2019 State of the Market Report for the New York ISO Markets

POTOMAC ECONOMICS

By:
David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.
Raghu Palavadi Naga

Market Monitoring Unit
for the New York ISO

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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 the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. The 2019 State of the Market Report presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2019. This executive summary provides an overview of market outcomes and highlights and discussion of recommended market enhancements.

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 2019

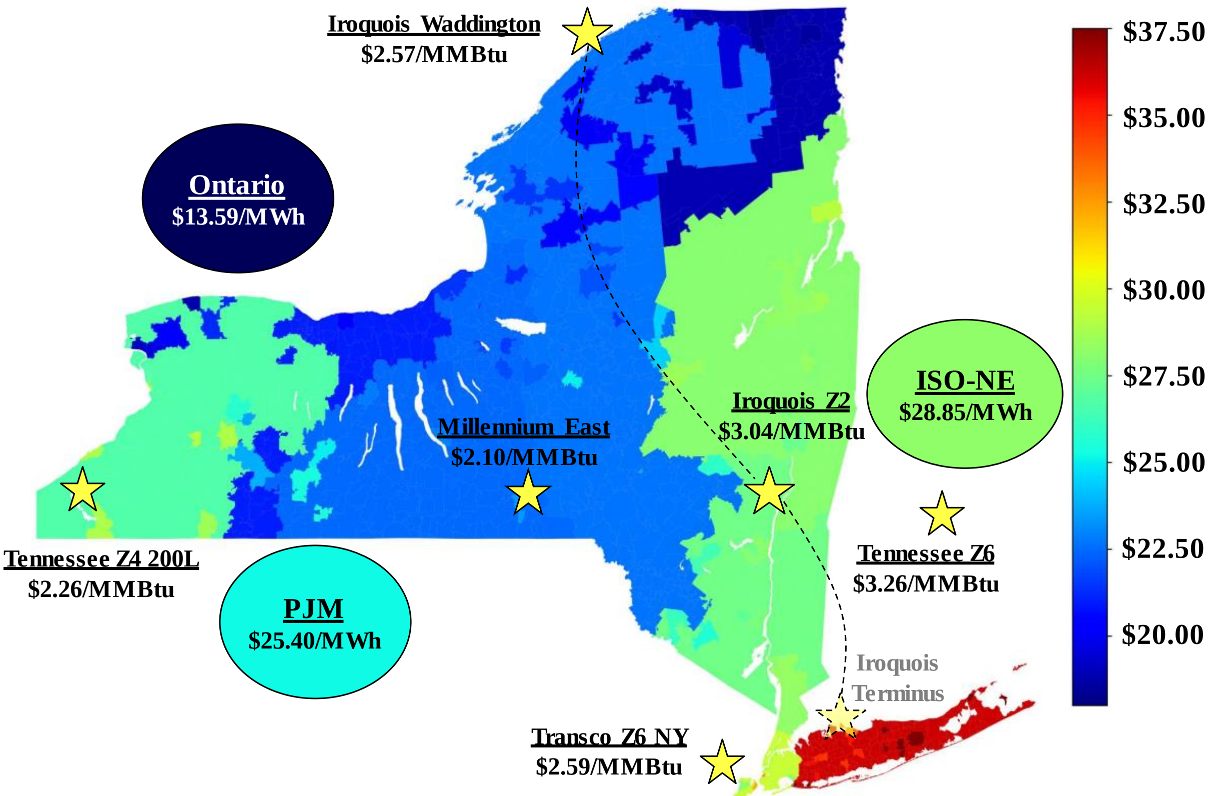
The NYISO markets performed competitively in 2019 because the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were mostly effective in limiting conduct that would raise energy prices above competitive levels. Market results and trends are summarized below.

Natural Gas Prices and Load Levels

Natural gas prices and load levels are two key drivers of market outcomes. Average gas prices fell 22 to 41 percent across the state from 2018 to 2019. Gas prices declined as producers continued to increase production at regional shale plays, and storage levels remained high because of mild winter weather in early 2019. Gas price spreads between western and eastern New York declined from 2018 to 2019 as well, which helped reduce the congestion on the electric system as well.

Loads also declined significantly in 2019, averaging the lowest level in more than a decade. The annual peak load decreased by five percent to 30.4 GW. Lower load levels helped reduce congestion in the downstate regions.

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2019



Energy Prices and Transmission Congestion

Average energy prices decreased 22 to 34 percent across the state from 2018 to 2019 primarily because of lower demand and gas prices in 2019, especially during the winter months. A strong relationship between energy and natural gas prices is expected in a well-functioning, competitive market because gas-fired resources are the marginal source of supply in most intervals.

Transmission congestion and losses led real-time prices to vary from an average of $18 per MWh in the North Zone to $35 per MWh in Long Island in 2019. Congestion revenues collected in the day-ahead market fell 14 percent from 2018, totaling $432 million in 2019. The following transmission corridors accounted for most of the congestion:

- Central-East Interface – 34 percent
- West Zone (flowing east) – 22 percent
- New York City – 11 percent
- Long Island – 11 percent

Congestion revenue collected in the West Zone increased considerably in 2019 because: (a) the NYISO incorporated into its market models constraints on the lower voltage system that were previously unpriced, and (b) the impact of loop flows around Lake Erie became more significant on West Zone constraints following the closure of the South Ripley-Dunkirk 230 kV line at the NY/PJM border.

Installed Capacity Market

Capacity prices continued to be very low because of significant capacity surpluses throughout the state. Outside New York City, capacity prices decreased in the 2019/20 Capability Year by 24 to 65 percent primarily because the statewide requirement fell by 1 GW due to a reduced load forecast and lower IRM and the G-J Locality requirement fell by 420 MW due to a lower local requirement. In New York City, capacity prices rose 50 percent largely because of a 320 MW increase in the local requirement.

As result, investment in a new gas turbine that is the demand curve proxy unit would not be economic at any location in the state. As a share of the capacity revenues needed to cover the proxy unit's annualized cost of new entry (i.e., "Net CONE"), spot capacity prices in the 2019/20 Capability Year provided just:

- 8 percent of Net CONE outside Southeast New York (Zones A-F);
- 20 percent of Net CONE in the Lower Hudson Valley (Zones G-I);
- 58 percent of Net CONE in New York City (Zone J); and
- 26 percent of Net CONE in Long Island (Zone K).

Long Run Investment Incentives

The NYISO market provides price signals that motivate firms to invest in new resources, retire older units, and/or maintain their existing generating units. Even for new investment that is primarily motivated by state policy through competitive solicitations by state agencies, wholesale prices strongly influence the particular locations and technologies of projects that are ultimately selected. Net revenues (i.e., the revenues generators receive in excess of their production costs) decreased for most new and existing generators in 2019 because of low gas prices and low load levels. We summarize below the results for various types of resources:

New Gas Turbines. There are no areas where investment in a new H-class Frame gas turbine would be economic because of the large capacity surpluses that currently exist throughout the state. However, projects with site-specific benefits (such as repowering projects) could provide investors significantly better returns. The feasibility of a new or repowered gas-fired unit is unclear because of permitting challenges, especially in New York City given a recent executive order that prohibits new gas infrastructure.

Battery Storage. The estimated returns for a 4-hour battery storage project were well below the returns that would be expected by a merchant entity, even after including state subsidies. However, the costs of battery systems are projected to decline significantly over the next five to ten years, which would boost the returns for battery storage projects. Furthermore, adopting several of our recommendations to enhance the operating reserve markets would help shift investment incentives toward newer more flexible technologies. (See Section VIII and Recommendations #2018-1, #2017-1, #2017-2, #2016-1, and #2015-16 for additional details.) Given the large infusion of intermittent renewables that is expected in the coming years, better market incentives are needed to motivate investment to build and maintain resources with flexible characteristics.

Existing Steam Turbines. Some existing steam turbine units may not be profitable to operate in New York City and Long Island under the current market conditions. However, the net revenues of steam units exceeded the GFC estimate for five of the last eight years in New York City, and unit owners may choose to continue operating for a variety of reasons. The existing steam turbines in New York City tend to receive a majority of their revenues from the capacity market, and from out-of-market commitments that are required to satisfy local reliability needs. Hence, to the extent that the current design does not efficiently reflect the value of energy and ancillary services, it results in higher capacity prices that provide incentives for firms to continue operating older inflexible units such as steam turbines. Our recommendations would increase the economic pressure on steam units to retire by reducing capacity revenues and out-of-market payments for reliability commitments.

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. Nonetheless, the NYISO markets play a key role in providing price signals that help direct investment in renewables to locations and technologies that are more valuable to the system in terms of being deliverable and/or providing congestion relief.

The cost of reducing CO_2 emissions varies widely from: a) developing new renewable generation; b) retaining existing nuclear generation, or c) developing new flexible and fuel-efficient gas-fired generation. This underscores the importance of encouraging emission reductions through technology-neutral mechanisms such as the carbon pricing proposal that was developed by the NYISO. Resource-specific and technology-specific subsidies increase the system-wide costs of achieving emission reduction objectives compared with technology-neutral market mechanisms.

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 flexibly and reliably during tight real-time conditions. This will become increasingly important as the New York system has higher levels of intermittent renewable resources and distributed generation.

Incentives for 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 requires 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. We found that the GT startup performance improved notably in 2018 and 2019 from prior years. The NYISO is enhancing its audit procedure to test each unit each year (rather than the previous process of testing each unit every three years). The NYISO has stated that it can and will disqualify generators from providing reserves based on audit results and/or failure to respond to reserve pick-ups. In light of this, we have withdrawn a previous recommendation to modify reserve compensation to GTs based on performance, but we will continue to monitor GT startup performance and the NYISO's qualification process.

Second, we evaluated how the availability and expected performance of operating reserve providers affected the costs of congestion management in New York City. The availability of reserves allows the operator to increase transmission flows on certain facilities, thereby increasing the utilization of the transmission system. In 2019, this allowed additional flows of:

- 27 to 30 percent (of the facility seasonal LTE rating) on several 345 kV transmission lines into New York City; and
- 6 to 34 percent on the 138 kV lines into the Greenwood/Staten Island load pockets.

However, reserve providers are not generally compensated for this type of congestion relief, which can lead to inefficient scheduling in the real-time market and inefficient investment incentives for gas turbines that can reduce congestion. Since the New York DEC's Peaker Rule will lead many peakers in New York City to retire in the next five years, efficient market incentives are needed to attract new investment in peaking resources. Otherwise, transmission capability into New York City will be degraded. Hence, we recommend compensating resources for this value. (See Recommendation #2016-1)

Market Performance under Shortage Conditions

Shortage conditions occur in a small share of real-time intervals, but their impact on incentives is large. Most shortages are transitory as flexible generators ramp in response to rapid or unforeseen changes in load, external interchange, and other system conditions. Brief shortages provide strong incentives for resources to be flexible and perform reliably, and shortage pricing accounts for a significant share of the net revenues that allow a generator to recoup its capital investment costs. Efficient shortage pricing should reflect the risk of load shedding when supply is not sufficient to satisfy all market requirements.

The operating reserve demand curves determine shortage pricing levels, but these are set well below: (a) the cost of out-of-market actions to maintain reserves during moderate reserve shortages and (b) the expected value of reserves given the likelihood of load shedding during severe reserve shortages. The operating reserve demand curve levels became more concerning after PJM and ISO New England implemented Pay-for-Performance ("PFP") rules in June 2018. The new rules provide strong incentives to schedule transactions to PJM and ISO-NE during reserve shortages. Our 2018 State of the Market report demonstrated the weak market incentives on the NYISO side and resulting OOM actions by the NYISO during the first-ever PFP event in the ISO-NE market on September 3, 2018. If the NYISO reserve demand curves provided stronger incentives, these OOM actions would not have been necessary. We continue to recommend the NYISO consider rule changes to help maintain reliability and provide appropriate incentives during shortage conditions and avoid out-of-market actions. To ensure these levels are reasonable, the NYISO should also consider the value of lost load and the likelihood that various operating reserve shortage levels could result in load shedding. (See Recommendation #2017-2)

Transmission shortages occurred in 6 percent of intervals in 2019, accounting for the majority of shortage pricing incentives. We found that the correlation between the severity and prices during transmission shortages was greatly improved following revisions to the transmission shortage pricing rules in June 2017 which have made congestion more predictable and reduced real-time price volatility. The NYISO modified its Tariff to allow more flexibility in setting Constraint Reliability Margin ("CRM") values for transmission constraints in December 2018. This has greatly reduced unnecessarily high congestion costs on lower-voltage transmission facilities in northern New York. Despite these improvements, constraint shadow prices often did not reflect the severity of transmission shortages in 2019 because the same Graduated Transmission Demand Curve ("GTDC") is used for all constraints. The NYISO has proposed to address this by modifying the GTDC to: (a) increase more gradually than the current GTDC; and (b) have a MW-range that corresponds to the CRM of the constraint. This would be a significant improvement over the current GTDC in the short-term. However, in the long term, we recommend the NYISO develop constraint-specific transmission demand curves 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, especially as New York's resource mix shifts towards increased penetration of intermittent renewable generation.

We performed an evaluation of the drivers of real-time price volatility in 2019 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 and frequent flow variations on Phase Angle Regulator ("PAR")-controlled lines (primarily on the A, J, K, and 5018 lines between New York and New Jersey). These flow changes are caused by inaccurate PAR modeling assumptions and 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 factors cause brief shortages and over-generation conditions when flexible generators cannot ramp quickly enough to compensate, leading to sharp changes in energy prices and congestion. Loop flows have had a more concentrated effect on transient price spikes since the 115 kV constraints in the West Zone were incorporated into the pricing model in December 2018. West Zone 115 kV constraints accounted for over 65 percent of transient price spikes in 2019. In this report, we discuss potential solutions and recommend improvements to ameliorate 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.

The CTS process at the New England interface continued to perform better than at the PJM interface in 2019. The potential savings in production costs were generally higher at the New England interface because the much higher liquidity of bids at the interface contributed to larger and more frequent intra-hour interface adjustments. This large difference between the two CTS processes is likely the result of large fees and uplift costs imposed on CTS transactions at the

PJM interface. In contrast, fees are not imposed on transactions 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 the NYISO continue its attempts to work with other parties to eliminate these charges at the border. (See Recommendation #2015-9)

Large adjustments in net interchange can cause transient shortages because RTC does not have an accurate representation of ramp-limitations. Thus, the NYISO limits CTS to relatively small (300 MW maximum) adjustments in net interchange every 15 minutes. While the CTS process is capable of providing significant benefits under current conditions, it has significantly greater potential to help the three markets more efficiently balance short-term variations in supply as intermittent resources are added to New York and neighboring systems.

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 300 MW of power from Long Island to New York City in accordance with a wheeling agreement between Consolidated Edison ("ConEd") and Long Island Power Authority ("LIPA"). In 2019, the operation of these lines (in accordance with the wheeling agreements) ***increased*** (a) production costs by an estimated $10 million and (b) CO_2 emissions by an estimated 250 thousand tons.

The ConEd-LIPA wheeling agreement continues to use the 901 and 903 lines in a manner that raises production costs inefficiently. As offshore wind and other intermittent generation is added to New York City and Long Island, the operational flexibility of these lines would become increasingly useful if these lines could be utilized to avoid curtailing renewable generation. 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

These PARs are currently scheduled under the M2M process with PJM, and they have provided benefit to the NYISO in managing congestion on coordinated transmission flow gates. However, we have observed instances of PAR operations that were efficient for M2M constraints but aggravated congestion on other constraints that are not incorporated in the M2M process (e.g., the West Zone 115 kV constraints). The NYISO recognized this issue and was able to incorporate these 115 kV constraints in the list of PAR Coordination Flowgates in December 2019. Despite these improvements, PAR adjustments were still frequently operated well below their operational limits, so opportunities for improved utilization remain. (See Section IX.E)

Out-of-Market Actions and Guarantee Payment Uplift

Guarantee payments to generators fell 32 percent from 2018 to $52 million in 2019. The reduction was driven primarily by decreased supplemental commitment for N-1-1 requirements in New York City and lower load levels and natural gas prices.

New York City. Although New York City accounted for most of the decrease, over $21 million of guarantee payment uplift accrued on units that were committed for N-1-1 requirements in New York City load pockets. We estimated the increase in operating reserve prices that would be necessary to represent the marginal costs of satisfying N-1-1 requirements and the resulting increase in net revenues, and we found that this pricing enhancement would have had a large impact, increasing net revenues by $19/kW-year for the demand curve unit in New York City. Therefore, we have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should provide more transparent and efficient price signals. (See Recommendation #2017-1)

Long Island. Long Island BPCG uplift did not change significantly from 2018 to 2019 because the effects of lower load levels and gas prices were offsetting by more frequent out-of-merit ("OOM") actions, which rose 21 percent from 2018. Nearly $10 million of local uplift was paid to high-cost peaking resources when they were deployed out-of-merit to manage congestion in the 69 kV network and voltage needs on the East End of Long Island on high load days. These OOM actions have increased in recent years, resulting in inefficient pricing and dispatch as well as uplift charges. For instance, oil-fired generation is often used to satisfy these constraints when imports and/or gas-fired generation was unutilized. We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets, which would be more efficient and would provide better incentives for new investment. (See Recommendation #2018-1)

Other Areas. OOM actions to manage congestion on the lower-voltage network in the other regions have fallen dramatically since the NYISO incorporated most 115 kV constraints that bind in upstate New York into the market software. This has led to more efficient management of transmission constraints, more transparent price signals, and improved investment incentives.

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. This report identifies several areas for improvement in the capacity market, including the following:

Locational Capacity-Pricing Enhancements. The current capacity market design is generally based on the NYISO's planning criteria. However, capacity prices are poorly aligned with the reliability value that is provided by resources at some locations in the current market framework. Furthermore, it will be difficult for the current capacity market to adapt to changes over the coming decade, including large-scale retirements and new entry, the introduction of new intermittent generation, energy storage, and new transmission. We have recommended a capacity pricing framework known as Locational Marginal Pricing of Capacity ("C-LMP") that would: (a) be more adaptable to changes in resource mix and transmission flows, (b) produce prices that are better aligned with NYISO's planning criteria, and (c) reduce the overall costs of maintaining reliability. (Recommendation #2013-1c)

Transmission Investment. New transmission enhances reliability and helps satisfy planning criteria, but most transmission projects are not eligible to be compensated for these benefits through the capacity market. We estimated the capacity payments that would have been received by a recently-built transmission project into Southeast New York and found it would have recouped 80 percent of its annualized cost of investment from the capacity market if efficient capacity payments were available to transmission projects (in a scenario where there is no capacity surplus). 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)

Mitigation Rules. The FERC recently issued a series of Orders that have extended or tightened the application of BSM measures for several types of resources. Given New York State's ambitious clean energy policies, the mitigation rules should strike a reasonable balance between: (a) protecting the integrity of the market by preventing capacity price suppression, and (b) facilitating the state's efforts to shape its resource mix to achieve its policy objectives. Recognizing this need, the NYISO recently worked with us and its stakeholders to develop a set of enhancements that would enable PPRs to avoid mitigation as long as sufficient quantity of existing capacity exits the market or demand growth leads to higher capacity requirements. This would allow for a workable balance between facilitating state policy objectives and ensuring that prices are just and reasonable. Our energy and ancillary services market recommendations would further harmonize the state's policy goals and mitigation rules by:

- Producing strong market signals that increase the net revenues of flexible resources that would play a critical role in facilitating integration of intermittent generation.
- Increasing economic pressure on inefficient and inflexible units to retire, thus reducing the capacity surplus and facilitating the entry of an increased amount of PPRs.

Transmission Planning

The NYISO estimates the economic benefits that would result from a new transmission project in the CARIS study evaluation and in the Public Policy Transmission Need evaluation processes. These estimates are used to rank projects and ultimately determine whether a project provides sufficient benefits to justify the costs of the project. We recommend several changes to the NYISO's estimation of benefits (see Recommendation #2015-7), including:

- Inclusion of Capacity Market Benefits – Excluding these benefits undervalues transmission projects that could make significant contributions to satisfying the NYISO's planning reliability requirements.
- Modeling Economic Retirements and New Entry – Scenarios should recognize that if a new transmission project moves forward, it will likely affect the retirement and/or entry decisions of other resources.
- Modeling Reserve Requirements and Local Reliability Needs – As zero-marginal cost resources are added to the electrical grid, it will be increasingly important to consider where local reserve needs may still lead to operation of conventional resources, but these are not considered in the GE MAPS model that is used to assess benefits of transmission.

Overview of Recommendations

The NYISO electricity markets generally performed well in 2019 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 2020 Market 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-two recommendations are presented in six categories below. Most of these were made in our 2018 SOM report, but Recommendations #2019-1 to #2019-5 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				
2019-1	VIII.C	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.		
2018-1	V.B, VIII.C	Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions and develop associated mitigation measures.		
2017-1	VIII.C, IX.G	Model local reserve requirements in New York City load pockets.	✓	✓
2017-2	VIII.C, IX.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	✓	✓
2016-1	VIII.C, IX.C	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		✓
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.	✓	
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				
2019-2	V.A	Adjust offer/bid floor from negative $1000/MWh to negative $150/MWh.		
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	IX.D	Operate PAR-controlled lines between New York City and Long Island 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.		
Capacity Market – Market Power Mitigation Measures				
2019-3	III.C	Modify the Part A test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels.	✓	✓
2018-3	III.C	Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.	✓	

Number	Section	Recommendation	Current Effort	High Priority
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
Capacity Market – Design Enhancements				
2019-4	VII.B	Modify translation of the annual revenue requirement for the demand curve unit into monthly demand curves that consider reliability value.		
2019-5	VII.B	Translate demand curve reference point from ICAP to UCAP terms based on the demand curve unit technology.		
2013-1c	VII.D	Implement locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements.		✓
2012-1c	VII.E	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.F	Reform the transmission planning 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 2019.[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.

As federal and state policy-makers promote public policy objectives such as environmental quality through investments in electricity generation and transmission,[2] the NYISO markets provide useful information regarding the value of electricity and cost of production throughout the State. As policy-makers seek to reduce emissions and reliance on fossil fuels, the NYISO markets provide incentives for both conventional and new resources that help integrate clean energy resources.

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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."

2 For instance, see the New York's Climate Leadership and Community Protection Act ("CLCPA").

The NYISO markets have several key features that are designed to allow the power of markets to satisfy the needs of the system efficiently, including:

- Simultaneous optimization of energy, operating reserves, and regulation, which efficiently allocates resources to provide these products;
- Locational requirements in its operating reserve and capacity markets, which play a crucial role in signaling the need for resources in transmission-constrained areas;
- Capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals;
- Ancillary services demand curves, which contribute to efficient prices during shortages when resources are insufficient to satisfy all of needs of the system;
- 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.
- A market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets.
- 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.
- 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, controllable, and centralized to having higher levels of intermittent renewables and distributed generation. Although large-scale changes in the resource mix currently result primarily from public policies to reduce pollution and promote cleaner generation, the NYISO markets should still 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.

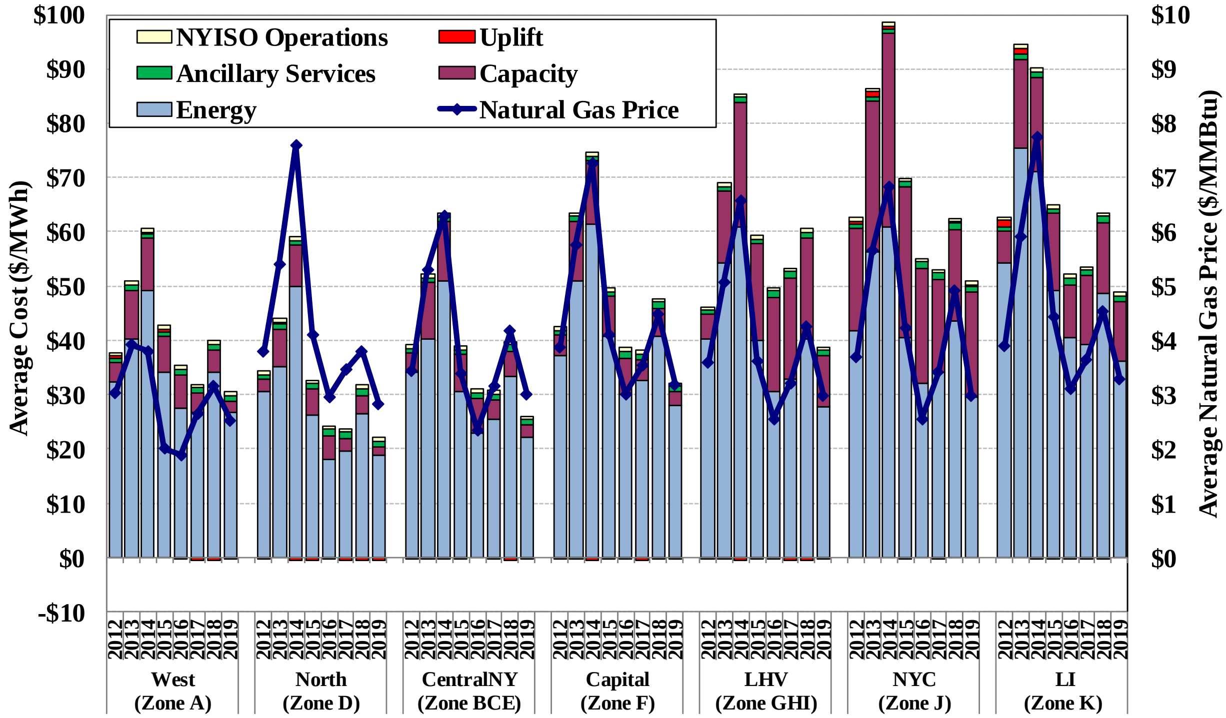
II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2019. It evaluates energy and ancillary service prices, fuel prices, generation and demand patterns, and congestion patterns.

A. Total Wholesale Market Costs

Figure 1 summarizes wholesale market costs over the past eight years by showing the all-in price for electricity, which reflects the average cost of serving load from the NYISO markets. The energy component of this metric is the load-weighted average real-time energy price, while all other components are the costs divided by the real-time load in the area.[3]

Figure 1: Average All-In Price by Region
2012-2019



All-in prices decreased in 2019 to historically low levels throughout the state. All-in prices ranged from as little as $22 per MWh in the North Zone to $51 per MWh in New York City, reflecting year-over-year decreases of 19 to 36 percent.

Energy costs are typically the largest component of the all-in prices, and in 2019, they accounted for 58 percent to 88 percent of the all-in price in each region. Over the eight years shown, variations in natural gas prices have been the primary driver of variations in the energy

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

component of the all-in price, consistent with expectations for a well-functioning competitive market since fuel costs constitute the vast majority of most units' marginal costs and natural gas-fired units most on the margin setting prices. Changes in congestion patterns have also significantly affected the energy prices at some locations.

Average energy fell prices in all seven regions shown by 22 percent to 34 percent from 2018 to 2019. The two primary drivers of the year-over-year decrease in energy prices were substantial reductions in (a) natural gas prices (20 percent to 40 percent, depending on the region), and (b) electric load on account of mild weather conditions in the summer months.[4] The low load levels contributed to reduced output from higher-cost gas-fired generators, including steam units and peaking facilities.[5]

As observed during the past several years, Long Island experienced the highest energy prices of all regions across the state in 2019. Long Island has an older less-fuel-efficient generation fleet that typically faces higher gas prices than other regions. The lowest energy costs were observed in the North Zone due to the presence of significant wind resources and frequent transmission congestion. West Zone prices also fell but by an amount smaller than in other upstate zones. This was because of the increase in priced congestion on the 115 kV system after the NYISO incorporated these constraints into its market software. The 115 kV system constraints were previously managed using OOM actions and surrogate transmission constraints.[6]

Although capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs, capacity costs were lower than the average over the previous seven years in each region. In 2019, average capacity costs fell significantly from the previous year in all regions (except for NYC) by the following amounts:

- 47 percent to 52 percent decrease in Rest of State regions (i.e. Zones A-F),
- 50 percent decrease in the Lower Hudson Valley (i.e., Zones G, H, and I),
- 15 percent increase in New York City, and
- 17 percent decrease in Long Island.

The year-over-year changes in the capacity costs were primarily driven by changes to the peak load forecasts and the ("LCRs") for each Locality in the 2019/20 Capability Period.[7]

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4 See subsection D for discussion of load patterns.

5 See subsection C for generation mix over the last three years.

6 See section IX.G for year-over-year changes in out-of-merit actions.

7 See subsection VII.A for discussion of key drivers of capacity prices in the NYISO.

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 as noted above. Table 1 summarizes fuel prices in 2018 and 2019 on an annual basis, for January alone, and for the remaining eleven months of the year. The table also shows average real-time energy prices in seven regions of the state over the same time periods. A representative gas price index is shown for each region, and the three most commonly burned oil fuel prices are also shown.[8]

Table 1: Average Fuel Prices and Real-Time Energy Prices
2018-2019

	Annual Average			January Average			Rest-of-Year Average		
	2018	2019	% Change	2018	2019	% Change	2018	2019	% Change
Fuel Prices ($/MMBtu)									
Ultra Low-Sulfur Kerosene	$16.60	$15.45	-7%	$17.08	$15.24	-11%	$16.56	$15.47	-7%
Ultra Low-Sulfur Diesel Oil	$15.07	$13.95	-7%	$14.94	$13.26	-11%	$15.08	$14.01	-7%
Low-Sulfur Residual Oil	$11.49	$11.85	3%	$10.76	$10.96	2%	$11.55	$11.93	3%
Tetco M3	$3.67	$2.39	-35%	$13.29	$4.35	-67%	$2.80	$2.21	-21%
Transco Z6 (NY)	$4.39	$2.59	-41%	$18.73	$6.02	-68%	$3.09	$2.28	-26%
Iroquois Z2	$4.28	$3.04	-29%	$14.65	$6.95	-53%	$3.34	$2.69	-19%
Tennessee Z4 200L	$2.88	$2.26	-22%	$3.51	$2.91	-17%	$2.82	$2.20	-22%
Tennessee Z6	$5.07	$3.26	-36%	$17.59	$7.03	-60%	$3.93	$2.91	-26%
Energy Prices ($/MWh)									
West (TN Z4 200L)	$33.83	$26.51	-22%	$66.95	$34.68	-48%	$30.33	$25.56	-16%
North (Waddington)	$25.57	$18.41	-28%	$65.37	$28.67	-56%	$23.00	$18.44	-20%
Central NY (TN Z4 200L/TN Z6)	$32.79	$21.71	-34%	$70.83	$31.37	-56%	$29.18	$20.70	-29%
Capital (Min of Iroq. Zn 2 & TN Z6)	$39.82	$27.69	-30%	$109.34	$46.52	-57%	$32.90	$25.16	-24%
Lw. Hudson (Tetco M3/Iroq.)	$39.68	$27.58	-30%	$101.56	$44.25	-56%	$33.53	$25.40	-24%
New York City (Transco Z6 NY)	$43.22	$29.41	-32%	$108.28	$45.70	-58%	$38.10	$29.28	-23%
Long Island (Iroq. Zn 2)	$48.14	$35.41	-26%	$108.32	$50.84	-53%	$41.90	$32.74	-22%

Although more than half (over 55 percent in 2019) of the energy consumed was generated by hydro and nuclear units, natural gas units were 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.

Average natural gas prices across the state decreased by 22 percent (Tennessee Z4 200L) to 41 percent (Transco Zone 6 (NY)) from 2018 to 2019. Gas prices declined as producers continued to increase production at regional shale plays, and storage levels remained elevated on account of mild winter weather in 2019. The year-over-year decrease in prices in the eastern New York was particularly steep during the winter due to the spike in gas prices during the severe cold weather

8 Section I.B in the Appendix shows the monthly variation of fuel prices and provides our assumptions about representative gas price indices in each region.

experienced in January 2018. For example, the average Transco Z6 NY and Iroquois Z2 gas prices in January fell 68 percent and 53 percent, respectively, from 2018 levels.

Gas pipeline congestion patterns were similar to electricity congestion patterns with larger spreads between Western and Eastern New York in January 2019 than in other months. Gas spreads between regions decreased in 2019 relative to 2018, contributing to reduced electricity congestion.[9,10]

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 2017 to 2019, 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
2017-2019

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2017	2018	2019	2017	2018	2019	2017	2018	2019
Nuclear	4.8	4.9	5.1	33%	32%	34%	0%	0%	0%
Hydro	3.2	3.2	3.3	22%	21%	22%	43%	44%	43%
Coal	0.1	0.1	0.0	0%	1%	0%	1%	1%	1%
Natural Gas CC	4.6	4.9	4.9	31%	32%	32%	77%	77%	82%
Natural Gas Other	1.2	1.3	1.0	8%	9%	7%	32%	41%	33%
Fuel Oil	0.1	0.2	0.1	0%	1%	0%	2%	3%	2%
Wind	0.5	0.5	0.5	3%	3%	3%	5%	7%	7%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

Gas-fired units accounted for the largest share of electricity production in each year of 2017 to 2019, but more than half of generation (53 percent to 56 percent) came from a combination of hydro and nuclear units over this same period. The share of gas-fired generation decreased from

9 For instance, the Tennessee Zone 4 200L index exhibited an average discount of 43 percent relative to the Transco Zone 6 (NY) index in 2018 compared to an average discount of 13 percent in 2019.

10 See subsection E for discussion on congestion patterns.

11 Section I.B in the Appendix provides additional detail 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).

41 percent in 2018 to 39 percent in 2019 mostly due to less output from steam turbine units. These units have relatively high heat rates and tend to operate during high load periods, the incidence of which was significantly lower in 2019.

Generation from nuclear units consistently accounted for over 30 percent of total in-state generation for several years. However, the planned retirement of the two Indian Point nuclear units in the near future will shift much of this output to other resource types. The two Indian Point nuclear units are scheduled to retire in April 2020 and in April 2021. These retirements could reduce the share of nuclear generation to roughly 21 percent (using 2019 generation levels as the baseline).

The share of coal-fired generation (less than half of one percent) continued to shrink because of low gas prices, transmission upgrades that eliminated the need to commit coal for reliability, and coal unit retirements. The last coal-fired unit in the state stopped operations in March 2020. The absence of severe cold weather in 2019 led to very little generation from oil-fired facilities.

Gas-fired units and hydro resources were most frequently on the margin in recent years. Lower load levels and decreased congestion (particularly in New York City) led gas-fired peakers and steam units to be on the margin less often in 2019. Most marginal hydro units have storage capacity, leading their offers to include the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by natural gas prices. Other fuel types set prices much less frequently.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Table 3 shows the following load statistics for the New York Control Area ("NYCA") since 2011: (a) annual summer peak; (b) reconstituted annual summer peak; (c) annual winter peak; (d) annual average load; and (e) number of hours when load exceeded certain levels. The reconstituted summer peak incorporates any demand response that was activated during the peak load hour. Hence, the reconstituted value differs from the actual reported value in years when the utility and/or the NYISO activated demand response during the peak load hour.

In 2019, load levels were exceedingly low, particularly the average load, which was the lowest witnessed in over 10 years. The average load fell by 3.3 percent (relative to the 2018 level) because of temperate conditions throughout the year. The summer peak load fell by 4.6 percent from 2018 because of a milder summer in 2019. Demand response activations have occurred more in years with high summer loads, but have not reduced the peak by more than 2.4 percent since 2012.

Table 3: Peak and Average Load Levels for NYCA
2011 – 2019

Year	Load (GW)				Number of Hours >		
	Summer Peak (as Reported)	Summer Peak (Reconstituted)	Winter Peak	Annual Average	32GW	30GW	28GW
2011	33.9	35.4	24.3	18.6	17	68	139
2012	32.4	32.6	23.9	18.5	6	54	162
2013	34.0	34.8	24.7	18.7	33	66	145
2014	29.8	29.8	25.7	18.3	0	0	40
2015	31.1	31.1	24.6	18.4	0	23	105
2016	32.1	32.5	24.2	18.3	1	33	163
2017	29.7	29.7	24.3	17.9	0	0	43
2018	31.9	32.5	25.1	18.4	0	59	167
2019	30.4	30.4	24.7	17.8	0	11	66

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.[12] 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.[13]

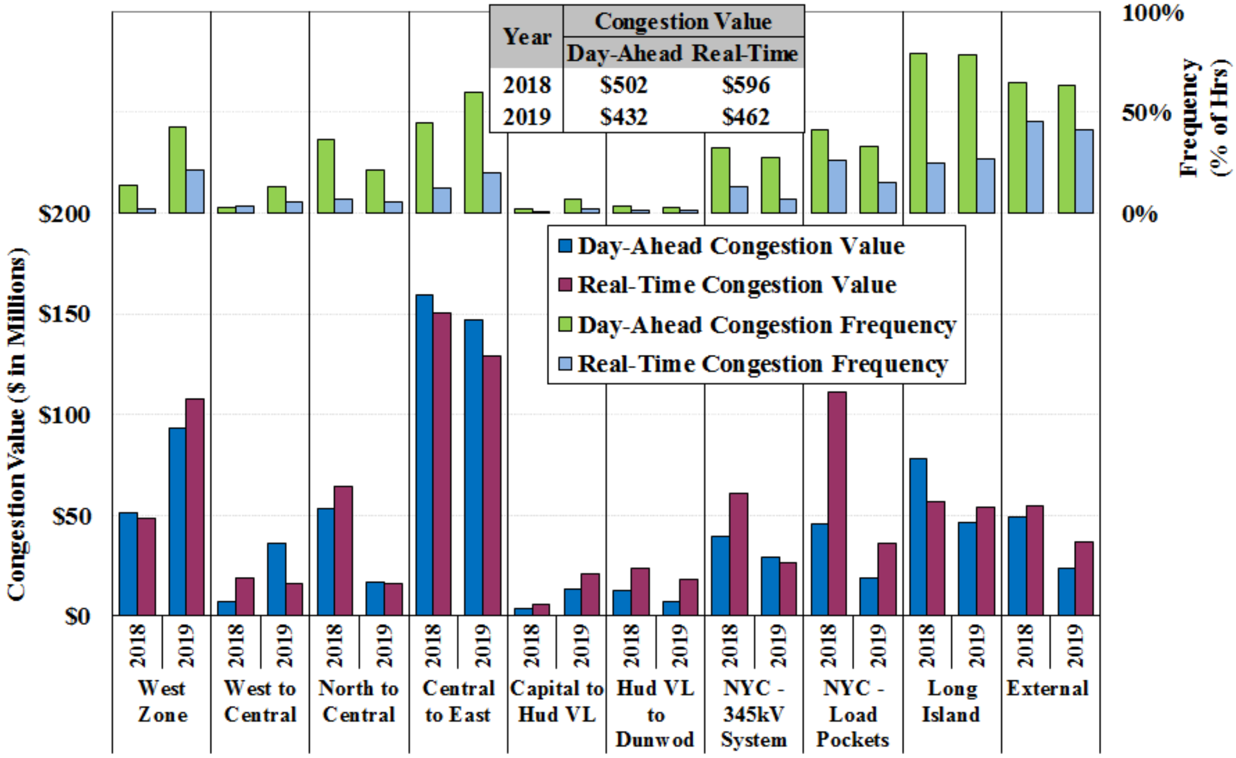
The value of day-ahead congestion fell 14 percent to $432 million in 2019, consistent with lower load levels, low natural gas prices, and mild summer and winter weather. In contrast, extreme cold in the first eight days of January 2018 led to natural gas prices of up to $140/MMBtu in some areas and resulted in $56 million of day-ahead congestion revenues.

Congestion values were lower in 2019 in most regions but rose significantly (by $43 million) in the West Zone from 2018 for at least two reasons. First, NYISO began to incorporate 115 kV constraints in the West Zone into the day-ahead and real-time markets in December 2018. Previously, these transmission constraints were managed using out-of-market actions. This change has helped improve overall efficiency of scheduling and pricing. Second, the impact of loop flows around Lake Erie became more significant on West Zone constraints following the closure of the South Ripley-Dunkirk 230 kV line at the NY/PJM border in April 2019.

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

13 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.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2018-2019



Another key driver of reduced congestion was that there were fewer costly transmission outages on several major transmission corridors, particularly paths into and within New York City, from the North Zone to Central New York, and from New York to New England across its primary interface. However, the Central-East interface had more transmission outages in 2019.

Other factors also played important roles in affecting year-over-year changes in congestion. In the North Zone for example, the implementation of lower Constraint Reliability Margins for 115 kV facilities effectively increased the allowable flow on those facilities and contributed to lower annual congestion values in 2019.[14] In addition, the NYISO improved modeling of the Niagara Plant in December 2018 that better recognizes the different congestion impacts from 115 kV and 230 kV units at the plant, enabling the NYISO to more efficiently manage associated congestion.

F. Ancillary Services Markets

Ancillary services and energy scheduling is co-optimized. Part of the cost of providing ancillary services is the opportunity cost of not providing energy when it otherwise would be economic to

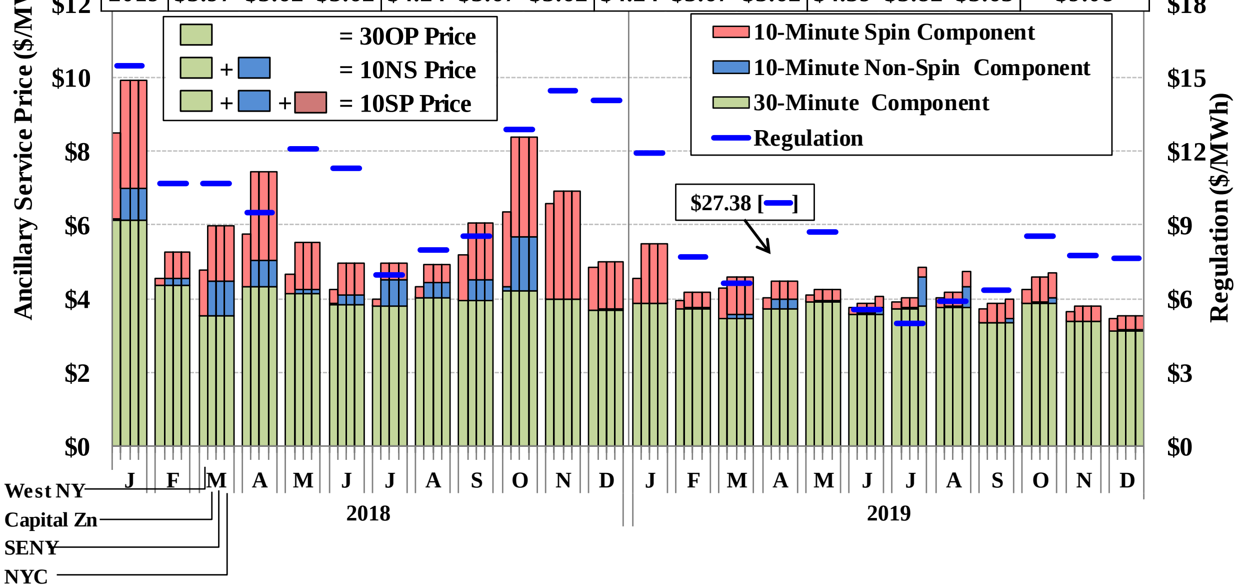
14 The Constraint Reliability Margin ("CRM") values for 115 kV facilities were unnecessarily high (to confirm with approved tariff rules) when the constraints were first modeled, leading to higher congestion costs as discussed in Section V.G in the Appendix. The NYISO filed a tariff change with the FERC to allow the use of lower CRM values for these transmission facilities, effective on December 4, 2018.

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 2018 and 2019.[15] Table 4 summarizes reserve market outcomes in New York City since the NYISO began to model reserve requirements there on June 26, 2019.

Figure 3: Average Day-Ahead Ancillary Services Prices

2018-2019

	West NY			Capital Zone			Southeast NY			New York City			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
2018	$5.31	$4.18	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$11.24
2019	$3.97	$3.62	$3.62	$4.24	$3.67	$3.62	$4.24	$3.67	$3.62	$4.39	$3.82	$3.63	$9.08



Average day-ahead prices for all reserve products fell in 2019 consistent with the decrease in opportunity costs of not providing energy. Low load levels and gas prices resulted in low energy prices, which contributed to low prices for all reserve products. Lower reserve offer prices in the day-ahead market also contributed to lower ancillary service prices.[16]

As in 2018, the price of the NYCA 30-minute reserves accounted for most of the day-ahead market reserve prices in 2019. However, the 10-minute spinning component decreased significantly from 2018 to 2019. The premium for the 10-minute spinning reserves in 2018 was

15 See Appendix Section I.H for additional information regarding the ancillary services markets and detailed description of this chart.

16 See Appendix Section II.D for additional details about reserve offer patterns.

driven by large increases in months with severe cold weather (January 2018), gas pipeline repairs (April 2018) and maintenance outages of 10-minute capable generators in shoulder months.

Shoulder months exhibited higher regulation prices in 2019, consistent with recent years. The amount of online generating capacity is relatively low during these months, and more generators are on maintenance outages, thereby reducing the supply of regulation offers. With the exception of April, the average regulation prices were lower in every month of 2019 than the prior year because of lower opportunity costs and fewer outages of regulation suppliers. The high prices for regulation in April (averaging $27 per MWh) was due to: (a) planned outages of key regulation providers, (b) very low load conditions driving down energy commitments of suppliers to their minimum generation levels, and (c) many regulation-capable units choosing not to offer, especially combined cycle units. Combined cycle units face the risk of needing to regulate into the duct-firing range, so many units avoid offering regulation. Recently, the NYISO has worked to enable suppliers to reduce their real-time normal upper operating limits below their duct-firing ranges, which has increased the availability of regulation offers.

The NYISO incorporated the New York City reserve requirements (500 MW of 10-minute reserves and 1000 MW of 30-minute reserves) into the pricing software starting June 26, 2019. Table 4 below compares the prices for 10-minute and 30-minute reserve products in New York City to the broader SENY region.

Table 4: Comparison of Reserve Prices DA and RT between NYC and SENY
June 26 to Dec 31, 2019

Market	10-Minute Spinning Price			10-Minute Nonspinning Price			30-Minute Operating Price		
	SENY	NYC	NYC Premium	SENY	NYC	NYC Premium	SENY	NYC	NYC Premium
Day-Ahead	$4.01	$4.30	$0.29	$3.57	$3.85	$0.29	$3.54	$3.56	$0.01
Real-Time	$1.58	$1.96	$0.38	$0.09	$0.47	$0.38	$0.06	$0.19	$0.13

Overall, the day-ahead premium for the New York City reserve products was $0.29 per MWh for 10-minute reserves ($0.38 per MWh in RT), and $0.01 per MWh for 30-minute reserves ($0.38 per MWh in RT). The separation of New York City reserve prices from SENY led to modest BPCG reductions, but out-of-market commitments were still frequently needed to maintain adequate reserves in load pockets where local N-1-1 requirements are not explicitly represented as day-ahead and real-time reserve market requirements. Such out-of-market actions are not reflected in market clearing prices, leading to inefficient incentives for investment in resources that can satisfy the local requirements. Accordingly, we have recommended the NYISO consider incorporating these local reserve requirements in the New York City load pockets.[17]

[17] See discussion in Sections IX.G and VIII.C.

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 2019 market outcomes in three areas: Subsection A evaluates patterns of potential economic and physical withholding by load level in Eastern New York; Subsection 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 2019.

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.

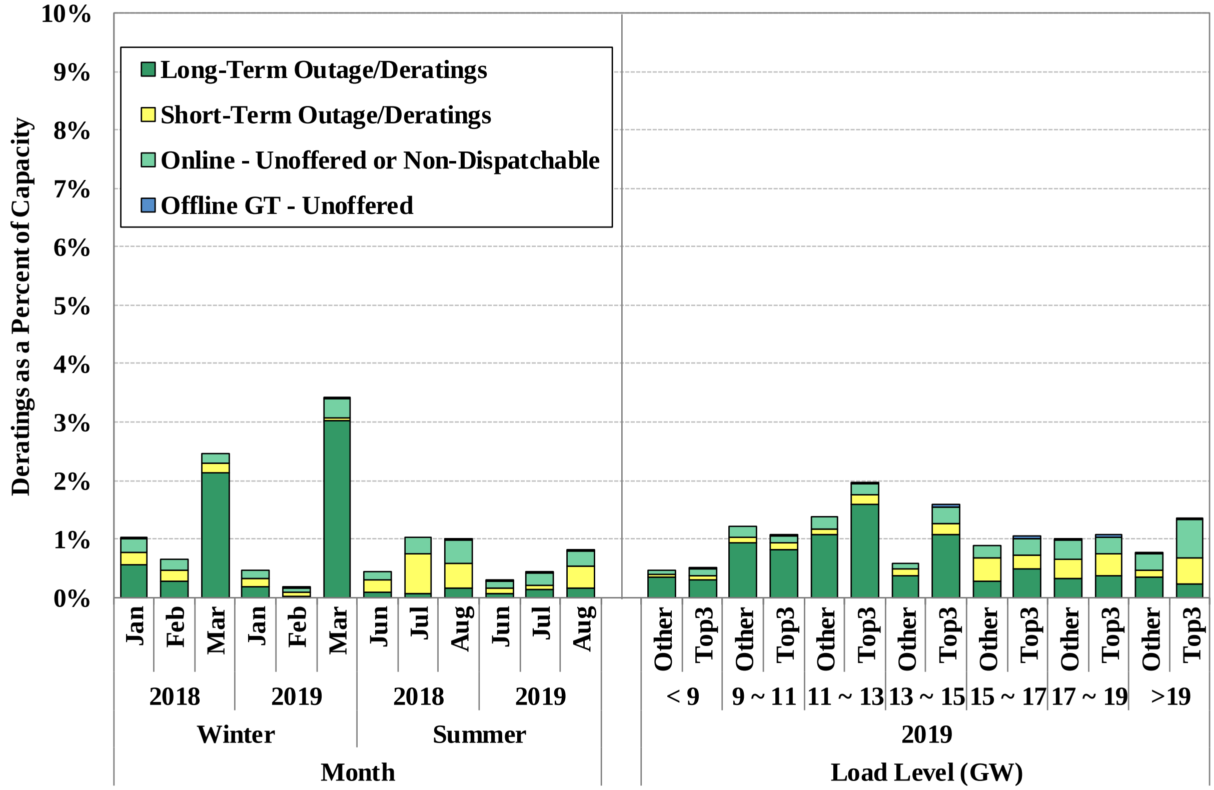
In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap" which is the amount of generation that 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.[18]

Figure 4 and Figure 5 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[19] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

18 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.

19 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
2018 – 2019



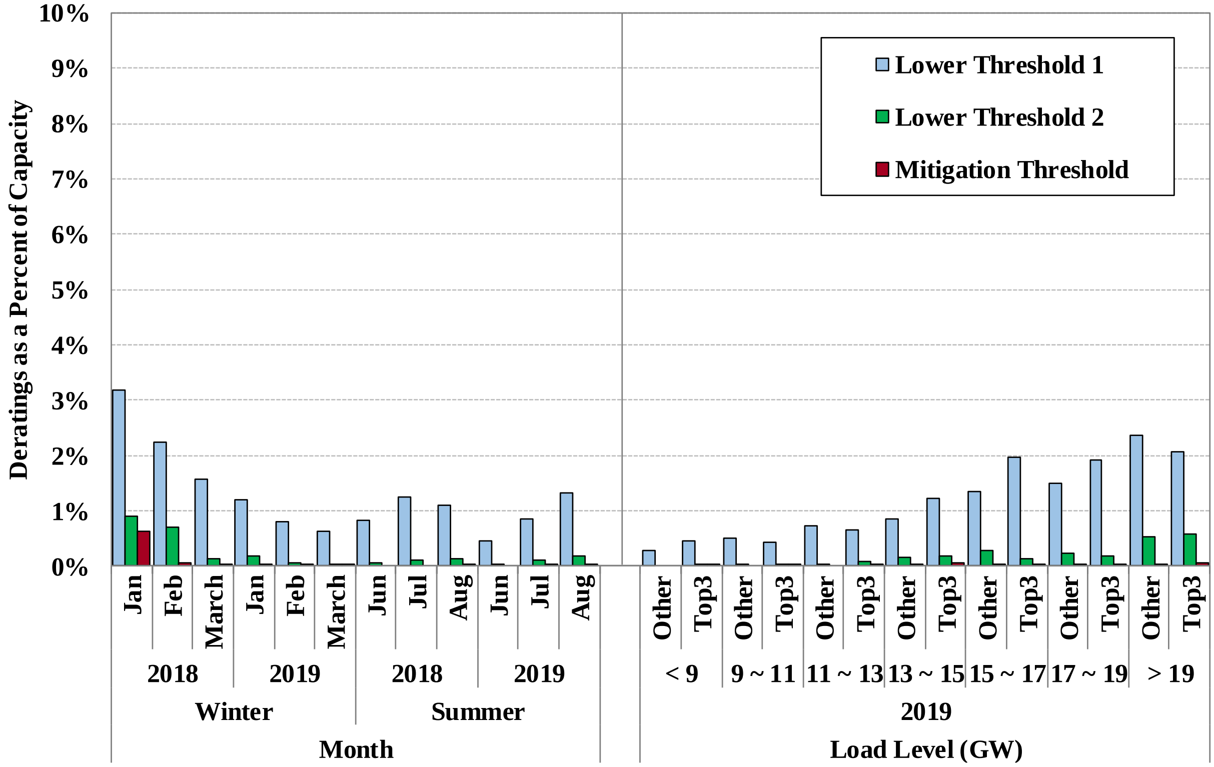
Unoffered economic capacity averaged 1.1 percent of total capacity (DMNC) in NYCA and 1.2 percent in Eastern New York in 2019, down slightly from 2018 levels. The pattern of generator outages and deratings in Eastern New York in 2019 was consistent with patterns observed in 2018. Most unoffered capacity resulted from long-term outages during shoulder months in the spring and autumn. Unoffered economic capacity was lower in the summer of 2019 relative to 2018 primarily because of milder weather conditions and fewer nuclear outages.[20]

The amount of output gap in Eastern New York remained very low in 2019, averaging 0.01 percent of total capacity at the statewide mitigation threshold and 0.65 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.

20 Low prices likely contributed to an over-estimate of unoffered economic capacity in 2019 because the 25 percent threshold used to make the estimate is tighter (per MWh) in a low gas price environment. For example, if a generator has an incremental heat rate equal to 7 MMBtu/MWh, a VOM of $3/MWh, $5/RGGI allowance, and the gas price is $2/MMBtu, then the Reference Level would be (7 MWh/MMBtu x 2 MMBtu) + $3/MWh + ($5/ton x 0.06 ton/MMbtu emission rate) = $17.30/MWh. The 25 percent threshold would be $4.33/MWh. If the gas price doubled to $4/MMBtu, the Reference Level would be $31.30/MWh, and the 25 percent threshold would be $7.83/MWh. Thus, the 25 percent threshold is nearly 45 percent lower in the lower gas price scenario, making it more likely for a unit on outage to appear economic despite low LBMPs.

Figure 5: Output Gap in Eastern New York
2018 – 2019



The output gap in Eastern New York is usually largest during high load conditions, especially in peak winter conditions when fuel prices become volatile. In 2019, low load conditions and mild winter weather resulted in negligible amounts of output gap at the mitigation threshold.

Most of the output gap in 2019 was attributable to units that typically have bid-based reference levels that are lower than the true marginal cost of generation. Thus, a significant portion of the capacity identified as output gap is due to low reference levels rather than inappropriately high energy offers.[21] To limit the potential for excessive mitigation in areas with strict mitigation measures (i.e., New York City), most NYC generators have cost-based 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 consistent with competitive expectations and did not raise significant concerns regarding potential physical or economic withholding under most conditions.

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21 Attachment H of the NYISO Market Services Tariff outlines the three type of reference levels that a generator may have. The first type that will be calculated based on the availability of data is a bid-based reference level. This value is calculated as the average of accepted economic bids during unconstrained intervals over the past 90 days, adjusted for changes in gas prices. This approach may under-state marginal costs for units that face fluctuating fuel prices.

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.[22]

- 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.

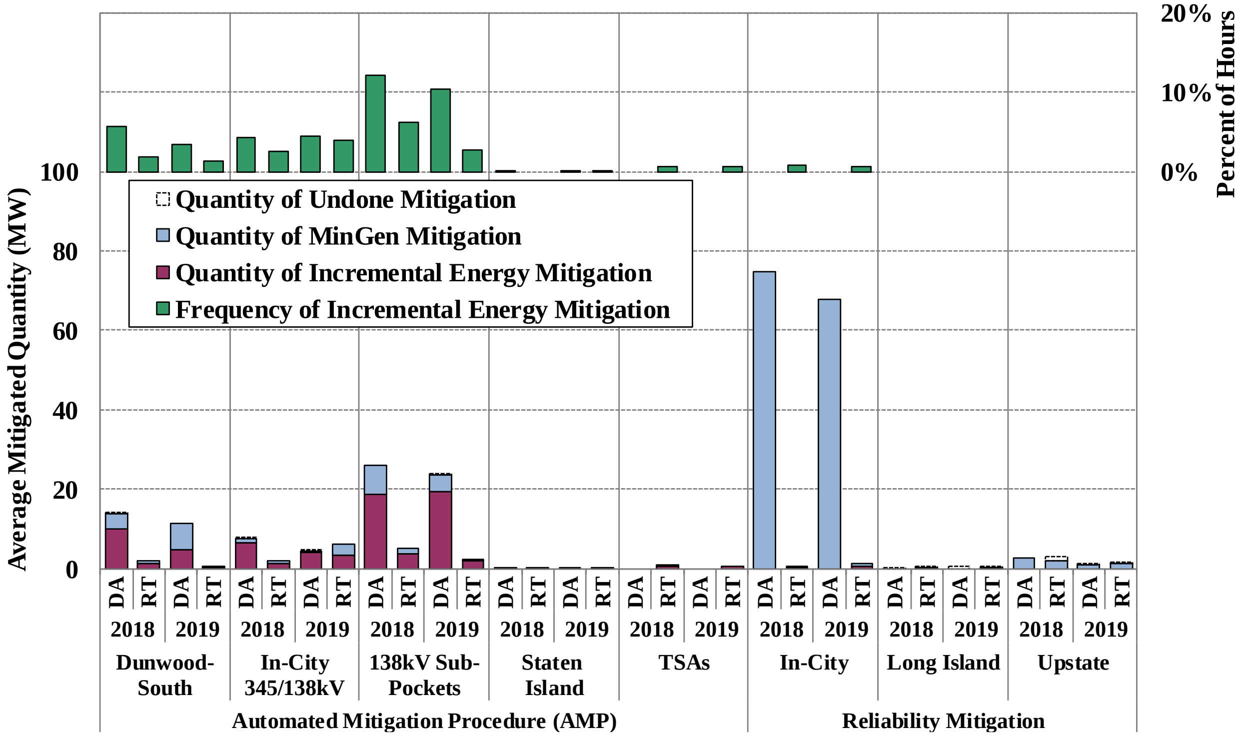
- Reliability Mitigation in Other Areas – When a generator is committed for reliability and the generator is pivotal, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A conduct threshold of the higher of $10 per MWh or 10 percent of the reference 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 2018 and in 2019. This figure shows that most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for 59 percent of all mitigation in 2019, nearly all of which occurred in the day-ahead market. Both the amount of capacity committed for reliability in New York City and the frequency of mitigation decreased from 2018 to 2019. This is largely because of less frequent load conditions that required the reliability commitments in New York City.[23] 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 market power.

[22] 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.

[23] See Section IX.G for more details on the reduced reliability commitments in New York City.

Figure 6: Summary of Day-Ahead and Real-Time Mitigation
2018 - 2019



AMP mitigation accounted for 36 percent of day-ahead mitigation and was down from 2018 in all areas of New York City. This decreased primarily because of fewer congested intervals in-city during 2019.

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. For instance, on gas days during the cold spell from December 27, 2017 to January 8, 2018 an average of 1.9 GW (or 18 percent) of NYC generating capacity submitted FCAs for natural gas before the day-ahead market. Even during mild conditions, significant numbers of generators often submit FCAs with their day-ahead and real-time offers.

The FCA functionality is important because it allows a generator to reflect fuel cost variations closer to when the market clears. 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 subsequently scheduled. Accordingly, we monitor for biased FCAs and the NYISO administers mitigation measures that impose financial sanctions on generators that submit biased FCAs under certain conditions. Our review of the 2018/19 winter found little cause for concern in this regard due to the absence of severe volatility in the gas markets.

Nonetheless, we have 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.[24]

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. The NYISO has market power mitigation measures that are designed to ensure that the markets perform competitively.

Supply-side market power mitigation measures prevent or deter suppliers with market power from inflating prices above competitive levels by withholding economic capacity in these areas. 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.[25]

Buyer-side market power 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. The BSM measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. To be exempt from an offer floor, a new resource must pass one of the following evaluations:[26]

- Competitive Entry Exemption – For a new resource that agrees not to accept subsidies from a state agency or other prohibited entity.
- Part B Test Exemption – For a new resource that demonstrates that it is forecasted to be economic in the first three years of operation.
- Part A Test Exemption – For a new resource that enters when the surplus capacity margin in the area is forecasted to be less than a specified level.
- Renewable Entry Exemption – For new intermittent renewable units with low capacity factors.

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24 See Section XI, Recommendation #2017-4.

25 See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

26 See NYISO MST, Section 23.4.5.7 for the current rules related to BSM exemptions. The BSM measures are likely to be modified in several open FERC dockets, including: EL20-663-000 where the NYISO filed amendments to allow Competitive Entry Exemptions for Additional CRIS interconnection projects, ER20-1718-000 where the NYISO filed to amend the Part A Exemption Test, and ER16-1404 where the NYISO filed rules for setting the quantity of exemptions available in each class year.

- Self-Supply Exemption – For a load-serving entity that self-supplies most of its capacity needs.

Given the sensitivity of prices in the Mitigated Capacity Zones, these market power mitigation measures are essential for ensuring that capacity prices in these zones are competitive. This section discusses the use and design of capacity market mitigation measures in 2019.

Application of the Supply-Side Mitigation Measures

From time to time, the NYISO evaluates whether a proposal to remove capacity from a Mitigated Capacity Zone has a legitimate economic justification. We have found that the NYISO's evaluations in recent years have been in accordance with the tariff.

Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests ("METs") and confidentially provided BSM determinations for three Examined Facilities in July 2019. These projects were part of the second phase of the bifurcated Class Year 2017 ("CY17-2").[27] Table 5 describes each CY17 Examined Facility and the final status of its BSM evaluations.

Table 5: Status of CY17 BSM Evaluations

Examined Facility	Zone	Summer ICAP MW	Type	CY17 Phase	Determination
Cricket Valley Energy Center Project	G	1020	CC	17-1	Exempt - CEE
Bayonne Energy Center II Project	J	120	CT	17-1	Exempt - CEE
Berrians East Replacement Project	J	508 (Net +4MW)	CT	17-1	Exempt - Part B
East River 6 Additional CRIS MW Project	J	8	Additional CRIS	17-1	Exempt - Part B
Champlain Hudson Interconnection Project	J	1000	HVDC Line	17-2	No Final Determination - Dropped out
Linden Cogen Uprate Project	J	234	CT	17-2	No Final Determination - Rejected SDU cost allocation
Linden Additional CRIS MW Project	J	32	Additional CRIS	17-2	No Final Determination - Dropped out

Improvements to the Part A and Part B BSM Evaluations

The NYISO made several modifications to its test methodology in the CY17 evaluations.[28] The application of new inclusion and exclusion rules for determining the in-service capacity

27 In CY17, the NYISO issued final determinations in two settlement phases as the CY "bifurcated." The first phase was for Examined Facilities that do not require additional System Deliverability Upgrades ("SDU") studies and elected to settle early as part of the first phase of CY. The second phase was for Examined Facilities that require additional SDU studies and elected to proceed with the studies, and for Examined Facilities that did not require additional SDU studied but elected to settle in the second phase. CY17 bifurcated because two Examined Facilities elected to proceed with additional SDU studies.

28 See the MMU's BSM Report for CY17-1 Projects for changes the NYISO made to the test methodology.

corrected a major deficiency of the test procedure. In addition, the NYISO forecasted the LCRs using the new LCR methodology after accounting for changes in the resource mix (e.g., Indian Point retirement) and interface transfer limits. Both of these changes had a considerable impact on the CY17 price forecasts and significantly enhanced the test procedure.

Our CY17 and past BSM reports have identified additional concerns with several assumptions that are used in the BSM evaluations. Table 6 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"). [29]

Table 6: Recommended Enhancements to the Part A and Part B 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 Existing 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 exempt Prior Class Year Projects in the Interconnection Queue may be unrealistic (Part A & B tests)	I
Modify Part A test procedure to exempt Zone J projects if they are needed to satisfy the G-J Locality's capacity requirement (Part A test)	T

Recent Changes to the BSM Rules

The FERC recently issued multiple Orders that affect the BSM rules for different types of resources in the NYISO. The following is a summary of the key elements of the FERC Orders, and ongoing compliance efforts.

The first Order addressed multiple filings by IPPNY and affirmed its decision to not extend the BSM measures to existing units in the ROS Zone that are pursuing repowering agreements.[30] Specifically, the Commission did not rule on the merits of: (a) whether the ZECs ("Zero Emission Credits") constitute subsidies that should be subject to BSM measures and (b) whether extension of BSM measures to new resources located in the ROS Zone is warranted.

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29 For details, see the BSM Report for CY17. The NYISO's filing on April 30, 2020 addresses the last issue (related to Part A test procedure), and partially addresses the second (related to Starting Capability Period).

30 See Commission's February 20, 2020 Order in EL13-62.

Second, FERC, in response to the NYISO's compliance filing, issued an Order that covered various elements of the design of the Renewable Entry Exemption ("REE"), and Self-Supply Exemption.[31] The Commission accepted the NYISO's proposed criteria for determining eligibility of resources for REE. However, the Commission found that the NYISO's proposed MW cap does not comply with its prior directives, and ordered the NYISO to propose a cap that is narrowly tailored to the Mitigated Capacity Zones, and is based on UCAP. The NYISO submitted a compliance filing with a formulaic methodology for the REE on April 7, 2020.

Third, the Commission denied a compliant by NYSERDA and the DPS, ruling that Energy Storage Resources ("ESRs") should not receive a special exemption from the NYISO's BSM measures.[32] So, ESRs will be evaluated under the same rules as generators.

Fourth, the Commission granted IPPNY's rehearing request, and ruled that all new SCRs should be subject to the BSM rules. The Commission also initiated a paper hearing to perform a program-specific review and determine payments that could be excluded from the Offer Floor for SCRs. The NYISO submitted its compliance plan, and indicated that it will commence monthly evaluations of new SCRs starting May 2020.[33]

Ultimately, the Commission's Orders have extended or tightened the application of BSM measures for several types of resources, but they do not preclude New York State from pursuing its environmental policy objectives. The Commission has affirmed the right of a state to exercise "their traditional authority over electricity generation and retail operations—encourage renewable resources and direct the planning decisions of electric utilities within their jurisdiction over its resource mix." However, the Commission also affirmed that its jurisdiction over rates may lead some resources to be mitigated to ensure "just and reasonable" rates. These recent orders have reinforced the need for NYISO stakeholders to pursue rule changes that will harmonize Commission regulations with New York State policy, balancing state policies to promote resources with desirable environmental attributes against the Commission's mandate to ensure just and reasonable wholesale prices.

In the next subsection, we discuss the compatibility of BSM measures and the state's policy goals, and a potential pathway for harmonizing the two.

Harmonizing State Public Policy Goals with Buyer-Side Mitigation Measures

The State of New York has ambitious public policy goals for decarbonizing the electricity sector. Robust market incentives will be needed for New York State to satisfy its goals at a reasonable

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31 See Commission's February 20, 2020 Order in ER16-1404-000.

32 See Commission's February 20, 2020 Order in EL19-86-000.

33 See Commission's February 20, 2020 Order in ER17-996-000.

cost. Market price signals could help shift investment towards renewable energy projects that are more effective in displacing fossil-fuel generation as well as flexible resources that are more effective in helping to integrate intermittent renewable generation. In particular, an efficient capacity market that produces just and reasonable prices will become increasingly important to subsidized resources whose long-term profitability will depend in part on future revenue streams from selling capacity in the NYISO market.

The BSM rules play a critical role in ensuring that out-of-market investment does not suppress capacity prices below competitive levels in the short-run, and are a critical tool in fostering confidence in the market and the competitiveness of future prices. The BSM measures were originally designed to prevent entities from suppressing capacity prices below competitive levels by subsidizing uneconomic new entry of a conventional generator. The BSM measures are not intended to deter states from promoting clean energy and other legitimate public policy objectives.

However, the BSM rules should strike a reasonable balance between: (a) protecting the integrity of the market by preventing capacity price suppression, and (b) facilitating the state's efforts to shape its resource mix to achieve its policy objectives. Given New York's increasingly ambitious agenda to promote clean energy policies, the BSM rules will need to evolve to maintain a proper balance between these two objectives.

Recognizing this need, the NYISO recently worked with us and its stakeholders to develop a set of enhancements to the Part A test.[34] New entrants would be exempted from Buyer-Side Mitigation under the Part A test criteria if the capacity surplus is lower than a certain threshold ("Part A threshold"). The NYISO proposal, among other changes, will allow Public Policy Resources ("PPRs") to be tested under the Part A test ahead of non-PPR entrants.[35] Hence, the NYISO's proposed rules would enable PPRs to avoid mitigation as long as sufficient quantity of existing capacity exits the market or demand growth leads to higher capacity requirements. This would allow for a workable balance between facilitating state policy objectives and ensuring that prices are just and reasonable. Accordingly, we support the NYISO's proposal.

Furthermore, we have recommended additional energy and ancillary services market reforms that would further enhance investment incentives for flexible resources that help integrate intermittent renewable generation. These reforms address the underlying design issues that cause systematic under-compensation of flexible resources (including clean resources such as battery storage) and would efficiently shift net revenues from the capacity market to the energy

34 The NYISO filed these provisions with the Commission on April 30, 2020, and intends to apply the filed rules for the Class Year 2019 BSM evaluations.

35 See NYISO "Comprehensive Mitigation Review: Revisions to part A Exemption Test" presented March 18, 2020 to the ICAP Working Group.

and ancillary services markets. We evaluate the effects of the following recommendations in Section VIII:

- Recommendation #2016-1 would compensate reserve providers that relieve congestion, which increases import capability into and throughout New York City, allowing the city to be served by more imported renewable energy.
- Recommendation #2017-1 would create reserve markets to reward reserve providers that maintain reliability in NYC load pockets, which would reduce the need to retain older fossil-fueled generation in the city.
- Recommendation #2017-2 would raise reserve shortage pricing levels when the New York Control Area is short of 10-minute or 30-minute reserves, rewarding flexible generation that helps integrate intermittent renewables.
- Recommendation #2018-1 would compensate resources that help manage transmission congestion on Long Island when wholesale generators are dispatched to secure lower-voltage transmission facilities.

As illustrated in Figure 22, these recommendations would increase the returns for more efficient and flexible resources while reducing the returns for older generators with less reliable characteristics. Taken together with the Part A enhancements, our recommendations would could help achieve the state's goals in two ways:

- They will produce strong market signals by increasing the net revenues of flexible resources that would play a critical role in facilitating integration of intermittent generation.
- They will reduce compensation for relatively inflexible and inefficient units among the existing resources, thus increasing the economic pressure on them to retire. This would facilitate the entry of an increased amount of PPRs under the Part A test.[36]

Overall, we believe that the BSM measures are compatible with the state's public policy goals, and that the Part A test enhancements along with our proposed reforms would enable the NYISO's markets to promote the state's objectives cost-effectively.[37]

36 See Section VII of the Appendix.

37 This is in contrast with state-directed contracting, which as discussed in our reply comments in the Resource Adequacy Matters proceeding, could be extremely costly and inefficient as it will not coordinate efficient investment in new resources or retirement of existing resources.

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 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. The table also reports the average absolute value of the difference between hourly day-ahead and real-time prices.[38] These statistics are shown on an annual basis.

Table 7: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2018-2019

	Annual Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff	
Zone	2018	2019	2018	2019
West	0.7%	-0.1%	40.6%	41.3%
Central	-1.9%	2.8%	35.1%	28.6%
North	-3.3%	-0.1%	55.6%	39.8%
Capital	-1.3%	4.2%	31.8%	26.0%
Hudson Valley	-1.1%	3.1%	31.2%	24.8%
New York City	-3.2%	2.4%	31.5%	25.4%
Long Island	1.6%	-3.0%	37.7%	37.5%

East of the Central East interface, day-ahead prices were higher on average than real-time prices (by two to four percent) in 2019. This coincided with lower real-time price volatility than in previous years. The only exception was Long Island where average real-time prices were higher than the day-ahead prices (by three percent). The real-time price premium observed in Long

38 Section I.G in the Appendix evaluates the monthly variations of average day-ahead and real-time energy and he price convergence for selected nodes.

Island was largely driven by a combination of factors that raised the real-time cost of managing congestion including unforeseen outages of transmission facilities, difficulty forecasting PAR-controlled line flows, and limited availability of 5-minute ramping capability. 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.

West of the Central East interface, the West and North Zones saw small (0.1 percent) average real-time premiums, which was an improvement from 2018. This was likely because modeling 115 kV constraints in the West zone and reducing CRM values for 115 kV transmission facilities improved consistency of congestion pricing between the day-ahead and real-time markets.

The average absolute difference between day-ahead and real-time prices fell from 2018 to 2019 in all zones except the West Zone. The improved convergence was driven primarily by lower load levels, less volatile gas prices, and fewer major transmission outages in several areas. In the West zone, transmission constraints were hard to manage despite modeling enhancements. Unforeseen loop flows can lead to severe congestion and increased price volatility in real-time, leading to larger average absolute differences between day-ahead and real-time prices.

Notwithstanding these improvements, the average absolute difference continues to indicate the highest volatility is in the West zone, the North zone, and in Long Island. The West and North zones 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. Long Island is a small, import-constrained zone with an older and less flexible generating fleet, which contributes to real-time price volatility during periods of high load or when import line limits are reduced unexpectedly.

Convergence between day-ahead and real-time energy prices is generally better at the zone level than at the node level, primarily because physical loads and virtual traders are only able to bid at the zonal level in the day-ahead market. Our analysis at the node level identified several areas of poor convergence between day-ahead and real-time prices. These include: (a) load pockets on the east and west ends of Long Island, (b) the Staten Island generation pocket in New York City, (c) the Niagara station in the West Zone, and (d) the Oswego Complex in the Central Zone. These areas exhibit poor convergence primarily because of differences between the day-ahead and real-time offer prices of generation and/or modeling of transmission facilities. [39]

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[39] See Appendix section I.G for the node-level analysis.

Convergence of Ancillary Service Prices

Day-ahead prices for operating reserves were systematically higher than real-time prices in 2019. This day-ahead premium 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).[40]

The average day-ahead premium increased from 2018 to 2019 partly because reserves prices were lower in real-time, reflecting lower opportunity costs that are associated with lower energy prices and a significant reduction in reserve shortages because of lower load levels.

The NYISO established the New York City operating reserve requirements on June 26, 2019. This included a 500 MW 10-minute reserve requirement and a 1,000 MW 30-minute reserve requirement, both of which have a $25/MWh operating reserve demand curves.[41] The low operating reserve demand curves for these requirements limited the average price impact from these changes. However, increasing the demand curve from the current $25/MWh level could lead to inappropriately high RT prices and inefficient scheduling until dynamic reserve modeling can be implemented. Thus, we support the implementation of dynamic reserve requirements, which will allow NYISO to increase the demand curves to more efficient levels. This will help schedule resources efficiently during operating conditions such as TSAs.[42]

B. Day-Ahead Load Scheduling and Virtual Trading

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.

Under-scheduling load generally leads to lower day-ahead prices, while over-scheduling can raise day-ahead prices above real-time prices. Table 8 shows the average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2018 and 2019 for several regions.[43] Overall, net scheduled load in the day-ahead market was

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40 The availability offers of generators in the day-ahead market consider several factors. See Appendix section I.H for a discussion of factors that could influence day-ahead reserve offers.

41 See "Establishing Zone J Operating Reserves" by Ashley Ferrer at MC meeting on March 27, 2019.

42 See Recommendation #2015-16 in section XI.

43 Figure A-41 to Figure A-48 in the Appendix also show these quantities on a monthly basis.

roughly 94 percent of actual NYCA load during daily peak load hours in 2019, two percentage points less than in 2018 (96 percent).

Figure 7 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 highest in the West Zone, where the majority of load is located just downstream of transmission bottlenecks. Day-ahead net load scheduling continued to be high in New York City and Long Island, which are also downstream of congested interfaces. Over-scheduling generally helped improve the commitment of resources in these three areas.

Table 8: Day-Ahead Load Scheduling versus Actual Load
By Region, During Daily Peak Load Hours, 2018 – 2019

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2018	95.4%	0.0%	-2.6%	17.4%			110.2%
	2019	97.6%	0.0%	-3.3%	21.3%			115.7%
Central NY	2018	114.9%	0.0%	31.3%	4.0%			87.7%
	2019	119.3%	0.0%	35.2%	6.0%			90.1%
North	2018	94.7%	0.0%	-46.3%	4.6%			53.0%
	2019	90.9%	0.0%	-40.4%	4.0%			54.4%
Capital	2018	95.9%	0.0%	-6.5%	4.5%			93.8%
	2019	97.1%	0.0%	-9.3%	5.1%			92.9%
Lower Hudson	2018	73.6%	23.2%	-14.8%	13.2%			95.2%
	2019	76.1%	22.0%	-24.4%	10.8%			84.5%
New York City	2018	70.1%	26.0%	-1.2%	5.9%			100.8%
	2019	70.6%	25.9%	-1.6%	5.3%			100.2%
Long Island	2018	101.0%	0.0%	-3.3%	7.7%			105.5%
	2019	97.3%	0.0%	-4.0%	10.2%			103.5%
NYCA	2018	89.1%	11.5%	-11.0%	7.6%	-2.4%	1.1%	95.9%
	2019	90.0%	11.4%	-13.4%	8.2%	-3.1%	1.0%	94.1%

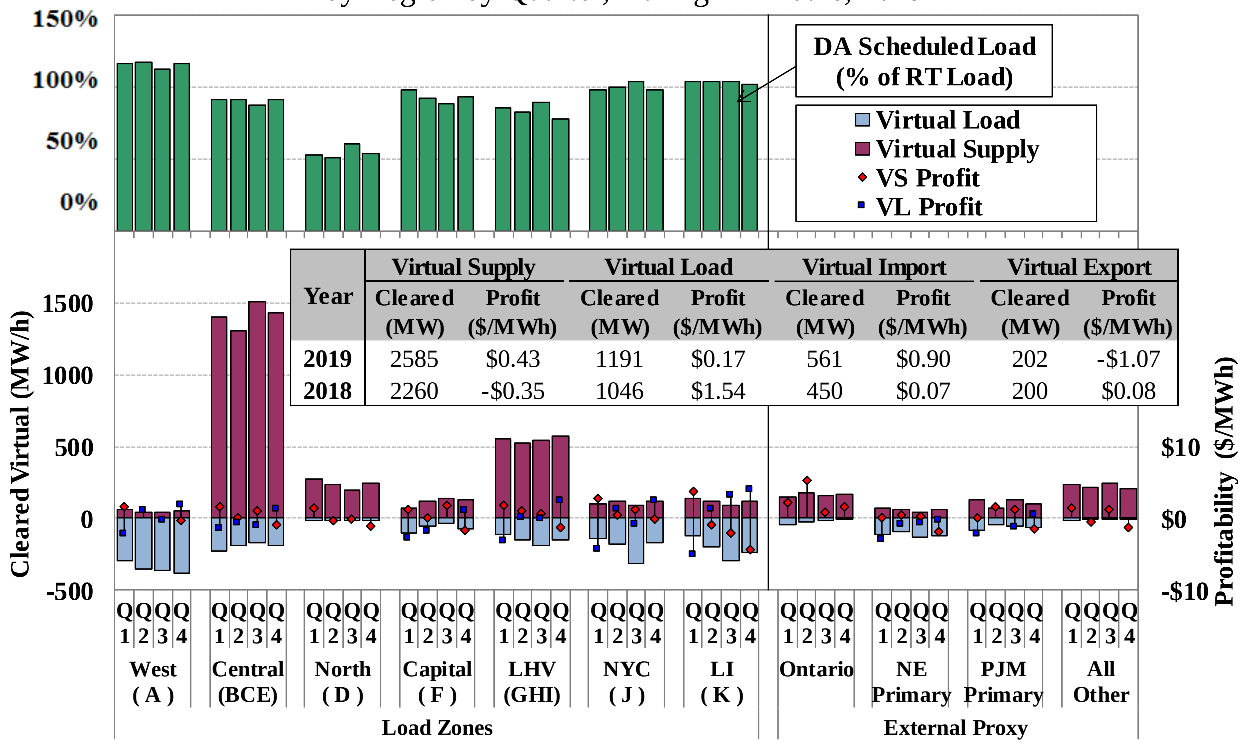
Net load scheduling was generally lower in other regions. Load was under-scheduled most in the North Zone where real-time prices can fall to very low (negative) levels when transmission bottlenecks limit the amount of renewable generation and imports from Ontario and Quebec that can be delivered south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

Net load scheduling fell significantly in the Lower Hudson Valley region reflecting an increase in virtual supply positions. New generation additions in Lower Hudson Valley have contributed to increased real-time congestion in the G-I regions in recent years. The increase in virtual supply positions in Zone G seem to be in response the increase in congestion.

As discussed above, net day-ahead scheduling patterns are determined by virtual trading activity to a large extent. Figure 7 summarizes virtual trading by location in 2019, including internal zones and external interfaces.[44] The pattern of virtual trading did not change significantly in 2019 from the prior year, with the exception of the Hudson Valley which saw a noticeable increase in virtual supply. 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, During All Hours, 2019



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)
2019	2585	$0.43	1191	$0.17	561	$0.90	202	-$1.07
2018	2260	-$0.35	1046	$1.54	450	$0.07	200	$0.08

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 $14 million in 2019, indicating that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability was $0.35 per MWh in 2019, higher than the $0.22 per MWh in 2018. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market.

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

V. TRANSMISSION CONGESTION AND TCC CONTRACTS

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.

This section discusses three aspects of congestion management in 2019:

- Day-ahead and real-time transmission congestion
- Transmission constraints on the low voltage network
- Transmission congestion contracts

In addition, general congestion patterns are summarized in the Market Trends and Highlights section, while the Market Operations section also evaluates elements of congestion management.[45]

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.[46] 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.

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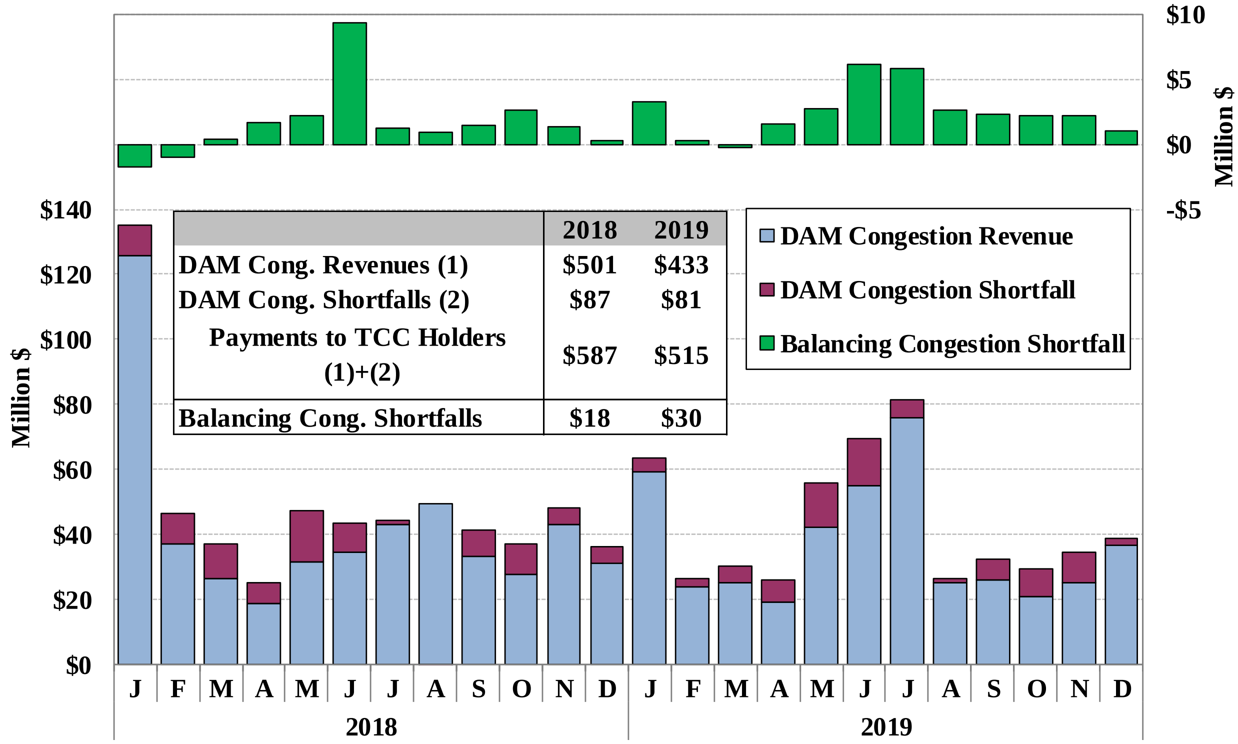
45 The Market Operations section evaluates pricing during transmission shortage conditions (IX.A), the use of reserve units to manage New York City transmission congestion (IX.C), and the coordinated congestion management with PJM (IX.E).

46 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 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.

Figure 8: Congestion Revenues and Shortfalls
2018 – 2019



	2018	2019
DAM Cong. Revenues (1)	$501	$433
DAM Cong. Shortfalls (2)	$87	$81
Payments to TCC Holders (1)+(2)	$587	$515
Balancing Cong. Shortfalls	$18	$30

Day-ahead congestion revenues and shortfalls fell 14 and 5 percent from 2018 to 2019, respectively. In contrast, balancing congestion shortfalls rose 62 percent from 2018 to $30 million in 2019.

Day-Ahead Congestion Revenues

The decrease in day-ahead congestion revenues from 2018 and 2019 was likely primarily due to:

- Lower load levels and less frequent peaking conditions in both winter and summer months, which reduced network flows and eased transmission bottlenecks; and

- Lower natural gas prices and lower gas price spreads across New York, which decreased the redispatch cost of relieving congestion.

The reduction occurred primarily in the first quarter of 2019, where day-ahead congestion revenues fell $82 million (or 43 percent) from the first quarter of 2018. This was driven primarily by much milder weather conditions in 2019. The first quarter of 2018 had several periods with severe weather conditions leading to high load levels and extreme gas prices. In particular, the eight-day cold spell ("Bomb Cyclone") at the beginning of 2018 accounted for $56 million of day-ahead congestion revenues.

In spite of the overall reduction, day-ahead congestion revenues rose modestly in the second and third quarters because the NYISO began to price congestion on 115 kV constraints in the West Zone. The NYISO incorporated these constraints in the day-ahead and real-time markets in December 2018. This change reduced priced congestion on the higher voltage (e.g., 230 kV) network, but it also led to a large increase in overall priced congestion in the West Zone. As a result, day-ahead congestion revenues in the West Zone rose 81 percent from 2018 to $93 million in 2019, roughly 80 percent of which accrued on the 115 kV constraints.

Transmission outages played a key role in congestion patterns. Fewer costly outages from North to Central New York, into and within New York City, and across the primary interface between NYISO and ISO-NE contributed to less congestion. On the other hand, the Central-East interface had more costly outages, partly offsetting its overall reduction in congestion.

In addition, changes in congestion patterns from 2018 to 2019 were also affected by the following factors:

- Reduced CRM values for small transmission facilities in December 2018 – The CRM values for 115 kV facilities were unnecessarily high to conform with approved tariff rules when the constraints were first modeled. This, contributed to higher congestion over these constraints. The NYISO filed tariff revisions with the FERC to allow the use of lower CRM values for small facilities, effective in December 2018.[47]
- Improved modeling of the Niagara Plant in December 2018 – This better recognizes the different congestion impacts of 115 kV and 230 kV units at the plant, enabling the NYISO to more efficiently manage congestion in the West Zone and allowing more of the plant's output to be deliverable through the West Zone.[48]
- The closure of the South Ripley-to-Dunkirk 230 kV line – The line was normally "open" but has been "closed" since April 2019. This line flowed an average of more than 150

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47 The use of CRMs is discussed further in Section IX.A.

48 The enhanced modeling of the Niagara generator is discussed in subsection B.

MW from the West Zone to PJM after April 2019, increasing congestion across the West Zone and increasing the effect of volatile loop flow around Lake Erie.

- The removal of additional in-series segments of 115 kV lines from the market models in September 2019 – Modeling in-series line segments led to excessively large shortage pricing outcomes when multiple such segments were priced simultaneously by the GTDC. We found that West Zone lines accounted for the vast majority of the occurrences and estimated an increase of $16 million in real-time congestion and an increase of $0.36/MWh in average LBMPs in the West Zone.[49]
- Inclusion of West Zone 115 kV constraints in the M2M process with PJM beginning in November 2019 – Although this did not have significant impact on West Zone 115 kV congestion in 2019 given its timing of implementation, it should help reduce congestion in the West Zone going forward.[50]

Day-Ahead Congestion Shortfalls

Day-ahead shortfalls occur when the day-ahead network capability is less than the capability reflected in TCCs, while day-ahead surpluses (i.e., negative shortfalls) occur when day-ahead schedules across a binding constraint exceed the amount of TCCs. Table 9 shows total day-ahead congestion shortfalls for selected transmission facility groups.[51] Day-ahead congestion shortfalls fell 5 percent from $87 million in 2018 to $81 million in 2019.

Table 9: Day-Ahead Congestion Shortfalls in 2019

Facility Group	Annual Shortfalls ($ Million)
North to Central	$7.2
NYC Lines	$9.0
Primary NY/NE Interface	$6.1
West Zone Lines	$40.8
Central to East	$19.5
All Other Facilities	-$1.1

West Zone Lines – These exhibited a dramatic increase in shortfalls, accounting for 50 percent of all shortfalls in 2019. The increase was driven primarily by newly modeled 115 kV facilities, which accounted for $36 million of the shortfall. The 230 kV facilities accounted for less than $5 million of shortfalls. Although transmission outages were an important driver of shortfalls, less than $10 million were allocated to NYTOs for this reason. The remaining over $30 million

49 This issue is discussed further in Section III.F in the Appendix

50 This change is discussed further in Section IX.D

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

of shortfalls resulted from other factors. The different assumption of Lake Erie Circulation between the TCC auction and the day-ahead market is one of the key factors.

Central-East interface. The interface accounted for $19 million of shortfalls in 2019, up $10 million from 2018. The increase resulted from more costly planned transmission outages and more generator AVR outages for generators at the Oswego Complex.

New York City – $9 million of shortfalls accrued on New York City lines in 2019, down 58 percent from 2018 because of fewer costly transmission outages. The high shortfalls in 2018 were driven primarily by the lengthy outage of one of the Dunwoodie-Motthaven 345 kV lines (for more than 4 months), while there was no such lengthy outage in 2019.

North to Central & Primary NY/NE Interface – These lines accounted for noticeably less shortfalls primarily because of fewer costly planned transmission outages.

The NYISO allocates day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[52] In 2019, the NYISO allocated 47 percent of the net total day-ahead congestion shortfalls in this manner, down noticeably from prior years. Transmission owners can schedule outages in ways that reduce labor and other maintenance costs, but these savings should be balanced against the additional uplift costs from congestion shortfalls. Allocating congestion shortfalls to the responsible transmission owners is a best practice for RTOs because it provides incentives to minimize the overall costs of transmission outages.[53]

Congestion shortfalls that are not allocated to individual transmission owners are currently allocated to statewide. These shortfalls typically result from modeling inconsistencies between the TCC auction and day-ahead market that do not result from the outage of a NYCA facility. This includes factors such as transmission outages in neighboring control areas (which cannot be allocated to the responsible TO); the assumed level of loop flows (which is significant for West Zone lines as mentioned earlier); 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

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

53 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.

Schedule 1 charges.[54] Table 10 shows total balancing congestion shortfalls by transmission facility group.[55]

Table 10: Balancing Congestion Shortfalls in 2019 [56]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, ABC & JK PARs	$4.8
Other Factors	$8.8
North to Central	$2.0
Central to East	
Ramapo, ABC & JK PARs	-$2.1
Other Factors	$0.1
TSA Constraints	$5.3
Long Island Lines	$4.6
Hudson Valley to Dunwoodie	$2.3
External	$4.2
All Other Facilities	$1.6

Balancing congestion shortfalls were generally small on most days in 2019, but rose notably on several days when unexpected real-time events occurred. TSA events were a key driver of high balancing shortfalls on these days, during which the transfer capability into Southeast New York was greatly reduced in real time, accounting for more than $5 million of shortfalls in 2019. Unplanned and forced outages were another key driver. For example, more than $2 million of shortfalls accrued on the corridor from the Hudson Valley Zone to the Dunwoodie Zone during a two-day period in June because of the outages of the Buchannan South-Millwood 345 kV line the Ladentown-Buchannan 345 kV line.

Balancing congestion shortfalls accruing on the West Zone constraints rose significantly from roughly $2 million in 2018 to nearly $14 million in 2019. More than $10 million accrued on the 115 kV constraints that were incorporated into the market models beginning in December 2018. Unplanned transmission outages and clockwise loop flows accounted for nearly $9 million of balancing shortfalls. The impact of clockwise loop flows has increased since the closure of the South Ripley-to-Dunkirk line in April 2019. Another $5 million of shortfalls were attributable to the operations of the NJ-NY PARs (i.e., Ramapo, A, & JK PARs). Their operations under the

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

55 Section III.E in the Appendix provides additional results, a detailed description for these transmission facility groups, and a variety of reasons why their actual flows deviated from their day-ahead flows.

56 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.

M2M JOA with PJM has provided significant benefits to the NYISO in managing congestion on coordinated transmission flow gates – for example, contributing $2 million of *surpluses* from relieving Central-East congestion in 2019. However, it frequently aggravated congestion on some non-M2M constraints such as the West Zone 115 kV constraints with contributing shortfalls. The NYISO has worked with PJM to incorporate these 115 kV constraints in the M2M process beginning in November 2019, This should improve overall congestion management going forward.

Long Island lines accounted for nearly $5 million of shortfalls in 2019, 55 percent of which was attributable to the inconsistency between the assumption of Pilgrim PAR flows in the day-ahead market and its real-time operation. The PAR flows have significant impact on both the 138 kV and the 69 kV constraints, while only the 138 kV network is currently modeled in the day-ahead and real-time markets. In real-time operations, the PAR adjustments to manage the 138 kV constraints were often limited by its impact on the 69 kV network, and vice versa. However, this limitation is not reflected in the day-ahead market or in the real-time commitment (“RTC”) model, making the congestion-effects of the Pilgrim PAR hard to predict. We have recommended that the NYISO model 69 kV constraints in the day-ahead and real-time models that are typically relieved by redispatching wholesale generators and/or adjusting PAR-controlled lines.[57]

More than $4 million of balancing congestion shortfalls accrued on external interfaces in 2019, 93 percent of which occurred on the Ontario interface. Most of the shortfalls resulted from a relatively small number of intervals when the Ontario transfer limit was derated below the day-ahead limit to relieve congestion on downstream constraints in real-time. During such circumstances, imports initially scheduled in the day-ahead market were able to buy-out of their schedules at extreme negative real-time prices when very low offer prices (can be as low as the current offer floor of -$1000/MWh, which is an arbitrarily low level) were on the margin to set the interface prices. [58] We recognize that although it is generally most efficient to secure the downstream facilities directly in the real-time market model, there may be circumstances when reducing the transfer limit of the external interface may be appropriate. To reduce unnecessarily high uplift that occurs during such circumstances, we recommend that the NYISO raise the offer floor to -$150/MWh.[59]

57 See Recommendation #2018-1. Management of these constraints is analyzed in Subsection B.

58 Imports scheduled in the day-ahead market often an offer in real-time at the offer floor.

59 See Recommendation #2019-2.

B. Transmission Constraints on the Low Voltage Network in New York

Transmission constraints on 138 kV and above facilities 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 New York were resolved primarily through out-of-market actions until May 2018 when the NYISO started to incorporate certain 115 kV constraints in the market software, 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/constraint transfer limit that functions as a proxy for the limiting transmission facility; and
- Adjusting PAR-controlled line flows on the higher voltage network.

Table 11 shows the frequency of out of market actions to manage constraints on the low voltage network in six areas of New York. The table summarizes the number of days in 2018 and 2019 when OOM actions were used in each area.

Table 11: Constraints on the Low Voltage Network in New York [60]
Summary of OOM Days for Managing Constraints, 2019

Area	# of Days with OOM Actions	
	2018	2019
West Zone	260	50
Central Zone	35	18
North Zone	81	53
Capital Zone	130	83
Central Hudson	11	34
Long Island	121	156

OOM actions fell substantially in Western New York from 2018 to 2019 primarily because of three market enhancements in 2018:

- Modeling 115 kV constraints between northern and central New York in May;
- Modeling 115 kV constraints in western New York in December; and

60 See Section III.C in the Appendix for more details on the use of various resource types in 2019.

- Improving modeling of the Niagara plant to better recognize the different congestion impact from its 115 kV and 230 kV units in December.[61, 62]

The reduction was most evident in the West Zone, where OOM actions occurred on only 50 days in 2019, down from 260 days in 2018. In the past, operator actions to manage the 115 kV constraints in Western New York frequently involved:

- Limiting low-cost imports from Ontario and Quebec;
- Limiting generation from the Niagara Plant and other renewable generation;
- Limiting flows using surrogate interface constraints (e.g., Dysinger East interface, West to Central interface, and an increased CRM for Packard-Sawyer 230 kV lines); and
- Using phase-angle regulators in Northern New York (i.e., the Saint Lawrence PARs) and Southeast New York (i.e., the Ramapo and ABC PARs).

The first three manage congestion by reducing low-cost generation and may raise LBMPs in other areas. The last one may exacerbate congestion in other areas 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.[63] Therefore, these modeling enhancements have improved the efficiency of scheduling and pricing in Western New York as well as in other areas of New York that were adversely affected by congestion management of Western New York facilities in the past.

Nonetheless, there were still many days when OOM actions were used to manage congestion in:

- Capital Zone – 83 days – The vast majority occurred in the first half of the year when the Bethlehem units were frequently dispatched down to manage nearby 115 kV constraints. This need has been greatly mitigated following the completion of transmission upgrades in mid-2019.
- North Zone – 53 days – Most of these were to commit the Saranac generator out-of-market to relieve N-1 transmission constraints that are not modeled in the day-ahead and real-time markets.
- West Zone – 50 days – Most of these were to manage congestion on the Gardenville-to-Dunkirk 115 kV lines, which the NYISO still does not model in the day-ahead and real-time market software.
- Long Island – 156 days – These are evaluated below in detail.

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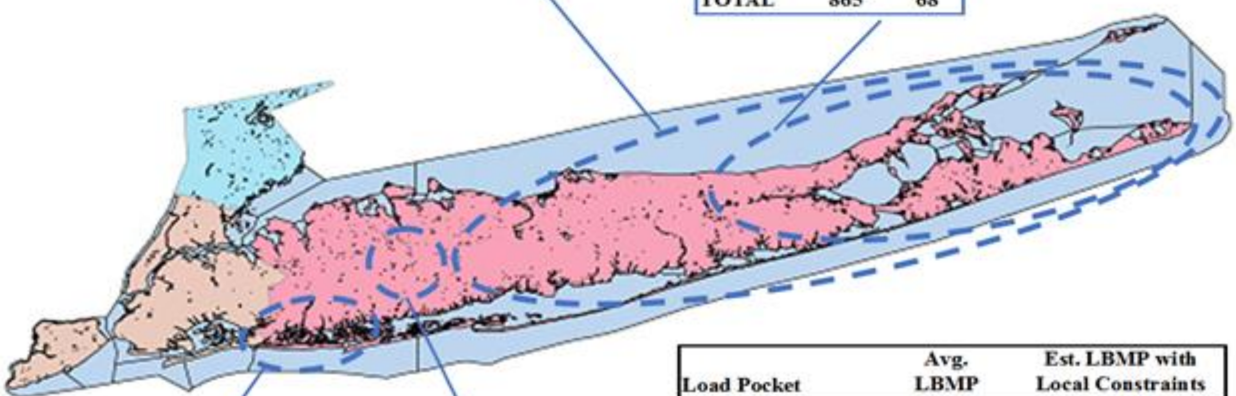
61 The plant consists of seven generating units on the 115 kV network and 18 generating units on the 230 kV network, and output can be shifted among these generators to manage congestion on both networks and make more of the plant's output deliverable to consumers.

62 See *Niagara Generation Modeling Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

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

Unlike the other areas, OOM actions to manage low-voltage network congestion became more frequent on Long Island. Figure 9 evaluates the frequency of actions to manage 69 kV constraints on Long Island in 2019. Since most load pockets are fed by 69 kV and 138 kV transmission circuits, the figure shows how frequently this congestion is managed through the day-ahead and real-time markets (for 138 kV facilities) and how frequently it is managed through out-of-merit actions (for 69 kV facilities). An inset table shows the average estimated LBMP in each pocket reflecting the marginal costs of resources used to manage 69 kV constraints.

Figure 9: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2019



East of Northport	#Hours	#Days
69kV	754	48
138kV	1173	114
TOTAL	1860	145

East End	#Hours	#Days
69kV	71	8
138kV	71	13
TVR	813	61
TOTAL	865	68

Valley Stream	#Hours	#Days
69kV	624	53
138kV	6601	353
TOTAL	6780	354

Brentwood	#Hours	#Days
69kV	381	48
138kV	2	1
TOTAL	383	49

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$32.69	$33.68
East End	$36.19	$55.41
East of Northport	$34.76	$38.82
Valley Stream	$36.84	$39.39

OOM dispatch was frequently used to manage 69 kV constraints and voltage constraints (i.e., TVR requirement on the East End of Long Island). These actions reduced LBMPs in Long Island load pockets, resulting in roughly $10 million of BPCG uplift in 2019. Our estimates show that if these constraints had been modeled in 2019 average LBMPs would have:

- Risen 12 percent in the East of Northport load pocket of Long Island and
- Risen 53 percent in the East End load pocket on Long Island.[64]

64 Our 2018 SOM report showed comparable estimates for 2018, which would have led to a 17 percent increase in average LBMPs in East of Northport load pocket and 44 percent in the East End load pocket.

Managing these constraints with OOM actions rather than in the market software has led to at least two types of inefficient scheduling. First, when a 69 kV facility is constrained flowing into a load pocket, the local TO often provides relief by starting a peaking unit in the pocket. However, when this is done on short notice and there is no least-cost economic evaluation of offers, the local TO often runs oil-fired generation with a relatively high heat rate when much lower-cost resources could have been scheduled to relieve the constraint.

Second, since PARs usually control the distribution of flows across a group of parallel 138 kV and 69 kV transmission facilities flowing into a load pocket, adjusting a PAR too far in one direction will tend to overload one set of facilities while relieving another, and vice versa. If the local TO frequently adjusts a PAR to relieve 69 kV congestion, the NYISO will have difficulty predicting the PAR schedule since it does not model the constraint that the PAR is adjusted to relieve. Consequently, errors in forecasting the schedules of the Pilgrim PAR on Long Island in the day-ahead market and in the RTC model has been a significant contributor to unnecessary operation of oil-fired generation, balancing market congestion residuals, and inefficient scheduling by RTC.

