantly from one interval to the next, resulting in transitory price spikes. In addition, when the PARs are adjusted, it may cause congestion that was not anticipated because the operator does not have a model that forecasts the congestion impact of making tap adjustments.

We also evaluated factors that made the largest contributions to price divergences between RTC and RTD Section VI.D. The factors mentioned above that contributed most to transient price spikes were also identified as significant contributors to this price divergence.

Inconsistent Ramp Assumptions 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 significant driver of the price volatility evaluated above.

- Generators shutting can cause a transient shortage because RTC has 15 minutes of ramp capability in each evaluation period so it may shut down several gas turbines simultaneously. 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.
- RTC assumes transactions ramp in at the quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange actually ramps 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 at the quarter hour interval because the external transactions have not finished ramping.

172 RTD and RTC assume that the flows across these PAR-controlled lines would remain fixed at the most recent telemetered values plus an adjustment for DNI changes on the PJAC interface.

173 Section IX.E evaluates the performance of these PAR-controlled lines under M2M with PJM and shows that these tap adjustments on these PARs averaged one to five times per day.

To reduce these sources of unnecessary price volatility, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:[174]

- 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.
- 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 a GT shut-down for five minutes when it is economic to remain on.
- 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.
- Modify ramp limits to reflect that a unit providing regulation service cannot ramp as far in a five-minute interval as a unit that is not providing regulation (since regulation deployments may lead the unit to move against its five-minute dispatch instruction).

Potential Solutions to Address Non-Modeled Factors

To reduce unnecessary price volatility from variations in loop flows and flows over PAR-controlled lines that are not modeled in the dispatch software, we recommend the NYISO: [175]

- Make additional adjustments for loop flows. The adjustment should be "biased" in the clockwise direction to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., under-forecasting is more costly than over-forecasting); and
- Reconsider its method for calculating shift factors. The current method assumes that pre-contingent PAR-controlled line flows are unaffected by generation re-dispatch and load changes, although this is unrealistic.

In addition, 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.[176] This would also reduce unnecessary price volatility on 230kV constraints in the West Zone because it would allow the market to re-dispatch generation efficiently to relieve congestion. Currently, any such re-dispatch occurs through less precise out-of-market dispatch.[177]

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174 See Recommendation #2012-13 in Section XI.

175 See Recommendation #2014-9 in Section XI.

176 See Recommendation #2014-12.

177 See Section III.D in the Appendix for more discussion on out-of-merit dispatch for West Zone 115 kV lines.

G. Supplemental Commitment & Out of Merit Dispatch for Reliability

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

Similarly, the NYISO and local transmission owners sometimes dispatch generators out-of-merit ("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 increases production from capacity that is normally uneconomic and displaces output 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 and look for ways to procure the underlying reliability services through the day-ahead and real-time market systems.

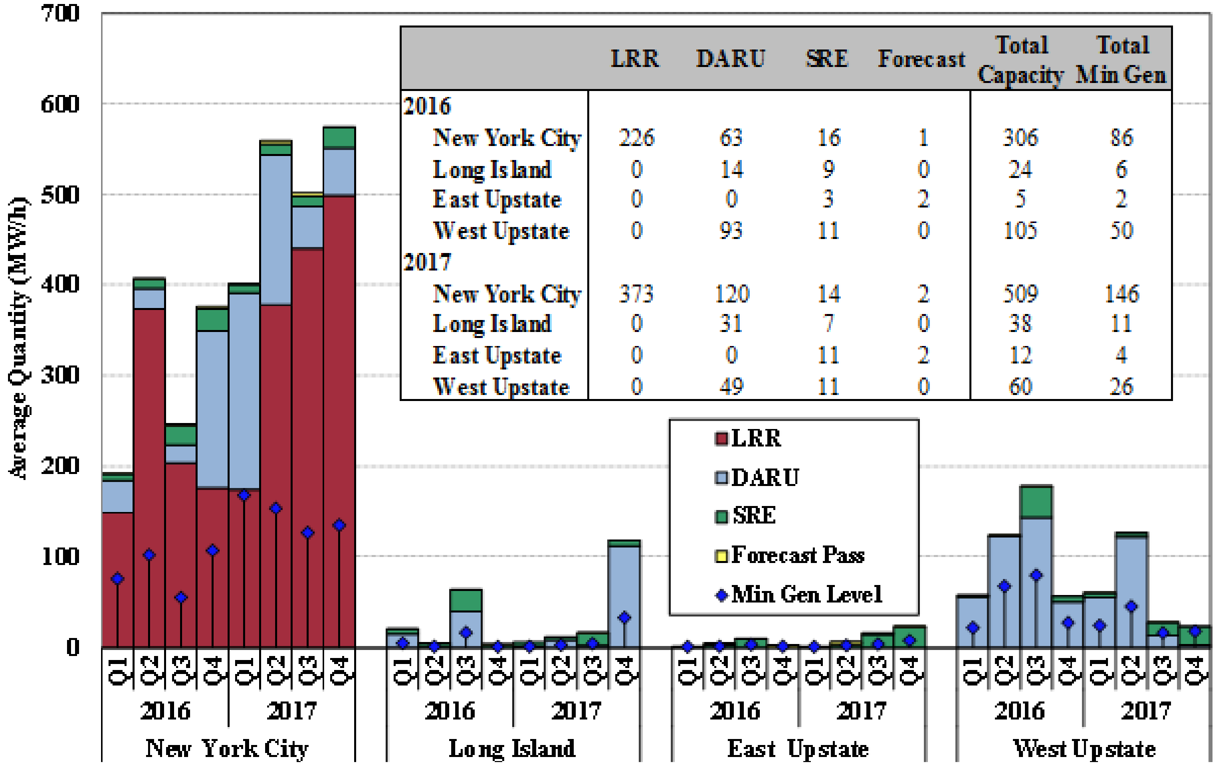
Supplemental Commitment in New York State

Figure 20 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2016 and 2017. [178]

Roughly 620 MW of capacity was committed on average for reliability in 2017, up 41 percent from 2016. The increase occurred primarily in New York City, which rose 66 percent from 2016 and accounted for 82 percent of total reliability commitment in 2017. Units that were often needed for local reliability were economically committed less frequently in 2017 because of higher gas prices in New York City (relative to other areas of East New York) and lower load levels. Most of these commitments were made to satisfy the N-1-1 requirements in the sub-regions on the 138 kV system. There were also more planned transmission outages in the Freshkills load pocket and the City's 345 kV system that increased the local needs in these areas.

[178] See Section V.H in the Appendix for a description of the figure.

Figure 20: Supplemental Commitment for Reliability in New York
By Category and Region, 2016 – 2017



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2017						
New York City	373	120	14	2	509	146
Long Island	0	31	7	0	38	11
East Upstate	0	0	11	2	12	4
West Upstate	0	49	11	0	60	26

However, reliability commitments in Western New York continued to fall in 2017 -- by 43 percent from 2016. This was primarily because DARU commitments fell sharply as transmission upgrades completed in early July allowed the Milliken RSSA to expire.

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.[179] 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.

179 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."

NOx bubble commitments accounted for 10 percent of all reliability commitment in New York City in 2017. These commitments generally do not reduce output from older gas turbines (as intended). Table 16 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.[180]

Table 16: Energy Production from NOx Bubble Generators
2017

Daily Load Levels	Generation Output from GTs in NOx Bubble	Generation Output from STs Committed for NOx
Low	7.5%	90.3%
Medium	8.7%	9.4%
High	83.8%	0.4%
Total	100%	100%

Similar to prior years, 93 percent of energy production from the gas turbines in the NOx Bubbles occurred on days with medium to high load levels in 2017, while 90 percent of the production from steam units committed for the NOx constraints occurred on low-load days in 2017. Hence, most of the NOx bubble commitments were made on low-load days when older gas turbines rarely operated. 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 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, cleaner generators (equipped with emission-reducing equipment such as SCRs) in New York City was 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

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

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.[181]

Supplemental Commitment in New York City for N-1-1 Constraints

Reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1 criteria) in New York City. Since such units would not be economic if they were not needed for local reliability, they ordinarily do not earn enough market revenue to recoup their day-ahead as-offered costs. Hence, such units typically receive a day-ahead BPCG payment.

Although the resulting amount of compensation (i.e., revenue = cost) is reasonably efficient for the marginal commitment needed to satisfy the needs of the pocket, it does not provide efficient incentives for lower cost resources that can also provide valuable operating reserves in the pocket to be available. Moreover, it does not provide investors with efficient incentives to invest in new and existing resources that are capable of satisfying the need at a lower cost. Therefore, it would be beneficial for the NYISO to seek ways to design a reserve product that could satisfy the local N-1-1 requirements in a way that provides market-based compensation to all suppliers that provide the product in the load pocket, not just the ones with high operating costs.

To assess the potential market incentives that would result from modeling local N-1-1 requirements in New York City, we estimated the average clearing prices that would have occurred in 2017 if the NYISO were to devise a day-ahead market requirement that set clearing prices.[182] Table 17 summarizes the results of this evaluation based on 2017 market results for three locations in New York City: the 345kV network north of Staten Island, the Astoria West/Queensbridge load pocket, and the Vernon location on the 138 kV network.

Table 17: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2017

Area	**Average Marginal Commitment Cost ($/MWh)**
NYC 345 kV System	**$0.88**
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	**$2.71**
Vernon	**$1.65**

Based on our analysis of operating reserve price increases that would be necessary to represent the marginal costs of satisfying N-1-1 requirements in the day-ahead market, we find such price

181 See Recommendation #2014-13 in Section XI.

182 Section V.H in the Appendix describes the methodology of our estimation.

increases would range from an average of $0.88 per MWh in most areas to as much as $2.71 per MWh in the Astoria West/Queensbridge load pocket in 2017. These price increases would be in addition to the prices of operating reserve products in Southeast New York.

In addition, we estimated the likely increase in energy and reserve net revenues that different types of units would have received if they were compensated for reserves in New York City load pockets at the rates shown in Table 17.[183] Other load pockets would also have binding N-1-1 requirements, but we were unable to finalize the estimates for those pockets. This analysis illustrates the enhanced incentives that would result from satisfying these requirements through the day-ahead and real-time markets. Given these results, we have recommended that the NYISO design a reserve product to model N-1-1 constraints in New York City, which should provide a more efficient market mechanism to satisfy reliability criteria in the load pockets.[184]

Out of Merit Dispatch

Table 18 summarizes the frequency (in station-hours) of OOM actions over the past two years for four regions: (a) West Upstate, including Zones A through E; (b) East Upstate, including Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K.[185]

Table 18: Frequency of Out-of-Merit Dispatch
By Region, 2016-2017

Region	OOM Station-Hours		
	2016	2017	% Change
West Upstate	2854	1668	-42%
East Upstate	279	1169	319%
New York City	312	147	-53%
Long Island	1849	755	-59%
Total	**5294**	**3739**	**-29%**

The quantity of OOM actions fell 29 percent in 2017 partly due to less frequent peak load levels. OOM levels fell 42 percent in Western New York partly because of transmission upgrades completed in July 2017. This allowed the Milliken RSSA to expire, which was frequently used for local reliability. Nonetheless, Western New York still accounted for the largest share of OOM station hours in 2017. Several hydro units were frequently OOMed-down in the months of June and July as transmission outages led to increased local needs on the 115 kV network.

183 See analysis in Section VIII.C.

184 See Recommendation #2017-1 in Section XI.

185 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 2017 for each region.

In addition, 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 2017, this manual shift was required in 951 hours to manage 115 kV constraints and in 222 hours to manage 230 or 345 kV constraints. This pattern continued after the Huntley reactors were activated in May 2016, but a larger share of the manual shifting was done to secure the 115 kV system.

However, the quantity of OOM actions increased substantially in East Upstate in 2017 as the Bethlehem units were frequently dispatched OOM to manage post-contingency flow on the Albany-Greenbush 115 kV facility. Given the inefficient pricing, dispatch and uplift caused by, the frequent DARU commitments and OOM actions taken to manage 115 kV congestion, 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.[186]

OOM dispatch on Long Island fell 59 percent from 2016 to 2017. Most of the reduction was in the summer as lower load levels and fewer transmission outages led to reduced needs to dispatch peaking generators to manage thermal and voltage constraints on the east end of Long Island.

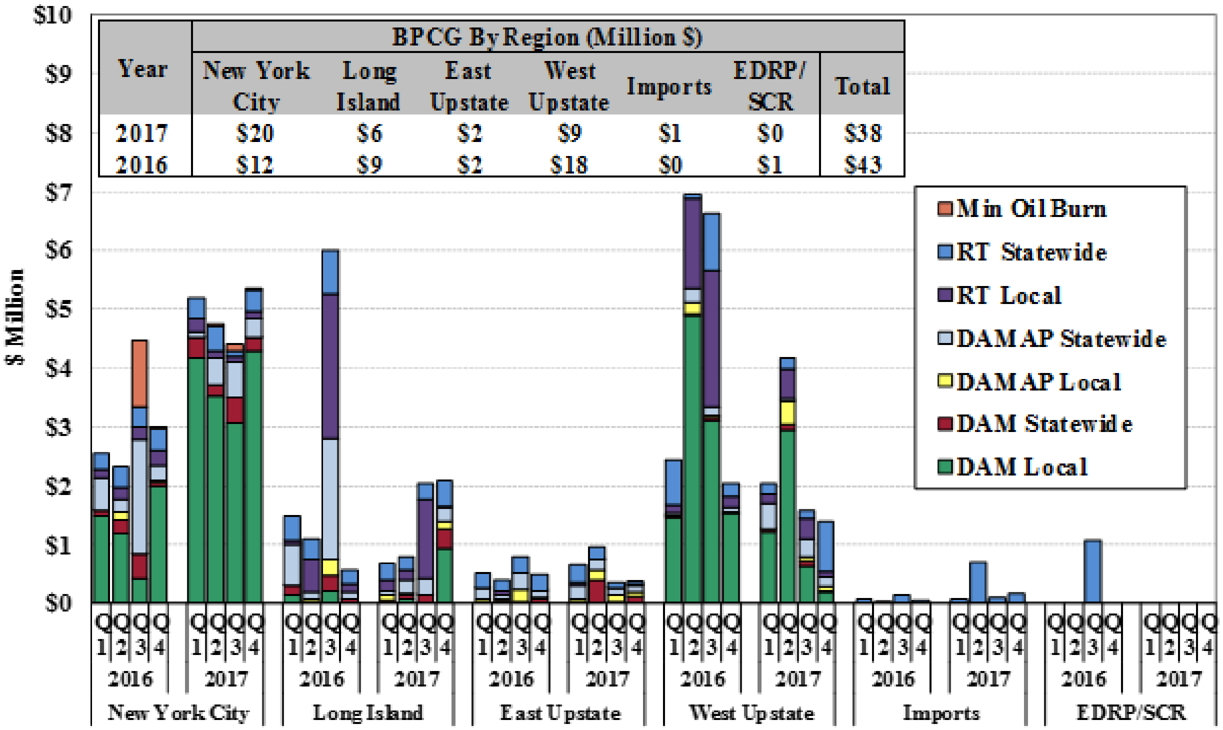
H. Guarantee Payment Uplift Charges

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 2016 and 2017 on a quarterly basis.[187]

186 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.

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

Figure 21: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2016 – 2017



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2017	$20	$6	$2	$9	$1	$0	$38
2016	$12	$9	$2	$18	$0	$1	$43

The figure shows that the guarantee payment uplift totaled $38 million in 2017, down 12 percent from 2016.[188] The decline occurred primarily in Western New York, which exhibited a reduction of 49 percent, and Long Island, which exhibited a reduction of 38 percent. These reductions resulted from less reliability commitment and OOM dispatch as discussed above in Subsection G. The local uplift in Western New York has been greatly reduced following the transmission upgrades that facilitated the expiration of Milliken RSSA. Most of the local uplift was paid to units that were committed for reliability and/or dispatched OOM to manage congestion on the 115 kV transmission facilities (which are discussed earlier). The remaining local uplift would likely be eliminated if these constraints were modeled in NYISO's day-ahead and real-time markets.

In addition, guarantee payment uplift in the category of DAMAP, Min Oil Burn, and EDRP/SCR accounted for a reduction of more than $5 million. Most of these uplift charges in 2016 accrued on several days in July and August with high load levels, which were not seen in 2017 because of milder weather conditions.

188 The 2017 number was based on billing data available at the time of reporting, which may be different from final settlement.

Despite the reduction in other areas, guarantee payment uplift in New York City rose 59 percent from 2016 to 2017. Increased supplemental commitment for reliability (as discussed earlier) was the primary driver. Additionally, higher natural gas prices also increased the commitment costs of gas-fired units.

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.

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, 99 percent of the 1.2 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 1,221 MW of resources participating in 2017. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. In the six months of the Summer 2017 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.2 percent of the UCAP requirement for New York City;
- An average of 3.3 percent of the UCAP requirement for the G-J Locality;
- An average of 1.9 percent of the UCAP requirement for Long Island; and
- An average of 3.7 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources has fallen by roughly 50 percent from 2010 to 2017 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 to reduce or cease participation have been 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. Currently, 117 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 17 percent of the NYCA 10-minute spinning reserve requirement in 2017.

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 2017, the NYISO did not deploy EDRP and SCR resources, therefore related operations and pricing efficiency area not evaluated in this report.[189]

189 See Appendix Section VIII of the 2016 SOM Report for a detailed evaluation of pricing outcomes during the demand response deployments in 2016.

XI. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2017, although we recommend additional enhancements to improve market performance. Twenty-one recommendations are presented in six categories below. A numbering system is used 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 2016 SOM Report, but Recommendations #2017-1 to #2017-4 are new in this report. The following table summarizes our current recommendations.

Number	Section	Recommendation	Current Effort	High Priority
Energy Market Enhancements - Pricing and Performance Incentives				
2017-1	IX.G	Model local reserve requirements in New York City load pockets.		
2017-2	IX.A	Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules.		✓
2016-1	VIII.C	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		
2016-2	IX.C	Consider means to allow reserve market compensation to reflect actual and/or expected performance.		
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.		
2015-16	IX.A	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	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	✓	
2014-12	V.A	Model 100+ kV transmission constraints in the day-ahead and real-time markets, and develop associated mitigation measures.	✓	✓
Energy Market Enhancements – Market Power Mitigation Measures				
2017-3	IX.A	Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.		
2017-4	III.B	Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.		
Energy Market Enhancements - Real-Time Market Operations				
2014-9	VI.D, IX.F	Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.		
2012-8	VI.D,	Operate certain PAR-controlled lines to minimize production		

Number	Section	Recommendation	Current Effort	High Priority
	IX.F	costs and create financial rights that compensate affected transmission owners.		
2012-13	VI.D, IX.F	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.		
Energy Market Enhancements - BPCG Eligibility and Fuel Limitations/Storage				
2014-13	IX.G	Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.		
2013-11	IX.B.2 (2015 SOM)	Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	✓	
Capacity Market Enhancements				
2015-8	VII.C	Modify the capacity market to better account for imports from neighboring control areas to import-constrained capacity zones.		
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
2013-1c	VII.B	Implement optimal location marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements.		
2012-1a	VII.F	Establish a dynamic locational capacity framework that reflects potential deliverability, resource adequacy, and transmission security requirements.		
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.		
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 is designed to 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. 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. However, market rule changes that reduce production 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

<u>Energy Market Enhancements – Pricing and Performance Incentives</u>

2017-1: Model local reserve requirements in New York City load pockets.

The NYISO is required to maintain sufficient energy and operating reserves to satisfy N-1-1 local reliability criteria in New York City. These local requirements are not satisfied through market-based scheduling and pricing, so it is necessary for the NYISO to satisfy these local requirements with out-of-market commitments in the majority of hours. The costs of out-of-market commitments are recouped through make-whole payments rather than through market clearing prices for energy and operating reserves. The routine use of make-whole payments distorts short-term performance incentives, as well as incentives for new investment that can satisfy the local requirements.[190] Hence, we recommend the NYISO consider implementing local reserve requirements in the New York City load pockets.

Additionally, while most local N-1-1 requirements are driven by the potential loss of the two largest Bulk Power System elements supporting a particular load pocket, the NYISO also should consider whether local reserve requirements would be appropriate for maintaining reliability following the loss of multiple generators due to a sudden natural gas system contingency.

2017-2: Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules. (High Priority)

Since it first implemented shortage pricing for energy and operating reserves in 2003, the NYISO has generally benefited from significant net imports during reserve shortages and other extreme scarcity conditions. However, ISO New England and PJM will be phasing-in the implementation of new PFP ("Pay For Performance") rules from 2018 to 2022. PFP rules provide incentives similar to shortage pricing, whereby incremental compensation for energy and operating reserves will rise to $3,000+ per MWh during reserve shortages. Consequently, the market incentives that have encouraged generators and power marketers to bring power into New York may change in the future. Hence, we recommend that the NYISO evaluate the incentive effects of the PFP rules and consider modifying its operating reserve demand curves to ensure reliability during shortage conditions. This evaluation should consider having multiple steps for each operating reserve demand curve so that clearing prices rise with the severity of the shortage and so that the real-time market will schedule available resources such that out-of-market actions are not needed to maintain reliability.[191]

This recommendation is high priority because taking out-of-market actions to maintain reliability during reserve shortage conditions (because the real-time market does not schedule available resources) leads to inefficient scheduling, poor real-time performance incentives, and less efficient commitment and investment incentives. Further, we believe this has a relatively low level of complexity and should be less difficult to implement than most other recommendations.

2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.

190 See discussion in Section IX.G. See 2019 Project Candidate: *More Granular Operating Reserves*.

191 See discussion in Section IX.A. See 2019 Project Candidate: *Ancillary Services Shortage Pricing*.

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 and pollution in the load center. 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.[192] The NYISO should also consider market-based compensation for generators that support transmission security by continuing to operate following the loss of multiple generators due to a sudden natural gas system contingency.

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

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.[193]

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.[194]

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.

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192 See discussion in Section VIII.C of this report and Section IX.C of the 2016 SOM Report. See 2019 Project Candidate: *Pricing Reserves for Congestion Management*.

193 See discussion in Section IX.C. See 2019 Project Candidate: *Performance-Based Reserve Payments*.

194 See discussion in Section VI.D. See 2019 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

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 four examples where this functionality would provide significant benefits.

- Resources in Zone K are limited in satisfying operating reserve requirements for SENY, Eastern NY, and NYCA, but the amount operating reserves scheduled in Zone K could be increased in many hours. Long Island frequently imports more than one GW from upstate, allowing larger amounts 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 or into SENY. In fact, it is often less costly to reduce flows across Central East or the interface into SENY (i.e., to hold reserves on these interface) rather than hold reserves on internal units in Eastern New York.
- Imports across the HVDC connection with Quebec could be increased significantly above the level currently allowed, but this would require corresponding increases in the operating reserve requirements (to account for a larger potential contingency). Since increased imports would not always be economic, it would be important to optimize the reserve requirement with the level of imports.
- If the NYISO implements recommendation 2017-1, the amount of operating reserves that need to be held on resources in a particular load pocket could be reduced when there is unused import capability into load pocket. In many cases, it will be less costly to reduce flows into the load pocket (i.e., to hold reserves on these interface) rather than hold reserves on internal units inside the load pocket.

Hence, we recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each of these requirements.[195]

2015-17: Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages. (Current Effort)

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, the NYISO began to use a Graduated Transmission Demand Curve ("GTDC") to set prices during the vast majority of transmission shortages starting in June 2017. The use of the GTDC is a significant improvement, but it does not appropriately prioritize transmission constraints according to the importance of the facility, the severity of the violation,

195 See discussion in Section IX.A. See 2019 Project Candidate: *Dynamic Reserve Requirements*.

or other relevant criteria. Hence, we recommend the NYISO replace the single GTDC with multiple GTDCs that can vary according to the importance, severity, and/or duration of the transmission constraint violation. [196]

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

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, out-of-market actions exacerbate congestion on the 230+kV systems in other parts of New York state. In other 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 requires significant effort, since it requires additional coordination with the local Transmission Owner. [197]

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.

This recommendation is a high priority because we find that out-of-market actions to manage 115kV transmission constraints occur on a daily basis, and these actions have significant impacts on congestion management for the high voltage networks throughout New York. The use of out-of-market actions to manage transmission constraints is less efficient than when they are managed through the day-ahead and real-time markets.

Energy Market Enhancements – Market Power Mitigation Measures

2017-3: Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.

The current market power mitigation rules impose financial penalties on a supplier that over-produces to create transmission congestion, but this happens only if the congestion leads to high

196 See discussion in Section IX.A. See 2019 Project Candidate: *Constraint Specific Transmission Shortage Pricing*.

197 See discussion in Section V.A. See 2019 Project Candidate: *Model 100+kV Transmission Constraints*.

prices downstream of the transmission constraint. However, a supplier with a significant long position in the forward market can benefit from setting extremely low clearing prices in the spot market. So, the current market power mitigation rules should be modified to deter uneconomic over-production even when it does not result in high clearing prices downstream of the constraint.[198]

2017-4: Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.

The automated mitigation procedure ("AMP") applies generator-specific offer caps when necessary to limit the exercise of market power in New York City. Each generator-specific offer cap is based on an estimate of the generator's marginal cost, which is known as its "reference level." Natural gas price volatility and limitations on the availability of fuel have increased the need to adjust reference levels to reflect changing market conditions. Generators can reflect changes in their fuel costs and fuel availability by submitting a "fuel cost adjustment." The current market power mitigation rules include provisions that are designed to prevent a supplier from submitting inappropriately high fuel cost adjustments to avoid mitigation by the AMP. However, the current rules are inadequate to deter a supplier from submitting inappropriately high fuel cost adjustments during some conditions. To address this deficiency, we recommend that the NYISO impose a financial sanction for economic withholding by submitting an inappropriately high fuel cost adjustment that is comparable to the financial sanction for physical withholding. [199]

Energy Market Enhancements – Real-Time Market Operations

2014-9: Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.

Variations in loop flows and flows over PAR-controlled lines were among the leading causes of real-time transient price spikes and poor convergence between RTC and RTD prices in 2017. To reduce the effects of variations in loop flows, we recommend the NYISO consider developing a mechanism for forecasting additional adjustments from the telemetered value. 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). A significant portion of the variations in unmodeled flows result from two unrealistic assumptions in the modeling of PAR-controlled lines: (a) that the pre-contingent flows over PAR-controlled lines are not influenced by generator redispatch even though generator redispatch affects PAR-controlled lines like it would any other AC circuit, and

198 See discussion in Section IX.A.

199 See discussion in Section III.B.

(b) that PARs are continuously adjusted in real-time to maintain flows at a desired level even though most PAR-controlled lines are adjusted in fewer than 4 percent of intervals.[200]

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 2017, 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) 93 percent of the time. Their operation increased production costs by an estimated $13 million, and sometimes restricted production by economic generation in New York City. [201]

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.H 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.

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: [202]

- 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.

[200] See discussion in Sections VI.D and IX.F. See 2019 Project Candidate: *Enhanced PAR Modeling*.

[201] See discussion in Section IX.D. See 2019 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

[202] See discussion in Sections VI.D and IX.F. See 2019 Project Candidate: *RTC-RTD Convergence Improvements*.

- 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.
- Modify ramp limits of individual units to reflect that a unit providing regulation service cannot ramp as far in a particular five-minute interval as a unit that is not providing regulation (since regulation deployments may lead the unit to move against its five-minute dispatch instruction).

This recommendation is likely to become more important in the future because the CTS process has potential to provide significant additional flexibility above the current limit of 300 MW of adjustment every 15 minutes. Additional flexibility will become increasingly important as the NYISO integrates more intermittent renewable generation in the coming years.

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.[203]

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

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

[203] See discussion in Section IX.G. See 2019 Project Candidate: *Review of RACT Compliance Plans*.

- Hydroelectric plants have inventory constraints that may limit their output over a 24-hour period. Likewise, output from generators is often limited by oil inventories, air permit restrictions, or total daily gas burn limitations. 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.[204]

Capacity Market Enhancements

2015-8: Modify the capacity market to better account for imports from neighboring control areas to import-constrained capacity zones.

The NYISO recently implemented tariff provisions that will allow it to recognize the local reliability benefits from capacity that is exported from an import-constrained capacity zone, and we support the NYISO's efforts to develop a probabilistic method for quantifying those benefits. However, additional market enhancements are needed to provide efficient incentives to import capacity. Under the current rules, capacity in PJM and ISO-NE may be helpful in meeting the local requirements of the G-J Locality and more valuable to the NYISO than to the neighboring region, but the capacity may not have an incentive to sell into the NYISO because the price paid to such capacity does not reflect its value to the locality. Hence, we recommend setting clearing prices for such capacity imports that are consistent with their value to the NYISO.[205]

2013-2d: Enhance Buyer-Side Mitigation Forecast Assumptions.

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. Likewise, the timing of new entry is also important, since the

204 See discussion in Section IX.B.2 of the 2015 State of the Market Report. See 2019 Project Candidate: *ESR Participation Model*.

205 See discussion in Section VII.C. See 2019 Project Candidate: *Treatment of Locality Exports and Imports*.

economic value of a project may improve after future retirements and transmission additions. We recommend the NYISO modify the BSM assumptions to allow the forecasted prices and project interconnection costs to be reasonably consistent with expectations. [206]

2013-1c: Implement optimal locational pricing of capacity that minimizes the cost of satisfying planning requirements.

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 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. The NYISO has recently filed market enhancements that would improve the pricing by setting LCRs more efficiently. However, we recommend additional enhancements to further improve the efficient pricing of capacity throughout the NYISO.[207]

2012-1a: Establish a dynamic locational capacity framework that reflects potential deliverability, resource adequacy, and transmission security requirements.

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.

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206 See discussion in Section VII.B. See 2019 Project Candidate: *Enhanced Mitigation Study Period*.

207 See discussion in Section VII.F. See 2019 Project Candidate: *Explore Locational Reliability Pricing*.

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.[208]

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.

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.[209]

Enhance Planning Processes

2015-7: Reform the CARIS process to better identify and fund economically efficient transmission investments.

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.[210]

[208] See discussion in Section VII.D. See 2019 Project Candidate: *Dynamic Capacity Zones*.

[209] See discussion in Section VII.D. See 2019 Project Candidate: *Capacity Transfer Rights for Internal Transmission Upgrades*.

[210] See discussion in Section VII.E.

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 2016 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2016 State of the Market Report.

#2013-2d – The NYISO revised its tariff with a set of significant reforms that addressed deficiencies that we identified in the 2016 SOM Report in time for the 2017 Class Year interconnection process. Specifically, the revisions have allowed the NYISO to make more reasonable assumptions in the energy and capacity forecasts regarding the future status of generators in a mothballed, forced outage, and/or retired state as well as in-service generators that would have to be retired to allow the new generator to interconnect. [211]

#2015-17 – The NYISO revised its tariff and market software in June 2017 to address one aspect of this recommendation. Specifically, the pricing logic was modified to expand the use of the GTDC in cases where a transmission constraint cannot be satisfied with the available resources while respecting other constraints.[212] Previously, most transmission constraint violations were satisfied by "relaxing" (i.e., raising) the flow limit rather than using the GTDC to set clearing prices, but the share of violations that are relaxed has fallen to just 7 percent since the software changes were implemented.

#2013-1c – NYISO stakeholders have approved tariff revisions that will make significant progress towards the goals of this recommendation.[213] Specifically, it will begin (starting in May 2019) to set LCRs in a manner that is designed to minimize the cost of procuring capacity to satisfy the one-day-in-ten resource adequacy standard for NYCA and certain transmission security criteria.

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211 See [cite filing].

212 See Commission Docket ER17-1453-000.

213 See February 28, 2018 Management Committee materials related to *Alternative Methods for Determining LCRs*.

Other Recommendations Not Included on the List for 2017

This subsection describes several recommendations from previous reports that were not resolved but that are not included in this report. First, 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 pending before the Commission in a complaint proceeding.[214] After the Commission orders on this proposal, we will reassess the adequacy of the buyer-side mitigation measures.

Second, 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.[215] 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.

Third, Recommendation #2014-10 in the 2016 State of the Market Report proposed that the NYISO include start-up costs in the fast-start pricing logic when fast-start units are in their initial minimum run time. The Commission has since issued a 206 filing that preliminarily found the NYISO pricing to be unjust and unreasonable partly because it did not incorporate start-up costs in the fast-start pricing logic. The NYISO has responded with a proposal that would remedy this deficiency and which we support.[216] After the Commission orders on this proposal, we will reassess whether additional changes to the fast-start pricing logic are warranted.

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214 See Commission Docket EL13-62.

215 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.

216 See Commission Docket EL18-33-000.

Analytic Appendix

2017 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 IV of the Appendix.

This section of the appendix summarizes the market results and performance in 2017 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 2017 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;[217] 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

2009-2017

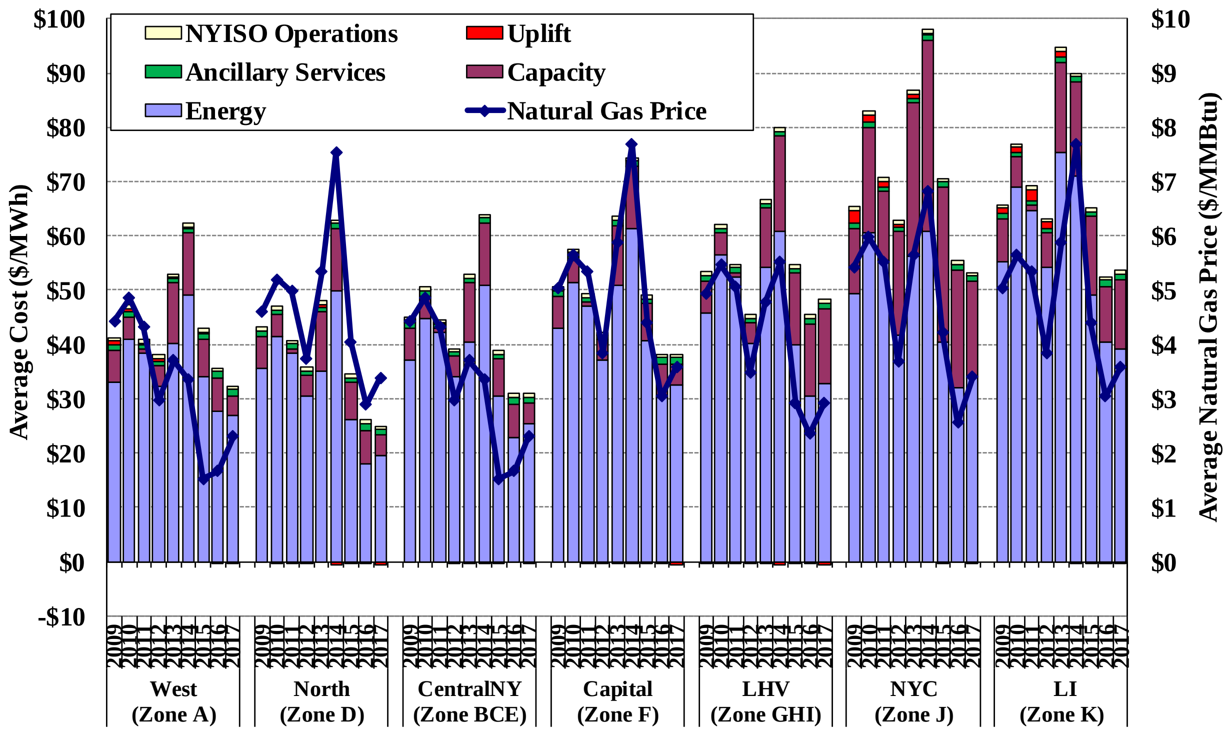

Figure A-2: Day-Ahead Electricity and Natural Gas Costs

Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2017 for the seven locations shown in Figure A-1. The table overlapping the chart shows the annual averages of natural gas costs and LBMPs for 2016 and 2017. Although hydro and nuclear generators produce much of the electricity used by New York

217 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.

consumers, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York.[218]

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2017

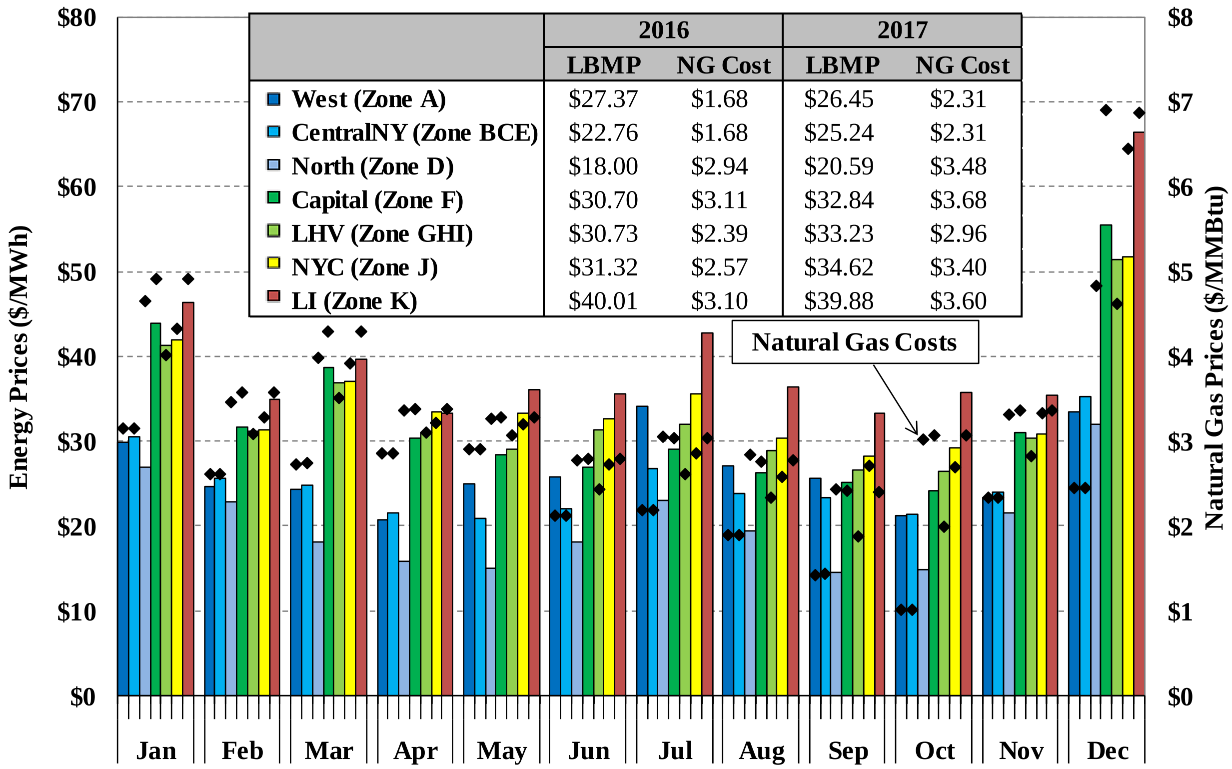

Figure A-3: Average Monthly Implied Marginal Heat Rate

The following figure summarizes the monthly average implied marginal heat rate. The implied marginal heat rate, the calculation of which is described in detail below, highlights changes in electricity prices that are not driven by changes in fuel prices.

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).[219] 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.[220]

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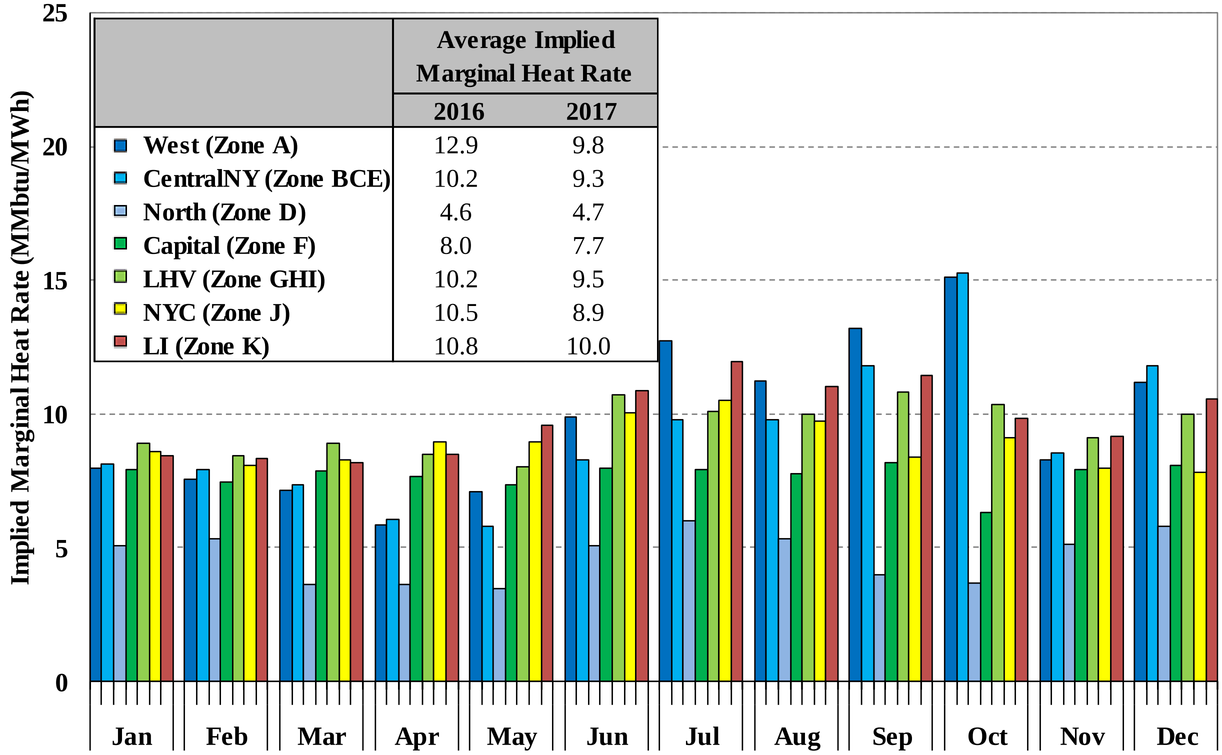
218 The prevalence of natural gas units as the marginal resource is apparent from the strong correlation between LBMP and natural gas price, particularly in Eastern New York.

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

220 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 shows the load-weighted average implied marginal heat rate in each month of 2017 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 2016 and in 2017 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.

Figure A-3: Average Monthly Implied Marginal Heat Rate
Day-Ahead Market, 2017



	Average Implied Marginal Heat Rate 2016	Average Implied Marginal Heat Rate 2017
West (Zone A)	12.9	9.8
CentralNY (Zone BCE)	10.2	9.3
North (Zone D)	4.6	4.7
Capital (Zone F)	8.0	7.7
LHV (Zone GHI)	10.2	9.5
NYC (Zone J)	10.5	8.9
LI (Zone K)	10.8	10.0

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 2017, 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 2017 at each location when the real-time price exceeded \$100, \$200, and \$500 per MWh.

The price duration curves show the distribution of prices in wholesale power markets, in which a small number of hours exhibited very high prices that are typically associated with shortages. Prices during shortages may rise to more than ten times the annual average price level. As such, a small number of hours with price spikes can have a significant effect on the average price level.[221] Fuel price changes from year to year are more apparent in the flatter portion of the price duration curve, since fuel price changes affect power prices most in these hours.

Figure A-4: Real-Time Price Duration Curves by Region
2017

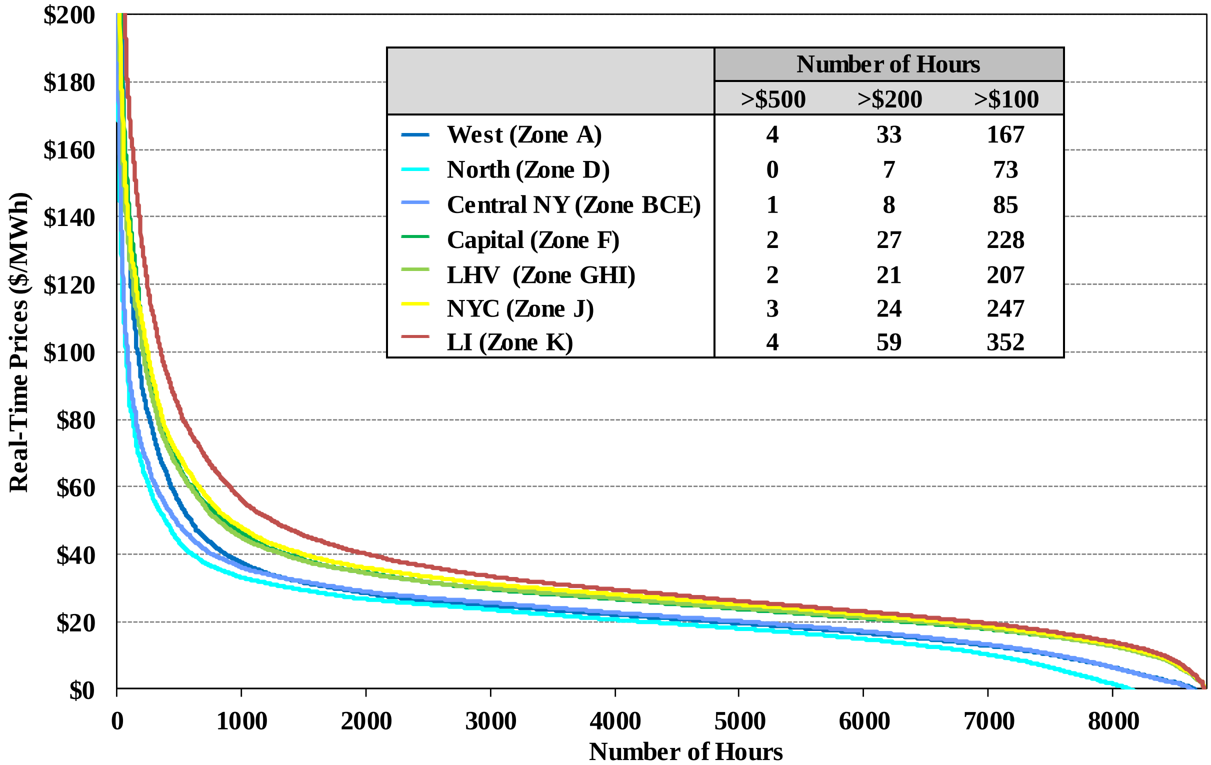
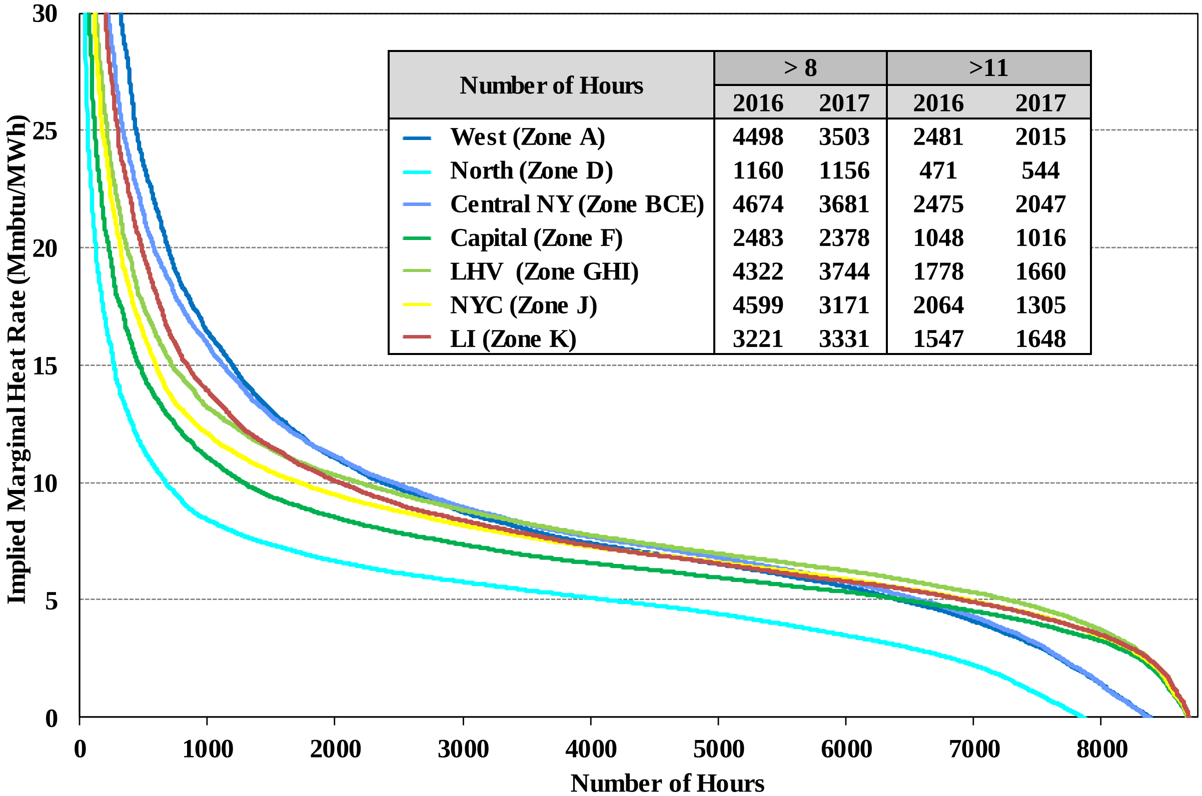


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2017. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation 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 2016 and 2017.

221 In other words, the distribution of energy prices across the year is "right skewed" which means that the average is greater than the median observation due to the impact of shortage pricing hours.

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

2017



Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from roughly \$25/MWh in the North Zone to \$53/MWh in Long Island in 2017.
  - All-in prices fell by 1 to 10 percent in most regions from 2016 to 2017 but rose 2 to 6 percent in Lower Hudson Valley and Long Island.
- Energy prices rose by 7 to 12 percent in most regions from 2016 to 2017 but fell by 3 percent in both the West Zone and Long Island.
  - Energy prices rose in most regions primarily because of higher natural gas prices (see subsection B).
    - However, this was partly offset by lower load levels (see subsection D) and higher generation output from nuclear and hydro resources (see subsection B).
  - Energy prices fell in the West Zone and in Long Island largely because of greatly reduced congestion in these areas for the reasons discussed in Section III of this Appendix.
- Capacity costs accounted for 33 percent of the all-in price in New York City and 10 to 29 percent of the all-in price in the other six regions.

- Capacity costs rose 5 percent in Lower Hudson Valley and 25 percent in Long Island from 2016 to 2017, but capacity costs fell 19 percent in New York City and 40 percent in the Rest of the State.
- Changes to administrative parameters from the latest Demand Curve Reset process and variations in cleared import capacity were the primary drivers of these cost changes (see Appendix VI for details).

- The average implied marginal heat rates fell from 2016 to 2017 in almost every region.
  - The primary driver were lower load levels (especially during the summer months) and higher hydro and nuclear generation.
  - The average implied marginal heat rates fell the most in the West Zone because of noticeably lower congestion in 2017 in this region.
  - 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

Fossil fuel price fluctuations, especially those of gas prices, have been the primary drivers of changes in wholesale power prices over the past several years.[222] This is because fuel costs accounted for the majority of the marginal production costs of fossil fuel generators.

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 which, at most times of the year, means they default to burning natural gas. Situations do arise, however, where some generators may burn oil even when it is more expensive.[223] Since most large steam units can burn either residual fuel oil (No.6) or natural gas, the effects of natural gas price spikes on power prices during periods of high volatility 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 small 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, particularly during peak winter conditions. This in turn can produce comparable differences in energy prices when network congestion occurs. The natural gas price

222 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.

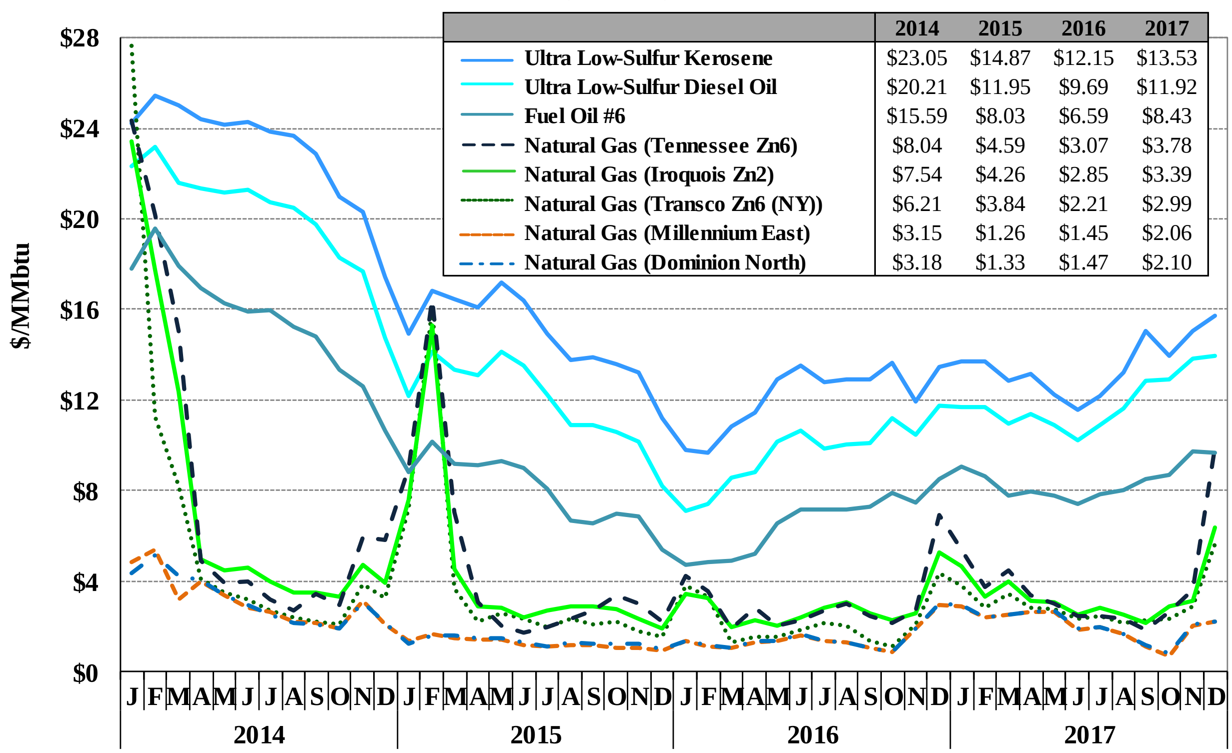
223 For instance, if natural gas is difficult to obtain on short notice, or if there is uncertainty about its availability. In addition, New York City and Long Island reliability rules sometimes require that certain units burn oil to limit the exposure of the electrical grid to possible disruptions in the supply of natural gas.

differences generally emerge by pipeline and by 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 natural gas and fuel oil prices by month from 2014 to 2017. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices [224]
2014 – 2017



	2014	2015	2016	2017
Ultra Low-Sulfur Kerosene	$23.05	$14.87	$12.15	$13.53
Ultra Low-Sulfur Diesel Oil	$20.21	$11.95	$9.69	$11.92
Fuel Oil #6	$15.59	$8.03	$6.59	$8.43
Natural Gas (Tennessee Zn6)	$8.04	$4.59	$3.07	$3.78
Natural Gas (Iroquois Zn2)	$7.54	$4.26	$2.85	$3.39
Natural Gas (Transco Zn6 (NY))	$6.21	$3.84	$2.21	$2.99
Natural Gas (Millennium East)	$3.15	$1.26	$1.45	$2.06
Natural Gas (Dominion North)	$3.18	$1.33	$1.47	$2.10

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2017 as well as for NYCA as a whole. [225] The table in the chart shows annual average generation by fuel type from 2015 to 2017.

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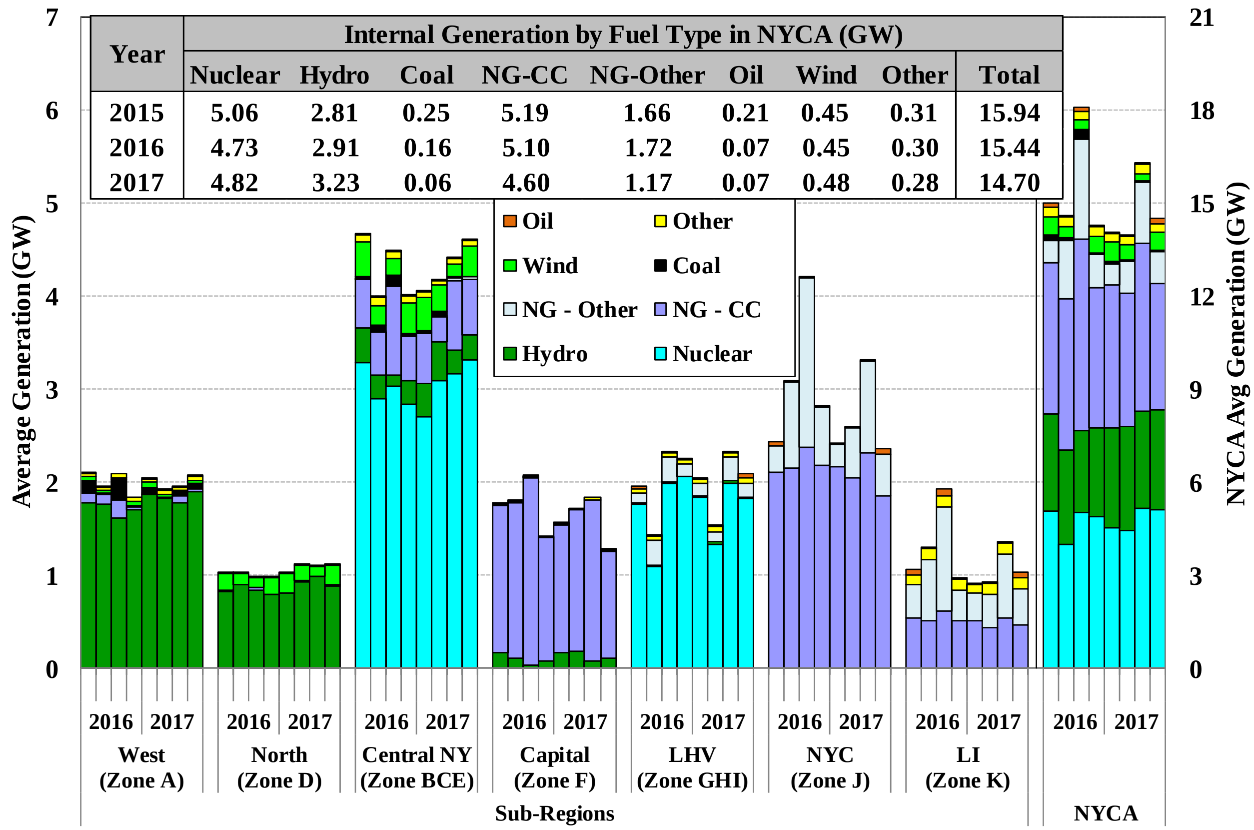
224 These are index prices that do not include transportation charges or applicable local taxes.

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 2017. 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 that 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").

Figure A-7: Generation by Fuel Type in New York

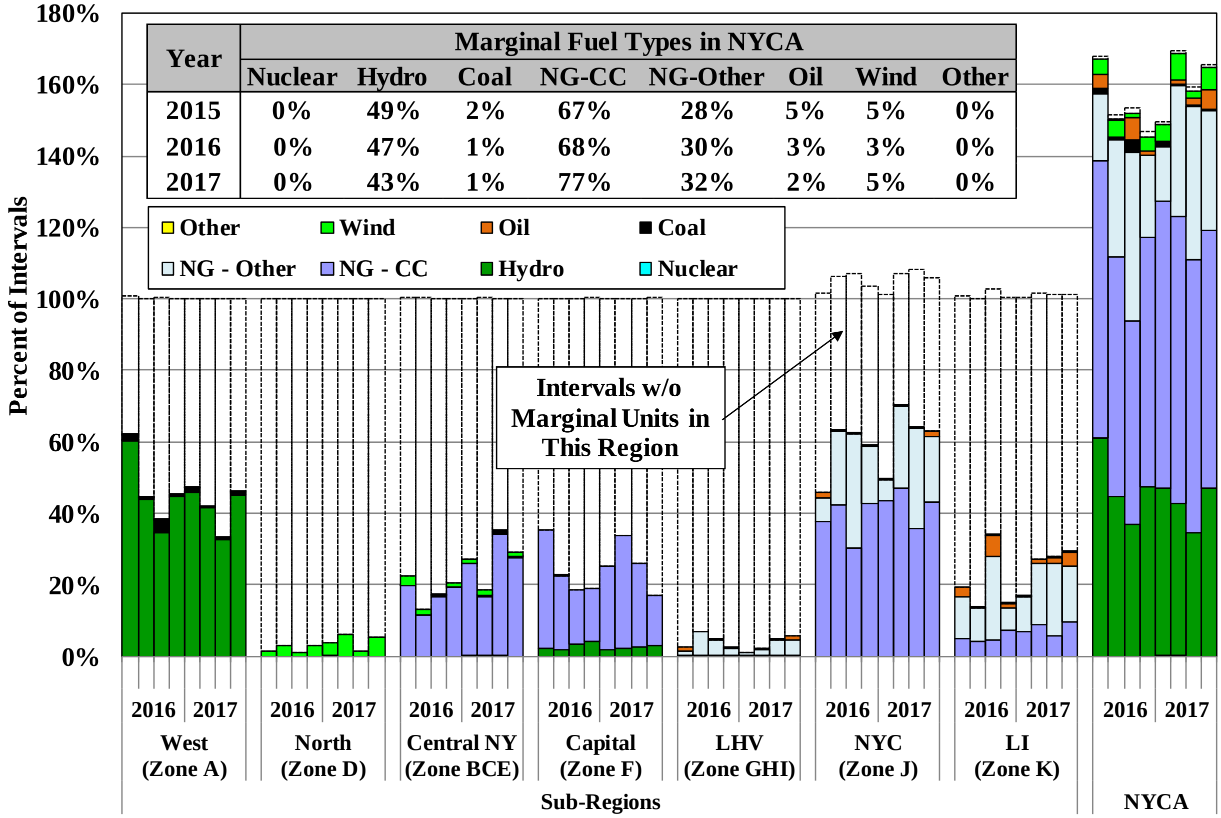
By Quarter by Region, 2017



Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2015	5.06	2.81	0.25	5.19	1.66	0.21	0.45	0.31	15.94
2016	4.73	2.91	0.16	5.10	1.72	0.07	0.45	0.30	15.44
2017	4.82	3.23	0.06	4.60	1.17	0.07	0.48	0.28	14.70

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

Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2017



Key Observations: Fuel Prices and Generation by Fuel Type

- Natural gas prices, which have a strong 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.
- Average natural gas prices rose by 19 to 43 percent across the system from 2016 to 2017, and there was a general reduction in gas pipeline congestion over the same period, leading to smaller gas price spreads between regions.
  - The Millennium East index exhibited an average discount of 39 percent relative to the Iroquois Zone 2 index in 2017, down from an average discount of 49 percent in 2016.
  - The Transco Zone 6 NY index exhibited an average discount of 12 percent relative to the Iroquois Zone 2 index in 2017, down from an average discount of 24 percent in 2016. Compared to 2016, this led generators in New York City to become less economic (relative to other generation in the rest of Eastern New York) in 2017.
- Natural gas prices and gas spreads between regions (e.g., between Western and Eastern New York) exhibited a typical seasonal pattern.

    - Regional spreads rose in the winter months due to higher gas demand. The magnitude of this winter premium was more pronounced than what occurred in 2016 due to colder winter conditions at the end of 2017.

- Gas-fired (39 percent), nuclear (33 percent), and hydro (22 percent) generation accounted for 94 percent of all internal generation in New York during 2017.
    - Average nuclear generation rose 90 MW from 2016, reflecting fewer maintenance and refueling outages at multiple units across the year.
    - Coal-fired generation continued to fall in 2017, reflecting that:
        - Lower LBMPs in the West Zone made it less economic; and
        - The Milliken units (previously often DARUed and OOMed) were no longer needed for local reliability because of transmission upgrades in the Central Zone.
    - Gas-fired production fell from 2016 levels, especially from steam units in the summer in New York City and in Long Island, reflecting lower loads and higher gas prices.
    - Average oil-fired generation was comparable between 2016 and 2017.
        - Lower oil-fired production in the third quarter, driven by reduced reliability requirement associated with lower load levels, was offset by higher oil-fired production in December during cold weather.
    - Average hydro generation rose 330 MW from 2016, reflecting:
        - Higher water availability across the system due to wetter weather; and
        - Less frequent West Zone congestion.
- Gas-fired and hydro resources continued to be marginal the vast majority of time in 2017.
    - 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 prices 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;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;

- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and

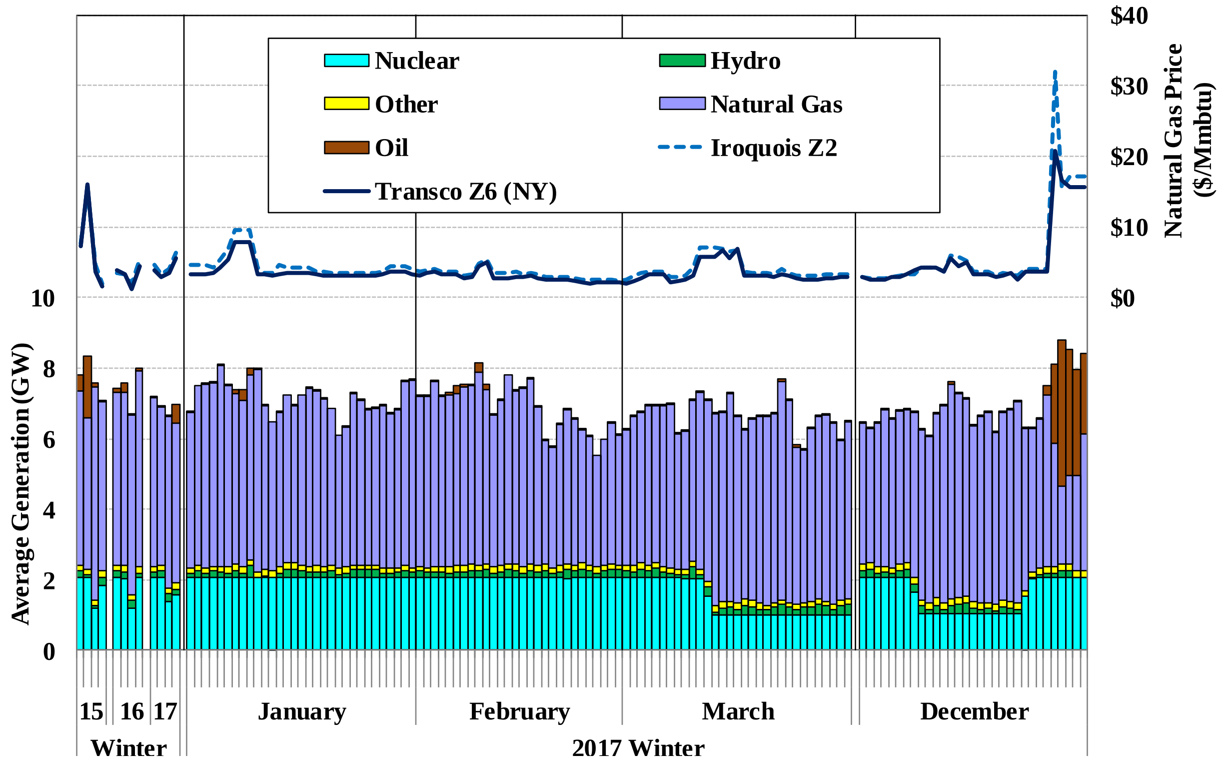
- NOx emissions limitations.

This sub-section examines actual fuel usage in the winter of 2017, focusing on days when supply of natural gas was very tight.[226] 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 fuel consumed in Eastern New York on a daily basis during the winter months of 2017 (including the months of January, February, March, and December). 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 for the same four-month period between 2015 and 2017. 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, Winter Months, 2017



226 This section deals strictly with winter conditions from the calendar year 2017. A significant cold spell gripped the state at the end of 2017, but the bulk of that impact occurred in January of 2018. Our First Quarter Report on the 2018 State of the Market will cover that period in further detail.

Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Oil-fired generation in Eastern New York totaled roughly 435 GWh in the four-month period (i.e., January to March, and December) of 2017, up modestly from the 355 GWh in the same period of 2016 but down notably from the nearly 1,600 GWh in 2015.
  - Gas supply constraints became severe during the last five-day period of 2017 because of a cold snap that extended well into January 2018.
  - During this period, gas prices exceeded $15/MMBtu each day and were over $30/MMBtu on one day on the Iroquois Zone 2 pipeline.
    - This five-day period accounted for nearly 85 percent of all oil-fired generation in the four-month period of 2017.
- The large difference in the amount of oil use over the past few years illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.

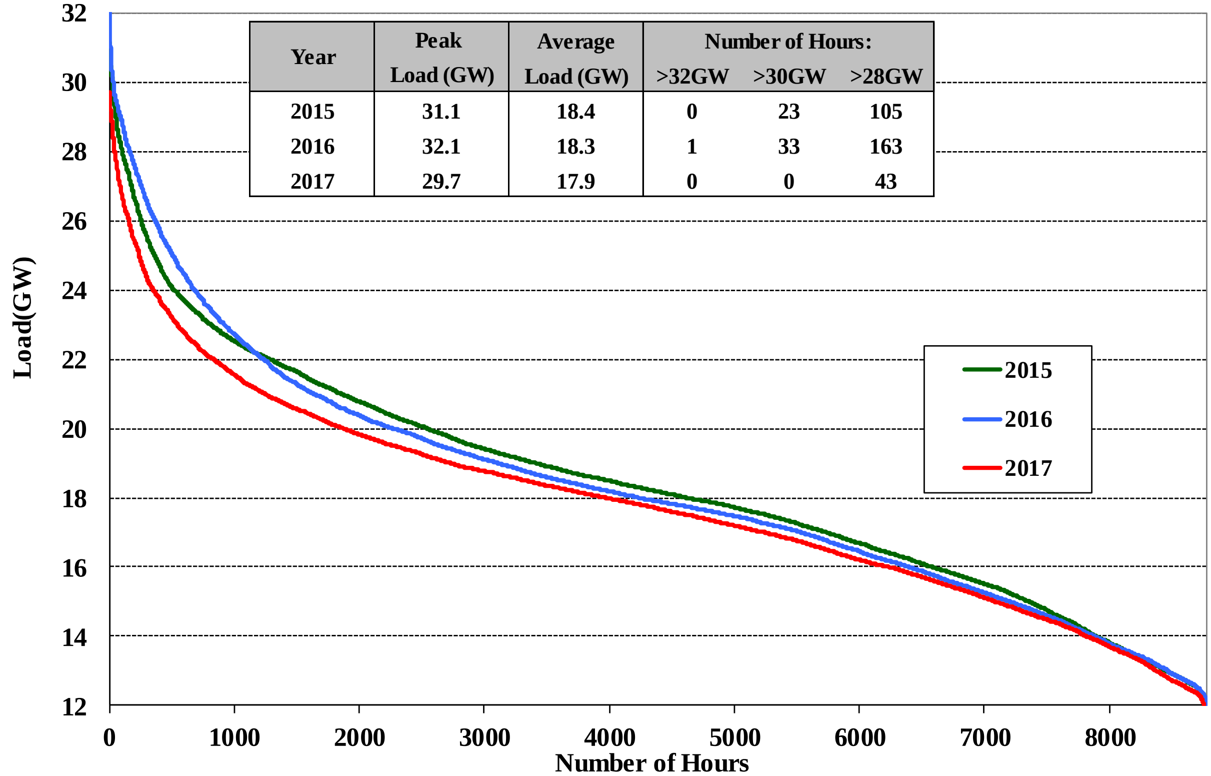
D. Load Levels

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. Since changes in the quantity of supply from year-to-year are usually small, 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 both the market costs to consumers and the revenues to generators occur during these hours.

The load duration curves in Figure A-10 illustrate the variation in demand during each of the last three years. 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 along with the number of hours in each year when the system was under high load conditions (i.e., when load exceeded 28, 30, and 32 GW).

Figure A-10: Load Duration Curves for New York State
2015 – 2017



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

- The year of 2017 was characterized by low load levels.
  - Average load fell 2 percent from 2016 to the lowest level in the past decade.
  - Annual peak load fell markedly (by 7 percent) from 2016 due primarily to very mild weather conditions in the summer of 2017.

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.

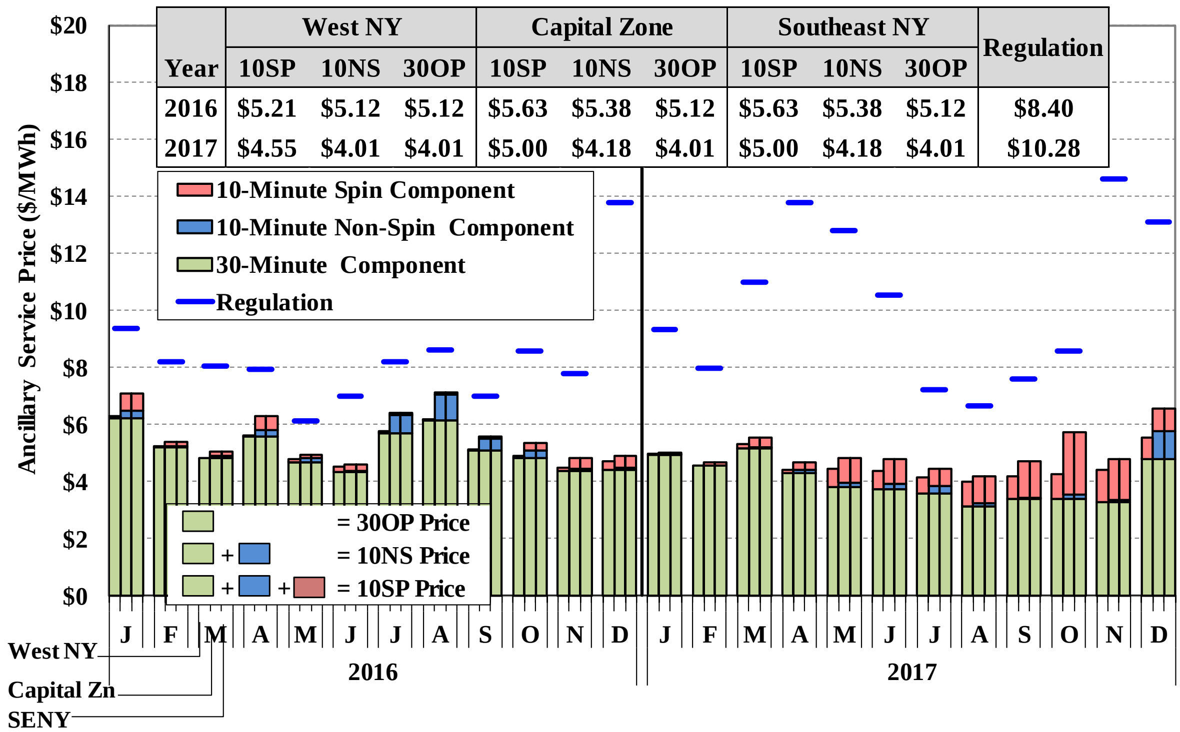
The NYISO has four ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation. In addition, the NYISO has locational reserve requirements that result in differences between Western, Eastern, and Southeast New York reserve prices. Figure A-11 shows the average day-ahead prices for these four ancillary services products in each month of 2016 and 2017. 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 2016 and 2017 on an annual basis.

Figure A-11: Day-Ahead Ancillary Services Prices
2016- 2017



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
2016	$5.21	$5.12	$5.12	$5.63	$5.38	$5.12	$5.63	$5.38	$5.12	$8.40
2017	$4.55	$4.01	$4.01	$5.00	$4.18	$4.01	$5.00	$4.18	$4.01	$10.28

<u>Key Observations: Day-ahead Ancillary Service Prices</u>

- The average day-ahead prices for all reserve products fell in 2017 despite the increase in energy prices in most areas.
  - Reserve prices fell largely because 30-minute reserve prices were reduced. This was primarily attributable to a reduction in day-ahead operating reserve offer prices. (see Section II.D of the Appendix).
- However, the average regulation price and the 10-minute spin component of reserve price (i.e., the shadow price of the 10-minute spinning reserve requirement) rose from 2016.
  - Lower load levels in 2017 were the primary driver, since lower load levels led to the commitment of less generating capacity, which thereby reduced the available supply of regulation and 10-minute spinning reserve offers.

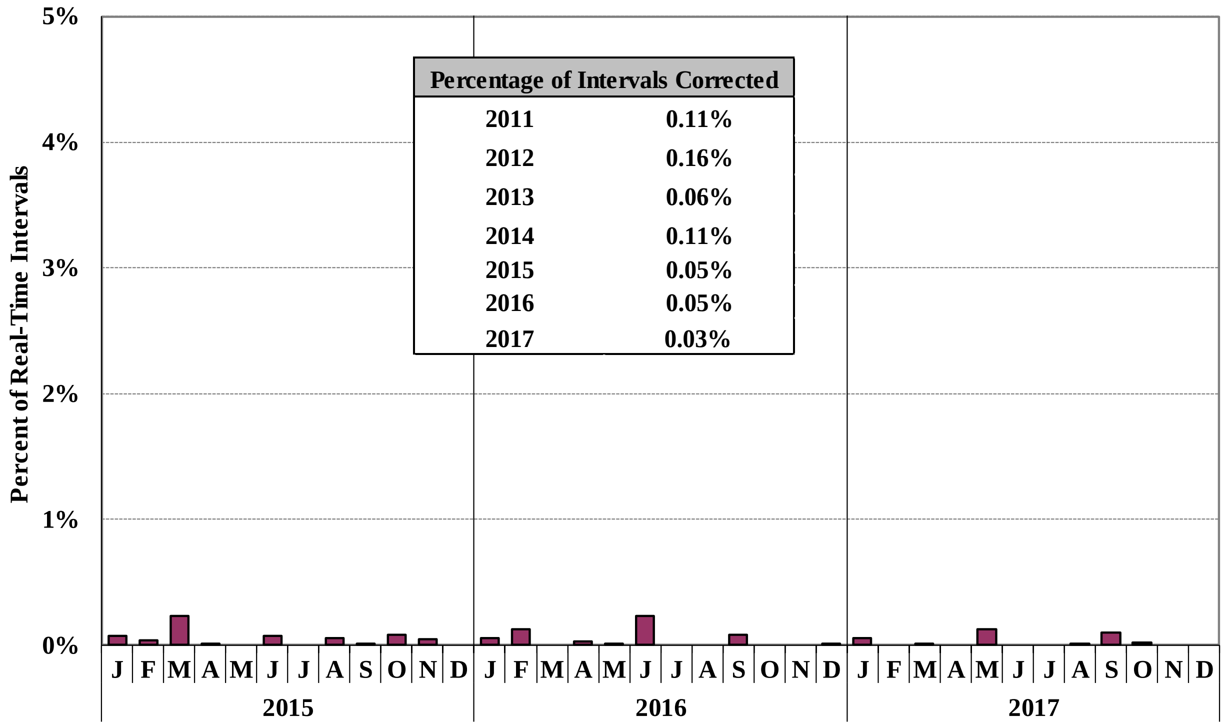
F. Price Corrections

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 2015 to 2017. 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
2015-2017



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. Similarly, 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.

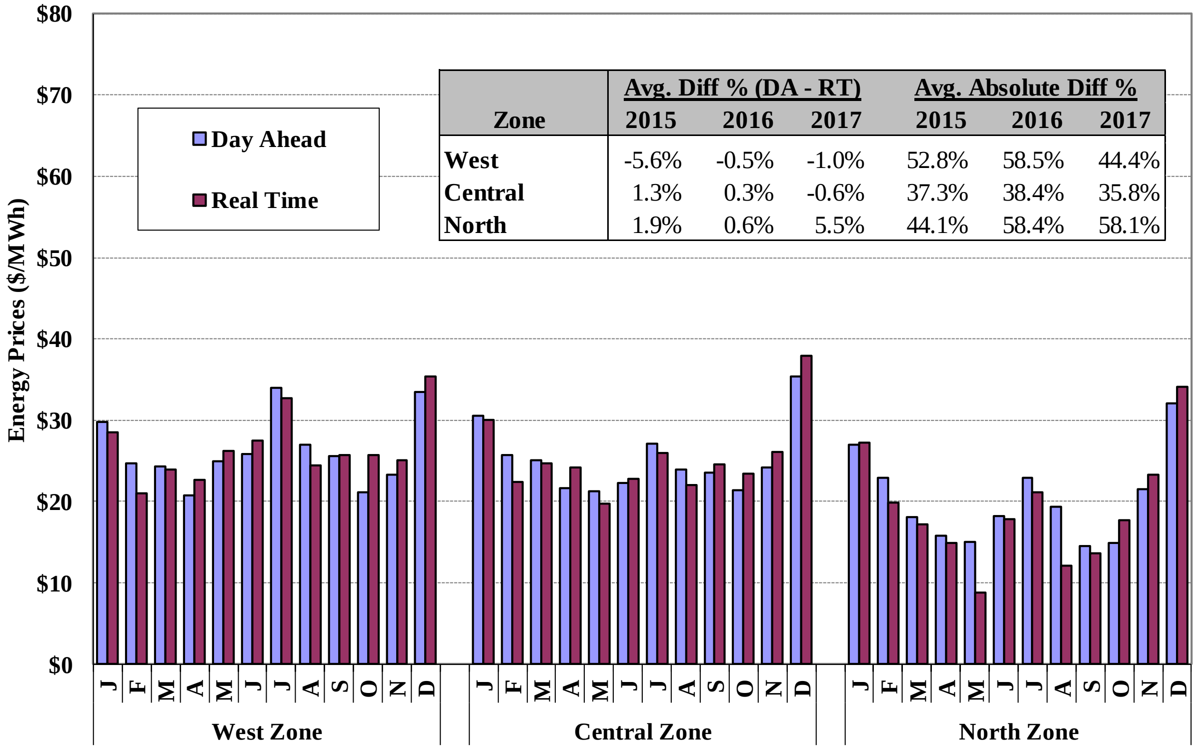
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the 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.

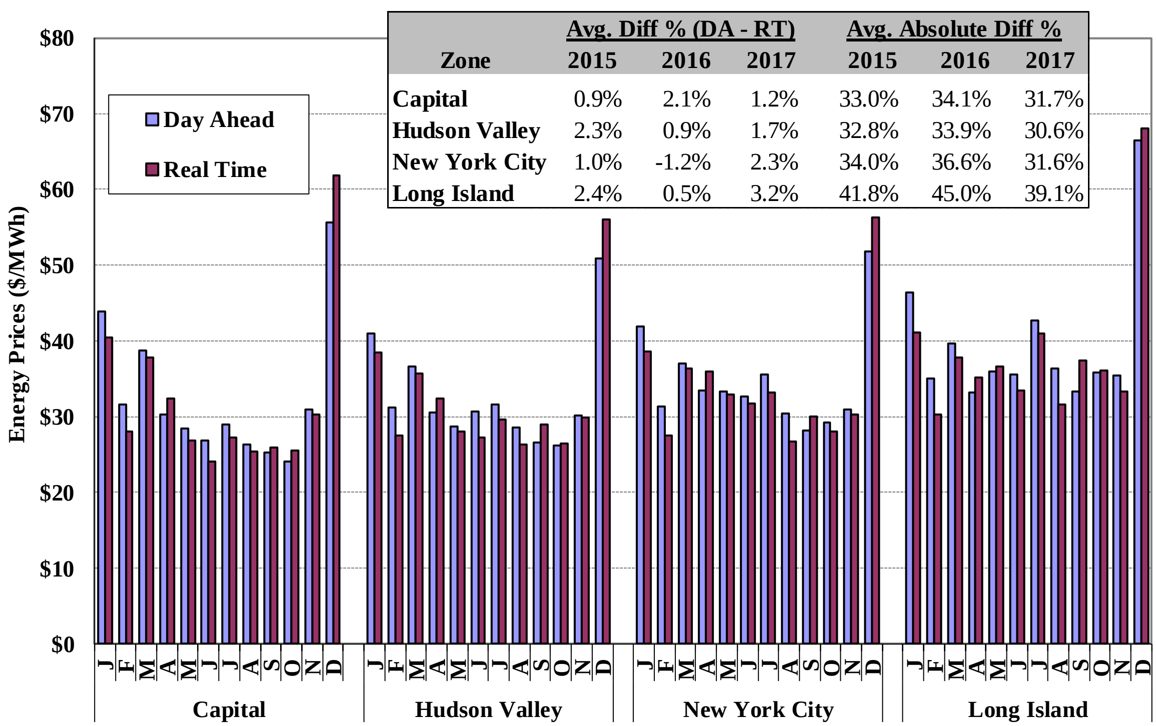
Figure A-13 and Figure A-14 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead 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 2017. 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 – 2017



Zone	Avg. Diff % (DA - RT) 2015	2016	2017	Avg. Absolute Diff % 2015	2016	2017
West	-5.6%	-0.5%	-1.0%	52.8%	58.5%	44.4%
Central	1.3%	0.3%	-0.6%	37.3%	38.4%	35.8%
North	1.9%	0.6%	5.5%	44.1%	58.4%	58.1%

Figure A-14: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2017



Zone	Avg. Diff % (DA - RT) 2015	2016	2017	Avg. Absolute Diff % 2015	2016	2017
Capital	0.9%	2.1%	1.2%	33.0%	34.1%	31.7%
Hudson Valley	2.3%	0.9%	1.7%	32.8%	33.9%	30.6%
New York City	1.0%	-1.2%	2.3%	34.0%	36.6%	31.6%
Long Island	2.4%	0.5%	3.2%	41.8%	45.0%	39.1%

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 zonal level.

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

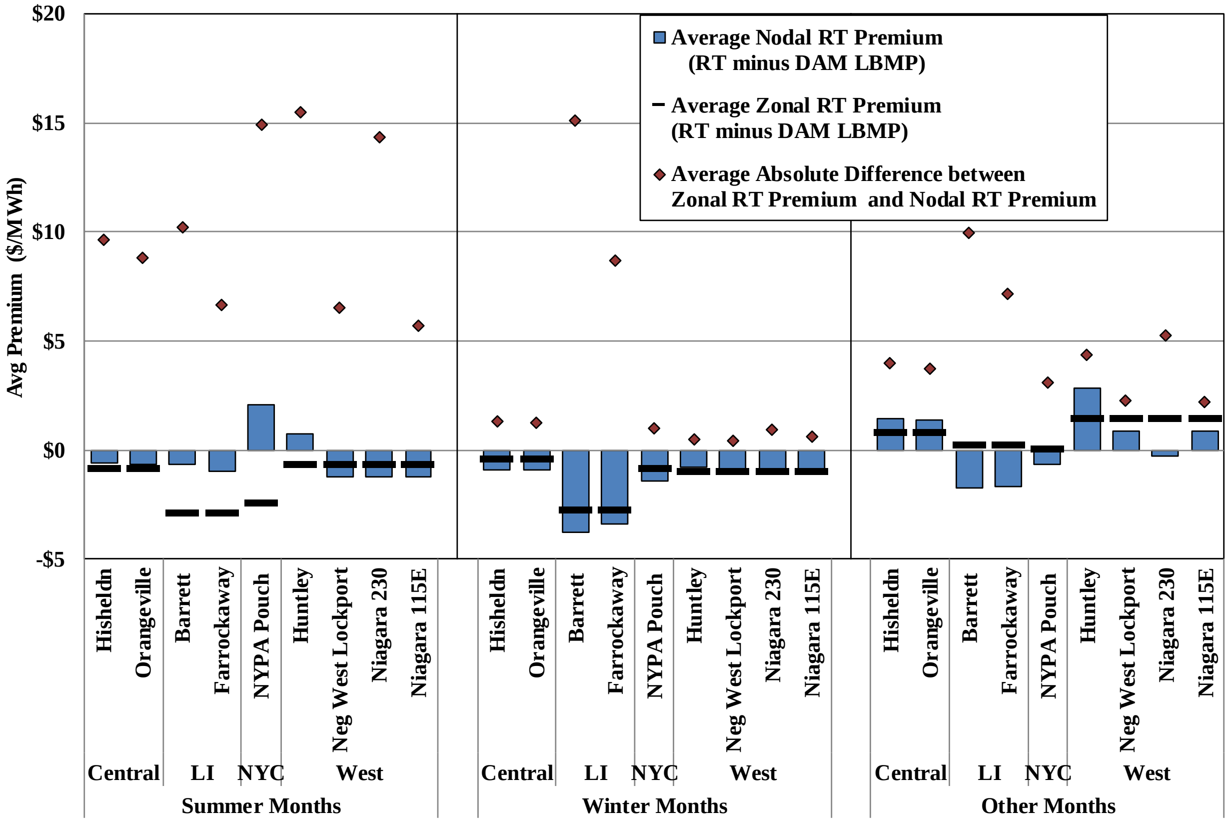
- Generators may change their offers after the day-ahead market. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead.
- Generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows.
- Constraint limits used to manage congestion may change from the day-ahead market to the real-time market.
- Transmission constraints that are sensitive to the level of demand may become more or less acute after the day-ahead market due to differences between expected load and actual load.
- Transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit either virtual trades or price sensitive load bids at the load pocket level or a more disaggregated level. Thus, 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 2017 for selected locations in New York City, Long Island, and Upstate New York.[227] 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. Due to seasonal variations in congestion patterns, these are shown separately for the summer months (June to August), the winter months (December, January, and February), and other months.

227 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 Hisheldn 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.

Figure A-15: Average Real-Time Price Premium at Select Nodes
2017



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

- Average day-ahead prices were generally within 1 to 3 percent of average real-time prices in most areas in 2017.
    - The North Zone was an exception that exhibited an annual day-ahead premium of over 5 percent, attributable to high day-ahead premiums in May and August when real-time congestion was frequent partly because of transmission outages.
    - 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 average absolute difference between hourly day-ahead and real-time prices, improved for all regions in 2017, reflecting lower price volatility generally associated with lower load levels.
    - Congestion greatly reduced in the West Zone and Long Island for the reasons discussed in Section III of the Appendix, contributing to lower price volatility as well.

- The modification of the GTDC in June 2017 resulted in lower congestion costs on most transmission constraints during transmission shortages, which led to lower price volatility in affected areas. (see Section III of the Appendix)

- At the nodal level, although a few locations still exhibited less consistency between average day-ahead and real-time prices, their differences became smaller in 2017.
  - Real-time price volatility in the Valley Stream load pocket (represented by the Barrett and Farrockaway locations) of Long Island decreased following improvements to the modeling of the 901 & 903 lines (which connect western Long Island to the 138kV network in New York City) in April 2016. (For a description of the improvements, see Appendix Section V.D of our 2016 SOM Report.)

H. Day-Ahead Reserve Market Performance

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. 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.

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 directly participate 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

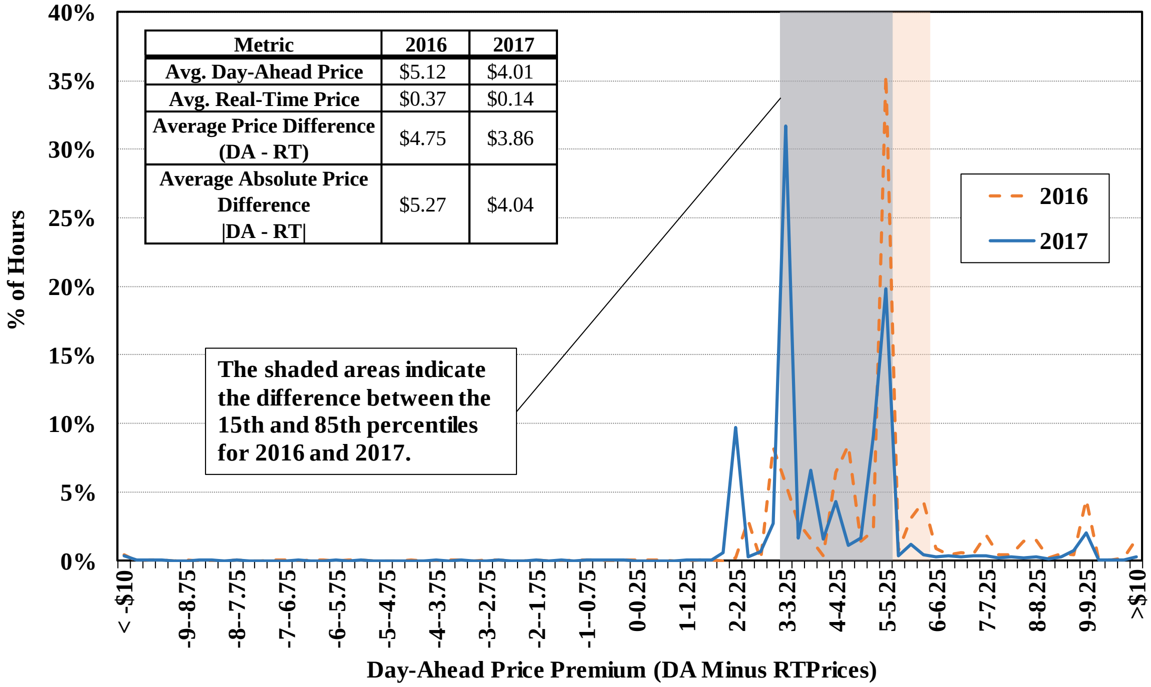
To evaluate the performance of the day-ahead ancillary service markets, the following four figures show distributions of day-ahead premiums (i.e., day-ahead prices minus real-time prices) in: (a) Western 30-minute reserve prices; (b) Western 10-minute spinning reserve prices; (c) Eastern 10-minute spinning 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 $3/MWh to $3.25/MWh during roughly 30 percent of the hours in 2017.

The figures compare the distributions between 2016 and 2017. The distributions between the 15th percentile and the 85th percentile are also highlighted in shaded areas (light orange for 2016 and light blue for 2017). The inset tables summarize the following annual averages in 2016 and

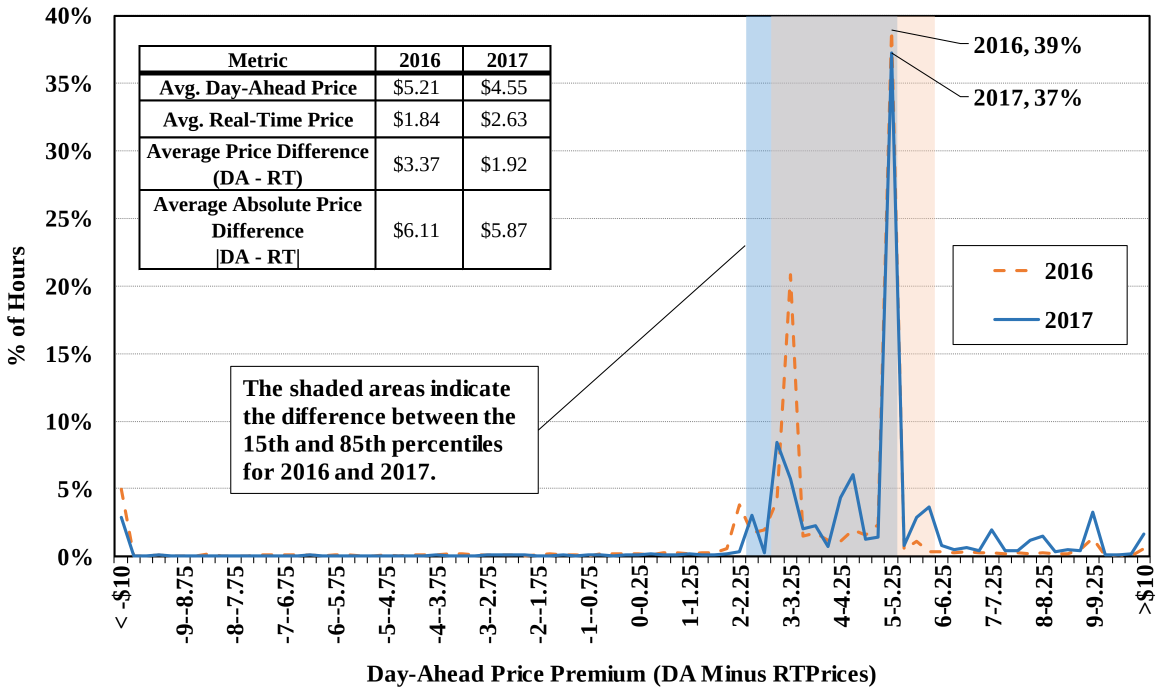
2017: (a) the average day-ahead price; (b) the average real-time price; (c) the difference between the average day-ahead price and the real-time price; and (d) the average absolute difference between the day-ahead price and the real-time price.

Figure A-16: Day-Ahead Premiums for 30-Minute Reserves in West New York
2016 – 2017



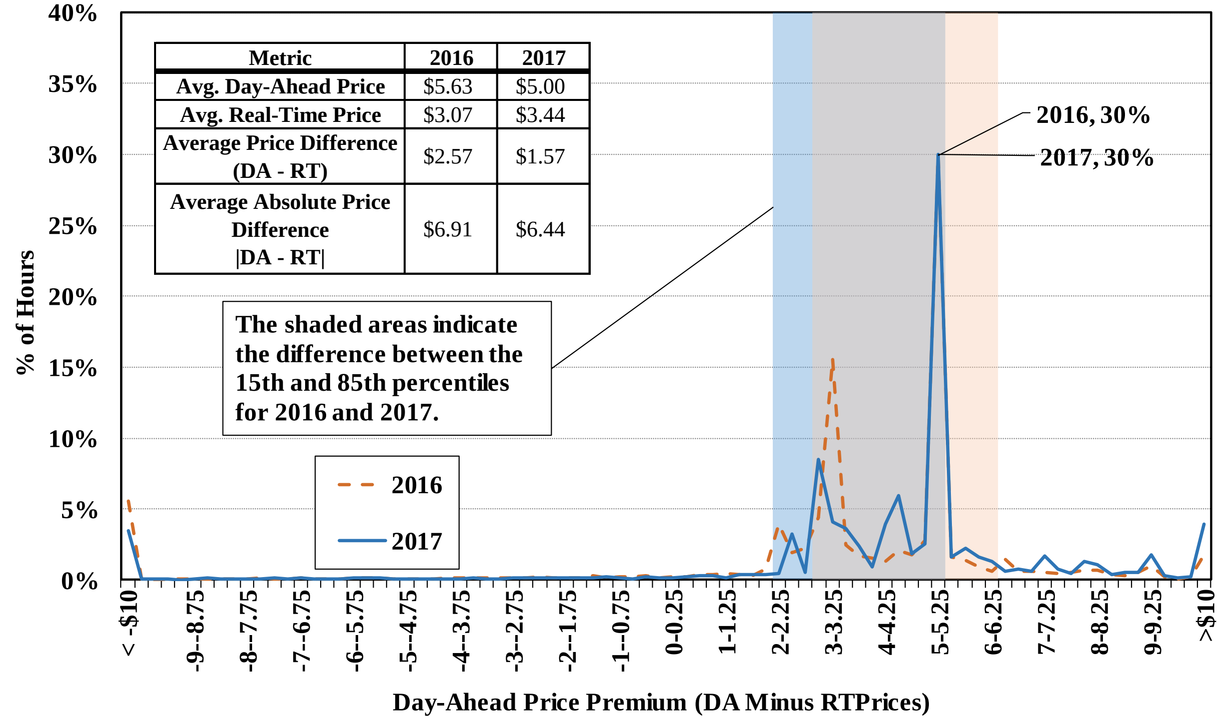
Metric	2016	2017
Avg. Day-Ahead Price	$5.12	$4.01
Avg. Real-Time Price	$0.37	$0.14
Average Price Difference (DA - RT)	$4.75	$3.86
Average Absolute Price Difference |DA - RT|	$5.27	$4.04

Figure A-17: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2016 - 2017



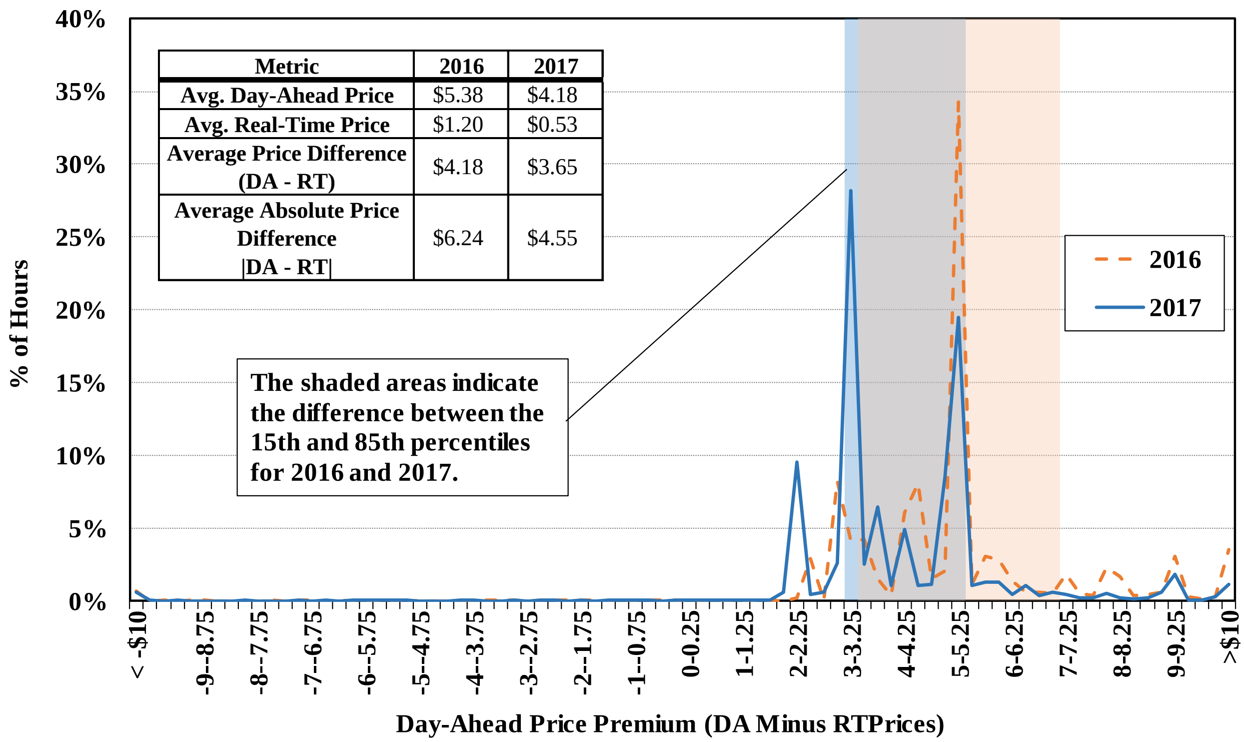
Metric	2016	2017
Avg. Day-Ahead Price	$5.21	$4.55
Avg. Real-Time Price	$1.84	$2.63
Average Price Difference (DA - RT)	$3.37	$1.92
Average Absolute Price Difference |DA - RT|	$6.11	$5.87

Figure A-18: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2016 – 2017



Metric	2016	2017
Avg. Day-Ahead Price	$5.63	$5.00
Avg. Real-Time Price	$3.07	$3.44
Average Price Difference (DA - RT)	$2.57	$1.57
Average Absolute Price Difference |DA - RT|	$6.91	$6.44

Figure A-19: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2016 – 2017



Metric	2016	2017
Avg. Day-Ahead Price	$5.38	$4.18
Avg. Real-Time Price	$1.20	$0.53
Average Price Difference (DA - RT)	$4.18	$3.65
Average Absolute Price Difference |DA - RT|	$6.24	$4.55

Key Observations: Day-Ahead Reserve Market Performance

- Unlike real-time reserve prices, which are only based on the opportunity cost of not serving energy (because units are deemed to have a $0 availability offer in real-time), day-ahead reserve prices also depend on supplier's availability offers, which reflect factors such as:
  - The expected differences between day-ahead and real-time prices,
  - The costs associated with ensuring sufficient fuel is available in case the unit is converted to energy, and
  - Financial risks associated with being deployed in real-time after selling reserves in the day-ahead.
- Although day-ahead price premiums are generally expected in a competitive market without virtual trading, the day-ahead price premiums have increased significantly since November 2015 when the Comprehensive Shortage Pricing project was implemented.
  - When the costs listed above are greater than $0 for a significant portion of suppliers submitting offers in the day-ahead market, it leads to day-ahead prices being higher on average than real-time prices.
  - Nonetheless, day-ahead prices fell for all reserve products from 2016 to 2017 largely because of lower NYCA 30-minute reserve prices resulted partly from lower offer prices from some capacity (see Section II.D of the Appendix for more discussions).
  - This contributed to improved convergence between day-ahead and real-time reserve prices in 2017 (i.e., the average absolute difference is smaller).
- Average real-time prices fell from 2016 to 2017 for non-spinning reserve products but rose for spinning reserve products.
  - Lower load levels were the primary driver, which led to ample offline reserves but reduced surplus capacity from online resources because of fewer units were committed.

I. Regulation Market Performance

Figure A-20 – Regulation Prices and Expenses

Figure A-20 shows the regulation prices and expenses in each month of 2016 and 2017. 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:

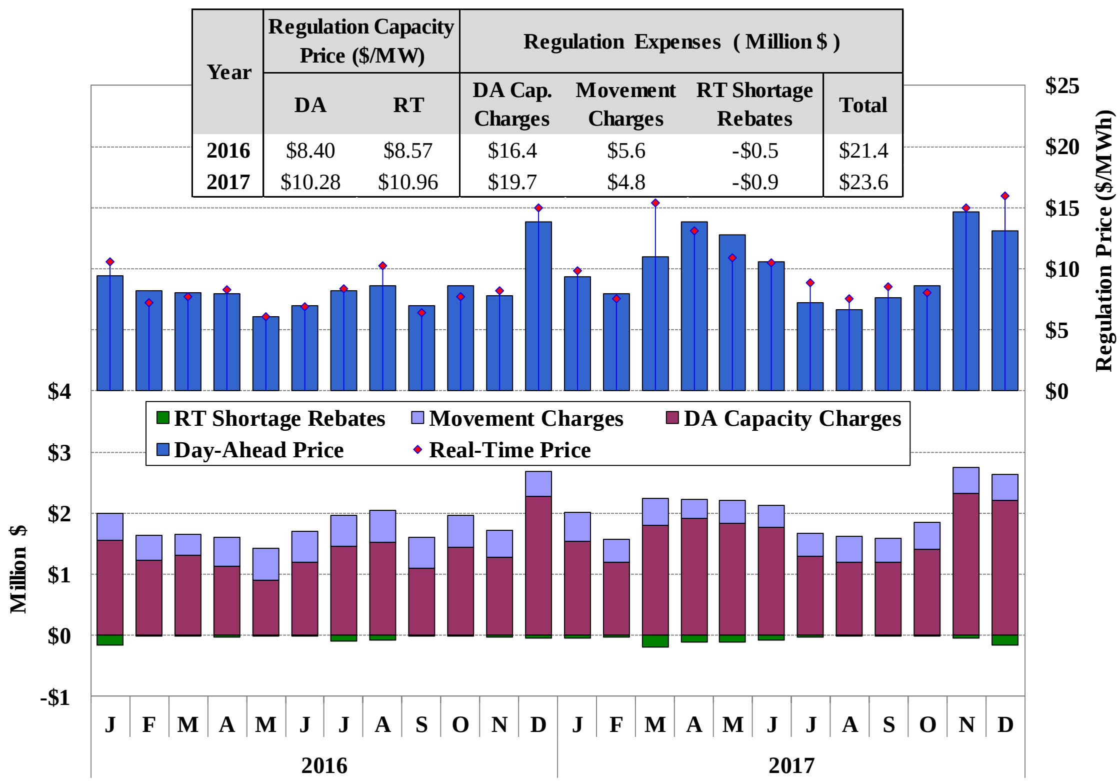
- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.

- Real-Time Shortage Rebate – This arises when a regulation shortage occurs in the real-time market and regulation suppliers have to 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, 2016-2017



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2016	$8.40	$8.57	$16.4	$5.6	-$0.5	$21.4
2017	$10.28	$10.96	$19.7	$4.8	-$0.9	$23.6

Key Observations: Regulation Market Performance

- Monthly average day-ahead regulation capacity prices were generally consistent with real-time prices in 2017.

- Regulation expenses increased modestly from 2016 to 2017 as a result of higher regulation capacity prices.
  - Less generation capacity was committed because of lower load levels in 2017, resulting in lower regulation supply from online resources.

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., providing an exceedingly long start-up notification 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 estimates of their marginal costs when their uncapped offers both substantially exceed their estimated marginal cost and would have a material 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 for a particular ancillary service product by allowing the market to flexibly shift resources between products, thereby increasing the competition to provide each product. Ancillary services offer patterns are evaluated in Section D.

In addition to screening the conduct of suppliers, it is important to evaluate how the behavior of buyers influences energy prices. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load. The consistency of day-ahead load scheduling with actual load is evaluated in Section E.

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. When virtual trading is profitable, it generally promotes convergence between day-ahead and real-time prices and tends to improve the efficiency of resource commitment and scheduling. The efficiency of virtual trading is evaluated in Section F.

A. Potential Physical Withholding

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 either 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 days or fewer. The remaining deratings are shown as *Long-Term Deratings.* [228]

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

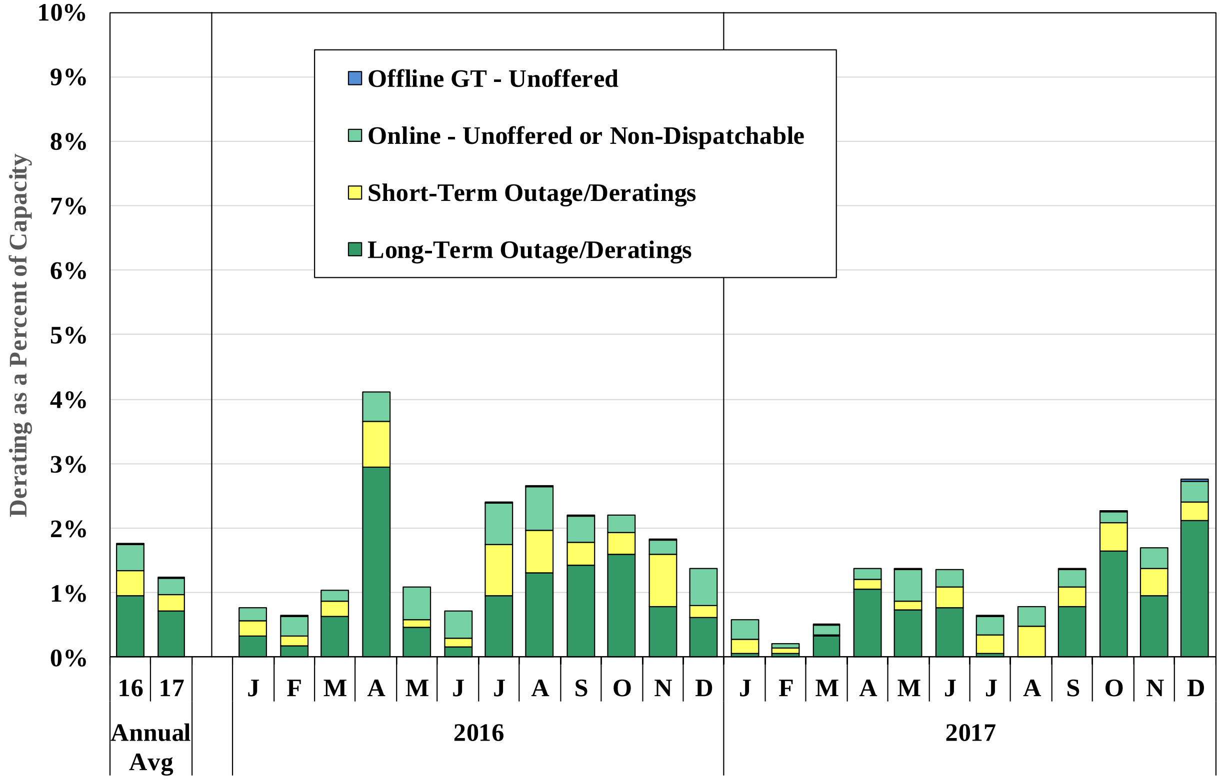
228 For our analyses of physical and economic withholding, we exclude unoffered capacity from hydro, solar, wind, landfill-gas and biomass generators as well as nuclear units on planned maintenance outages.

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.[229] 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.[230] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[231]

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

Figure A-21 and Figure A-22 show the broad patterns of deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2016 and 2017.

Figure A-21: Unoffered Economic Capacity by Month in NYCA
2016 – 2017



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

230 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.

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

Figure A-22: Unoffered Economic Capacity by Month in East New York
2016 - 2017

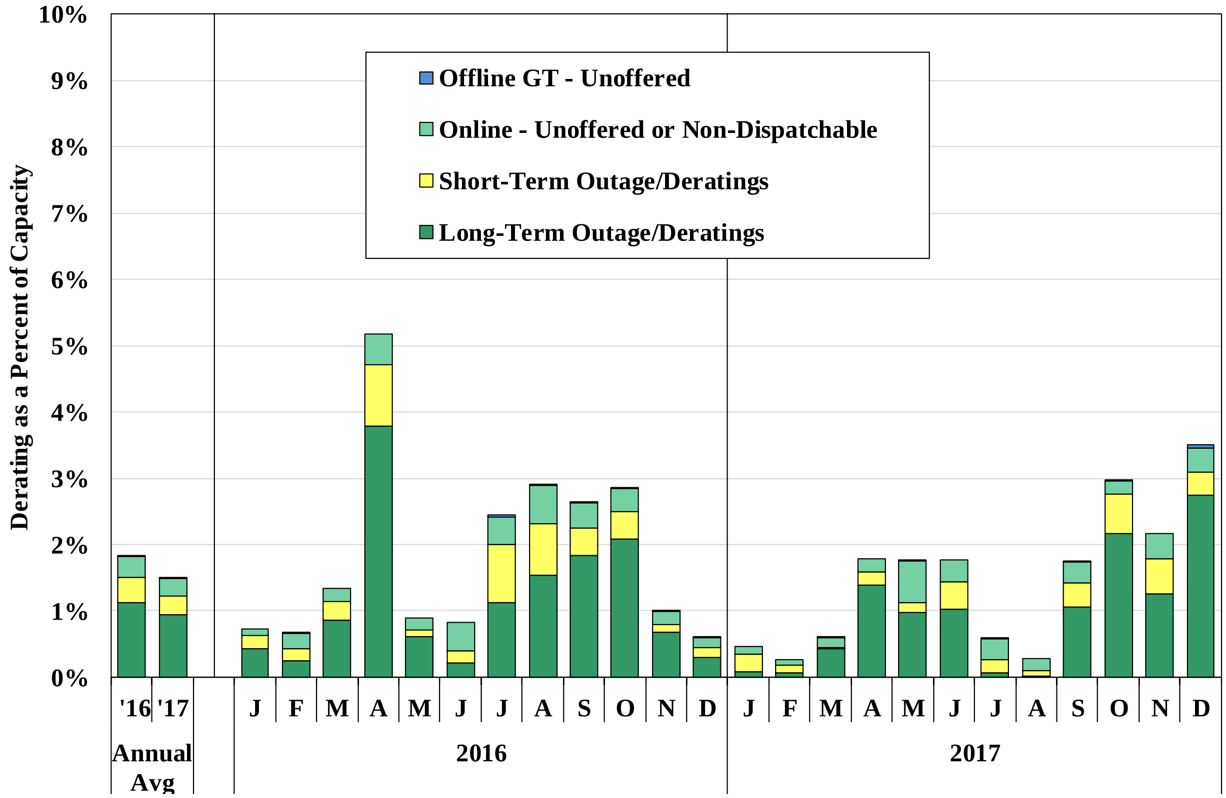


*Figure A-23 & Figure A-**24**: Unoffered Economic Capacity by Load Level & Portfolio Size*

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 both the ability and the 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.

As noted previously, 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
2016 – 2017

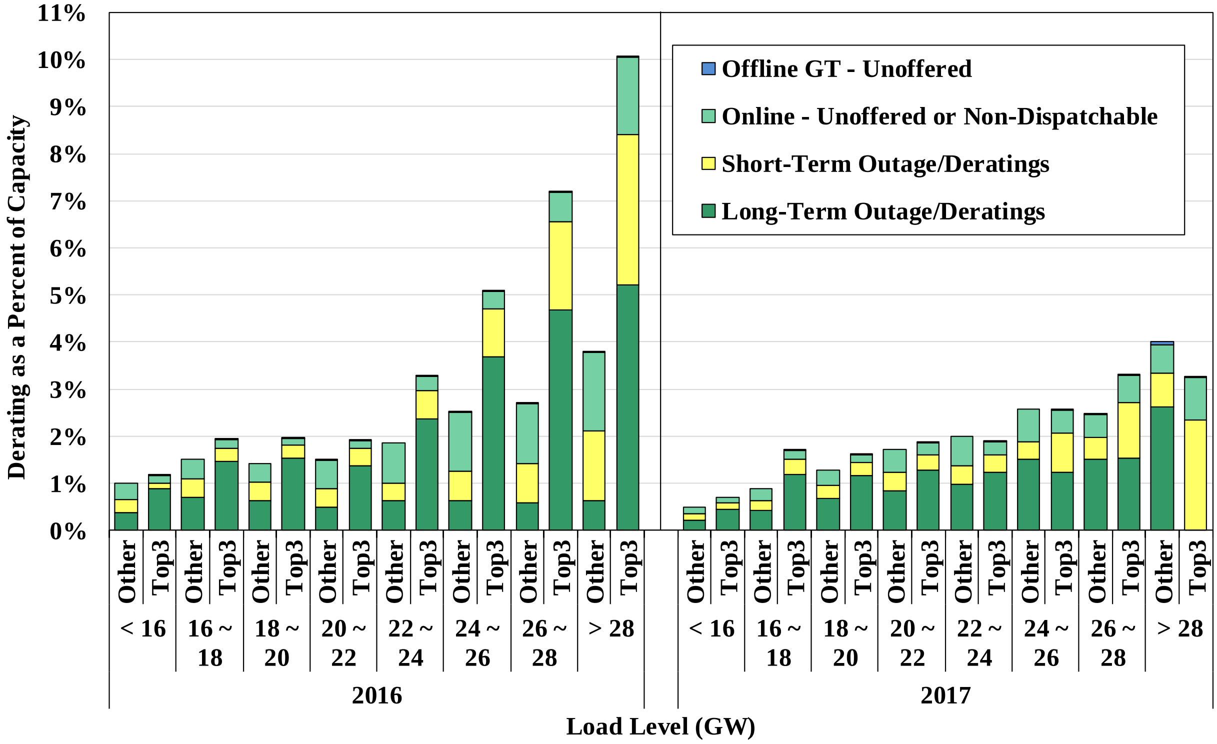
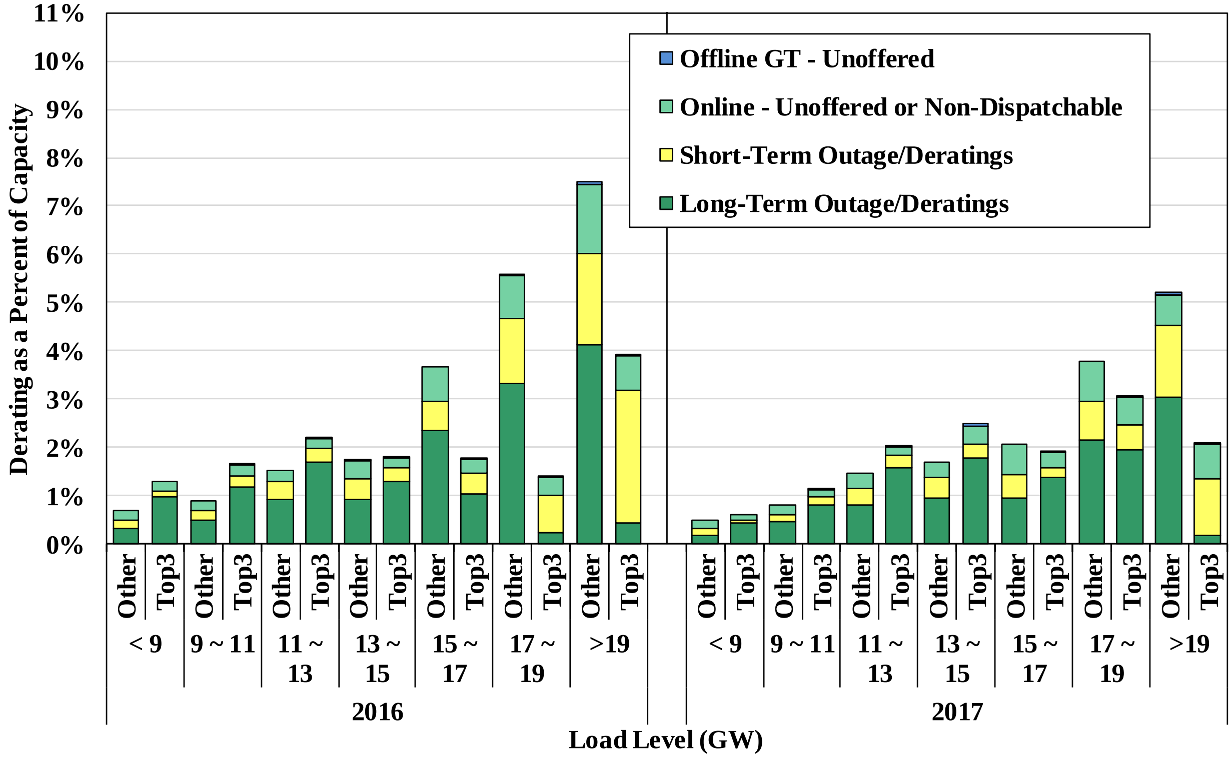


Figure A-24: Unoffered Economic Capacity by Supplier by Load Level in East New York
2016 – 2017



Key Observations: Unoffered Economic Capacity

- The general pattern of deratings was reasonably consistent with expectations for a competitive market in 2017.
  - Derated and unoffered economic capacity averaged 1.3 percent of total DMNC in NYCA, and 1.5 percent in Eastern New York in 2017, which was modestly lower than 2016 levels.[232]
  - Derated and unoffered economic capacity was mostly attributable to long-term maintenance deratings (making up 57 percent of the total derated and unoffered economic capacity in NYCA and 63 percent in Eastern New York in 2017).
    - Most of this economic capacity on long-term maintenance was scheduled during shoulder months as would be expected.
    - The largest three suppliers in Eastern New York contributed very little to the total long-term outages during the highest load hours.

232 The numbers reported here for 2016 are lower than the ones in our prior reports because we have refined our methodology to calculate economic capacity and attribute it to different categories.

- Economic capacity on outage/deratings was lower in the summer of 2017 than in the previous summer largely because of fewer outages and deratings this summer.
  - A large unit in SENY was forced out-of-service during most of last summer, contributing to higher economic capacity on long-term outages in 2016.
  - Short-term deratings and outages were less frequent this summer partly because fewer hot days required less operation of older less-reliable units.
- 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.

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.[233, 234] An offer parameter is

233 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.

234 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.

generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-25 to Figure A-28: Output Gap by Month, Supplier Size, and Load Level

One useful metric for identifying potential economic withholding is the "output gap." The output gap is the amount of generation that is otherwise economic at the market clearing price but for owner's elevated offer.[235] 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 we 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 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.

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.

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

Figure A-25: Output Gap by Month in New York State
2016 – 2017

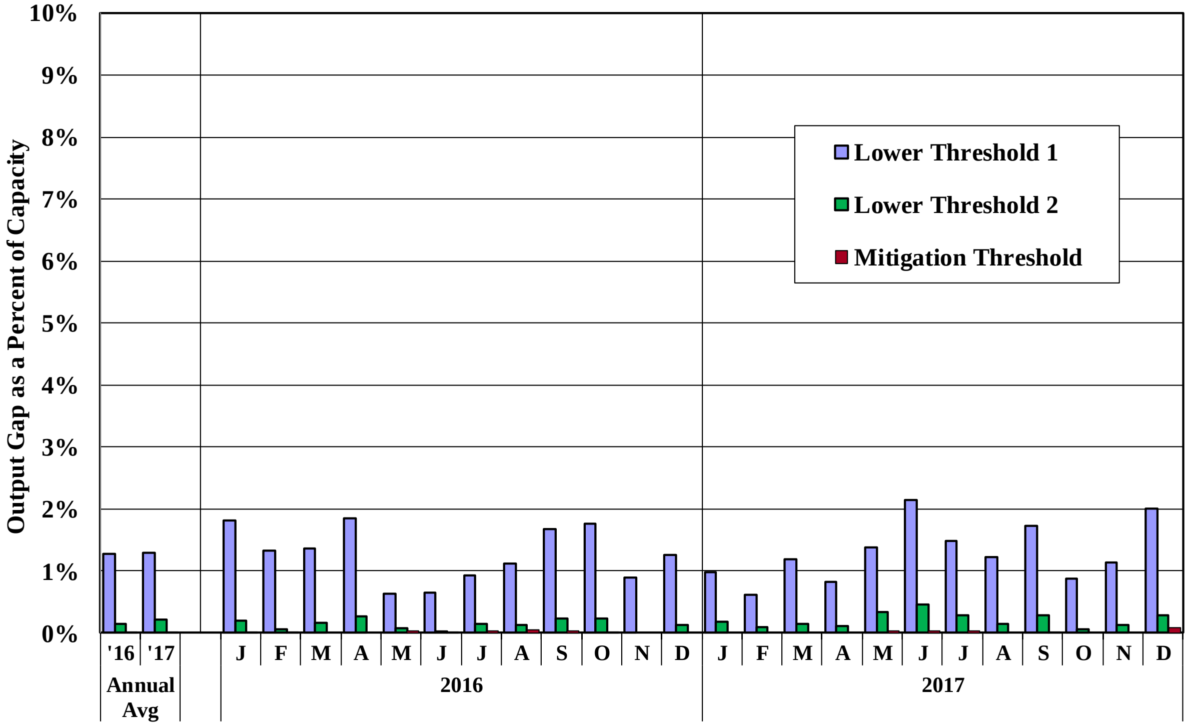


Figure A-26: Output Gap by Month in East New York
2016 - 2017

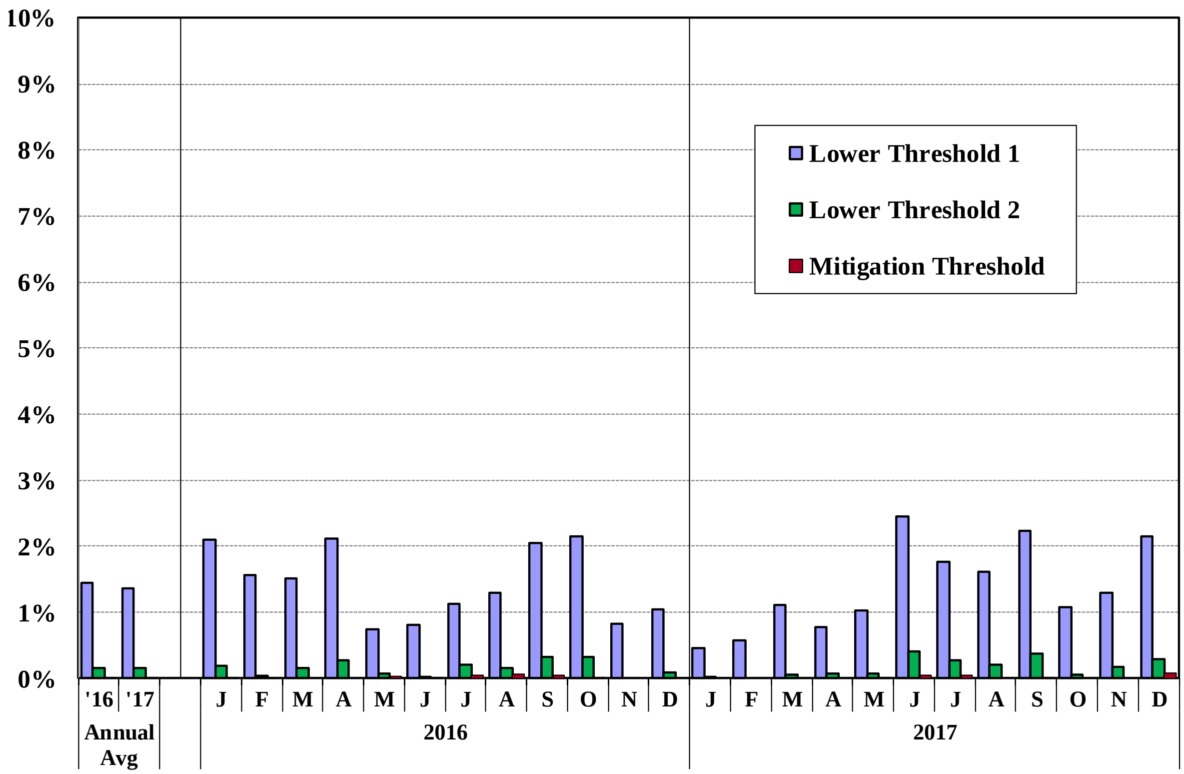


Figure A-27: Output Gap by Supplier by Load Level in New York State
2017

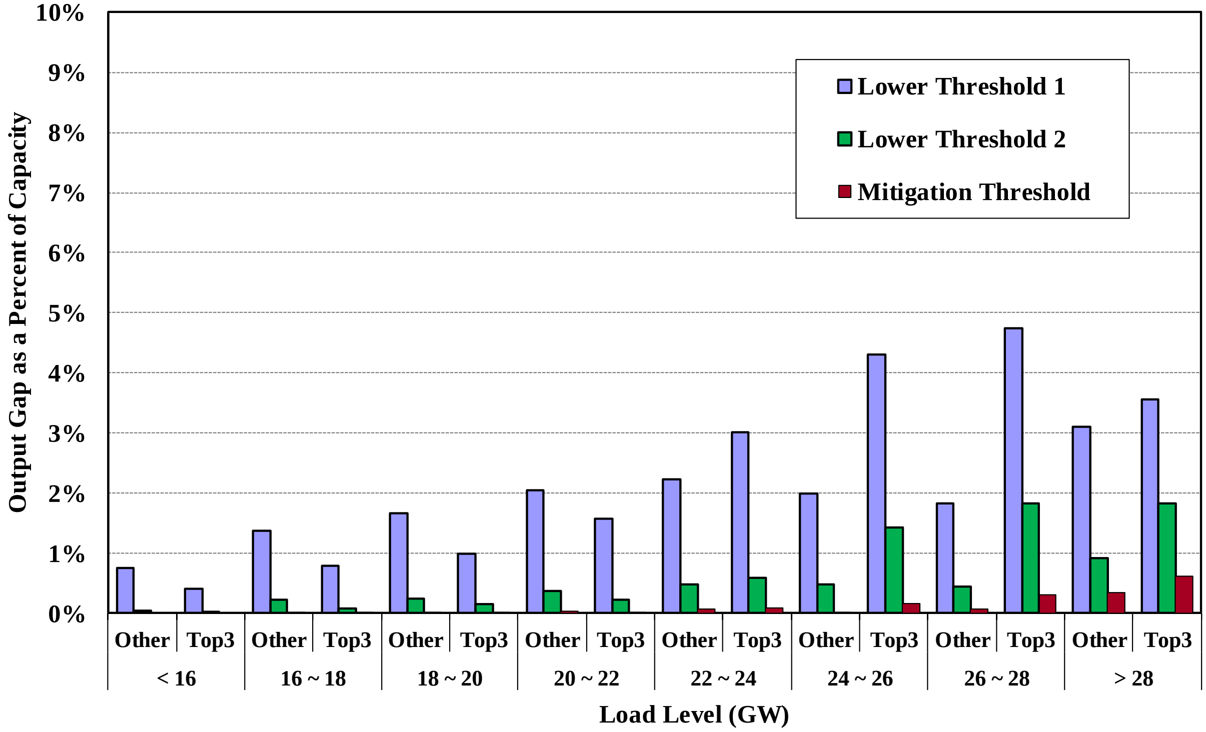
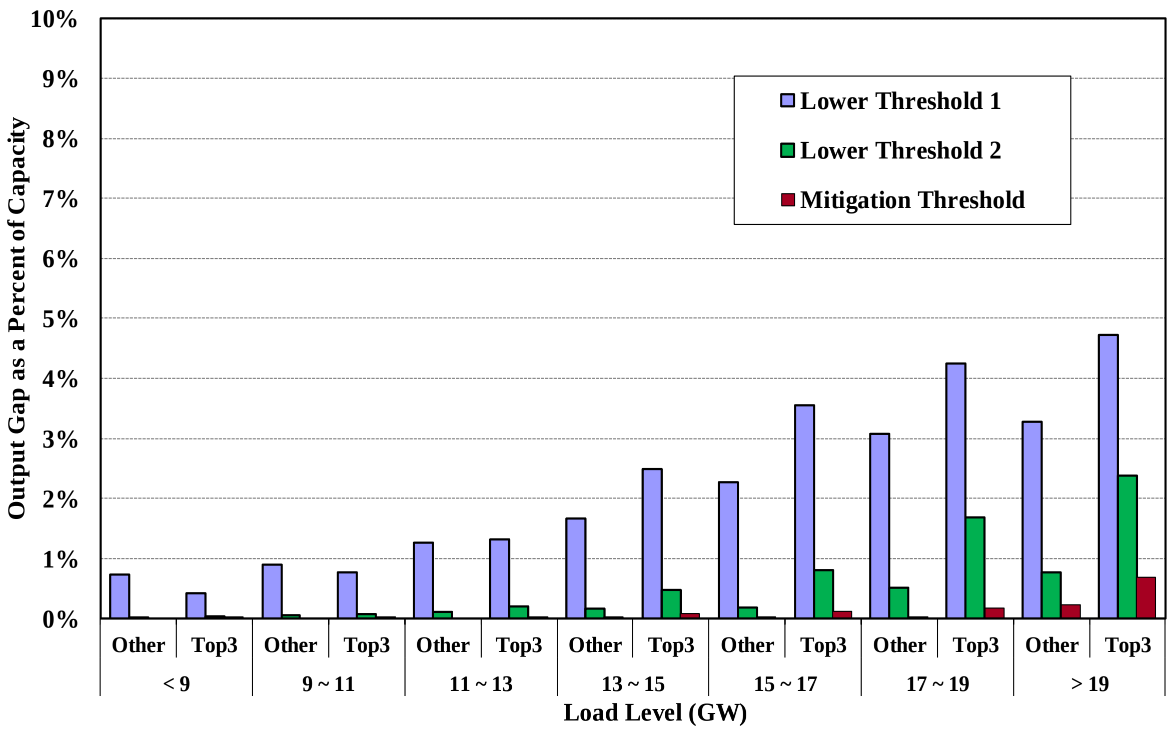


Figure A-28: Output Gap by Supplier by Load Level in East New York
2017



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged less than 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 2017 for NYCA.
- Output Gap rose modestly as load rose. This was primarily due to the following factors:
  - The Output Gap Calculation takes market prices as fixed. However, committing an additional 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 2017 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.[236] 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

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

determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[237] 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.[238] 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.[239]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[240] 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.[241]
- 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

237 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.

238 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.

239 See NYISO Market Services Tariff, Section 23.3.1.2.3.

240 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.

241 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.

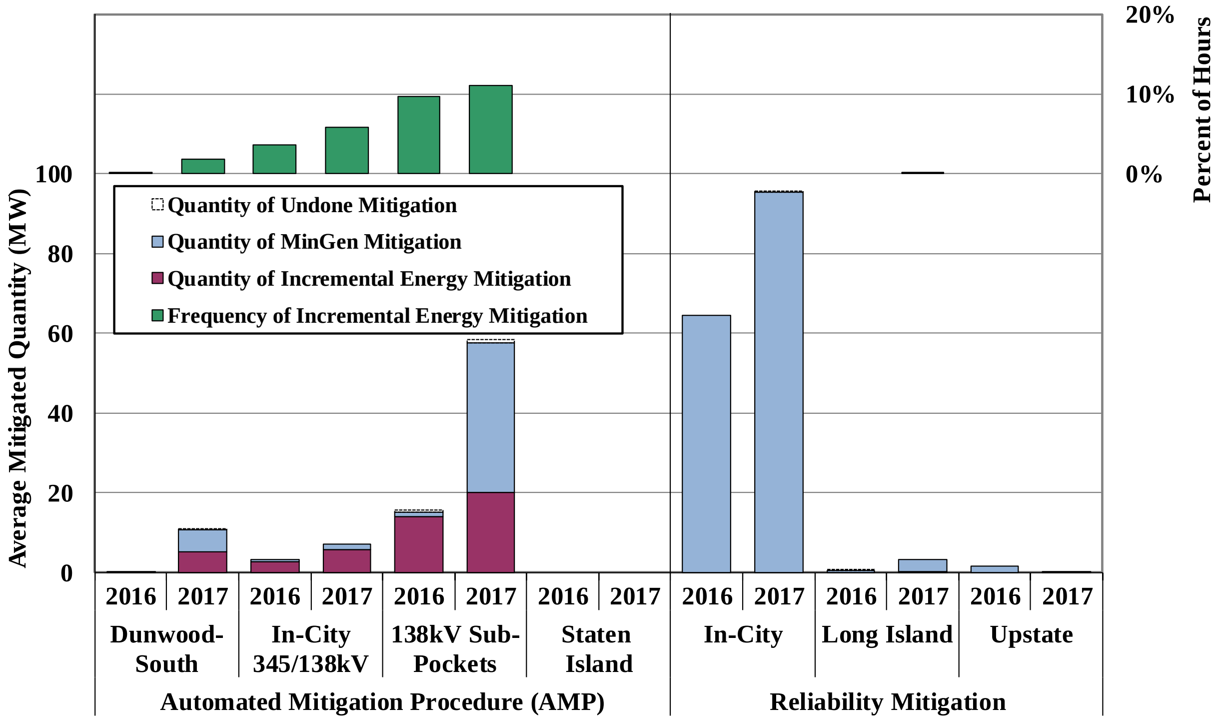
generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

Figure A-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 2016 and 2017. These figures do not include guarantee payment mitigation that occurs in the settlement system.

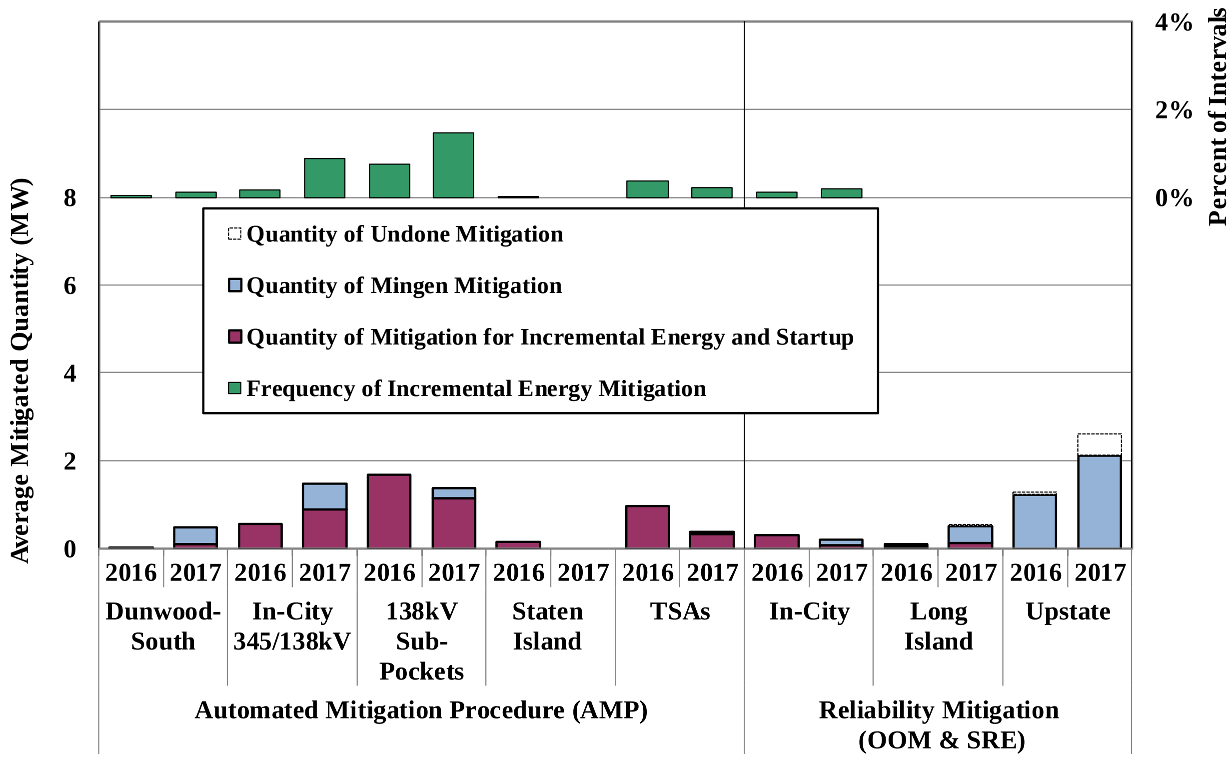
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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).[242] 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
2016 – 2017



242 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
2016 – 2017



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

- Most mitigation occurs in the day-ahead market, since this is where most supply is scheduled. Day-ahead mitigation rose noticeably from 2016.
  - Local reliability (i.e., DARU and LRR) mitigation (which accounted for 56 percent of day-ahead mitigation) rose because of more frequent DARU and LRR commitments in New York City (see Section V.H in the Appendix). These mitigations limited guarantee payment uplift but did not affect LBMPs.
  - AMP mitigation accounted for 44 percent of day-ahead mitigation, up from 2016.
    - Most of the increase occurred in the 138kV load pockets partly because more frequent congestion resulted in lower Load Pocket Thresholds and because AMP is designed to function only during periods of congestion in New York City.

D. Ancillary Services Offers in the Day-Ahead Market

Multiple factors, including opportunity costs, demand curves, and offers, determine the prices of ancillary services. The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. The 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 subsection focuses on examining ancillary services offer patterns in the day-ahead market. In an efficient market, we expect suppliers to respond to predictable differences between day-ahead and real-time prices by raising or lowering their offer prices in the day-ahead market. However, the high volatility of real-time clearing prices is difficult 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 scarcity revenues if they have already sold reserves in the day-ahead market. Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

Figure A-31 to Figure A-35: Summary of Day-ahead Ancillary Services Offers

The following five figures compare the ancillary services offers for generators in the day-ahead market for 2016 and 2017 on a monthly basis as well as on an annual basis.[243] The quantities offered are shown for the following categories:[244]

- 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,[245] and
- Regulation.

Offer quantities are shown according to offer price level for each category. This evaluation summarizes offers for the five ancillary services products from all hours and all resources.

243 These figures do not include several demand resources that are eligible for providing 10-minute spinning reserves and have a total capability of roughly 110 MW.

244 The quantity of 10-minute non-spinning reserve offers in Western New York is very small and is not reported here.

245 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, 2016-2017

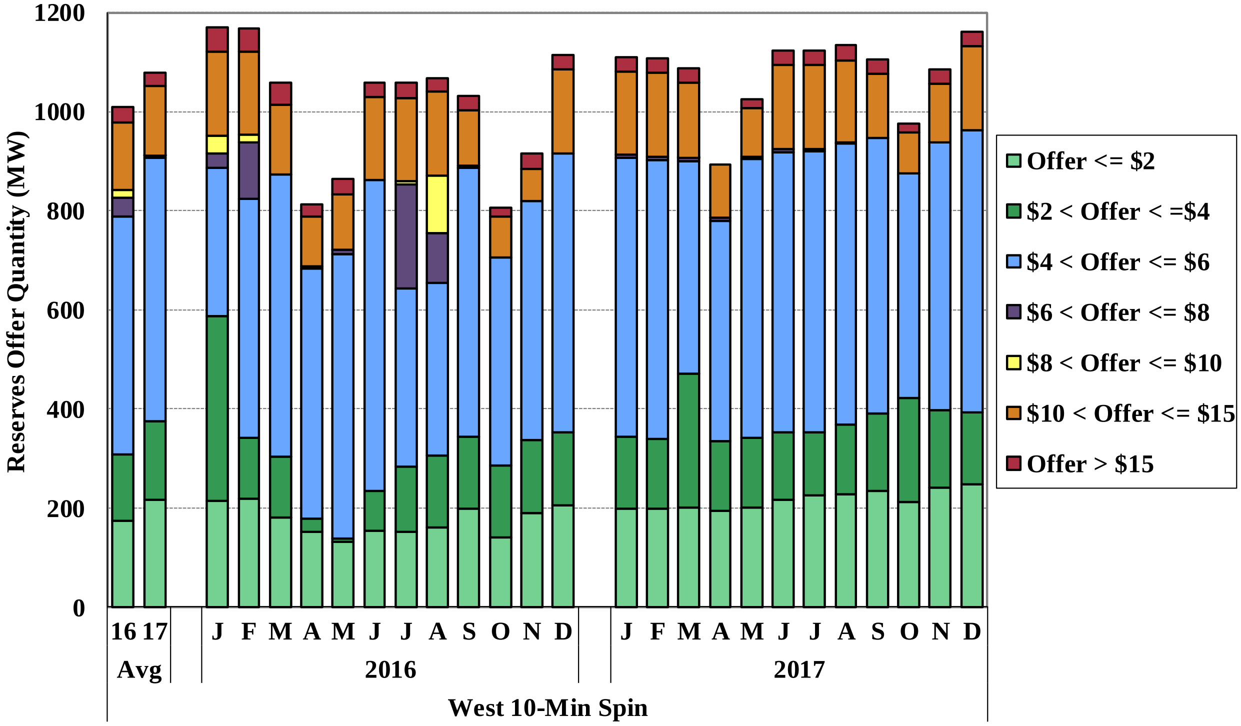


Figure A-32: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2016-2017

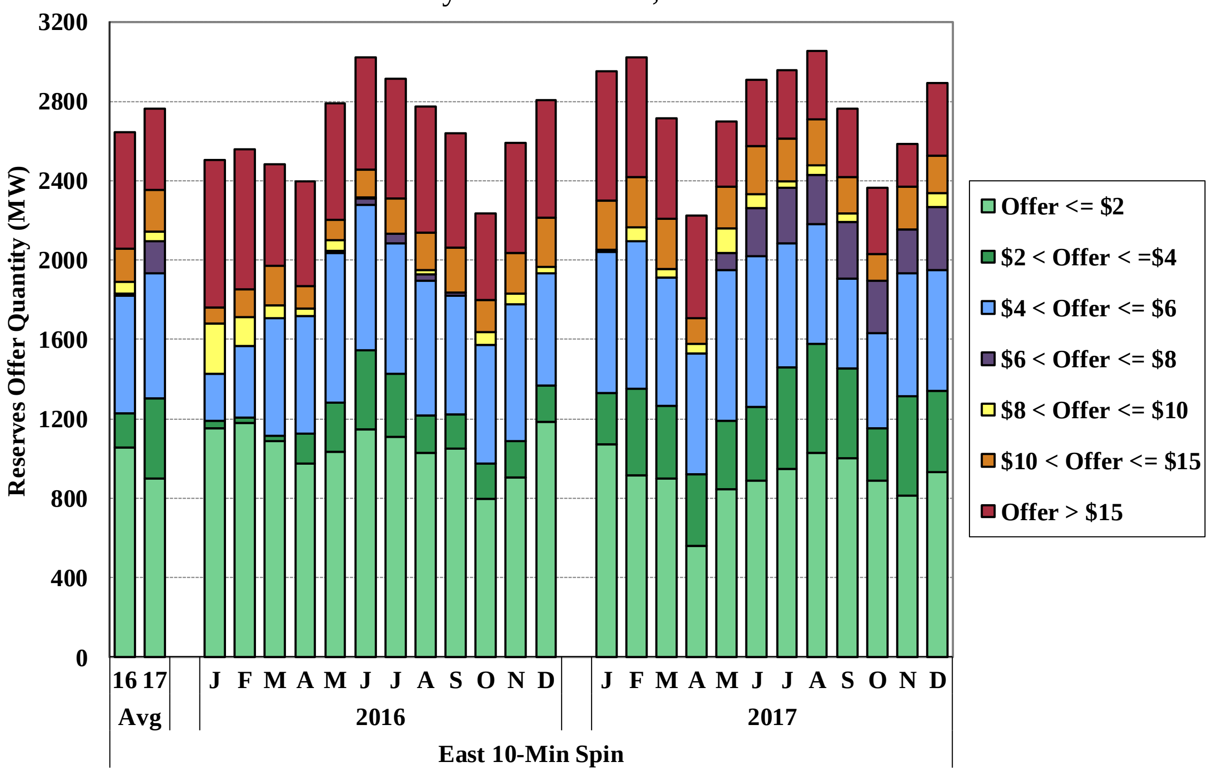


Figure A-33: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2016-2017

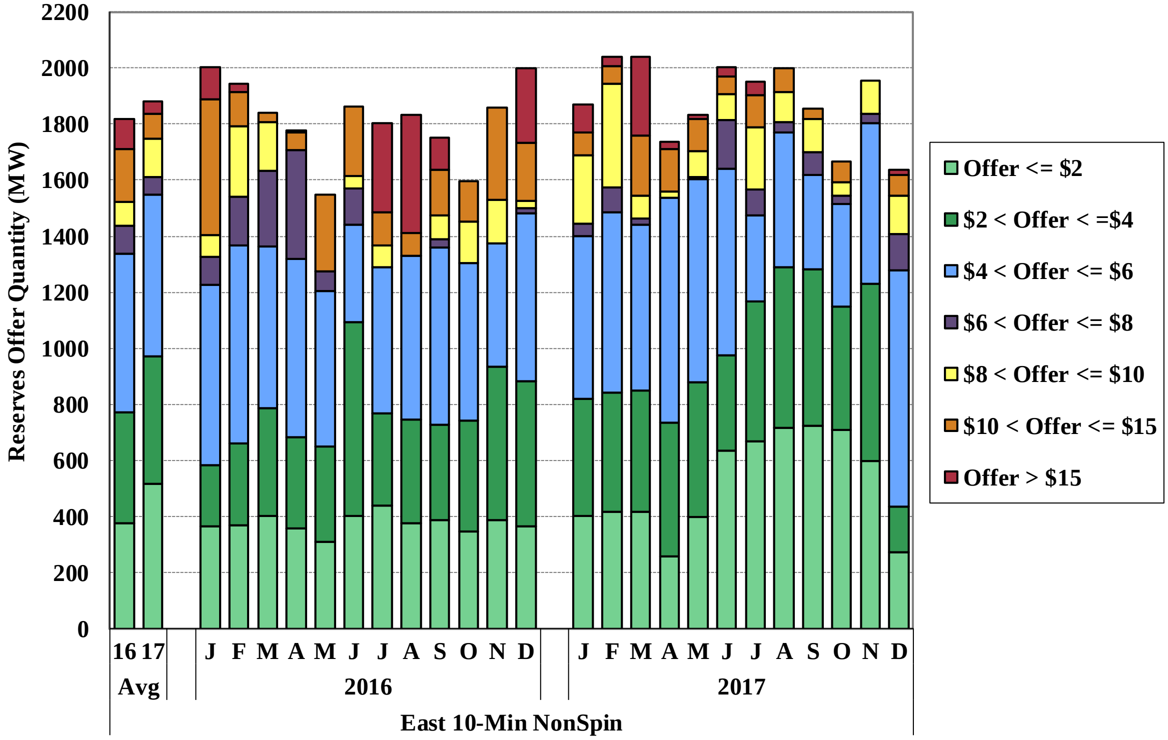


Figure A-34: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2016-2017

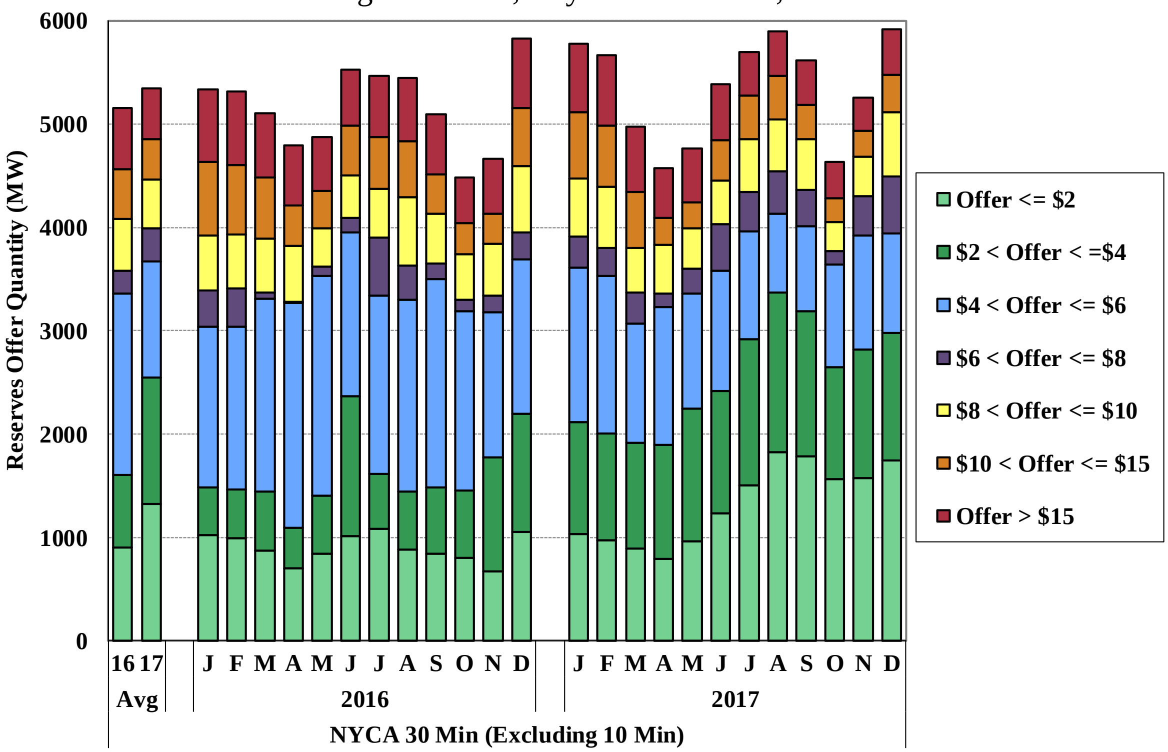


Figure A-35: Summary of Regulation Capacity Offers
Day-Ahead Market, 2016-2017

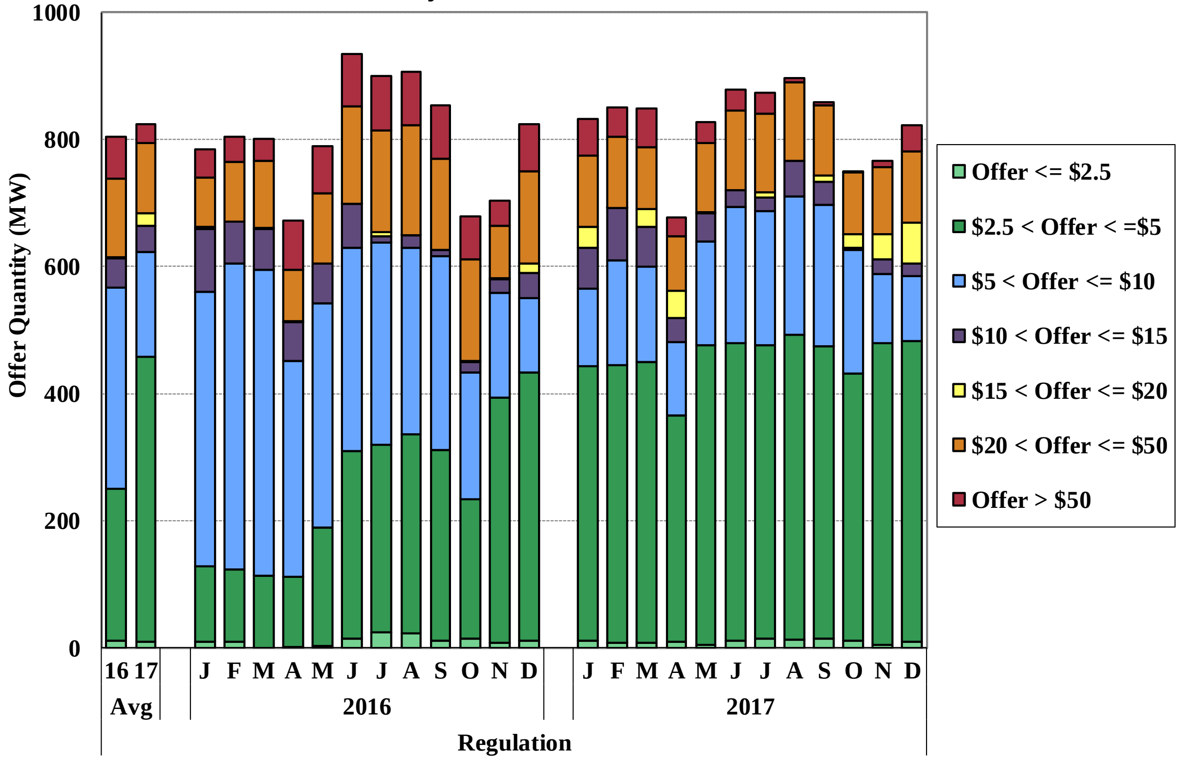


Figure A-36: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

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 in the day-ahead market, which rose sharply after the initial implementation but have since fallen significantly. Reserve prices increased in part due to higher reserve offer prices in the day-ahead market. The next analysis evaluates the changes in offer patterns over time.

Figure A-36 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2015 to 2017.[246] 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, since they directly affect the reserve prices.

The stacked bars in the figure show the amount of reserve offers in selected price ranges for West New York (Zones A to E), East New York (Zones F to J), and NYCA (excluding Zone K). Long Island is excluded because the current rules limit its reserve contribution to the broader

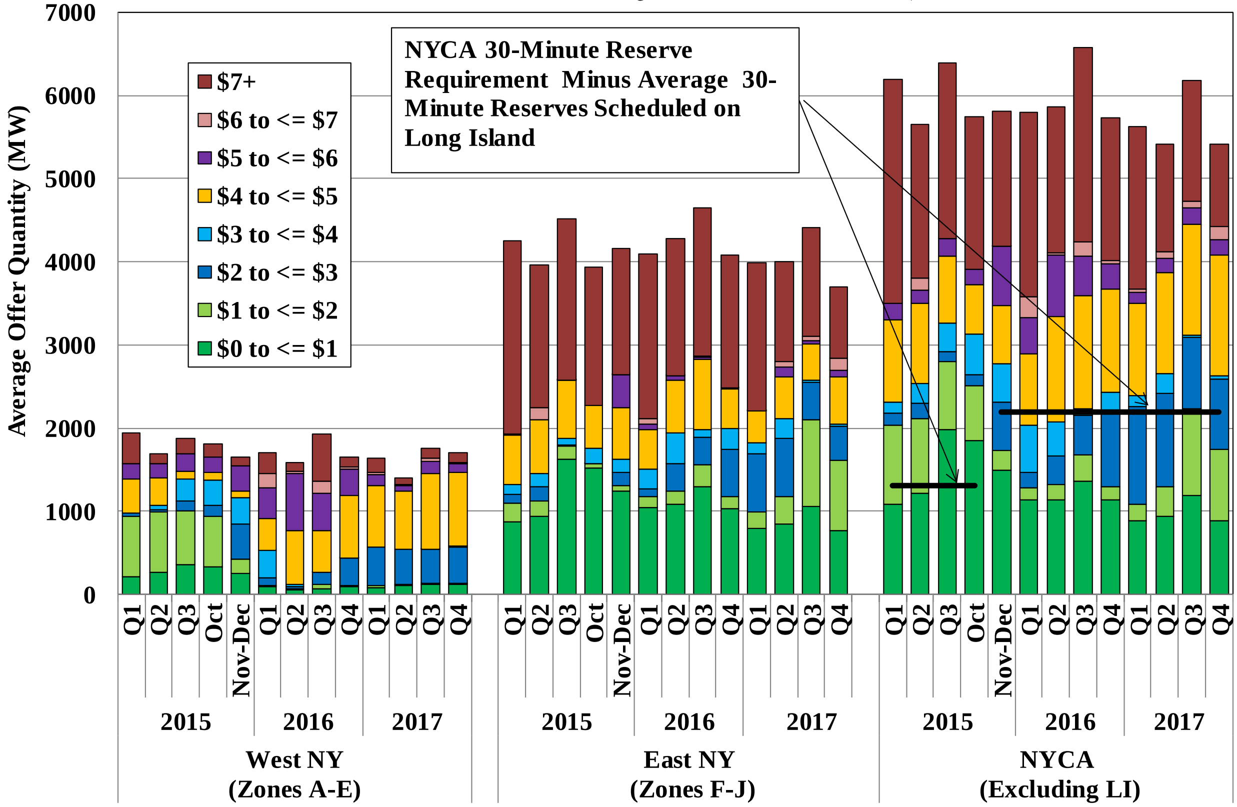
246 The fourth quarter of 2015 is split into "Oct" and "Nov-Dec", representing the two periods before and after the implementation of CSPP.

areas (i.e., 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, 2016-2017



Key Observations: Ancillary Services Offers

- The quantity of ancillary services offered in each of the five categories did not change significantly on an annual basis from 2016 to 2017.
  - The figures show a typical seasonal pattern in the offer quantities, which 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 NYCA 30-minute reserve prices rose significantly after implementation of the Comprehensive Shortage Pricing Project in November 2015, driven primarily by:
  - The increase of the reserve requirement from 1,965 to 2,620 MW;

  - The limit on Long Island reserves to meet the NYCA requirement; and
  - The increased reserve offer prices from some capacity.

- We have reviewed day-ahead reserve offers and found many units that offer above the standard competitive benchmark (i.e., estimated marginal cost).
  - This is partly due to the difficulty of accurately estimating the marginal cost of providing reserves. Thus, day-ahead offer prices may fall as suppliers gain more experience with market changes.
    - The quantity of 30-minute reserves offered at lower prices rose from 2016 to 2017. The proportion of lower-cost reserves (e.g., $3 or less) increased in Eastern New York (excluding Long Island) from an average of 38 percent in 2016 to 50 percent in 2017 and from 14 percent to 34 percent in Western New York.
  - 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.

- Although the quantity of regulation offers from all resources was similar between 2016 and 2017, available capacity from committed resources (which directly affect the regulation price) fell in 2017.
  - Fewer regulation-capable units were scheduled in the day-ahead market because of lower load levels in 2017, contributing to higher regulation prices, particularly in April and May 2017. (see Figure A-20)

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.[247]

- *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 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.

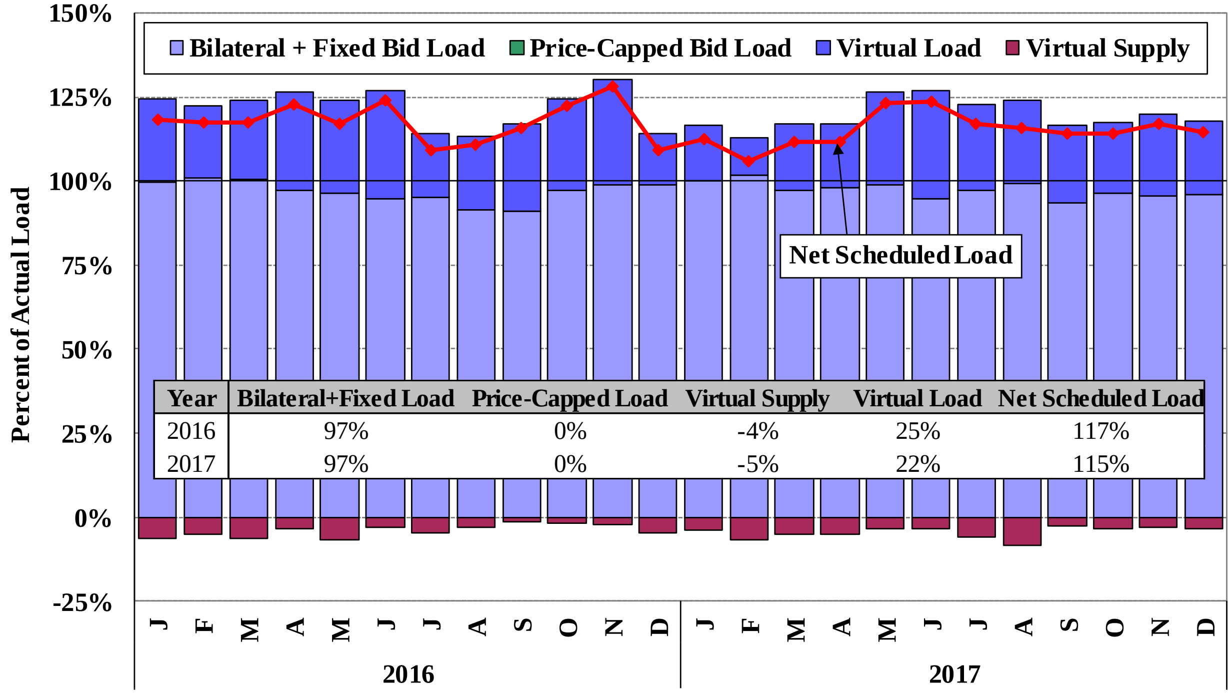
We expect day-ahead load schedules to be generally consistent with actual load in a well-functioning market. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market 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 2016 and in 2017 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

247 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.

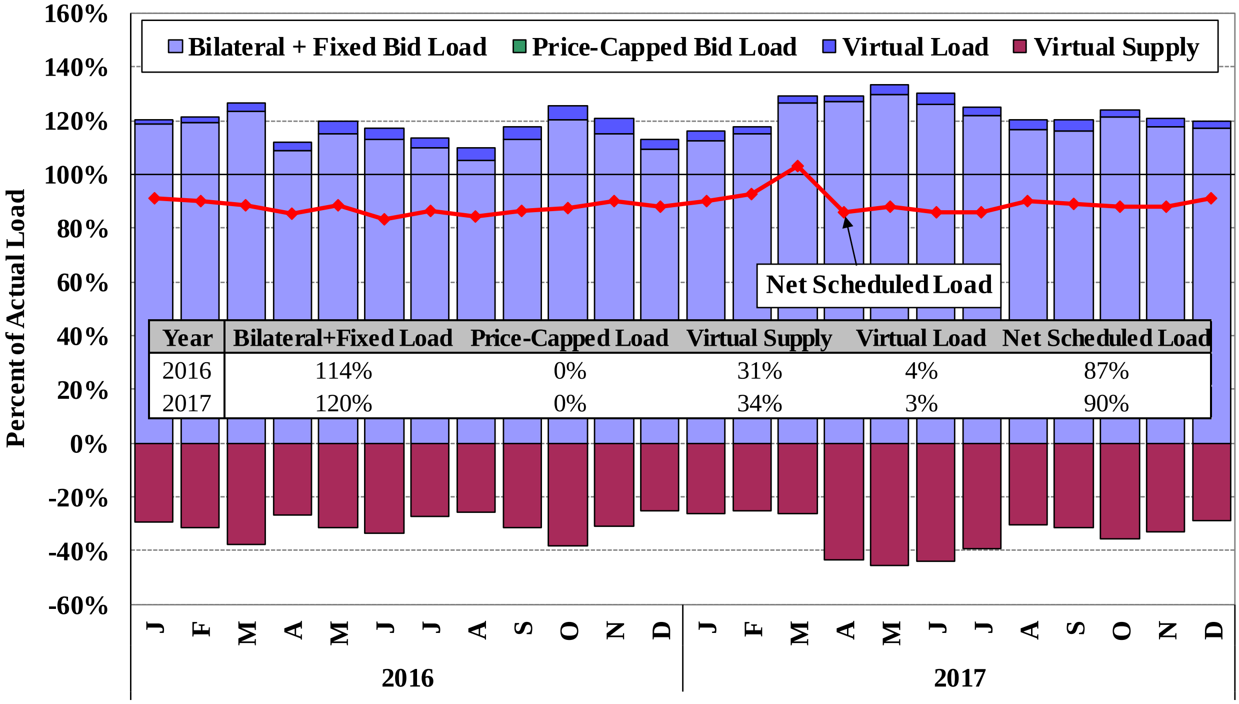
together in this analysis. Conversely, virtual supply (including virtual imports) has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis. For each period, physical load and virtual load are 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 2016 to 2017. 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, 2016 – 2017



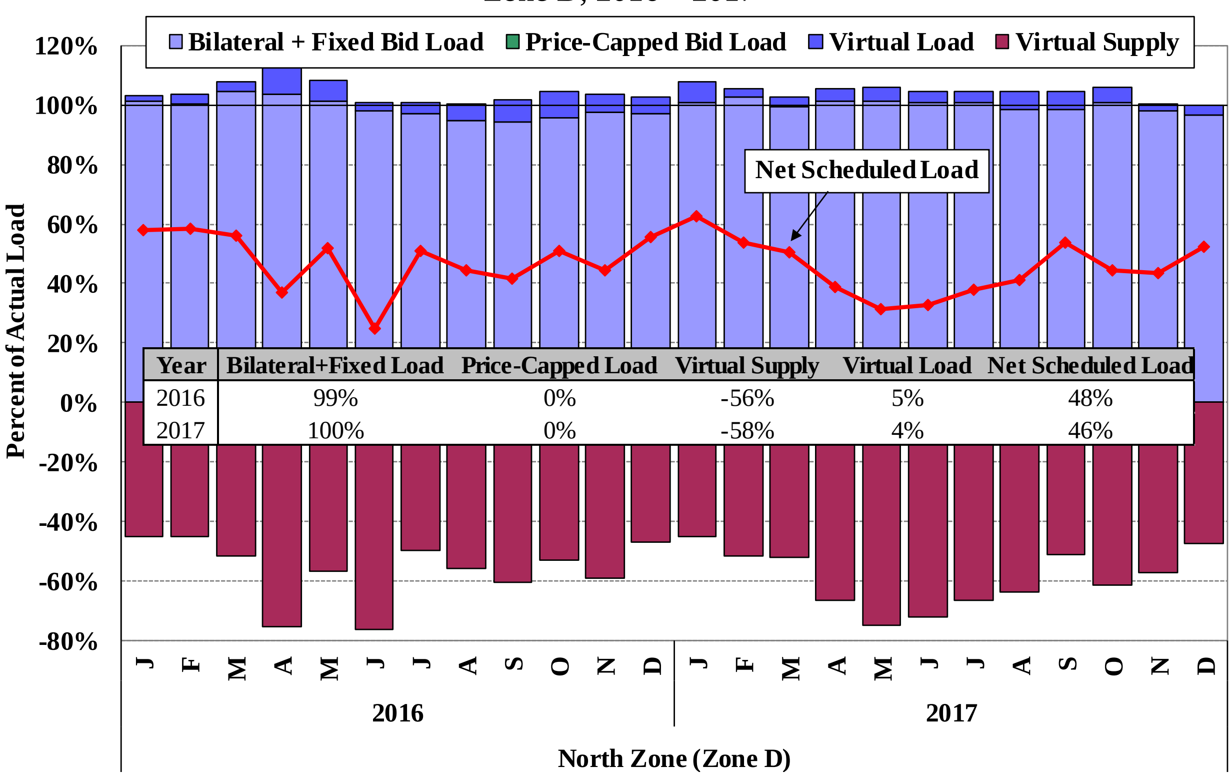
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	97%	0%	-4%	25%	117%
2017	97%	0%	-5%	22%	115%

Figure A-38: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2016 – 2017



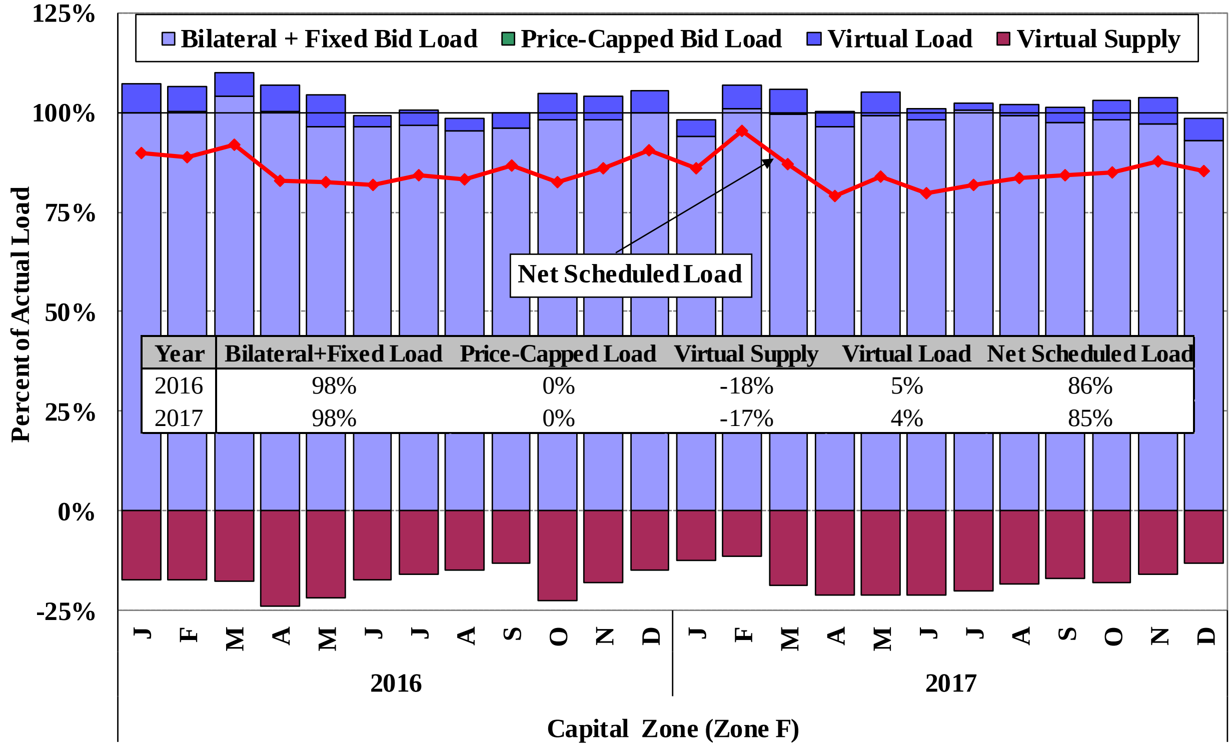
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	114%	0%	31%	4%	87%
2017	120%	0%	34%	3%	90%

Figure A-39: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2016 – 2017



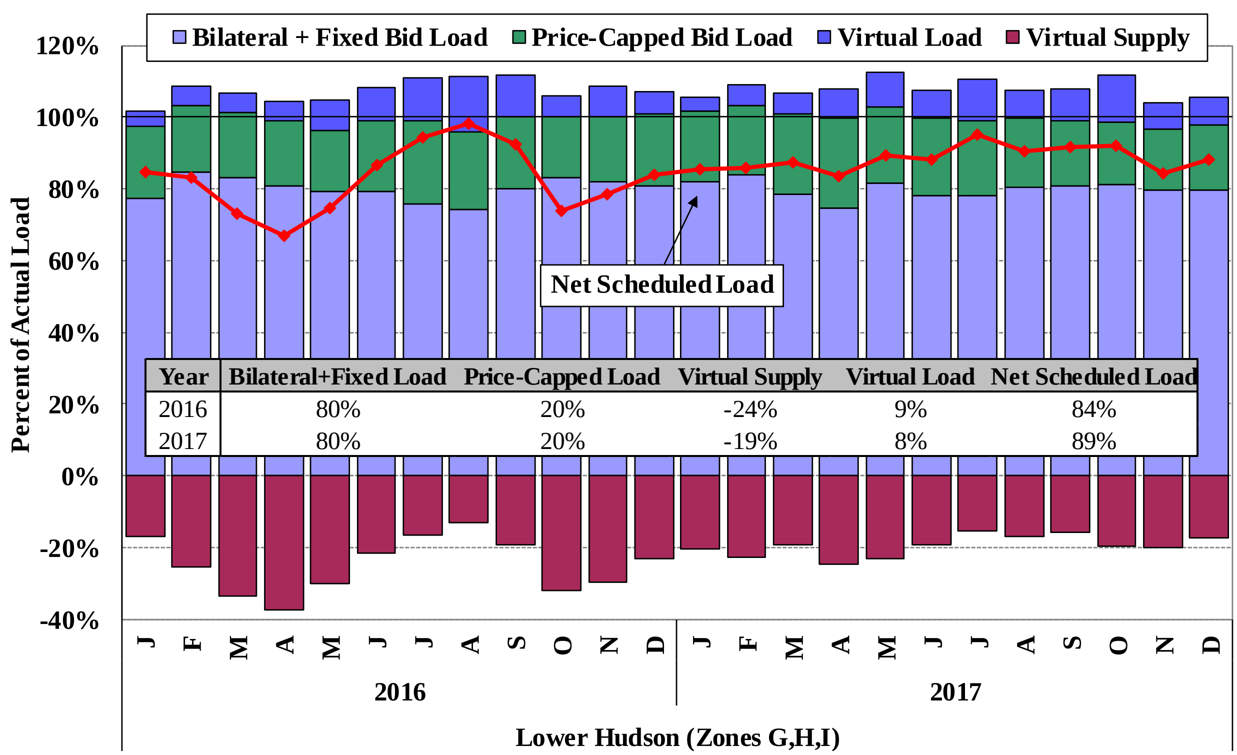
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	99%	0%	-56%	5%	48%
2017	100%	0%	-58%	4%	46%

Figure A-40: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2016 – 2017



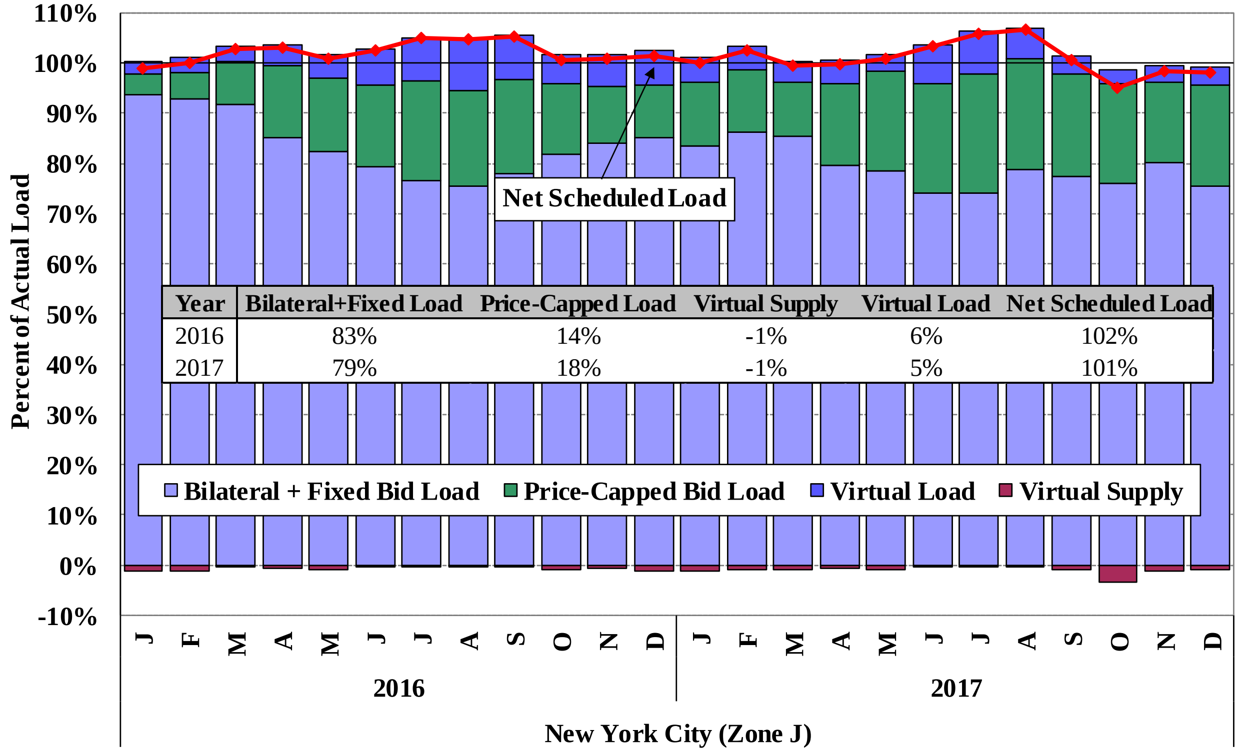
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	98%	0%	-18%	5%	86%
2017	98%	0%	-17%	4%	85%

Figure A-41: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2016 – 2017



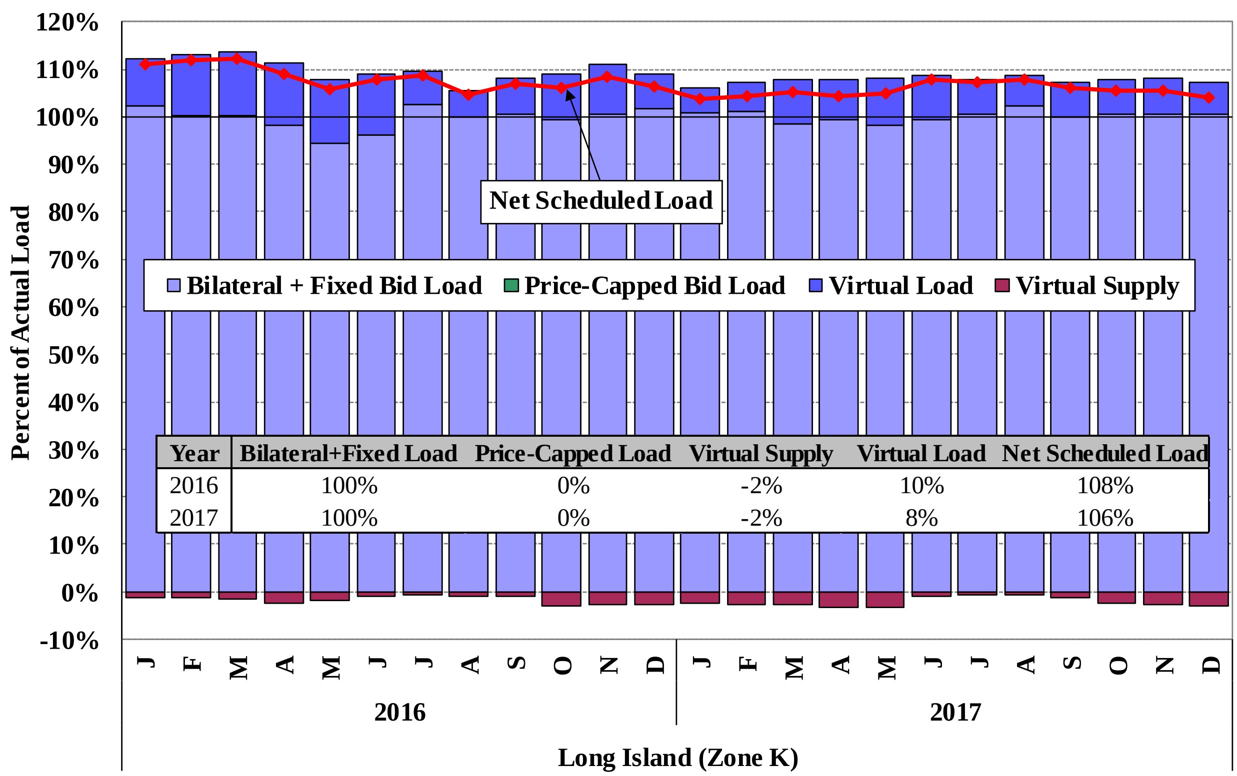
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	80%	20%	-24%	9%	84%
2017	80%	20%	-19%	8%	89%

Figure A-42: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2016 – 2017



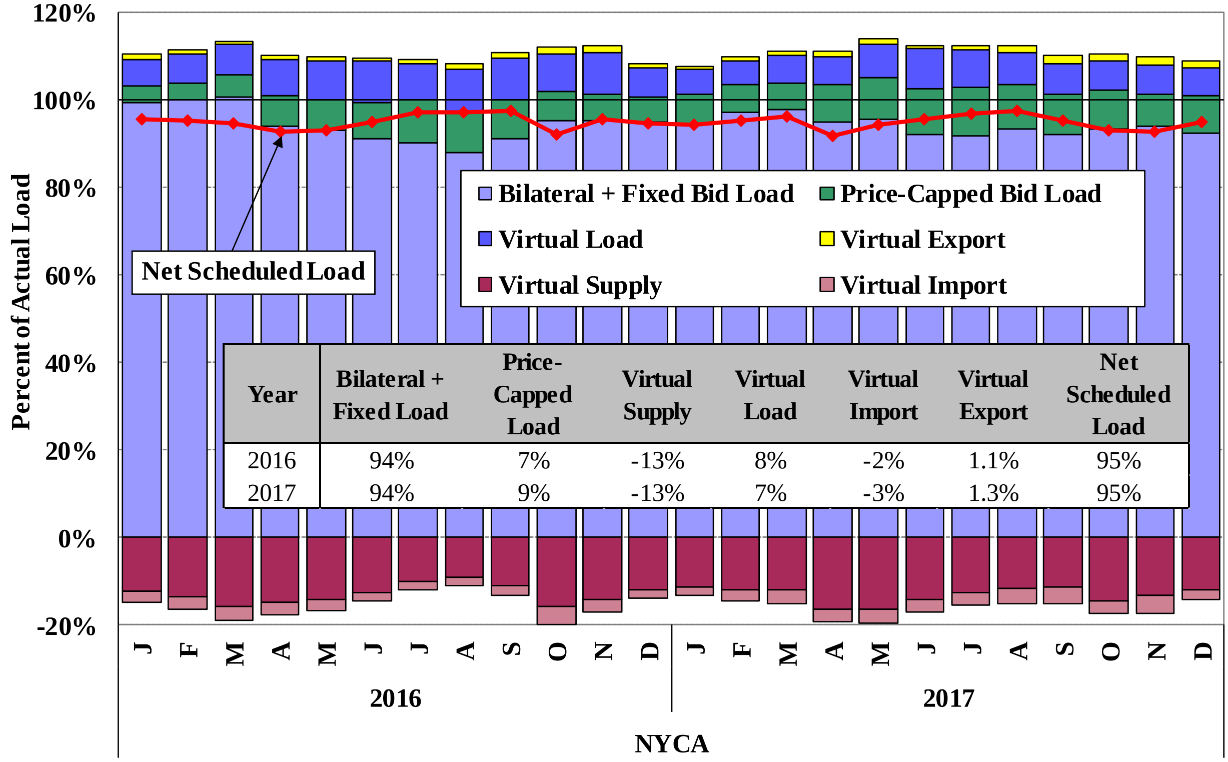
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	83%	14%	-1%	6%	102%
2017	79%	18%	-1%	5%	101%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2016 – 2017



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2016	100%	0%	-2%	10%	108%
2017	100%	0%	-2%	8%	106%

Figure A-44: Day-Ahead Load Schedules versus Actual Load in NYCA
2016 – 2017



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2016	94%	7%	-13%	8%	-2%	1.1%	95%
2017	94%	9%	-13%	7%	-3%	1.3%	95%

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

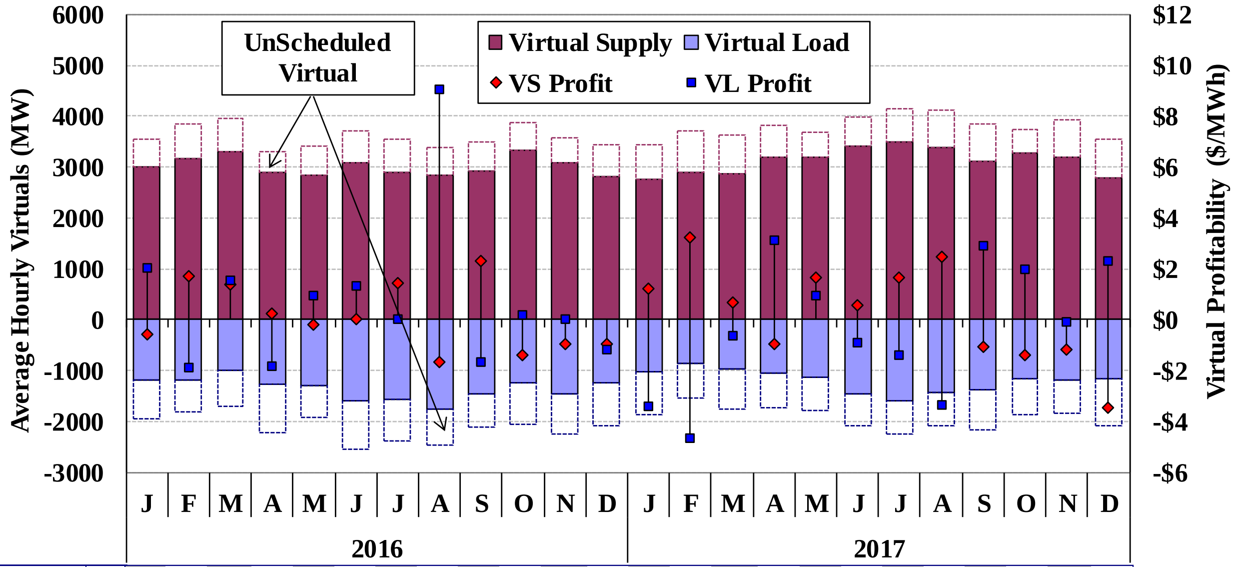
Figure A-45 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2016 and 2017. The amount of scheduled virtual supply in the chart includes scheduled virtual supply at the load 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.[248, 249]

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 396 MW of virtual transactions (or 10 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2017. 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.

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

249 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-45: Virtual Trading Volumes and Profitability
2016 – 2017



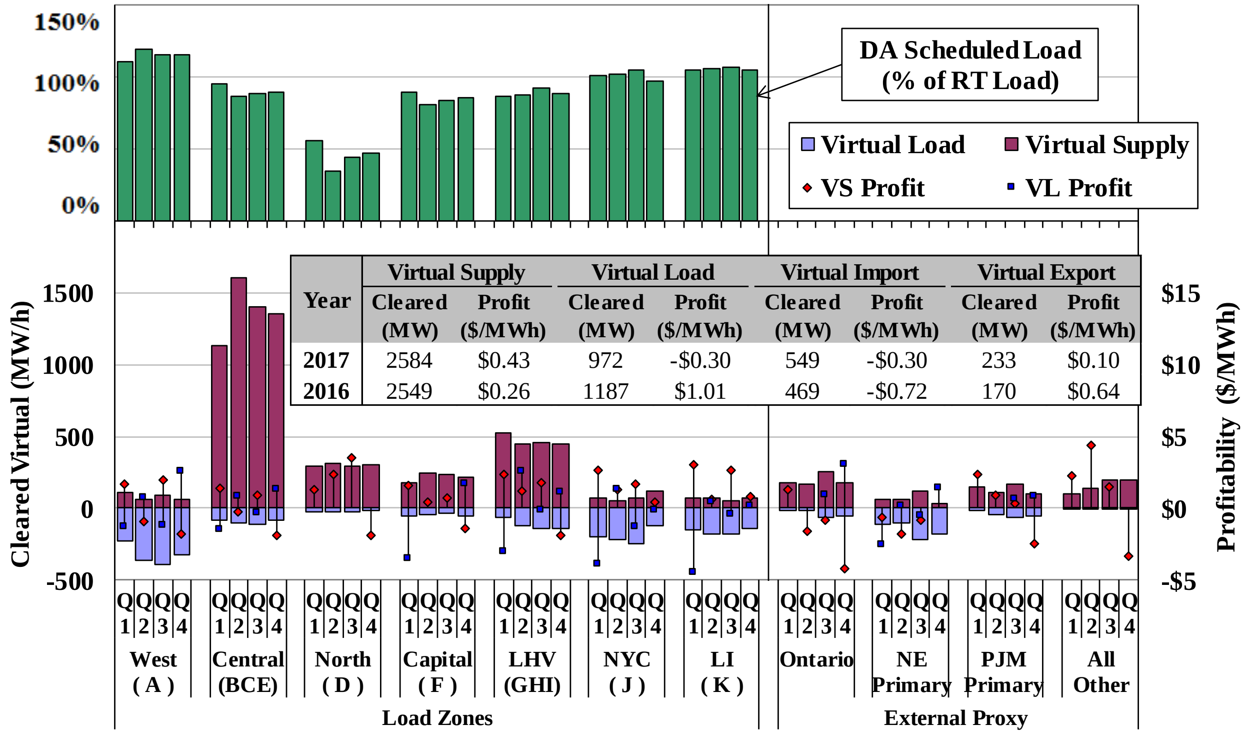
Profit > 50% of Avg. Zone Price	MW	692	638	1003	354	431	460	596	398	360	281	261	490	243	507	585	449	645	502	593	435	257	271	320	396
	%	17%	15%	23%	8%	10%	10%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%
Loss > 50% of Avg. Zone Price	MW	553	547	680	682	550	528	517	413	411	419	345	587	284	336	514	454	553	542	568	465	418	399	412	478
	%	13%	13%	16%	16%	13%	11%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%

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 2017. The upper portion of the figure shows the average day-ahead scheduled load (as a percent of real-time load) at each geographic region. The table in the middle compares the overall virtual trading activity in 2016 and 2017.

Figure A-46: Virtual Trading Activity[250]
by Region by Quarter, 2017



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)
2017	2584	$0.43	972	-$0.30	549	-$0.30	233	$0.10
2016	2549	$0.26	1187	$1.01	469	-$0.72	170	$0.64

Key Observations: Day-Ahead Load Scheduling and Virtual Trading

- For NYCA, roughly 95 percent of actual load was scheduled in the day-ahead market (including virtual imports and exports) during peak load hours in 2017, similar to 2016.
    - The scheduling pattern in each sub-region was generally consistent as well.
- The patterns of virtual trading and load scheduling were similar. Net load scheduling (including net virtual load) tend to be higher in locations where high real-time prices frequently result from volatile congestion.
    - This has led to a seasonal pattern in some regions. For example:
        - Net load scheduling in the Capital Zone typically rose in the winter months because of much higher congestion across the Central-East interface.
        - Net load scheduling in New York City increased in the summer months when acute real-time congestion into Southeast New York was more prevalent.
    - This has also resulted in locational differences between regions.

250 Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW.

    - Average net 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.

- 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.
  - Load was typically under-scheduled in the North Zone by a large margin because large amounts of virtual supply are often scheduled here. This is an efficient response to the scheduling patterns of wind resources in the zone and imports from Canada, which typically rose in real-time above their day-ahead schedules.
- In aggregate, virtual traders netted approximately $6 million of gross profits in 2017 versus the $14 million in 2016.
  - 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 2017, 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.

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 Revenues and Patterns* – Sub-sections A and B evaluate the congestion revenues collected by the NYISO from the day-ahead market as well as the patterns of congestion on major transmission paths in the day-ahead and real-time markets.
- *Constraints Requiring Frequent Out-of-Market Actions* – Sub-sections C and D evaluate the management of transmission constraints that are frequently resolved using out-of-market actions, including the management of the 115 kV network in upstate New York and the high voltage network around the Niagara complex.
- *Congestion Revenue Shortfalls* – Sub-sections E and F analyze shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- *TCC Prices and Day-Ahead Market Congestion* – Sub-section G reviews the consistency of TCC prices and day-ahead congestion, which determine payments to TCC holders.

- *Transitioning Physical Contracts to Financial Rights* – Sub-section H presents a concept for modernizing contracts for physical power delivery that pre-date the NYISO market to financial rights that would allow key transmission facilities to be used more efficiently.

A. Summary of Congestion Revenue and Shortfalls in 2017

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.[251]

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.[252] 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.[253] 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

251 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).

252 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).

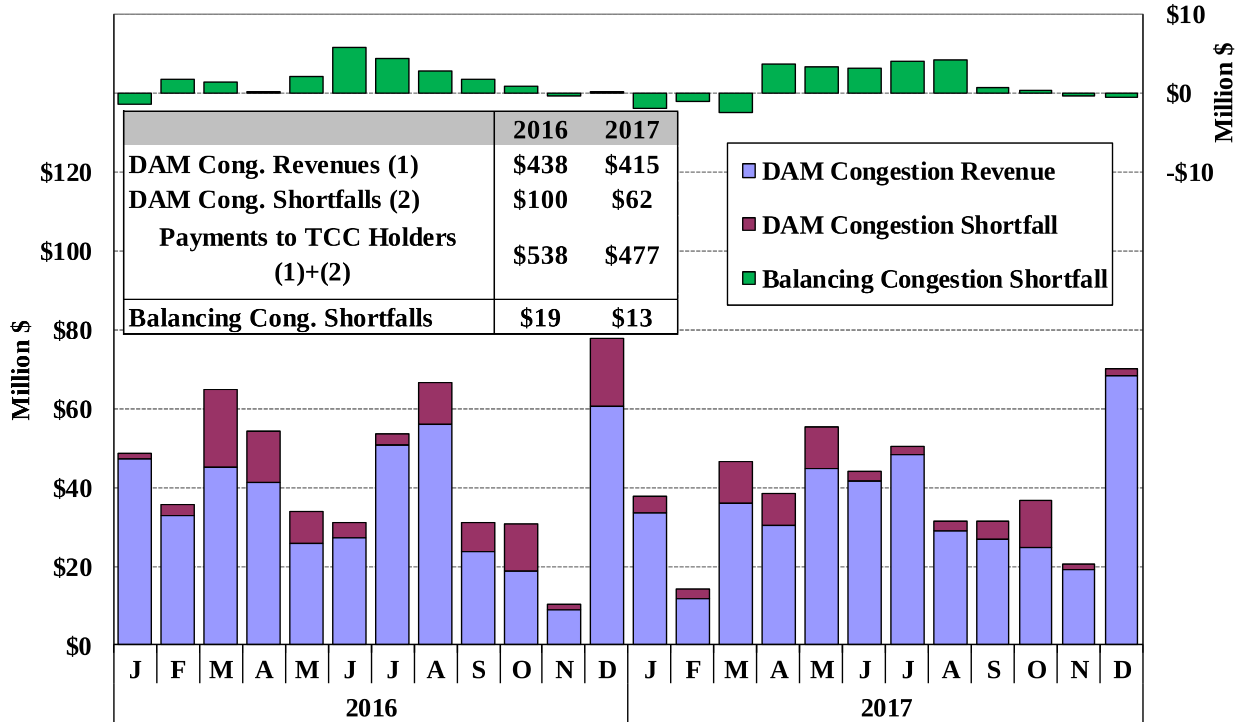
253 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) *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

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 2016 and 2017. 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.

Figure A-47: Congestion Revenue Collections and Shortfalls
2016 - 2017



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 2016 and 2017 on an annual basis, while Figure A-49 and Figure A-50 show the quantities separately for each quarter of 2017.

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.[254]

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.
- 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.