Therefore, setting LBMPs on Long Island more efficiently to recognize the marginal cost of satisfying local transmission constraints would provide better signals for future investment. This is particularly important now as investment decisions are being made to determine how best to satisfy reliability needs and environmental policy objectives in Long Island over the coming decades. Hence, we recommend the NYISO consider modeling the 69 kV constraints and East End TVR needs (using surrogate thermal constraints) in the market software.[65]

C. 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 2018/19 and Summer 2019 Capability Periods (i.e., November 2018 to October 2019).

Table 12 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[66]

- 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.

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65 See Recommendation #2018-1. We analyze the impact of modeling these constraints in the market software on incentives for investment in new and existing resources in Section VIII.

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

- 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.

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2018 to October 2019 netted a total *loss* of $57 million. Overall, the net profitability for TCC holders in this period was *negative* 18 percent (as a weighted percentage of the original TCC prices), compared to 19 percent in the previous 12-month period.

In this reporting period, TCC buyers netted sizable profits on: a) intra-zonal transmission paths in West Zone and Central Zone; and b) inter-zonal transmission paths sinking at the West Zone. Their net profitability ranged from 34 percent to 107 percent. This was in line with changes in the congestion pattern from the prior year. For example, the day-ahead congestion revenues that accrued on transmission facilities in West Zone rose 81 percent from 2018 to 2019 (for the reasons discussed in Section II.E).

Table 12: TCC Cost and Profit

Winter 2018/19 and Summer 2019 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$19	$11	59%
Central Zone	$16	$18	107%
New York City	$20	-$10	-47%
Long Island	$11	-$3	-26%
All Other	$4	$3	90%
Total	**$71**	**$19**	**28%**
Inter-Zonal TCC			
Other to West Zone	$63	$21	34%
Other to Central New York	$37	-$20	-55%
UpState to New York City	$44	-$22	-52%
New York to New England	$59	-$17	-29%
All Other	$37	-$38	-102%
Total	**$240**	**-$76**	**-32%**

Conversely, TCC buyers netted a relatively large loss on most of transmission paths in other regions. For example, TCC buyers netted a 55 percent loss on transmission paths sinking in Central New York, as the day-ahead congestion revenues that accrued on the "North to Central" facilities fell 68 percent from 2018 to 2019. Similarly, TCC buyers netted a 50 percent loss on transmission paths from upstate into and within New York City, consistent with a 43 percent reduction in day-ahead congestion from 2018 to 2019. These results show that the TCC prices generally reflect 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 Balance-of-Period Auctions. 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.

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 six controllable lines that are collectively able to import up to roughly 2.7 GW directly to downstate areas.[67,68] 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 13 summarizes the net scheduled imports between New York and neighboring control areas in 2018 and 2019 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[69] Total net imports from neighboring areas averaged 2.9 GW during peak hours in 2019, down 9 percent from 2018.

Table 13: Average Net Imports from Neighboring Areas
Peak Hours, 2018 – 2019

Year	Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2018	1,372	733	442	-564	164	561	30	201	253	3,192
2019	1,327	686	492	-810	155	610	37	224	179	2,900

Controllable Interfaces

As in prior years, imports from neighboring control areas satisfied slightly more than 30 percent of the demand on Long Island in 2019. The Neptune line was typically fully scheduled during

67 The controllable lines are: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, the Neptune Cable, and the A line.

68 The A line is a PAR-controlled line that interconnects NYC to New Jersey. Currently, the line is scheduled as part of the primary PJM to NYISO interface and is also operated under M2M JOA with PJM in real-time. This line is further evaluated in Sections IX.D and IX.E.

69 Figure A-61 to Figure A-64 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

daily peak hours absent outages/deratings. Average Neptune imports rose by 50 MW in 2019 because of fewer transmission outages. Net imports over the Cross Sound Cable and the 1385 line varied in a manner similar to the primary New England interface – lower in the winter when natural gas prices in New England were much higher than natural gas prices on Long Island.

Net imports to New York City over the Linden VFT and the HTP interfaces fell by an average of 50 MW in peak hours from 2018 to 405 MW in 2019. The decrease occurred primarily on the HTP interface because of lower LBMPs in the 345 kV system of New York City for reasons discussed in Section II.E. Net imports across these two controllable interfaces typically rise in the winter when natural gas prices in New York tend to rise relative to those in New Jersey.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces fell nearly 15 percent from 1,985 MW in 2018 to 1,695 MW in 2019 in peak hours. Net imports from Quebec to New York accounted for 78 percent of net imports across the primary interfaces in 2019. Variations in Quebec imports are normally caused by transmission outages on the interface.[70]

Average net imports from Ontario fell modestly (by 50 MW) from 2018 to 2019. This was driven largely by smaller energy price spreads between Ontario and NYISO markets. In 2019, the real-time price on the New York side was consistently higher by an average of roughly $5.30/MWh, down significantly from the $11.30/MWh in 2018.

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, consistent with the spreads in gas prices between markets in the winter (i.e., New England > New York > PJM). Overall, New York was typically a net importer from PJM and a net exporter to New England across their primary interfaces. Net exports to New England increased by 44 percent from 2018 to 2019, reflecting fewer lengthy transmission outages at the interface in 2019.[71]

B. Unscheduled Power Flows around Lake Erie

Unscheduled power flows (i.e., loop flows) around Lake Erie have significant effects 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

70 Imports from Quebec were high in most months of 2019 but fell notably in several shoulder months (e.g., April May, and October) because of transmission outages.

71 In 2018, the New Scotland-Alps and the Long Mountain-Pleasant Valley 345 kV lines were OOS for roughly four months, during which the NY/NE interface limit was reduced from 1400 MW to around 500 MW.

into service in April 2012, large fluctuations in loop flows are still common.[72] In December 2018, the NYISO made two market enhancements to improve the efficiency of congestion management in the West zone: (a) incorporating 115 kV constraints in the day-ahead and real-time markets; and (b) improved modeling of the Niagara Plant. Notwithstanding these improvements, our analysis shows a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows in 2019.[73]

When loop flows were clockwise or swung rapidly in the clockwise direction, NYISO operators often reduced transmission scheduling limits when necessary to ensure line flows remained at acceptable physical levels. In addition, to better manage the effects of loop flows, the NYISO:

- Increased the CRM on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 line from 20 MW to 40 MW in June 2019 and to 60 MW in late July 2019.
- Changed the loop flow assumption in RTC from 0 MW when loop flows were counter-clockwise at the time RTC initialized to 100 MW when loop flows were clockwise by less than 100 MW (or counter-clockwise). Before this change was implemented in late November 2019, our analysis suggested the change would be beneficial overall. However, it would be best to modify the market software to allow adjustments that vary according to loop flows and other conditions at the time RTC initialized.[74]
- Moved the electrical location of the IESO proxy bus in its scheduling models to a more appropriate location. Specifically, the proxy bus was moved from the Bruce 500 kV station to the Beck 220 kV station (near the Niagara station in New York) on April 21, 2020. The new location will result in a more accurate representation of the effects of interchange with Ontario.[75]

In addition to the effects of loop flows on West Zone congestion, we also discuss the effects on: (a) inconsistencies between RTC and RTD in Subsection D; (b) the transient congestion (along with other factors that are not explicitly modeled in the dispatch software) in Section IX.F; and (c) the day-ahead and balancing congestion shortfall uplift in Section V.A.

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 2019. As in previous reports, we find that while external transaction scheduling by market participants provided

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

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

74 See Section V.E in the Appendix for more details.

75 See “Relocating the IESO Proxy Bus” by Tolu Dina, at December 3, 2019 MIWG meeting.

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 14 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets in 2019.[76] Participant-scheduled transactions 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 $126 million in production cost savings during 2019.

Table 14: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2019

	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	-896	$0.25	45%	-$0.3	80	$0.72	54%	$1
Ontario	706	$6.92	86%	$45	13	$5.33	51%	$4
PJM	342	$0.13	71%	$10	31	-$0.29	60%	$5
Controllable Ties								
1385 Line	51	$0.35	67%	$2	-24	$0.21	52%	$1
Cross Sound Cable	126	$1.39	71%	$4	6	$3.49	54%	$0.5
Neptune	588	$6.93	93%	$35	-5	$6.85	49%	$0.2
HTP	87	$3.19	90%	$4	63	$2.61	71%	$4
Linden VFT	152	$4.14	91%	$8	71	$2.07	71%	$3

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 $53 million in day-ahead production cost savings was achieved in 2019 across the five controllable ties. The Neptune Cable accounted for 66 percent of these savings because the interface was generally fully scheduled and the New York price was roughly $6.9 per MWh higher on average in 2019.

Likewise, day-ahead transactions between Ontario and New York flowed in the efficient direction in 86 percent of hours. This was largely because the price on the New York side was consistently higher by an average of nearly $7 per MWh in 2019. As a result, a total of $45 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 generally more active at the interfaces with CTS ("Coordinated

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

Transaction Scheduling”, including the NY/NE primary interface and all four interfaces with PJM). Real-time adjustments in flows were more frequent across the VFT and HTP ties than in prior years, as market participants more actively responded to real-time price variations by increasing net flows into the higher-prices region across these ties. As a result, a total of $7 million in real-time production cost savings was achieved in 2019 from the real-time adjustments over these two controllable ties, up from $4 million in 2018.

We evaluate real-time price convergence between New York and neighboring areas (in Section IV.B in the Appendix) and find that price convergence at the NY/NE CTS interface was better than at the primary 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.

D. Evaluation of Coordinated Transaction Scheduling

Coordinated Transaction Scheduling (“CTS”) allows two neighboring RTOs to exchange and use real-time market information to clear market participants’ intra-hour external transactions more efficiently. CTS has at least two 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 schedules transactions much closer to the operating time. Hourly LBMP-based schedules are established up to 105 minutes in advance, while CTS schedules are determined less than 30 minutes ahead when more accurate system information is available.

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

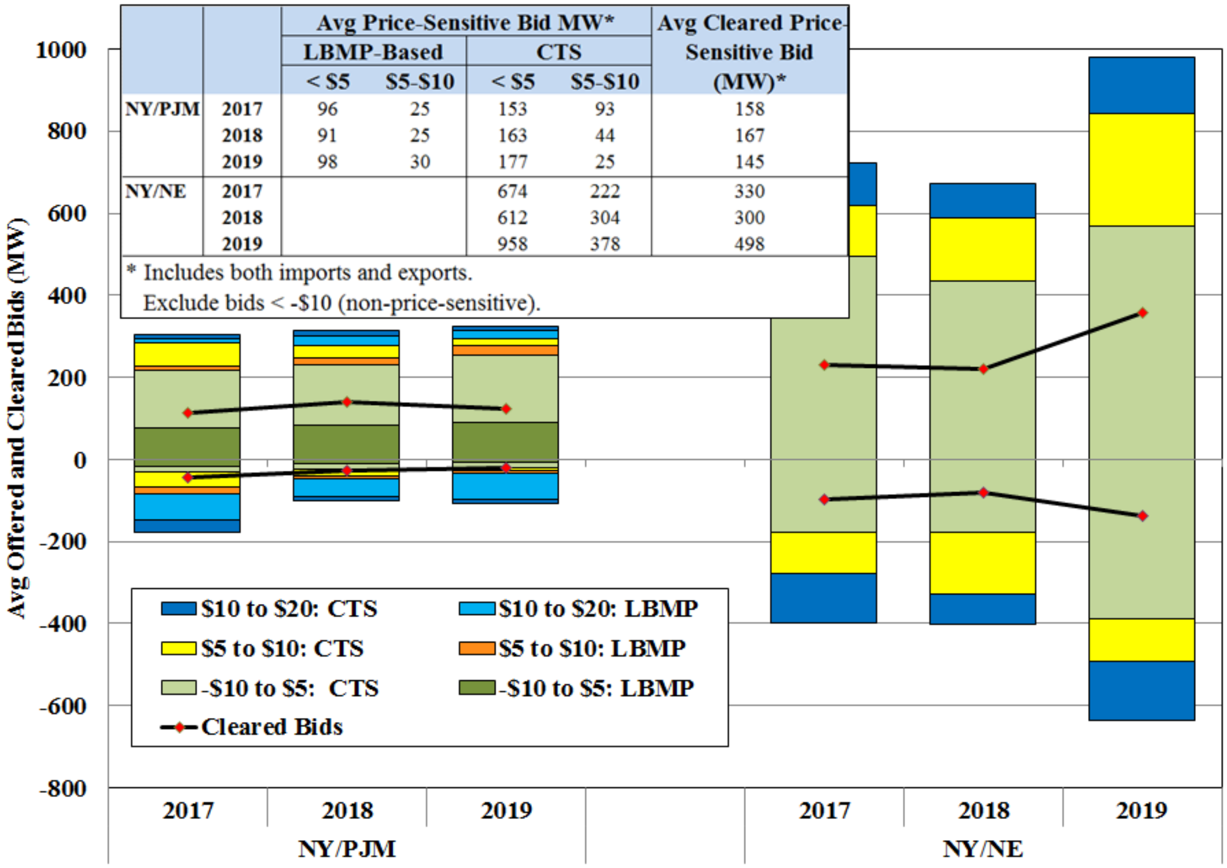
Under CTS, traders submit bids that are scheduled if the RTOs’ forecasted price spread is greater than the bid price, so the process requires a sufficient quantity of price-sensitive bids. Figure 10 evaluates the price-sensitivity of bids at the PJM and ISO-NE interfaces, showing the average amount of bids at each interface during peak hours (i.e., HB 7 to 22) from 2017 to 2019.[77] Only CTS bids are allowed at the ISO-NE interface, while CTS bids and LBMP-based bids are used at

77 Figure A-66 in the Appendix shows the same information by month for 2019.

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.[78]

Figure 10: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2017-2019



		Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
		LBMP-Based		CTS		
		< $5	$5-$10	< $5	$5-$10	
NY/PJM	2017	96	25	153	93	158
	2018	91	25	163	44	167
	2019	98	30	177	25	145
NY/NE	2017			674	222	330
	2018			612	304	300
	2019			958	378	498

* Includes both imports and exports.
Exclude bids < -$10 (non-price-sensitive).

The average amount of price-sensitive bids at the PJM interface was significantly lower than at the New England interface in each year from 2017 to 2019. An average of roughly 750 MW (including both imports and exports) were offered between -$10 and $5 per MWh at the New England interface over this three-year period, substantially higher than the 260 MW offered in the same price range at the PJM interface. Likewise, the amount of cleared price-sensitive bids at the New England interface was more than double the amount cleared at the PJM interface.

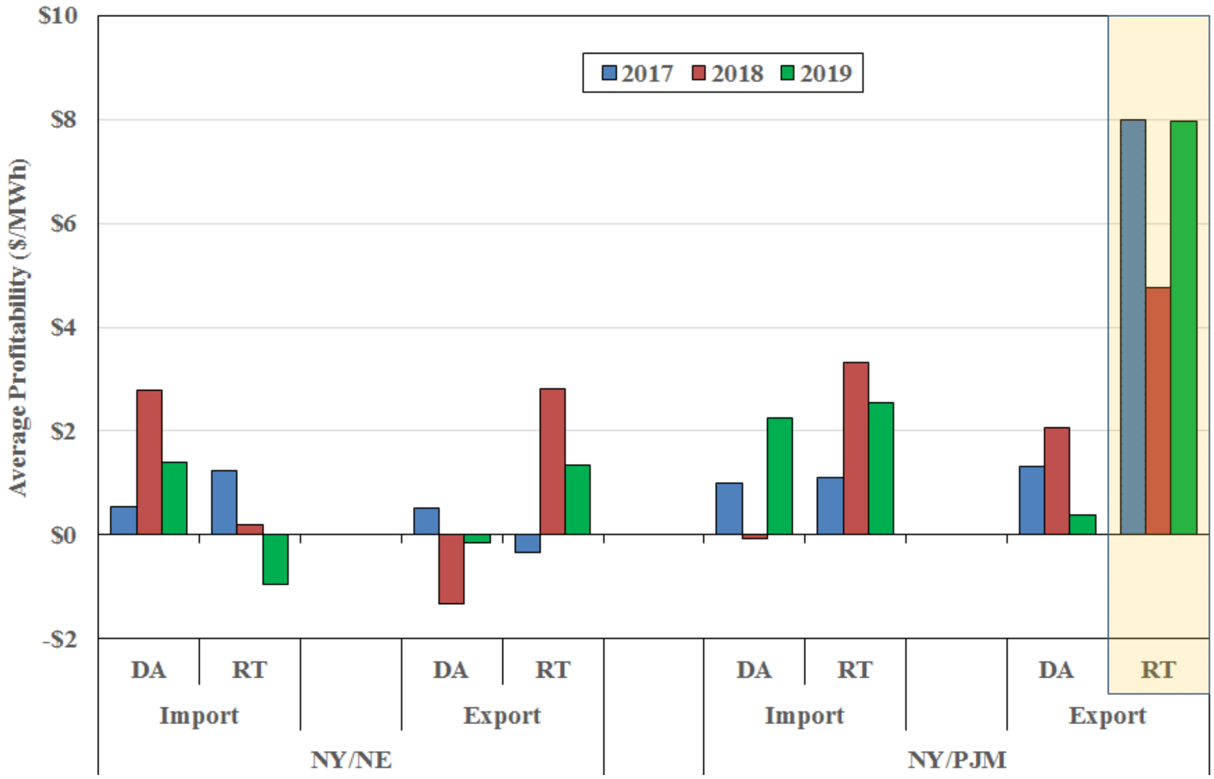
The differences between the two CTS processes are largely attributable to the large fees that are imposed at the PJM interface, while there are no substantial transmission charges or uplift charges on transactions between New York and New England. Typically, the NYISO charges physical exports to PJM at a rate ranging from $4 to $8 per MWh, while PJM charges physical

78 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.

imports and exports a transmission rate and uplift allocation that averages less than $3 per MWh.[79] 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 average gross profitability of scheduled transactions (not including fees mentioned above) at the two CTS interfaces from 2017 to 2019. The gross profitability of scheduled transactions (including both imports and exports) averaged roughly $0.7 per MWh over the three-year period at the primary New England interface, indicating this is generally a low-margin trading activity.

Figure 11: Average Gross Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2017-2019



At the PJM border, the average gross profitability was moderately higher for scheduled imports and far higher for scheduled exports. 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.

79 Although PJM increased its Transmission Service Charge substantially to firm imports/exports to $6.34/MWh in 2020, it kept the non-firm transactions at a low level of $0.67/MWh. This change to firm transactions has little impact on CTS transactions.

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.[80]

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.[81]

The potential savings in production costs were generally higher at the New England interface because the higher liquidity of bids at that interface contributed to larger and more frequent intra-hour interchange adjustments. In 2019, this adjustment (from our estimated hourly schedule) occurred in 77 percent of intervals at the New England interface, compared to 58 percent at the PJM interface. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that in 2019,[82]

- $4.1 million of potential savings were realized at the New England interface; and
- $0.1 million were realized at the PJM interface.

Although the actual production cost savings fell from $5.5 million in 2018 at the New England interface, the decrease resulted from smaller differences in energy prices between the two markets because of partly lower loads and gas prices in 2019. The price forecasting actually became better on both sides of the border as NYISO forecast error improved from 24 percent in 2018 to 21 percent in 2019 and ISO-NE forecast errors improved from 20 to 19 percent.

On the other hand, the actual production cost savings at the PJM border was minimal ($0.1 million) in 2019, consistent with prior years. A large portion of projected savings were over-projections because of price forecast errors. NYISO forecast errors at the PJM border worsened modestly from 26 percent in 2018 to 28 percent in 2019, while PJM forecast errors worsened from 35 percent to 43 percent.

80 See Section XI, Recommendation #2015-9.

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

82 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.

Our analysis found that the unrealized savings were much larger in periods when the forecast errors exceeded $20 per MWh. Most of the unrealized savings occurred in a small number of intervals with large forecast errors, particularly at the PJM interface.

The efficient performance of CTS depends on the accuracy of price forecasting, so it is important to evaluate market outcomes to identify sources of forecast errors. The remainder of this subsection summarizes our analysis of factors that contributed 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 2019. 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.[83] 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 2019.[84] Similar to our findings from previous reports, our evaluation identified three primary groups of factors that contributed most to RTC price forecast errors in 2019.[85] First, transmission network modeling issues were the most significant category, accounting for 42 percent of the divergence between RTC and RTD in 2019. In this category, key drivers include:

- Errors in the forecasted flows over PAR-controlled lines between the NYISO and PJM (i.e., the 5018, A, and JK lines), which occur primarily because the RTC forecast: (a) does not have a module that predicts variations in loop flows from PJM across these lines, (b) assumes that no PAR tap adjustments are made to adjust the flows across these lines, and (c) assumes that NYISO generation re-dispatch does not affect the flows across these lines although it does.
- Variations in the transfer capability available to NYISO-scheduled resources that result primarily from: (a) transmission outages, (b) changes in loop flows around Lake Erie and from New England, (c) inaccuracies in the calculation of shift factors of NYISO units, which are caused by 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.

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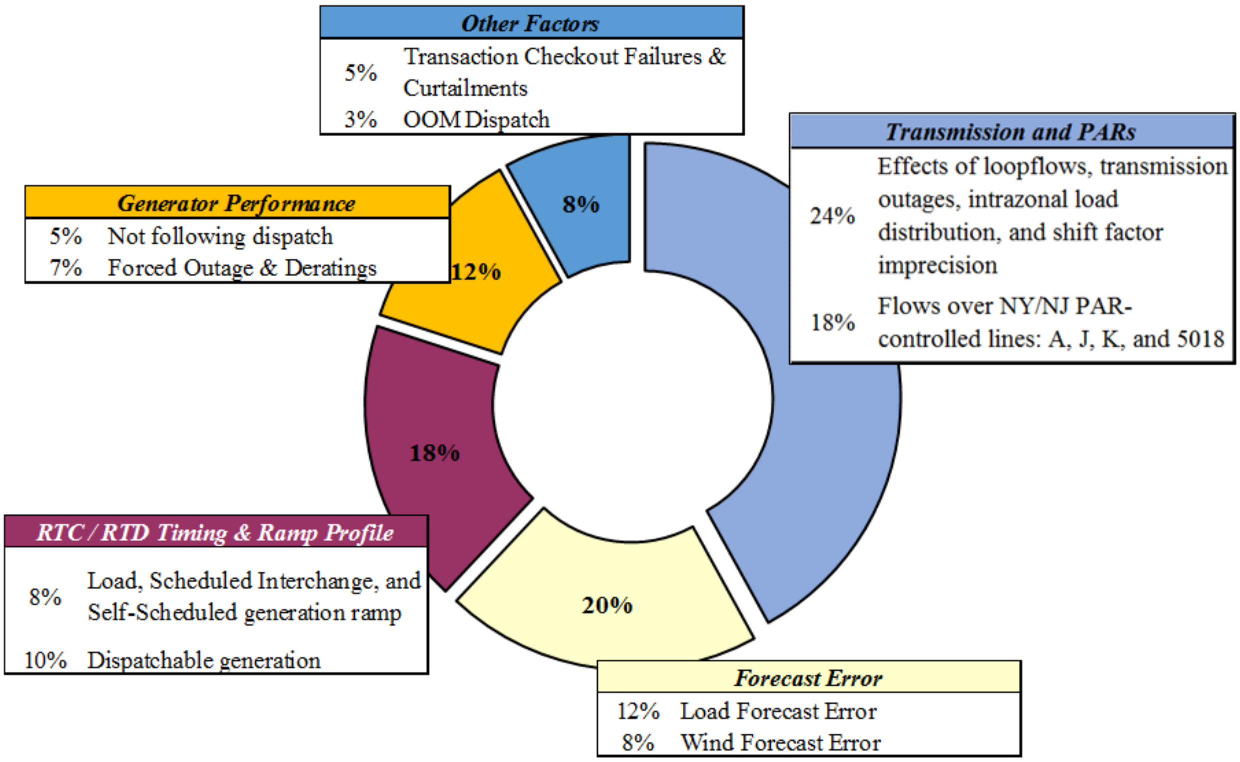
83 See Section IV.D in the Appendix for a detailed description of this metric (illustrated with examples).

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

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

The contribution of this category rose from 31 percent in 2018. The increase occurred primarily on the West Zone constraints as most of the 115 kV constraints have been managed through market software rather than out-of-market operator actions since December 2018.

Figure 12: Detrimental Factors Causing Divergence Between RTC and RTD
2019



Second, errors in load forecasting and wind forecasting were another large contributor to price differences between RTC and RTD. This accounted for 20 percent of the overall divergence between RTC and RTD in 2019. [86]

Third, the next largest category, which accounted for 18 percent of the divergence between RTC and RTD prices in 2019, was related to inconsistencies in assumptions related to the timing of the RTC and RTD evaluations. This includes inconsistent 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).[87]

86 In this case, the forecast error is the difference between the forecast used by RTC and the forecast used by RTD, however, even the RTD forecast can differ from the actual real-time value.

87 Figure A-72 in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transactions.

We have made recommended improving 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,[88] 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.

Addressing sources of inconsistency between RTC and RTD is important for improving the performance of CTS with ISO New England and PJM under present market conditions. It will be even more important in the foreseeable future as the NYISO is exploring the possibility of scheduling the Ontario interface every 15 minutes. More importantly, RTC will be taking more responsibility for scheduling flexible resources that can start-up in 45 minutes or less. The resource mix of New York is changing away from traditional fossil-fuel generation towards: (a) intermittent renewable generation that will increase uncertainty of resource availability in real time, and (b) new types of peaking generators and energy storage resources that must be deployed based on a short-term forecast of system conditions. A better-performing RTC will more efficiently schedule flexible resources in timely response to quick changes in system conditions, which are critical for successful integration of renewables and energy storage resources.

88 The NYISO revised the cap of 0 MW on the counter-clockwise loop flows in the RTC initialization to 100 MW (for counter-clockwise loop flows and clockwise loop flows under 100 MW) in late November 2019. We support this improvement but still recommend the NYISO implement varying optimal levels of adjustments to different levels of loop flows.

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 clearing price in each Locality, the capacity market facilitates investment where it is most valuable for satisfying the NYISO's planning needs. This section summarizes the capacity market results, discusses the cost of reliability improvement from additional capacity, 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 2019

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices. Table 15 shows average spot auction prices for each locality for the 2019/20 Capability Year and year-over-year changes in key factors from the prior Capability Year.

Table 15: Capacity Spot Prices and Key Drivers by Capacity Zone [89]
2019/20 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2019 Margin (% of Requirement)	10.5%	10.9%	7.5%	11.9%
Net Change from Previous Yr	2.0%	4.0%	-3.7%	1.8%
Average Spot Price				
2019/20 Price ($/kW-month)	$0.68	$2.49	$8.64	$2.90
Percent Change Yr-Yr	-65%	-57%	50%	-24%
Change in Demand				
Load Forecast (MW)	-519	-72	68	-136
IRM/LCR	-1.2%	-2.2%	2.3%	0.6%
ICAP Requirement (MW)	-1,002	-417	322	-109
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-73	210	76	-19
SCR (MW)	-47	-26	-33	-3
Import Capacity (MW)	-178			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	-2%	1%	5%	32%

89 See Section VI in the Appendix for more details.

Capacity prices rose in New York City, but fell significantly in the other localities. These changes were driven primarily by changes to the Installed Reserve Margin ("IRM") and Locational Capacity Requirements ("LCRs"), with variations in supply and peak load contributing to a lesser extent. Key factors include:

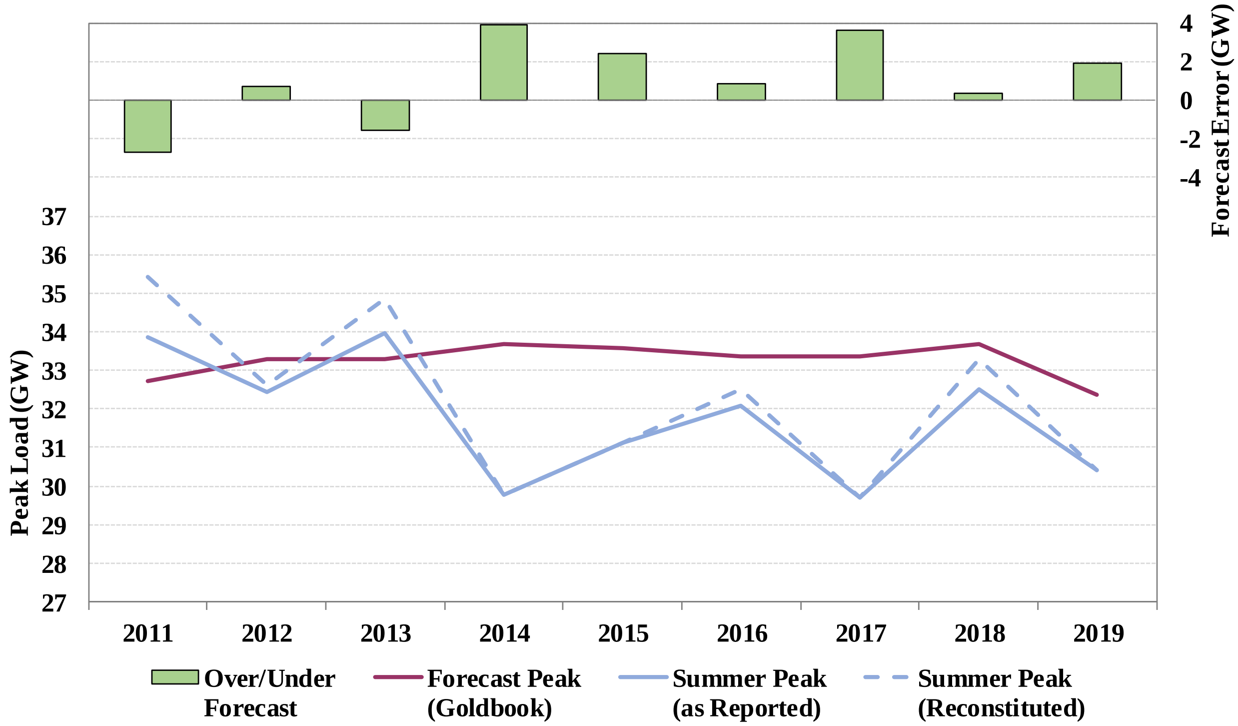
- In the Rest of State, spot prices fell 65 percent primarily due to a 483 MW reduction in the IRM and a 519 MW reduction in the load forecast. Reductions in supply due to unit retirements, fewer imports, and increased exports helped mitigate some of the price reduction from the lower requirement.
- In the G-J Locality, spot prices fell by 57 percent largely due to the 345 MW reduction in the LCR. Additionally, year-over-year increase in the internal capacity from the entry of Bayonne II (August 2018) and capacity uprates at several units further increased the UCAP margin.
- In New York City, spot prices rose by 50 percent. The primary drivers of this were the year-over-year (a) increase in the LCR of 254 MW, and (b) increase in the load forecast of 68 MW.
- In Long Island, spot prices fell by 24 percent largely due to surplus conditions in the Winter 2019/20, so the prices on Long Island were determined by the NYCA demand curve. In addition, the ICAP Requirement on Long Island fell by 109 MW because of a lower load forecast.

Peak load forecasts are an important driver of the capacity requirements. Peak load forecasts have been relatively flat over the past decade as modest economic growth and adoption of energy efficiency have led to relatively flat capacity requirements. The drive to conserve energy, add distributed solar, and shift consumption away from peak periods have led to changes in demand patterns that have made it more difficult to forecast peak load.

Figure 13 evaluates the pattern of load forecast error by comparing the actual NYCA peak load against the forecasted peak load from the Gold Book for each year from 2011 through 2019. The figure shows the reconstituted peak load, which represents the reported summer peak load that is adjusted by adding back any load reductions from the NYISO and various utilities' Demand Response activations and actual performance.[90] The forecasted peak load has exceeded the reconstituted peak load in every year since 2014. The peak load was over-forecasted by an average 7 percent over the last six years. It is important to ensure that load forecasting models are kept up-to-date to reflect demand-side changes so that the load forecasts are unbiased.

90 Results for various utilities are not complete for the given time period. The numbers in the chart include reported DR activations on the peak load days for the following utilities: Con Ed: 2011-2019; National Grid: 2015-2019; Orange & Rockland: 2015-2019; Central Hudson: 2015-2019; NYSEG: 2015-2019; NYISO activations span 2011-2019.

Figure 13: Forecasted Peak Load vs. Actual and Reconstituted Peak Loads
2011-2019



B. Enhancements to Capacity Demand Curves

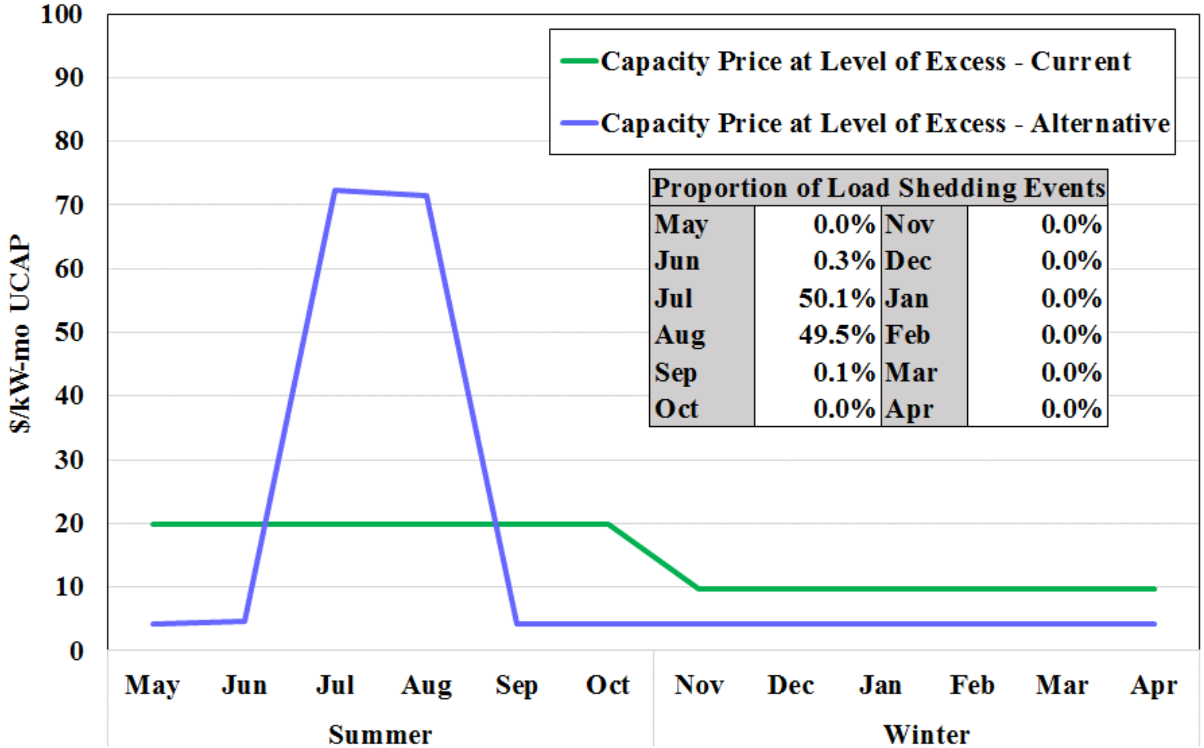
The capacity demand curves used for the monthly spot auctions every month are defined by a number of parameters that include the net CONE of the demand curve unit, the summer peak load, the LCR/IRM, the ICAP to UCAP translation factor for each region, and the Winter-to-Summer ratio. In this subsection, we identify two issues with the implementation of the demand curves and discuss potential changes.

Translation of the Annual Revenue Requirement into Monthly Demand Curves

The capacity market is divided into Summer and Winter Capability Periods of six months each. Within each capability period, the capacity requirements and demand curves remain constant, although the reliability value of resources is much greater in high-demand months (e.g., July) than in low-demand months (e.g., October). This consistency ensures that resource owners have an incentive to coordinate their planned outages through the NYISO outage scheduling process throughout the year. However, it may lead to inefficient incentives for resources that are not consistently available during all 12 months of the year.

Figure 14 shows the clearing price that capacity resources would receive in each month of the year based on the currently effective demand curve for New York City if the supply was equal to the requirement. This clearing price is compared to: (a) the price that would occur if the demand curve was set in order to distribute revenue to each month in proportion to the likelihood of a load shedding event based on the NYISO's resource adequacy model if a minimum of $4/kW-month was placed on the demand curve reference point to provide suppliers with incentives to coordinate outages through the NYISO outage scheduling process.

Figure 14: Monthly Capacity Clearing Prices Compared to Capacity Value
At Level of Excess Conditions



The figure shows that the value of capacity is concentrated during a relatively small number of months. Although most generators sell a uniform amount of capacity during the year, this is expected to change as the resource mix evolves and environmental limitations are imposed during the critical ozone season (May to September).

Hence, we recommend the NYISO translate the annual revenue requirement into monthly capacity demand curves based on:[91]

- Setting a minimum demand curve reference point sufficiently high to ensure resources have incentives to coordinate planned outages with the NYISO; while
- Allocating the remainder of the demand curve unit's annual revenue requirement in proportion to the marginal reliability value of capacity across the 12 months of the year.

These changes would concentrate the incentives for resources to sell capacity into New York during the peak demand months of the summer (i.e., June to August).

91 See Recommendation #2019-4 in Section XI.

Translation of Demand Curve Reference Point from ICAP to UCAP Terms

As part of the demand curve reset study, and the subsequent annual updates, the NYISO and its consultants estimate the net cost of new entry for the demand curve unit. This is estimated in ICAP-terms and then converted into UCAP-terms for each Capability Period based on the regional average derating factor. The derating factor reflects the forced outage rates of the existing fleet as well as UCAP-ICAP ratios of intermittent resources. The demand curve unit being a new unit would have a lower forced outage rate relative to the derating factor. Hence, this method leads the monthly capacity demand curves to be set higher than if the derating factor of the demand curve technology were used. Under this approach, the annual capacity revenue accrued to the demand curve unit at the Level-of-Excess conditions would exceed the annual revenue requirement (i.e. the net CONE) of the unit.

The above inconsistency will become more pronounced as additional intermittent resources are added to the system, which would tend to increase the regional average derating factor. Hence, we recommend the NYISO utilize the estimated forced outage rate of the demand curve unit technology to perform the ICAP to UCAP translation.[92]

C. Cost of Reliability Improvement from Additional Capacity

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 satisfy the "one day in ten year" planning reliability standard. In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the 2020/21 Capability Year.

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:

- Marginal Reliability Impact ("MRI") – The estimated reliability benefit (i.e., reduction in annual loss of load expectation ("LOLE")) from adding an amount 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 (i.e. Level of Excess or "LOE"). 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.

92 See Recommendation #2019-4 in Section XI.

The NYISO recently implemented the Optimized LCRs Method, which was first applied to the 2019/2020 Capability Year. It seeks to minimize capacity procurement costs: (a) assuming the system is at an LOLE of 0.1 days per year over the long-term, (b) while taking the NYSRC-determined IRM as given, and (c) imposing minimum transmission security limits ("TSL") for each locality. The Optimized LCRs Method minimizes procurement costs (i.e., capacity clearing price times quantity) rather than investment costs (i.e., the marginal cost of supply in the capacity market). Minimizing procurement costs is inefficient because it does not select the lowest cost supply to satisfy reliability. Minimizing investment costs is efficient because it selects the lowest cost resources (just as the real-time market selects the lowest cost resources to satisfy load and ancillary services requirements).

Table 16 shows the estimated MRI and CRI for each load zone and for the Staten Island location that is represented in the GE-MARS topology that is used for the IRM process.[93] For the CPV VEC, Cricket VEC, and Athens areas, it was not possible to assess the MRI using the technique described above because this technique does not capture the effect of supply on dynamic transfer limits in MARS. Consequently, the values for these areas are TBD (To Be Determined) because they cannot be measured without additional modifications to MARS. We intend to measure these using a tool that simulates MARS results and publish the results in a subsequent report.

Table 16: Marginal Reliability Impact and Cost of Reliability Improvement by Locality
2020/21 Capability Year

Zone	Net CONE of Demand Curve Unit *$/kW-yr*	NYCA LOLE at Excess Level	LOLE with 100 MW UCAP Addition	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*
A	$105	0.071	0.067	0.0044	$2.4
B	$105		0.066	0.0050	$2.1
C	$105		0.066	0.0050	$2.1
D	$105		0.066	0.0051	$2.1
E	$105		0.066	0.0050	$2.1
F	$105		0.066	0.0050	$2.1
G	$157		0.066	0.0057	$2.8
H	$157		0.065	0.0062	$2.5
I	$157		0.065	0.0062	$2.5
J	$192		0.065	0.0068	$2.8
K	$150		0.064	0.0069	$2.2
Other Areas					
Staten Island (J3)	$192	0.071	0.070	0.0015	$12.8
CPV VEC	$157		TBD	TBD	
Cricket VEC	$157		TBD	TBD	
Athens	$105		TBD	TBD	

93 See Section VI.F of the Appendix for methodology and assumptions used to estimate the CRI and MRI for each area.

The Optimized LCRs Method has reduced the range in CRI values across load zones compared to previous years. Nevertheless, the range between the minimum CRI-value location of Zones B-F (at $2.1 million per 0.001 events) and the maximum CRI-value location of Zone J (i.e., NYC at $2.8 million per 0.001 events) is still significant.

The results reveal substantial differences in the MRI values for specific areas within a capacity zone. For instance, the MRI for Staten Island is only 0.001—significantly lower than the Zone J MRI. This disparity suggests that generation in Staten Island is over-priced.

The CRI values for some zones exhibit considerable differences from those of other zones within the same capacity pricing region under the current configuration. Large disparities within a region imply it should be broken into multiple regions to ensure that capacity is priced efficiently. However, the MRI and the CRI for each zone depend on several factors that could evolve in the future. For instance:

- Zone G has a higher CRI than zones H and I even though UCAP resources in these areas receive the same price currently. The assumed retirement of Indian Point Unit 2 (“IP 2”) in Zone H in April 2020 leads to a reduction in the MRI of Zone G relative to zones H and I. This indicates that the constraints between zones G and H are binding after the retirement of IP2, which may be exacerbated after the retirement of IP 3.
- Zone A exhibits a higher CRI than zones B to F. This reflects transmission constraints within Zone A that limit the deliverability of most (but not all) Zone A generation to the rest of NYCA. The Western New York public policy transmission project could help eliminate disparities between Zones A and B.
- Recognition in the demand curve reset of lower net new entry costs in central New York would reveal disparities between Zones A to E and Zone F.[94]

This subsection introduces two concepts for evaluating the efficiency of capacity prices:

- the MRI – quantifies the impact on reliability of capacity in a particular area; and
- the CRI – relates the reliability impact of capacity to the net cost of new entry in each area.

The next three subsections apply these concepts to support recommendations in three areas. Subsection D recommends a mechanism for setting prices in the capacity market that is simpler and more efficient than the current processes, Subsection E recommends a framework for compensating transmission investments for the capacity value of the transmission, and Subsection F recommends techniques for quantifying the capacity value of new transmission projects in the NYISO’s transmission planning processes.

94 See comments of the Market Monitoring Unit in Commission Docket ER17-386-000, December 9 2016.

D. Optimal Locational Marginal Cost Pricing of Capacity Approach

As discussed in Subsection C, in an efficient capacity market, prices should be aligned with the reliability value of capacity in each locality. In this subsection, we highlight concerns with the existing framework for pricing capacity, propose an alternative approach to setting capacity prices, and discuss how our approach would address the concerns with the existing framework. Our approach to capacity pricing would:

- Reduce the costs of satisfying resource adequacy needs,
- Provide efficient incentives for investment under a wide range of conditions,
- Improve the adaptability of the capacity market to future changes in transmission network topology and in the resource mix, and
- Reduce the complexity of administering the capacity market as the system evolves.

Issues with Current Capacity Market Framework

The current framework for determining capacity prices involves estimating Net CONE and creating a demand curve for each existing locality, determining the optimal amounts of capacity to be procured in each locality at the LOE using the LCR Optimizer, and setting the spot prices based on the locality's capacity margin relative to the prevailing demand curve. This approach can result in misalignment between the value and compensation of capacity for some types of capacity in some locations. We summarize below several aspects of the current framework that can lead to inefficient capacity market outcomes.

- The NYISO currently sets the LCRs by minimizing the total procurement cost of capacity in a 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 typically prevail.
- Under the NYISO's Optimized LCRs method, the LCRs depend directly on the Net CONE estimate for each zone. Hence, errors in estimating the Net CONEs can lead to an inefficient allocation of capacity across zones.
- The rules for creating New Capacity Zones will not lead to the timely creation of a new capacity zones in several circumstances (e.g., after Indian Point retires). This delay could lead to prices that do not reflect critical resource adequacy needs in some areas. Furthermore, the current rules cannot accommodate differences in pricing within an existing load zone.
- The NYISO's current approach to compensating non-conventional technologies (e.g. battery storage and intermittent resources) relies on periodic studies. These updates are based on resource mix assumptions that do not always represent the penetration levels and/or geographical distribution of the new technologies. Therefore, compensation for new technologies may not be consistent with their actual reliability value.
- The NYISO currently allocates the cost of capacity based on where the capacity is located rather than to the load customers that benefit from the capacity.

- The market does not accurately reflect the value of imports, and the NYISO's approach to accounting for exports from an import-constrained zone relies on a deterministic power flow analysis instead of a probabilistic MARS-based method. Consequently, the basis for pricing import and export transactions is inconsistent with the basis for valuing internal capacity sales.

Proposed Locational Marginal Pricing of Capacity ("C-LMP") Framework

We recommend the NYISO adopt our proposed C-LMP Framework, which would involve: [95]

- Eliminating all existing capacity zones;
- Establishing pricing nodes throughout the State and for each external interface;
- Clearing the capacity market with an auction engine that is based on the resource adequacy model and constraints identified in the planning process.
- Set locational capacity prices that reflect the marginal capacity value at each location.

The C-LMP method involves estimating one key market parameter every four years (concurrent with the Demand Curve reset study) – the optimal level of CRI, which is estimated in a manner similar to the Optimized LCRs method. Under C-LMP, the spot market prices are determined by the optimal CRI level and the MRIs (i.e., incremental reliability impacts) under as-found conditions at the time of the monthly auction.[96] The MRI values would be calculated for: (a) each location in NYISO's planning model for generation (and for each generator type) and load, (b) internal transmission interfaces, (c) external interfaces, and (d) UDRs.

Figure 15 illustrates the inefficiencies with the current framework by comparing the estimated capacity prices under the C-LMP framework and current pricing at LOE conditions for internal capacity resources as well as external interfaces and UDRs.[97] Prices for the current design reflect Net CONE for each existing capacity zone at LOE conditions, with the NYCA price shown for external import regions and the appropriate locality price for UDRs. The bars show the estimated C-LMP calculated for each zone, sub-zone, external import and UDR at LOE conditions based on estimates of MRI in 2019.

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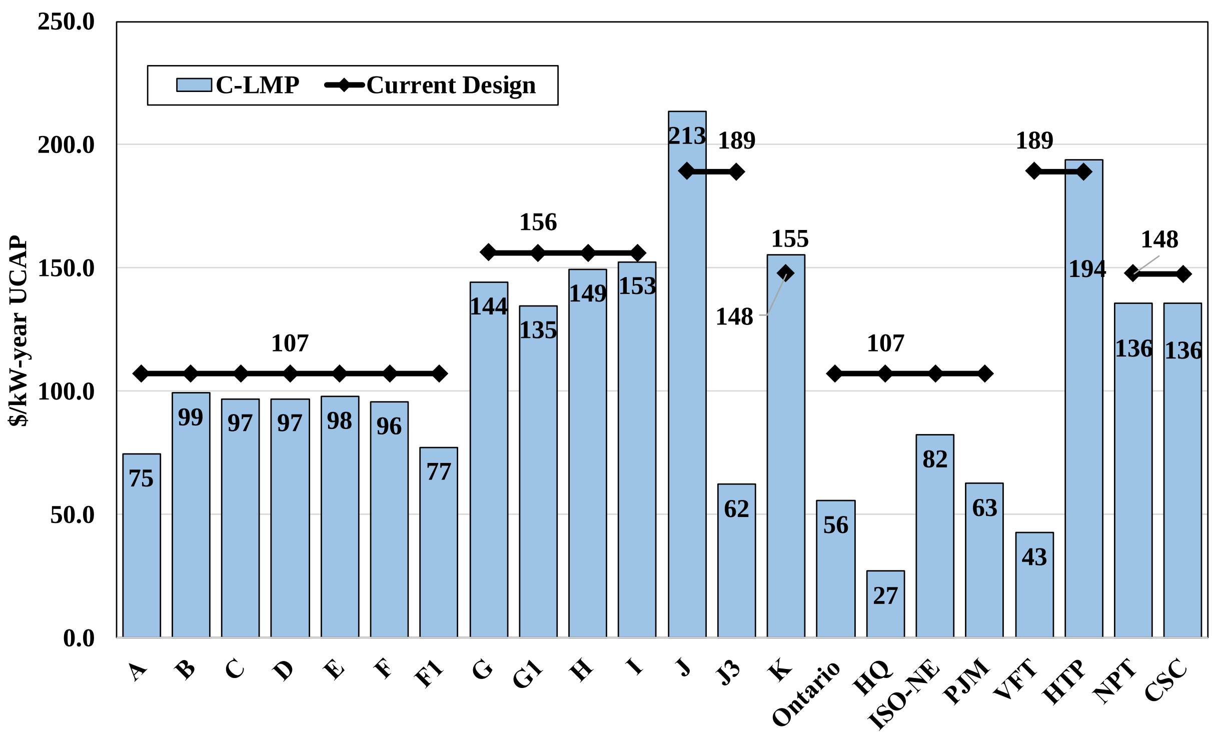
95 The MMU delivered a series of presentations to the Installed Capacity Working Group in the first quarter of 2020 on the conceptual design, implementation, and preliminary simulation results based on the 2019/2020 LCR Case and 2019 demand curves. This section summarizes the results of this analysis. For more information, see ICAPWG presentations dated February 6, February 19, and March 10, 2020.

96 See Recommendation #2013-1c in Section XI.

97 Capacity prices under the C-LMP approach are calculated based on MRI estimates reflecting the 2019/2020 MARS transmission topology and a CRI* of $2.65m per 0.001 change in LOLE. The capacity price for zone z is then calculated as the product of CRI* and MRIz. Status quo capacity prices at LOE conditions reflect the 2019/2020 Demand Curve Net CONE in each location.

The capacity price in each location under the C-LMP approach, by definition, is more aligned with the marginal reliability value of additional capacity in that location. These results highlight the misalignment between prices and value in several locations under the current framework. In particular, the resources in the Staten Island area appear to be vastly over-priced. Similarly, resources in Zone A also appear to be over-compensated under the existing framework. Furthermore, the prices in Zones A and G-I may decline, while Zone K prices may increase under the C-LMP approach. Lastly, the estimated prices for imports are lower under the C-LMP framework, which reflects the lower reliability value of externally located capacity compared to resources located in NYCA.

Figure 15: Capacity Prices at the Level of Excess for C-LMP vs. Existing Framework

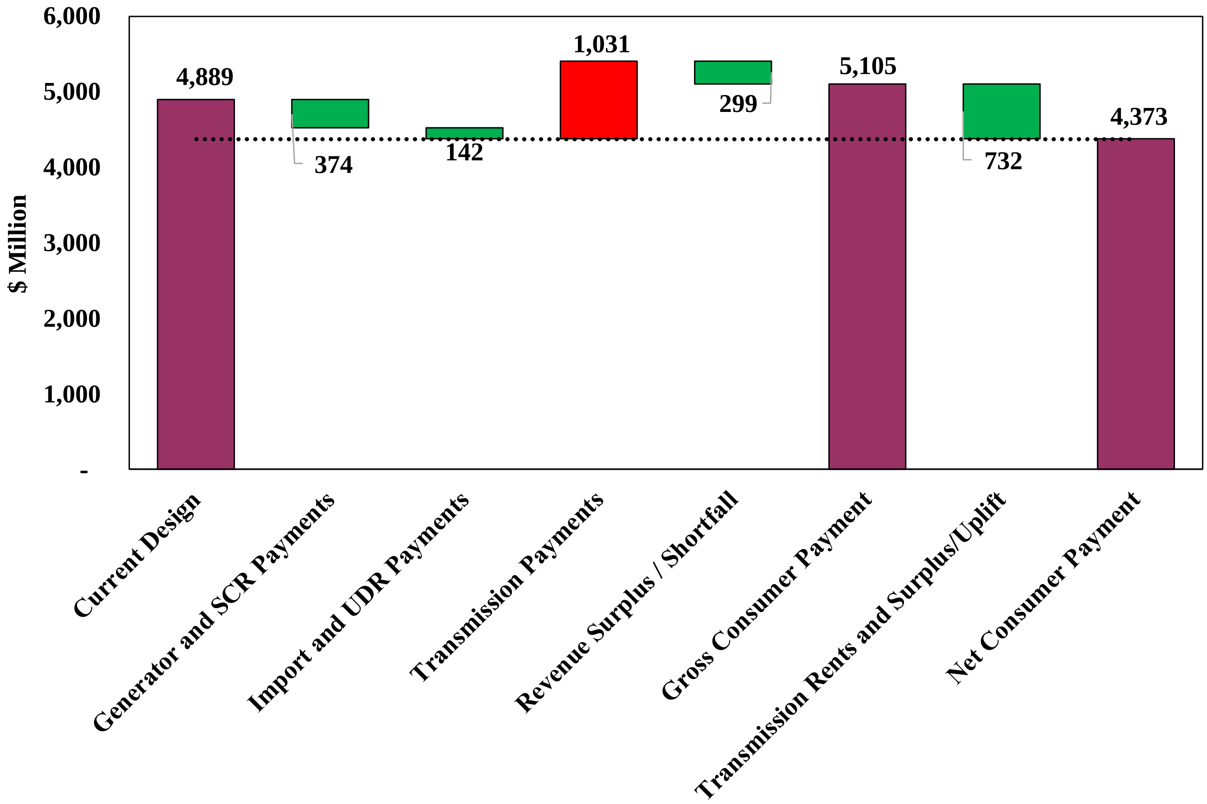


C-LMP would set distinct prices for loads, supply resources, and transmission interfaces. This would: (a) more accurately incorporate the marginal cost of load to the system, (b) recognize the reliability value of transmission and create the energy market-equivalent of TCCs (i.e. FCTRs) for the TOs, and (c) allow for a more equitable allocation of capacity costs across consumers than in the current framework, which allocates capacity costs to the area where the capacity is located rather than the area that benefits from the capacity. Figure 16 shows the change in estimated consumer payments between the current framework and C-LMP framework at 2019/2020 LOE conditions.[98]

98 For additional detail on the assumptions employed for this analysis, see *Locational Marginal Pricing of Capacity – Implementation Issues and Market Impacts* presented to the Installed Capacity Working Group on March 10, 2020.

Overall, the total consumer payment falls by an estimated $516 million under the C-LMP framework. The primary reason for this reduction is the decline in payments to generators in locations that do not provide commensurate reliability value to the system, and to imports that have lower reliability value than internal capacity. Furthermore, payments to TOs can be used to offset embedded costs of transmission infrastructure that are borne by ratepayers, thus lowering the overall net consumer payments.[99, 100]

Figure 16: Consumer Payments at Level of Excess for C-LMP vs. Existing Framework



The C-LMP pricing approach would be less administratively burdensome because it would require fewer approximations and simplifying assumptions than the current framework for determining capacity market parameters and prices. Changes in the network topology that result from new transmission investment and generation additions and retirements would transfer seamlessly from the planning models to the capacity price-setting mechanism. Furthermore, since the C-LMP framework approach sets prices in each area based on its MRI relative to other areas (rather than individual Net CONE values for each area), any bias in the estimation of Net CONE will not bias the distribution of capacity across different areas.

99 This is similar to how revenues from the sale of TCCs in the energy market accrue to transmission owners.

100 Because it separately values the reliability impacts of load and generation, C-LMP may produce a payment surplus or deficit within a given year, which may require uplift or allocation of surplus back to consumers.

Finally, the C-LMP framework will be more adaptable to changes in the generation mix than the current framework, and will facilitate the integration of large quantities of intermittent renewables and energy storage by accurately signaling the reliability value of each resource as the grid evolves. New technologies provide significant reliability benefits but also have a range of characteristics that need to be accounted for efficiently, including: (a) intermittency that is correlated with other resources of the same technology or location, (b) energy storage limitations that limit the duration of output during peak conditions, and (c) small-scale distributed resources that reduce the potential effects of supply contingencies during peak conditions. The C-LMP method captures the interaction of all existing resources when estimating the marginal reliability values for each resource type and location. Hence, it will reward complementarities between technologies, and can help guide investment decisions that cost-effectively achieve policy goals.

E. Financial Capacity Transfer Rights for Transmission Upgrades

Investment in transmission can reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. To provide efficient incentives to invest in transmission, we recommend that transmission developers receive financial capacity transfer rights ("FCTRs") for upgrades.[101] The value of the rights should be based on the C-LMP framework laid out in the previous subsection. This subsection analyzes how FCTRs might affect a transmission investment decision.

Figure 17 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. It shows the comparable information for the Marcy-South Series Compensation ("MSSC") portion of the TOTS project. For the MSSC project, the figure reports the Incremental TCC revenues received by the project under "Energy Market Revenue." The figure reports 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."[102] However, transmission projects do not receive actual revenue for this capacity value.

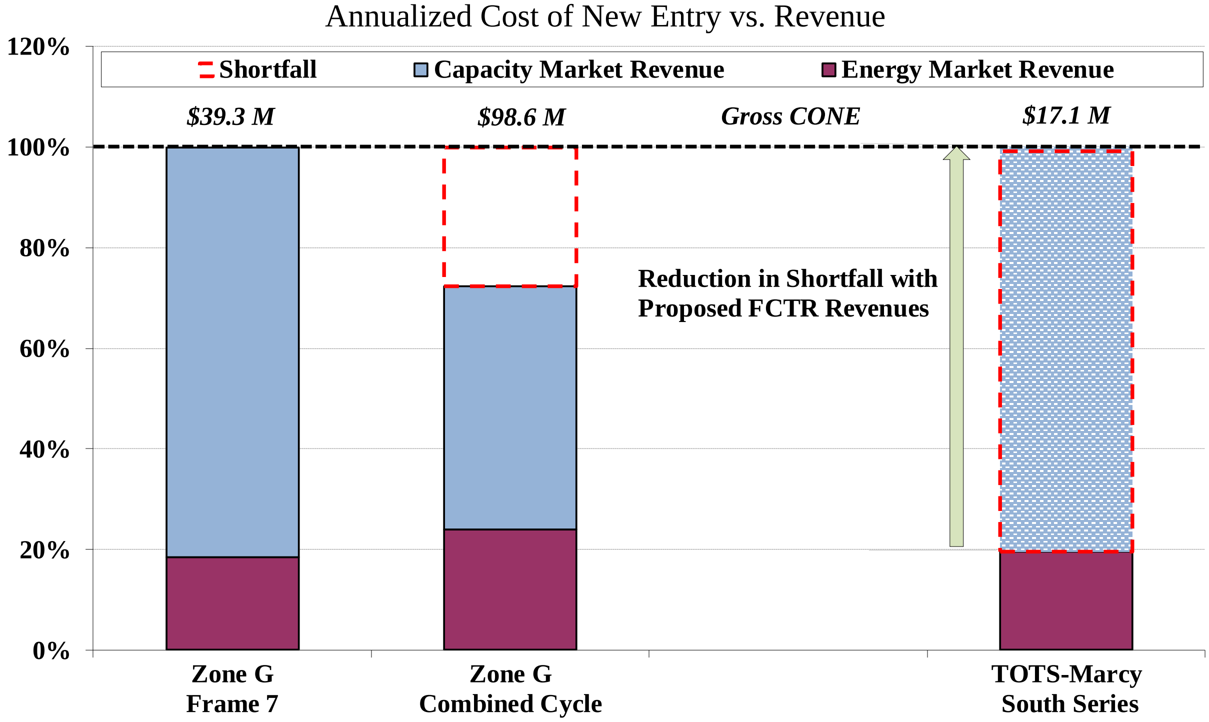
The results illustrate the disadvantages that transmission projects have relative to generation in being compensated for the benefits they provide to the system. Capacity markets provide a critical portion of the incentive (up to 81 percent) for a new generator in Zone G. In the absence of capacity payments to the MSSC project, the project would recoup only 20 percent of its annualized gross CONE. However, granting FCTRs to the project based on its capacity value

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

102 See Appendix Section VI.G for the assumptions and inputs underlying the data shown in the figure.

would have provided an additional 80 percent of the annualized gross CONE in this scenario, making it possible that the project could have recovered most of its costs through energy and capacity revenues. 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.

Figure 17: Valuation of Generation and Transmission Projects at DCR Conditions



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.

F. 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 has evaluated solutions for two Public Policy Transmission Needs ("PPTN"): the Western New York PPTN and the AC Transmission PPTN.[103] The third Public Policy Transmission Planning Process was launched in November 2018. The use of the PPTN assessment process to address congestion in New York highlights deficiencies in the CARIS process. Our reports evaluating proposed PPTN projects have also identified a number of areas for potential improvement in that process.

The need to integrate large quantities of public policy resources, including intermittent generation and other non-conventional technologies, will create opportunities for beneficial transmission investment in the future. Hence, it is important for the transmission planning processes to be able to identify the projects that would achieve public policy goals and/ or reduce congestion in a cost-effective manner. Table 17 summarizes our recommended enhancements to the CARIS and PPTN evaluations, many of which would be applicable to both.[104]

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103 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.

104 For details of recommendations for the PPTN process, see January 22, 2019 comments of Potomac Economics in NYPSC Case 18-E-0623 and February 2019 report *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects*. For details of recommendations for the CARIS process, see Section VII.E of the 2018 State of the Market report.

Table 17: Recommended Improvements to CARIS and PPTN Evaluations

Recommendation	CARIS	PPTN
Assumptions Impacting Project Valuation		
Quantify capacity market benefits of transmission projects in benefit-cost ratio.	✓	✓
Model entry and exit decisions for generators in a manner that is consistent with the expected competitive market outcomes.	✓	✓
Specify policy-related assumptions for resource additions and retirements to be included in study.		✓
Estimate O&M costs of new and decommissioned facilities.		✓
Estimate the cost savings from avoided refurbishment of older facilities.		✓
Enhancements to Forecast Models		
Enhance quality of natural gas and emissions allowance price forecasts	✓	✓
Consider transmission outages and other unforeseen factors in estimating production cost savings.	✓	✓
Improve modeling of operating reserve requirements and deliverability as intermittent resources are added to the system.	✓	✓
Model local reliability requirements in GE-MAPS.	✓	✓
Process Enhancements		
Relax CARIS requirement for approval from 80% of project beneficiaries to facilitate selection of more economic projects.	✓	
Relax threshold of $25 million project size to be considered in CARIS to facilitate optimal project sizing.	✓	

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.[105] In addition, we have submitted comments to the NYPSC recommending improvements to the identification of PPTNs that are more likely to result in cost-effective proposals.[106]

105 See Recommendation #2015-7 in Section XI.

106 See January 22, 2019 comments of Potomac Economics in NYPSC Case 18-E-0623.

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 investment signals by comparing the net revenue that generators would have received from the NYISO markets and to the capital investment costs of the generator.[107] This section:

- Evaluates incentives for investment in new generation,
- Compares net revenues and costs of existing facilities, and
- Analyzes how several of our recommended market design enhancements would affect investment incentives in New York City and Long Island.

A. Incentives for Investment in New Generation

With the adoption of ambitious state policies to attract large amounts of new intermittent renewable generation, it will be critical to provide efficient investment incentives to two types of developer in particular:

- Developers of new intermittent renewable generation – These firms have choices about where to locate and what technologies to use for specific projects. The wholesale market will reward firms that can avoid transmission bottlenecks and generate at times that are most valuable to end users. Developers that expect to receive more in wholesale market revenues will tend to submit lower offers in solicitations by the state and, therefore, are more likely to be selected.
- Developers of new flexible resources – Increased flexibility will be needed to integrate high levels of renewable generation, particularly around critical transmission bottlenecks. Hence, the wholesale market provides nodal price signals that differentiate the value of resources based on their locational value and flexibility, thereby delivering the highest revenues to resources that are most effective in complementing renewable generation.

The analysis in this subsection focuses on how location, technology, and flexibility play key roles in determining whether a particular project will be profitable to a developer.

Figure 18 shows the estimated after-tax Internal Rate of Return ("IRR") of investments in several types of new generation based on the annual average net revenues from 2017 to 2019 and annualized capital and operating costs in 2019.[108] Energy and ancillary services revenues, capacity market revenues, and applicable incentives including renewable energy credits, ITC/PTC tax credits, and bulk storage incentives are included in the calculation of the IRR. The

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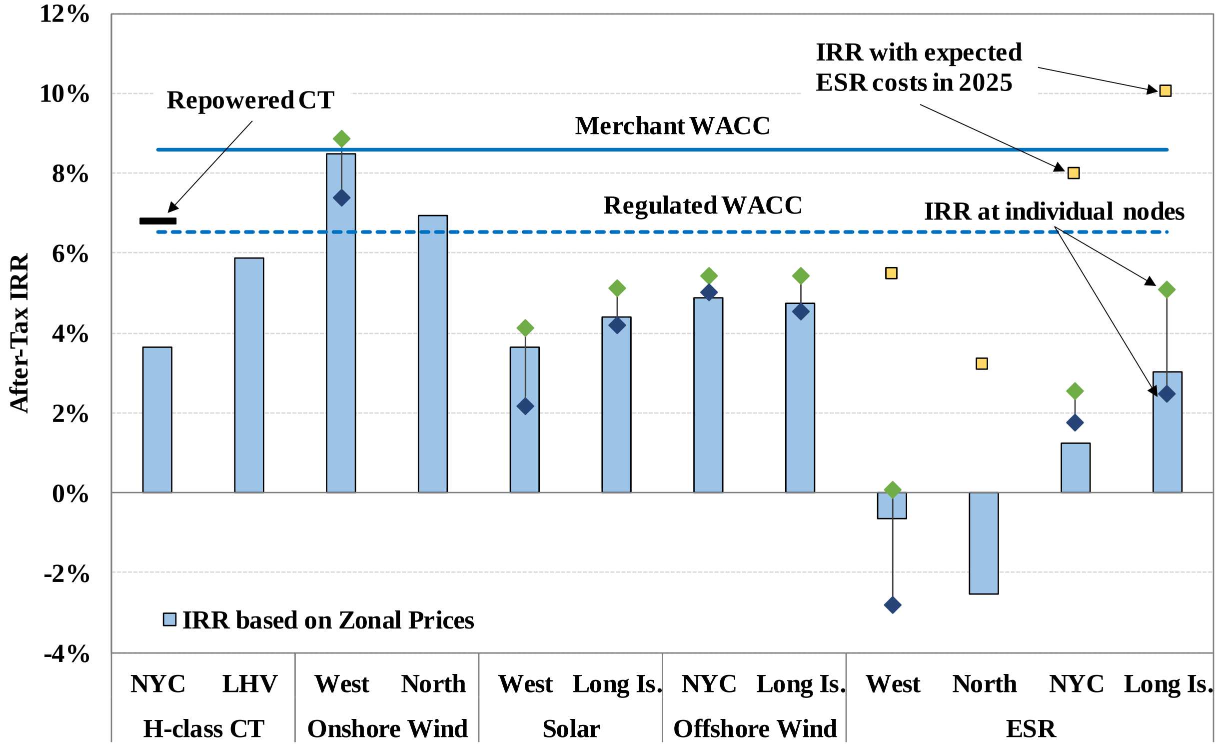
107 Net revenue is the total revenue that a generator would earn less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units.

108 Details of the estimated net revenues for each technology type can be found in Appendix subsections VII.A and VII.C.

figure compares the IRR for each project with the after-tax WACC for: (a) a merchant entrant using data from the latest demand curve reset study, and (b) a regulated entity calculated from recent New York utility rate cases.[109] A project with a weighted average cost of capital below its estimated IRR would have a positive net present value and, thus, be profitable. For each technology and location, the bars shows the IRR based on the zonal price and base cost assumptions. The green diamonds show how the IRR would change at individual locations downstream of transmission bottlenecks within the zone, while black diamonds show locations upstream of transmission bottlenecks.[110] Additional symbols indicate how the IRR would change under alterative cost scenarios.

Figure 18: After-Tax IRR of New Generation
2017 – 2019



Our analysis of the economics of generation investment indicates that there are significant differences in the IRR by technology and zone, and there is substantial variation even within a zone. Based on the 2017 to 2019 market outcomes, investment in the generic onshore wind project in the West zone would have the highest IRR, while investment in ESRs and solar PV

109 The regulated WACC shown is calculated as an average of cost of capital values approved by the NYPSC in rate cases for Consolidated Edison, Central Hudson and Niagara Mohawk (National Grid) in 2018 and 2019.

110 Black diamonds indicate the Niagara station (West Zone), Staten Island (NYC), and Northport station (Long Island), and green diamond show the area south of Buffalo (West Zone), the Greenwood load pocket (NYC), and the Valley Stream load pocket (Long Island).

exhibited the lowest projected returns among all the technology-location combinations we analyzed. The IRR for nearly all new generation is well below the benchmark for the merchant WACC. Given the surplus capacity levels in most regions, this result is consistent with our expectations for generic projects.

Discussion of Incentives for New Units by Technology Type

Gas-fired Combustion Turbines – The estimated IRR was below the typical merchant WACC for the locations that we analyzed.[111] However, it is possible for investments in projects with site-specific benefits to provide a significantly better IRR. For instance, the IRR for a New York City repowered project that utilizes existing infrastructure is over 3 percentage points higher than a generic brownfield project. The feasibility of building a new or repowered gas-fired unit in New York City is unclear given a recent executive order that prohibits new gas infrastructure and other permitting challenges.[112, 113]

Renewable units – The estimated IRRs for all renewable technologies and locations were positive, but only the IRR of the generic onshore wind project in the West Zone would nearly meet the merchant WACC under current market conditions. In New York State, state and federal incentives account for the majority of net revenues for all renewable projects evaluated.[114] These incentives are generally subject to little market risk, which may lower the returns required by investors to a value closer to the WACC of the regulated entity.

Energy storage – The estimated IRRs of four-hour battery storage projects were well below the typical merchant and regulated entity WACCs, even after assuming that the projects in New York City and Long Island qualify for the $85/kWh NYSERDA Bulk Storage Incentive.[115] However, the costs of battery systems are expected to decline significantly in the coming years. Estimated IRRs of battery projects in NYC and Long Island using projected 2025 costs are near or above typical merchant WACC levels. Furthermore, the incentives for storage projects are much stronger at individual nodes that experience high price volatility. Subsection C discusses

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111 Costs and revenues for the Combustion turbine reflect a 7HA.02 Frame unit, assumed to be at a brownfield site in NYC. The IRR for a repowered unit with a discounted capital cost is also shown.

112 See Executive order No. 52, signed February 6, 2020, https://www1.nyc.gov/assets/home/downloads/pdf/executive-orders/2020/eo-52.pdf

113 In addition, to the extent that the existing units are economic to continue operating, the returns for the repowered project would be reduced commensurately. The recently adopted New York DEC's regulations could result in several potential repowering sites where the existing peaking units will not operate beyond 2025.

114 See subsection VII.C of the Appendix.

115 See https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Developers-Contractors-and-Vendors/Bulk-Storage-Incentives

enhancements to the energy and ancillary services markets that could improve the merchant economics of storage projects.

Although state and federal incentives account for large components of the net revenues that would be earned by renewable generation and energy storage projects, the NYISO markets play a key role in providing price signals that differentiate among projects by rewarding those at locations and technologies that are most valuable to the system in terms of deliverability, reliability, and congestion relief. For instance, the analysis suggests that during the period evaluated a land-based wind turbine in the West Zone would be far more economic than a land-based wind turbine in the North Zone or a utility scale solar generator in Long Island. When NYSERDA and other entities contract for resources to help satisfy state mandates, the most economic projects are likely to submit the lowest-cost proposals and more likely to be selected. Hence, even though these projects are ostensibly developed to satisfy state policy objectives, the NYISO market provides incentives that will channel investment towards the most effective and efficient uses.

B. Net Revenues of Existing Generators

Figure 19 shows the net revenues, as a percentage of estimated going-forward costs ("GFCs") (or average generation cost for nuclear units), for several existing technology types in the period 2017-2019. The "Estimated GFC" includes the long-run average cost of maintaining an existing generation facility in reliable condition, including plant-level and other costs that may be shared across multiple units. However, a firm may not be able to avoid all such costs by retiring just a single unit at a facility, and a firm may be able to avoid a substantial portion of the cost by deferring maintenance and other capital expenditures in the short-term. So, the figure also shows a "Short-Term GFC" for New York City steam units, which excludes major maintenance and other capital expenditures. However, even the "Short-Term GFC" includes some plant-level costs that would be difficult to avoid by retiring a single unit.[116] [117]

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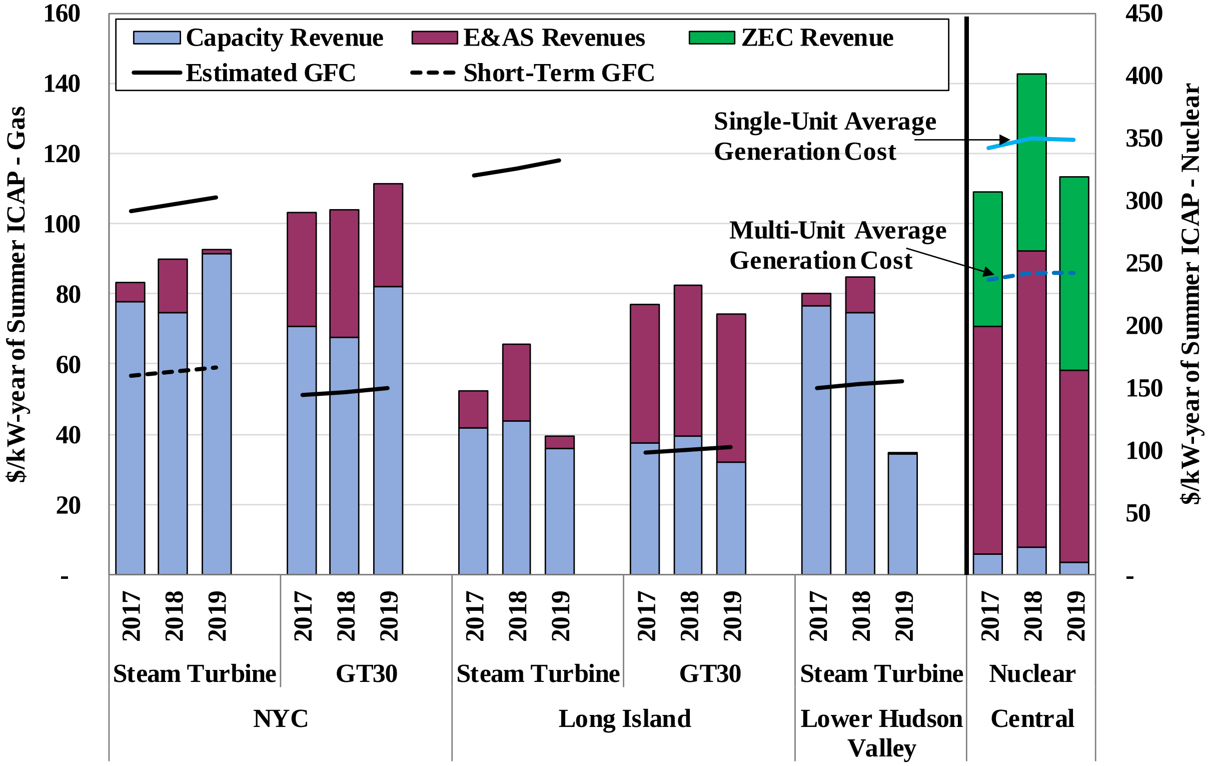
116 The "Estimated GFC" for existing gas generators is based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

The "Short-Term GFC" includes estimated fixed O&M costs, property tax and administrative costs with all major maintenance and capital expenses excluded. This was based on multiple sources including: (a) Burns & McDonnel's report "Life Extension & Condition Assessment for Rio Grande Unit 7", (b) New England States Committee on Electricity (NESCOE) Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study, Phase I, Scenario Analysis Report, 2017, (c) Analysis Group's report "NYISO Capacity Market: Evaluation of Options", and confidential unit-specific information.

Annualized average generation costs for US nuclear units are $349/kW-year for a single-unit facility and $241/kW-year for a multi-unit facility. The estimated average costs of nuclear plants are based on NEI/EUCG reports and presentations.

117 Additional details regarding net revenues and GFCs for existing units may be found in subsections VII.A and VII.B of the Appendix.

Figure 19: Net Revenues and Going-Forward Costs of Existing Units
2017 – 2019



The net revenues of existing units in all regions outside of New York City declined between 2018 and 2019, due to lower energy and capacity prices in 2019. As with new units, the net revenues of existing units relative to their costs varied significantly by technology and location.

Steam Turbines – Of the existing fossil-fuel technologies we evaluated, steam turbine units appear to be 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 marginally lower than the estimated GFC in New York City. Net revenues for steam turbines in the Lower Hudson Valley dropped below the estimated GFC in 2019 due to the drop in capacity prices.[118] However, the net revenues of steam units exceeded the estimated GFC for five of the last eight years in New York City and six of the last eight years in Lower Hudson Valley.

There is considerable uncertainty in the actual price level at which an existing unit owner would choose to retire or mothball. The decision to retire and the actual GFCs depend on a range of factors including whether the units are under long-term contracts, the age and condition of the individual unit, the level of incremental capital and/ or maintenance expenditure required to continue operations, and the owner's expectations of future market prices.

118 The Lower Hudson Valley LCR for the 2019/2020 capability year declined to 92.3 percent, from 94.5 percent in the 2018/2019 capability year, causing capacity prices to decline. See subsection VII.A.

Gas Turbines – Net revenues of existing gas turbine units in New York City and Long Island were consistently above the estimated GFC because of high reserve market revenues and relatively low GFCs for the generic units. However, many of these units currently face the decision to incur significant additional capital costs or cease operating to comply with regulations adopted by the New York DEC. These regulations impose limits on the NOx emissions rates during the ozone season of simple-cycle units.[119] Over 3.3 GW (nameplate) of GT capacity in Zones J and K is impacted by this rule, which requires plants to comply with initial limits by May 2023 and stricter limits by May 2025.[120]

Nuclear Plants – Net revenues of existing nuclear plants in 2019 were above the US average generation costs for multiple-unit facilities and below the average generation costs for single-unit facilities.[121] Average net revenues over the 2017-2019 period have been approximately adequate to recover the average generation costs for a single-unit facility. ZECs make up a large portion of nuclear plant net revenues, constituting 40 percent of average net revenues from 2017 to 2019. Hence, ZECs continue to be a critical for the operation of these units.

C. Impacts of Energy & Ancillary Services Pricing Enhancements on Net Revenue

Section XI 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. They would also increase the economic pressure on inefficient and inflexible resources. 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 the impacts of several recommendations on the capacity prices and long-term investment incentives for several new and existing technologies.

In an efficient market, higher energy and ancillary services net revenues reduce the “missing money” that is needed to attract sufficient investment to satisfy planning reliability criteria. In recent years, the capacity demand curve has been set based on the missing money for a new

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119 See DEC’s proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, available at: http://www.dec.ny.gov/regulations/116131.html

120 See NYISO, *2019-2028 Comprehensive Reliability Plan*, July 16, 2019.

121 Average costs reported by the owners of the Nine Mile Point and Ginna facilities are higher than the US average. Nuclear costs are plant-specific and facilities in New York may be subject to higher labor costs and property taxes. See subsection VII.B of the Appendix for a detailed discussion of nuclear plant revenues and costs.

Frame unit.[122] Hence, market enhancements that efficiently move net revenues to the energy and ancillary services markets lead to reductions in the capacity demand curves. We make several recommendations in this report that would shift revenues from the capacity market to the energy and ancillary services markets, thereby increasing the financial returns for resources that perform flexibly and reliably, while reducing the financial returns to poor-performing resources.

We modeled the net revenue impact of four different enhancements to real-time pricing in the context of New York City and two others in the context of Long Island. Figure 20 and Figure 21 show the incremental impact of our recommendations on the change in net revenues of the Frame units under the long-term equilibrium conditions in New York City and Long Island, respectively.[123, 124] The New York City-specific recommendations we modeled are as follows:

- 2017-1: Model local reserve requirements in New York City load pockets.[125]
- 2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.
- 2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.

The Long Island-specific recommendations we modeled are as follows:

- 2019-1: Set day-ahead and real-time clearing prices considering reserve constraints for Long Island.
- 2018-1: Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions.
- 2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.

The figures also show the total increase in the H-class Frame unit's net revenues, which would result in an equivalent decrease in the Net CONE that is used for determining the ICAP Demand Curve for the zone.

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122 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.

123 See subsection VII.D in the Appendix for details about the assumptions used in this analysis.

124 See Section XI for more details regarding these recommendations.

125 In estimating the impact of Recommendation # 2017-1, we included the impacts of modeling incentive payments to units that have the capability of instantaneously switching over from gas to oil fuel supply.

Figure 20: Impact of Pricing Enhancements on Net Revenues of NYC Demand Curve Unit
At Level of Excess Conditions

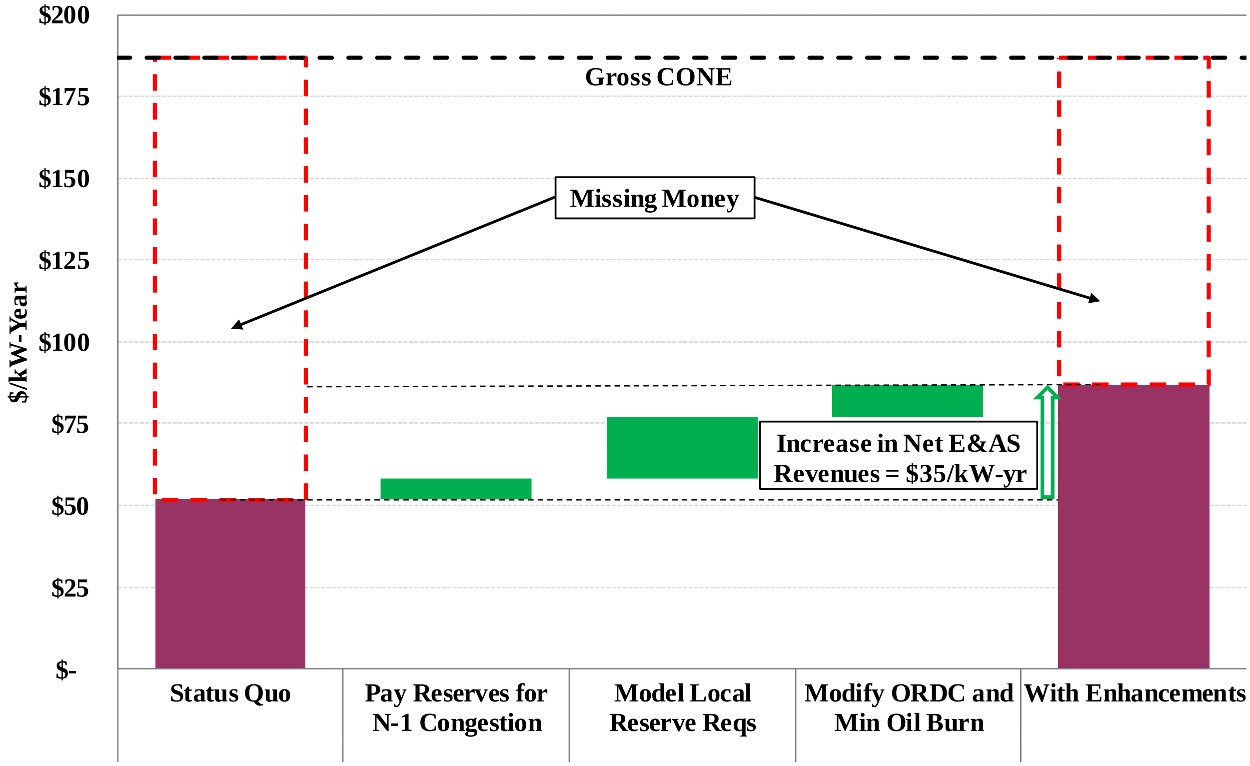
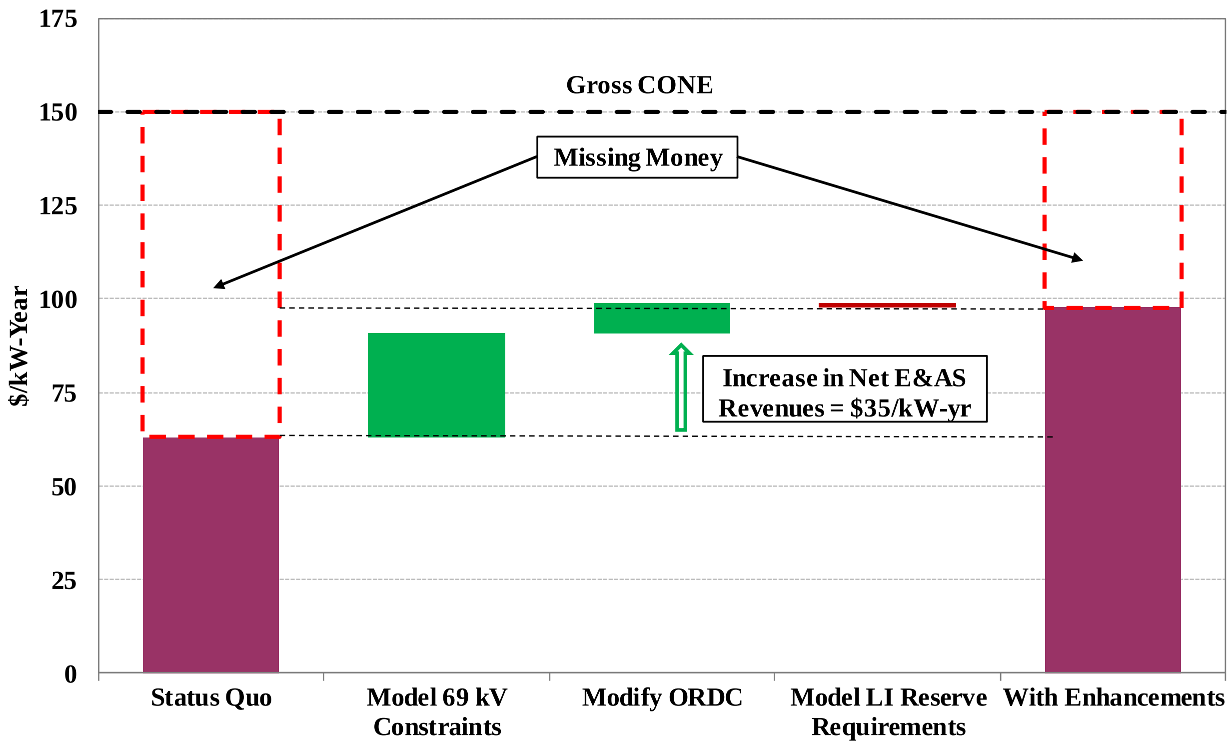


Figure 21: Impact of Pricing Enhancements on Net Revenues of LI Demand Curve Unit
At Level of Excess Conditions



Our simulation results indicate that the E&AS revenues of a new Frame unit would increase by 68 percent in New York City and by 55 percent on Long Island if our recommendations were implemented. Consequently, the Net CONE for the ICAP demand curve and the capacity payments to all resources would decline by 26 percent in New York City and by 40 percent on Long Island. Overall net revenues to the demand curve unit would not change, but the recommendations would shift a large portion from the capacity market to the E&AS markets.

Of the recommendations that we considered for New York City, modeling local reserve requirements in load pockets (i.e. 2017-1) had the largest impact and accounted for 54 percent increase in the E&AS revenues. In Long Island, our recommendation to modeling the transmission constraints in energy markets (i.e. 2018-1) accounted for most of the increase in E&AS revenues. In addition, our previous analyses have suggested that Carbon Pricing coupled with the above market reforms would substantially increase the net revenues for the demand curve unit and for new flexible technologies.[126]

Figure 22 summarizes the estimated impact of recommended enhancements on energy and capacity revenues compared to the corresponding CONE/GFC for various resources based on zonal prices in New York City and prices in the East of Northport load pocket in Long Island. The "Base" category shows the estimated net revenues that would be received by each type of unit under the current market rules if the capacity margin was at the Part A threshold in New York City, and at the Level of Excess in Long Island.[127] The "wRecs" category shows our estimates if the above recommendations were adopted.

In general, the recommended enhancements result in higher net E&AS revenues for all units. This illustrates the value of our recommendations in improving the E&AS prices that better reflect the need for investments in locations where it is most valuable in managing congestion. The net impact of the enhancements on total net revenues would depend on the trade-off between higher E&S revenues and lower capacity revenues.

In both New York City and Long Island, the recommended enhancements would increase net revenues to new flexible technologies as the increase in E&AS revenues would outweigh the decrease in capacity revenues.

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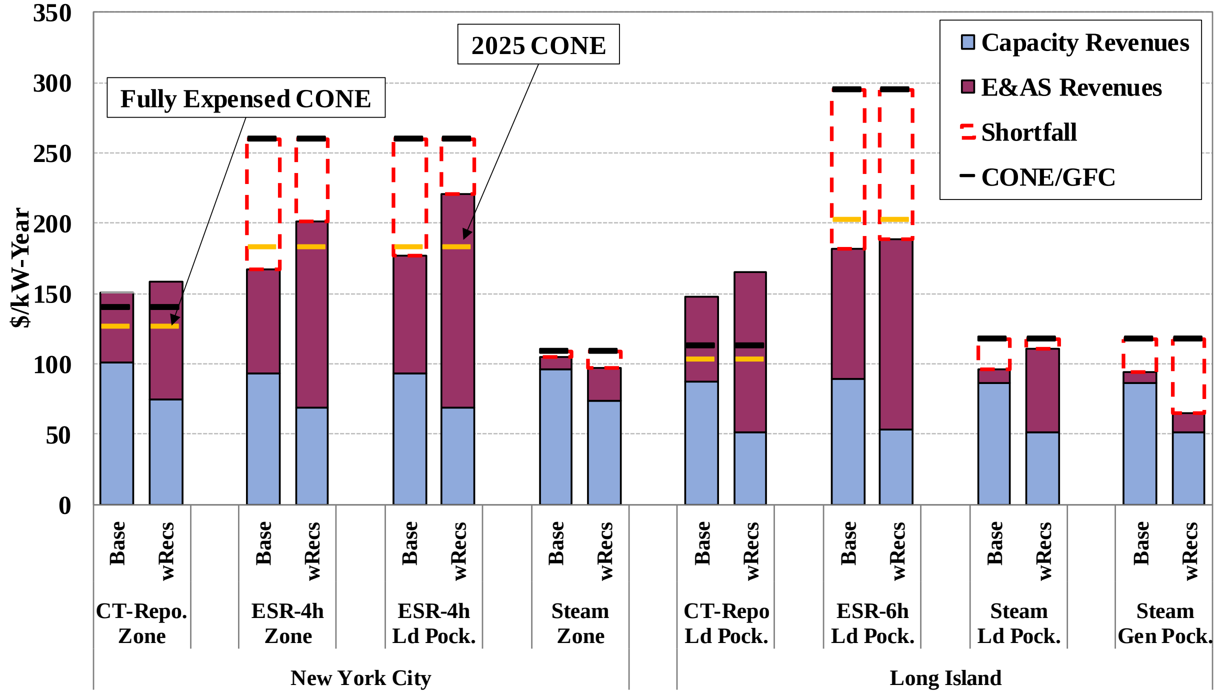
126 Net revenues of the demand curve unit in NYC are estimated to increase by $19/kW due to the effects of carbon pricing and reserve enhancements by 2025. See *MMU Evaluation of Impacts of Carbon Pricing*, May 9, 2019.

127 The NYISO recently proposed Tariff revisions to the Part A test that will allow subsidized public policy resources to sell capacity (i.e., avoid mitigation) as long as the existing capacity surplus does not exceed the Part A threshold.

Figure 22: Net Revenue Impact from Market Enhancements
New York City at the Part A Threshold and Long Island at Level-Of-Excess



In contrast, the economics of older existing in-city steam generators with less flexible and reliable characteristics would become less attractive. For average-performing steam turbines in New York City, the recommended enhancements would lead to a drop in overall net revenues by an estimated eight percent primarily because of the reduced capacity demand curve. 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, resulting in increased economic pressure on these units to retire. However, as discussed earlier in subsection B, retirement decisions depend on a number of unit-specific factors. Nonetheless, structural changes that push revenues well below expenses would worsen the outlook for owners and shorten the period over which they may be willing to incur losses or defer expenses, thereby increasing the likelihood of retirements.[128]

The in-city steam turbine units also receive a considerable portion of their revenues from OOM commitments that are required to satisfy local reliability needs. Hence, to the extent that the status quo does not adequately reflect the value of E&AS products, steam units tend to receive higher levels of compensation. Overall, inefficient E&AS prices are likely to result in retention of existing steam turbine capacity in New York City.

128 See subsection VII.E of the Appendix.

On Long Island, our recommended enhancements are likely to result in higher net revenues for all units (including steam turbines) that are located in the load pocket we analyzed.[129] However, the revenues of the steam unit located in a generation pocket are likely to be significantly lower. This illustrates the value of our recommendations in improving the E&AS price signals on Long Island. There is currently a large amount of capacity of PPRs in the NYISO interconnection queue that is seeking to interconnect in the load pockets on Long Island. The REC contract structures offered to offshore wind developers favor interconnection at locations with favorable LBMPs relative to the average for Zone K. Hence, improving the alignment of price signals with the value of generation at each location in managing congestion will help developers make more efficient decisions regarding the siting of PPRs.

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. Furthermore, as discussed in the Section detailing Competitive Performance of the Market, the recommended enhancements are also likely to enable higher penetration of renewables by increasing the pressure on existing generation to retire, thus increasing the likelihood of renewables (and other PPRs) to be exempt from BSM.

129 Given their high heat rates, the energy revenues of steam units in the load pocket are more likely to be adversely impacted by new entry from more efficient CTs or more flexible ESRs.

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.

We evaluate eight aspects of market operations, focusing on the efficiency of scheduling and whether 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
- Market-to-Market Operations with PJM
- 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: [130]

130 Our previous reports also evaluated market performance during demand response deployments – a third type of shortages. In 2019, the NYISO did not deploy reliability demand response resources, so the performance under this type of shortage is not evaluated in this report.

- *Operating reserve and regulation shortages* – These occur when the market schedules less than the required amount of ancillary services. Co-optimizing energy and ancillary services causes the foregone value of the ancillary services 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

Operating reserve and regulation shortages were much less frequent in 2019 because lower load levels led to fewer hours of tight operating conditions and the opportunity costs to provide ancillary services decreased due to lower energy prices. Regulation shortages were most frequent, occurring in 4.5 percent of intervals in 2019 (down from 12 percent in 2018). An increase in the quantity of low to medium priced regulation offers contributed to fewer regulation shortages. Reserve shortages occurred very infrequently in 2019. While infrequent, shortages of regulation and operating reserves collectively increased average LBMPs by 3.5 to 6 percent in 2019.[131] Thus, ancillary services shortages have a significant impact on investment signals, shifting incentives toward generation with flexible operating characteristics.

In this report, we identify two enhancements that would improve scheduling efficiency and ensure that the real-time market provides appropriate price signals during shortage conditions. First, the NYISO does not always schedule operating reserves efficiently when the reserve needs of a local area can be satisfied by reducing imports to the area (rather than holding reserves on units inside the area).[132] Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves to hold inside:[133]

- Eastern New York given flows over the Central-East Interface;
- Southeast New York given flows over the UPNY-SENY interface;
- Long Island given transmission constraints that may limit the amount of reserves that can be deployed there in response to a contingency outside Long Island;
- NYCA given imports across the HVDC connection with Quebec; and
- New York City load pockets considering unused import capability into the pocket.
- In addition, day-ahead reserve requirements should be calculated considering the amount by which energy is under-scheduled to satisfy forecast load in a given area, since more reserves are needed to maintain adequate resources when energy is under-scheduled.

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131 See Section V.G in the Appendix for this analysis.

132 See, for example, Section V.F in the Appendix for our analysis of New York City requirements during TSAs.

133 See Recommendation #2015-16 in Section XI.

Second, the operating reserve demand curves in New York are substantially lower than the reliability value of holding the reserves. Efficient reserve demand curves should reflect the probability of losing load times the value of lost load ("VOLL") as reserves levels drop. Additionally, the NYISO curves are relatively low considering recent market design changes in neighboring markets. ISO New England and PJM both implemented Pay For Performance ("PFP") rules in mid-2018, which provide incentives similar to extreme shortage pricing.

- In ISO-NE, the Performance Payment Rate levels will rise from an initial rate of $2,000 per MWh to $5,455 in 2024.[134] 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, an initial Performance Rate was set to be 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 also expected to rise in subsequent years.[135]

Consequently, the incentives to import power to New York under tight conditions have changed dramatically, reducing the available supply to New York. Our 2018 State of the Market report demonstrated the weak market incentives on the NYISO side and resulting OOM actions by NYISO during the first-ever PFP event in the ISO-NE market.[136] If the NYISO reserve demand curves provided stronger incentives, these OOM actions may not have been necessary.

The operating reserve demand curves in New York are too low considering the willingness of NYISO operators to engage in out-of-market actions to procure more costly resources during reserve shortages. Hence, we recommend that the NYISO increase its operating reserve demand curves to levels that will schedule resources appropriately so that out-of-market actions are not necessary to maintain reliability during tight operating conditions. To ensure these levels are reasonable, the NYISO should also consider the value of lost load and the likelihood that various operating reserve shortage levels could result in load shedding. This recommendation includes establishing multiple steps for each operating reserve demand curve so that clearing prices rise efficiently with the severity of the shortage.[137] The NYISO has taken steps towards addressing this recommendation with a proposal to raise the NYCA 30-minute reserve demand curve from current levels.[138] This will significantly reduce (but not eliminate) the need for OOM dispatch of internal generation, emergency purchases, and export curtailments to maintain reserves.

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134 See ISO New England Tariff Section III.13.7.2.

135 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.

136 See the analysis in Section V.F of the Appendix of our 2018 State of the Market Report for details.

137 See Recommendation #2017-2 in Section XI.

138 See *Ancillary Services Shortage Pricing*, presented to the Market Issues Working Group on April 27, 2020.

Transmission Shortages

During transmission shortages, when power flows exceed the transmission limit, the market should set efficient prices that reflect the severity of shortage. The latest revision of the transmission shortage pricing rules in June 2017 has greatly improved the relationship between price and severity.[139] Constraint relaxation has been much less frequent following the revision, occurring in just 3 percent of transmission shortages in 2019.[140,141] This was down from over 50 percent in the year before the revision. The reduced use of constraint relaxation has resulted in congestion prices that are more transparent and predictable for market participants.

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 such payments. To address this, we recommend changes to the market power mitigation measures for uneconomic over-production.[142]

Another improvement in transmission shortage pricing was to allow more flexibility in setting Constraint Reliability Margin ("CRM") values for transmission constraints beginning in December 2018. Prior to that, the tariff did not allow the use of a non-zero CRM value of less than 20 MW, and the NYISO was forced to use unnecessarily large CRM values for low-voltage facilities, which led to excessive congestion on these facilities (e.g., the transmission corridor from Northern to Central New York). Since the CRM is designed to provide a margin to account for differences between the modeled flows and actual flows and to reduce the likelihood that a transmission constraint violation results in an actual overload, the sizes of such differences are usually correlated with the rating of the facility. Starting in December 2018, a CRM value of 10 MW is used for 115 kV constraints, which represents roughly 5 to 7 percent of the average transfer capability of these 115 kV facilities.

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139 The latest revision of the transmission shortage pricing rules in June 2017 includes: a) modifying the second step of the GTDC from $2,350 to $1,175/MWh; and b) applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM").

140 Constraint relaxation is done in a way that a transmission shortage is resolved by "relaxing" the limit of the constraint—that is, automatically raising the limit of the constraint to a level that could be resolved by the market software.

141 The constraint relaxation is shown by the points that are off the GTDC curve in Figure A-85 .

142 See Recommendation #2017-3 in Section XI.

Despite the improved transmission shortage pricing, constraint shadow prices often did not reflect the severity of transmission shortages in 2019. The GTDC has a 5-MW step and a 15-MW step for a total of 20 MW where redispatch costs are limited. Since the GTDC is always 20-MW long, it is overly conservative for a large facility with a 50-MW CRM and excessively slack for a small facility with a 10-MW CRM.[143] Hence, we continue to recommend that, in the long term, the NYISO replace the current GTDC with a set of constraint-specific GTDCs that can vary according to the size of the CRM and the importance, severity, and/or duration of a transmission shortage. This will ensure a logical relationship between shadow prices and the severity of transmission constraints.[144,145]

In the short-term, the NYISO's proposed modifications to the GTDC would be a significant improvement over the current GTDC for at least two reasons.[146] First, the proposed GTDC would increase more gradually than the current GTDC, which will reduce price volatility. Second, the MW-range of the proposed GTDC is based on the CRM of the constraint, which is a significant improvement over the current GTDC, which uses a 20-MW range regardless of the CRM value.

B. Efficiency of Gas Turbine Commitments

We evaluate the efficiency of gas turbine commitment in the real-time market, which is important because over-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 44 percent of the capacity committed by the real-time market model in 2019 was clearly economic over the initial commitment period (one hour for GTs), generally consistent with recent years.[147] This, however, likely understates the share of GT commitments that are

143 See Table A-11 in the Appendix for a more detailed description.

144 Recommendation #2015-17 in Section XI.

145 In addition, we have found that CRMs are sometimes inflated because of so-called "offline gas turbine price-setting" whereby offline gas turbines are treated as able to respond to dispatch instructions when they actually cannot do so, leading to large differences between modeled flows and actual flows for some facilities (e.g., the Dunwoodie-ShoreRd 345kV line from upstate to Long Island). We recommend eliminating offline gas turbine price-setting in conjunction with the implementation of constraint-specific GTDCs.