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

- 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 into 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
2016 – 2017

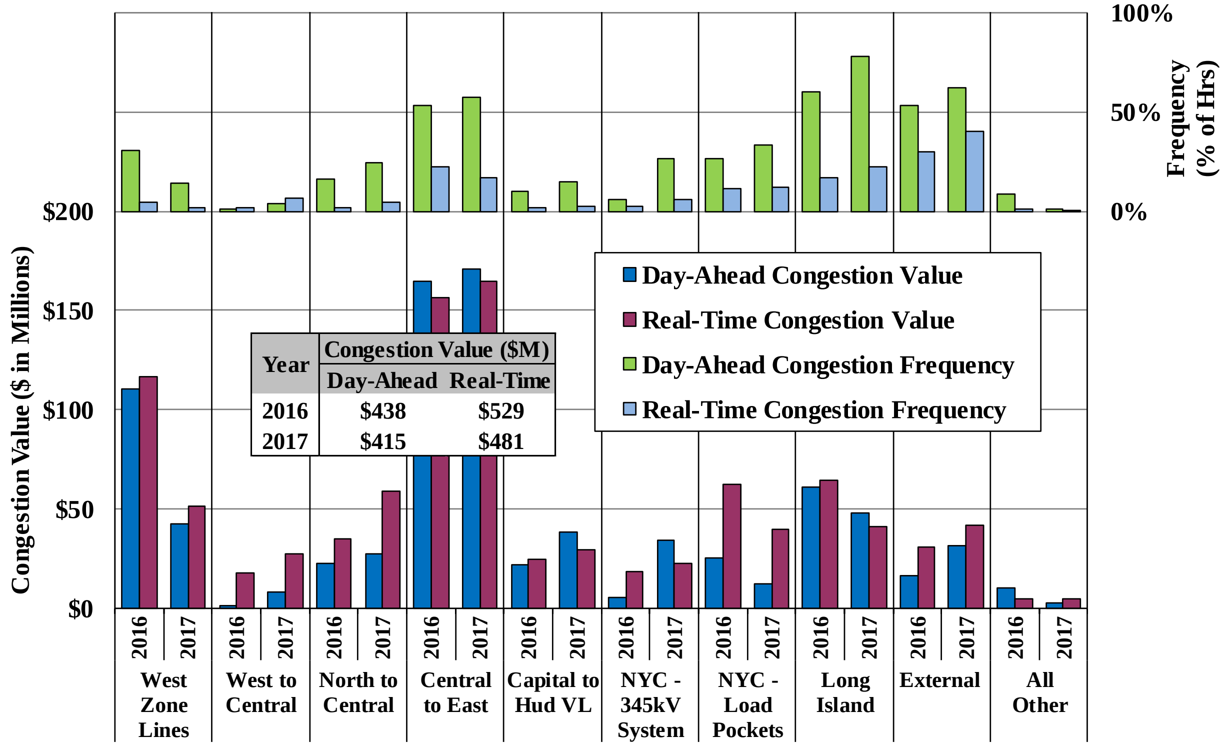


Figure A-49: Day-Ahead Congestion by Transmission Path
By Quarter, 2017

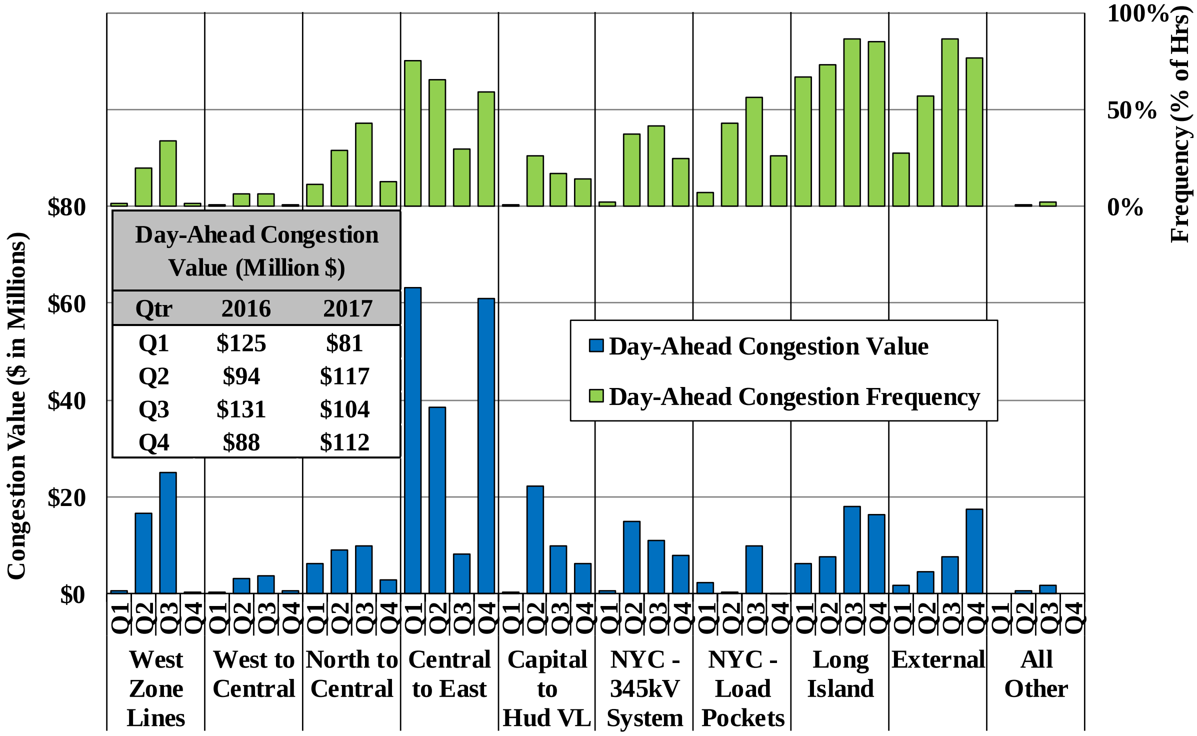
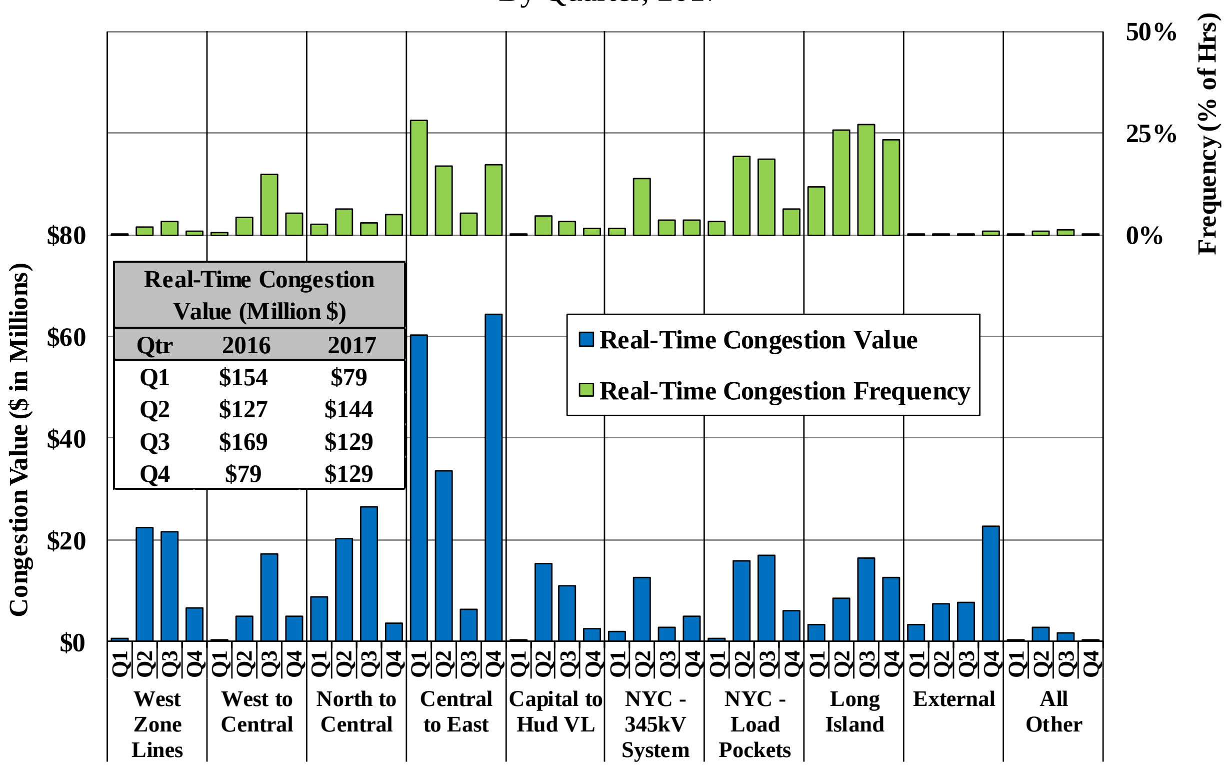


Figure A-50: Real-Time Congestion by Transmission Path
By Quarter, 2017



Key Observations: Congestion Revenues and Patterns

- Day-ahead congestion revenues totaled roughly $415 million, down 5 percent from 2016, driven partly by lower load levels and milder peaking conditions in both winter and summer seasons.
  - Modifications to the transmission shortage pricing in June 2017 also helped reduce constraint costs during transmission shortages in most areas, contributing to the overall decrease (see Section V.G).
- The largest share of congestion values accrued on the Central-East interface, which accounted for 41 percent of congestion value in the day-ahead market and 31 percent in the real-time market in 2017.
  - 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 typically increase in the winter season).
- Congestion on 230kV lines in the West Zone fell significantly from 2016 to 2017—by 56 percent in the day-ahead and 62 percent in the real-time, reflecting the following changes:
  - Lower and less volatile clockwise loop flows around Lake Erie (see Sub-section E);
  - Transmission upgrades completed in May 2016 (i.e., two new series reactors on the Packard-Huntley 230 kV #77 and #78 lines, which can be used to divert a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities). However, this has also led to increased congestion on the 115 kV network (which is discussed further in Sub-sections C and D);
  - The inclusion of West Zone constraints in the M2M process with PJM in May 2017 (see Appendix Section V.C);
  - Modifications to transmission shortage pricing in June 2017 (see Appendix Section V.G).
- Congestion rose notably from 2016 on the 345 kV system of New York City, reflecting:
  - More transmission outages (see Sub-section F);
  - Higher gas prices (see Appendix Section I.B); and
  - Reduced imports from PJM across the A, B, and C lines following the expiration of the PSEG/ConEd Wheeling agreement.
  - Nonetheless, congestion fell noticeably in the 138 kV load pockets because of fewer transmission shortages and lower shortage costs.

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. [255] 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. The NYISO has acknowledged these issues and indicated that it is currently evaluating potential enhancements that would improve the efficiency of schedules and prices when there is congestion around the Niagara facility even if the NYISO cannot schedule generation at the individual Niagara buses. [256]

Figure A-51 - Figure A-52 : 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 an example day (September 10, 2016) for the most frequently congested constraints in the West Zone: the Niagara-Packard and Packard-Sawyer 230 kV lines.

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,

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255 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. See April 5, 2016 Market Issues Working Group materials: *Niagara Generation Modeling Update*, presented by David Edelson.

256 See February 21, 2018 Market Issues Working Group materials: *Niagara Generation Modeling Update*, presented by David Edelson.

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

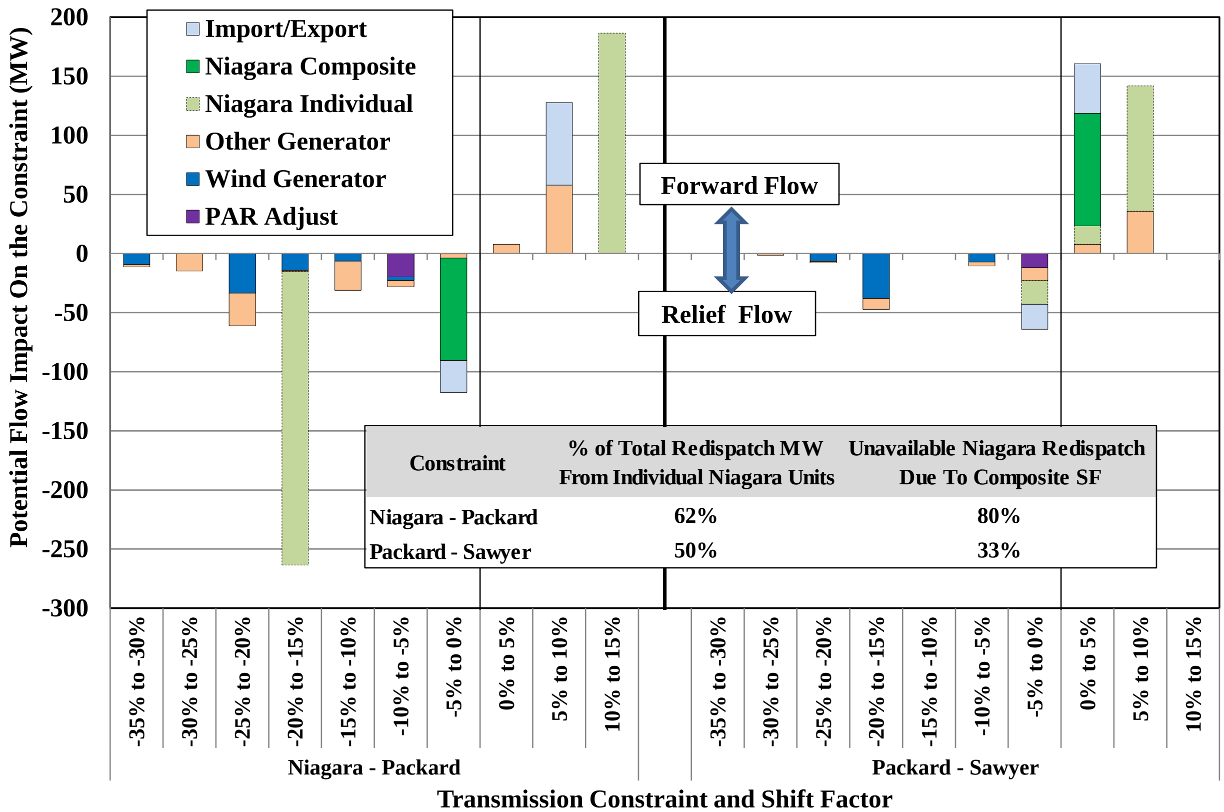


Figure A-52: Niagara LBMPs and Under-Utilization of 115 kV Circuits

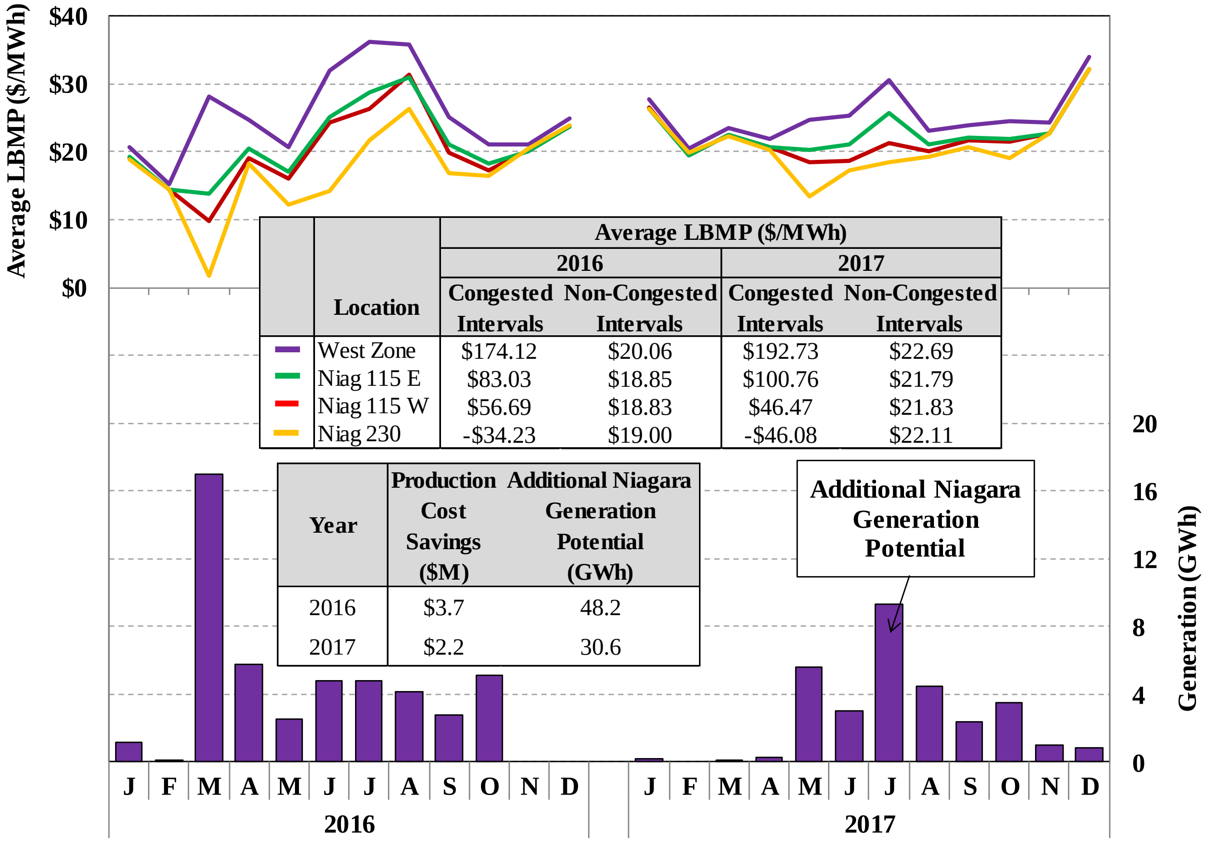
Figure A-52 estimates the remaining benefits that might have occurred if the distribution of generation at Niagara was optimized in each month of 2016 and 2017 by showing:

- 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-52: Niagara LBMPs and Under-Utilization of 115 kV Circuits
By Month, 2016- 2017



	Location	Average LBMP ($/MWh) 2016 Congested Intervals	2016 Non-Congested Intervals	2017 Congested Intervals	2017 Non-Congested Intervals
	West Zone	$174.12	$20.06	$192.73	$22.69
	Niag 115 E	$83.03	$18.85	$100.76	$21.79
	Niag 115 W	$56.69	$18.83	$46.47	$21.83
	Niag 230	-$34.23	$19.00	-$46.08	$22.11

Year	Production Cost Savings ($M)	Additional Niagara Generation Potential (GWh)
2016	$3.7	48.2
2017	$2.2	30.6

Key Observations: West Zone Congestion and Niagara Generation

- Figure A-51 illustrates that most potential redispatch (for the two most congested West Zone constraints) is at the Niagara plant, but a large portion of this potential congestion relief is not available because the plant is dispatched as a single unit based on a composite shift factor.
  - If dispatched individually, Niagara units would account for 62 and 50 percent of potential redispatch options for managing congestion on these two key constraints. 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 circuits due to the large inconsistences between modeled and actual Niagara redispatch.
    - The Packard-Sawyer constraints are currently operated at a higher CRM (i.e., 50 MW rather than the normal 20 MW) to prevent overloads on Niagara-Packard circuits because the Packard-Sawyer constraint has more predictable effects on congestion. This further reduces the usable transfer capability in the West Zone.

- 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.
  - In 2017, average LBMPs were $93 to $147/MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during congested intervals.
  - Negative LBMPs at the 230 kV bus indicate over-utilization of 230kV units at the Niagara plant during periods of severe congestion.
- We estimate that if the 115kV circuits were fully utilized to relieve the 230kV constraints in the West Zone: [257]
  - Production costs would have been reduced by an additional $3.7 million in 2016 and $2.2 million in 2017 (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 48 and 31 GWh of Niagara generation would have been deliverable in 2016 and 2017. This would have reduced LBMPs in other zones as well, although we have not estimated the effect on statewide average LBMPs.
- The NYISO is developing an improved modeling approach that will better recognize congestion impact from 115 kV and 230 kV units.[258]

D. Transmission Constraints on the Low Voltage Network in Upstate NY

In this sub-section, we evaluate the actions that are used to manage transmission constraints on the low voltage network in upstate New York, including 115 kV and 69 kV facilities. While such constraints are sometimes managed with the use of line switching on the distribution system, this evaluation focuses on actions that involve wholesale market generators, adjustments to phase-angle regulators on the high-voltage network (including 230+ kV facilities), curtailment or limitation of external transactions, and/or line switching of facilities along the external interfaces with adjacent control areas.

In upstate New York, constraints on 230 and 345 kV facilities are generally managed through the day-ahead and real-time market systems.[259] This provides several benefits including: (a) that the

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257 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.

258 The NYISO recently announced an initiative to enhance the modeling of the Niagara facility. See *Niagara Generation Modeling Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

market optimization balances the costs of satisfying demand, ancillary services, and transmission security requirements, resulting in more efficient scheduling decisions; and (b) that the market optimization also produces a set of transparent clearing prices, which provide efficient signals for longer lead time decisions such as fuel procurement, generator commitment, external transaction scheduling, and investment in new and existing resources and transmission.

However, transmission constraints on the 115 kV and lower voltage networks in upstate New York are resolved in other ways, including: (a) out of merit dispatch and supplemental commitment of generation; (b) curtailment of external transactions and limitations on external interface transfer limits; (c) use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and (d) adjusting PAR-controlled lines on the high voltage network.

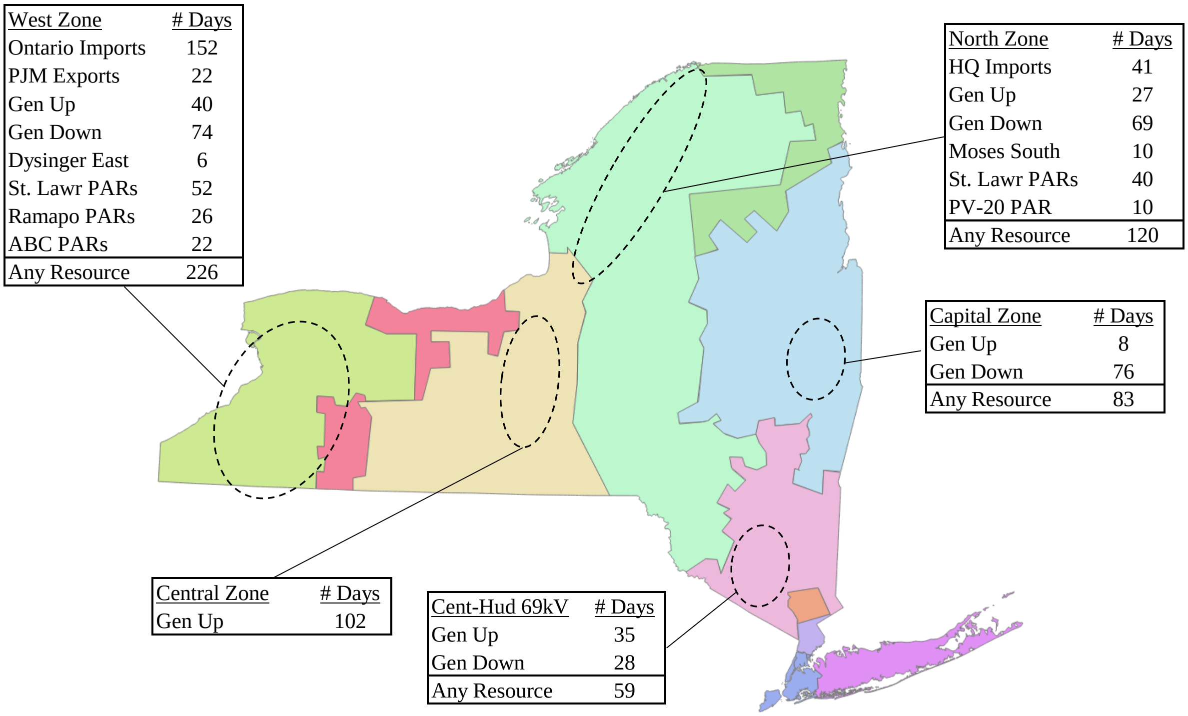
Figure A-57: Transmission Constraints on the Low Voltage Network Upstate NY

Figure A-57 shows the number of days in 2017 when various resources were used to manage constraints in five areas of upstate NY:

- West Zone: Mostly Niagara-to-Gardenville and Gardenville-to-Dunkirk circuits;
- Central Zone: Mostly constraints around the State Street 115kV bus;
- Capital Zone: Mostly Albany-to-Greenbush 115kV constraints;
- North & Mohawk Valley Zones: Mostly 115kV constraints on facilities that flow power south from the North Zone and through the Mohawk Valley Zone between the Colton 115kV and Taylorville 115kV buses; and
- Hudson Valley Zone: Mostly constraints on the 69kV system in the Hudson Valley.

[259] Note, most transmission constraints on the 138 kV system in New York City and Long Island are also managed using the day-ahead and real-time markets. The primary exception is on the 138 kV network on the east end of Long Island where many constraints are managed using out-of-merit dispatch, which is evaluated in Appendix Section V.H.

Figure A-53: Constraints on the Low Voltage Network Upstate NY
Number of Days Action Was Used to Manage Constraint



<u>Key Observations: Transmission Constraints on the Low Voltage Network Upstate NY</u>

- The West Zone contains the 115 kV facilities most frequently constrained in 2017.
  - These constraints have been more prevalent since May 2016 when transmission upgrades were made (to reduce congestion on 230 kV facilities in the West Zone following the retirement of the Huntley plant) that shifted some west-to-east flows onto the 115 kV network.
    - Congestion on the 115 kV network in the West Zone has become more prevalent than congestion on the 230 kV network there. In 2017, resources were utilized to manage 115 kV constraints on 226 days compared to just 158 days with congestion 230 kV facilities in the day-ahead and/or real-time markets.
  - In addition, (although not shown in the figure above) a 230 kV facility connecting NYISO to PJM, the "Dunkirk-South Ripley" line, was taken out of service to manage 115 kV constraints on almost every day. It was reconnected on just a few days at the request of PJM to facilitate outage work.
  - Generation and Ontario imports were constrained on a large number of days, while phase-angle regulators in Northern NY (i.e., the St. Lawr PARs) and Southeast NY (i.e., the Ramapo and ABC PARs) were also used on some days.
  - West Zone constraint management affected other areas of New York because:
    - Reducing low-cost imports from Ontario raised LBMPs in other areas; and

        - Using PARs in the North Zone to relieve West Zone constraints exacerbated constraints going south from the North Zone and across the Central East interface, while using PARs in Southeast New York to relieve West Zone constraints exacerbated constraints across the Central East interface and into New York City.

        - Constraint management should be done in a manner that balances the benefits of relieving constraints in one area against the cost of exacerbating congestion in another. This can be done more effectively if low-voltage constraints were managed using the day-ahead and real-time market systems. The NYISO has recognized this and is currently evaluating potential changes that would allow 115 kV constraints to be scheduled and priced in the day-ahead and real-time markets.[260]

    - Although the PJM export limit bound on just 22 days, PJM imports are generally helpful for managing 115kV congestion in the West Zone. Modeling 115kV constraints in the market systems would provide incentives for PJM imports to relieve congestion in New York.

    - Enhanced modeling of the Niagara generating plant would significantly reduce the costs of managing 115 and 230 kV congestion in the West Zone. This is because the plant consists of 7 generating units on the 115 kV network and 18 generating units on the 230 kV network, so output can be shifted among these generators to manage congestion on both networks. However, the NYISO currently represents these 25 generating units as a single facility in the market models, which prevents the NYISO from shifting generation among these units to manage congestion. Instead, the market scheduling systems turn the entire facility up or down without distinguishing between generators that relieve congestion and generators that exacerbate congestion, which increases the costs of congestion management. The NYISO recently recognized this and announced an initiative to improve the modeling of the Niagara generator. [261]

- Resources were used to manage 115kV congestion on flows from northern New York towards the central part of the state on 120 days in 2017 compared to 166 days of congestion on parallel 230 and 765 kV facilities in the day-ahead and/or real-time markets. To manage 115 kV constraints, the NYISO primarily:

    - Reduce generation primarily from hydro generating facilities,

    - Limit imports from Quebec across the Cedars-Dennison Scheduled line, and

    - Limit imports from Ontario across the Saint Lawrence PAR-controlled lines.

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260 See *Securing 100+kV Transmission Facilities in the Market Model* presented by Ethan Avallone to the Market Issues Working Group on February 21, 2018.

261 The modeling of the Niagara facility is evaluated above in Sub-section C. The initiative is described in *Niagara Generation Modeling Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

  - The NYISO has indicated that it will begin to model these constraints in the day-ahead and real-time markets beginning in the second quarter of 2018.

- The costs and reliability effects of this congestion could be reduced by modeling the 115kV constraints in the day-ahead and real-time market systems. The NYISO and stakeholders have recognized this and currently have a 2018 project to evaluate the potential for modeling 115 kV facilities in upstate New York. The NYISO has announced that it intends to begin modeling 115 kV constraints in the day-ahead and real-time markets during the second quarter of 2018, while other areas of the state will not be modeled until sometime after November 2018. [262]

E. 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.

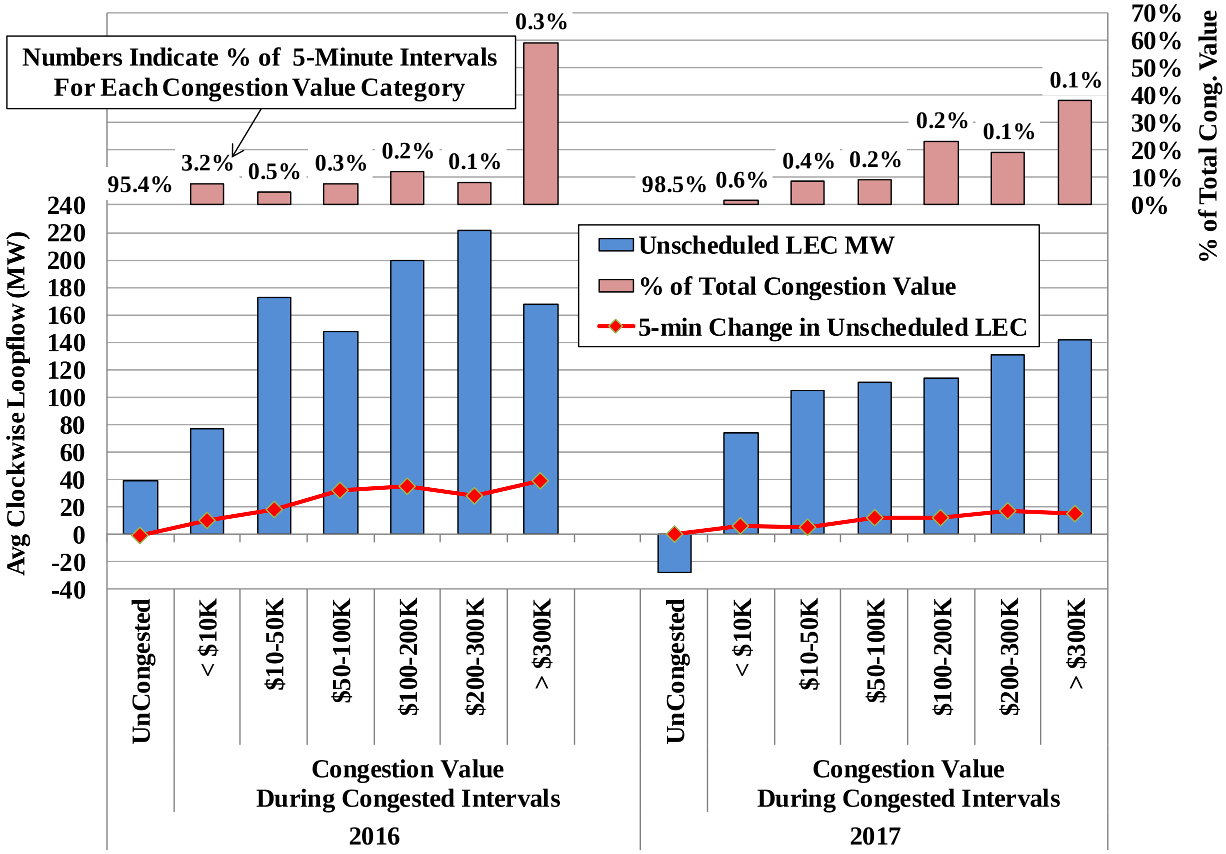
Figure A-54 illustrates how and to what extent unscheduled loop flows affected congestion on West Zone 230 kV constraints in 2016 and 2017. The bottom portion of the chart shows the average amount of: (a) unscheduled loop flows (the blue bar); and (b) changes in unscheduled loop flows from the prior 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)

262 See *Securing 100+kV Transmission Facilities in the Market Model* presented by Ethan Avallone to the Market Issues Working Group on February 21, 2018.

between $200,000 and $300,000; and (f) more than $300,000.[263] 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 2016 and 2017, 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 0.1 percent of all intervals in 2017, which accounted for nearly 40 percent of total congestion value in the West Zone.

Figure A-54: Clockwise Lake Erie Circulation and West Zone Congestion
2016 - 2017



Key Observations: Lake Erie Circulation and West Zone Congestion

- There has been a significant shift in the pattern of loop flows around Lake Erie. In uncongested periods (which includes the vast majority of intervals), loop flows have

263 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.

shifted from an average of nearly 40 MW in the clockwise direction to an average of more than 20 MW in the counter-clockwise direction.

- 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.
  - 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.[264] These modifications have helped reduce the severity of real-time congestion during periods with highly volatile loop flows.
- A small number of intervals accounted for relatively large share of the total congestion in both 2016 and 2017.
  - In 2017, just 0.1 percent of intervals accounted for nearly 40 percent of the total congestion value in the West Zone. Similarly, 0.3 percent of intervals in 2016 accounted for 60 percent of congestion value.
  - This reinforces the importance of efforts to improve congestion management during periods of extreme congestion.

F. 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.

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

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 2016 and 2017. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

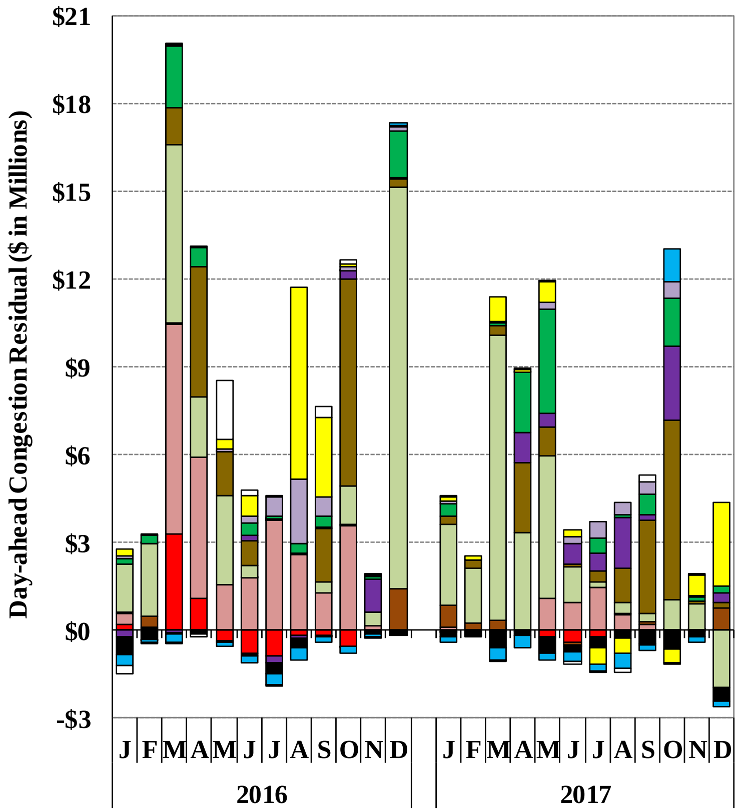
- West Zone Lines: Transmission lines in the West Zone.
- North to Central: Transmission lines in the North Zone, the Moses-South Interface, EDIC-Marcy 345 line, and Marcy 765-Marcy 345 line.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Transmission lines into Hudson Valley, primarily lines connecting Leeds, Pleasant Valley, and New Scotland stations.
- 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:

- o Grandfathered TCCs ("GFTCC") that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K); and
- o 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
2016 – 2017



Category		Annual Shortfall ($M) 2016	Annual Shortfall ($M) 2017
	West Zone Lines		
	Niagara Modeling Assumption	**$1.8**	**-$0.8**
	Other Factors	**$27.2**	**$4.3**
	Central to East		
	Ramapo, ABC & JK PARs	**$1.9**	**$2.2**
	Other Factors	**$31.7**	**$24.7**
	North to Central	**$17.2**	**$15.5**
	Capital to Hud VL	**$1.0**	**$7.6**
	NYC Lines	**$6.2**	**$9.3**
	Long Island Lines		
	901/903 PARs	**-$2.0**	**-$4.2**
	Excess GFTCC Allocations	**$4.3**	**$2.7**
	Other Factors	**$10.6**	**$4.0**
	External	**-$2.4**	**-$1.8**
	All Other Facilities	**$2.4**	**$0.1**

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.

- Fast-Start 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.

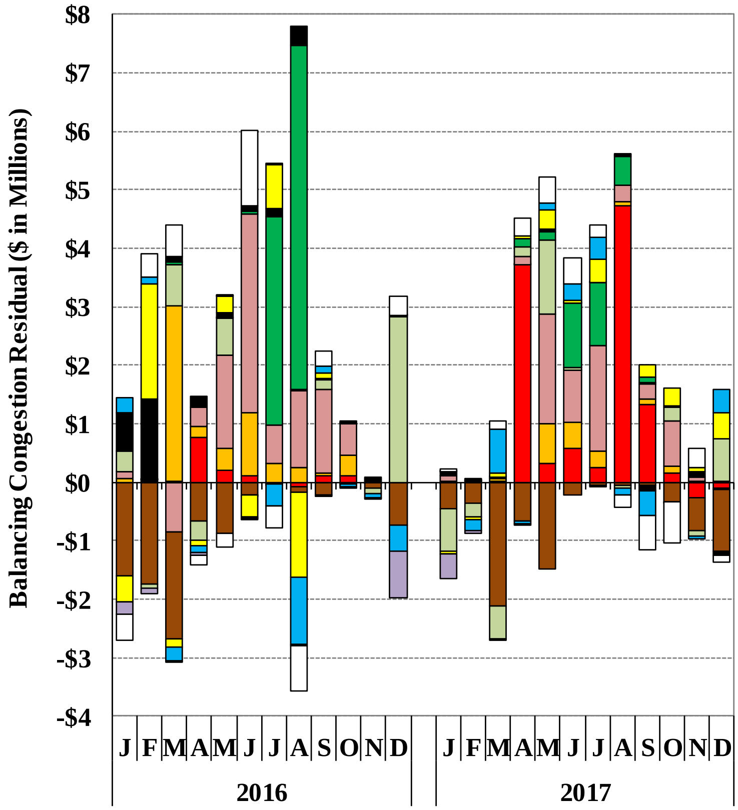
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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 2016 and 2017. 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[265]
2016 – 2017



	Category	Annual Shortfall ($M)	
		2016	**2017**
	West Zone Lines		
	Ramapo, ABC & JK PARs	**$5.7**	**$1.8**
	Other Factors	**$8.6**	**$6.2**
	North to Central	**$1.3**	**$10.7**
	Central to East		
	Ramapo, ABC & JK PARs	**-$8.1**	**-$7.4**
	Other Factors	**$4.2**	**$0.8**
	Capital to HVL (TSAs)	**$9.5**	**$3.0**
	Long Island Lines		
	901/903 PARs	**$3.0**	**$0.1**
	Other Factors	**$0.7**	**$1.8**
	External	**-$2.0**	**$1.1**
	PJM M2M Payment	**-$1.2**	**-$0.5**
	All Other Facilities	**$0.9**	**$0.3**

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled $62 million in 2017, down 38 percent from 2016, reflecting fewer costly transmission outages in 2017.
  - In 2017, roughly $50 million (or 81 percent) were allocated to responsible Transmission Owners for transmission outages.
- Nearly $27 million of shortfalls accrued on the Central-East interface, most of which was attributable to transmission outages. [266]

265 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; 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.

266 Major transmission outages include: a) the Fitzpatrick-EDIC 345 line in January and February; b) the EDIC-Fraser 345 line in March and June; c) the Marcy-Coopers-Rock Tavern 345 lines in March; d) the Fraser-Gilboa and Fraser-Coopers 345 lines in April; e) the Marcy-New Scotland 345 line in May; and f) the Massena-Marcy 765 line in October.

  - A significant portion of shortfalls (>$5 million) resulted from other factors that include nuclear outages and unit commitments of capacity with voltage regulating equipment at the Oswego complex and the status of capacitors and SVCs.
    - These affect the voltage collapse limit on the Central-East interface and the resulting shortfalls are currently allocated to statewide.
    - However, these factors resulted in over $1.5 million of surpluses in the final week of December because of higher unit commitments and more in-service capacitors during this cold snap.

- Transmission constraints categorized as "North to Central" accounted for nearly $16 million of shortfalls in 2017.
  - 52 percent of shortfalls accrued on one of either the Marcy 765/345 kV lines or the Moses-Adirondack 230 kV lines when their parallel paths were OOS on many days in April, May, August, and September.
  - 41 percent of shortfalls accrued on Moses-South interface on 8 days (including one week in October) during which one 765 kV transmission line was OOS and reduced the interface transfer capability by nearly 2,500 MW.
    - The Moses-South interface is typically utilized to secure 115kV facilities that are not modeled in the day-ahead and real-time market software. (see Section III.D)

- Roughly $9 million of shortfalls accrued on New York City lines.
  - Most of these shortfalls were attributable to the outage of: a) the Dunwoodie-Motthaven 345 line from mid-April to the end of May; and b) the Springbrook-West 49th Street 345 line from early October to mid-November.
  - The three PAR-controlled lines between NJ and NYC (i.e., A, B & C lines) were OOS in various periods of April, May, and July to September, contributing to shortfalls as well.

- The transmission paths from Capital to Hudson Valley saw a notable increase in shortfalls because of more costly transmission outages in 2017.
  - Conversely, the West Zone and Long Island lines accrued substantially less shortfalls because of fewer outages.
    - In addition, contribution (to West Zone shortfalls) from different loop flow assumption between the TCC auction and the day-ahead market became smaller as average clockwise loop flows fell noticeably in 2017.

- 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. [267]

- 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 222 MW in that direction in 2016 and 197 MW in 2017.
- 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

- Transmission facilities in the "North to Central" group accounted for the largest share of balancing shortfalls in 2017, most of which accrued on several days:
  - Over \$3.5 million of shortfalls accrued on April 6 and 7.
    - The primary HQ interface was forced out on April 6 and returned the next day. During this period, the Moses-South interface was operated with greatly reduced limits for system reliability.
  - Over \$4.5 million of shortfalls accrued during morning hours on August 3.
    - The Marcy-Fraser Annex 345 kV Line returned to service later than scheduled. Operators reduced the BMS limit on the Edic-Marcy 345 kV Line to prevent EMS overflow because of large mismatches between its EMS and BMS flows.
  - Over \$1.0 million of shortfalls accrued on September 7.
    - Operators reduced transfer limits across the system to ensure security during a Solar Magnetic Event, which particularly caused large shortfalls in the North Zone.
- The 230 kV transmission facilities in the West Zone accounted for the second largest share of balancing congestion shortfalls in 2017.
  - Unexpected changes in loop flows were a key driver.
- The PAR operations 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 \$7.4 million of surpluses on the Central-East interface in 2017.

[267] This is categorized as "901/903 PARs" under "Long Island Lines" in the figure.

  - This, however, was offset by $1.8 million of shortfalls on the West Zone lines.
    - The reduction from the $5.7 million of shortfalls in 2016 resulted partly from the inclusion of West Zone constraints in the M2M JOA since May 2017.
    - The JK PARs accrued more shortfalls than the Ramapo and ABC PARs, reflecting that the JK PARs are operated less actively to reduce congestion.

G. 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.

- *Balance-of-Period Auctions* [268] – The NYISO conducts a Balance-of-Period Auction once every month for the remaining months in the same Capability Period for which the TCC will be effective. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Balance-of-Period Auction. Each monthly Balance-of-Period 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 2016/17 and Summer 2017 Capability Periods (i.e., the 12-month period from November 2016 through October 2017). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

268 The Balance-of-Period Auction started with the September 2017 monthly auction, which replaced the previous Reconfiguration Auction that was conducted only for the next one-month period.

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) four rounds of six-month auctions for the Winter 2016/17 Capability Period; (c) four rounds of six-month auctions for the Summer 2017 Capability Period; and (d) twelve Reconfiguration or Balance-of-Period auctions for each month of the 12-month Capability Period. [269] 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.[270]

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.

[269] In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable Reconfiguration/BOP auctions.

[270] 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 2016/17 and Summer 2017 Capability Periods

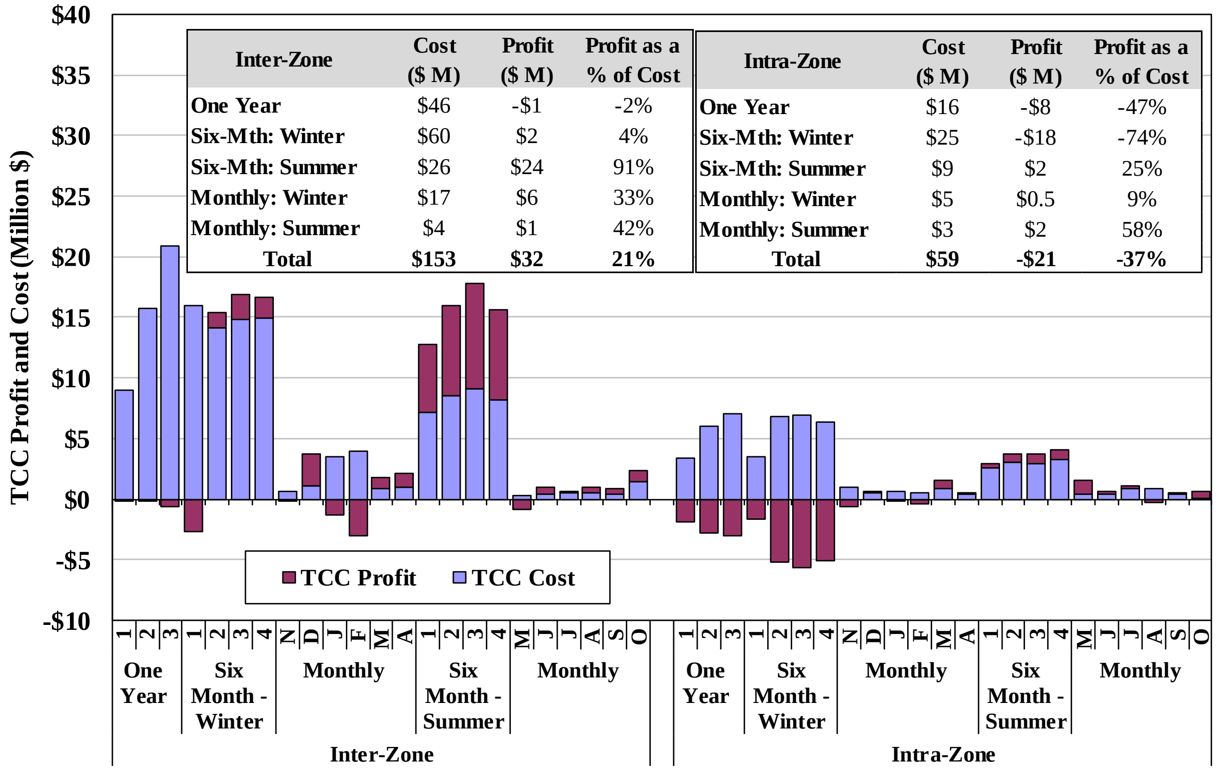


Table A-1 & Table A-2: TCC Cost and Profit by Path

The following two tables compare TCC costs with TCC profits for both intra-zonal paths and inter-zonal paths during the Winter 2016/17 and Summer 2017 Capability Periods (i.e., the 12-month period from November 2016 through October 2017). 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 2016/17 and Summer 2017 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	$30	-$7	-$11	-$1	$0	$0	$5	$0	$0	$0	$0	-$11	$0	$0	$0	**$6**
GENESE	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
CENTRL	$26	-$2	$10	$0	-$3	$1	$43	$0	$0	$0	$0	$0	$0	$0	$0	**$74**
MHK VL	$16	$0	$1	-$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14	$0	**$25**
NORTH	$5	$1	$9	$13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$29**
CAPITL	$0	$0	$0	-$1	$0	$7	-$3	$0	$0	$0	$0	$0	$0	-$2	$0	**$0**
HUD VL	-$1	$0	$0	$0	$0	$9	$0	$1	$1	$22	$0	$0	$0	$2	-$4	**$29**
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	$2	$0	$0	$0	$0	$0	**$2**
N.Y.C.	$0	$0	$0	$0	$0	$0	-$1	-$1	-$3	$10	$0	$0	$0	$0	$0	**$5**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8	$0	$0	$0	$0	**$6**
O H	$5	$0	$1	$0	$0	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	**$10**
H Q	$0	$0	$2	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$19**
NPX	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	**-$1**
PJM	$0	$0	-$7	$0	$0	$0	$11	$0	$1	$0	$0	$0	$0	$0	$0	**$5**
Total	**$84**	**-$7**	**$5**	**$22**	**-$3**	**$18**	**$55**	**-$1**	**-$2**	**$34**	**$8**	**-$11**	**$0**	**$15**	**-$4**	**$212**

Table A-2: TCC Profit by Path
Winter 2016/17 and Summer 2017 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	-$19	$5	$8	$1	$0	$0	$5	$0	$0	$0	$0	$6	$0	$0	$0	**$5**
GENESE	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$1**
CENTRL	-$12	$1	$0	$0	-$1	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	**-$8**
MHK VL	-$9	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$9**
NORTH	-$2	$1	$5	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$8**
CAPITL	$0	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	-$2	$0	**$0**
HUD VL	-$3	$0	$0	$0	$0	-$1	$0	$0	$0	$1	$0	$0	$0	$0	$2	**-$1**
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	$2	$0	$0	$0	$0	$0	**$2**
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	-$1	-$2	$0	$0	$0	$0	$0	**-$3**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
O H	-$4	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$5**
H Q	$0	$0	$1	$11	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	**$14**
NPX	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	**-$1**
PJM	-$1	$0	$3	$0	$0	$0	$8	$0	$0	$0	$0	$0	$0	$0	$0	**$11**
Total	**-$52**	**$7**	**$15**	**$15**	**-$1**	**$2**	**$16**	**$0**	**$0**	**$1**	**-$1**	**$8**	**$0**	**-$1**	**$2**	**$11**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a total profit of $11 million in the TCC auctions during the reporting 12-month period (November 2016 to October 2017), resulting in an average profitability (profit as a percent of TCC cost) of 5 percent. [271]

- Nearly 40 percent of total TCC purchase costs in this reporting period were spent on transmission paths sinking at the West Zone.

271 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 2016 and 2017. 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 2016 to October 2017.

- A total loss of \$52 million accrued on these paths, compared with a \$59 million profit on a \$102 million cost in 2016 and a \$25 million profit on a \$28 million cost in 2015.
- The loss was largely driven by lower-than-anticipated congestion in the West Zone and higher-than-anticipated congestion from West to Central and North to Central (see Figure A-48).
- Consequently, TCC buyers netted a \$38 million profit off a \$19 million purchase cost on transmission paths sinking at the Genesee, Central, and Mohawk Valley Zones.

H. 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, which is described in Section XI. 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:

- <u>Basecase Scenario</u> – 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.
- <u>PAR Relief Scenario</u> – 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.
- <u>PAR Loading Scenario</u> – 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.[272,273] 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 control areas;
- Convergence of prices between New York and neighboring control areas; and
- The efficiency of Coordinated Transaction Scheduling ("CTS"), including an evaluation of factors that lead to inconsistencies between:
  - The RTC evaluation, which schedules CTS transactions every 15 minutes, and
  - The RTD evaluation, which determines real-time prices every five minutes that are used for settlements.

272 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 Linden VFT Line, which connects New York City to PJM with a transfer capability of 315 MW. The Hudson Transmission Project ("HTP Line") connects New York City to New Jersey with a transfer capability of 660 MW.

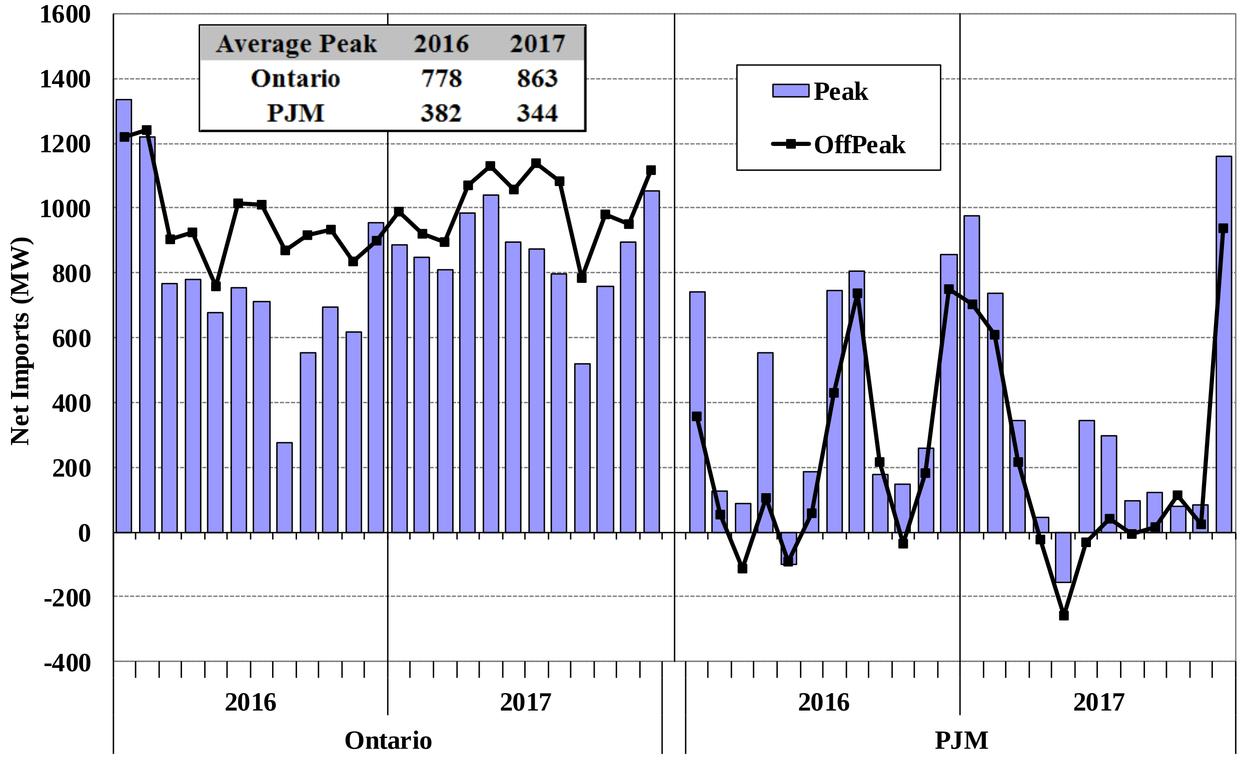
273 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the "Dennison Scheduled Line" and which is scheduled separately from the primary interface between New 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 2016 and 2017. 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
2016 – 2017



Average Peak	2016	2017
Ontario	778	863
PJM	382	344

Figure A-59: Monthly Average Net Imports from Quebec and New England
2016 – 2017

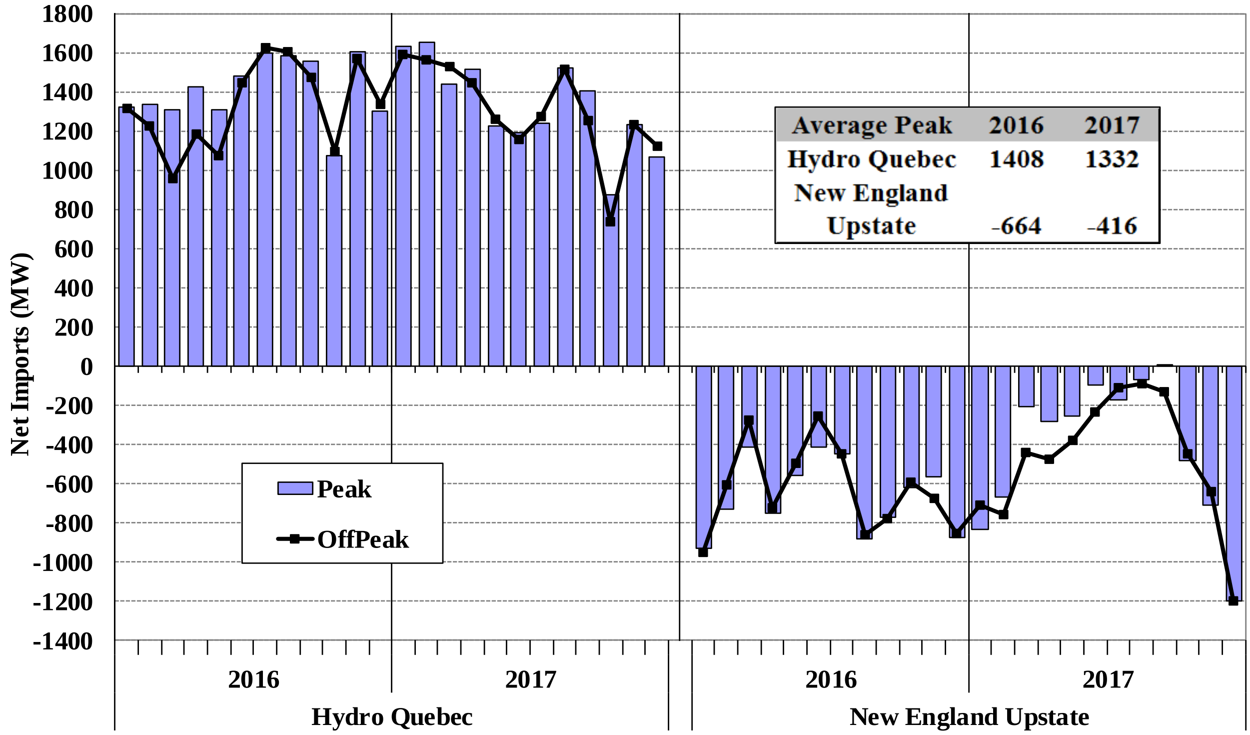


Figure A-60: Monthly Average Net Imports into New York City
2016 – 2017

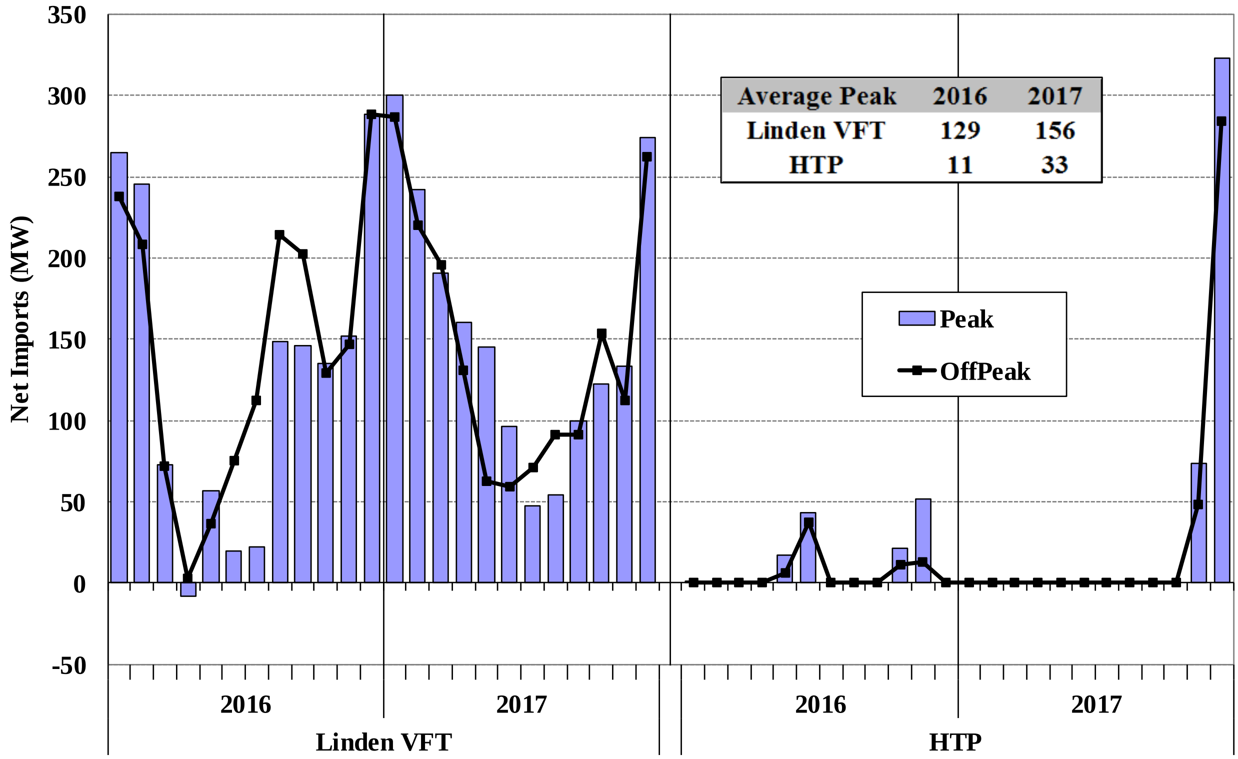
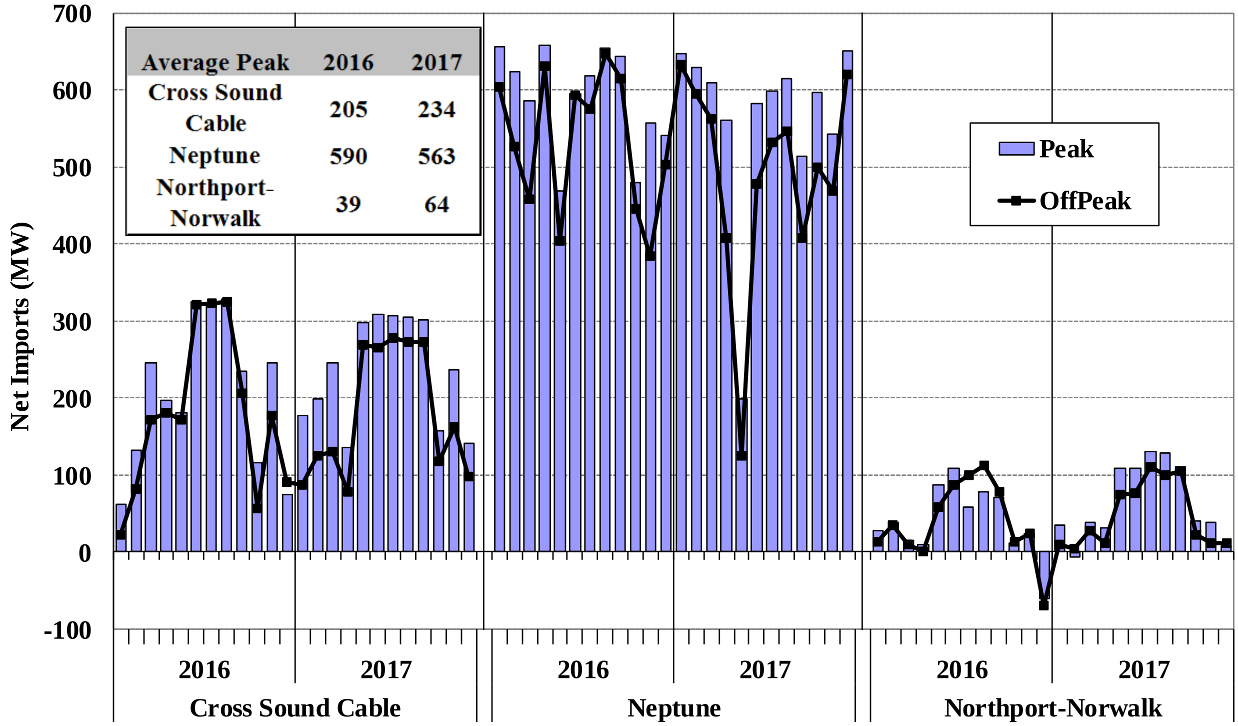


Figure A-61: Monthly Average Net Imports into Long Island
2016 – 2017



Key Observations: Average Net Imports

- Total net imports averaged roughly 3,170 MW (serving about 17 percent of all load) during peak hours in 2017, up 295 MW (or 10 percent) from 2016.
- Average net imports from neighboring areas across the primary interfaces increased 12 percent from about 1,905 MW in 2016 to 2,125 MW in 2017 during the peak hours.
  - Net imports from HQ averaged roughly 1,330 MW, accounting for 63 percent of net imports across the primary interfaces in 2017.
    - Imports from HQ fell modestly from 2016, reflecting the variations in transmission outages that reduced deliverability of HQ imports.
  - Average net imports from Ontario rose 85 MW (or 11 percent) from 2016 to 2017, due partly to less West Zone congestion (see Section III.C of the Appendix) and elimination of a NYISO procedure that previously reduced the TTC limit of the interface to manage transmission constraints on the 230+ kV networks. [274]
  - New York was typically a net importer from PJM and a net exporter to New England across their primary interfaces.

274 See *External Operating Limits*, presented by Wes Yeomans at the March 16, 2017 Operating Committee meeting.

    - This pattern (and the amount of net imports from PJM and net exports to New England) was generally consistent with the spreads in natural gas prices between these markets (i.e., NE > NY > PJM), which was most evident in the winter months.

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged about 860 MW during peak hours in 2017, up 3 percent from 2016.
    - Net imports across the Neptune Cable were normally fully scheduled during peak hours but fell notably in May 2017 because of a two-week-long cable outage.
    - 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 2016 and 2017.
- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged 190 MW during peak hours in 2017, up 35 percent from 2016.
    - The increase reflected higher LBMPs in the 345 kV system of New York City for the reasons discussed in Section III of the Appendix.

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 timing in the markets serve as barriers to full arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants cannot be expected to schedule additional power between regions unless they anticipate a price difference greater than these costs.

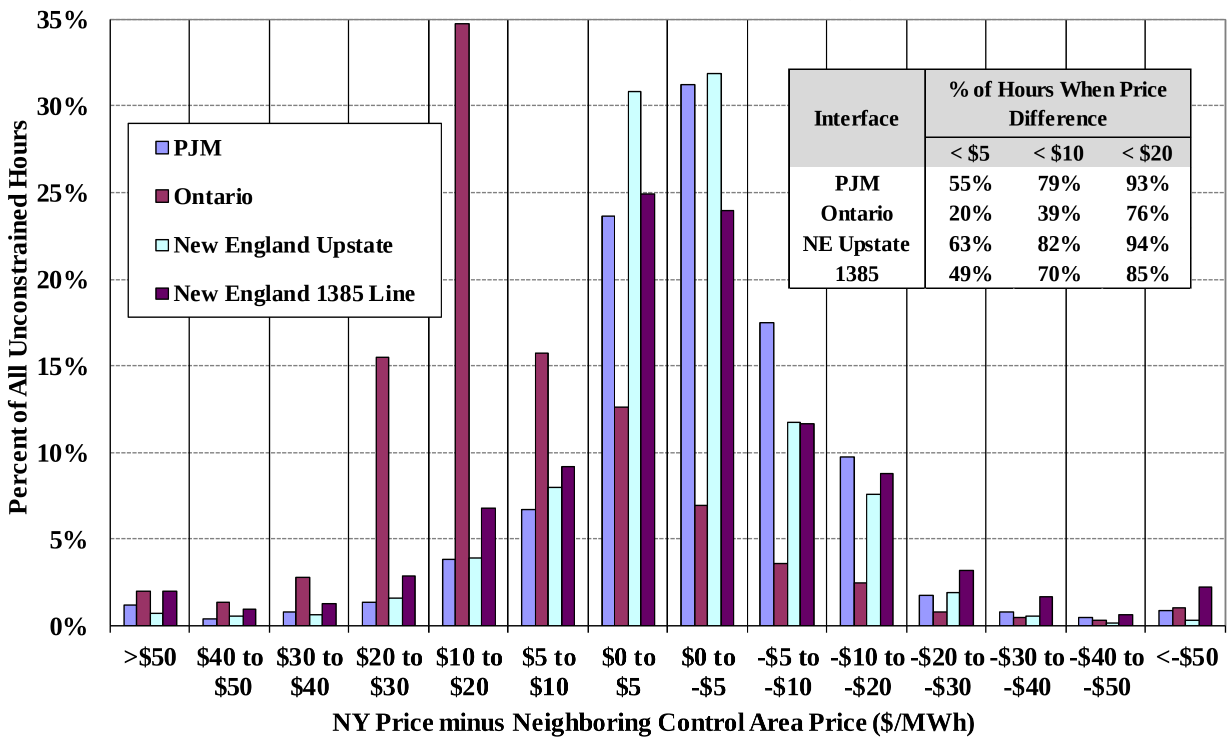
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-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 2017. 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.[275] 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, 2017



275 In these hours, prices in ISO-NE and PJM (i.e., prices at the NYISO proxy in each RTO market are used) reflect transmission constraints in those markets, but the price used here for Ontario (i.e., the Ontario HOEP) does not incorporate such constraints.

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 2017. 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. [276]

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.[277]

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

[276] 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.

[277] 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.

this will induce other firms to schedule counter-flow transactions, thereby offsetting the effect of the individual transaction. Ultimately, the net scheduled interchange is what determines how much of the generation resources in one control area will be used to satisfy load in another control area, which determines whether the external interface is used efficiently.

Table A-1: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2017

	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	-547	-$0.01	42%	$4	104	$0.35	56%	$3
Ontario	854	$11.22	89%	$88	87	$11.01	61%	$7
PJM	312	-$1.27	63%	$4	-47	-$1.39	66%	$8
Controllable Ties								
1385 Line	80	$1.01	76%	$2	-24	-$0.78	51%	$0
Cross Sound Cable	209	$2.73	80%	$8	-3	$1.97	53%	$0.1
Neptune	528	$6.58	89%	$32	-4	$5.46	54%	$0.0
HTP	22	$2.66	71%	$0.2	8	$1.13	62%	$0.6
Linden VFT	96	$4.06	92%	$6	54	$1.50	64%	$4

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 (excluding Ontario),[278] a substantial number of unconstrained hours (6 to 15 percent) had price differences exceeding $20/MWh for every interface in 2017.
  - Price differences at the CTS interfaces (PJM and ISO-NE) were smaller than for the hourly-scheduled Northport-to-Norwalk interface, reflecting that CTS has improved the utilization of the interfaces. The price differences at the CTS interface with ISO-NE were smaller than the price differences at the CTS interface with PJM, which is at least in part due to the better performance of CTS with ISO-NE.
- 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 2017.
- 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.

278 The distribution at the Ontario-NYISO border is skewed because the HOEP understates the border price when there is congestion to the border on the Ontario side.

- A total of $11 million in real-time production cost savings was achieved in 2017 from the real-time adjustments over the PJM and New England free-flowing interfaces.