146 See *Constraint Specific Transmission Shortage Pricing* presented at the November 21, 2019 MIWG meeting.

147 See Figure A-74 in the Appendix for details of this analysis.

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 2019 when the total cost of starting gas turbines exceeded the LBMP by a wide margin (>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 current fast-start price-setting rules do not usually reflect the start-up costs of the gas turbine in the price-setting logic.[149]

The "Enhanced Fast-Start Pricing" project is currently underway in the NYISO, which will: (a) extend the existing logic (currently applied only to Fixed Block fast-start units) to all fast-start resources; and (b) include the start-up and minimum generation costs of all fast-start resources in the LBMP calculation. These will lead real-time prices to better reflect system conditions and better performance incentives for flexible resources when fast-start units are deployed. This market change is scheduled to be implemented in the fourth quarter of 2020. [150]

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 23 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 2019. Units that were not started in-merit by RTC in 2019 are shown in "Not Started."[151]

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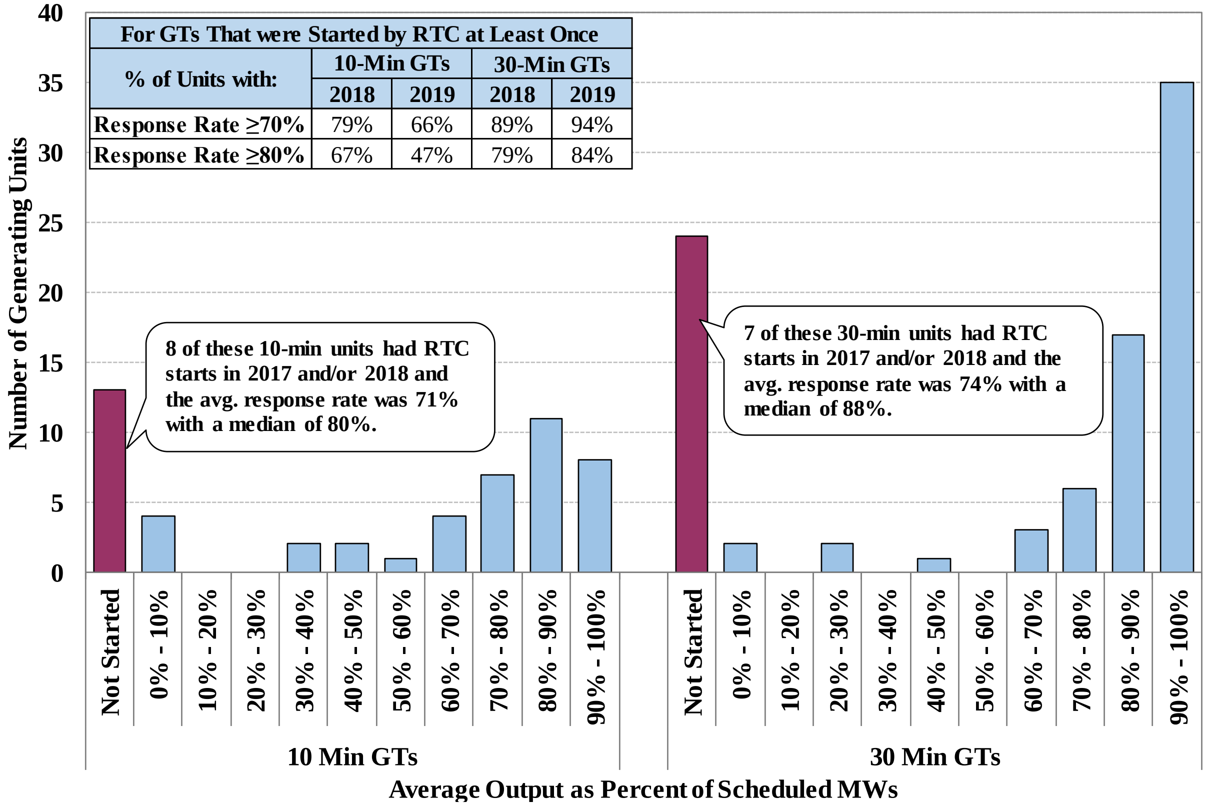
148 See Section IV.D in the Appendix for analysis of divergence between RTC and RTD.

149 See in Docket EL18-33-000, comments of Potomac Economics, dated February 12 and March 14, 2018.

150 See "Enhanced Fast-Start Pricing" by Mike DeSocio, MIWG meeting on October 28, 2019.

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

Figure 23: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts, 2019



Gas turbines exhibited a wide range of performance in responding to start-up instructions in recent years. GT startup performance generally worsened in 2019 from 2018 for the 10-minute units, but it improved slightly overall for 30-minute units. For the same set of units that were started economically by RTC at least once in every year from 2018 to 2019,[152,153]

- *10-minute units*: 66 percent of units had an average response of 70 percent or better in 2019, down from 79 percent in 2018. Meanwhile, the average response of all units was 69 percent in 2019, down from 71 percent in 2018.
- *30-minute units*: 94 percent of units had an average response of 70 percent or better in 2019, up from 89 percent in 2018. Meanwhile, the average response of all units was 84 percent in 2019, up slightly from 83 percent in 2018.

Response rates fell in 2019 because of worse performance by GTs with relatively few economic starts over the year. Performance among frequently started and 10-minute units fell slightly (~4

152 A total of 37 gas turbines were not evaluated in 2019 since they were never started economically by RTC. We only evaluate RTC start-ups because the available data does not allow us to reliably evaluate the performance of gas turbines during other types of start-ups.

153 Note, some reported values are lower than reported in previous SOM Reports because of an issue that inadvertently led to the exclusion of some failed starts before 2019.

percent) in 2019 from the prior year levels. Nonetheless, GT startup performance improved significantly from 2017 to 2018 because of retirements and IIFOs of poor performing units. This trend may continue as older units continue to leave the market.

In general, gas turbines miss out on 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.[154] Because operating reserve revenues are not sensitive to suppliers' performance, the market does not provide efficient performance incentives to reserve providers. To address this concern, we previously recommended that the NYISO consider ways to allow reserve revenues to reflect suppliers' performance.[155] As part of the *More Granular Operating Reserve* Project, the NYISO is enhancing its audit procedure to test each gas turbine more frequently (at least once per year). The NYISO has also stated that it may disqualify generators from providing reserves based on audit results and/or failure to respond to reserve pick-ups.[156] In light of these procedure changes, overall improved startup performance in recent years, and the significant administrative efforts that would be required to implement a performance-based adjustment to payments to reserve providers, we have withdrawn Recommendation #2016-2 from this report, but we will continue to monitor GT startup performance going forward.

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 is sometimes allowed to operate 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 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 reserves rather than actual generation dispatch becomes apparent when reserves and other post-contingency actions become unavailable. In such cases, transfer capability is reduced, requiring more generation in the load pocket to manage congestion. This can happen during severe cold weather conditions when

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

155 See Recommendation #2016-2 in our *2018 State of the Market Report*.

156 See *More Granular Operating Reserves: Reserve Provider Performance* at April 7, 2020 MIWG meeting.

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

constraints on the gas pipeline system in New York City limit the fuel supply of some units that usually provide operating reserves, reducing the import capability of the transmission system.

In 2019, 47 percent (or $29 million) of real-time congestion occurred on N-1 transmission constraints that would have been loaded above LTE after a single contingency. As shown in Table 18, the additional transfer capability above LTE on New York City transmission facilities averaged: (a) 15 to 90 MW for 138 kV load-pockets; and (b) 200 to 300 MW for the 345 kV system during congested hours.[158]

Table 18: Modeled Limits vs Seasonal Limits for Select New York City N-1 Constraints
2019

Transmission Facility		Average Constraint Limit (MW)		
		N-1 Limit Used	Seasonal LTE	Seasonal STE
345 kV	Gowanus-Farragut	1067	834	1303
	Motthavn-Rainey	1067	834	1298
	Dunwodie-Motthavn	1073	842	1302
	Sprnbrk-W49th ST	1292	1009	1575
	W49th ST-E13th ST	1251	961	1537
138 kV	Foxhills-Greenwd	312	247	377
	Willwbrk-Foxhills	351	262	439
	Gowanus-Greenwd	324	298	350
	Vernon-Greenwd	240	228	251

Although these increases were largely due to the availability of operating reserves in New York City, reserve providers are not compensated for this type of congestion relief. 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 software dispatches this reserve capacity, it can reduce the transfer capability into New York City, making the dispatch of these units inefficient in some cases.

Hence, we recommend the NYISO evaluate ways to efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria.[159] 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.

D. Operations of Non-Optimized PAR-Controlled Lines

Most 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,

158 See Appendix Section V.B for more information about this analysis.

159 Recommendation #2016-1 in Section XI.

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.C that assesses external transaction scheduling.[160]
- "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 19 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2019. This is done for seven 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.

The Lake Success and Valley Stream PARs 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. Similar to prior years, power was scheduled in the efficient direction in only 5 to 10 percent of hours in the day-ahead market in 2019. This is primarily because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect.[161] 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 the 901 and 903 lines:

- *Increased* day-ahead production costs by $10 million in 2019 (and $16 million in 2018).
- Restrict output from more economic generation in the Astoria East/Corona/Jamaica pocket where the lines connect.
- Increase the consumption of gas from the Iroquois pipeline, which often trades at a significant premium over gas consumed from the Transco pipeline.

160 This includes HVDC lines (Cross Sound Cable, Neptune Cable, the line connecting NYCA to Quebec, and the HTP Line), VFT-controlled lines (Dennison Line and Linden VFT), and the 1385 PAR-controlled line.

161 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.

Table 19: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[162, 163]
2019

	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					-6	$2.42	53%	$1
New England to NYCA								
Sand Bar	-79	-$11.76	96%	$8	0.3	-$11.37	54%	$0.3
PJM to NYCA								
Waldwick	-43	$2.17	44%	$0.2	16	$1.35	45%	-$3
Ramapo	258	$3.09	77%	$11	155	$2.20	65%	$6
Goethals	107	$4.27	80%	$5	107	$2.03	61%	$0.5
Long Island to NYC								
Lake Success	140	-$3.48	10%	-$5	0	-$4.54	43%	$0.0
Valley Stream	80	-$6.53	5%	-$5	2	-$7.27	35%	-$0.2

In the long-term, the operation of these two PAR-controlled lines to rigidly flow a fixed quantity rather than to relieve congestion (as most other PARs are used) will make it more costly to integrate intermittent renewable generation in New York City and Long Island. It would be highly beneficial to modify this contract or find other ways under the current contract to operate the lines more efficiently.[164] Although this should benefit both parties in aggregate, it may financially harm one party. Hence, a new financial settlement mechanism is needed to ensure that both parties benefit from the changes.[165] We recommend the NYISO work with the parties to this contract to explore changes that would allow the lines to be used more efficiently.[166]

162 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.

163 As discussed further in Section V.E 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.

164 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.

165 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 VI.H of the Appendix.

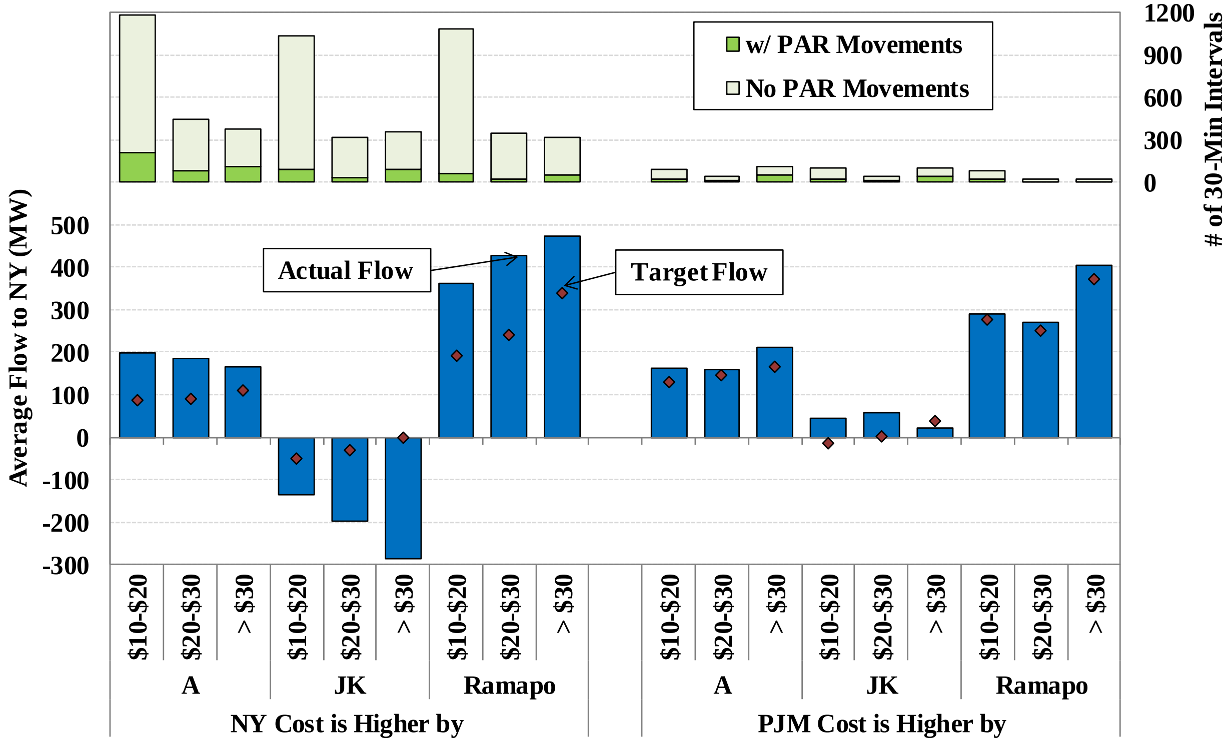
166 See Recommendation #2012-8 in Section XI.

Although the PAR-controlled lines between PJM and the NYISO are operated under the M2M JOA in a way more responsive to market price signals, the scheduling efficiency over some of these lines was poor in 2019. Operation of the 5018 line was most efficient, but operation of the J and K lines was much less active and efficient. Consequently, the J and K lines accounted for a $3 million net *increase* in production costs in 2019, while the 5018 line and the Goethals line accounted for a net *reduction* of $17 million and $5 million, respectively. 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.[167,168] Figure 24 evaluates operations of these PARs under M2M with PJM in 2019 during periods of congestion between New York and PJM.[169]

Figure 24: NY-NJ PAR Operation Under M2M with PJM
During Congested Periods, 2019



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

168 Ramapo PARs have been used in the M2M process since its inception in January 2013, while the A and J&K lines were added in May 2017 following the expiration of the ConEd-PSEG Wheel agreement.

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

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 (including an estimated $5.5 million of revenue surpluses for 2018 and 2019. See Section V in the Appendix). However, this operation led to a similar amount of balancing congestion shortfalls on West Zone constraints in 2018 and 2019. This is because when more flows are brought into New York to relieve congestion on the Central-East interface, these additional flows tend to aggravate congestion on the constraints in the West Zone. The amount of shortfalls on the West Zone constraints rose in 2019 because the NYISO began to model 115 kV West Zone constraints, but these constraints were not initially included in the set of PAR Coordination Flowgates that were addressed by the M2M JOA. The NYISO recognized this issue and was able to incorporate these 115 kV constraints in the list of PAR Coordination Flowgates in December 2019.

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 in 2019 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 16 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.

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 one of the most significant net contributors to price divergence, accounting for a 18 percent of overall price divergence in 2019, comparable to load forecast error and wind forecast error combined.[170] This is partly because RTC has no information related to expected tap changes. Consequently, RTC may schedule CTS imports to relieve congestion, but operators may already be taking tap adjustments in response to the congestion, leading the scheduled imports to be uneconomic. This illustrates why forecasting PAR tap adjustments would also help reduce divergences between RTC and RTD. 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

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

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 2019. 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 just 6 percent of all intervals in 2019, 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.

Drivers of Transient Real-Time Price Volatility

Table 20 summarizes the most significant factors that contributed to real-time price volatility in 2019. It shows their contributions to spikes in the power-balance constraint and the most volatile transmission constraints. Contributions are also shown for: (a) external interchange and other resources scheduled by RTC; (b) flow changes from un-modeled factors, such as loop flows; and (c) load and wind forecast error and generator derates.[171] For each group of constraints, the most significant categories and sub-categories are highlighted in purple and green, respectively.

Table 20: Drivers of Transient Real-Time Price Volatility

2019

	Power Balance		West Zone Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints		Capital to Hudson Valley		New York City Load Pockets		North to Central	
Average Transfer Limit	n/a		247		2041		790		305		608		269		362	
Number of Price Spikes	273		6875		144		136		722		160		1119		141	
Average Constraint Shadow Price	$208		$528		$362		$354		$524		$669		$532		$636	
Source of Increased Constraint Cost:	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Scheduled By RTC	185	66%	1	20%	58	45%	66	67%	8	67%	11	28%	3	27%	2	11%
External Interchange	96	34%	1	20%	27	21%	41	42%	2	17%	7	18%	1	9%	2	11%
RTC Shutdown Resource	71	25%	0	0%	21	16%	23	23%	4	33%	3	8%	1	9%	0	0%
Self Scheduled Shutdown/Dispatch	18	6%	0	0%	10	8%	2	2%	2	17%	1	3%	1	9%	0	0%
Flow Change from Non-Modeled Factors	10	4%	4	80%	54	42%	17	17%	2	17%	23	59%	7	64%	9	50%
Loop Flows & Other Non-Market	2	1%	3	60%	16	12%	12	12%	2	17%	11	28%	3	27%	7	39%
Fixed Schedule PARs	0	0%	1	20%	36	28%	4	4%	0	0%	12	31%	3	27%	2	11%
Redispatch for Other Constraint (OOM)	8	3%	0	0%	2	2%	1	1%	0	0%	0	0%	1	9%	0	0%
Other Factors	85	30%	0	0%	18	14%	15	15%	2	17%	5	13%	1	9%	7	39%
Load	47	17%	0	0%	9	7%	8	8%	1	8%	4	10%	0	0%	1	6%
Generator Trip/Derate/Dragging	17	6%	0	0%	8	6%	7	7%	1	8%	1	3%	1	9%	0	0%
Wind	21	8%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	6	33%
Total	280		5		130		98		12		39		11		18	

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

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. 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, reserves, and other operating requirements.

Flow changes from non-modeled factors were the primary driver of constraints across the West Zone line, the Central-East interface, constraints from the Capital Zone to the Hudson Valley Zone, lines in the New York City load pockets, and constraints from North to Central New York.

Loop flows and other non-market factors were the primary driver for the West Zone lines. Clockwise circulation around Lake Erie puts a large amount of non-market flows over lines in the West Zone, which can be volatile and difficult to predict since it depends on scheduling outside the NYISO market. This has had greater impact on transient price spikes since the 115 kV constraints in the West Zone were incorporated into the pricing model in December 2018. West Zone lines accounted for 67 percent of transient price spikes in 2019 shown in the table.

Fixed-schedule PAR-controlled line flow variations (over the A, J, K, and 5018 lines) were a key driver of price spikes for the West Zone lines, the Central-East Interface, Capital to Hudson Valley constraints, and the lines in New York City load pockets. 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.

Among other factors, variations in load forecast had significant impact on the power balance constraint, while changes in wind forecast were a key driver of constraints from North to Central New York as well. Overall, load forecast error and wind forecast error accounted for a relatively small portion of the transient prices spikes.

We also evaluated factors that made the largest contributions to price divergences between RTC and RTD in Section V. The factors mentioned above that contributed most to transient price

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.

spikes were also identified as significant contributors to this price divergence. We also evaluate the effects of inconsistencies between the ramp assumptions used in RTC versus the ones used in RTD in Appendix Section V.

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: [174]

- 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).[175]
- 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 with the exception of PARs with auto-tap changers, this is not what occurs in actual operations unless PAR tap moves are manually taken.

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 energy and reserves 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.

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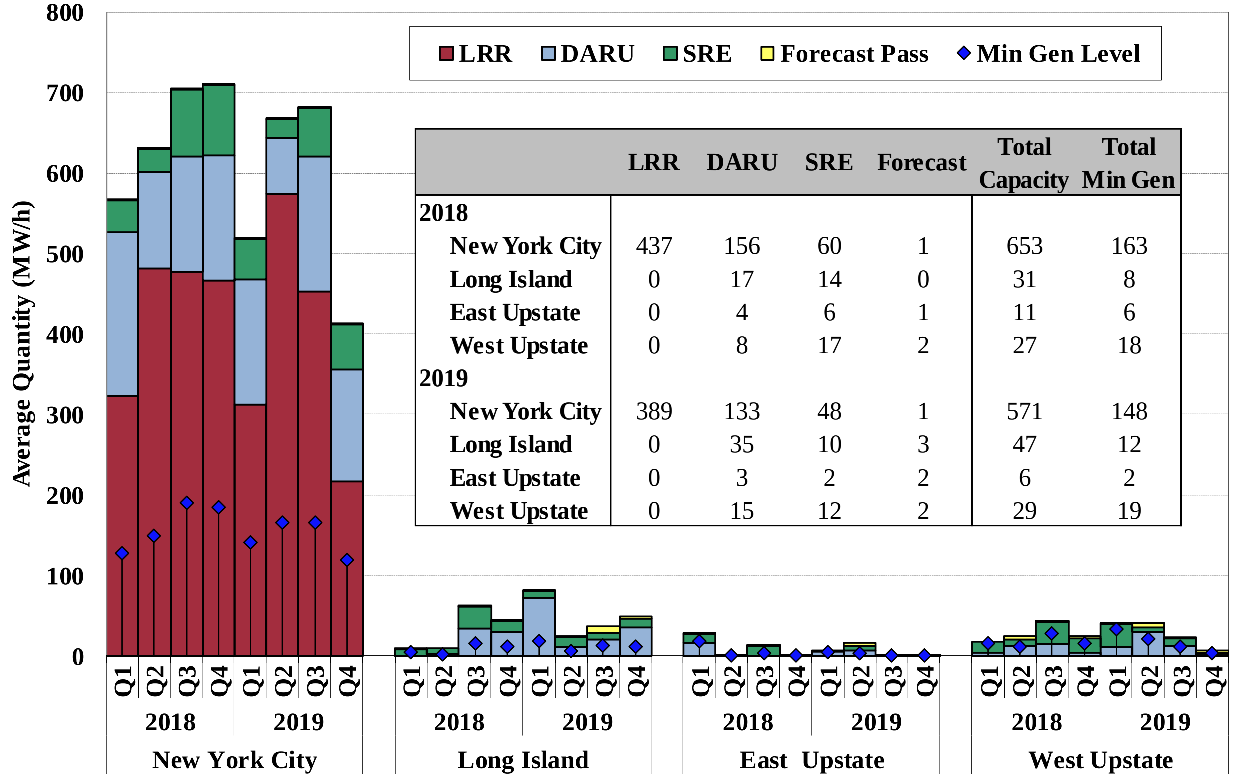
174 See Recommendation #2014-9 in Section XI.

175 In November 2019, the NYISO adjusted the Lake Erie loop flow assumption used in RTC to be the higher of 100 MW clockwise or the value observed at the time RTC initializes. Previously, it was the higher of 0 MW clockwise or the value observed at the time RTC initialized. We supported this change given that the NYISO market software does not allow the use of a bias that varies according to the level of loop flows at the time RTC initializes. See Figure A-82 in the Appendix.

Supplemental Commitment in New York State

Figure 25 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2018 and 2019.[176]

Figure 25: Supplemental Commitment for Reliability in New York
By Category and Region, 2018-2019



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2018						
New York City	437	156	60	1	653	163
Long Island	0	17	14	0	31	8
East Upstate	0	4	6	1	11	6
West Upstate	0	8	17	2	27	18
2019						
New York City	389	133	48	1	571	148
Long Island	0	35	10	3	47	12
East Upstate	0	3	2	2	6	2
West Upstate	0	15	12	2	29	19

Roughly 650 MW of capacity was committed on average for reliability in 2019, down 10 percent from 2018. New York City accounted for 87 percent of total reliability commitment in 2019. The decrease was driven by lower load levels, which reduced the need to commit generation for New York City load pocket reserve requirements; lower natural gas prices in New York City relative to other areas in 2019; and fewer generation and transmission outages.

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 revenues to recoup their day-ahead as-offered costs. Hence, such units typically receive a day-ahead BPCG payment.

176 See Section V.H in the Appendix for a description of the figure.

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 market incentives that would result from modeling N-1-1 requirements in New York City, we estimated the clearing prices that would have occurred in 2019 if the NYISO were to devise a day-ahead market reserve requirement.[177] Table 21 summarizes the results of this evaluation based on market results for four locations in New York City: the 345kV network north of Staten Island, the Astoria West/Queensbridge load pocket, the Vernon location on the 138 kV network, and the Greenwood/Staten Island load pocket.

Table 21: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2019

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$1.38
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$3.66
Vernon	$2.51
Greenwood/Staten Is.	$1.45

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 increases would range from an average of $1.38 per MWh in most areas to as much as $3.66 per MWh in the Astoria West/Queensbridge load pocket in 2019. These price increases would be in addition to the prices of operating reserve products in New York City.

We have recommended that the NYISO model N-1-1 constraints in New York City load pockets, which would provide an efficient market mechanism to satisfy reliability criteria at these locations.[178] We estimated how the energy and reserve net revenues of units would be affected if they were compensated for reserves in New York City load pockets at the rates shown in Table

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

178 See Recommendation #2017-1 in Section XI.

21. This pricing enhancement would have had a large impact, increasing net revenues by $19/kW-year for the demand curve unit in New York City.[179]

To improve market incentives, the NYISO implemented 10-minute and 30-minute reserve requirements for New York City in June 2019. In addition, the NYISO has proposed to model 30-minute reserve requirements in the market software for three load pockets: (a) Astoria East/Corona/Jamaica; (b) Astoria West/Queensbridge/Vernon; and (c) Greenwood/Staten Island. We support this effort and believe it is a good step towards more efficient scheduling and pricing in New York City load pockets.[180]

Out of Merit Dispatch

Table 22 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.[181]

Table 22: Frequency of Out-of-Merit Dispatch
By Region, 2018-2019

Region	OOM Station-Hours		
	2018	2019	% Change
West Upstate	875	234	-73%
East Upstate	1643	2245	37%
New York City	463	440	-5%
Long Island	2310	2802	21%
Total	**5291**	**5721**	**8%**

The quantity of OOM dispatch rose 8 percent from 2018 to 2019. Long Island accounted for the largest share (nearly 50 percent) of OOM actions in 2019 and saw a 21 percent increase from 2018. The increase occurred primarily in the summer months when high-cost peaking resources were frequently used out-of-market to manage congestion on the 69 kV network and voltage needs on the East End of Long Island under high load conditions. These OOM actions have been increasing in recent years, resulting in inefficient pricing and dispatch as well as uplift charges. We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets to allow them to be priced and managed efficiently.[182]

179 See analysis in Section VIII.C.

180 See *More Granular Operating Reserves: Market Design Complete* at MIWG meeting on October 28, 2019.

181 Figure A-89: Frequency of Out-of-Merit DispatchFigure A-89 in the Appendix provides additional detail for 2019 for each region.

182 See Recommendation #2018-1.

On the other hand, Western New York, which used to account for the largest share of OOM actions, saw a reduction of 86 percent from 2017 to 2019. This decrease was driven by transmission upgrades in 2017 and incorporating 115 kV constraints in the West Zone into the market model starting in December 2018.

The OOM actions were significant in the East Upstate area in the first half of 2019. Units at the Bethlehem plant were frequently OOMed to manage post-contingency flow on some 115 kV facilities that were not modeled in the day-ahead and real-time markets. However, this need has been greatly reduced following the completion of transmission upgrades in mid-2019 that were made to make more of the plant's output deliverable.

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 2018 and 2019 on a quarterly basis.[183]

The figure shows that the guarantee payment uplift totaled $52 million in 2019, down 32 percent from 2018. The decrease was driven primarily by:

- Decreased supplemental commitments in New York City (as discussed above in subsection G);
- Lower gas prices, which decreased the commitment costs of gas-fired units; and
- Lower load levels in the summer months, which reduced the Min Oil Burn need for this period and did not require demand response activation as well.

New York City accounted for $29 million (or 55 percent) of BPCG in 2019, down 33 percent from 2018. Over $21 million was paid to generators that were committed for N-1-1 local requirements. We have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals. [184]

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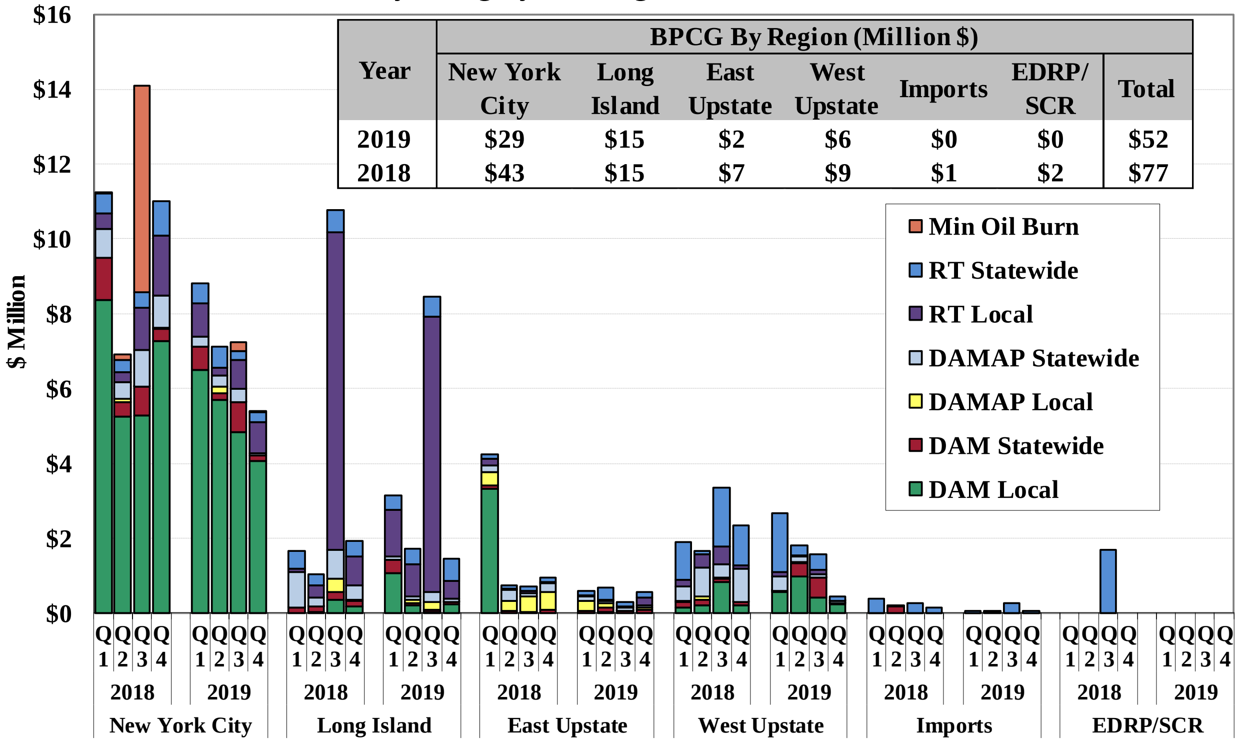
183 See Figure A-90 and Figure A-91 in the Appendix for a more detailed description of this analysis.

184 See Recommendation #2017-1.

Figure 26: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2018 – 2019



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2019	$29	$15	$2	$6	$0	$0	$52
2018	$43	$15	$7	$9	$1	$2	$77

Long Island, did not exhibit much change in total BPCG uplift from 2018 to 2019, accounted for roughly $15 million each year. Nearly $10 million (or 67 percent) of BPCG uplift in each year was paid to high-cost peaking resources on Long Island that were frequently OOMed to manage congestion in the 69 kV network and voltage needs on the East End of Long Island. We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets.[185] Our estimates have shown significant impact on LBMPs and net revenues in the Long Island load pockets from this potential modeling improvements, which should provide a more efficient market signals for investment that tends to help satisfy reliability criteria and relieve congestion.[186]

185 See Recommendation #2018-2.

186 See Section V.B and Section VIII.C for these analyses.

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. As more intermittent generation enters the market over the coming decades, demand response and price-responsive loads will become increasingly important as the NYISO maintains reliability, transmission security, and a supply-demand balance at the lowest cost. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response.

The NYISO has been working on a series of market design projects that are intended to facilitate more active participation by consumers. These projects include:

- DER Participation Model – This should allow individual large consumers and aggregations of consumers to participate more directly in the market, which will better reflect duration limitations in their offers, payments, and obligations.[187]
- Meter Service Entity for DER – This should allow third party metering that could provide greater flexibility to consumers and retail load serving entities.[188]
- Dual Participation – This will allow resources to provide wholesale and retail market services.[189]

This section evaluates existing demand response programs. Future reports will examine the performance of the programs that are currently under development.

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

187 This is scheduled for deployment in 2021.

188 This is scheduled for deployment in 2021.

189 This is scheduled for deployment in 2020.

shortage. Currently, nearly all of the 1,288 MW of demand response resources registered in New York are reliability demand response resources.[190]

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,282 MW of resources participating in 2019. 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 2019 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.9 percent of the UCAP requirement for New York City;
- An average of 4.1 percent of the UCAP requirement for the G-J Locality;
- An average of 0.9 percent of the UCAP requirement for Long Island; and
- An average of 3.5 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources fell by roughly 50 percent from 2010 to 2019 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011 (registered quantity did not change significantly each year from 2013 to 2019). These have improved the accuracy of baselines for some resources, reducing the amount of capacity they is 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, three DSASP resources in Upstate New York actively participate in the market, providing considerable value by reducing the cost of ancillary services in the New York market. These resources collectively provided an average of more than 60 MW of 10-minute spinning reserves in 2019, satisfying nearly 10 percent of the NYCA 10-minute spinning reserve requirement.

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.

190 In addition, there are demand response programs that are administered by local TOs.

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 2019, the NYISO did not activate reliability demand response resources, therefore, the performance of demand response calls is not evaluated in this report.[191]

However, demand response resources in local utility programs were activated on 15 days in 2019. The amount of these deployments exceeded 100 MW on five days and approached 600 MW on one day. These demand response resources were activated for peak-shaving and distribution system security mostly in New York City and on days when the economics of the energy market usually did not indicate a need for peak load reduction.[192]

Utility demand response deployments are not currently considered in the market scheduling and pricing. The capacity of utility-activated demand response is not considered in day-ahead forecasts, which may lead to excessive reliability commitments on high-load days. In addition, the deployed MW is not considered in the current scarcity pricing rules in the real-time market even though it may help avoid capacity deficiency. Therefore, it would be beneficial for the NYISO to work with TOs to evaluate the feasibility of including utility demand response deployments in its market scheduling and pricing.

191 See our prior SOM reports for the evaluation of operations and pricing efficiency of historical demand response calls.

192 Utility demand response resources are paid primarily for availability (including capacity). Utility programs often provide large payments (~$1,000/MWh) for peak-shaving when it is not cost-effective by local TOs.

XI. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2019, although we recommend additional enhancements to improve market performance. Twenty-two 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 #2015-16 originally appeared in the 2015 SOM Report as Recommendation #16. The majority of these recommendations were made in the 2018 SOM Report, but Recommendations #2019-1 to #2019-5 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				
2019-1	VIII.C	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.		
2018-1	V.B, VIII.C	Model Long Island transmission constraints in the day-ahead and real-time markets that are currently managed by NYISO with OOM actions and develop associated mitigation measures.		
2017-1	VIII.C, IX.G	Model local reserve requirements in New York City load pockets.	✓	✓
2017-2	VIII.C, IX.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	✓	✓
2016-1	VIII.C, IX.C	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		✓
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.	✓	
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				
2019-2	V.A	Adjust offer/bid floor from negative $1000/MWh to negative $150/MWh.		
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.		

Number	Section	Recommendation	Current Effort	High Priority
2012-8	IX.D	Operate PAR-controlled lines between New York City and Long Island 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.		
Capacity Market – Market Power Mitigation Measures				
2019-3	III.C	Modify the Part A test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels.	✓	✓
2018-3	III.C	Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.	✓	
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
Capacity Market – Design Enhancements				
2019-4	VII.B	Modify translation of the annual revenue requirement for the demand curve unit into monthly demand curves that consider reliability value.		
2019-5	VII.C	Translate demand curve reference point from ICAP to UCAP terms based on the demand curve unit technology.		
2013-1c	VII.D	Implement locational marginal pricing of capacity (“C-LMP”) that minimizes the cost of satisfying planning requirements.		✓
2012-1c	VII.E	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.F	Reform the transmission planning 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

Energy Market Enhancements – Pricing and Performance Incentives

2019-1: Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.

The day-ahead and real-time markets schedule resources to satisfy reserve requirements, including specific requirements for 10-minute spinning reserves, 10-minute total reserves, and 30-minute total reserves on Long Island. However, reserve providers on Long Island are not paid reserve clearing prices corresponding to these requirements. Instead, they are paid based on the clearing prices for the larger Southeast New York region. Compensating reserve providers in accordance with the day-ahead and real-time scheduling decisions would improve incentives in the day-ahead and real-time markets, and it would also provide better signals to new investors in over the long term.[193]

2018-1: Model Long Island transmission constraints in the day-ahead and real-time markets that are currently managed by NYISO with OOM actions and develop associated mitigation measures.

Market incentives are inadequate for investment in resources that help secure the 69kV system on Long Island partly because these facilities are not modeled in the NYISO's energy and ancillary services markets. Currently, these constraints are secured primarily through out-of-market actions, which has raised guarantee payments and is sometimes inefficient. We recognize that implementing a process to manage these constraints in the day-ahead and real-time markets would require significant effort, since it would requires additional coordination with the local Transmission Owner. [194]

Some lower-voltage 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 may need to be expanded to address the potential exercise of market power in day-ahead or real-time energy markets.

2017-1: Model local reserve requirements in New York City load pockets. (Current Effort, High Priority)

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.[195] Hence, we recommend the NYISO consider implementing local reserve requirements in the New York City load pockets.

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193 See discussion in Section VIII.C. See 2021 Project Candidate: *Long Island Reserve Constraint Pricing*.

194 See discussion in Sections V.B and VIII.C. This project would require operational changes but no tariff changes, so this project is not listed as a 2021 Project Candidate.

195 See discussion in Sections IX.G and VIII.C. For current effort, see the 2020 Project *More Granular Operating Reserves*, which seeks stakeholder approval for a market design that would implement this recommendation to a limited extent. The 2021 Project Candidate of the same name would move the limited-

The NYISO's assessment should consider three related issues. First, the NYISO should consider whether changes are necessary to the market power mitigation measures. Second, since the amount of reserves needed to satisfy the N-1-1 requirements in the day-ahead market depends on whether sufficient energy is scheduled to satisfy forecast load, we recommend that the NYISO consider adjusting the reserve requirement to account for any under-scheduling of energy. This concern would be addressed comprehensively by Recommendation #2015-16 (see below).

Third, 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: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability. (Current Effort, 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 are 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 are changing. Hence, we recommend that the NYISO evaluate the incentive effects of the PFP rules and consider modifying its operating reserve demand curves to provide efficient incentives and ensure reliability during shortage conditions. This evaluation should consider having multiple steps for each operating reserve demand curve so that:

- Clearing prices rise to levels that are efficient given the value-of-lost-load and the risk of load shedding; and
- The real-time market schedules available resources such that NYISO operators do not need to engage in out-of-market actions to maintain reliability.[196]

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

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scope project to Development Complete. The 2021 Project Candidate: *Reserve Enhancements for Constrained Areas* would perform a study of a comprehensive market design solution.

196 See discussion in Sections IX.A and VIII.C. For current effort, see the 2020 Project: *Ancillary Services Shortage Pricing*, which seeks stakeholder approval for a market design that would implement this recommendation to a limited extent. The 2021 Project Candidate of the same name would move the project to Development Complete.

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. (High Priority)

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.[197] 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.

This recommendation has been raised to a high priority because New York City is expected to lose up to 1300 MW of peaking generation over the next five years and it has become critically important for the NYISO market to provide efficient signals for new investment. Some of the retiring peakers are currently utilized for thousands of hours per year to manage congestion by providing offline reserves, which reduces production costs and allows higher levels of imports to New York City. If reserve providers are not compensated in a manner that is consistent with their value, it is less likely that new investors will place resources in areas that relieve congestion and that new resources will have flexible operating characteristics.

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 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 is due partly 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

197 See discussion in Section IX.C of this report and Section IX.C of the 2016 SOM Report. See 2021 Project Candidate: *Reserve Enhancements for Constrained Areas*.

expected value of spreads between markets. Hence, we recommend eliminating transaction fees and uplift charges between the PJM and NYISO.[198]

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. (High Priority)

In some cases, the reserve requirement for an area can be met more efficiently by scheduling additional generation in the area (i.e., reducing flows into the area and treating the unused interface capability as reserves), rather than scheduling reserves on internal generation. Likewise, reducing the availability of generation within an area may require the NYISO to hold additional reserves within the area. This report identifies five examples where this functionality would provide significant benefits.

- *Long Island reserve requirements* – 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.
- *Eastern and Southeastern New York reserve requirements* – 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.
- *NYCA reserve requirements*:
  - ✓ 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.
  - ✓ The reserve market requirement is frequently satisfied in the day-ahead market by under-scheduling physical energy supply needed to satisfy the forecast load (to make additional resources available to be scheduled reserves). Under peak operating conditions, this can lead to insufficient commitment to satisfy the combined energy and operating reserves requirements for the next day, leading the NYISO to commit generation out of market, which tends to depress clearing prices and undermine incentives for resources to be available. Raising the NYCA

198 See discussion in Section VI.D. See 2021 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

reserve requirement to account for such under-scheduling of energy would help ensure that the market schedules and prices resources efficiently.

- *New York City zone-level and load pocket reserve requirements* – 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 the interface) rather than hold reserves on internal units inside the load pocket. This will become particularly important when offshore wind is added to New York City because it will lead to situations where a load pocket reserve requirement is met by energy generation (rather than reserves) inside the pocket.

Hence, we recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each of these requirements.[199]

This recommendation has been raised to a high priority because will enable to the NYISO to schedule and price operating reserves efficiently as it implements other high priority recommendations. This will become more important as the New York energy supply mix evolves over the coming decade.

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, 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.[200]

Energy Market Enhancements – Market Power Mitigation Measures

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

[199] See discussion in Section IX.A. See 2021 Project Candidate: *Reserve Enhancements for Constrained Areas*.

[200] See discussion in Section IX.A. See 2020 Project: *Constraint Specific Transmission Shortage Pricing*, which seeks stakeholder approval for a market design that would partially implement this recommendation. The 2021 Project Candidate of the same name would move the project to Development Complete.

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 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.[201]

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.[202]

Energy Market Enhancements – Real-Time Market Operations

2019-2: Adjust offer/bid floor from negative $1000/MWh to negative $150/MWh.

The bid and offer floor for internal resources and external transactions is negative $1,000/MWh. Under rare conditions, the NYISO operators may have to reduce external interface limits and/or curtail external transactions to maintain transmission security on an external interface. In such cases, external transaction schedulers are effectively able to "buy" power at arbitrarily low price levels, resulting in uplift for NYISO customers. We recommend raising the bid and offer floor to a level that is closer to the range of potential avoided costs of supply for generation resources. Negative $150/MWh should be more than adequate to provide such flexibility.[203]

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201 See discussion in Section IX.A.

202 See discussion in Section III.B.

203 See discussion in Section V.A. See 2021 Project Candidate: *Adjustment of Energy Offer/Bid Floor*.

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 2019. 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 (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.[204] Eliminating these unrealistic assumptions would improve the accuracy of the modeling of these PARs and reduce the frequency of transient price spikes and improve consistency between RTC and RTD.

2012-8: Operate PAR-controlled lines between New York City and Long Island 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 2019, 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) 5 and 10 percent of the time. Their operation increased production costs by an estimated $10 million, and sometimes restricted production by economic generation in New York City.[205]

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 VI.G of the Appendix.

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204 See discussion in Sections VI.D and IX.E. See 2021 Project Candidate: *Enhanced PAR Modeling*.

205 See discussion in Section IX.D. See 2021 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

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: [206]

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

Capacity Market – Market Power Mitigation Measures

2019-3: Modify the Part A test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels. (Current Effort, High Priority)

The BSM rules play a critical role in ensuring that out-of-market investment does not suppress capacity prices below competitive levels in the short-run, and are a critical tool in fostering

206 See discussion in Sections VI.D and IX.F. See 2021 Project Candidate: *RTC-RTD Convergence Improvements*.

confidence in the market and the competitiveness of future prices. The BSM measures were originally designed to prevent entities from suppressing capacity prices below competitive levels by subsidizing uneconomic new entry of a conventional generator. The BSM measures are not intended to deter states from promoting clean energy and other legitimate public policy objectives. The BSM rules should strike a reasonable balance between: (a) protecting the integrity of the market by preventing capacity price suppression, and (b) facilitating the state's efforts to shape its resource mix to achieve its policy objectives. The BSM rules should evolve to maintain a proper balance between these two objectives.

The NYISO recently worked with us and its stakeholders to develop a set of enhancements whereby new entrants would be exempted under the Part A test if the capacity surplus is lower than a certain threshold ("Part A threshold"). The NYISO proposal allows Public Policy Resources ("PPRs") to avoid mitigation as long as sufficient quantity of existing capacity exits the market or demand growth leads to higher capacity requirements. This would allow for a workable balance between facilitating state policy objectives and ensuring that prices are just and reasonable. Accordingly, we support the NYISO's proposal.[207]

2018-3: Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.

The Part A test of BSM evaluations is designed to exempt a project whose capacity is needed to satisfy the local capacity planning requirement where the project would locate. Thus, a New York City generator would be exempt if it was needed to satisfy the LCR for New York City. However, a New York City generator would not be exempt if it was needed to satisfy the LCR for the G-J Locality. Given the large resource mix changes that are expected in the coming years, we recommend modifying the Part A test to test a New York City generator against the larger G-J Locality requirement in addition to the New York City requirement.[208]

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 economic value of a project may improve after future retirements and transmission additions.

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[207] See discussion in Section III.C.

[208] See discussion in Section III.C.

We recommend the NYISO modify the BSM assumptions to allow the forecasted prices and project interconnection costs to be reasonably consistent with expectations.[209]

<u>Capacity Market – Design Enhancements</u>

2019-4: Modify translation of the annual revenue requirement for the demand curve unit into monthly demand curves that consider reliability value.

The capacity market is divided into summer and winter capability periods of six months. Within each capability period, the capacity requirements and demand curves remain constant, although the reliability value of resources is much greater in high-demand months (e.g., July) than in low-demand months (e.g., October). This ensures that resource owners have an incentive to coordinate their planned outages through the NYISO outage scheduling process throughout the year, however, it may lead to inefficient incentives for resources that are not consistently available during all 12 months of the year. We recommend the NYISO translate the annual revenue requirement into monthly capacity demand curves based on:

- Setting a minimum demand curve reference point sufficiently high to ensure resources have incentives to coordinate planned outages with the NYISO; while
- Allocating the remainder of the demand curve unit's annual revenue requirement in proportion to the marginal reliability value of capacity across the 12 months of the year.

These changes would concentrate the incentives for resources to sell capacity into New York during the peak demand months of the summer (i.e., June to August).[210]

2019-5: Translate demand curve reference point from ICAP to UCAP terms based on the demand curve unit technology.

The capacity demand curves are based on the net cost of new entry for the demand curve unit. This is estimated in ICAP-terms and then converted into UCAP-terms based on the regional average derating factor, which reflects the forced outage rates of the existing fleet as well as UCAP-ICAP ratios of intermittent resources. Since the demand curve unit would have a low forced outage rate, this method leads the monthly capacity demand curves to be set higher than if the derating factor of the demand curve technology were used. This inconsistency will become more pronounced as additional intermittent resources are added to the system. We recommend the NYISO utilize the estimated forced outage rate of the demand curve unit technology to perform the ICAP to UCAP translation.[211]

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209 See list of recommended assumptions in Section III.C. See 2021 Project Candidate: *Enhanced BSM Forecasts Assumptions*.

210 See discussion in Section VII.B. See 2021 Project Candidate: *Monthly Demand Curves.*

211 See discussion in Section VII.B. See 2021 Project Candidate: *Demand Curve Translation Enhancement.*

2013-1c: Implement locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements. (High Priority)

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 fully considering whether this results in a consistent relationship between the clearing prices of capacity and the marginal reliability value of capacity in each Locality. Although the changes in the LCR implemented in 2018 are an improvement, the resulting capacity procurements and prices are not fully efficient, which raises the overall cost of satisfying the capacity needs. Reliance on four fixed capacity zones will also prevent the current market from responding to significant resource additions, retirements, or transmission network changes.

We recommend the NYISO implement a capacity pricing framework where the procurements and clearing price at each location is set in accordance with the marginal reliability value of capacity at the location.[212] Our proposed Locational Marginal Pricing of Capacity (C-LMP) would eliminate the existing capacity zones and clear the capacity market with an auction engine that will include the planning criteria and constraints. This will optimize the capacity procurements at locations throughout the State, and establish locational capacity prices that reflect the marginal capacity value at these locations. This proposal would reduce the costs of satisfying resource adequacy needs, facilitate efficient investment and retirement, be more adaptable to changes in resource mix (i.e., increasing penetration of wind, solar, and energy storage), and simplify market administration.

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.[213]

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212 See discussion in Section VII.D. See 2021 Project Candidate: *Locational Marginal Pricing of Capacity*.

213 See discussion in Section VII.E. See 2021 Project Candidate: *Capacity Transfer Rights for Internal Transmission Upgrades*.

Enhance Planning Processes

2015-7: Reform the transmission planning 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 transmission planning processes to identify any additional changes that would be valuable, and make the changes necessary to ensure that they will identify and fund economic transmission projects.[214]

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 2018 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2018 State of the Market Report.

#2016-2 – The NYISO has begun to increase the number of audits it performs of offline reserve units each year. The average performance of existing generators has improved considerably and there are relatively few generators that are chronically poor performers. Furthermore, the NYISO has indicated that it may temporarily disqualify generators that perform poorly in audits and/or reserve pick-ups. In light of these changes and the significant administrative effort that would be required to implement a performance-based adjustment to the payments to reserve providers, we have removed this recommendation.[215]

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214 See discussion in Section VII.D.

215 See *More Granular Operating Reserves: Reserve Provider Performance*, presented to ICAP Work Group/Market Issues Working Group on April 7, 2020.

#2018-2 – In February 2020, the NYISO filed amendments to the Competitive Entry Exemption rules that would expand types of contracts that a competitive entrant could have with certain counterparties to allow normal hedging agreements that do not serve as a conduit for subsidies.[216] The Commission accepted these amendments, which addressed the recommendation.

#2018-4 – The NYISO tariff currently does not provide a mechanism for generators smaller than 2 MW to receive an exemption from buyer-side mitigation rules. In addition, the tariff may automatically exempt load-based distributed energy resources smaller than 2 MW while subjecting SCRs to buyer-side mitigation. This narrow recommendation has been withdrawn and may be replaced with a more comprehensive recommendation in the future.

Other Recommendations Not Included on the List for 2018

This subsection describes recommendations from previous reports that were not resolved but that are not included in this report.

#2012-1a – This recommendation would have established a process for creating additional capacity pricing regions when transmission limitations bind in deliverability, resource adequacy, and transmission security studies. The substance of this recommendation would be addressed if the NYISO adopts #2013-1c, so there is no need to maintain this recommendation separately.

216 See the NYISO's February 7, 2020 filing supplementing its December 20, 2019 filing in docket numbers ER20-663-000 and ER20-663-001.

Analytic Appendix

2019 State of the Market Report

For the

New York ISO Markets

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I. MARKET PRICES AND OUTCOMES

The New York ISO operates a multi-settlement wholesale market system consisting of financially-binding day-ahead and real-time markets for energy, operating reserves, and regulation (i.e., automatic generation control). Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. The NYISO also operates markets for transmission congestion contracts and installed capacity, which are evaluated in Sections III and VI of the Appendix.

This section of the appendix summarizes the market results and performance in 2019 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.

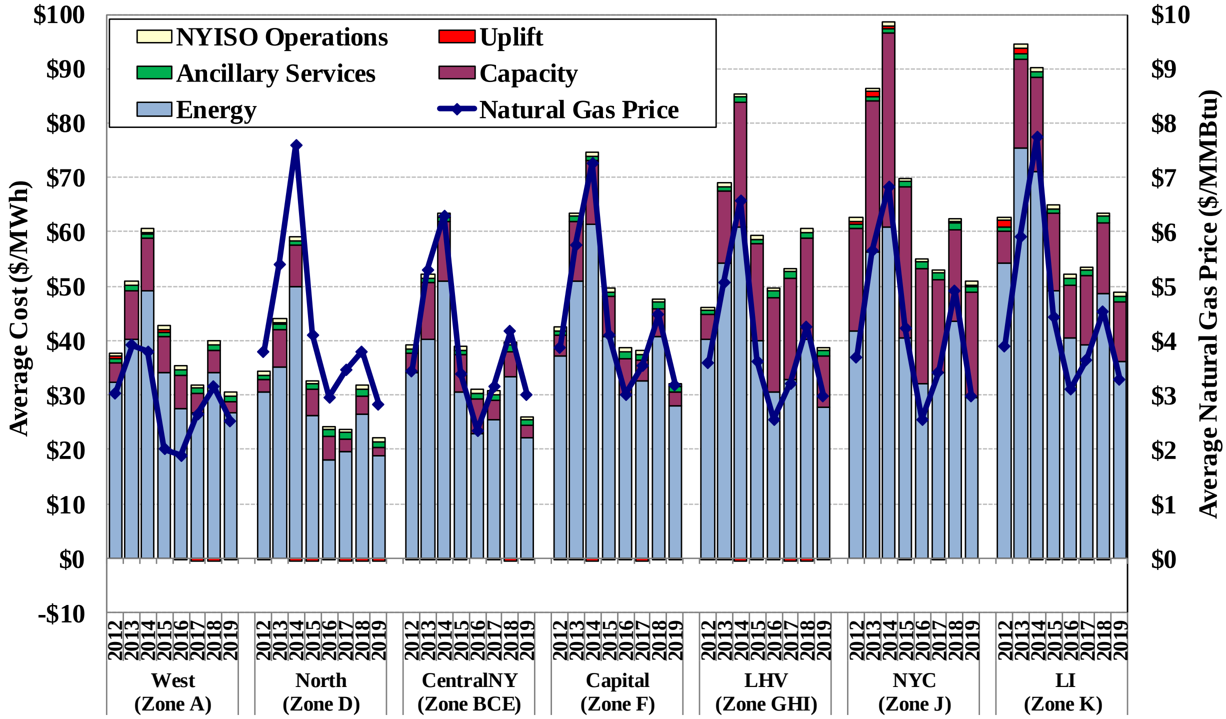
The energy prices in this metric are load-weighted average real-time energy prices. The capacity component is calculated based on clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over the energy consumption in that area.[217] The uplift component is based on local and statewide uplift from Schedule 1 charges, allocated over the

217 In prior State of the Market reports, our cost allocation was based on UCAP numbers and prices along with peak load share for the four localities. New to this year's report, is a more precise calculation of capacity costs for each of the 11 load zones and its peak load share. Thus, numbers will differ from what we reported in the past as the cost is more appropriately allocated to each locality.

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 2012 to 2019 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.

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

2012 – 2019



Natural gas prices are based on the following gas indices (plus a transportation charge): (a) the Tennessee Zone 4 200L index for the West Zone, (b) the minimum of Tennessee Zone 6 and Iroquois Zone 2 indices during the months December through February, and Tennessee Zone 4 200L index during the rest of the year for Central New York; (c) the Iroquois Waddington index for North Zone; (d) the minimum of Tennessee Zone 6 and Iroquois Zone 2 indices for the Capital Zone; (e) the average of Iroquois Zone 2 index and the Tetco M3 index for Lower Hudson Valley; (f) the Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Zone 2 index for Long Island.[218] An incremental 6.9 percent tax rate is also reflected in the natural gas

218 The following transportation costs are included in the delivered prices for each region: (a) $0.27 per MMBtu for Zones A through I, (b) $0.20 per MMBtu for New York City, and (c) $0.25 per MMBtu for Long Island.

prices for New York City. An incremental 1 percent tax rate is reflected for Long Island on top of the delivered gas prices. [219]

Table A-1: Average Fuel Prices and Real-Time Energy Prices

Natural gas prices often exhibit high volatility during periods of severe cold weather. This has resulted in large differences between the average gas and energy prices during winter months and the remainder of the year in the past several years. Table A-1 shows the average gas and real-time energy prices in 2018 and 2019, both on an annual basis and for the month of January. The table also shows representative gas price indices that are associated with each of the seven regions.

Table A-1: Average Natural Gas Prices and Real-Time Energy Prices
2018-2019

	Annual Average			January Average			Rest-of-Year Average		
	2018	2019	% Change	2018	2019	% Change	2018	2019	% Change
Gas Prices ($/MMBtu)									
Tennessee Z4 200L	$2.88	$2.26	-22%	$3.51	$2.91	-17%	$2.82	$2.19	-22%
Tetco M3	$3.69	$2.39	-35%	$13.29	$4.35	-67%	$2.80	$2.21	-21%
Transco Z6 (NY)	$4.42	$2.59	-41%	$18.73	$6.02	-68%	$3.09	$2.27	-26%
Iroquois Z2	$4.30	$3.05	-29%	$14.65	$6.95	-53%	$3.33	$2.68	-19%
Tennessee Z6	$5.08	$3.26	-36%	$17.59	$7.03	-60%	$3.92	$2.91	-26%
Energy Prices ($/MWh)									
West (TN Z4 200L)	$33.83	$26.51	-22%	$66.95	$34.68	-48%	$30.82	$25.77	-16%
Capital Zone (min of Iroq. & TN Z6)	$39.82	$27.69	-30%	$109.34	$46.52	-57%	$33.50	$25.98	-22%
Lw. Hudson (Tetco M3/Iroq.)	$39.68	$27.58	-30%	$101.56	$44.25	-56%	$34.06	$26.07	-23%
New York City (Transco)	$43.22	$29.41	-32%	$108.28	$45.70	-58%	$37.31	$27.93	-25%
Long Island (Iroquois)	$48.14	$35.41	-26%	$108.32	$50.84	-53%	$42.67	$34.01	-20%

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

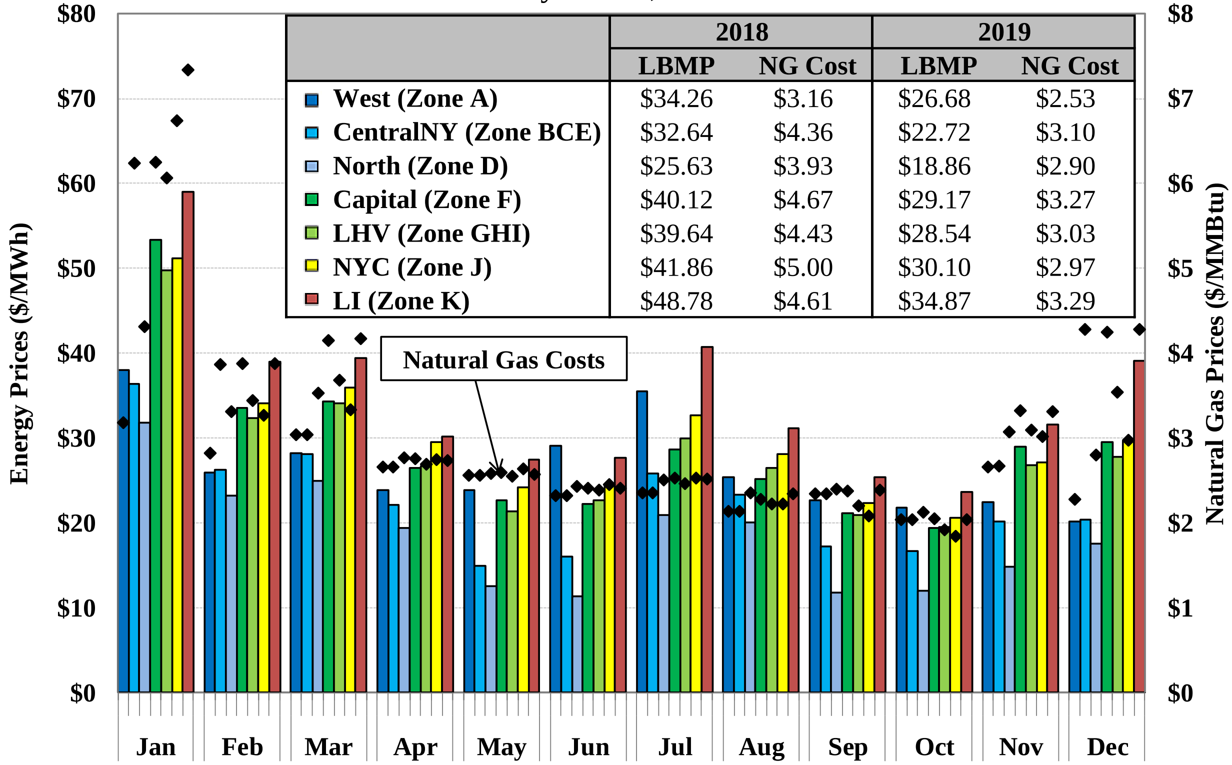
Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2019 for the seven locations shown in Figure A-1.[220] The table overlapping the chart shows the annual averages of natural gas costs and LBMPs for 2018 and 2019. Although hydro and nuclear generators produce much of the electricity used by New York consumers, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York.[221]

219 Some gas price indices were significantly less liquid in the past than in recent years. Tennessee Z4 200L was illiquid prior to spring (April) of 2013. For zones that rely on gas from that source prior to 2013, we used the following assumptions in place of Tennessee Z4 200L: when Tennessee Z4 200L data was missing for a given day, use the first non-missing value from, in order, the Millennium East, Dominion North, Dominion South, and Niagara indices.

220 Note that reported gas costs for 2018 may differ from values published in our 2018 SOM due to the change in natural gas index assumptions documented in the description for Figure A-1.

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

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2019



	2018		2019	
	LBMP	NG Cost	LBMP	NG Cost
West (Zone A)	$34.26	$3.16	$26.68	$2.53
CentralNY (Zone BCE)	$32.64	$4.36	$22.72	$3.10
North (Zone D)	$25.63	$3.93	$18.86	$2.90
Capital (Zone F)	$40.12	$4.67	$29.17	$3.27
LHV (Zone GHI)	$39.64	$4.43	$28.54	$3.03
NYC (Zone J)	$41.86	$5.00	$30.10	$2.97
LI (Zone K)	$48.78	$4.61	$34.87	$3.29

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).[222] 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.[223]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2019 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 2018 and in 2019 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.

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

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

Figure A-3: Average Monthly Implied Marginal Heat Rate

Day-Ahead Market, 2019

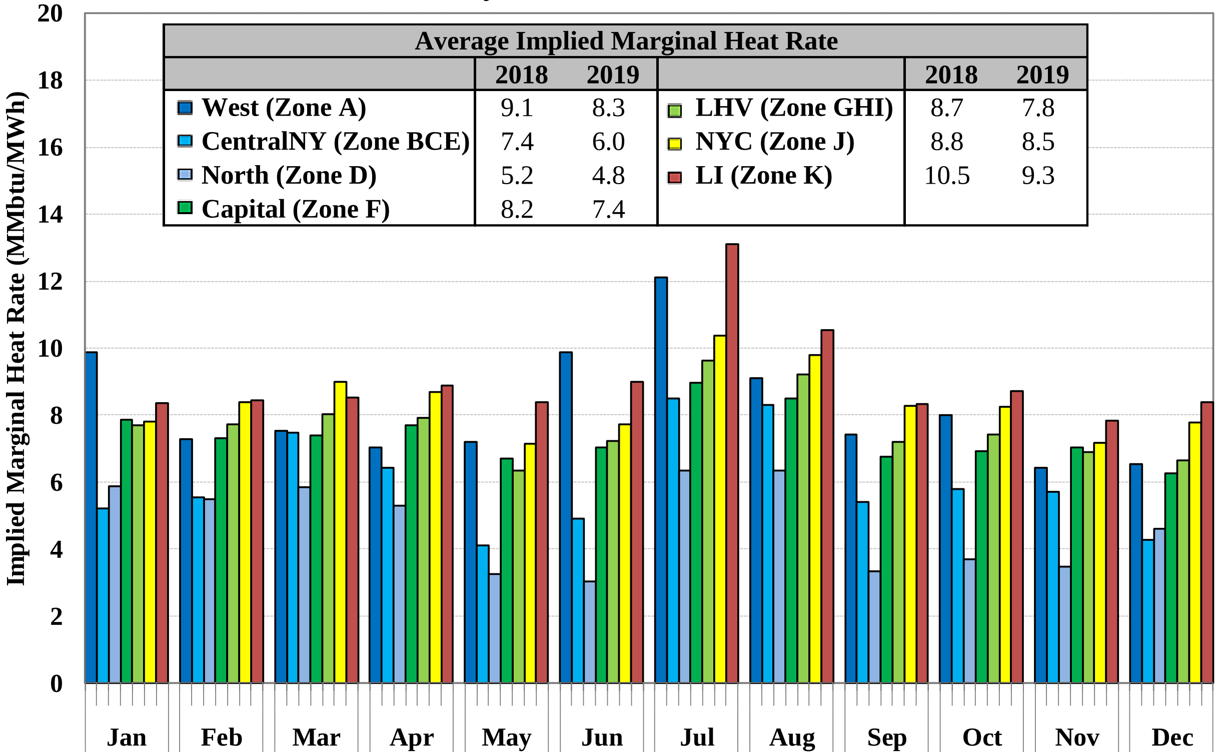


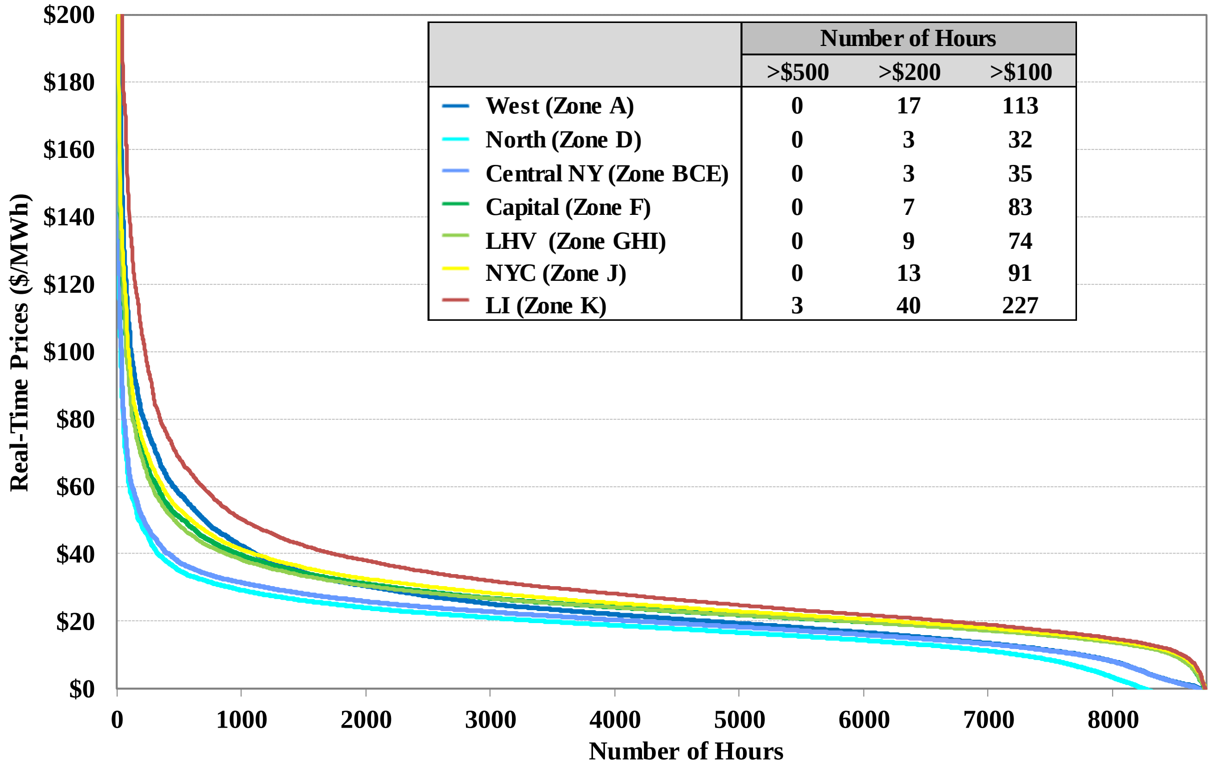
Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

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 2019, 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 2019 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.[224] 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.

224 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.

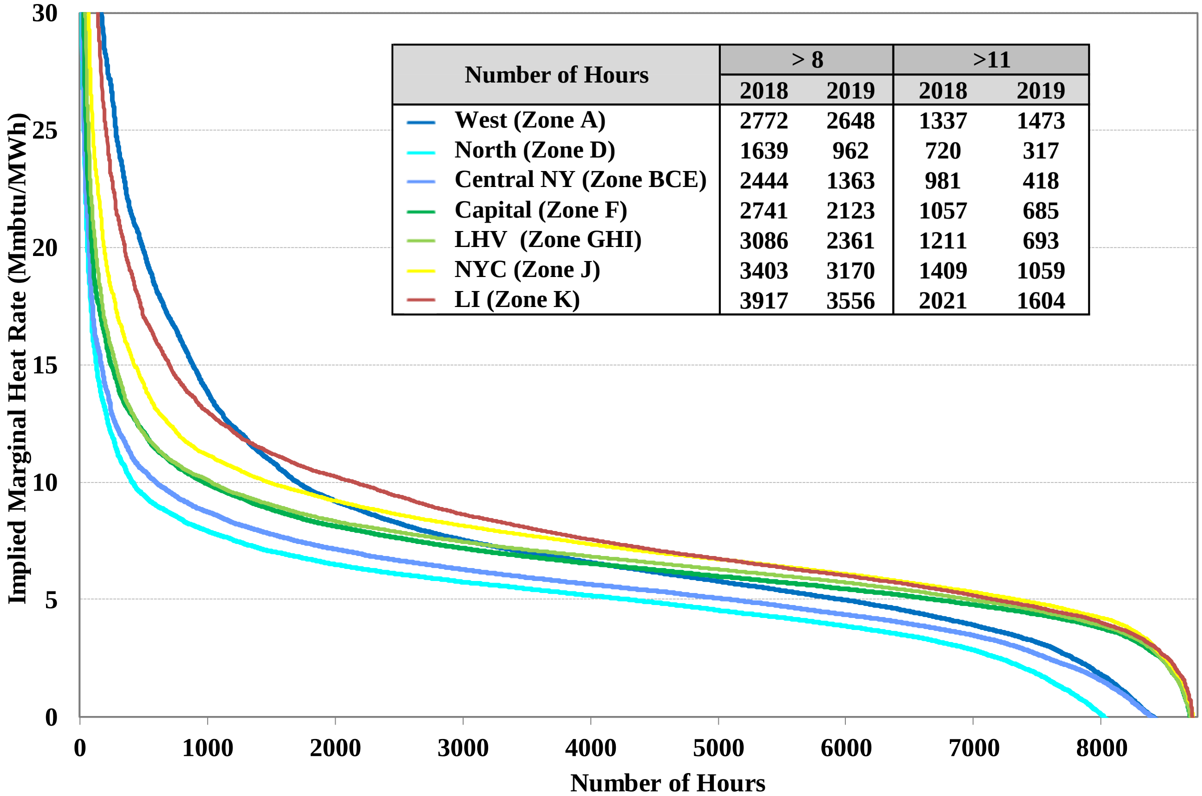
Figure A-4: Real-Time Price Duration Curves by Region
2019



	Number of Hours		
	>$500	>$200	>$100
West (Zone A)	0	17	113
North (Zone D)	0	3	32
Central NY (Zone BCE)	0	3	35
Capital (Zone F)	0	7	83
LHV (Zone GHI)	0	9	74
NYC (Zone J)	0	13	91
LI (Zone K)	3	40	227

Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2019. 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 2018 and 2019.

Figure A-5: Implied Heat Rate Duration Curves by Region
2019



Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from roughly \$22/MWh in the North Zone to \$51/MWh in New York City in 2019.
  - All-in prices fell in all regions from 2018 to 2019. The prices in individual regions fell by 19 percent to 36 percent.
- Energy costs accounted for 58 to 74 percent of the all-in prices in the downstate regions, and 86 to 88 percent of all-in prices in upstate regions.
  - Energy costs in all regions decreased by 22 to 34 percent from 2018 to 2019. Low natural gas prices coupled with low summer load conditions drove the majority of this reduction in 2019.
    - The 2019 winter months were significantly milder than in 2018 and had few days of high gas prices. In contrast, severe cold weather in most of January 2018 led to high gas prices. The mild winter conditions in 2019 contributed to high natural gas storage levels, which, coupled with the continued increase in production from regional shale gas plays, helped keep gas prices low throughout 2019.
    - Lower load levels during the summer months further contributed to reduced energy prices. In 2019, the peak load and average load decreased by 4.7 percent and 3.3 percent respectively compared to the 2018 levels (see subsection D).

- In late August 2018, the NYISO filed tariff revisions that allowed it to use lower Constraint Reliability Margins ("CRM") when securing transmission facilities. This change contributed to less severe congestion (and negative pricing intervals) in the North Zone during periods with significant transmission outages and reduced congestion between the North and Central NY zones in 2019 when compared to 2018.
- The year-over-year energy price reduction in the West Zone was the smallest of the upstate zones. This was due to the increase in priced congestion on the 115 kV system, especially during the first and third quarters. The 115 kV constraints were previously managed using OOM actions and surrogate transmission constraints, but most of these previously unpriced constraints were incorporated into the market since December 2018 (see Section III of the Appendix).
- The highest energy costs occurred in Long Island, especially during the peak winter months (i.e., January and December) and during the peak load month (July). Long Island has an older less-fuel-efficient generation fleet that typically faces higher gas prices than other regions. Long Island also requires oil-fired generation to run more frequently than other regions.

- Capacity costs accounted for 22 to 38 percent of the all-in price in downstate regions and 7 to 9 percent of the all-in price in the upstate regions.
  - Capacity rose in New York City (16 percent) primarily because of a 2.3 percentage point increase in the Locational Capacity Requirement ("LCR").
  - Lower Hudson Valley capacity costs fell 50 percent due to improved Unforced Capacity ("UCAP") ratings of the supply resources, and a 2.2 percentage point reduction in the LCR.
  - Capacity costs in the Rest of State ("ROS") and in Long Island ("LI") also fell year-over-year by 47-to-52 and 17 percent, respectively. Changes to the ICAP requirements and increases in UCAP from internal resources drove these reductions (see Section VI in the Appendix).
- The average implied marginal heat rates fell from 2018 to 2019 in most regions.
  - These decreases were primarily due to lower load levels during the summer and winter months.
    - The steepest reductions in the implied marginal heat rates occurred in the Central Zone (32 percent) and in the Lower Hudson Valley (25 percent), The Central Zone saw an uptick in congestion on the Scriba-Volney lines due to a surplus of economic production within a generation pocket, which resulted in lower prices for the zone across much of the year. Mild winter and summer conditions along with the entry of new fuel-efficient baseload generation drove much of the reductions in heat rates in the Lower Hudson Valley.
    - The smallest year-over-year reductions in the implied marginal heat rates occurred in the West Zone (congestion) and New York City. As noted above,

congestion across West Zone increased in 2019 due to the modeling of 115kV constraints. The reduction in implied marginal heat rate in New York City was muted likely due to two factors: (a) the NYISO implemented New York City reserve requirements starting June 2019, which likely increased the energy prices, and (b) unlike previous years, gas priced at the Transco Zone 6 (NY) index was not always available, and instead in-city suppliers had to rely on gas priced at the Iroquois Zone 2 index.

B. Fuel Prices and Generation by Fuel Type

Figure A-6 to Figure A-8: Monthly Average Fuel Prices and Generation by Fuel Type

Fluctuations in fossil fuel prices, especially gas prices, have been the primary driver of changes in wholesale power prices over the past several years.[228] 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.[229] 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.[230]

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 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 Capital Zone and Central Zone as well as 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;

228 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.

229 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.

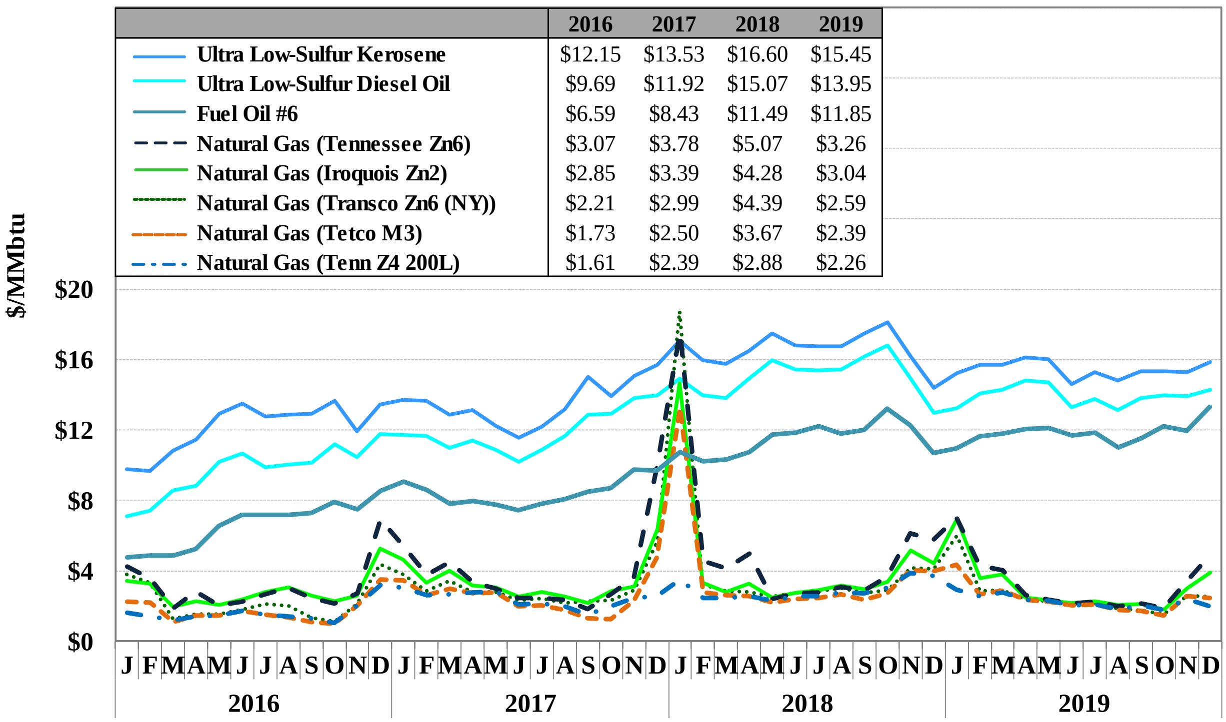
230 Emissions restrictions have tightened over the past years such that some steam turbines in New York City burn a No. 4 residual fuel oil blend.

- Tetco M3 prices and Iroquois Zone 2 are representative of natural gas prices in various locations of the Lower Hudson Valley; and

- Tennessee Zone 4 200L 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 2016 to 2019. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices[231]
2016 – 2019



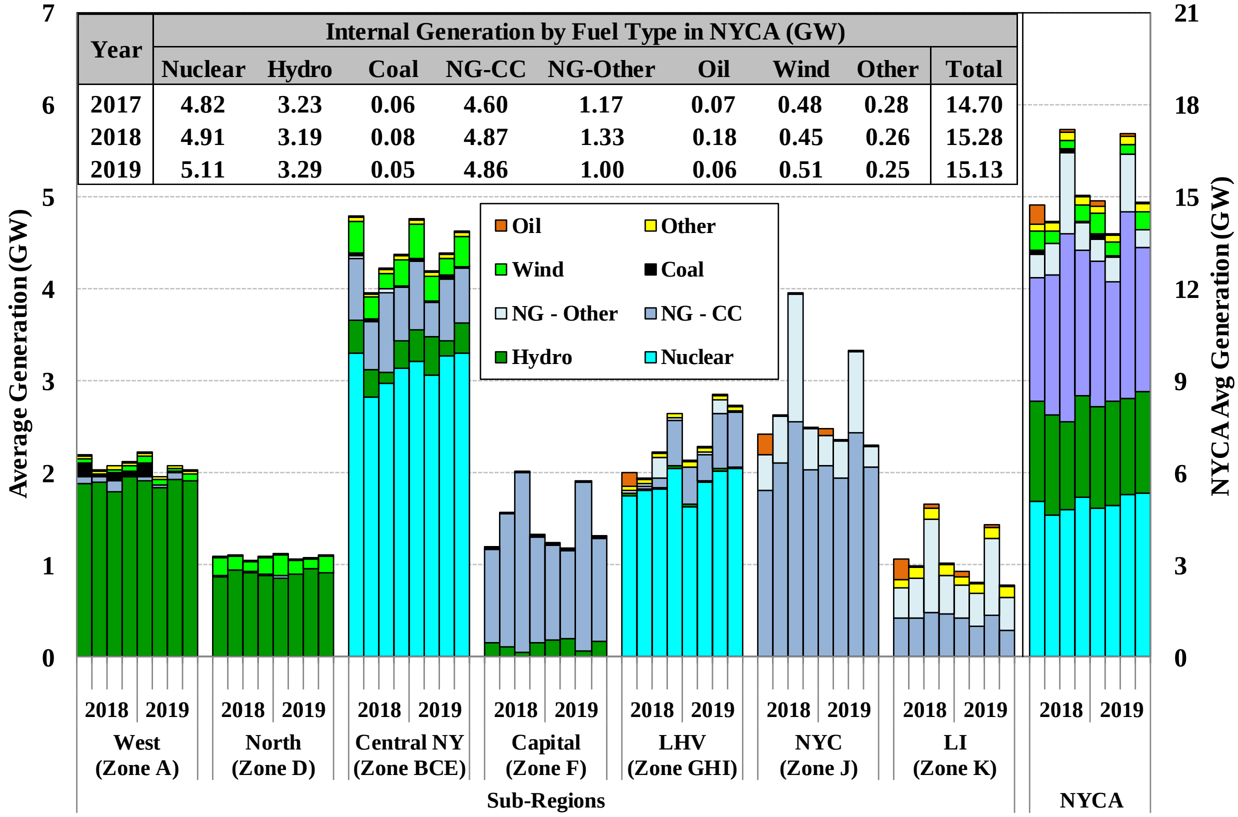
	2016	2017	2018	2019
Ultra Low-Sulfur Kerosene	$12.15	$13.53	$16.60	$15.45
Ultra Low-Sulfur Diesel Oil	$9.69	$11.92	$15.07	$13.95
Fuel Oil #6	$6.59	$8.43	$11.49	$11.85
Natural Gas (Tennessee Zn6)	$3.07	$3.78	$5.07	$3.26
Natural Gas (Iroquois Zn2)	$2.85	$3.39	$4.28	$3.04
Natural Gas (Transco Zn6 (NY))	$2.21	$2.99	$4.39	$2.59
Natural Gas (Tetco M3)	$1.73	$2.50	$3.67	$2.39
Natural Gas (Tenn Z4 200L)	$1.61	$2.39	$2.88	$2.26

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2019 as well as for NYCA as a whole.[232] The table in the chart shows annual average generation by fuel type from 2017 to 2019.

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

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

Figure A-7: Generation by Fuel Type in New York
By Quarter by Region, 2019

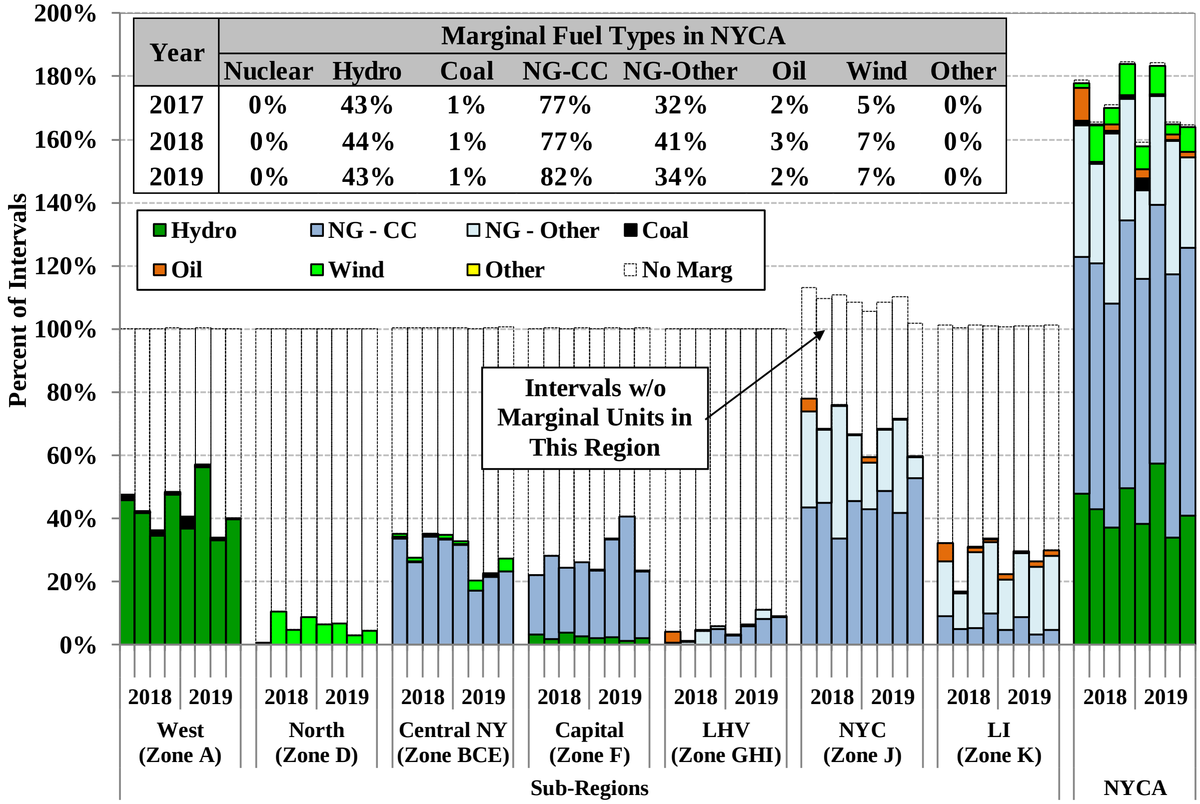


Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2017	4.82	3.23	0.06	4.60	1.17	0.07	0.48	0.28	14.70
2018	4.91	3.19	0.08	4.87	1.33	0.18	0.45	0.26	15.28
2019	5.11	3.29	0.05	4.86	1.00	0.06	0.51	0.25	15.13

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 2019. 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-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2019



Year	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2017	0%	43%	1%	77%	32%	2%	5%	0%
2018	0%	44%	1%	77%	41%	3%	7%	0%
2019	0%	43%	1%	82%	34%	2%	7%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- Natural gas prices, which have a strong effect on wholesale energy prices, exhibited significant variations 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 fell by 16 to 41 percent across the system from 2018 to 2019. The decline was largely due to milder weather conditions, and the concomitant decrease in overall demand and pipeline congestion.
  - The spread between Western NY gas indices (such as Tennessee Z4 200L) and Eastern NY gas indices (such as Transco Z6 NY) fell in 2019 compared to the previous year. For instance, the Tennessee Zone 4 200L index exhibited an average discount of 34 percent relative to the Transco Zone 6 NY index in 2018, but this discount was just 13 percent in 2019.
  - Gas prices fell most steeply in the downstate regions. For instance, the annual average of Transco Z6 NY prices declined by 41 percent, and the average price for the month of January fell by 68 percent from 2018 to 2019.

- Gas-fired (39 percent), nuclear (34 percent), and hydro (22 percent) generation accounted for 94 percent of all internal generation in New York during 2019.
  - Gas-fired production decreased by 5.5 percent from the prior year.
    - The decrease in 2019 was almost entirely due to reduced production from steam turbine and gas peaking facilities. These units, given their high heat rates, tend to be produce more energy during high load periods, the incidence of which was significantly lower in 2019.
    - The steam turbine units in the Lower Hudson Valley also ran far less frequently on account of the load conditions, and increased competition from more fuel-efficient combined cycle units.
  - Average nuclear generation rose 200 MW from 2018, reflecting fewer maintenance and refueling outages at multiple units across the year.
  - Average hydro generation increased by 100 MW year-over-year.
  - Average coal-fired generation fell 30 MW from 2018.
    - Of the two coal units that were operating at the beginning of 2019, Milliken 1 entered an ICAP Ineligible Forced Outage (“IIFO”) in November, and Kintigh retired as of April 1, 2020.
  - Average oil-fired generation decreased by 120 MW (or roughly 67 percent) from 2018 levels but were consistent with levels seen in 2017.
    - There were few periods of very cold weather in 2017 and 2019. In contrast, frequent congestion and flow restrictions on gas pipelines in January 2018 forced dual-fuel generators, especially in downstate regions, to operate on oil for long stretches of time.
- Gas-fired and hydro resources continued to be marginal the vast majority of time in 2019.
  - 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.
  - The expansion of 115 kV modeling, especially in the West Zone, contributed to more transmission congestion in 2019 (see Section III of the Appendix). However, this did not translate to significant increases in frequency of hydro units on the margin due to the manner in which marginal flags are set for various resources.
    - Generators are flagged with a positive marginal flag when the bid from its offer curve is on the margin to satisfy the power-balance constraint. However, the transmission constraints covered later in this Appendix document cases where individual buses are marginal for transmission constraints. Thus, we see instances where the frequency of transmission congestion increased markedly in the West (see Section III of the Appendix) but did not translate to more frequency of hydro on the margin for the power supply balance.

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:

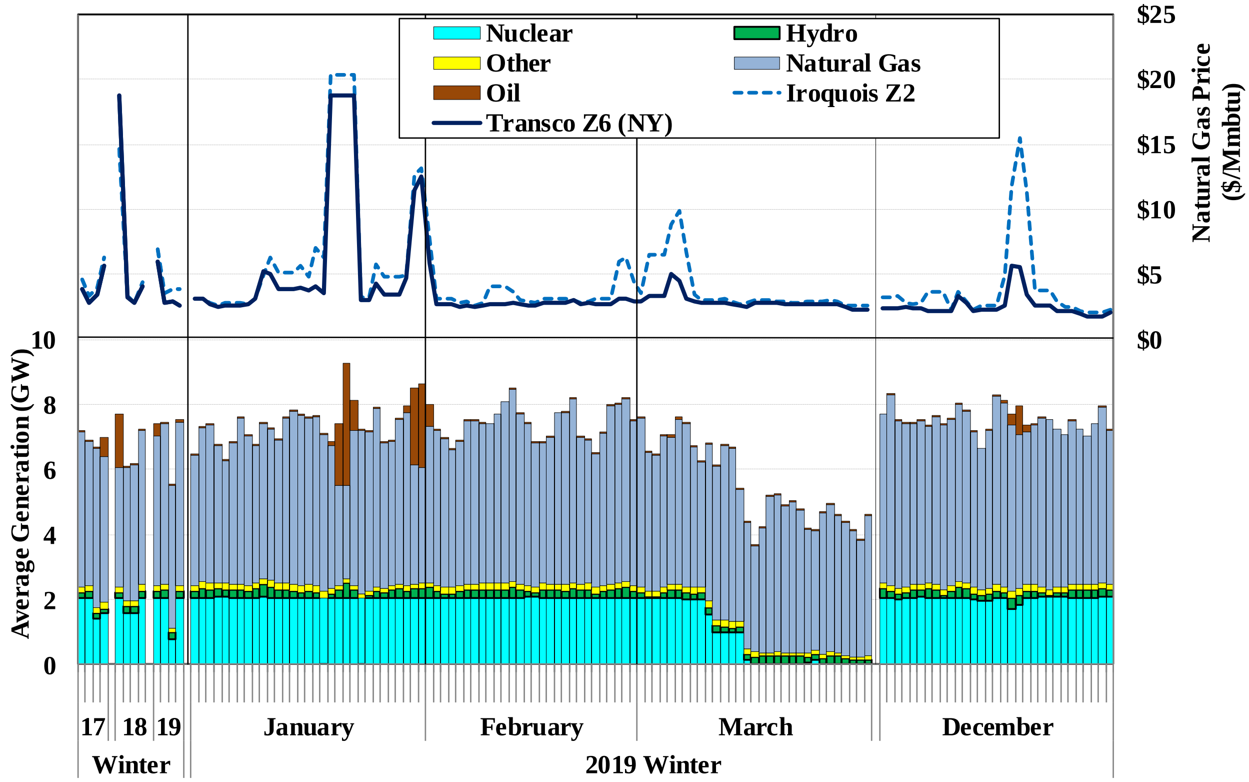
- Not having the necessary air permits;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and
- NOx emissions limitations.

This subsection examines actual fuel usage in the winter of 2019, focusing on the portion of the year where the supply of natural gas is likely to be tight. This has historically 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 2019 (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 2017 and 2019. 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, 2019



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Oil-fired generation in Eastern New York totaled roughly 356 GWh in the four-month period (i.e., January to March, and December) of 2019, down sharply from the 1,269 GWh in the same period of 2018.[233]
  - There were two noteworthy cold periods this winter during which generators burned oil: (a) January 19 to 22 and (b) January 30 to February 2.
    - Although temperatures fell to single digits during both periods, they were higher than in last winter's lengthier cold spell.
    - Natural gas prices briefly reached the $20/MMbtu level in Eastern NY, which was much lower than the $141/MMbtu seen last winter.
- The NYISO's fuel survey indicated that suppliers maintained sufficient oil inventory throughout the winter. 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.

233 Our 2018 SOM published a number totaling 1,266 GWh for total oil-fired generation over the four month period covered in this chart. Oil-fired generation hours from units that are capable of burning either gas or oil are updated annually based on EPA reported numbers which can cause the oil-fired generation MWhs to increase slightly from previously reported numbers.

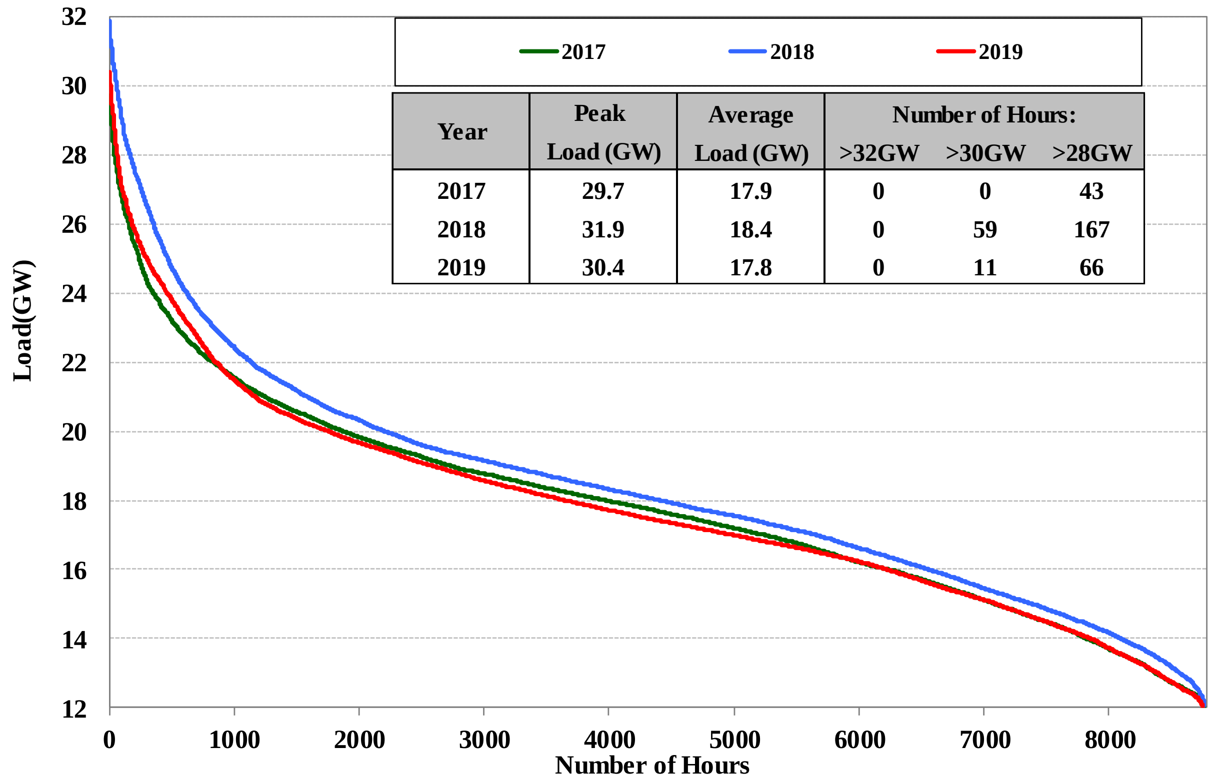
D. Load Levels

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
2017 – 2019



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2017	29.7	17.9	0	0	43
2018	31.9	18.4	0	59	167
2019	30.4	17.8	0	11	66

Key Observations: Load Levels

- Loads were much lower in 2019 than in 2018, but they were comparable to 2017 levels.
  - In 2019, the annual average load fell by 3 percent to 17.8 GW, which is the lowest observed in the past ten years.

- The annual peak load fell even more sharply (by 5 percent) from the summer peak in 2018. The lowest annual peak load over the past decade was observed in 2017.
  - The peak load day of 2019 occurred on a weekend (Saturday, July 20). If similar temperatures had materialized during a weekday, the peak load would have been higher.

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, Southeast New York and New York City reserve prices. Figure A-11 shows the average day-ahead prices for these four ancillary services products in each month of 2018 and 2019. The prices are shown separately for the following four distinct regions: (a) New York City, (b) Southeast New York (including Zones G-I and Zone 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 New York City as an example:

- The 30-minute component represents the cost to simultaneously meet the 30-minute reserve requirements for New York City, 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 New York City, 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 New York City, 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 2018 and 2019 on an annual basis.

Figure A-11: Day-Ahead Ancillary Services Prices
2018- 2019

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	New York City 10SP	New York City 10NS	New York City 30OP	Regulation
2018	$5.31	$4.18	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$11.24
2019	$3.97	$3.62	$3.62	$4.24	$3.67	$3.62	$4.24	$3.67	$3.62	$4.39	$3.82	$3.63	$9.08

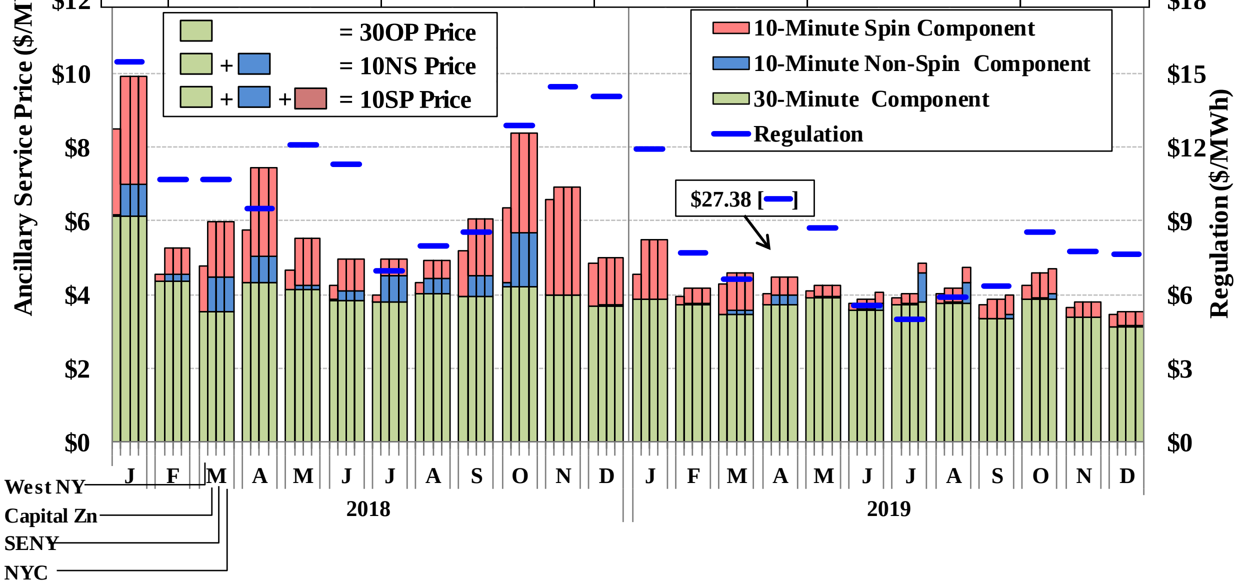


Table A-2: Price Divergence between New York City and Eastern New York Reserve Products in 2019

Table A-2 compares the prices across SENY and New York City for 10-minute and 30-minute reserve products. The New York City reserve requirements represent some of the local reliability needs that lead to frequent supplemental commitment and out-of-market compensation. These New York City reserve requirements were binding in many intervals in 2019, and consequently, the reserve products in New York City were priced at a premium relative those in SENY.

Table A-2: Price Divergence between NYC and Southeastern NY Reserve Products in 2019
June 26 through December 31, 2019

Market	10-Minute Spinning Price			10-Minute Nonspinning Price			30-Minute Operating Price		
	SENY	NYC	NYC Premium	SENY	NYC	NYC Premium	SENY	NYC	NYC Premium
Day-Ahead	$4.01	$4.30	$0.29	$3.57	$3.85	$0.29	$3.54	$3.56	$0.01
Real-Time	$1.58	$1.96	$0.38	$0.09	$0.47	$0.38	$0.06	$0.19	$0.13

Key Observations: Day-ahead Ancillary Service Prices

- The average day-ahead prices for all reserve products fell in 2019 consistent with the decrease in opportunity costs associated with lower energy prices and less frequent supply limitations.
  - Gas supply was severely constrained in January 2018 due to extended cold weather conditions, and again in the third week in April due to major pipeline repair work, contributing to higher reserve prices. Furthermore, generator outages during the shoulder months reduced the supply of reserve offers in 2018. None of these conditions applied to the 2019 outcomes.
- Average annual day-ahead regulation prices also decreased (by 19 percent) in 2019 partly because of decreased opportunity costs from lower energy prices. (see Section II)
  - A notable exception to this trend occurred in April 2019, when regulation prices hit the $525 per MWh portion of the scarcity pricing curve on 8 non-consecutive days, most frequently during the off peak hours when load was lowest.[234] During this period, the market experienced significant reductions in regulation capacity offered because of planned outages and low load levels, which led some regulation-capable units to be offline (and unavailable to provide regulation).
  - The Tariff does not require generators to offer regulation capacity. However, after April 2019, the NYISO conducted outreach to encourage greater participation from regulation-capable units. Some combined cycle generators do not offer because it may be difficult to avoid being dispatched into the generator's duct-firing range while providing regulation service.
- The New York City reserve requirements (500 MW of 10-minute reserves and 1000 MW of 30-minute reserves) were incorporated into the pricing software starting June 26, 2019. The prices for New York City reserve products exhibited small premiums relative to the prices for corresponding SENY reserve products.
  - For the 10-minute products, the New York City experienced higher reserve pricing by $0.29 per MWh in the DA and $0.38 per MWh in the RT over SENY reserve prices.
  - For the 30-minute product, interzonal-price differences were relatively small because a large share of the 30-minute non-spin capable resources are located in New York City.
  - The separation of New York City reserve prices from SENY led to modest BPCG reductions, but OOM commitments were still frequently needed to maintain adequate reserves in load pockets where local N-1-1 requirements are not represented in the DA and RT markets with distinct local reserve requirements.

[234] See our Quarterly Report for the Third Quarter of 2019.

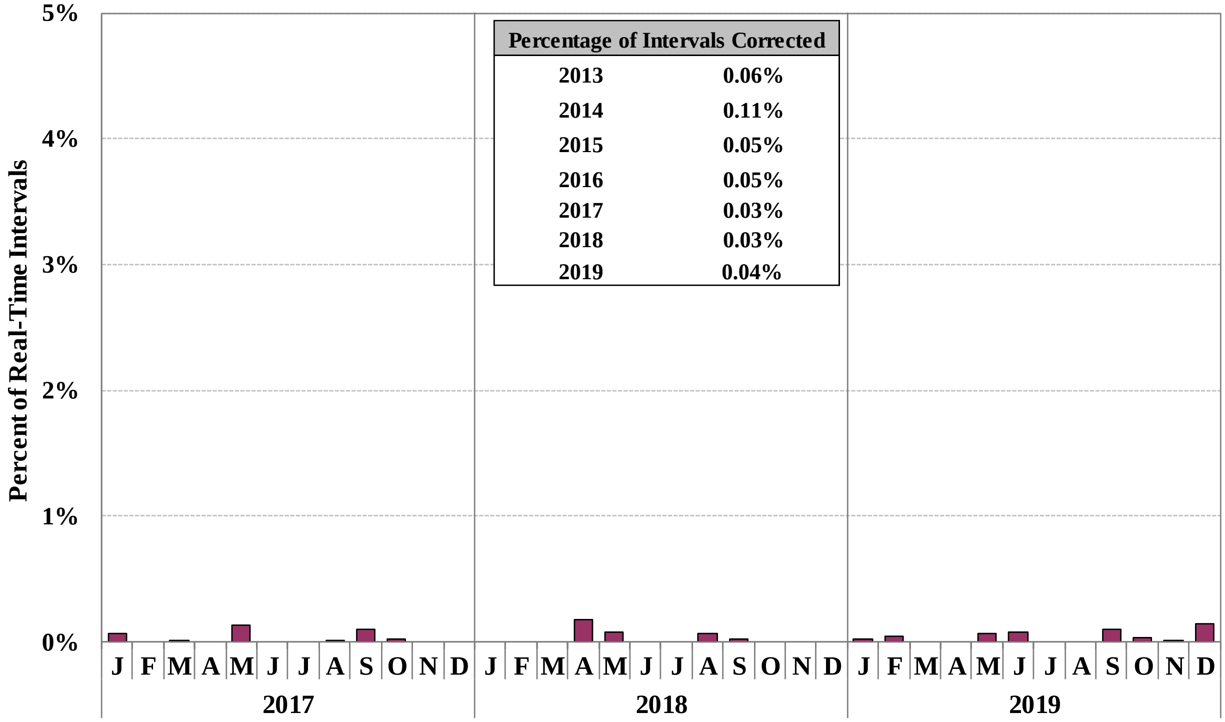
F. Price Corrections

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 2017 to 2019. The table in the figure indicates the change of the frequency of price corrections over the past several years. Price corrections continue to be very infrequent for several years running.

Figure A-12: Frequency of Real-Time Price Corrections
2017-2019



Percentage of Intervals Corrected	
2013	0.06%
2014	0.11%
2015	0.05%
2016	0.05%
2017	0.03%
2018	0.03%
2019	0.04%

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 commitments are profitable. 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.

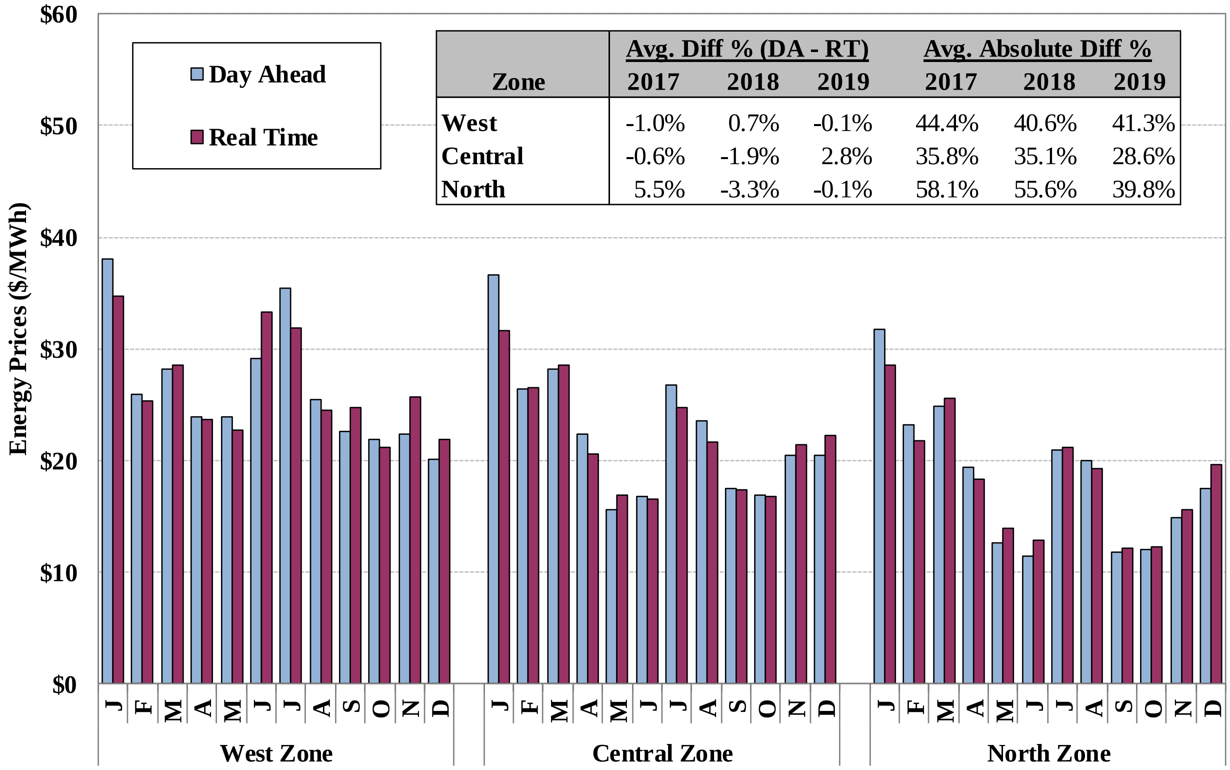
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the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

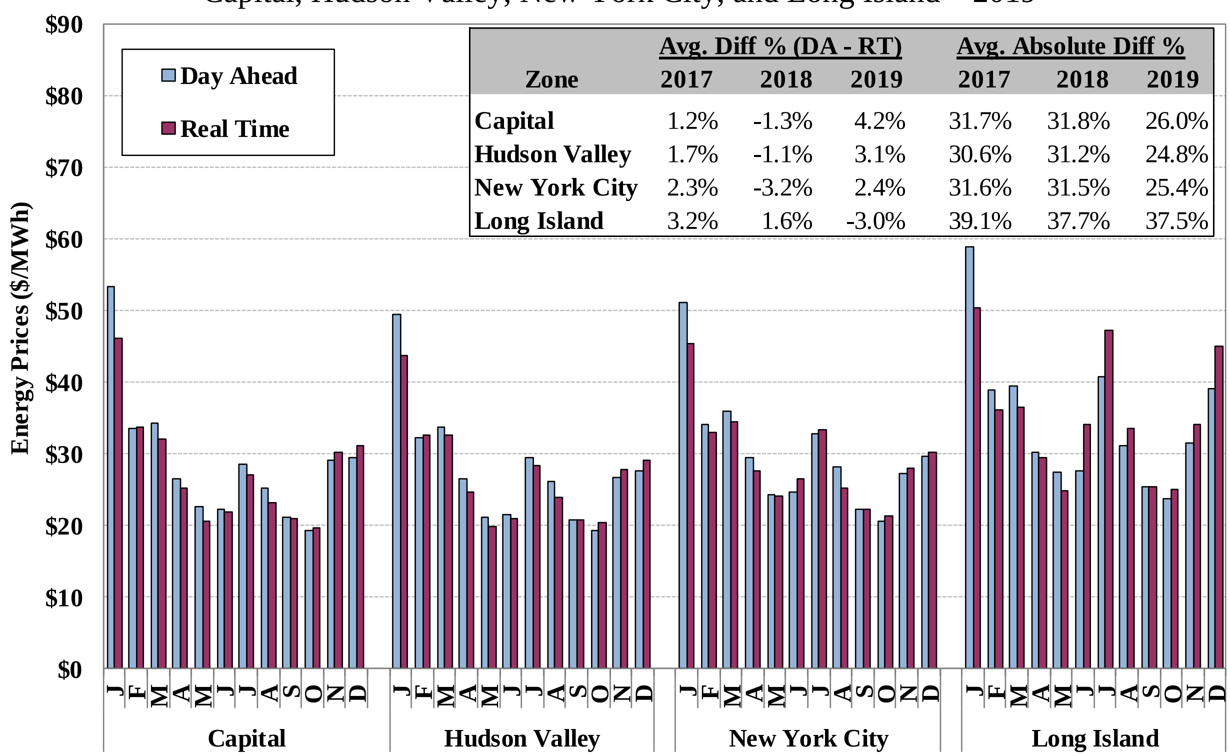
Figure A-13 and Figure A-14 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars compare the load-weighted average day-ahead and real-time prices in each zone in each month of 2019. 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 – 2019



Zone	Avg. Diff % (DA - RT) 2017	2018	2019	Avg. Absolute Diff % 2017	2018	2019
West	-1.0%	0.7%	-0.1%	44.4%	40.6%	41.3%
Central	-0.6%	-1.9%	2.8%	35.8%	35.1%	28.6%
North	5.5%	-3.3%	-0.1%	58.1%	55.6%	39.8%

Figure A-14: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2019



Zone	Avg. Diff % (DA - RT) 2017	2018	2019	Avg. Absolute Diff % 2017	2018	2019
Capital	1.2%	-1.3%	4.2%	31.7%	31.8%	26.0%
Hudson Valley	1.7%	-1.1%	3.1%	30.6%	31.2%	24.8%
New York City	2.3%	-3.2%	2.4%	31.6%	31.5%	25.4%
Long Island	3.2%	1.6%	-3.0%	39.1%	37.7%	37.5%

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 2019 for selected locations in New York City, Long Island, and Upstate New York.[235] 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.

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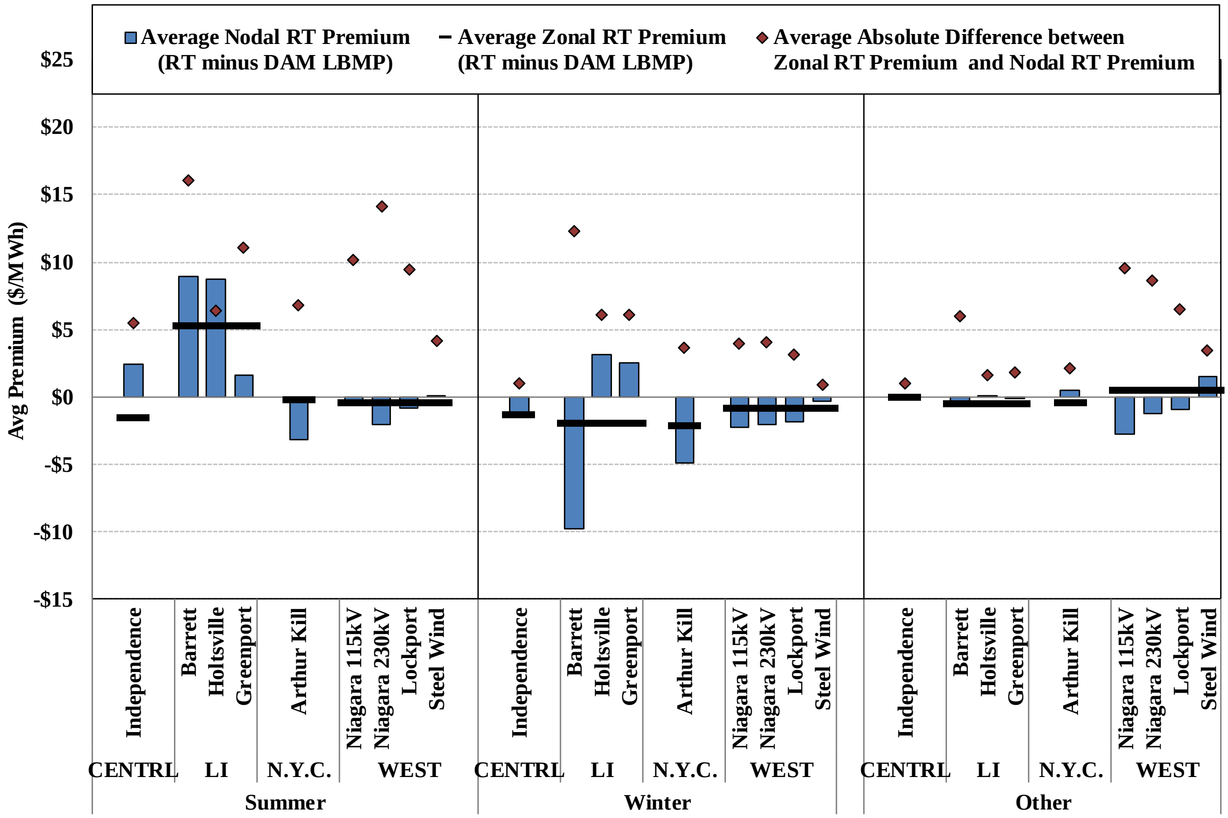
235 In the Central Zone, Independence is represented by the Sithe Independence GS1 bus. In Long Island, Barret is the Barrett 1 bus, NYPA Holtsville is the NYPA Holtsville bus, and Greeport is the Global Greenport bus. In New York City, Arthur Kill is the Arthur Kill 3 bus. Niagara 230kV, Niagara 115kV East, NEG West Lockport, and Steel Wind represent generator locations in the West Zone.

Figure A-15: Average Real-Time Price Premium at Select Nodes
2019



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

- In eastern New York, average day-ahead prices were at a premium of two percent to four percent of the average real-time prices in most zones in 2019. The only exception to this trend was Long Island where average real-time prices were higher than the day-ahead prices (by 3 percent).
  - Relatively low real-time price volatility led to small day-ahead premia in 2019. Small average day-ahead premiums were in line with historical patterns and are generally desirable in a competitive market.
  - The real-time price premium observed in Long Island was largely driven by a combination of factors that include outages of transmission facilities, transient congestion in the lower voltage network, and limited availability of 5-minute ramping capability.
- In western New York, the difference between day-ahead and real-time prices in West and North zones improved in 2019 likely because the modeling of 115 kV constraints in the West zone and the reduction of the CRM values for lower transmission facilities improved consistency of congestion pricing between the day-ahead and real-time markets.

- The average real-time price in the Central Zone exhibited a discount to the day-ahead average in 2019.
  - Congestion along the Scriba-Volney 345 kV line rose in 2019, which limited otherwise economic output from baseload nuclear and thermal generation in the Oswego Complex generation pocket.
    - This congestion was more frequent in the day-ahead market, reflecting lower offer prices in the generation pocket in day-ahead and higher export limit in real-time during congested periods.
- At the zonal level, energy price convergence, as measured by the load-weighted average absolute difference between hourly day-ahead and real-time prices, improved across all zones except for the West Zone, which remained similar to 2018.
  - Lower load levels and lower and less volatile gas prices were the primary drivers of improved consistency between the day-ahead and real-time prices in most regions in 2019.
    - Fewer major transmission outages also contributed to improved convergency in several areas (e.g., the North Zone, New York City).
  - In the West zone, transmission constraints were hard to manage despite modeling enhancements. As noted in our report, unforeseen loop flows can lead to severe congestion and increase the price volatility in real-time.
    - The clockwise loop flows had higher impact on the priced West Zone congestion following the modeling 115 kV constraints in the market models and the closure of South Ripley-Dunkirk 230 kV line.
- At the nodal level, some locations exhibited less consistency between average day-ahead and real-time prices in 2019 than at the zonal level and illustrate areas where nodal virtual trading would improve market efficiency. A key reason why most of these areas exhibit poor convergence is because of differences between the day-ahead and real-time offer prices of generation. Virtual trading would be beneficial at nodes where systematic, somewhat predictable differences between the real-time and day-ahead schedules of supply or demand occur.
  - In the Central zone, price convergence improved in 2019 with a small day-ahead premium throughout most of the year. However, on a nodal basis in the summer, real-time price premia occurred upstream of the Scriba-Volney transmission line (e.g. Independence), while the zone still exhibited day-ahead premia. This was driven predominantly by differences in line ratings out of a generator load pocket whereby the real-time export limits often surpassed those set in day-ahead. Thus, real-time prices were often set by higher portions of the dispatchable range of flexible resources in this pocket than were scheduled in the day-ahead market.
  - In Long Island, there were multiple factors impacting differences between zonal and nodal price convergence:

- Lower voltage constraints in Long Island were not modeled which meant that pricing signals associated with congestion on those lines were not priced into the market for unit commitment. Instead of potentially committing less-costly, slower ramping generation in the day-ahead or in the real-time commitment process, these were typically managed with out-of-market actions. Though these constraints were not priced, transient nodal pricing arose as the operators tried to manage congestion on unmodeled lines in real-time by adjusting transfer limits.
- In addition, PAR adjustments to manage higher voltage lines were sometimes limited in real-time because of operators' efforts to avoid unintended detrimental impacts on lower voltage, unmodeled lines. These real-time limitations on PAR usage made it more difficult to manage congestion on modeled lines and impacted nodal prices. In addition, in the day-ahead model, PAR assumptions proved to be less than optimal at times due to the unknown limitations of unmodeled lines.
- On the west end of Long Island, significant differences between day-ahead and real-time prices resulted in the summer months as the result of transient real-time price spikes during generator ramping hours.

- In New York City, though the entire City zone and the Arthur Kill node both have a real-time price premium in the summer and winter months, the absolute difference between the zonal real-time premium and the nodal real-time premium can still be quite large. The Arthur Kill node is located in a pocket where transmission can be severely constrained resulting in very low real-time prices.
- In the West, zonal convergence has improved in part due to enhanced Niagara modeling and the modeling of 115 kV constraints. As a result of modeling the 115kV constraints, more congestion is captured in the day-ahead model, and the volatile issues that arose in real-time with unanticipated congestion is less prevalent. However, even with these improvements, unmodeled loop flows in the clockwise direction can still exacerbate western congestion and nodal price divergence. Nodes in the West that lie outside of the more constrained pocket (e.g. Steel Wind) show less divergence from the zonal price premium.

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 to

Figure A-22: Distribution of day-ahead price premiums for reserves

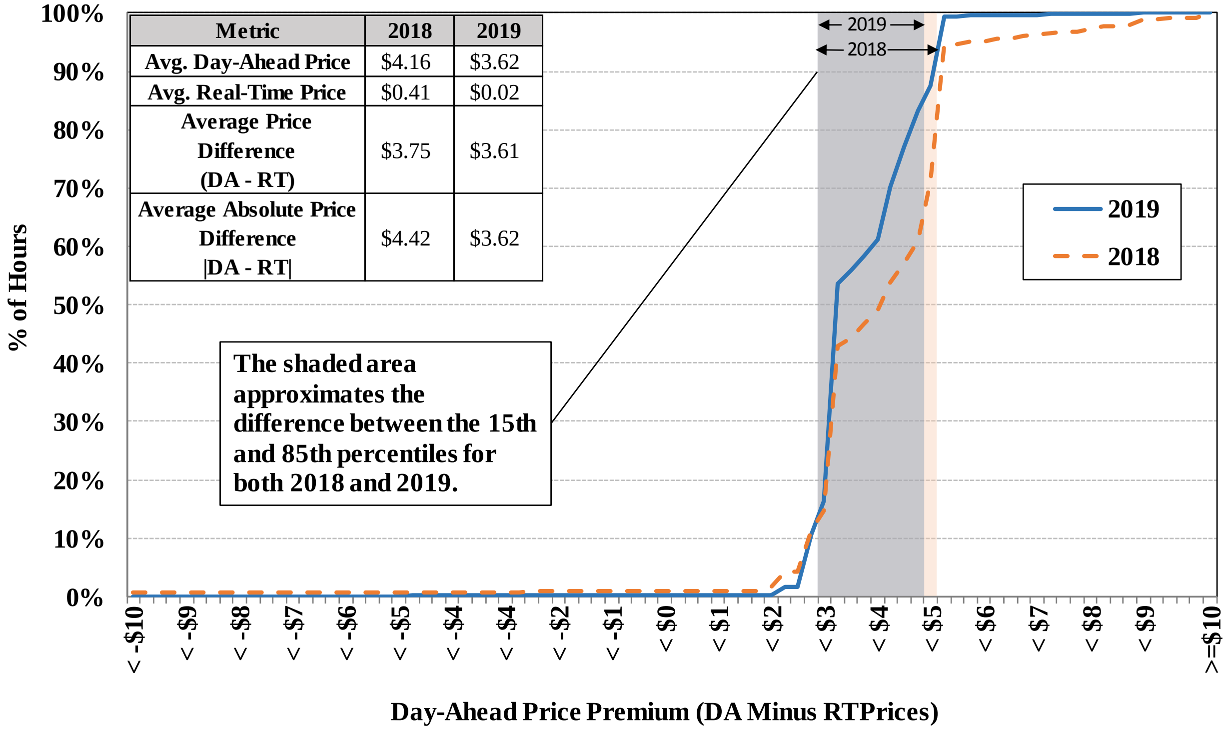
To evaluate the performance of the day-ahead ancillary service markets, the following seven figures show distributions of day-ahead premiums (i.e., day-ahead prices minus real-time prices) in: (a) Western 30-minute reserve prices; (b) Western 10-minute spinning reserve prices; (c) Eastern 10-minute spinning reserve prices; (d) Eastern 10-minute non-spin reserve prices; (e) New York City 30-minute reserve prices; (f) New York City 10-minute spinning reserve prices; and (g) New York City 10-minute non-spin reserve prices. In prior years, we reported on only the first four ancillary service products. At the end of June of 2019, the NYISO introduced the New York City locational reserve region with its own explicit reserve requirements.[236] The additional charts show the distributions of New York City day-ahead reserve price premiums for the period July through December, months when the new reserve requirements were fully in effect in 2019.

In each of the seven figures, the day-ahead premium is calculated at the hourly level and grouped by ascending dollar range (in $0.25 tranches). The cumulative 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 for approximately 85 percent of hours had a day-ahead premium of $4.75 or less, in 2019 including intervals where the day-ahead premium was negative (i.e. real-time prices exceeded day-ahead prices).

The figures compare the distributions between 2018 and 2019. The distributions between the 15th percentile and the 85th percentile are highlighted in shaded areas for each of the years. Thus, the Western 30-minute reserves day-ahead premium was between $2.75 and $4.75/MWh for 70 percent of the hours in 2019 (between $2.75 and $5/MWh in 2018). The inset tables summarize the following annual averages in 2018 and 2019: (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.

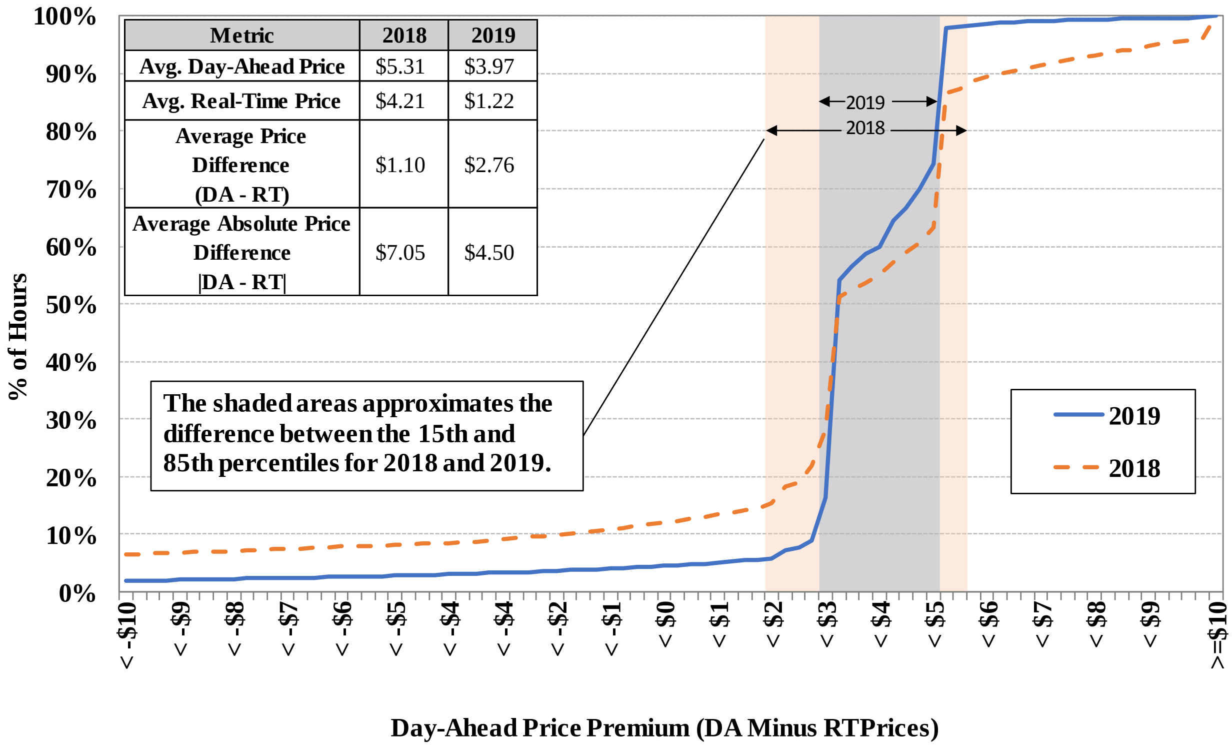
236 The reserve requirements for New York City are 500 MW of 10-Minute capable resources and 1000 MW of 30-Minute capable units for a total of 1000 MW of reserves in a given hour.

Figure A-16: Day-Ahead Premiums for 30-Minute Reserves in West New York
2018 – 2019



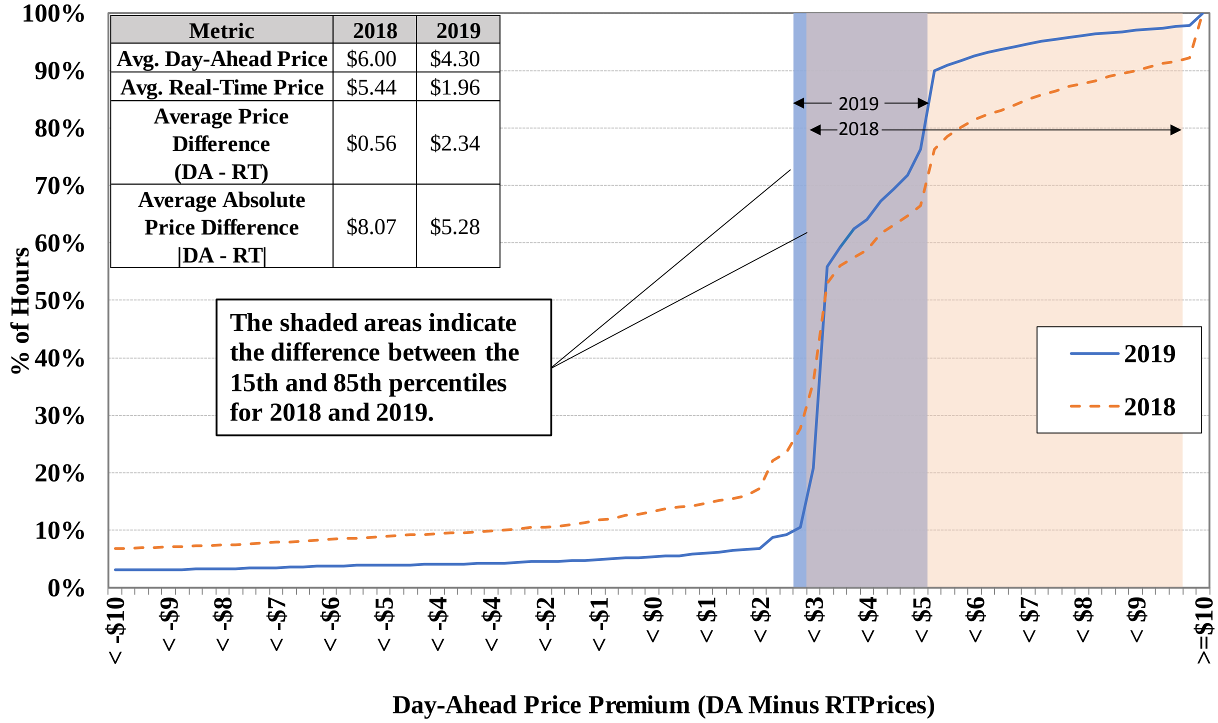
Metric	2018	2019
Avg. Day-Ahead Price	$4.16	$3.62
Avg. Real-Time Price	$0.41	$0.02
Average Price Difference (DA - RT)	$3.75	$3.61
Average Absolute Price Difference |DA - RT|	$4.42	$3.62

Figure A-17: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2018 - 2019



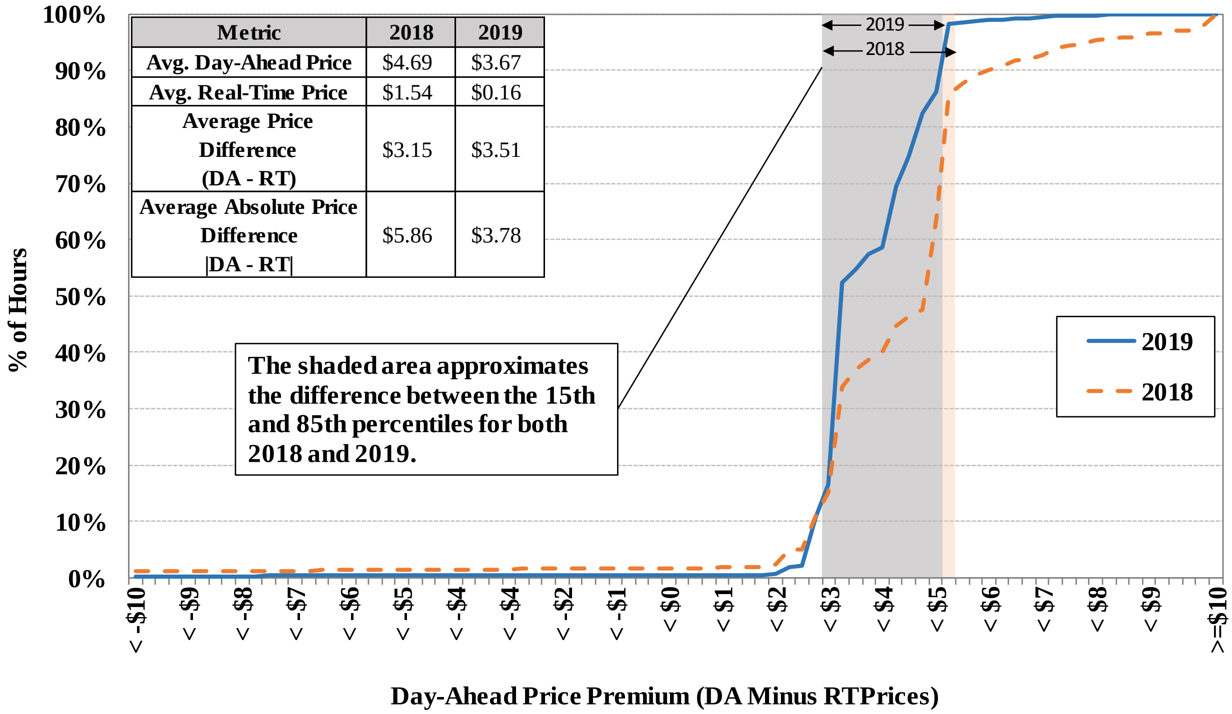
Metric	2018	2019
Avg. Day-Ahead Price	$5.31	$3.97
Avg. Real-Time Price	$4.21	$1.22
Average Price Difference (DA - RT)	$1.10	$2.76
Average Absolute Price Difference |DA - RT|	$7.05	$4.50

Figure A-18: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2018 – 2019



Metric	2018	2019
Avg. Day-Ahead Price	$6.00	$4.30
Avg. Real-Time Price	$5.44	$1.96
Average Price Difference (DA - RT)	$0.56	$2.34
Average Absolute Price Difference |DA - RT|	$8.07	$5.28

Figure A-19: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2018 – 2019



Metric	2018	2019
Avg. Day-Ahead Price	$4.69	$3.67
Avg. Real-Time Price	$1.54	$0.16
Average Price Difference (DA - RT)	$3.15	$3.51
Average Absolute Price Difference |DA - RT|	$5.86	$3.78

Figure A-20: Day-Ahead Premiums for 30-Minute Reserves in New York City
2018-2019 (July-December)

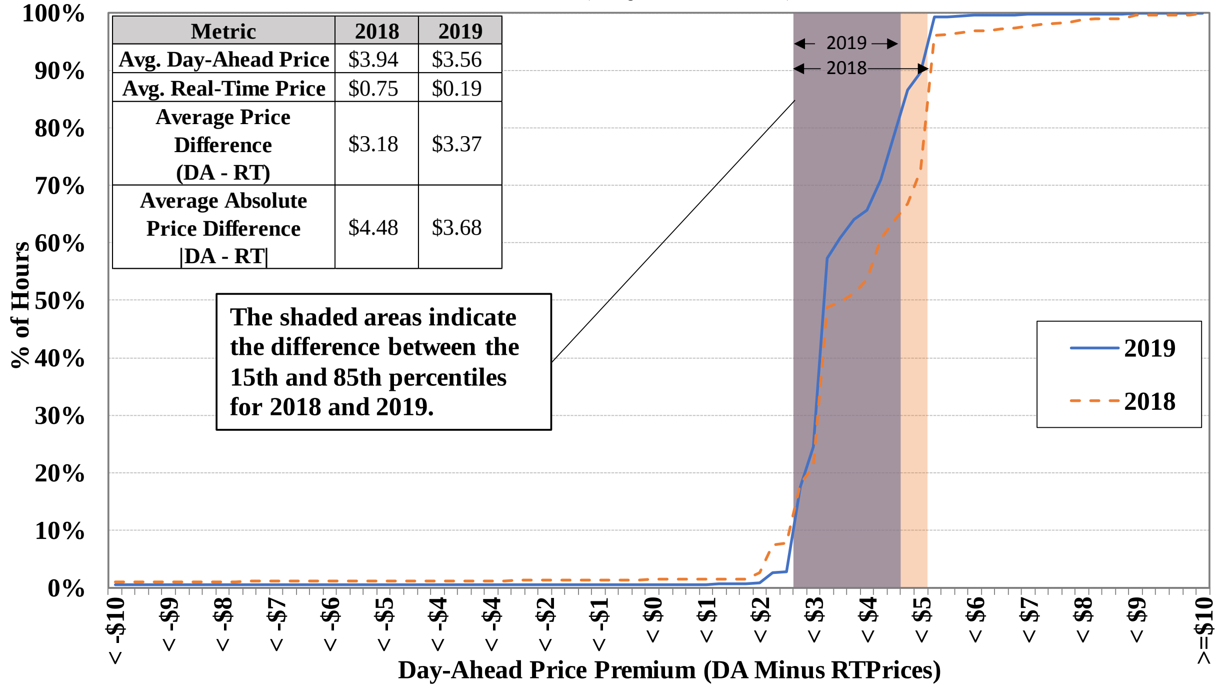


Figure A-21: Day-Ahead Premiums for 10-Minute Spinning Reserves in New York City
2018-2019 (July-December)

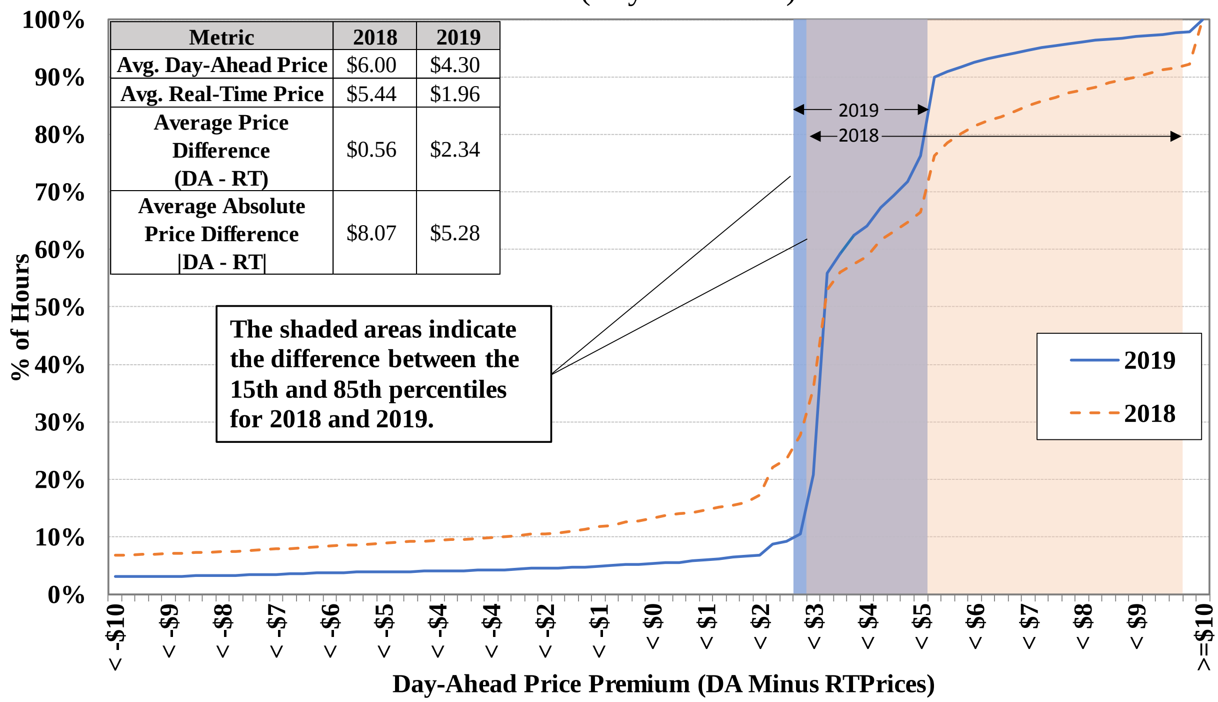
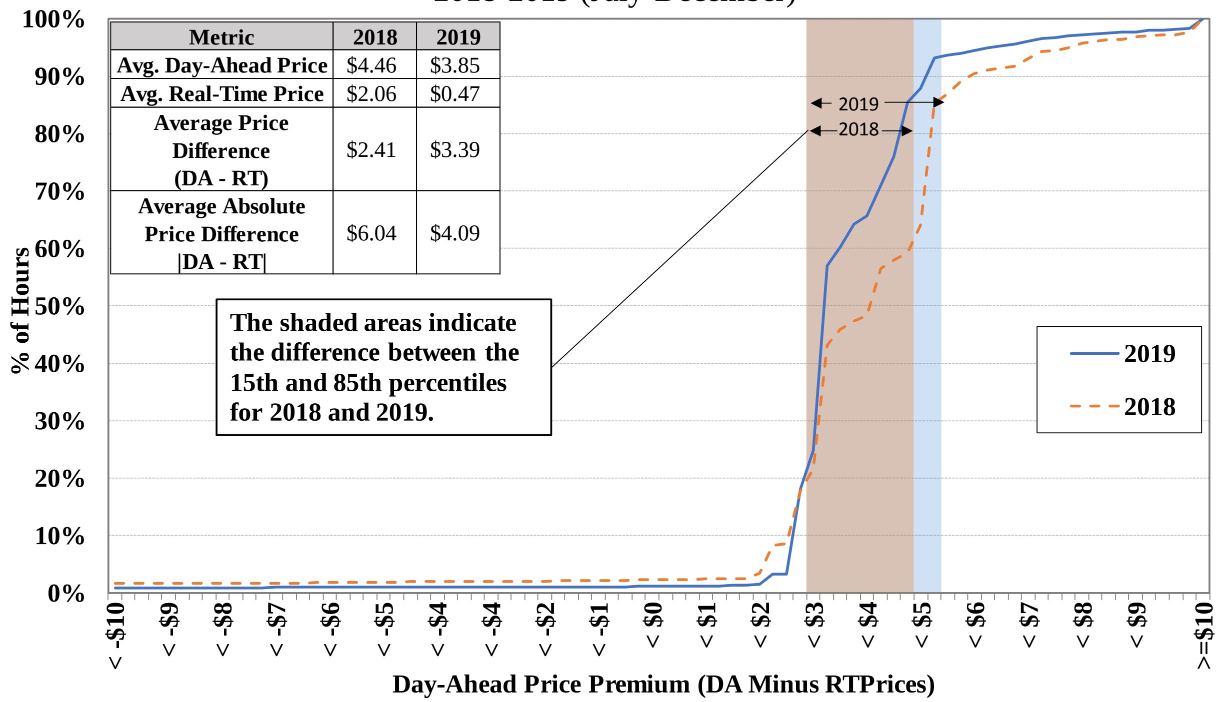


Figure A-22: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in New York City
2018-2019 (July-December)



Metric	2018	2019
Avg. Day-Ahead Price	$4.46	$3.85
Avg. Real-Time Price	$2.06	$0.47
Average Price Difference (DA - RT)	$2.41	$3.39
Average Absolute Price Difference |DA - RT|	$6.04	$4.09

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 suppliers' 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;
  - Financial risks associated with being deployed in real-time after selling reserves in the day-ahead; and
  - NYISO rules that limit the flexibility of generators' offers in real-time if a generator was scheduled for reserves in the day-ahead market.
- In 2019, for most reserve products, DA reserve price premiums remain in a relatively small band between about $3 and $5. The number of hours found in the tails of the distribution, where the DA price premium was much larger or smaller, was lower in 2019 due to lower opportunity costs and less severe unexpected RT reserve events relative to the DA forecasts.

- The average spread between DA and RT reserve prices widened in 2019 in most regions, while the relative volatility in the spread (as measured by the average absolute difference between the DA and RT prices) fell significantly from 2018 to 2019.
    - This was driven by lower reserves prices in the real-time, which reflected lower opportunity costs that are associated with lower energy prices and a significant reduction in reserve shortages because of lower load levels.
        - Fewer RT shortage events and less resultant price spikes tend to increase the average difference in the DA and RT reserve prices but decrease the average absolute difference between them.
    - DA prices tend to be less volatile because of the availability offers that reflect various factors mentioned above. The decrease in the average DA reserves prices was smaller than the reduction in the average RT reserves prices in 2019.

I. Regulation Market Performance

Figure A-23 – Regulation Prices and Expenses

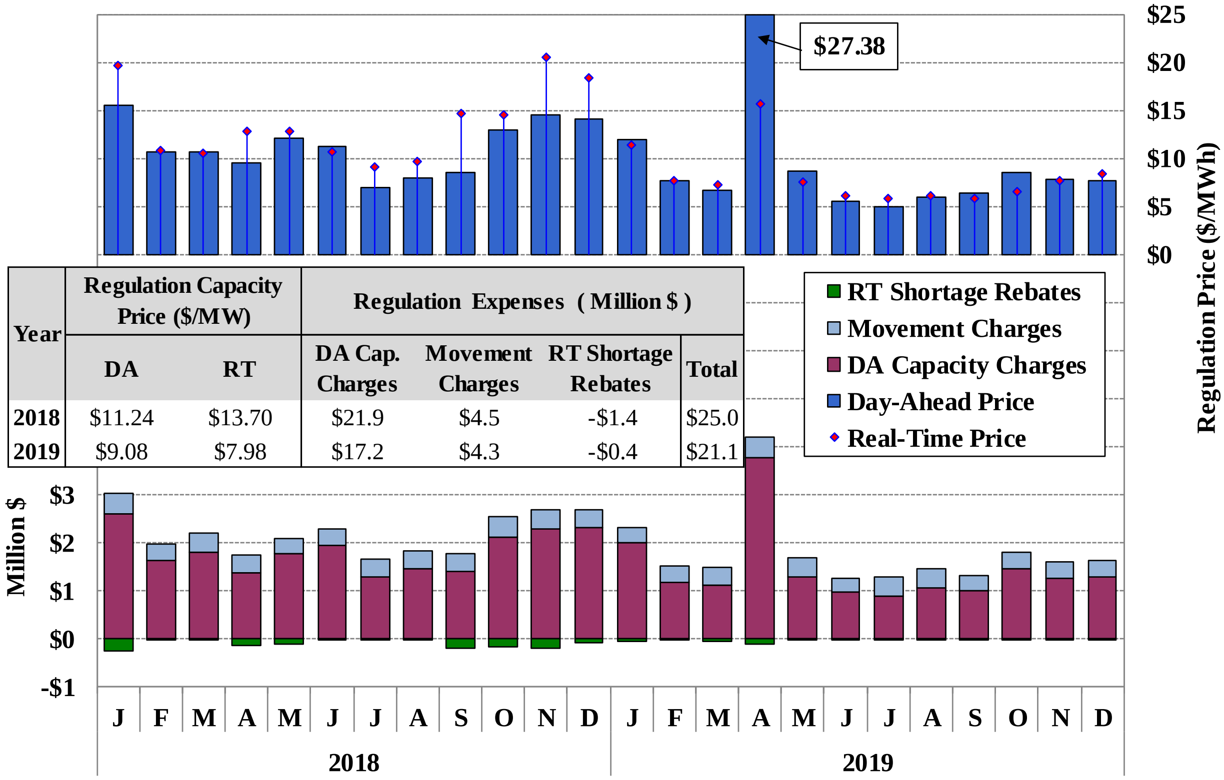
Figure A-23 shows the regulation prices and expenses in each month of 2018 and 2019. The upper portion of the figure compares the regulation capacity prices in the day-ahead and real-time markets. The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

- 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-23: Regulation Prices and Expenses
by Month, 2018-2019



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2018	$11.24	$13.70	$21.9	$4.5	-$1.4	$25.0
2019	$9.08	$7.98	$17.2	$4.3	-$0.4	$21.1

Key Observations: Regulation Market Performance

- Average real-time regulation capacity prices fell 42 percent from prior year levels in 2019 while day-ahead capacity prices fell 19 percent. The steeper reduction in the real-time price was a consequence of:
  - Low volatility in energy markets during both the summer and winter; and
  - The impacts of the April capacity shortages contributed more severely to day-ahead premiums (see Subsection H).
- Regulation expenses decreased by 16 percent in 2019 primarily due to a steep reduction in costs associated with the DA Capacity Charges ($4.7 million reduction). (see Section V in the Appendix).

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. In recent years, marginal cost estimates have become more uncertain because of gas scheduling limitations and gas price volatility, so the efficiency of the mitigation measures depend on the accuracy of fuel cost estimates. Market power mitigation by the NYISO is evaluated in subsection 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 subsection 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 subsection 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 subsection 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.* [237]

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 subsection 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.

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[237] 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.

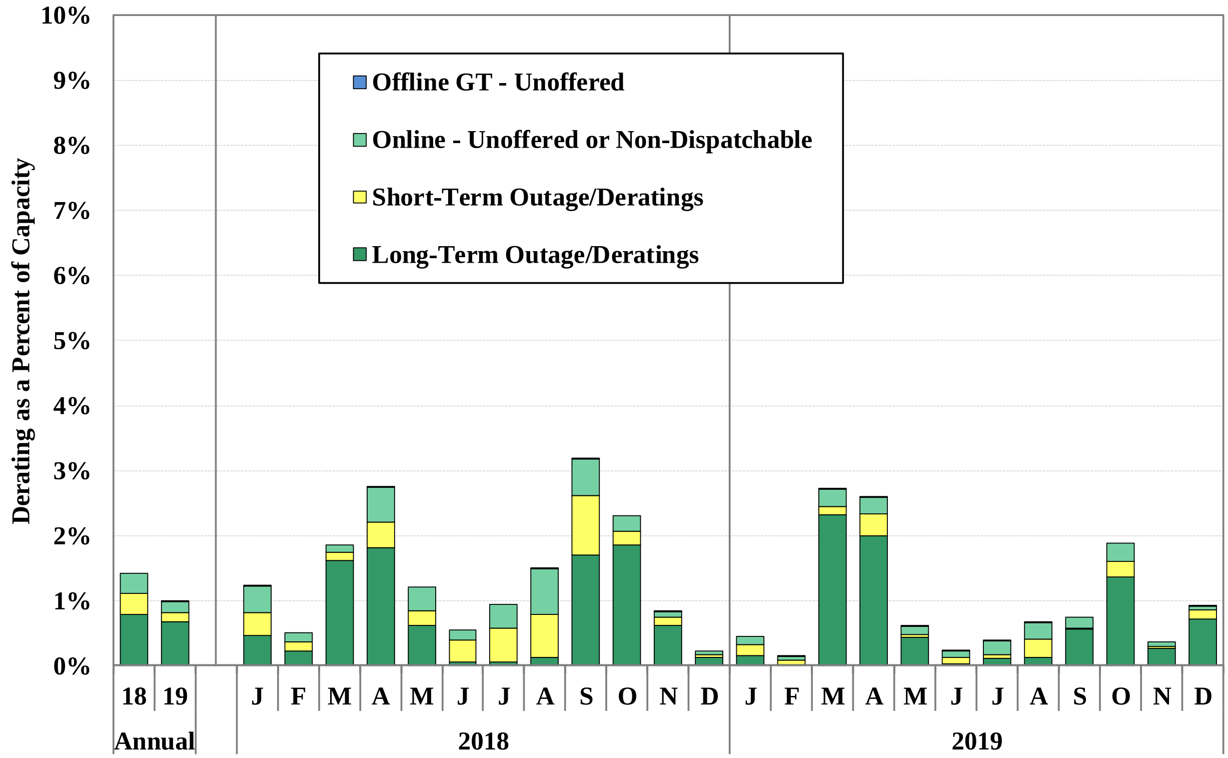
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

The figures in this subsection show the portion of derated and unoffered capacity that would have been economic based on Reference Levels and market prices.[238] 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.[239] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[240]

Figure A-24 - Figure A-25: Unoffered Economic Capacity by Month

Figure A-24 and Figure A-25 show the broad patterns of deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2018 and 2019.

Figure A-24: Unoffered Economic Capacity by Month in NYCA
2018 – 2019



238 This evaluation includes a modest threshold, which is described in subsection B as "Lower Threshold 1."

239 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.

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

Figure A-25: Unoffered Economic Capacity by Month in East New York
2018 - 2019

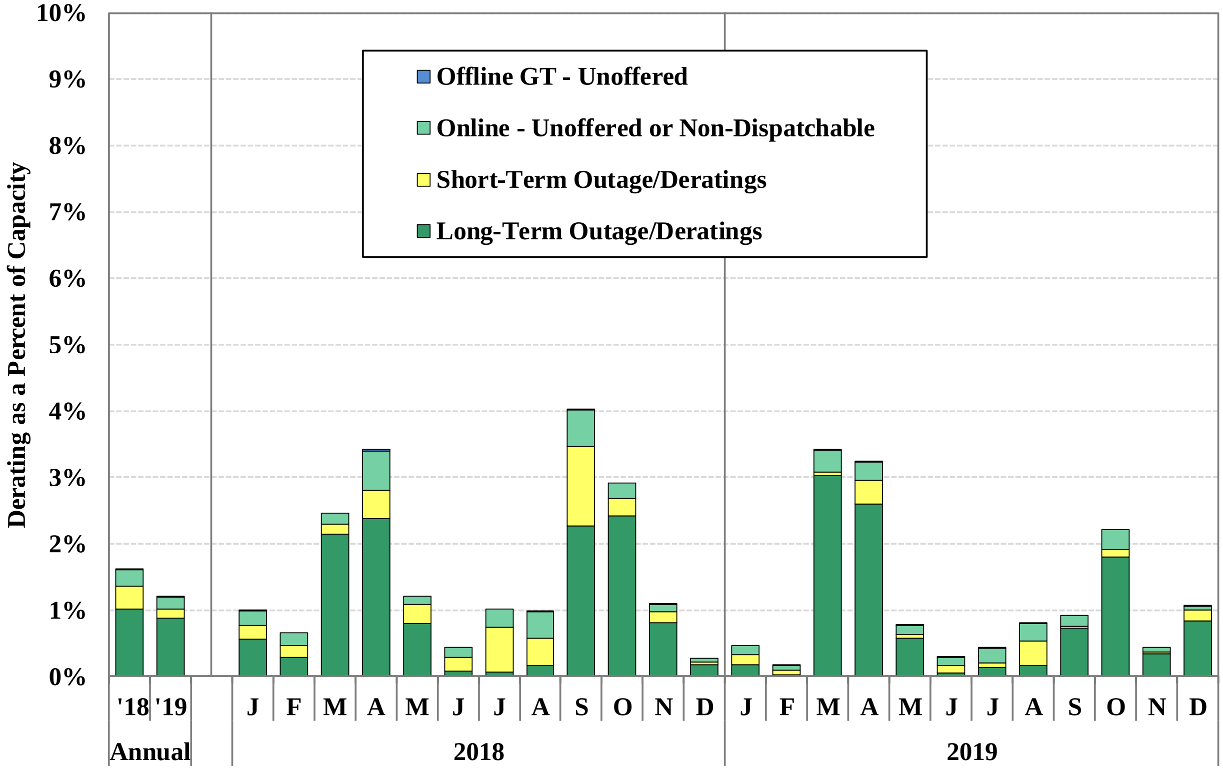


Figure A-26 & Figure A-27: Unoffered Economic Capacity by Load Level & Portfolio Size

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.

Figure A-26: Unoffered Economic Capacity by Supplier by Load Level in New York
2018 – 2019

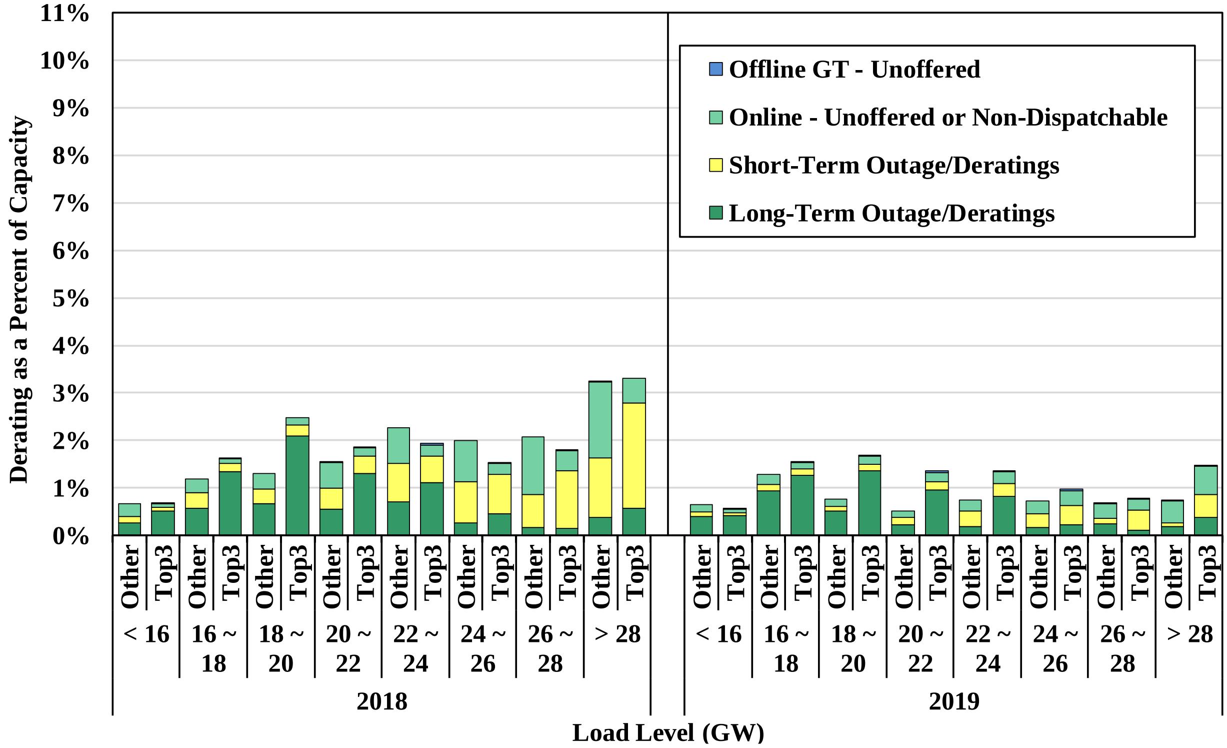
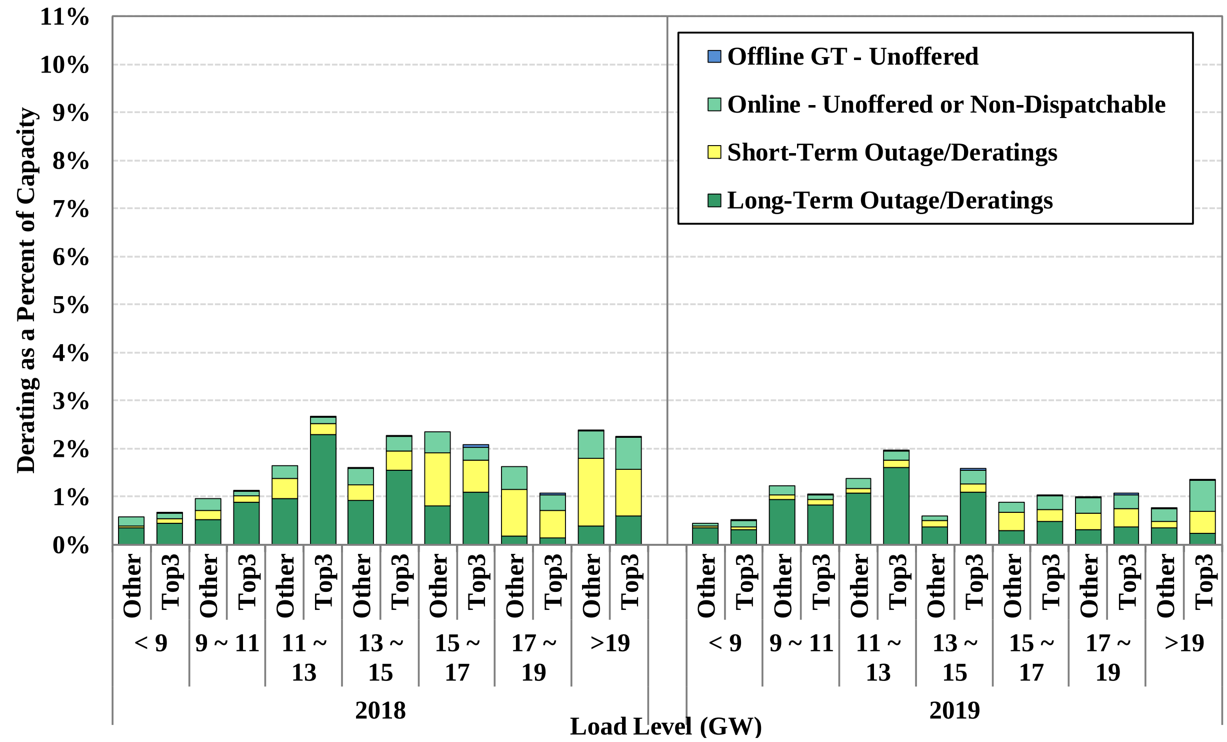


Figure A-27: Unoffered Economic Capacity by Supplier by Load Level in East New York
2018 – 2019



As noted previously, a supplier with market power is most likely to profit from withholding in periods when the market supply curve becomes steep (e.g., 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-26 and Figure A-27 to determine whether the conduct is consistent with workable competition.

Key Observations: Unoffered Economic Capacity

- The pattern of deratings was reasonably consistent with expectations for a competitive market.
  - Derated and unoffered economic capacity averaged 1 percent of total DMNC in NYCA, and 1.2 percent in Eastern New York in 2019, which was lower than 2018 levels.
  - Derated and unoffered economic capacity was mostly attributable to long-term maintenance (making up 69 percent of the total in NYCA and 73 percent in Eastern New York in 2019).
    - 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 had only small totals of long-term outages during the highest load hours.
- Economic capacity on outage/deratings was marginally lower in the summer of 2019 than in the previous summer largely because of a mild weather and fewer outages at nuclear units. The mild winter weather reduced the frequency of potential withholding during the winter months.
  - Gas market volatility during cold weather can lead to circumstances where a generator's expected costs may be significantly higher than its Reference Level based on published fuel indexes. Thus, potential withholding estimates can be overstated when the frequency and/ or length of cold weather events is high.
- Although long-term deratings are not likely to reflect withholding, inefficient long-term outage scheduling (i.e., scheduling an outage when the capacity is likely economic for a 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.
  - 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.[241, 242] An offer parameter is generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-28 to Figure A-31: 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.[243] 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.

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241 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.

242 Due to the Fuel Cost Adjustment (FCA) 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 FCA reference levels and may request documentation substantiating a generator FCA.

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

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

Figure A-28: Output Gap by Month in New York State
2018 – 2019

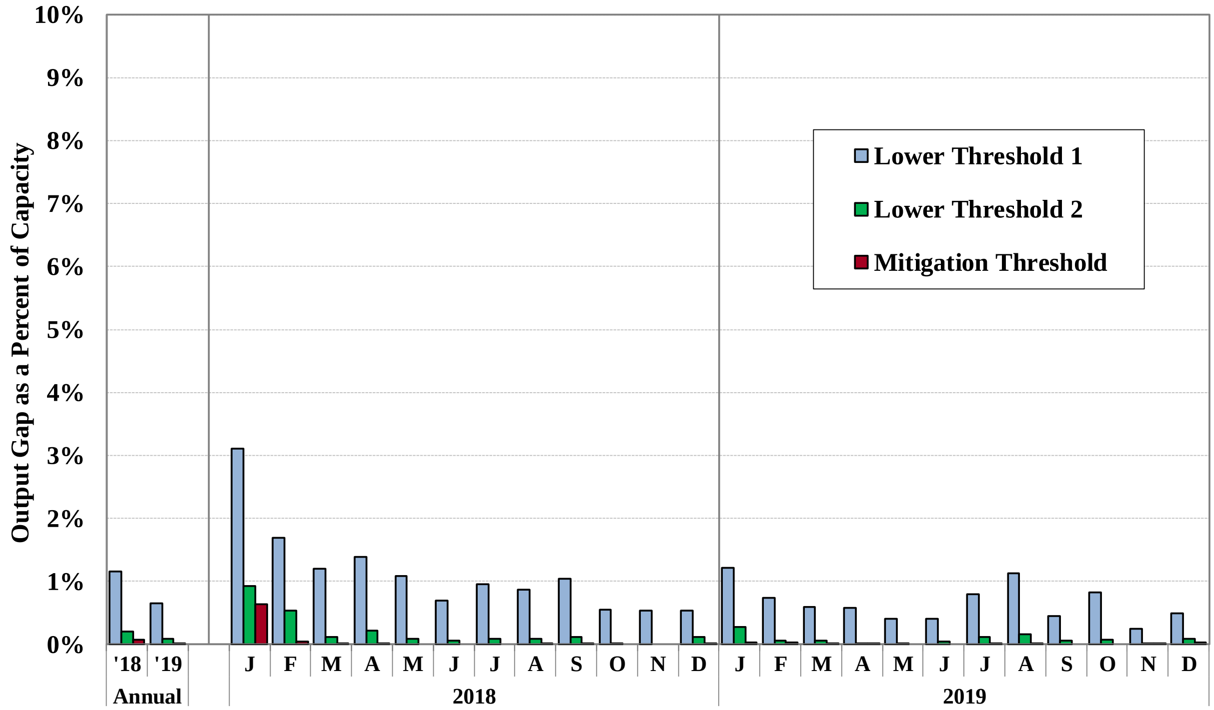


Figure A-29: Output Gap by Month in East New York
2018 - 2019

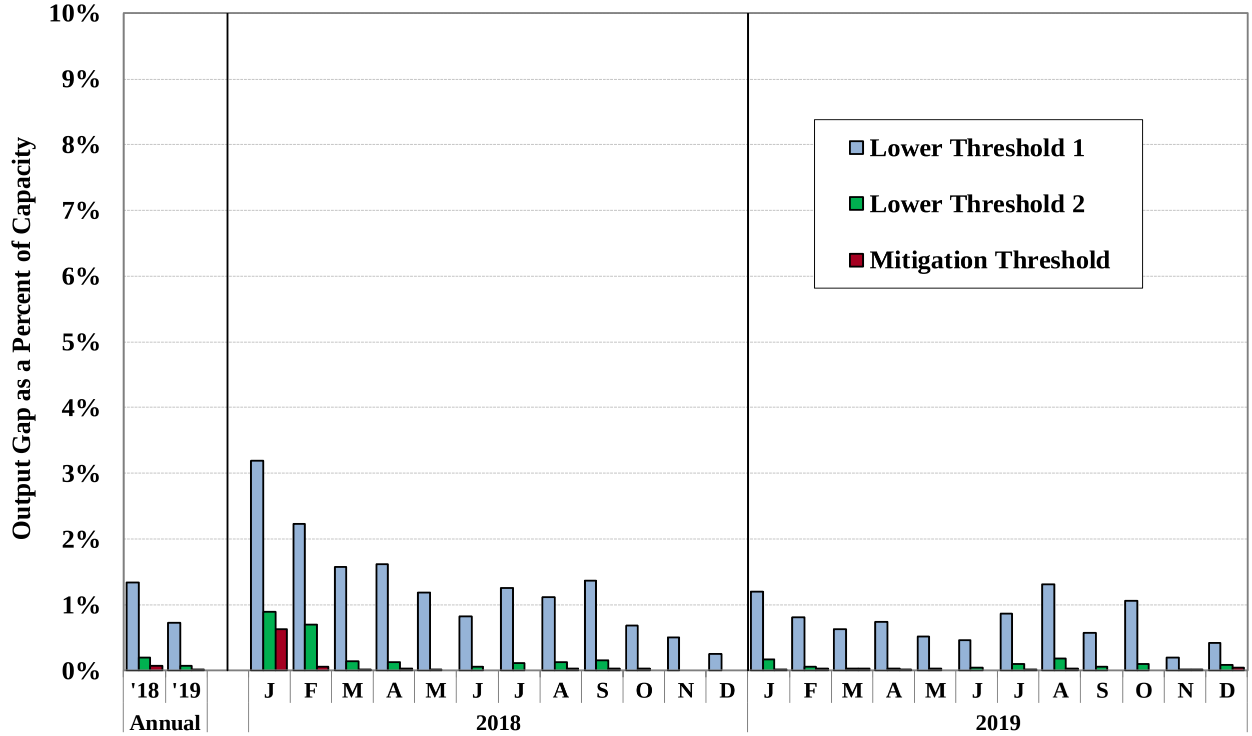


Figure A-30: Output Gap by Supplier by Load Level in New York State
2019

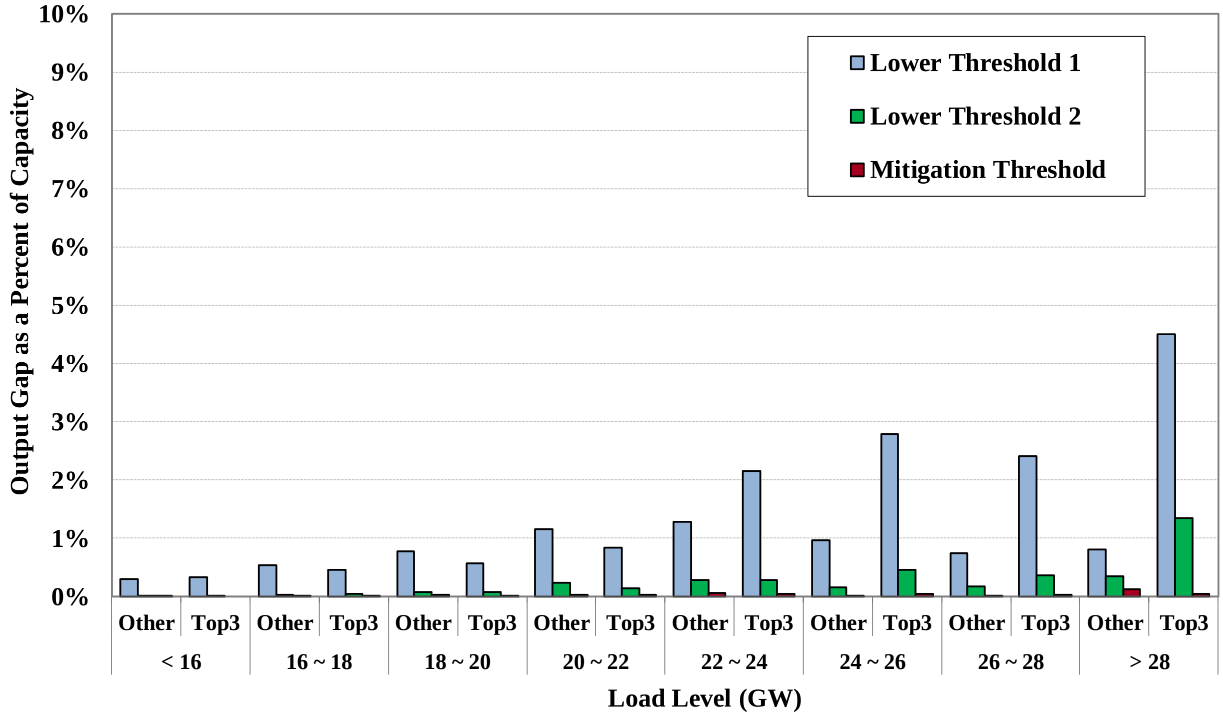
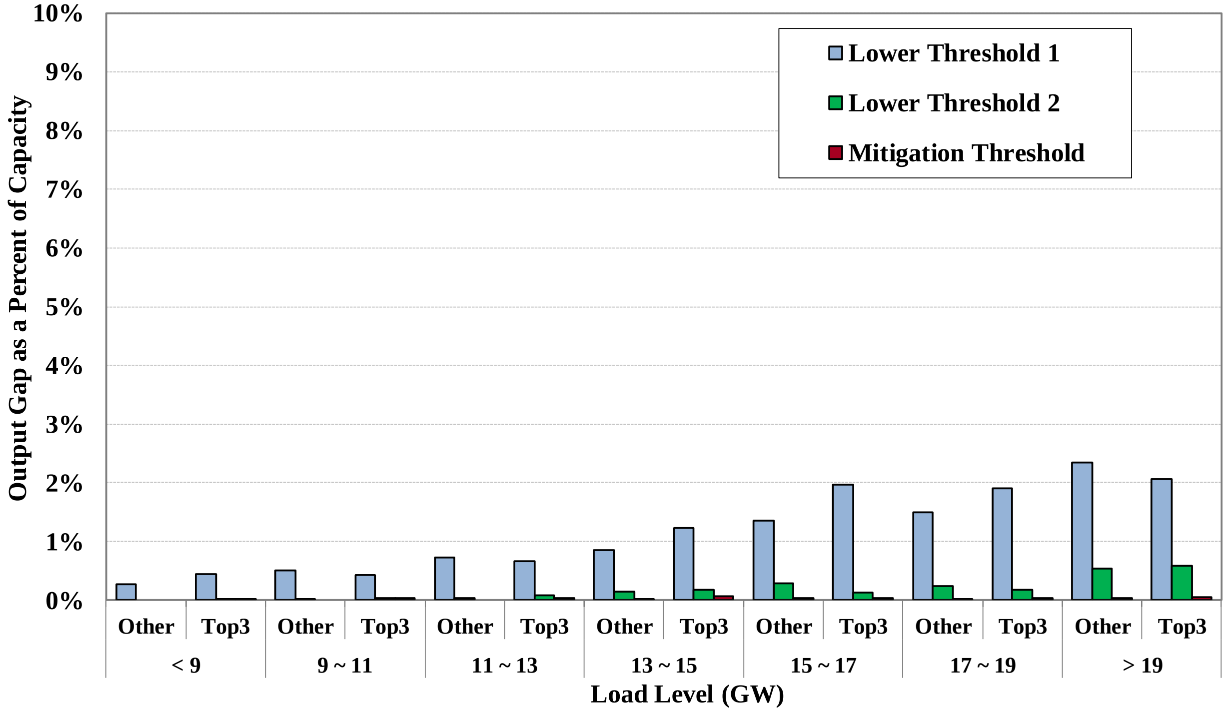


Figure A-31: Output Gap by Supplier by Load Level in East New York
2019



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged 0.01 percent of total capacity at the mitigation threshold and roughly 0.65 percent at the lowest threshold evaluated (i.e., 25 percent) in 2019 for NYCA.
- A large majority of the output gap was attributable to low reference levels used in evaluating the bids rather than inappropriately high energy offers. The factors that lead to inappropriately low reference levels include:
  - Many units that have a significant number of run hours, especially combined cycle units where the supply stack is most competitive, will develop bid-based reference levels that often understate true marginal costs at the stations.[244]
  - Individual unit Reference Levels often do not take into consideration fuel limitations or price effects of operating several units at a multi-generator station. In such

244 Attachment H of the NYISO Market Services Tariff outlines the three type of reference levels that a generator may have. The first type that will be calculated based on the availability of data is a bid-based reference level. This value is calculated as the 25 percentile of the accepted economic bids during unconstrained intervals over the past 90 days. This approach has often understated marginal costs for combined cycle units which face a flatter portion of the supply curve and have been observed to adjust their bid during periods when expected margins are high to ensure they are successfully committed.

situations, the Reference Levels may not reflect the full marginal cost of operating individual units.

- Overall, the output gap level in 2019 does not raise significant concerns about 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.[245] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

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

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[246] 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 has more restrictive conduct and impact thresholds when a single supplier is pivotal for satisfying local reliability criteria outside

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

246 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.

New York City.[247] 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.[248]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[249] 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.[250]
- The generator took appropriate steps to inform the NYISO of a fuel price change prior to being scheduled (either through an FCA or some other means), but the generator was still mitigated.
- A generator's fuel cost may change significantly by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day, so such a generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

Figure A-32 & Figure A-33: Summary of Day-Ahead and Real-Time Mitigation

Figure A-32 and Figure A-33 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2018 and 2019. 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.

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247 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.

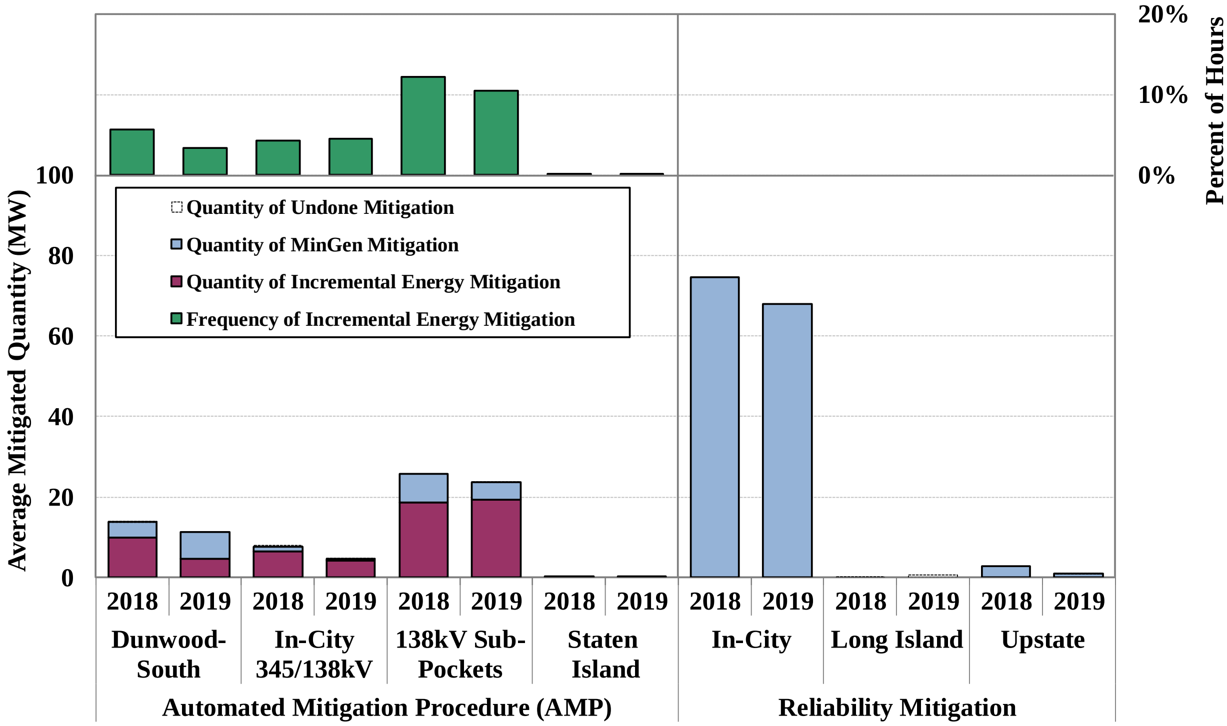
248 See NYISO Market Services Tariff, Section 23.3.1.2.3.

249 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.

250 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.

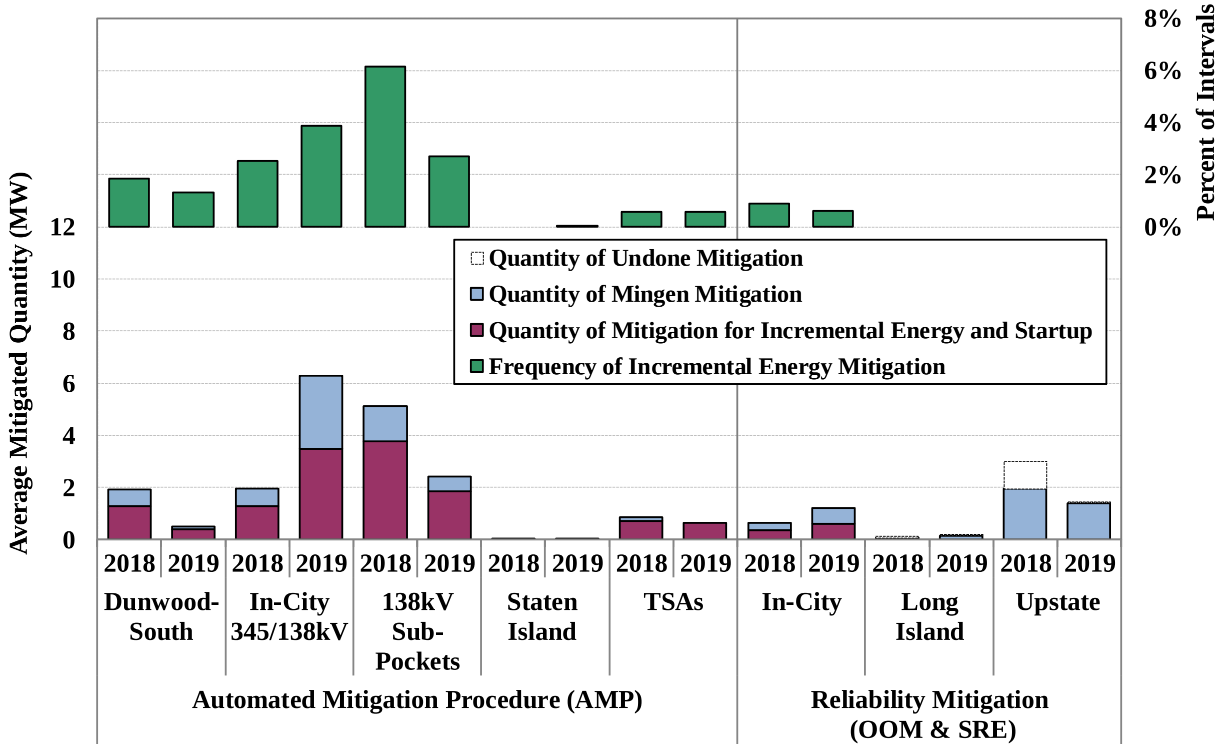
MinGen).[251] In each figure, the left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

Figure A-32: Summary of Day-Ahead Mitigation
2018 – 2019



251 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-33: Summary of Real-Time Mitigation
2018 – 2019



Key Observations: Day-ahead and Real-time Mitigation

- Most mitigation occurs in the day-ahead market, since this is where most supply is scheduled. The total day-ahead mitigation fell by 11 percent from 2018.
  - Local reliability (i.e., DARU and LRR) mitigation in New York City (which accounted for 64 percent of day-ahead mitigation in 2019) fell modestly because of less frequent load conditions that required the reliability commitments of New York City steam units.
    - Steam units are frequently committed in the DA market to satisfy reserve requirements for New York City load pockets. Hence, although high load conditions could enhance the margins for a portion of steam unit capacity, such conditions also often lead to surplus reliability commitments (most often through DARUs) to satisfy reserve needs.[252]
    - These mitigations limited guarantee payment uplift but did not affect LBMPs.
  - Reliability mitigation in the upstate regions was small and fell markedly from 2018. Most of this mitigation in 2018 occurred during the winter cold spell in January. The

[252] See Section XI for our recommendation (#2017-1) to model local reliability requirements in NYC load pockets.

absence of such extreme weather resulted in fewer mitigation and reliability commitments in 2019.

- AMP mitigation accounted for 36 percent of day-ahead mitigation and was down marginally from 2018. The largest year-over-year decrease was for the Dunwoodie-South load pocket.
  - The milder winter and summer conditions prevalent in the state during 2019 led to fewer congested intervals for AMP to be applied (see Section III of the Appendix).

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. Co-optimization causes the prices of 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 use demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be satisfied at a cost lower than the demand curve, the system is in a shortage and the reserve demand curve value is included in 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 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-34 to Figure A-38: Summary of Day-ahead Ancillary Services Offers

The following figures show ancillary services offers for generators in the day-ahead market for 2018 and 2019 on a monthly basis and an annual basis.[253] Quantities offered are shown for:[254]

- 10-minute spinning reserves in Western New York,

253 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.

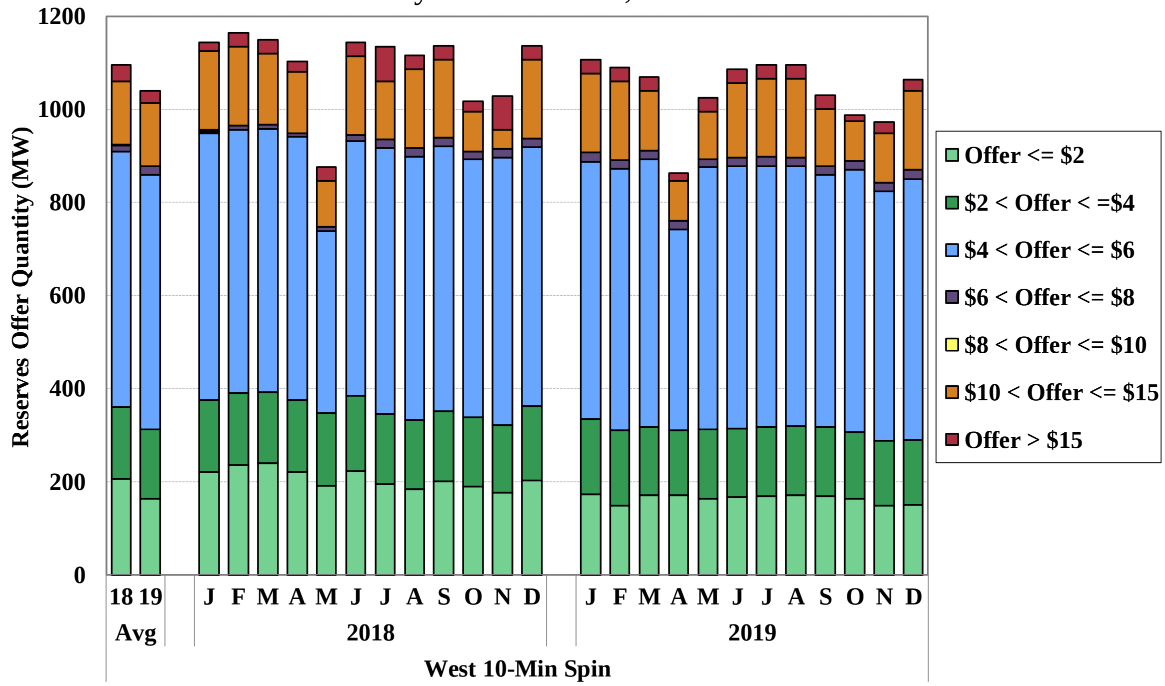
254 The quantity of 10-minute non-spinning reserve offers in Western NY is very small and not reported here.

- 10-minute spinning reserves in Eastern New York,
- 10-minute non-spinning reserves in Eastern New York,
- 30-minute operating reserves in NYCA,[255] 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.

Figure A-34: Summary of West 10-Minute Spinning Reserves Offers

Day-Ahead Market, 2018 - 2019



255 This category only includes the reserve capacity that can be used to satisfy the 30-minute reserve requirements but not 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-35: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2018 – 2019

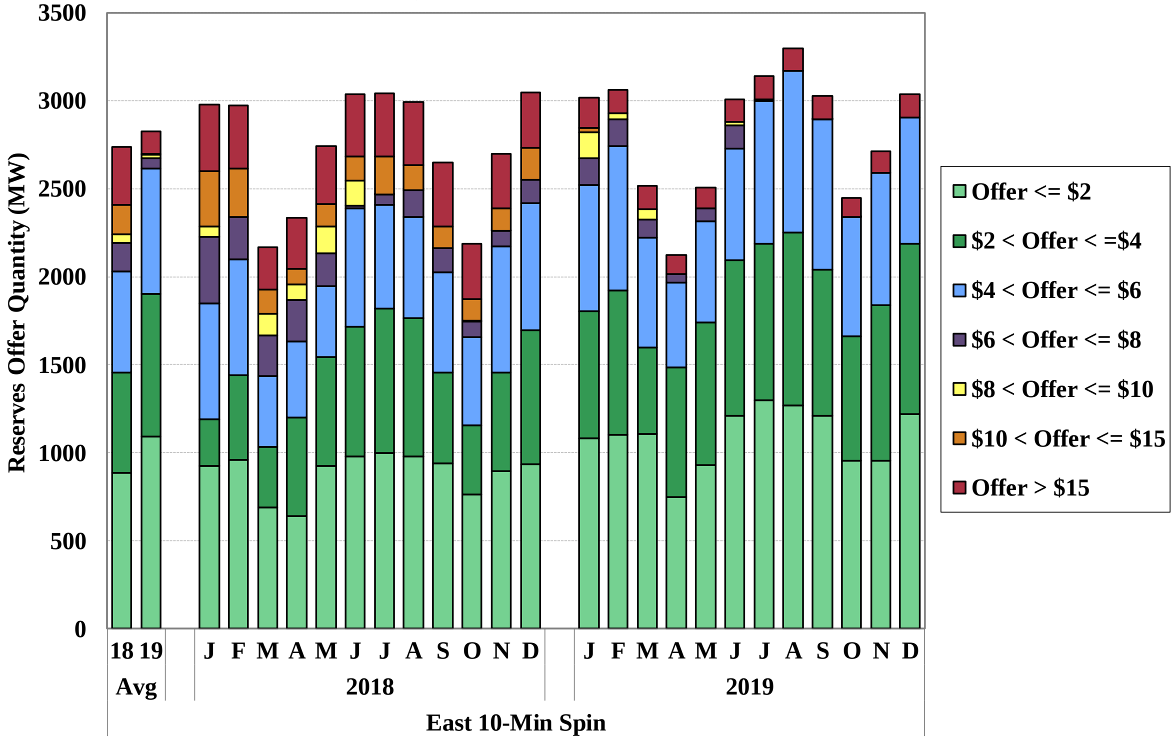


Figure A-36: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2018 – 2019

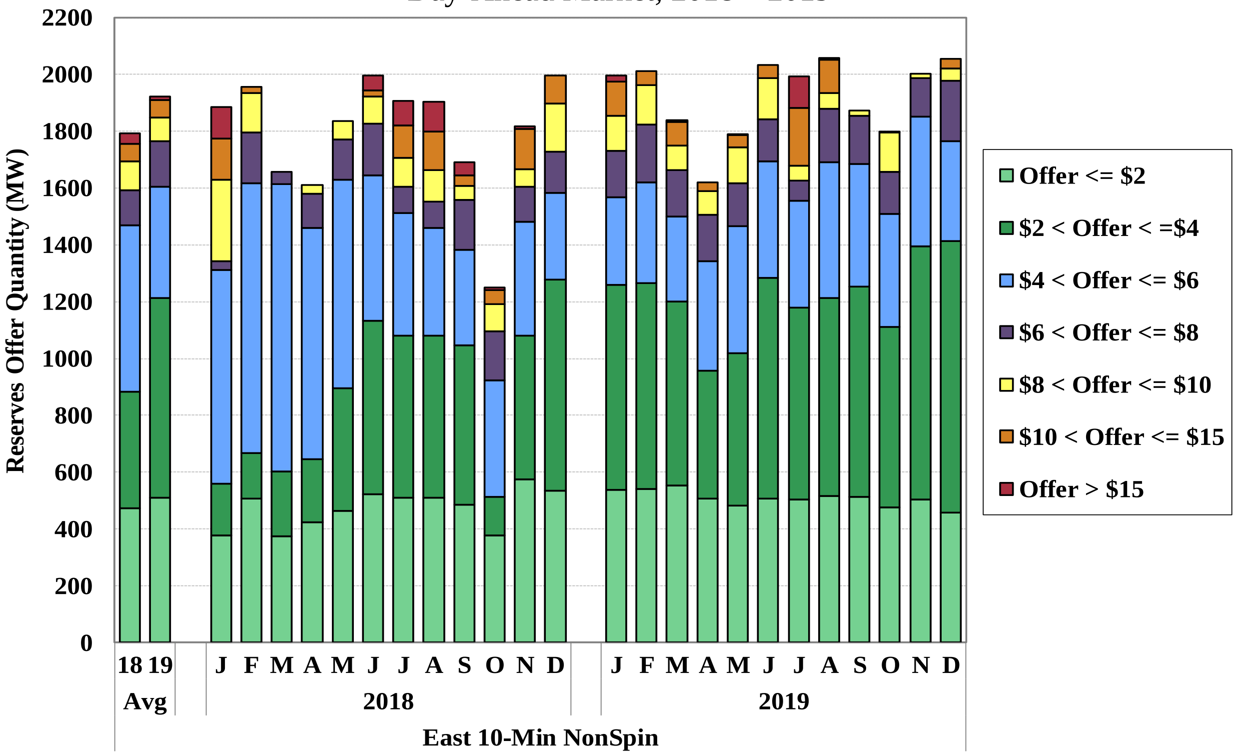


Figure A-37: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2018 - 2019

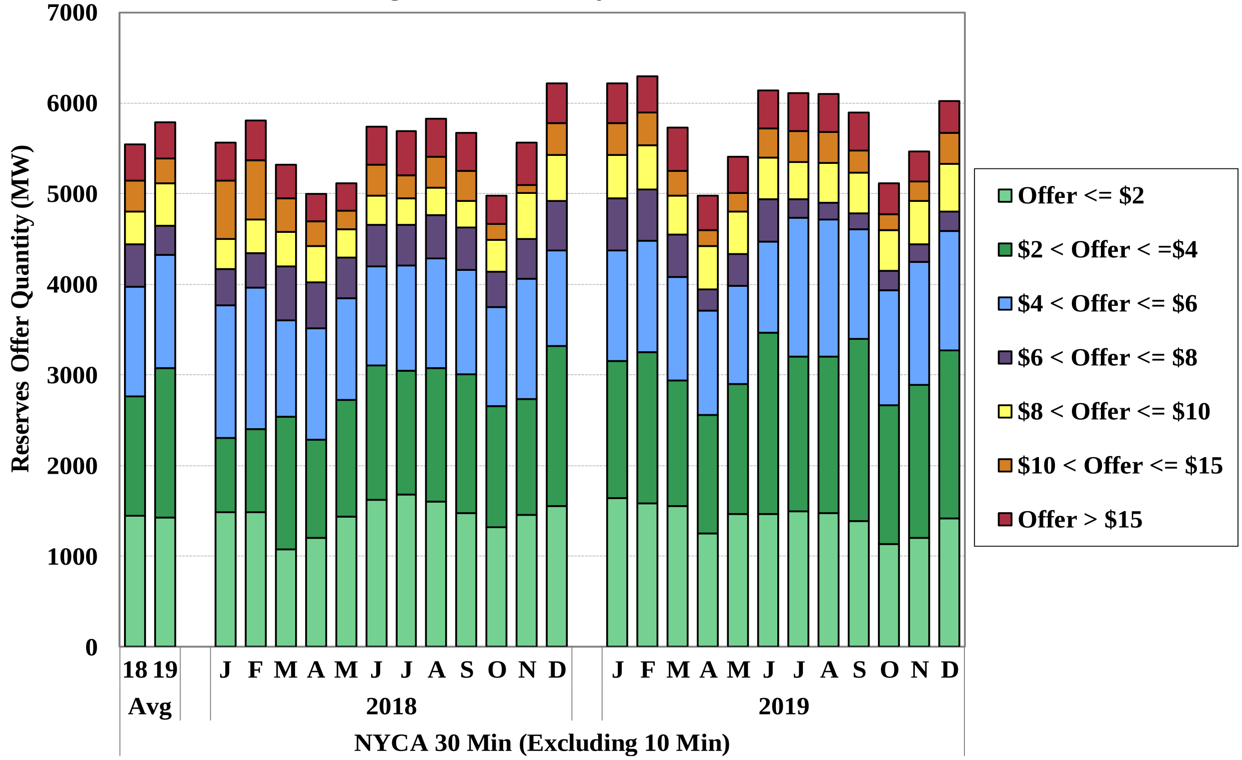


Figure A-38: Summary of Regulation Capacity Offers
Day-Ahead Market, 2018 - 2019

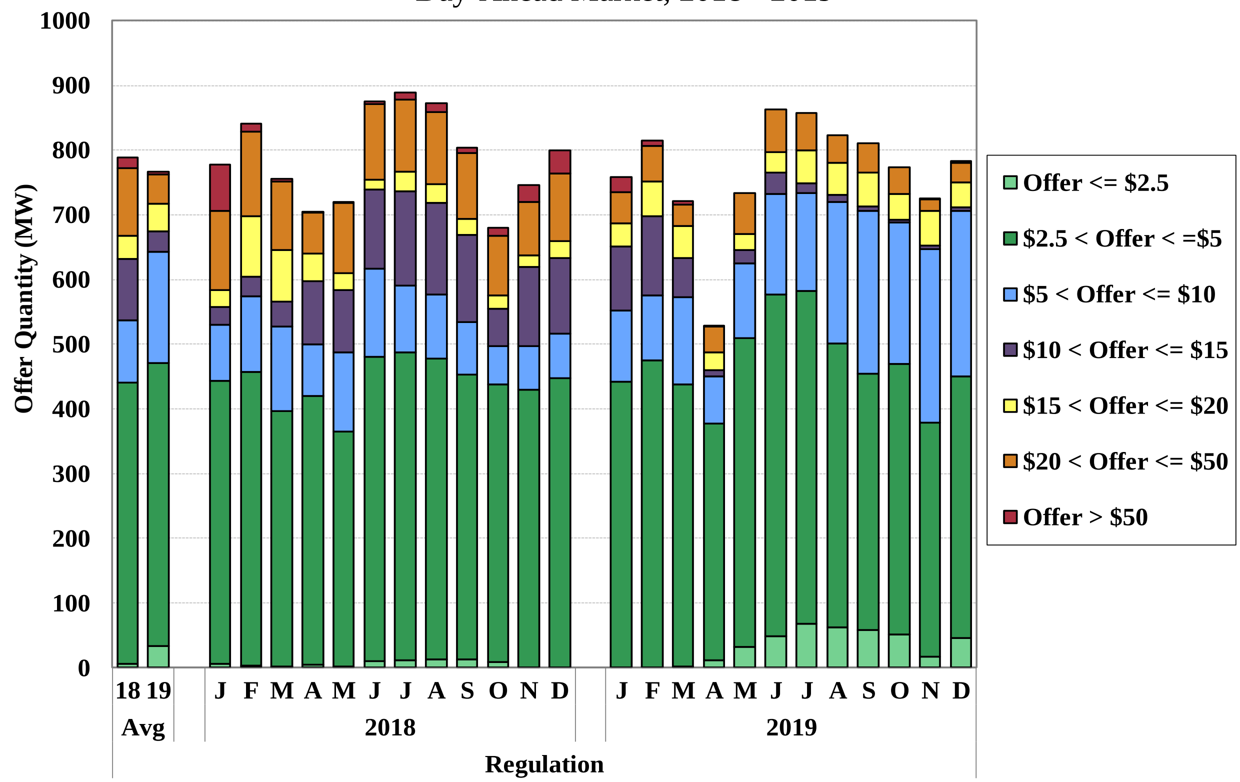


Figure A-39 to Figure A- 40: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement and NYC Reserve Requirement

Figure A-39 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2017 to 2019 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 A-39 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 areas (i.e., SENY, East, NYCA). As a result, Long Island reserve offers have little impact on NYCA reserve prices.

The black bar in the figure represents the equivalent average 30-minute reserve requirements for areas outside Long Island. This is calculated as NYCA 30-minute reserve requirement *minus* 30-minute reserves scheduled on Long Island. Where the line intersects the bar 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-39: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

Committed and Available Offline Quick-Start Resources, 2017 - 2019

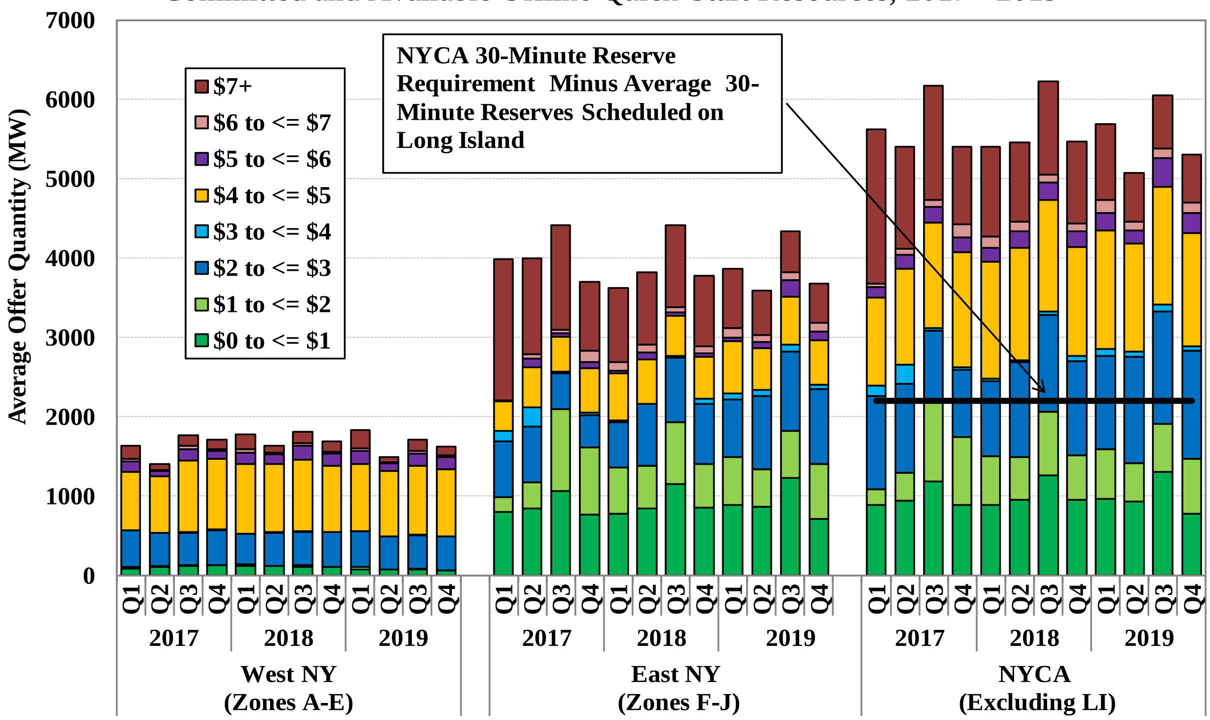


Figure A- 40: Day-Ahead Reserve Offers that Satisfy NYC Reserve Requirement
Committed and Available Offline Quick-Start Resources, 2017-2019

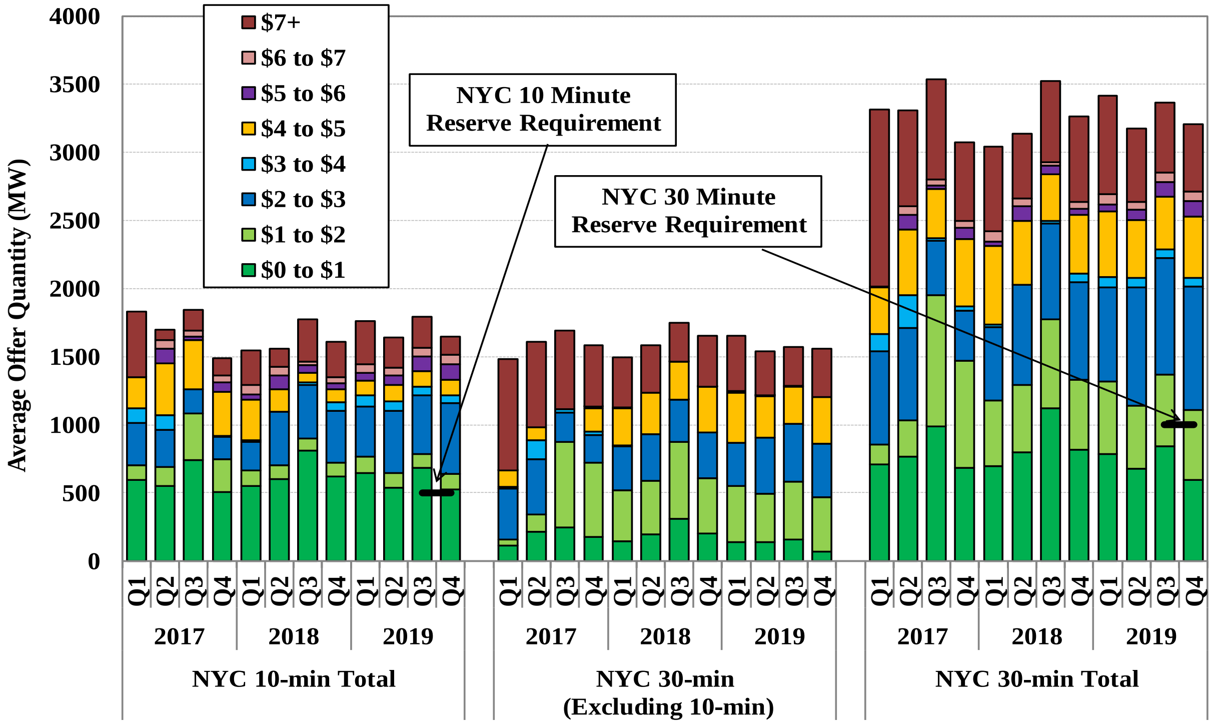


Figure A- 40 summarizes offers that can satisfy the new NYC reserves requirement and shows NYC generator offers for 10- and 30-minute reserves from committed resources and available offline quick-start resources. The information is provided by quarter from 2017 and extending through 2019 for comparative purposes even though the NYC requirement was only recently implemented in late-June 2019. The first set of stacked bars shows the offers from NYC generators for the 10-minute requirement (set at 500 MWs and shown with a black bar) while the second set of stacked bars show the offers for 30-minute reserves (excluding 10-minute offers). The final stack is the sum of the first two and is shown with a black bar designating the NYC 30-minute requirement of 1000 MWs. Similar to Figure A-37, the intersection of the black bars with the stacked lines is a rough indication of reserve prices, but is generally lower than actual reserve prices because opportunity costs are not reflected in the figure.