- Although significant production cost savings have been achieved through transaction scheduling over New York's external interfaces, there was still 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 2017. 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 2017. 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 (i.e., 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

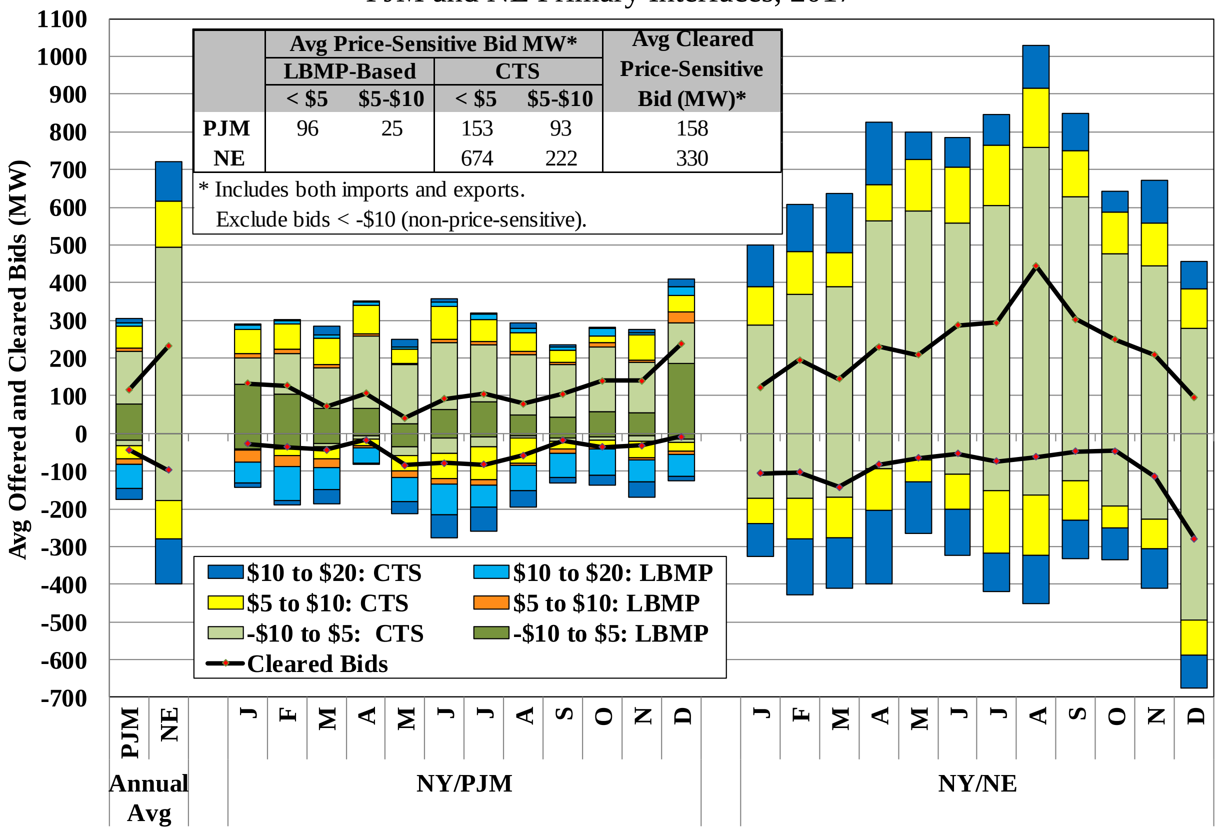
$10/MWh; and (c) between $10 and $20/MWh.[279] The traditional LBMP-based bids still co-exist with the CTS bids at the PJM interface (unlike the primary New England interface where only CTS bids are allowed). To make a fair comparison between the two primary interfaces, LBMP-based bids at the PJM interface 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 2017. 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, 2017



[279] 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.

Figure A-65: Transaction Profitability at the Primary PJM and NE Interfaces

The second analysis examines the profitability of scheduled transactions at the two CTS-enabled interfaces. In the bottom portion of Figure A-64, the column bars indicate the profitability spread of the middle two quartiles (i.e, 25 to 75 percentile) in 2017. The line inside each bar denotes the median value of the distribution. These are shown separately for imports and exports at the two interfaces. Scheduled transactions are categorized in the following three groups:

- *Day-ahead* – Transactions scheduled in the day-ahead market with no changes in the real-time market (i.e., day-ahead schedules equal real-time schedules);
- *Real-time* – Transactions not offered or scheduled in the day-ahead market but scheduled in the real-time market (i.e., day-ahead schedules are zero but real-time schedules are not zero); and
- *Day-ahead Schedule with Real-Time Adjustment* – Transactions scheduled in the day-ahead market and schedule adjusted in the real-time market (i.e., day-ahead schedules are higher or lower than real-time schedules).[280]

The bars in the top portion of the figure show the average quantity of scheduled transactions for each category in 2017 and the inset table summarizes the annual average profit.

[280] However, we exclude virtual imports and exports from the evaluation. These have a non-zero day-ahead schedule but do not bid/offer in real-time.

Figure A-64: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2017

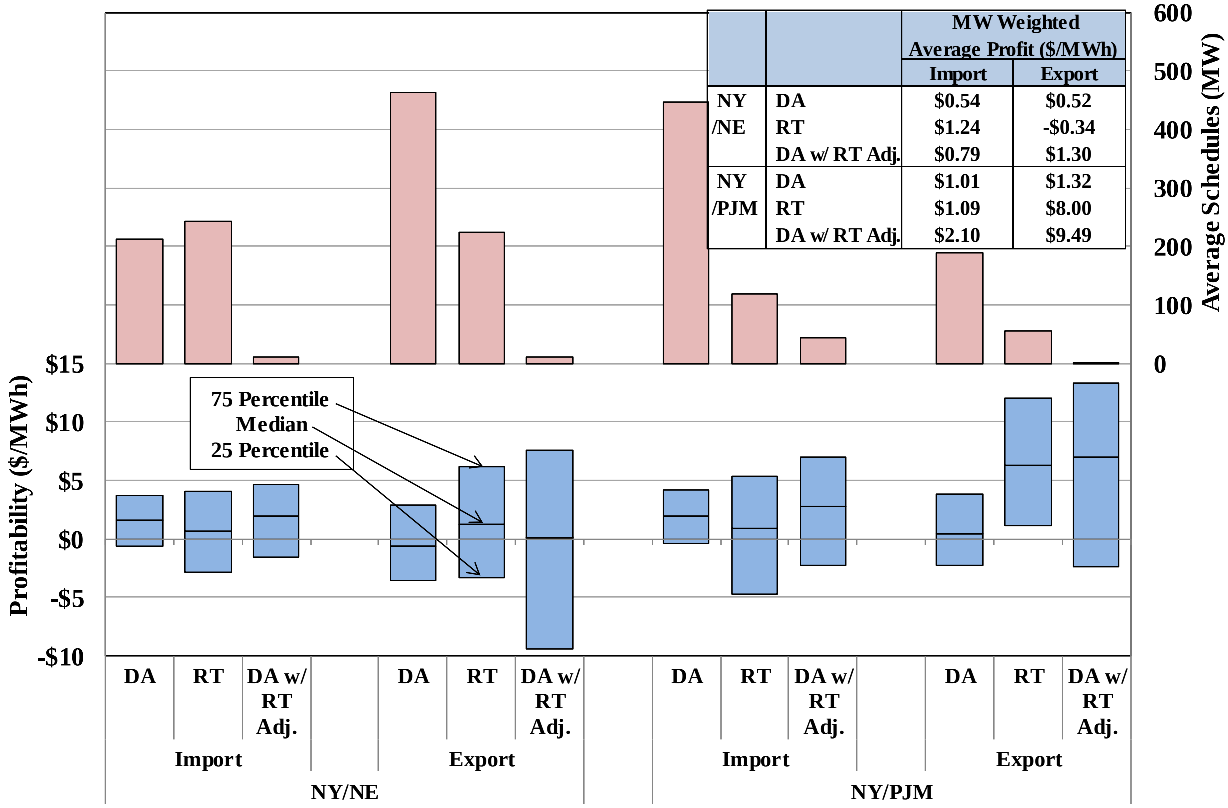


Table A-2: Efficiency of Intra-Hour Scheduling Under CTS

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 an 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. [281]

Table A-2 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2017. The table shows the following quantities:

281 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.

- % of All Intervals with Adjustment– 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.[282]
  - 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. [283]
  - Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
    - Real-time Curtailment[284] - 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[285] - 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.

282 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 287.

283 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.

284 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).

285 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).

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-66). 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[286,287] – 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.

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.

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286 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).

287 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, .

Table A-2: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and New England Interfaces, 2017

			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 > $20	Total
% of All Intervals w/ Adjustment			77%	12%	**89%**	58%	8%	**66%**
Average Flow Adjustment (MW)	Net Imports		14	0	**12**	12	17	**13**
	Gross		95	109	**97**	71	114	**76**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$3.7	$2.2	**$5.9**	$1.3	$2.4	**$3.7**
	Net Over-Projection by:	NY	-$0.1	-$0.1	**-$0.2**	-$0.2	-$1.4	**-$1.7**
		NE or PJM	$0.1	-$0.5	**-$0.5**	-$0.3	-$0.9	**-$1.2**
	Other Unrealized Savings		-$0.2	-$0.3	**-$0.4**	-$0.1	-$0.2	**-$0.3**
	Actual Savings		$3.5	$1.4	**$4.8**	$0.7	-$0.1	**$0.6**
Interface Prices ($/MWh)	NY	Actual	$25.63	$59.20	**$29.99**	$23.67	$59.84	**$28.26**
		Forecast	$26.39	$46.52	**$29.01**	$24.47	$52.95	**$28.09**
	NE or PJM	Actual	$27.29	$53.15	**$30.65**	$25.61	$58.52	**$29.79**
		Forecast	$27.02	$57.06	**$30.92**	$26.34	$55.45	**$30.04**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.76	-$12.68	**-$0.99**	$0.80	-$6.89	**-$0.17**
		Abs. Val.	$3.54	$34.35	**$7.54**	$3.40	$38.47	**$7.85**
	NE or PJM	Fcst. - Act.	-$0.27	$3.90	**$0.27**	$0.73	-$3.08	**$0.25**
		Abs. Val.	$3.84	$30.92	**$7.36**	$3.34	$40.78	**$8.09**

Figure A-65 - Figure A-66: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-65 shows the cumulative distribution of forecasting errors in 2017. 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-66 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-65: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2017

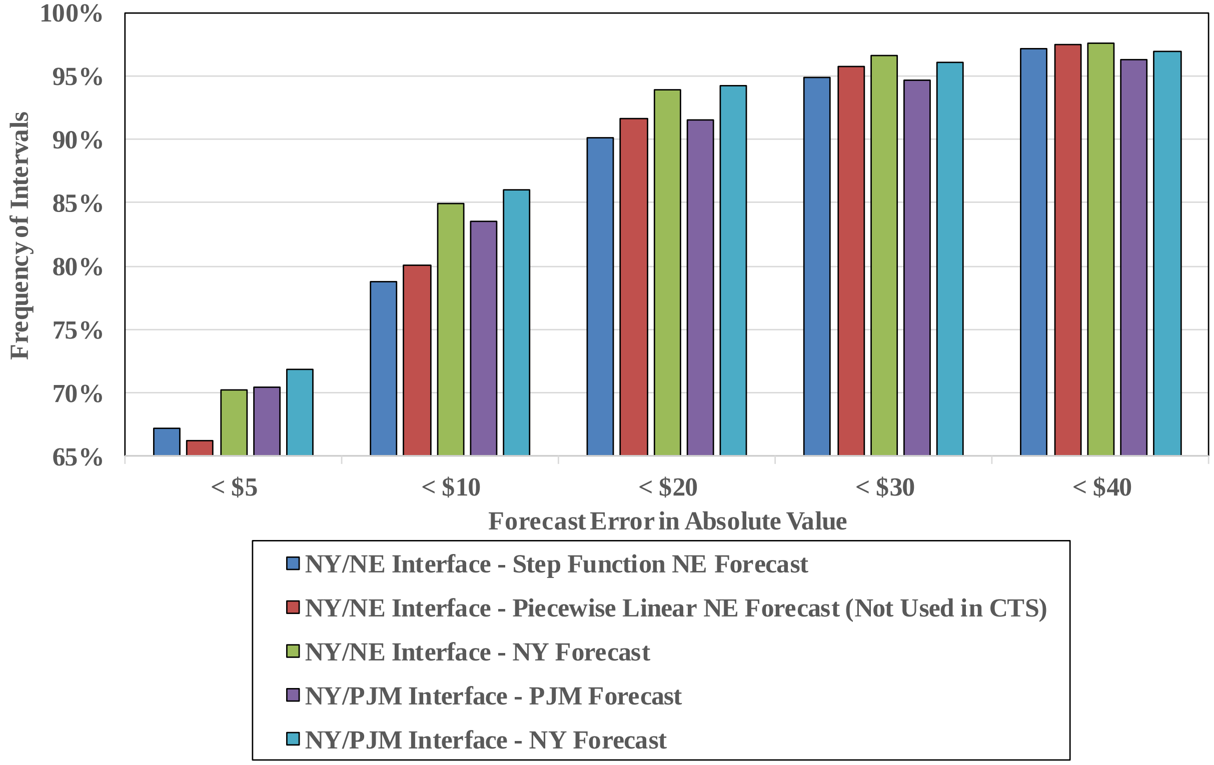
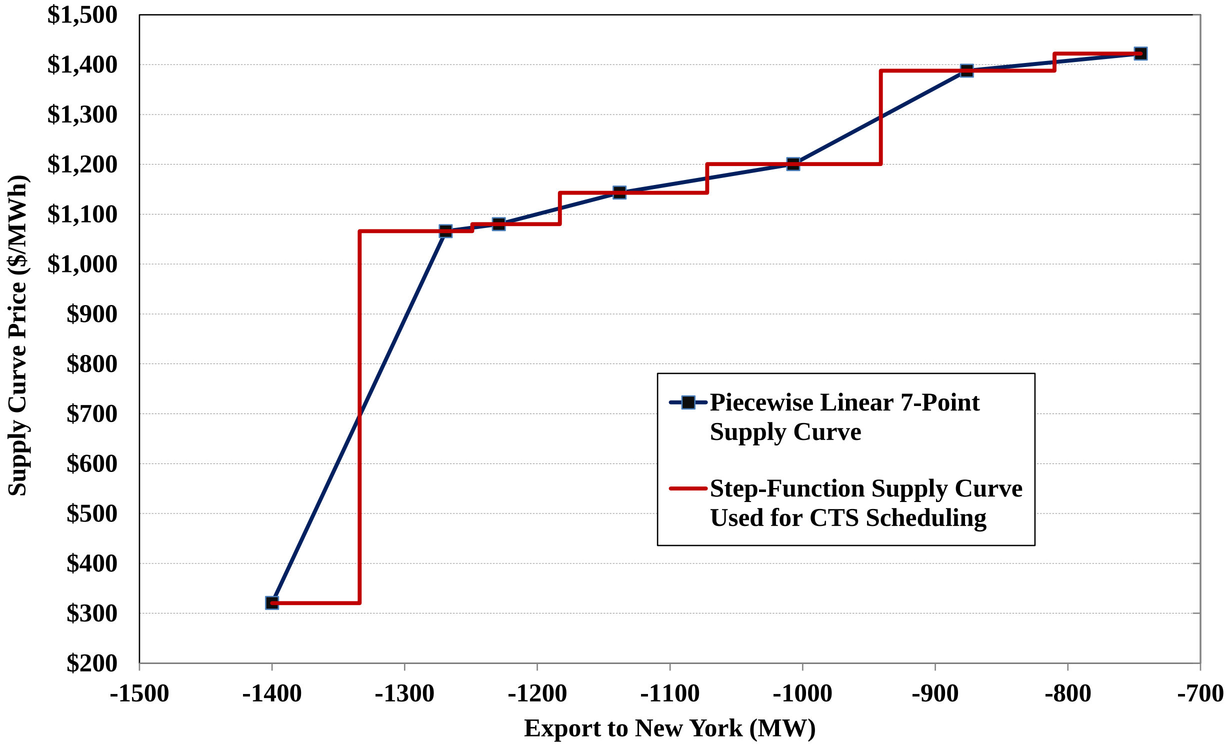


Figure A-66: Example of Supply Curve Produced by ISO-NE and Used by RTC



Key Observations: Evaluation of Coordinated Transaction Scheduling

- Participation in CTS at the primary PJM interface improved from 2016 to 2017.
  - Of all price-sensitive bids in the price range of -$10 to $10/MWh, the share of CTS bids increased from 30 percent in 2016 to 67 percent in 2017 and the average bid quantity (including both imports and exports) increased from 82 MW in 2016 to 245 MW in 2017 (see Figure A-63).
- Nonetheless, the average amount of price-sensitive bids (including both CTS and LBMP-based) submitted at the primary PJM interface was still significantly lower than at the primary New England interface (see Figure A-63).
  - In 2017, an average of 674 MW (including both imports and exports) were offered between -$10 and $5/MWh at the NY/NE interface, while only 249 MW were offered at the primary NY/PJM interface.
  - Likewise, the amount of cleared price-sensitive bids at NY/NE interface more than 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 89 percent of all quarter-hour intervals in 2017 at the NY/NE interface, higher than the 66 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.
  - On the ISO-NE border, most of the cleared transactions were offered at less than $5/MWh (see Figure A-63) and their average profit (including both imports and exports) was less than $1/MWh in 2017 (see Figure A-64).
    - However, on the PJM border, given that the NYISO charges to exports are often expected to exceed $5/MWh, it is not surprising that almost no CTS export bids were offered at less than $5/MWh (see Figure A-63) and the average profit (not including fees) for real-time exports was above $8/MWh (see Figure A-64). Most of the day-ahead exports are scheduled by participants with physical contract obligations and are not necessarily sensitive to these export fees.

- 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.

- We find significant improvement in the overall performance of CTS as the production cost savings increased:
  - At the New England border from $2.0 million in 2016 to $4.8 million in 2017, and
  - At the PJM border from -$0.1 million in 2016 to $0.6 million in 2017.
  - This improvement is likely attributable to factors including:
    - Better price forecasting: NYISO forecast error fell from 29 and 34 percent for the NE and PJM borders in 2016 to 25 and 28 percent in 2017, while ISO-NE forecast error fell from 33 percent in 2016 to 24 percent in 2017.
    - Improved performance of traders, which have become better at avoiding scheduling at particularly unprofitable times.

- 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 either market were less than $20/MWh, a total of $4.2 million out of projected $5.0 million of production cost savings were realized at the NY/NE and NY/PJM interfaces (see Table A-2).
  - 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 2017 (see Figure A-65). In particular,
  - Price forecast errors were less than $5/MWh in 70 to 72 percent of intervals at the NY/PJM interface, compared to 67 to 70 percent at the NY/NE interface; and
  - Price forecast errors were less than $10/MWh in 83 to 86 percent of intervals at the NY/PJM interface, compared to 79 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.

- 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, PJM, and ISO-NE would lead to more efficient interchange scheduling. The following sub-section evaluates factors that contribute to forecast errors by the NYISO.

D. Factors Contributing to Inconsistency between RTC and RTD

RTC schedules gas turbines and external transactions shortly in advance of the 5-minute real-time market, so its assumptions regarding factors such as the load forecast, the wind forecast, and the ramp profile of individual resources are important. The following analyses: (a) evaluate the magnitude and patterns of forecast errors and (b) examine how the assumptions regarding key inputs affect the accuracy of RTC's price forecasting.

Figure A-67– Figure A-68: Patterns in Differences between RTC Forecast Prices and RTD Prices

Figure A-67 shows a histogram of the resulting differences in 2017 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
2017

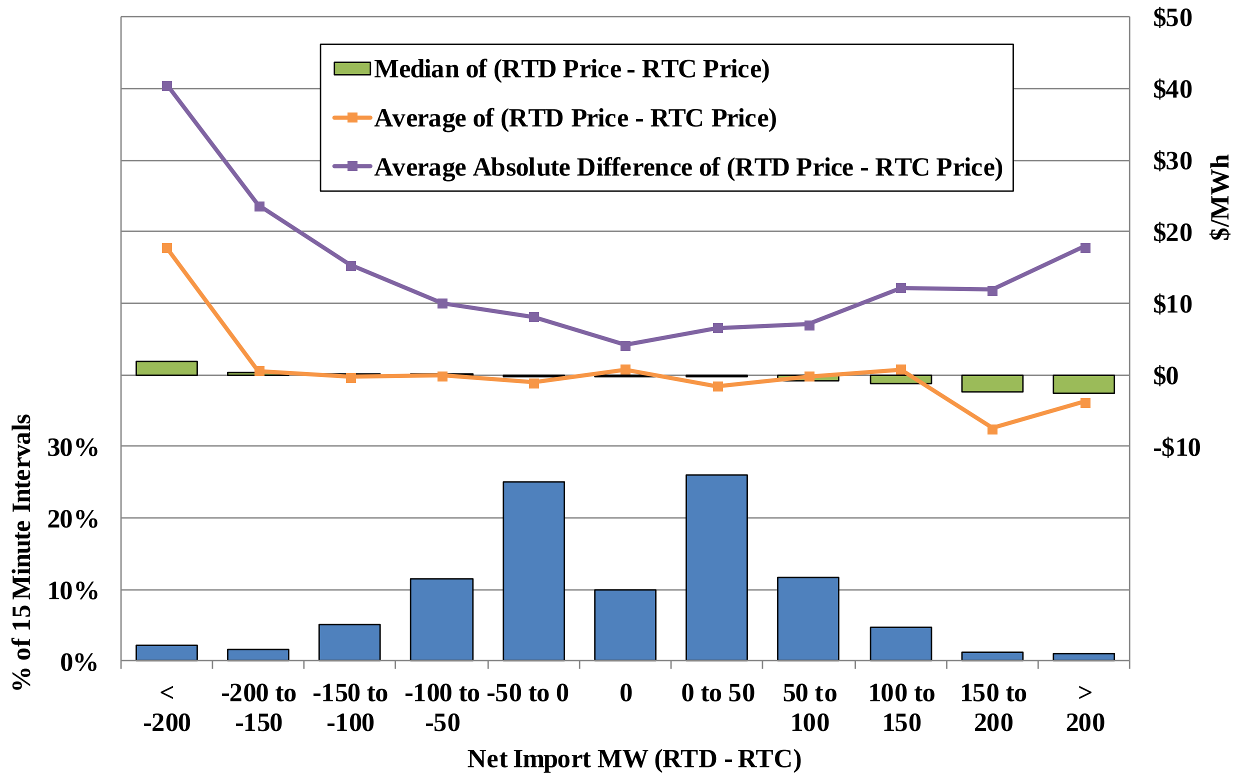


Figure A-68 summarizing these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels that exceed 100 MW by time of day, while the upper portion summarizes 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
2017

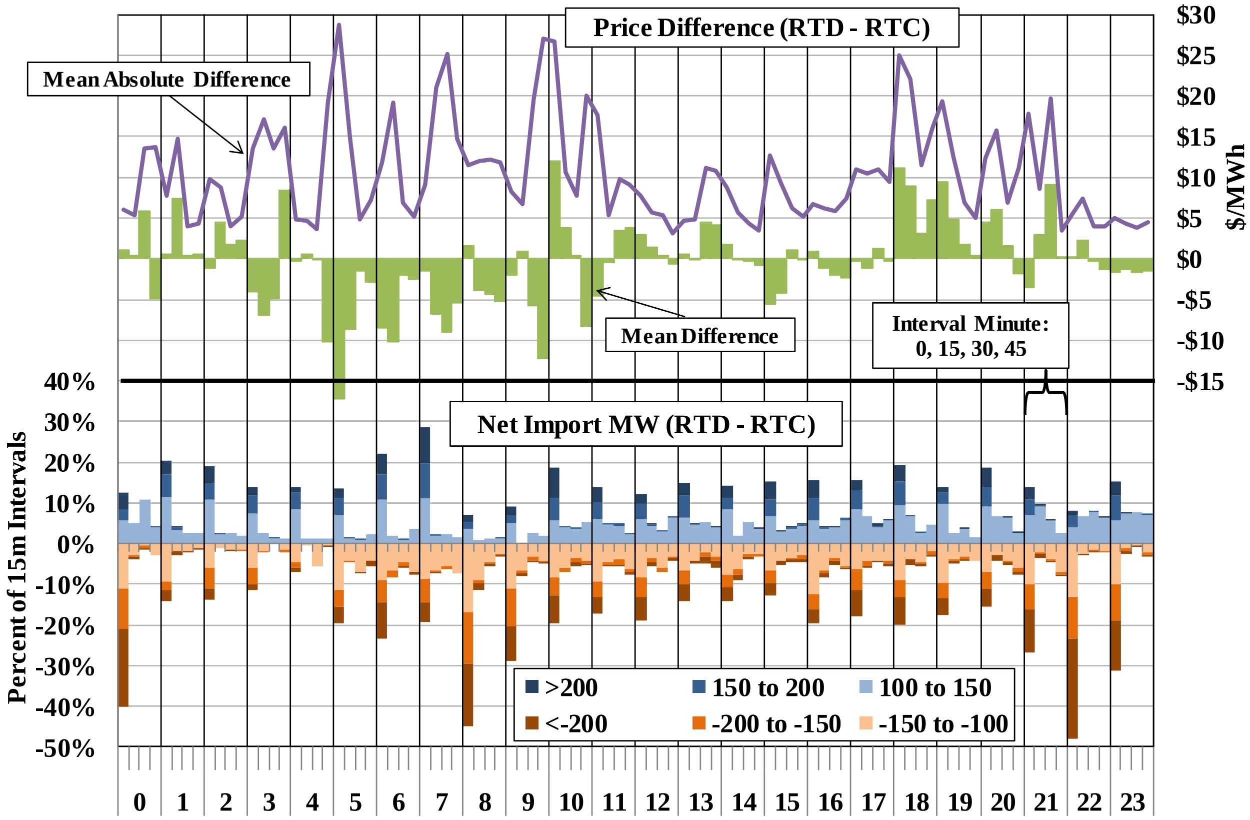


Figure A-69 – Figure A-72: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-69 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. While inconsistent ramp profile assumptions are not the only source of inconsistent RTC and RTD results, they illustrate how inconsistent modeling assumptions can lead to inconsistent pricing outcomes.

In RTD, the assumed level of net imports 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-69: Illustration of External Transaction Ramp Profiles in RTC and RTD

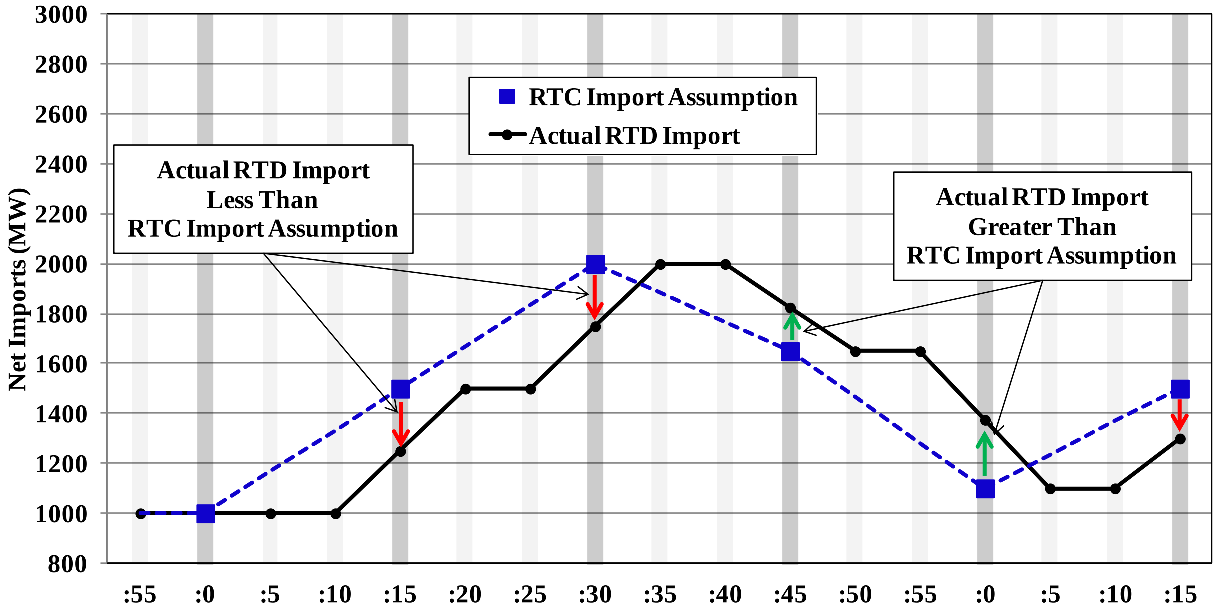


Figure A-70 to Figure A-72 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it distinguishes between factors that *cause* differences between RTC forecast prices and actual RTD prices (which we call "detrimental" factors) and factors that *reduce* differences between RTC forecast prices and actual RTD prices (which we call "beneficial" factors). [288]

RTC schedules resources with lead times of 15 minutes to one hour, including fast start units and external transactions. Inconsistency between RTC and RTD prices is an indication that some scheduling decisions may be inefficient. For example, suppose that RTC forecasts an LBMP of $45/MWh and this leads RTC to forego 100 MW of CTS import offers priced at $50/MWh, and suppose that RTD clears at $65/MWh because actual load is higher than the load forecast in RTC and RTD satisfies the additional load with 100 MW of online generation priced at $65/MWh. In this example, the under-forecast of load leads the NYISO to use 100 MW of $65/MWh generation rather than $50/MWh of CTS imports, resulting in $1,500/hour (= 100 MW *

288 Although RTC produces ten forecasts looking 150 minutes into the future, and RTD produces four forecasts looking one hour into the future that are in addition to the binding schedules and prices that are produced for the next five minutes, this metric is calculated comparing just the 15-minute ahead forecast of RTC (which sets the interchange schedules for the interfaces with PJM and ISO-NE that use CTS) to the 5-minute financially binding interval of RTD. Future reports will perform the analysis based on other time frames as well.

{\$65/MWh - \$50/MWh}) of additional production costs. Thus, the inefficiency resulting from poor forecasting by RTC is correlated with: (a) the inconsistency between the MW value used in RTC versus the one used in RTD, and (b) the inconsistency between the price forecasted by RTC versus the actual price determined by RTD. Hence, we use a metric that multiplies the MW-differential between RTC and RTD with the corresponding price-differential for resources that are explicitly considered and priced by the real-time models.

For generation resource, external transaction, or load i, our inconsistency metric is calculated as follows:

$$Metric_i = (NetInjectionMW_{i,RTC} – NetInjectionMW_{i,RTD}) * (Price_{i,RTC} – Price_{i,RTD})$$ [289]

Hence, for the load forecast in the example above, the metric is:

$$Metric_{load} = 100 \text{ MW} * (\$45/\text{MWh} – \$65/\text{MWh}) = -\$2{,}000/\text{hour}$$

For the high-cost generator in the example above, the metric is:

$$Metric_{generator} = -100 \text{ MW} * (\$45/\text{MWh} – \$65/\text{MWh}) = +\$2{,}000/\text{hour}$$

For the foregone CTS imports in the example above, the metric is:

$$Metric_{import} = 0 \text{ MW} * (\$45/\text{MWh} – \$65/\text{MWh}) = \$0/\text{hour}$$

The metric produces a negative value for the load forecast, indicating that the under-forecast of load was a “detrimental” factor that contributed to the divergence between the RTC forecast price and the actual RTD price. The metric produces a positive value for the generator that responded to the need for additional supply in RTD, indicating that the generator’s response was a “beneficial” factor that helped limit the divergence between the RTC forecast price and the actual RTD price. The metric produces a zero value for the foregone CTS imports, recognizing that the divergence was not caused by the CTS imports not being scheduled, but rather that their not being scheduled was the result of poor forecasting.

For PAR-controlled line i, our inconsistency metric is calculated across binding constraints c:

$$Metric_i = (FlowMW_{i,RTC} – FlowMW_{i,RTD}) * \sum_c \{(ShadowPrice_{c,RTC} * ShiftFactor_{i,c,RTC} – ShadowPriceMW_{c,RTD} * ShiftFactor_{i,c,RTD})\}$$

Hence, for a PAR-controlled line that is capable of relieving congestion on a binding constraint, if the flow on the PAR-controlled line is higher in RTD than in RTC and the shadow price of the constraint is higher in RTD than in RTC, the metric will produce a positive value, indicating that the PAR-controlled line had a beneficial inconsistency (i.e., it helped reduce the divergence between RTC and RTD congestion prices). However, if the flow on the PAR-controlled line decreases in RTD while the shadow price is increasing, the metric will produce a negative value, indicating that the PAR-controlled line had a detrimental inconsistency (i.e., it contributed to the

289 Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

divergence between RTC and RTD congestion prices). This calculation is performed for both "optimized" PARs and "non-optimized" PARs.[290]

For transmission constraints that are modeled, it is also important to quantify inconsistencies that lead to divergence between RTC and RTD. To the extent that such inconsistencies result from reductions in available transfer capability that increase congestion, the metric will produce a negative (i.e., detrimental) result. On the other hand, if inconsistencies result from an increase in transfer capability that helps ameliorate an increase in congestion, the metric will produce a positive (i.e., beneficial) result. For each limiting facility/contingency pair c, the calculation utilizes the shift factors and schedules for resources and other inputs i:

$$\text{Metric\_BindingTx}_c = \text{ShadowPrice}_{c,RTC} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTC} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\} \\ - \text{ShadowPrice}_{c,RTD} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTD} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$

Once the metric is calculated for each optimized PAR and each binding constraint, the transmission system is divided into regions and if a particular region has optimized PARs and/or binding constraints with positive and negative values, the following adjustments are used. If the sum across all values is positive, then each positive value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossPositive} and each negative value is discarded. If the sum across all values is negative, then each negative value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossNegative} and each positive value is discarded. This is done because when transfer capability on one facility in a particular region is reduced, the optimization engine often increases utilization of parallel circuits, so the adjustments above are helpful in discerning whether the net effect was beneficial or detrimental.

Example 1

The following two-node example illustrates how the metrics would be calculated if a transmission line tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose, RTC forecasts:

- Load_A = 100 MW and Load_B = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);
- Gen_A produces 250 MW at a cost of \$20/MWh and Gen_B produces 50 MW at a cost of \$30/MWh; and
- Thus, in RTC, Price_A = \$20/MWh, Price_B = \$30/MWh, Flow_{AB1} on Line 1 = 50 MW, so the ShadowPrice_{AB1} = \$30/MWh.

[290] A PAR is called "non-optimized" if the RTC and RTD models treat the flow as a fixed value in the optimization engine, while a PAR is called "optimized" if the optimization engines of the RTC and RTD models treat the flow as a flexible within some range.

Suppose that before RTD runs, Line 2 trips, reducing flows from Node A to Node B and requiring output from a $45/MWh generator at Node B. This will lead to the following changes:

- Only two transmission lines (Lines 1 and 3) with equal impedance connect A to B, so the shift factor of node A on Line 1 is 0.5 (assuming node B is the reference bus);
- Gen_A produces 200 MW at a cost of $20/MWh, Gen_B produces 50 MW at a cost of $30/MWh, and Gen_{B2} produces 50 MW at a cost of $45/MWh; and
- Thus, in RTD, $Price_A$ = $20/MWh, $Price_B$ = $45/MWh, $Flow_{AB1}$ on Line 1 = 50 MW, so the $ShadowPrice_{AB1}$ = $50/MWh.

In this example, the metric would be calculated as follows for each input:

- $Metric\_Load_A$ = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)
- $Metric\_Load_B$ = $0 = (-200MW - -200MW) * ($30/MWh - $45/MWh)
- $Metric\_Gen_A$ = $0 = (250MW - 200MW) * ($20/MWh - $20/MWh)
- $Metric\_Gen_B$ = $0 = (50MW - 50MW) * ($30/MWh - $45/MWh)
- $Metric\_Gen_{B2}$ = $750/hour = (0MW - 50MW) * ($30/MWh - $45/MWh)
- Metric_BindingTx = -$750/hour = $30/MWh * 0.333 * (250MW - 200MW) – $50/MWh * 0.5 * (250MW - 200MW)

Metric_BindingTx exhibits a negative value, indicating a detrimental factor because the divergence between RTC prices and RTD prices was caused by a reduction in transfer capability from Node A to Node B. $Metric\_Gen_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Example 2

The following two-node example illustrates how the metrics would be calculated if a generator tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose, RTC forecasts:

- $Load_A$ = 100 MW and $Load_B$ = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);
- Gen_A produces 200 MW at a cost of $20/MWh and Gen_B produces 100 MW at a cost of $20/MWh; and

- Thus, in RTC, $Price_A$ = $20/MWh, $Price_B$ = $20/MWh, $Flow_{AB1}$ on Line 1 = 33.33 MW, so the $ShadowPrice_{AB1}$ = $0/MWh.

Suppose that before RTD runs, Gen_B trips, increasing flows from Node A to Node B from 100 MW to 150 MW, requiring 50 MW of additional production from Gen_A and requiring 50 MW of production from a $45/MWh generator at Node B. This will lead to the following changes:

- Gen_A produces 250 MW at a cost of $20/MWh and Gen_{B2} produces 50 MW at a cost of $45/MWh; and

- Thus, in RTD, $Price_A$ = $20/MWh, $Price_B$ = $45/MWh, $Flow_{AB1}$ on Line 1 = 50 MW, so the $ShadowPrice_{AB1}$ = $75/MWh.

In this example, the metric would be calculated as follows for each input:

- $Metric\_Load_A$ = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)

- $Metric\_Load_B$ = $0 = (-200MW - -200MW) * ($20/MWh - $45/MWh)

- $Metric\_Gen_A$ = $0 = (200MW - 250MW) * ($20/MWh - $20/MWh)

- $Metric\_Gen_B$ = -$2,500/hour = (100MW - 0MW) * ($20/MWh - $45/MWh)

- $Metric\_Gen_{B2}$ = $1,250/hour = (0MW - 50MW) * ($20/MWh - $45/MWh)

- Metric_BindingTx = $1,250/hour = $0/MWh * 0.333 * (200MW - 250MW) – $75/MWh * 0.333 * (200MW - 250MW)

Metric_BindingTx exhibits a positive value, indicating a beneficial factor because excess transfer capability was utilized to reduce the divergence between RTC prices and RTD prices that was caused by the generator trip at Node B. $Metric\_Gen_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Categories of Factors Affecting RTC/RTD Price Divergence

RTC and RTD forecasts are based on numerous inputs. We summarize inputs that change between RTC and RTD in the following ten categories for the purposes of this analysis:

- Load Forecast Error – Combines the forecast of the load forecasting model with any upward or downward adjustment by the operator.

- Wind Forecast Error – Uses the blended value that is a weighted average of the wind forecasting model and the current telemetered value.

- External Transaction Curtailments and Checkout Failures

- Generator Forced Outages and Derates
- Generator Not Following Schedule – Includes situations where a generator's RTD schedule is affected by a ramp-constraint and where the ramp-constraint was tighter as a result of the generator not following its schedule in a previous interval.
- Generator on OOM Dispatch
- Generator Dispatch In Merit
- NY/NJ PARs and Other Non-Optimized PARs – Includes the A, B, C, J, K, and 5018 PAR-controlled lines.
- Transmission Utilization – Includes contributions from binding constraints and optimized PARs. This category is organized into the following regional transmission corridors:
    - West Zone
    - West Zone to Central NY
    - North Zone to Central NY
    - Central East
    - UPNY-SENY & UPNY-ConEd
    - New York City
    - Long Island
- Schedule Timing and Ramp Profiling – This includes differences that result from inconsistent timing and treatment of ramp between RTC and RTD for load forecast, external interchange, self-scheduled generation, and dispatchable generation. This is illustrated for external interchange in Figure A-69.

Figure A-70 summarizes the RTC/RTD divergence metric results for detrimental factors in 2017, while Figure A-71 provides the summary for beneficial factors. Figure A-72 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-70: Detrimental Factors Causing Divergence between RTC and RTD
2017

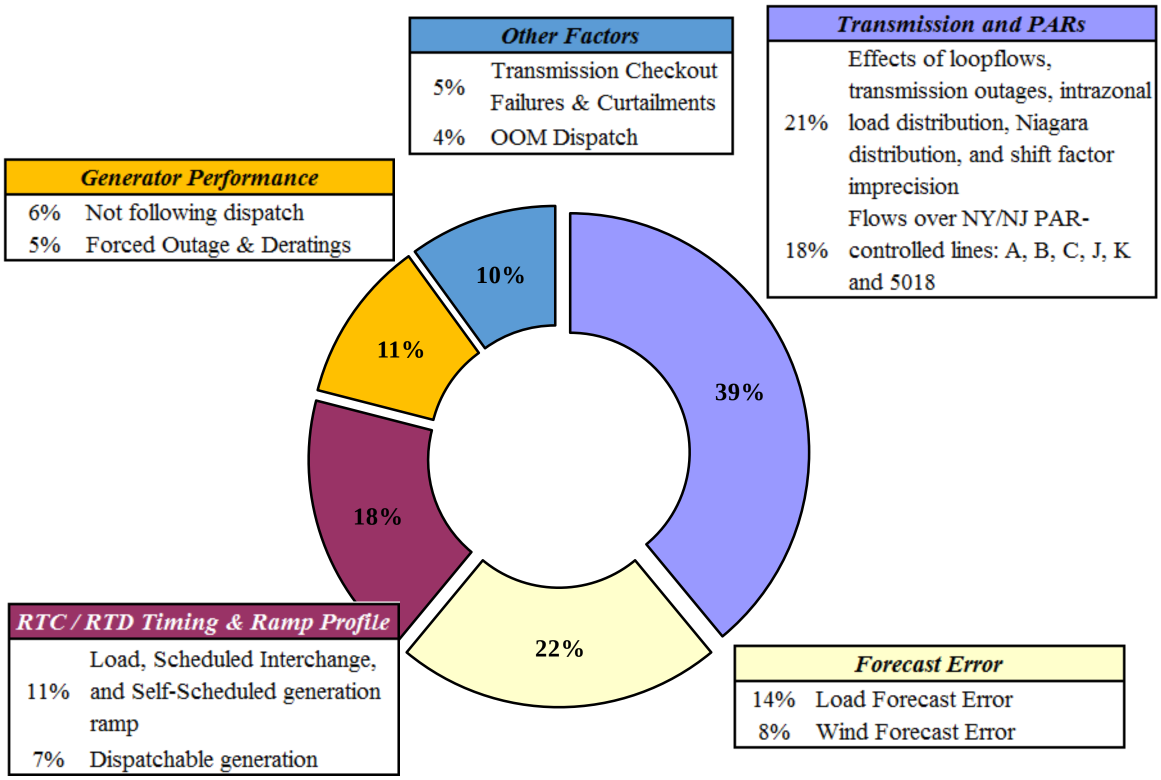
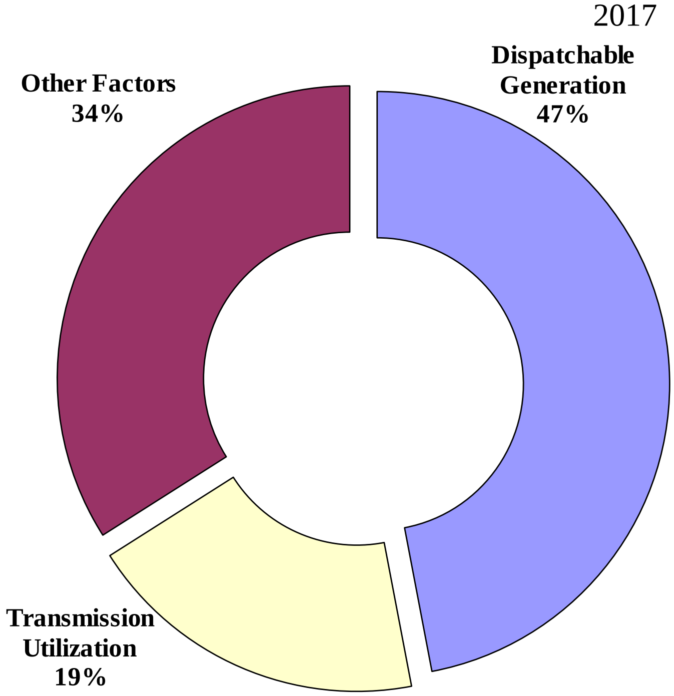
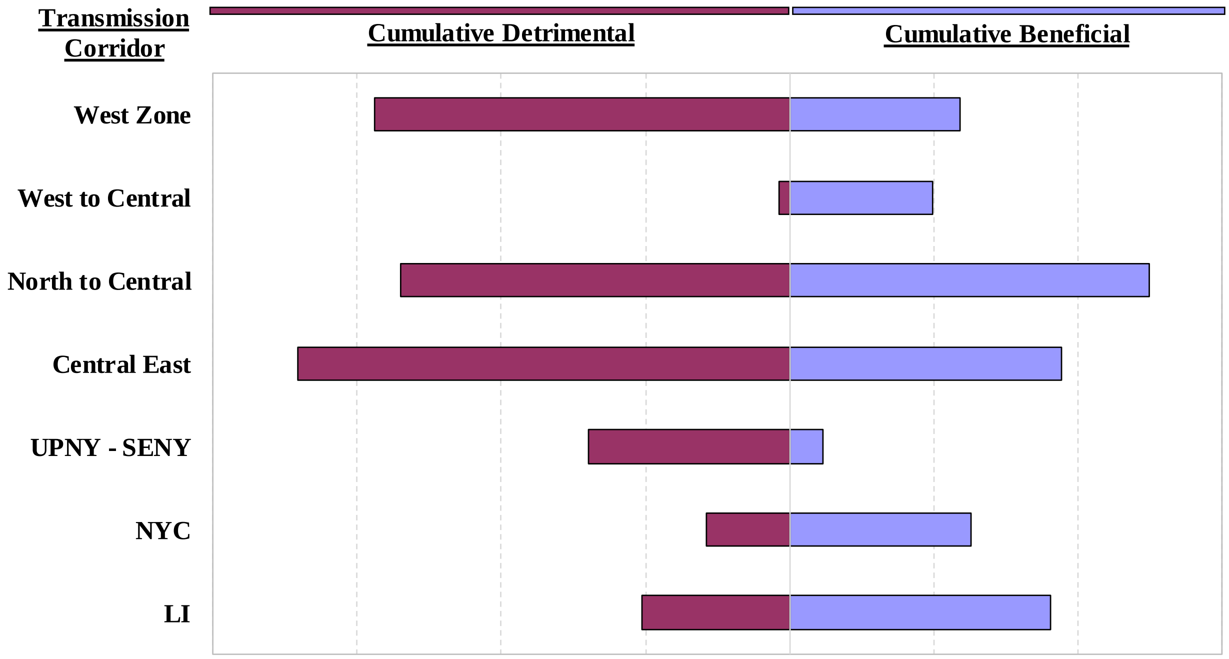


Figure A-71: Beneficial Factors Reducing Divergence between RTC and RTD
2017



"Dispatchable Generation"	
Factors for the redispatch of generators.	
"Other Factors"	
Wind Forecast Error	8%
Ramp Profile	7%
Load Forecast Error	6%
Non-optimized PARs	5%
Not-Following Dispatch	3%
Forced Outage / Derate	2%
OOM Dispatch	1%
Checkout Failures / Curtailment	1%
"Transmission Utilization"	
Includes optimized transmission and PAR operations responding to system conditions and beneficial changes in Loopflow.	

Figure A-72: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2017



Key Observations: Evaluation of Coordinated Transaction Scheduling

- The evaluations correlating RTC price forecast error with the magnitude of changes in scheduled interchange (which are shown in Figure A-67 and in Figure A-68) suggest that inconsistencies in the ramp assumptions that are used in RTC and RTD (which are illustrated in Figure A-69) contribute to forecasting errors on the NYISO side of the interfaces.
  - RTC price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions (see Figure A-67 and Figure A-68). This deters large schedule changes that might otherwise be economic, thereby reducing the efficiency gains from CTS.
  - However, it is evident from Figure A-68 that there must be other very significant drivers of divergence not explained by this particular inconsistency between RTC and RTD.
- In the assessment of detrimental factors, we find the following were the primary causes of divergence:
  - 39 percent from changes between RTC and RTD in network modeling, including the modeling of the transmission network and PAR-controlled lines.
  - The largest component was the flow across NYISO-to-PJM PAR-controlled lines (i.e., the A, B, C, J, K, and 5018 lines), which are assumed to remain at the most recent telemetered value plus an adjustment for changes in interchange between NYISO and PJM. However, the actual flows over these lines are affected by the re-

dispatch of resources in PJM and NYISO as well as when taps are taken to relieve congestion in the market-to-market congestion management process.

- Other significant contributions to this category include variations in transfer capability available to NYISO-scheduled resources resulting from: transmission outages, loop flows, inaccuracies in the calculation of shift factors for NYISO resources because of the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch, inaccuracies in the modeling of the Niagara generator, and changes in the distribution of load within a zone.
- 22 percent from errors in forecasting of load and production from wind turbines.
- 18 percent from inconsistencies in assumptions related to the timing of the RTC evaluation versus the RTD evaluation. This includes inconsistencies in the ramp profiles assumed for external interchange (which is depicted in Figure A-69), load, self-scheduled generators, and dispatchable generators.
- 16 percent from changes by a market participant or another control area, which are generally outside the NYISO's control, including:
  - 11 percent from generators experiencing a derating, forced outage, or not following dispatch.
  - 5 percent from transaction checkout failures and curtailments.

- In the assessment of beneficial factors, we find the following were the primary factors that helped reduce divergence:
  - 47 percent from dispatchable generation, which is to be expected since many generators are flexible and respond efficiently to changes in system conditions.
  - 24 percent from changes between RTC and RTD in network modeling, including the modeling of the transmission network and PAR-controlled lines. Some of this benefit results from random variations in transfer capability, while most of this benefit results from the flexibility of the transmission system to respond to changes in system conditions between RTC and RTD.
- In the detailed summary of transmission network modeling issues, we found that transmission facilities in some regions generally exhibited detrimental contributions while others exhibited significant beneficial contributions.
  - The following regions exhibited the most substantial detrimental contributions:
    - West Zone – Loop flows around Lake Erie are the primary driver of detrimental contributions in this category. Large variations in loop flows around Lake Erie lead to transmission bottlenecks near the Niagara plant. Reductions in available transfer capability after RTC runs lead to higher congestion costs in RTD, while increases in available transfer capability after RTC runs lead to lower congestion costs in RTD.

- Central East – Transfer capability across the Central East interface as well as the impacts of resources on the interface (i.e., resource shift factors) are affected by changes in the status of capacitors, SVCs, and generation with AVR equipment. These frequently change throughout the operating day and the timing of these changes are frequently not in-sync, leading to inconsistencies between RTC and RTD.
- UPNY-SENY & UPNY-ConEd – The primary drivers of in this category occur during TSA operations when large reductions in transfer capability and are imposed. These are not always in-sync in RTC and RTD. A portion of this category is driven by inconsistencies in the evaluation horizon between RTC and RTD.

- The following regions exhibited the most substantial beneficial contributions:
  - West Zone to Central NY – These were mostly Dysinger East and West to Central interface constraints. This category shows that large beneficial contributions tend to occur from the flexibility of the model to change in response to system conditions when there are not significant changes in topology, transfer capability, or the timing of the constraint's imposition between RTC and RTD.
  - Long Island and New York City – These tend to exhibit beneficial contributions because of the flexibility of the model to adapt to system conditions. These areas also benefit from having a large number of PAR-controlled lines that are normally used to minimize congestion.
- The North Zone to Central NY exhibited large beneficial and detrimental contributions.
  - The large beneficial contributions result primarily because: (a) the flexibility of the lines to increase or reduce transfers in response to variations in intermittent generation from hydro and wind units, and (b) this category includes the effects of the modeling the Saint Lawrence PAR-controlled lines as flexible in response to congestion.
- The large detrimental contributions result primarily because of: (a) circumstances when the Moses South interface is imposed or the limit changes and the timing is not synced-up between RTC and RTD, and (b) transfer limit adjustments on other binding constraints that result from inconsistencies between the modeled flows and the actual flows over the Saint Lawrence PAR-controlled lines (because they are not actually used to manage congestion in the manner assumed by RTC and/or RTD).

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 2017:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *Gas Turbine Start-Up Performance* – This sub-section analyzes the performance of gas turbines in responding to a signal to start-up in the real-time market.
- *M2M Coordination* – This sub-section evaluates the operation of 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 more generally.
- *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 units when it is economic to do so.[291] 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 units and 30-minute units when it is economic to do so.[292] 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

291 Quick-start units can start quickly enough to provide 10-minute non-synchronous reserves.

292 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

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-73: Efficiency of Gas Turbine Commitment

Figure A-73 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 price components to be greater than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

Figure A-73 shows the average quantity of gas turbine capacity started each day in 2017. 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; and
- Gas turbines that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period.

Starts are shown separately for quick start 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,[293] or by an out-of-merit (OOM) instruction.

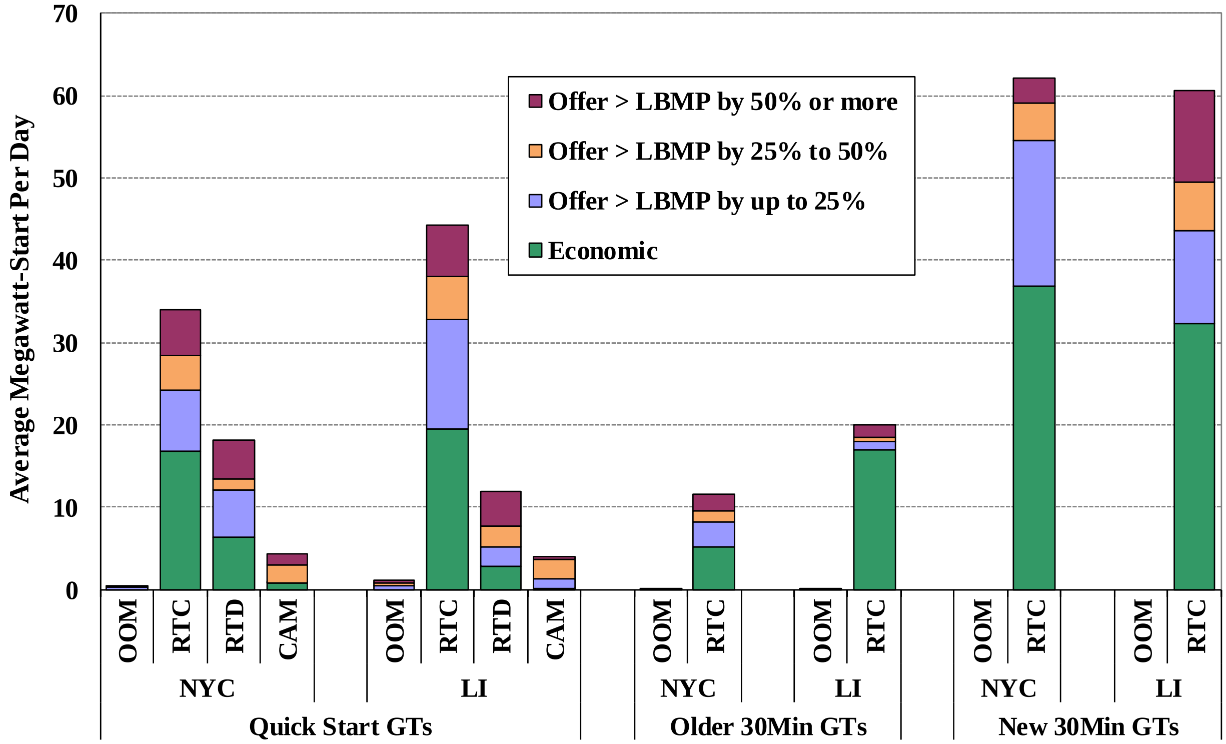
The real-time market software currently uses a two-pass mechanism for the purpose of dispatching and pricing. [294] The first pass is a physical dispatch pass, which produces physically

293 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.

294 The current two-pass mechanism was first implemented on February 28, 2017. This implementation eliminated the third pass from the prior three-pass mechanism and uses prices from the second pass. Previously, the additional third pass produced LBMPs for the market interval, which treated gas turbines

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 pricing pass, which treats gas turbines as flexible resources that can be dispatched between zero and the maximum output level and produces LBMPs for the market interval.

Figure A-73: Efficiency of Gas Turbine Commitment
2017



Key Observations: Efficiency of Gas Turbine Commitment

- Most gas turbine commitments were made by RTC. In 2017, roughly 85 percent was committed by RTC, 14 percent by RTD and RTD-CAM, and less than 1 percent through OOM instructions.

- Of all gas turbine commitments in 2017, only 51 percent were clearly economic (indicated by green bars in the figure).

that are not economic (i.e., dispatched at zero) in the second pass but are still within their minimum run times as inflexible (i.e., forced on and dispatched at the maximum output level). Consequently, when uneconomic gas turbines were forced on in the third pass, it led some economic gas turbines to not set the LBMP. This change in price-setting rules was a significant improvement and results in market clearing prices that are more consistent with the operational needs of the system.

- An additional 23 percent of commitments were cases when the gas turbine offer was within 125 percent of LBMP, a significant portion of which may be efficient for the reasons discussed earlier in this subsection.

- Nonetheless, there were many commitments in 2017 when the total cost of starting gas turbines exceeded the LBMP by 25 percent or more.
  - The divergence between RTC and RTD may lead an economic RTC-committed GT to be uneconomic in RTD (see subsection IV.D for analysis of divergence between RTC and RTD); and
  - Although the newly implemented fast-start price-setting rule 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. The Commission has also recognized the need for the price-setting logic to consider the start-up and other commitment costs of gas turbines. [295]

B. Performance of Gas Turbines in Responding to Start-up Instructions

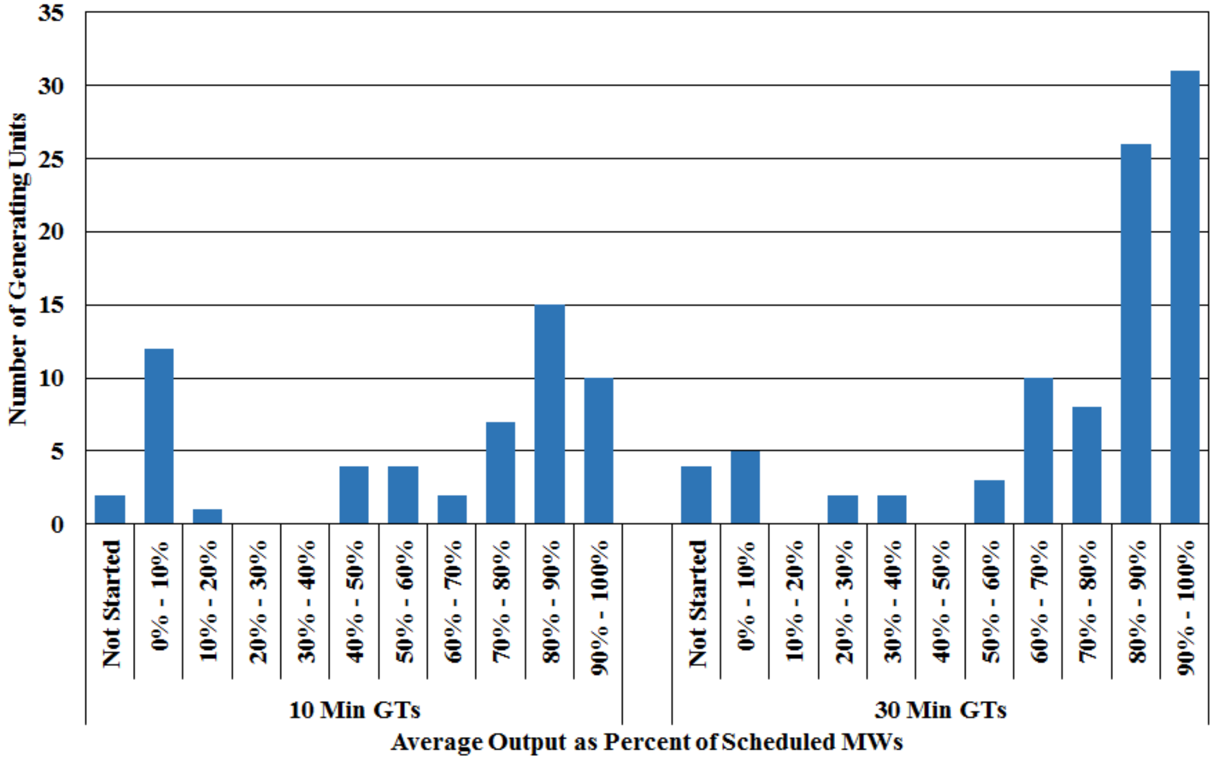
Wholesale markets should provide efficient incentives for resources to help the ISO maintain reliability by compensating resources consistent with the value they provide. This sub-section evaluates the performance of GTs in responding to start-up instructions in the real-time market.

Figure A-74: Average Production by GTs after a Start-Up Instruction

Figure A-74 summarizes the performance of offline GTs in responding to start-up instructions that result from in-merit commitment by RTC (excluding self-schedules). The figure reports the average performance in 2017 for GTs that received a start instruction in 2017 and the average performance in 2016 for GTs that did not receive a start instruction in 2017. Performance is shown for 10-minute GTs (offering Non-Synchronous 10-Minute Reserves) and 30-minute GTs (offering Non-Synchronous 30-Minute Reserves). For each GT, the figure shows the average number of MWs the unit was producing after 10 or 30 minutes as a percent of its offer.

295 In Docket EL18-33-000, see *Order Instituting Section 206 Proceeding and Commencing Paper Hearing Procedures and Establishing Refund Effective Date re New York Independent System Operator, Inc.*, dated December 21, 2017 and comments of Potomac Economics, dated February 12 and March 14, 2018.

Figure A-74: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts



Key Observations: Performance of Gas Turbines after a Start-up Instruction

- Gas turbines exhibited a wide range of performance in 2017.
  - For 10-minute units, only 46 percent of units that were started economically by RTC at least one time in 2016 or 2017 had an average response of 80 percent or better. The average response across all of these units was just 61 percent of the amount offered.
  - For 30-minute units, 66 percent of units that were started economically by RTC at least one time in 2016 or 2017 had an average response of 80 percent better. The average response across all of these units was just 77 percent of the amount offered.
  - Six gas turbines were not evaluated because they were never started economically by RTC in 2016 or 2017 and the available data does not allow us to accurately evaluate the performance of gas turbines during other types of start-ups.
- Units that perform poorly in response to start-up instructions tend to have higher EFORds, which leads to proportional reductions in their capacity payments. However, the EFORd calculation is not designed to reflect how well a fast-start unit responds following a start-up instruction. For example, if a 10-minute GT is producing 0 MW after 10 minutes and takes 25 minutes to start, it will be treated as having a successful service hour. Consequently, the EFORds of gas turbines are generally much lower than the average amounts not produced after start-up.

- For 10-minute units, the average EFORd was 11 percent during the summer months, while the average under-performance (i.e., the difference between the offered amount and the actual production) across these units was just 39 percent of the amount offered after 10 minutes.
- For 30-minute units, the average EFORd was 7 percent during the summer months, while the average under-performance across these units was just 23 percent of the amount offered after 30 minutes.

C. 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.[296] 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.
- PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, three sets of PAR-controlled lines between New York and New Jersey can be adjusted to reduce overall congestion.[297]

Ramapo PARs have been used for the M2M process since its inception, while ABC and JK PARs were incorporated into this process later in May 2017 following the expiration of the ConEd-PSEG Wheel agreement. The NYISO and PJM have an established process for identifying constraints that will be on the list of pre-defined flow gates for Re-dispatch Coordination and PAR Coordination.[298]

Figure A-75: NY-NJ PAR Operation under M2M with PJM

The use of Re-dispatch Coordination has been infrequent since the inception of M2M, while the use of PAR Coordination had far more significant impacts on the market. Hence, the following analysis focuses on the operation of NY-NJ PARs in 2017.

Figure A-75 evaluates operations of these NY-NJ PARs under M2M with PJM from May to December 2017 during periods of noticeable congestion differential between NY and PJM. For each PAR group in the figure, the evaluation is done for the following periods:

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296 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

297 These include two Ramapo PARs that control the 5018 line, three Waldwick PARs that control the J and K lines, and three PARs that control the A, B, and C lines.

298 The list of pre-defined flowgates is posted at http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/CoordinatedFlowgatesandEntitlements.mht.

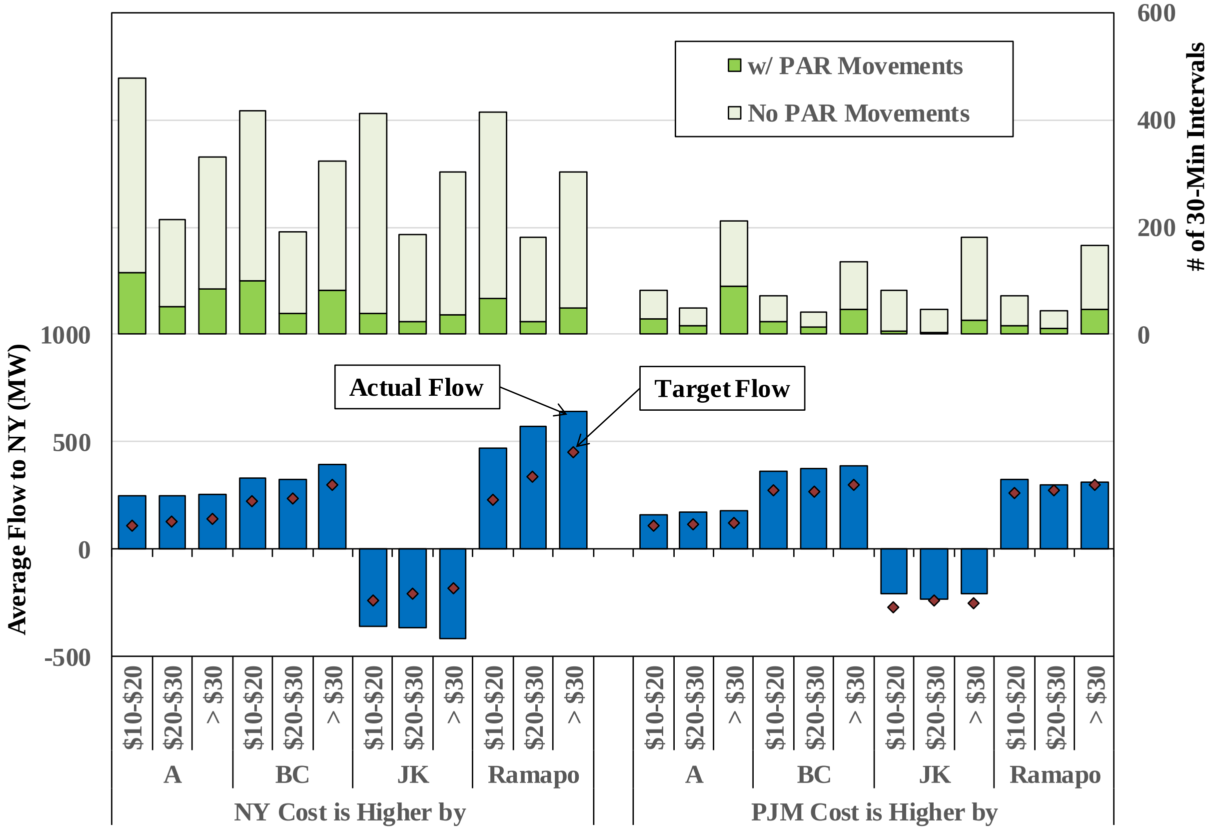
- When NY costs on relevant M2M constraints exceed PJM costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh.

- When PJM costs on relevant M2M constraints exceed NY costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh;

The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.

In the figure, the top portion shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements; while the bottom portion shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

Figure A-75: NY-NJ PAR Operation under M2M with PJM
May – December, 2017



Key Observations: PAR Operation under M2M with PJM

- The PAR operations under the M2M JOA with PJM has provided benefit to the NYISO in managing congestion on coordinated transmission flow gates.

- o We have observed instances of efficient M2M coordination as PARs were moved in the direction to reduce overall congestion costs in a relatively timely manner.
- o Balancing congestion surpluses frequently resulted from this operation on the Central-East interface and transmission paths into Southeast New York (an estimated over $7 million of surpluses in 2017, see Section III.B in the Appendix), indicating that it reduced production costs and congestion in New York.

- Nonetheless, there were instances when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.
- o During all the 30-minute periods when the congestion differential between PJM and NYISO exceeded $10/MWh across these PAR-controlled lines (which averaged less than five times per day), PAR taps were taken in only 21 percent of these intervals.
  - o Overall, each PAR was adjusted 1 to 5 times per day on average, which was well below the operational limits of 20 taps/day and 400 taps/month.
- o Although actual flows across these PAR-controlled lines typically exceeded their M2M targets towards NYISO during these periods, flows were generally well below their seasonal normal limits (i.e., over 500 MW for each line).
- o In some cases, PAR adjustments were not taken because of:
  - o Difficulty predicting the effects of PAR movements under uncertain conditions;
  - o Adjustment would push actual flows or post-contingent flows close to the limit;
  - o Adjustment was not necessary to maintain flows above the M2M target (even though additional adjustment would have been efficient and reduced congestion);
  - o The transient nature of congestion; and
  - o Mechanical failures (e.g., stuck PARs).
  - o However, we lack the information necessary to determine how often some of these factors prevented PAR adjustments.