Key Observations: Ancillary Services Offers

- The overall quantity of reserve services offered in each of the four broad categories (East and West 10-minute spinning, East 10-minute non-spinning, and NYCA 30-minute operating reserves) did not change significantly from 2018 to 2019.
  - The day-ahead offer quantities for all reserve products show a typical seasonal pattern, with planned outages leading to considerably lower quantities offered in the spring and fall than in the summer and winter.

  - East 10-minute non-spinning supply increased by 3 percent in 2019 because of additional offers from new entrants, units that returned to service, and a reduction in generator outages (notably in the month of October) relative to 2018.[256]
  - The overall quantity of reserve capacity offered below $6 in the East increased in 2019, with much of the increase occurring in the $2-$4 category. Most of the increase was due to several resources reducing their offer prices in 2019.
  - An additional reserve requirement of 500 MW for 10-minutes reserves and 1000 MW for 30-minute operating reserves in New York City was implemented in late June 2019. The offer patterns in Q3 and Q4 of 2019 changed only modestly when compared to the corresponding quarters from 2018.
  - Day-ahead clearing prices fell compared to 2018, reflecting lower opportunity costs to provide reserves and lower reserve offer prices in 2019 (see Figure A-11).

- We have reviewed day-ahead reserve offers and found many units that may be offering above the standard competitive benchmark (i.e., estimated marginal cost). However, the marginal cost of providing reserves in the day-ahead market is difficult to quantify.
  - We will continue to monitor day-ahead reserve offer patterns and consider additional rule changes including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the market power mitigation measures.

- The overall quantity of regulation offers from all resources was similar between 2018 and 2019, but a few generators decreased bids from the $10-$15 per MWh range in 2018 to the $5-$10 per MWh range in 2019, reversing a pattern observed in 2018. During years with lower load and fuel prices (e.g.. 2017 and 2019), the costs of regulating tends to decrease.[257]
  - Similar to other ancillary services, regulation also shows seasonal variation where offers are fewer in shoulder months due to outages. However, the quantity of regulation offers fell by a more significant amount (25 percent) in April 2019 compared to the prior year due to multiple planned outages of regulation suppliers.

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

256 New entrants included new units and existing generators, which expanded participation in the reserves markets in 2019.

257 Above average load conditions tend to result in more units being committed which can increase the surplus regulation capacity which could offset the upward price pressure from higher bids.

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.[258]

- *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-41 to Figure A-48: 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

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

unit commitment relies on consistency between the day-ahead and the real-time markets. The following figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

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

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2018 and in 2019 at various locations in New York on a monthly average basis. Virtual load (including virtual exports) scheduling has the same effect on day-ahead prices and resource commitment as physical load scheduling, so they are shown together in this analysis. Conversely, virtual supply (including virtual imports) has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis. For each period, physical load and virtual load are shown by bars in the positive direction, while virtual supply is shown by bars in the negative direction. Net scheduled load, indicated by the line, is the sum of scheduled physical and virtual load minus scheduled virtual supply. The inset table shows the overall changes in scheduling pattern from 2018 to 2019. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-41: Day-Ahead Load Schedules versus Actual Load in West Zone
Zone A, 2018 – 2019

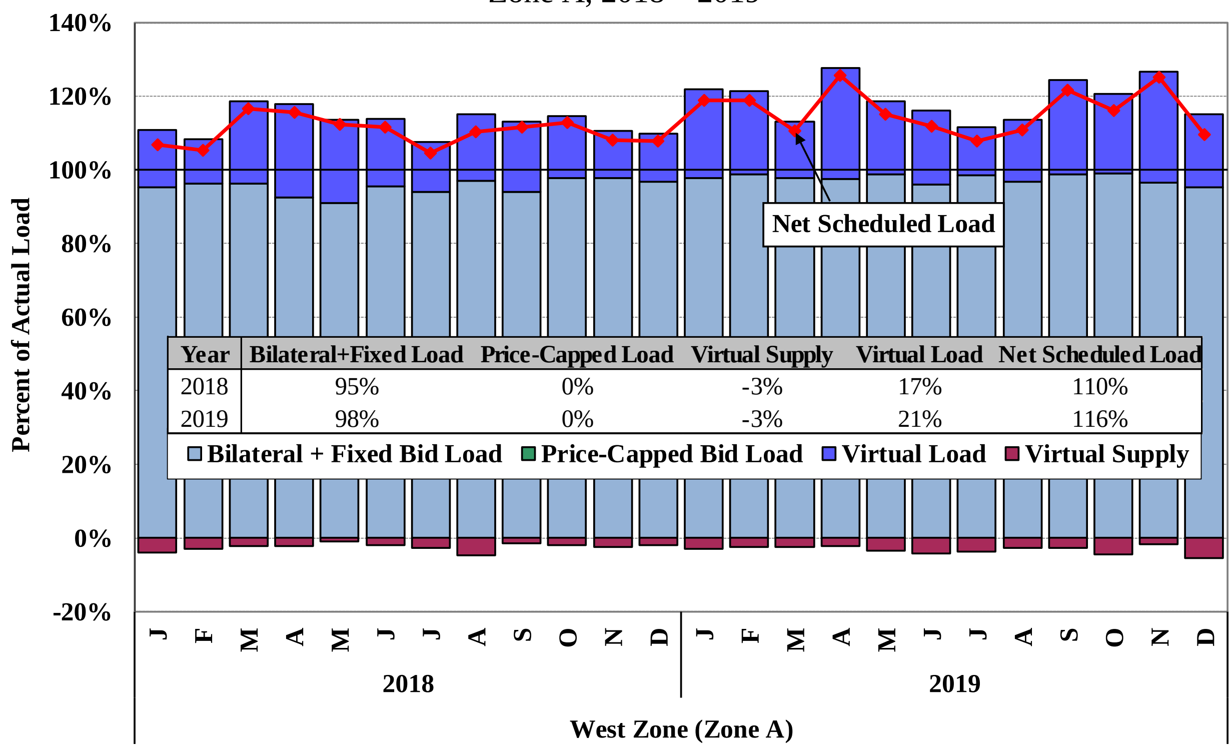
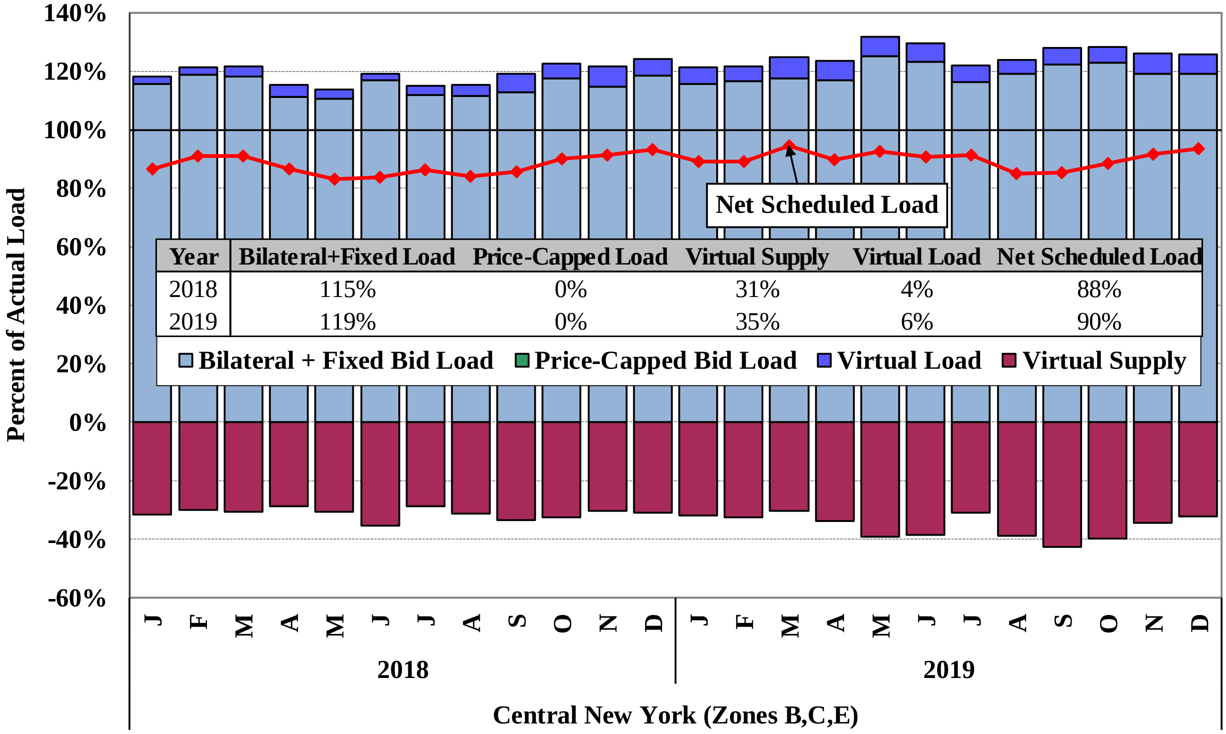


Figure A-42: Day-Ahead Load Schedules versus Actual Load in Central New York

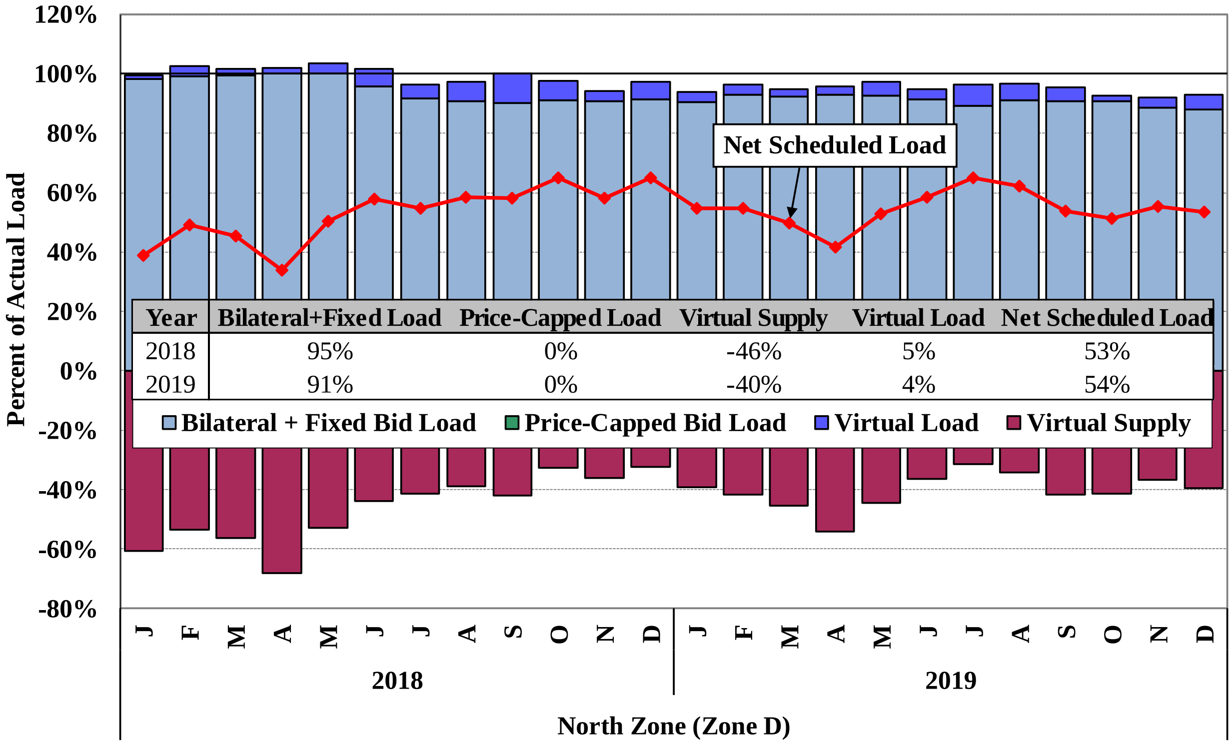
Zones B, C, & E, 2018 – 2019



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2018	115%	0%	31%	4%	88%
2019	119%	0%	35%	6%	90%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in North Zone

Zone D, 2018 – 2019



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2018	95%	0%	-46%	5%	53%
2019	91%	0%	-40%	4%	54%

Figure A-44: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2018 – 2019

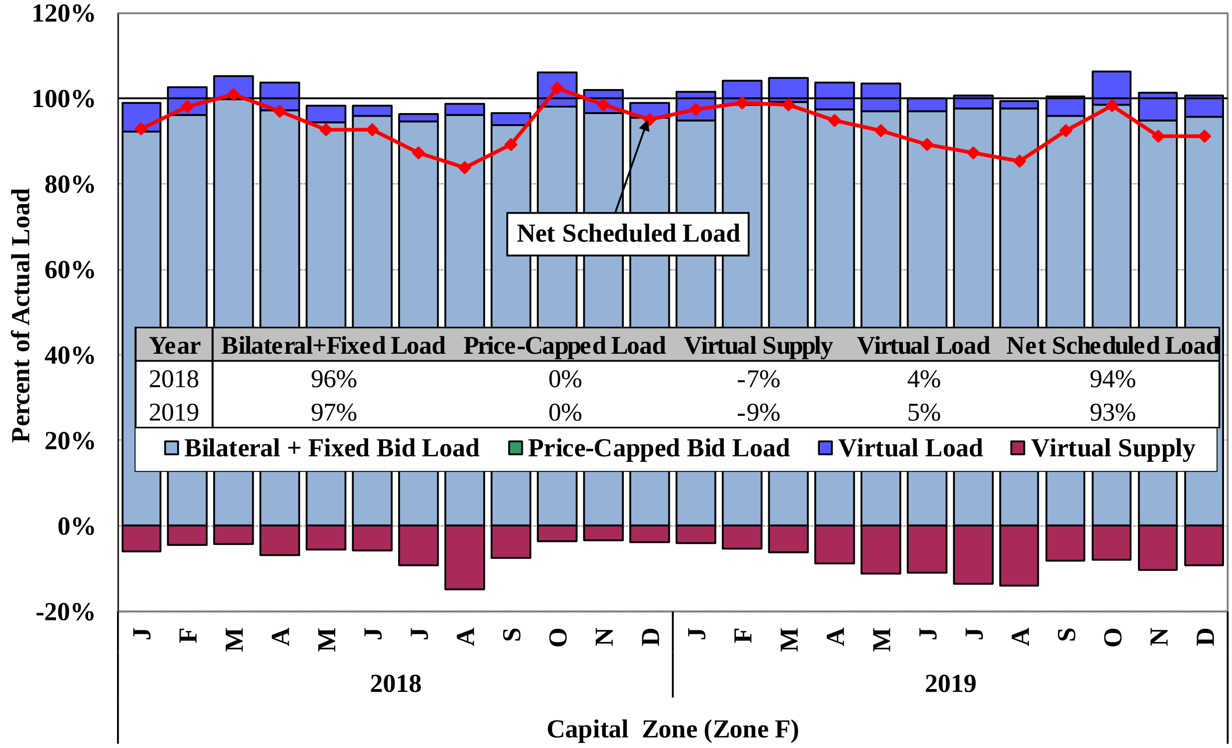


Figure A-45: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2018 – 2019

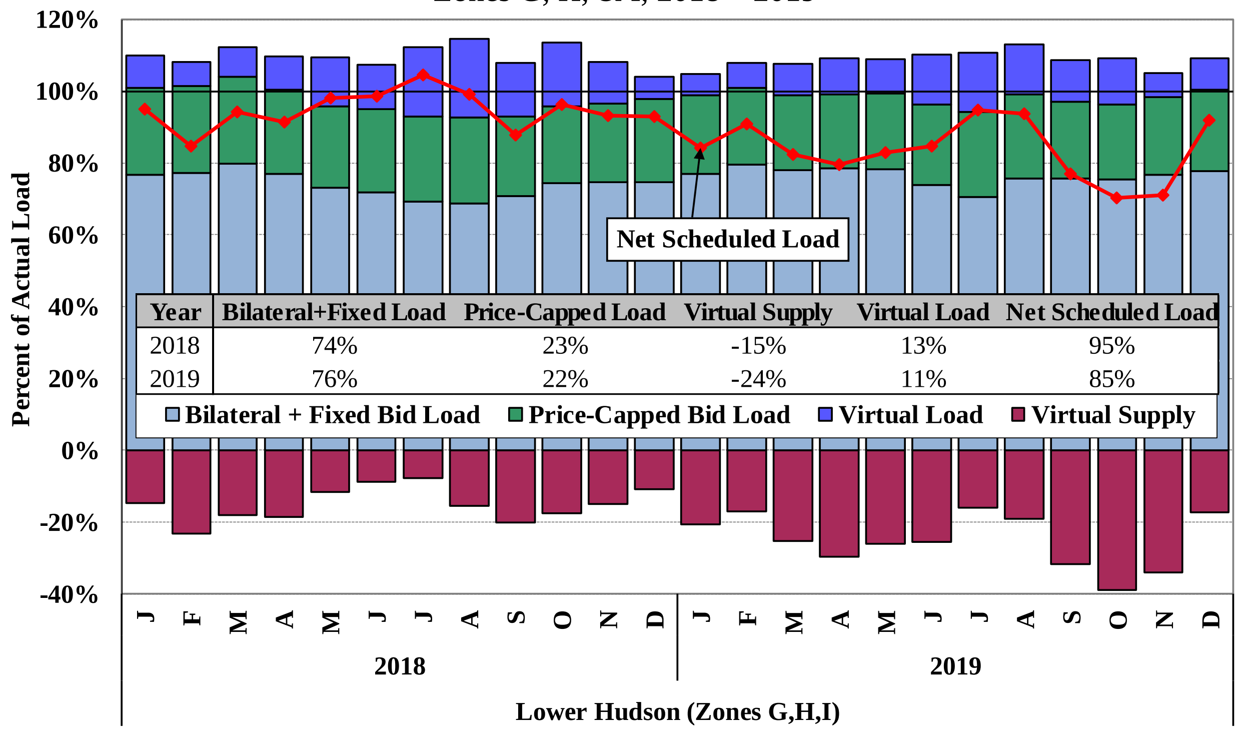


Figure A-46: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2018 – 2019

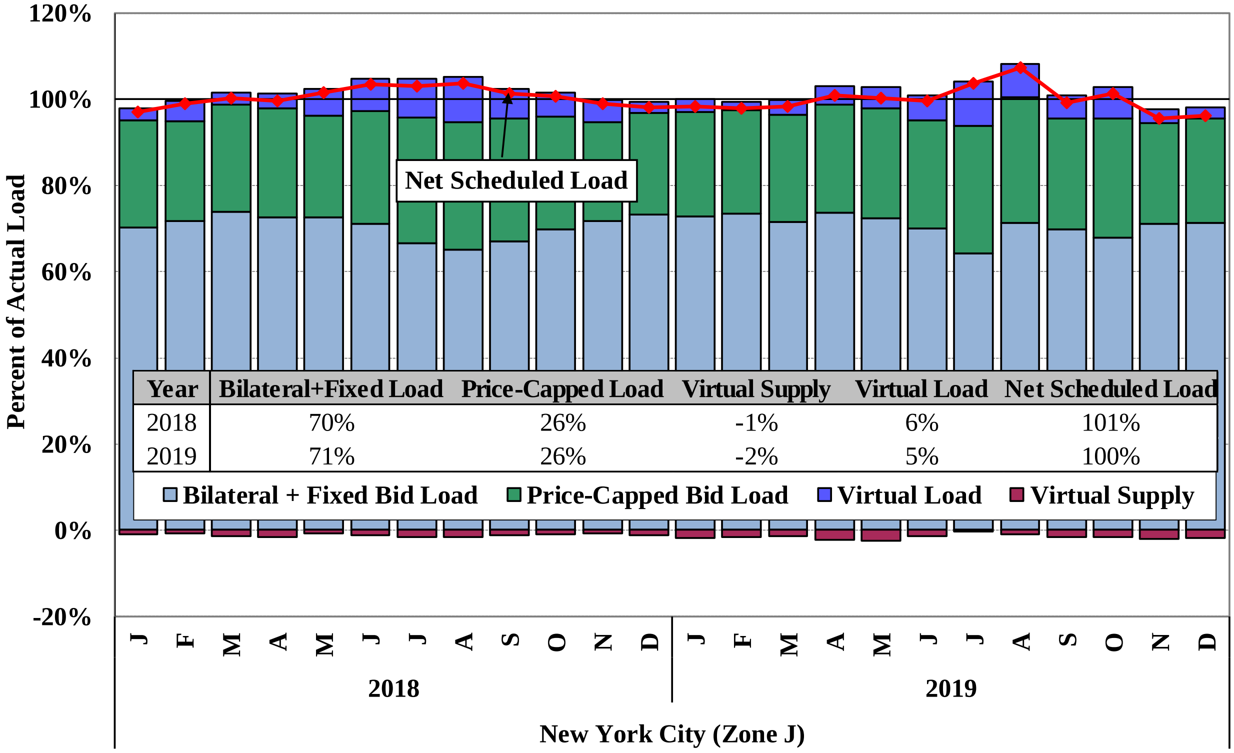


Figure A-47: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2018 – 2019

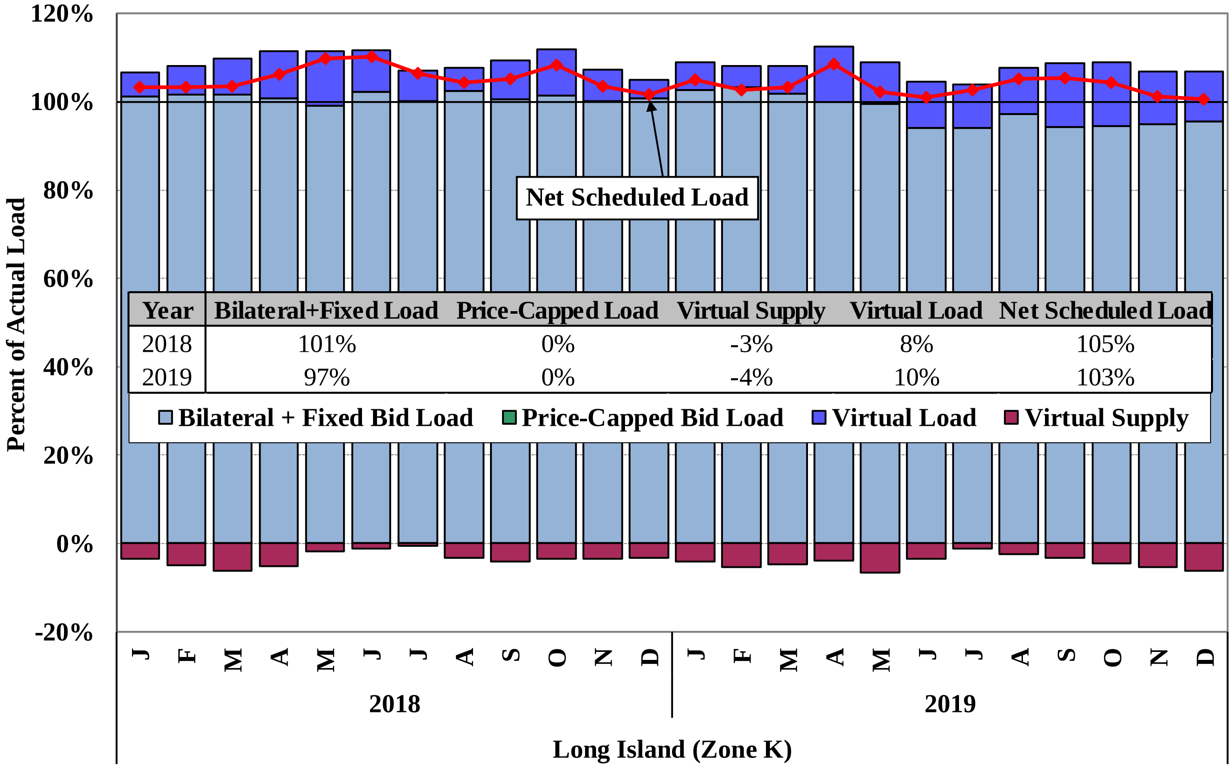
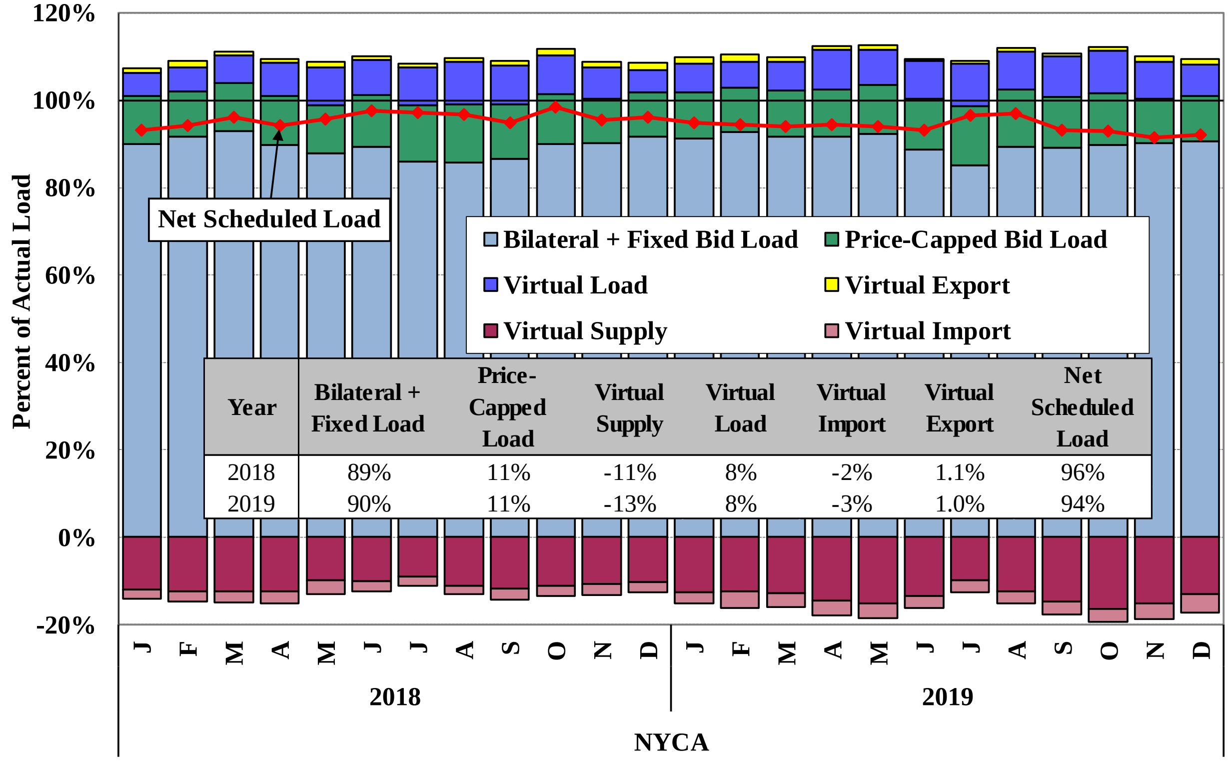


Figure A-48: Day-Ahead Load Schedules versus Actual Load in NYCA
2018 – 2019



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2018	89%	11%	-11%	8%	-2%	1.1%	96%
2019	90%	11%	-13%	8%	-3%	1.0%	94%

Key Observations: Day-ahead Load Scheduling

- For NYCA, roughly 94 percent of actual load was scheduled in the day-ahead market (including virtual imports and exports) during peak load hours in 2019, about two percent less than in 2018.
- The 2019 scheduling patterns in most zones were generally consistent with the 2018 patterns, but the net scheduled load levels varied noticeably in some zones:
  - Over-scheduling in the West Zone has fallen steadily in recent years, but in 2019 it increased by six percentage points. Real-time congestion increased in the West Zone on account of the NYISO incorporating some (previously unpriced) 115 kV West Zone constraints in the market software in December 2018. Furthermore, as noted in Section 0, volatile loop flows had a larger effect on real-time congestion and price volatility following this change.
  - Virtual supply in the North Zone fell from 2018 levels. The frequency and severity of real-time congestion decreased year-over-year in that region in large part due to the NYISO changes to lower limits on transmission line CRMs which likely contributed to reduced virtual supply in 2019 (See discussion in Section III).

  - Net scheduled load fell sharply in the Lower Hudson Valley region (10 percentage points) primarily because more virtual supply was scheduled during the shoulder months (i.e., March through May and September through November).
    - There was a fairly substantial increase in activity among participants who have historically not traded or traded less frequently with lower volumes in the Hudson Valley. The volumes transacted tended to display typical patterns of generally being net-profitable but were susceptible to volatile swings when real-time prices spiked which resulted in some substantial losses. We continue to monitor these transactions.

- The patterns of virtual trading and load scheduling were similar. Net load scheduling (including net virtual load) tends 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 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.
    - 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 continued to be prevalent in Zones B-F.
  - 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.

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-49: Virtual Trading Volumes and Profitability

The figure summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2018 and 2019. The amount of scheduled virtual supply in the figure includes scheduled virtual supply at the load zones and 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.[259,260]

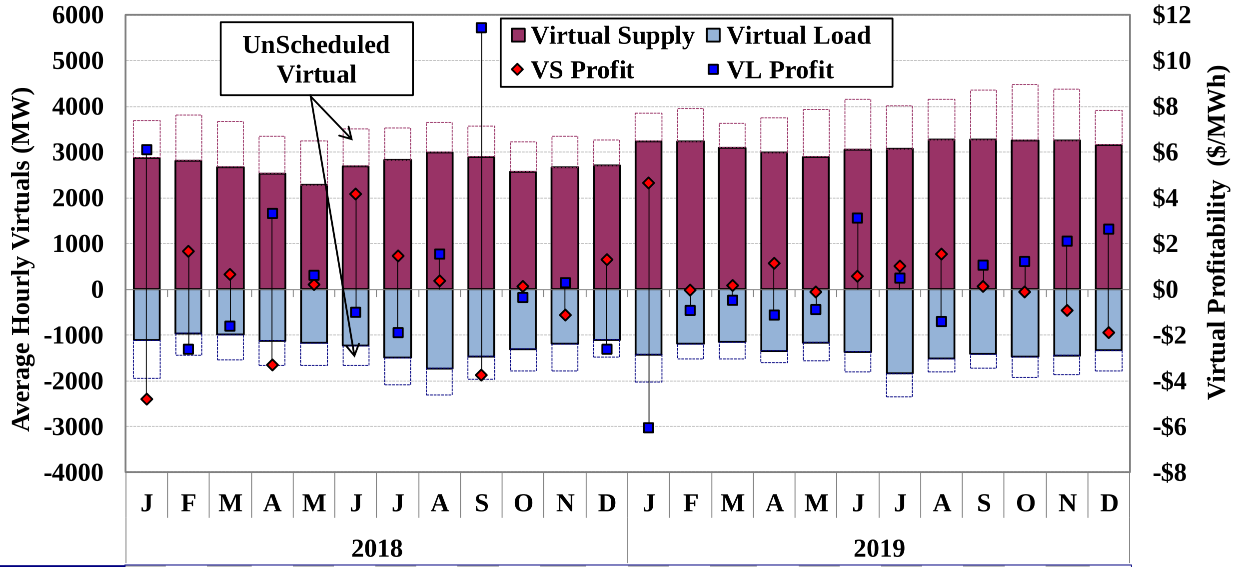
The table below the figure shows a screen for relatively large profits or losses, which identifies virtual transactions with gross profits (or losses) larger than 50 percent of the average zone (or proxy bus) price. For example, an average of 274 MW of virtual transactions (or 6 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2010. Large profits may be an indicator of a modeling inconsistency, while sustained losses may be an indicator of potential manipulation of the day-ahead market.

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

260 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-49: Virtual Trading Volumes and Profitability

2018 – 2019



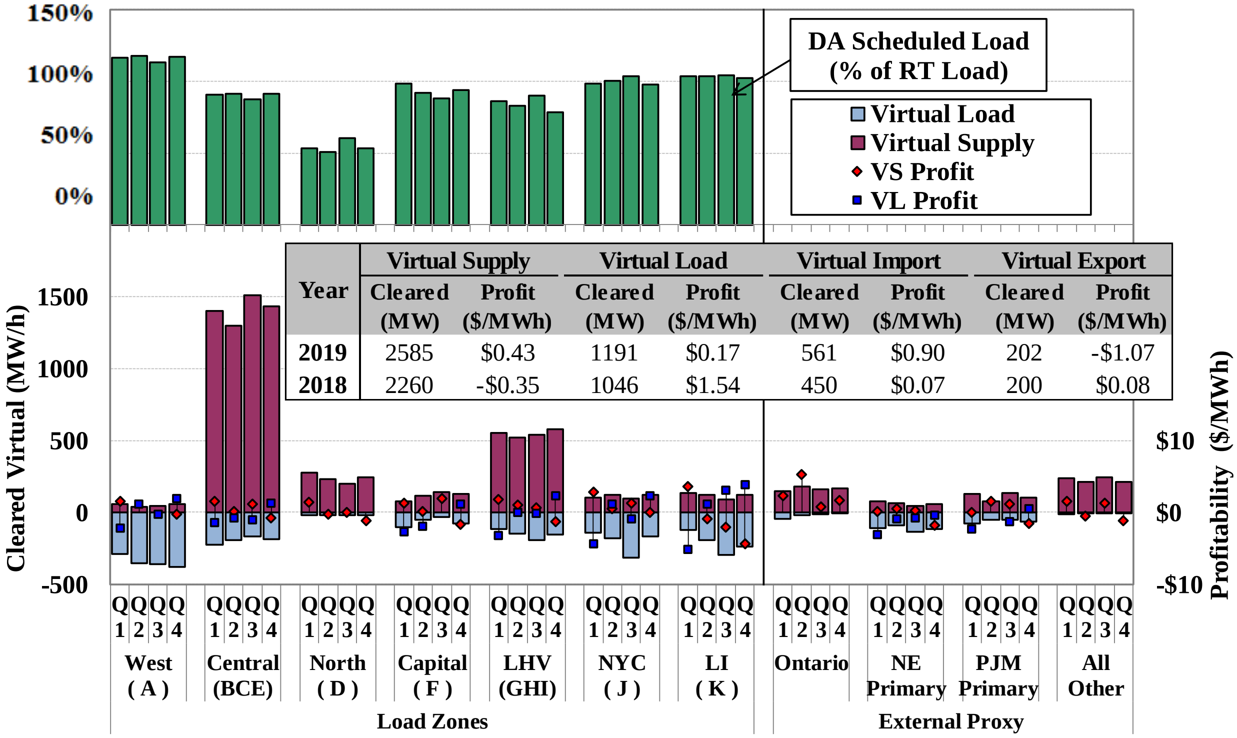
		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
		2018												2019											
Profit > 50% of Avg. Zone Price	MW	373	450	419	376	475	620	320	299	437	366	312	326	612	279	167	473	477	587	384	396	249	312	290	274
	%	9%	12%	11%	10%	14%	16%	7%	6%	10%	9%	8%	9%	13%	6%	4%	11%	12%	13%	8%	8%	5%	7%	6%	6%
Loss > 50% of Avg. Zone Price	MW	442	342	401	466	537	531	329	328	428	430	345	317	439	331	178	348	591	548	372	321	293	376	344	305
	%	11%	9%	11%	13%	16%	14%	8%	7%	10%	11%	9%	8%	9%	7%	4%	8%	15%	12%	8%	7%	6%	8%	7%	7%

Figure A-50: Virtual Trading Activity

Figure A-50 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 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 figure also shows 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 2019. 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 2018 and 2019.

Figure A-50: Virtual Trading Activity [261]
by Region by Quarter, 2019



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)
2019	2585	$0.43	1191	$0.17	561	$0.90	202	-$1.07
2018	2260	-$0.35	1046	$1.54	450	$0.07	200	$0.08

Key Observations: Virtual Trading

- In aggregate, virtual traders netted $14 million of gross profits in 2019 and $7.5 million in 2018.
  - Profitable virtual transactions over the period indicate that they have generally improved convergence between day-ahead and real-time prices.
  - 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 2019, consistent with prior periods.
  - Many of these losing trades were associated with high real-time price volatility that resulted from unexpected events and did not raise significant manipulation concerns.
  - On the other hand, virtual load positions lost heavily during cold weather periods in January on the expectation of greater natural gas market volatility than what actually occurred.

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

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 the following aspects of transmission congestion and locational pricing:

- Congestion Revenues and Patterns – Subsections 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 – Subsection C evaluates the management of transmission constraints that are frequently resolved using out-of-market actions, including the management of the 115 kV and lower voltage network in New York.

- Congestion Revenue Shortfalls – Subsections D and E analyze shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- In-Series Line Segments in the Market Model – Subsection F analyzes the market impact of modeling in-series line segments in the market model.

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

- Transitioning Physical Contracts to Financial Rights – Subsection 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 2019

In this subsection, 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.[262]

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.[263] 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.[264] 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

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262 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).

263 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).

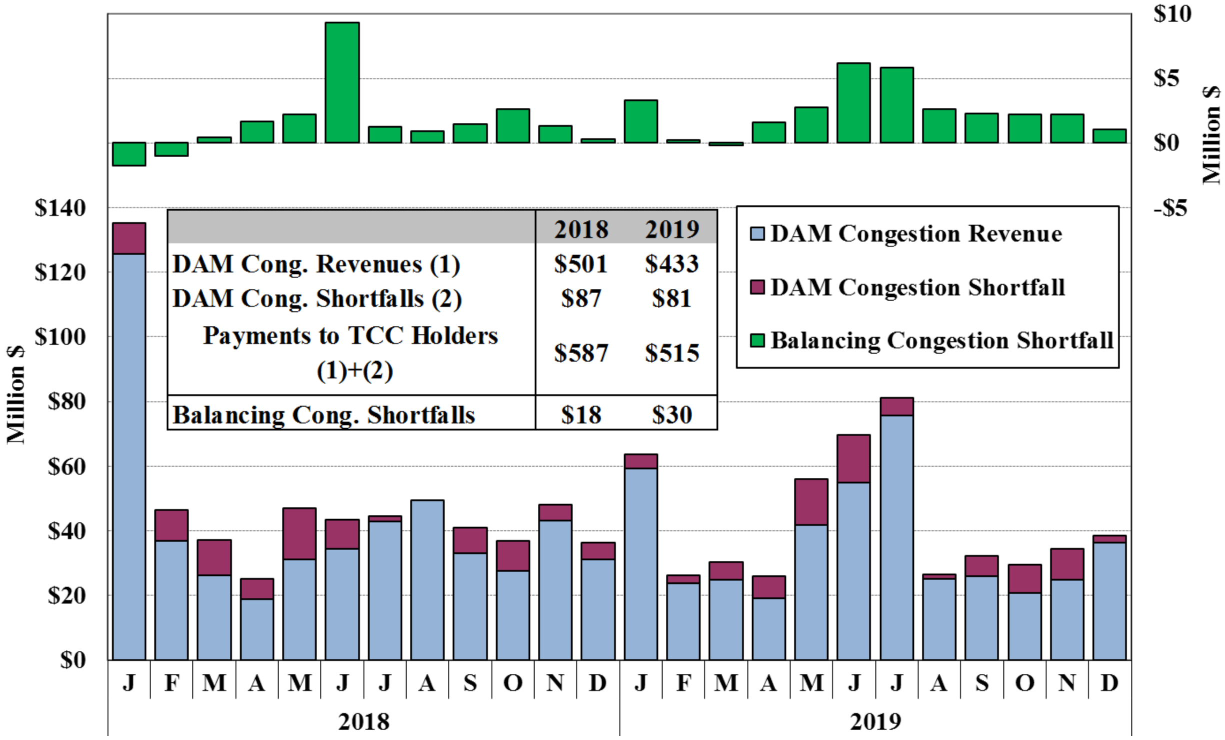
264 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) *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

for increased generation and the revenues from reduced generation in the two areas) are the balancing congestion shortfall that is recovered through uplift.

Figure A-51: Congestion Revenue Collections and Shortfalls

Figure A-51 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2018 and 2019. 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-51: Congestion Revenue Collections and Shortfalls
2018 - 2019



	2018	2019
DAM Cong. Revenues (1)	$501	$433
DAM Cong. Shortfalls (2)	$87	$81
Payments to TCC Holders (1)+(2)	$587	$515
Balancing Cong. Shortfalls	$18	$30

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 subsection 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-52 to Figure A-54: Day-Ahead and Real-Time Congestion by Path

Figure A-52 to Figure A-54 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-52 compares these quantities in 2018 and 2019 on an annual basis, while Figure A-53 and Figure A-54 show the quantities separately for each quarter of 2019.

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.[265]

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.
- West to Central: Primarily West-to-Central interface, Dysinger East interface, and transmission facilities in the Central Zone.
- North to Central: Primarily transmission facilities within and out of the North Zone.
- Central to East: Primarily the Central-to-East interface.
- Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the New Scotland-to-Leeds Line, the Leeds-to-Pleasant Valley Line).

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

- Hudson Valley to Dunwoodie: Lines and interfaces leading into Dunwoodie from Hudson Valley.
- 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.

Figure A-52: Day-Ahead and Real-Time Congestion by Transmission Path

2018 – 2019

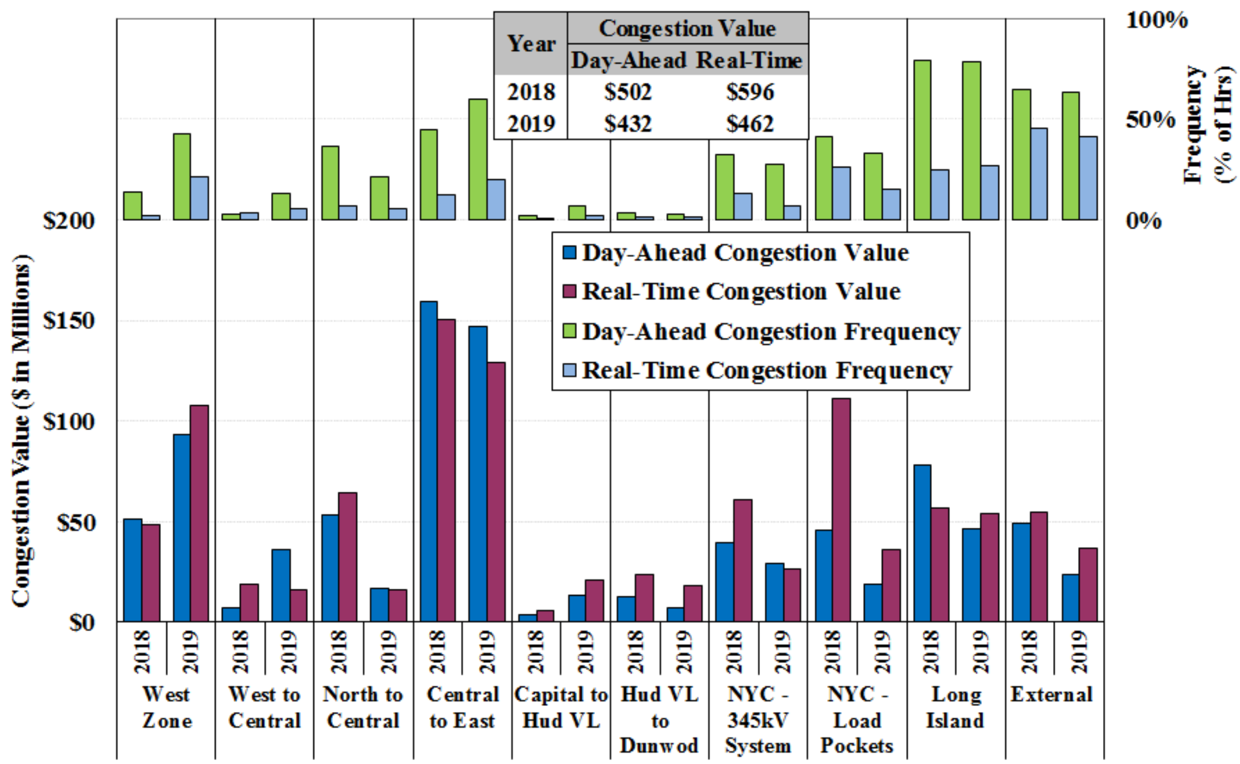


Figure A-53: Day-Ahead Congestion by Transmission Path
By Quarter, 2019

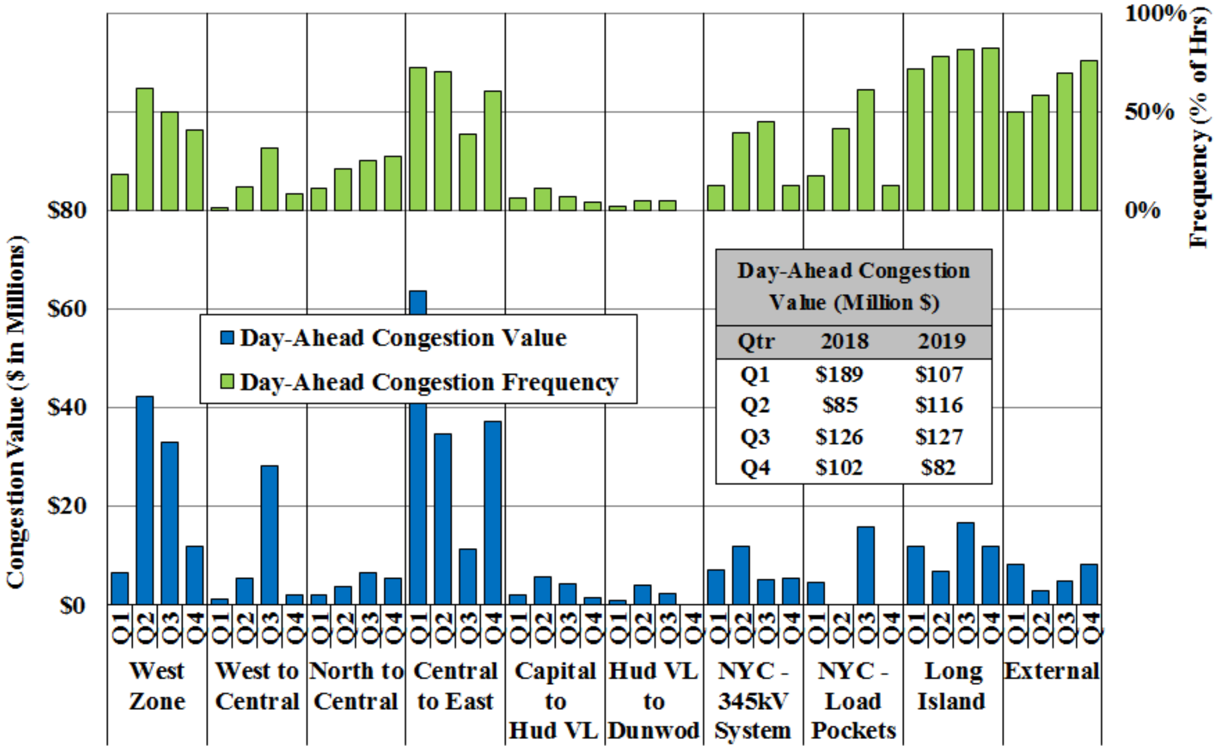
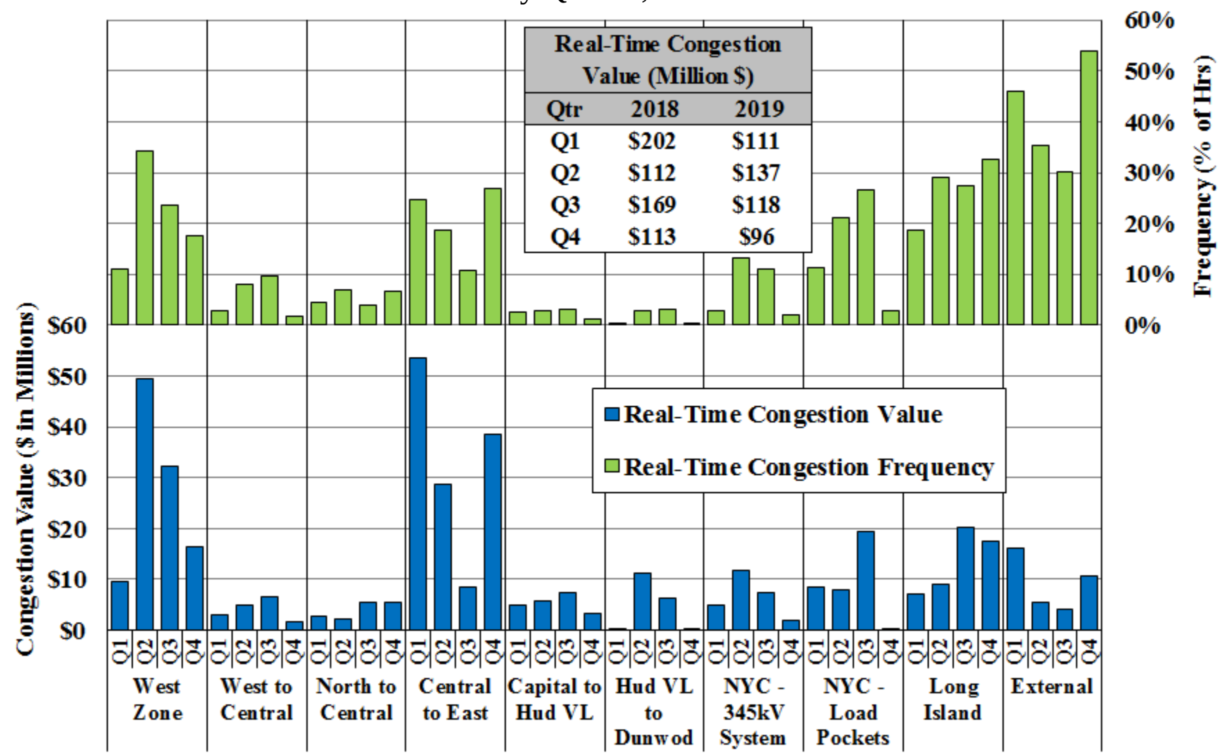


Figure A-54: Real-Time Congestion by Transmission Path
By Quarter, 2019



Key Observations: Congestion Revenues and Patterns

- Day-ahead congestion revenues totaled roughly $433 million in 2019, down 14 percent from 2018.
  - The reduction occurred primarily in the first quarter of 2019 because of much milder weather conditions in Winter 2018/19.
    - Day-ahead congestion revenues fell $82 million (or 43 percent) from the first quarter of 2018, where $56 million (or 29 percent) of day-ahead congestion revenues accrued in the first 8 days of the year (during a cold spell, the "Bomb Cyclone") with particularly high natural gas prices.
  - In spite of the overall decrease, day-ahead congestion revenues rose modestly in the second and third quarters, reflecting higher priced congestion in the West Zone.
- Similar to prior years, the largest share of congestion values accrued on the Central-East interface, which accounted for 34 percent of congestion value in the day-ahead market and 28 percent in the real-time market in 2019.
  - The majority of this congestion occurred in the winter months as a result of higher natural gas prices and larger gas price spreads between regions (which typically increase in the winter season).
  - Day-ahead congestion revenues accrued on the Central-East interface fell only by 8 percent from 2018 to 2019 in spite of substantially lower load levels and natural gas prices in 2019.
    - The reduction was partially offset by more costly transmission outages at the Central East interface (see Subsection E).
- Congestion fell from 2018 to 2019 in most regions, driven largely by lower gas prices, lower loads, and lower gas price spreads across New York. In addition,
  - Congestion in New York City fell 43 percent in the day-ahead market and 64 percent in the real-time market from 2018, which was also attributable to fewer costly transmission outages in 2019 (see Subsection E).
  - Congestion from North to Central New York decreased by 68 percent in the day-ahead market and 75 percent in the real-time market in 2019. Additional key drivers include:
    - A lower CRM (reduced from 20 to 10 MW) for 115 kV facilities, which reduced the frequency of unnecessarily high congestion (see Section V);
    - Some wind turbine units that are upstream of congestion bottlenecks have raised their negative offer prices to levels closer to $0, which has helped moderate the price effects of congestion; and
    - Fewer costly transmission outages (see Subsection E).

  - Congestion across the external interfaces decreased by 51 percent in the day-ahead market and 33 percent in the real-time market from 2019. The reduction occurred primarily on the NY/NE interface, where lengthy outages were pervasive in 2018 but not in 2019 (see Subsection E).

- Congestion in the West Zone increased 81 percent in the day-ahead market and 121 percent in the real-time market from 2018, accounting for the second largest share of congestion in 2019.
  - Nearly 80 percent of congestion occurred on the 115 kV constraints in 2019.
  - 115 kV constraints were previously managed using OOM actions and surrogate transmission constraints, but most of these constraints have been incorporated into the day-ahead and real-time markets since December 2018.
    - This change led to a large increase in priced congestion in the West Zone.
  - The South Ripley-to-Dunkirk 230 kV line, which was normally "open" in the past, has been "closed" since April 2019. This line flowed an average of more than 150 MW from the West Zone to PJM, increasing congestion across the West Zone.
  - More costly transmission outages were also an important driver of higher congestion in the West Zone. (see Subsection E)

C. Transmission Constraints on the Low Voltage Network in New York

In this subsection, we evaluate the actions that are used to manage transmission constraints on the low voltage network in 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.[266] This provides several benefits including: (a) that the 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 New York are resolved in other ways, including: (a) out of merit dispatch and supplemental commitment of

266 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.

generation; (b) curtailment of external transactions and limitations on external interface transfer limits; (c) use of an internal interface/constraint transfer limit that functions as a proxy for the limiting transmission facility; and (d) adjusting PAR-controlled lines on the high voltage network. [267]

Figure A-55 & Figure A-56: Transmission Constraints on the Low Voltage Network

Figure A-55 shows the number of days in 2019 when various resources were used to manage constraints in six areas of New York:

- West Zone: Mostly 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;
- Hudson Valley Zone: Mostly constraints on the 69kV system in the Hudson Valley; and
- Long Island: Mostly constraints on the 69 kV system on Long Island

Figure A-56 focuses on the area of Long Island, showing the number of hours and days in 2019 when various resources were used to manage 69 kV and TVR ("Transient Voltage Recovery") constraints in four load pockets of Long Island:

- Valley Stream: Mostly constraints around the Valley Stream bus;
- Brentwood: Mostly constraints around the Brentwood bus;
- East of Northport: Mostly the Central Islip-Hauppauge and the Elwood-Deposit circuits;
- East End: Mostly the constraints around the Riverhead bus and the TVR requirement.

For a comparison, the tables also show the frequency of congestion management on the 138 kV constraint via the market model. Figure A-56 also shows our estimated price impacts in each Long Island load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.[268]

267 Most 115 kV constraints in West Zone and the North Zone that were previously managed via these OOM actions are now managed in the day-ahead and real-time markets.

268 The following generator locations are chosen to represent each load pocket: (a) Barrett ST for the Valley Stream pocket; (b) NYPA Brentwood GT for the Brentwood pocket; (c) Holtsville IC for the East of Northport pocket; and (d) Green Port GT for the East End pocket.

Figure A-55: Constraints on the Low Voltage Network in New York
Summary of Resources Used to Manage Constraint, 2019

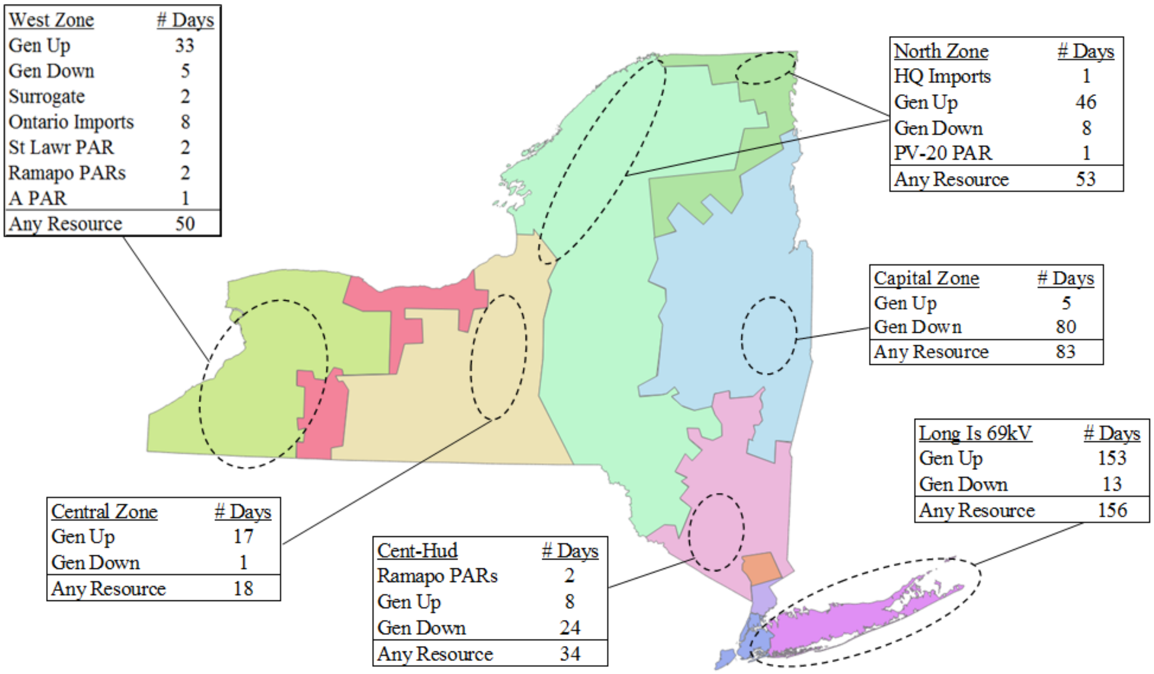
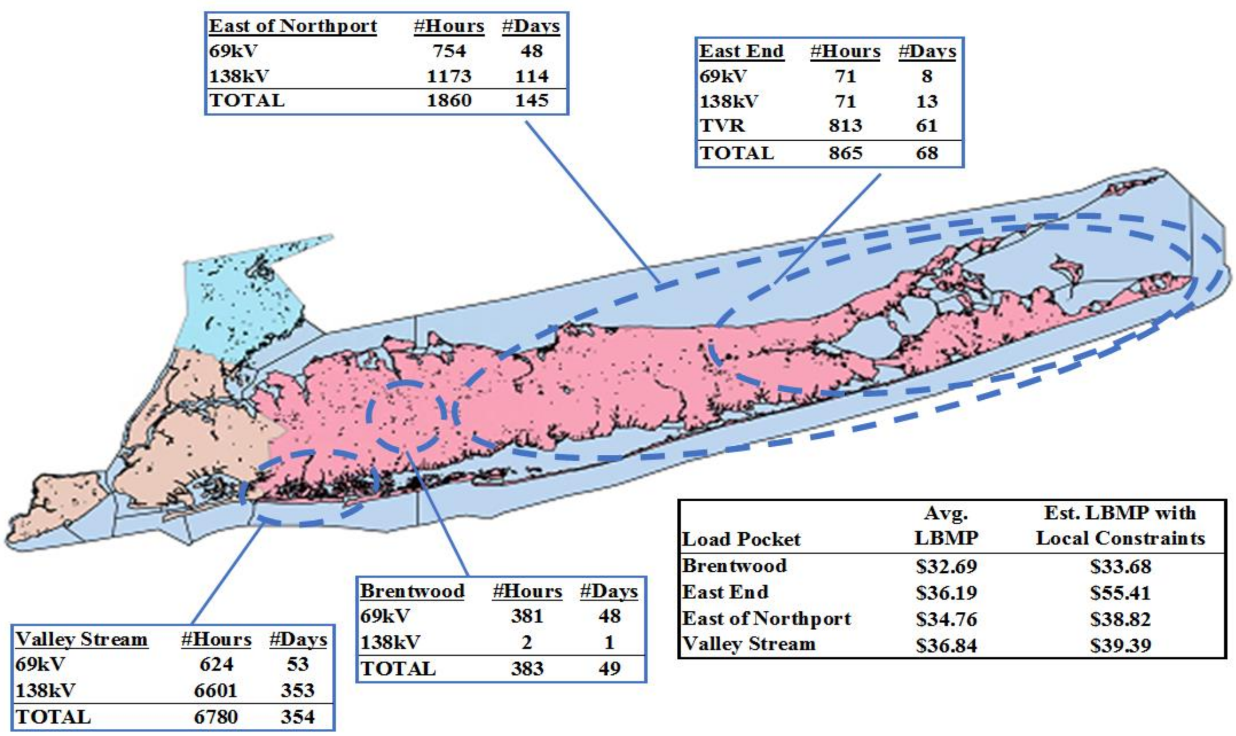


Figure A-56: Constraints on the Low Voltage Network on Long Island
Frequency of Action Used to Manage Constraint, 2019



Key Observations: Transmission Constraints on the Low Voltage Network in New York

- The NYISO has greatly reduced the use of OOM actions over the last year to manage low-voltage transmission constraints by modeling most 115 kV constraints in the day-ahead and real-time markets.
  - This was most evident in the West Zone, where OOM actions used to be most frequent. This category of OOM actions occurred on only 50 days in 2019, down from 260 days in 2018.
    - This modeling enhancement has improved the efficiency of scheduling and pricing in the West Zone as well as in other areas of New York that were adversely affected by congestion management of West Zone facilities in the past.
    - In 2019, most of the OOM actions were to manage congestion on the Gardenville-to-Dunkirk 115 kV lines, which the NYISO still does not model in the day-ahead and real-time market software.
- OOM actions to manage lower-voltage network congestion were most frequent on Long Island in 2019, occurring on 156 days.
  - OOM actions on Long Island were primarily to manage 69 kV constraints and voltage constraints (TVR requirement on the East End). (see Figure A-56) Not modeling these constraints in the market software leads to at least two types of inefficient scheduling:
    - When a 69 kV facility is constrained flowing into a load pocket, the local TO often provides relief by starting a peaking unit in the pocket. However, when this is done on short notice and there is no least-cost economic evaluation of offers, the local TO often runs oil-fired generation with a relatively high heat rate when much lower-cost resources could have been scheduled to relieve the constraint.
    - Since PARs usually control the distribution of flows across a group of parallel transmission facilities flowing into a load pocket, adjusting a PAR too far in one direction will tend to overload one set of facilities while relieving another, and vice versa. If the local TO frequently adjusts a PAR to relieve 69 kV congestion, the NYISO will have difficulty predicting the schedule of the PAR since it does not model the constraint that the PAR is adjusted to relieve. Consequently, errors in forecasting the schedules of the Pilgrim PAR on Long Island in the day-ahead market and in the RTC model is a significant contributor to unnecessary operation of oil-fired generation, balancing market congestion residuals (see Section III), and inefficient scheduling by RTC (see Section IV).
  - We recommend that the NYISO model the 69 kV constraints and East End TVR needs (likely via surrogate thermal constraints) in the market software.
    - This would greatly reduce associated BPCG uplift (roughly $10 million in 2019, see Figure A-91), better compensate resources that satisfy the needs, and provide more efficient signals for future investment.

- Our estimates show that: (a) average LBMPs would rise by as little as $1.00/MWh in the Brentwood load pocket and $4.06/MWh in the East of Northport pocket to $19.21/MWh in the East End load pocket in 2019 (see Figure A-56); and (b) net revenues of a new Frame 7 unit on Long Island would rise $27/kW-year. (see Figure A-117)

- OOM actions occurred on 83 days in the Capital Zone.
  - The vast majority of these occurred in the first half of the year when the Bethlehem units were frequently dispatched down to manage nearby 115 kV constraints.
  - The need has been greatly reduced following the completion of transmission upgrades in mid-2019.

D. Lake Erie Circulation and West Zone Congestion

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York.

Phase angle regulators ("PARs") were installed at the interface between the MISO and IESO in April 2012 partly to control loop flows around Lake Erie. In general, these PARs are used to maintain loop flows at the MISO-IESO interface to less than 200 MW in either direction. Because of the configuration of surrounding systems, the volume and direction of loop flows at the MISO-IESO interface is comparable to the loop flows at the IESO-NYISO interface. The volume of loop flows has been reduced since the PARs were installed in 2012, but excursions outside the 200 MW band still occur on a daily basis, so loop flows continue to have significant effects on congestion patterns in the NYISO.

Figure A-57: Clockwise Loop Flows and West Zone Congestion

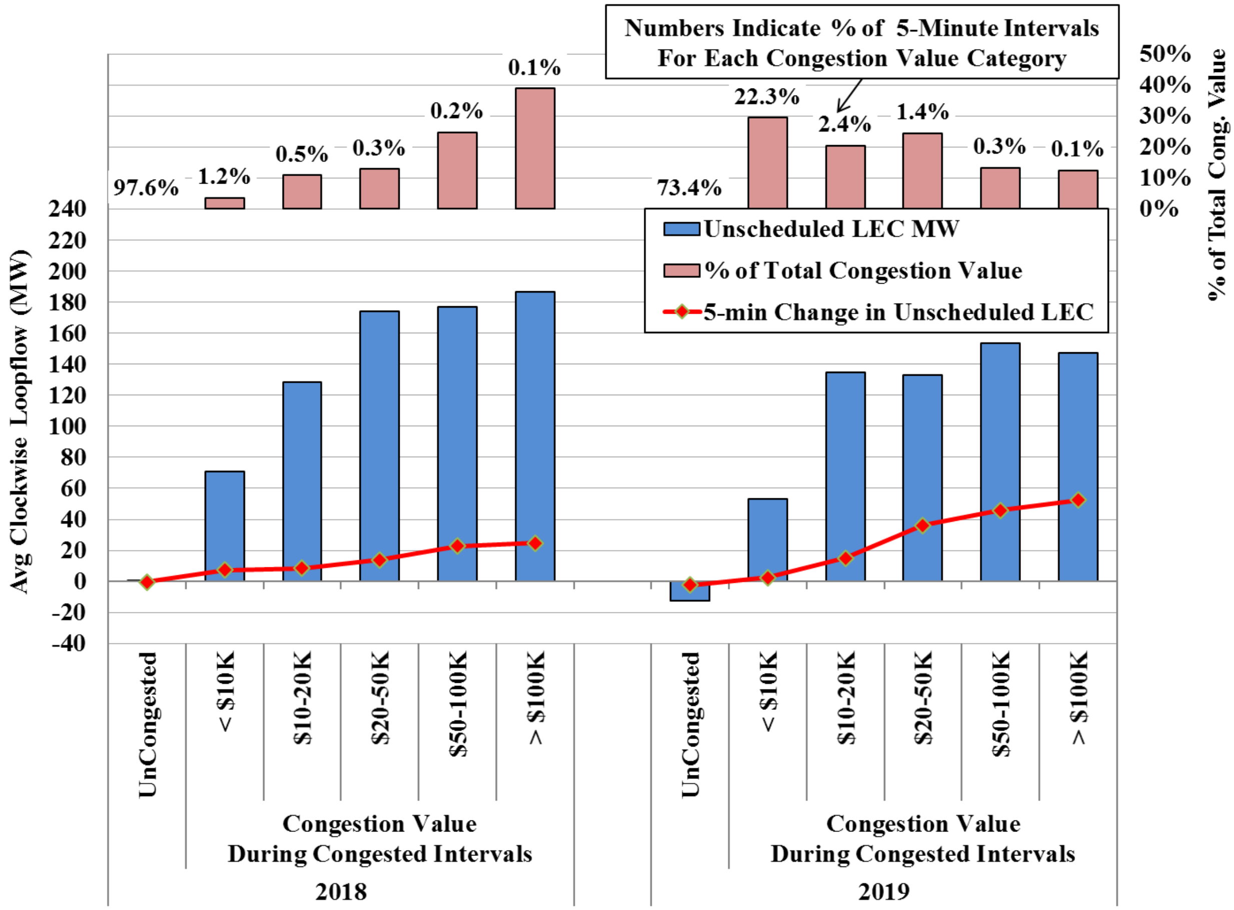
Unscheduled clockwise loop flows are primarily of concern in the congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths in Western New York, particularly in the West Zone.

Figure A-57 illustrates how and to what extent unscheduled loop flows affected congestion on market-modeled West Zone constraints in 2018 and 2019. 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 constraints. The congested intervals are grouped based on the following ranges of congestion values: (a) less than $10,000; (b) between $10,000 and $20,000; (c) between $20,000 and $50,000; (d) between $50,000 and $100,000; and

(e) more than $100,000.[269] 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 2018 and 2019, 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 $100,000 during 0.1 percent of all intervals in 2019, which however accounted for more than 12 percent of total modeled congestion value in the West Zone.

Figure A-57: Clockwise Lake Erie Circulation and West Zone Congestion
2018 - 2019



269 The congestion value for each constraint is calculated as (constraint flow × constraint shadow cost × interval duration). Then this is summed up for all binding 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.

Key Observations: Lake Erie Circulation and West Zone Congestion

- The pattern of congestion in the West Zone was markedly different in 2019 compared to 2018.
  - Priced congestion in the West Zone became more prevalent in 2019 following the incorporation of 115 kV constraints in the market models in December 2018.
    - Congestion occurred in 27 percent of intervals in the real-time market in 2019, up from just 2.5 percent in 2018.
  - Although a small number of intervals with severe congestion still accounted for a relatively large share of total priced congestion, this became less dramatic in 2019 as a result of more priced congestion on the 115 kV network (nearly 80 percent of congestion occurred on the 115 kV constraints in 2019).
    - Congestion values exceeded $100,000 in roughly 0.1 percent of intervals in both 2018 and 2019. These intervals accounted for nearly 40 percent of total priced congestion in 2018 but only 12 percent in 2019.
    - Congestion values were lower than $10,000 in 22 percent of intervals in 2019 (accounting for nearly 30 percent of total priced congestion), while this happened only in roughly 1 percent of intervals in 2018 (accounting for 4 percent of total priced congestion).
- Nonetheless, West Zone congestion was still much 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.
  - High clockwise loop flows or rapid swing of loop flows in the clockwise direction often led physical flows (i.e., EMS flows) on some West Zone constraints to exceed flows considered by the scheduling models (i.e., BMS flows) by a significant margin. To assist in managing the loop flows,
    - The NYISO increased the CRM on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 line from 20 MW to 40 MW in June 2019 and to 60 MW in late July 2019;
    - The NYISO reduced scheduling limits (i.e., BMS limits) when necessary to ensure flows remain at acceptable levels;
    - The NYISO changed the cap of 0 MW on the counter-clockwise loop flows in the RTC initialization to 100 MW (for counter-clockwise loop flows and smaller-than-100-MW clockwise loop flows) in late November 2019. (see Section V); and
    - The NYISO will be moving the electrical location of the IESO proxy bus in its scheduling models to a more appropriate location. Specifically, the proxy bus will be moved from the Bruce 500 kV station to the Beck 220 kV station (near the

Niagara station in New York) on April 21, 2020. The new location will result in a more accurate representation of the effects of interchange with Ontario.[270]

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

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

Figure A-58: Day-Ahead Congestion Revenue Shortfalls

Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion. Similarly, surpluses occur when the quantity of TCCs sold for a path is less than the transfer capability of the path in the day-ahead market during periods of congestion. The NYISO minimizes day-ahead congestion revenue surpluses and shortfalls by offering TCCs in the forward auction that reflect the expected transfer capability of the system. In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantities of TCCs that are offered by the NYISO.

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

Figure A-58 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2018 and 2019. 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.

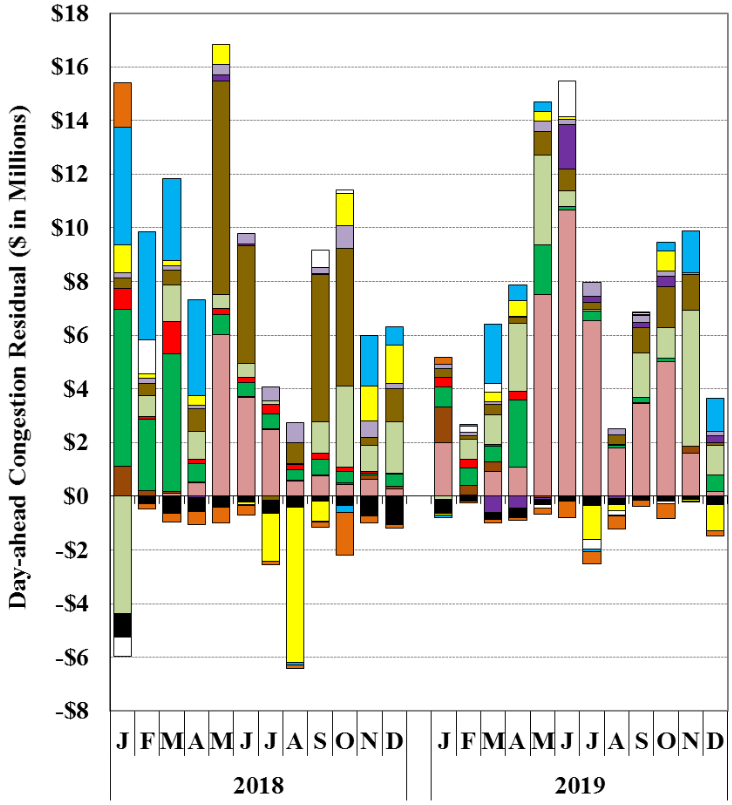
270 See "Relocating the IESO Proxy Bus" by Tolu Dina, at December 3, 2019 MIWG meeting.

- 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: 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 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, A, and JK lines) between the TCC auction and the DAM.
- For Long Island lines, the figure shows separately the shortfalls resulted from:
  - Grandfathered TCCs ("GFTCC") that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K); and
  - Differences in assumed schedules across the two PAR controlled lines between Lake Success and Valley Stream in Long Island and Jamaica in New York City (i.e., 901/903 lines) between the TCC auction and the day-ahead market.

Figure A-58: Day-Ahead Congestion Shortfalls
2018 – 2019



	Category	Annual Shortfall ($M)	
		2018	2019
	West Zone Lines	$15.5	$40.8
	Central to East		
	Ramapo, ABC & JK PARs	$1.9	$2.2
	Other Factors	$7.2	$17.2
	North to Central	$27.4	$7.2
	Capital to Hud VL	$0.3	$1.5
	New York City		
	ABC PARs	$3.6	$1.1
	Other Factors	$18.1	$8.0
	Long Island Lines		
	901/903 PARs	-$6.0	-$2.9
	Excess GFTCC Allocations	$4.5	$2.5
	Other Factors	-$2.0	-$0.5
	External		
	Primary NY/NE	$17.3	$6.1
	Other	-$2.8	-$2.9
	All Other Facilities	$1.2	$1.2

Figure A-59: 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.

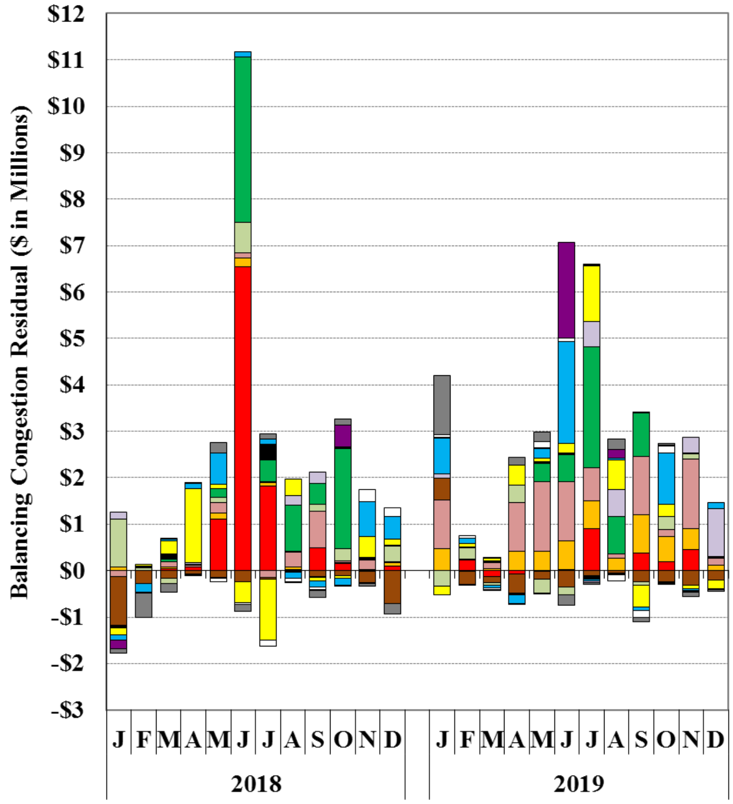
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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-58, Figure A-59 shows balancing congestion shortfalls by transmission path or facility in each month of 2018 and 2019. 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-59: Balancing Congestion Shortfalls[271]
2018 – 2019



	Category	Annual Shortfall ($M) 2018	Annual Shortfall ($M) 2019
	West Zone Lines		
	Ramapo, A & JK PARs	$0.6	$4.8
	Other Factors	$1.6	$8.8
	North to Central	$10.3	$2.0
	Central to East		
	Ramapo, A & JK PARs	-$3.2	-$2.1
	Other Factors	$2.5	$0.1
	TSA Constraints	$7.9	$5.3
	Long Island Lines		
	901/903 PARs	$0.4	$0.0
	Pilgrim PAR	$0.7	$2.6
	Other Factors	$0.9	$2.0
	New York City	-$0.9	$1.4
	Hudson Valley to Dunwoodie	$0.3	$2.3
	External	$1.5	$4.2
	All Other Facilities	$0.0	$0.1

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled $81 million in 2019, down 5 percent from 2018.
  - In 2019, roughly $38 million (or 47 percent) were allocated to responsible Transmission Owners for transmission outages.
- The transmission paths in the West Zone saw dramatic increases in shortfalls from 2018, accounting for nearly $41 million of shortfalls in 2019.
  - Most of these shortfalls accrued on newly modeled 115 kV facilities. The 115 kV facilities accounted for $36 million of shortfalls in 2019, while the 230 kV facilities accounted for less than $5 million of shortfalls.
  - Transmission outages are an important driver of shortfalls. Notable outages include:

271 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 any ex-post price corrections.

    - The Niagara-Robinson Rd 230 kV line was OOS for two weeks from late June to early July;
    - The Gardenville-Stolle Rd 230 kV line was OOS for several days in mid August;
    - The Niagara-Packard 230 kV line was OOS from early September to mid October; and
    - The Piercebrook-Fivemile 345 kV line was OOS for several periods in March, May, and November.
  - However, less than $10 million of shortfalls were allocated to TOs because of transmission outages.
  - The remaining shortfalls (over $30 million) resulted from other factors, of which the different assumption of Lake Erie Circulation between the TCC auction and the day-ahead market is a key one.

- The Central-East interface accrued more than $19 million of shortfalls in 2019, up $10 million from 2018, attributable to more costly transmission outages. Notable outages include:
  - The Edic-Fraser 345 kV line was OOS for one week in April, reducing the Central-East interface limit by 475 MW;
  - The Volney-Marcy 345 kV line was OOS for ten days in April, reducing the interface limit by 150 MW;
  - The Massena-Marcy MSU1 765 kV line was OOS for several periods in May, August, and October, reducing the interface limit by 700 MW;
  - The Gilboa-Leeds 345 kV line was OOS for almost three weeks in September, reducing the interface limit by 775 MW; and
  - The Marcy-New Scotland 345 kV line was OOS for several periods in September, October, and November, reducing the interface limit by 885 MW.
  - Nonetheless, a significant portion of shortfalls were incurred by factors other than transmission outages, including:
    - Different assumptions in generator commitment patterns and status of Capacitors and SVCs between the TCC auction and the day-ahead market;
    - AVR outages in the Oswego Complex from mid-November to the end of year.
    - Shortfalls caused by these factors are not allocated to TOs.

- Shortfalls accrued on the transmission paths in other regions fell noticeably from 2018 to 2019 because of fewer costly transmission outages.
  - Transmission paths from "North to Central" accounted for $7 million of shortfalls in 2019, down 74 percent from 2018.

  - Nonetheless, the Moses-Massena 230 kV lines, the Moses-Adirondack 230 kV lines, and the Marcy 765/345 transformers had outages for various periods in September, October, and November, driving shortfalls higher during these periods.
  - Transmission constraints in New York City accounted for $9 million of shortfalls in 2019, down 58 percent from 2018.
    - The high shortfalls in 2018 were driven largely by the lengthy (for a total of almost 4 months) outage of the Dunwoodie-Motthaven 345 kV line, while there was no such lengthy outage in 2019.
    - The TCC auction modeled the B and C PARs OOS beginning in May 2019 (although they have been OOS since early 2018), eliminating their contribution to New York City shortfalls thereafter.
  - The primary NY/NE interface accounted for $6 million of shortfalls in 2019, down 65 percent from 2018.
    - High shortfalls in 2018 accrued primarily in the months from January to April as a result of lengthy transmission outages and higher gas spreads between New York and New England.
    - The Long Mountain-Pleasant Valley 345 kV line had a similar lengthy outage in 2019 from early March to late May, but its impact was much less significant because of lower load and gas spreads.
- 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.[272]
  - The TCC auctions typically assumed a total of 300 MW flow from Long Island to New York City across the two lines while the day-ahead market assumed lower values—an average of 205 MW in that direction in 2018 and 220 MW in 2019.
  - 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

- Balancing congestion shortfalls totaled $30 million in 2019, up 62 percent from 2018.

272 This is categorized as “901/903 PARs” under “Long Island Lines” in the figure.

- Balancing congestion shortfalls were generally small on most days of 2019 but rose notably on several days when unexpected real-time events occurred.
  - TSA events were a key driver of high balancing shortfalls on these days, during which the transfer capability into SENY was greatly reduced in real time.
    - This led to a total of $5 million of shortfalls in 2019.
  - Unplanned/forced outages and deratings were another dominant driver. Notable examples include:
    - More than $2 million of shortfalls accrued on the Ontario interface on three days in May and June because the interface limit was reduced in real time to facilitate market operations.
    - A total of over $2 million of shortfalls accrued on transmission paths from Hudson Valley to Dunwoodie on two days in June, driven by outages on the Buchanan South-Millwood 345 kV line ("W97" line) and the Ladentown-Buchanan 345 kV line ("Y88" line).
    - Nearly $1 million of shortfalls accrued each day in Long Island on July 16 and August 11 when the Springbrook-East Garden City 345 kV line ("Y49" line) were forced out of service on both days.
- Balancing congestion shortfalls and surpluses accrued on external interfaces, and the Ontario interface contributed $3.9 million to a net shortfall of $4.2 million for all external interfaces combined.
  - Most of the shortfalls resulted from a relatively small number of days when the Ontario transfer limit was derated below the day-ahead limit to relieve congestion on downstream constraints in real-time. During such circumstances, imports initially scheduled in the day-ahead market were able to buy-out of their schedule at extreme negative real-time prices. These prices can be very low because there is a -$1000/MWh offer floor, which is an arbitrarily low level. To reduce the uplift that occurs during such extreme negative price, we recommend (see #2019-2) that the NYISO raise the lower bound of the offer price limit to -$150/MWh.
  - Although it is generally most efficient to secure such facilities directly in the real-time market model, there may be circumstances when the transfer limit reduction may be appropriate.
- Balancing congestion shortfalls accruing on the West Zone constraints rose significantly from roughly $2 million in 2018 to nearly $14 million in 2019.
  - More than $10 million accrued on the 115 kV constraints, which were modeled in the day-ahead and real-time markets beginning in December 2018.
  - In addition to unplanned and forced transmission outages, clockwise loop flows were also a primary driver of balancing shortfalls.

  - The closure of the South Ripley-to-Dunkirk line has increased flows significantly across the West Zone, particularly during periods with high clockwise loop flows.

- Although the PAR operation under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flowgates (e.g., the Central-East interface), it frequently aggravated congestion on some non-M2M constraints (e.g., the West Zone 115 kV constraints).
  - Additional flows (into New York) across the Ramapo, A, & JK PAR-controlled lines contributed an estimated $2 million of surpluses on the Central-East interface in 2019.
  - However, this was offset by nearly $5 million of shortfalls on the West Zone 115 kV constraints.
  - The NYISO has worked with PJM to incorporate these 115 kV constraints into the M2M process, effective November 2019. This should improve overall congestion management going forward.

- The inconsistency between the assumption of Pilgrim PAR flows in the day-ahead market and its real-time operation contributed more than $2.5 million of shortfalls on Long Island in 2019.
  - The PAR flows has significant impact on both the 138 kV and the 69 kV constraints, while only the 138 kV network is modeled in the day-ahead and real-time markets.
  - In real-time operations, the PAR adjustments to manage the 138 kV constraints were often limited by its impact on the 69 kV network, and vice versa.
  - However, this limitation was not reflected in the day-ahead market and the congestion on the unmodeled 69 kV constraints was hard to predict, making it difficult for day-ahead PAR schedules to be consistent with real-time flows. Accordingly, we have recommended (see #2018-1) that the NYISO model 69 kV constraints in the day-ahead and real-time models that are typically relieved by redispatching wholesale generators and/or adjusting PAR-controlled lines.

F. In-Series Line Segments in the Market Model

A transmission line is typically composed of a number of segments. When one line segment becomes binding in the market model, it is likely that other line segments that are in series-connection with it are binding simultaneously. This usually does not lead to pricing anomalies when a physical resource is available to provide congestion relief since the market software accounts for the ability of the physical resource to provide relief to all in-series line segments simultaneously. However, unnecessarily and arbitrarily high prices may occur when transmission shortage occurs on the line and the transmission demand curve is applied for pricing. Under the current implementation (which is consistent with the Tariff), the transmission demand curve applies needed relief to each line segment independently. As a result, multiple transmission demand curves are applied to price transmission shortages on the same line, one for each binding in-series line segment. The cumulative effect of using multiple demand curves will lead to an unnecessarily high congestion price across the line and affect resulting market outcomes.

Table A-3: Impact of Securing In-Series Line Segments in the Market Model

The NYISO identified such unintended pricing outcomes and removed less limiting and less restricted in-series segments on 21 transmission lines from the market models, effective September 24, 2019.[273] summarizes real-time market impact from these line segments in 2019 prior to their removal from the market models.

The table shows the following quantities:

- # RT Intervals – the total number of real-time intervals, during which multiple segments of the line were priced simultaneously by the Graduated Transmission Demand Curve ("GTDC").
- RT Congestion Value – the estimated congestion values on the binding line segments in the real-time market (i.e., constraint shadow price*line flows).
- BMCR – the balancing congestion shortfalls accrued on the binding line segments when identified issues occurred.
- LBMP Impact – the real-time LBMP impact at relevant Zones that resulted from the identified issues. This is shown as an annual average.

Table A-3: Impact of Securing In-Series Line Segments in the Market Model

January 1 – September 23, 2019

Line	# RT Intervals w/ Multi-Segments Priced Simultaneously at GTDC	Market Impact from Removed In-Series Line Segments During These Intervals					
		RT Congestion Value ($M)	BMCR ($M)	LBMP Impact - Annual Avg ($/MWh)			
				MHK VL	North	Genese	West
Colton - Browns Falls 1	3	$0.1	$0.02	$0.00	-$0.01		
Colton - Browns Falls 2	3	$0.1	$0.03	$0.00	-$0.02		
Huntley - Gardenville 38	5	$0.1	$0.01			$0.00	$0.00
Huntley - Gardenville 39	36	$0.3	$0.02			$0.00	$0.01
WalckRd - Huntley 133	12	$0.3	$0.04			$0.00	$0.01
Packard - Gardenwille 182	10	$0.3	$0.02			$0.00	$0.01
Packard - Erie St 181-922	958	$14.8	$0.90			-$0.06	$0.33
Total	**990**	**$16.1**	**$1.0**	**$0.00**	**-$0.03**	**-$0.07**	**$0.36**

273 See "Update on Facilities Secured in the Market Models" by David Edelson, at September 10, 2019 MIWG meeting.

<u>Key Observations: In-Series Line Segments in the Market Model</u>

- A number of facilities representing in-series segments of the same transmission line were secured in the market models. This can lead to excessively large shortage pricing outcomes when multiple in-series segments were priced simultaneously by the GTDC.
  - To address this, the NYISO removed all but one most limiting segment for each of 21 transmission lines from the market models, effective September 24, 2019. We support the removal of these additional in-series segments.
- We have estimated the market impact of securing multiple in-series portions of line segments in 2019 prior to September 24.
  - Seven of the 21 transmission lines showed excessive shortage pricing outcomes during 990 real-time intervals. These accounted for:
    - $16 million of real-time congestion value;
    - $1 million balancing congestion shortfalls; and
    - A shift in annual average LBMPs from negative $0.07/MWh in Zone B to $0.36/MWh in Zone A.
  - The Packard-Erie St 115 kV line (“181-922 line”) in the West Zone accounted for the vast majority of the occurrences. Thus, nearly all of the resulting market impact occurred in the West Zone.

G. TCC Prices and DAM Congestion

In this subsection, 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* [274] – 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-60: TCC Cost and Profit by Auction Round and Path Type

Figure A-60 summarizes TCC cost and profit for the Winter 2018/19 and Summer 2019 Capability Periods (i.e., the 12-month period from November 2018 through October 2019). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

The 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 2018/19 Capability Period; (c) four rounds of six-month auctions for the Summer 2019 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[275] 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.[276]

274 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.

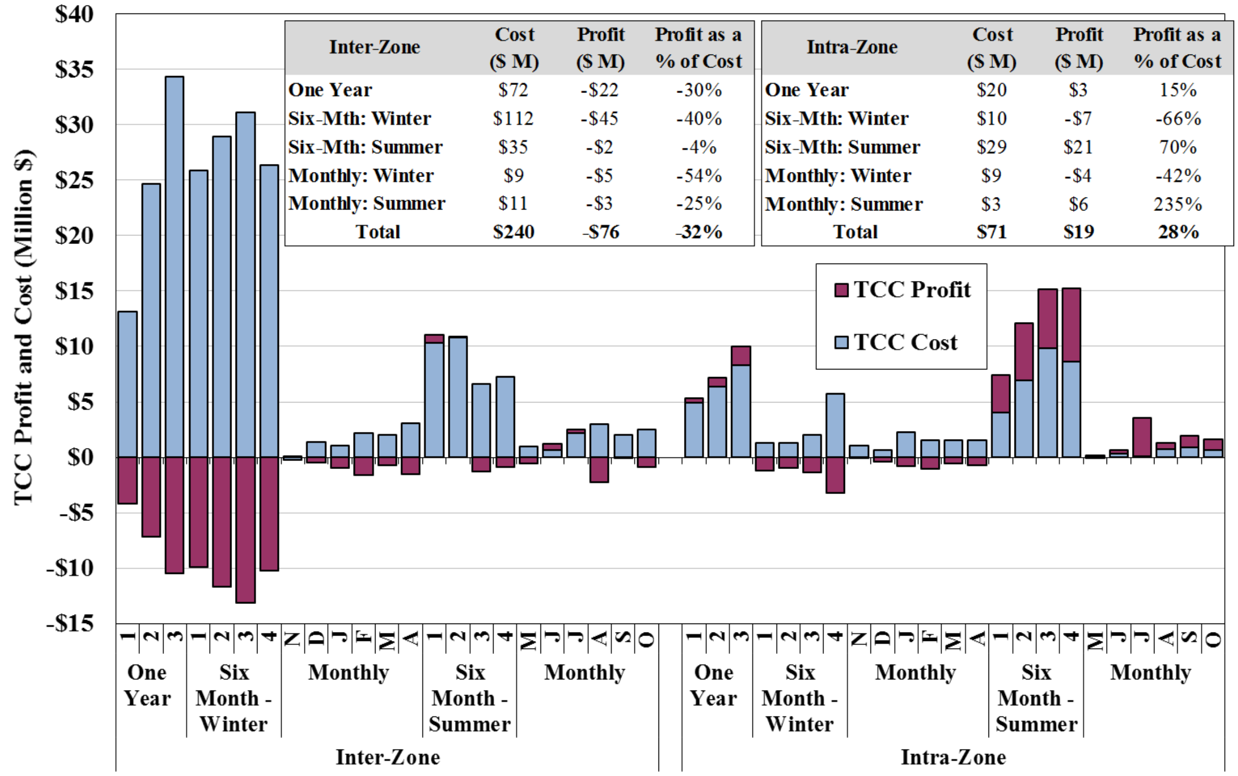
275 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

276 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.

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.

Figure A-60: TCC Cost and Profit by Auction Round and Path Type

Winter 2018/19 and Summer 2019 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$72	-$22	-30%
Six-Mth: Winter	$112	-$45	-40%
Six-Mth: Summer	$35	-$2	-4%
Monthly: Winter	$9	-$5	-54%
Monthly: Summer	$11	-$3	-25%
Total	$240	-$76	-32%

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$20	$3	15%
Six-Mth: Winter	$10	-$7	-66%
Six-Mth: Summer	$29	$21	70%
Monthly: Winter	$9	-$4	-42%
Monthly: Summer	$3	$6	235%
Total	$71	$19	28%

Table A-4 & Table A-5: 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 2018/19 and Summer 2019 Capability Periods (i.e., the 12-month period from November 2018 through October 2019). 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-4: TCC Cost by Path
Winter 2018/19 and Summer 2019 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	-$14	-$14	-$1	-$1	$0	$19	$0	$0	$0	$0	-$5	$0	$0	-$1	**$4**
GENESE	$7	-$1	$2	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	**$9**
CENTRL	$39	-$4	$16	-$1	-$4	$0	$30	$0	$0	$0	$0	$0	$0	$0	$0	**$76**
MHK VL	$6	$0	$3	-$9	-$3	$1	$2	$0	$0	$0	$0	$0	-$1	$9	$0	**$8**
NORTH	$2	$3	$7	$23	-$1	$0	$0	$0	$0	$0	$0	$1	$1	$0	$0	**$37**
CAPITL	$0	$0	$0	-$1	$0	$11	-$11	-$1	-$4	$0	$0	$0	$0	$2	$0	**-$3**
HUD VL	$1	$0	-$4	-$1	$0	$20	$1	$1	$2	$42	$0	$0	$0	$48	-$1	**$108**
MILLWD	$0	$0	$0	$0	$0	$0	-$1	$2	$1	$0	$0	$0	$0	$0	$0	**$2**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$1	$0	$0	$0	$0	**$2**
N.Y.C.	$0	$0	$0	-$1	-$2	$0	-$4	$0	-$4	$20	$1	$0	$0	$0	$0	**$10**
LONGIL	$0	-$1	-$1	$0	$0	$0	$0	$0	$0	-$1	$11	$0	$0	$0	$0	**$8**
O H	$11	$2	$1	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	**$16**
H Q	$0	$0	$5	$27	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	**$33**
NPX	$0	$0	$0	$0	$0	$0	-$9	$0	$0	$0	$0	$0	$0	$0	$0	**-$9**
PJM	-$3	$0	-$9	$0	$0	$0	$19	$0	$3	$1	$0	-$1	$0	$0	$0	**$11**
Total	**$82**	**-$15**	**$7**	**$38**	**-$11**	**$33**	**$48**	**$2**	**-$2**	**$64**	**$13**	**-$5**	**-$1**	**$60**	**-$2**	**$311**

Table A-5: TCC Profit by Path
Winter 2018/19 and Summer 2019 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	$11	-$5	-$4	$0	$0	$0	-$13	$0	$0	$0	$0	$0	$0	$0	$0	**-$13**
GENESE	$2	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
CENTRL	$12	$0	$18	$1	$1	$0	-$11	$0	$0	$0	$0	$0	$0	$0	$0	**$20**
MHK VL	$2	-$1	-$1	$4	$1	$0	$0	$0	$0	$0	$0	$0	$0	-$2	$0	**$2**
NORTH	$0	-$1	-$2	-$7	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$11**
CAPITL	$0	$0	$0	$0	$0	-$3	$3	$0	$1	$0	$0	$0	$0	-$1	$0	**$1**
HUD VL	$0	$0	$2	$0	$0	-$10	$1	$0	-$1	-$22	$0	$0	$0	-$15	$0	**-$44**
MILLWD	$0	$0	$0	$0	$0	$0	$1	$0	-$1	$0	$0	$0	$0	$0	$0	**$0**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	**$0**
N.Y.C.	$0	$0	$0	$0	$0	$0	$2	$0	$2	-$10	$0	$0	$0	$0	$0	**-$4**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$3	$0	$0	$0	$0	**-$2**
O H	$1	-$1	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
H Q	$0	$0	-$2	-$11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$14**
NPX	$0	$0	$0	$0	$0	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
PJM	$4	$0	$5	$0	$0	$0	-$5	$0	-$1	$0	$0	$0	$0	$0	$0	**$3**
Total	**$32**	**-$7**	**$14**	**-$13**	**$2**	**-$13**	**-$21**	**$0**	**$1**	**-$32**	**-$3**	**-$1**	**$0**	**-$17**	**$0**	**-$57**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a total loss of $57 million in the TCC auctions during the reporting 12-month period (November 2018 to October 2019), resulting in an average profitability (profit as a percent of TCC cost) of negative 18 percent.[277]
  - TCC buyers netted an average *loss* of 32 percent on the inter-zonal transmission paths but an average *profit* of 28 percent on the intra-zonal paths.
- TCC profitability coincided with changes in the congestion pattern from the prior year.

277 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 2018 and 2019. 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 2018 to October 2019.

- For example, TCC buyers netted a $32 million profit from a $82 million purchase cost on transmission paths sinking at the West Zone.
  - This coincided with substantially higher congestion in the West Zone (for the reasons discussed in subsection B).
- A total of $23 million in losses (from a $63 million purchase cost) accrued on transmission paths from HQ and the North Zone to the Central Zone and the Mohawk Valley Zone.
  - This coincided with a 68 percent decrease in day-ahead congestion on "North to Central" transmission facilities (see Figure A-52).
- Similarly, TCC buyers netted a loss of $32 million (from a $64 million purchase cost) on transmission paths sinking at New York City, consistent with a 43 percent reduction in day-ahead congestion from 2018 to 2019.
- These results indicate that market participants' anticipated congestion levels were generally in line with the levels observed in the prior year.

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 =

$$\sum_{l=901,903}\left(\left[DAM\ MW_l - TCC\ MW_l\right] \times \sum_{c=constraint}\left[-DAM\ SF_{l,c} \times DAM\ SP_c\right]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left(\left[RTM\ MW_l - DAM\ MW_l\right] \times \sum_{c=constraint}\left[-RTM\ SF_{l,c} \times RTM\ SP_c\right]\right)$$

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.[278,279] 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 helps lower the cost of serving New York load when 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 three 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.

278 The Cross Sound Cable ("CSC") connects Long Island to Connecticut with a transfer capability of 330 MW. The Neptune Cable connects Long Island to New Jersey with a transfer capability of 660 MW. The Northport-to-Norwalk line ("1385 Line") connects Long Island to Connecticut with a transfer capability of 200 MW. The Linden VFT Line 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.

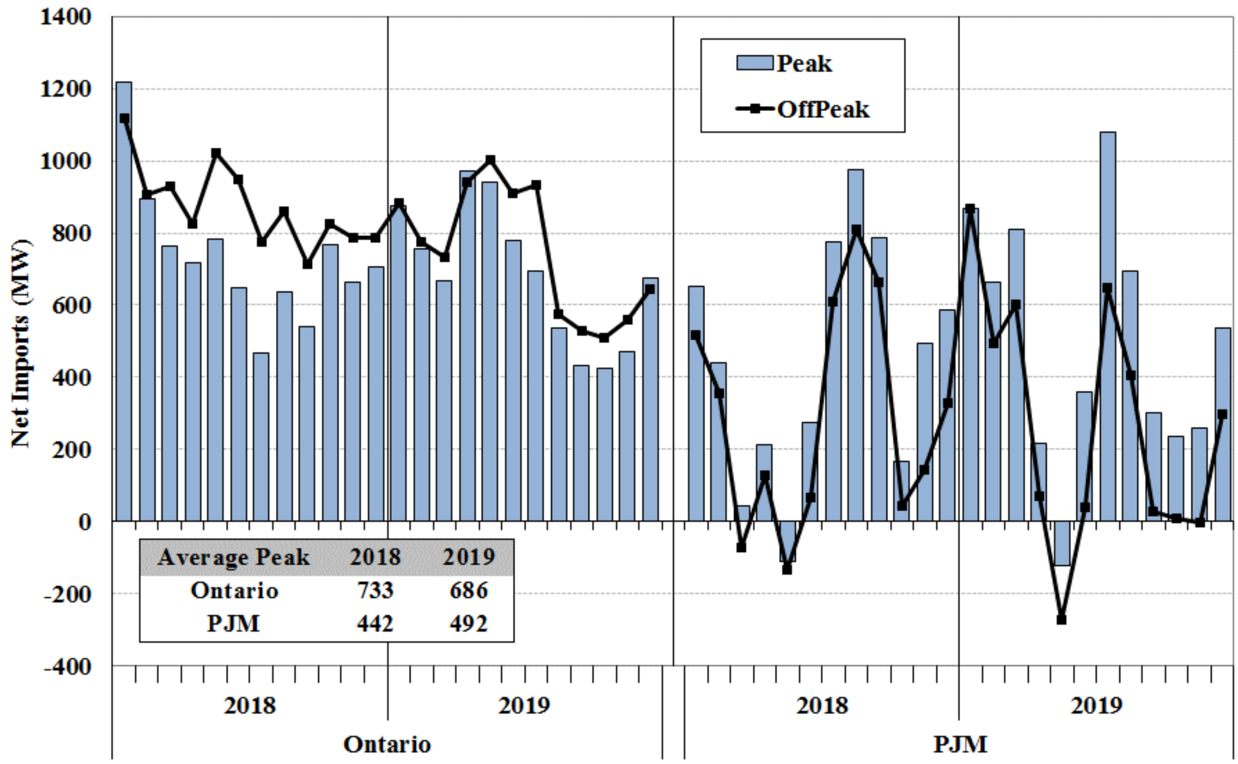
279 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the "Dennison Scheduled Line" and is scheduled separately from the primary interface between New York and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

A. Summary of Scheduled Imports and Exports

Figure A-61 to Figure A-64 : Average Net Imports from Ontario, PJM, Quebec, and New England

The following four figures summarize the net scheduled interchanges in real-time between New York and neighboring control areas in 2018 and 2019. 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-61, the primary interfaces with Quebec and New England in Figure A-62, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-63 and Figure A-64.