- These results highlight potential opportunities for increased utilization of M2M PARs.
- o However, the NYISO operators do not have a congestion or production cost forecasting model that can be used to determine the efficient schedule for these M2M PARs, so it will be difficult to optimize the PAR operation without a model to forecast the impacts of PAR tap adjustments in real-time.
- o In Section IV.D, our evaluation of factors causing divergences between RTC and RTD identifies the operation of the NY-NJ PARs as a net contributor to price divergence. This is because RTC has no information related to potential tap changes. Consequently, RTC may schedule CTS imports to relieve congestion, but, if after RTC kicks-off, the operator taps the A, B, C, and 5018 PARs in response to the

congestion, it often leads the imports to be uneconomic. Hence, forecasting PAR tap adjustments would also help reduce divergences between RTC and RTD.

D. Operation of Controllable Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows below applicable limits. However, there are still a significant number of controllable transmission lines that source and/or sink in New York. This includes HVDC transmission lines, PAR-controlled lines, and 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.[299] 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-76: 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 2017.

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 2017. 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). These lines are

299 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.

currently scheduled in accordance with the M2M coordination agreement with PJM, which is discussed in Subsection C. [300]

- Two between Long Island and New York City: Lake Success-Jamaica PAR (903 line) and Valley Stream-Jamaica PAR (901 line). These 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 NYC 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.[301]

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.[302] 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.

300 Prior to May 1, 2017, the A, B, C, J, & K lines supported the operation of the ConEd-PSEG wheeling agreement whereby 1,000 MW was ordinarily scheduled to flow out of NYCA on the J & K lines and 1,000 MW was scheduled to flow into New York City on the A, B, & C lines.

301 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 high-priced region towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

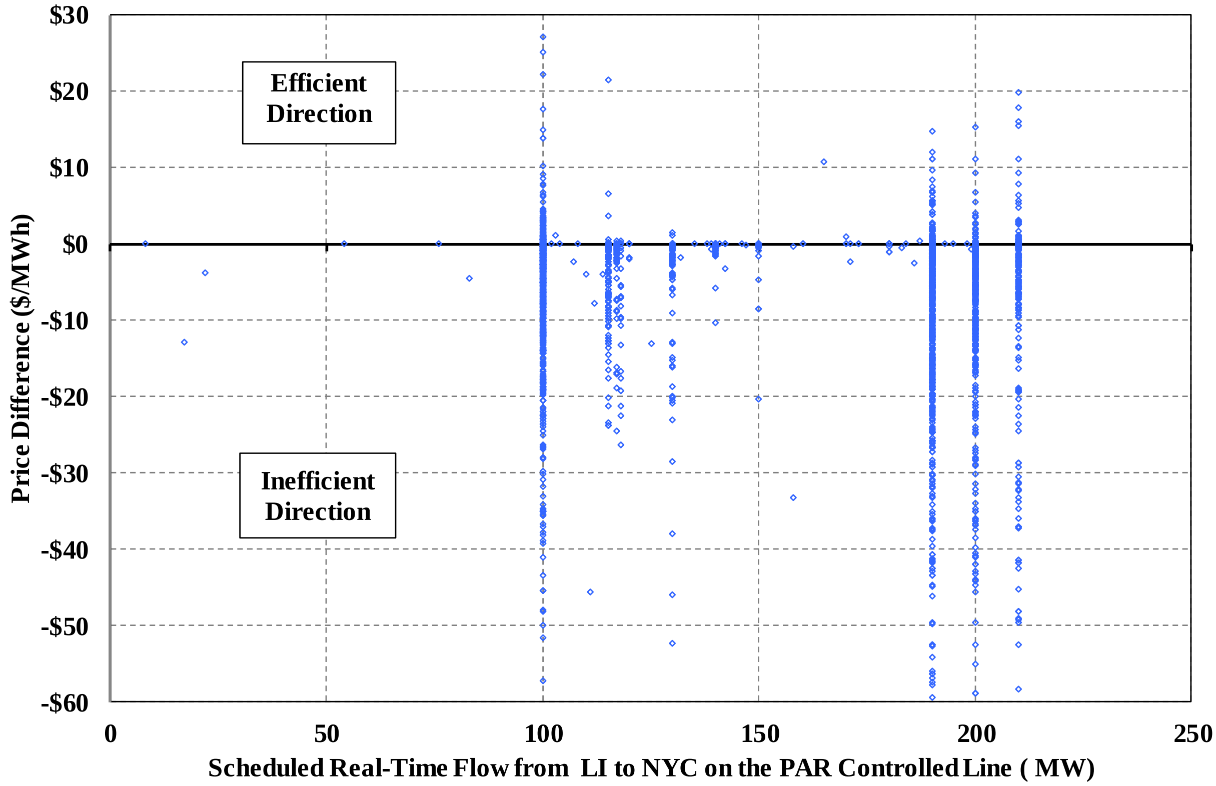
302 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule is considered *efficient direction*, and if the relative prices of the two regions is switched in the real-time market and the flow was reduced to 80 MW, the adjustment is shown as -20 MW and the real-time schedule adjustment is considered *efficient direction* as well.

Table A-3: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2017

	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					-35	$7.26	47%	$1
New England to NYCA								
Sand Bar	-75	-$12.72	92%	$7	0.3	-$14.34	52%	$0.1
PJM to NYCA								
Waldwick	-398	$2.11	36%	-$10	45	$1.17	51%	$2
Ramapo	191	$2.76	70%	$11	173	$1.74	52%	$6
Farragut	284	$3.28	73%	$10	34	$1.79	49%	-$0.4
Goethals	156	$4.07	79%	$6	99	$1.49	52%	$1
Long Island to NYC								
Lake Success	115	-$4.19	7%	-$6	-0.2	-$4.13	34%	-$0.03
Valley Stream	82	-$9.12	7%	-$7	2	-$8.29	23%	-$0.04

Figure A-76 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 above the $0-dollar line in 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 below the $0-dollar line 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-76: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2017



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- The scheduling of PAR-controlled lines that are used to support contractual wheeling agreements was less efficient than other PAR-controlled lines.

- The 901/903 lines are used under the ConEd-LIPA wheeling agreement to wheel roughly half of the power flowed on the Y50 line (from upstate to Long Island) back to New York City. In 2017,

  - In the day-ahead market, scheduled power flowed in the inefficient direction in 93 percent of hours, much inefficient than any of other PAR-controlled lines. Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.

  - 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).

- o Moreover, these transfers also lead to increased pollution because they require older steam turbines and gas turbines without back-end controls in Long Island to ramp up while newer combined cycle generation with selective catalytic reduction in New York City are ramped down.

- o The efficiency of scheduling over PAR-controlled ABC and JK lines improved from prior years following the expiration of the ConEd-PSEG wheeling agreement at the end of April 2017.
  - o Instead of wheeling power (up to 1000 MW) from Hudson Valley to PJM across the JK lines and then wheeling power back from PJM to New York City across the ABC lines, they are now operated to: (a) to flow a share of the external transactions between control areas that are submitted by traders; and (b) to manage real-time congestion under M2M with PJM.

- Significant opportunities remain to improve the operation of the lines between New York City and Long Island.

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

- o 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). [303]

E. 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

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

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 2017. 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
- It increases by at least 100 percent from the previous interval.

Although the price spikes meeting these criteria account for less than 4 percent of the real-time pricing intervals in 2017, 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 2017 for facilities exhibiting the most volatility. It also shows Long Island constraints, which were significant in 2016 but became less prevalent in 2017. 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 transitioned from being used to support the ConEd-PSEG wheeling agreement to being scheduled under the M2M process), the 5018 line (which was scheduled under the M2M process) and the 901 and 903 lines (which are used to support the ConEd-LIPA wheeling agreement).[304,305] RTD and RTC assume the flow over these lines will remain fixed in future intervals at 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 resources 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

304 These lines are discussed further in Subsection D.

305 M2M coordination is discussed further in Subsection C.

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).

- 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. For each constraint category, we highlight the category of aggravating factors that most contributed to the transient price spike in purple. We highlight the largest sub-categories in green.

Table A-4: Drivers of Transient Real-Time Price Volatility
2017

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints		UPNY-SENY		Marcy-Edic	
Average Transfer Limit	**n/a**		**689**		**2138**		**804**		**289**		**1616**		**1593**	
Number of Price Spikes	**525**		**708**		**225**		**192**		**641**		**88**		**69**	
Average Constraint Shadow Price	**$217**		**$1,028**		**$355**		**$321**		**$132**		**$643**		**$1,337**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**169**	**64%**	**1**	**8%**	**59**	**43%**	**55**	**71%**	**8**	**53%**	**31**	**30%**	**82**	**40%**
External Interchange	79	30%	1	8%	21	15%	38	49%	3	20%	14	14%	35	17%
RTC Shutdown Resource	62	23%	0	0%	24	18%	14	18%	4	27%	13	13%	25	12%
Self Scheduled Shutdown/Dispatch	28	11%	0	0%	14	10%	3	4%	1	7%	4	4%	22	11%
Flow Change from Non-Modeled Factors	**14**	**5%**	**10**	**77%**	**60**	**44%**	**11**	**14%**	**4**	**27%**	**64**	**62%**	**30**	**15%**
Loop Flows & Other Non-Market	2	1%	6	46%	24	18%	8	10%	3	20%	43	42%	15	7%
Fixed Schedule PARs	0	0%	3	23%	36	26%	3	4%	1	7%	21	20%	12	6%
Niagara Generator Distribution	0	0%	1	8%	0	0%	0	0%	0	0%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	12	5%	0	0%	0	0%	0	0%	0	0%	0	0%	3	1%
Other Factors	**81**	**31%**	**2**	**15%**	**18**	**13%**	**11**	**14%**	**3**	**20%**	**8**	**8%**	**94**	**46%**
Load	44	17%	1	8%	8	6%	5	6%	1	7%	5	5%	48	23%
Generator Trip/Derate/Dragging	17	6%	0	0%	9	7%	6	8%	2	13%	3	3%	16	8%
Wind	20	8%	1	8%	1	1%	0	0%	0	0%	0	0%	30	15%
Total	**264**		**13**		**137**		**77**		**15**		**103**		**206**	
Redispatch for Other Constraint (RTD)	**85**		**1**		**17**		**3**		**1**		**3**		**106**	

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes (as defined in this report) occurred in less than 4 percent of all intervals in 2017.
  - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and re-dispatch for other constraints.
  - For the West Zone 230kV Lines, the primary drivers were loops flow and other non-market scheduled factors and fluctuations in fixed-schedule PAR flows between NYISO and PJM (i.e., the A, B, C, J, K, and 5018 circuits).
  - For the Central-East Interface, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A, B, C, J, K, and 5018 lines), generator shutdowns by RTC, and loops flow and factors that reduce the Central East transfer capability.
  - Likewise, for the UPNY-SENY interface, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A, B, C, J, K, and 5018 lines) and loop flows and factors that affect the interface transfer capability.
  - Dunwoodie-to-Shore Rd and other Long Island constraints became less erratic primarily because of the introduction of the lower GTDC in June 2017 and fewer significant transmission outages.
  - For Marcy-to-Edic constraints, the primary drivers were external interchange adjustments, load variations, and re-dispatch for other constraints.

- External interchange variations were a key driver of transient price spikes for the power-balance constraint, Long Island constraints, and Marcy-Edic constraints.
  - 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 operation of the A, B, C, J, K, and 5018 lines was a key driver for the West Zone 230kV lines, the Central-East Interface, and the UPNY-SENY interface.
  - These PARs are modeled as if they fully control 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 (plus an adjustment for DNI changes for the PJAC interface). However, this assumption is unrealistic for two reasons:
    - The PARs are not 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.
    - When the PARs are adjusted, it may cause congestion that was not anticipated because the operator does not have a model that forecasts the congestion impact of making tap adjustments.
- Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines and the UPNY-SENY interface.
  - 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.
  - TSA ("thunderstorm alert") operations require dramatic reductions in transfer capability across the UPNY-SENY interface and often lead to severe congestion.
- 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.
    - 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: [306]
    - 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.

306 See Recommendation #2012-13

  - 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 the 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 Loop Flows and Other Non-Modeled Factors* – To reduce unnecessary price volatility from variations in:
  - Loop flows around Lake Erie, we recommend the NYISO make an additional adjustment to the telemetered value. This adjustment should "bias" the loop flow assumption in the clockwise direction to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an under-forecast tends to be much greater than the cost of an over-forecast of the same magnitude).
  - Flows over fixed-schedule PAR-controlled lines, we recommend the NYISO reconsider its method for calculating shift factors. The current method assumes that PAR-controlled line flows are unaffected by generation re-dispatch and load changes, although this is unrealistic.[307]

- 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. [308] 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. [309]

F. Market Operations under Shortage Conditions

Prices that occur under shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves and regulation 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

307 See Recommendation #2014-9.

308 See Recommendation #2014-12.

309 See Section V.H in the Appendix for more discussion on out-of-merit dispatch for West Zone 115 kV lines.

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 reserves and regulation demand curves to set real-time clearing prices during operating reserves and regulation 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 two types of shortage conditions: [310]

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection G).

Figure A-77: 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-77 summarizes physical ancillary services shortages and their effects on real-time prices in 2016 and 2017 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.
- 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.

310 Our prior reports also evaluated market operations during reliability demand response deployments. In 2017, the NYISO did not deploy reliability demand response resources, so the effect of the scarcity pricing is not evaluated in this report.

- 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.

- 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.

- 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.

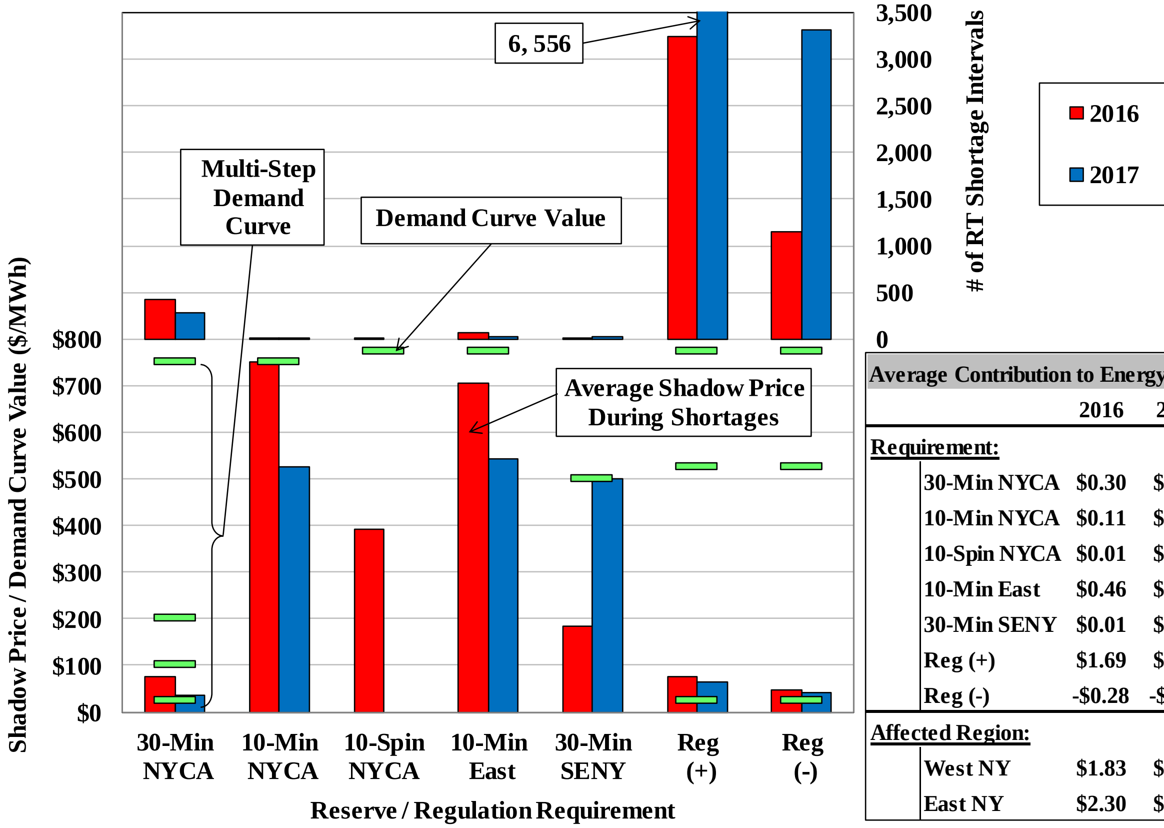
- Regulation – The ISO is required to hold 150 to 300 MW of regulation capability in the state and has a demand curve value of $25/MWh if the shortage is less than 25 MW, $525/MWh if the shortage is between 25 and 80 MW, and $775/MWh if the shortage is more than 80 MW.

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 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-77: Real-Time Prices During Ancillary Services Shortages
2016 – 2017



Average Contribution to Energy Price	2016	2017
Requirement:		
30-Min NYCA	$0.30	$0.10
10-Min NYCA	$0.11	$0.07
10-Spin NYCA	$0.01	$0.00
10-Min East	$0.46	$0.16
30-Min SENY	$0.01	$0.09
Reg (+)	$1.69	$2.75
Reg (-)	-$0.28	-$0.69
Affected Region:		
West NY	$1.83	$2.23
East NY	$2.30	$2.48

Key Observations: Real-Time Prices During Physical Ancillary Services Shortages

- Regulation shortages were most frequent in both years, which occurred in 4.2 percent of all intervals in 2016 and 9.4 percent in 2017, and had the largest effects on real-time prices.
  - Regulation shortages occurred mostly when the dispatch model "chose" to be short when the cost to provide regulation exceeded its lowest demand curve value of $25/MWh.
  - All other shortages occurred in less than 0.5 percent of all intervals each year.
- Regulation shortages rose substantially in 2017, particularly in low load periods (e.g., off-peak hours) because:
  - Generally, less capacity is committed (or online) during low load periods, resulting in reduced regulation capability; and
  - The redispatch cost to maintain sufficient capacity for down regulation may be higher when the system is close to Minimum Generation condition.

G. Real-Time Prices During Transmission Shortages

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

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes.

If the available physical capacity is not sufficient to resolve a transmission constraint, a Graduated Transmission Demand Curve ("GTDC"), combined with the constraint relaxation (which increases the constraint limit to a level that can be resolved) under certain circumstances, will be used to set prices under shortage conditions. The NYISO first adopted the GTDC approach on February 12, 2016, [311] and revised this pricing process on June 20, 2017 to improve market efficiency during transmission shortages. Key changes include:

- Modifying the second step of the Graduated Transmission Demand Curve ("GTDC") from $2,350 to $1,175/MWh; and
- Removing the "feasibility screen" and applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM").[312]

This subsection evaluates market performance during transmission shortages, particularly comparing the changes in congestion management before and after the enhancements in the GTDC.

In addition, a condition 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.[313] 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 clearing price because such a unit: (a) does not reflect the marginal cost of supply

[311] See Section V.F in the Appendix of our 2016 State of Market Report for a detailed description of the initial implementation of the GTDC.

[312] These changes are discussed in detail in Commission Docket ER17-1453-000.

[313] 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.

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.[314] This category of shortage is evaluated in this section as well.

Table A-5 - Figure A-79: Real-Time Congestion Management with GTDC

Table A-5 summarizes the following quantities in the real-time market by constraint group in the months of July to December 2017 (when the revision of GTDC was effective), compared with the same period in 2016:

- The frequency of transmission constraint shortages;
- Average constraint shadow prices; and
- Average shortage quantities (relative to the BMS limit adjusted for the CRM).[315]

These quantities are shown separately for constraints with different pricing treatments (i.e., various applications of the GTDC vs constraint relaxation).

314 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.

315 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.

Table A-5: Summary of Real-Time Congestion Management with GTDC
July-December, 2016 - 2017

Location of Constrained Facilities	CRM = 0?	Shortage Handling	# of Constraint-Intervals		Avg Shadow Price ($/MWh)		Avg Shortage (MW)	
			2016	2017	2016	2017	2016	2017
West Zone	Y	Relaxation Only						
	N	Relaxation & GTDC	10	71	$2,414	$2,470	31	32
		Relaxation Only	416		$1,775		13	
		GTDC Only	332	669	$832	$781	4	7
	SubTotal		**758**	**740**	**$1,370**	**$943**	**9**	**9**
New York City	Y	Relaxation Only	47	17	$9	$4	58	42
	N	Relaxation & GTDC	2	38	$3,020	$1,427	24	44
		Relaxation Only	1109		$569		14	
		GTDC Only	830	1429	$780	$595	4	5
	SubTotal		**1988**	**1484**	**$647**	**$609**	**11**	**6**
North to Central	Y	Relaxation Only						
	N	Relaxation & GTDC	2	73	$2,548	$2,520	38	74
		Relaxation Only	67		$511		27	
		GTDC Only	91	191	$575	$647	3	5
	SubTotal		**160**	**264**	**$572**	**$1,165**	**14**	**24**
Long Island	Y	Relaxation Only	495	8	$166	$444	23	10
	N	Relaxation & GTDC	25	29	$2,614	$2,200	37	34
		Relaxation Only	439		$967		15	
		GTDC Only	437	974	$629	$543	4	4
	SubTotal		**1396**	**1011**	**$607**	**$590**	**15**	**5**
All Other	Y	Relaxation Only	3	13	$2,995	$2,602	87	142
	N	Relaxation & GTDC	5	3	$3,727	$2,738	92	280
		Relaxation Only	24		$2,306		34	
		GTDC Only	121	152	$936	$668	6	7
	SubTotal		**153**	**168**	**$1,282**	**$855**	**15**	**22**
Grand Total			**4455**	**3667**	**$776**	**$723**	**12**	**8**

Figure A-78 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 two GTDC curves (old vs. revised) are also plotted to illustrate how constraint shadow costs deviate from the curves in many cases.

Figure A-78: Real-Time Transmission Shortages with the GTDC
By Transmission Group, July-December, 2016-2017

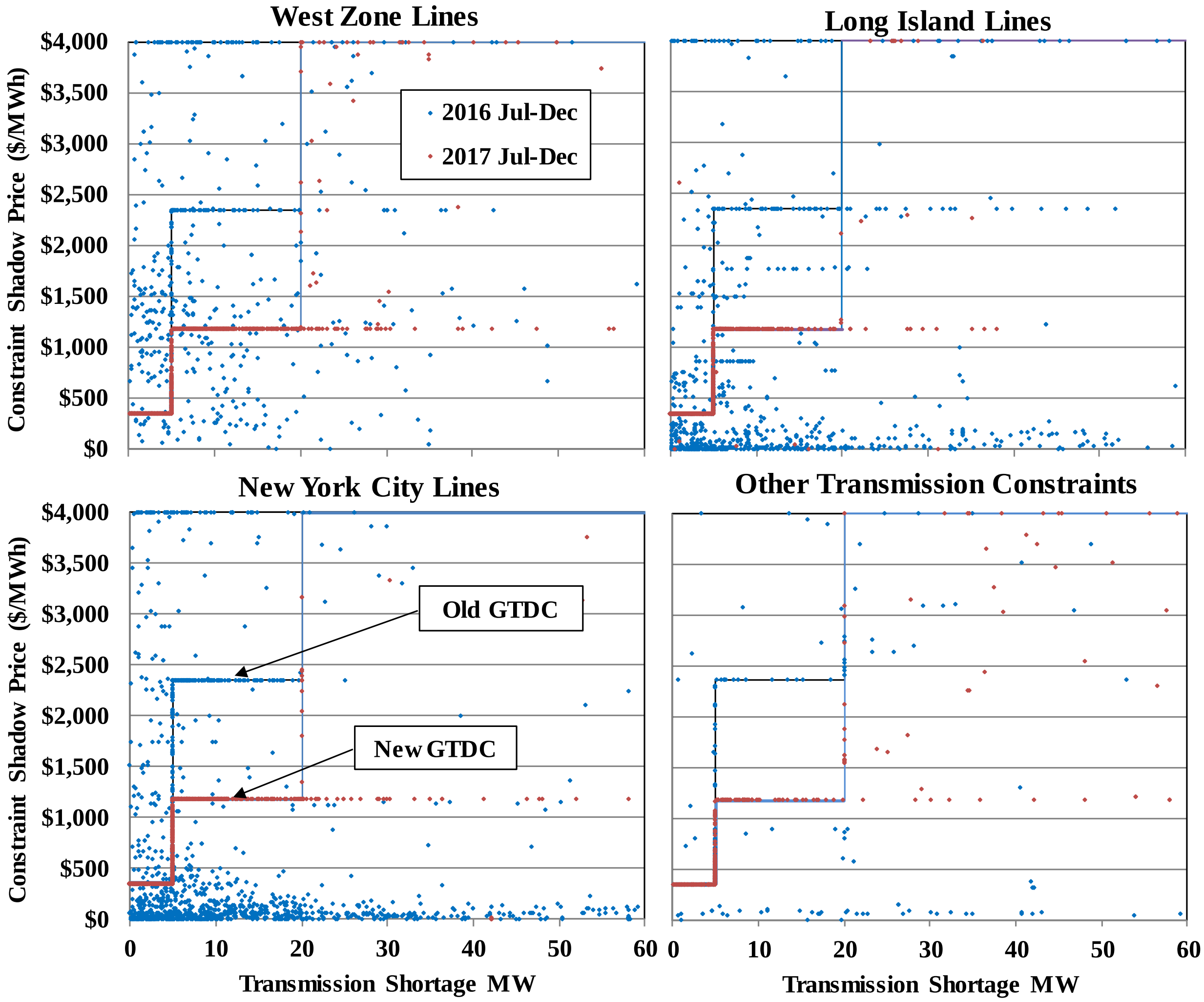
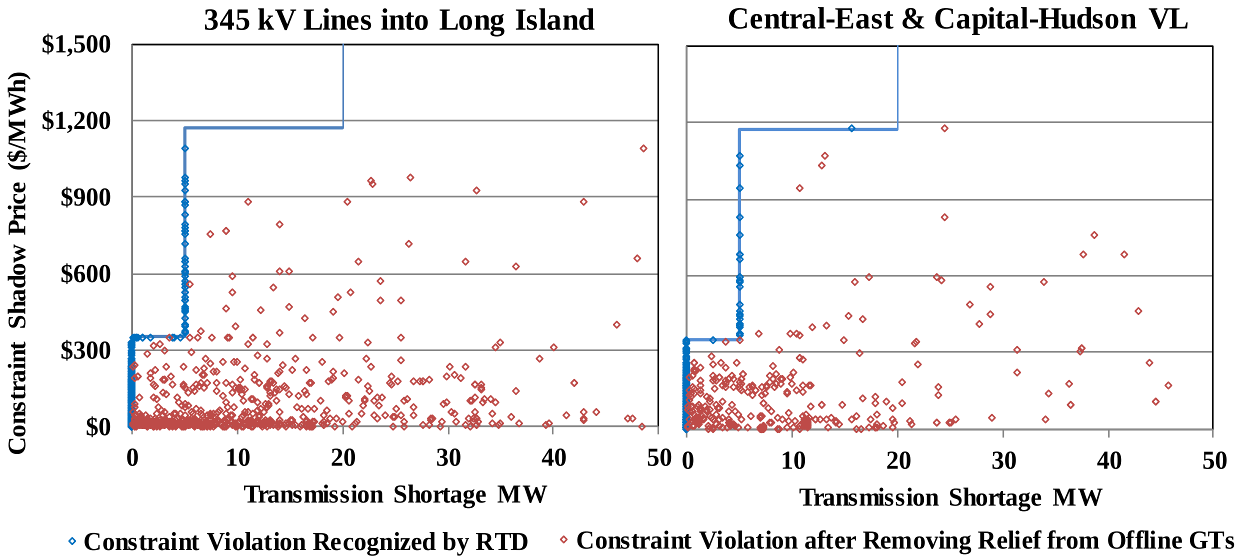


Figure A-79 examines the pricing effects of offline GTs on transmission shortages in July to December 2017 for select transmission groups: a) the two 345 kV transmission circuits from upstate to Long Island; and b) major transmission constraint from Central to East and from Capital to Hudson Valley. Offline GTs were used most frequently to alleviate transmission shortages on these transmission facilities during the examined period.

The scatter plots show transmission constraint shadow prices on the y-axis and transmission violations on the x-axis. For one particular constraint shadow price, the blue diamond represents the transmission violation recognized by RTD, while the red diamond represents the violation after removing the relief from offline GTs.

Figure A-79: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, July to December 2017



Key Observations: Real-Time Prices During Transmission Shortages

- Constraint relaxation has been much less frequent following the revision of transmission shortage pricing in June 2017.
  - Only 7 percent of all transmission shortages involved constraint relaxation after the revision in 2017, compared with 59 percent in the same period of 2016.
  - It is desirable to minimize the use of constraint relaxation because it:
    - Leads constraint shadow prices to be uncorrelated with the severity of the shortage (e.g., the shortage amount, the duration of the constraint), and
    - Makes congestion less transparent and predictable for market participants.
- Average constraint shadow prices during transmission shortages fell modestly from a year ago in most areas.
  - This was partly because the GTDC's second step changed from $2,350 to $1,175.
- Despite overall improved market outcomes, at times constraint shadow prices still did not properly reflect the importance and severity of a transmission shortage.
  - For example, the NYISO uses a higher CRM for certain facilities such as the Dunwoodie-ShoreRd 345kV line (which has a CRM of 50 MW), leading the GTDC to over-value some constraint violations.
  - Thus, we continue to 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. [316]

- The shadow prices that result from offline GT pricing are not well-correlated with the severity of the transmission constraint, leading to prices during tight operating conditions that are volatile.
  - The introduction of constraint-specific GTDCs should enable the NYISO to phase-out the use of offline fast-start pricing.

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:

- Manage constraints of high voltage transmission facilities that are not fully represented in the market model; or
- Maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is frequently uneconomic, which displaces 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-80: 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 the following three ways:

316 Recommendation #2015-17 discusses how the NYISO should further enhance real-time scheduling models during periods of severe congestion.

- Day-Ahead Reliability Units ("DARU") Commitment, which typically occurs at the request of local Transmission Owner prior to the economic commitment in SCUC;
- Day-Ahead Local Reliability ("LRR") Commitment, which takes place during the economic commitment pass in SCUC to secure reliability in New York City; and
- Supplemental Resource Evaluation ("SRE") Commitment, which occurs after the day-ahead market closes.

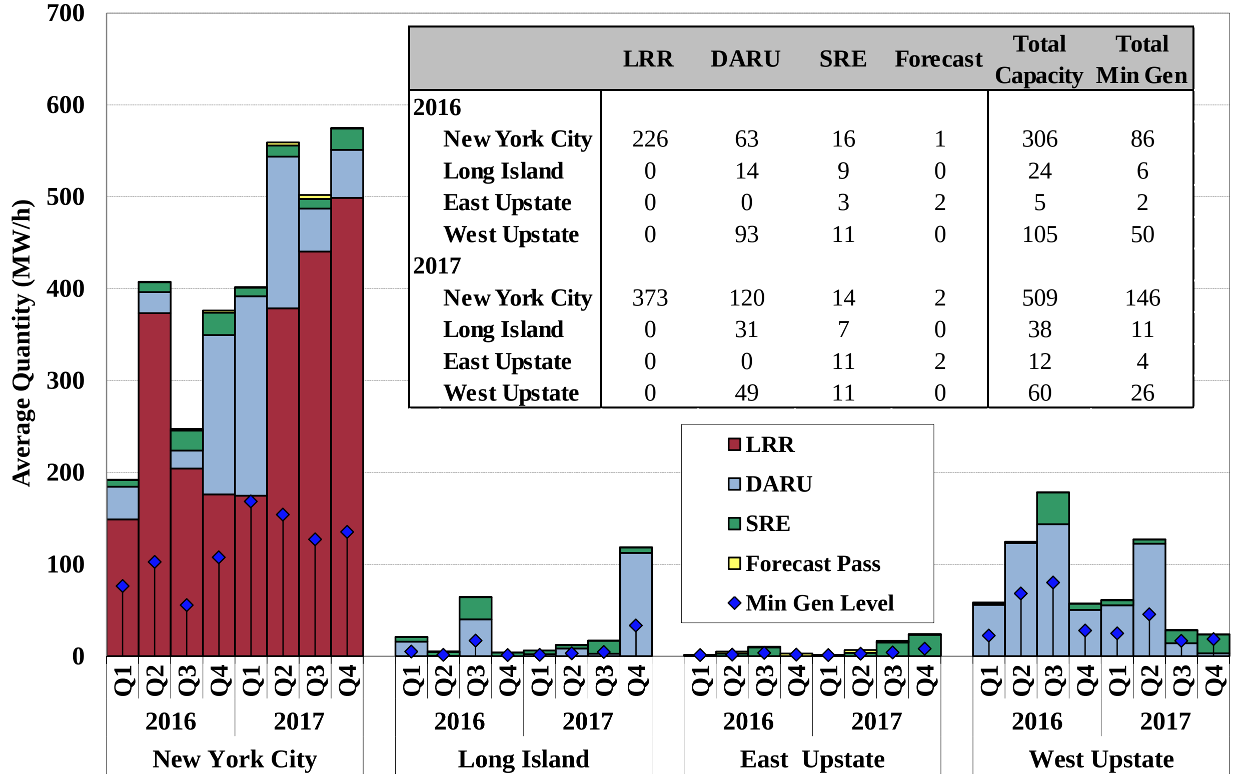
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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-80 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 2016 and 2017. 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 2016 and 2017 on an annual basis.

Figure A-80: Supplemental Commitment for Reliability in New York
By Category and Region, 2016 – 2017



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2017						
New York City	373	120	14	2	509	146
Long Island	0	31	7	0	38	11
East Upstate	0	0	11	2	12	4
West Upstate	0	49	11	0	60	26

Figure A-81 to Figure A-83: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability typically occurred in New York City. Figure A-81 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-81 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2016 and 2017.

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: [317]

- Voltage – If needed for Application of Reliability Rule (“ARR”) 26 and no other reason except NOx. This occurs when additional resources are needed to maintain voltage without shedding load in an N-1-1 scenario.

- Thermal – If needed for ARR 37 and no other reason except NOx. This occurs when additional resources are needed to maintain flows below acceptable levels without shedding load in an N-1-1 scenario.

317 A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity.

- Loss of Gas – If needed to protect NYC against a sudden loss of gas supply and no other reason except NOx.[318]

- NOx Only – If needed for NOx bubble and no other reason.[319] When a steam turbine is committed for a NOx bubble, it is because the bubble contains gas turbines that are needed for local reliability, particularly in an N-1-1 scenario.

- 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.

In Figure A-81, 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

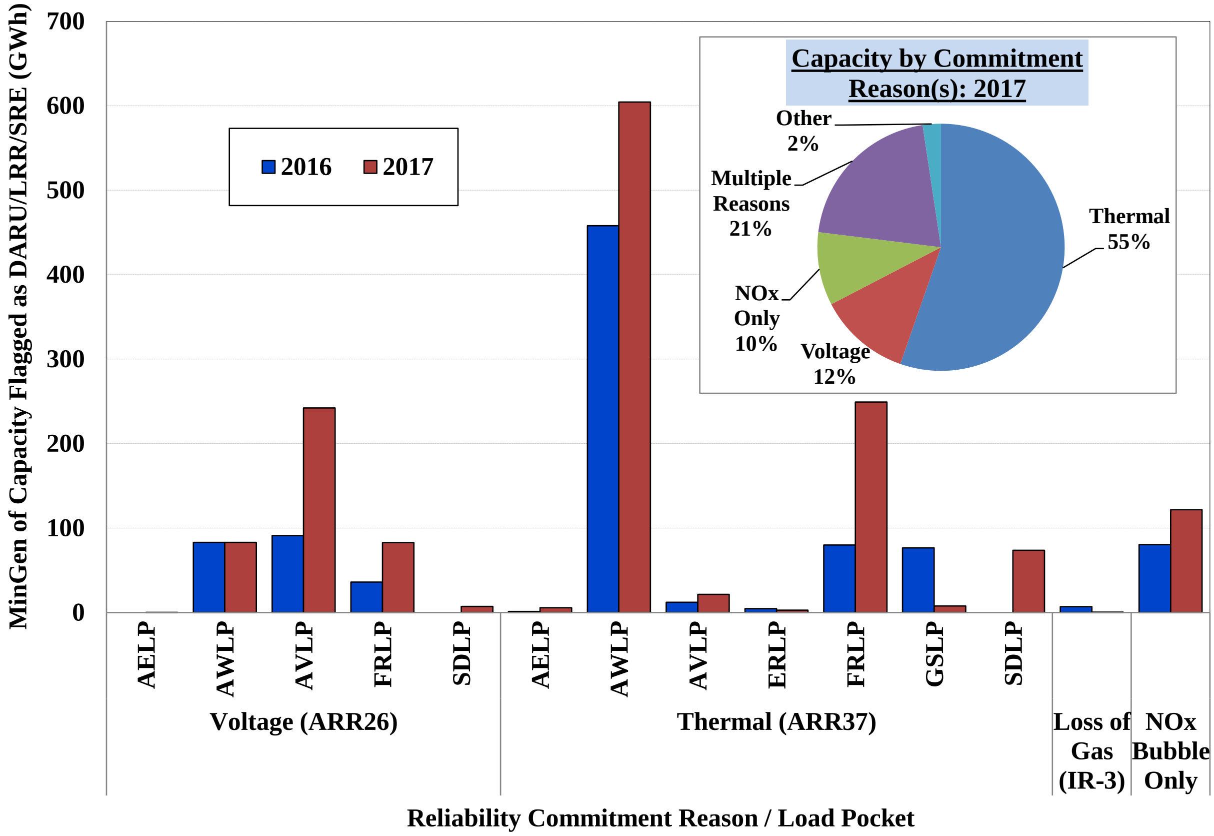
- SDLP - Sprainbrook Dunwoodie Load Pocket.

The pie chart in the figure shows the portion of total capacity committed under different reasons for 2017 only.

318 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

319 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 of Oxides Of Nitrogen (NOx) - Control Requirements”, which is available online at: http://www.dec.ny.gov/regs/4217.html#13915.

Figure A-81: Supplemental Commitment for Reliability in New York City
By Category and Region, 2016 – 2017



The previous figure shows that reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1 criteria) in New York City. Since such units would not be economic if they were not needed for local reliability, they ordinarily do not earn enough market revenue to recoup their day-ahead as-offered costs. Hence, such units typically receive a day-ahead BPCG payments.

Although the resulting amount of compensation (i.e., revenue = cost) is reasonably efficient for the marginal commitment needed to satisfy the needs of the pocket, it does not provide efficient incentives for lower cost resources that can also provide valuable operating reserves in the pocket to be available. Moreover, it does not provide investors with efficient incentives to invest in new and existing resources that are capable of satisfying the need at a lower cost. Therefore, it would be beneficial for the NYISO to seek ways to design a reserve product that could satisfy the local N-1-1 requirements in a way that provides market-based compensation to all suppliers that provide the product in the load pocket, not just the ones with high operating costs.

To assess the potential market incentives that would result from modeling local N-1-1 requirements in New York City, we estimated the average clearing prices that would have occurred in 2017 if the NYISO were to devise a day-ahead market requirement that set clearing prices using the following rules:

- If a single unit was committed for a single load pocket requirement: Price in \$/MW-day = $DA\_BPCG_g \div UOL_g$.
- If a single unit was committed for NOx to make gas turbines available for a single load pocket requirement: Price in \$/MW-day = $DA\_BPCG_g \div UOL_{GT}$.
- If a single unit was committed for more than one load pocket requirement: the Price for each load pocket in \$/MW-day = $DA\_BPCG_g \div UOL_g \div$ # of load pockets.
- If two units are committed for a single load pocket, the price is based on the generator g with a larger value of $DA\_BPCG_g \div UOL_g$.
- If two units are committed for different non-overlapping load pockets, the price is calculated for each load pocket in the same manner as a single unit for a single load pocket.
- If two units are committed for two load pockets where one circumscribes the other, the price of the interior pocket is calculated in the same manner as a single unit for a single load pocket, and the price of the outer pocket is calculated as $Price_{outer} = \max\{\$0,(DA\_BPCG_{g\_outer} \div UOL_{g\_outer}) – Price_{interior})$.

Table A-6 summarizes the results of this evaluation based on 2017 market results for three locations in New York City: the 345kV network north of Staten Island and the Astoria West/Queensbridge load pocket, and the Vernon location on the 138 kV network. Several other load pockets would also have binding N-1-1 requirements, but we were unable to finalize the estimates for those pockets. Ultimately, this analysis is meant to be illustrative of the potential benefits of satisfying these requirements through the day-ahead and real-time markets.

Table A-6: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets
2017

Area	Average Marginal Commitment Cost (\$/MWh)
NYC 345 kV System	**\$0.88**
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	**\$2.71**
Vernon	**\$1.65**

Figure A-82: 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.[320] For owners of generators that emit beyond the presumptive RACT limits, they have the following three "compliance options": [321, 322]

- Fuel Switching Option;
- System Averaging Plan – This allows a "weighted average permissible emission rate" across multiple generators; and
- Higher source-specific emission limit – This may be allowed if "the applicable presumptive RACT emission limit is not economically or technically feasible." [323, 324]

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. [325] 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-82 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

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320 See 9 NYCRR III , §227-2.4 "Control Requirements" for these presumptive limits.

321 See 9 NYCRR III , §227-2.5(a) - (c) for more details.

322 A fourth compliance option, "shutdown of an emission source," is also listed in 9 NYCRR III , §227-2.5(d).

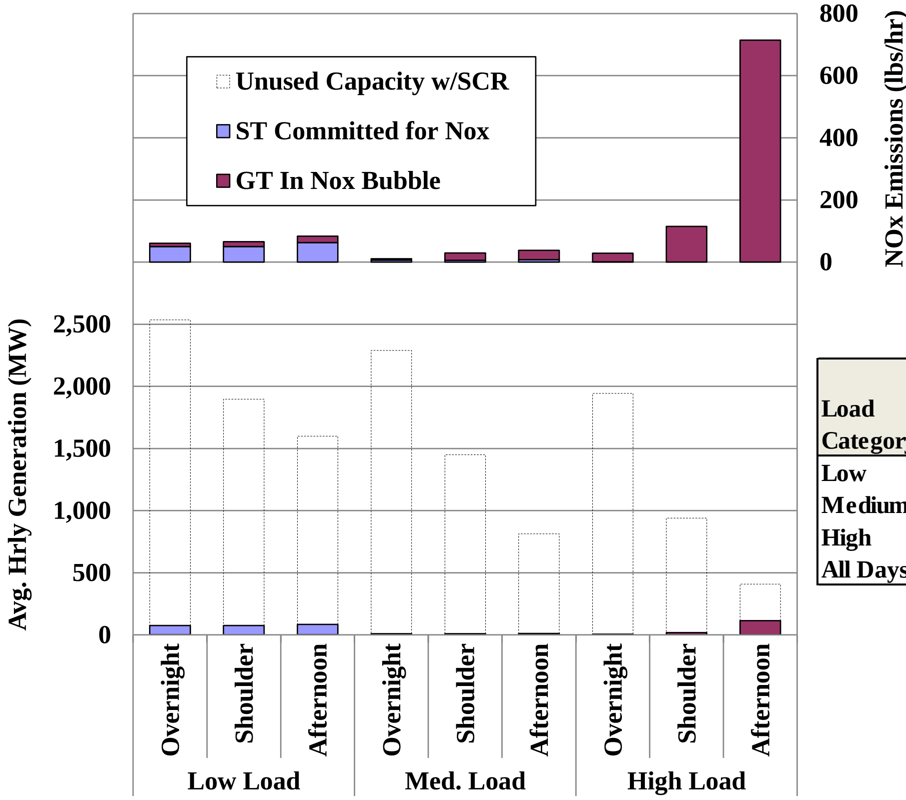
323 The current economic feasibility threshold in the NYDEC regulations is $5,000 per ton of NOx reduced. This threshold was first introduced as $3,000 per ton of NO_x reduced (based on a 1994 finding). The NYDEC elaborates "$3,000.00 dollars in 1994 equates to $4,637.73 dollars in 2012, which is then 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).

324 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.

325 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."

Reduction ("SCR") equipment. The top section of the chart shows average hourly NOx emissions for NOx Bubble gas turbines and steam units.

Figure A-82: NOx Emissions and Energy Production from NOx Bubble Generators
By Time of Day, by Load Category, 2017



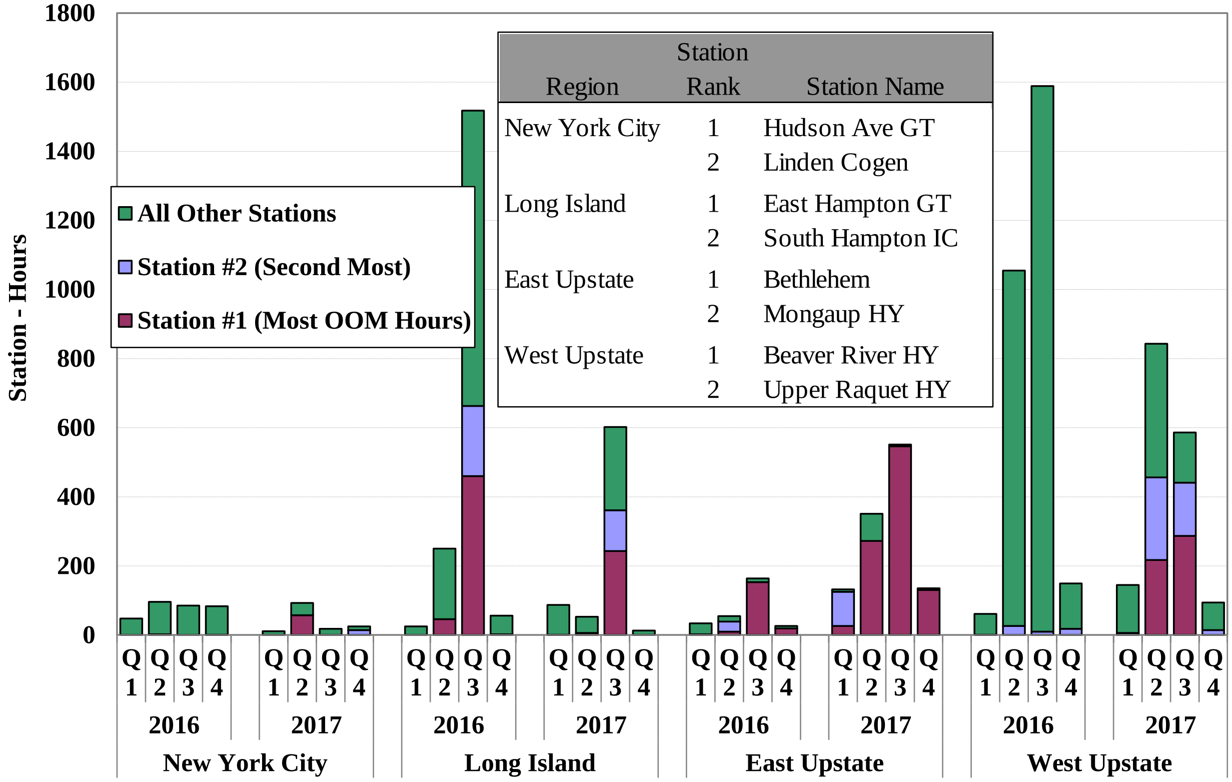
Load Category:	Output from GTs in NOx Bubble	Output from STs Committed for NOx
Low	7.5%	90.3%
Medium	8.7%	9.4%
High	83.8%	0.4%
All Days	100%	100%

Figure A-83: Frequency of Out-of-Merit Dispatch

Figure A-83 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2016 and 2017 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 2017 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2017, 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-83: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2016 - 2017



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-84 and Figure A-85 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.

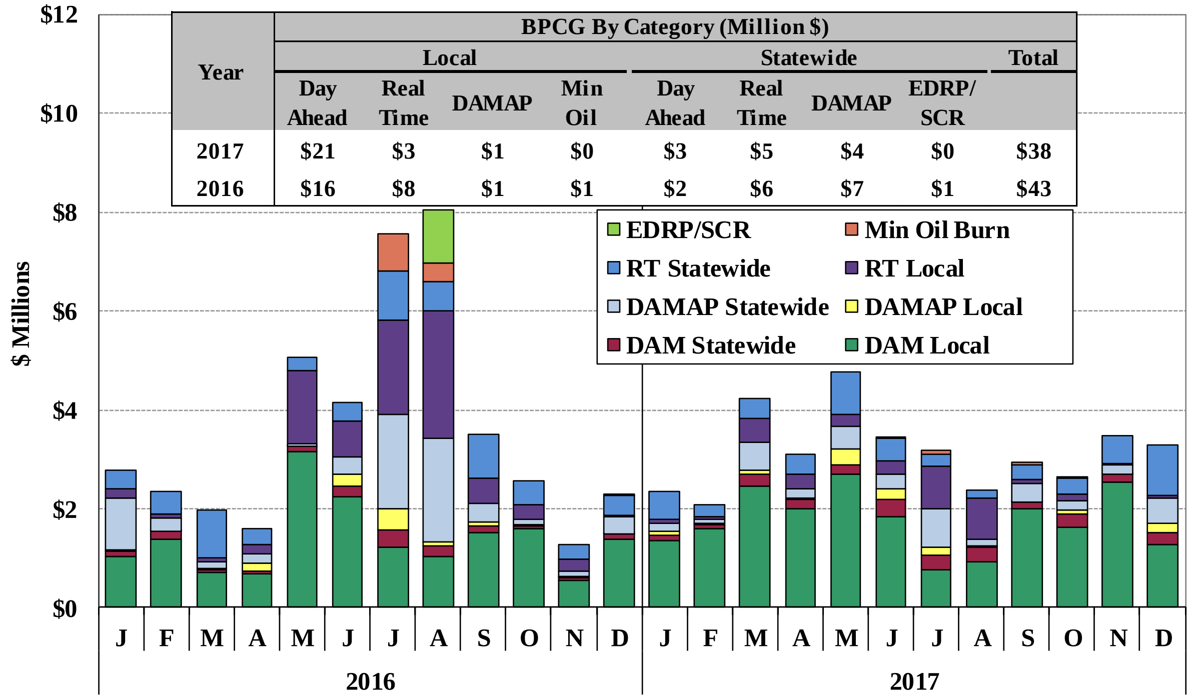
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-84 & Figure A-85: Uplift Costs from Guarantee Payments

Figure A-84 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2016 and 2017. 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-85 shows the seven categories of uplift charges on a quarterly basis in 2016 and 2017 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.

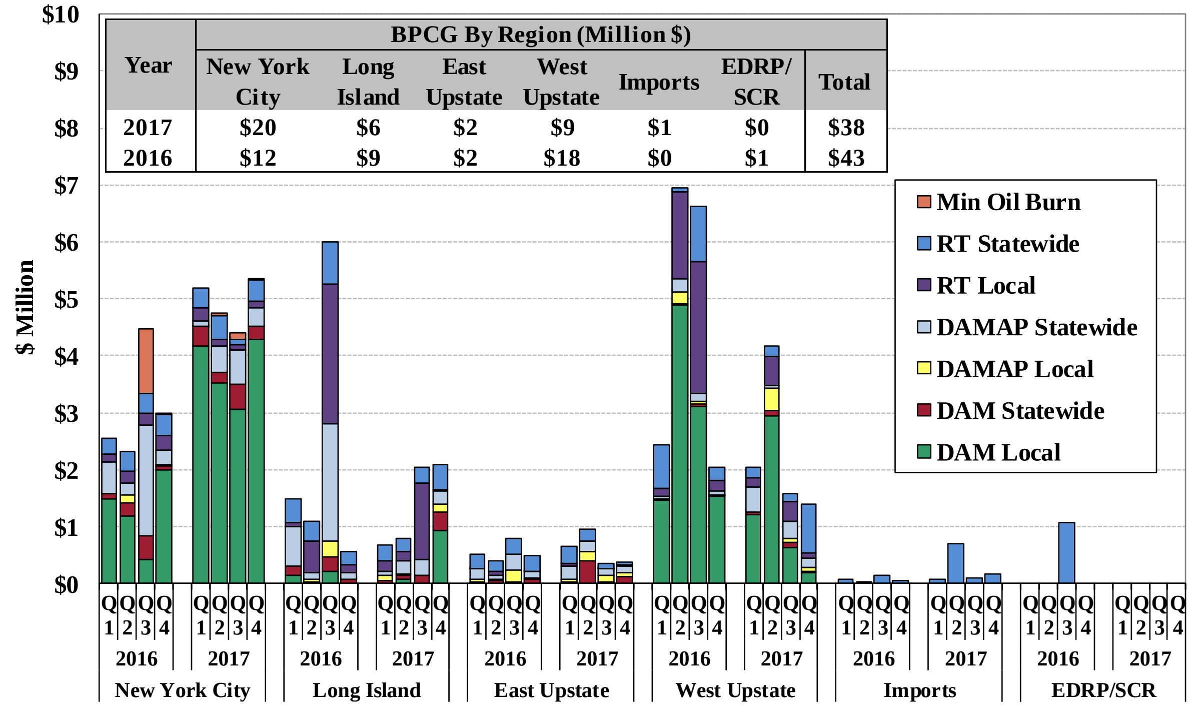
It is also noted that Figure A-84 and Figure A-85 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-84: Uplift Costs from Guarantee Payments by Month
2016 – 2017



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2017	$21	$3	$1	$0	$3	$5	$4	$0	$38
2016	$16	$8	$1	$1	$2	$6	$7	$1	$43

Figure A-85: Uplift Costs from Guarantee Payments by Region
2016 – 2017



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2017	$20	$6	$2	$9	$1	$0	$38
2016	$12	$9	$2	$18	$0	$1	$43

Key Observations: Reliability Commitment

- Reliability commitment averaged roughly 620 MW in 2017, up 41 percent from 2016.

- The increase occurred primarily in New York City, which rose 66 percent from a year ago and accounted for 82 percent of total reliability commitment in 2017, reflecting:

  - Increased local needs in the Freshkills load pocket and the 345 kV system because of more planned transmission outages in these areas; and

  - Units needed for local reliability were economically committed less frequently in 2017 as a result of increased gas prices in New York City (relative to other areas of East New York) and lower load levels.

    - Most of these commitments were made to satisfy the N-1-1 thermal and voltage requirements in the Astoria West/Queensbridge load pocket.

  - Based on our analysis of operating reserve price levels that would be necessary to represent the marginal costs of satisfying N-1-1 requirements in the day-ahead market, we find such price levels would range from an average of $0.88/MWh in most areas to as much as $2.71/MWh in the Astoria West/Queensbridge load pocket.

- However, reliability commitments in Western New York fell 43 percent from 2016, partly offsetting the overall increase.

  - DARU commitment fell notably in the second half of 2017 since the completion of transmission upgrades in early July that allowed for the expiration of Milliken RSSA.

- DARU commitments in Long Island:

  - Fell in the third quarter of 2017 from a year ago because lower load levels and fewer transmission outages reduced the capacity needed to prevent voltage collapse from inadequate transient voltage recovery. (see ARR-28C)

  - But rose in November as lower load levels increased the needs for overvoltage control in the 138 kV system. (see ARR-28A)

- Similar to prior years, our analysis indicates that in 2017 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.
- Committing steam turbines for the NOx Bubble constraints rarely reduced output from gas turbines with high emissions rates.
  - In 2017, 93 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 needs.

Key Observations: OOM Dispatch[326]

- Generators were dispatched Out-of-Merit ("OOM") for 3,740 station-hours in 2017, down 29 percent from 2016.
- OOM levels fell 42 percent in Western New York due partly to transmission upgrades completed in July 2017, which allowed the Milliken RSSA to expire and reduced OOM needs.
  - However, two hydro units were frequently OOMed-down due to increased local needs on the 115 kV network because of transmission outages.
- OOM levels also fell 59 percent in Long Island, particularly in the summer, as lower loads and fewer transmission outages led to decreased needs for voltage support on the East End.
- However, these decreases were partly offset by frequent OOMs of the Bethlehem units to manage post-contingency flow on the Albany-Greenbush 115 kV facility.

- Nonetheless, the Niagara facility was still 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 2017, this manual shift was required in about 951 hours to manage 115 kV constraints and in 222 hours to manage 230 or 345 kV constraints.

326 A detailed evaluation of the actions used to manage 115 kV congestion in upstate New York is provided in Appendix Section III.D.

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell 12 percent from \$43 million in 2016 to \$38 million in 2017.
  - The reduction occurred primarily in Western New York (by 49 percent) and on Long Island (by 38 percent) because of decreased supplemental commitment and OOM dispatches in these areas for the reasons discussed earlier.
  - However, guarantee payments in New York City rose by 59 percent (or \$8 million), offsetting the decrease and reflecting:
    - Increased supplemental commitment for reliability; and
    - Higher natural gas prices, which increased the commitment costs of gas-fired units.
- Guarantee payments in the category of DAMAP, Min Oil Burn, and EDRP/SCR accounted for a reduction of more than \$5 million.
  - Most of these uplift charges in 2016 accrued on several days in the third quarter with high load levels, which, however, were not seen in 2017 because of milder weather.

VI. CAPACITY MARKET

This section evaluates the performance of the capacity market, which is designed to ensure that sufficient resources are available to satisfy New York's planning reserve margin requirements. The capacity market provides economic signals that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide incentives for new investment, retirement decisions, and participation by demand response.

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.[327] 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.[328]

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 sell the excess into the spot auction. The capacity demand curves are used to determine the clearing prices and quantities purchased in each locality in each monthly UCAP spot auction.[329] The amount of UCAP

327 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 18 percent in the most recent Capability Year (i.e., the period from May 2017 to April 2018). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

328 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 102.5 percent from May 2016 to April 2017 and 103.5 percent from May 2017 to April 2018. The New York City LCR was 80.5 percent from May 2016 to April 2017 and 81.5 percent from May 2017 to April 2018. The LCR for the G-J Locality was set at 90 percent from May 2016 to April 2017 and 91.5 percent from May 2017 to April 2018. 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".

329 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.

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 purchases more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

The demand curve for a capacity market Locality is defined as a straight line through the following two points: [330]

- 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 known as the "Level of Excess".
- 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.

Every four years, the NYISO and its consultants establish the parameters of the capacity demand curves through a study that includes a review of the selection, costs and revenues of the peaking technology.[331] Each year, the NYISO further adjusts the demand curve to account for changes in Net CONE of a new peaking unit.

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). 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 Locality, although the clearing price in a nested Locality cannot be lower than the clearing price in the surrounding Locality.

This section evaluates the following aspects of the capacity market:

- Trends in internal installed capacity, capacity exports, and imports from neighboring control areas (sub-sections A and B);
- Equivalent Forced Outage Rates ("EFORDs") and Derating Factors (sub-section C);
- Capacity supply and quantities purchased each month as well as clearing prices in monthly spot auctions (sub-section D and E);

330 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2016/2017 and 2017/2018 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".

331 Before the 2016 demand curve reset, each reset set the demand curves for three years rather than four. Materials related to past Demand Curve Reset studies may be found at: "http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp".

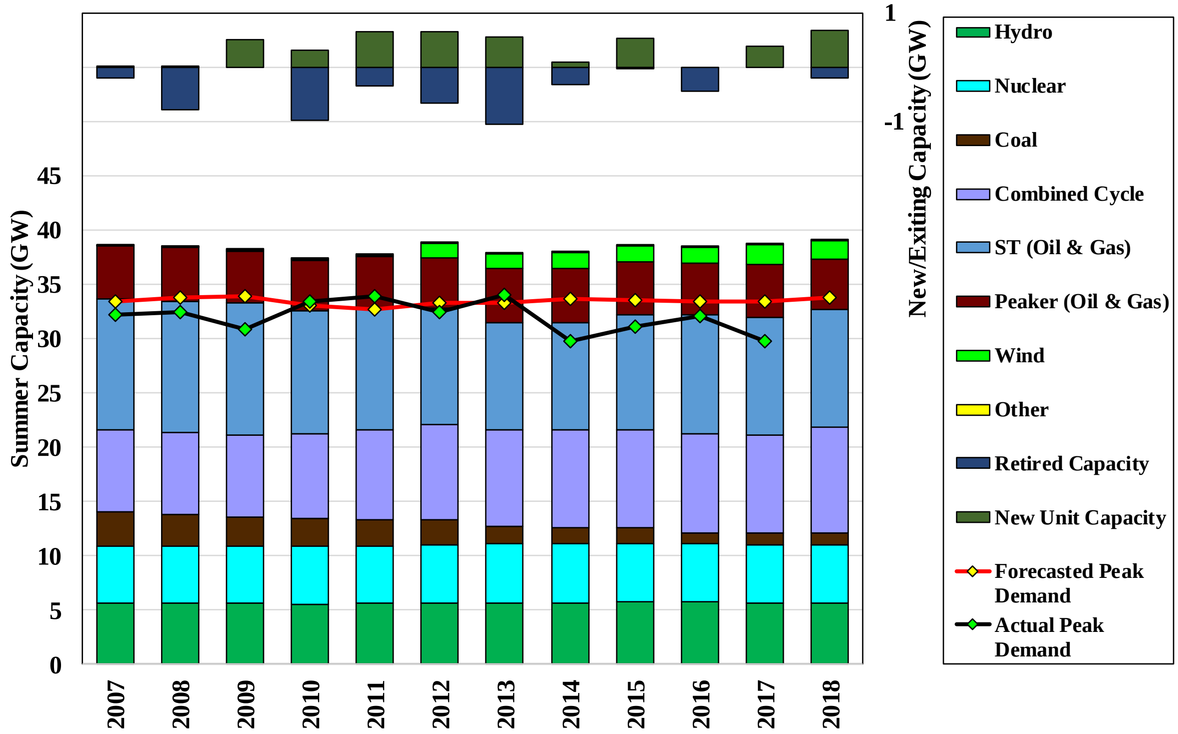
- Cost of improving reliability from additional capacity by zone (sub-section F); and
- The need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section G).

A. Installed Capacity of Generators in NYCA

Figure A-86 - Figure A-87: Installed Summer Capacity and Forecasted Peak Demand

The bottom panel of Figure A-86 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 2018.[332] The top panel of Figure A-86 shows the amount of capacity that entered or exited the market during each year.[333] Figure A-87 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 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).

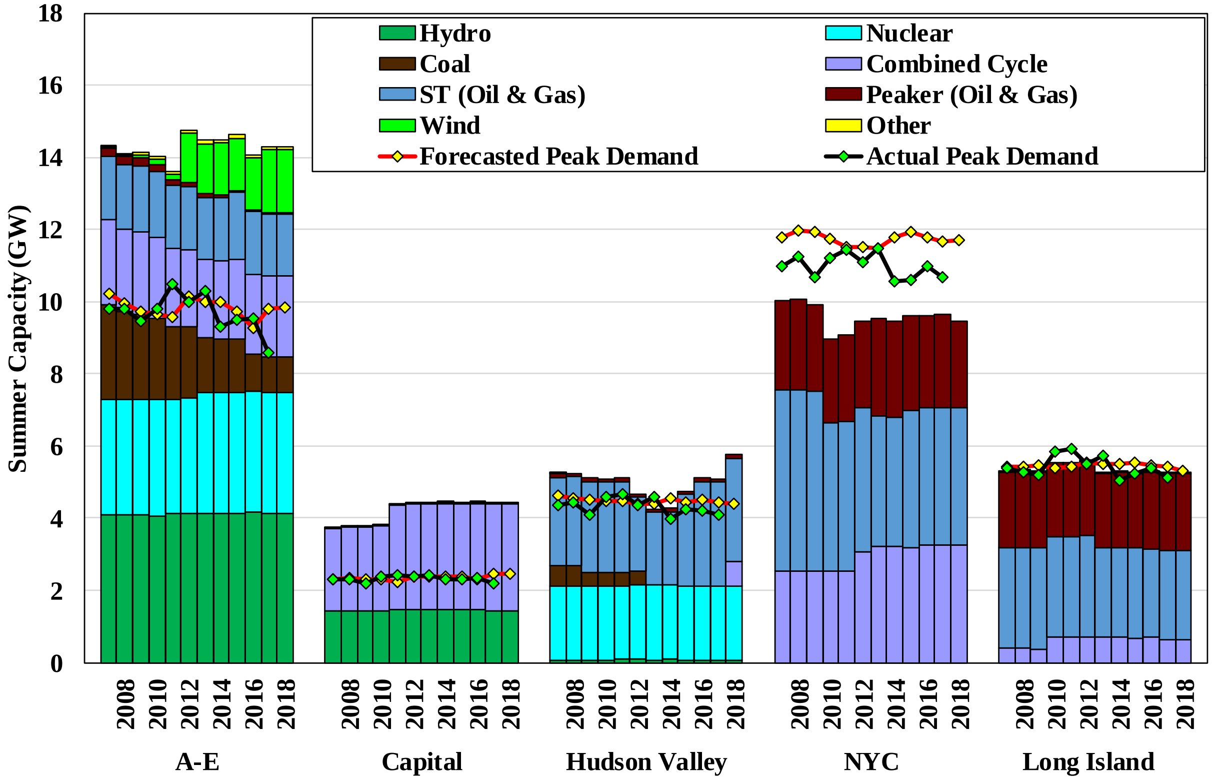
Figure A-86: Installed Summer Capacity of Generation by Prime Mover
2007 - 2018



332 The summer peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. Capacity is based on the Gold Book and and Generator Status Update files available at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

333 Both the annual capacity and capacity from new additions from wind resources are given for units with both ERIS and CRIS rights. ERIS-only wind units do not appear in this chart as capacity resources.

Figure A-87: Installed Summer Capacity of Generation by Region and by Prime Mover
2007 – 2018



Key Observations: Installed Capacity in NYISO

- The total generating capacity in the NYISO remained relatively flat just under 40 GW (summer) between 2007 and 2018. 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 as new resources or units returning from a mothball. The 2017 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).
  - While the total natural gas-fired capacity has increased only marginally since 2007, more than 2 GW of new combined cycle resources have entered the market. 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.[334]
  - Policies promoting renewable energy have motivated investment in new wind units, adding roughly 1.7 GW of nameplate capacity to the state resource mix. Most of this

334 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

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. [335]

- 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 2017, a 68 percent decrease.[336] Other notable retirements include several dual-fueled steam units such as Poletti 1 in NYC in 2010. Astoria 4 in NYC in 2012, and the Glenwood 04 and 05 units in Long Island in 2012.

- As shown in Figure A-87, a dichotomy exists in the state between the eastern and western regions with the western zones (Zones A-E) possessing greater fuel diversity in the mix of installed capacity resources. This stands in contrast to the eastern zones (Zones F-K) 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. The planned 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.[337]
  - 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.

B. Capacity Imports and Exports

Figure A-88: NYISO Capacity Imports and Exports by Interface

Figure A-88 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2006/07 through Winter 2017/18[338] 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.