Figure A-61: Monthly Average Net Imports from Ontario and PJM
2018 – 2019



Average Peak	2018	2019
Ontario	733	686
PJM	442	492

Figure A-62: Monthly Average Net Imports from Quebec and New England
2018 – 2019

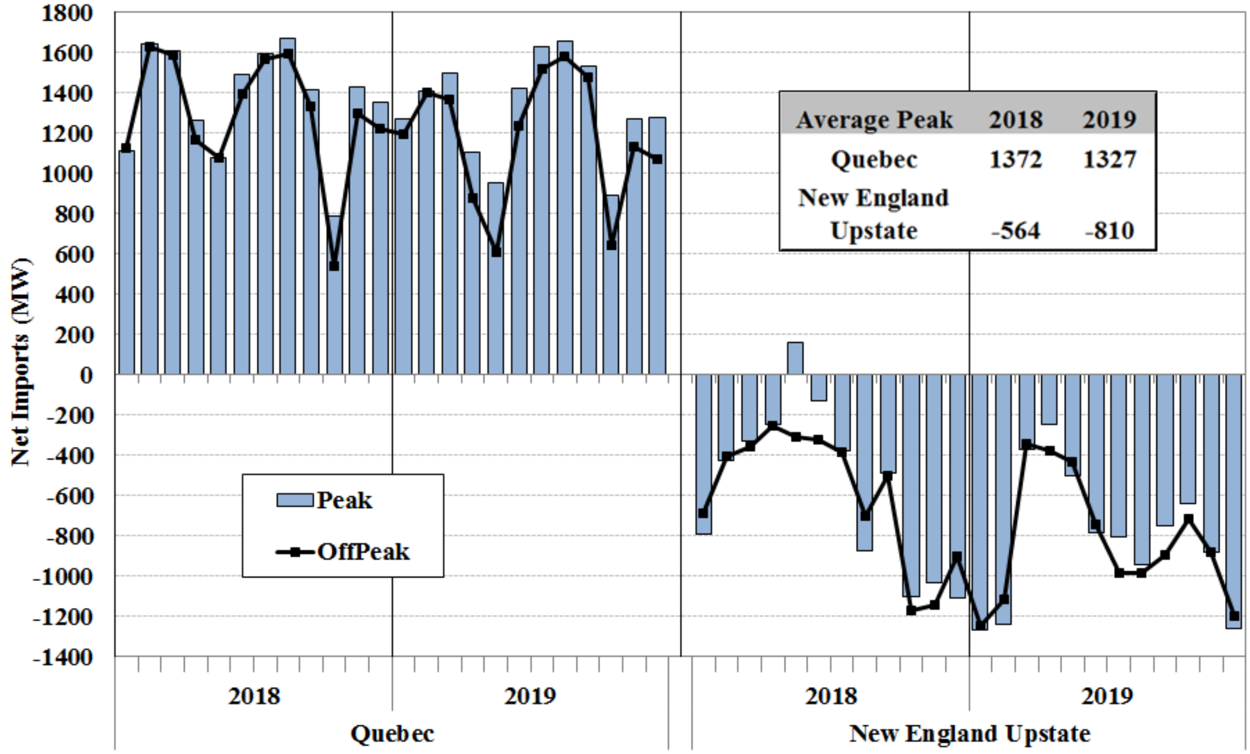


Figure A-63: Monthly Average Net Imports into New York City
2018 – 2019

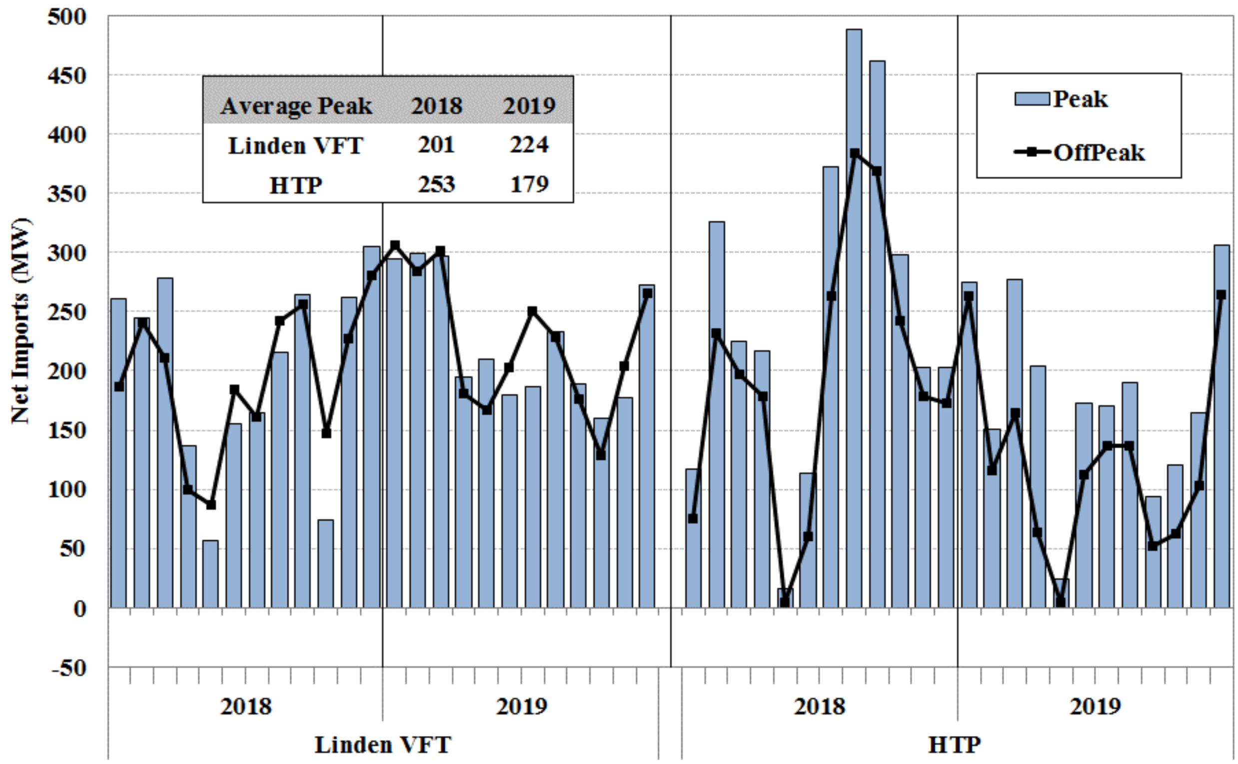
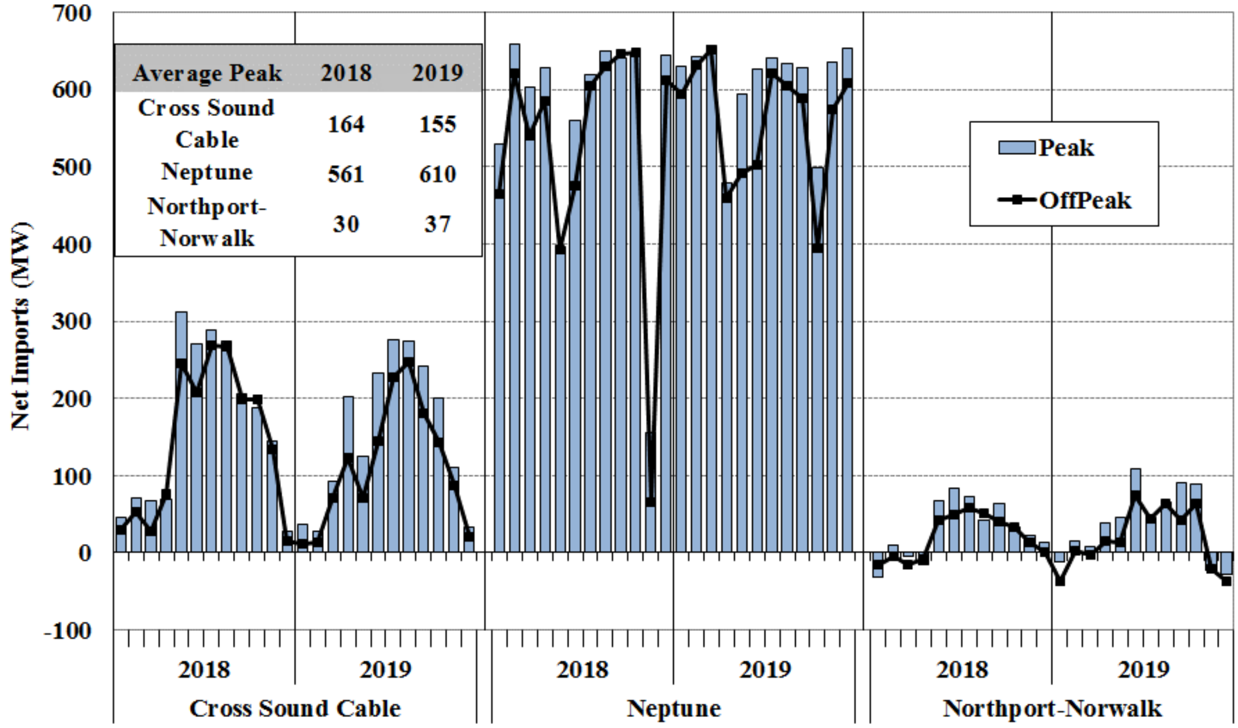


Figure A-64: Monthly Average Net Imports into Long Island
2018 – 2019



Key Observations: Average Net Imports

- Total net imports averaged roughly 2,900 MW during peak hours in 2019, down 9 percent from 2018.
  - Net imports served approximately 15 percent of load in 2019.
  - The reduction from 2018 reflected higher net exports to New England in 2019.
- Average net imports from neighboring areas across the primary interfaces fell nearly 15 percent from about 1,985 MW in 2018 to 1,695 MW in 2019 during the peak hours.
  - Net imports from Quebec averaged roughly 1,330 MW, accounting for 78 percent of net imports across the primary interfaces in 2019. Imports from Quebec were high in most months of 2019 but fell notably in several shoulder months (e.g., April, May, and October) because of transmission outages.
  - New York was typically a net importer from PJM and a net exporter to New England across their primary interfaces. This pattern is generally consistent with gas price spreads between these markets.
    - Net exports to New England increased 44 percent from 2018 to 2019, reflecting fewer lengthy transmission outages at the interface in 2019. In 2018, the New Scotland-Alps and the Long Mountain-Pleasant Valley 345 kV lines were OOS in various periods for a total of roughly 4 months, during which the NY/NE interface limit was greatly reduced to around 500 MW.

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged roughly 800 MW during peak hours in 2019, up 6 percent from 2018.
  - The increase occurred primarily on the Neptune Cable because of fewer transmission outages in 2019 (A three-week-long cable outage resulted in unusually low Neptune imports in November 2018).
  - Imports over the three controllable interfaces account for a large share of the supply to Long Island, serving slightly more than 30 percent of the load in Long Island in recent years.
- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged roughly 405 MW during peak hours in 2019, down 11 percent from 2018.
  - The decrease occurred primarily on the HTP interface, which reflected lower LBMPs in the 345 kV system of New York City for the reasons discussed in Section III.B 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.

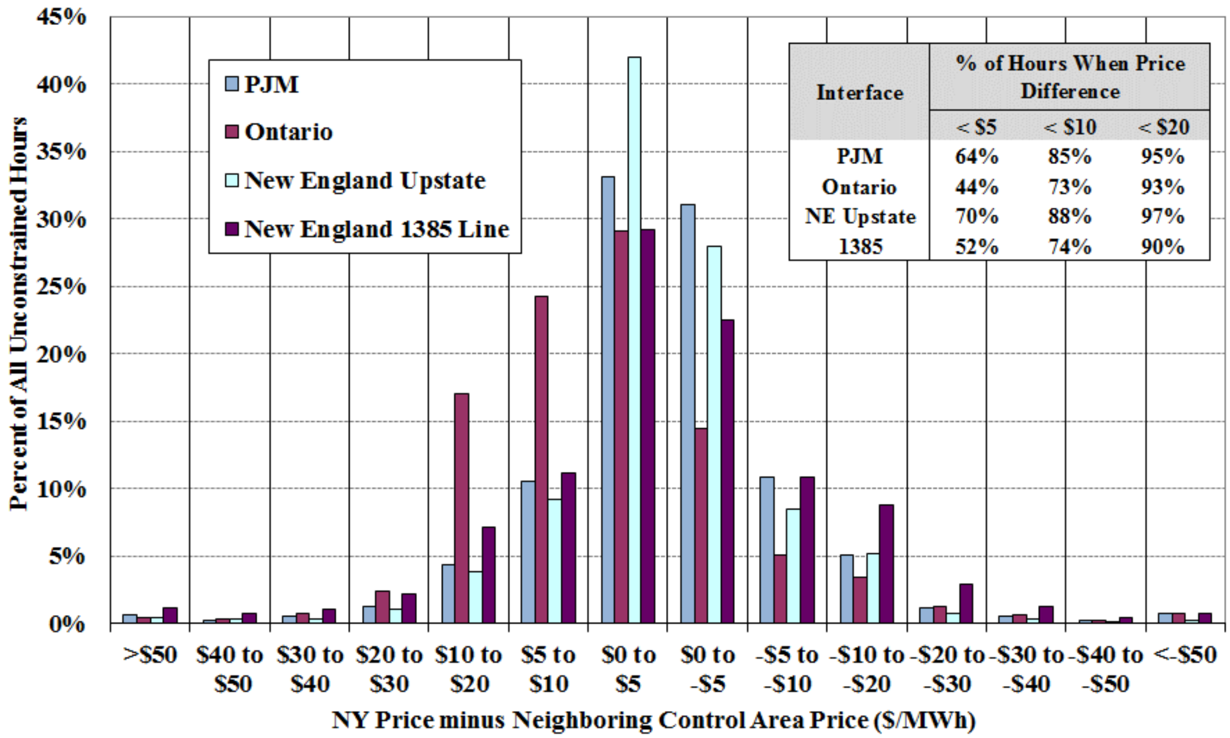
- Market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible.
- Differences in scheduling procedures and timing in the markets are barriers to 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-65: Price Convergence Between New York and Adjacent Markets

Figure A-65 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-65 summarizes price differences between New York and neighboring markets during unconstrained hours in 2019. 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.[280] 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-65: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2019



Interface	% of Hours When Price Difference		
	< $5	< $10	< $20
PJM	64%	85%	95%
Ontario	44%	73%	93%
NE Upstate	70%	88%	97%
1385	52%	74%	90%

Table A-6: Efficiency of Inter-Market Scheduling

Table A-6 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2019. It evaluates

280 In these hours, prices in neighboring RTOs (i.e., prices at the NYISO proxy in each RTO market are used) reflect transmission constraints in those markets.

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:

- 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. [281]
- 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 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.[282]

Table A-6 evaluates the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but this will induce other firms to schedule 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.

281 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.

282 For example, if 100 MW is scheduled from the low-priced to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-6: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2019

	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	-896	$0.25	45%	-$0.3	80	$0.72	54%	$1
Ontario	706	$6.92	86%	$45	13	$5.33	51%	$4
PJM	342	$0.13	71%	$10	31	-$0.29	60%	$5
Controllable Ties								
1385 Line	51	$0.35	67%	$2	-24	$0.21	52%	$1
Cross Sound Cable	126	$1.39	71%	$4	6	$3.49	54%	$0.5
Neptune	588	$6.93	93%	$35	-5	$6.85	49%	$0.2
HTP	87	$3.19	90%	$4	63	$2.61	71%	$4
Linden VFT	152	$4.14	91%	$8	71	$2.07	71%	$3

Key Observations: Efficiency of Inter-Market Scheduling

- Price differences across New York's external interfaces were smaller in 2019 than in 2018, partly driven by lower load levels and lower and less volatile gas prices.
  - Price differences at the CTS interfaces (PJM and ISO-NE) were generally smaller than for the hourly-scheduled Northport-to-Norwalk and Ontario interfaces, reflecting that CTS has improved the utilization of the interfaces (see table in Figure A-65).
  - Similarly, 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.
    - Estimated production cost savings were smaller at the NY/NE border than at the NY/PJM border, reflecting better arbitraged interface with ISO-NE.
- Nonetheless, the price differences were still widely distributed and a substantial number of unconstrained hours (12 to 27 percent) had price differences exceeding $10/MWh for every interface in 2019.
  - These results indicate plenty of room for improvement in the current process in order to maximize the utilization of the interfaces.
- 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 2019.
- Real-time adjustments in flows were more frequent across the controllable VFT and HTP ties than in prior years, as market participants more actively responded to real-time price variations by increasing net flows into the higher-prices region across these ties.

    - A total of $7 million in real-time production cost savings was achieved in 2019 from the real-time adjustments over these two controllable ties, up from $4 million in 2018.

- 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 and the other costs and risks that interfere with efficient interchange scheduling.

C. Evaluation of Coordinated Transaction Scheduling

Coordination Transaction Scheduling ("CTS") allows 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 hourly LBMP-based scheduling:

- CTS bids are evaluated relative to the adjacent ISO's short-term price forecast, while LBMP-based scheduling requires bidders to forecast prices in the adjacent market.

- The CTS process schedules transactions much closer to the operating time. Hourly LBMP-based schedules are established up to 105 minutes in advance, while CTS schedules are 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-66: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

The first analysis examines the trading volumes of CTS transactions in 2019. In particular, Figure A-66 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 2019. 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 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.[283] Bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis.

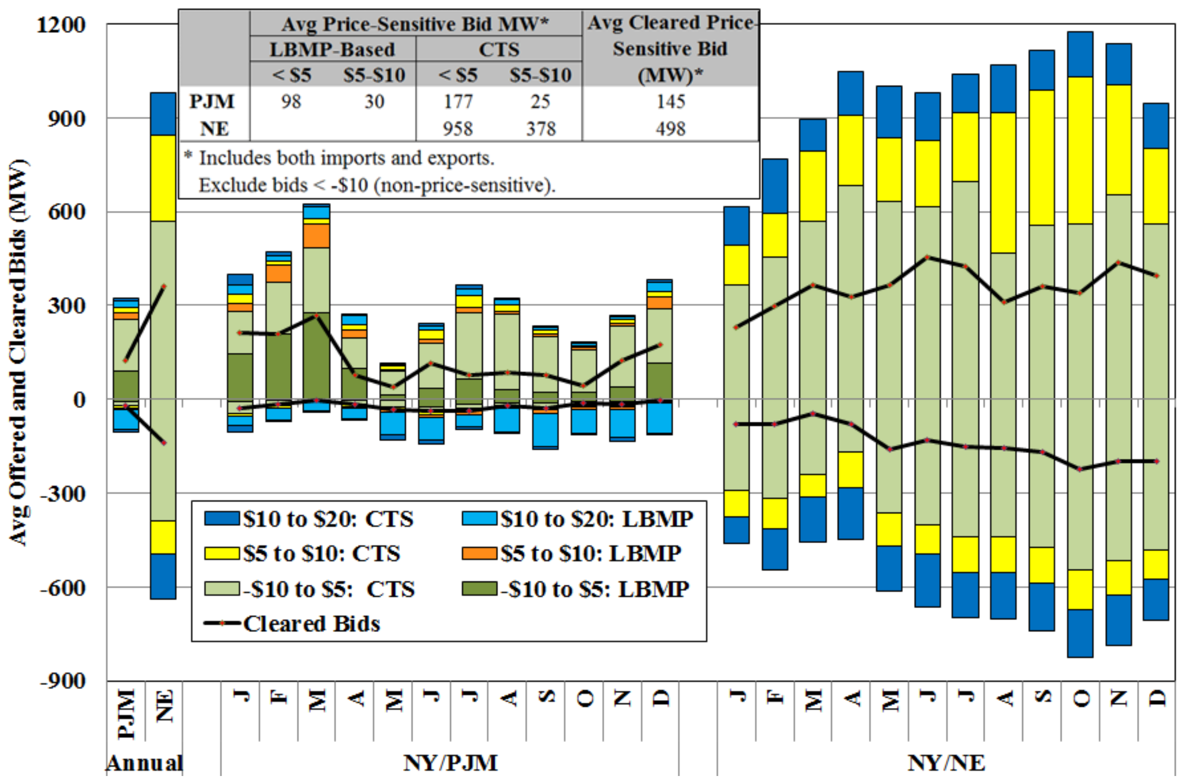
Traditional LBMP-based bids and CTS bids are allowed at the PJM interface (unlike the primary New England interface where only CTS bids are allowed). To make a fair comparison between the two primary interfaces, LBMP-based bids at the PJM interface are converted to equivalent CTS bids and are shown in 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 imports and exports (including both CTS and 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 bids with low offer prices, which are either less than $5/MWh or between $5 and $10/MWh; and b) the average cleared price-sensitive bids in 2019.

Figure A-66: Price-Sensitive Real-Time Transaction Bids and Offers by Month

PJM and NE Primary Interfaces, 2019



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283 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-67: 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-67, the column bars indicate the profitability spread of the middle two quartiles (i.e, 25 to 75 percentile) in 2019. 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:

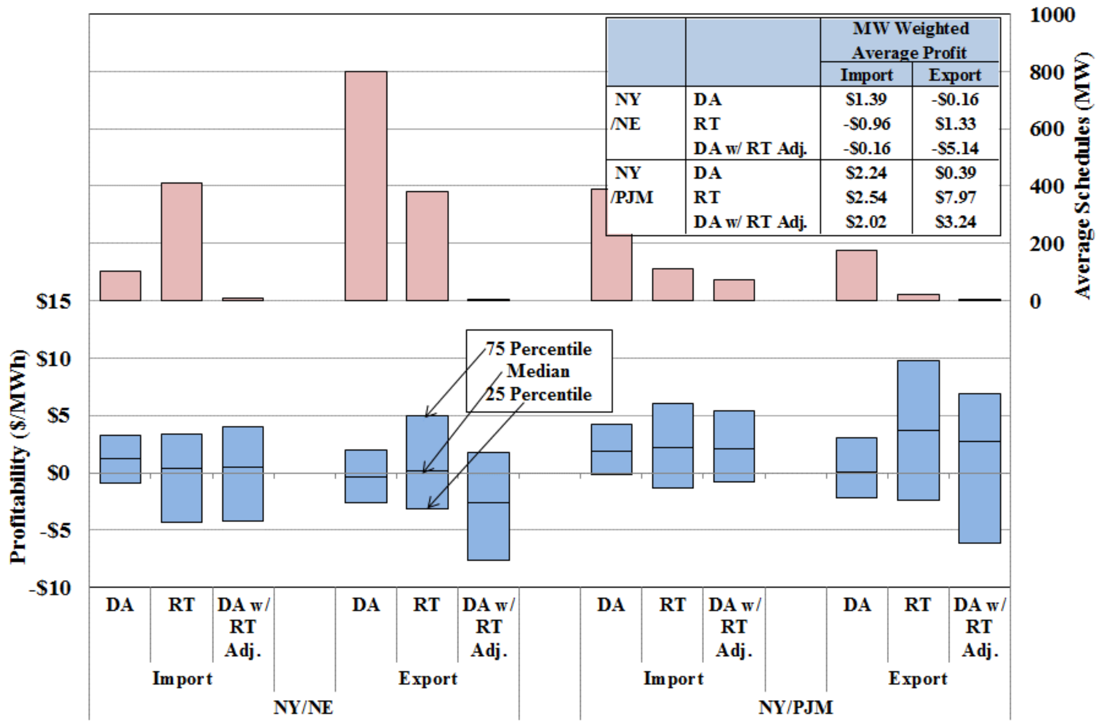
- *Day-ahead* – Transactions scheduled in the day-ahead market with no changes in the real-time market (i.e., day-ahead schedules equal real-time schedules);

- *Real-time* – Transactions not offered or scheduled in the day-ahead but scheduled in the real-time (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 but adjusted in the real-time market (i.e., day-ahead schedules are higher or lower than real-time schedules).[284]

The bars in the top portion of the figure show the average quantity of scheduled transactions for each category in 2019 and the inset table summarizes the annual average profit.

Figure A-67: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2019



284 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.

Table A-7: 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 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. [285]

Table A-7 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2019. The table shows the following quantities:

- % 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.[286]
    - 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,

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285 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.

286 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 291.

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. [287]

- Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
  - Real-time Curtailment[288] - 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[289] - RTD and RTC have different assumptions regarding interface schedule ramping. In RTD, interface flows start to ramp at 5 minutes before each quarter-hour interval and reach the target level at 5 minutes after. RTC assumes that the target flow level is reached at the top of the quarter-hour interval. Therefore, an inherent difference exists between RTD flows and RTC flows at the top of each quarter-hour interval, which will lead a portion of projected savings to be unrealized in real time.
  - Price Curve Approximation – This applies only to the CTS process between New York and New England. CTSPE forecasts a 7-point piecewise linear supply curve and NYISO transfers it into a step-function curve for use in the CTS process (as shown in Figure A-69). 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[290,291] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

287 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.

288 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).

289 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).

290 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).

291 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

- 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.

Table A-7: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and New England Interfaces, 2019

			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 > $20	Total
% of All Intervals w/ Adjustment			71%	6%	**77%**	49%	9%	**58%**
Average Flow Adjustment (MW)	Net Imports		11	3	**10**	4	-41	**-3**
	Gross		107	131	**109**	79	121	**85**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$3.6	$1.2	**$4.8**	$1.5	$3.7	**$5.2**
	Net Over-Projection by:	NY	-$0.3	-$0.3	**-$0.6**	-$0.4	-$0.7	**-$1.1**
		NE or PJM	$0.1	$0.0	**$0.1**	-$0.3	-$3.6	**-$4.0**
	Other Unrealized Savings		-$0.1	-$0.1	**-$0.3**	$0.0	-$0.1	**-$0.1**
	Actual Savings		$3.3	$0.8	**$4.1**	$0.7	-$0.7	**$0.1**
Interface Prices ($/MWh)	NY	Actual	$23.77	$55.02	**$26.19**	$23.49	$44.46	**$26.83**
		Forecast	$25.01	$45.67	**$26.61**	$25.18	$42.26	**$27.90**
	NE or PJM	Actual	$24.34	$58.75	**$27.00**	$22.91	$45.03	**$26.43**
		Forecast	$23.41	$41.68	**$24.83**	$24.77	$67.07	**$31.50**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.24	-$9.35	**$0.42**	$1.69	-$2.19	**$1.07**
		Abs. Val.	$3.21	$34.28	**$5.62**	$3.99	$26.92	**$7.64**
	NE or PJM	Fcst. - Act.	-$0.93	-$17.06	**-$2.18**	$1.86	$22.05	**$5.07**
		Abs. Val.	$3.27	$28.07	**$5.19**	$3.28	$53.36	**$11.25**

Figure A-68 & Figure A-69: Price Forecast Errors Under CTS

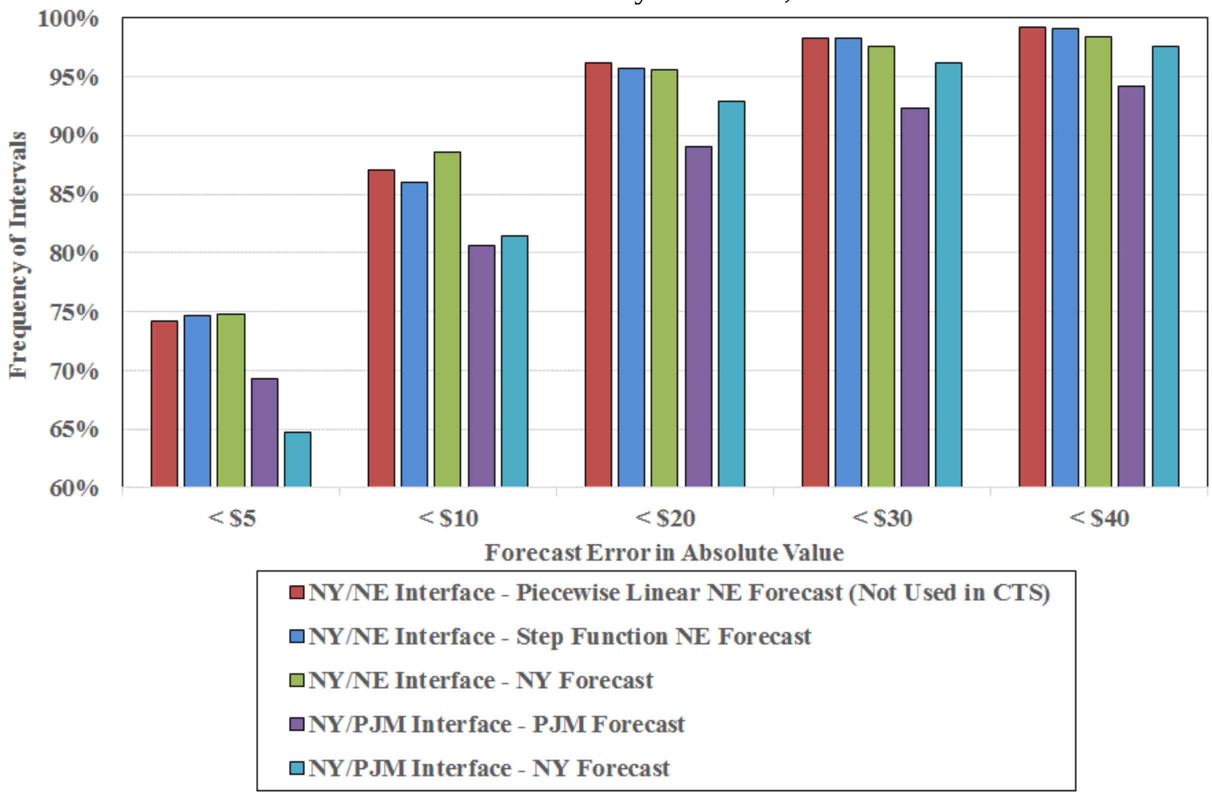
The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-68 shows the cumulative distribution of forecasting errors in 2019. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast 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

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.

linear curve. Figure A-69 illustrates this with example curves. [292] The blue squares in the figure show the seven price/quantity pairs that are produced by the ISO-NE price forecast engine (CTSPE). The blue line connecting these seven squares represents a piecewise linear supply curve at the New England border. The red step-function curve is an approximation of the piecewise linear curve and is actually used in RTC for scheduling CTS transactions at the New England border.

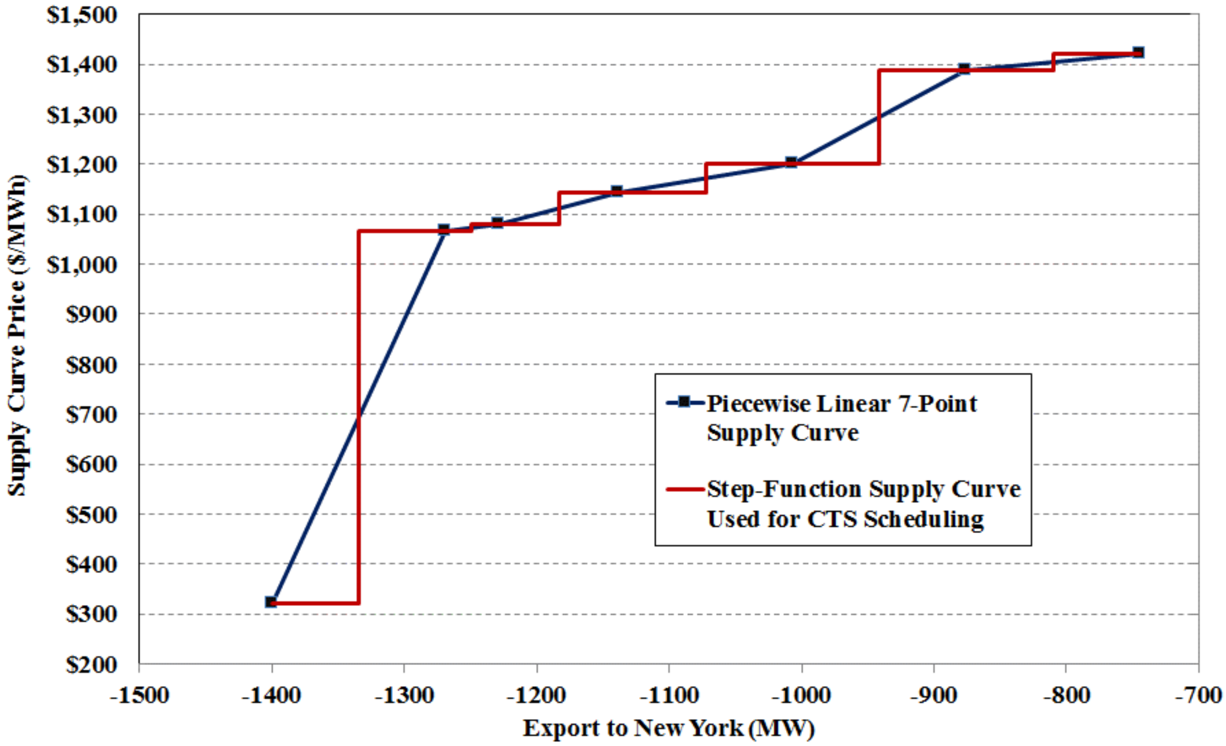
Figure A-68: Distribution of Price Forecast Errors Under CTS

NE and PJM Primary Interfaces, 2019



292 The two curves are forecasted supply curves used in the market on January 5, 2016.

Figure A-69: Example of Supply Curve Produced by ISO-NE and Used by RTC



Key Observations: Evaluation of Coordinated Transaction Scheduling

- The average amount of price-sensitive bids (including both CTS and LBMP-based) submitted at the primary PJM interface was significantly lower than at the primary New England interface (see Figure A-66). In 2019,
  - An average of 958 MW (including both imports and exports) were offered between -$10 and $5/MWh at the NY/NE interface, while only 276 MW were offered in this range at the primary NY/PJM interface.
  - Likewise, the amount of cleared price-sensitive bids at NY/NE interface nearly tripled 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) more frequently at the NY/NE interface (77 percent of intervals) than at the NY/PJM interface (58 percent of intervals). and
    - The projected production cost saving at the scheduling time was higher at the NY/NE interface ($3.6 million) than at the NY/PJM interface ($1.5 million).[293]

293 These projected cost savings exclude estimates from intervals with relatively large price forecast errors (i.e., > $20/MWh). Large forecast errors tend to over-estimate achievable benefits significantly.

- 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 $6 to $7/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-66) and their average profit (including both imports and exports) was slightly more than $1/MWh in 2019 (see Figure A-67).
    - 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-66) and the average profit (not including fees) for real-time exports was close to $8/MWh (see Figure A-67). [294]
    - 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.
- The actual production cost savings fell from $5.5 million in 2018 to $4.1 million in 2019.
  - This reduction reflected smaller differences in energy prices between neighboring markets that partly resulted from lower natural gas prices and load levels.
  - Nonetheless, price forecasting became better at the NY/NE border, where NYISO forecast error improved from 24 percent in 2018 to 21 percent in 2019 and ISO-NE forecast error improved from 20 percent to 19 percent.
  - The actual production cost savings at the PJM border has been minimal ($0.6 million in 2017, $0.7 million in 2018, and $0.1 million in 2019) in spite of projected savings of $5.2 million at the scheduling time.
    - A large portion of projected savings occurred during intervals when forecasting errors were significant (i.e., > $20/MWh).

294 Most of the day-ahead exports to PJM were scheduled by participants with physical contract obligations and were not necessarily sensitive to these export fees.

   - The forecast error at the PJM border rose from 35 percent in 2018 to 43 percent in 2019, while NYISO forecast error increased from 26 percent to 28 percent.
   - Of all price forecasts at the two CTS interfaces, the performance of PJM price forecasts were the worst in 2019. (see Figure A-68).

- Our analyses also 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.
  - In 2019, nearly 80 percent of projected production cost savings were realized when the forecast errors were moderate, while a much smaller portion was realized (particularly at the NY/PJM border) when forecast errors were larger, which undermined the overall efficiency of CTS. (see Table A-7).
  - Therefore, improvements in the CTS process should focus on identifying sources of forecast errors. 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-70 & Figure A-71: Patterns in Differences between RTC Forecast Prices and RTD Prices

Figure A-70 shows a histogram of the resulting differences in 2019 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-71 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-70: Histogram of Differences Between RTC and RTD Prices and Schedules
2019

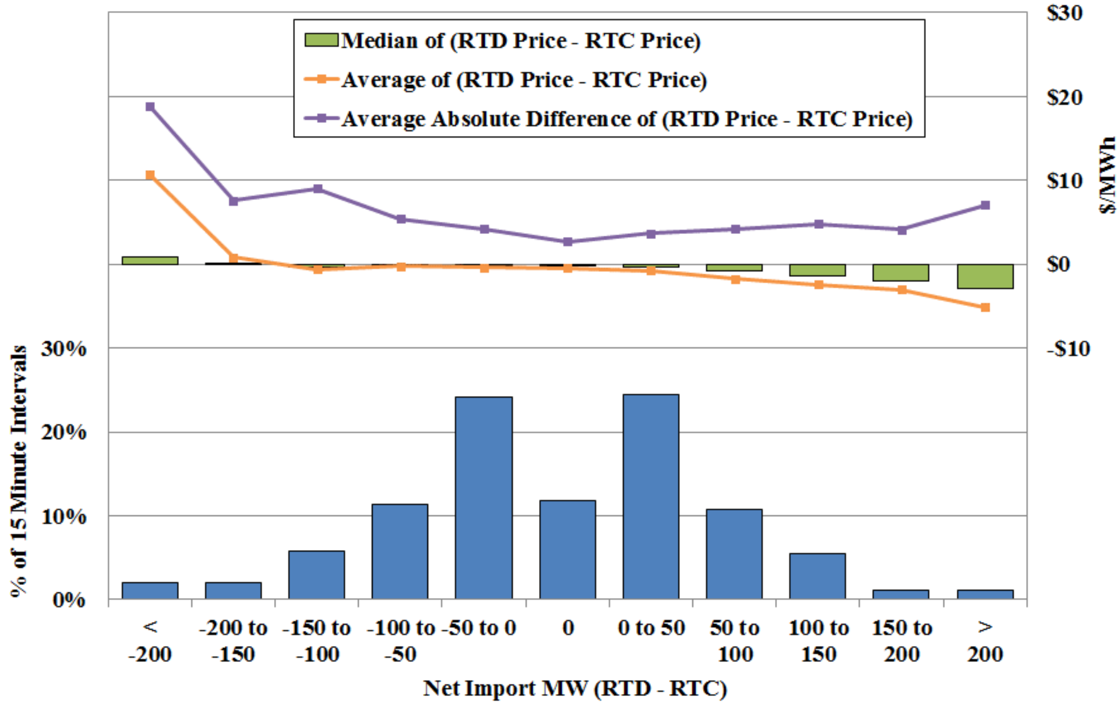


Figure A-71: Differences Between RTC and RTD Prices and Schedules by Time of Day
2019

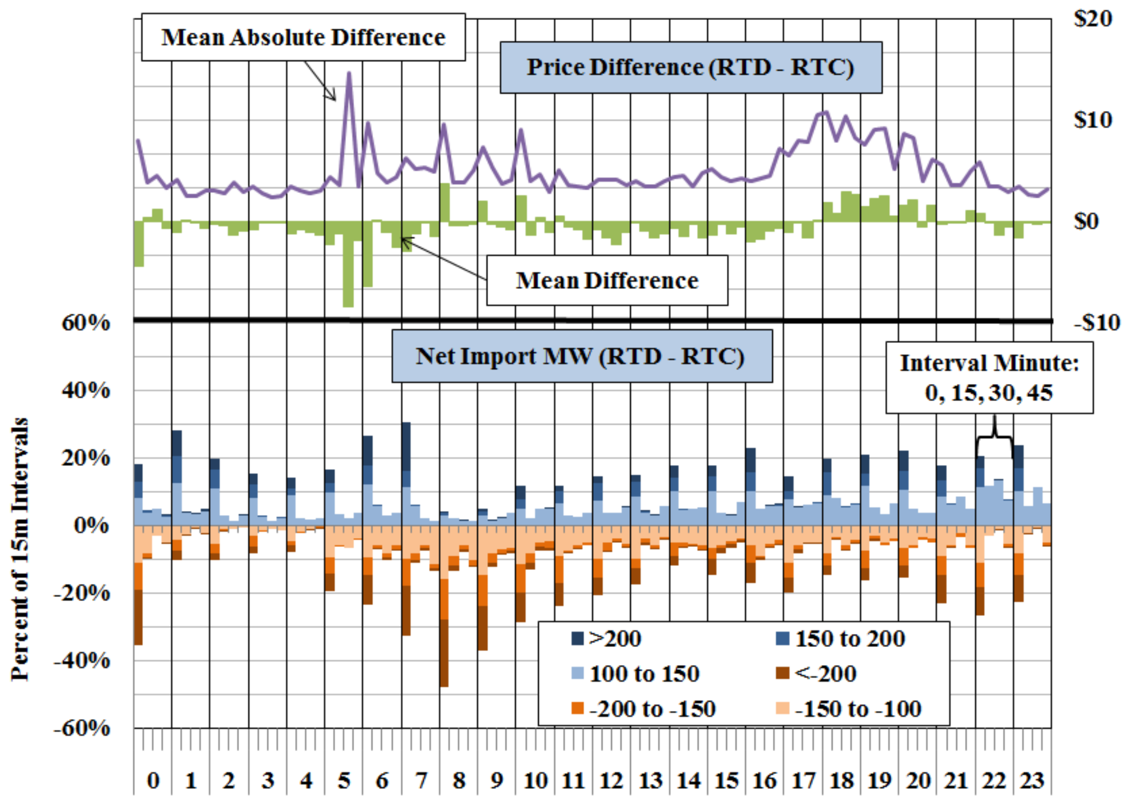


Figure A-72 to Figure A-75: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-72 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-72: Illustration of External Transaction Ramp Profiles in RTC and RTD

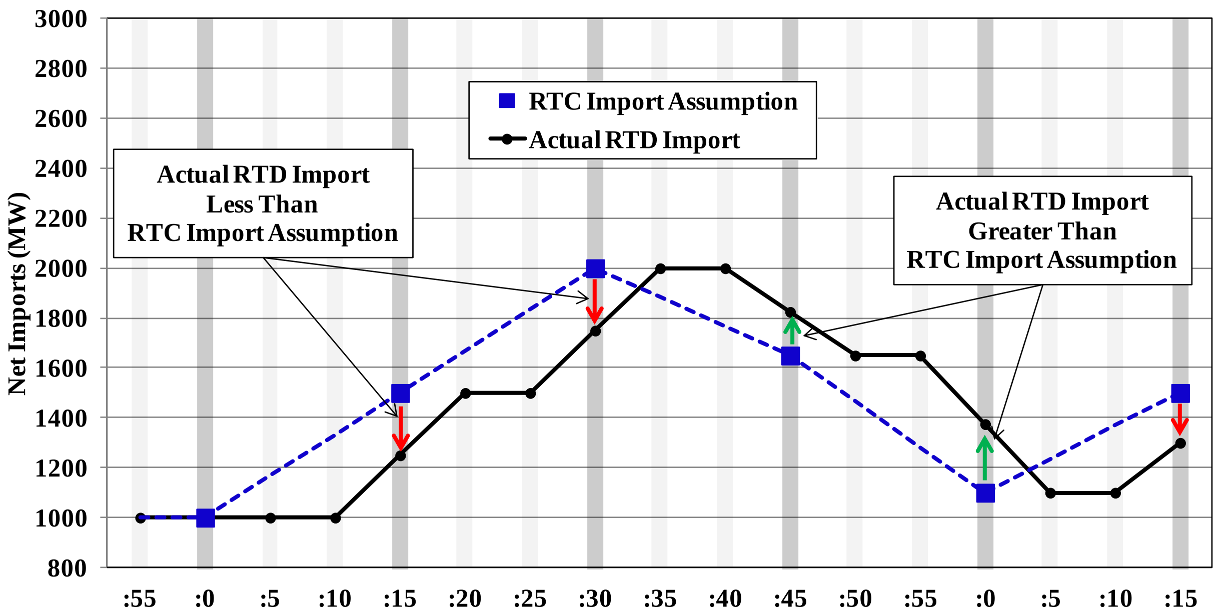


Figure A-73 to Figure A-75 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it 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).[295]

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 * {$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:

$$\text{Metric}_{i} = (\text{NetInjectionMW}_{i,RTC} - \text{NetInjectionMW}_{i,RTD}) * (\text{Price}_{i,RTC} - \text{Price}_{i,RTD})$$ [296]

Hence, for the load forecast in the example above, the metric is:

$$\text{Metric}_{load} = 100 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = -\$2{,}000/\text{hour}$$

For the high-cost generator in the example above, the metric is:

$$\text{Metric}_{generator} = -100 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = +\$2{,}000/\text{hour}$$

For the foregone CTS imports in the example above, the metric is:

$$\text{Metric}_{import} = 0 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = \$0/\text{hour}$$

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

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295 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.

296 Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

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:

$$\text{Metric}_i = (\text{FlowMW}_{i,RTC} - \text{FlowMW}_{i,RTD}) * \textstyle\sum_c \{(\text{ShadowPrice}_{c,RTC} * \text{ShiftFactor}_{i,c,RTC} - \text{ShadowPriceMW}_{c,RTD} * \text{ShiftFactor}_{i,c,RTD})\}$$

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 divergence between RTC and RTD congestion prices). This calculation is performed for both "optimized" PARs and "non-optimized" PARs.[297]

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.

297 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.

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.

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-72.

Figure A-73 summarizes the RTC/RTD divergence metric results for detrimental factors in 2018, while Figure A-74 provides the summary for beneficial factors. Figure A-75 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-73: Detrimental Factors Causing Divergence between RTC and RTD
2019

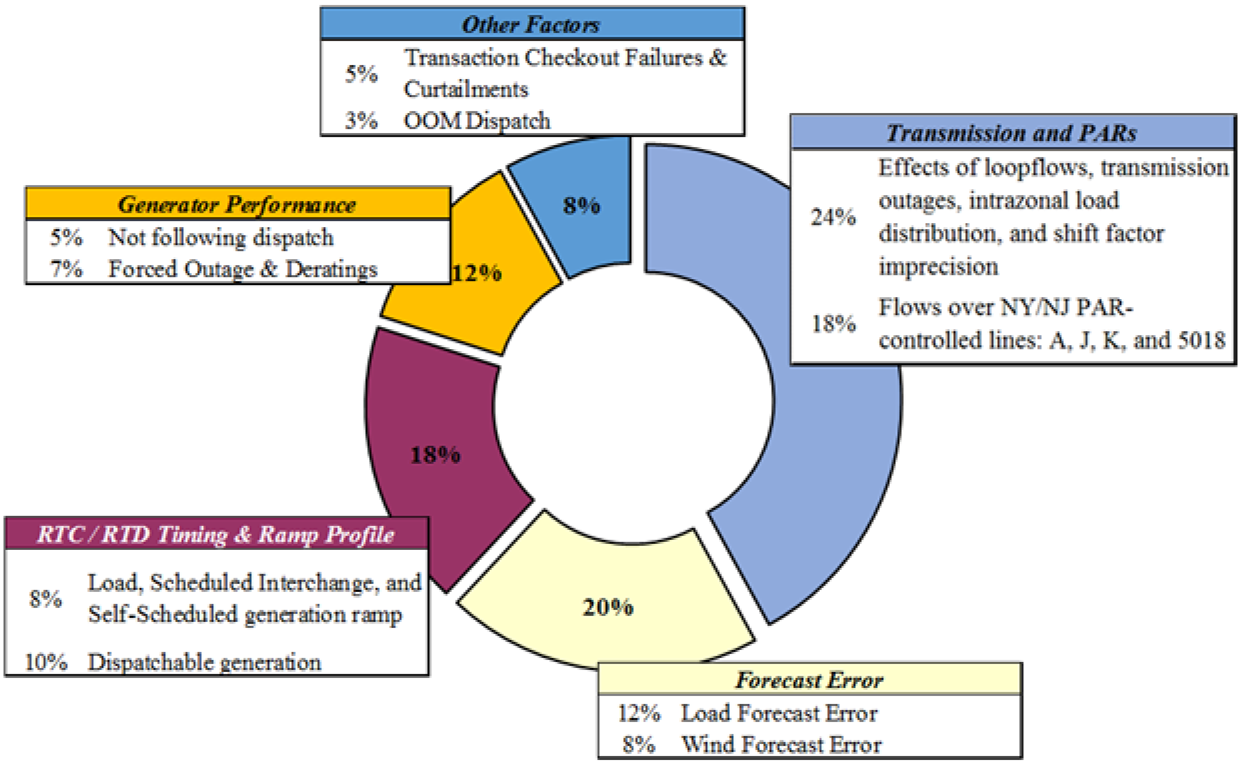
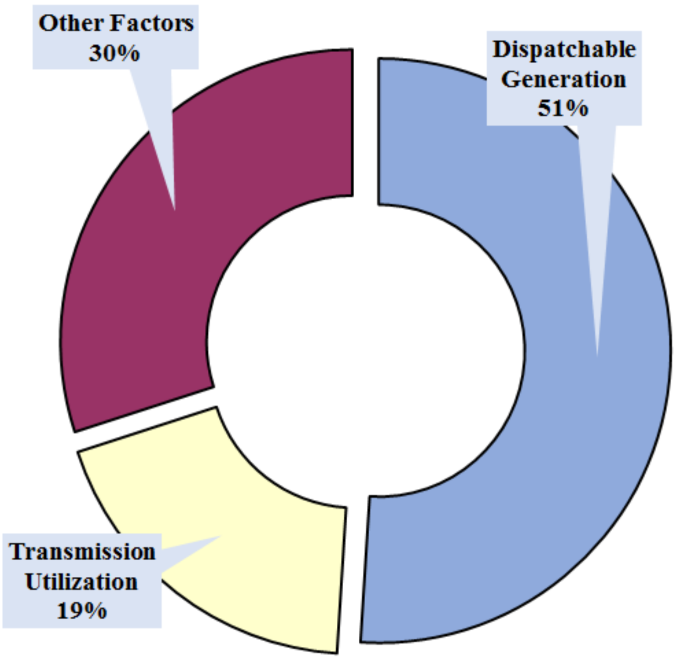
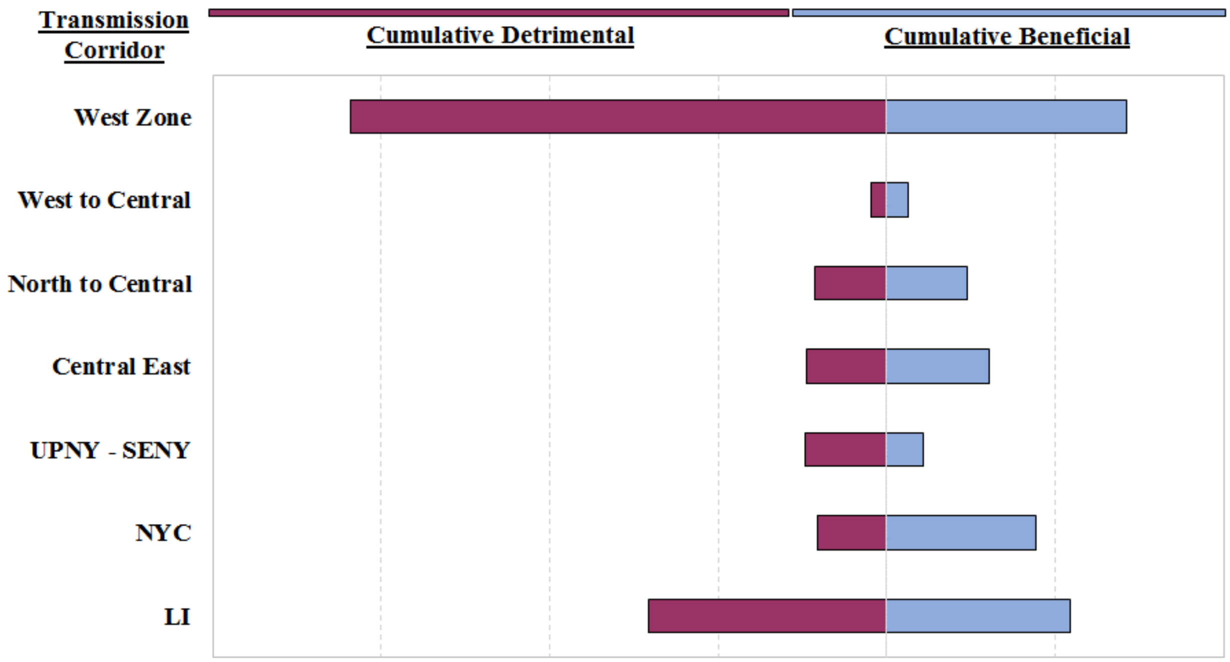


Figure A-74: Beneficial Factors Reducing Divergence between RTC and RTD
2019



"Dispatchable Generation"	
Factors for the redispatch of generators.	
"Other Factors"	
Wind Forecast Error	6%
Ramp Profile	6%
Load Forecast Error	6%
Non-optimized PARs	5%
Not-Following Dispatch	2%
Forced Outage / Derate	3%
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-75: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2019



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-70 and Figure A-71) suggest that inconsistencies in the ramp assumptions that are used in RTC and RTD (which are illustrated in Figure A-72) 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-70 and Figure A-71). This deters large schedule changes that might otherwise be economic, thereby reducing the efficiency gains from CTS.
  - However, it is evident from Figure A-71 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 in 2019, which were generally similar to those identified for prior years:
  - 42 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 flows on PAR-controlled lines between NYISO and PJM (i.e., the A, 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 that result primarily from: a) transmission outages; b) changes in loop flows; and c) inaccuracies in the calculation of shift factors for NYISO resources, which are caused by the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch, and changes in the distribution of load within a zone.
    - The detrimental contribution of this category rose in 2019, primarily in the West Zone as the 115 kV constraints are now managed through market software rather than OOM actions.
  - 20 percent from errors in forecasting of load and production from wind turbines.
  - 17 percent from changes by a market participant or another control area, which are generally outside the NYISO's control, including:
    - 12 percent from generators experiencing a derating, forced outage, or not following dispatch; and
    - 5 percent from transaction checkout failures and curtailments.

  - 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-72), load, self-scheduled generators, and dispatchable generators.

- In the assessment of beneficial factors, we find the following were the primary factors that helped reduce divergence in 2019, similar to prior years as well:
  - 51 percent from dispatchable generation, which is expected since many generators are flexible and respond efficiently to changes in system conditions.
  - 19 percent from changes between RTC and RTD in network modeling, including the modeling of the transmission network and PAR-controlled lines. Most of this benefit results from the flexibility of the transmission system to respond to changes in system conditions between RTC and RTD. Sometimes, random variations in transfer capability contribute to this beneficial category as well.

- In the detailed summary of transmission network modeling issues, we find that transmission facilities in some regions generally exhibited detrimental contributions while others exhibited significant beneficial contributions.
  - The following regions generally exhibited 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 lead to higher congestion costs in RTD, while increases in available transfer capability after RTC lead to lower congestion costs in RTD. The overall detrimental contribution rose in 2019 as the NYISO started to manage 115 kV constraints through markets rather than OOM actions.
    - UPNY-SENY – The primary driver was TSA operations, which impose large reductions in transfer capability across the interface. However, these are often not in-sync between RTC and RTD.
  - New York City constraints generally exhibited beneficial contributions.
    - 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.

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 2019:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *Performance of Operating Reserve Providers* – This sub-section analyzes: a) the performance of gas turbines in responding to a signal to start-up in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.
- *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 two types of shortage conditions: (a) shortages of operating reserves and regulation, and (b) transmission shortages.
- *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 10-minute units when it is economic to do so.[298] 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 10-minute and 30-minute units when it is economic to do so.[299] RTC also schedules bids and offers 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 subsection F.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of gas turbines, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it leads to depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section evaluates the efficiency of real-time commitment and scheduling of gas turbines.

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298 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

299 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

Figure A-76: Efficiency of Gas Turbine Commitment

Figure A-76 measures the efficiency of gas turbine commitment by comparing the offer price (energy plus start-up costs amortized over the initial 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. 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.

Therefore, the following analysis tends to understate the fraction of decisions that were economic. Figure A-76 shows the average quantity of gas turbine capacity started each day in 2019. 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.

Starts are shown separately for 10-minute 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,[300] or by an out-of-merit (OOM) instruction.

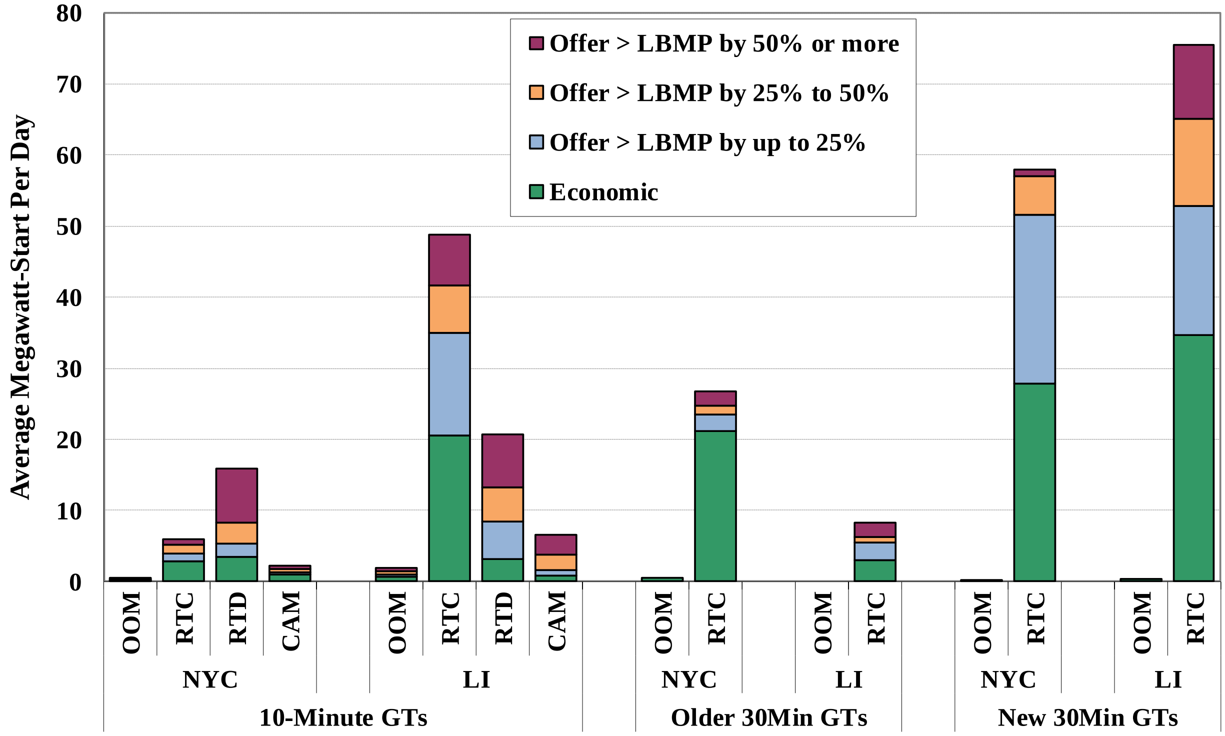
The real-time market software currently uses a two-pass mechanism for the purpose of dispatching and pricing.[301] The first pass is a physical dispatch pass, which produces physically

300 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.

301 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 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.

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-76: Efficiency of Gas Turbine Commitment
2019



Key Observations: Efficiency of Gas Turbine Commitment

- Most gas turbine commitments were made by RTC. In 2019, roughly 82 percent was committed by RTC, 17 percent by RTD and RTD-CAM, and 1 percent through OOM instructions.
- Of all gas turbine commitments in 2019, only 44 percent were clearly economic (indicated by green bars in the figure). An additional 26 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.
    - These statistics were consistent with those calculated for 2017 and 2018.
- Nonetheless, there were many commitments in 2019 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).
- In addition, the current fast-start price-setting rules do not necessarily reflect the start-up and other commitment costs of the gas turbine in the price-setting logic. We have recommended that the NYISO incorporate these costs into the price-setting logic.
  - The "Enhanced Fast-Start Pricing" project is currently underway in the NYISO, which will: (a) extend the existing logic (currently applied only to Fixed Block fast-start units) to all fast-start resources; and (b) include the start-up and minimum generation costs of all fast-start resources in the LBMP calculation.
  - This will improve the efficiency of clearing prices for all market participants when fast-start generation resources are being deployed. This market change is scheduled to be implemented in the fourth quarter of 2020. [302]

B. Performance of Operating Reserve Providers

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: a) the performance of GTs in responding to start-up instructions in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.

Figure A-77: Average Production by GTs after a Start-Up Instruction

Figure A-77 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 2019. Performance is shown for 10-minute GTs (offering non-synchronous 10-minute reserves) and 30-minute GTs (offering non-synchronous 30-minute reserves). In the figure, the x-axis shows response rates to start-up instructions in groups with a 10-percent increment from 0 to 100 percent (i.e., measured as the GT output at 10 or 30 minutes after receiving a start-up instruction as a percent of its UOL).[303] The units that are in service but were never started by RTC in 2019 are placed in a separate category of "Not Started". The text boxes in the figure summarize their start-up performance in 2018 and 2019. The table in the figure compares GT start-up performance from 2018 to 2019 for GTs that were started by RTC at least once in each of the three years.

302 See "Enhanced Fast-Start Pricing" by Mike DeSocio, MIWG meeting on October 28, 2019.

303 For example, for a 40 MW 10-minute GT, if its output is 30 MW at 10 minute after receiving a start-up instruction, then its response rate is 75 percent, which falls into the 70-to-80-percent group.

Figure A-77: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts, 2019

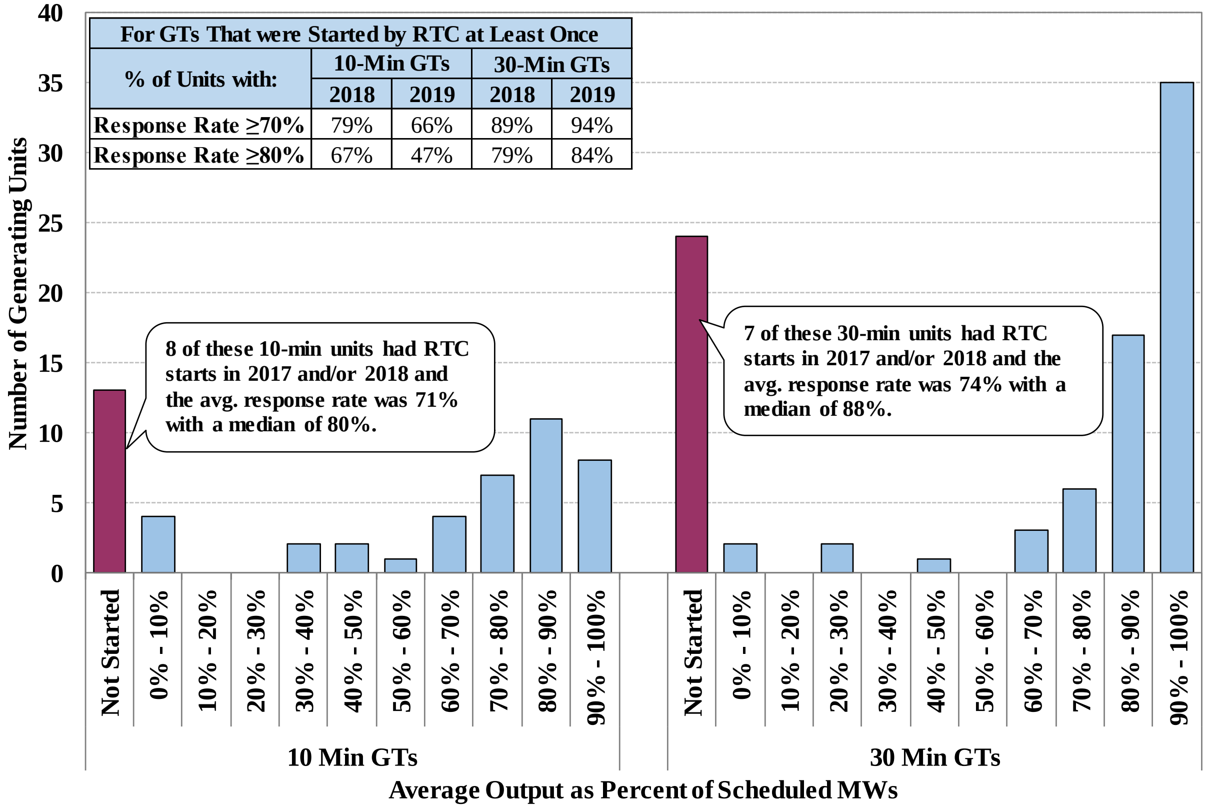


Figure A-78: Use of Operating Reserves to Manage Congestion in New York City

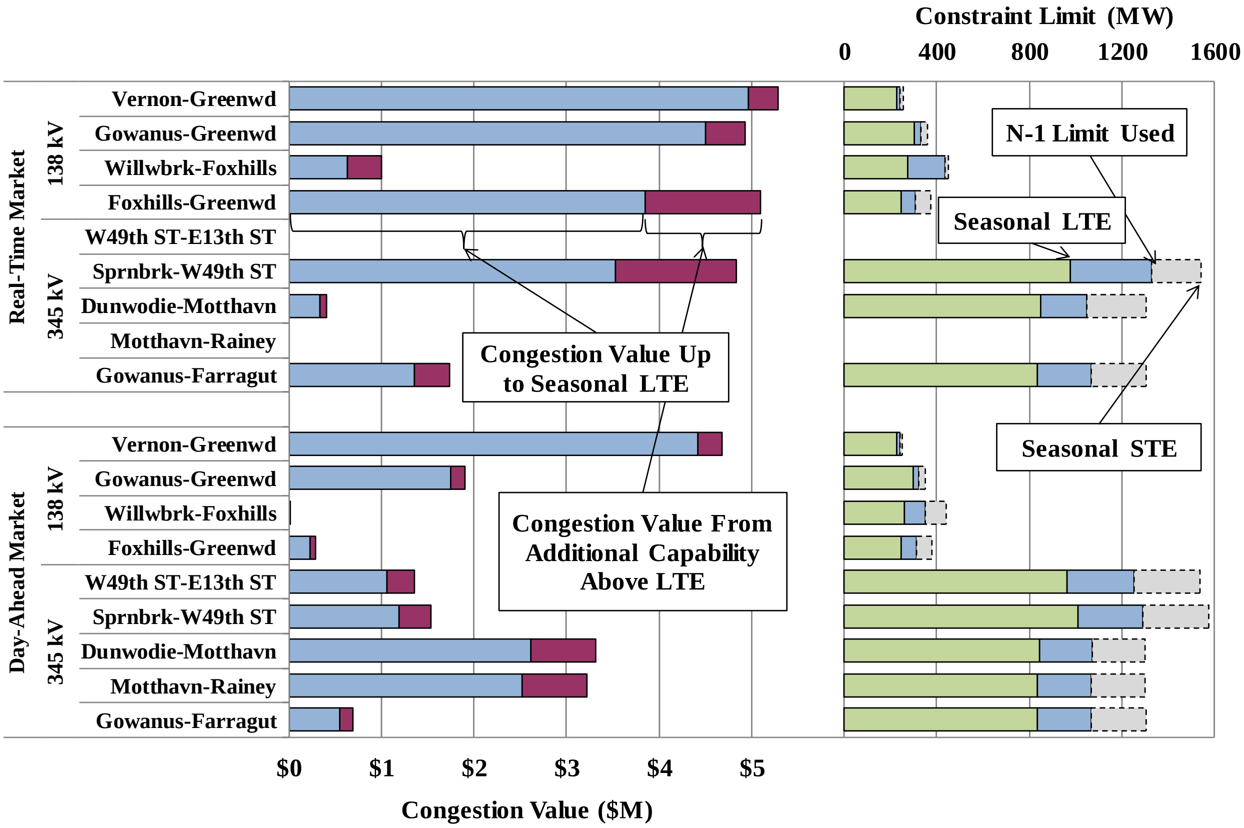
The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE. The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs. However, the service provided by these actions are not properly compensated.

Figure A-78 shows such select N-1 constraints in New York City. The left panel in the figure summarizes their day-ahead and real-time congestion values in 2019. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[304] The red bars represent the congestion values measured for the additional transfer capability above LTE.[305] The bars in the right panel show the average seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.

304 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

305 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

Figure A-78: Use of Operating Reserves to Manage N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings, 2019



Key Observations: Performance of Operating Reserve Providers

- GT start-up performance generally worsened in 2019 from the prior year for 10-minute units, but it improved slightly overall for 30-minute units.
  - Most 30-Minute GTs have far fewer economic commitments over the course of the year than do 10-Minute GTs. For instance, the average number of RTC starts for the 30-Minute GTs with at least one such start in 2019 was 21.6 with a median value of 15. Those values for 10-Minute GTs are 84.2 average starts with a median of 7 starts per year. Thus, 30-Minute GTs are more uniform in having few evaluated starts per years whereas there are far more economic 10-Minute GT starts, but they are heavily skewed to the most efficient units.
  - The most significant improvement in 2019 from the 2018 results among the 30-Minute GTs came from units that started, on average, 9 times per year. With only 9 starts per year, a change in the number of poor starts from one year to the next can change annual outcomes by more than 10 percent, increasing the potential for large year-to-year variations in performance for individual units.
  - Performance among the most commonly started 10-Minute GTs fell moderately in 2019. Effectively, this moved a majority of these individual units from the lower end

of higher performing buckets (i.e., from ~90 percent performance) to the higher end of the bucket immediately lower (i.e., ~87 percent).

- Performance improved significantly from 2017 to 2018 partly because of retirements and IIFOs of poor performing units. This trend may continue as older units continue to leave the market.

- The NYISO is enhancing its audit procedure to test each unit at least once per year. The NYISO has also stated that it may disqualify generators from providing reserves based on audit results and/or failure to respond to reserve pick-ups.[306]
  - In light of these changes and the significant administrative efforts that would be required to implement a performance-based adjustment to payments to reserve providers, we have withdrawn our previous Recommendation #2016-2.
  - We will continue to monitor performance going forward.

- Transmission facilities in New York City can be operated above their LTE rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - The availability of post-contingency actions is important because they allow the NYISO to increase flows into load pockets in New York City and reduce overall congestion costs.

- In 2019, 47 percent (or $29 million) of real-time congestion in New York City occurred on N-1 constraints that would have been loaded above LTE after a single contingency.
  - The additional capability above LTE averaged: (a) 15 to 90 MW for the 138 kV constraints; and (b) 200 to 300 MW for 345 kV facilities.
  - These increases were largely due to the availability of operating reserves in New York City, but reserve providers are not compensated for this type of congestion relief.
    - This reduces their incentives to be available in the short term and to invest in flexible resources in the long term.
    - When the market software dispatches this reserve capacity, it can reduce transfer capability in NYC, making the dispatch of these units inefficient in some cases.
  - We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria.[307]

306 See "More Granular Operating Reserves: Reserve Provider Performance", by Ashley Ferrer at April 7, 2020 MIWG meeting.

307 See Recommendation #2016-1.

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.[308] 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.[309]

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.[310]

Figure A-79: 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 2019.

Figure A-79 evaluates operations of these NY-NJ PARs under M2M with PJM in 2019 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:

- 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;

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

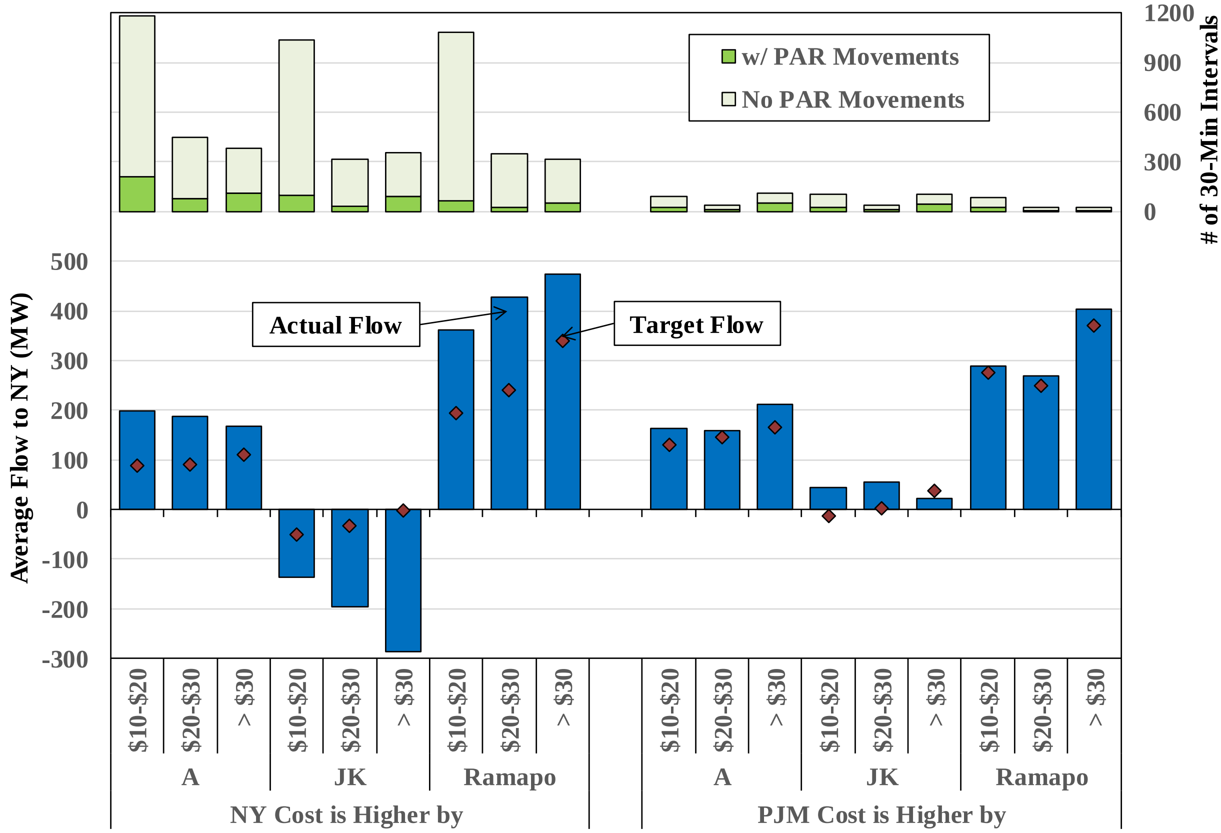
309 These include two Ramapo PARs that control the 5018 line, three Waldwick PARs that control the J and K lines, and one PAR that controls the A line.

310 The list of pre-defined flowgates is posted at https://www.nyiso.com/reports_information in the sub-group "Notices" under "General Information".

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-79: NY-NJ PAR Operation under M2M with PJM
2019



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.
  - 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 surpluses frequently resulted from this operation on the Central-East interface. We estimated a total of nearly $5.5 million of such surpluses for 2018 and 2019 (see Section III in the Appendix).

- However, this operation led to a similar amount of balancing congestion shortfalls on the West Zone constraints in 2018 and 2019. This is because when more flows are brought into New York to relieve congestion on the Central-East interface, these additional flows tend to aggravate congestion on the constraints in the West Zone.
  - The amount of shortfalls on the West Zone constraints rose in 2019. This was because the NYISO began to model 115 kV West Zone constraints, but these constraints were not initially included in the set of PAR Coordination Flowgates that are addressed by the M2M JOA.
  - The NYISO recognized this issue and was able to incorporate these 115 kV constraints in the list of PAR Coordination Flowgates in December 2019.

- Nonetheless, there were instances when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.
  - During all the 30-minute periods of 2019 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 16 percent of these intervals.
    - Overall, each PAR was adjusted 1 to 5 times per day on average, which was well below the 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 normal limits (i.e., over 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 (even though additional adjustment would have been efficient and reduced congestion);
    - The transient nature of congestion; and
    - Mechanical failures (e.g., stuck PARs).
    - 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.
  - 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.

- In Section IV.D of the Appendix, 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.
  - Operations of the NY-NJ PARs was one of the most significant net contributors to price divergence, accounting for 18 percent of overall price divergence in 2019, comparable to load forecast error and wind forecast error combined.
  - This is because RTC has no information related to potential tap changes. Consequently, RTC may schedule imports to relieve congestion, but, if after RTC kicks-off, the operator taps the A or 5018 PARs in response to the congestion, it often leads the imports to be uneconomic.

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.[311] Such lines are analyzed in Section V.D 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-8 and Figure A-80: 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 2019.

Table A-8 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2019. The evaluation is done for the following eleven PAR-controlled lines:

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311 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.

- One between IESO and NYISO: St. Lawrence – Moses PAR (L34 line).
- One between ISO-NE and NYISO: Sand Bar – Plattsburgh PAR (PV20 line).
- Four between PJM and NYISO: Two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), and one Linden-Goethals PAR (A line). These lines are currently scheduled in accordance with the M2M coordination agreement with PJM, which is discussed in sub-section C.
- 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-8 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.[312]

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.[313] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead

312 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.

313 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.

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.

Table A-8: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2019

	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					-6	$2.42	53%	$1
New England to NYCA								
Sand Bar	-79	-$11.76	96%	$8	0.3	-$11.37	54%	$0.3
PJM to NYCA								
Waldwick	-43	$2.17	44%	$0.2	16	$1.35	45%	-$3
Ramapo	258	$3.09	77%	$11	155	$2.20	65%	$6
Goethals	107	$4.27	80%	$5	107	$2.03	61%	$0.5
Long Island to NYC								
Lake Success	140	-$3.48	10%	-$5	0	-$4.54	43%	$0.0
Valley Stream	80	-$6.53	5%	-$5	2	-$7.27	35%	-$0.2

Figure A-80: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2019

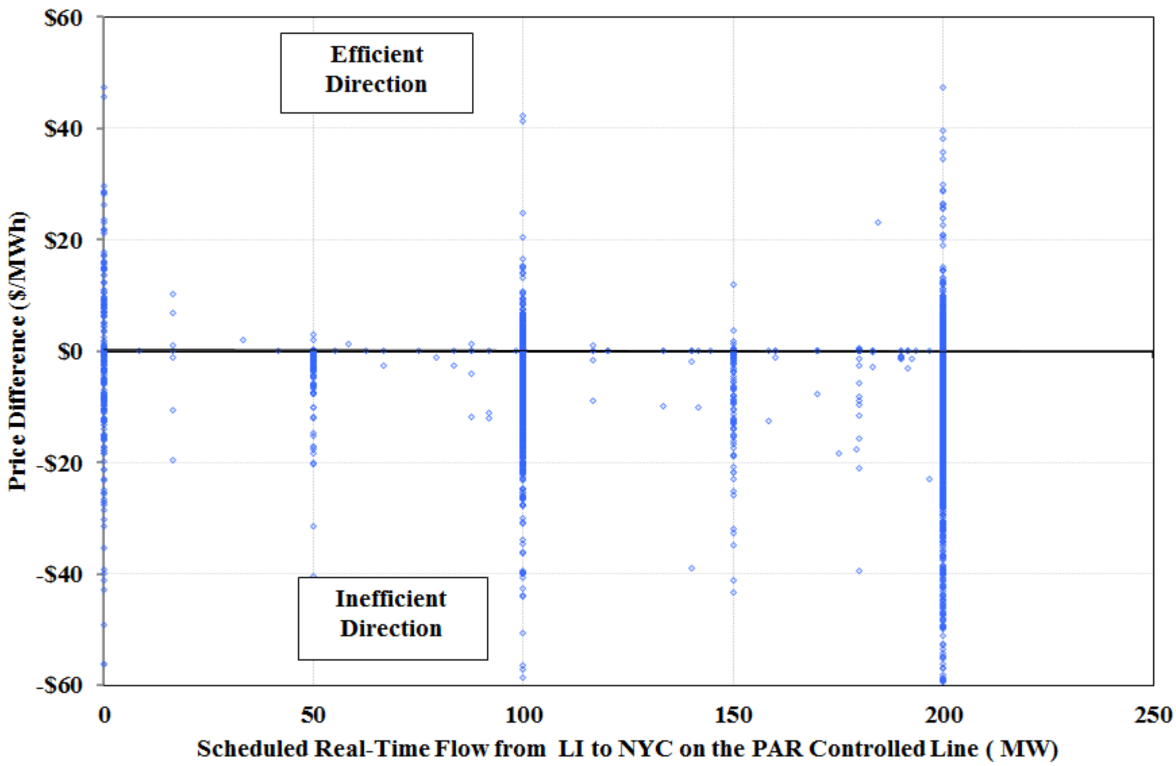

Figure A-80 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake Success-Jamaica line. The figure shows hourly price differences in the real-time market on the vertical axis versus 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.

Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- The 901 and 903 lines are used to support the ConEd-LIPA wheeling agreement, which requires that roughly half of the power flowing on the Y50 line (from upstate to Long Island) will be wheeled back to New York City.
  - 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).
  - Therefore, the scheduling across the 901 and 903 lines was much less efficient than the scheduling of other PAR-controlled lines. In 2019,
    - Scheduled power across the 901 and 903 lines flowed in the efficient direction in only 5 to 10 percent of hours in the day-ahead market. [314]
    - As a result, the use of the two lines increased day-ahead production costs by an estimated $10 million.
  - 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.
    - 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.
    - In the long-term, the operation of these lines to rigidly flow a fixed quantity rather than to relieve congestion (as nearly all other PARs are used) will make it more costly to integrate intermittent renewable generation in New York City and Long Island.
- Although the PAR-controlled lines between PJM and the NYISO are operated under the M2M JOA in a way more responsive to market price signals, the scheduling efficiency over some of these lines was very poor.

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314 Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these two PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.

- Operations over the 5018 line were the most efficient, while operations over the J and K lines were much less active and efficient (see Figure A-79). Consequently,
  - The 5018 line accounted for a $17 million net reduction in production costs;
  - The A line accounted for a $5 million net reduction in production costs; while
  - The J and K lines accounted for a $3 million net *increase* in production costs.

- Significant opportunities remain to improve the operation of the lines between New York City and Long Island.
  - 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 to modify this contract or find other ways under the current contract to operate the lines efficiently.
  - Under the ConEd-LIPA wheeling agreement, ConEd possesses a physical right to receive power across the 901 and 903 lines. To compensate ConEd during periods when it does not receive power across these lines, ConEd should be granted a financial right that would compensate it based on LBMPs when the lines are redispatched to minimize production costs (similar to a generator). [315]

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 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 2019. The effects of transient transmission constraints tend to be localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

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315 The proposed financial right is described in Section III.F of the Appendix.

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 usually account for a small number of the real-time pricing intervals, 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-9: Transient Real-Time Price Volatility

Table A-9 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2019 for facilities exhibiting the most volatility. The table reports the frequency of transient price spikes, the average shadow price during the spikes, and the average transfer limit during the spikes.

The table also analyzes major factors that contributed to price volatility in these price spike intervals. These factors are grouped into three categories:

- Flows from resources scheduled by RTC
- Flow changes from non-modeled factors
- Other factors

Specifically, the table shows factors that contributed to an increase in flows from the previous five-minute interval. For the power-balance constraint, the table summarizes factors that contributed to an increase in demand and/or reduction in supply. This analysis quantifies contributions from the following factors, which are listed in order of significance:

- External Interchange – This adjusts as often as every 15 minutes, depending on the interface. The interchange at each interface is assumed to "ramp" over a 10-minute period from five minutes before the quarter hour (i.e., :55, :10, :25, :40) to five minutes after the quarter hour (i.e., :05, :20, :35, :50). Interchange schedules are determined before each 5-minute interval, so RTD must schedule internal dispatchable resources up or down to accommodate adjustments in interchange.

- Fixed Schedule PARs – These include PARs that are operated to a fixed schedule (as opposed to optimized PARs, which are operated to relieve congestion). The fixed schedule PARs that are the most significant drivers of price volatility include the A, J, K, and the 5018 lines (which are scheduled under the M2M process) and the 901 and 903 lines (which are used to support the ConEd-LIPA wheeling agreement).[316,317] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[318] 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 purposes and the actual flows that result from adjustments in generation, load, interchange, and PAR controls.

- 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.

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316 These lines are discussed further in Subsection D.

317 M2M coordination is discussed further in Subsection C.

318 The flows over the A, JK, and 5018 lines are assumed to be fixed in future intervals at the most recent telemetered value plus a portion of expected changes of interchanges between PJM and New York over its primary interface.

- 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-9, 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-9: Drivers of Transient Real-Time Price Volatility
2019

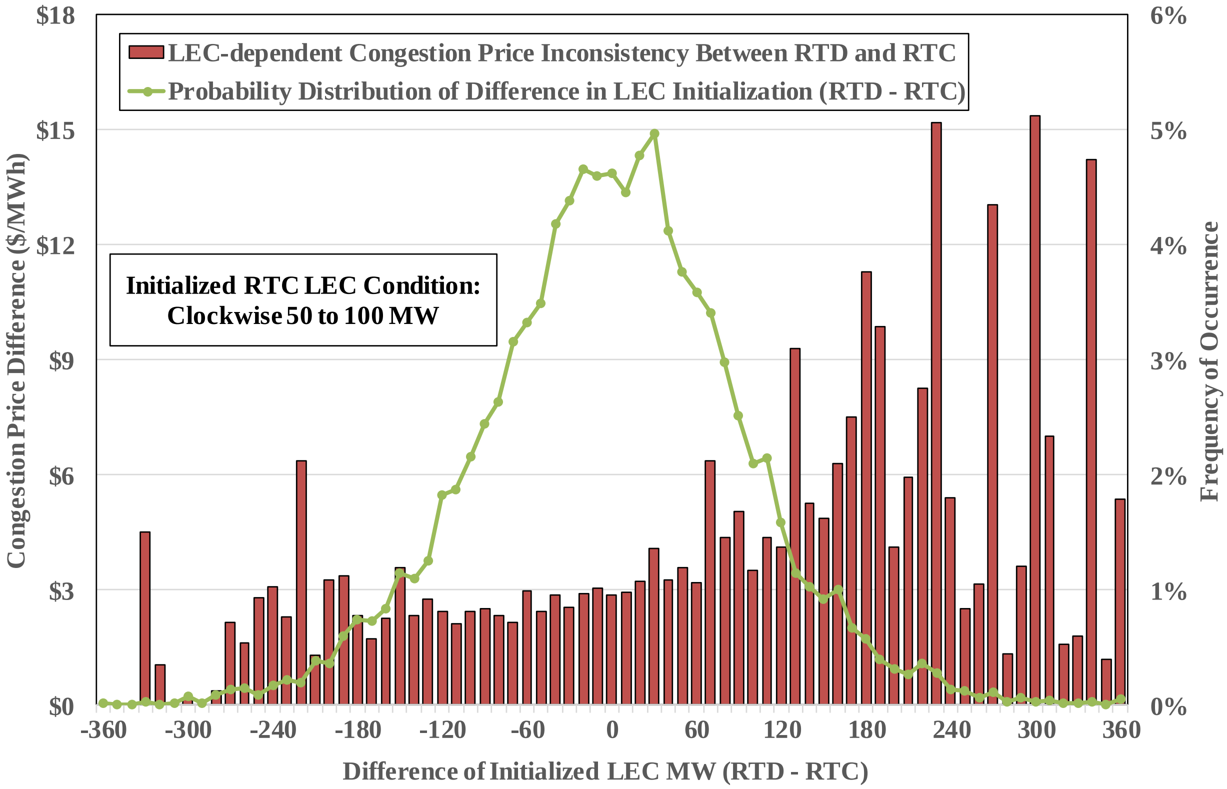
	Power Balance		West Zone Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints		Capital to Hudson Valley		New York City Load Pockets		North to Central	
Average Transfer Limit	**n/a**		**247**		**2041**		**790**		**305**		**608**		**269**		**362**	
Number of Price Spikes	**273**		**6875**		**144**		**136**		**722**		**160**		**1119**		**141**	
Average Constraint Shadow Price	**$208**		**$528**		**$362**		**$354**		**$524**		**$669**		**$532**		**$636**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**185**	**66%**	**1**	**20%**	**58**	**45%**	**66**	**67%**	**8**	**67%**	**11**	**28%**	**3**	**27%**	**2**	**11%**
External Interchange	96	34%	1	20%	27	21%	41	42%	2	17%	7	18%	1	9%	2	11%
RTC Shutdown Resource	71	25%	0	0%	21	16%	23	23%	4	33%	3	8%	1	9%	0	0%
Self Scheduled Shutdown/Dispatch	18	6%	0	0%	10	8%	2	2%	2	17%	1	3%	1	9%	0	0%
Flow Change from Non-Modeled Factors	**10**	**4%**	**4**	**80%**	**54**	**42%**	**17**	**17%**	**2**	**17%**	**23**	**59%**	**7**	**64%**	**9**	**50%**
Loop Flows & Other Non-Market	2	1%	3	60%	16	12%	12	12%	2	17%	11	28%	3	27%	7	39%
Fixed Schedule PARs	0	0%	1	20%	36	28%	4	4%	0	0%	12	31%	3	27%	2	11%
Redispatch for Other Constraint (OOM)	8	3%	0	0%	2	2%	1	1%	0	0%	0	0%	1	9%	0	0%
Other Factors	**85**	**30%**	**0**	**0%**	**18**	**14%**	**15**	**15%**	**2**	**17%**	**5**	**13%**	**1**	**9%**	**7**	**39%**
Load	47	17%	0	0%	9	7%	8	8%	1	8%	4	10%	0	0%	1	6%
Generator Trip/Derate/Dragging	17	6%	0	0%	8	6%	7	7%	1	8%	1	3%	1	9%	0	0%
Wind	21	8%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	6	33%
Total	**280**		**5**		**130**		**98**		**12**		**39**		**11**		**18**	
Redispatch for Other Constraint (RTD)	**99**		**1**		**14**		**6**		**2**		**3**		**7**		**7**	

Figure A-81 & Figure A-82: LEC Initialization and Congestion in RTC and RTD

As indicated earlier in the report, Lake Erie Circulation ("LEC", i.e., loop flows around Lake Erie) was a significant contributor to transient real-time volatility and one of the leading causes of poor convergence between RTC and RTD prices.

Figure A-81 correlates the inconsistencies between RTC and RTD prices with the inconsistencies between the LEC quantities assumed in RTC and RTD.[319] The x-axis shows the difference in initialized LEC MW between RTC and RTD, grouped in 10-MW tranches. Positive numbers indicate LEC in the clockwise direction, while negative numbers indicate LEC in the counter-clockwise direction. For example, 10 MW on the x-axis indicates that the RTD initialized LEC MW is higher than RTC initialized LEC MW by 0 to 10 MW in the clockwise direction. The bars represent the congestion price difference between RTC and RTD for each LEC MW tranche. The congestion price difference between RTD and RTC is measured at the Niagara plant. The absolute value of this difference is taken from each RTD interval and then averaged over all intervals in each LEC tranche. The line shows the frequency distribution of each LEC tranche. This sample distribution is done for all RTC intervals from January 2019 to September 2019 that had an initialized LEC MW from 50 to 100 MW in the clockwise direction. The differences in prices and initialized LEC quantities are measured against their corresponding RTD intervals.

Figure A-81: Differences between RTC and RTD in the LEC Assumption and Congestion



To reduce the effects of variations in LEC, we have recommended the NYISO consider developing a mechanism for forecasting additional adjustments from the initialized value.[320] This forecast can be "biased" in a way that tends to reduce overall differences between RTC and RTD. In general, biasing the assumed LEC value in the clockwise direction in RTC will lead

319 The initialized LEC MW refers to the telemetered LEC at the time when each RTC or RTD run initializes.

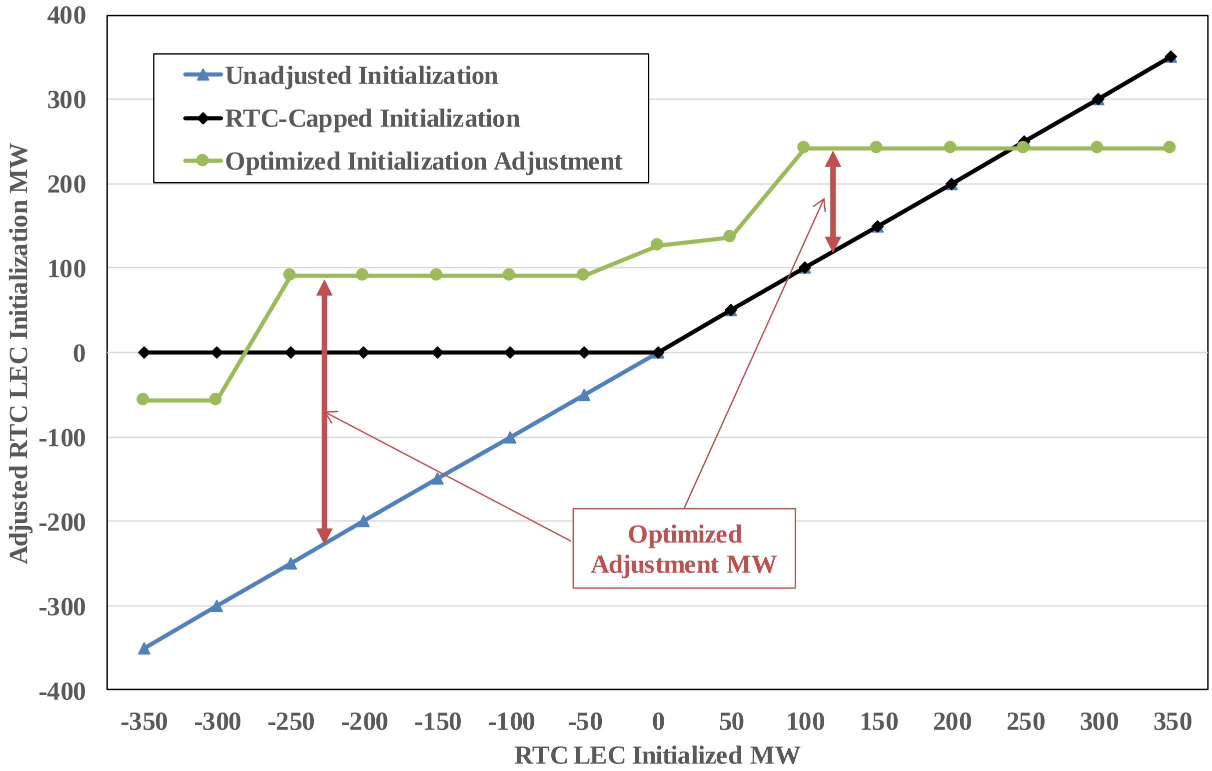
320 See Recommendation #2014-9.

RTC to schedule fewer transactions that would reduce the congestion component of the LBMP at the Niagara generator, thereby raising the congestion component of the LBMP at the same node in RTD, and vice versa. Therefore, it should be possible to bias the assumed LEC value in RTC by an amount that tends to minimize congestion price inconsistencies between RTC and RTD. The discussion of the following figure describes how this minimization was performed.

Figure A-82 shows our analysis estimating the optimal adjustment for the LEC assumption in RTC, which is designed to minimize the congestion price inconsistency between RTC and RTD. For the example shown in Figure A-81, the weighted-average congestion price inconsistency is measured by multiplying the frequency distribution (the line) with the conditional congestion price inconsistency (the bar) and summing over all LEC tranches. Since the estimated RTC-RTD price differential depends on the RTC-RTD LEC assumption differential, the bias can be adjusted to minimize the weighted-average congestion price inconsistency. In the figure,

- The blue line shows the unadjusted RTC LEC assumption (i.e., the initialized LEC).
- The black line shows the adjusted RTC LEC assumption that was used by NYISO until November 2019. This capped the assumed counter-clockwise LEC at zero in RTC.[321]
- The green line shows the optimized adjustments from our analysis.

Figure A-82: Optimized Adjustment of RTC LEC Initialization



321 The NYISO changed this cap in November 2019 to 100 MW in the clockwise direction for any counter-clockwise LEC and any clockwise LEC under 100 MW.

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes (as defined in this report) occurred in more than 6 percent of all intervals in 2019. Newly modeled West Zone 115 kV constraints accounted for most of these transient spikes.
    - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and re-dispatch for other constraints in RTD.
    - For the West Zone Lines, the primary driver was loop flows and other non-market scheduled factors. Fluctuations in fixed-schedule PAR flows between NYISO and PJM (i.e., the A, J, K, and 5018 circuits) were an additional key driver.
    - For the Central-East Interface, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A, J, K, and 5018 lines), external interchange adjustments, and generator shutdowns by RTC.
    - For Dunwoodie-to-Shore Rd 345 kV line, the primary driver was external interchange adjustment. Generator shutdowns by RTC and loop flows and other non-market scheduled factors were two additional key drivers, which were also the primary drivers for other Long Island constraints.
    - For Capital to Hudson Valley constraints, the primary drivers were loop flows and other non-market factors and fluctuations in fixed-schedule PAR flows (i.e., the A, J, K, and 5018 lines).
    - For the New York City load pockets, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A line) and loop flows and other non-market factors that affect the constraint transfer capability.
    - For North to Central constraints, the primary drivers were loop flows and other non-market factors that affect the constraint transfer capability and variations in wind output.
- External interchange variations were a key driver of transient price spikes for the power-balance constraint, Dunwoodie-Shore Rd 345 kV line, the Central-East interface, and Capital to Hudson Valley 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, J, K, and 5018 lines was a key driver for the West Zone lines, the Central-East Interface, Capital to Hudson Valley constraints, and the lines in the New York City load pockets.
  - 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 each of these PARs 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.
    - 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 lines.
  - Clockwise circulation around Lake Erie puts a large amount of non-market flow on these lines. Circulation can be highly volatile and difficult to predict, since it depends on facilities scheduled outside the NYISO market.
- Generators that are shut down by RTC and/or self-scheduled in a direction that exacerbates a constraint were a significant driver of statewide, Central East, and Long Island price spikes.
  - A large amount of generation may be scheduled to go offline simultaneously, which may not cause ramp constraints in the 15-minute evaluation by RTC but which may cause ramp constraints in the 5-minute evaluation by RTD. Slow-moving generators such as steam turbines are frequently much more ramp-limited in the 5-minute evaluation than in the 15-minute evaluation.

Discussion of Potential Solutions

- When gas turbines and other units are in the process of shutting-down, they may reduce output quickly. When decommitments are not staggered, it sometimes results in a transitory statewide or local price spike.
  - RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut-down gas turbines.

- 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: [322]
  - Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.
  - Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
  - Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
  - Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbines generators with the actual demonstrated performance to account for units that often ramp at a rate that is lower than their claimed ramp rate capability.
  - Address 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:

[322] See Recommendation #2012-13

- 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).
- We analyzed variations in LEC and congestion between the initialization times of RTC and RTD to estimate how the assumed LEC in RTC could be adjusted to minimize inconsistencies between RTC and RTD. We find that:
  - Congestion price inconsistency between RTC and RTD increases with the difference in LEC assumptions between RTC and RTD.
  - However, price inconsistencies are larger when LEC is higher in RTD.
  - We find that it would be beneficial to adjust the assumed level of LEC in RTC in the clockwise direction under most conditions.
    - Because of the current software limitation, the NYISO cannot implement variable adjustments for different levels of LEC although this is desirable.
    - The NYISO had a previous cap of 0 MW for any counter-clockwise LEC in RTC and changed this cap in November 2019 to 100 MW in the clockwise direction for any counter-clockwise LEC and any clockwise LEC under 100 MW. We supported this change, but we continue to recommend the NYISO develop the capability to put in adjustments that can vary according to the level of LEC at the time RTC initializes.
- 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.[323]

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 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.

323 See Recommendation #2014-9.

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 in 2019: [324]

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection G).

Figure A-83: 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-83 summarizes physical ancillary services shortages and their effects on real-time prices in 2018 and 2019 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.
- 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.

324 Our prior reports also evaluated market operations during reliability demand response deployments. In 2019, the NYISO did not deploy reliability demand response resources, so the effect of the scarcity pricing is not evaluated in this report.

- 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.

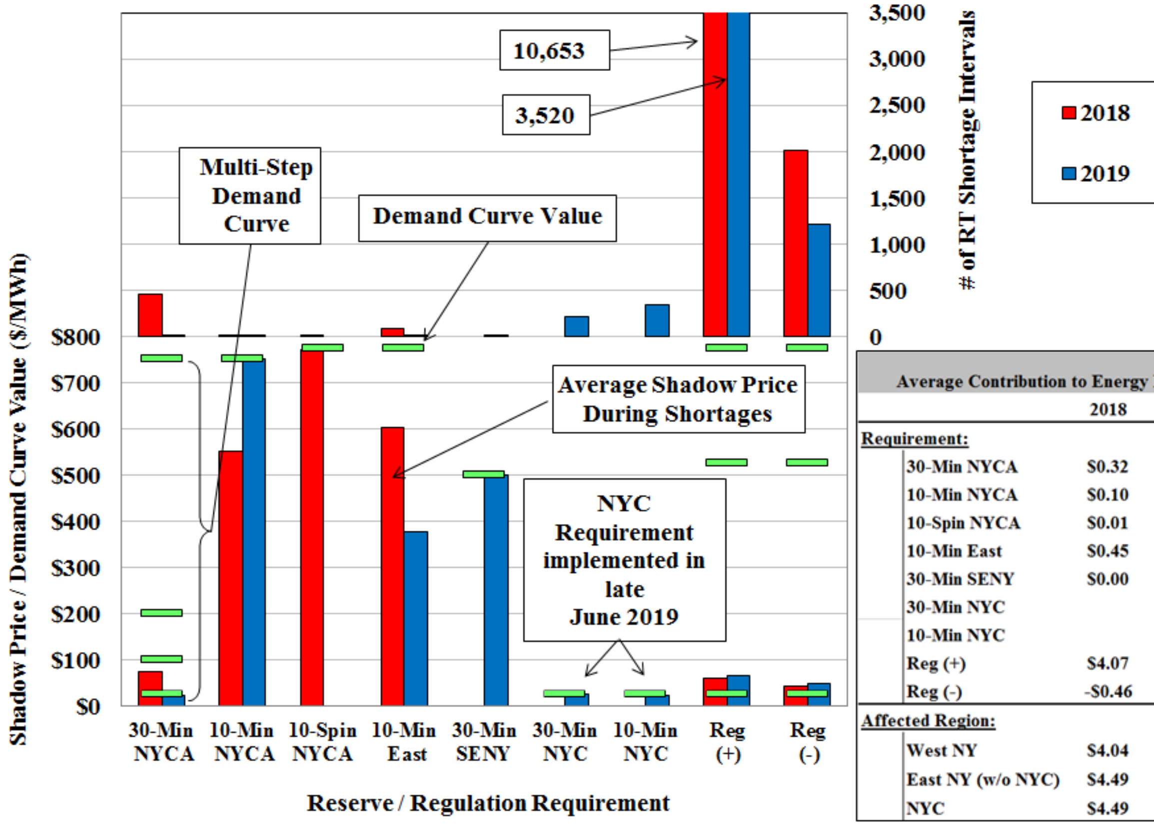
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency 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 (outside New York City) – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

- New York City – This equals the Eastern New York effect plus the sum of shadow prices of SENY and New York City reserve requirements.

Figure A-83: Real-Time Prices During Ancillary Services Shortages
2018 – 2019



Average Contribution to Energy Price	2018	2019
Requirement:		
30-Min NYCA	$0.32	$0.00
10-Min NYCA	$0.10	$0.01
10-Spin NYCA	$0.01	$0.00
10-Min East	$0.45	$0.05
30-Min SENY	$0.00	$0.01
30-Min NYC		$0.05
10-Min NYC		$0.08
Reg (+)	$4.07	$1.48
Reg (-)	-$0.46	-$0.33
Affected Region:		
West NY	$4.04	$1.17
East NY (w/o NYC)	$4.49	$1.24
NYC	$4.49	$1.36

Figure A-84 & Table A-10: Reserves Shortages in New York City

The NYISO started to model two reserves requirements in NYC on June 26, 2019:

- 10-minute Reserves Requirement – The ISO is required to hold 500 MW of 10-minute operating reserves in New York City and has a demand curve value of $25/MWh; and

- 30-minute Reserves Requirement – The ISO is required to hold 1,000 MW of 30-minute operating reserves in New York City and has a demand curve value of $25/MWh.

Table A-10 shows the real-time market performance during reserves shortages in New York City for each month in the period from June 26, 2019 to the end of the year. The table shows the following quantities:

- # Intervals – This is the total number of real-time intervals in each month when either 10-minute reserves or 30-minute reserves or both were short in New York City.

- Average Shortage MW – This is the average quantity of reserve shortages over all shortage intervals in each month. In each interval, the shortage quantity is equal to the higher amount of 10-minute and 30-minute shortages.