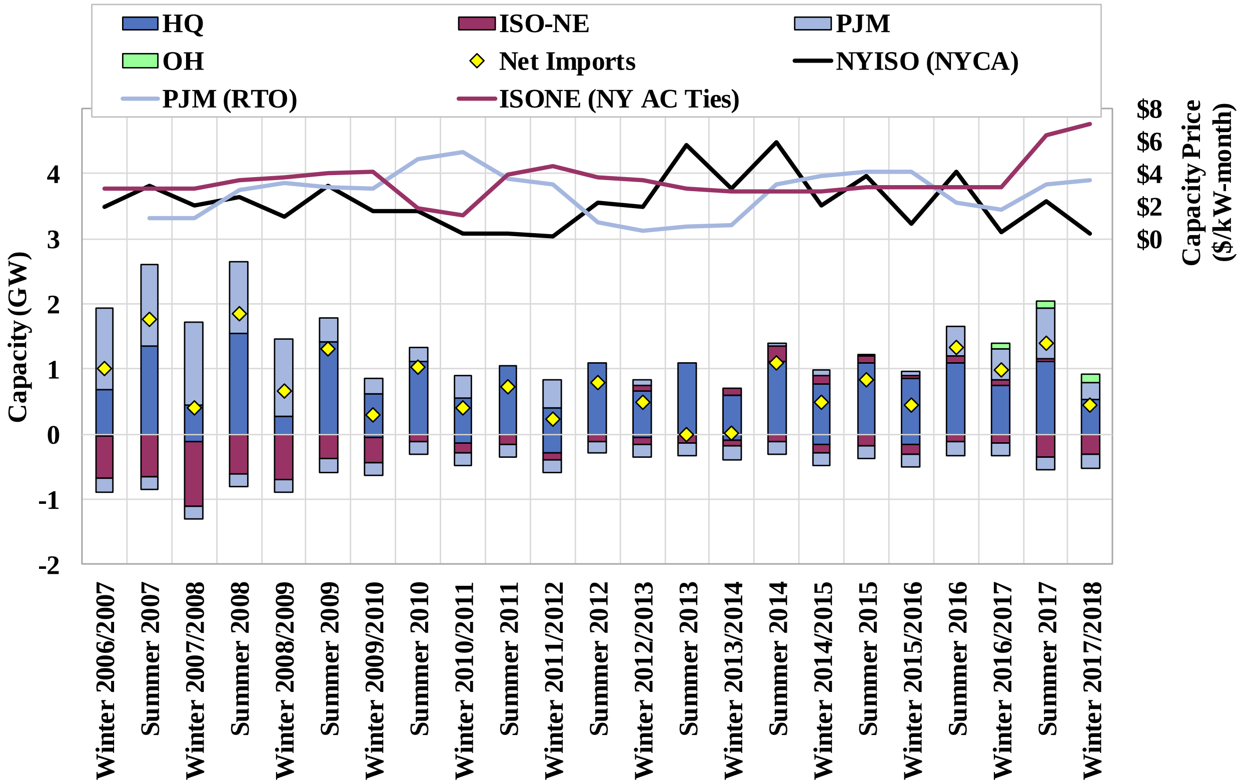
335 See Section VII.D of the Appendix for the contribution of federal and state incentives to the net revenues of a hypothetical wind unit in New York.

336 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.

337 Entergy announced on Jan 9, 2017 its intent to close the Indian Point nuclear units in 2020 and 2021. See: “www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/”.

338 This data shown is the monthly average of capacity imported/ exported over the capability period.

Figure A-88: NYISO Capacity Imports and Exports by Interface
Winter 2006/07– Winter 2017/18



Key Observations: Capacity Imports and Exports

- Capacity imports and exports flow between NYISO and four of its neighboring regions: Hydro Quebec ("HQ"), Ontario ("OH"), PJM, and ISO-NE. NYISO's capacity imports and exports have fluctuated over the years that is a function of several factors, including but not limited to the seasons and price differences between control areas.

- HQ is a large exporter of hydro capacity with an internal load profile that peaks in the winter. Since the Summer 2010 capability period, the imports from HQ have been close to 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 occasionally reversing according 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.[339]

- This trend reversed in the past two Capability Years, with imports from PJM averaging roughly 440 MW and 780 MW in the summer capability periods for 2016 and 2017. Much of this change is likely driven by regional price differences and the low cost of selling capacity into the NYCA as an ICAP resource.[340]

- 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 the Summer 2017. Consequently, larger amounts of New York capacity were exported to ISO-NE during the 2017/ 2018 Capability Year.

- The NYISO signed an MOU with IESO in 2016 regarding import of capacity from Ontario beginning with the Winter 2016/2017 Capability Period. Since then, capacity imports from Ontario have increased with the import allotment.[341]

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

339 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.

340 The NYISO approved changes to the requirements of external resources selling into the NY capacity markets to require such resources to acquire firm transmission rights. These requirements are outlined in §4.9.3 of the NYISO ICAP Manual: "www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf".

Capacity price differences between the NYISO and PJM are not the only driver of capacity imports. There are major structural differences between the two regions' procurement mechanisms (for instance, PJM's three-year forward procurement relative to New York's monthly spot procurement) which limit the extent to which imports respond to price differentials.

341 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.

tested capacity and an EFORd of 7 percent would be able to sell 93 MW of UCAP.[342] This gives suppliers a strong incentive to perform reliably.

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.[343]

Table A-7: Historic Derating Factors by Locality

Table A-7 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2013 onwards.

Table A-7: Derating Factors by Locality
Summer 2013 – Winter 2017/18

Locality	Summer 2017	Summer 2016	Summer 2015	Summer 2014	Summer 2013	Winter 2017/18	Winter 2016/17	Winter 2015/16	Winter 2014/15	Winter 2013/14
G-I	12.70%	5.00%	3.40%	6.86%	N/A	11.72%	6.46%	4.24%	5.72%	N/A
LI	5.60%	7.27%	7.83%	7.65%	6.84%	6.07%	6.36%	9.02%	8.28%	7.37%
NYC	4.37%	9.53%	6.92%	5.44%	5.59%	5.26%	5.44%	10.49%	5.06%	6.63%
A-F	10.48%	10.62%	10.21%	10.92%	N/A	8.96%	8.12%	9.43%	8.50%	N/A
NYCA	9.29%	9.61%	8.54%	9.08%	8.91%	8.43%	7.25%	9.06%	7.32%	8.31%

<u>Key Observations: Equivalent Forced Outage Rates</u>

- The NYCA-wide Derating Factor decreased marginally from Summer 2016 to Summer 2017 while the Derating Factor for the Winter 2017/18 Capability Period rose relative to the Winter 2016/17 Capability Period.
  - The change in NYCA-wide summer Derating Factor can largely be attributed to the decreases in the EFORd of generation located in NYC, although this improvement was offset to a large extent by increased EFORd at a few large generators in G-I. These generator outages in G-I drove the increase in the 2017/2018 Winter Derating Factor for NYCA relative to the previous winter capability period.
- The Derating Factor for Zones A-F is generally higher than observed in other zones.
  - As shown in Figure A-87, nearly 10 percent of the installed generating facilities located in Zones A-F are intermittent in nature. Consequently, the average EFORd of

342 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

343 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".

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.

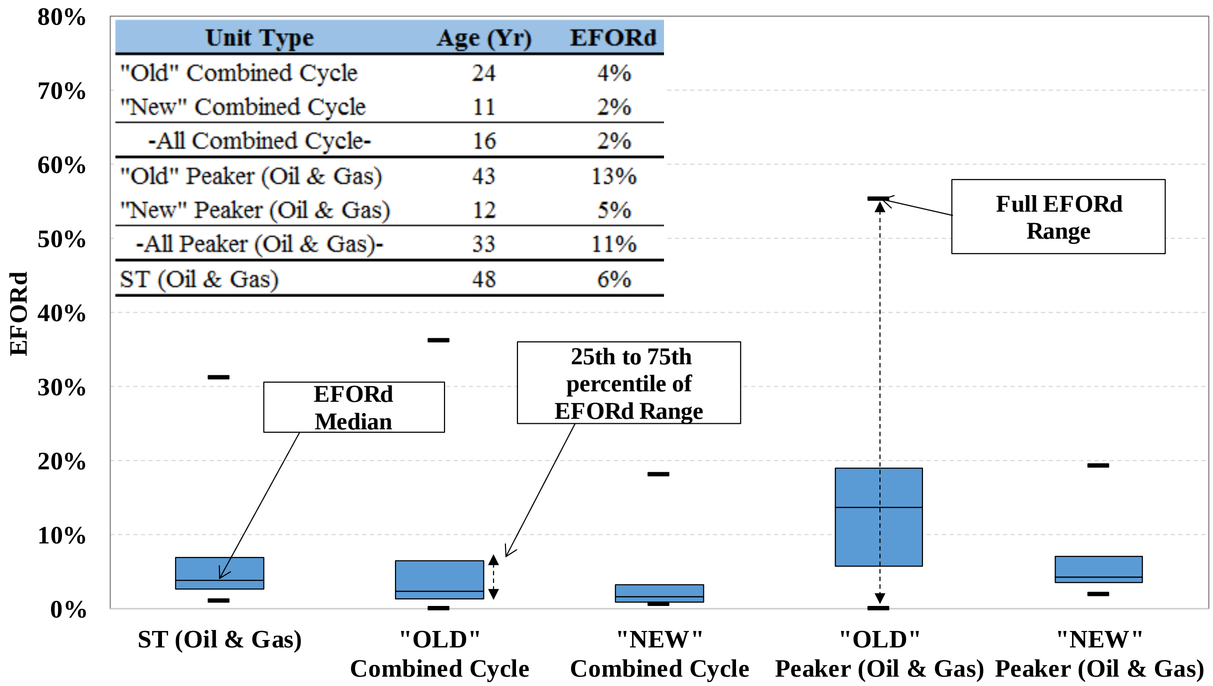
- The overall mix of capacity resources located in Long Island, as shown in Figure A-87, has a high proportion (84 percent) of older steam and peaking units, when compared to NYC (65 percent). A number of relatively new combined cycle units (over 2.2 GW of capacity that is less than 10 years old) are also located in NYC. As a result, the Derating Factors for Long Island have generally been higher than those for NYC.

Figure A-89: Gas and Oil-Fired EFORds by Technology Type and Region

Figure A-89 presents information related to the distributions of EFORd of natural gas and oil-fired units based on technology type and age designation. [344] The column bars for each technology-age 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. Each column is bounded by two dashed lines that denote the full range of observed EFORd values for the given technology. The table included in the chart gives the capacity-weighted average age and EFORd of each technology-age category.

Figure A-89: EFORd of Gas and Oil-fired Generation by Age

Summer – Five-Year Average



344 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."

Key Observations: EFORd of Gas and Oil Units

- As shown in Figure A-89, the distribution of EFORds varies considerably by technology-type and unit age. Units that are younger and units that have a greater number of annual operating hours tend to have lower EFORds.
- 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 have the second lowest average 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-90: Capacity Sales and Prices in NYCA

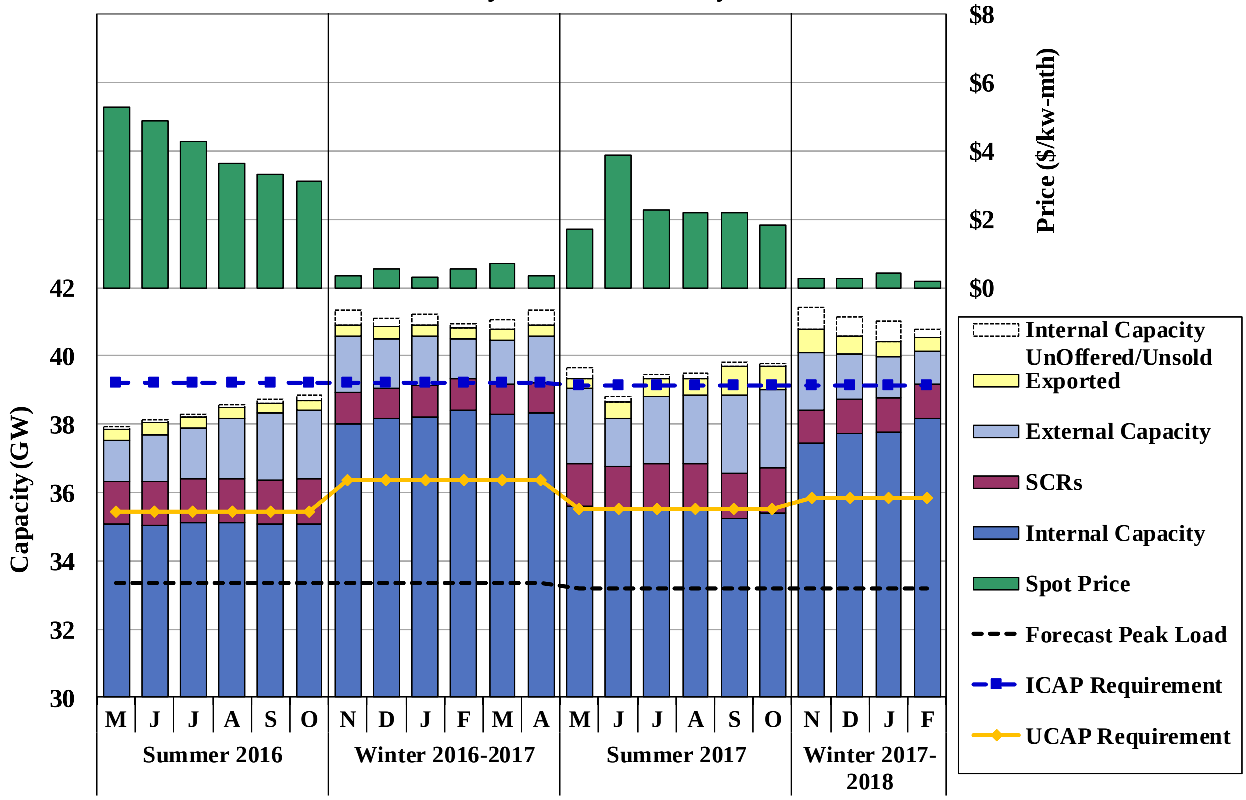
Figure A-90 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs") and sales from SCRs.[345] The hollow portion of each bar represents the In-State capacity in each region not sold

[345] 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.

(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-90 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-90 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-90 also shows the forecasted peak load and the ICAP requirements.

Figure A-90: UCAP Sales and Prices in NYCA
May 2016 to February 2018



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 fell in Rest of State in both Capability Periods of the 2017/18 Capability Year, relative to the previous year.
   - The spot price averaged $2.35/kW-month in the Summer 2017 Capability Period, which was down 43 percent from the prior summer, and $0.29/kW-month in the Winter 2016/17 Capability Period, which was down 35 percent from the prior winter.
   - Summer prices fell primarily due to higher net import levels from external control areas (particularly PJM), new capacity additions like Greenidge 4 steam unit, and a lower Reference Point value from the latest Demand Curve Reset.
   - Although imports from external control areas decreased likely from the previous year due to persistent low UCAP prices, Winter prices fell due to the decrease in UCAP requirement for the Winter Capability Period.
   - The 2017/18 ICAP requirement fell 47 MW from the 2016/17 Capability Year because of a modest decrease in the peak load forecast.[346]
      - However, the UCAP Requirement rose 83 MW in the Summer Capability Period and fell 505 MW in the Winter Capability Period because of the year-over-year increase in Derating Factors.
      - 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-91 - Figure A-93: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-91 to Figure A-93 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-90 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

346 ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2017 Summer and 2017/18 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.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-91: UCAP Sales and Prices in New York City
May 2016 to February 2018

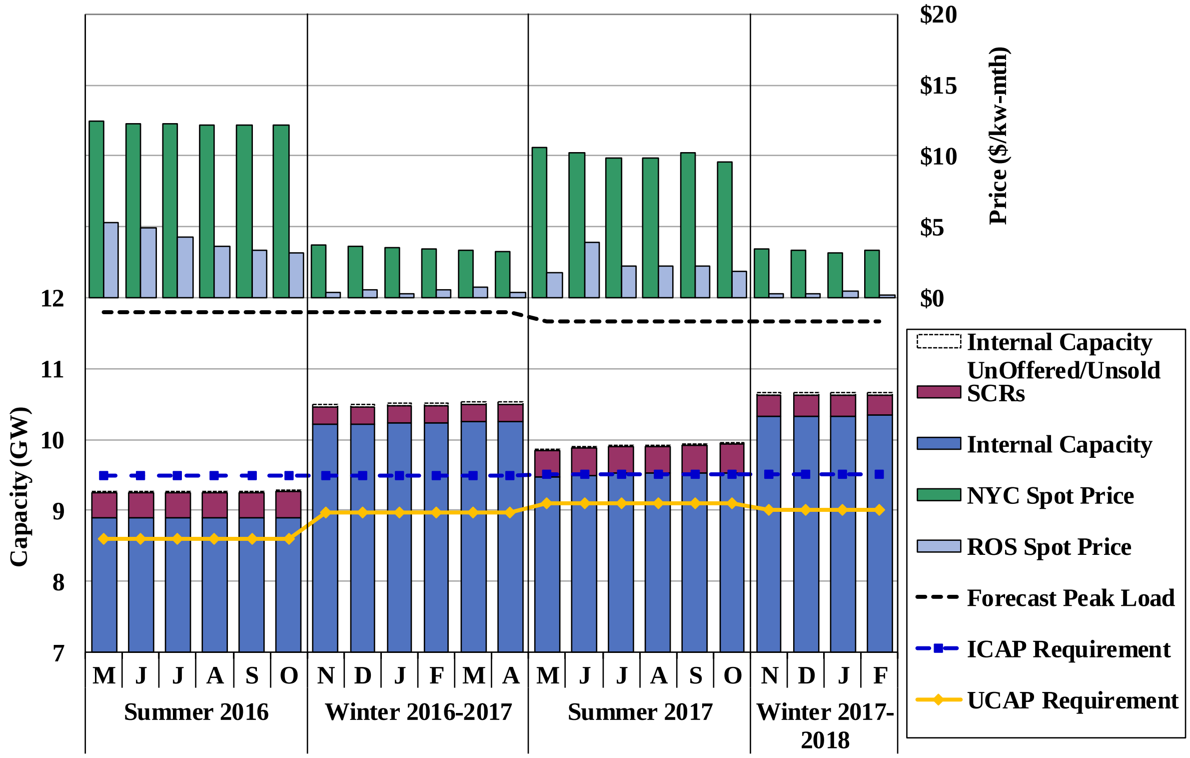


Figure A-92: UCAP Sales and Prices in Long Island
May 2016 to February 2018

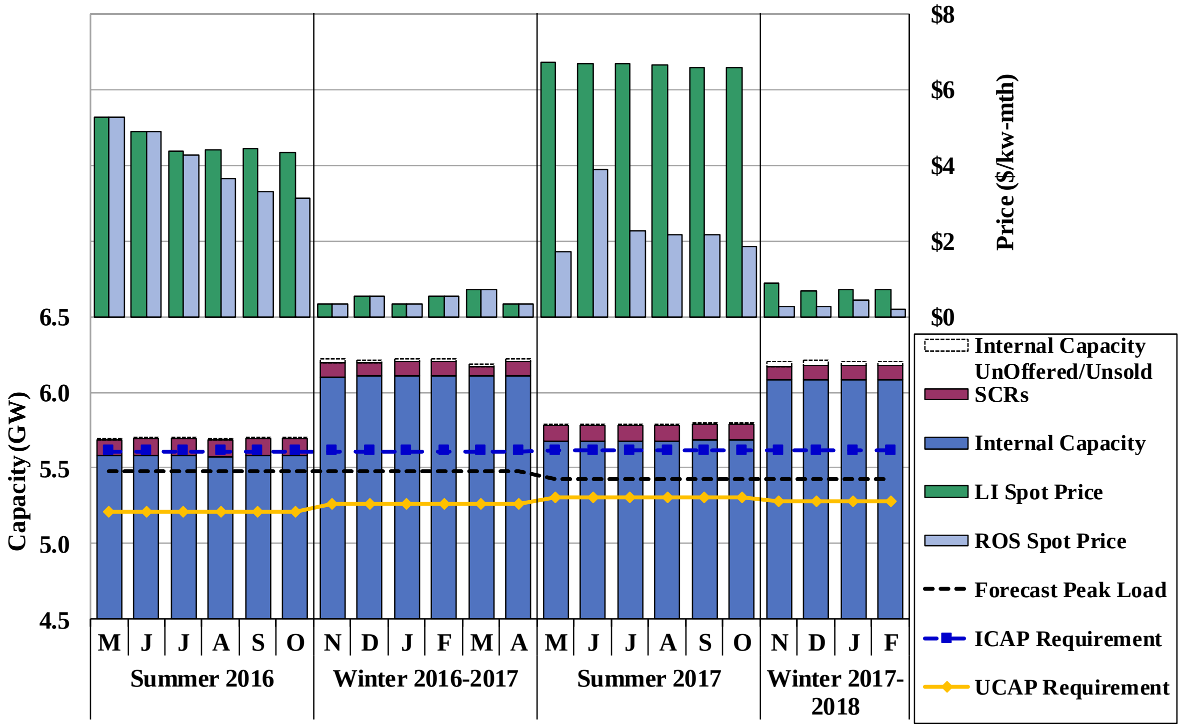
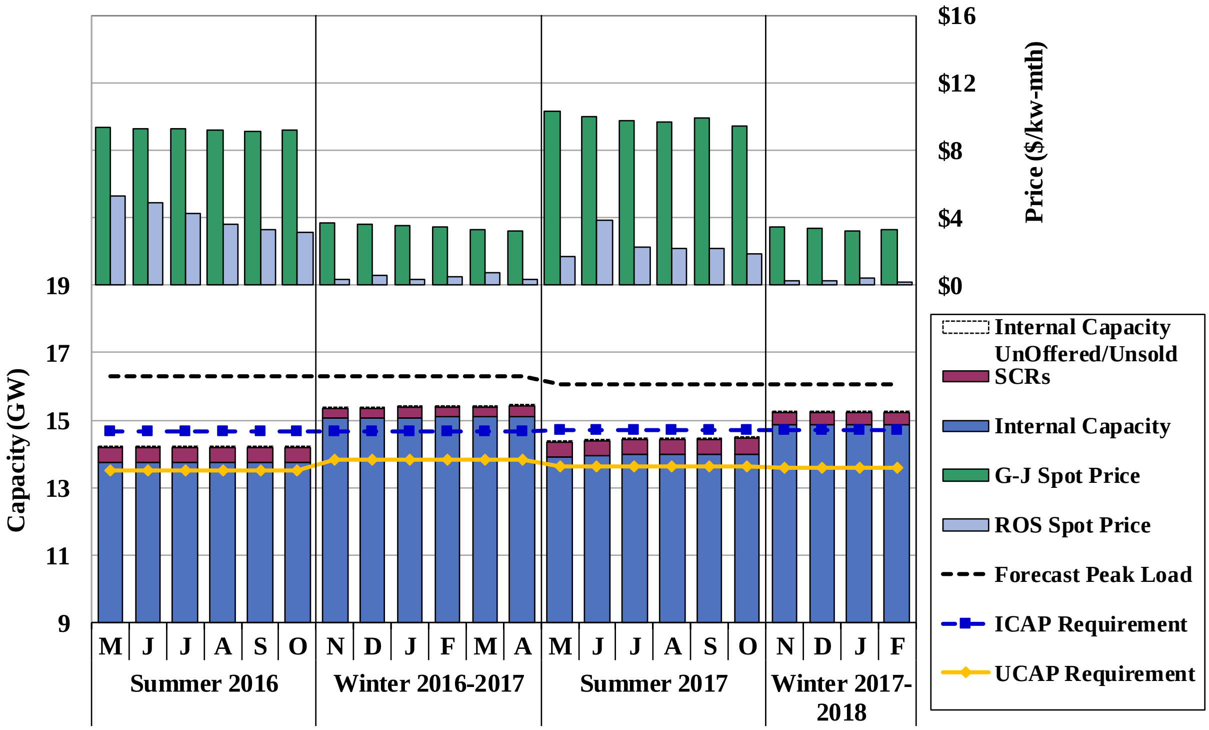


Figure A-93: UCAP Sales and Prices in the G-J Locality
May 2016 to February 2018



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 capacity zone in the 2017/18 Capability Year from the prior Capability Year, but rose in the G-J Locality and in Long Island year over year. Specifically,

  - New York City spot prices fell: (a) 18 percent to an average of $10.04/kW-month in the Summer 2017 Capability Period; and (b) 7 percent to an average of $3.34/kW-month in the Winter 2017/18 Capability Period.

  - Long Island spot prices rose: (a) 44 percent to an average of $6.66/kW-month in the Summer 2017 Capability Period; and (b) 70 percent to an average of $0.75/kW-month in the Winter 2017/18 Capability Period.

  - The G-J Locality spot prices: (a) increased 7 percent to an average of $9.85/kW-month in the 2017 Summer Capability Period; and (b) decreased 7 percent to an average of $3.34/kW-month in the Winter 2017/18 Capability Period.

- The spot prices in New York City fell largely because:

  - Increased UCAP sales from large generators previously on outage increased NYC capacity during the Summer period by roughly 600 MW.

  - New capacity demand curves for the 2017/18 Capability Period resulted in downward shift in the NYC demand curve, which further reduced spot market prices.[347] Other administrative changes that impacted the NYC prices included:

    - The ICAP requirement rose by 17 MW from the 2016/17 Capability Year to the 2017/18 Capability Year, which was primarily due to an increase in the LCR requirement from 80.5 to 81.5 percent.

    - However, the increase in the LCR was offset to an extent by a 124 MW decrease in the peak load forecast.

- The spot prices rose in Long Island because:

  - Revisions to the locality's demand curve from the latest DCR study led to a 50 percent increase for the current Capability Year.

  - In addition, the Long Island UCAP requirement increased by 95 MW primarily due to the higher Derating Factor (see VIII.C) in the 2017/18 Capability Year. ICAP requirement rose insignificantly by 2 MW in the 2017/18 Capability Year because of competing effects of an increasing LCR (from 102.5 percent to 103.5 percent, year-

[347] See footnote 330 for more information on how to find the demand curves for the 2017/18 Capability Period.

over-year) and decreasing peak load forecast (down 51 MW from prior Capability Year).

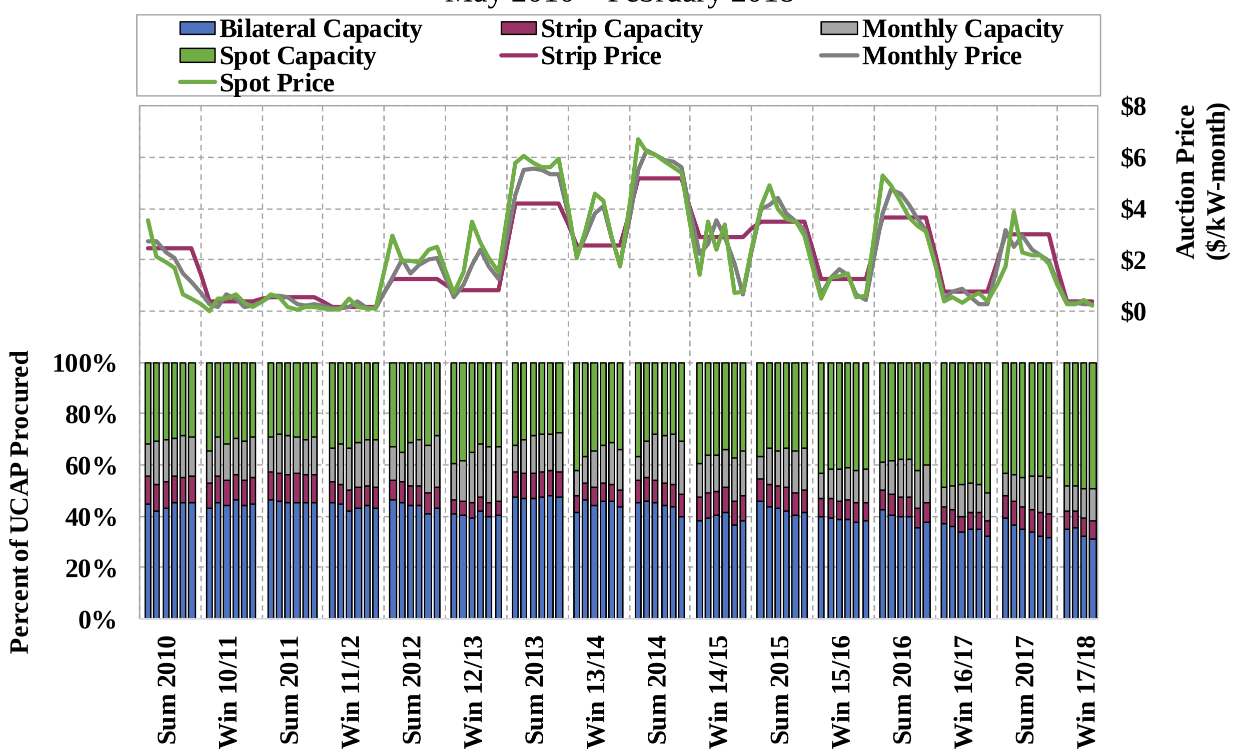
- The spot prices in the G-J Locality increased during the Summer months because the administrative changes to the demand curve outweighed internal capacity increases:
  - The demand curve reference point increase by 17 percent which more than offset the price reducing impact of a 200 MW net addition of internal capacity during the Summer period.
- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2017.

Figure A-94: Capacity Procurement by Type and Auction Price Differentials

Figure A-94 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-94: Auction Procurement and Price Differentials in NYCA

May 2010 – February 2018



Key Observations: Capacity Procurement and Price Comparison

- Almost 80 percent of the total UCAP in NYCA is procured via bilateral transactions (35 percent in Summer 2017) or in the spot market (44 percent in Summer 2017). The remaining capacity is procured through the strip (9 percent in Summer 2017) and monthly (12 percent in Summer 2017) 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.
- Between Summer 2011 and Summer 2016, monthly and the spot auction prices have frequently been set at a premium to the strip price during the summer capability periods. However, Summer 2017 saw Strip Auction prices at a higher average value compared to the Spot and Monthly prices, likely due to the variation in monthly net imports (and expectations regarding the level of imports).

F. Cost of Reliability Improvement from Additional Capacity

Since the inception of the NYISO, the installed capacity requirements have been primarily based on resource adequacy criteria, which require sufficient capacity to maintain the likelihood of a load shedding event in the NYCA below the prescribed level (i.e., 1 day in 10 years). Hence, the capacity price in a particular location should depend on how much capacity at that location would reduce the likelihood of load shedding in NYCA. Since implementing the downward sloping capacity demand curves in 2004, the NYISO has used the cost of new entry as the basis for placing the demand curve, placing the demand curve sufficiently high to allow a hypothetical new entrant to recover its capital costs over an assumed project life. Hence, capacity markets should provide price signals that reflect: the reliability impact and the cost of procuring additional capacity in each location.

The Cost of Reliability Improvement ("CRI"), which is defined as the cost of additional capacity to a zone that would improve LOLE by 0.001, characterizes the value of additional capacity in a zone and captures the two key factors that should be considered while determining capacity prices. Under an efficient market design, the CRI should be the same in every zone under long term equilibrium conditions. This will reduce the overall cost of maintaining reliability and direct investment to the most valuable locations. To achieve these efficient locational capacity prices, the market should procure amounts of capacity in each area that minimize the cost of satisfying the resource adequacy standard.

The current annual process for determining the IRM and LCRs is known as the "Unified Methodology".[348] 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

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

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. Therefore, the NYISO recently proposed an alternative methodology for determining the LCRs. The NYISO's alternative methodology ("Optimized LCRs Method") seeks to minimize the total cost of capacity under long term equilibrium while conforming to: (a) an LOLE of less than 0.1 days/ year, (b) the NYSRC-determined IRM, and (c) transmission security limits ("TSL") for individual Localities.

Table A-7: Cost of Reliability Improvement – Unified Methodology and Optimized LCRs Method

Table A-8 and Table A-9 compare the CRI in each zone under the Unified Methodology and the Optimized LCRs Method for determining the LCRs. Both the tables are 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 of 0.069 under the Unified Methodology and an LOLE of 0.071 under the Optimized LCRs Method.[349] The 2018/19 LCRs for Zone J, Zone K and G-J Locality are 80.5, 103.5 and 94.5 percent under the Unified Methodology and 79.7, 90.8 and 107.5 percent under the Optimized LCRs Method, respectively.

For each methodology, the corresponding table shows the following for each area:

- *Net CONE of Demand Curve Unit* – Based on the uncollared Net CONE curves that were derived from the annual updates to the demand curves for the 2018/19 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.

- *LOLE from 200 MW UCAP Addition* – The estimated LOLE from placing 200 MW of additional UCAP in the zone.[350]

- *Marginal Reliability Impact ("MRI")* - The estimated reliability benefit (reduction in LOLE) from placing 100 MW of additional UCAP in the area. This is calculated as half

349 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 to the Excess Level in each area.

350 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.

the difference between the NYCA LOLE at Excess Level and the LOLE from adding 200 MW of UCAP to the zone.

- *Cost of Reliability Improvement ("CRI")* – This is the annual levelized investment cost necessary for a 0.001 improvement in the LOLE from placing capacity in the area.[351, 352] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each zone.

Table A-8: Cost of Reliability Improvement – Unified Methodology
2018/19 Capability Year

Zone	Net CONE of Demand Curve Unit (Uncollared) *$/kW-yr*	LOLE with 200 MW UCAP Addition	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*
A	$100	0.062	0.003	$2.9
B	$100	0.062	0.003	$3.0
C	$100	0.062	0.003	$3.0
D	$100	0.062	0.003	$3.0
E	$100	0.062	0.003	$3.0
F	$100	0.062	0.003	$3.0
G	$150	0.061	0.004	$4.0
H	$150	0.061	0.004	$3.9
I	$150	0.061	0.004	$3.9
J	$177	0.058	0.006	$3.2
K	$126	0.057	0.006	$2.2

Table A-9: Cost of Reliability Improvement – Optimized LCRs Method
2018/19 Capability Year

Zone	Net CONE of Demand Curve Unit (Uncollared) *$/kW-yr*	LOLE with 200 MW UCAP Addition	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*
A	$100	0.064	0.003	$3.2
B	$100	0.064	0.003	$3.2
C	$100	0.064	0.003	$3.2
D	$100	0.064	0.003	$3.2
E	$100	0.064	0.003	$3.3
F	$100	0.064	0.003	$3.2
G	$149	0.062	0.004	$3.5
H	$149	0.062	0.004	$3.5
I	$149	0.062	0.004	$3.5
J	$176	0.057	0.007	$2.7
K	$130	0.061	0.005	$2.9

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

352 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.

Key Observations: Cost of Reliability Improvement

- Table A-8 shows large disparities in the CRI across zones under the Unified Methodology, ranging from a minimum of $2.2 million per 0.001 events in Long Island to a maximum of $4.0 million in Zone G (Lower Hudson Valley). The wide range in CRI values illustrates that the IRM and LCRs under the Unified Methodology are not determined optimally, since it implies that the ISO could significantly reduce capacity investment costs by:
    - Increasing capacity purchases in Long Island at a cost of $2.2 million per 0.001 events, and
    - Reducing capacity purchases in Hudson Valley for a savings of $4.0 million per 0.001 events.
- The Optimized LCRs Method reduces investment costs by shifting capacity purchases from high-cost areas to low-cost areas while achieving a similar LOLE as the Unified Methodology. Consequently, the range in CRI values across zones in Table A-9 is significantly smaller than the range observed under the Unified Methodology. Nevertheless, the range between the minimum CRI-value location (New York City at $2.7 million per 0.001 events) and the maximum CRI-value location (Zones G-I at $3.5 million per 0.001 events) is still substantial. The results suggest:
    - The LCRs might be further reduced by increasing purchases slightly in Zone J at a cost of $2.7 million per 0.001 events and reducing purchases slightly in Zones G-I at a savings of $3.5 million per 0.001 events (which may require some modification to the algorithm that optimizes the LCRs); and
    - The CRI for Zone K continues to be lower than the CRI for Zones G-I, although the difference between the two values has narrowed considerably under the Optimized LCRs Method.
- The CRI values for zones within the current configuration of capacity market zones (i.e. zones G-I and A-F) are relatively similar. However, the MRI and the Net CONE for each zone depend on several factors that could evolve in the future. For instance, the zonal MRIs could change significantly with retirement of a large plant like Indian Point or with increase in the UPNY-SENY transfer capability. Similarly, gas pipeline congestion patterns could lead to large differences in the Net CONE values within a capacity market locality.[353]
    - Such developments could lead to large disparities in the CRI values of different locations within a capacity locality. Such large disparities usually imply that a locality should be broken into multiple localities to ensure that capacity is priced and scheduled efficiently.

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[353] See comments of the Market Monitoring Unit in Commission Docket ER17-386-000, dated December 9, 2016.

G. Financial Capacity Transfer Rights for Transmission Projects

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. Recognizing these reliability benefits of transmission projects and providing them access to capacity market revenues could provide substantial incentives to invest in transmission. In this subsection, we discuss the reliability value of transmission projects and the potential for financial capacity transfer rights ("FCTRs") in providing investment signals for merchant transmission projects.[354]

Figure A-95: Breakdown of Revenues for Generation and Transmission Projects

Figure A-95 compares the breakdown of capacity and energy revenues for two hypothetical new generators (Frame CT and a CC) in Zone G with the revenue breakdown for two recently completed transmission projects: (a) the Ramapo – Rock Tavern 345 kV Line ("RRT") portion of the Transmission Owner Transmission Solutions ("TOTS") projects, and (b) the Marcy-South Series Compensation ("MSSC") portion of the TOTS projects. The figure also compares the net revenues for these projects against their gross CONE and highlights the reduction in shortfall of revenues due to the proposed FCTRs for transmission projects. The information presented in the figure is based on the following assumptions and inputs:

- The RRT project is assumed to increase transfer capability of the UPNY-SENY interface by 135 MW and the MSSC project is assumed to increase the transfer capability by 287 MW.[355]
- The system is assumed to be at the long-term equilibrium that is modeled in the demand curve reset process, with each locality at its Excess Level. GE-MARS simulations of the

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354 See Recommendation 2012-1c in Section XI.

355 Although the RRT and MSSC projects increase the limit for the Central-East interface, MARS results indicate that the MRI for this interface is zero in the current year. Our assumptions for increases in UPNY-SENY transfer capability are based on a) for the RRT project, see May 20, 2013 Case 12-E-0503 – Con Edison Filing of Supplemental Information Regarding its Ramapo to Rock Tavern Project, b) for the MSSC project, see https://nyisoviewer.etariff.biz/viewerdoclibrary/Filing/Filing1033/Attachments/NYPA%20Trnsmttl%20Ltt r%20Frml%20Rt%20Flng%2007.02.2015%20F.pdf.

We estimated the Gross CONE for the TOTS projects using the following inputs:

a) Carrying charge of 9.2 percent based on the WACC developed in the demand curve reset study, a 40 year project life and 15 years MACRS depreciation schedule.

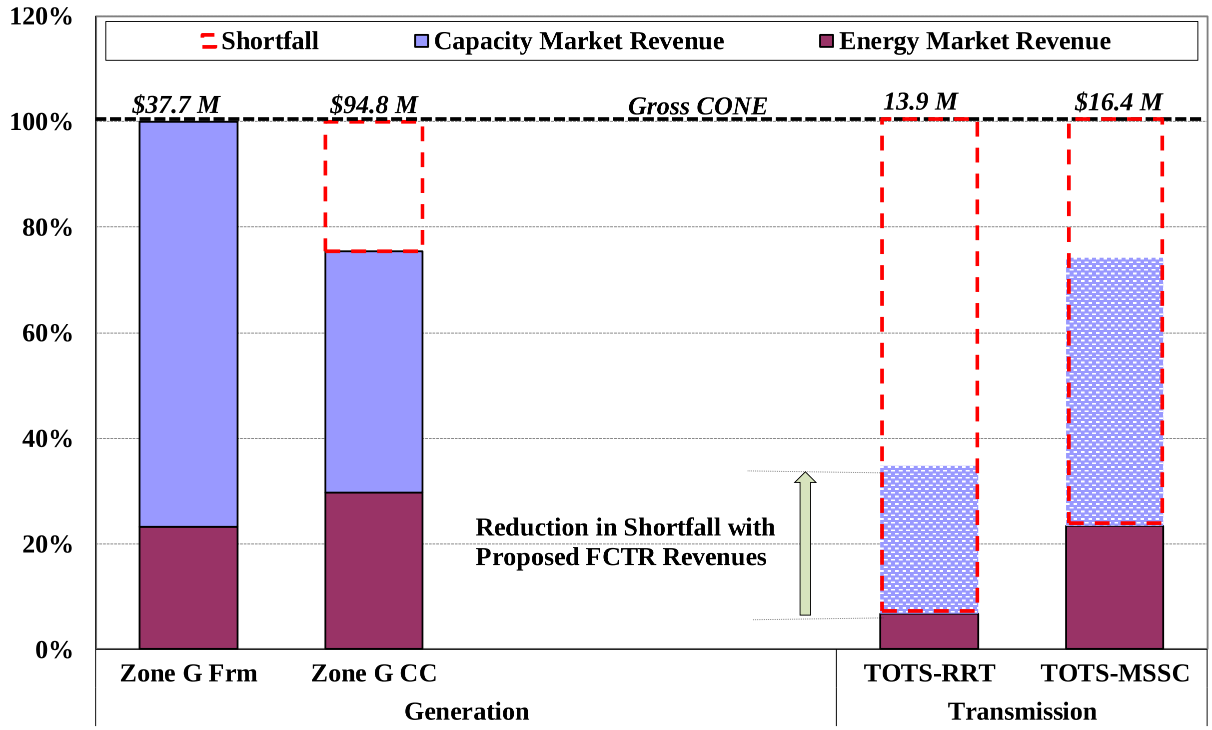
b) An investment cost of $120 million for the MSSC project (see https://www.utilitydive.com/news/new-york-finishes-transmission-project-to-access-440-mw-of-capacity/421104/), and $102 million for the RRT project (see page 6 of April 21, 2016 NYPSC Order in Case 16-E-0012 and Case 16-E-0013)

c) An additional annual charge of 5 percent of investment costs to account for O&M and other taxes, based on the share of these costs reported in the New York Transco's Annual Projection dated 09/30/2017 for the TOTS projects.

system indicate that the estimated reliability benefit (reduction in LOLE) from increasing the transfer capability of the UPNY-SENY interface by 200 MW is 0.002 events per year.

- The FCTR revenues for the transmission projects equal the product of the following three inputs:
  - The effect on the transfer limit of one or more interfaces (only UPNY-SENY in the case of the TOTS projects) from adding the new facility to the as-found system, and
  - The MRI of the increasing the transfer limit of UNPY-SENY, and
  - The value of reliability in dollars per unit of LOLE. Based on the results of the Optimized LCRs Method, this value is assumed to be $2.9 million per 0.001 events change in LOLE.
- The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the TOTS projects. The TCCs were valued based on the energy prices during 2017.
- The gross CONE, energy and capacity market revenues for the Zone G Frame and CC units are based on the 2017 demand curve reset study.

Figure A-95: Breakdown of Revenues for Generation and Transmission Projects
2018/19 Capability Year



Key Observations: Financial Capacity Transfer Rights for Transmission Projects

- The results illustrate the disadvantages that transmission projects have relative to generation (and demand response) in receiving compensation for the planning reliability benefits they provide to the system.
- Capacity market compensation has historically provided a critical portion of the incentive for generator entry and exit decisions.
  - The figures shows that capacity markets provide 46 to 77 percent of a new generator in Zone G and it is highly unlikely that a new generator would be built without this revenue stream.
  - Because of the absence of capacity market compensation for transmission projects, developers lack the critical market incentive necessary for market-based (rather than cost-of-service-based) investment in transmission.
- Figure A-95 illustrates the potential of FCTRs in incentivizing development of merchant transmission projects. In the absence of capacity payments to the TOTS projects, the TOTS projects recoup only seven to 23 percent of their annualized gross CONE. However, granting FCTRs to the projects would have provided an additional 28 to 51 percent of the annualized gross CONE. These results indicate:
  - A major benefit of most generation and transmission projects is that they provide significant planning reliability benefits.
  - Generators receive high rates of compensation for the planning reliability benefits they provide in the capacity market.
- However, transmission projects receive no compensation for such benefits through the market. Thus, it is unlikely that market-based investment in transmission will occur if transmission providers cannot receive capacity market compensation for providing planning.

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.

In this section, we estimate the net revenues the markets would have provided to: (a) new and existing gas-fired units (subsection A), (b) existing nuclear plants (subsection C), (c) new utility-scale solar PV units, (d) new onshore wind units, and (e) new offshore wind units (subsection D). 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 number of our recommendations (see section XI.B) for enhancing real time markets would result in significant changes to the energy and reserve prices, and could impact the operation of various resources. In subsection E, we evaluate the potential impact of a subset of these recommendations on the net revenues of different types of resources under the long-run equilibrium conditions.

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 zone. Energy and ancillary services revenues for units in the Central Zone, 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 future years, the node-to-zone basis spread is based on the average in 2017. For New York City, results are shown for the Ravenswood GT3/4 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-10 to Table A-13: Assumptions for Net Revenues of Fossil Fuel Units

Our net revenue estimates for gas-fired units are 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.[356] 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

356 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.

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.
  - 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-10: Day-ahead Fuel Assumptions During Hourly OFOs[357]

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-11: 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%

357 **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.

- 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 the 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.

- We also use the operating and cost assumptions listed in the following tables:

Table A-12: New Gas-fired Unit Parameters for Net Revenue Estimates[358]

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 (2017$/MWh)	$2.5	$5.7	$0.8	$0.2
Variable O&M - Oil (2017$/MWh)	$2.9	$9.8	$2.7	$1.6
Startup Cost (2017$)	$0	$0	$11,054	$10,792
Startup Cost (MMBTU)	3700	61	350	350
EFORd	2.50%	2.17%	2.17%	2.17%

Table A-13: 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 (2017$/MWh)	$8.4	$4.7	$5.7
Startup Cost (2017$)	$6,267	$1,253	$542
Startup Cost (MMBTU)	2000	50	60
EFORd	5.14%	10.46%	19.73%

Figure A-96 and Figure A-97: Forward Prices and Implied Heat Rate Trends

We estimate the net revenues from 2018 to 2020 using forward prices for power, fuel and capacity.[359] We developed the hourly day ahead power price forecast for each zone by adjusting

358 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.

the 2017 LBMPs using the ratio of monthly forward prices and the observed monthly average prices in 2017.[360] We held the reserve prices for future years at their 2017 levels. Figure A-96 shows the variation in the forward prices and implied marginal heat rates for Zone A and Zone G over a six month (July-Dec, 2017) trading period. In general, there is considerable volatility in power and gas forward prices during the last two quarters of 2017. The zonal forward prices in Zone G have ranged from $32 to $37 per MWh while Zone A forward prices were in the $25 to $29 per MWh range. Therefore, we used the trailing 90-day average of the forward prices as of January 1st 2018. 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 an increase in the 2018 implied marginal heat rates in the last weeks of 2017. 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-97 shows the assumed monthly forward power and gas prices for the 2018-2020 period along with the observed monthly average prices during the 2015-2017 period. The power forward prices for 2018 are higher than the 2017 prices. The forward prices for 2019 and 2020 delivery of power and gas are only slightly lower than the 2018 prices. The year-over-year change in pricing of gas and power forward prices are generally consistent with each other. This indicates that the lower implied marginal heat rate observed in 2017 for New York City (see Section I.A of the Appendix) is expected to continue in the future years as well.

359 We used average monthly capacity forwards pricing data over the period of October 2017 through December 2017 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.

360 Our net revenue estimates for the 2018-20 time period are based on zonal and not nodal prices.

Figure A-96: Forward Prices and Implied Marginal Heat Rates by Transaction Date
2018, 2019, & 2020 Strip Prices from July to December 2017

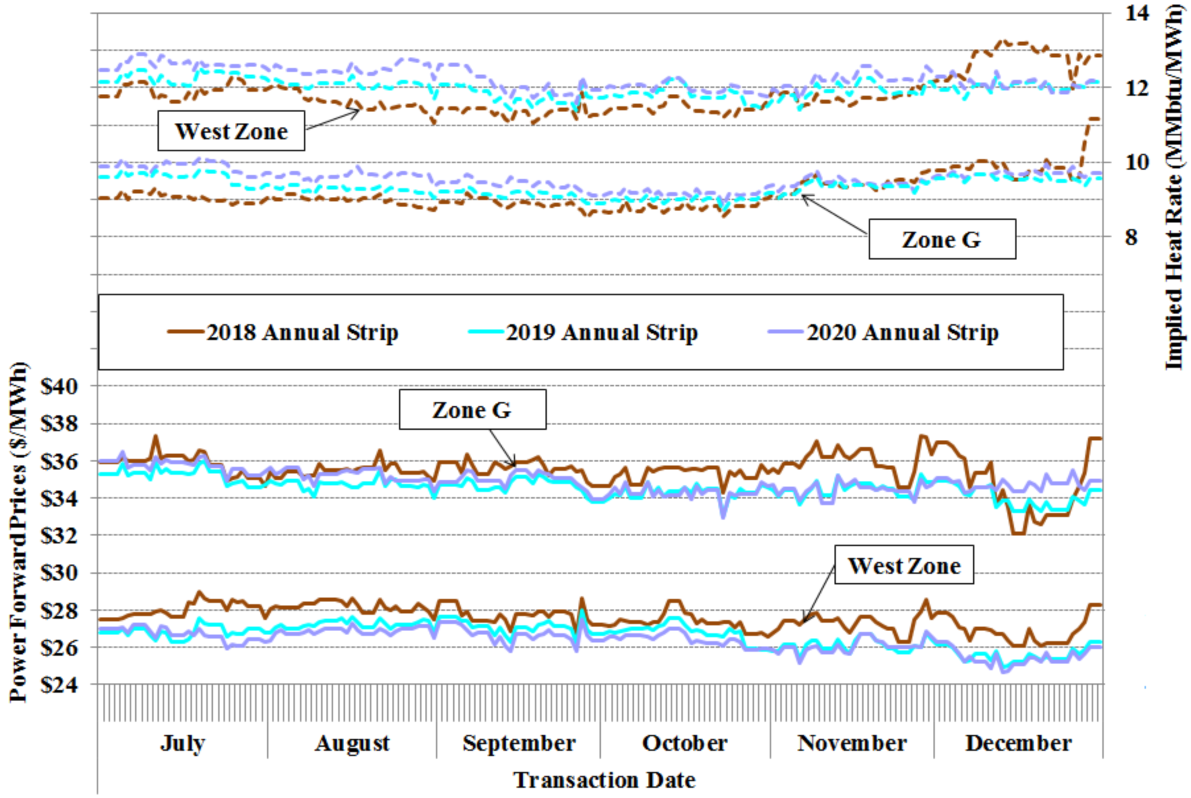
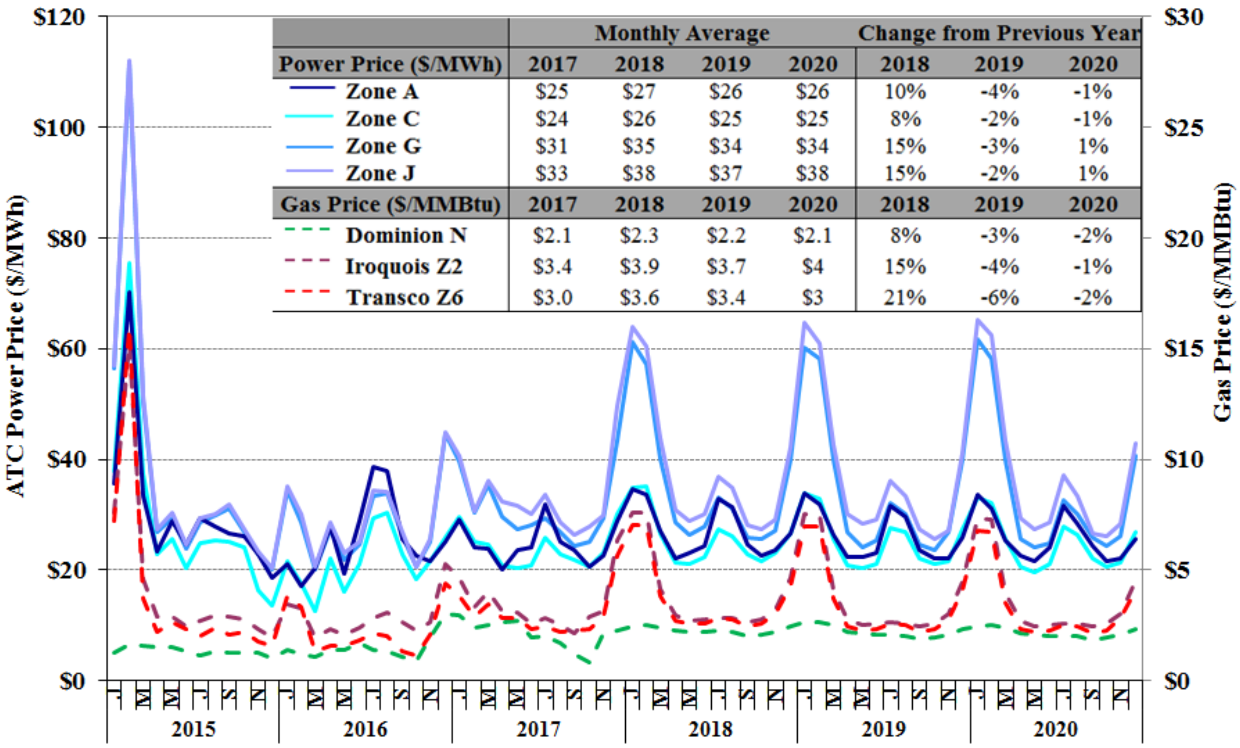


Figure A-97: Past and Forward Price Trends of Monthly Power and Gas Prices
2015 – 2020



	Monthly Average				Change from Previous Year		
Power Price ($/MWh)	2017	2018	2019	2020	2018	2019	2020
Zone A	$25	$27	$26	$26	10%	-4%	-1%
Zone C	$24	$26	$25	$25	8%	-2%	-1%
Zone G	$31	$35	$34	$34	15%	-3%	1%
Zone J	$33	$38	$37	$38	15%	-2%	1%
Gas Price ($/MMBtu)	2017	2018	2019	2020	2018	2019	2020
Dominion N	$2.1	$2.3	$2.2	$2.1	8%	-3%	-2%
Iroquois Z2	$3.4	$3.9	$3.7	$4	15%	-4%	-1%
Transco Z6	$3.0	$3.6	$3.4	$3	21%	-6%	-2%

Figure A-98 to Table A-15: 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.[361] Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-14 shows our estimates of net revenues and run hours for all the locations and gas unit types in 2017. Table A-15 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2017.

361 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 percent 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. The GFCs for older generators are based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

Figure A-98: Net Revenue & Cost for Fossil Units in West Zone
2015-2020

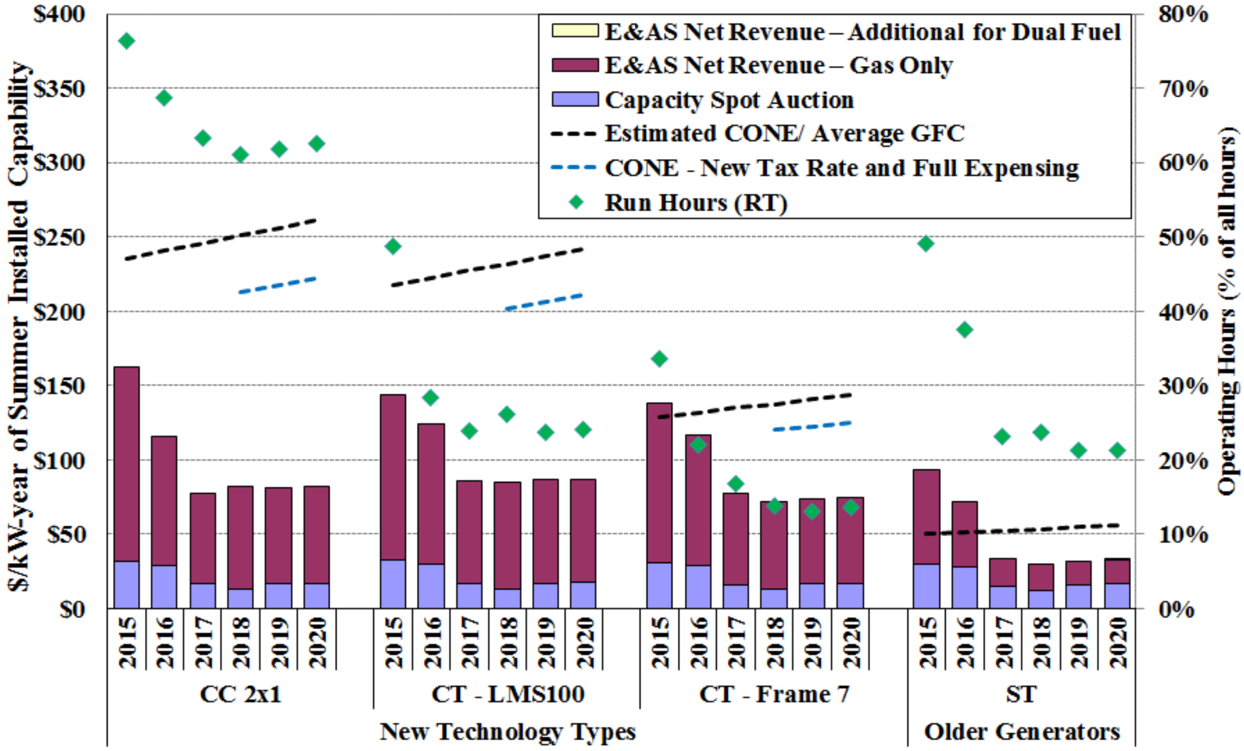


Figure A-99: Net Revenue & Cost for Fossil Units in Central Zone
2015-2020

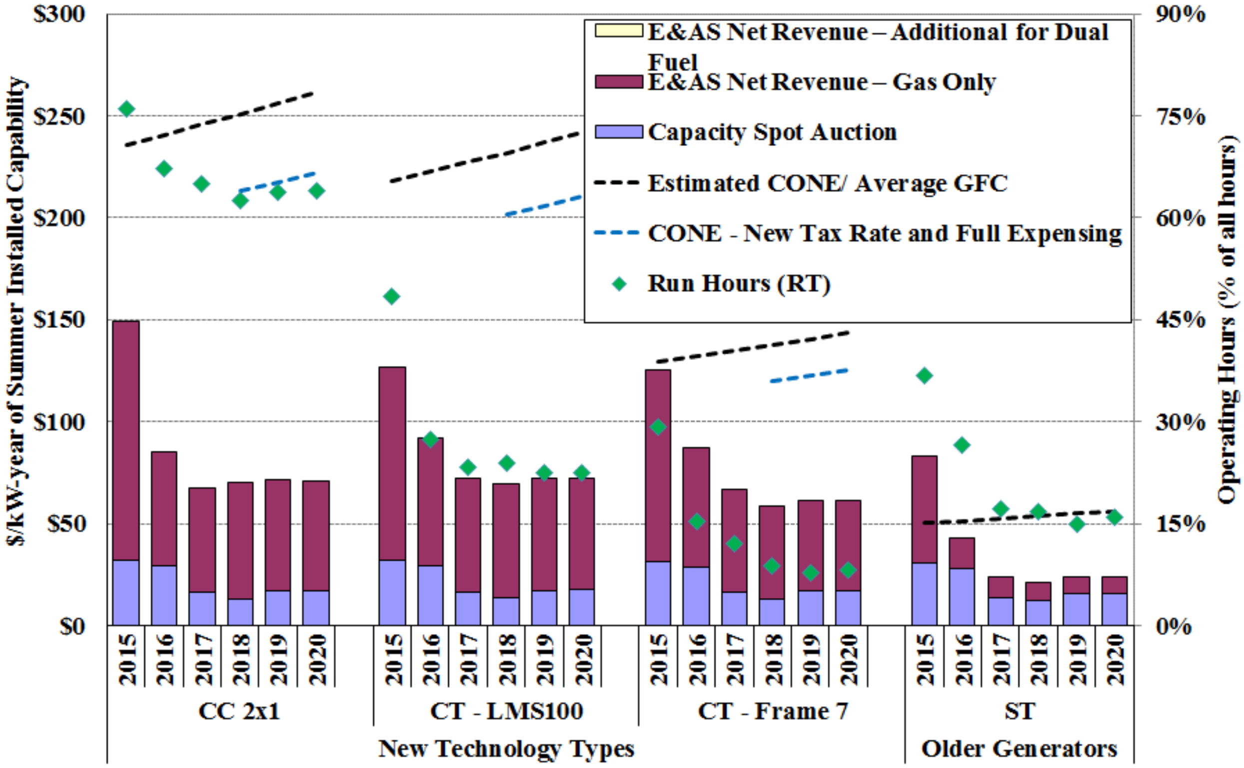


Figure A-100: Net Revenue & Cost for Fossil Units in Capital Zone
2015-2020

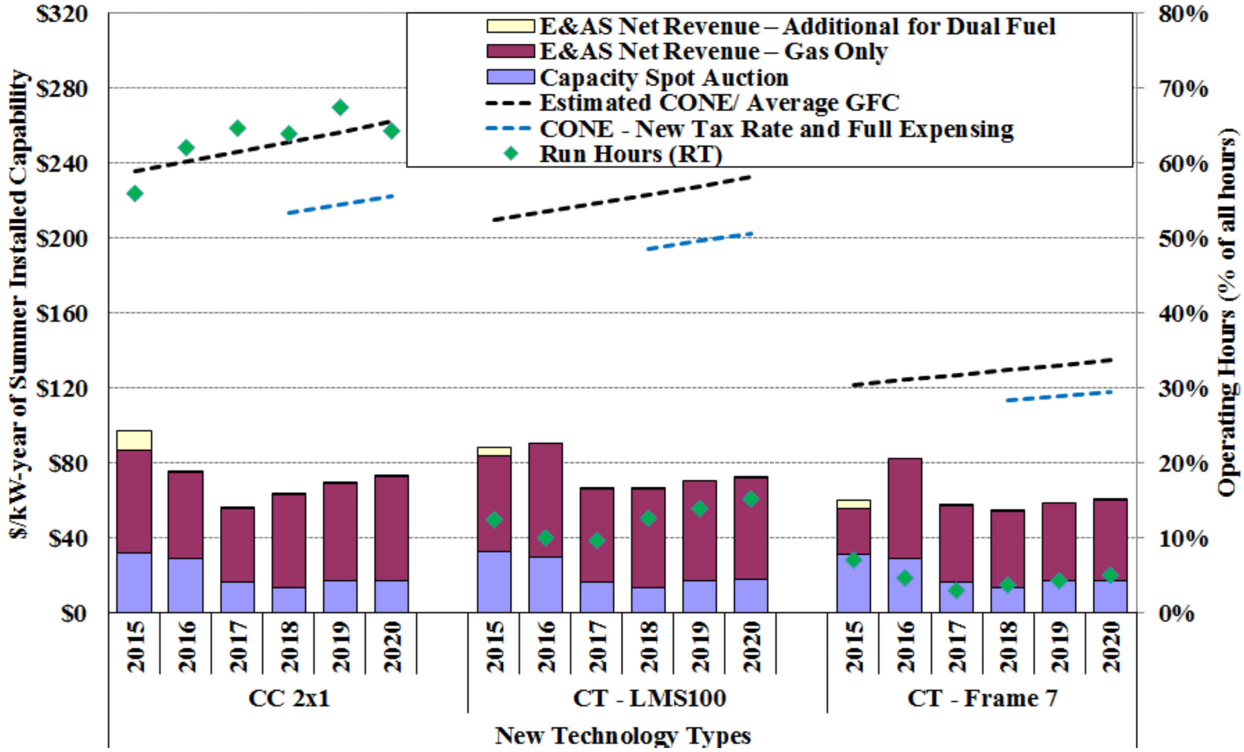


Figure A-101: Net Revenue & Cost for Fossil Units in Hudson Valley
2015-2020

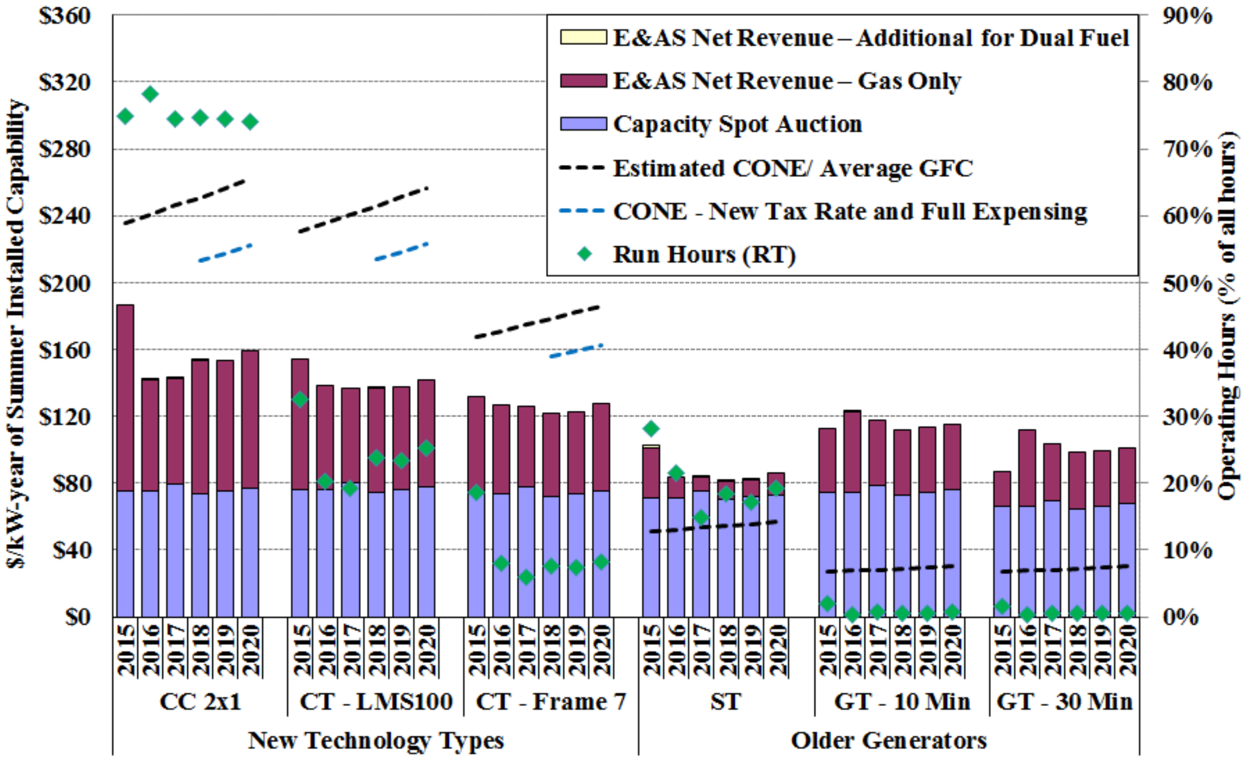


Figure A-102: Net Revenue & Cost for Fossil Units in New York City
2015-2020

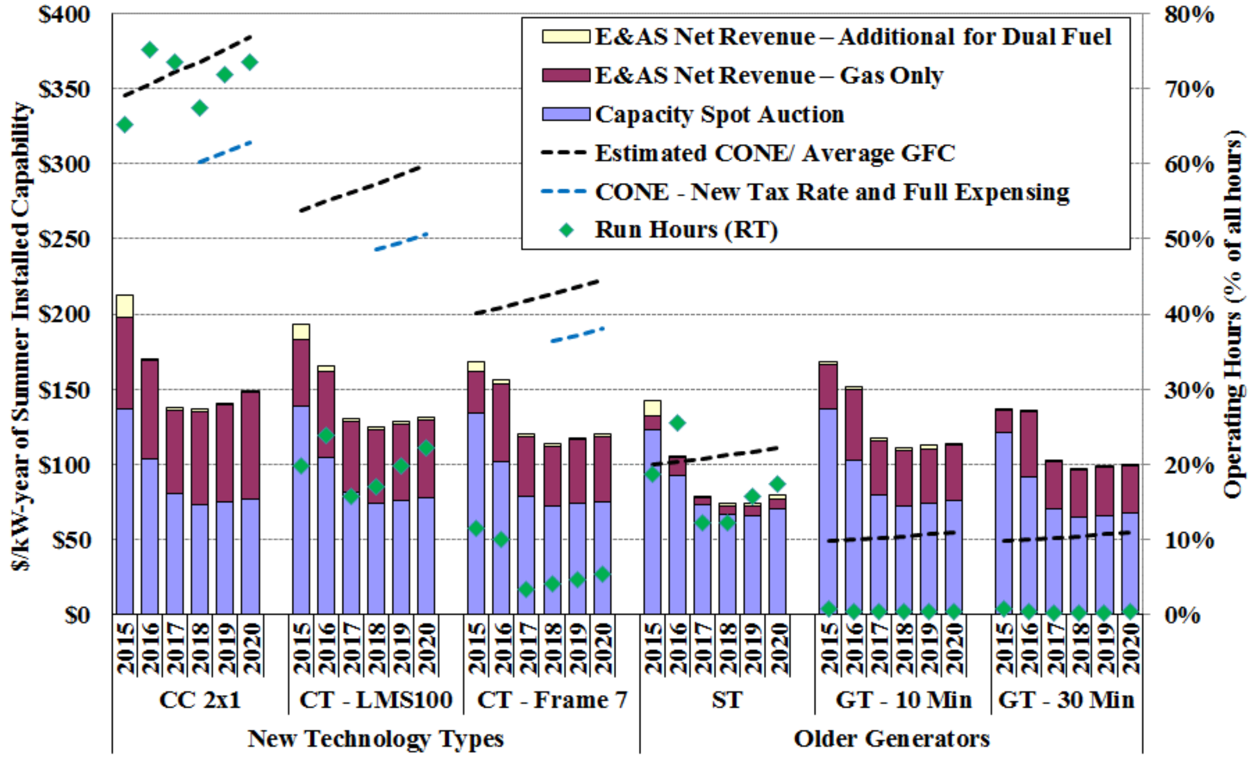


Figure A-103: Net Revenue & Cost for Fossil Units in Long Island
2015-2020

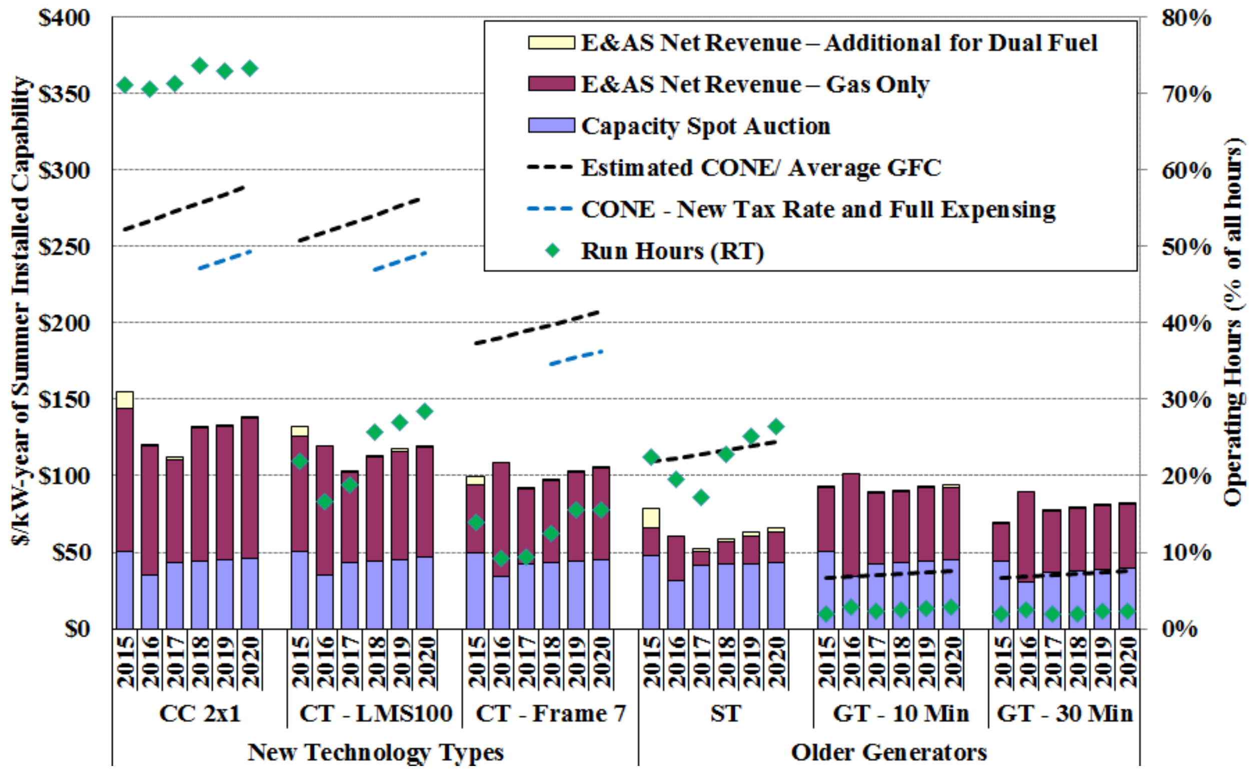


Table A-14: Net Revenue for Gas-Fired & Dual Fuel Units

2017

Location	Unit Type	Capacity	2017 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	$16	$39	$1	$56	5632	5581	80	5661
	CT - Frame 7	$16	$41	$0	$57	252	252	0	252
	CT - LMS100	$17	$50	$0	$66	839	839	2	841
Central Zone	CC 2x1	$16	$51	$0	$67	5686	5686	0	5686
	CT - Frame 7	$16	$50	$0	$66	1062	1062	0	1062
	CT - LMS100	$17	$56	$0	$72	2038	2038	0	2038
	ST	$14	$10	$0	$24	1494	1494	0	1494
West Zone	CC 2x1	$16	$61	$0	$77	5538	5538	0	5538
	CT - Frame 7	$16	$61	$0	$77	1477	1477	0	1477
	CT - LMS100	$17	$69	$0	$85	2099	2099	0	2099
	ST	$15	$18	$0	$33	2050	2035	0	2035
Hudson Valley (Iroquois-Zn2 Gas)	CC 2x1	$79	$39	$1	$119	5121	5086	54	5140
	CT - Frame 7	$78	$40	$0	$118	204	204	0	204
	GT - 10 Min	$78	$38	$0	$116	26	25	1	26
	GT - 30 Min	$70	$32	$0	$102	26	26	0	26
	CT - LMS100	$80	$48	$0	$128	753	753	0	753
	ST	$58	$2	$1	$62	454	454	70	524
Hudson Valley	CC 2x1	$79	$64	$0	$143	6515	6512	4	6515
	CT - Frame 7	$78	$48	$0	$126	516	516	0	516
	GT - 10 Min	$78	$39	$0	$118	59	59	0	59
	GT - 30 Min	$70	$34	$0	$103	43	43	0	43
	CT - LMS100	$80	$56	$0	$137	1683	1683	0	1683
	ST	$75	$8	$0	$84	1319	1301	4	1305
Hudson Valley (Millenium E Gas)	CC 2x1	$79	$96	$0	$175	7292	7292	0	7292
	CT - Frame 7	$78	$75	$0	$152	1658	1658	0	1658
	GT - 10 Min	$78	$50	$0	$128	247	247	0	247
	GT - 30 Min	$70	$43	$0	$112	198	198	0	198
	CT - LMS100	$80	$78	$0	$158	3258	3251	0	3251
	ST	$78	$32	$0	$110	3144	3144	0	3144
Long Island	CC 2x1	$43	$68	$2	$113	6219	6167	82	6249
	CT - Frame 7	$43	$49	$1	$92	811	811	13	824
	GT - 10 Min	$42	$46	$1	$89	201	198	1	199
	GT - 30 Min	$37	$39	$1	$77	162	162	0	162
	CT - LMS100	$43	$58	$2	$104	1623	1623	18	1641
	ST	$41	$9	$2	$52	1381	1391	120	1510
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$43	$132	$5	$180	7001	6908	107	7015
	CT - Frame 7	$43	$92	$9	$144	1896	1884	64	1948
	GT - 10 Min	$42	$72	$6	$120	634	634	40	673
	GT - 30 Min	$37	$60	$4	$102	514	514	16	530
	CT - LMS100	$43	$106	$11	$161	2613	2624	62	2685
	ST	$43	$50	$8	$100	3816	3787	126	3913
NYC	CC 2x1	$80	$55	$2	$138	6400	6347	94	6441
	CT - Frame 7	$79	$40	$1	$120	297	297	2	299
	GT - 10 Min	$79	$37	$1	$118	32	32	2	34
	GT - 30 Min	$71	$31	$1	$103	25	25	0	25
	CT - LMS100	$81	$48	$2	$131	1357	1357	18	1375
	ST	$73	$4	$1	$79	988	988	91	1080