- # Intervals with 'toNYC' Congestion – This is the total number of real-time shortage intervals that coincided with congestion on transmission paths into New York City.

TSA events have significant impact on scheduling and pricing reserves in SENY, during which the import capability into SENY is greatly reduce and the SENY 30-minute reserve requirement is reduced to zero accordingly. Therefore, these quantities are shown separately for periods with and without TSA events in the table.

Table A-10: Real-Time Reserve Shortages in New York City
June 26-December 31, 2019

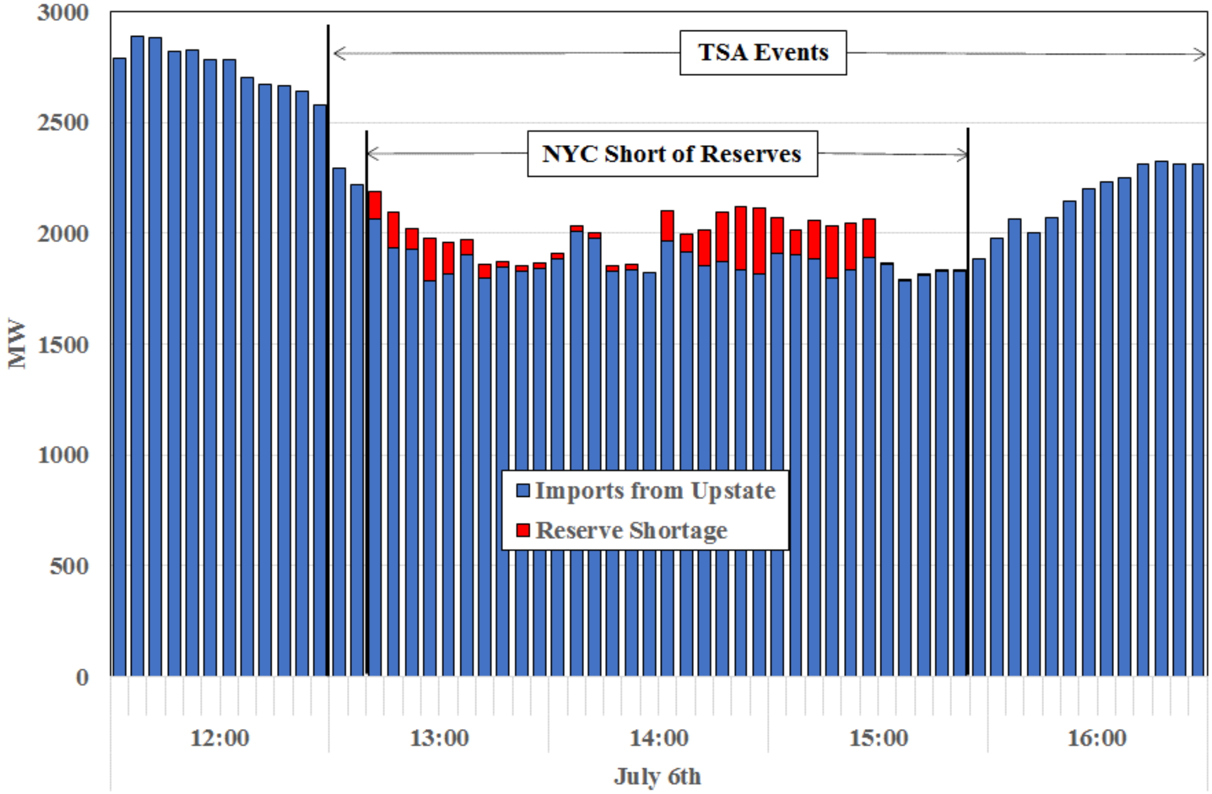
Month	RT Reserve Shortages in NYC in 2019					
	w/ TSA			w/o TSA		
	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion
Jun	28	463	0	69	119	5
Jul	127	229	0	17	71	17
Aug	43	114	0	11	53	1
Sep	39	107	0	28	138	15
Oct	0		0	119	150	2
Nov	0		0	0		0
Dec	0		0	2	23	0
Total	**237**	**216**	**0**	**246**	**129**	**40**

Figure A-84 illustrates a sample real-time shortage event that coincided with a TSA event on July 6, 2019. The TSA event occurred from 13:00 to 21:00, while New York City was short of reserves (either 10-minute or 30-minute or both) from 13:10 to 15:50. For each interval from the beginning of hour 12 to the end of hour 16, the figure shows;

- The amount of reserve shortages (red bar); and
- Net imports from upstate areas (blue bar). [325]

325 This is calculated as (NYC load – NYC gen – HTP imports – VFT imports – flows on the 901/903 lines into NYC – flows on the A line into NYC).

Figure A-84: Real-Time Reserve Shortages in New York City
Sample Event on July 6, 2019



Key Observations: Market Prices and Operations During Ancillary Services Shortages

- Regulation shortages were most frequent among all ancillary services shortages, and had the largest effects on real-time prices.
  - Regulation shortages occurred in 4.5 percent of intervals in 2019, down significantly from 12 percent in 2018.
  - All other shortages occurred very infrequently in 2019.
  - The substantial reduction in ancillary services shortages from 2018 to 2019 resulted primarily from:
    - An increased supply of low and medium-priced offers (e.g., Section II of the Appendix shows a 20 percent increase from 2018 to 2019 in the volume of regulation offers priced below $10/MWh);
    - Lower load levels, which led generator capacity to be more available for regulation and reserves; and
    - Lower energy prices, which led to lower opportunity costs to provide regulation and reserves.

- New York City experienced RT reserve shortages in 483 intervals in the period from June 26 to December 31 in 2019.
  - Roughly 50 percent of these intervals coincided with TSA events, during which transmission constraints from upstate into New York City were never binding.
    - As illustrated in Figure A-84, unutilized import capability during shortage intervals often exceeded the shortage quantity.
  - In the remaining half of the shortage intervals that did not have TSA events, transmission constraints from upstate to New York City were binding in only 16 percent of these intervals.
    - The shortages were moderate in most of these intervals, averaging only 129 MW.
- These results imply that there was sufficient unused transfer capability in most shortage intervals to satisfy the need for New York City reserves.
  - Therefore, dynamic reserve requirements are needed to schedule resources more efficiently during many operating conditions such as TSAs. [326]
- These results also suggest that increasing the New York City reserve demand curves significantly from the current $25/MWh level would lead to inappropriately high real-time prices and inefficient scheduling until dynamic reserve modeling can be implemented.
  - After the implementation of dynamic reserve requirements, the New York City reserve demand curves could be increased to levels that reflect appropriate shortage pricing.
- Notwithstanding, the operating reserve demand curves in New York are relatively low considering:
  - The willingness of NYISO operators to engage in OOM actions to procure more costly resources during reserve shortages; and
  - The incentives provided in neighboring markets during shortages.
    - For example, the demand curve value for the system-wide 30-minute reserves requirement is set at a high value of $1000/MW for any amount of shortage in the ISO-NE market, while it is set at below $200/MW in the NYISO market when the shortage is less than 955 MW. The ISO-NE's Pay-for-Performance ("PFP") rules provide additional very high market incentives during shortage intervals.
  - Therefore, the market incentives to import power into New York under tight conditions were not sufficient.[327]

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326 See Recommendation #2015-16.

327 See the analysis in Section V.F of the Appendix of our *2018 State of the Market Report* for details.

- We have recommended that the NYISO consider increasing the operating reserve demand curves to: (a) ensure reliability after PJM and ISO-NE implement PFP rules and (b) do so without resorting to OOM actions. Furthermore, we recommend the NYISO ensure that the operating reserve demand curves are reasonably consistent with the expected value of foregone energy consumption that would result from going short of operating reserves.[328]

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, [329] 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").[330]

A CRM is a reduction in actual physical limit used in the market software, largely to account for loop flows and other un-modeled factors. A default CRM value of 20 MW is used for most facilities across the system regardless of their actual physical limits. This often overly restricted transmission constraints with small physical limits. Starting in December 2018, a CRM of 10 MW was used on 115 kV facilities in the Upstate area.

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328 See Recommendation #2017-2.

329 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.

330 These changes are discussed in detail in Commission Docket ER17-1453-000.

This subsection evaluates market performance during transmission shortages in 2019, focusing on the use of the GTDC and the CRM. 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.[331] 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 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.[332] This category of shortage is evaluated in this section as well.

Figure A-85, Table A-11 & Figure A-86: Real-Time Congestion Management with GTDC

Figure A-85 examines the use of the GTDC during transmission shortages in the real-time market by constraint group in 2019. 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 (relative to the BMS limit adjusted for the CRM)[333] showing on the x-axis and the constraint shadow price on the y-axis.

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331 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.

332 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.

333 BMS limit is the constraint limit that is used in the market dispatch model. For example, if a constraint has a 1000 MW BMS limit and a 20 MW CRM, the shortage quantities reported here are measured against a constraint limit of 980 MW.

Figure A-85: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2019

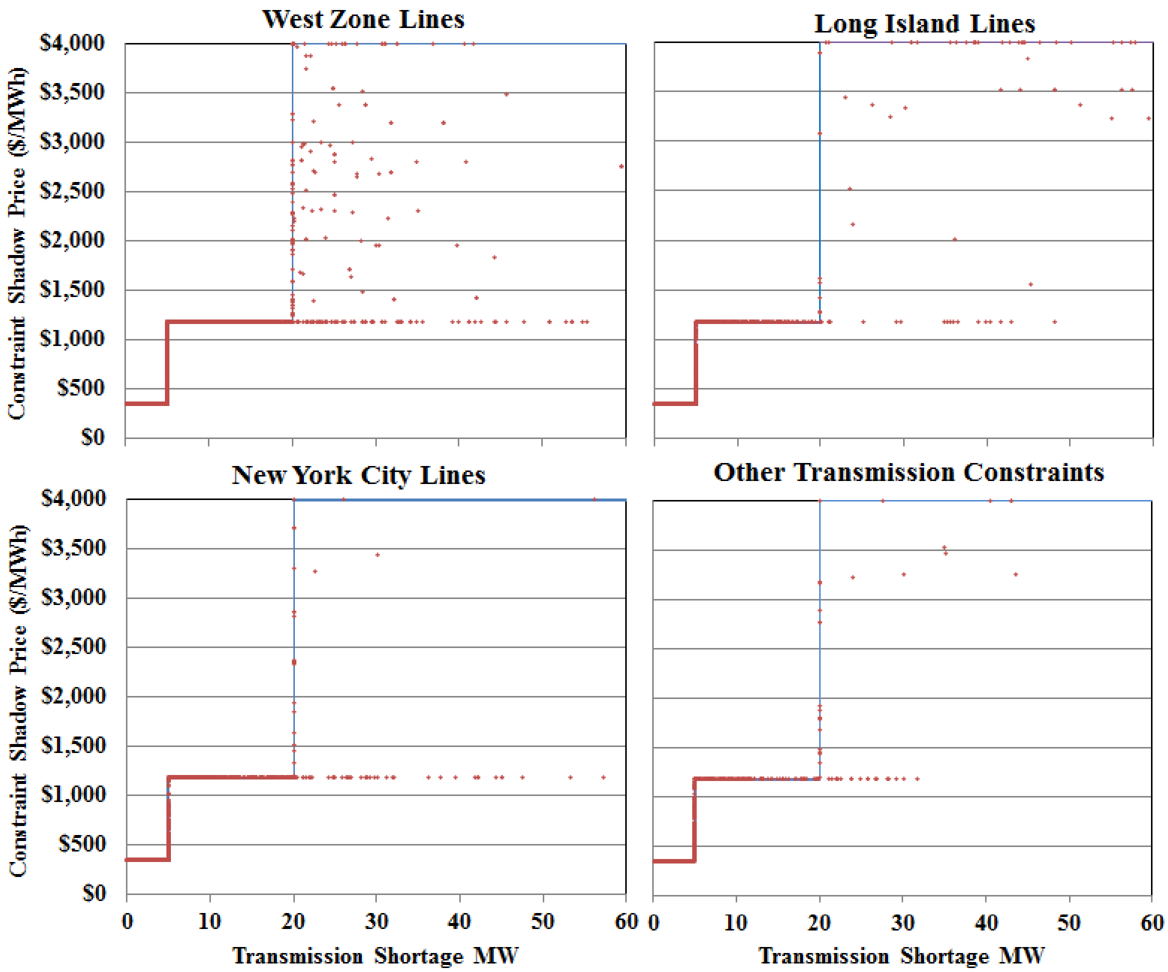


Table A-11 evaluates the effect of CRM on different transmission constraints by summarizing the following quantities for the transmission constraints grouped by facility voltage class and by location in 2018 and 2019:

- The number of constraint-shortage intervals – indicating the total number of constraint-shortage intervals in each facility group, which excludes the congestion-relief effect from offline GTs.

- Average constraint limit – indicating the average transmission limit overall all transmission constraints in each facility group.

- Average CRM – indicating the average CRM MW used in each facility group.

- Average shortage quantity - including: a) the average transmission shortage quantity that is recognized in the market model; and b) additional shortages when removing the congestion-relief effect from offline GTs.

- CRM as a percent of limit – indicating the average CRM as a percentage of average limit.

These quantities are summarized over real-time transmission shortage intervals and for transmission constraints that have a 10+ MW CRM.

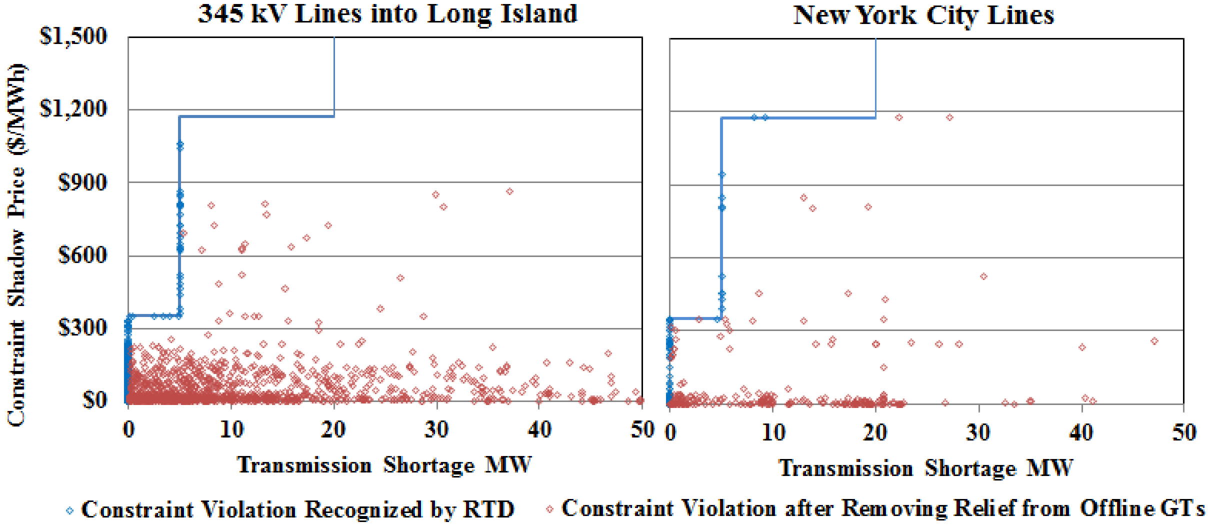
Table A-11: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2018 - 2019

Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals		Avg Constraint Limit (MW)		Avg CRM (MW)		Avg Shortage MW: Recognized in Model		Avg Shortage MW: Excluding Offline GT		CRM as % of Limit	
		2018	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
115 kV	West	311	11577	202	204	10	10	4	5	4	5	5%	5%
	North	1146	212	141	142	20	10	4	15	4	15	14%	7%
	All Others		147		173		10		6		6		6%
138 kV	New York City	6220	2006	241	229	20	20	6	6	6	7	8%	9%
	Long Island	2025	2712	281	298	28	24	4	4	8	7	10%	8%
	All Others		365		294		20		5		7		7%
230 kV	West	1275	457	681	708	45	39	9	12	9	12	7%	6%
	North	80	67	403	435	20	20	7	5	7	6	5%	5%
	All Others	17	22	503	560	20	20	5	2	5	3	4%	4%
345 kV	New York City	1174	305	823	746	20	20	7	4	14	11	2%	3%
	North	206	28	1602	1801	50	50	38	10	42	11	3%	3%
	Long Island	1364	1344	797	775	50	50	1	3	15	17	6%	6%
	All Others	147	303	1737	1609	28	30	12	4	28	13	2%	2%

Figure A-86 examines the pricing effects of offline GTs on transmission shortages in 2019 for select transmission groups: a) the two 345 kV transmission circuits from upstate to Long Island; and b) 138 and 345 kV transmission constraints into and within New York City. Offline GTs were used 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-86: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2019



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.
  - Constraint relaxation occurred in 7 percent of all transmission shortages in 2018 and only 3 percent in 2019 (shown by the points that are off the GTDC curve in Figure A-85), compared with over 50 percent in the periods before the revision.
  - Less frequent use of constraint relaxation greatly improved pricing efficiency during transmission outages, which resulted in:
    - That constraint shadow prices were more correlated with the severity of the shortage (e.g., the shortage amount, the duration of the constraint); and
    - That congestion price was more transparent and predictable for market participants.
    - Therefore, it is desirable to minimize the use of constraint relaxation.
- A default CRM value of 20 MW is used for most facilities regardless of their actual physical limits.
  - This is overly conservative for lower-voltage constraints, which leads to unnecessarily high congestion costs in these areas.
  - The NYISO recognized this issue and implemented revisions to its tariff to permit the use of non-zero CRM values less than 20 MW in December 2018.
    - A 10 MW CRM is currently used for modeled 115 kV transmission constraints in upstate New York, which represents roughly 5 to 7 percent of the average transfer capability of these 115 kV facilities.

- The default 20 MW CRM is still used for most facilities at voltage levels of 138 kV and above. On average, this was roughly: (see Table A-11)
  - 2 to 3 percent of the transfer capability of the 345 kV constrained facilities;
  - 4 to 5 percent of the transfer capability of the 230 kV constrained facilities; and
  - 7 to 9 percent of the transfer capability of the 138 kV constrained facilities.
  - However, factors that drive differences between physical flows and modeled flows, such as loop flows and imprecise PAR modeling, do not rise in this pattern at lower voltages.
- Higher CRMs are used for a small set of facilities to account for more uncertain loop flows and other un-modeled factors.
  - For example, a 50 MW CRM is used for the Dunwoodie-Shore Rd 345 kV line, which accounted for a significant portion of congestion on Long Island.
  - However, actual flows were frequently well below their operational limits (because of the high CRM) during periods of modeled congestion. The average shortage quantity was only 15 MW in 2018 and 17 MW in 2019 on the Dunwoodie-Shore Rd constraint, leading the GTDC to often over-value constraint violations. (see Table A-11)

- Therefore, despite overall improved market outcomes, at times constraint shadow prices still did not properly reflect the importance and severity of a transmission shortage.
  - In the long-term, we continue to recommend replacing the current transmission shortage pricing 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. [334]
  - In the short-term, the NYISO's proposed modifications to the GTDC would be a significant improvement over the current GTDC for at least two reasons. [335] First, the proposed GTDC would increase more gradually than the current GTDC, which is likely to reduce price volatility. Second, the MW-range of the proposed GTDC is based on the CRM of the constraint, which is a significant improvement over the current GTDC, which uses a 20-MW range regardless of the CRM value.
- 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. (see Figure A-86)

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334 Recommendation #2015-17 discusses how the NYISO should further enhance real-time scheduling models during periods of severe congestion.

335 See "Constraint Specific Transmission Shortage Pricing", by Kanchan Upadhyay, at November 21, 2019 MIWG meeting.

- The introduction of the NYISO's proposed 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-87: 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:

- 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.

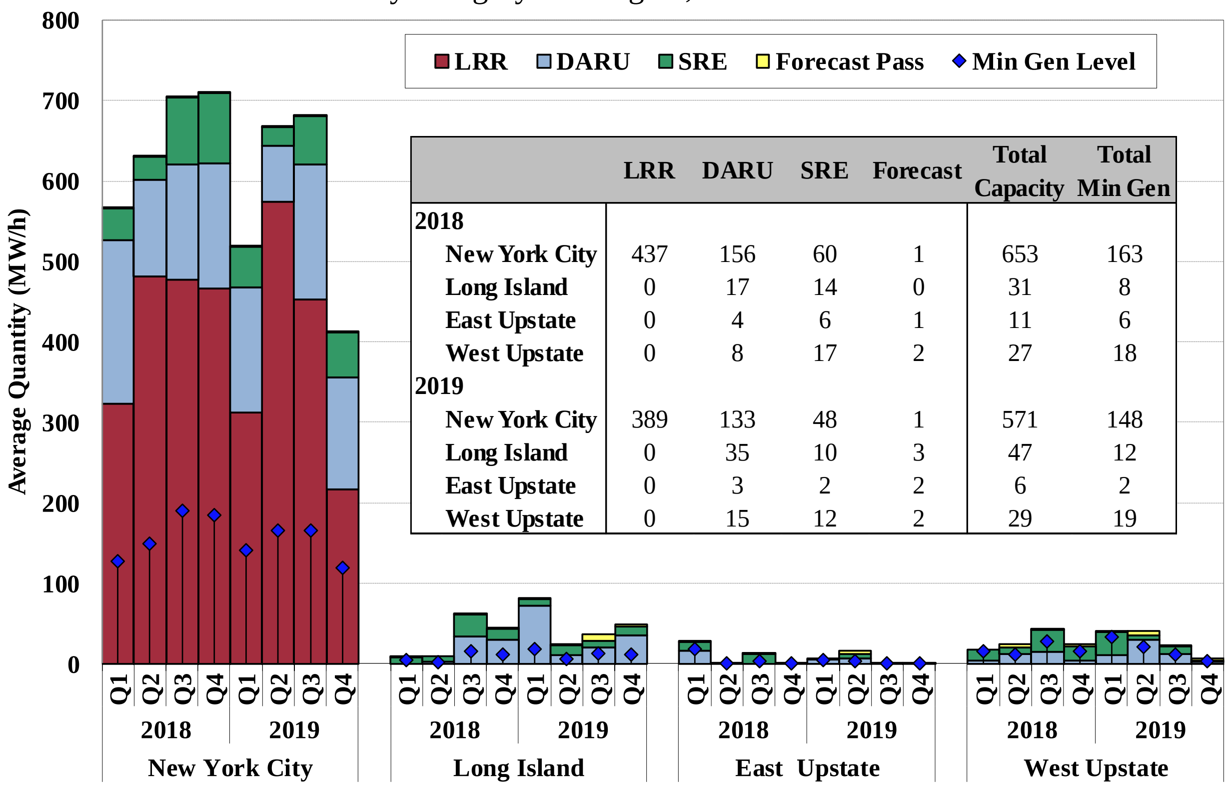
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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-87 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 2018 and 2019. 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 2018 and 2019 on an annual basis.

Figure A-87: Supplemental Commitment for Reliability in New York
By Category and Region, 2018 – 2019



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2018						
New York City	437	156	60	1	653	163
Long Island	0	17	14	0	31	8
East Upstate	0	4	6	1	11	6
West Upstate	0	8	17	2	27	18
2019						
New York City	389	133	48	1	571	148
Long Island	0	35	10	3	47	12
East Upstate	0	3	2	2	6	2
West Upstate	0	15	12	2	29	19

Figure A-88 & Figure A-89: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability typically occurred in New York City. Figure A-88 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-88 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2018 and 2019.

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: [336]

- N-1-1 – If needed for one or two of the following reasons:
    - Voltage Support – If needed for Application of Reliability Rule ("ARR") 26. This occurs when additional resources are needed to maintain voltage without shedding load in an N-1-1 scenario.
    - Thermal Support – If needed for ARR 37. This occurs when additional resources are needed to maintain flows below acceptable levels without shedding load in an N-1-1 scenario.
- NOx – If needed for the NOx bubble requirement. [337] 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.
- Loss of Gas – If needed to protect NYC against a sudden loss of gas supply and no other reason except NOx. [338]

In Figure A-88, for N-1-1 constraints, the capacity is shown for the load pocket that was secured, including:

- ERLP - East River Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket

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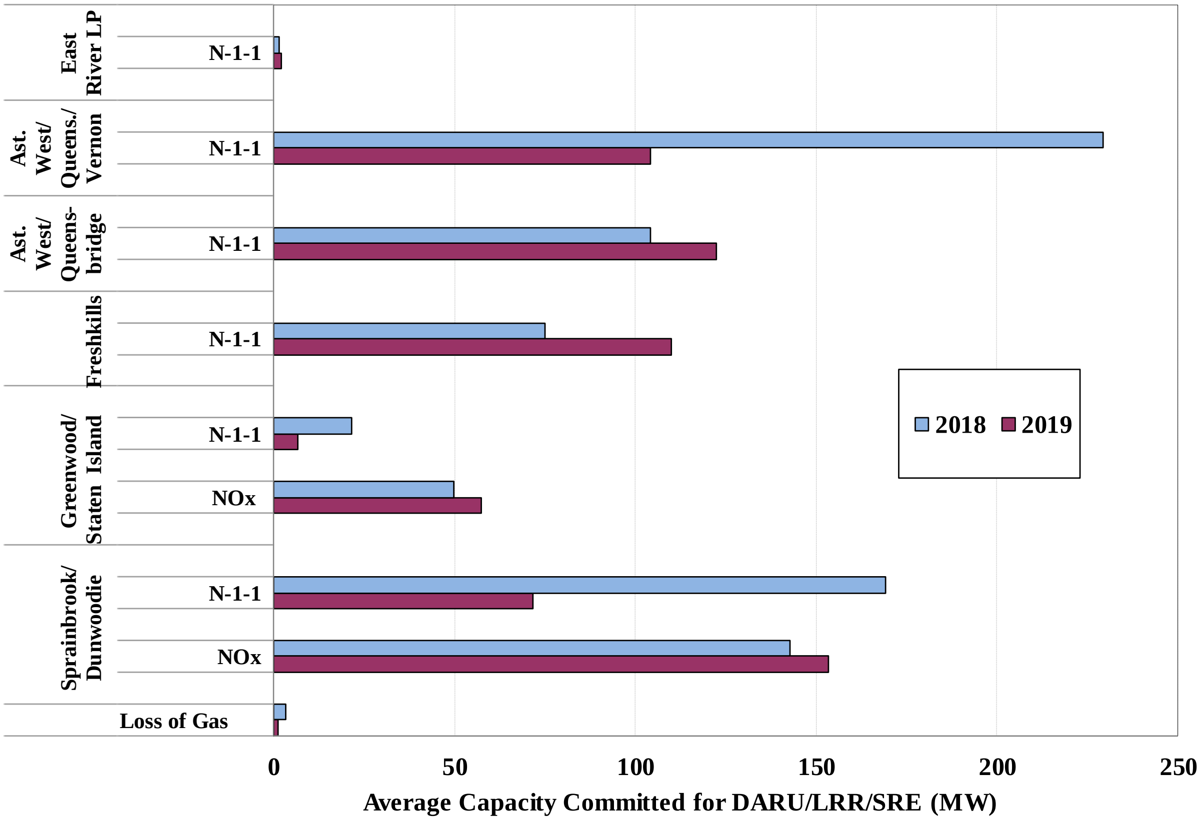
336 A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.

337 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.

338 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

Figure A-88: Supplemental Commitment for Reliability in New York City
By Category and Region, 2018 – 2019



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 service 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 2019 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-12 summarizes the results of this evaluation based on 2019 market results for four locations in New York City: (a) the 345kV network north of Staten Island; (b) the Astoria West/Queensbridge load pocket; (c) the Vernon location on the 138 kV network; and (d) the Greenwood/Staten Island load pocket. 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-12: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets
2019

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	**$1.38**
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	**$3.66**
Vernon	**$2.51**
Greenwood/Staten Is.	**$1.45**

Key Observations: Reliability Commitment

- Reliability commitment averaged roughly 650 MW in 2019, down 10 percent from 2018.
- The decrease occurred primarily in New York City, which accounted for 87 percent of total reliability commitment in 2019 and saw a reduction of 13 percent from a year ago.
  - Lower load levels reduced the need to commit generation for the N-1-1 thermal requirements in the New York City load pockets.
  - Gas prices fell more in New York City than in the rest of East New York, leading New York City generation to be more economic relative to the rest of East New York.
    - Accordingly, New York City units were flagged for reliability commitment less frequently in 2019 than in 2018.
  - In addition, the local needs were further reduced:
    - In the Sprainbrook/Dunwoodie Load Pocket because of fewer lengthy transmission outages in the 345 kV system; and
    - In the Astoria West/Queensbridge/Vernon load pocket because of fewer planned generation outages of combined-cycle units in the pocket.
  - However, reliability commitment in the Freshkills load pocket rose modestly as a result of additional needs identified by ConEd for the Winter 2018/19 period.
    - Updated study by Con Ed for the Winter 2019/20 period showed no more such local need.
  - 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 $1.38/MWh in most areas to as much as $3.66/MWh in the Astoria West/Queensbridge load pocket in 2019.
  - We have recommended the NYISO model local reserve requirements in New York City load pockets.[339]
    - The More Granular Operating Reserves project is currently underway in the NYISO, which has proposed to model explicit 30-minute reserve requirements in the market software for the following three load pockets: (a) Astoria East/Corona/Jamaica; (b) Astoria West/Queensbridge/Vernon; and (c) Greenwood/Staten Island.
- Reliability comments in other areas were relatively infrequent in 2019.
  - DARU commitment in Long Island rose modestly in the first quarter of 2019 for reliability and congestion management on the 69 kV network.

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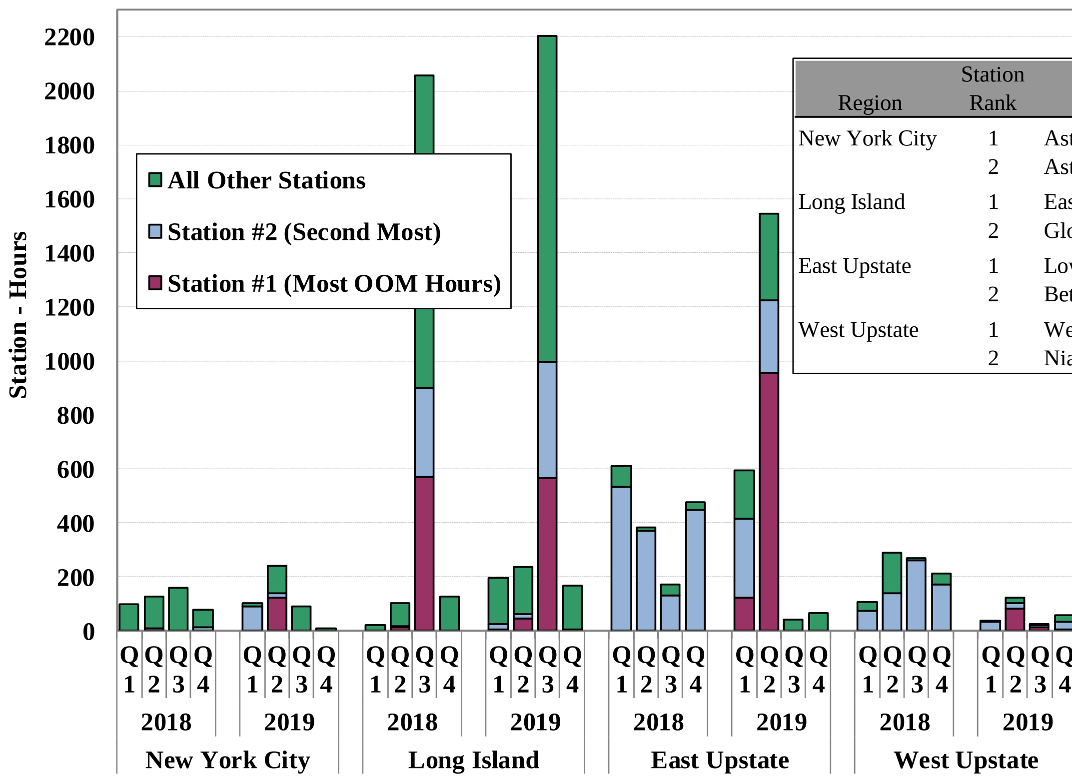
339 See Recommendation #2017-1.

Figure A-89: Frequency of Out-of-Merit Dispatch

Figure A-89 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2018 and 2019 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 2019 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2019, 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-89: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2018 - 2019



Region	Station Rank	Station Name
New York City	1	Astoria Energy CC
	2	Astoria Steam
Long Island	1	East Hampton GT
	2	Global Greenport
East Upstate	1	Lower Hudson
	2	Bethlehem
West Upstate	1	West Canada Hydro
	2	Niagara

Key Observations: OOM Dispatch [340]

- Generators were dispatched Out-of-Merit ("OOM") for roughly 5,720 station-hours in 2019, up 8 percent from 2018.

340 A detailed evaluation of the actions used to manage low-voltage network congestion in New York is provided in Appendix Section III.C.

- OOM levels were highest on Long Island, accounting for nearly 50 percent of all OOM actions in 2019.
    - Most of the OOM actions occurred in the summer months when high-cost peaking resources were frequently needed out-of-merit to manage congestion on the 69 kV network and voltage needs on the East End of Long Island during high load conditions.
        - We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets. (see Recommendation #2018-1)
- The Bethlehem units used to be the primary OOM resource in the East Upstate region, which were frequently needed to manage post-contingency flow on the Albany-Greenbush 115 kV facility.
    - However, this need has been greatly reduced with the completion of transmission upgrades in mid-2019.
    - In the second quarter of 2019, the Lower Hudson hydro unit was frequently OOMed down to manage post-contingency flow on the School St-Newark St 34.5 kV line.
- OOM levels in Western New York continued to fall in 2019 because most 115 kV facilities that were previously managed by OOM actions have been managed by the market models since December 2018.

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-90 and Figure A-91 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-90 & Figure A-91: Uplift Costs from Guarantee Payments

Figure A-90 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2018 and 2019. 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-91 shows the seven categories of uplift charges on a quarterly basis in 2018 and 2019 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.

Figure A-90: Uplift Costs from Guarantee Payments by Month
2018 – 2019

Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2019	$24	$13	$1	$0	$4	$7	$2	$0	$52
2018	$31	$15	$2	$6	$4	$9	$9	$2	$77

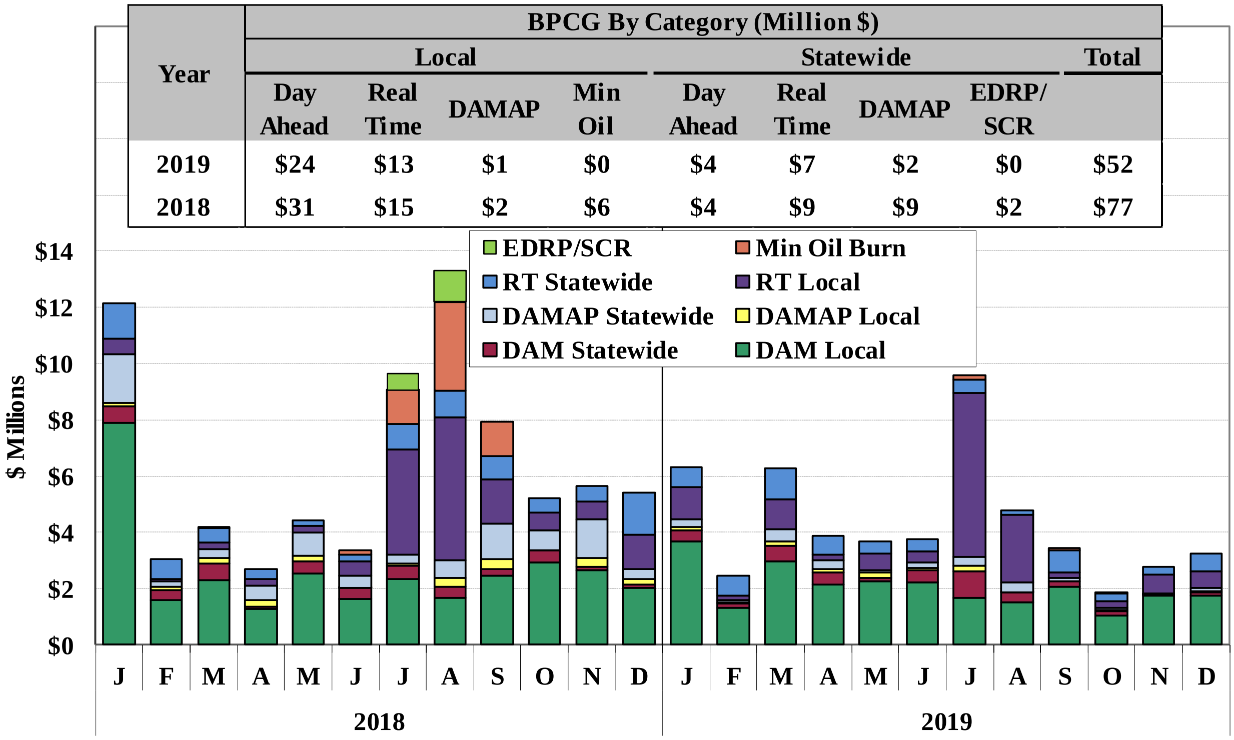
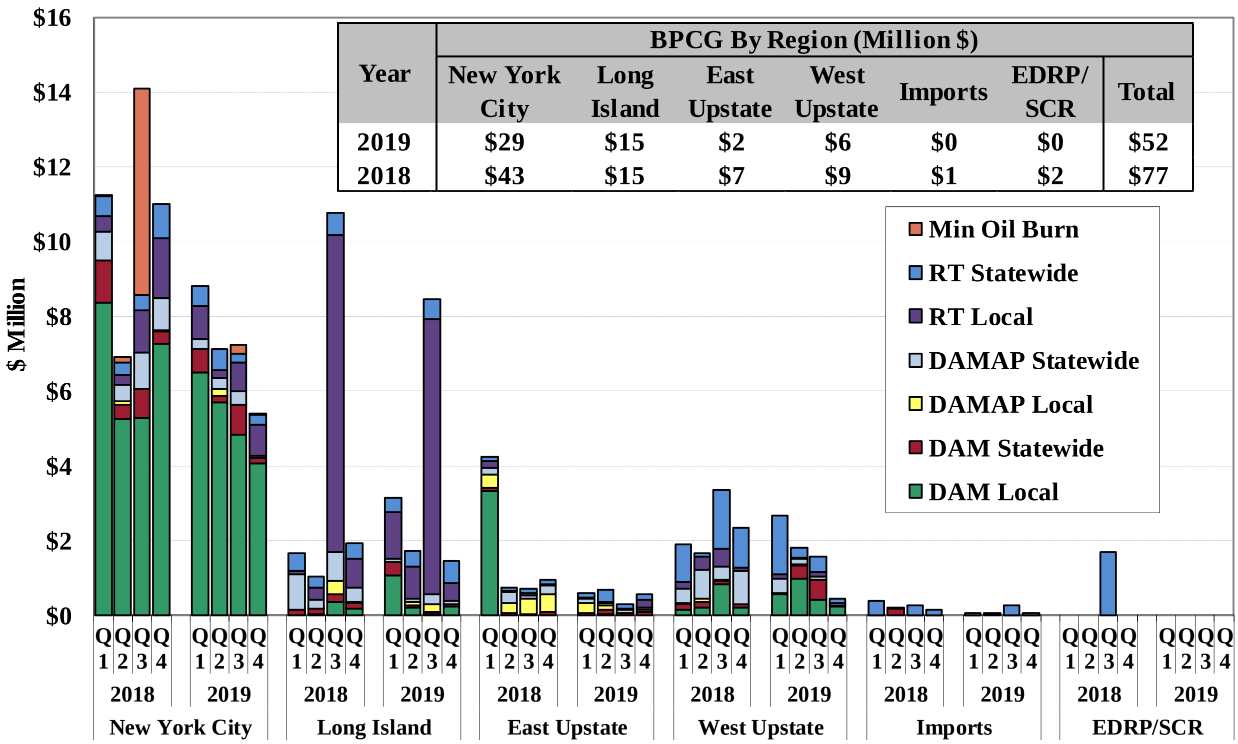


Figure A-91: Uplift Costs from Guarantee Payments by Region
2018 – 2019

Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2019	$29	$15	$2	$6	$0	$0	$52
2018	$43	$15	$7	$9	$1	$2	$77



It is also noted that Figure A-90 and Figure A-91 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.

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell 32 percent from $77 million in 2018 to $52 million in 2019. This was driven by:
  - Decreased supplemental commitments in New York City (for the reasons discussed earlier);
  - Lower gas prices, which decreased the commitment costs of gas-fired units; and
  - Lower load levels in the summer months, which reduced the Min Oil Burn need for this period and did not require demand response activation as well.
- New York City accounted for $29 million (or 55 percent) of BPCG in 2019.
  - Over $21 million were paid to generators committed for N-1-1 local requirements.
    - We have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals. [341]
- Long Island accounted for $15 million (or 28 percent) of BPCG in 2019.
  - Nearly $10 million of BPCG uplift accrued on high-cost peaking resources on Long Island when OOMed to manage 69 kV congestion and local voltage needs.
    - We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets. [342]

341 See Recommendation #2017-1.

342 See Recommendation #2018-2.

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.[343] 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.[344]

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.[345] The amount of UCAP

343 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 17 percent in the most recent Capability Year (i.e., the period from May 2019 to April 2020). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

344 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 103.5 percent from May 2018 to April 2019 and 104.1 percent from May 2019 to April 2020. The New York City LCR was 80.5 percent from May 2018 to April 2019 and 82.8 percent from May 2019 to April 2020. The LCR for the G-J Locality was set at 94.5 percent from May 2018 to April 2019 and 92.3 percent from May 2019 to April 2020. 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 "https://www.nyiso.com/documents/20142/3056465/LCR2018_Report.pdf/249964c0-9ea9-c6ee-c265-435d0290aff7".

345 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: [346]

- 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.[347] 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);

- Cost of improving reliability from additional capacity by zone (sub-section F); and

346 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2018/2019 and 2019/2020 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 "https://www.nyiso.com/documents/20142/1399473/Demand-Curve-UCAP-translation-Summer-2018.pdf/37e5aeca-d825-fa4a-be34-d30fe8f503c7".

347 Before the 2016 demand curve reset, demand curves were reset every three years rather than four. Past Demand Curve Reset studies may be found at: "https://www.nyiso.com/installed-capacity-market".

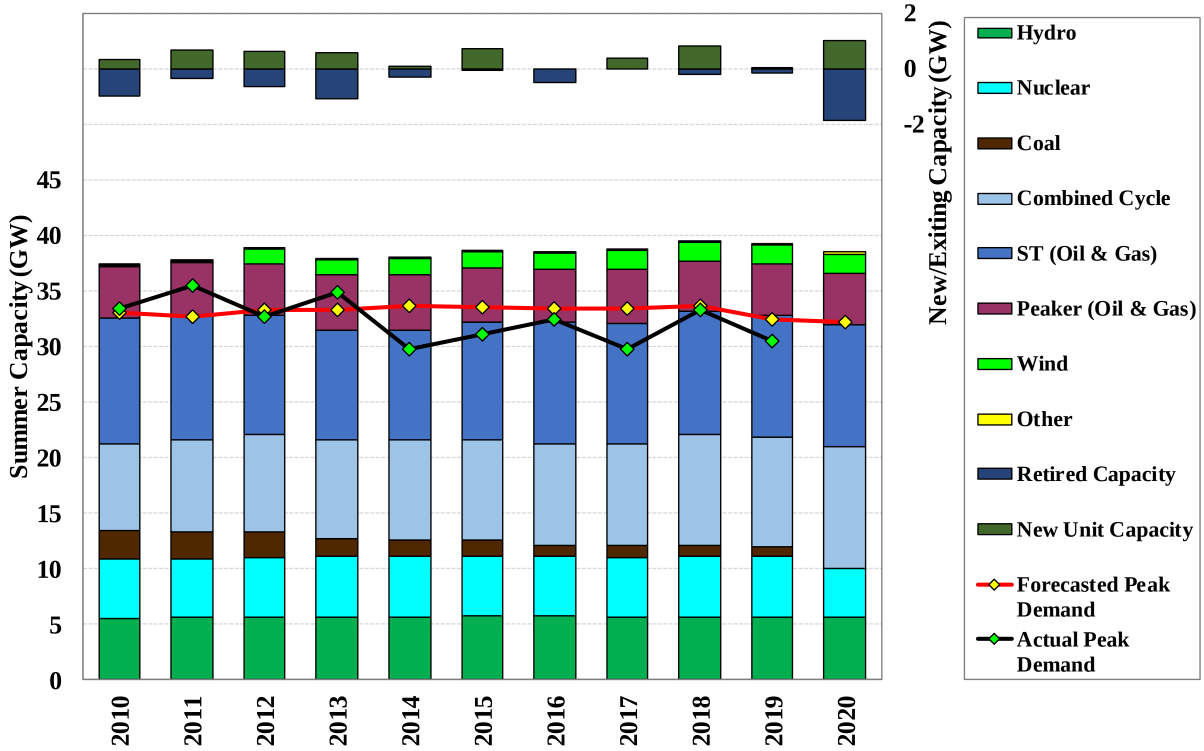
- The need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section G).

A. Installed Capacity of Generators in NYCA

Figure A-92 - Figure A-93: Installed Summer Capacity and Forecasted Peak Demand

The bottom panel of Figure A-92 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 2010 through 2020.[348, 349] The top panel of Figure A-92 shows the amount of capacity that entered or exited the market during each year.[350]

Figure A-92: Installed Summer Capacity of Generation by Prime Mover
2010 - 2020



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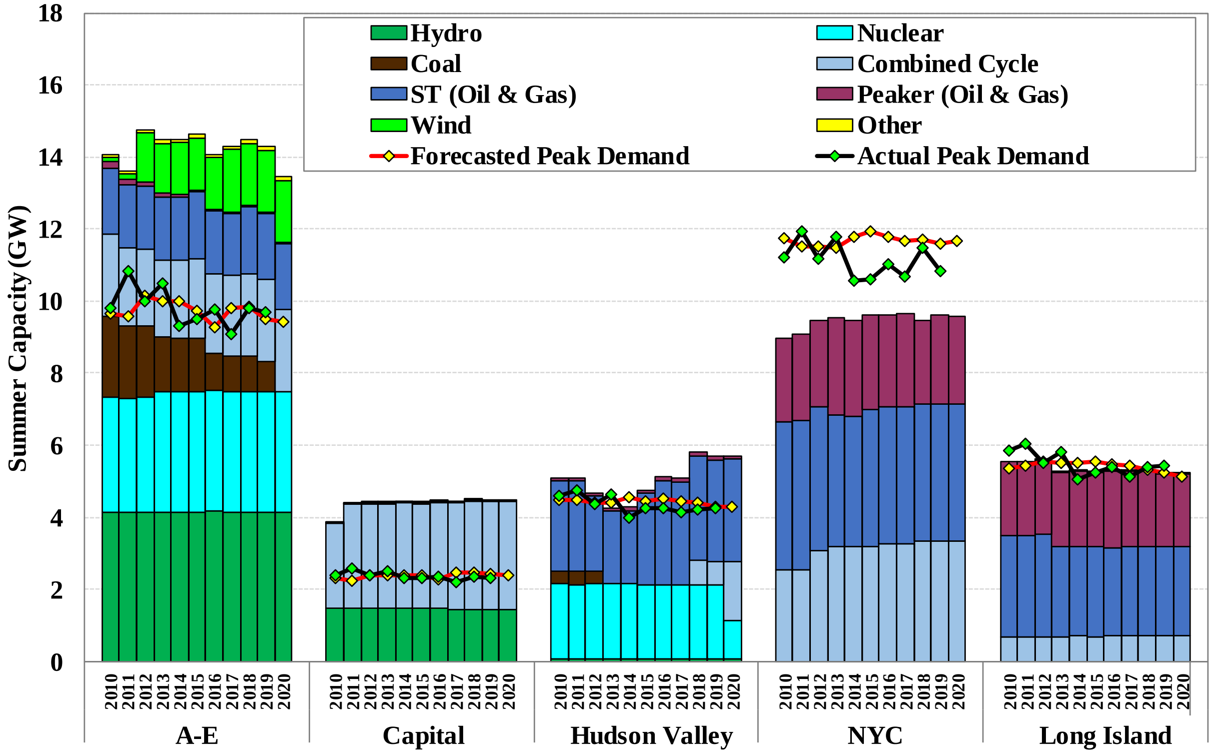
348 The forecasted peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. Capacity is based on the Gold Book and Generator Status Update files available at: https://www.nyiso.com/documents/20142/2226333/2018-Load-Capacity-Data-Report-Gold-Book.pdf/7014d670-2896-e729-0992-be44eb935cc2.

349 In this report, we have reconstituted the historic coincident and non-coincident peak demand values in both Figure A-92 and Figure A-93 to include the demand reductions achieved through NYISO and Utility-based activation of Demand Resources ("DR") on the peak load days. Thus, these numbers may differ from published values during years in which DR was activated to reduce the peak demand.

350 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-93 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-93: Installed Summer Capacity of Generation by Region and by Prime Mover
2010 – 2020



Key Observations: Installed Capacity in NYISO

- The total generating capacity in the NYISO remained relatively flat between 37.5 and 39.5 GW (summer) between 2010 and 2020.
  - However, since 2010, more than 4 GW of capacity has left the market either through retirement, mothball, or ICAP-Ineligible Forced Outage with another 2 GW of capacity slated to leave the market prior to Summer 2020.
  - In the same timeframe, roughly 4 GW of capacity has entered the market as new resources or units returning from a mothball status. Another 1 GW is expected to begin operations by the beginning of Summer 2020 bringing the total new generation capacity up to 5 GW.
  - The 2019 capacity mix in New York was predominantly gas and oil resources (65 percent) while the remainder is primarily hydro and nuclear (each 14 percent).

  - While these percentages have held more or less constant for the past few years, announced entry and retirements of certain units is expected to shift the share of for gas and oil generation up (69 percent) and nuclear down (11 percent) in 2020.

- Most new generation investment since 2010 has been in the form of natural gas-fired power plants, especially combined cycle units east of the Central-East Interface.
  - Combined cycle capacity has increased by roughly 2.1 GW between 2010 and 2019. Major unit additions include the Empire (Capital zone), Astoria Energy II (New York City), and CPV Valley (Hudson Valley) facilities that commenced commercial operations between 2010 and 2018. In addition, the Cricket Valley combined cycle unit is expected be online by Summer 2020 adding another roughly 1 GW of summer installed capacity in the Hudson Valley.
  - In addition, Some new investment has occurred in the form of dual-fuel peaking resources as well, specifically with the Bayonne I and II projects in New York City. Total peaking capacity, however, in the state has decreased slightly (100 MW) from 2010 to 2019 because the exit of older, less-fuel-efficient peakers (such as several Ravenswood GTs) has outpaced entry of newer, more-efficient resources (such as the Bayonne units).
- Additional investments in the resource mix have come predominantly from renewable resources, especially in wind resources upstate.
  - Policies promoting renewable energy have motivated investment in new onshore wind units, adding nearly 2 GW of nameplate capacity to the state resource mix. Most of this capacity is located in zones A-E, with significant amounts of additional onshore wind and solar PV capacity projected to enter as the procurement of Tier1 Renewable Energy Credits accelerates under the Clean Energy Standard. [351]
  - In addition, the State has also initiated procurements that are likely to result in the addition of several GW of battery storage and offshore wind projects in the near term.
- 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. These factors will also result in the retirement of several old gas turbine units, and both units at the Indian Point nuclear plant.
  - The capacity associated with coal units has shrunk from nearly 3 GW in 2009 to less than 1 GW from two resources heading into 2019, a 64 percent decrease.[352] Since then, one of those stations (Milliken 1) has entered an IIFO and the only remaining coal unit (Kintigh) has submitted a notice to retire the plant ahead of the Summer

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351 See Section VII.C of the Appendix for the contribution of federal and state incentives to the net revenues of renewable units in New York.

352 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 a coal-fired resource to a natural gas-fired plant.

2020 Capability Period. Thus, the contribution of coal to the state's ICAP mix is anticipated to be 0 MW in Summer 2020.

- An agreement between the asset owners of the Indian Point nuclear facility and the State has resulted in the decision to retire both of the reactors, one in 2020 and the other in 2021. Thus, we expect to see a reduction in nuclear capacity of roughly 1 GW by Summer 2020.[353]
- The DEC peaker rule may require large additional expenditures for GTs to continue operations, and could result in retirement of many units in downstate areas.
- Other notable retirements in the last decade 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-93, 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.

    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-94: NYISO Capacity Imports and Exports by Interface

Figure A-94 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2007/08 through Winter 2019/20 along with capacity prices in the New York Control Area and its neighboring control areas, including Hydro Quebec ("HQ"), Ontario ("OH"), PJM, and ISO-NE. The capacity imported from each region is shown by the positive value stacked bars, while the capacity exported from 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.

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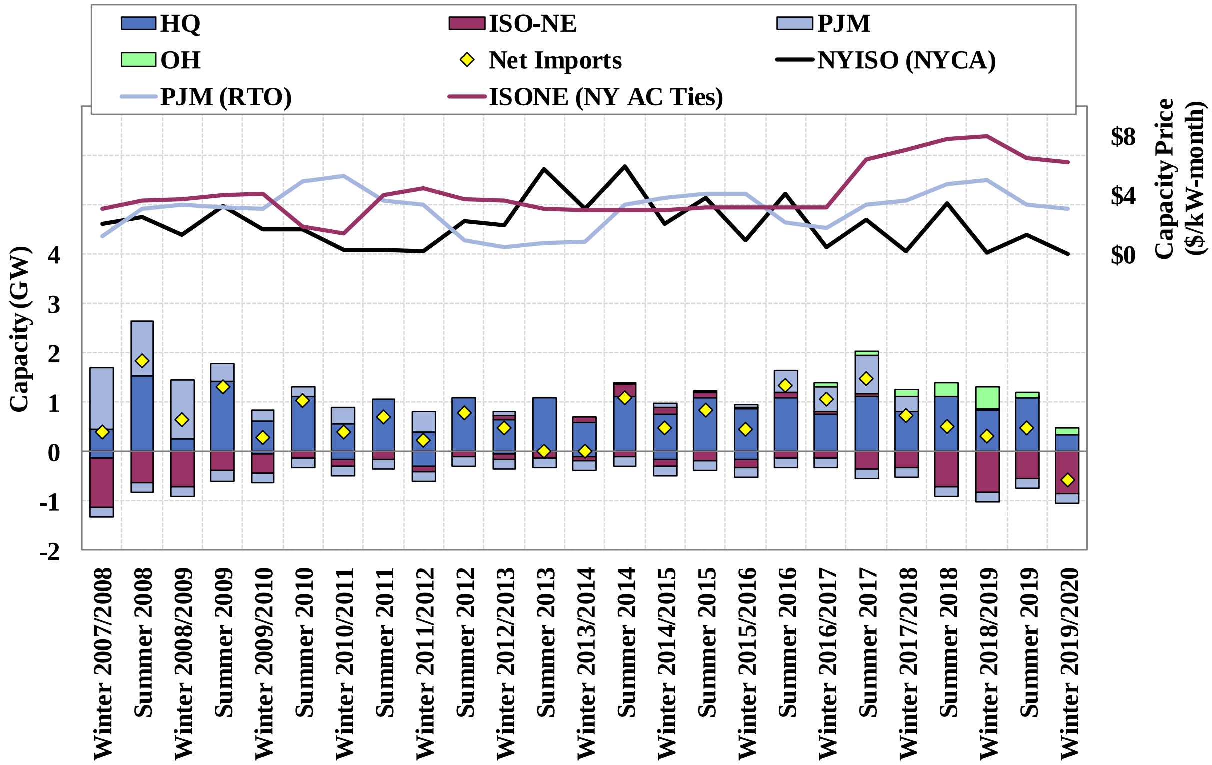
353 Entergy announced on Jan 9, 2017 its intent to close the Indian Point nuclear units in 2020 and 2021. See: "www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/".

Figure A-94: NYISO Capacity Imports and Exports by Interface
Winter 2007/08– Winter 2019/20



Key Observations: Capacity Imports and Exports

- Net capacity imports have fluctuated over the years, and are a function of several factors that include price differences between control areas and seasonal constraints.
- 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.
- Imports from PJM historically constituted the second largest source of external capacity into the NYISO, though this has not been the case in recent years.
  - 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.[354]

354 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.

- Imports from PJM increased considerably during the 2016/17 and the 2017/18 Capability Years, and averaged roughly 440 MW and 780 MW in the summer capability periods for 2016 and 2017, respectively. Much of that change was likely driven by regional price differences and the low cost of selling capacity into NYCA.
- In 2018, the NYISO implemented changes to its Tariff requiring external resources seeking to sell capacity in NYISO along the PJM AC-Interface to acquire firm transmission rights. Consequently, capacity imports from PJM fell to an average of just 5.7 MW in the 2018/19 Capability Year and dropped to 0 MW for the 2019/2020 Capability Year (through January 2020).[355, 356]

- Capacity exports to ISO-NE increased significantly inrecent years, with 600 MW to 850 MW sold over the NY-NE AC Ties.
  - Retirements in New England and structural changes to the Forward Capacity Auctions (e.g. sloped demand curves) have yielded much higher capacity prices since Summer 2017. These factors coupled with the persistent surplus conditions in the ROS regions of the NYISO, resulted in substantial amounts of New York capacity were exported to ISO-NE during the 2018/2019 and 2019/2020 Capability Years.

- 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 increase in ICAP import rights.[357]
  - The Summer 2019 Capability Period witnessed over 50 percent reduction in capacity imports from the IESO to the NYISO. This was due to a reduction in the amount of External CRIS Rights determined by the NYISO for the Ontario interface.[358]

C. Derating Factors and Equivalent Forced Outage Rates

The UCAP of a resource is equal to its installed capacity adjusted to reflect its expected availability, 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) with the same installed capacity. For example, a unit with 100 MW of tested capacity

355 The changes to requirements of external capacity suppliers are outlined in §4.9.3 of the NYISO ICAP Manual. See https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

356 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.

357 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.

358 See External Rights Availability by interface and by Capability Period at nyiso.com/installed-capacity-market.

and an EFORd of 7 percent would be able to sell 93 MW of UCAP. [359] This gives suppliers a strong incentive to perform reliably.

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.[360]

Table A-13: Historic Derating Factors by Locality

Table A-13 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2015 onwards.

Table A-13: Derating Factors by Locality
Summer 2015 – Winter 2019/20

Locality	Summer 2019	Summer 2018	Summer 2017	Summer 2016	Summer 2015	Winter 2019/20	Winter 2018/19	Winter 2017/18	Winter 2016/17	Winter 2015/16
G-I	7.15%	4.92%	12.70%	5.00%	3.40%	6.87%	6.45%	11.72%	6.46%	4.24%
LI	6.47%	6.28%	5.60%	7.27%	7.83%	7.96%	6.90%	6.07%	6.36%	9.02%
NYC	4.09%	7.09%	4.37%	9.53%	6.92%	4.42%	5.98%	5.26%	5.44%	10.49%
A-F	12.50%	11.15%	11.94%	11.61%	10.94%	10.26%	8.93%	9.83%	8.64%	9.55%
NYCA	8.79%	8.56%	9.29%	9.61%	8.54%	8.00%	7.57%	8.43%	7.25%	9.06%

Key Observations: Equivalent Forced Outage Rates

- The NYCA-wide Derating Factor increased (i.e., worsened) from Summer 2018 to Summer 2019 (by 0.23 percentage points) and from Winter 2018/19 to the Winter 2019/20 Capability Period (by 0.43 percentage points).
  - The change in NYCA-wide summer and winter Derating Factors can largely be attributed to increased EFORd ratings of certain larger steam generators offsetting reductions to EFORds of the remaining units.
- The Derating Factor for Zones A-F is generally higher than observed in other zones.
  - As shown in Figure A-93, nearly 10 percent of the installed generating facilities located in Zones A-F are intermittent in nature. Consequently, the average EFORd of capacity resources located in Zones A-F is higher than the average EFORd for other zones, where the resources are predominantly gas, oil-fired, or nuclear units.

359 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

360 The Derating Factor used in each six-month capability period for each Locality may be found at: "https://www.nyiso.com/installed-capacity-market."

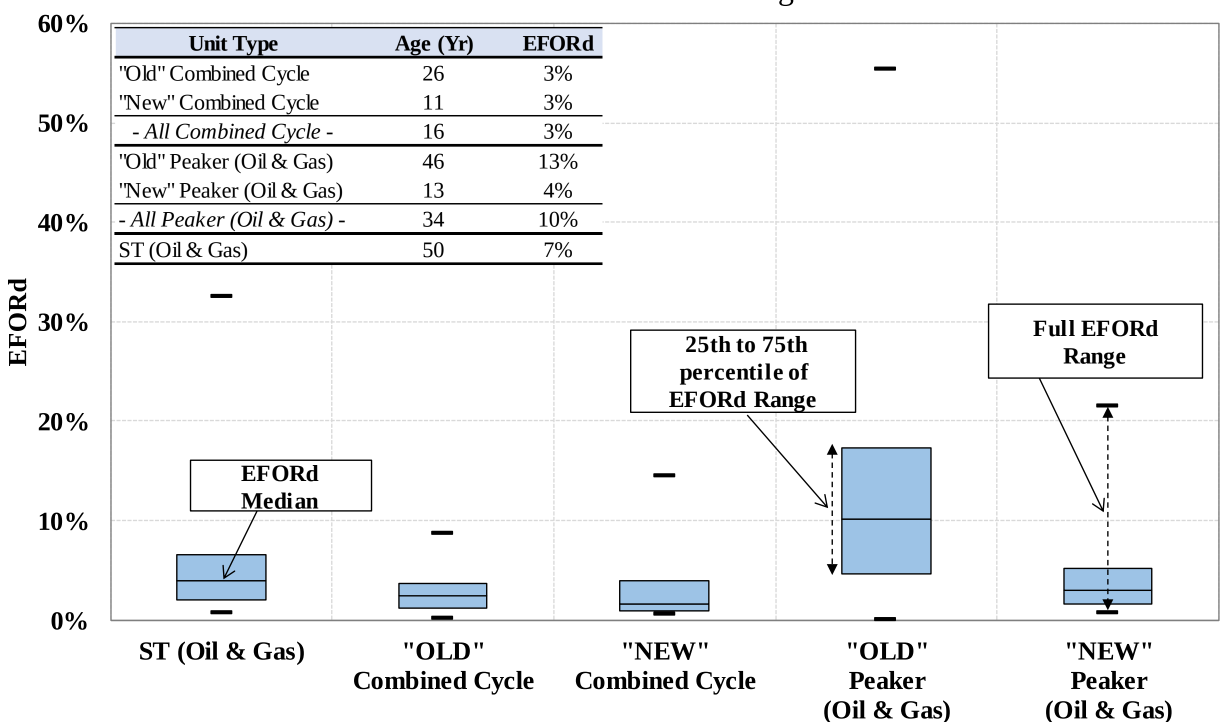
- The NYC Derating Factor is prone to considerable swings from one year to the next based on the performance of its old generation fleet. Although over 2 GW of relatively new gas-fired capacity is interconnected in this zone, it also contains several old peaking units which run for very few hours and can be prone to outages and large changes in EFORd. Additionally, extended outages on any of the large units in-city can cause fairly drastic swings in the derating factors year-over-year.

Figure A-95: Gas and Oil-Fired EFORds by Technology Type and Region

Figure A-95 presents the distribution of EFORds of natural gas and oil-fired units based on technology type and age designation.[361] 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 specified capacity type. 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-95: EFORd of Gas and Oil-fired Generation by Age

Summer – Five-Year Average



Unit Type	Age (Yr)	EFORd
"Old" Combined Cycle	26	3%
"New" Combined Cycle	11	3%
- All Combined Cycle -	16	3%
"Old" Peaker (Oil & Gas)	46	13%
"New" Peaker (Oil & Gas)	13	4%
- All Peaker (Oil & Gas) -	34	10%
ST (Oil & Gas)	50	7%

361 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-95, the distribution of EFORds varies considerably by technology-type and unit age. Units that are new 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. Newer combined cycle units also display the least variation in EFORd values of all technology-age categories.

- 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 about one year to over 50 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-96: Capacity Sales and Prices in NYCA

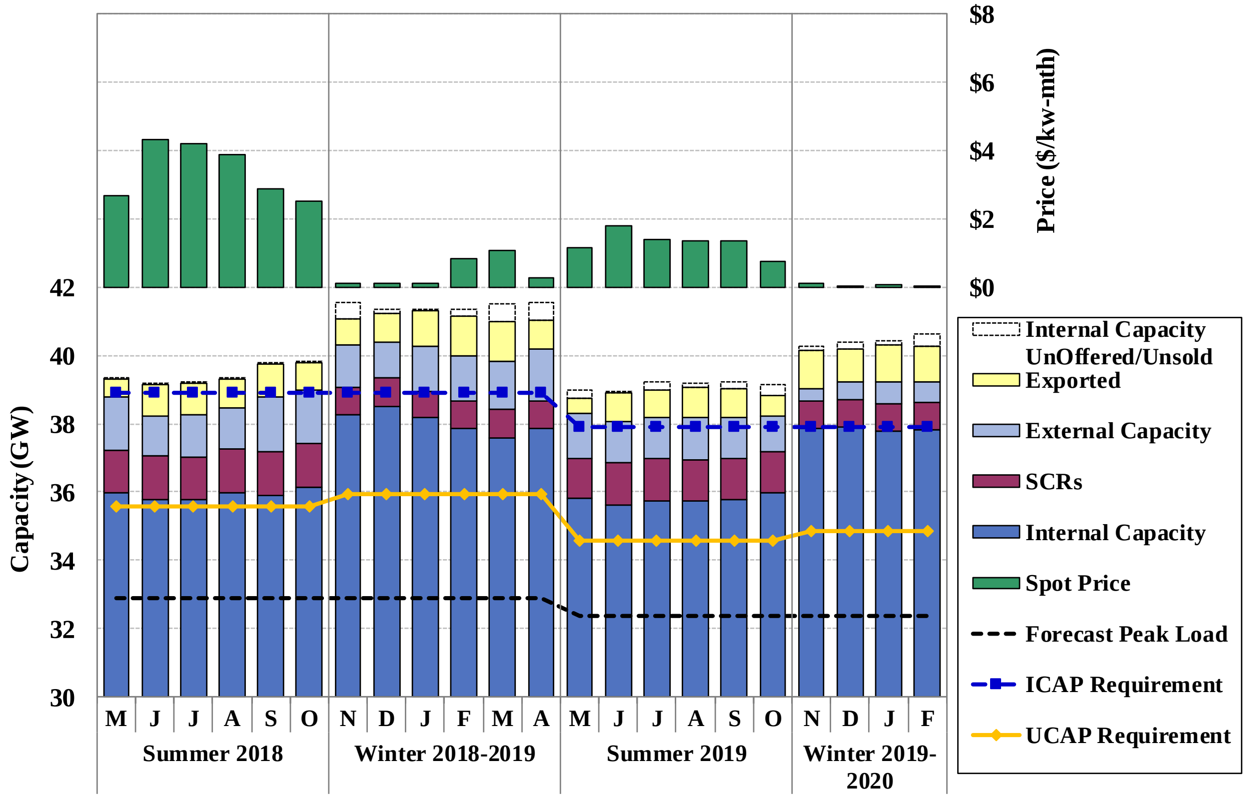
Figure A-96 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights (“UDRs”) and sales from SCRs.[362] The hollow portion of each bar represents the In-State capacity in each region not sold

362 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

(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-96 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-96 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-96 also shows the forecasted peak load and the ICAP requirements.

Figure A-96: UCAP Sales and Prices in NYCA
May 2018 to February 2020



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

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.

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 sharply in Rest of State in the 2019/20 Capability Year from the prior year.
  - The spot price averaged $1.30/kW-month in the Summer 2019 Capability Period, which was down 62 percent from the prior summer, and $0.06/kW-month in the 2019/20 Winter Capability Period, which was down 80 percent from the prior winter.
  - A key driver of the year-over-year drop in prices was the reduction in the ICAP requirement of 1,002 MW from the 2018/19 Capability Year. This was caused by:
    - The peak demand forecast for the NYCA fell by nearly 520 MW from the prior year; and
    - The IRM fell from 18.2 percent in Capability Year 2018/19 to 17 percent in 2019/20. This coincided with an increase in the LCR for Zone J (which is discussed in the next subsection). Since generation in Zone J is more deliverable to load customers, increasing the amount of capacity in Zone J tends to reduce the overall amount of capacity needed in NYCA.
  - During the 2019 Summer Capability Period, the total imports from external control areas fell by an average of 180 MW, although this was partially offset by a 100 MW reduction in exports from NYCA to neighboring regions. The small decrease in net imports helped mitigate the price drop to some extent.
  - Although prices during the 2018/19 Winter Capability Period were low, the prices in 2019/20 fell even further on account of a continued large surplus of installed capacity. The UCAP margin in the winter has averaged above 111 percent, which is close to the Zero Crossing Point ("ZCP") of the NYCA demand curve.

- The UCAP Requirement fell 1,004 MW in the Summer Capability Period and 704 MW in the Winter Capability Period because of the year-over-year increase in Derating Factors. [363]
  - 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.

[363] ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2019 Summer and 2019/20 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.

- 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-97 - Figure A-99: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-97 to Figure A-99 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-96 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-97: UCAP Sales and Prices in New York City
May 2018 to February 2020

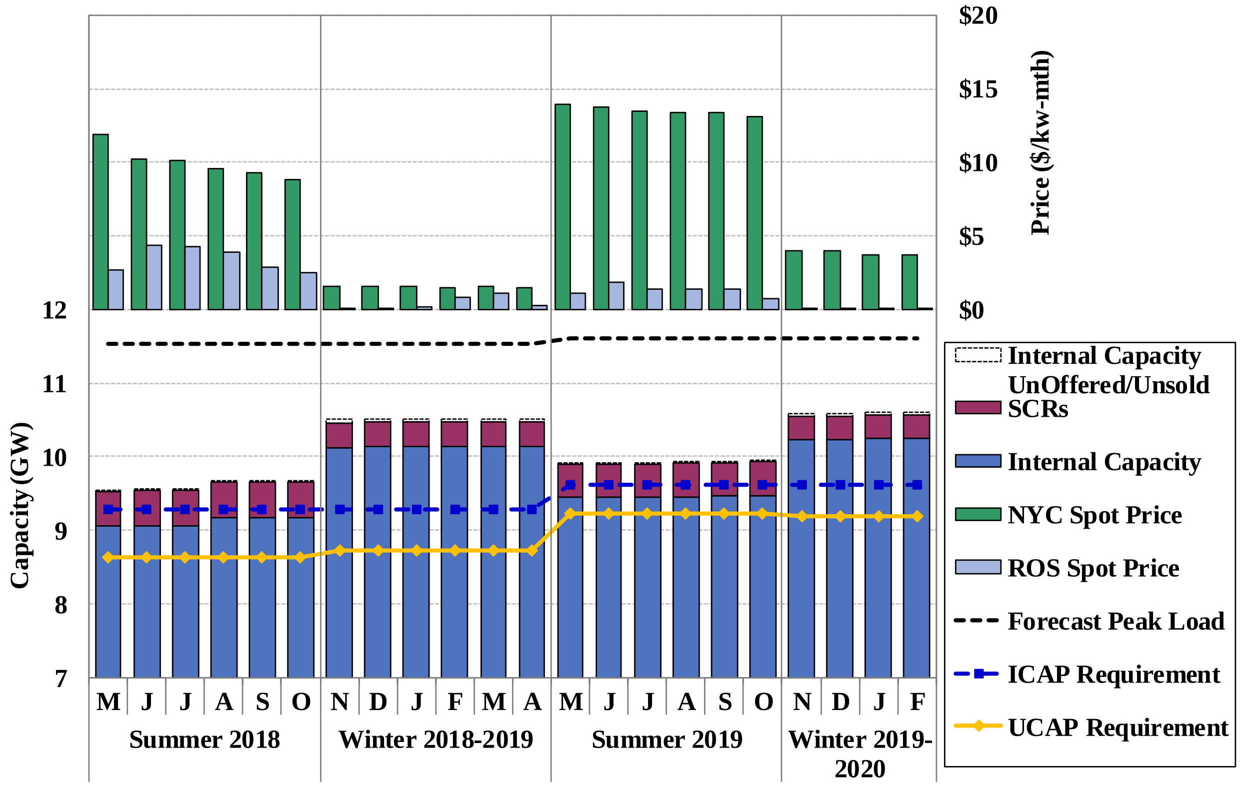


Figure A-98: UCAP Sales and Prices in Long Island
May 2018 to February 2020

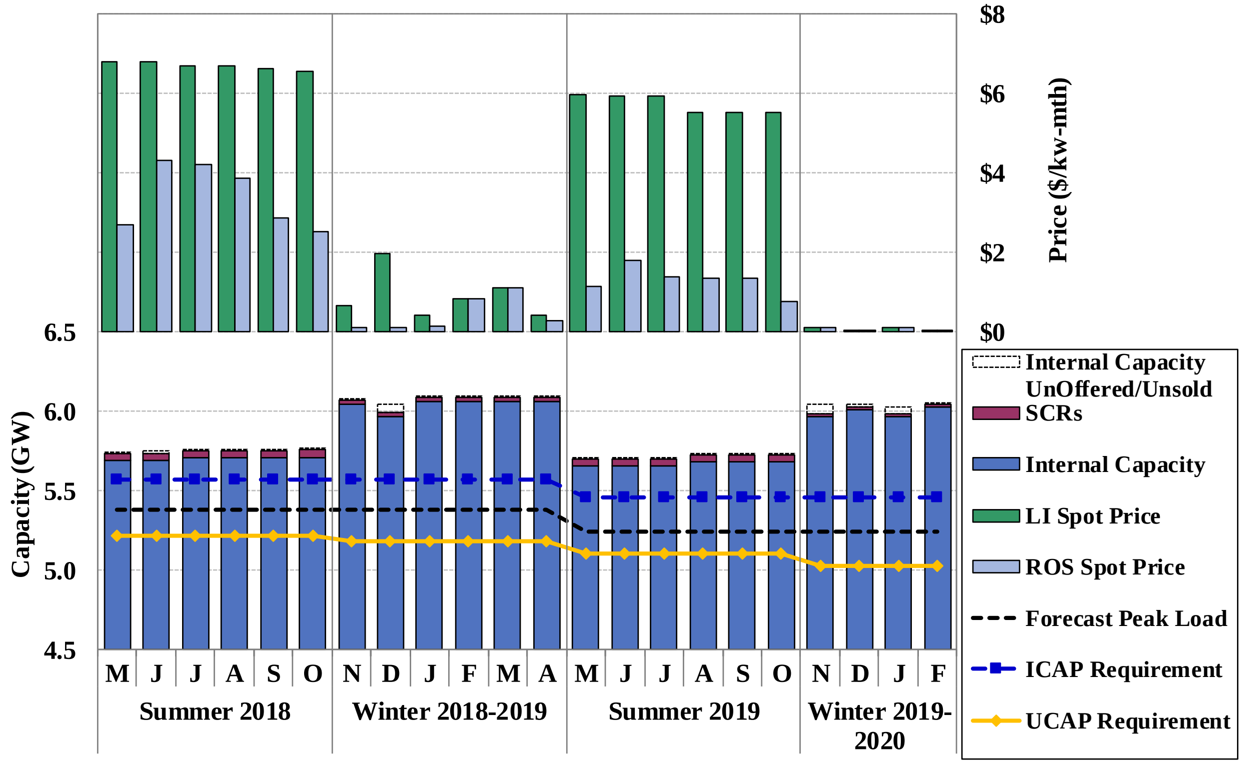
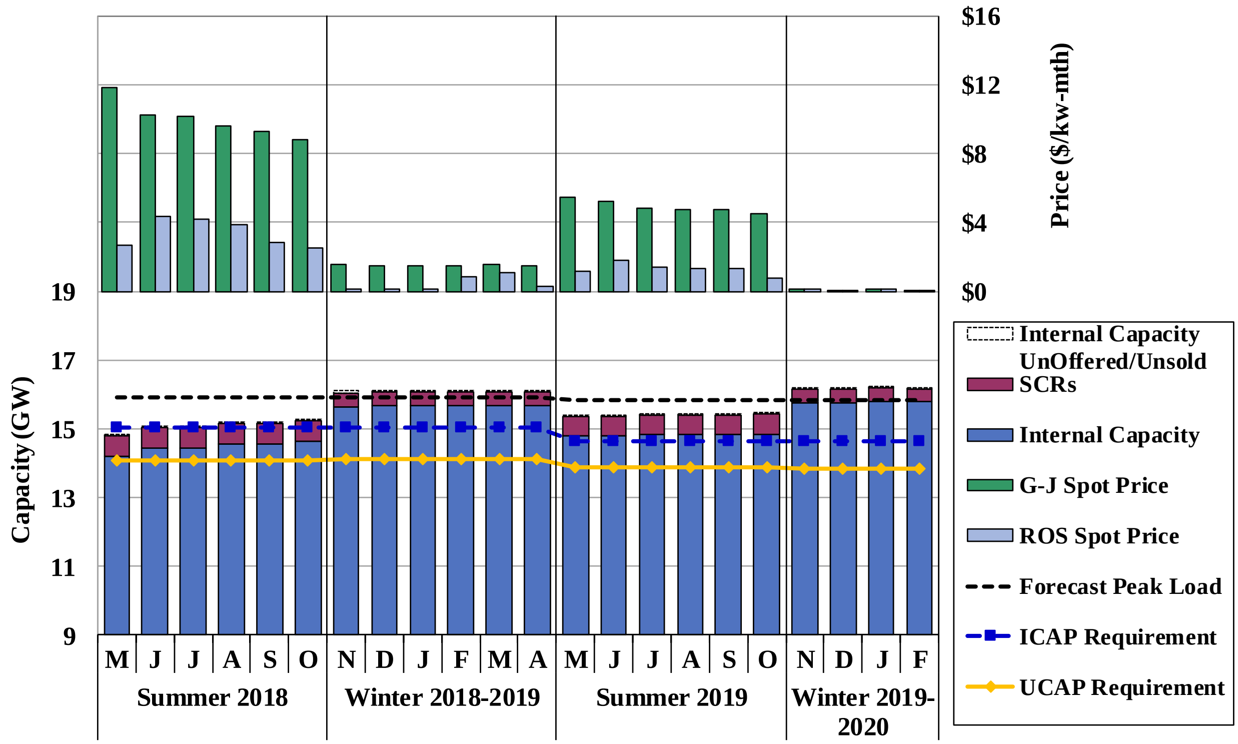


Figure A-99: UCAP Sales and Prices in the G-J Locality
May 2018 to February 2020



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.

- The Summer and Winter UCAP spot prices changed substantially in the three eastern capacity zones during the 2019/20 Capability Year from the prior year. Specifically:

  - New York City spot prices rose: (a) 35 percent to an average of $13.50/kW-month in the 2019 Summer Capability Period; and (b) 151 percent to an average of $3.86/kW-month in the 2019/20 Winter Capability Period.

  - Long Island spot prices fell: (a) 14 percent to an average of $5.74/kW-month in the 2019 Summer Capability Period; and (b) 94 percent to an average of $0.06/kW-month in the 2019/20 Winter Capability Period.

  - The G-J Locality spot prices fell: (a) 51 percent to an average of $4.93/kW-month in the 2019 Summer Capability Period; and (b) decreased 96 percent to an average of $0.06/kW-month in the 2019/20 Winter Capability Period.

- Spot auction prices rose in New York City (as opposed to falling everywhere else) due to a sharp increase in the LCR from 80.5 percent to 82.8 percent. Additionally, the NYC peak demand forecast increased by roughly 70 MW.

- The spot prices fell in Long Island because:

  - Although the LCR increased year-over-year from 103.5 percent to 104.1 percent, the load forecast fell by more than 135 MW. Thus, the ICAP Requirement on Long Island fell by about 109 MW.

  - The capacity surplus on Long Island exceeded the ZCP of the demand curve during the 2019/20 Winter Capability Period. Hence, the prices on Long Island were determined by the NYCA demand curve.

- The spot prices in the G-J Locality fell dramatically due to:

  - The LCR in G-J fell by 2.2 percentage points while the load forecast fell by roughly 72 MW. Consequently, the ICAP requirement in this region fell by 417 MW from the previous Capability Year.

  - The amount of installed capacity did not change significantly, but some large resources achieved much better EFORd ratings in 2019, resulting in higher UCAP supply in the Hudson Valley.

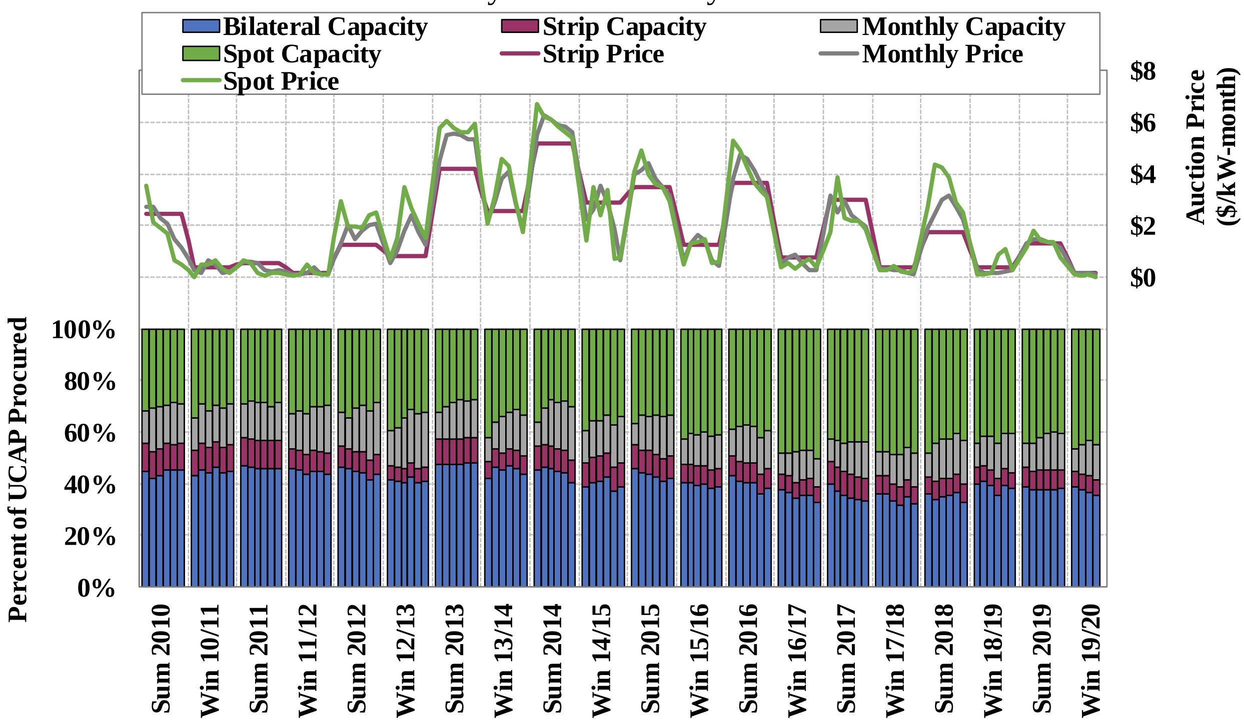
  - Like Long Island, excess supply during the Winter Capability Period led to a surplus level that exceeded the ZCP of the G-J demand curve. Thus, G-J cleared at the NYCA-wide price as well during the Winter 2019/2020.

- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2019.

Figure A-100: Capacity Procurement by Type and Auction Price Differentials

Figure A-100 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-100: Auction Procurement and Price Differentials in NYCA
May 2010 – February 2020



<u>Key Observations: Capacity Procurement and Price Comparison</u>

- Almost 80 percent of the total UCAP in NYCA is procured via bilateral transactions (38 percent in Summer 2019) or in the spot market (42 percent in Summer 2019). The remaining capacity is procured through the strip (7 percent in Summer 2019) and monthly (13 percent in Summer 2019) auctions.
  - The proportions of capacity procured through the four different mechanisms has remained in a relatively narrow range, with the procurement in the spot market increasing slightly at the expense of the other three mechanisms.
- The Summer 2018 saw the Spot Market prices average almost double what posted in the Strip Auction; however, Spot prices tracked much closer to Strip and Monthly values

during Summer 2019. These results were likely driven by changes in patterns of imports from external control areas, especially with the elimination of ICAP imports from PJM during Capability Year 2019/2020 (see Figure A-94).

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 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 NYISO implemented a new methodology for determining the LCRs, first applied to the 2019/2020 Capability Year. The NYISO's methodology ("Optimized LCRs Method") seeks to minimize the total procurement 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. The "Optimized LCRs Method" minimizes procurement costs (i.e., capacity clearing price times quantity) rather than investment costs (i.e., the marginal cost of supply in the capacity market). Minimizing procurement costs is inefficient because it does not necessarily select the lowest cost supply to satisfy reliability. Minimizing investment costs is efficient because it selects the lowest cost resources just as the energy and ancillary services markets select the lowest cost resources to satisfy load and ancillary services requirements.

Table A-14: Cost of Reliability Improvement

Table A-14 shows the CRI in each zone based on the system at the long-term equilibrium that is modeled in the demand curve reset process. Under these conditions, 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 0.071. [364]

In addition to the CRI in each actual load zone, the table also shows the CRI at three additional locations that are represented as "dummy bubbles" in the GE-MARS topology. The bubbles shown in the table are: (a) the CPV VEC bubble, which contains the 680 MW CPV Valley Energy Center combined cycle plant, (b) the Cricket Valley bubble, which contains the 1,020 MW Cricket Valley Energy Center combined cycle plant, (c) the Athens bubble, which contains 1.1 GW of generation from the Athens combined cycle plants, and (d) the J3 bubble representing Staten Island. Although the J3 bubble technically includes just injections from the Linden VFT-controlled and Linden-Goethals PAR-controlled interconnections with New Jersey, the 1.7 GW of generation at the Arthur Kill and Linden Cogeneration plants are modeled in GE-MARS in a manner that is designed to reflect that their output tends to cause transmission bottlenecks from J3 to the rest of Zone J to a degree that is comparable to injections at the J3 bubble.[365]

The 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 2020/21 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 100 MW UCAP Addition* – The estimated LOLE from placing 100 MW of additional UCAP in the area.[366]
- *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 the difference between the NYCA LOLE at Excess Level and the LOLE from adding 100 MW of UCAP to the area.

364 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 last 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.

365 See *NYCA Installed Capacity Requirement, May 2020 to April 2021*, Technical Study Report Appendices, Figure A.12.

366 These values were obtained by starting with the system at Excess Level with an LOLE of 0.071 and calculating the change in LOLE from a 100 MW of perfect capacity addition in each area.

- *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.[367, 368] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

For the CPV VEC, Cricket VEC, and Athens areas, it was not possible to assess the MRI using the technique described above because this technique does not capture the effect of supply on dynamic transfer limits in MARS. Consequently, the values for these areas are TBD (To Be Determined) because they cannot be measured without simple modifications to MARS. We intend to measure these using a tool that simulated MARS results.

Table A-14: Cost of Reliability Improvement
2020/21 Capability Year

Zone	Net CONE of Demand Curve Unit *$/kW-yr*	NYCA LOLE at Excess Level	LOLE with 100 MW UCAP Addition	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *MM$ per 0.001 ΔLOLE*
A	$105	0.071	0.067	0.0044	$2.4
B	$105		0.066	0.0050	$2.1
C	$105		0.066	0.0050	$2.1
D	$105		0.066	0.0051	$2.1
E	$105		0.066	0.0050	$2.1
F	$105		0.066	0.0050	$2.1
G	$157		0.066	0.0057	$2.8
H	$157		0.065	0.0062	$2.5
I	$157		0.065	0.0062	$2.5
J	$192		0.065	0.0068	$2.8
K	$150		0.064	0.0069	$2.2
Other Areas					
Staten Island (J3)	$192	0.071	0.070	0.0015	$12.8
CPV VEC	$157		TBD	TBD	
Cricket VEC	$157		TBD	TBD	
Athens	$105		TBD	TBD	

Key Observations: Cost of Reliability Improvement

- The Optimized LCRs Method has reduced the range in CRI values across load zones when compared to previous years. Nevertheless, the range between the minimum CRI-value location (Zones B-F at $2.1 million per 0.001 events) and the maximum CRI-value location (NYC at $2.8 million per 0.001 events) is still substantial.
  - The CRI for Zone K ($2.2 million per 0.001 events) continues to be lower than the CRI for Zone G ($2.8 million per 0.001 events). However, some have asserted that

367 For example, for Zone F: $105/kW-year × 1000kW/MW ÷ (0.005LOLEchange/100MW) × 0.001LOLEchange = $2.1 million.

368 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.

the Net CONE for Zone K was under-estimated in the last demand curve reset, suggesting that the true CRI for Zone K may actually be higher.

- The results reveal that there are substantial differences in the MRI values for specific areas within a capacity zone. In particular, the MRI for Staten Island is only 0.002, and is significantly lower than the Zone J MRI. This disparity suggests that generation in this area is overpriced relative to its reliability value.
  - The CPV VEC and Cricket VEC generators are located in Zone G, and the Athens generator is located in Zone F. However, the availability of these generators affects the transfer limits between F and G, so these generators may have higher or lower MRI values than the MRI of the zone in which they are located. We are not able to measure the MRIs for these generators using the 2020/21 case without modifications to GE-MARS. Consequently, the values for these areas are currently TBD. We intend to measure these using a tool that simulates MARS results later this year.

- The CRI values for some zones exhibit considerable differences from those of other zones within the same capacity pricing region under the current configuration.
  - Zone G has a higher CRI than zones H and I even though UCAP resources in these areas receive the same price. The assumed retirement of Indian Point Unit 2 (which is located in Zone H) in April 2020 led to a reduction in the MRI of Zone G relative to zones H and I when compared with the results for Capability Year 2019 CRI results. This indicates that the constraints between zones G and H are binding after the retirement of one Indian Point unit.
  - Zone A exhibits a higher CRI than zones B to F. This reflects transmission constraints within Zone A that limit the deliverability of most (but not all) Zone A generation to the rest of NYCA.
  - The Zone G and H MRIs could diverge more with retirement of Indian Point 3 before the 2021/22 capability year.[369] Similarly, gas pipeline congestion patterns could lead to large differences in the Net CONE values within a capacity market locality.[370] 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.

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

369 However, this retirement will lead to a 750 MW increase in the transfer limit between Zone G and Zone H, which will partly mitigate the effect of the Indian Point retirement.

370 See comments of the Market Monitoring Unit in Commission Docket ER17-386-000, dated December 9, 2016.

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.[371]

Figure A-101: Breakdown of Revenues for Generation and Transmission Projects

Figure A-101 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 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. The information presented in the figure is based on the following assumptions and inputs:

- The MSSC project is assumed to increase the UPNY-SENY transfer capability by 287 MW.[372]
- 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 2019 IRM topology indicate that the estimated reliability benefit (reduction in LOLE) from increasing the transfer capability of the UPNY-SENY interface by 50 MW is 0.0009 events per year.
- The FCTR revenues for the transmission project 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

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371 See Recommendation 2012-1c in Section XI.

372 Although the MSSC project increase the limit for the Central-East interface, MARS results indicate that the MRI for this interface is zero in the current year. Our assumption for increase in UPNY-SENY transfer capability is based on the following - https://nyisoviewer.etariff.biz/viewerdoclibrary/Filing/Filing1033/Attachments/NYPA%20Trnsmttl%20Lttr%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 $120 million for the MSSC project (see https://www.utilitydive.com/news/new-york-finishes-transmission-project-to-access-440-mw-of-capacity/421104/), inflated to 2019$.

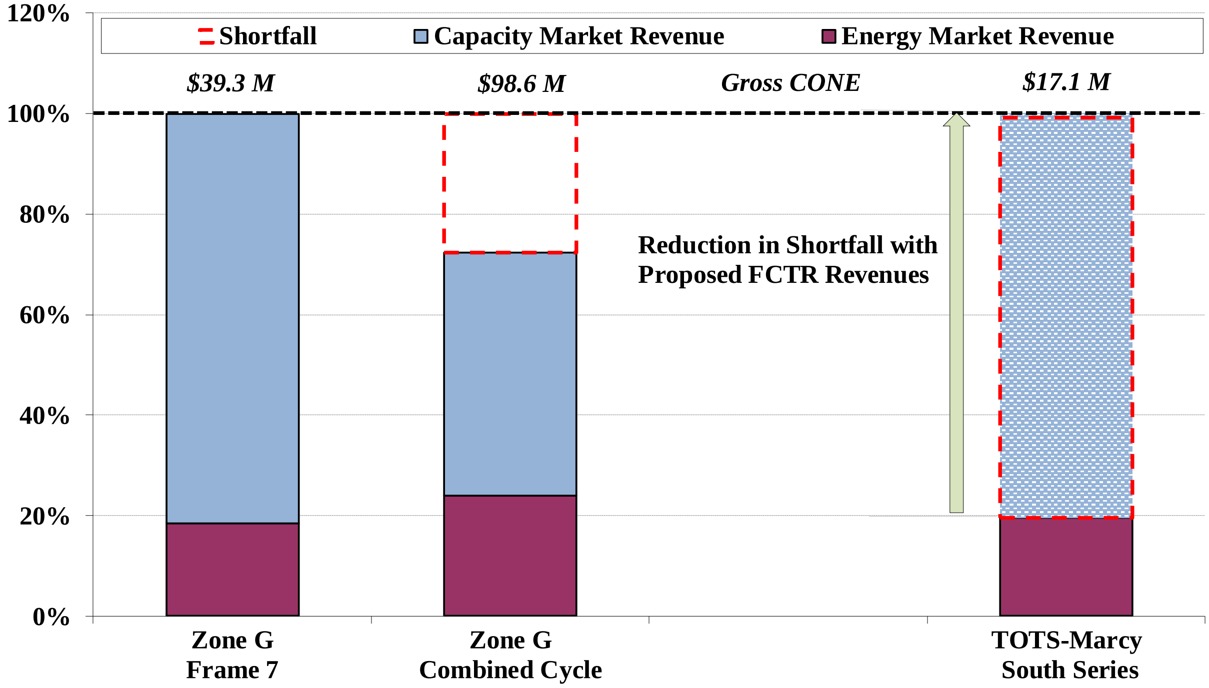
c) An additional annual charge of 5 percent of investment costs to account for O&M and other taxes, based on the share of these costs reported in the New York Transco's Annual Projection dated 09/30/2017 for the TOTS projects.

- ○ The value of reliability in dollars per unit of LOLE. Based on the results of the GE-MARS runs for the 2019 IRM topology, this value is assumed to be \$2.65 million per 0.001 events change in LOLE.[373]

- The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the MSSC project. Consistent with the 2019/20 Demand Curve annual update, the TCCs were valued based on the energy prices during September 2015 through August 2018.

- The gross CONE, energy and capacity market revenues for the Zone G Frame and CC units are based on the 2019/20 annual Demand Curve update.

Figure A-101: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



Key Observations: Financial Capacity Transfer Rights for Transmission Projects

- Figure A-101 illustrates the disadvantages that most transmission projects have relative to generation and demand response in receiving compensation for the planning reliability benefits they provide to the system, since transmission projects do not receive capacity payments (except for UDR projects).

- Capacity market compensation has historically provided a critical portion of the incentive for generator entry and exit decisions.

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373 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

  - The figures show that capacity markets provide 48 to 81 percent of the net revenue to a new generator in Zone G and it is highly unlikely that a new generator would be built without this revenue stream.

- The results also illustrate the potential of FCTRs in incentivizing development of merchant transmission projects. In the absence of capacity payments, the MSSC project recoups only 20 percent of its annualized gross CONE. However, granting FCTRs to the project would have provided an additional 80 percent of the annualized gross CONE in this scenario, making it possible that the project could have recovered most of its costs through energy and capacity revenues. 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 reliability benefits.

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 B), (c) new utility-scale solar PV units (subsection C), (d) new onshore wind units (subsection C), and (e) new offshore wind units (subsection C). 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) 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 D, we evaluate the potential impact of a subset of these recommendations on the net revenues of different types of resources. In subsection E, we discuss the impacts of these recommendations specifically in context of existing generation in New York City, and how they would affect the Buyer-Side Mitigation ("BSM") evaluations for Public Policy Resources ("PPRs").

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:

- *Hypothetical new units*: (a) a 1x1 Combined Cycle ("CC 1x1") unit, (b) a SGT-A65 aeroderivative combustion turbine ("3xA65") unit, and (c) a frame-type H-Class simple-cycle combustion turbine ("CT - 7HA.02") 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. For 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 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 zone that are downstream of the UPNY-SENY interface.

Table A-15 to Table A-18: 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 based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limits.

- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while CTs may sell energy and 10-minute or 30-minute non-spinning reserves.

- CTs (including older gas turbines) are committed in real-time based on RTC prices.[374] CTs 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 real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, for the ST unit, a limitation on its ramp capability is assumed to keep the unit within a certain margin of the day-ahead schedule. The margin is assumed to be 25 percent of UOL.

- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability.

374 Our method assumes that a Frame 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 the full RTC look-ahead period of 2.5 hours, and an aeroderivative 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.

- 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-15: Day-ahead Fuel Assumptions During Hourly OFOs[375]

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-16: Gas and Oil Price Indices and Other Charges by Region

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	Discount
West	Tennessee Zn 4 - 200 Leg	$0.27	$2.00	$1.50	10%
Central	March - November: Tennessee Zn 4 - 200 Leg December - February: min(Tennessee Zn 6,Iroquois Zn 2)	$0.27	$2.00	$1.50	10%
Capital	min(Tennessee Zn 6,Iroquois Zn 2)	$0.27	$2.00	$1.50	10%
Hudson Valley	Iroquois Zn2	$0.27	$1.50	$1.00	10%
New York City	Transco Zn6	$0.20	$1.50	$1.00	20%
Long Island	Iroquois Zn 2	$0.25	$1.50	$1.00	30%

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered for all years. However, the older GT-30 unit is assumed not to have RGGI compliance costs because the RGGI program does not cover units below 25 MW.

375 **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.

- The minimum generation level is 216 MW for the CC 1x1 unit and 90 MW for the ST unit. At this level, the heat rate is 7,343 btu/kWh for the CC 1x1 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-17: New Gas-fired Unit Parameters for Net Revenue Estimates[376]

Characteristics	CC 1x1	3XA65	Frame 7HA.02
Summer Capacity (MW)	617	166	355
Winter Capacity (MW)	648	188	371
Summer Heat Rate (Btu/kWh)	6738	9695	9385
Winter Heat Rate (Btu/kWh)	6729	9437	9283
Min Run Time (hrs)	4	1	1
Variable O&M - Gas (2020$/MWh)	$2.6	$12.8	$1.3
Variable O&M - Oil (2020$/MWh)	$2.8	$12.9	$10.9
Startup Cost (2020$)	$0	$0	$16,200
Startup Cost (MMBTU)	3940	100	350
EFORd	2.90%	2.17%	4.30%

Table A-18: 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)	24	1	1
Variable O&M (2020$/MWh)	$9.9	$5.0	$6.1
Startup Cost (2020$)	$6,637	$1,327	$574
Startup Cost (MMBTU)	3500	50	60
EFORd	5.14%	10.46%	19.73%

Figure A-102 and Figure A-103: Forward Prices and Implied Heat Rate Trends

We developed the hourly day-ahead power price forecast for each zone by adjusting the 2019 LBMPs using the ratio of monthly forward prices and the observed monthly average prices in

376 These parameters are based on technologies being studied as part of the 2019/20 NYISO ICAP Demand Curve reset. The CONE estimate for gas-fired units in West Zone are based on preliminary cost data from Zone C in the 2019/20ICAP Demand Curve reset study. See, ICAP WG presentation *NYISO ICAP Demand Curve Reset: Updates to Gross CONE Inputs* by B&M on 26th March, 2020, available at : https://www.nyiso.com/documents/20142/11554944/Final%20BMcD%20DCR%20ICAPWG%2003262020.pdf/5e44b033-ef0a-4b17-b140-946eb4b25a56

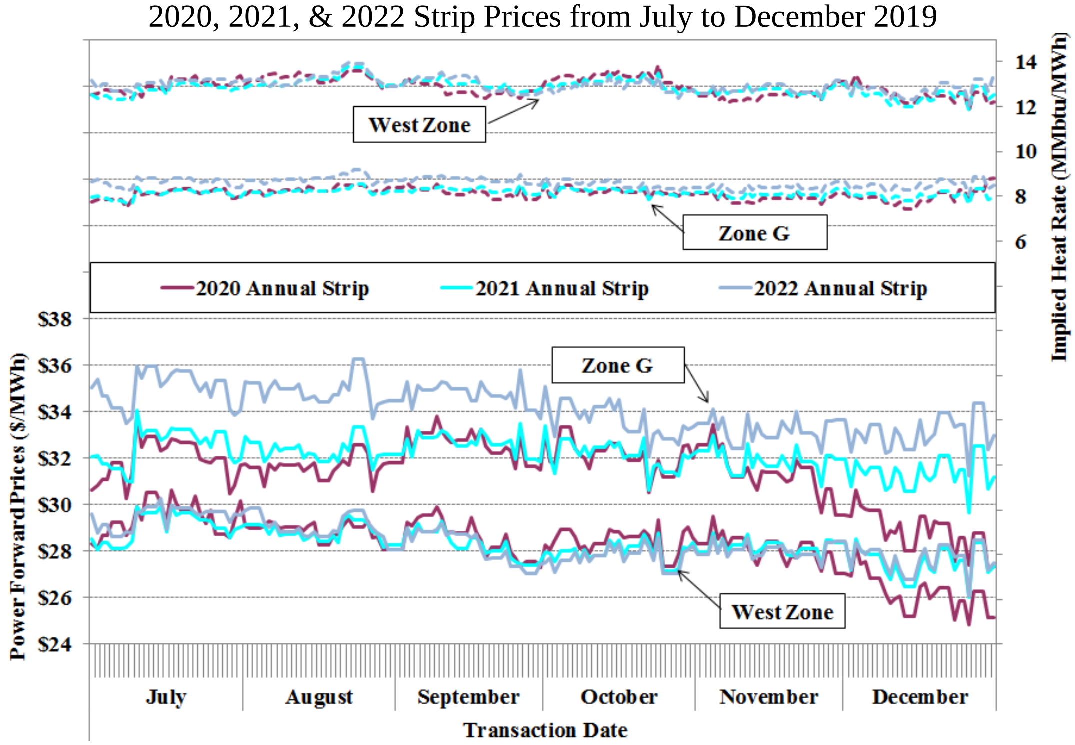
2019. Net revenues from 2020 to 2022 are estimated using forward prices for power.[377, 378] We held the reserve prices for future years at their 2019 levels.

Figure A-102 shows the variation in the forward prices and implied marginal heat rates for Zone A and Zone G over a six month (July-Dec 2019) trading period. Figure A-103 shows the monthly forward power and gas prices for the 2020-2022 period along with the observed monthly average prices during the 2017-2019 period.

In general, there is considerable volatility in power and gas forward prices during the last two quarters of 2019. The zonal forward prices in Zone G have ranged from \$27 to \$37 per MWh while Zone A forward prices were in the \$25 to \$31 per MWh range. Therefore, we used the trailing 90-day average of the forward prices as of January 1st, 2020. In contrast, the implied marginal heat rates (and the spark spreads) have been reasonably stable over the last six months in all zones for 2020 and 2021 delivery years. However, the implied marginal heat rates for delivery year 2022 are slightly higher in all the downstate zones, likely due to the retirement of both Indian Point units.

Figure A-102: Forward Prices and Implied Marginal Heat Rates by Transaction Date

2020, 2021, & 2022 Strip Prices from July to December 2019



377 For power forward prices between 2020 and 2022, we used OTC Global Holdings' forward strips published by SNL Energy.

378 We estimate the net revenues in future years for only nuclear and renewable units. The net revenues of fossil generation in a number of locations are influenced heavily by capacity revenues. The ICAP demand curve reset study is underway at the time of this analysis. Hence, the future capacity prices (and the net revenues of fossil-fired generators) are subject to significant uncertainty.

Figure A-103: Past and Forward Price Trends of Monthly Power and Gas Prices
2017 – 2022

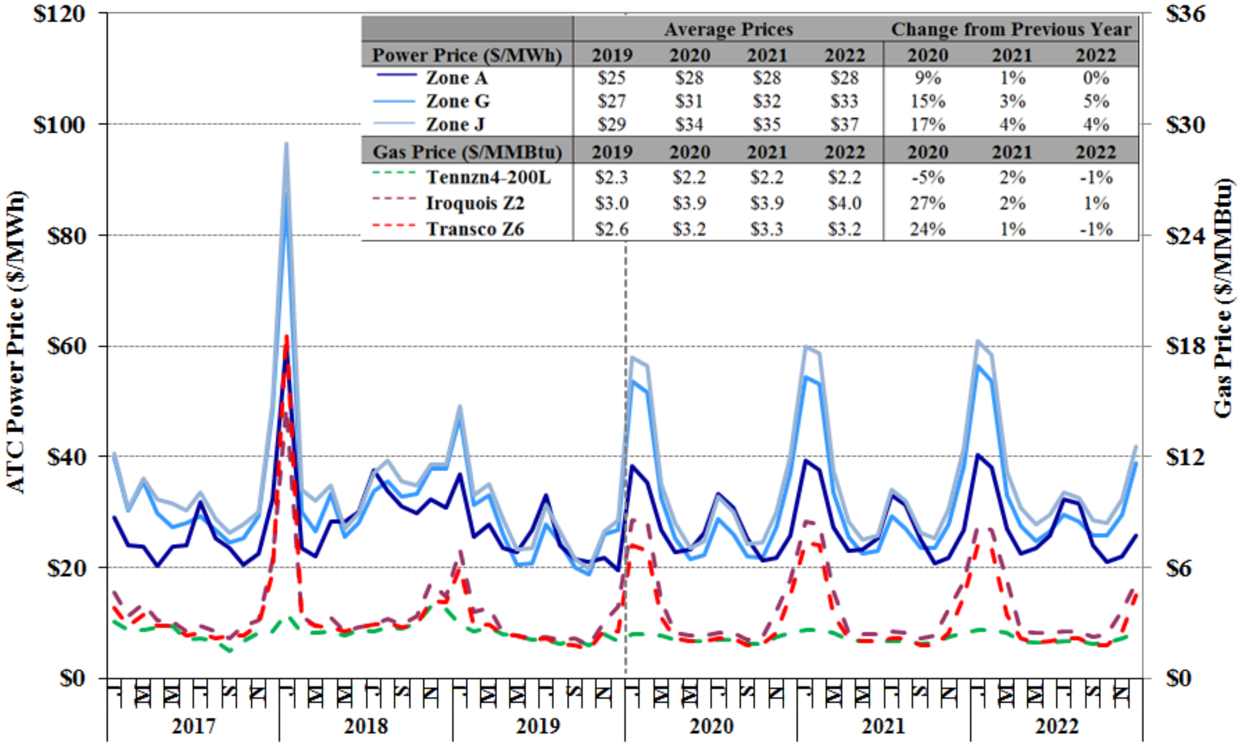


Figure A-104 to Table A-20: Net Revenues Estimates for Fossil Fuel Units

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.[379] Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-19 shows our estimates of net revenues and run hours for all the locations and gas unit types in 2019. Table A-20 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2019.

379 The CONE for the new technology types is based on the most recent preliminary capital cost information that was available, from the ongoing Demand Curve Reset study, at the time of publishing this report. See, ICAP WG presentation *NYISO ICAP Demand Curve Reset: Updates to Gross CONE Inputs* by B&M on 26th March, 2020, available at: https://www.nyiso.com/documents/20142/11554944/Final%20BMcD%20DCR%20ICAPWG%200326202 0.pdf/5e44b033-ef0a-4b17-b140-946eb4b25a56. The financing assumptions and insurance costs are sourced from the *2017/18 ICAP Demand Curve Reset*. For NYC CC unit we limit the capacity factor of the unit to 75 percent and assume that the unit will secure a property tax exemption. The GFCs for older generators are based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

Figure A-104: Net Revenue & Cost for Fossil Units in West Zone
2017-2019

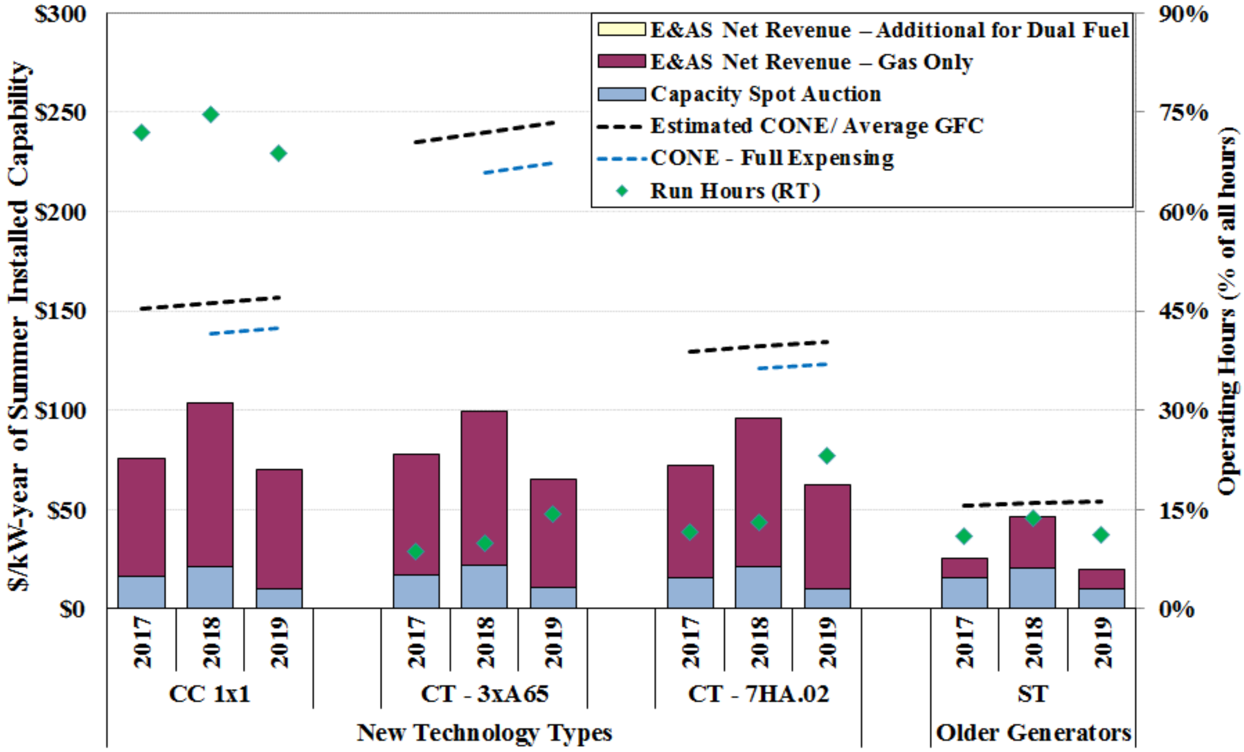


Figure A-105: Net Revenue & Cost for Fossil Units in Central Zone
2017-2019

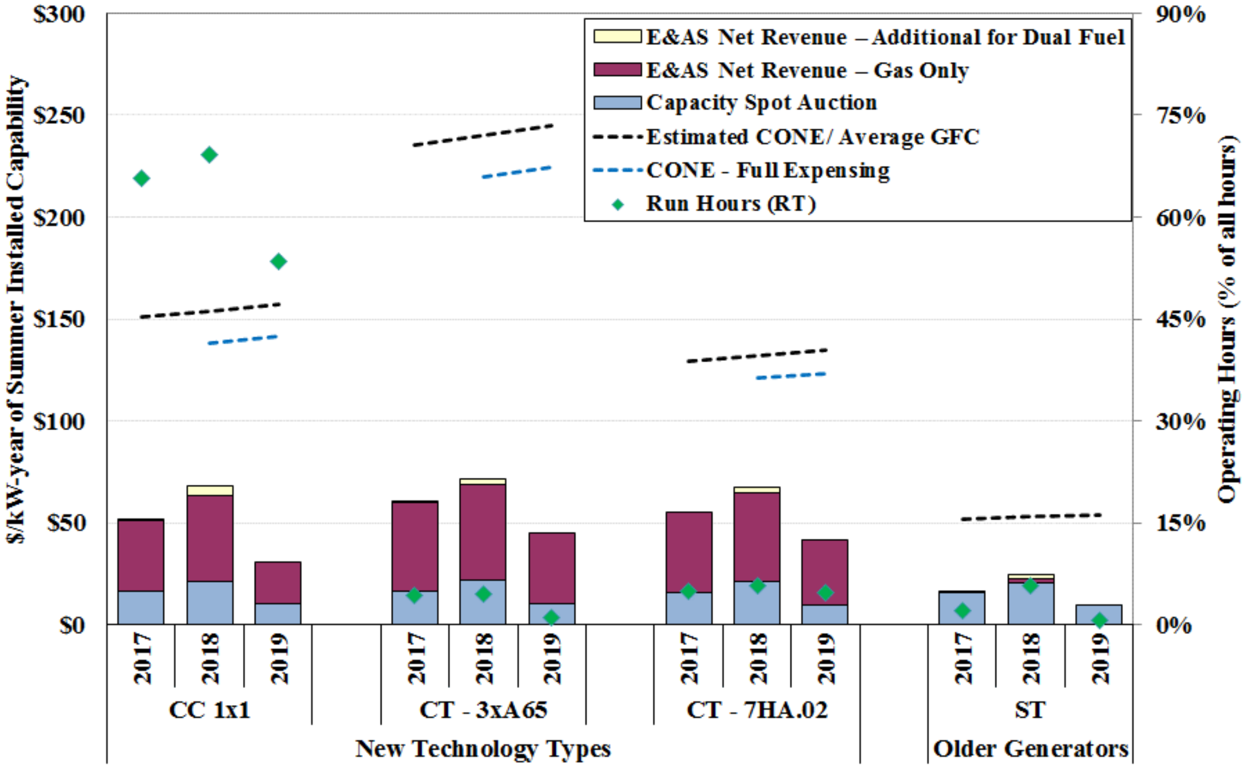


Figure A-106: Net Revenue & Cost for Fossil Units in Capital Zone
2017-2019

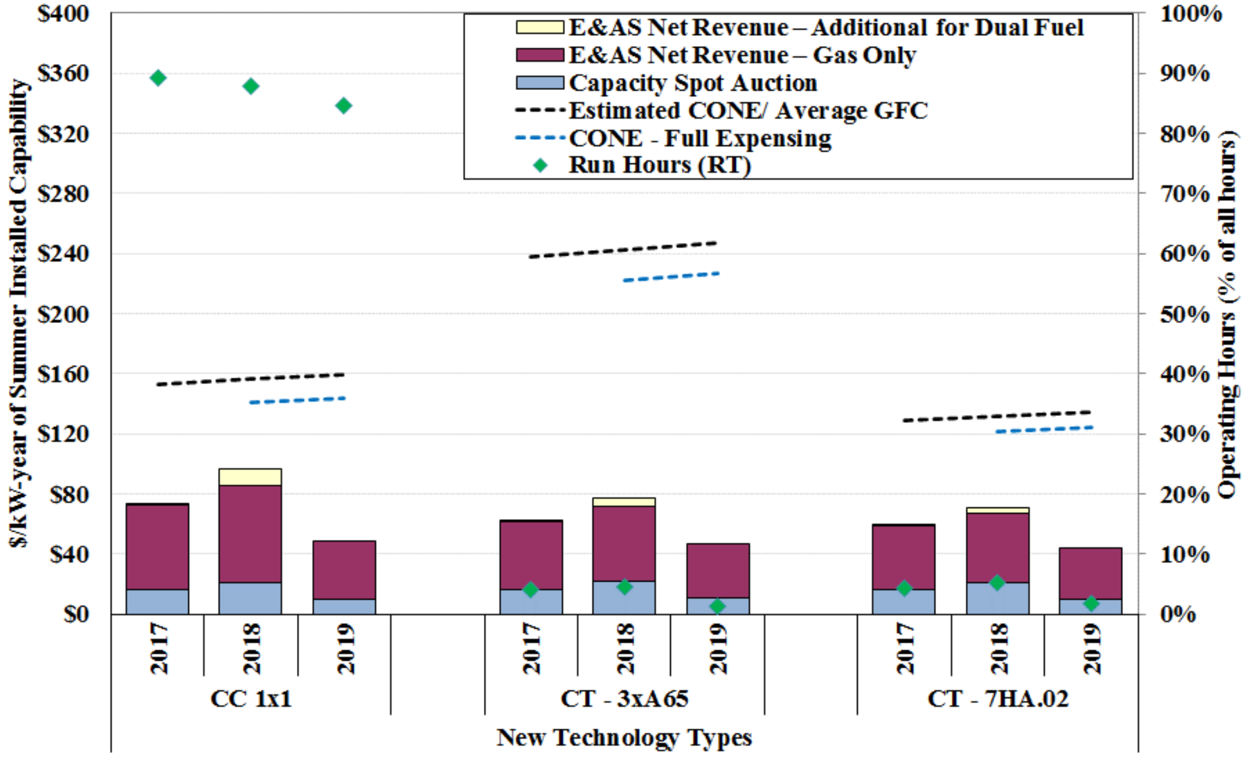


Figure A-107: Net Revenue & Cost for Fossil Units in Hudson Valley
2017-2019

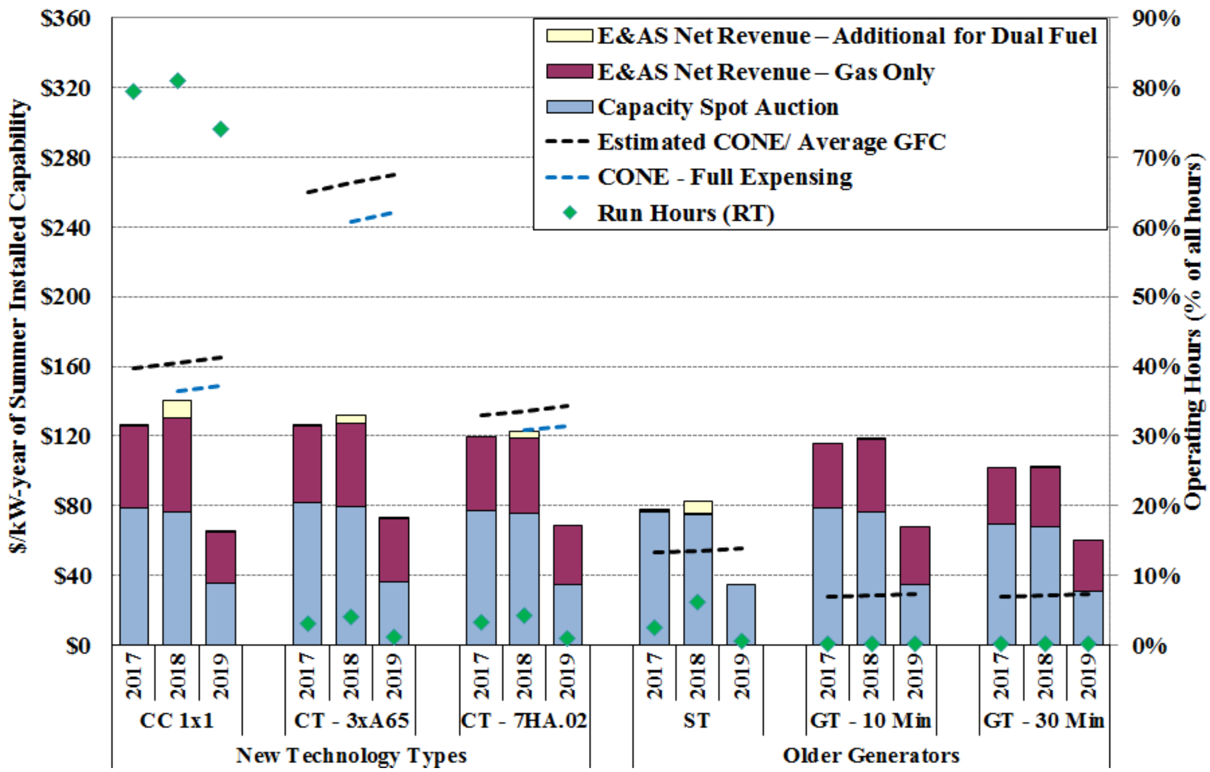


Figure A-108: Net Revenue & Cost for Fossil Units in New York City
2017-2019

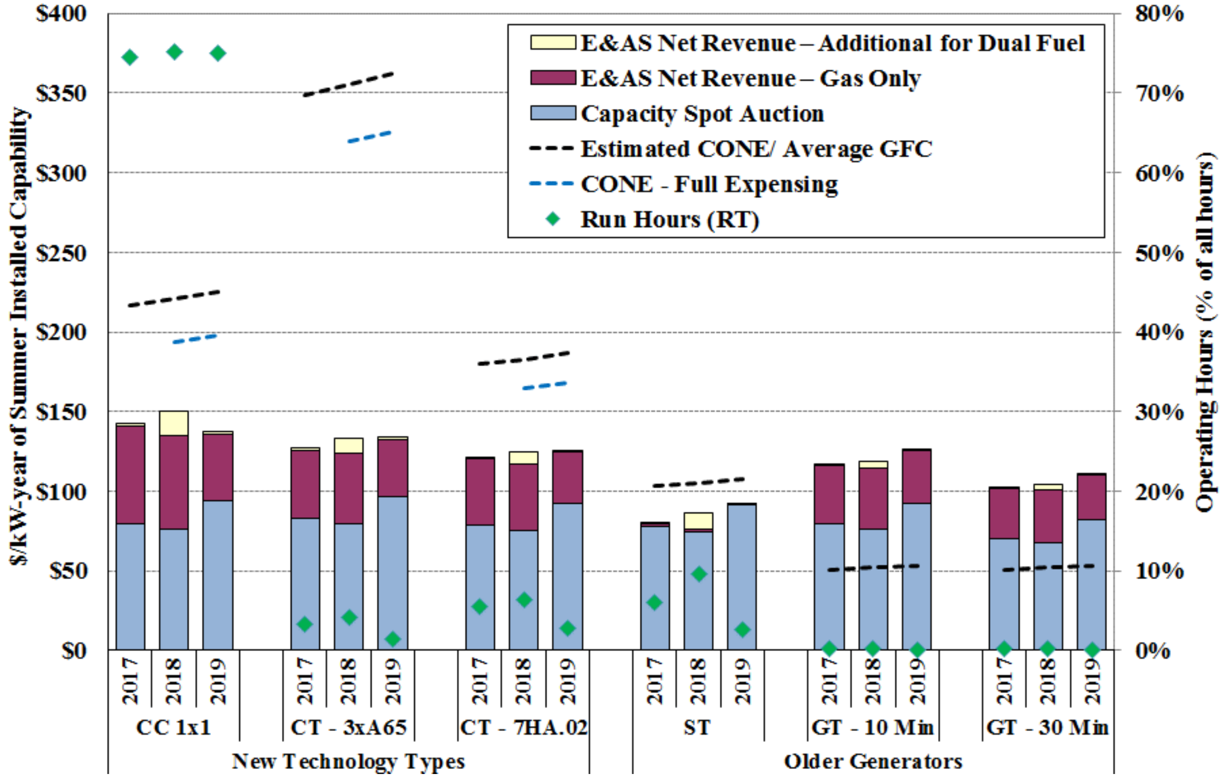


Figure A-109: Net Revenue & Cost for Fossil Units in Long Island
2017-2019

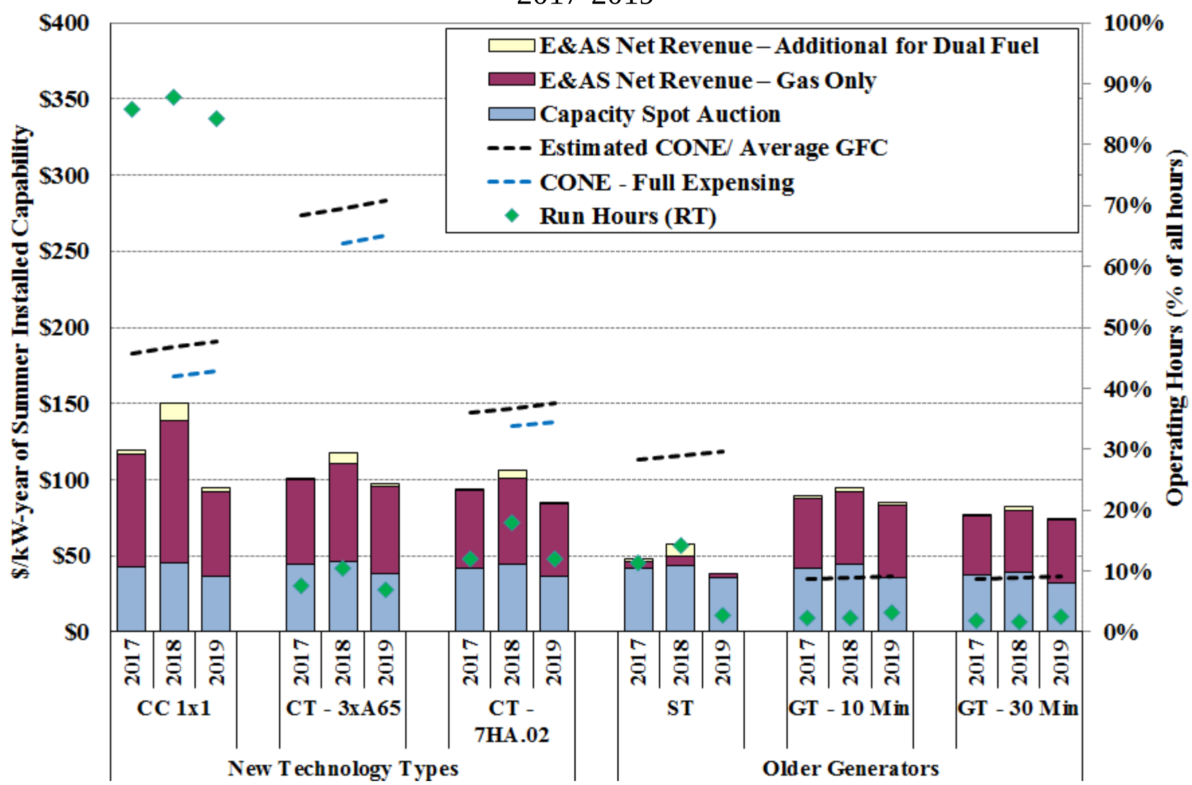


Table A-19: Net Revenue for Gas-Fired & Dual Fuel Units
2019

Location	Unit Type	Capacity	2019 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 1x1	$10	$39	$0	$49	7421	7421	0	7421
	CT - 7HA.02	$10	$34	$0	$44	159	159	0	159
	CT - 3xA65	$11	$37	$0	$47	123	123	0	123
Capital (Tennessee Zone 6 Gas)	CC 1x1	$10	$29	$0	$39	5974	5974	0	5974
	CT - 7HA.02	$10	$34	$0	$44	109	109	0	109
	CT - 3xA65	$11	$36	$0	$47	95	95	0	95
Central Zone	CC 1x1	$10	$21	$0	$31	4680	4680	0	4680
	CT - 7HA.02	$10	$32	$0	$42	426	426	0	426
	CT - 3xA65	$11	$35	$0	$45	98	98	0	98
	ST	$10	$0	$0	$10	67	67	0	67
West Zone	CC 1x1	$10	$60	$0	$70	6055	6015	8	6023
	CT - 7HA.02	$10	$52	$0	$62	2029	2029	0	2029
	CT - 3xA65	$11	$55	$0	$65	1261	1261	0	1261
	ST	$10	$10	$0	$20	978	978	0	978
Hudson Valley	CC 1x1	$35	$29	$1	$65	6438	6438	51	6489
	CT - 7HA.02	$35	$34	$0	$68	87	87	0	87
	GT - 10 Min	$35	$33	$0	$68	9	9	0	9
	GT - 30 Min	$31	$29	$0	$60	12	12	0	12
	CT - 3xA65	$37	$36	$0	$73	96	95	3	98
	ST	$34	$0	$0	$34	45	45	0	45
Hudson Valley (Tetco Gas)	CC 1x1	$35	$49	$0	$85	7567	7567	0	7567
	CT - 7HA.02	$35	$38	$0	$72	281	281	0	281
	GT - 10 Min	$35	$33	$0	$68	10	10	0	10
	GT - 30 Min	$31	$29	$0	$60	13	13	0	13
	CT - 3xA65	$37	$39	$0	$76	249	249	0	249
	ST	$34	$1	$0	$35	204	204	0	204
Long Island	CC 1x1	$37	$55	$3	$95	7352	7246	144	7389
	CT - 7HA.02	$36	$48	$1	$85	1072	1044	15	1059
	GT - 10 Min	$36	$48	$1	$85	267	267	4	271
	GT - 30 Min	$32	$41	$1	$74	218	218	2	220
	CT - 3xA65	$38	$58	$2	$97	603	595	14	609
	ST	$36	$2	$0	$38	249	249	0	249
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$37	$98	$3	$138	7471	7427	98	7525
	CT - 7HA.02	$36	$68	$0	$104	2067	2056	7	2062
	GT - 10 Min	$36	$62	$1	$99	402	400	6	406
	GT - 30 Min	$32	$54	$1	$87	326	325	6	330
	CT - 3xA65	$38	$79	$0	$117	902	894	9	903
	ST	$36	$18	$0	$54	2071	2097	19	2116
NYC	CC 1x1	$94	$43	$2	$139	7578	7368	121	7489
	CT - 7HA.02	$92	$32	$1	$126	248	248	0	248
	GT - 10 Min	$92	$33	$1	$127	8	8	0	8
	GT - 30 Min	$82	$28	$1	$111	14	14	0	14
	CT - 3xA65	$97	$35	$2	$134	118	118	3	121
	ST	$91	$0	$0	$92	204	204	23	227

Table A-20: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units

2019

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 1x1	$14	$8	$11	$6	1800	1907	2122	1593	$14	$6	1800	1593
	CT - 7HA.02	$9	$8	$9	$8	32	8	59	60	$9	$8	32	60
	CT - 3xA65	$11	$9	$9	$8	27	12	51	33	$11	$8	27	33
Capital (Tennessee Zone 6 Gas)	CC 1x1	$9	$6	$11	$3	1306	1722	2105	840	$9	$3	1306	840
	CT - 7HA.02	$9	$8	$9	$7	16	8	56	30	$9	$7	16	30
	CT - 3xA65	$10	$9	$9	$8	18	12	51	15	$10	$8	18	15
Central Zone	CC 1x1	$5	$3	$10	$3	1133	904	1809	833	$5	$3	1133	833
	CT - 7HA.02	$8	$8	$9	$7	12	266	105	42	$8	$7	12	42
	CT - 3xA65	$9	$9	$9	$8	10	19	42	27	$9	$8	10	27
	ST	$0	$0	$0	$0	0	0	46	22	$0	$0	0	22
West Zone	CC 1x1	$18	$15	$20	$8	1811	1172	1839	1234	$18	$8	1811	1194
	CT - 7HA.02	$14	$14	$15	$10	267	807	567	389	$14	$10	267	389
	CT - 3xA65	$15	$14	$15	$11	209	413	360	279	$15	$11	209	279
	ST	$4	$2	$4	$0	205	228	433	113	$4	$0	205	113
Hudson Valley	CC 1x1	$9	$6	$11	$3	1590	1557	2058	1232	$10	$3	1642	1232
	CT - 7HA.02	$8	$9	$9	$8	4	8	57	18	$8	$8	4	18
	GT - 10 Min	$9	$9	$8	$8	0	5	5	0	$9	$8	0	0
	GT - 30 Min	$8	$8	$7	$7	0	5	4	3	$8	$7	0	3
	CT - 3xA65	$9	$9	$10	$8	8	14	57	18	$9	$8	10	18
	ST	$0	$0	$0	$0	0	0	23	22	$0	$0	0	22
Hudson Valley (Tetco Gas)	CC 1x1	$21	$7	$14	$8	2063	1623	2131	1749	$21	$8	2063	1749
	CT - 7HA.02	$11	$9	$10	$8	136	8	78	59	$11	$8	136	59
	GT - 10 Min	$9	$9	$8	$8	0	5	5	1	$9	$8	0	1
	GT - 30 Min	$8	$8	$7	$7	0	5	4	4	$8	$7	0	4
	CT - 3xA65	$11	$9	$10	$9	96	15	78	61	$11	$9	96	61
	ST	$1	$0	$0	$0	114	0	46	45	$1	$0	114	45
Long Island	CC 1x1	$13	$11	$19	$12	1830	1750	2136	1636	$16	$12	1867	1636
	CT - 7HA.02	$8	$10	$17	$13	98	283	415	276	$9	$14	99	278
	GT - 10 Min	$8	$10	$18	$12	9	38	127	94	$9	$12	11	95
	GT - 30 Min	$7	$9	$16	$10	6	31	106	75	$8	$10	8	75
	CT - 3xA65	$9	$11	$21	$17	43	95	264	201	$10	$17	46	203
	ST	$0	$0	$2	$0	0	23	205	22	$0	$0	0	22
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$31	$17	$35	$15	1931	1750	2143	1647	$34	$16	1986	1647
	CT - 7HA.02	$20	$13	$25	$10	417	470	867	313	$20	$10	412	313
	GT - 10 Min	$11	$11	$32	$8	45	77	231	50	$12	$8	49	50
	GT - 30 Min	$9	$10	$27	$7	30	65	188	42	$10	$7	35	42
	CT - 3xA65	$20	$14	$34	$11	183	173	414	132	$20	$11	184	132
	ST	$4	$1	$11	$1	546	296	1116	113	$5	$1	569	113
NYC	CC 1x1	$14	$8	$14	$7	1975	1732	2138	1732	$16	$6	1941	1678
	CT - 7HA.02	$8	$8	$9	$7	72	62	100	14	$9	$7	72	14
	GT - 10 Min	$8	$9	$9	$8	0	5	4	0	$9	$8	0	0
	GT - 30 Min	$7	$8	$7	$7	0	6	6	3	$8	$7	0	3
	CT - 3xA65	$8	$9	$10	$8	24	22	61	12	$10	$8	26	13
	ST	$0	$0	$0	$0	0	23	159	22	$0	$0	0	45

Key Observations: Net Revenues of Gas-fired and Dual Fuel Units

- *Year-Over-Year Changes* – The results indicate that the 2019 net revenues for gas-fired units were lower than the 2018 net revenues for nearly all technology types and locations.
  - As discussed in Section I of the Appendix, 2019 witnessed (a) mild weather in winter, (b) lower gas prices throughout the year, and (c) lower summer peak and annual average load levels, all of which contributed to lower energy prices and lower implied marginal heat rates. Consequently, the energy margins and E&AS net revenues in 2019 were lower relative to 2018 in all of the locations that we studied.
    - As discussed in Section III, the West Zone continued to experience significant volatility and congestion in real-time prices. As a result, the year-over-year reductions in E&AS revenues of new technologies in the West Zone were the smallest of all the other locations.
  - The increase in capacity prices in New York City (see subsection VI.E of the appendix) offset the decrease in E&AS revenues of units located in the zone, causing net revenues to increase relative to 2018 for most unit types (except for Combined Cycle).[380] The capacity revenues in all other locations decreased in 2019.
- *Estimated Future Net Revenues* – Given the current pricing of forward contracts, the net E&AS revenues of most units in the 2020 to 2022 timeframe are likely to be similar or slightly higher than 2019 as the forward power prices and the implied marginal heat rates are rising in most regions. Ultimately, any estimates based on forwards are uncertain because of the volatility in 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 2019 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 2019.
- *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 gas turbine units, but lower than some estimates of GFCs for steam turbines in several zones.
  - Among older technologies, the estimated net revenues were highest for a GT-10 unit. In addition to capacity revenues, reserve revenues play a pivotal role in the continued operation of older GTs.

380 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.

- The net E&AS revenues of steam turbines in 2019 were lower than in 2018. Reduced capacity prices in all regions outside of NYC in 2019 led to significantly lower net revenues of steam turbines. The total net revenues of steam turbines relative to some estimates of the GFCs suggests increased economic pressure on these units across the state. However, retirement decisions are also impacted by other factors including unit-specific GFCs, value of interconnection rights, the ability to defer costs, 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, the recently adopted rule by the New York DEC would require older GTs to install back-end controls (e.g., selective catalytic reduction) for limiting NOx and other pollutants by May 2023 or May 2025, depending on the facility's emissions rate.[381] The owners of affected units filed initial compliance plans in March 2020, indicating that some existing units will retire and others will consider repowering or continued operation.[382] 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.[383]

- *Potential Reserve Market Revenues for Gas Turbines in 2018* – The 2019 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 46 years and 8 run hours in 2019) with over 85 percent of its total E&AS revenues of $34/kW-year. However, most of the 10-minute and 30-minute capable supply was scheduled far less frequently for reserves than the net revenue analysis would predict. 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 Cuts and Jobs Act ("TCJA")* – A number of provisions of the TCJA legislation affect the CONE estimates of new units. The results indicate that full expensing of equipment cost reduces the CONE by approximately 10 percent. Such a reduction by itself is not be sufficient to render new entry economic based on 2019 net revenues.[384]

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381 See DEC's rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, available at: http://www.dec.ny.gov/regulations/116131.html

382 In New York City, the owner of the Gowanus and Narrows facilities plans to comply by operating only in winter and has also filed an Article X application to repower the Gowanus facility, while the owner of the Astoria Gas Turbines facility is reported to plan to comply by retiring the units. See https://www.politico.com/states/new-york/newsletters/politico-new-york-energy/2020/03/05/peaker-plants-face-emissions-limits-333198

383 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*.

384 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.

- *Incentive for Dual Fuel Units* – Additional energy net revenues from dual fuel capability were de minimis in 2019 and decreased significantly compared to 2018. This is due to mild weather and low natural gas prices in the winter of 2019. Additional returns from dual fuel capability were high in 2018 across several zones because of very high gas prices during the cold snap in January 2018. The average additional revenues for CC and ST units in recent years have generally been sufficient to incent dual fuel capability, although there is significant annual variation due to weather patterns.[385] Dual-fuel capability provides a hedge against gas curtailment under tight supply conditions and reduces potential for fuel-related outages. 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. Nuclear Unit Net Revenues

We estimate the net revenues the markets provide to the nuclear plants in the Genesee and Central Zones. The estimates are based on LBMPs at the Ginna bus (for Genesee), and the Fitzpatrick and Nine Mile Unit 1 buses (for Central Zone). For future years, bus prices are estimated by assuming the same basis differential as the historical year.

Figure A-110: Net Revenues for Nuclear Plants

Figure A-110 shows the net revenues and the US-average operating costs for the nuclear units from 2017 to 2022. 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.[386]

- 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 2018.[387]

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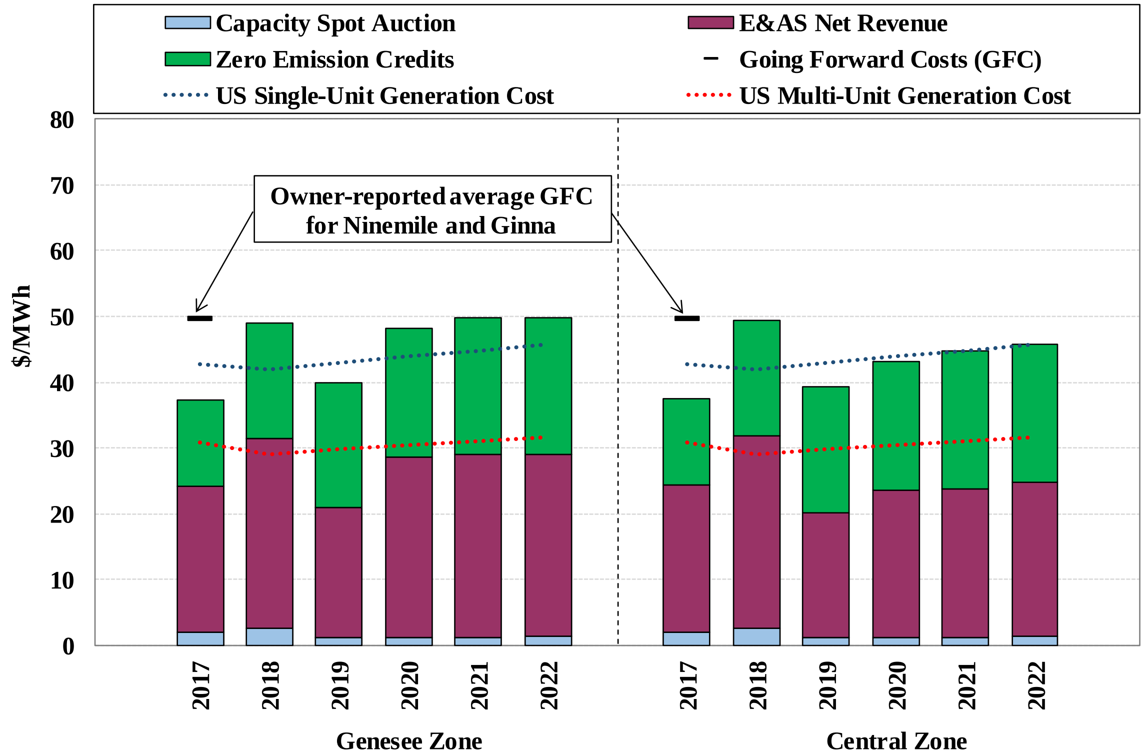
385 See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

386 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.

387 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See https://www.nei.org/CorporateSite/media/filefolder/resources/fact-sheets/nuclear-by-the-numbers.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.

- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[388] The ZEC price was $17.54/MWh for compliance year 2017 (April 2017 to March 2018) and $17.48/MWh for compliance year 2018. ZEC prices are estimated at $19.59 for compliance years 2019 and 2020 (April 2019 through March 2021) and $21.38/MWh beginning in April 2022.

Figure A-110: Net Revenue of Existing Nuclear Units
2017-2022



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 2017 to 2018 due to high energy prices and higher ZEC revenues, [389] and decreased substantially from 2018 to 2019, tracking movements in energy prices. The energy futures prices suggest that the net revenue of nuclear plants from NYISO-administered markets over the next three years are expected to exceed 2019 levels due to higher energy prices and slightly higher ZEC prices.

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388 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.

389 The upstate nuclear units received ZEC revenues only for nine months in 2017 (April through December).

- *Incentives for Existing Nuclear Plants* – The estimated total net revenues of nuclear plants were below the U.S. single-unit average generation costs in 2019 due to low energy prices at upstate plant locations. In future years, total net revenues are estimated to be marginally at or above the average cost of single unit plants, due in large part to ZEC revenues. ZEC revenues accounted for approximately 48 percent of the total revenues earned in 2019.
    - 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-110. 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) to be only marginally economic.

C. 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, and Long Island zones, and to offshore wind plants interconnecting in the Long Island zone and Gowanus 345 kV bus in New York City.[390] For onshore wind units in the Central zone, we calculated the net E&AS revenues using the capacity-weighted average of LBMPs at major wind installations in the zone.[391] For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-21 and Figure A-111: Costs, Performance Parameters, and Net Revenues 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.[392]
- 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

390 Nearly 2.9 GW of offshore wind projects in the interconnection queue is proposing to interconnect at the Gowanus 345kV substation.

391 We considered only the wind units whose nameplate capacity is larger than 100 MW.

392 The assumed capacity factors for solar PV, Onshore and Offshore wind units are sourced from NREL's Annual Technology Baseline, 2019 available at : https://atb.nrel.gov/electricity/2018/index.html

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 2020 NYISO Installed Capacity Manual.[393]

- We estimated the value of Renewable Energy Credits ("RECs") produced by utility-scale solar PV and onshore wind units using annual Tier 1 REC sale prices published by NYSERDA for the years 2017 through 2020. Future REC prices are derived by inflating the 2020 Tier 1 REC sale price.[394] Offshore REC (OREC) prices were derived from the Index OREC values and calculation methodology in NYSERDA's public purchase and sale agreements with projected selected in its 2018 offshore wind solicitation.[395]

- 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 a fraction of a unit's eligible investment costs depending on the resource type, 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.[396] We

393 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 https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

394 For more information on the recent RES Tier 1 REC procurements, see https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/REC-and-ZEC-Purchasers/2020-Compliance-Year. The Tier 1 REC sale price for LSEs to satisfy Renewable Energy Standard (RES) requirements by purchasing RECs from NYSERDA for the 2020 Compliance Year is $22.09/MWh.

395 See Appendix A and B of NYSERDA's October 2019 "Launching New York's Offshore Wind Industry: Phase I Report", https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-procurement-report.pdf

396 For solar PV, the ITC is 30 percent of the eligible investment costs for projects that commence construction by end of 2019. It will step down to 26 percent for projects starting construction in 2020 and 22 percent for projects starting construction in 2021. As per IRS guidelines, solar PV developers in most circumstances can safe harbor their investments for a maximum of four calendar years and receive ITC. For example, a project that commences construction in 2019 and comes online in 2023, will be considered to satisfy the continuity Safe Harbor, and thus will receive the full 30 percent ITC, see https://www.irs.gov/pub/irs-drop/n-18-59.pdf. Consequently, we assumed 30 percent ITC for solar PV in our analysis.

For offshore wind, the ITC is 30 percent of the eligible investment costs for projects that commence construction by end of 2016. It will reduce to 24 percent for projects starting construction in 2017, 18 percent for projects starting construction in 2018, 12 percent for projects starting construction in 2019, and 18 percent for projects starting construction in 2020, after which the ITC will reduce to zero. Consequently, considering the safe harbor provisions, we assumed 30 percent ITC for units coming online between 2017 and 2020, 24 percent for unit coming online in 2021, and 18 percent for unit coming online in 2022.

The Production Tax Credit is also scheduled to step down by 20 percent each year starting 2017 i.e., wind facilities commencing construction in 2017 will receive 80 percent PTC, commencing construction in 2018 will receive 60 percent PTC, and commencing construction in 2019 will receive 40 percent PTC. However, like solar PV, developers of onshore wind can safe harbor their investments for a maximum of four calendar years and receive PTC. Thus, we assume 60 percent PTC for a unit coming online in 2022, 80 incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[397]

The cost of developing new renewable units, particularly offshore wind and solar PV, 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-21 shows cost estimates for solar PV, onshore wind and offshore wind units we used for a unit that commence operations in 2019. The data shown are largely based on NREL's 2019 Annual Technology Baseline.[398] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units. The CONE for renewable units was calculated using the financing parameters and tax rates specified in the most recent ICAP demand curve reset study.

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percent PTC for a unit coming online in 2021, and 100 percent PTC for units coming online before 2021. 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.

397 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.

398 See NREL, 2019, *Annual Technology Baseline and Standard Scenarios*, https://atb.nrel.gov/electricity/2019/index.html

The assumed investment costs and fixed O&M costs for solar PV, onshore wind and offshore wind are based on the 2019 NREL ATB (Mid) values. 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 onshore wind units, we used capex values corresponding to TRG-5 in Central and LI zones. For offshore wind, capex values correspond to TRG-2 for the Long island zone. CONE calculation for offshore wind in NYC assumes zero city tax rate, and the property tax payments for the project is estimated using the same approach as utilized in the DCR process for the reference unit in the upstate zones i.e., annual property tax payment = 0.75% of capital cost.

For 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 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Regional multiplier for solar PV was utilized from ReEDS input data used for the 2019 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.

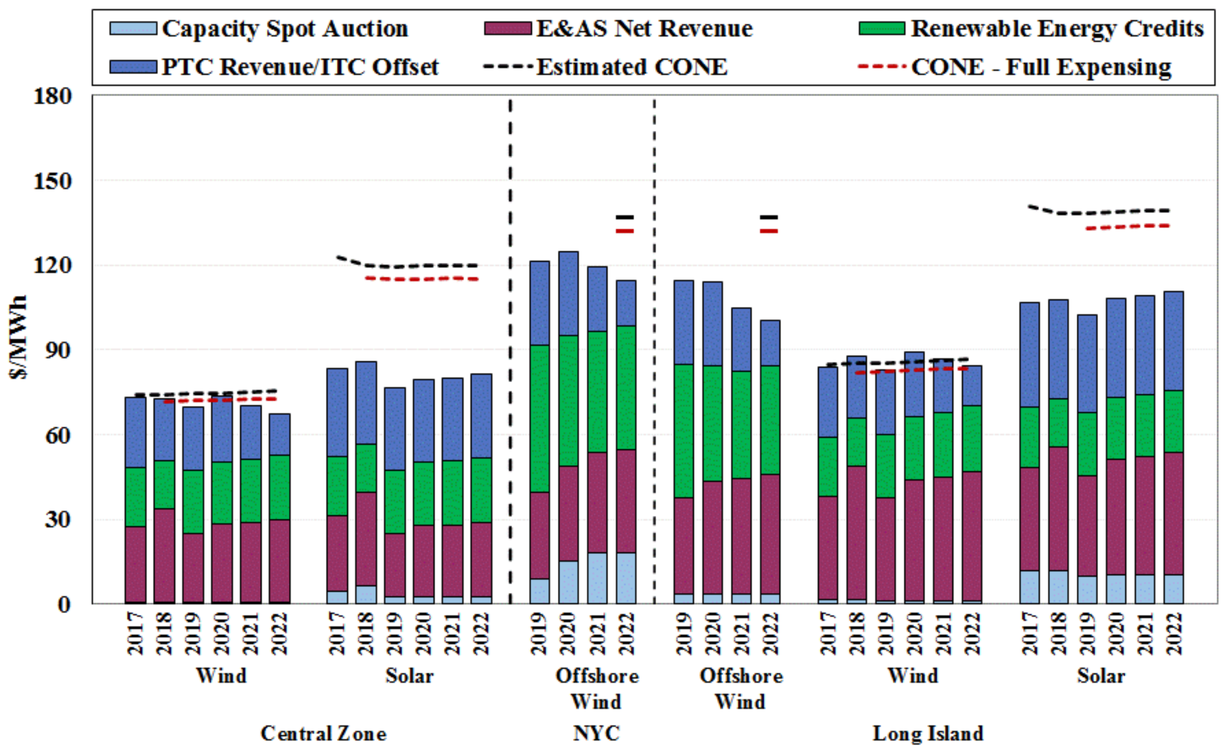
The assumed investment cost trajectory over the years for onshore wind and solar PV units was assumed to follow the technology-specific CapEx trajectory specified in the 2019 NREL ATB.

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, onshore wind, and offshore wind the interconnection cost of $18/kW, $22/kW, and $240/kW respectively were sourced from NREL ATB 2019. 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.

Table A-21: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2019$/kW AC basis)	*Upstate NY*: $1458 *Long Island*: $1897	*Upstate NY*: $1767 *Long Island*: $2384	*NYC/Long Island* : $4571
Fixed O&M (2019$/kW-yr)	$18	$50	$127
Federal Incentives	ITC	PTC	ITC
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	Upstate NY: 16.4% LI: 17.9%	Upstate NY: 36.0% LI: 40.0%	NYC/LI: 45.9%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 10% Winter: 30%	Summer: 38% Winter: 38%
Renewable Energy Credits (Nominal $/MWh)	*Onshore Wind and Solar PV:* ***2020*** - $22.09 ***2019*** - $22.43 ***2018*** - $17.01 ***2017*** - $21.16 *Offshore Wind:* Calculated using Offshore Wind Solicitation Round 1 Indexed REC strike price of $88/MWh NYC / $96/MWh LI (2018$) less energy and capacity prices.		

Figure A-111: Net Revenues of Solar, Onshore Wind and Offshore Wind Units
2017-2022



Assuming the operating and cost parameters shown in the table above, Figure A-111 shows the net revenues and the estimated CONE for each of the units during years 2017-2022. 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.

Key Observations: Net Revenues of New Utility-Scale Solar PV, Onshore Wind, and Offshore Wind Plants

- *Net Revenues from NYISO Markets* – Renewable resources have relatively low capacity value, so energy market revenues constitute a large majority of the revenues these units receive from the NYISO markets. Energy prices declined in 2019 relative to 2018, putting downward pressure on the estimated net revenues of renewables. Forward prices suggest a slight increase in the net revenues is expected from 2020-2022 relative to 2019.

- *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 contributions of state and federal programs to the 2019 net revenues range from 56 percent to 67 percent for a new solar PV project and 55 percent to 64 percent for a new onshore wind project.
  - As with the new gas-fired units, the TCJA could also benefit renewable energy projects by lowering their CONE. However, as shown in the Figure A-111, 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.
  - Long-term contracted revenues through state and federal programs may serve as an additional incentive for renewable projects by reducing their risk profile and cost of capital.[399] The New York State Public Service Commission issued an order in January 2020 requiring NYSERDA to offer an Index REC option in future solicitations for large-scale renewables. The REC payments under the Index RECs option would vary inversely with NYISO energy and capacity market prices.[400] Such a contract structure would embed a hedge against wholesale energy and capacity prices, thus reducing the risks and financing costs for asset owners.

- *Incentives for Onshore Wind Units* – The estimated net revenues of the generic onshore wind units are close to the estimated CONE values in 2018 through 2022.[401] The difference between net revenues and CONE is expected to widen slightly in the coming

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399 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, offshore wind, and solar PV units by roughly 10, 13, and 14 percent, respectively.

400 See Commission Order Modifying Tier 1 Renewable Procurements issued January 16, 2020, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1F9CA0EB-3968-41DB-BBE0-C251A3FE52DE}

401 Over 1,200 MW of wind projects in West and Central zones were awarded REC contracts as part of NYSERDA's 2017, 2018 and 2019 Renewable Energy Standard Solicitations. See https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts

years, as declining value of the PTC offsets slightly higher forward energy prices unless REC contracts increase in value significantly. The returns from individual projects would depend on several additional factors such as REC prices and procurement targets, resource potential at the project sites, curtailment risk, and future cost declines.

- *Incentives for Utility-scale Solar PV Units* – Estimated net revenues of the generic solar project are significantly lower than the annualized CONE in any of the years studied. Solar project costs, based on the most recent NREL 2019 ATB mid case estimates, are expected to remain relatively flat in nominal terms over the next several years.[402] Despite the calculated shortfall of net revenues relative to CONE, many solar projects continue to advance in the interconnection queue and Class Year process. Individual projects may benefit from advantages due to favorable sites or interconnection points, stockpiled materials and other cost-reducing measures, or favorable contracts.[403]

- *Incentives for Offshore Wind Units* – Net revenues of offshore wind are estimated to be insufficient to recover CONE in the years analyzed. However, costs of developing offshore wind are expected to decline for projects with in-service dates in the mid-2020s, when currently contracted projects are expected to enter service.
  - Offshore wind plants have relatively high capacity factors and capacity value. Consequently, NYISO market revenues of offshore wind plants are the highest on a $/kW-year basis among renewables we studied.
  - Offshore RECs (ORECs) also constitute a large share of offshore wind plant revenues, contributing 43 percent of estimated net revenues in 2019.[404] Furthermore, the Index OREC contract structure could support the project developers by reducing merchant energy and capacity price exposure, thus lowering the cost of capital to the developer.

402 See, *CAPEX historical trends, current estimates, and future projection for utility PV(DC)* figure for capital cost projections under the Utility-Scale PV section of the NREL Annual Technology Baseline 2019 website, available at: https://atb.nrel.gov/electricity/2019/index.html?t=su. Also, NREL reports a 0.4% increase in the cost benchmark for 2018 installations over 2017 installations. See, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018*, available at: https://www.nrel.gov/docs/fy19osti/72133.pdf.

403 Large amounts of solar projects have been selected in NYSERDA's bid-based Large-Scale Renewable solicitations and are proceeding in the Class Year 2019 process. We expect that the vast majority of solar projects entering service during the next several years will benefit from long-term contracts to sell RECs to NYSERDA or another state entity – hence, it is likely that financing costs incurred by project developers reflect the large share of federal and state incentives in total project revenues, as discussed above.

404 ORECs produced by the Empire Wind project will be purchased by NYSERDA at a strike price of $99.08 during the first in-service year (estimated at $88/MWh in 2019 dollars assuming a planned 2025 in-service date), less weighted average NYISO energy prices in Zones J and K and weighted average NYISO capacity prices in zones G, H, I, J and K. See Appendix A of NYSERDA's October 2019 "Launching New York's Offshore Wind Industry: Phase I Report", https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-procurement-report.pdf

D. Energy & Ancillary Services Pricing Enhancements Impacts on Investment Signals

Section XI 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 help direct investment to the most valuable resources and locations. In this subsection, we illustrate the impacts of implementing a subset of our real-time market recommendations on: (a) the mix of energy and capacity market revenues, and (b) the long-term investment signals of various resource types in several Zone J and Zone K locations. We modeled the net revenue impact of four different enhancements to real-time pricing in the context of New York City and two others in the context of Long Island.

We estimated the impact of the following four enhancements affecting New York City by adjusting the 2017-2019 energy and reserve prices:

- Compensate operating reserve units that provide congestion relief ("2016-1") – We estimated the increase in 10-minute reserve prices at locations where 10-minute reserve providers can help relieve N-1 transmission congestion.[405]
- Model local reserve requirements in New York City load pockets ("2017-1") – We estimated the impact of this recommendation by increasing the DA energy and reserve prices by an amount equal to the BPCG per MW-day of the UOL for DARU and LRR-committed units.[406, 407]
- Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules ("2017-2") – We estimated the net revenue impact assuming an additional $8.2/kW-year of net revenue from reserve shortages in southeast New York.[408]
- Model incentive payments to the units having the capability of instantaneously switching over from gas to oil fuel supply – We model this benefit by estimating the impact on LBMPs that would be paid to generators that would remain online and available one minute after a sudden loss of gas supply if such a product was cleared considering the incremental marginal cost of steam units burning a blend of oil and gas for reliability.

We modeled the impact of the following three enhancements affecting Long Island by adjusting 2018 and 2019 energy and reserve prices:

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405 See Section V of the report.

406 See Section V of the Appendix.

407 The estimated price adder for each day was applied to LBMPs and reserve prices in Hour 16.

408 We note that this corresponds to 1.25 hours of shortage per year times the ISO-NE PFP rate of $5,545/MWh plus its $1,000/MWh reserve demand curve for 30-minute operating reserves. However, the actual level of additional shortage pricing would like include more hours at lower average price levels.

- Set day-ahead and real-time clearing prices considering reserve constraints for Long Island ("2019-1") – We estimated the price adders/discounts for the Long Island reserve products (relative to SENY prices) as the shadow price on the Long Island reserve requirements that are consistent with current NYISO procurements.

- Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions ("2018-1") – We estimated the price impacts from explicitly modeling constraints on the 69 kV network and transient voltage recovery ("TVR") needs in Long Island by increasing prices at constrained locations. We estimated LBMP price adders such that the adjusted LBMPs are no lower than the marginal cost of the unit committed through out-of-merit actions.

- Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules ("2017-2") – We estimated the net revenue impact assuming an additional $8.2/kW-year of net revenue from reserve shortages in southeast New York and Long Island.[409]

Table A-22: Assumptions for Operating Characteristics of Repowered Combined Cycle and Grid-scale Storage Units

The technologies we considered for this analysis and their assumed operating characteristics are as follows:[410]

- New Frame CT (7HA.02), Existing GT-30, and Existing ST Units – The operating characteristics and CONE/ GFCs for these units are identical to the assumptions we made in Subsections A.[411]

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409 We note that this corresponds to 1.25 hours of shortage per year times the ISO-NE PFP rate of $5,545/MWh plus its $1,000/MWh reserve demand curve for 30-minute operating reserves. However, the actual level of additional shortage pricing would like include more hours at lower average price levels.

410 The CONE/ GFCs estimates for new technologies correspond to units that would be able to commence operations in 2019.

411 We assumed that the demand curve unit is the 7HA.02 Frame unit for the purpose of this analysis. Also, we assumed for this analysis that the 7HA.02 unit would be able to offer its full capacity for reserve commitment.

Table A-22: Operating Parameters and CONE of Storage Unit[412]

Characteristics	Storage
Gross CONE (2020$/kW-yr)	$260
Technology	Li-ion Battery
Service Life (Years)	20
Withdrawal (4 Hrs)	Lowest priced hours each day
Injection (4 Hrs)	Highest priced hours each day
Reserve Selling Capability	10-min spin
Roundtrip Efficiency	85%
EFORd	2%
Capacity Value	90%

- Grid-scale Storage – We studied a grid-scale storage unit with a power rating of one MW and four hours of energy storage capacity. The unit's injections and withdrawals are optimized over 24-hour period in the day ahead market. The costs and operating characteristics of this unit are summarized above in Table A-22.

Figure A-112: Impacts of Real Time Pricing Enhancements on Net Revenues of NYC Demand Curve unit under Long-term Equilibrium Conditions

In addition to improving the efficiency of energy and reserve prices, implementing real time market enhancements could also shift payments from capacity to energy markets. Under long-term equilibrium conditions, an increase in the E&AS revenues of the demand curve unit would translate into reduced capacity prices for all resources operating in the market.

To determine the impact on Annual ICAP Reference Value, we estimated net CONE of the Frame unit under two scenarios with the system at the tariff-prescribed Level of Excess conditions modeled in the ICAP demand curve reset.[413] Figure A-112 shows the incremental impact of each recommendation on the change in net revenues of the Frame unit under the long-term equilibrium conditions. The figure also shows the total increase in the Frame unit's net revenues, which would result in an equivalent decrease in the Net CONE that is used for determining the ICAP Demand Curve.

412 Cost assumptions are sourced from the ongoing 2019/20 NYISO ICAP Demand Curve Reset study. See, ICAP WG presentation *NYISO ICAP Demand Curve Reset: Updates to Gross CONE Inputs* by B&M on 26th March, 2020, available at : https://www.nyiso.com/documents/20142/11554944/Final%20BMcD%20DCR%20ICAPWG%200326202 0.pdf/5e44b033-ef0a-4b17-b140-946eb4b25a56 .

413 We estimated the energy prices under the long-term equilibrium conditions by applying to LBMPs and reserve prices the Level of Excess-Adjustment Factors that are used in the annual updates to ICAP demand curve parameters. See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

Figure A-112: Impact of Price Enhancements on Net Revenues of NYC Demand Curve
At Level of Excess Conditions

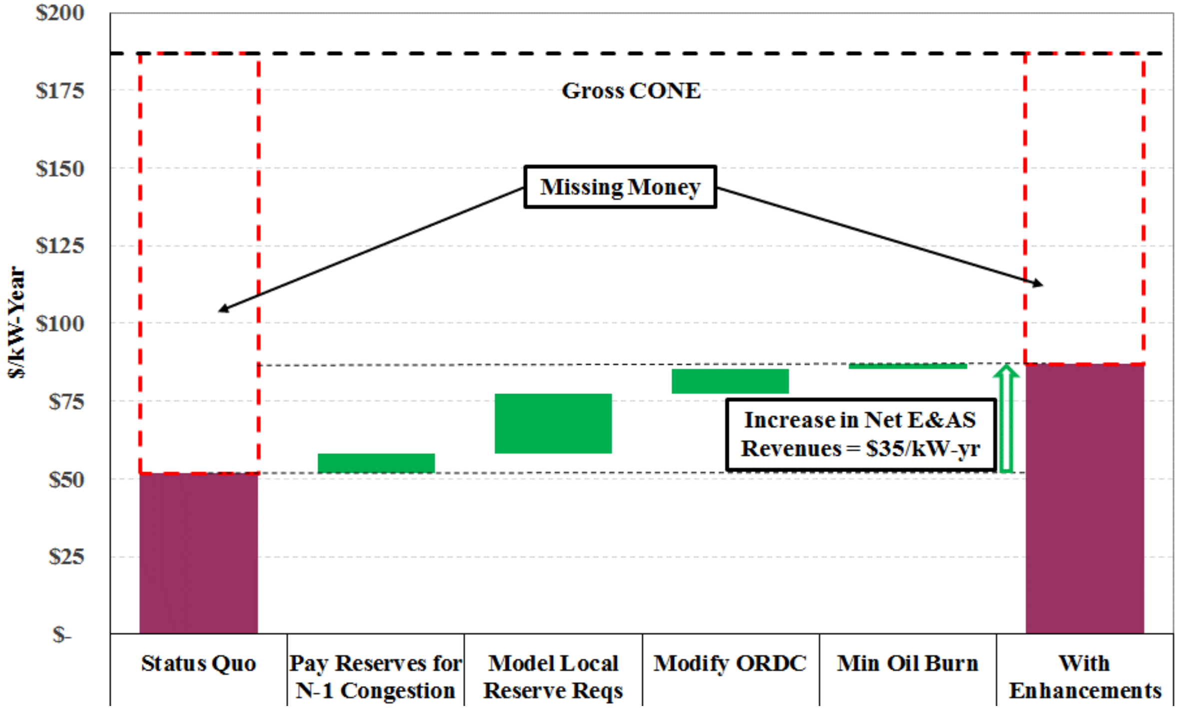

Figure A-113 to Figure A-116: Impacts of Real Time Pricing Enhancements on New York City Net Revenues

Figure A-113 through Figure A-116 show the energy and capacity revenues for each resource type before ("Base") and after the implementation of real time pricing enhancements ("wRecs"), 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 figures also shows the shortfall in net revenues relative to the CONE/ GFC for each technology.

Capacity revenues in each case reflect prices at the Default Net CONE, which is calculated as 75 percent of the net CONE of the Demand Curve unit. The Default Net CONE is the price that corresponds to the "Part A test threshold". New entrants would be exempted from Buyer-Side Mitigation ("BSM") under the Part A test criteria if the capacity surplus is lower than a certain threshold ("Part A threshold"). The NYISO recently proposed Tariff provisions which will allow Public Policy Resources ("PPRs") to be tested under the Part A test ahead of non-PPR entrants.[414] Hence, the NYISO's proposed rules would enable PPRs to avoid mitigation as long as sufficient quantity of existing capacity exits the market. Therefore, the economics of new and existing units at the Part A threshold are highly relevant for facilitating the entry of PPRs.

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414 See NYISO "Comprehensive Mitigation Review: Revisions to part A Exemption Test", presented March 18, 2020, at https://www.nyiso.com/documents/20142/11387339/Revisions%20to%20Part%20A%20Exemption%20Test.pdf/ecc014ae-96ed-8150-7cfb-d0f183aceeda

Figure A-113: Impact of Pricing Enhancements on Net Revenues - New York City
At Part A Threshold

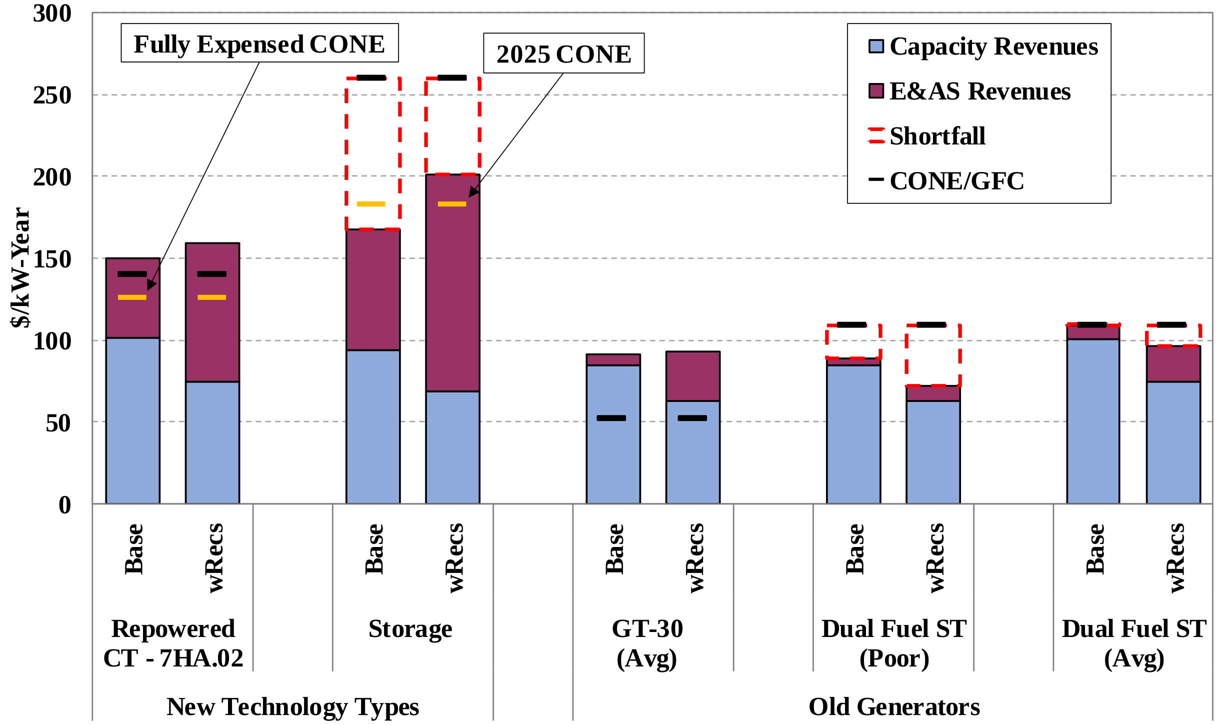


Figure A-114: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #1
At Part A Threshold

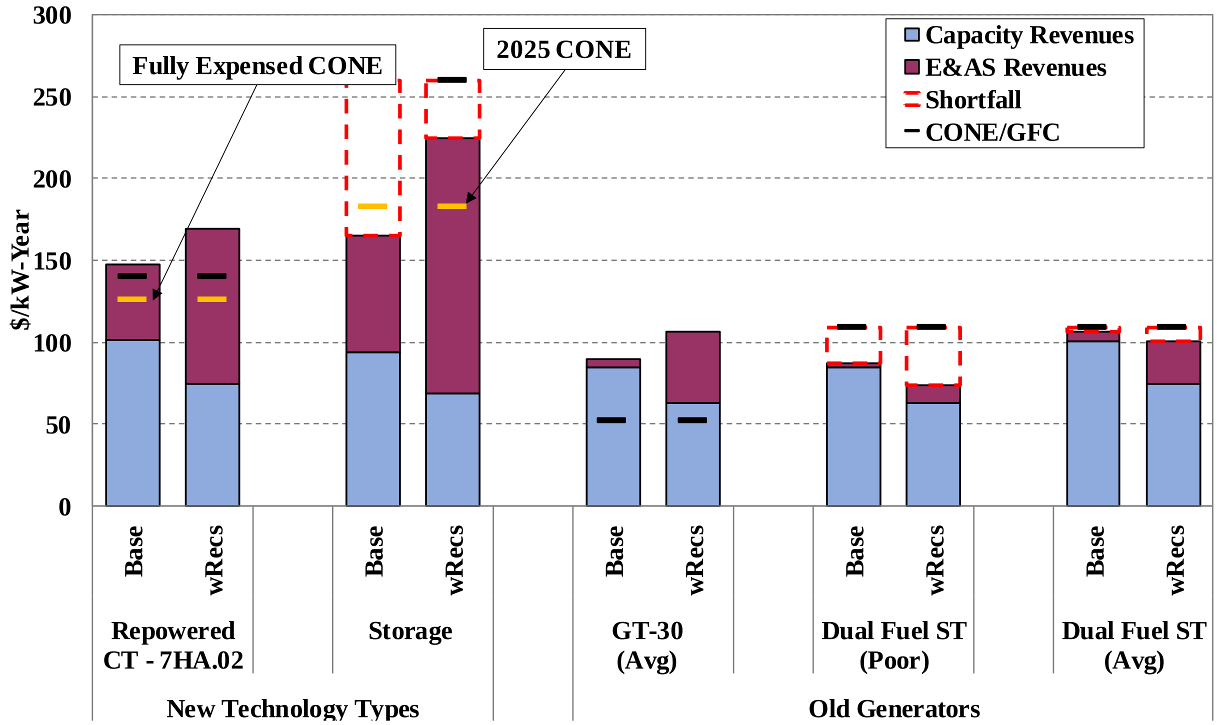


Figure A-115: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #2
At Part A Threshold

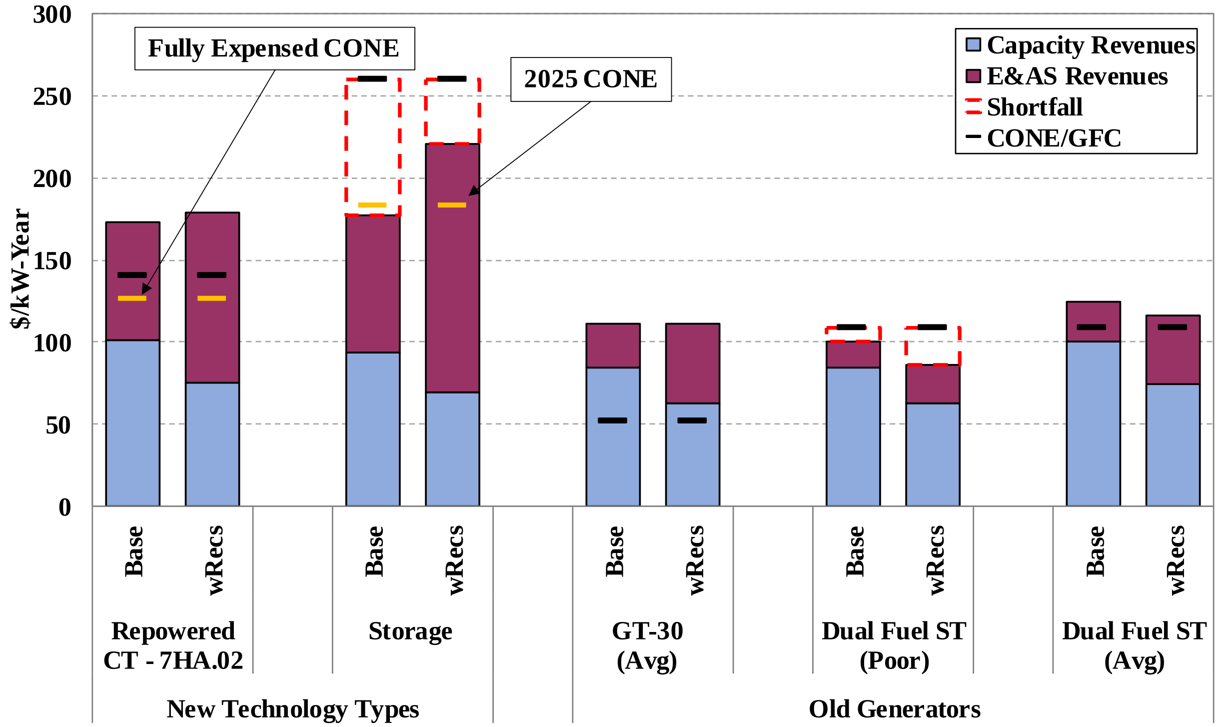


Figure A-116: Impact of Pricing Enhancements on Net Revenues – NYC 345 kV
At Part A Threshold

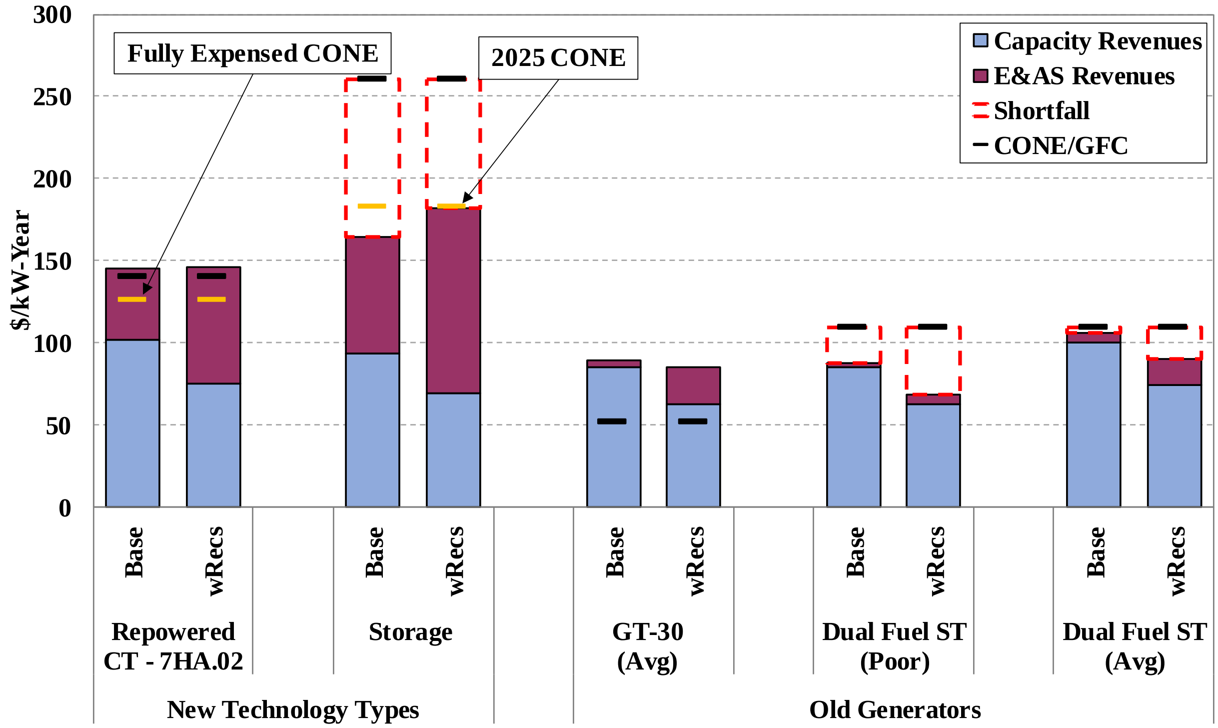


Figure A-117: Impacts of Real Time Pricing Enhancements on Net Revenues of Long Island Demand Curve unit under Long-term Equilibrium Conditions

The proposed enhancements impacting Long Island, could shift payments from the capacity to energy markets by increasing E&AS revenues of the demand curve unit. Figure A-117 shows the incremental impact of each of the two recommendations on the change in E&AS revenues of the Frame unit in Long Island under long-term equilibrium conditions. The figure also shows the total increase in the Frame unit's net revenues, which would result in an equivalent decrease in the net CONE that is used for determining the ICAP Demand Curve for Zone K.

Figure A-117: Impact of Price Enhancements on Net Revenues of Zone K Demand Curve
At Level of Excess Conditions

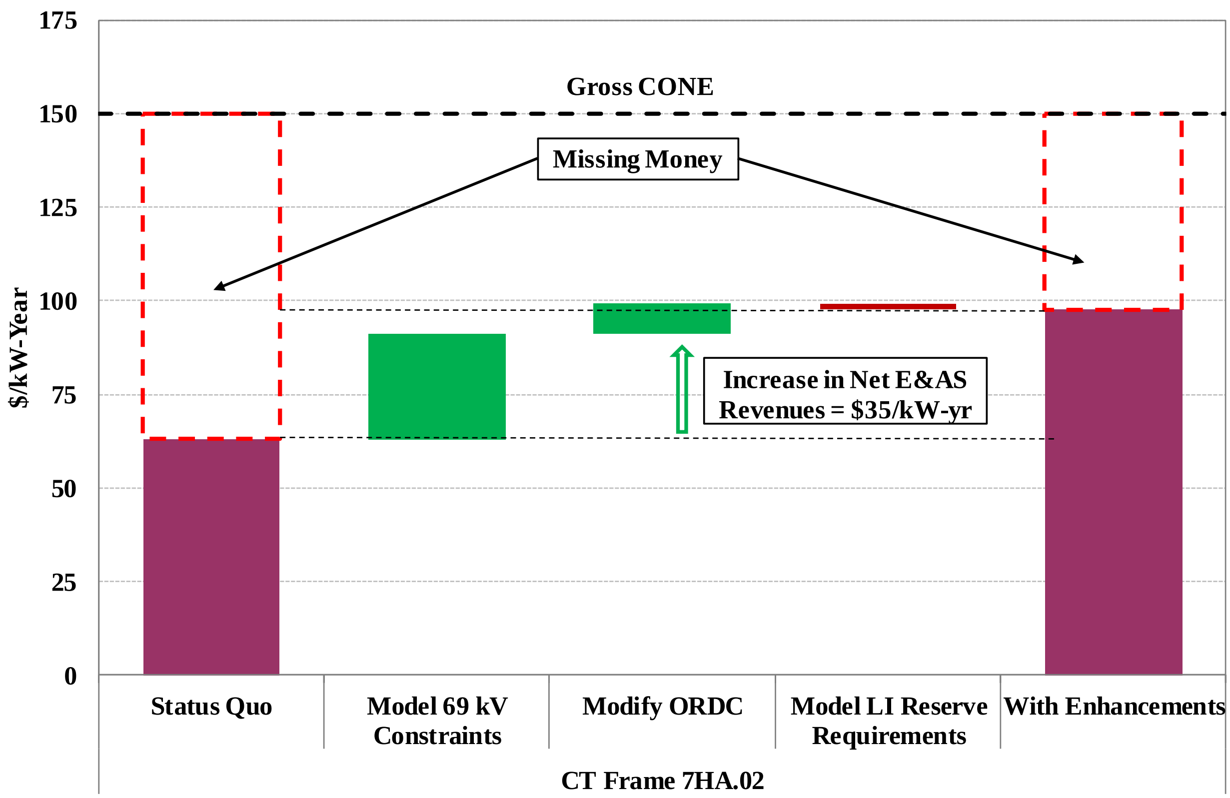
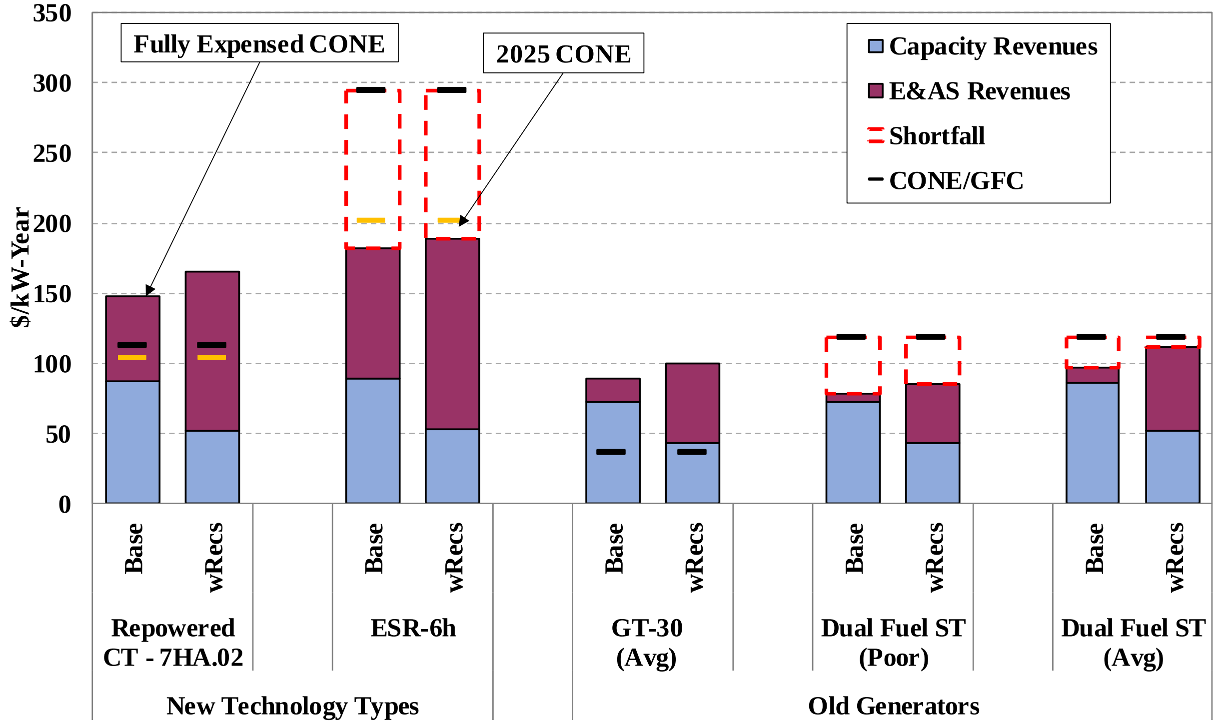


Figure A- 118: Impacts of Real Time Pricing Enhancements on Net Revenues

Figure A- 118 shows the E&AS and capacity revenues for each resource type before ("Base") and after the implementation of Long Island transmission constraint and reserve modeling enhancements ("wRecs"), in the East of Northport location. The figure also shows the shortfall in net revenues relative to the CONE/ GFC for each technology. Capacity revenues in each case reflect prices at the Level of Excess ("LOE") conditions. Base case energy and ancillary services revenues are estimated using historical pricing data from 2018 and 2019, and the LOE adjustment factors from the most recent ICAP Demand Curve reset study.

Figure A- 118: Impact of Price Enhancements on Net Revenue – East of Northport Pocket
At Level of Excess Conditions



Key Observations: Impacts of Real Time Pricing Enhancements on Net Revenues

- *Impact on Capacity Prices in New York City* – The results indicate that the E&AS revenues of the Frame unit under long-term equilibrium conditions would increase by $35/kW-year as a result of implementing the pricing recommendations. This would reduce the Annual Reference Value (i.e. net CONE for the demand curve unit) by an equivalent amount, and would result in reduced capacity payments to all resources.
  - 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 54 percent increase in the E&AS revenues for the demand curve unit.
- *Incentives for Resources at Representative New York City Node* – At the surplus level of the Part A threshold, our simulations for resources at the representative New York City node indicate that E&AS pricing enhancements are likely to improve the net revenues of newer, more flexible units (Figure A-113). In contrast, the economics of older existing units are likely to become less attractive.
  - Net E&AS services revenues for battery storage units increase significantly, due to their ability to monetize the increases in 10-minute spinning reserve prices and energy prices during high-load hours. The increase in E&AS revenues of these units is greater than the drop in their capacity revenues.
  - Under status quo conditions, the repowered Frame unit may earn revenues that would be marginally sufficient to cover its Gross CONE. The results suggest that

implementing the recommended changes is likely to increase the net revenues to a level that could further result in profitable repowering of some existing units.

- 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. Higher energy and ancillary services revenues for GT-30 units would be offset by lower capacity prices, while ST units would receive lower capacity revenues, and lower total net revenues.[416]

- *Incentives for Investment in other New York City Locations* – The effects of the pricing enhancements on the energy and reserve prices vary significantly by location. Accordingly, as shown in Figure A-114 through Figure A-116, there is substantial variation in the changes in net revenues of each resource by location.
  - The results for Load Pocket #1 and #2 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 poor performers, less decrease) in their revenues when compared to other locations. In particular, battery storage units in both load pockets see an increase in revenues that could be sufficient to incent economic entry on an unsubsidized basis (based on the projected costs in 2025). Additionally, the Frame unit in Load Pocket #1 is likely to see an increase in revenues which would significantly improve the economics of repowering in this location.
  - 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. Net revenues of steam turbines, particularly poor performer units with higher EFORds, are likely to decline significantly, thus increasing the economic pressure on these units.
  - 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.

- *Impact on Capacity Prices on Long Island* – The results indicate that the E&AS revenues of the Frame unit under long-term equilibrium conditions would increase by $35/kW-year as a result of implementing the pricing recommendations. This would reduce the Annual Reference Value (i.e. net CONE for the demand curve unit) by an equivalent amount, and would result in reduced capacity payments to all resources.

[416] For poor performing ST units, we assumed an EFORd of 20 percent. For average performing GT-30 and ST units, we assumed an EFORd of 20 and 5 percent, respectively.

- Our recommendation of modeling transmission constraints on the 69 kV network that are currently managed by OOM actions (i.e. 2018-1) accounted for all of the increase in the E&AS revenues for the demand curve unit.
- Modeling day-ahead and real-time reserve requirements for Long Island (2019-1) had a small negative impact on the E&AS revenues of the demand curve unit. This is because Long Island currently has a surplus of units capable of providing reserves relative to its requirements, but may provide only 270-540 MW to the SENY reserve requirements. Hence, the marginal value of reserve providers in Long Island is slightly lower than in other locations in SENY.

- *Incentives for Resources in the East of Northport Pocket* – Our results indicate that modeling transmission constraints and reserve requirements on Long Island results in higher net E&AS revenues for units (by $19 to $45 per kW-year) located in the East of Northport region. This illustrates the value of our recommendations in improving the E&AS prices so that it reflects need for investments in locations where it is most valuable in managing congestion.
  - There is currently a large amount of capacity of PPRs in the NYISO interconnection queue that is seeking to interconnect in the four load pockets on Long Island.[417] Both the Fixed and Index OREC contract structures offered to offshore wind developers favor interconnection at locations with favorable LBMPs relative to the average for zones J and K. Hence, improving the alignment of pricing signals with the value of generation at each location in managing congestion will help developers make more efficient decisions regarding the siting of PPRs.
  - Net revenues of a Frame unit increased significantly when the recommendations were included. However, the total revenues of battery storage increased by a lower amount when the effects of recommendations were included. [418]
    - The increase in LBMPs due to modeling of 69 kV constraints often occur for an extended number of hours on a day. Hence, the energy arbitrage revenues of the storage unit increased by less than those of non-duration limited resources, which could operate during a larger share of congested hours. This suggests that batteries of greater duration are likely to benefit more (relative to lower duration batteries) from the E&AS enhancements that we modeled.

E. Impact of Price Enhancements on Existing Units and BSM Evaluations

The State of New York has aggressive goals for decarbonizing the electricity sector that it seeks to achieve by increasing the share of renewable and battery storage resources in the generation

417 See Figure A-56.

418 Results derived from historical OOM action data in load pockets indicate that increase in LBMPs due to modeling of 69 kV constraints often occur for long durations. As a result, energy margins of the storage unit with 4-hour discharge capability increased by less than those of non-duration limited resources, which could operate during a larger share of congested hours.

mix. The NYISO has proposed and is analyzing a number of market design changes that could enable meeting the state's goals in a cost-effective manner. In particular:

- The NYISO is performing several studies that would improve the efficiency of E&AS products' pricing. These initiatives include ancillary services shortage pricing, more granular operating reserves, reserves for resources flexibility, and fast start pricing. We evaluated the effects of four relevant MMU recommendations on the investment signals for various types of resources in subsection D.

- The NYISO evaluated a carbon pricing proposal, which would incorporate a Social Cost of Carbon value in the energy market.[419] In 2019, we evaluated the impact of carbon pricing in conjunction with other E&AS pricing enhancements on consumer benefits and investment signals for various types of resources.[420]

- The NYISO recently proposed enhancements to the Part A test of the BSM. The enhancements allow PPRs to be exempt from BSM on a priority basis (relative to non-PPRs) as long as the capacity surplus is below a certain threshold.[421]

Taken together, these proposals would could help achieve the state's goals in two ways:

- As discussed in subsection D, E&AS enhancements and carbon pricing can produce strong market signals by increasing the net revenues of flexible resources (e.g. ESRs) that would play a critical role in facilitating integration of intermittent generation.

- E&AS enhancements and carbon pricing would also reduce compensation for relatively inflexible and inefficient units among the existing resources, thus reducing the incentive for them to continue operating. This would facilitate an increased amount of Part A exemptions for PPRs under the recently developed BSM provisions.

The DEC's recent regulations are likely to lead to the retirement or repowering of a significant portion of peaking plant capacity in New York City, which is likely to enable entry of many PPRs in Class Year 2019. However, given the aggressive decarbonization targets, a considerable proportion of the in-city steam turbine capacity may need to exit the market to enable further entry of PPRs under the Part A test provisions. In this subsection, we discuss the impact of the proposed EAS enhancements on the incentives for existing steam turbines in New York City.

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419 See NYISO IPPTF Carbon Pricing Proposal, December 2018, at https://www.nyiso.com/documents/20142/2244202/IPPTF-Carbon-Pricing-Proposal.pdf/60889852-2eaf-6157-796f-0b73333847e8

420 See May 2019 MMU analysis of the Carbon Pricing Proposal impacts at https://www.nyiso.com/documents/20142/6474763/MMU+Study+re+Carbon+Pricing__5092019.pdf/40b832a6-b1f7-f973-9f60-4aaf4e9ab22f?version=1.0&t=1557161407651&download=true

421 See NYISO "Comprehensive Mitigation Review: Revisions to part A Exemption Test", presented March 18, 2020, at https://www.nyiso.com/documents/20142/11387339/Revisions%20to%20Part%20A%20Exemption%20Test.pdf/ecc014ae-96ed-8150-7cfb-d0f183aceeda

The existing steam turbines in New York City are relatively inflexible and inefficient units, and they tend to receive a majority of their revenues from the capacity market. As discussed in subsection D, the capacity market compensation to all resources is directly driven by the E&AS prices available to the demand curve unit. The in-city steam turbine units also receive a considerable portion of their revenues from OOM commitments that are required to satisfy local reliability needs. Hence, these units tend to receive higher levels of compensation when the markets do not adequately reflect the value of E&AS products to the power system. Inefficient E&AS prices are likely to result in retention of existing steam turbine capacity in New York City.

Figure A- 119: Impact of EAS Pricing Enhancements on Incentives for Steam Turbines in New York City

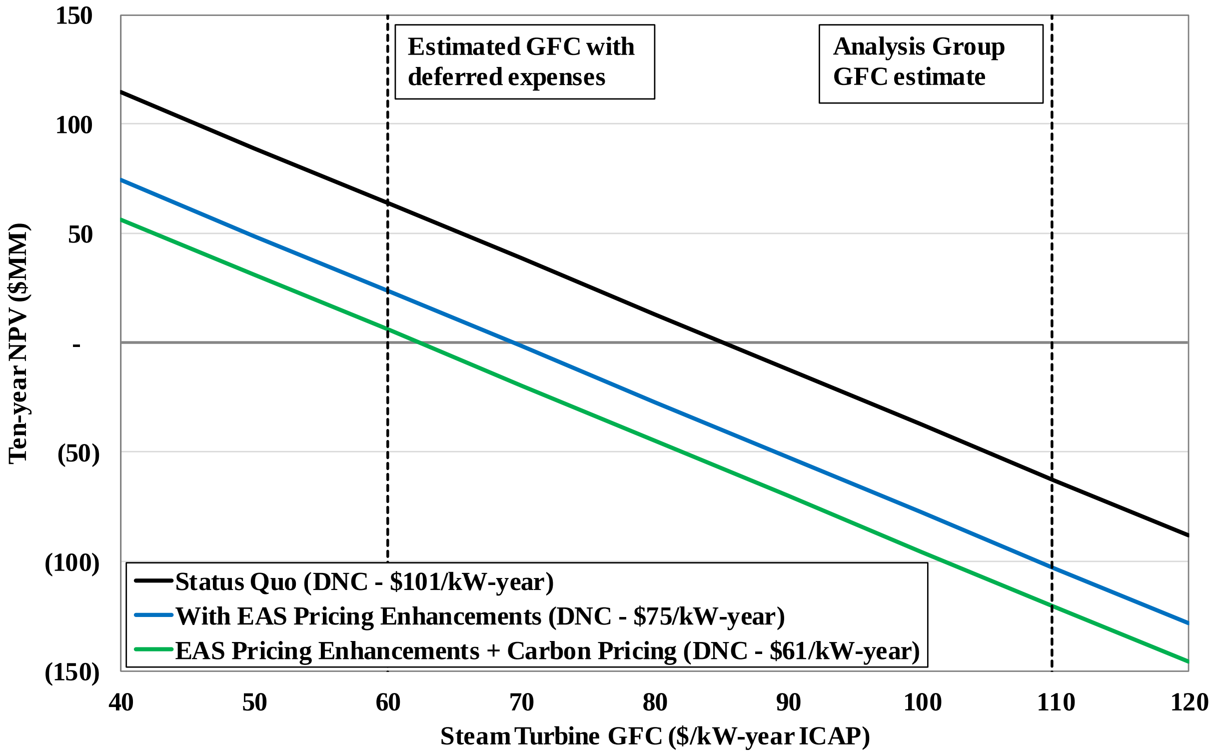
Figure A- 119 shows the estimated net present value ("NPV") of an existing poor-performing 350 MW steam turbine unit in New York City, as a function of its GFC. We estimate the unit's NPV under three scenarios: (a) status quo, (b) with E&AS pricing enhancements discussed in subsection D, and (c) with NYISO's carbon pricing proposal (in addition to (b)).

NPV is calculated as the discounted value of net revenues minus going-forward costs over a ten-year period. Revenues used to calculate NPV reflect market prices at Default Net CONE conditions in each scenario. Net revenues are estimated for a relatively poor-performing steam turbine unit, reflecting a unit most likely to be adversely affected by the proposed enhancements.

The figure shows a range of values for GFC due to the uncertainty in estimating the actual price level at which an existing unit owner would choose to retire or mothball. The actual GFC depends on several factors including the age and condition of the individual unit, existence of offtake agreements, the level of incremental capital and/ or maintenance expenditure required to continue operations, and the owner's expectations of future market prices. The two estimates of GFC shown include (a) estimated of GFC for older generators by Analysis Group, and (b) a lower GFC estimate that reflects the ability of units to defer incremental capital expenses.[422]

422 See Analysis Group's 2015 report "NYISO Capacity Market: Evaluation of Options"

Figure A- 119: Impact of Price Enhancements on Incentives for Steam Turbines in NYC
At Part A Threshold



<u>Key Observations – Impact of Pricing Enhancements on Incentives for Steam Turbines and BSM Evaluations</u>

- For any level of GFC, the NPV of existing steam turbines is significantly reduced under the E&AS pricing enhancements and carbon pricing scenarios, relative to status quo. For example, for a unit with a GFC of $80/kW-year, the estimated NPV would be $13 million under status quo, -$27 million in the EAS pricing enhancements scenario, and -$45 million in the carbon pricing scenario.[423]

- For much of the range of potential GFCs, the NPV is negative in the E&AS pricing enhancements and carbon pricing scenarios. As noted in subsection D, the economic pressure on steam units is likely to increase in these scenarios. However, retirement decisions depend on a number of unit-specific factors. Nonetheless, structural changes that keep revenues well below expenses would shorten the duration over which owners may willingly incur losses or defer expenses, and increase the likelihood of retirements.

- Retirement or CRIS transfer by existing steam unit would reduce capacity surpluses and increase the amount of PPR capacity that could receive a BSM exemption under the Part A test criteria. For instance, in a scenario where the capacity surplus is at the Part A

423 NPV is lower in the latter two scenarios because the reduction in capacity revenues more than offsets the increase in EAS revenues.

threshold, the retirement of a 350 MW steam unit could allow for entry of over 900 MW of offshore wind (ICAP), over 750 MW of solar PV (ICAP), or nearly 390 MW of 4-hour battery storage (ICAP). Furthermore, the capacity value of most renewable resources and battery storage resources will decrease at higher penetrations. Hence, retirements are likely to allow for entry of more capacity from PPRs as their penetration increases.

- The NYISO is currently considering a potential "available capacity transfer" mechanism to allow existing resources to retire and transfer their CRIS rights to new PPRs in exchange for compensation.[424] If a mechanism of this type is adopted, lower NPVs of existing units would reduce the opportunity costs of retiring for some generators.

[424] See NYISO February 6, 2020 "Comprehensive Mitigation Review" at https://www.nyiso.com/documents/20142/10718541/Comprehensive%20Mitigation%20Review.pdf/aefa8ce3-e3dc-994e-07e7-8feffc834cfc

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.[425]

- 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.[426]

- 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 (subject to a floor price) like any supply resource.[427] 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.

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

426 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.

427 The floor price was $75/MWh prior to November 2018. Since then it has been updated on a monthly basis to reflect the Monthly Net Benefits Floor per Order 745 compliance.

- Demand Side Ancillary Services Program ("DSASP") – This program allows Demand Side Resources to offer their load curtailment capability to provide regulation and 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 would be beneficial, although it is important that such a program provide efficient incentives to demand response resources.

The NYISO has been working on a series of market design projects that are intended to facilitate more active participation by consumers. These projects include:

- DER Participation Model – Scheduled for deployment in 2021 – This should allow individual large consumers and aggregations of consumers to participate more directly in the market, and this will better reflect duration limitations in their offers, payments, and obligations.

- Meter Service Entity for DER – Scheduled for deployment in 2021 – This should allow third party metering which could provide greater flexibility to consumers and retail load serving entities.

- Dual Participation – Scheduled for deployment in 2020 – This will allow resources to provide wholesale and retail market services.

This section evaluates the performance of the existing programs in 2019 in the following subsections: (a) reliability demand response programs, (b) economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions. Future reports will examine the performance of the programs that are currently under development.

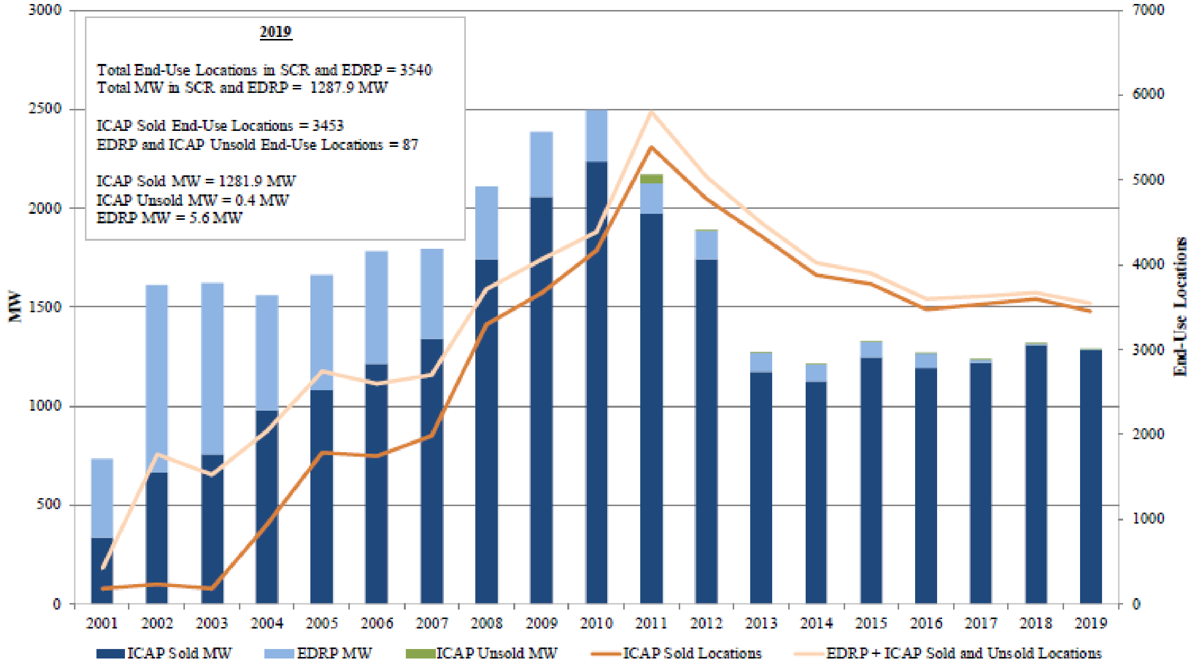
A. Reliability Demand Response Programs

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-120: Registration in NYISO Demand Response Reliability Programs

Figure A-120 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2019 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-120: Registration in NYISO Demand Response Reliability Programs [428]
2001 – 2019



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. Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. Load reductions scheduled in the day-ahead market obligate the resource to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead and the real-time price of energy.

The DSASP program was established in June 2008 to enable demand response resources to provide ancillary services. This program has the potential to increase the amount of resources that provide operating reserves and regulation services, which enhances competition, reduces costs, and improves reliability. Under this program, resources must qualify to provide operating reserves or regulation under the same requirements as generators, and they are paid the same market clearing prices as generators for the ancillary service products they provide. To the extent that DSASP resources increase or decrease consumption when deployed for regulation or reserves in the real-time, they settle the energy consumption with their load serving entity rather than with the NYISO. But they are eligible for a Day-Ahead Margin Assurance Payment (“DAMAP”) to make up for any balancing differences between their day-ahead operating reserves or regulation service schedule and real-time dispatch, subject to their performance for the scheduled service.

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428 This figure is excerpted from the compliance filing report to FERC: *NYISO 2019 Annual Report on Demand Response Programs*, January 14, 2020.

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.

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 very low 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 has the TDRP currently available in New York City. This program enables the local Transmission Owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. This prevents the local Transmission Owner from calling all of the EDRP and SCR resources in New York City to address local issues and avoids deploying substantial quantities of demand response that provide no reliability benefit but unnecessarily depress real-time prices and increase 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 enhanced 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.

<u>Key Observations: Demand Response Programs</u>

- In 2019, total registration in the EDRP and SCR programs included 3,540 end-use locations enrolled, providing a total of 1,288 MW of demand response capability.
    - SCR resources accounted for nearly 100 percent the total enrolled MWs in the reliability-based program in 2019. 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.

- o In the Summer 2019 Capability Period, market-cleared SCRs contributed to resource adequacy by satisfying:
  - 4.9 percent of the UCAP requirement for New York City;
  - 4.1 percent of the UCAP requirement for the G-J Locality;
  - 0.9 percent of the UCAP requirement for Long Island; and
  - 3.5 percent of the UCAP requirement for NYCA.

- No resources have participated in the DADRP program since December 2010.
  - o 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 actively participated in the market in 2019 as providers of operating reserves.
  - o On average, the three resources collectively provided more than 60 MW of 10-minute spinning reserves in 2019, satisfying nearly 10 percent of the NYCA 10-minute spinning reserve requirement.
- In 2019, the NYISO did not activate reliability demand response resources, therefore, the performance of DR calls is not evaluated in this report.
  - o However, DR resources in local Utility programs were activated on 15 days in 2019. The deployment exceeded 100 MW on five of these days .
    - Resources were activated for peak-shaving and distribution system security mostly in New York City. The statewide quantity ranged to nearly 600 MW on July 19 (when NYCA peak demand was roughly 30 GW).
    - Utility DR was activated on days when the economics of the energy market did not indicate a need for peak load reduction.
    - Utility DR resources are paid primarily for availability (including capacity). Utility programs often provide large payments (~$1,000/MWh) for peak-shaving when it is not cost-effective.
  - o Utility DR deployments are not currently considered in the market scheduling and pricing.
    - The capacity of utility-activated DR is not considered in day-ahead forecasts, which may lead to excessive reliability commitments.
    - Utility DR MW is not considered in the current scarcity pricing rules in the real-time market even though it may help avoid capacity deficiency.

– It would be beneficial for the NYISO to work with TOs to evaluate the feasibility of including Utility DR deployments in its market scheduling and pricing.