Table A-15: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units
2017

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	$9	$11	1666	1249	1370	1346	$12	$12	1666	1375
	CT - Frame 7	$11	$12	$8	$10	28	79	77	68	$11	$10	28	68
	CT - LMS100	$13	$12	$10	$14	154	192	229	265	$13	$14	154	267
Central Zone	CC 2x1	$11	$6	$16	$18	1567	918	1791	1410	$11	$18	1567	1410
	CT - Frame 7	$11	$9	$11	$18	37	86	354	585	$11	$18	37	585
	CT - LMS100	$0	$0	$0	$0	0	0	0	0	$0	$0	0	0
	ST	$0	$0	$3	$7	108	82	523	782	$0	$7	108	782
West Zone	CC 2x1	$9	$11	$24	$17	1462	922	1772	1383	$9	$17	1462	1383
	CT - Frame 7	$11	$13	$18	$19	46	210	594	627	$11	$19	46	627
	CT - LMS100	$13	$16	$21	$19	137	275	744	943	$13	$19	137	943
	ST	$0	$3	$9	$6	107	309	898	735	$0	$6	92	735
Hudson Valley (Iroquois-Zone2 Gas)	CC 2x1	$9	$9	$12	$9	1398	1107	1403	1213	$9	$9	1398	1232
	CT - Frame 7	$10	$11	$9	$10	7	68	88	42	$10	$10	7	42
	GT - 10 Min	$12	$9	$7	$10	0	10	6	10	$12	$10	0	10
	GT - 30 Min	$10	$8	$6	$8	0	9	10	6	$10	$8	0	6
	CT - LMS100	$12	$12	$11	$13	74	197	267	215	$12	$13	74	215
	ST	$0	$1	$1	$0	0	172	250	31	$0	$1	0	102
Hudson Valley	CC 2x1	$17	$12	$16	$19	1857	1282	1849	1527	$17	$19	1857	1527
	CT - Frame 7	$11	$12	$11	$14	48	98	159	210	$11	$14	48	210
	GT - 10 Min	$12	$9	$7	$11	0	13	20	26	$12	$11	0	26
	GT - 30 Min	$10	$8	$6	$9	0	10	16	18	$10	$9	0	18
	CT - LMS100	$14	$13	$12	$17	239	292	511	642	$14	$17	239	642
	ST	$1	$2	$2	$3	180	270	471	397	$1	$3	165	398
Hudson Valley (Millenium E Gas)	CC 2x1	$26	$14	$22	$33	2028	1498	2067	1699	$26	$33	2028	1699
	CT - Frame 7	$16	$14	$15	$30	201	135	406	917	$16	$30	201	917
	GT - 10 Min	$13	$9	$8	$20	49	13	25	160	$13	$20	49	160
	GT - 30 Min	$11	$8	$7	$17	17	11	26	144	$11	$17	17	144
	CT - LMS100	$19	$15	$15	$29	597	457	841	1363	$19	$29	594	1363
	ST	$6	$3	$5	$18	509	389	922	1325	$6	$18	509	1325
Long Island	CC 2x1	$13	$15	$22	$18	1639	1409	1726	1444	$13	$20	1639	1475
	CT - Frame 7	$11	$12	$14	$12	51	129	375	256	$11	$13	51	269
	GT - 10 Min	$12	$10	$13	$12	8	34	95	64	$12	$13	8	62
	GT - 30 Min	$10	$9	$11	$10	6	26	78	50	$10	$10	6	50
	CT - LMS100	$13	$14	$15	$16	195	352	585	491	$13	$18	195	509
	ST	$0	$2	$5	$3	98	262	599	423	$0	$4	98	552
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$25	$27	$45	$35	1801	1666	1963	1572	$25	$40	1801	1586
	CT - Frame 7	$15	$21	$31	$26	119	441	875	461	$15	$34	119	524
	GT - 10 Min	$14	$19	$18	$21	17	151	338	128	$14	$27	17	167
	GT - 30 Min	$12	$16	$15	$18	13	115	282	104	$12	$22	13	120
	CT - LMS100	$20	$22	$34	$31	282	695	895	742	$20	$41	282	803
	ST	$4	$8	$22	$16	464	775	1539	1039	$4	$23	464	1136
NYC	CC 2x1	$14	$15	$16	$10	1876	1426	1794	1304	$14	$13	1837	1384
	CT - Frame 7	$10	$12	$9	$9	10	110	126	52	$11	$10	10	54
	GT - 10 Min	$11	$9	$7	$9	0	15	10	7	$12	$10	0	9
	GT - 30 Min	$10	$8	$6	$7	0	13	10	2	$10	$8	0	2
	CT - LMS100	$12	$13	$11	$12	185	417	430	325	$12	$13	185	342
	ST	$0	$2	$2	$1	65	309	418	195	$0	$2	65	286

Key Observations: Net Revenues of Gas-fired and Dual Fuel Units

- *Year-Over-Year Changes* – The results indicate that the 2017 net revenues for gas-fired units were lower than the 2016 net revenues for almost all technology types and locations. A common driver of this broad year-over-year decrease in net revenues is the lower load levels in 2017, which resulted in smaller energy net revenues despite higher LBMPs and gas prices in several locations.
    - In addition to lower energy margins, the decrease in capacity and reserve prices further depressed the net revenues for units located in the West, Central, Capital, and New York City zones. As discussed in subsection I.B of the Appendix, congestion on the gas pipeline system that kept gas prices very low in 2016 was alleviated somewhat in 2017. As a result, the energy margins of units located in the West and Central zones fell significantly year-over-year compared to units in eastern zones.
    - The increase in capacity prices in Lower Hudson Valley and Long Island (see subsection VII.E of the appendix) partially offset the drop in E&AS revenues of units located in these zones.[362] As a result, the year-over-year changes to net revenues of units in these zones were much smaller compared to units in other zones.
- *Estimated Future Net Revenues* - Given the current pricing of forward contracts, the net revenues of most units in the 2018 to 2020 timeframe appear to be higher than 2017 because of higher expected energy margins, with the largest year-over-year increase from 2017 to 2018. However, these estimates are uncertain because they depend on volatile power and gas forward prices. Forward price expectations are affected by expected retirements, new generator entry, transmission additions, clean energy mandates, and new gas pipeline development.
- *Incentives for New Units* - The 2017 net revenues for all the new technologies were well below the respective CONE estimates in all the locations we studied. There continues to be a significant amount of surplus installed capacity which, in conjunction with low demand, has led to net revenues being lower than the annualized CONE for all new hypothetical units in 2017. Figure A-104 illustrates the relationship between net revenues and the size of the installed capacity surplus.
    - After several years of congestion-driven high net revenues, the 2017 estimated net revenues for the Frame unit in the West zone dropped to a level below its CONE. Additionally, the proposed transmission build out in the western New York is expected to reduce electric system congestion and potentially lower West Zone energy prices in the future.[363]

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362 The increase in capacity market revenues was sufficient to fully offset the smaller energy margin for the combined cycle unit located in Lower Hudson Valley.

363 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-

- *Estimated Net Revenues for Existing Units* – Over the last three years, the estimated average net revenues of older existing gas-fired units were higher than their estimated going-forward costs ("GFCs") for most location-technology combinations, except for steam turbines in Long Island.
  - Among older technologies, the estimated net revenues were highest for a GT-10 unit. In addition to capacity revenues, the persistence of relatively high reserve prices in 2017 continue to provide strong incentives for operation of existing gas turbines. Reserve revenues play a pivotal role in the continued operation of older GTs, particularly for units whose EFORds are high or units which require higher capital expenditures than normal.[364] Therefore, adjusting reserve revenues for the performance of operating reserve providers (as discussed in our recommendation 2016-2) could have a significant impact on the financial viability of these units.
  - 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 are not as high as GT net revenues are and dropped further in 2017. Simulation results for 2017-2020 suggest continued pressure for steam turbines to retire because of low capacity prices and energy margins in several locations across the state, particularly Long Island. 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.
  - New environmental regulations may require GTs and STs in New York City to incur significant additional capital expenditures to remain in operation. First, it has been discussed that the New York DEC is considering a rule that would require older GTs to install back-end controls (e.g., selective catalytic reduction) for limiting NOx and other pollutants. Second, the City of New York passed an ordinance preventing steam turbine generators from burning residual oil beginning in 2022, so steam turbines will have to install facilities for burning diesel oil in order to remain dual-fueled.[365]
- *Potential Reserve Market Revenues for Gas Turbines in 2017* – The 2017 results for gas turbines include substantial revenues from the sale of reserves. For instance, 10-minute reserve sales in New York City would have provided a typical GT-10 (average age of 43 years and 34 run hours in 2017) with 85 percent of its total E&AS revenues of $38/kW-

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.

364 In 2017, some older GTs' were found to have EFORds that were well above the 10 to 20 percent level that we assumed for our generic older GTs. Figure A-89 shows that some of the GTs have EFORds that are well in excess of 50 percent. Reserve revenues could be pivotal for a New York City unit with an EFORd of 40 percent.

365 See bill INT 1465-A, *Phasing out the use of residual fuel oil and fuel oil grade no.4 in boilers in in-city power plants*.

year. The GT-10 total E&AS revenue is only 33 percent lower than the E&AS revenues for a new combined cycle (6441 run hours in 2017).

- However, the actual reserves revenues received by gas turbines were considerably lower than our estimates for all firms. Most of the 10-minute and 30-minute capable supply was scheduled far less frequently for reserves than the net revenue analysis would predict. 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 2017.[366] Consequently, the actual reserve revenues of most peaking units were substantially lower than the simulated net revenues reported in this section.

- *Potential Implications of 2017 Tax Reform* – A number of provisions of the recent tax legislation will affect the CONE estimates of new units. The results indicate that lowering the federal tax rate to 21 percent and allowing full expensing of equipment cost could lower the CONE by 15 to 18 percent. Such a reduction by itself would not be sufficient to render new entry economic based on 2018-2020 net revenues. Several other provisions of tax bill (such as limits on interest deductions on debt and usage of net operating loss to reduce income) and capital market changes could limit the extent to which new projects can benefit from the new legislation. Moreover, to the extent that these provisions reduce the CONE of the demand curve unit in the next reset study, the capacity revenues a new unit would earn would also be reduced accordingly.

- *Incentive for Dual Fuel Units* - Our results indicate that the additional returns from dual fuel capability were de minimis in 2017 across all zones because of the relatively low gas prices throughout the year (except for the last week of 2017). 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 (such as the cold snap in early 2018) 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.[367] Thus, most unit owners will continue to have incentives for installing and maintaining dual fuel capability (even in areas that do not mandate dual-fuel capability as a condition for gas interconnection).

B. Net Revenues and Capacity Margins

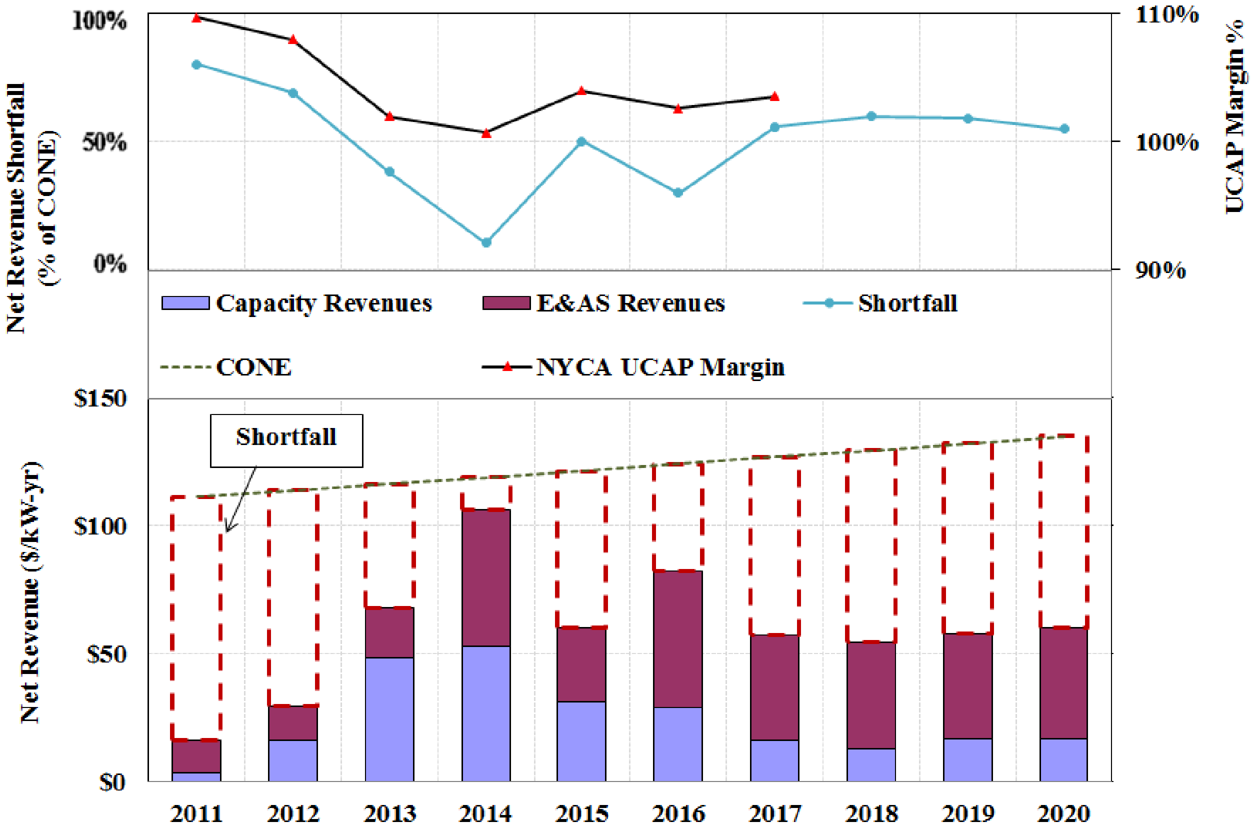
Figure A-104: Relationship between Net Revenues and Installed Capacity Margins

The bottom panel of Figure A-104 shows the shortfall in the net revenues of a Zone F Frame unit relative to its CONE from 2011 through 2020. The top panel of Figure A-104 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.

366 The operating reserve offer prices are discussed in Section II of the Appendix.

367 See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

Figure A-104: Relationship between Net Revenues and Installed Capacity Margins



Key Observations: Relationship between Net Revenues and Capacity Margins

- The shortfall in net revenues for a hypothetical new unit is significant for the 2011-2020 time period, indicating a prolonged period of unfavorable conditions for new entry in Zone F. 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. Overall, the shortfall in net revenues received by the hypothetical new entrant has been consistent with the trends in NYCA capacity margins.

- Capacity markets are the primary source of revenue for the demand curve unit and gas-fired units in general, and consequently, the market has been fairly responsive to capacity prices. 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. The share of capacity revenues for gas-fired units in Lower Hudson Valley during 2017 ranged from 23 percent to 57 percent, with older existing generators exhibiting greater reliance on capacity revenues.[368]

368 In contrast, the share of capacity revenues for nuclear and renewable units in Zone C ranged from one percent to four percent in 2017.

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-105: Net Revenues for Nuclear Plants

Figure A-105 shows the net revenues and the US-average operating costs for the nuclear units from 2015 to 2020. 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.[369]
- 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 single-unit and larger nuclear plants are based on observed average costs of nuclear plants in the US from 2015 through 2017.[370]
- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[371] The ZEC price for compliance year 2017 (April 2017 to March 2018) is $17.54/MWh. For, compliance year 2018 the ZEC sale price is

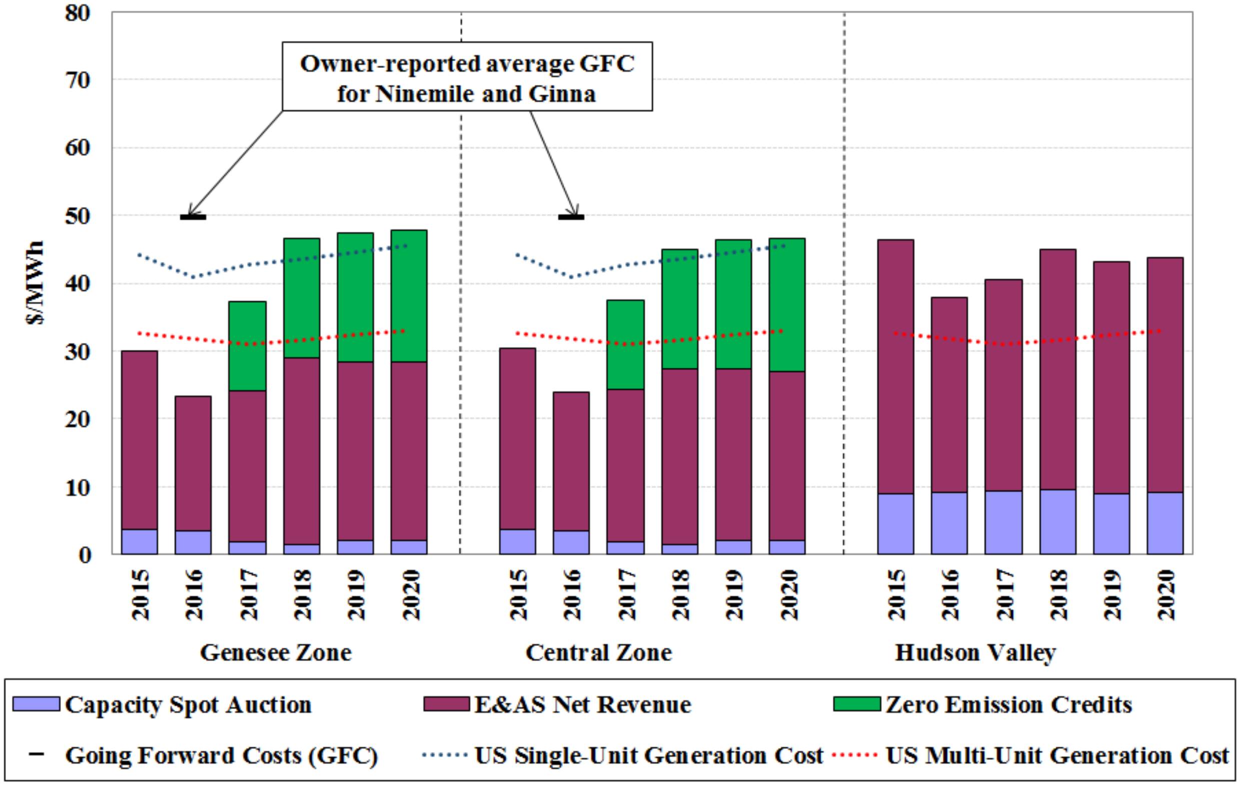
369 The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year to enable a year over year comparison of net revenues.

370 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context and https://www.nei.org/CorporateSite/media/filefolder/resources/fact-sheets/nuclear-by-the-numbers-20180412.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.

371 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.

$17.48/MWh and for the subsequent tranche (April 2019 to March 2021), the DPS-estimated ZEC price is $19.59/MWh.

Figure A-105: Net Revenue of Existing Nuclear Units
2015-2020



__Key Observations: Net Revenues of Existing Nuclear Units__

- *Year-Over-Year Changes* – The estimated total net revenues for nuclear units in the upstate zones increased substantially from 2016 to 2017. In addition to a modest increase in energy revenues, the net revenue increase was primarily driven by ZEC payments to upstate nuclear plants starting in April 2017. The estimated net revenues for the Hudson Valley units rose consistent with the year-over-year increase in energy prices. The energy and capacity futures prices suggest that the net revenue of nuclear plants from the NYISO-administered markets is expected to increase from 2017 levels by 7 to 20 percent over the next three years.

- *Incentives for Existing Nuclear Plants* – Energy revenues constitute the majority of the NYISO-administered revenues received by nuclear plants and accounted for an average of 88 percent of the estimated net revenue over the last three years, much higher than the levels of renewable and gas-fired units. Consequently, expected energy prices have a larger impact on the retirement decisions of nuclear plants than expected capacity prices.
  - Although energy revenues have declined significantly in recent years (see Figure A-1), the estimated 2017-2020 total net revenues of single-unit nuclear plants are above the US average of nuclear generation costs for upstate zones, due in large part to the

ZEC revenues. The 2017-2020 net revenues for units located in Hudson Valley exceed the average generation costs of multi-unit nuclear plants.

- Nuclear operating and decommissioning costs are highly plant-specific, and the retirement GFCs of the nuclear plants in New York may differ significantly from the US average operating costs. Therefore, the difference between the net revenues and GFCs may be smaller than the value implied in Figure A-105. In particular, nuclear units located in New York may be subject to higher labor costs and property taxes. Publicly available estimates for property taxes range from $2 to $3 per MWh. These factors in conjunction with the volatility of futures prices may render the nuclear plants in upstate New York (particularly single-unit) and LHV to be only marginally economic if the generation costs do not decline.

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 Long Island zone. 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.[372] For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-16: 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.[373]
- 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 2018 NYISO Installed Capacity Manual.[374]

372 We considered only the wind units whose nameplate capacity is larger than 100 MW.

373 The data sources for assumed capacity factors are as following: (a) Onshore and Offshore wind: NREL Annual Technology Baseline, 2017 available at : https://atb.nrel.gov/electricity/2017/index.html, (b) Solar PV: CES Cost Study, 2016 (see page 166 of the Clean Energy Standard White Paper – Cost Study April 8, 2016).

374 The capacity value for renewable resources 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

- 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 2018 REC price.[375]

- 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.[376] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[377]

The cost of developing new renewable units, especially solar PV plants, has dropped rapidly over the last few years. As such, the estimated investment costs vary significantly based on the year in which the unit becomes operational. Table A-16 shows cost estimates for solar PV, onshore wind and offshore wind units we used for a unit that commence operations in 2017. The data shown are largely based on NREL's 2017 Annual Technology Baseline.[378] The table also shows

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www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf.

375 For more information on the recent Main Tier procurements, see https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/REC-and-ZEC-Purchasers/2018-Compliance-Year. The 2018 REC price of $17.01/MWh for the 2018 compliance year, for the sale of the RECs between NYSERDA and the LSEs.

376 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.

377 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.

378 See NREL, 2017, *Annual Technology Baseline and Standard Scenarios*, https://atb.nrel.gov/electricity/2017/index.html

The assumed investment costs and fixed O&M costs for solar PV, onshore wind, and offshore wind are based on the 2017 NREL ATB (Mid) values for Utility PV-20%, TRG-6, and TRG 2 respectively. 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 solar PV and onshore wind, 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 the capacity factor and capacity value 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.

Table A-16: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2017$/kW AC basis)	*Upstate NY*: $1589 *Long Island*: $2475	*Upstate NY*: $1858 *Long Island*: $2820	*Long Island* : $5635
Fixed O&M (2017$/kW-yr)	$17	$58	$161
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: 38.0% LI: 39.9%	LI: 45.9%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 10% Winter: 30%	Summer: 38% Winter: 38%
Renewable Energy Credits (Nominal $/MWh)	***2018*** - $17.01 ***2017*** - $21.16 ***2016*** - $24.24 ***2015*** - $24.57		

Figure A-106: Net Revenues of Solar, Onshore Wind and Offshore Wind Units

Assuming the operating and cost parameters shown in the table above, Figure A-106 shows the net revenues and the estimated CONE for each of the units during years 2015-2020.

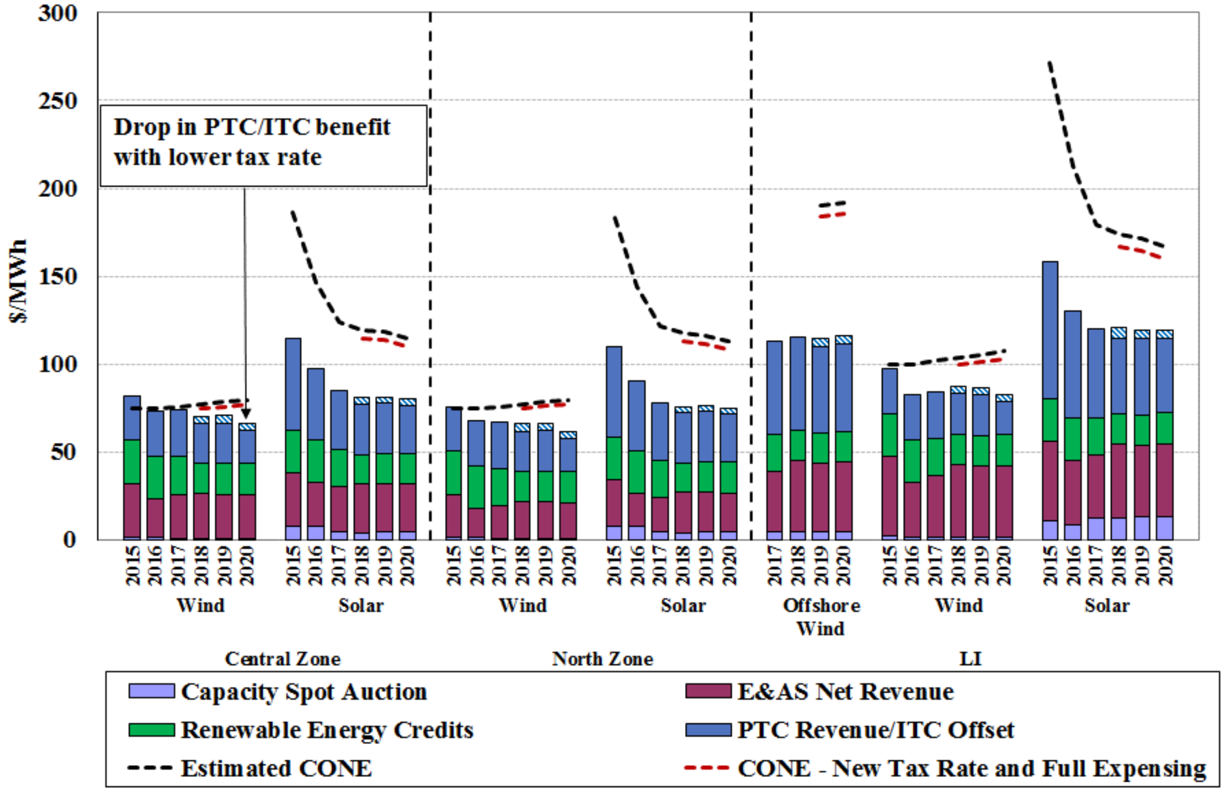
https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Regional multiplier for offshore wind was utilized from ReEDS input data used for the 2017 NREL ATB analysis.

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.

The assumed investment cost trajectory over the years was assumed to follow the technology-specific CapEx trajectory specified in the 2017 NREL ATB.

The assumed investment cost estimates also include interconnection costs. Interconnections costs for wind and solar PV units can vary significantly from project to project. For upstate solar PV and onshore wind the interconnection cost of $51/kW and $43/kW respectively were sourced from NREL ATB 2017. For offshore wind unit in LI zone, interconnection cost of $1032/kW was obtained from the 2018 Offshore Wind Policy Options Paper (see page 83 of the paper available at https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan/Studies-and-Surveys). We assume construction lead time (i.e. time taken by a unit from commencement of its construction to commercial operation) of 1 year for solar PV plant and 3 years for onshore and offshore wind plants.

Figure A-106: Net Revenues of Solar, Onshore Wind and Offshore Wind Units[379]
2015-2020



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 renewable resources, energy market revenues constitute a large majority of the revenues these units receive from the NYISO markets. Consequently, the results indicate an increase in the estimated net revenues of onshore and offshore wind units from 2016 to 2017 in all the three locations we studied because of the rise in energy prices. However, the NYISO market revenues for solar PV units, which have the highest summer capacity value of all the renewable resources we studied, fell slightly in the upstate zones due to the large (44 percent) year-over-year decrease in NYCA capacity prices. 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 the

379 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.

contributions of state and federal programs to the 2017 net revenues range from 60 percent to 70 percent for a new solar PV project and 57 percent to 71 percent for a new onshore wind project.

  - As with the new gas-fired units, the recent tax legislation could also benefit renewable energy projects by lowering their CONE. However, as shown in the Figure A-106, the reduction in CONE is smaller than that of gas-fired units, largely because of the eligibility of renewables to accelerated depreciation benefits under current rules. In addition, the reduction in CONE of renewables is offset to some extent by the decrease in ITC/PTC benefits.

- *Incentives for Onshore Wind Units* – In 2017, the estimated net revenues of onshore wind units were likely to be insufficient to meet their CONE in the North and LI locations, and marginally sufficient for Central location.[380] In addition, future power prices through 2020 indicate an increasing shortfall of net revenues of the generic wind units. However, the near term economics would depend on several additional factors such as differences in returns required by investors, resource potential at individual sites, curtailment risk, REC prices/ procurement targets, and future cost declines.[381]

- *Incentives for Utility-scale Solar PV Units* – The results indicate that the net revenues of a solar PV unit would be insufficient to meet the estimated CONE of a project coming online in 2017 in all the locations studied. The investment costs for solar PV units have dropped significantly in the past few years, and are expected to drop further in the near future.[382] However, a generic utility-scale solar PV unit we studied is unlikely to be economic through 2020 under the current energy future and REC prices. As with onshore wind units, a number of additional factors could drive the near term economics and entry of solar PV projects.

- *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 (about 23 percent lower in 2020) than most estimates of the CONE in Long Island.

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380 There are about 410 MW of wind projects that expressed interest in obtaining CRIS and ERIS rights Zone C as part Class Year 2017 evaluations

381 The contracts for RECs are fixed and could be up to 20 years long. In addition, the benefits to renewable units from federal incentives are less volatile than the NYISO-market revenues. Therefore, the overall risk profile of the revenues of a renewable units in New York could be considerably different from that of a merchant generator. In the CES Cost Study, the DPS Staff assumed that longer term fixed REC contracts would result in a WACC of 6.99 percent. This could lower the CONE of a generic onshore wind and solar PV units by roughly 10 and 11 percent, respectively.

382 NREL reports a 20% decrease in capex for the utility-scale PV projects that were built in Q1 of 2016 over Q1 of 2015. See https://www.nrel.gov/docs/fy16osti/67142.pdf

E. Impacts of Real Time Pricing Enhancements on Net Revenue

Section XI.B of the report discusses several recommendations that are aimed at enhancing the pricing and performance incentives in the real time markets. Implementing these recommendations would improve the efficiency of energy and reserve market prices, and direct investment to the most valuable set of resources and locations.

The impact of energy/ reserve market-focused enhancements on the long-term economic signals could vary significantly by resource type and resource location. Under long-term equilibrium conditions, an increase in the E&AS revenues of the demand curve unit (i.e. the Frame unit) would translate into reduced capacity prices for all resources operating in the market. Therefore, implementing real time market enhancements could potentially shift payments from capacity to energy markets. The net revenue results for gas-fired, nuclear and renewable resources indicate that there is substantial disparity in the extent to which various resources depend on revenues from energy and capacity markets for recovering their costs.[383] Similarly, the results also indicate large differences in the energy market revenues even for resources that may be located in the same capacity zone, but are in a different load pocket.[384]

In this subsection, we illustrate the impacts of implementing a subset of our real time market recommendations on the net revenues of multiple resources. These resources are of particular interest for various stakeholders and/ or could play a significant role in the future energy portfolio of New York. We examine for resources in various locations within Zone J - (a) the changes to composition of revenue streams, and (b) the consequent impacts on investment signals.

Table A-17 to Table A-18: Assumptions for Operating Characteristics of Repowered Combined Cycle and Grid-scale Storage Units

Our analysis of the impact of real time pricing enhancements on net revenues is based on the following inputs and assumptions:

- The technologies considered for our analysis and their operating characteristics are as follows:[385]
  - Frame-7, GT-30, ST, and Offshore Wind Units – The operating characteristics and CONE/ GFCs for these units are identical to the assumptions we made in Subsections A and D. For GT-30, we incorporated into its GFC an additional capital expenditure of $150 per kW (amortized over 6 years) to account for SCR installation costs in

383 For instance, as noted in Section VIII, capacity market revenues constitute 58 to 93 percent of net revenues for gas-fired units. For nukes and renewables, capacity market revenues constitute just 2 to 23 percent of net revenues.

384 See Table 17.

385 The CONE/ GFCs estimates for new technologies correspond to units that would be able to commence operations in 2020.

compliance with environmental regulations that are being discussed for gas turbines in New York City and Long Island.

- Repowered Fast-Start Combined Cycle Unit – We studied a 1x1 fast-start CC that would be built by repowering an existing or retired generation facility in New York City. The operating characteristics of this unit are summarized in Table A-17.

Table A-17: Operating Parameters and CONE of Repowered Fast-start CC[386]

Characteristics	CC 1x1
Summer Capacity (MW)	240
10-min Non-spin Summer Capability (MW)	126
Average Summer Heat Rate (Btu/kWh)	8040
Min Run Time (hrs)	4
Capital Cost (2020$/kW)	$1,840

- Grid-scale Storage – We studied a grid-scale storage unit with a power rating of 1MW and four hours of energy storage capacity. The operating characteristics of this unit are summarized in Table A-18.

Table A-18: Operating Parameters and CONE of Storage Unit[387]

Characteristics	Storage
Gross CONE (2020$/kW-yr)	$286
Technology	Li-ion Battery
Service Life (Years)	20
Hours of Charge	3am to 7am
Hours of Discharge	5pm to 9pm
Reserve Selling Hours (Day-Ahead)	10am to 1pm
Reserve Selling Hours (Real Time)	1pm to 4pm
Efficiency	86%
EFORd	2.17%

- Our analysis is based on net revenues under long-term equilibrium conditions i.e. with the system at the tariff-prescribed excess level conditions modeled in the ICAP demand curve reset. We estimated the energy prices under these conditions by applying to

386 The capital cost for repowered CC-FAST unit is estimated by discounting the cost of the CC 1x1 unit from the latest Demand Curve Reset study by roughly 20 percent. This adjustment is based on review of recent project cost information in New York and New England. The operating parameters are based on NRG Energy's filing with DEC on Astoria Repowering Project. The DEC filing can be found here: https://www.dec.ny.gov/docs/permits_ej_operations_pdf/pp1.pdf

387 See EPRI's report "Energy Storage Cost Summary for Utility Planning". The overnight cost considered in the report does not include costs for project development, warranty extension, Insurance and contingency. These excluded costs were supplemented from Lazard's report on "Levelized Cost of Storage 2017".

LBMPs for the year-ending March 21st, 2018, the Level of Excess-Adjustment Factors that are used in the annual updates to ICAP demand curve parameters.[388]

- We modeled the impact of individual recommendations by further adjusting the energy/ reserve prices (at Level of Excess) or individual unit net revenues in the following manner:
  - 2016-12: Pricing when operating reserve providers provide congestion relief – We estimated the increase in 10-minute reserve prices at locations where 10-minute reserve providers can help relieve N-1 transmission congestion.[389]
  - 2016-2: Discount reserve revenues to reflect performance – Based on the median performance of GTs in responding to the NYISO's start-up instructions, we discounted the reserve revenues that an average GT-30 unit would receive by 40 percent.[390] We used a discount rate of 75 percent to reflect GTs that are poor performers and therefore, are at a higher risk of leaving the market.
  - 2017-1: Model local reserved requirements in New York City load pockets – We estimated the impact of this recommendation by increasing the peak hour DA energy and reserve prices to reflect the BPCG per MW-day of UOL for DARU/ LRR-committed units.[391]
  - 2017-2: Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules.

Figure A-107 to Figure A-110: Impacts of Real Time Pricing Enhancements on Net Revenues under Long-term Equilibrium Conditions

The blue and purple bars in Figure A-107 through Figure A-110 characterize the impact of real time pricing enhancements on energy and capacity revenues (as percentage of the corresponding CONE/ GFC) for various types of resources in the following locations in New York City: a node that is representative of New York City prices, a node representative of the 345 kV system, and nodes in two load pockets. The dashes for each resource indicate the total change in net revenues for that resource as a percentage of its CONE/ GFC.

Figure A-107 shows the energy and capacity revenues for each resource type (in $/kW-year) before and after the implementation of real time pricing enhancements. The figure also shows the shortfall in net revenues relative to the CONE/ GFC for each technology.

388 See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

389 See Section XI.B of the report.

390 See Section V.B of the Appendix.

391 See Section V.H of the Appendix.

Figure A-107: Impact of Pricing Enhancements on Net Revenues - New York City
At Level of Excess Conditions

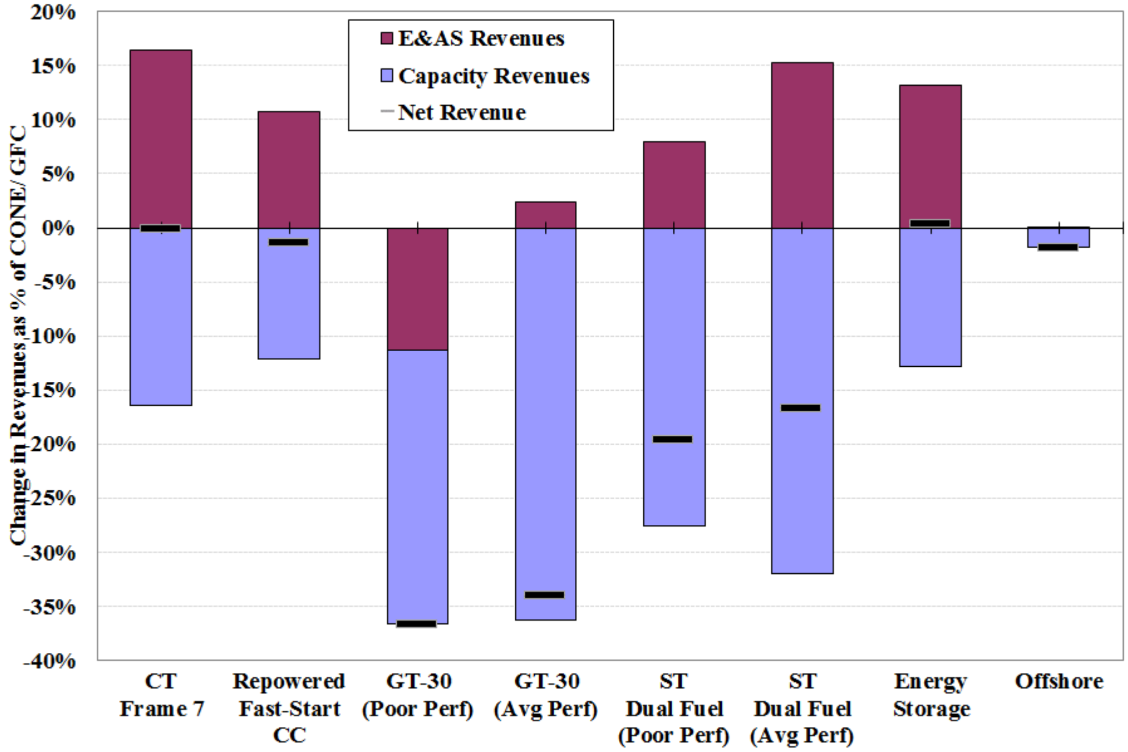


Figure A-108: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #1
At Level of Excess Conditions

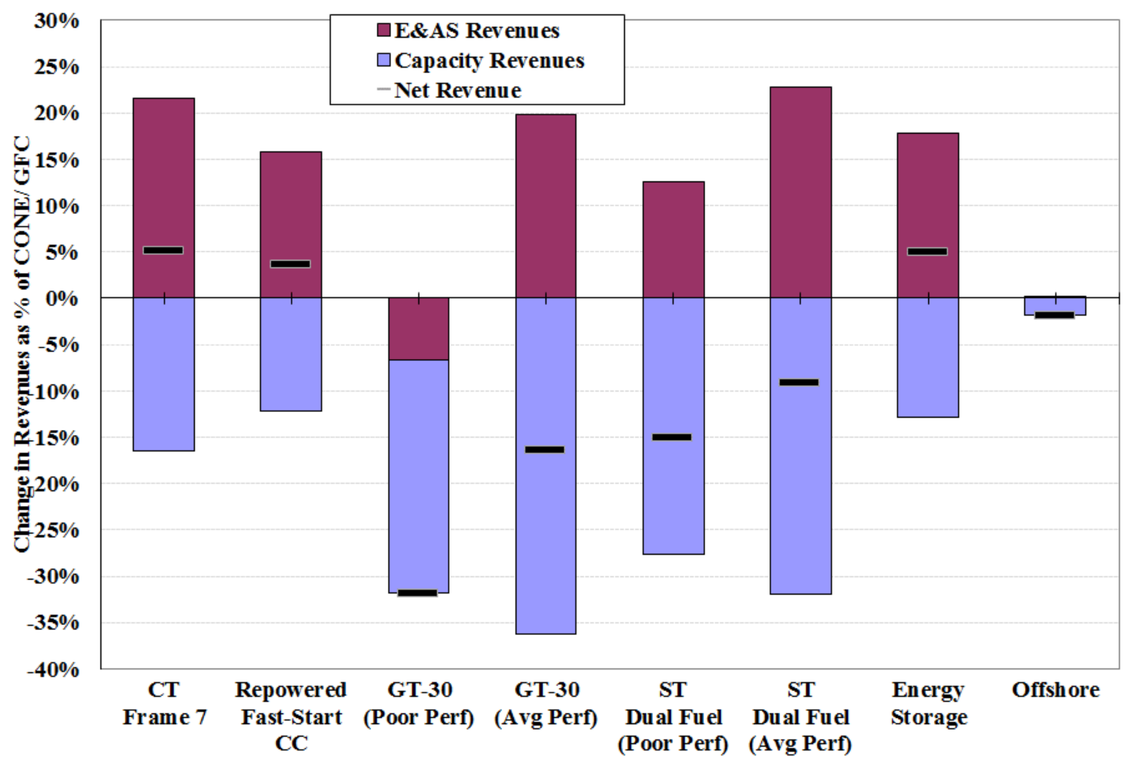


Figure A-109: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #2
At Level of Excess Conditions

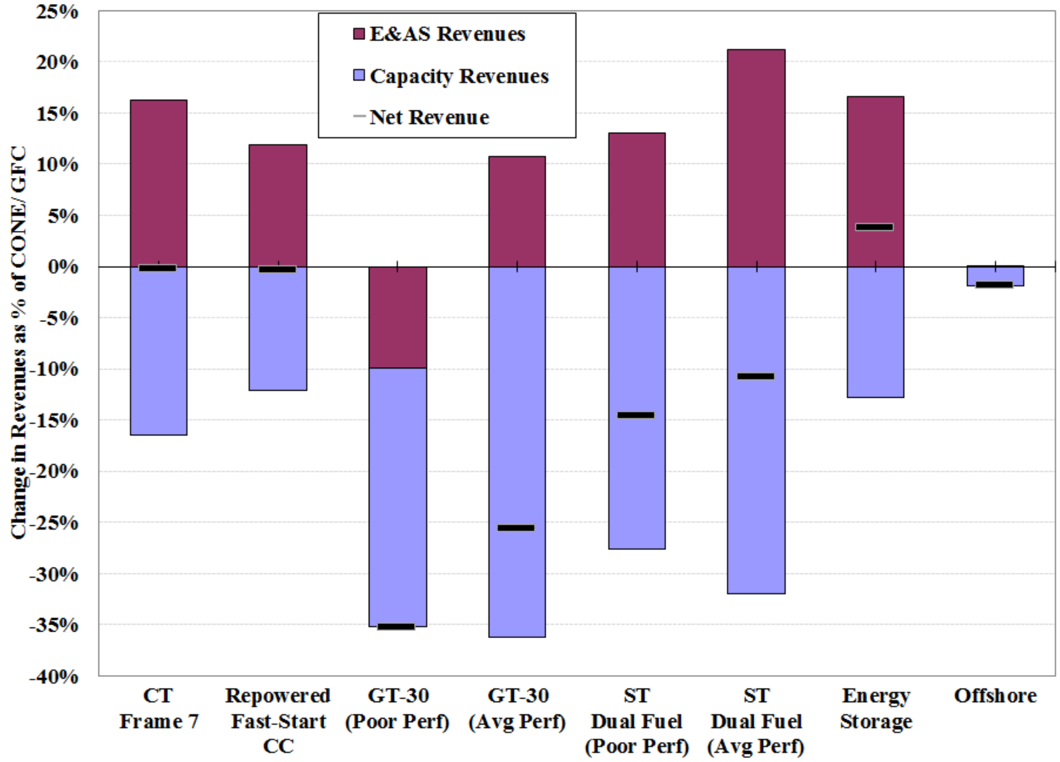


Figure A-110: Impact of Pricing Enhancements on Net Revenues – NYC 345 kV
At Level of Excess Conditions

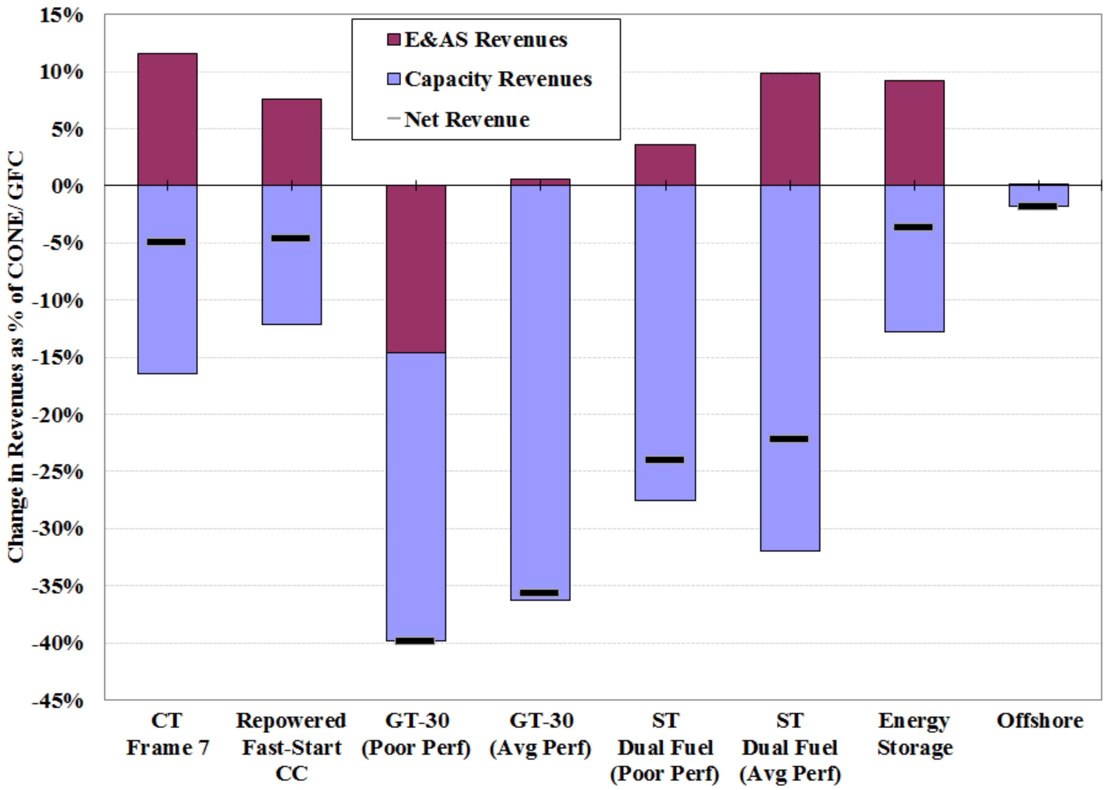
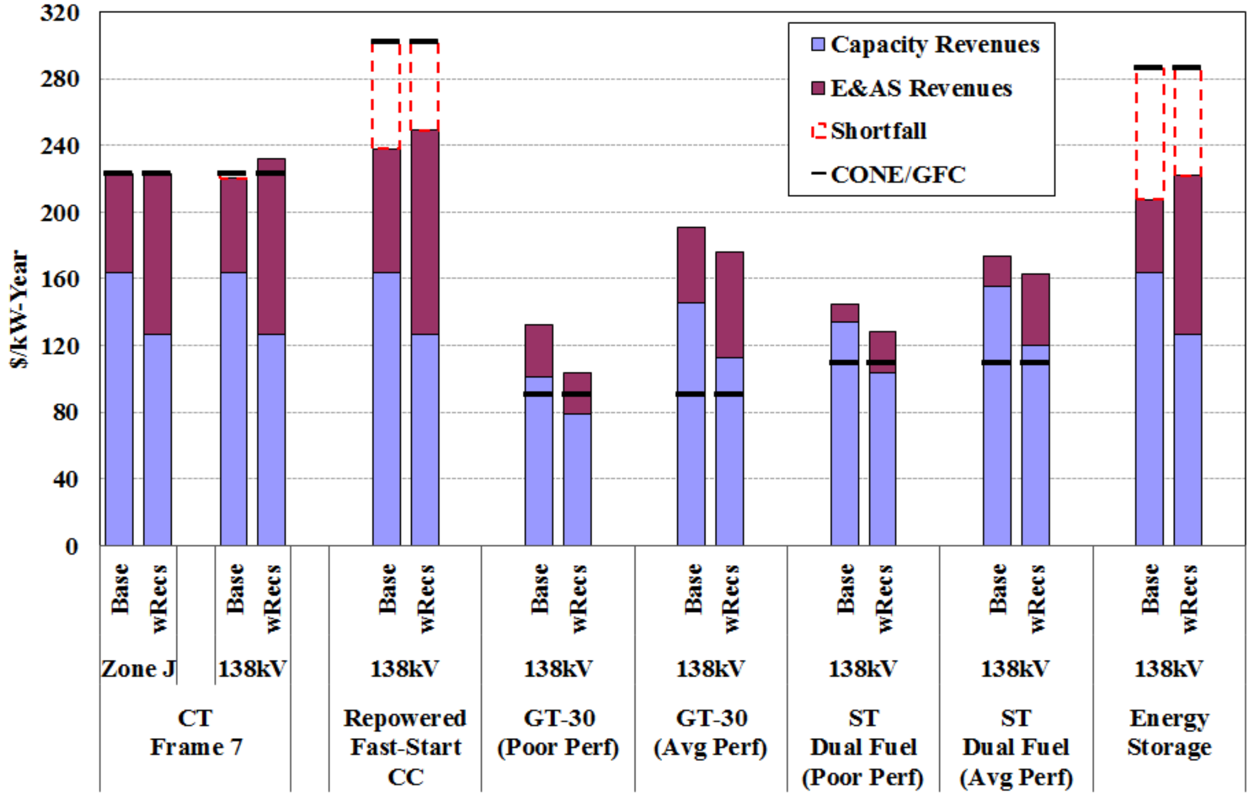


Figure A-111: Net Revenue Impact from Pricing Enhancements in New York City
At Level of Excess Conditions



Key Observations: Impacts of Real Time Pricing Enhancements on Net Revenues

- *Impact on Capacity Prices* – The results indicate that the E&AS revenues of the Frame unit would increase by roughly forty percent as a result of implementing the recommendations discussed above. This would reduce the Reference Point for the ICAP demand curve by an equivalent amount and therefore, the capacity payments to all resources would decline by $37 per kW-year.
  - Of the recommendations that we considered for this analysis, modeling local reserve requirements in New York City load pockets (i.e. 2017-1) had the largest impact and accounted for 48 percent increase in the E&AS revenues for the demand curve unit.
  - The fall in the Reference Point of the ICAP demand would likely be larger if the methodology for estimating it was based on LBMPs from an average of three earlier years instead of 2017. As discussed in section I of the Appendix, 2017 was a mild year with low load levels and relatively low gas prices. Consequently, the incidence of congestion, uplift costs from guarantee payments (see subsection V.I of the Appendix) and RTC GT starts were all much lower in 2017 compared to the prior three year averages.
- *Incentives for Resources at Representative New York City Node* – Under long-term equilibrium conditions, our simulations for resources located at a representative New

York City node indicate that energy market enhancements are likely to improve the net revenues of newer and flexible units (Figure A-107). In contrast, the economics of older existing units are likely to become less attractive.

- A fast-start CC, given its lesser reliance on capacity revenues and ability to provide 10-minute non-spinning reserves, would benefit more than the Frame unit from pricing enhancements. As a result, the net E&AS revenues of a fast-start CC unit would improve by close to $33 per kW-year after the recommendations are implemented.
- As noted above, the economics of both of the older existing resources that we studied (GT-30 and ST) would be adversely impacted by the recommended enhancements to the real-time markets.
  - Both types of older unit would receive lower capacity payments.[392]
  - For older GT-30 units, reserve revenues would drop if units were compensated in accordance with their performance as proposed in Recommendation 2016-2. GTs that perform worse than average would see a bigger drop—their total net revenues would decrease by an estimated $33 per kW-year.
  - The net impact on ST units would be de minimis because these units benefit more than GTs from the Recommendation 2017-1 and because there would be no performance-related reduction in reserve revenues.
- Of all the technologies we studied, storage units, with their ability to derive significant revenues from energy, reserve as well as capacity markets, are likely to see the largest increase in net revenues. The flexibility of storage units would enable them to monetize improvements in energy and reserve prices to a greater degree than a demand curve unit can. As a result, the increase in energy and reserve revenues of these units is greater than the drop in their capacity revenues.
- Offshore wind units that interconnect in Zone J are unlikely to see any meaningful change to their net revenues due to limited increase in energy prices during hours coinciding with their generation.
- Overall, as shown in Figure A-107, the pricing enhancements we studied are likely to increase net revenues of new units that are reliable, flexible and more dependent on energy/ reserve revenues, although the additional revenue by itself is unlikely to render new units economic. Similarly, the net revenues for older units are unlikely to fall below their GFCs under long-term equilibrium conditions. However, under as-found conditions, the enhancements we studied could be instrumental in driving down capacity and reserve revenues to levels that could cause significant challenges for operation of older GTs.

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[392] For poor performing GT-30 and ST units, we assumed an EFORd of 40% and 20%, respectively. For average performing GT-30 and ST units, we assumed an EFORd of 13% and 7%, respectively

- *Incentives for Investment by Location* – As noted in the assumptions, the effect of the pricing enhancements on the energy and reserve prices differs by location. Accordingly, as shown in Figure A-107 through Figure A-110, there is substantial variation in the changes in net revenues of each resource by location.
    - The results for Load Pocket #1 are heavily influenced by the large additional net energy and reserve revenues from implementing 2017-1. As a result, several resource types see a net increase (or in case of GTs, less decrease) in their revenues when compared to other locations.
    - The results for Load Pocket #2 are more driven by higher 10-minute reserve revenues (due to 2016-1, and no significant DA energy/ reserve price increases due to 2017-1) relative to the representative node in New York City. Therefore, the only type of resources that see any increase in net revenues are storage units. Any increase in GT revenues would be more than offset by decreases due to reserve revenue discounting (due to 2016-2).
    - The nodes on the 345 kV system do not see a significant increase in energy or reserve prices from all the recommendations we considered. Hence, the increases in net revenues of all resources at this location are well below the increases in other locations.
- The increased diversity in revenue mix by location is beneficial for the system. Energy and reserve markets model the electric system at a more granular level when compared to capacity markets, and hence more accurately value the benefits/ costs of placing resources in certain locations. As such, it is generally more efficient to compensate resources through the energy and reserve markets than through capacity markets.

VIII. DEMAND RESPONSE PROGRAMS

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 NYISO operates five demand response programs that allow retail loads to participate in the wholesale market. Three 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.[393]

- 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.[394]

- 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 current 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. Failure to curtail may result in penalties being assessed in accordance with applicable rules.

- Demand Side Ancillary Services Program ("DSASP") – This program allows Demand Side Resources to offer their load curtailment capability to provide regulation and

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

394 SCRs participate through Responsible Interface Parties ("RIPs"). Resources are obligated to curtail when called upon by NYISO to do so with two or more hours in-day notice, provided that the resource is informed on the previous day of the possibility of such a call.

operating reserves in both day-ahead and real-time markets. DSASP resources that are dispatched for Energy in real-time are not paid for that Energy. Instead, DSASP resources receive DAMAP to make up for any balancing differences.

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

This section evaluates: (a) reliability demand response programs, (b) economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions.

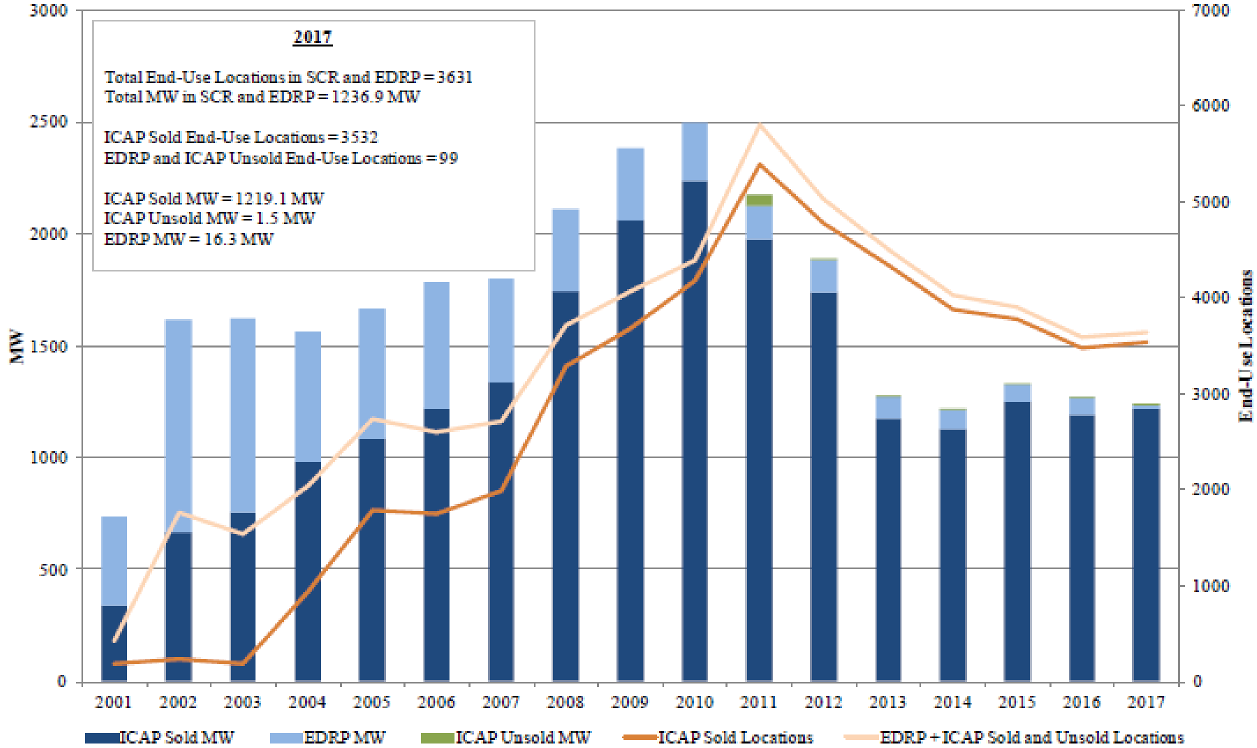
A. Reliability Demand Response Programs

The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when the NYISO and/or a TO forecast a reliability issue.

Figure A-112: Registration in NYISO Demand Response Reliability Programs

Figure A-112 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2017 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-112: Registration in NYISO Demand Response Reliability Programs [395]
2001 – 2017



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

395 This figure is excerpted from the compliance filing report to FERC: *NYISO 2017 Annual Report on Demand Response Programs*, January 12, 2018.

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.

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, 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.

Second, 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, 2016 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.

Key Observations: Demand Response Programs

- In 2017, total registration in the EDRP and SCR programs included 3,631 end-use locations enrolled, providing a total of 1,237 MW of demand response capability.
  - SCR resources accounted for 99 percent the total enrolled MWs in the reliability-based program in 2017. This share has been increasing over time, reflecting that many resources have switched from the EDRP program to the SCR program in order to earn revenue from the capacity market.
  - In the Summer 2017 Capability Period, market-cleared SCRs contributed to resource adequacy by satisfying:
    - 4.2 percent of the UCAP requirement for New York City;
    - 3.3 percent of the UCAP requirement for the G-J Locality;
    - 1.9 percent of the UCAP requirement for Long Island; and
    - 3.7 percent of the UCAP requirement for NYCA.
- 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.
- Three DSASP resources in Upstate New York (with a combined capability of nearly 117 MW) actively participated in the market in 2017 as providers of operating reserves.
  - These resources were capable of providing up to 17 percent of the NYCA 10-minute spinning reserve requirement in 2017.
  - In 2017, the NYISO did not activate reliability demand response resources. Therefore, the performance of EDRP/SCR resources is not evaluated in this report.